California Air Resources Board

Public Hearing to Consider Amendments to the Low Carbon Fuel Standard

Final Statement of Reasons for Rulemaking, Including Summary of Comments and Agency Response

Attachment 1.a - Table 1
45-Day Comments

Public Hearing Date: November 8, 2024
Agenda Item No.: 24-6-2

Comment Log Display

Here is the comment you selected to display.

Comment 1 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Board
Last Name	Clerk
Email Address	Non-web submitted comment
Affiliation	
Subject	EJAC Resolution on LCFS
Comment	Posted by CARB on behalf of the Environmental Justice Advisory Committee.
Attachment	www.arb.ca.gov/lists/com-attach/1-lcfs2024-VjMFaQNjUGABWFA0.pdf
Original File Name	EJAC DRAFT Low Carbon Fuel Standard Recommendations.pdf
Date and Time Comment Was Submitted	2024-01-05 16:19:01

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Assembly Bill 32 Environmental Justice Advisory Committee (EJAC)
DRAFT Recommendations to the California Air Resources Board (CARB) on the Low Carbon Fuel Standard Regulation Updates

Draft Version 2: August 28, 2023

Amended Language Highlighted Based on 8/25/2023 EJAC Discussion

At the August 25, 2023, EJAC meeting, the fourth item on the agenda is "Discussion on the Low Carbon Fuel Standard Panel and Provide EJAC Recommendations to CARB".

The draft EJAC resolution below supports the August 25th discussion in preparation for the joint EJAC/CARB Board meeting planned for September 14, 2023. EJAC recommendations are advisory in nature.

WHEREAS, the Low Carbon Fuel Standard (LCFS) has exacerbated and entrenched air, water, and odor pollution in communities most impacted by environmental injustices;

WHEREAS, The LCFS has worsened environmental injustice issues across the state, nation, and world by increasing and entrenching pollution on the frontlines of industrial agribusiness;

WHEREAS, California Air Resources Board (CARB) has the authority to regulate methane emissions from livestock as soon as January 1, 2024, pursuant to Health and Safety Code section 39730.7(b).

WHEREAS, the LCFS has exacerbated and entrenched harmful pollution in frontline oil refinery communities;

WHEREAS, the LCFS has exacerbated and entrenched harmful pollution from tailpipes by incentivizing combustion fuels;

WHEREAS, the LCFS has exacerbated and entrenched harmful pollution to global communities from deforestation and using food for fuels;

WHEREAS, the LCFS has exacerbated and entrenched harmful pollution in communities near and regions containing large dairies and other confined animal feeding operations by incentivizing the production, storage, and land application of wet manure;

WHEREAS, insofar as the LCFS reduces carbon emissions from the transportation sector, the provision of LCFS credits for carbon removal such as direct air capture eliminates the possibility of reducing commensurate carbon emissions and co-pollutant emissions from the transportation sector through the LCFS;

WHEREAS, insofar as CARB's goal for carbon removal is to be carbon negative, issuing LCFS credits for carbon removal such as direct air capture (DAC) ensures that it will not be carbon negative but rather offset continued burning of fossil fuels;

WHEREAS, the provision of LCFS credits for direct air capture harms frontline communities both directly with harms and risks from capturing and storing the carbon, and indirectly from displaced renewable deployment that could reduce emissions from fossil fuel power plants, as well as from foregone reductions in transportation sector emissions;

Therefore, be it resolved that the EJAC recommends that the CARB board direct staff to address the above risks, threats, and harms to environmental justice communities by incorporating the following changes, referenced throughout as the "Comprehensive EJ Scenario" into the Low Carbon Fuel Standard through the current rulemaking:

001.1
1. Conduct and incorporate a full life cycle assessment of all air pollution and greenhouse gas (GHG) emissions for all pathways, and their implications for environmental justice communities.
2. Conduct a full accounting of GHG and air pollution emissions associated with pathways relying on the production of fuel from livestock and dairy manure. 001.2
3. 001.3 Eliminate avoided methane credits effective January 1, 2024.
4. Eliminate credit generation for pathways relying on the production of fuel from livestock and dairy manure for emissions reductions that otherwise would have occurred or were legally or contractually required to occur. 001.4
5. 001.5 Cap the use of lipid biofuels at 2020 levels pending an updated risk assessment to determine phase out timelines for high-risk, crop-based feedstocks.
6. Prohibit enhanced oil recovery as an eligible sequestration method. 001.6
7. 001.7 Do not issue LCFS credits for carbon removal projects such as Direct Air Capture.
8. Consider the inclusion of intrastate jet fuel and marine fuels as a deficit generator and provide analysis of this option as part of the LCFS. 001.8

001.9 Be it further resolved that the EJAC recommends that CARB formally consider the Comprehensive EJ Scenario as a regulatory alternative in the LCFS rulemaking process.

Be it further resolved that the EJAC recommends that CARB reform the LCFS to strengthen the Low Carbon Fuel Standard's support for zero emission vehicles including mass transit vehicles, drayage duty trucks, and heavy duty trucks. 001.10

001.11 Be it further resolved that the EJAC recommends that CARB immediately initiate formal rulemaking for the regulation of livestock methane pursuant to Health and Safety Code section 39730.7(b).

Comment Log Display

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Comment 4 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mary
Last Name	Ames
Email Address	amesink@earthlink.net
Affiliation	
Subject	Bring the LCFS in Line with State Goals

Comment

Dear California Air Resources Board,

I am writing to point out what a lost opportunity it would be to adopt the proposed amendments to California's Low Carbon Fuel Standard, thereby continuing to subsidize the use of combustion fuels when the public is calling for zero-emission transportation systems and the earth is crying out for an end to carbon pollutior

Historically, every year, California has spent 80% of the Low Carbon Fuel Standard's three- to four-billion dollars on combustic technology. This money should be spent, instead, on non-combustior technologies, to speed the state's transition to a zero-emissions future.

002.1 California cannot meet its clean air and climate goals without bringing the Low Carbon Fuel Standard's several billion-dollar program in line with those goals.

I trust, therefore, that you will reject the proposed amendments and overhaul the program accordingly.

Thank you for your serious consideration of my comments.

Sincerely,
Mary Ames
30657 Sky Terrace Dr Temecula, CA 92592-3257

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-01-17 20:58:29

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Comment 5 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	paula
Last Name	levine
Email Address	paula-levine@sbcglobal.net
Affiliation	

Subject	Low Carbon Fuel Standard is the goal and a necessity

Comment

Dear California Air Resources Board,

I am a high risk asthmatic. This means that I read the quality oi the air daily, several times a day, in some circumstances, to determine the quality of the air in order to plan whether I am abl to exercise outside that day .

I am not alone. There are many like me in this city, country, world.

You have a role and responsibilities to further proposals that could impact me and the millions of others who have compromised breathing because of air quality. Subsiding and supporting combustible fuels is not a compatible strategy that will meet these goals for clear air.

003.1

Stick with the plan. Make air quality standards the priority at any and all turns.

Make wise and ecological decisions and stop wavering and thinking that it is something that can be negotiated. Breathing is not a negotiable issue.

Sincerely,
paula levine
SUSSEX St San Francisco, CA 94131

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-01-18 00:09:20

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Comment 6 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Yasser
Last Name	Jaber
Email Address	seagatesd@yahoo.com
Affiliation	Seagate Produce, Inc.
Subject	Proposed changes to LCFS

Comment

Please stop making it harder and harder to operate a business in California. Every year there is a new fee or in the case here, additional costs and less credits for doing the right things (e.g operating electric equipment at my facility).

I am opposed to reduction in number of credits generated by e-forklifts for the reasons below:

004.1

- Unlike other EVs, most forklifts do not have energy measurement devices, making this an additional expense in hardware as well as resources to implement
- The reduction of credit generation will make it difficult to finance implementation the required metering.
- I Recommend leaving the current credit generation or evaluating ways to temper the reduction
- These changes make it more difficult for smalle operations to participate as the cost of metering cannot be split across as many forklifts as larger operations
- Implementation of metering:

004.2

- More time needed for implementation: The time needed to evaluate appropriate solutions relative to specific flee (e.g. charger frequencies) and operating conditions (i.e. cold storage) and cost-effectiveness relative to estimated revenue.
- If more time is not allowed, there may be month or up to a year that we are not able to participate in this program, which is a dramatic change rather than the more typical phased-in approach used by CARB to avoid volatile impacts on businesses.

004.3

- Recommend extending estimation method for several quarters to give industry opportunity to adapt.

Regards,
Yasser Jaber

> Vice-President
> Seagate Produce, Inc.

Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-01-18 14:33:41

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 7 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Steven
Last Name	Schroeder
Email Address	stevenschroeder@att.net
Affiliation	
Subject	LCFS Pricing
Comment	What is CARB doing to support their mandates and make it financially possible for companies by increasing the price and demand for LCFS credits? It is clear you want cleaner air, but at current LCFS pricing it does not support this initiative. Something needs to be done fast this year to improve the prices.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-01-20 16:11:30

005.1

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Comment 8 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Massimo
Last Name	Fiorella
Email Address	Massimo.fiorella@hotmail.com
Affiliation	
Subject	CARB

Comment

Dear Carb,
I encourage you to give a constant look to the California Low Carbon Fuel Standard Credit price in order to make them economic viable for long term investments in the sector.

Current price (mid January 2024) is around 65 USD/ton and it is nc feasible for planning long term investments that also contribute : a better environment in California and worldwide.

In my opinion, you should make sure to regulate the sector and tal actions to make sure that California Low Carbon Fuel Standard
006.1 Credit price can be constantly above the 200 USD/ton threshold anc possibly hit 300 USD/ton to boost investments in the sector and make California a better environment.

I really hope immediate actions to get those results and see a spike in the Credit starting from January 2024

Regards,
Massimo Fiorella

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-01-21 14:33:50

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Comment 10 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Thomas
Last Name	MacLean
Email Address	T.maclean@comcast.net
Affiliation	
Subject	Transportation vs Food

Comment

One issue of concern has been the use of food crops for transportation fuel - specifically the use of soy beans for renewable diesel. While we love the increased use of R99 in boat trucks and generators I was thinking back to the problems attributed to the corn ethanol industry and its impact on food co prices.
https://www.farmaid.org/blog/askfarmaid/does-corn-and-ethanol-eff

To understand this issue I contacted Professor Aaron Smith, PhD, the Ag Econ Department at the University of California, Davis. From him I learned that the soy beans produce both oil and meal, where the meal is used for animal feed - primarily chickens in th US and hogs in China. Historically on the commodity market the prices of oil and meal moved together depending on the crop suppl each year; however a few years ago the prices unlinked because of the demand for the oil increased more than the demand for soy mea Today while oil makes ups 20% of the weight it provides 40% of t value for a crop of soy beans.

Going forward, in reaction to the higher demand and higher price oil we would expect to see more soy beans planted. This will also increase the supply of soy meal, without a corresponding increase in demand. The net result could be lower prices for soy meal that goes to feed chickens in the US.
Contrary to the problems caused by ethanol, the move to soy-base renewable diesel could also benefit farmers who buy soy meal for feed.

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-01-26 09:38:29

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 11 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Doug
Last Name	Sommer
Email Address	doug.sommer@ekaellc.com
Affiliation	East Kansas Agri-Energy, LLC
Subject	CARB Amendment Comments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/4406-lcfs2024-UWMHMVxvVzABNwMy.pdf
Original File Name	20240130084123313.pdf
Date and Time Comment Was Submitted	2024-01-30 06:28:00

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

East Kansas Agri-Energy LLC
Fuel for the Future

January 30, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

As a renewable fuel producer and participant in CARB's LCFS program, my team and I value the partnership and mission shared with you and your state to reduce the carbon intensity of transportation fuels.

I am writing to share our company's perspective on two key program areas for your consideration. These requests address the topics of **firm rotation** and **less intensive verification**.

Firm Rotation

The existing regulations within the LCFS verification program stipulate a mandatory rotation of audit firms every six years to assess participants' carbon intensity (CI) and fuel quantities compliance.

Our request is that CARB amend the mandatory firm rotation regulation to include an exception for licensed CPA firms. Of the 30 approved LCFS verification bodies, there are only four licensed CPA firms.

> ***An approved verification body, that is also a licensed CPA firm, exceeds the standards in place for verification bodies and is already subject to***
> 008.1 ***additional oversight on the entity's quality control system in accounting and auditing practices through the required AICPA peer review process.***
>
> ***Due to the increased regulatory oversight, we suggest a CPA firm not be subject to the audit firm rotation but would instead adhere to a Lead Verifier rotation after six consecutive years.***

A licensed CPA firm differs from other consulting agencies by adhering to more rigorous standards and oversight at a state and national level. If a verification body were to violate a Lead Verifier rotation requirement, it would put the firm license at risk. The firm

license is required for all services provided by the firm, not just the LCFS verification services, thereby ensuring adherence to requirements.

Licensed CPA firm requirements

- A licensed CPA firm must be comprised of over 50% of the ownership being licensed CPAs.
    - To earn the accreditation to be a CPA, one must pass a rigorous four-part CPA exam, accumulate education hours, and in many states, one must fulfill 1-2 years of work experience.

- 3-year peer review audit
    - Each licensed CPA firm must enroll in an approved peer review program with reviews conducted every 3 years. The peer review requirement is a requirement of the American Institute of Certified Public Accountants (AICPA) and is an external review of a firm's quality control system in accounting and auditing practices. CPA firms' peer review results can be found on AICPA's website under the Peer Review Public File Search.

- State Boards of Accountancy (SBOA) are found in each state's statute to aid state governments in the licensing and regulation of the public accounting profession.
    - SBOAs provide further oversight on CPA firms by evaluating CPA licensees' examinations and regulatory oversight to ensure a firm is practicing within their statutory scope.

The audit quality and efficiency improve as the auditor becomes more familiar with our company's processes. In addition, with the limited number of firms available as verification bodies and a five-year lookback period in place, it is proving difficult to identify a quality verification body that is not also working with our facility in other consulting capacities. The number of people available with the proper expertise to assist us in design and development of projects and to reserve for verification purposes has proven even more limiting, which is also why we request a Lead Verifier rotation rather than a full firm rotation.

Less Intensive Verification

Regarding less intensive verification, we noted in Appendix E staff's proposal for less intensive verifications for when electricity is used as a transportation fuel, allowing verification bodies to skip site visits if they visited the site in the last two years and issued a positive verification statement.

The rationale for this proposed change states, "there is little change of operation from reporting period to reporting period thus reducing the benefit of annual site visits." Additionally, staff rationale states, "There is no or little risk to the integrity of the LCFS program to allow for less intensive verification services without a site visit in the annual verifications for the following two years. This should reduce the cost of verification services which is often passed on to program participants."

Currently, the proposed language limits this allowance for less intensive verifications to QFTR third-party verification bodies for fuel reporting entities only reporting electricity transactions.

008.2 We agree with the staff's stated rationale, but **we request for less intensive verification to be extended as an option for verification bodies on all validations and annual verifications for any reporting entities**.

In CARB's MRR program (section 95130), less intensive verification is applied without prejudice to verification services by accredited verification bodies.

We agree with staff that less intensive verification leads to little to no risk to the integrity of the LCFS program and that there is little change in operation from reporting period to reporting period, while also providing cost savings to verification providers and passed on to our company as program participants.

We acknowledge the importance of adhering to CARB's specified conditions that necessitate comprehensive verification services. These conditions include the issuance of an adverse verification statement or a qualified positive verification statement in the preceding year and the occurrence of a change in operational control of the reporting entity in the previous year.

Thank you for your time and consideration. Please reach out to us if you have any questions.

Sincerely,

Doug Sommer

1-30-2024

Comment Log Display

Here is the comment you selected to display.

Comment 12 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Kari
Last Name	Buttenhoff
Email Address	danderson@christiansoncpa.com
Affiliation	Christianson CPA
Subject	Christianson PLLP Comments re: LCFS 2024 proposed amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/4437-lcfs2024-WjldMwNwVW9SJwRw.pdf
Original File Name	Christianson PLLP public comments, LCFS 2024.pdf
Date and Time Comment Was Submitted	2024-01-30 11:31:37

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

January 30, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

Christianson PLLP is a full-service public accounting firm located in Willmar, Minnesota and has worked with renewable fuels producers for over 30 years, providing technical assistance and professional services that promote industry compliance.

We are honored to be the chosen and trusted fuel pathway verification body for several biofuel producers across our nation that participate in CARB's LCFS program.

We are writing to share our perspective on two key program areas for your consideration. These requests address the topics of **firm rotation** and **less intensive verification**.

Firm Rotation

The existing regulations within the LCFS verification program stipulate a mandatory rotation of audit firms every six years to assess participants' carbon intensity (CI) and fuel quantities compliance.

Our request is that CARB amend the mandatory firm rotation regulation to include an exception for licensed CPA firms. Of the 30 approved LCFS verification bodies, there are only four licensed CPA firms.

009.1

> ***An approved verification body, that is also a licensed CPA firm, exceeds the standards in place for verification bodies and is already subject to additional oversight on the entity's quality control system in accounting and auditing practices through the required AICPA peer review process.***
>
> ***Due to the increased regulatory oversight, we suggest a CPA firm not be subject to the audit firm rotation but would instead adhere to a Lead Verifier rotation after six consecutive years.***

A licensed CPA firm differs from other consulting agencies by adhering to more rigorous standards and oversight at a state and national level. If a verification body were to violate a Lead Verifier rotation requirement, it would put the firm license at risk. The firm license is required for all services provided by the firm, not just the LCFS verification services, thereby ensuring adherence to requirements.

Licensed CPA firm requirements

- A licensed CPA firm must be comprised of over 50% of the ownership being licensed CPAs.
    - To earn the accreditation to be a CPA, one must pass a rigorous four-part CPA exam, accumulate education hours, and in many states, one must fulfill 1-2 years of work experience.

- 3-year peer review audit
    - Each licensed CPA firm must enroll in an approved peer review program with reviews conducted every 3 years. The peer review requirement is a requirement of the American Institute of Certified Public Accountants (AICPA) and is an external review of a firm's quality control system in accounting and auditing practices. CPA firms' peer review results can be found on AICPA's website under the Peer Review Public File Search.

- State Boards of Accountancy (SBOA) are found in each state's statute to aid state governments in the licensing and regulation of the public accounting profession.
    - SBOAs provide further oversight on CPA firms by evaluating CPA licensees' examinations and regulatory oversight to ensure a firm is practicing within their statutory scope.

In addition to the information noted above, we can also note that through the first three years of the LCFS program, familiarity and efficiency have been gained, allowing us to find and resolve additional issues in reporting.

In the first year, extensive time is spent understanding the company's processes, controls around the processes, software and methodologies around fuel pathway reporting. While comprehending these aspects and pinpointing significant overarching issues or addressing numerous items during a company's initiation into the program, there is a possibility that additional issues might go unnoticed in the initial year of reporting.

The audit quality and efficiency improve as the auditor becomes more familiar with the client and their processes. Upon resolution of the major items, the auditor can redirect their time and energy towards other areas, thereby uncovering additional issues that might have been overlooked in the initial year of review.

Less Intensive Verification

Regarding less intensive verification, we noted in Appendix E staff's proposal for less intensive verifications for when electricity is used as a transportation fuel, allowing verification bodies to skip site visits if they visited the site in the last two years and issued a positive verification statement.

The rationale for this proposed change states, "there is little change of operation from reporting period to reporting period thus reducing the benefit of annual site visits." Additionally, staff rationale states, "There is no or little risk to the integrity of the LCFS program to allow for less intensive verification services without a site visit in the annual verifications for the following two years. This should reduce the cost of verification services which is often passed on to program participants."

Currently, the proposed language limits this allowance for less intensive verifications to QFTR third-party verification bodies for fuel reporting entities only reporting electricity transactions.

009.2 We agree with the staff's stated rationale, but **we request for less intensive verification to be extended as an option for verification bodies on all validations and annual verifications for any reporting entities.**

In CARB's MRR program (section 95130), less intensive verification is applied without prejudice to verification services by accredited verification bodies.

We agree with staff that less intensive verification leads to little to no risk to the integrity of the LCFS program and that there is little change in operation from reporting period to reporting period, while also providing cost savings to verification providers and passed on to program participants.

We acknowledge the importance of adhering to CARB's specified conditions that necessitate comprehensive verification services. These conditions include the issuance of an adverse verification statement or a qualified positive verification statement in the preceding year and the occurrence of a change in operational control of the reporting entity in the previous year.

In addition to the cost-savings rationale mentioned in Appendix E, allowing for less intensive verification reduces the amount of greenhouse gas emissions from traveling to site visits for our many clients spread out throughout the country. In 2023, our team traveled 21,818 miles solely via passenger vehicles, with supplementary air travel to personally visit a portion of our client base. Through less intensive verification, this is an easy way to reduce carbon emissions while maintaining the program's integrity.

We at Christianson PLLP thank you for your time and consideration. Please reach out to us if you have any questions.

Sincerely,

Kari Buttenhoff, CPA

Kari Buttenhoff, CPA
Partner, Christianson PLLP

Christianson PLLP
302 5th St. SW
Willmar, MN 56201

Comment Log Display

Here is the comment you selected to display.

Comment 13 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nasser
Last Name	Kutkut
Email Address	nkutkut@smartchargetech.com
Affiliation	Smart Charging Technologies LLC
Subject	Comments on Forklift Truck Proposed EER Reduction
Comment	Please see attached
Attachment	www.arb.ca.gov/lists/com-attach/4441-lcfs2024-VTlTNgdgUnJXDgcq.pdf
Original File Name	LCFS - Comment - Nasser Kutkut.pdf
Date and Time Comment Was Submitted	2024-01-30 12:47:07

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smartCHARGING TECHNOLOGIES

January 30th, 2023

Comments on the Proposed Low Carbon Fuel Standard Amendments Related to the Reduction of EER Ratio for Forklift Trucks with <12,000 lbs Lift Capacity

010.1 In response to CARB's proposed Low Carbon Fuel Standard Amendments, we would like to submit our strongest opposition to the reduction of EER Ratio for Forklift Trucks with <12,000lbs Lift Capacity by 50%, down to 1.9 from the current value of 3.8.

CARB is also mandating the use of metering to meter the credits for forklift trucks. Note that reducing the EER ratio by 50% reduces the number of credits generated by two-thirds, or 67%. When the two are combined, i.e., reducing EER to 1.9 and metering the electricity dispensed for forklifts, the total number of credits per forklift truck will be reduced by >90%. In fact, this is evident from CARB's projected published CATs model output file for 2025, where the LCFS credits generated by forklifts in 2025 are projected at 174,459 credits, dropping from a peak of 1.882 million LCFS credits in 2023, a 92.7% reduction in the number of credits.

This proposed reduction in EER is an attempt to allow forklift trucks to earn credits. However, its impact will prevent most participants from being able to claim any credits under the program. The cost of the added metering requirements and the major reduction in the number of credits that can be generated will make it uneconomical for most users to remain or opt into the program. This is especially the case for smaller and medium-sized operators of forklifts. In essence, CARB is actually phasing out forklifts with lift capacity <12,000 lbs, one of the first proposals they proposed.

010.2 One of the justifications that CARB has given in the statement of reasons is that many of the forklifts have successfully transitioned to zero-emission technology, which is widely available. Yet, CARB doesn't seem to have a standard to apply across the board when a certain pathway or technology has successfully transitioned to low/zero-emission or becomes widely available. For example, biodiesel and renewable diesel are also becoming widely available, and the share of biodiesel and renewable diesel in the diesel mix has exceeded 57%. Yet, CARB has not placed any limits on these two fuel alternatives. In fact, biodiesel and renewable diesel have negatively impacted LCFS credit prices to the point where many technologies are no longer feasible and can no longer benefit from the LCFS program.

Given the above facts, we strongly oppose reducing the EER ratio for forklifts with lift capacities <12,000 lbs. Reducing the EER ratio is a death sentence to forklift truck LCFS crediting.

Respectfully.
/s/
Nasser Kutkut, PhD, DBA
CEO
Smart Charging Technologies LLC

574 Econ River Pl, Suite 1050, Oviedo FL 32765
www.smartchargetech.com

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Here is the comment you selected to display.

Comment 14 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Khalid
Last Name	Rustom
Email Address	krustom@verdant-es.com
Affiliation	
Subject	Comments on proposed CI Targets and the ratcheting mechanism
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/4513-lcfs2024-UiQCYVMhVVkCaAht.pdf
Original File Name	VES Letter to CARB - Rachetting Mechanism.pdf
Date and Time Comment Was Submitted	2024-01-31 07:34:49

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VERDANT
ENERGY SERVICES

January 30th, 2023

Comments on the Proposed Low Carbon Fuel Standard Amendments Related to CARB's CI Targets and the Proposed Ratcheting Mechanism

In response to CARB's proposed Low Carbon Fuel Standard Amendments, we would like to submit our opposition to the proposed ratcheting mechanism and the CI reduction schedules.

We have been investing heavily in deploying and financing EV fast chargers throughout California. To reduce the initial capital outlay by end users, we have developed a business model based on cost and revenue sharing, considering the projected charger use and the LCFS credit revenue that can be generated. However, the blow-up in the LCFS credit bank size and the significant drop in LCFS credit prices, down to the mid-50s, have greatly impacted our business model and eliminated our ability to finance future projects. How does CARB expect investors to invest in deploying new zero-emissions technologies if there is no way to ensure a minimum LCFS credit pricing and minimal returns?

The influx and unlimited supply of biodiesel and renewable diesel have destroyed the LCFS credit market. If no measures are placed, pricing and investors' confidence in the program will continue to erode. CARB will not, and cannot, meet any of its target CI reduction goals if no aggressive measures are adopted.

The proposed LCFS amendments are supposed to drive stronger target reductions and greater investments in new technologies. However, it has had the opposite effect as the market has reacted very negatively to these amendments, where the LCFS credit prices have fallen sharply, down to ~$55 /MT. At these price levels, many technologies can't be funded.

CARB proposed a soft approach to tightening targets if prices are too low, which is not working and may never work as the time lag to implement any ratcheting is too long. Instead, we strongly believe that CARB should reverse its strategy and start with tighter targets and tighter policies that can result in the immediate recovery of credit prices, which can be loosened if the prices become too high. This is the only way to save the LCFS program and allow new technologies to be funded.

To shore up the falling LCFS credit prices, we strongly recommend that CARB place a cap on biofuels 011.1
011.2 and correct the oversized negative CI scores awarded to biogases. In addition, instead of raising the CI target by 5% in 2025, CARB should start by raising the 2024 CI target by 5%. CARB should also allow the ratcheting mechanism to be triggered annually while giving CARB the option to decide if ratcheting is 011.3
needed or not.

We are committed to helping California reach its target CI reduction goals and hope the board will push CARB to address the above concerns to ensure the success of the LCFS program.

Respectfully.
/s/
Khalid Rustom, PhD, MBA
Managing Partner
Verdant Energy Services LLC

574 Econ River Pl, Suite 1050, Oviedo FL 32765 • www.verdant-es.com

Comment Log Display

Here is the comment you selected to display.

Comment 15 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nasser
Last Name	Mohsin
Email Address	nmohsin@islaverdecapital.com
Affiliation	
Subject	LCFS Regulation Feedback

Comment

The New LCFS Regulation was supposed to inspire the achievement of stronger target reductions; it has done the opposite. Prices are currently 55 USD/MT; many technologies at these prices cannot be funded. The market has reacted poorly to the AAM and step-down.

The approach ARB seems to have taken is allowing the legislation t tighten if prices are too weak. However, the problem with this is the time it takes for the results of tightening to manifest and market dynamics in between (many models predict we are going to have very low prices for the next few years, and most models lose their accuracy the farther out they try to predict because of changing market dynamics; one example is the underestimation of renewable diesel adoption).

An alternative approach is to start with very tight policies and
012.1 give ARB the option of loosening the legislation. this would look
like "We are triggering AAM twice today, but reserve the right to
use an Auto-Decelaration mechanism starting in 2028" for example.

Lastly, another recommended mechanism that can be employed is an
"ARB LCFS containment fund", this fund will have the power to buy
012.2 credits in the market when prices are low, and sell them when
prices are high. There would be a few other hurdles to work
through, but a fund like that would surely allow market prices to
converge faster, and would also help California reach its goals.

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-01-31 08:25:32

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 16 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Bob
Last Name	Istwan
Email Address	bistwan@motivecompanies.com
Affiliation	The Motive Companies
Subject	CARB Proposed 2024 LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/4641-lcfs2024-BWhUOwd1Aw9SOFI3.pdf
Original File Name	MIS Letter to CARB - LCFS Credit Price & Rachetting Mechanism.pdf
Date and Time Comment Was Submitted	2024-02-01 09:00:58

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

MOTIVE INFRASTRUCTURE SOLUTIONS

February 1, 2024

California Air Resources Board 1001 I Street
Sacramento, CA 95814

RE: CARB Proposed 2024 LCFS Amendments

In response to CARB's proposed Low Carbon Fuel Standard Amendments, we want to voice our concerns regarding the worsening level of LCFS credit prices and CARB's proposed ratcheting mechanism.

Motive Energy is a leading provider of energy management solutions, including solar energy systems, energy storage, and EV charging solutions. We are a leading installer of EV chargers (level 2 and level 3) throughout California. We have also financed many EV charger installations by leveraging the LCFS credits generated by these chargers. The program has been a win-win for both the state in meeting its CI reduction targets and end users who can reduce their initial capital investments.

However, the significant drop in LCFS credit prices has prevented us from financing further charger installations and is increasingly discouraging many end users from committing capital to charger installations. We have seen the credit prices collapse from the $200 level to ~$56 as of the last week of January 2024. CARB has not acted to provide any price support and has left many investors in deep red.

The proposed increase of the CI target in 2025 and the proposed ratcheting mechanism will not impact LCFS credit prices nor give investors or end users any confidence in the program.
The unlimited biodiesel and renewable diesel supply has destroyed the LCFS credit market. If no measures are put in place to cap the supply of biofuels, it will continue to erode pricing and investors' confidence in the program. CARB will not be able to meet any of its target CI reduction goals if no stringent measures are adopted.

While the proposed LCFS amendments are intended to drive stronger target reductions and greater
investments in new technologies, they have the opposite effect as the market reaction has been very
013.1 negative, where LCFS credit prices have fallen sharply (~$56 /MT). CARB's proposed amendments
include no actions to support LCFS credit prices in 2024. This will further increase the size of the
credit bank throughout 2024, which will further exacerbate the LCFS credit price. The proposed
increase in CI target by 5% in 2025 will do very little against an oversized credit bank to recover
credit prices. In addition, the proposed ratcheting mechanism will not be able to support the credit 013.2
prices due to the long time lag before it kicks in and its bi-annual triggering nature.

CARB should start with tighter targets and policies that can result in the immediate recovery of credit
prices. CARB can then loosen these targets if the prices become too high. Without that, new
technologies cannot be funded, and CARB will not be able to meet its goals. To that end, we
013.1 propose that CARB moves its 5% step up in CI target to 2024 and allow the ratcheting mechanism to 013.2
be triggered annually.

We are committed to helping California reach its target CI reduction goals, and we hope the board will push CARB to address our concerns to ensure the success of the LCFS program.

Respectfully.
/s/
Robert Istwan
CEO
The Motive Companies

755 Trademark Circle Corona, CA 92879 • www.motiveis.com

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Comment 17 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Chris
Last Name	Stowe
Email Address	cstowe@canarybiofuels.com
Affiliation	Canary Biofuels
Subject	Comments to Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendme
Comment	Please see attached
Attachment	www.arb.ca.gov/lists/com-attach/4647-lcfs2024-WytTIANgV2hRPgBj.pdf
Original File Name	Public Comment - Canary Renewables - lcfs2024.pdf
Date and Time Comment Was Submitted	2024-02-01 10:01:18

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

January 31, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

As a renewable fuel producer and participant in CARB's LCFS program, my team and I value the partnership and mission shared with you and your state to reduce the carbon intensity of transportation fuels.

I am writing to share our company's perspective on two key program areas for your consideration. These requests address the topics of **firm rotation** and **less intensive verification**.

Firm Rotation

The existing regulations within the LCFS verification program stipulate a mandatory rotation of audit firms every six years to assess participants' carbon intensity (CI) and fuel quantities compliance.

Our request is that CARB amend the mandatory firm rotation regulation to include an exception for licensed CPA firms. Of the 30 approved LCFS verification bodies, there are only four licensed CPA firms.

014.1 > ***An approved verification body, that is also a licensed CPA firm, exceeds the standards in place for verification bodies and is already subject to additional oversight on the entity's quality control system in accounting and auditing practices through the required AICPA peer review process.***
>
> ***Due to the increased regulatory oversight, we suggest a CPA firm not be subject to the audit firm rotation but would instead adhere to a Lead Verifier rotation after six consecutive years.***

A licensed CPA firm differs from other consulting agencies by adhering to more rigorous standards and oversight at a state and national level. If a verification body were to violate a Lead Verifier rotation requirement, it would put the firm license at risk. The firm license is required for all services provided by the firm, not just the LCFS verification services, thereby ensuring adherence to requirements.

Licensed CPA firm requirements

- A licensed CPA firm must be comprised of over 50% of the ownership being licensed CPAs.
    - To earn the accreditation to be a CPA, one must pass a rigorous four-part CPA exam, accumulate education hours, and in many states, one must fulfill 1-2 years of work experience.

- 3-year peer review audit
    - Each licensed CPA firm must enroll in an approved peer review program with reviews conducted every 3 years. The peer review requirement is a requirement of the American Institute of Certified Public Accountants (AICPA) and is an external review of a firm's quality control system in accounting and auditing practices. CPA firms' peer review results can be found on AICPA's website under the Peer Review Public File Search.

- State Boards of Accountancy (SBOA) are found in each state's statute to aid state governments in the licensing and regulation of the public accounting profession.
    - SBOAs provide further oversight on CPA firms by evaluating CPA licensees' examinations and regulatory oversight to ensure a firm is practicing within their statutory scope.

The audit quality and efficiency improve as the auditor becomes more familiar with our company's processes. In addition, with the limited number of firms available as verification bodies and a five-year lookback period in place, it is proving difficult to identify a quality verification body that is not also working with our facility in other consulting capacities. The number of people available with the proper expertise to assist us in design and development of projects and to reserve for verification purposes has proven even more limiting, which is also why we request a Lead Verifier rotation rather than a full firm rotation.

Less Intensive Verification

Regarding less intensive verification, we noted in Appendix E staff's proposal for less intensive verifications for when electricity is used as a transportation fuel, allowing verification bodies to skip site visits if they visited the site in the last two years and issued a positive verification statement.

The rationale for this proposed change states, “there is little change of operation from reporting period to reporting period thus reducing the benefit of annual site visits.” Additionally, staff rationale states, “There is no or little risk to the integrity of the LCFS program to allow for less intensive verification services without a site visit in the annual verifications for the following two years. This should reduce the cost of verification services which is often passed on to program participants.”

Currently, the proposed language limits this allowance for less intensive verifications to QFTR third-party verification bodies for fuel reporting entities only reporting electricity transactions.

014.2 We agree with the staff’s stated rationale, but **we request for less intensive verification to be extended as an option for verification bodies on all validations and annual verifications for any reporting entities.**

In CARB’s MRR program (section 95130), less intensive verification is applied without prejudice to verification services by accredited verification bodies.

We agree with staff that less intensive verification leads to little to no risk to the integrity of the LCFS program and that there is little change in operation from reporting period to reporting period, while also providing cost savings to verification providers and passed on to our company as program participants.

We acknowledge the importance of adhering to CARB’s specified conditions that necessitate comprehensive verification services. These conditions include the issuance of an adverse verification statement or a qualified positive verification statement in the preceding year and the occurrence of a change in operational control of the reporting entity in the previous year.

Thank you for your time and consideration. Please reach out to us if you have any questions.

Sincerely,

Chris Stowe
US Controller
cstowe@canarybiofuels.com
209-466-4823 x 107

Comment Log Display

Here is the comment you selected to display.

Comment 18 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	AARON
Last Name	BINKLEY
Email Address	agbinkley@gmail.com
Affiliation	
Subject	Cap vegetable oil-based fuels eligible for the LCFS
Comment	I encourage the Board to include a strong cap on vegetable oil-based fuels eligible for the LCFS to help strengthen and stabilize California's LCFS. This should be done in conjunction with and in addition to proposed chain of custody tracking requirements for virgin vegetable-based oils. This will have the added benefit of combatting greenwashing claims due to the climat[e] and land use impacts from rapidly increasing use of vegetable-bas[ed] oil feedstocks.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-01 16:01:38

015.1

015.2

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 19 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mike
Last Name	Noland
Email Address	quincoinc@yahoo.com
Affiliation	

Subject	Proposed reduction of credits for forklifts

Comment

Dear CARB,
We are very concerned about your proposed changes to the LCFS Program.

016.1 We oppose the proposed reduction in credits generated by e-forklifts. Unlike other EV's, our forklifts do not have energy measurement devices. We would be faced with the additional expense of purchase and installation of such devices.

LCFS Credit reduction will make it more difficult for our small family-owned business to purchase and install meters to continue t participate in this program. We are not as capable of installing measurement devices as other large companies nor do we have the number of forklifts over which to spread the costs of such device: Our rural location leads to additional risk in the implementatior of metering due to issues with internet connectivity.

016.2 If one or both of these proposed changes must be implemented, please allow us a minimum of 2 years before adoption. This time will allow us to evaluate and install the necessary equipment.

Please maintain the current level of credits and do not impose metering requirements so that operations like ours can continue to phase out the use of internal combustion forklifts and adopt the use of electric units.

Thank you,
Mike Noland

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-02-03 14:37:36

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 20 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Victor
Last Name	Reyes
Email Address	Victor@vica.com
Affiliation	Valley Industry and Commerce Association
Subject	SUBJECT: California Air Resources Board (CARB): Low Carbon Fuel Standar Elimination of

Comment

February 5, 2024

California Air Resources Board
1001 Street
Sacramento, CA, 95814

SUBJECT: California Air Resources Board (CARB): Low Carbon Fuel Standards: Elimination of Intrastate Fossil Jet Fuel Exemption - OPPOSE

Dear Members of the California Air Resources Board,

The Valley Industry & Commerce Association (VICA) asserts its opposition to the proposed elimination of the Low Carbon Fuel Standard (LCFS) exemption for intrastate fossil jet fuel. We firml
017.1 believe that the current proposal, if implemented, would fall shor of achieving its intended goal to increase Sustainable Aviation Fuel (SAF) production and mitigating greenhouse gas emissions, while inevitably leading to significant economic burdens on the aviation industry, travelers, and consumers.

VICA recognizes the aviation industry's commitment to voluntarily using cleaner alternatives in aviation fuel, as exemplified by the production of over 11.6 million gallons of Alternative Jet Fuel in 2022, working in alignment with California's environmental objectives to reduce greenhouse gas emissions. However, VICA contends that the proposed CARB regulation faces critical challenges to its feasibility that would, ultimately, undermine it core objective of enhancing SAF and Alternative Jet Fuel (AJF) utilization.

A core issue is the limits on AJF or SAF production. While SAF is being developed and provided, the technological landscape currentl would not align with CARB's stringent requirements, as there is currently a shortage of producers capable of meeting the demand fo AJF and SAF. Technological limitations would also impede the industry's ability to scale up AJF and SAF production to meet proposed standards; therefore, imposing such regulations would be premature, undoubtedly harming the industry and leading to adverse consequences for the broader economy.

The anticipated escalation of costs for the aviation industry resulting from this CARB ruling would not only impact aviation providers, but also directly affect travelers in the form of substantial airfare and fee hikes. These economic burdens would impede the movement of travelers while increasing the cost for the shipment of goods and products, resulting in increased costs for individuals, families, and businesses.

Considering these substantial concerns, VICA strongly urges CARB to
reconsider the proposed LCFS exemption elimination and instead
focus on a collaborative approach with the aviation community that
017.1 allows for necessary technological advancements and infrastructure
development before stringent regulations are considered. This
approach would ensure a seamless transition to cleaner aviation
fuels without compromising our economic stability.

For these reasons, we staunchly oppose the proposed ruling.

Sincerely,

Stuart Waldman
VICA President

Attachment	www.arb.ca.gov/lists/com-attach/5006-lcfs2024-AWJdOgNwUmMGXwlv.docx
Original File Name	CARB Fossil Fuel Exemption.docx
Date and Time Comment Was Submitted	2024-02-05 10:42:26

Board Comments Home

February 5, 2024

California Air Resources Board
1001 Street
Sacramento, CA, 95814

SUBJECT: California Air Resources Board (CARB): Low Carbon Fuel Standards: Elimination of Intrastate Fossil Jet Fuel Exemption – OPPOSE

Dear Members of the California Air Resources Board,

The Valley Industry & Commerce Association (VICA) asserts its opposition to the proposed elimination of the Low Carbon Fuel Standard (LCFS) exemption for intrastate fossil jet fuel. We firmly believe that the current proposal, if implemented, would fall short of achieving its intended goal to increase Sustainable Aviation Fuel (SAF) production and mitigating greenhouse gas emissions, while inevitably leading to significant economic burdens on the aviation industry, travelers, and consumers.

VICA recognizes the aviation industry's commitment to voluntarily using cleaner alternatives in aviation fuel, as exemplified by the production of over 11.6 million gallons of Alternative Jet Fuel in 2022, working in alignment with California's environmental objectives to reduce greenhouse gas emissions. However, VICA contends that the proposed CARB regulation faces critical challenges to its feasibility that would, ultimately, undermine its core objective of enhancing SAF and Alternative Jet Fuel (AJF) utilization.

A core issue is the limits on AJF or SAF production. While SAF is being developed and provided, the technological landscape currently would not align with CARB’s stringent requirements, as there is currently a shortage of producers capable of meeting the demand for AJF and SAF. Technological limitations would also impede the industry's ability to scale up AJF and SAF production to meet proposed standards; therefore, imposing such regulations would be premature, undoubtedly harming the industry and leading to adverse consequences for the broader economy.

The anticipated escalation of costs for the aviation industry resulting from this CARB ruling would not only impact aviation providers, but also directly affect travelers in the form of substantial airfare and fee hikes. These economic burdens would impede the movement of travelers while increasing the cost for the shipment of goods and products, resulting in increased costs for individuals, families, and businesses.

Considering these substantial concerns, VICA strongly urges CARB to reconsider the proposed LCFS exemption elimination and instead focus on a collaborative approach with the aviation community that allows for necessary technological advancements and infrastructure development before stringent regulations are considered. This approach would ensure a seamless transition to cleaner aviation fuels without compromising our economic stability.

For these reasons, we staunchly oppose the proposed ruling.

Sincerely,

Stuart Waldman
VICA President

Valley Industry & Commerce Association • 16600 Sherman Way, Suite 170 Van Nuys, CA 91406 • phone: 818.817.0545 • fax: 818.907.7934 • www.vica.com

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Comment 21 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Adrian
Last Name	M.
Email Address	amartinez@earthjustice.org
Affiliation	
Subject	LCFS
Comment	Please find the attached comment to the Board regarding the proce: for the LCFS. Earthjustice will be filing comments on the substan of the proposal by the comment deadline. All the best, Adrian
Attachment	www.arb.ca.gov/lists/com-attach/5029-lcfs2024-UzEAaQZmBCVRMwFe.pdf
Original File Name	Board LCFS Letter 2-5-2024 Final.pdf
Date and Time Comment Was Submitted	2024-02-05 15:39:01

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

EARTHJUSTICE

<u>VIA</u>: ELECTRONIC MAIL ONLY

February 5, 2024

Chair Liane Randolph and
Members of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814
cotb@arb.ca.gov

Re: Low Carbon Fuel Standard – Suggested Process for Rule Adoption

Dear Chair Randolph and Members of the Board:

Earthjustice respectfully requests that the California Air Resources Board (CARB) hold the March 21, 2024 meeting on the Low Carbon Fuel Standard (LCFS) as a non-voting item and bring back a final proposal for the Board to vote in July of this year. We do not make this request lightly. In rulemaking after rulemaking, we have opposed stakeholder efforts to delay life-saving regulations, particularly the landmark zero-emissions regulations like the Advanced Clean Fleets Rule and the Locomotive Rule. Here, however, the Board should measure twice and cut once, instead of barreling forward with a proposal that, as we explain below, lacks sufficient Board input. Importantly, this amendment process, which proposes targets through 2045, comes at an inflection point as California leaves polluting fuels behind and moves toward a zero-emission transportation system. CARB must get the policies right in this update to ensure that the LCFS both supports California's Zero Emission Vehicle (ZEV) goals through the tens of billions of investment dollars that flow through the program, and avoids exacerbating the State's environmental injustices. Below, we explain why holding a non-voting meeting in March and directing staff to come back in July with a revised proposal are necessary steps to achieving an LCFS that aligns with our zero-emission future. 018.1

I. The Board has not had a chance to weigh in on staff's proposal.

Most regulations heard by the Board include a non-voting Board meeting after the staff proposal is available. In September 2023, CARB staff held an informational meeting that provided a high-level summary of potential proposals. The proposed text was not released until December 2023, more than three months after the meeting. At the September meeting the Board provided initial reactions based on the limited information provided by staff at that time, and there are now additional issues where the Board should insist on providing feedback – especially since there is an actual proposal for review.

Earthjustice acknowledges that not all CARB regulations require two Board meetings. However, the norm for several years has been two meetings for major regulations. A one-meeting approach should not be tested on the LCFS, which is uniquely complex and wide-

CALIFORNIA OFFICE 707 WILSHIRE BLVD., SUITE 4300 LOS ANGELES, CA 90017

T: 415.217.2000 F: 213.403.4822 AMARTINEZ@EARTHJUSTICE.ORG WWW.EARTHJUSTICE.ORG

ranging, and poses profound environmental justice implications. Accordingly, it should be given adequate time for the Board to consider.

II. We request a reasonable opportunity to allow important conversations and a public workshop by staff to discuss recent changes.

The request to defer the vote to July would allow Board members to direct staff on the current proposal at a non-voting March meeting and allow staff to hold a public workshop on the significant changes made since past workshops and in accordance with additional Board direction at the non-voting meeting. This public engagement is crucial given the major implications of this program. 018.2

III. Staff made significant changes to the proposal from what was presented at public workshops and at the Board meeting, and only one of those changes was at the direction of the Board.

Staff have been conducting workshops on potential LCFS change concepts for three years. Yet, the proposal issued in December 2023 has many elements that differ significantly from what had been discussed publicly over this time period. Some of the significant changes include:

1. Inclusion of (inadequate) safeguards in response to Board direction on crop-based feedstocks that have not been publicly explained or vetted;
2. Backsliding on avoided methane policy from what was presented at multiple workshops and which runs *counter* to the Board's expressed concerns in September of 2023;
3. Changes to the automatic acceleration mechanism from staff's initial proposal;
4. Easing of violation provisions not previously discussed publicly;
5. Allowing retroactive crediting for pathways that favors non-ZEV fuels not previously discussed publicly; and
6. Changes to the use of base credit funds not previously discussed publicly.

These are not minor matters related to the program design. Rather, they represent core issues that require more Board and public debate.

IV. Without a second Board meeting, Staff will need to make at least one 15-day change, which creates an extremely tight timeline for Board review.

The current proposal will necessarily need some changes because some issues are not fully clarified. Clarifications and other changes will require staff to issue a 15-day change. If CARB staff are requesting Board approval on March 22, 2024, Earthjustice estimates the timeline as follows:

- **February 20:** Public comment period closes.
- **March 5:** Last business day for staff to post a 15-day change, assuming these materials do not need additional changes before a Board vote.
- **March 19:** Public comment period on changes closes.

- **March 21:** Board hearing and public comments. Staff must respond to any new environmental issues raised in oral or written comments before the Board vote. Staff would not be required to respond to non-environmental assessment comments prior to the Board vote.
- **March 22:** Board vote.

Under this rubric, there would not be adequate time between the March 19 close of comment on the 15-day changes and the March 22 vote for staff or the Board to review public comments or for the Board to provide direction to Staff.

Thus, the Board would be asked to vote on text released less than three months prior that differs from what was discussed publicly for many years and will guide investment decisions and climate and air quality results for decades. The Board must be given more time to consider such a consequential set of changes to this important program.

V. Providing 3-4 months of additional time for debate and input will not impede the rulemaking process.

The Office of Administrative Law (OAL) published the Notice of Proposed Action in the California Regulatory Notice Register on January 5, 2024. Per OAL, a "state agency must complete its rulemaking and submit the rulemaking file to OAL within one year of the date of publication of a Notice of Proposed Action ("Notice") in the Notice Register." A delay of 3-4 months should not affect staff's ability to complete the rulemaking, while giving time to the public and the Board to carefully consider the proposed changes.

VI. An additional 3-4 months will keep CARB on track for a 2025 implementation date, consistent with the current proposal for updating the carbon intensity benchmarks.

The current proposal includes an update to the carbon intensity benchmarks starting in 2025. The request to delay a vote by 3-4 months would **<u>not affect this timeline</u>**. Earthjustice approximates a revised timeline as:

- **March 21:** Board direction to staff on critical issues.
- **May:** Staff hold a public workshop to discuss proposed changes.
- **June:** Staff issue a 15-day change.
- **July:** Board vote.

VII. More time is needed to address EJAC recommendations and concerns.

In 2022, Chair Randolph committed to establish a permanent Environmental Justice Advisory Committee (EJAC). CARB subsequently established a permanent EJAC in March 2023, with a mission of "advis[ing] the Board on environmental justice considerations, prioritizing racial equity, related to implementation of AB 32, via input to CARB on the Scoping Plan Updates and any other pertinent matter related to the implementation of AB 32."[1]

Since then, the EJAC has convened for numerous meetings, with many of these meetings including LCFS as an agenda item, indicating high interest in the regulation.[2] In August 2023, the EJAC presented a draft resolution to CARB, which recommended eight changes to the LCFS. Only one of these eight recommendations is partially included in the staff's proposal. The perceived lack of acknowledgment or consideration of their resolution could cast doubt on the sincerity of establishing the permanent EJAC. By providing more time for Board action, staff would have additional time to interact with the EJAC and consider their proposed changes.

VIII. The LCFS is complex, and most of the Board members are new and may benefit from more time to understand and weigh in on staff's proposals.

The LCFS is one of the most complex climate regulations, if not the most complex regulation, that the State implements. The regulation spans multiple sectors and has gotten more complicated with time. Other states look to the California LCFS as the gold standard and generally align with its policies, so the impact of policy decisions is far-reaching.[3] Since 2018, the last major update of the regulation, a majority of the Board is new.[4] Specifically, the following Board Members did not participate in the last LCFS amendment process:

- Board Member Cliff Rechtschaffen (appointed September 2023);
- Board Member Susan Shaheen, Ph.D. (appointed January 2023);
- Supervisor V. Manuel Perez (appointed January 2023);
- Senator Henry Stern (appointed January 2023);[5]
- Supervisor Eric Guerra (appointed January 2023);
- Supervisor Nora Vargas (appointed February 2022);
- Board Chair Liane Randolph (appointed December 2020);
- Council Member Davina Hunt (appointed December 2020);
- Tania Pacheco-Werner, Ph.D. (appointed December 2020); and
- Board Member Gideon Kracov (appointed December 2020).

Given that this will be the first time that 10 of 16 Board members hear a major update to the LCFS, there is benefit from more time to understand the program and the menu of policy options available to them.

---

[1] AB 32 Environmental Justice Advisory Committee Charter as taken from CARB's website: https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2023/032323/23-3-4ejaccharter.pdf on February 1, 2024.
[2] https://ww2.arb.ca.gov/environmental-justice-advisory-committee-meetings-and-events.
[3] Oregon and Washington have LCFS programs and many other states are considering programs.
[4] As taken from CARB's website: https://ww2.arb.ca.gov/about/leadership, accessed February 1, 2024.
[5] Ex-Officio member.

Earthjustice reiterates its request to include the LCFS at the March Board meeting as a non-voting item, allowing Board members to hear from both stakeholders and Staff in a common forum before providing policy direction. Earthjustice further requests that staff conduct a public workshop on proposed changes. Moreover, a voting Board meeting necessarily needs more time to allow adequate public process. Implementing these requests would not affect the start date of staff's proposal to adjust the benchmarks beginning in 2025.

We appreciate your consideration of this request. Please do not hesitate to reach out if you would like to discuss the content of this letter.

Sincerely,

Adrian Martinez
Deputy Managing Attorney

CC: Governor Newsom
Yana Garcia, Secretary for Environmental Protection
Dr. Steve Cliff

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Comment 22 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Brian
Last Name	Kletscher
Email Address	brian.kletscher@highwaterethanol.com
Affiliation	
Subject	Comments to the Board LCFS2024
Comment	Please find attached comments from Highwater Ethanol, LLC. thank you! Brian Kletscher, CEO Highwater Ethanol, LLC
Attachment	www.arb.ca.gov/lists/com-attach/5091-lcfs2024-AmpQPwBmVW4HdlMy.pdf
Original File Name	Highwater Ethanol Comments California Air Resources Board 2-6-2024.pdf
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If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

HIGHWATER ETHANOL, LLC

February 6, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

As a renewable fuel producer and participant in CARB's LCFS program, my team and I value the partnership and mission shared with you and your state to reduce the carbon intensity of transportation fuels.

I am writing to share our company's perspective on two key program areas for your consideration. These requests address the topics of **firm rotation** and **less intensive verification**.

Firm Rotation

The existing regulations within the LCFS verification program stipulate a mandatory rotation of audit firms every six years to assess participants' carbon intensity (CI) and fuel quantities compliance.

Our request is that CARB amend the mandatory firm rotation regulation to include an exception for licensed CPA firms. Of the 30 approved LCFS verification bodies, there are only four licensed CPA firms.

019.1

> ***An approved verification body, that is also a licensed CPA firm, exceeds the standards in place for verification bodies and is already subject to additional oversight on the entity's quality control system in accounting and auditing practices through the required AICPA peer review process.***
>
> ***Due to the increased regulatory oversight, we suggest a CPA firm not be subject to the audit firm rotation but would instead adhere to a Lead Verifier rotation after six consecutive years.***

24500 US Highway 14
PO Box 96
Lamberton, MN 56152
Ph.: 507-752-6160
Toll Free: 888-MOREE85
Fax.: 507-752-6162
Email: info@highwaterethanol.com
www.highwaterethanol.com

A licensed CPA firm differs from other consulting agencies by adhering to more rigorous standards and oversight at a state and national level. If a verification body were to violate a Lead Verifier rotation requirement, it would put the firm license at risk. The firm license is required for all services provided by the firm, not just the LCFS verification services, thereby ensuring adherence to requirements.

Licensed CPA firm requirements

- A licensed CPA firm must be comprised of over 50% of the ownership being licensed CPAs.
    - To earn the accreditation to be a CPA, one must pass a rigorous four-part CPA exam, accumulate education hours, and in many states, one must fulfill 1-2 years of work experience.

- 3-year peer review audit
    - Each licensed CPA firm must enroll in an approved peer review program with reviews conducted every 3 years. The peer review requirement is a requirement of the American Institute of Certified Public Accountants (AICPA) and is an external review of a firm's quality control system in accounting and auditing practices. CPA firms' peer review results can be found on AICPA's website under the Peer Review Public File Search.

- State Boards of Accountancy (SBOA) are found in each state's statute to aid state governments in the licensing and regulation of the public accounting profession.
    - SBOAs provide further oversight on CPA firms by evaluating CPA licensees' examinations and regulatory oversight to ensure a firm is practicing within their statutory scope.

The audit quality and efficiency improve as the auditor becomes more familiar with our company's processes. In addition, with the limited number of firms available as verification bodies and a five-year lookback period in place, it is proving difficult to identify a quality verification body that is not also working with our facility in other consulting capacities. The number of people available with the proper expertise to assist us in design and development of projects and to reserve for verification purposes has proven even more limiting, which is also why we request a Lead Verifier rotation rather than a full firm rotation.

Less Intensive Verification

Regarding less intensive verification, we noted in Appendix E staff's proposal for less intensive verifications for when electricity is used as a transportation fuel, allowing verification bodies to skip site visits if they visited the site in the last two years and issued a positive verification statement.

The rationale for this proposed change states, "there is little change of operation from reporting period to reporting period thus reducing the benefit of annual site visits." Additionally, staff rationale states, "There is no or little risk to the integrity of the LCFS program to allow for less intensive verification services without a site visit in the annual verifications for the following two years. This should reduce the cost of verification services which is often passed on to program participants."

Currently, the proposed language limits this allowance for less intensive verifications to QFTR third-party verification bodies for fuel reporting entities only reporting electricity transactions.

019.2 We agree with the staff's stated rationale, but **we request for less intensive verification to be extended as an option for verification bodies on all validations and annual verifications for any reporting entities.**

In CARB's MRR program (section 95130), less intensive verification is applied without prejudice to verification services by accredited verification bodies.

We agree with staff that less intensive verification leads to little to no risk to the integrity of the LCFS program and that there is little change in operation from reporting period to reporting period, while also providing cost savings to verification providers and passed on to our company as program participants.

We acknowledge the importance of adhering to CARB's specified conditions that necessitate comprehensive verification services. These conditions include the issuance of an adverse verification statement or a qualified positive verification statement in the preceding year and the occurrence of a change in operational control of the reporting entity in the previous year.

Thank you for your time and consideration. Please reach out to us if you have any questions.

Sincerely,

Brian Kletscher

Brian Kletscher, CEO
Highwater Ethanol, LLC

Comment Log Display

Here is the comment you selected to display.

Comment 23 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jesse
Last Name	Holman
Email Address	senergyoilag@gmail.com
Affiliation	Senergy, LLC
Subject	Consider Innovative Production Method Lowers CI >60%

Comment

We kindly request consideration of adding to CCR Section 95489(c)(1)(A), Chemistry Replace Steam, as an innovative production method. This will incentive crude producers to stop using steam to extract heavy oil, reducing emissions in California's most disadvantaged communities while reducing overall fossil fuel demand. 020.1

Approving this incentive could reduce oil extraction emissions millions tons of CO2e, eliminating 1 billion mcf of natural gas burned by 2035. Reducing the dirtiest oil's carbon intensity over 60%. California producers will deliver the cleanest crude to California refineries, reducing emissions, imports, costly refinery
upgrades all while supporting a cleaner transition.

The chemistry proposed is plant based, pH neutral and biodegradable. This is safer, cleaner and more expensive than steam. Which is why approval of this innovation is necessary to accomplish the mission of CCR Section 95489. All approved innovations in 95489(c)(1)(A) are aimed at reducing, replacing or eliminating burning natural gas, either for steam or electricity. Approved innovations are reducing around 55,000 tons CO2e per year.
Approving this innovation reduce millions of tons within the first
two years.

This chemistry has so many other applications than just oil and gas. The biggest opportunities in O&G are the dirtiest production methods, which is steam in California and Canada. Next would be heavier oils from Alaska North Slope.

This chemistry outside O&G is an all-natural firefighting suppression innovation, lower emissions in agriculture, water treatment, enhanced oil recovery, eliminating solvents and harmful cleaning products, soil remediation, and the opportunities keep growing.

Attached is how chemistry replaces steam, and an application for approval. The chemistry proposed is plant based, pH neutral and biodegradable, that is 13x lower carbon intensity than steaming.

> Thank you for your consideration for creating California's clean transition.

Attachment	www.arb.ca.gov/lists/com-attach/5106-lcfs2024-USIBYl0yAzUDd1A3.pdf
Original File Name	SenergyCARBapplicationChemistryReplaceSteam.pdf
Date and Time Comment Was Submitted	2024-02-06 12:36:37

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

APPLICATION TO THE EXECUTIVE OFFICER FOR LCFS CREDITS

FOR USING INNOVATIVE METHODS FOR CRUDE PRODUCTION

OR AMEND §95849(c)(1)(A)

CYCLIC STEAM REPLACEMENT

CLEAN SURFACTANT ENERGY (CSE) PROJECT

RENEWABLE AND BIODEGRADABLE SURFACTANT

Site:

Thermal Heavy Oil Fields, California

See what chemistry reducing viscosity looks like in the following video:

[VIDEO]

EXECUTIVE SUMMARY

Respectfully, to the Executive Officer:

We apply for approval of a groundbreaking innovation in crude oil production—chemistry that replaces steam emissions and lowers the carbon intensity in California's thermal enhanced oil recovery ("TEOR") operations. Awarding credits for the CRSE process aligns perfectly with the innovative crude oil production credit provisions of Cal. Code of Regulations, Section 95489(c)(1)(A).

TEOR relies on steam injection to reduce oil's viscosity, improve mobility, and increase production rates. However, as thermal heavy oil fields deplete, the Carbon Intensity (CI) rises in proportion to the Steam Oil Ratio (SOR). The CRSE process employs chemistry to reduce oil viscosity, improve mobility, and increase production rates of clean incremental oil. Cyclic steam is the business-as-usual method to produce incremental oil. This proposed chemistry innovation could eventually replace all steam injection while delivering similar volume of oil without the emissions of current TEOR methods.

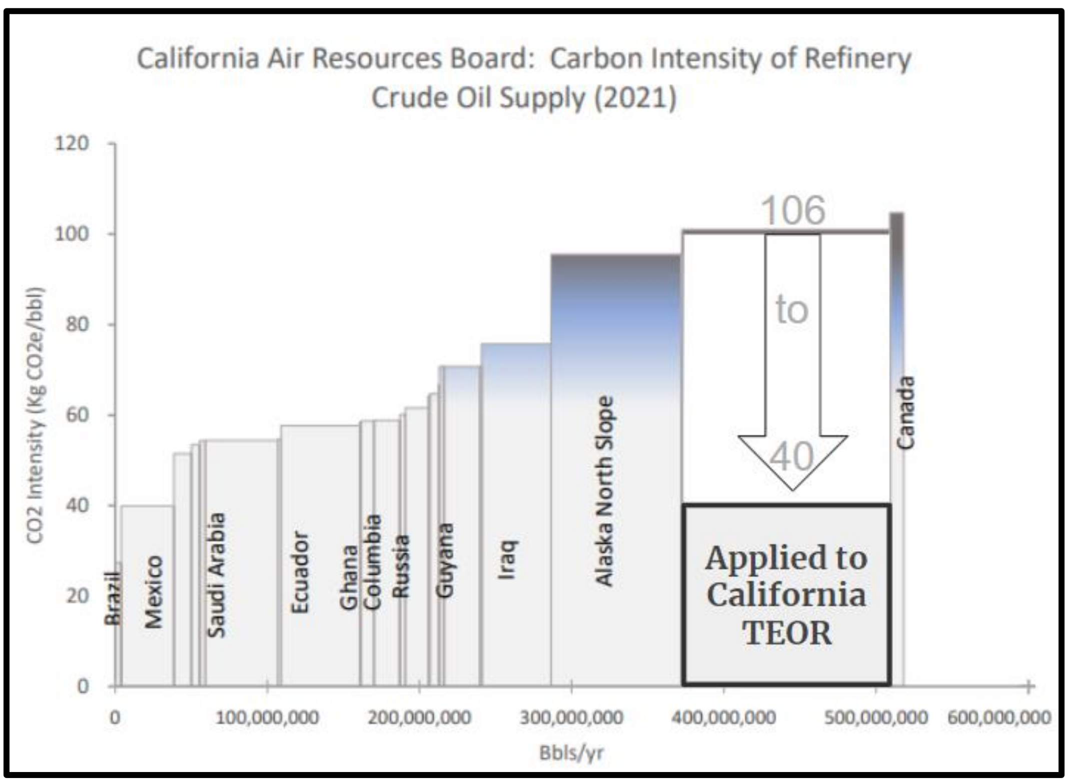
We are asking CARB to approve chemistry that replaces steam, as an innovative crude oil production method that is immediately scalable, sustainable and passes a cost-benefit analysis. The CRSE process enables Net Zero that is affordable, reliable and competitive. Decarbonizing goals require decarbonizing tools. Without approval, cyclic steam will continue polluting California's most vulnerable communities.

CARB can reasonably anticipate a reduction of over 30% in emissions associated with steam injection in TEOR projects. According to the OPGEE model, the carbon intensity of incremental oil from chemistry is 60-80% lower than steam.

Approving this method allows for chemistry to economically replace more than 2,600,000 tons of CO2 emitted per year from California's TEOR operations.

Using current natural gas prices, $5.12 per mcf, steam costs across California's largest TEOR fields are $12.18 per barrel of oil. The cost of chemistry is $15.00 per barrel of oil. Approval results in a $5.61 per barrel of oil incentive to TEOR producers in the project area to replace steam with chemistry. This ultimately could push emission reductions even higher than 30%.

Approving this "Chemistry Replacing Steam" category under the Innovative Crude Oil Production Methods rewards producers for reducing and replacing steam injection, resulting in lower emissions while maintaining normal decline rates. The result is cleaner oil delivered to California refineries, contributing to a lower-carbon future for California—a meaningful win-win. Lowering California's crude oil carbon intensity by more than 60% from 106 to 40 kg CO2e / barrel of oil.



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APPLICATION TO THE EXECUTIVE OFFICER

I. Project Description: Chemistry Reduces Steam Emissions (CRSE).

The focus of this application is replacement of cyclic steam injection-- the method practiced in all California TEOR fields—with clean, safe chemistry to achieve the GHG reduction goals of this agency. The CRSE process enables CARB to play offense against climate change by rewarding oil companies for significant emission reductions.

The CRSE process is the stimulation of producing oil wells with a *nature-based,* pH neutral, renewable, and biodegradable proprietary formula surfactant that replaces steam. It is an advanced chemical and mechanical innovation that reduces emissions by 1) replacing steam, 2) lowering energy to lift oil, 3) reducing system friction, 4) improving downhole efficiency and 5) lowering heat required to separate heavy oil and water—resulting in a true low-carbon oil.

Unfortunately, since 2010, the CI of the largest heavy oil fields in California has increased 27%. Over the same period, only ten (10) Innovative Crude Method projects have been approved, collectively reducing no more than about 55,753 tons of CO2 per year (all solar electricity projects). In contrast, heavy oil-steam injection wells have injected 347.18 million barrels of steam through the first nine (9) months of 2023 to extract 52.18 million barrels of oil, giving a weighted SOR of 6.78 for the 9 largest TEOR fields in California, Table I.

Table I. 2023 Forecast of California's Largest Heavy Oil Field.

Field	Steam[1]	Oil[2]	SOR'23	County
Belridge, South	64,263,856	10,998,115	5.84	Kern
Coalinga	26,066,726	3,286,604	7.93	Kings
Cymric	48,083,958	8,979,218	5.36	Kern
Kern Front	14,840,285	1,615,521	9.19	Kern
Kern River	16,543,815	8,125,523	2.04	Kern
McKittrick	19,202,564	2,206,573	8.70	Kern
Midway Sunset	113,975,635	10,937,839	10.42	Kern
Poso Creek	18,580,392	2,190,442	8.48	Kern
San Ardo	25,623,744	2,860,026	8.96	Monterey
9 Months 2023	**347,180,975**	**51,199,861**	**6.78**	**9 Months 2023**
1 - CALGEM Well Type SC, SF, OG, UNK				
2 - CALGEM All Well Types				
Waterflood oil and potential steam classified under another well type				

CalGEM 2023 first 9 months steam/water volume injected, and oil produced. There is not a good way to separate steam from water injected and the associated oil. Attempted to be as conservative with the average SOR.

Source: California Department of Conservation: Well Production and Well Injection 2021-2023

Steam injection requires burning natural gas to heat fresh water that is injected underground into the heavy oil reservoirs. A barrel of steam emits approximately 23.677 kg CO2e. The SOR is the efficiency measurement of a field's response to steam. Since steam is directly related to emissions of burning natural gas, the SOR is directly related to oil's CI.

There are two types of steam injection: 1) continuous; and 2) cyclic. Continuous steam injection, as the name suggests, is continuous steam volume sent to an injector which provides support to a pattern of producing wells. Cyclic steam injection is specifically applied to producing wells to 'stimulate' oil production from the producers, measured as incremental oil. Cyclic steam is the most common practice for stimulating incremental oil.

Incremental oil is the increase in oil production from the 'stimulation' above a baseline assuming the stimulation never took place. When the stimulated production declines to the baseline, there is no longer incremental oil. The amount of cyclic steam injected determines the amount of incremental oil produced, and corelates directly to a TEOR field's SOR.

Industry widely accepts the SOR as the efficiency measurement of steam injection and emissions per barrel of oil produced. An example: A thermal field with a 10.0 SOR means 1,000 barrels of steam are injected, and 100 barrels of incremental oil are returned. *Vice versa*: 100 barrels of incremental oil produced with CRSE, in the 10 SOR field example, replaces 1,000 barrels of steam.

The CI of heavy oil cannot be reduced without a scalable innovation like CRSE that can be applied to every well to eliminate emissions caused by generating steam. The CI of the incremental oil from CRSE is 60-80% lower. Utilization at about 30%, projects carbon emission avoided will exceed 2,000,000 metric tons annually. (Please refer to Appendix C.)

CRSE chemistry reduces oil's viscosity without steam, avoiding emissions, reducing pollution, reducing freshwater usage and increasing oil production. This method changes both the numerator and the denominator of the CI calculation. The emissions avoided are proportionate to the SOR and the total volume of incremental oil.[1]

As the CRSE project eliminates cyclic steam *and* produces incremental oil, the combination reduces SOR and GHG in the petroleum supply chain. The result perfectly answers the call of CCR Section 95489(c)(1)(A). Thinking globally, but

[1] OPGEE models Midway Sunset 10% incremental oil with and without steam, 29.33 to 3.54 gCO2/

acting locally, this agency can utilize CRSE to balance the need for emission reductions and energy security.

The CRSE project is the essence of energy efficiency, i.e., using less energy by eliminating cyclic steam to perform the same job (extraction of crude oil). In the process, CRSE cuts energy use; reduces air pollution; lessens freshwater usage; and poses no threat to water quality.

CRSE produces heavy oil with significantly less energy compared to steam, using chemistry, rather than heat, to reduce the Interfacial Tension (IFT) of oil in the formation.[2] This reduction eliminates the need for steam to lower oil viscosity. The product and process reduce CI from the baseline comparison by *far more* than the minimum of 0.10 gCO2e/MJ required by Cal. Code Regs. Title 17 § 95489.

CARB's 2030 CI target for the state's oil extraction industry will be achieved with a 45% adopted, this goal could be achieved in twenty-four (24) months.

The downhole placement of CRSE reduces friction in the artificial lifting and transportation process. Application of CRSE requires very limited energy inputs and results in near zero emissions. Using a limited equipment footprint, consisting of light duty trucks with a low- pressure pump, the CRSE is efficiently and safely placed. This equipment's footprint can be quickly scaled up across the region.

This project warrants rapid approval, first, because the innovative method can be easily scaled to impact every TEOR well that is, or will be, cyclic steamed. Second, this is the only reasonable solution to enable the oil industry to achieve

---

MJ.

[2] Incremental oil results from combination of the following: 1. removing organic deposits; 2. destabilizing emulsions; 3. modifying completion and wellbore region to water-wet state; and 4. mobilizing contacted oil.

20% CI reduction by 2030 and beyond. Third, approval will create a clean oil demand, prompting further innovation in production of cleaner crude by reducing reliance on steam, lowering harmful emissions, reducing freshwater demand, while providing economic security for impacted communities of the San Joaquin Valley. Ultimately, it must be acknowledged that achieving decarbonizing *goals* requires decarbonizing *tools* like the CRSE process.

The CRSE advantage is akin to the avoided emissions associated with solar steam generation. The avoided emissions from replacing steam are based on the average steam quality, multiplied by the SOR, multiplied by the amount of incremental oil produced by the innovative crude production method.

Assuming 60% steam quality for our example above: 100 barrels of oil incremental, and 10 SOR, avoids 1,000 barrels of steam, the emissions avoided is 23,677 gCO2e/barrels of steam. This is equivalent to 23,677,000 gCO2e or 23.67 tons CO2e for 100 barrels of incremental oil.

This agency has mandated that the Low Carbon Fuel Standard is designed *to decrease the carbon intensity of California's transportation fuel pool and provide an increasing range of low carbon and renewable alternatives.* Companies should be motivated to innovate ways to decrease steam *and* find new ways to make cleaner incremental oil. By accomplishing both objectives, the CRSE process achieves the essential purpose of the LCFS program.

A. CRSE Reduces Drilling and Workover Tasks.

The CRSE process enables a win-win by reducing steam injection volumes, greenhouse gas emissions *and* the SOR of TEOR production. While GHG reduction is guaranteed, incremental production is equally certain. Ultimately, the need to drill more wells is reduced by recovery of incremental oil. CRSE contributes to a resilient clean energy future.

The benefits of CRSE over cyclic steam injection also include lower injection pressures on the tubulars in each well. There is no heat to cause thermal expansion which jeopardizes wellbore integrity. The CRSE process uses the hydrostatic pressure of the well to push fluids into the formation. CRSE can employ recycled produced water in the process, rather than fresh water.

B. Process of Applying Renewable and Biodegradable Surfactant in the Producing Zone to Replace Steam Injection Is New.

The CRSE formulation was first achieved in the last year. The chemistry of the plant-based surfactant is a unique trade secret. Field and lab testing has been ongoing.

GHG reduction coupled with incremental oil from a nature-based process is revolutionary because conventional industry wisdom has formulated an "either or" decision. The operator can *either* cut emissions *or* maintain production. *Until now*, the industry has resisted the possibility of *achieving both critical goals*.[3]

Heavy oil operators have learned if they reduce steam injection, oil production declines almost immediately. Following conventional wisdom, the operator will never be able to reduce CI values *without* the CRSE innovation. Too, CRSE is the most efficient means available to achieve the desired outcome: lower CI, delivering cleaner crude oil to California refineries.

[3] Recent oil prices prompted increases in cyclic steam injection that would have been avoided with CRSE in use.

II. Process Diagrams

The CRSE process requires access to the same annulus or tubing string found in all existing wells. The product is pumped under low pressure down the backside of the well and the hydrostatic head of the fluid column pushes CRSE into the reservoir. The precise mechanical means of delivery will vary slightly from well-to-well and field-by-field.

The CRSE process takes sixty (60) minutes on-site. The well is put into circulation for twenty-four (24) hours, then returned to production. CRSE can be applied throughout the remaining economic life of the TEOR well. Please refer generally to diagrams at Appendix A.

III. Map and Location

The list of fields and opt-in operators which have cyclic steam or steamflood type well codes according to CalGEM, is listed in Appendix B (California Heavy Oil Production).

IV. Estimate of LCFS Credits

The renewable and biodegradable characteristics of the CRSE product is part of the value proposition in this application. Please refer to the LCA for Product and Process at Appendix C.

The credit calculation for crude oil produced or transported using any other innovative method listed in section 95489(c)(1)(A) can by used to calculate credits generated and *could* employ the following formula:

$$\text{Credits}_{innov}(MT) = \left(\text{Avoided}_{emissions} \times \text{SOR}_{cyclic} \times V_{innov} - \text{Emissions}_{innov} \times T_{innov}\right) \times C$$

Figure 1. Suggested Chemistry Reduces Steam Credit Calculation

Where, Credits_{Innov} (MT) is the amount of LCFS credits generated (a positive value), in metric tons, by the volume of a crude oil produced or transported using the innovative method and delivered to California refineries for processing.

$\text{Avoided}_{emissions}$ assuming displacement of steam produced using a natural gas fired once through steam generator are correlated with the steam quality as tabulated in section 95489(c)(1)(F).

SOR_{cyclic} is the fields previous year's SOR cyclic steam jobs.

V_{innov} is the volume, in barrels, of crude oil produced or transported using the innovative method and delivered to California refineries for processing. If the crude produced or transported using the innovative method and delivered to California refineries is part of a blend, then V_{innov} is the volume of blend delivered to California refineries times the volume fraction of crude within the blend that was produced or transported using the innovative method.

Emissions_{innov} are the life cycle emissions for the CRSE product and process, with the units of $gCO2e/bo_{innov}$.

T_{innov} is the number of treatments performed contributing to V_{innov}.

Where, C is $10x^{-6}$ MT/gCO_2e conversion.

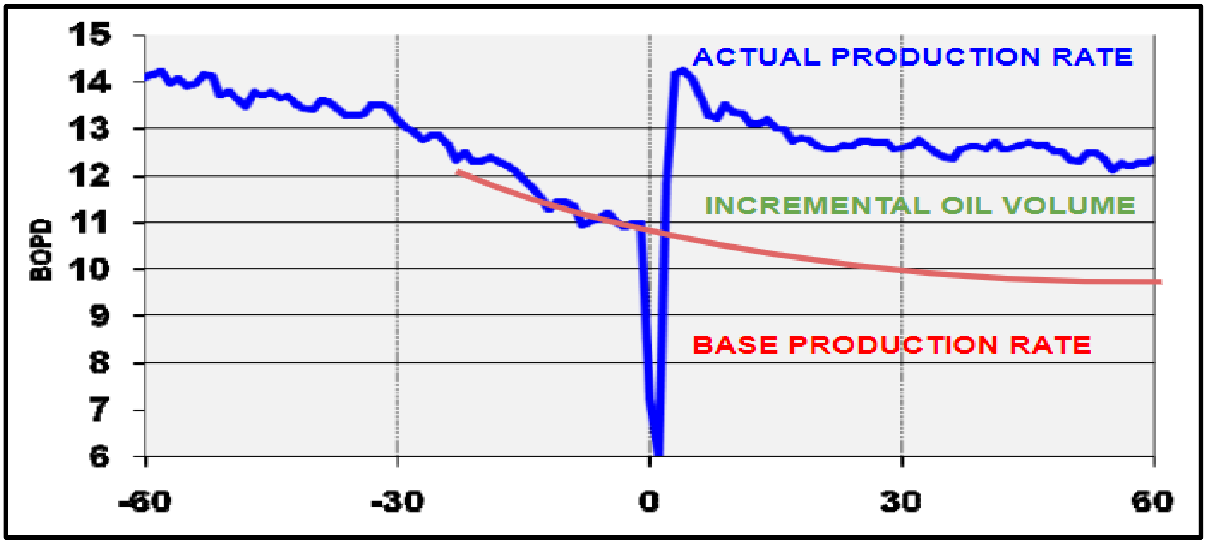


Figure 1. Volume Incremental Oil, V_{innov}

Incremental oil calculated from application of either cyclic steam or CRSE is actual production minus base production over a duration to determine volume. This is an example of a normalized plot over time, left is -60 days before job performed at time 0, to 60 days after job performed. This is an example of how incremental oil volume can be calculated for both cyclic steam jobs and CRSE.

V_{innov} is the volume of incremental crude oil produced using this method. This is calculated on a well-by-well basis as the difference between a forecasted base production and actual production. The difference between actual and base production equals positive incremental oil over a duration of time. The time that incremental oil becomes negative, or another intervention is initiated, actual production falls below the forecasted base production, or until another incremental oil intervention is initiated.

V. Opt-in Producers

The Opt-in Producers include TEOR operators presently using heat produced by cyclic steam to reduce viscosity of crude oil within the producing zone (Table III). The geographic location of the target fields is Table IV.

Table III. Opt-in Producers Steam Well Codes

OPT-IN OPERATOR LIST		
Aera Energy LLC	E&B Natural Resources Management Corp	Pacific Coast Energy Company LP
Almond Crest Oil LLC	Gray Development Co. LLC	Paris Valley Petroleum
Armstrong Petroleum Corp	Hathaway LLC	Peak Operator LLC
Asphalta LLC	Holmes Western Oil Corporation	Santa Maria Energy, LLC
Berry Petroleum Company, LLC	Hunter Endison Oil Development Limited Partnership	Seneca Resources Company, LLC
C&M Oil Co. & Investments	HVI Cat Canyon, Inc.	Sentienl Peak Resources California LLC
California Resources Elk Hills, LLC	Jaco Production Company	Shadow Wolf Energy, LLC
CalNRG Operating, LLC	Kern River Holdings II, LLC	Standard Oil Company LLC
Chevron U.S.A. Inc.	Macpherson Operating Company, L.P.	Tidelands Oil Production Co.
CMO, Inc.	Naftex Operating Company	TRC Operating Company, Inc.
Crimson Resources Management Corp	NewBridge Resources, LLC	Vaquero Energy, Inc.

CalGEM operators own well type of cyclic steam, CS or steamflood, SF.

Table IV. Fields with Steam Injection Reported

FIELDS		
Antelop Hills	Elk Hills	Newport, West
Arroyo Grande	Huntington Beach	Orcutt
Asphalto	Jasmin	Oxnard
Belridge, North	Kern Front	Paris Valley
Belridge, South	Kern River	Placerita
Cat Canyon	Lost Hills	Poso Creek
Chico-Martinez	Lost Hills, NW	Round Mountain
Coalinga	Lynch Canyon	San Ardo
Cymric	McKittrick	Wilmington
Edison	Midway-Sunset	
Edison, NE	Mount Poso	

CalGEM operators own well type of cyclic steam, CS or steamflood, SF.

The CRSE process is the only scalable potential for TEOR extraction companies to achieve a 20% CI reduction by 2030. It requires producers to adopt and scale CRSE, or similar advancements if they become available, to replace 45% of steam injection. Please refer to LCFS Credit Calculation at Appendix D.

The need for this process is made urgent in the context of a climate crisis by the deleterious trend of increasing steam injection *and* increasing SOR. Without approval of the CRSE application, oil companies will continue to inject more steam into the ground, causing more dangerous emissions, in pursuit of the remaining economic barrels of oil. CRSE is an immediate opportunity to reverse this trend.

Table V represents nine (9) months of data projected over twelve (12) months with a forecasted 7.80% increase of steam and emissions while oil decline rates accelerate. This relates to injecting more steam into the ground, more deadly emissions into the air and a higher decline rate. Most troublingly, it results in more emissions and less oil. This trend will continue until an economic alternative appears.

Table V: Three Year Steam Oil Change

YEAR	STEAM[1] bbls	OIL[2] bbls	% CHANGE	
2021	468,490,097	82,910,163	Steam%	Oil %
2022	453,476,668	76,921,783	-3.20%	-7.22%
Assume 22 to 23	438,944,366	71,365,927	-3.20%	-7.22%
Forecast 2023	474,332,861	69,578,400	4.60%	-9.55%
23 Fore-Assume	**35,388,496**	**(1,787,527)**	**7.80%**	**-2.32%**
1 - CALGEM Well Type SC, SF, OG, UNK - may not capture all steam				
2 - CALGEM All Well Types- includes waterflood oils.				

Table V is California's top 9 TEOR fields trend. Assume 22 to 23 is 'nothing changes from 22 to 23 scenario, could expect these numbers. Forecast 2023 is 9 months actual forecasted for 12 months.

23 Fore – Assume is the difference between Forecast 2023 minus Assume 22 to 23.

This trend will likely continue with depleted reservoirs.

Forecasting the nine (9) largest TEOR fields, producers are on track to inject 35 million more barrels of steam, nearly 828,000 tons of CO_2, and produce 1,700,000 barrels of oil less. More emissions that are uneconomical. This results in higher SORs and higher CIs. Expect more of this without CRSE. While employing CRSE would have improved those numbers significantly.

VI. CRSE and Confidential Business Information

The formulation of CRSE used downhole in any well will vary slightly to address specific geochemistry and downhole conditions. The principal product delivered by the project is a renewable and biodegradable surfactant formulated as a trade secret under proprietary terms and conditions.

VII. Reporting and Recordkeeping

Opt-in Producers will provide records of production and steam inputs from the normal course of operations to establish the historical SOR baseline. The same details are reported monthly to CalGEM. The incremental oil will be based on a well-by-well decline rate, as if the stimulation hadn't occurred. The incremental oil will be calculated above the baseline until production drops below the baseline.

Reporting will ensure compliance with robust standards of additionality, quantification, and permanence. Records will facilitate third-party audit of emissions claims and enable all interested parties to track and audit credits. Monitoring, reporting, and verification ensure that the CRSE project performs as predicted by project design.

VIII. CRSE Process Meets Standard Interpretation of CARB Regulations.

This application relates to a new innovative chemical method to reduce emissions and decarbonize oil production, incorporating Cal. Code of Regulations, Title 17, Section 95489(c)(1)(A), which provides, in pertinent part:

> For the purpose of this section, an innovative method means crude production or transport using one or more of the following technologies:

> 1. Solar steam generation (generated steam of 45 percent quality or greater). Steam must be used onsite at the crude oil production or transport facilities.
>
> 2. Carbon capture and sequestration (CCS). Carbon capture must take place onsite at the crude oil production or transport facilities.
>
> 3. Solar or wind electricity generation. To qualify for the credit, electricity must be produced and consumed onsite or be provided directly to the crude oil production or transport facilities from a third-party generator and not through a utility owned transmission or distribution network. Energy storage may be used to increase the quantity of electricity supplied to crude oil production or transport facilities from intermittent solar and wind electricity generation sources.
>
> 4. Solar heat generation including, but not limited to, boiler water preheating and solar steam generation with a steam quality of less than 45 percent. Heat must be used onsite at the crude oil production or transport facilities.
>
> 5. Renewable natural gas (RNG) or biogas energy. RNG or biogas must be physically supplied directly to the crude oil production or transport facilities.

Id.

The regulation is an open invitation to innovate the production of oil for one purpose: to reduce GHG emissions. Because the process proposed serves that purpose at scale, CRSE justifies *chemical reduction of viscosity* as a new category of innovative production method to eliminate steam *and* reduce emission of greenhouse gases.

Moreover, the innovative methods which have been previously approved, arguably encompass the functional advantages of CRSE and should justify approval of this application. Providing the same energy savings and emission reductions by innovative chemistry may prompt approval of this application without adding to the enumerated methods.

A. Reducing oil viscosity with a renewable product satisfies Method No. 1.

The CRSE process is a lower carbon alternative to solar steam generation whether viewed as a substitute or a perfect complement to steam by reducing oil viscosity. In direct competition, CRSE produces higher emission reductions than can be achieved by production from solar steam alone.

B. Sequestering carbon captured in CRSE satisfies Method No. 2.

The product is plant-based, absorbing carbon as it grows. By injecting the high carbon material into a geologic formation, the project sequesters carbon at every wellbore stimulation.

C. Renewable Product Facilitating Production Satisfies Method Nos. 3-5.

Downhole delivery of CRSE, a renewable and biodegradable product, to produce incremental oil is the functional equivalent of providing renewable energy for use in the production facility. It is simply an alternative tool for decarbonizing oil production.

D. Scalability Allows CRSE to Achieve High Volume Emission Reductions.

Oil and gas extraction have always confronted a declining denominator of the CI calculation. In heavy oil, reducing the emissions (numerator) as oil production (denominator) declines, still increases CI. Increasing oil production (denominator) while reducing emissions, is the only available means, given the constraints of technology and economics, to reduce CI of TEOR operations.

All current CARB innovative production methods focus on limited-scale emission reductions. None of these approved methods increase oil production.

None of them reduce operating costs. There is no economic incentive for the oil and gas industry to change, until they see a way to reduce emissions and extract more oil, in a truly scalable way. CRSE is that opportunity.

Replacing the business-as-usual method with the CRSE process delivering 60-80% lower emissions is the urgently needed answer. This innovation for the oil industry will spark new opportunities to replace high CI activities with lower carbon alternatives to achieve the desired outcome for all stakeholders.

CONCLUSION

Considering the urgent need to reduce emissions associated with production of oil in one of the most productive regions of the United States, the opportunity to cut emissions *and* maintain normal production decline rates justifies the expedited approval of this application. By reducing the amount of steam injected and complementing other methods to mitigate emissions, the applicant presents a rare win-win opportunity for this agency and the oil industry. We respectfully request your expedited approval of this innovative crude oil production method, recognizing its potential to revolutionize the industry and create a positive impact on both the environment and the economy.

Dated: December 15, 2023

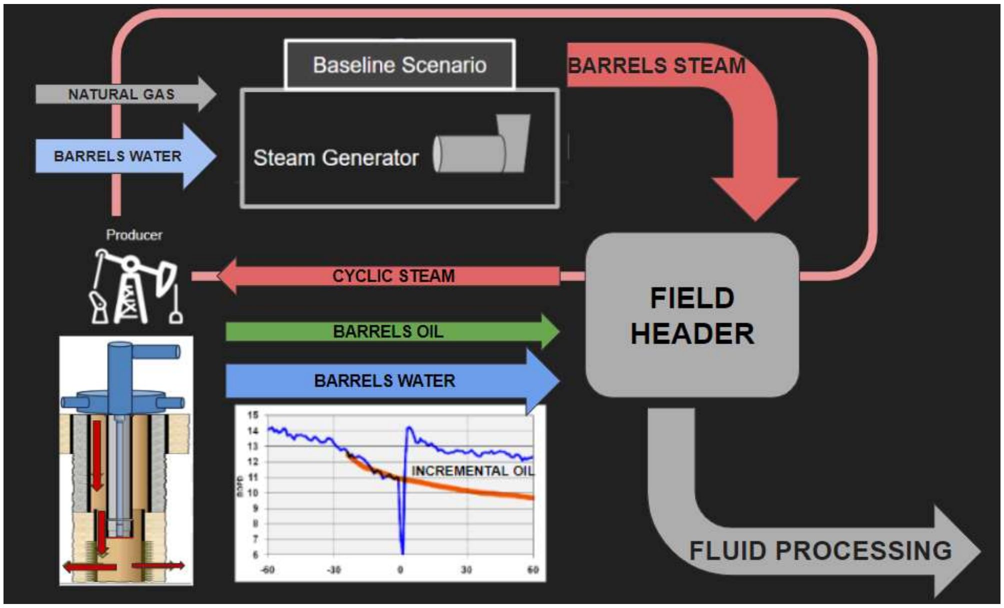
Respectfully Submitted,

Jesse Holman, CEO
Senergy, Inc.

LIST OF APPENDICES

APPENDIX A. Process Diagrams

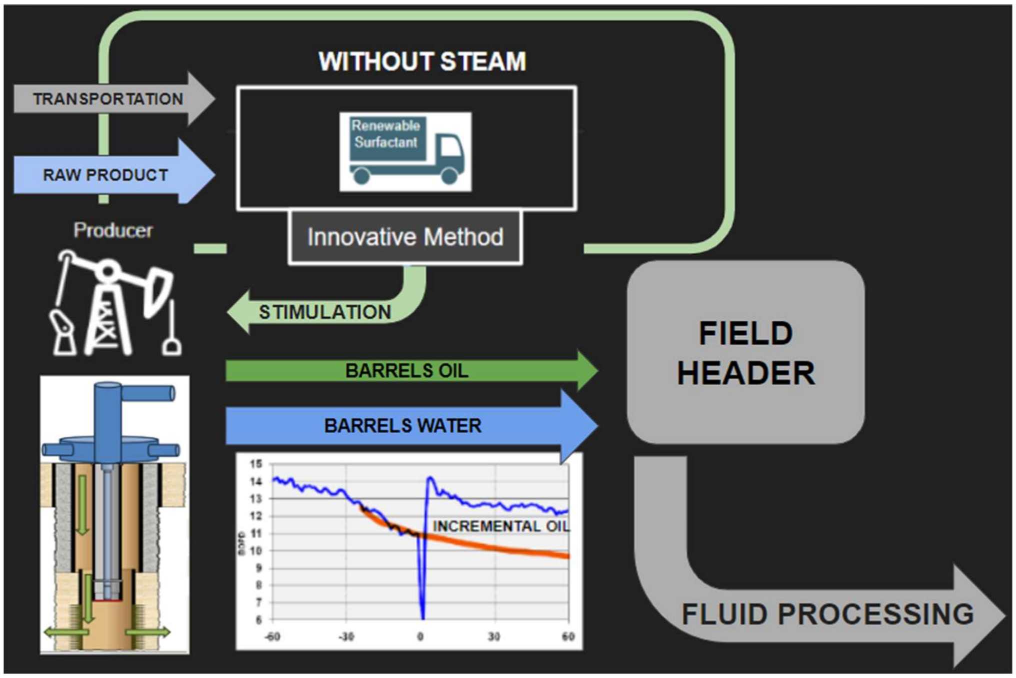
Baseline Scenario: Cyclic Steam



Cyclic steam used on producers for enhancing oil production.

A cyclic steam job is used to stimulate incremental oil in producer wells, the pumping unit is stopped, steam is diverted from the field header, down the flowline, into the backside annulus of the well delivering a predetermined volume of steam for a period of time. The steam is turned off and the well is put back on production. The steam volume injected must be recovered which contributes additional energy above the emissions injected. The well is back producing oil and water.

Innovative Method: CRSE replaces Cyclic Steam



Stimulation product assists with chemistry at fluid processing plant, there is no additional waste streams created.

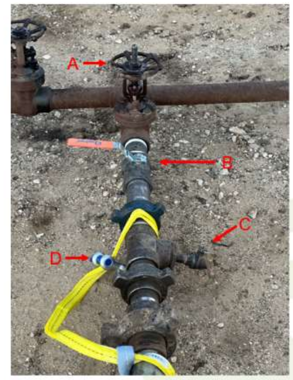
Clean Surfactant Energy stimulation is a renewable and biodegradable stimulation fluid. The well is shut down and isolated. Stimulation fluid is injected using low pressure centrifuge pump and reused lease water, approximately 25 barrels of water to hydrostatically push stimulation fluid into the formation. The well is then put in a 24 hour circulation period before being returned to production. The treatment process requires less than 20 minutes of pump time before moving on to the next well. The stimulation fluid is of similar components of chemistries injected at the fluid processing facility and improves the existing separation streams without creating any additional waste streams.

What does this look like in the field?

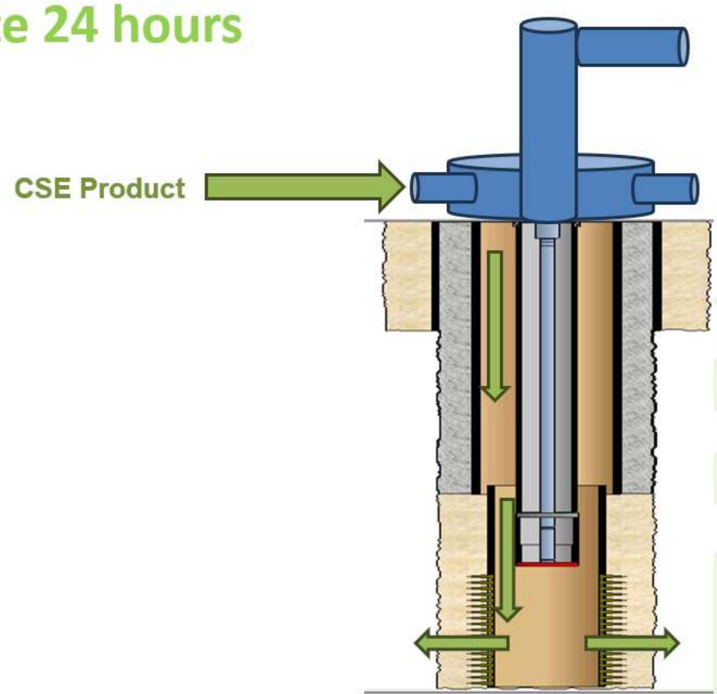
A – Chemical Totes
B – Water Source
C – Manifolded Suction Transfer Hoses
D – C-Pump (130 psi/4 bpm)
E – Pressure Hose (note check valve at E2)

Connected to Wells Flow Line

A – Operator Valve
B – Isolation Valve
C – Bleeder
D – Hose Hobble



Fluid Pumped Down Backside
Circulate 24 hours



APPENDIX B. List of Thermal Injection Fields and Operators.

Table I. Opt-in Producers Steam Well Codes

OPT-IN OPERATOR LIST		
Aera Energy LLC	E&B Natural Resources Management Corp	Pacific Coast Energy Company LP
Almond Crest Oil LLC	Gray Development Co. LLC	Paris Valley Petroleum
Armstrong Petroleum Corp	Hathaway LLC	Peak Operator LLC
Asphalta LLC	Holmes Western Oil Corporation	Santa Maria Energy, LLC
Berry Petroleum Company, LLC	Hunter Endison Oil Development Limited Partnership	Seneca Resources Company, LLC
C&M Oil Co. & Investments	HVI Cat Canyon, Inc.	Sentienl Peak Resources California LLC
California Resources Elk Hills, LLC	Jaco Production Company	Shadow Wolf Energy, LLC
CalNRG Operating, LLC	Kern River Holdings II, LLC	Standard Oil Company LLC
Chevron U.S.A. Inc.	Macpherson Operating Company, L.P.	Tidelands Oil Production Co.
CMO, Inc.	Naftex Operating Company	TRC Operating Company, Inc.
Crimson Resources Management Corp	NewBridge Resources, LLC	Vaquero Energy, Inc.

Table II. Fields with Steam Well Codes

FIELDS		
Antelop Hills	Elk Hills	Newport, West
Arroyo Grande	Huntington Beach	Orcutt
Asphalto	Jasmin	Oxnard
Belridge, North	Kern Front	Paris Valley
Belridge, South	Kern River	Placerita
Cat Canyon	Lost Hills	Poso Creek
Chico-Martinez	Lost Hills, NW	Round Mountain
Coalinga	Lynch Canyon	San Ardo
Cymric	McKittrick	Wilmington
Edison	Midway-Sunset	
Edison, NE	Mount Poso	

APPENDIX C. LCFS Credit Calculation

The credit calculation for crude oil produced or transported using any other innovative method listed in section 95489(c)(1)(A) can by used to calculate credits generated and *could* employ the following formula:

$$\text{Credits}_{innov}(\text{MT}) = (\text{Avoided}_{emissions} \times \text{SOR}_{cyclic} \times V_{innov} - \text{Emissions}_{innov} \times T_{innov}) \times C$$

Figure 1. Suggested Chemistry Reduces Steam Credit Calculation

Where, Credits_{Innov}(MT) is the amount of LCFS credits generated (a positive value), in metric tons, by the volume of a crude oil produced or transported using the innovative method and delivered to California refineries for processing.

$\text{Avoided}_{emissions}$ assuming displacement of steam produced using a natural gas fired once through steam generator are correlated with the steam quality as tabulated in section 95489(c)(1)(F).

SOR_{cyclic} is the fields previous year's SOR cyclic steam jobs.

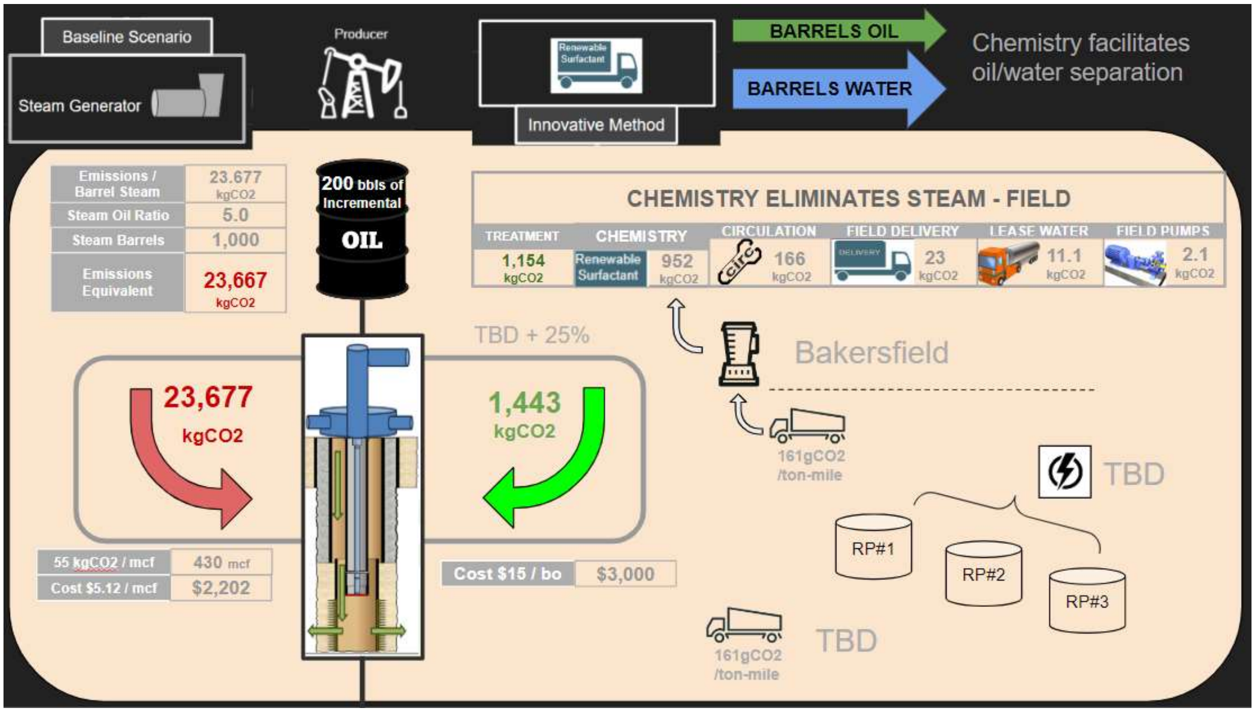
V_{innov} is the volume, in barrels, of crude oil produced or transported using the innovative method and delivered to California refineries for processing. If the crude produced or transported using the innovative method and delivered to California refineries is part of a blend, then V_{innov} is the volume of blend delivered to California refineries times the volume fraction of crude within the blend that was produced or transported using the innovative method.

Emissions_{innov} are the life cycle emissions for the CRSE product and process, with the units of $gCO2e/bo_{innov}$.

T_{innov} is the number of treatments performed contributing to V_{innov}.

Where, C is $10x^{-6}$ MT/gCO_2e conversion.

APPENDIX D. LCA for Product and Process



Lifecycle analysis of 200 barrels of oil, cyclic steam (baseline) SOR of 5 and Chemistry Reduce Steam (innovation).

The distance the raw products travel, and the blending electricity are currently unknown. We have added a 25% buffer for these emissions.

Source:

Vegetable Oil: https://www.epa.gov/sites/default/files/2015-07/documents/emission-factors_2014.pdf

Freight: Transportation value of 161 gCO2/ton-mile.

Steam Emissions from CARB.

Steam quality	*Avoided emissions (gCO_2e/bbl solar steam)*
95% and above	34,875
85% to <95%	30,443
75% to <85%	28,188
65% to <75%	25,932
55% to <65%	23,677
45% to <55%	21,421

APPENDIX E: Reporting and Record Keeping

Oil and steam volumes are reported and recorded to CalGEM agency. The additional record keeping required is the incremental oil volume using CSE. This requires a forecasted baseline production rate as if the stimulation didn't take place. Incremental oil is the difference between actual production post stimulation and the forecasted baseline until actual production falls below the baseline. This volume of incremental oil will be used to determine the credits available.

Therefore, records for incremental oil volume will vary well. The overall steam oil ratio and carbon intensity of the field will decline over time in accordance with the summation of all treatments that produce incremental oil.

APPENDIX F: Summary of Innovative Method Applications

SUMMARY OF INNOVATIVE METHOD APPLICATION

A. CRSE Delivers Emission Reductions *Beyond* Elimination of Steam in California.

1. Reduce lifting energy required in current levels of oil production.
2. Reduce maintenance demands for tubulars in existing oil wells.
3. Reduce drilling of new wells to bolster oil production.
4. Lower carbon emissions in production of heavy oil imported to California.
5. Reduce fuel consumed to transport imported crude to California refineries.
6. Reduces emissions in water flood production fields worldwide.
7. Increases efficiency of oil sand production in Alberta.
8. Reduces waste and downtime in aging refineries.
9. Encourages lower-carbon fuel production.
10. Sequesters carbon in geologic storage.

B. CRSE Delivers Advantages *Beyond* Decarbonization.

1. Reduce freshwater usage in oil and gas operations.
2. Increase recycling of produced water.
3. Efficient water polishing on-site.
4. Eliminate synthetic surfactants.
5. Cleanup facilities and sites.

C. CRSE Chemical Innovation Reduces Emissions *Beyond* the Oil Industry.

1. Firefighting:
   a) Reducing surface tension of water decreases evaporation before water reaches fuel.
   b) Reducing surface tension of water increases uptake on contact with fuel.
   c) Both effects increase firefighting efficiency at any scale.
   d) Efficiency reduces wildfire emissions.
   e) Efficiency saves water.
   f) Eliminates PFOAs.
2. Agriculture:
   a) Reducing surface tension of water increases plant uptake of moisture, reducing demand for water *and* improving yield.
   b) Reducing surface tension of water increases plant uptake of nutrients, reducing use of NPK fertilizer that contaminates water.
3. Environmental Remediation:
   a) Reducing surface tension of water improves removal of volatile organic compounds in soil.
   b) Reducing surface tension of water improves removal of oil spill contamination.
4. Cement Production:
   a) Reducing surface tension of water allows additives to reduce weight while increasing strength.

    b) Decreasing volume of cement production reduces carbon emissions.
5. Desalinization:
    a) Reducing surface tension of water improves efficiency of reverse osmosis.
    b) Cleaning RO filters prolongs the service life of the filter material.

D. Approving CRSE Application Puts a Carrot Before the Oil Industry Horse.

1. Increasing stakeholder expectations raise incentives for enterprise-level decarbonization.
2. Emerging laws and evolving regulations make decarbonization a C-suite priority.
3. Leaders will recognize competitive efficiency to seize growth opportunities.
4. Every measurable carbon reduction is progress to be encouraged.

E. Application Justifies Expeditious Approval of New Innovative Method.

1. Better to decarbonize than await a perfect solution.
2. Uncertainty should not create inertia.
3. CARB should lead the field.

F. CRSE Reduces More GHG Emissions than Currently Approved Methods Combined.

1. Section 95489(c)(1)(A) lists five (5) technologies approved as innovative methods.
2. The five (5) approved methods reduce emissions from generating steam.
3. CRSE eliminates steam generation altogether.

Comment Log Display

Here is the comment you selected to display.

Comment 24 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Amy
Last Name	Halpern-Laff
Email Address	amyhlaff@gmail.com
Affiliation	
Subject	factory farm gas
Comment 021.1	Please stop incentivizing factory farm gas and anaerobic digester: CAFOs are filthy, cruel, and exploitative of humans and animals. Rather than provide an additional revenue stream, we should be disincentivizing CAFOs.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-08 05:40:41

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Comment 25 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Tim
Last Name	Wenger
Email Address	tdwenger1@yahoo.com
Affiliation	
Subject	Enact Low Carbon Fuel Standard
Comment	Writing to encourage the enactment of the low carbon fuel standard in California. The state's policies impact the largest economy in the nation and one of the largest in the world, and these policies frequently spill over to other states - California should be leader in holding factory farms, already bastions of cruelty, t account for their emissions. 022.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-08 06:32:28

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 26 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Tom
Last Name	Progar
Email Address	justfarmingsystem@gmail.com
Affiliation	
Subject	CAFO Manure Biogas
Comment	Please remove CAFO (factory farm) manure biogas from the clean fue standard. This "avoided methane credit" is expanding destructive factory farming throughout the country. Rural communities, small farmers, farm animals, and the environment all suffer because of this horrible greenwashing scheme.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-08 06:52:40

023.1

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 27 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Julia
Last Name	Lowe
Email Address	J_lowe66@yahoo.com
Affiliation	Sierra Club Winding Waters Group
Subject	End the current LCFS policies that reward factory farm polluters

Comment

Governor Newsom and administration, please understand my concern.

Factory farm gas is not clean energy. It's composed primarily of
methane, a potent greenhouse gas that traps 80 times more heat tha
carbon dioxide.

The extraction of methane from factory farm waste does nothing to
alleviate the massive harm inflicted by factory farms on local
communities. The production of methane from factory farms causes
public health and climate impacts, compounding the existing impact
from factory farms.

The LCFS is a California policy, but it is driving the expansion
factory farms and factory farm gas in numerous states, including
state. Last Friday I attended an all day Ag Bioscience Conference
that was sponsored by Duke Energy. The only type of Climate
solution discussed was Agrivoltaics, of which I approve and
encourage farmers to include in the long-term plans for their lan
Solar farms on Ag land make a lot of sense, not burning and
producing more Methane that our atmosphere already cannot take.
What kind of technology is? This is a set back to our survival,
is a FALSE CLIMATE SOLUTION and it should be stopped. Please do
nothing to incentivize polluting factory farms. We have enough of
024.1 them in Indiana and I don't want any more. Turn to cleaner energy
technology now. Thank you, Julie Lowe, Columbus, Indiana

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-02-08 08:20:12

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Comment 28 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Robert
Last Name	Rhodes
Email Address	sycamorespringsfarms@earthlink.net
Affiliation	Wilderness Society
Subject	Factory Farms
Comment	Stop permitting FACTORY FARMS. Your environmental laws are a joke!!!
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-08 08:46:12

025.1

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 29 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Susan
Last Name	Frye
Email Address	susanjanefrye@gmail.com
Affiliation	
Subject	Animal factories
Comment	Please stop activity that promotes destructive and polluting CAFOs 026.1 Thank you.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-08 09:40:44

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 32 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ginny
Last Name	Masullo
Email Address	masullo.ginny1@gmail.com
Affiliation	Retired

Subject	LCFS

Comment

Dear Governor Newsom and Members of the California Air Resources Board (CARB),
I have concerns regarding California's Low Carbon Fuel Standard (LCFS) and to implore you to take immediate action to address the environmental injustices embedded in the program.

LCFS has become the nation's largest and most lucrative pollutior trading scheme for factory farm biogas, perpetuating harmful practices rather than serving its environmental objectives.
027.1 It is driving the construction of more factory farms and factory farm biogas projects in states far from California, causing severe harm to air, water, public health, rural economies, and overall quality of life. Incentives for more factory farms is not a solution for combatting climate pollution by factory farms.

I urge you to consider and prioritize the following reforms to the LCFS:

027.2 Eliminate "avoided methane crediting" in 2024.
027.3 Address inaccuracies in the Life Cycle Assessment that ignore associated up and downstream greenhouse gas emissions from factory farm gas production.
027.4 Remove the 10-year "grace period" for factory farm gas producers.
027.5 Stop double counting by allowing factory farm gas projects paid fo and claimed by other programs to sell LCFS credits as well.

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-02-08 14:02:25

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Comment 33 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Christine
Last Name	Reid
Email Address	creid0913@gmail.com
Affiliation	
Subject	CAFO biogas
Comment 028.1	Incentivizing digesters to remove methane from manure with very lucrative credits is backfiring. It has spawned a Ponzi scheme for investors in digesters to benefit financially on the overproductio of manure. Stop it please.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-08 14:45:16

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Comment 34 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mark
Last Name	Smith
Email Address	morgsat1@gmail.com
Affiliation	
Subject	New rules for CARB

Comment

California is exporting its dirty energy policy to rural communities throughout the U.S. without regard for the local impacts. The existing LCFS rules perpetuate environmental injustic by disproportionately harming low-income communities and communities of color.

Factory farms, predominantly located in these marginalized areas, cause severe harm to our air, water, public health, rural economies, and overall quality of life.

This year, the California Air Resources Board (CARB) has the chanc to adopt new rules that would realign the LCFS with California's environmental justice commitments and stop rewarding factory farms for their pollution.

029.1 CARB's Environmental Justice Advisory Committee presented a clear alternative to the dirty status quo, and submitted a resolution calling for an end to the current LCFS policies that reward factor farm polluters.

Please do the right and sustainable thing. Thank you.

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-02-08 17:56:47

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Comment 35 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name Elizabeth

Last Name York

Email Address lizpaintsnyc@gmail.com

Affiliation

Subject LCFS Laws

Comment

PLEASE make reforms to the LCFS:

030.1 Eliminate "avoided methane crediting" in 2024.

030.2 Address inaccuracies in the Life Cycle Assessment that ignore associated up and downstream greenhouse gas emissions from factory farm gas production.

030.3 Remove the 10-year "grace period" for factory farm gas producers.

030.4 Stop double counting by allowing factory farm gas projects pa for and claimed by other programs to sell LCFS credits as well.

Thank you for making changes that help the planet and farming communities, not big Ag.

Sincerely,
Elizabeth York

Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-08 23:07:31

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Here is the comment you selected to display.

Comment 36 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Teri
Last Name	Klitzke
Email Address	teri.klitzke@purefield.com
Affiliation	PureField Ingredients LLC
Subject	Mandatory firm rotation for VBs and less intensive verification
Comment	Please see attached comments.
Attachment	www.arb.ca.gov/lists/com-attach/5394-lcfs2024-WytWJQd0UmQCYgBp.pdf
Original File Name	PureField Ingredients LLC-comments-to-CARBs-proposed-LCFS-amendments.pdf
Date and Time Comment Was Submitted	2024-02-09 11:14:36

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

PureField INGREDIENTS

February 9, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

As a renewable fuel producer and participant in CARB's LCFS program, my team and I value the partnership and mission shared with you and your state to reduce the carbon intensity of transportation fuels.

I am writing to share our company's perspective on two key program areas for your consideration. These requests address the topics of **firm rotation** and **less intensive verification**.

Firm Rotation

The existing regulations within the LCFS verification program stipulate a mandatory rotation of audit firms every six years to assess participants' carbon intensity (CI) and fuel quantities compliance.

Our request is that CARB amend the mandatory firm rotation regulation to include an exception for licensed CPA firms. Of the 30 approved LCFS verification bodies, there are only four licensed CPA firms.

031.1

> ***An approved verification body, that is also a licensed CPA firm, exceeds the standards in place for verification bodies and is already subject to additional oversight on the entity's quality control system in accounting and auditing practices through the required AICPA peer review process.***
>
> ***Due to the increased regulatory oversight, we suggest a CPA firm not be subject to the audit firm rotation but would instead adhere to a Lead Verifier rotation after six consecutive years.***

A licensed CPA firm differs from other consulting agencies by adhering to more rigorous standards and oversight at a state and national level. If a verification body were to violate a Lead Verifier rotation requirement, it would put the firm license at risk. The firm

license is required for all services provided by the firm, not just the LCFS verification services, thereby ensuring adherence to requirements.

Licensed CPA firm requirements

- A licensed CPA firm must be comprised of over 50% of the ownership being licensed CPAs.
  - To earn the accreditation to be a CPA, one must pass a rigorous four-part CPA exam, accumulate education hours, and in many states, one must fulfill 1-2 years of work experience.

- 3-year peer review audit
  - Each licensed CPA firm must enroll in an approved peer review program with reviews conducted every 3 years. The peer review requirement is a requirement of the American Institute of Certified Public Accountants (AICPA) and is an external review of a firm's quality control system in accounting and auditing practices. CPA firms' peer review results can be found on AICPA's website under the Peer Review Public File Search.

- State Boards of Accountancy (SBOA) are found in each state's statute to aid state governments in the licensing and regulation of the public accounting profession.
  - SBOAs provide further oversight on CPA firms by evaluating CPA licensees' examinations and regulatory oversight to ensure a firm is practicing within their statutory scope.

The audit quality and efficiency improve as the auditor becomes more familiar with our company's processes. In addition, with the limited number of firms available as verification bodies and a five-year lookback period in place, it is proving difficult to identify a quality verification body that is not also working with our facility in other consulting capacities. The number of people available with the proper expertise to assist us in design and development of projects and to reserve for verification purposes has proven even more limiting, which is also why we request a Lead Verifier rotation rather than a full firm rotation.

Less Intensive Verification

Regarding less intensive verification, we noted in Appendix E staff's proposal for less intensive verifications for when electricity is used as a transportation fuel, allowing verification bodies to skip site visits if they visited the site in the last two years and issued a positive verification statement.

PureField INGREDIENTS

The rationale for this proposed change states, “there is little change of operation from reporting period to reporting period thus reducing the benefit of annual site visits.” Additionally, staff rationale states, “There is no or little risk to the integrity of the LCFS program to allow for less intensive verification services without a site visit in the annual verifications for the following two years. This should reduce the cost of verification services which is often passed on to program participants.”

Currently, the proposed language limits this allowance for less intensive verifications to QFTR third-party verification bodies for fuel reporting entities only reporting electricity transactions.

031.2 We agree with the staff’s stated rationale, but **we request for less intensive verification to be extended as an option for verification bodies on all validations and annual verifications for any reporting entities.**

In CARB’s MRR program (section 95130), less intensive verification is applied without prejudice to verification services by accredited verification bodies.

We agree with staff that less intensive verification leads to little to no risk to the integrity of the LCFS program and that there is little change in operation from reporting period to reporting period, while also providing cost savings to verification providers and passed on to our company as program participants.

We acknowledge the importance of adhering to CARB’s specified conditions that necessitate comprehensive verification services. These conditions include the issuance of an adverse verification statement or a qualified positive verification statement in the preceding year and the occurrence of a change in operational control of the reporting entity in the previous year.

Thank you for your time and consideration. Please reach out to us if you have any questions.

Sincerely,

Teri Klitzke

Teri Klitzke
Controller

PureField
INGREDIENTS

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Comment 37 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name Robert

Last Name Sijgers

Email Address robsijgers@gmail.com

Affiliation

Subject Stop incentivizing factory farm gas.

Comment

```
* Stop awarding the biggest polluters!
* Stop increased GHG emissions as a result of factory farming.
* Dairy manure contributes to about a third of the nitrate
polluting groundwater in the Central Valley and has polluted in
many areas 30-40% of private wells.
* It takes about 2 agricultural acres per head of cattle to susta:
just feeding them, which is then not available for feeding people
Incentivizing factory farms makes this worse. Biogas digester
promotion aggravates the problem and dairy herds become just the
first stage of an industrial money-making scheme that is already
severely impacting our public health and our environment.
* CARB disregards violations of out-of-state rules and regulation:
```

032.1

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-10 06:42:28

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Comment 38 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Reuben
Last Name	Franco
Email Address	aobeid@ochcc.com
Affiliation	
Subject	Opposition to California Air Resources Board Proposal to Regulate Jet Fuel
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/5769-lcfs2024-UD9WIFQlAj5VIAlg.pdf
Original File Name	Opposition to CA Air Resources Board Proposal.pdf
Date and Time Comment Was Submitted	2024-02-12 14:22:38

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

ORANGE COUNTY HISPANIC CHAMBER OF COMMERCE

February 9, 2024

CARB Board of Directors
California Air Resources Board
P.O. 2815
Sacramento, CA 95812

Re: Opposition to California Air Resources Board Proposal to Regulate Jet Fuel

Dear CARB Board of Directors,

The Orange County Hispanic Chamber of Commerce is writing to share our serious concern and opposition to the recent California Air Resources Board (CARB) proposal to regulate jet fuel under its Low Carb Fuel Standard (LCFS) program.

The Orange County Hispanic Chamber of Commerce represents the interests of and provides access to Orange County's 30,000 Hispanic-owned businesses. We support the development of these businesses by providing opportunities for networking, legislative advocacy, access to capital, education and training programs.

The U.S. airline industry plays a vital role in California's economy. Furthermore, the industry is committed to reducing its climate impact and achieving "net zero" carbon emissions by 2050. Transitioning to Sustainable Aviation Fuels (SAF) is core to this commitment, and the industry has pledged to work with governments and other stakeholders to make three billion gallons of SAF available in the United States by 2030. Achieving these goals requires new and additional policy incentives, streamlined permitting processes, and close collaboration among airlines, fuels industry, manufacturers, environmental organizations and governments, among others.

With respect to SAF, California has established itself as an early leader in attracting investment, production, and use of SAF through the existing Low Carbon Fuels Standard (LCFS) Program, which provides an opt-in credit for SAF that helps reduce the price difference between SAF and conventional jet fuel. This voluntary regulatory structure has been successful in enabling the growth of the SAF market in California and across the country. CA has the most viable market for SAF today in the United States and as airlines increase their demand for SAF the market continues to grow.

Aviation accounts for 2.6% of the US GHG emissions but 5% of US GDP and 4.1% of CA's GDP. There are 380 thousand employees of US Commercial aviation firms based in California, with an overall economic impact of $194 billion[1]. Aviation is critical to driving California's economy and it's rank as the 5th largest economy in the world, enabling $114 Billion in annual trade flows and underpinning the of many of the rest of California's biggest economic drivers such as agriculture, tourism, manufacturing, banking, technology and small business. Ensuring a healthy and vibrant aviation industry is essential to California's future, and leveraging CARB's early leadership on SAF can enable California leadership in the emerging SAF production industry, creating new jobs and economic development opportunities.

033.1

With this context, we express our serious concern with a new proposal by the California Air Resources Board (CARB) to regulate jet fuel as an obligated fuel under the LCFS Program. CARB's proposed changes to the LCFS program include a proposal to eliminate the existing exemption for conventional jet fuel use for flights within the state of California. This proposed change is unlikely to result in increased SAF production, availability, or use in California, but would lead to higher jet fuel prices. The primary impediment to increased SAF production and availability in California remains the higher cost of SAF for producers and buyers relative to conventional jet fuel and renewable diesel. The CARB proposal would not meaningfully address this fundamental challenge and therefore unlikely to meaningfully increase SAF supply or use.

The proposal seeks to regulate jet fuel and reduce emissions from aviation, both of which are pre-empted under federal law a fact that CARB recognized when it exempted jet fuel in 2018.[2]. Aviation has unique circumstances, that go beyond considerations of interstate commerce, for the safe operation and maintenance of aircraft that the federal government has recognized in the EPA's Clean Air Act and the jurisdiction of the FAA.

1 *The Economic Impact of Civil Aviation on the U.S. Economy, State Supplement, US Department of Transportation, November 2020*

2 CARB stated that "*[s]ubjecting aircraft fuels to annual carbon intensity standards would raise federal preemption issues*" available at https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/isor.pdf?_ga=2.259407882.1202437490.1641 231788-253234234.1573227006

These statutory authorities establish clear and broad federal authority for regulating jet fuel and aircraft engine emissions that pre-empts California from regulating jet fuel under the LCFS program.

Moving forward with eliminating the fossil jet fuel exemption and implementation of a new obligation will likely result in litigation that will be lengthy, costly and do nothing to advance the mission of more SAF production and uplift. Engaging in litigation will divert resources from the state and the aviation industry that would be better spent enabling greater SAF production. Our mutual interest is to increase SAF production, availability, and use and the most effective way to accomplish this is to continue the positive, collaborative approach represented by the existing "opt-in" mechanism
033.1 developed by CARB and the aviation community.

Based on these considerations, we urge CARB to reconsider and withdraw the proposal to remove the exemption for jet fuel for intrastate flights and instead preserve the existing opt-in approach for SAF and partner with the aviation sector and stakeholders across the emerging SAF ecosystem on new policies and approaches to rapidly increase the availability of SAF in California. We urge CARB to focus on the ultimate goal – how to get more SAF into planes in California by reducing barriers to production, availability and use.

Sincerely,

Reuben Franco
President & CEO
The Orange County Hispanic Chamber of Commerce

Comment Log Display

Here is the comment you selected to display.

Comment 38 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Josh
Last Name	Thome
Email Address	jthome@us-energy.com
Affiliation	U.S. Venture, Inc.
Subject	U.S. Venture Comments on CA-GREET 4.0
Comment	Please see the attached commentary provided by U.S. Energy, a U.S Venture company, on the default electricity emission factors derived from the CA-GREET 4.0 model. Thank you, Josh Thome Manager of Environmental Analytics U.S. Energy, a U.S. Venture company
Attachment	www.arb.ca.gov/lists/com-attach/5775-lcfs2024-VCEFLVYkVClVDAh+.pdf
Original File Name	U.S. Venture Comments on CA-GREET 4.0.pdf

Date and Time Comment Was Submitted	2024-02-12 15:52:11

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Finding a better way

February 12, 2024

Matthew Botill
Division Chief, Industrial Strategies Division
California Air Resources Board
1001 I Street
Sacramento, CA 95814
VIA ELECTRONIC DELIVERY

RE: Potential issue with CA-GREET 4.0 Electricity Emission Factor

Dear Mr. Botill,

In review of the default electricity emission factors proposed in the 2024 Low Carbon Fuel Standard (LCFS) Amendments, U.S. Venture has identified a potential modeling issue we submit for your consideration. As you know, U.S. Venture has actively participated in the LCFS since 2017. U.S. Venture is a leading vertically integrated solutions provider proficient in refined products, alternative fuels, and environmental credits. We will submit an additional set of comments on the LCFS Amendments, but submit this feedback on the CA-GREET 4.0 (CA-GREET) model to facilitate improvements to the model and emission factors.

034.1 In review of the default electricity emission factors in the CA-GREET model, an issue was identified in the regional refactoring by CARB staff that may need attention. U.S. Venture was evaluating the various calculation approaches utilized across the different methodologies (CA-GREET, National GREET, GHGenius, OpenLCA, etc.), when we ran into an issue which we could not reconcile. We found that the default electricity emission factors within CARB's Tier 1 calculators, which are derived from the CA-GREET model, (relative to the EPA eGRID 2021 numbers used in GREET) may be off by a significant amount.

CARB provided document "Appendix B: CA-GREET 4.0 Supplemental Document", which explains how they recalculated the electricity emission factors using the fuel mix from eGRID 2021. Unfortunately, as we reviewed the draft CA-GREET calculator to figure out how these fuel mix factors were utilized, we identified an issue. CARB adjusts the National GREET calculator, which uses an NERC region map (11 regions) to determine electricity emission profiles, to one that uses the eGRID subregions (27 regions). This appears to be okay on the surface, but there is a core INDEX formula inaccuracy in the CA-GREET calculator which is being caused by the adjustment of 11 regions to 27, and can't be fixed with the data which is available in the calculator. The formula inaccuracy is not easily noticeable, because there is an IFERROR correction in the formula which defaults ("value in error") to an incorrect conclusion, so the formula doesn't simply fail with reference errors. If this INDEX function was corrected, the default electricity emission factors could change significantly.

Below are some screenshots from the CA-GREET 4.0 draft calculator which layout my findings.

U.S. Venture, Inc. | 425 Better Way, Appleton, WI 54915 | 920.739.6101 | www.usventure.com

1. <u>Fuel/Technology Mix-Electric tab:</u> Circled cells show all formula inaccuracies mentioned. These cells feed numerous downstream formulas which ultimately produce the default electricity emissions for each subregion in the Tier 1 calculators.

58	2.2) Electricity Generation Mixes, Combustion Technolgy Shares and Power Plant Energy Conversion Efficiencies for GREET Calculation									
59		Generation Mix for EVs, Grid-Connected PHEVs, and Electrolysis H2	Generation Mix for Stationary Applications	Combustion Technology Shares for A Given Plant Fuel Type: EVs, GC PHEVs, and Electrolysis	Combustion Technology Shares for A Given Plant Fuel Type (Stationary)	Power Plant Energy Conversion Efficiency (Transportation)	Power Plant Energy Conversion Efficiency (Stationary)	Urban Emission Share for EVs, Grid-Connected PHEVs, and Electrolysis H2	Urban Emission Share for Stationary Applications	
60	Residual Oil-Fired Power Plants	1.2%	0.2%			31.9%	31.9%	1.0%	1.0%	
61	Boiler			76.6%	76.6%	32.6%	32.6%			
62	Internal Combustion Engine			9.9%	9.9%	34.9%	34.9%			
63	Gas Turbine			13.5%	13.5%	26.9%	26.9%			
64	Natural Gas-Fired Power Plants	38.9%	11.2%			47.3%	47.3%	31.3%	65.6%	
65	Boiler			7.1%	7.1%	33.8%	33.8%			
66	Simple-cycle gas turbine			8.8%	8.8%	32.9%	32.9%			
67	Combined-cycle gas turbine			83.1%	83.1%	51.6%	51.6%			
68	Internal Combustion Engine			1.0%	1.0%	41.0%	41.0%			
69	Coal-Fired Power Plants	21.3%	67.4%			34.5%	34.5%	38.0%	1.7%	
70	Boiler			100.0%	100.0%	34.5%	34.5%			
71	IGCC			0.0%	0.0%	39.0%	39.0%			
72	Biomass Power Plants	1.4%	0.1%			21.7%	21.7%	1.3%	1.9%	
73	Boiler			100.0%	100.0%	21.7%	21.7%			
74	IGCC			0.0%	0.0%	45.0%	45.0%			
75	Nuclear Power Plants	18.0%	11.1%			100.0%	100.0%	22.9%	9.1%	
76	Other Power Plants (hydro, wind, geothermal, etc.)	19.3%	10.0%			100.0%	100.0%			
77	Hydroelectric			30.6%	17.1%					
78	Geothermal			2.5%	0.0%					
79	Wind			50.6%	79.3%					
80	Solar PV			16.4%	3.6%					
81	Others (Biogenic Waste, Pumped Storage, etc.)			0.0%	0.0%					
82										
83	2.3) Combined Heat and Power Generation Technologies									

Overview | Inputs | Results | Petroleum | Co_processing | NG | MeOH_FTD | EtOH | Electric | Bio_electricity | Hydrogen | BioOil | Algae | Waste | RNG | Pyrolysis_IDL

2. <u>INDEX formula-Electric tab:</u> This screenshot shows the INDEX formula is searching for a result of 11 or under (from the GREET NERC regions), but is unlikely to function correctly given the 27 eGRID subregions breakout CARB adjusted the CA-GREET 4.0 model to.

TIME | =IFERROR(@IF(Inputs!$F$721<=11,INDEX(Electric!$B$46:$L$46,1,Inputs!$F$721),$B$46),$B$46)

	A	B	C	D	E	F
43	Combustion Technology					Combined
44	Region	U.S.	ASCC	FRCC	HICC	MRO
45	Efficiency	51.6%	44.6%	52.4%	51.6%	51.9%
46	Technology Share	83.1%	64.6%	86.2%	0.0%	69.6%
47	Emissions (g/kWh)					
48	VOC	0.004	0.010	0.002	0.004	0.001
49	CO	0.034	0.123	0.050	0.034	0.118
50	NOx	0.050	0.533	0.048	0.050	0.047
51	PM10	0.017	0.023	0.022	0.017	0.007
52	PM2.5	0.017	0.004	0.022	0.017	0.006
53	SOx	0.007	0.005	0.002	0.007	0.002
54	BC	0.000	0.000	0.001	0.000	0.000
55	OC	0.011	0.002	0.015	0.011	0.004
56	CH4	0.009	0.009	0.009	0.009	0.010
57	N2O	0.001	0.001	0.001	0.001	0.001
58	2.2) Electricity Generation Mixes, Combustion Technolgy Shares and Power Plant Energy Conversion Efficiencies for GREET Calculation					
59			Generation Mix for EVs, Grid-Connected PHEVs, and Electrolysis H2	Generation Mix for Stationary Applications	Combustion Technology Shares for A Given Plant Fuel Type: EVs, GC PHEVs, and Electrolysis	Combustion Technology Shares for A Given Plant Fuel Type (Stationary)
60	Residual Oil-Fired Power Plants		1.2%	0.2%		
61	Boiler				76.6%	76.6%
62	Internal Combustion Engine				9.9%	9.9%
63	Gas Turbine				13.5%	13.5%
64	Natural Gas-Fired Power Plants		38.9%	11.2%		
65	Boiler				7.1%	7.1%
66	Simple-cycle gas turbine				8.8%	8.8%
67	Combined-cycle gas turbine				83.1%	$B$46)
68	Internal Combustion Engine				1.0%	1.0%

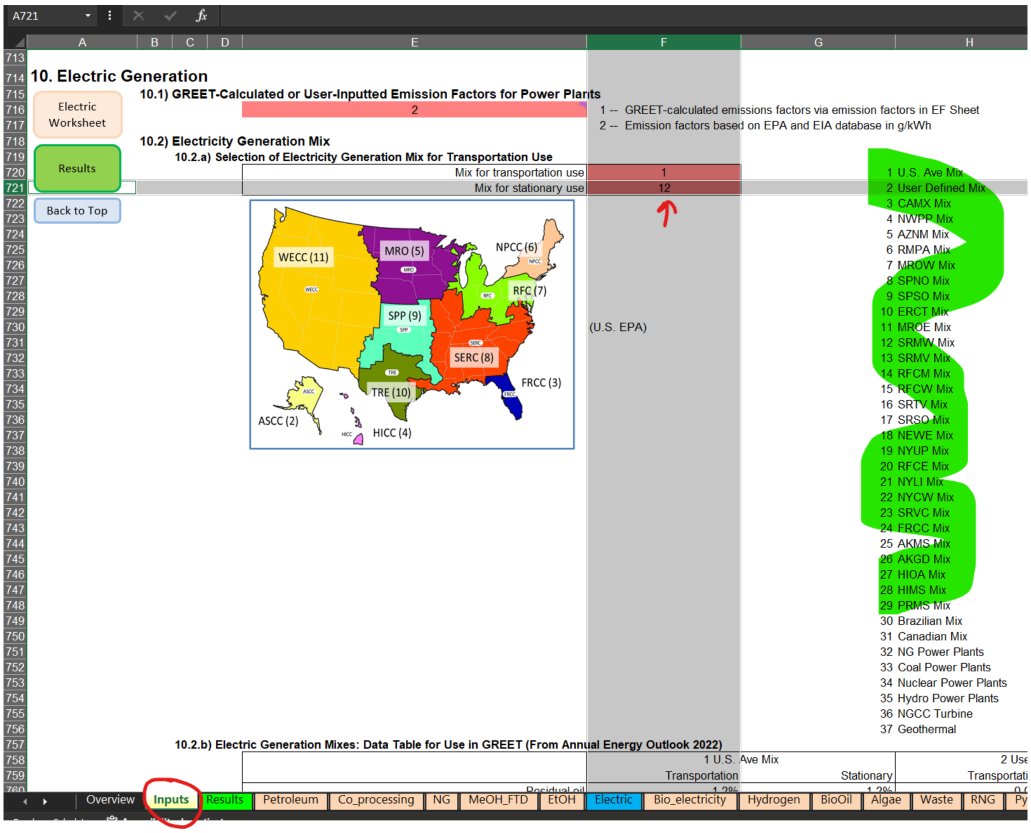
3. Default Regional EF-Electric tab: This screenshot displays the electricity emissions factor used in the Tier 1 calculators. The example below is from the SRMW sub-region, which was scored at 826 gCO2e/kwh.

200	9) Fuel-Cycle Energy Use, Water Consumption, and Emissions of Electric Generation: Btu or Gallons or			
201		Stationary Use: SRMW Mix		
202		Total		Urban
203		Feedstock	Fuel	Feedstock
204	Total energy	80,752	2,578,258	
205	Fossil fuels	79,492	2,346,209	
206	Coal	12,662	2,087,474	
207	Natural gas	33,635	253,710	
208	Petroleum	33,196	5,025	
209	Water consumption	10.944	144.821	
210	VOC	17.929	3.160	0.242
211	CO	11.235	65.872	0.702
212	NOx	20.413	155.730	1.512
213	PM10	18.044	17.048	0.063
214	PM2.5	2.672	13.427	0.053
215	SOx	17.362	200.712	0.467
216	BC	0.109	0.591	0.004
217	OC	0.212	1.507	0.014
218	CH4	378.912	33.782	
219	N2O	0.292	4.932	
220	CO2	5,839	224,124	
221	CO2 (w/ C in VOC & CO)	5,912	224,238	
222	GHGs	15,472	226,552	
223		14.66	214.7298862	825.820301
224	10) Calculation of Fuel-Cycle Energy Use, Water Consumption, and Emissions of other regional generati			

Overview | Inputs | Results | Petroleum | Co_processing | NG | MeOH_FTD | EtOH | Electric | Bi

Ready Calculate Accessibility: Investigate

4. Subregion Selection-Inputs tab: Screenshot 2 is looking for something 11 and under, but since there are 27 subregion selections, the vast majority (subregion selections 12 - 27) will drive the formula above to IFERROR correct to the U.S. average. This does not seem correct. Even if this were to be the case, for any subregion selection 11 and under, the INDEX formula operates "correctly," but then pulls a reference for an NERC region which has no association with the eGRID subregion selection the user made, which in turn drives an inaccurate calculation.



Thank you for the opportunity to provide feeback on the proposed LCFS regulations. We support CARB in its efforts to accelerate the carbon intensity reduction of transporation fuels through the LCFS Program, and appreciate the inclusiveness of stakeholders and thoroughness of its actions throughout the 2023/2024 LCFS rulemaking process. If CARB would like any further clarification on the comments above, please let us know.

Sincerely,

/Josh Thome/

Josh Thome, CPA
Manager of Environmental Analytics
U.S. Energy, a U.S. Venture company

Comment Log Display

Here is the comment you selected to display.

Comment 39 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Amy
Last Name	Hofmeister
Email Address	ahofmeister@glaciallakesenergy.com
Affiliation	Glacial Lakes Energy LLC
Subject	Proposed LCFS Amendments Comments
Comment	Please see my full comments in the uploaded file.
Attachment	www.arb.ca.gov/lists/com-attach/5824-lcfs2024-WzgBZgd0WWhWDwJu.pdf
Original File Name	CARB LCFS Amendments comments.pdf
Date and Time Comment Was Submitted	2024-02-13 07:47:08

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Glacial Lakes Energy, LLC
605-882-8480
PO Box 933, 301 20th Avenue SE, Watertown, SD 57201
www.glaciallakesenergy.com

February 13, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814
RE: Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

As a renewable fuel producer and participant in CARB's LCFS program, my team and I value the partnership and mission shared with you and your state to reduce the carbon intensity of transportation fuels.

I am writing to share our company's perspective on two key program areas for your consideration. These requests address the topics of **firm rotation** and **less intensive verification**.

Firm Rotation

The existing regulations within the LCFS verification program stipulate a mandatory rotation of audit firms every six years to assess participants' carbon intensity (CI) and fuel quantities compliance.

Our request is that CARB amend the mandatory firm rotation regulation to include an exception for licensed CPA firms. Of the 30 approved LCFS verification bodies, there are only four licensed CPA firms.

035.1 ***An approved verification body, that is also a licensed CPA firm, exceeds the standards in place for verification bodies and is already subject to additional oversight on the entity's quality control system in accounting and auditing practices through the required AICPA peer review process.***

Due to the increased regulatory oversight, we suggest a CPA firm not be subject to the audit firm rotation but would instead adhere to a Lead Verifier rotation after six consecutive years.

A licensed CPA firm differs from other consulting agencies by adhering to more rigorous standards and oversight at a state and national level. If a verification body were to violate a Lead Verifier rotation requirement, it would put the firm license at risk. The firm license is required for all services provided by the firm, not just the LCFS verification services, thereby ensuring adherence to requirements.

Licensed CPA firm requirements

- A licensed CPA firm must be comprised of over 50% of the ownership being licensed CPAs.
    - To earn the accreditation to be a CPA, one must pass a rigorous four-part CPA exam, accumulate education hours, and in many states, one must fulfill 1-2 years of work experience.

- 3-year peer review audit
    - Each licensed CPA firm must enroll in an approved peer review program with reviews conducted every 3 years. The peer review requirement is a requirement of the American Institute of Certified Public Accountants (AICPA) and is an external review of a firm's quality control system in accounting and auditing practices. CPA firms' peer review results can be found on AICPA's website under the Peer Review Public File Search.

- State Boards of Accountancy (SBOA) are found in each state's statute to aid state governments in the licensing and regulation of the public accounting profession.
    - SBOAs provide further oversight on CPA firms by evaluating CPA licensees' examinations and regulatory oversight to ensure a firm is practicing within their statutory scope.

The audit quality and efficiency improve as the auditor becomes more familiar with our company's processes. In addition, with the limited number of firms available as verification bodies and a five-year lookback period in place, it is proving difficult to identify a quality verification body that is not also working with our facility in other consulting capacities. The number of people available with the proper expertise to assist us in design and development of projects and to reserve for verification purposes has proven even more limiting, which is also why we request a Lead Verifier rotation rather than a full firm rotation.

Less Intensive Verification

Regarding less intensive verification, we noted in Appendix E staff's proposal for less intensive verifications for when electricity is used as a transportation fuel, allowing verification bodies to skip site visits if they visited the site in the last two years and issued a positive verification statement.

The rationale for this proposed change states, "there is little change of operation from reporting period to reporting period thus reducing the benefit of annual site visits." Additionally, staff rationale states, "There is no or little risk to the integrity of the LCFS program to allow for less intensive verification services without a site visit in the annual verifications for the following two years. This should reduce the cost of verification services which is often passed on to program participants."

Currently, the proposed language limits this allowance for less intensive verifications to QFTR third-party verification bodies for fuel reporting entities only reporting electricity transactions.

035.2 We agree with the staff's stated rationale, but **we request for less intensive verification to be extended as an option for verification bodies on all validations and annual verifications for any reporting entities.**

In CARB's MRR program (section 95130), less intensive verification is applied without prejudice to verification services by accredited verification bodies.

We agree with staff that less intensive verification leads too little to no risk to the integrity of the LCFS program and that there is little change in operation from reporting period to reporting period, while also providing cost savings to verification providers and passed on to our company as program participants.

We acknowledge the importance of adhering to CARB's specified conditions that necessitate comprehensive verification services. These conditions include the issuance of an adverse verification statement or a qualified positive verification statement in the preceding year and the occurrence of a change in operational control of the reporting entity in the previous year.

Thank you for your time and consideration. Please reach out to us if you have any questions.

Sincerely,

Amy Hofmeister

Amy Hofmeister
Environment, Health and Safety Manager

Comment Log Display

Here is the comment you selected to display.

Comment 41 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name Karen

Last Name Meyer

Email Address kb2bird@sbcglobal.net

Affiliation

Subject Factory Farm Gas in California's Fuel Standards

Comment

Dear Board Members,
I'm against including factory farm gas in California's Low Carbon
Fuel Standard. This will not be a positive solution for our climat
crisis. One of the main reasons to nix factory farm gas from the
standard is that it will encourage more large factory farms, makir
it harder for small family farms to prosper while these corporate
036.1 farms push down market prices with overproduction. More issues wit
this bill include the fact that multinational large meatpackers
will be paid for their pollution, and the bill will create
incentives via government subsidies to support anaerobic digester
for factory farm gas.
This would add more factory farms which will lead to more methane
more water and air pollution, more corporate consolidation. I'm ir
the Midwest and know this will not lead to less carbon release in
our atmosphere. Please strike this portion of the amendments.
Thank you for allowing comments.

Attachment

Original File Name	
Date and Time Comment Was Submitted	2024-02-14 09:52:05

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

Here is the comment you selected to display.

Comment 42 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ron
Last Name	Yarger
Email Address	ronyarger@live.com
Affiliation	
Subject	Biofuel
Comment	I am adamantly opposed to these and any support for them. 037.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-14 10:02:22

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

Here is the comment you selected to display.

Comment 44 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Margaret
Last Name	Eaton
Email Address	Mebwire@gmail.com
Affiliation	
Subject	California Bio Gas Bad Idea
Comment 038.1	Please do not allow the CA Air Resources Board to allow corporate factory farms across the country to sell methane to this misguided system- which is not a solution to our country's air pollution problem. We must stop allowing big corporate farms to create this hazardous gas in the first place.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-14 10:42:45

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

Here is the comment you selected to display.

Comment 45 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	susan
Last Name	austin
Email Address	susancataustin@gmail.com
Affiliation	
Subject	California low carbon fuel standard
Comment	

039.1

```
Please do not include factory farm gas in the new California Low
Carbon Fuel standard.  Doing so is harmful to the environment by
encouraging more factory farms.  These are polluting to our land,
water and air quality resources.
Corporate out of state and in many cases out of country businesse
will profit from this change.
Thank you for not including factory farms in your efforts to lowe
carbon emissions
```

Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-14 13:13:25

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

Here is the comment you selected to display.

Comment 49 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Anthony
Last Name	Trujillo
Email Address	ate2001@sbcglobal.net
Affiliation	
Subject	CARB
Comment	CARB lies about the efficiency of EVs!! In their ARB/MSD/7-6-94 they claim that battery efficiency is 80% and motor is 90%. These are LIES!!!! Charging a battery in one hour has an efficiency of 5.88%, in 15 minutes ONLY 0.3675%!! The motor efficiency depends on how many stops are made. Each time the motor starts the motor and system efficiency are almost ZERO!!!! Every time the motor starts the battery efficiency is also degraded because of the high motor starting current!!!! 040.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-14 22:14:21

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

Here is the comment you selected to display.

Comment 50 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nancy
Last Name	Ames
Email Address	njoames@gmail.com
Affiliation	
Subject	LCFS2024
Comment	This is a bad plan. Corporate livestock operations are massive polluters of air, water, and land. I do not want to incentivise these businesses or attract them to rural Missouri. They are a huge cost to the communities located near them, and massively destructive for wildlife. Vote NO
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-14 23:13:23

041.1

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Comment Log Display

Here is the comment you selected to display.

Comment 52 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ben
Last Name	Lilliston
Email Address	blilliston@iatp.org
Affiliation	Institute for Agriculture and Trade Poli
Subject	IATP Comment on LCFS2024
Comment	The Institute for Agriculture and Trade Policy submits the attache comment to CARB on the Low Carbon Fuel Standard's proposed amendments. Thank you for considering these comments as CARB move: forward on reforms.
Attachment	www.arb.ca.gov/lists/com-attach/6116-lcfs2024-WzgGYVMgVGVWDwZI.pdf
Original File Name	CARB comment on LCFS from IATP.pdf
Date and Time Comment Was Submitted	2024-02-15 09:04:17

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 15, 2024

To: California Air Resources Board

Re: Low Carbon Fuel Standard - https://ww2.arb.ca.gov/rulemaking/2024/lcfs2024

The Institute for Agriculture and Trade Policy (IATP) welcomes the opportunity to comment on the California Air Resources Board (CARB) proposed amendments to its Low Carbon Fuel Standard (LCFS). IATP is a 38-year-old, non-profit organization with headquarters in Minnesota that works nationally and internationally for fair and sustainable food and trade systems.

Throughout IATP's history, we have seen firsthand the economic and environmental harm the transition to large-scale confined animal feeding operations (CAFOs) has caused to rural communities in Midwest states. California's LCFS, unfortunately, has contributed to the further expansion of the CAFO system in Midwest states, such as Minnesota and Wisconsin, through its skewed emissions intensity scoring and associated credits for CAFO-derived biogas. An analysis by CoBank concluded that incentives and credits generated through California's LCFS "are the main source of revenue for dairy digester projects."[1] We do not believe biogas projects that subsidize Midwest CAFOs are consistent with California's LCFS intention and purpose: to reduce California's GHGs through its transportation sector by requiring cleaner fuels.

IATP offers the following comments on the LCFS's proposed amendments:

<u>CARB's LCA for biogas excludes significant emissions</u>

Biogas derived through methane digesters on large-scale CAFOs requires enormous quantities of animal manure. The largest source of direct methane emissions from dairy and beef CAFOs is the animals themselves (at least two-thirds), the remaining emissions (methane and nitrous oxide) come from giant, often liquified, waste lagoons. Hog CAFO emissions come entirely from liquified manure storage. Other greenhouse gas emissions associated with the CAFO system include feed production and the spreading of manure on neighboring fields. Despite the significant emissions coming from the CAFO system, CARB's current emissions intensity analysis gives biogas a negative carbon intensity score, lower than any other transportation fuel, including electricity produced by solar and wind energy which produce no discernable waste, emissions or water pollution.[2]

[1] https://sso.cobank.com/documents/7714906/7715329/Interest-in-California-Dairy-Manure-Methane-Digesters-Follows-the-Money-Aug2020.pdf/be11d7d6-80df-7a7e-0cbd-9f4ebe730b25?t=1603745079998

[2] https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2023/092823/23-8-1pres.pdf

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We urge CARB to reconsider how it calculates its biogas emissions intensity score in the following five areas:

1) The "avoided methane" crediting policy assumes that open air flaring is the only option for dairy, beef or hog producers and that captured methane is an "avoided emission." This ignores alternative approaches to raising animals (such as on appropriately scaled, pasture-based systems that avoid giant liquid manure lagoons all together) and better manure management (such as lower-emitting dried manure
042.1 systems). In other words, the CAFO system itself and its management of manure is demonstrably avoidable.
2) CARB's low score for biogas and ensuing credits incentivizes more manure production from large CAFOs. As farmers struggle through volatile and often below-cost markets, payments for waste production create a new income stream that can subsidize larger herd sizes to produce more manure and access more LCFS credits.[3] The growth of CAFOs mean additional direct cow-related emissions. Currently, CARB does not have an effective system to track operations seeking biogas credits that are expanding their herd size (with associated additional methane emissions), or whether the LCFS is helping to finance new CAFOs with additional emissions.
3) The state does not account for several major sources of CAFO emissions within its biogas scoring system. CAFO systems are entirely dependent on low cost (sometimes below cost) feed often from off the farm, just as ethanol or biodiesel are entirely dependent on corn and soy production. The LCA for biogas from beef, dairy and hog CAFOs does not include the significant emissions associated with feed, including nitrous oxide emissions associated with fertilizer use (particularly for corn) and emissions associated with the harvest, processing and transport of feed to the CAFO. The LCA also doesn't include emissions from cows themselves in the case of dairy and beef. Finally, the LCFS does not count the emissions associated with the application of biogas digestate on the land, which can emit more methane and nitrous oxide than undigested manure.[4]
4) There is growing evidence that CAFOs with biogas digesters are still significant sources of methane emissions. Recent Food & Water Watch research found that 15 California dairies, with biogas digesters receiving credits through the LCFS, emitted enough methane to be tracked by satellite and imaging aircraft.[5] Other researchers have found that digester systems often leak, leading to an underestimation of their emissions.[6] Methane leaks from digesters could contribute to as much as a 15% loss rate — cutting into its emissions intensity score and making it impossible to be a net loss emitter.[7]
5) CARB doesn't adequately consider new models of methane digesters, where manure or gas are trucked from several surrounding CAFOs to a centralized digester. For

[3] https://hoards.com/article-30925-energy-revenue-could-be-a-game-changer-for-dairy-farms.html
[4] https://www.sciencedirect.com/science/article/pii/S0167880917300701
[5] https://storymaps.arcgis.com/stories/4b708bdc0d2d419ba34cb352ca79b6e3
[6] https://www.sciencedirect.com/science/article/pii/S2590332222002676
[7] https://iopscience.iop.org/article/10.1088/1748-9326/ab9335

example, a Wisconsin digester project is accessing LCFS credits sources from three local dairies.[8] A proposed Minnesota digester would collect manure from four dairies in three counties.[9] Each project includes an enormous amount of additional truck traffic and fuel use to be workable, not to mention the emissions associated with each individual CAFO.

<u>CARB ignores impacts on rural communities outside of California</u>

042.2 One of the stated objectives of the LCFS and associated amendments is "to strengthen equity provisions and promote investment in low income, rural communities…." While the LCFS extends well beyond the boundaries of California, with projects all over the country, CARB's Standard Regulatory Assessment Analysis notably does not consider rural communities outside of California. We strongly urge CARB to conduct analysis and monitoring of whether low-income, rural communities outside of California are benefiting from biogas investment through the LCFS, including a process for direct public input from community-members.

California's LCFS has already sent credits to multiple dairy farms in western Minnesota, throughout Wisconsin and in states around the country.[10,11] Last month, Minnesota's Public Utility Commission held a hearing in western Minnesota for a $13.9 million plan for a 28-mile pipeline of methane gas from four local dairies into a nearby natural gas pipeline.[12] The project developers have stated they plan to have California's LCFS credits help pay for the project. Another digester in western Minnesota is capturing nearly 700,000 gallons of daily manure from three big dairies to power a digester that has partially financed by carbon credits.[13] Minnesota lost nearly 150 dairy permits in 2023, much of them due to the shift toward larger dairy CAFOs. Biogas digesters are too costly for small and mid-sized dairies, and the economics don't work for those not located near natural gas pipelines. In essence, CARB's LCFS system is picking winners and losers in states outside of California.

<u>The phase out timing for biogas credits is too long</u>

042.3 CARB's current "deliverability" requirements that out-of-state biogas be simply added to a North American pipeline — without assurance that it will be used in California — run counter to the intention of the LCFS and greatly weaken the effectiveness of the policy. The proposed amendments to strengthen the "deliverability" requirement for projects started after 2029,

[8] https://investigatemidwest.org/2023/12/22/bio-cash-how-a-cow-powered-controversial-fuel-ingests-wisconsin-clean-energy-dollars/

[9] https://www.mprnews.org/story/2023/09/12/digesters-make-renewable-energy-from-manure-but-face-hurdles

[10] https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities

[11] https://foodandwater.maps.arcgis.com/apps/mapviewer/index.html?webmap=a40e6dc32bfa4165af469b3a648d4a76

[12] https://www.agweek.com/livestock/dairy/minnesota-puc-to-host-meeting-on-13-9m-pipeline-transporting-renewable-natural-gas-from-dairy-farms

[13] https://www.dmt-cgs.com/minnesota-first-rng-plant-amp-americas-dmt/

with a 10-year grace period, unnecessarily delaying a much-needed fix that could and should happen next year.

CARB's own Initial Statement of Reasons (ISOR) admits that biogas takes up only a fraction of vehicle fuel use and that biogas use will decline as zero emission vehicles penetrate the market.[14] There is an acknowledgement that biogas as a transportation fuel will need to transition out of the fuel mix to avoid stranded assets. We agree and would argue that waiting until after 2029 (with an additional 10-year grace period) to phase out biogas crediting is an excessively long period and should be eliminated, particularly for a transportation fuel that depends on waste production and could add GHG emissions in its production.

<u>Guardrails for crop-based biofuels are threatened by Sustainable Aviation Fuels</u>

A recent National Academy of Sciences paper on life cycle assessments highlighted the critical importance of evaluating scale when assessing different transportation fuels.[15] The proposed amendments open the door for the inclusion of Sustainable Aviation Fuels (SAF) for flights within the state of California. The future of the SAF market is highly speculative. The World Resources Institute estimates that to meet the Energy Department's stated goal on SAF it would require an additional 114 million acres of corn, 20% more than current corn acreage.[16] This type of major expansion in corn production would have a profound effect on land use change. We urge CARB to consider the impact of the additional inclusion of SAFs within the
042.4 LCFS credit system for California and land use emissions in other states and countries.

<u>The LCFS Amendments Ignore California's own Environmental Justice Advisory Committee</u>

The state's Environmental Justice Advisory Committee (EJAC) was sharp in its criticism of the current LCFS, including the way CARB has evaluated CAFO biogas. In its comment, the Advisory Committee stated, "The LCFS has exacerbated and entrenched harmful pollution in communities near and regions containing large dairies and other confined animal feeding
042.5 operations by incentivizing the production, storage, and land application of wet manure."[17] EJAC specifically called on CARB to " Conduct a full accounting of GHG and air pollution emissions associated with pathways relying on the production of fuel from livestock and dairy manure"; "Eliminate avoided methane credits effective January 1, 2024;" and "Eliminate credit generation for pathways relying on the production of fuel from livestock and dairy manure for emissions reductions that otherwise would have occurred or were legally or contractually required to occur." EJAC further recommends that CARB take steps to "immediately initiate formal rulemaking for the regulation of livestock methane."

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[14] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf

[15] https://www.nationalacademies.org/our-work/current-methods-for-life-cycle-analyses-of-low-carbon-transportation-fuels-in-the-united-states

[16] https://www.wri.org/insights/us-sustainable-aviation-fuel-emissions-impacts#:~:text=If%20the%20U.S.%20were%20to,United%20States%20for%20all%20purposes

[17] https://www.arb.ca.gov/lists/com-attach/1-lcfs2024-VjMFaQNjUGABWFA0.pdf

IATP is supportive of EJAC's recommendations, and we urge CARB to revise its LCFS amendments accordingly.

IATP thanks CARB for considering these comments. Please direct follow-up questions or correspondence to Ben Lilliston at blilliston@iatp.org.

Comment Log Display

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Comment 53 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Margaret
Last Name	Laub
Email Address	margaret.laub@anaergia.com
Affiliation	Anaergia
Subject	Comments on Proposed LCFS Program Changes
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6120-lcfs2024-UTAGbgNjVGJWIgNk.pdf
Original File Name	Anaergia CARB LCFS Comments - 20240220.pdf
Date and Time Comment Was Submitted	2024-02-15 09:31:12

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Anaergia Services, LLC
705 Palomar Airport Rd, Ste 200
Carlsbad, CA 92011 USA

February 20, 2024

The Honorable Steven S. Cliff

Executive Officer

California Air Resources Board

Sacramento, CA 95814

Re: Proposed Amendments to the Low Carbon Fuel Standard Regulation

Dear Executive Officer Cliff,

Anaergia Services LLC (Anaergia) is a global leader in diverting organics from landfill-bound waste and converting them into renewable fuel and soil amendments. Based in Carlsbad, CA, Anaergia is actively deploying anaerobic digesters in California and converting landfill-diverted organic waste into carbon-negative fuels. Our Rialto Bioenergy Facility (RBF) – the largest landfill-diverted-organics-to-renewable-fuel facility in America – can process over 175,000 tons per year of diverted organics and produce 1,000,000 MMBtu/yr of renewable natural gas (RNG). After 4 years of planning and construction with over $180M invested, RBF is operational and has created at least 50 permanent jobs, hundreds of construction and service jobs, and over 500,000 hours of construction work.

These facilities are part of the 160 new projects that CalRecycle estimates are needed to meet California's statutory organic waste landfill diversion goals established under SB 1383 (Lara, Chapter 395, Statutes of 2016). A strong LCFS program is critical for the long-term success of RBF and is foundational to continued investment in development and expansion of similar critical infrastructure, which are foundational for achieving carbon neutrality by no later than 2045.

Biomethane, including biomethane from landfill-diverted organic waste, is a critical tool in meeting the State's targets, and it is essential that biomethane production within the State is not only supported but increased to achieve the necessary methane and carbon dioxide reductions most rapidly and most cost-effectively. Anaergia is heartened at the success to date of the LCFS in advancing biomethane production in the State and nationwide, in part through the adoption of similar programs which build on California's. However, we urge CARB to consider the below strategies preserve and accelerate progress made to date towards the State's and LCFS program's ambitious carbon intensity reduction goals.

Increase Near-Term Carbon Intensity (CI) Reduction Targets

043.1 We are supportive of CARB's proposed carbon intensity (CI) reduction targets. However, we encourage even more ambitious near-term targets to match statewide greenhouse gas reduction target codified in SB 32 (Pavley, Chapter 249, Statutes of 2016). While we are supportive of the increased 2045 carbon intensity target, emissions reduction in the near-term is most critical to avoid runaway climate change and its most harmful effects. We have seen the success of the LCFS in driving rapid transition towards renewables and decarbonization in the transportation industry. As California's largest source of emissions, the transportation sector must play a leading role in achieving the State's climate change and air quality objectives. Therefore, carbon intensity targets under the LCFS should be no less than statewide greenhouse gas reduction targets. Adopting higher near-term LCFS carbon intensity reduction targets of at least 40% will not only drive progress towards long-term Statewide climate goals; this change will also incentivize

Anaergia Services, LLC
705 Palomar Airport Rd, Ste 200
Carlsbad, CA 92011 USA

near-term achievement of emissions reductions, especially in the transportation sector and communities where they are needed most, providing additional runway to mitigate and reverse climate change. Anaergia encourages CARB to **adopt a more aggressive 2030 CI reduction target (40-55%) to be consistent with SB 32.** It is not the time to set manageable goals and to delay more significant reductions; rather, we must make leaps in carbon emissions reductions to secure additional runway to mitigate and reverse climate change.

Maintain Avoided Methane Crediting Beyond 2040

043.2 Anaergia urges the LCFS to maintain consistency with other California climate programs and with the LCFS itself. Of critical importance maintaining the GREET-based lifecycle approach to emissions accounting for biomethane, which is currently accurately employed for all other eligible LCFS fuels. Eliminating avoided methane crediting for only biomethane would represent a singular and premature change in accounting. Further, this change would contradict the program's design and objectives, the established GREET model, accepted science, and California's progress towards SLCP emissions reductions goals.

There are numerous avenues to achieve SB 1383 compliance, not all of which are equal from an emissions perspective. A particularly important tool is anaerobic digestion (AD) of landfill-diverted organics to generate biomethane, which results in greater methane emissions reductions than composting organic waste, while also generating RNG to reduce fossil fuel use. On balance, with the increased climate benefit of AD, these complex facilities are more expensive to construct and operate, especially in California. Investment and sustainable operation of organic waste digesters relies on adequate revenue generation through the project lifecycle, primarily through biomethane sales. With facility lifespans in excess of 20 years, eliminating avoided methane crediting – even as soon as 2040 – negatively impacts revenue available to finance these capital-intensive facilities. The resulting major reductions in expected revenue will halt investment and therefore the SLCP reduction potential of projects in operation and development today. These complex facilities are not financeable without long-term (20+ year) avoided methane crediting, especially as no other equivalent program has yet been established to appropriately incentivize biomethane uptake.

The full lifecycle benefits of AD must be accounted for via appropriate methane crediting and biomethane valuation to promote organic waste digesters and achieve SLCP reductions goals. Currently, it is clear that California-generated biomethane from organic waste does **not** have a market value reflective of its real-life climate benefits, nor sufficient to garner the needed investment: CalRecycle estimates over 100 such facilities are needed in California to accommodate the 20 million tons per year of organics that must be diverted from landfill per SB1383; however, RBF is the only such food waste digester currently operating in the State. (This is compounded by the near-term lack of deliverability requirements.) The premature and arbitrary elimination of biomethane crediting will further disincentivize development of this effective methane reduction strategy in two ways: first, by devaluing biomethane and negatively impacting project economics; and second, by creating uncertainty in the market and thereby reducing investor confidence and financeability. In short, changing the approach to avoided methane crediting in the LCFS will jeopardize
043.2 cont the State's ability to meet its SLCP reduction goals and to develop additional biomethane supplies necessary to achieve carbon neutrality.

Maintaining credits for avoided methane emissions beyond 2040 is absolutely essential to the continued operations of existing facilities generating biomethane from landfill-diverted organics, the

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705 Palomar Airport Rd, Ste 200
Carlsbad, CA 92011 USA

development of and investment in additional similar facilities, and ultimately the achievement of SB 1383, SB 32, and AB 1279 (Muratsuchi, Chapter 337, Statutes of 2022). Eliminating avoided methane credits will irreparably damage the industries sorely needed to achieve the State's highest priority climate goals.

Update Tier 1 Calculator for Food Waste Biomethane to Reflect Latest Science on GCE

043.3

Part and parcel with maintaining avoided methane crediting is ensuring the Tier 1 simplified calculator for Biomethane from Anaerobic Digestion (AD) of Organic Waste (OW) accurately quantifies the carbon intensity of biomethane from landfill-diverted organics. The LCFS Program has consistently presented on the importance to update aspects of the LCFS program to "reflect evolutions in technological performance and data availability.[1]" Anaergia commends CARB for updating the calculator in recognition of fugitive methane emissions from landfills' open face and the negligible gas collection efficiency (GCE) within the first few years of disposal of organics in landfill. However, more changes to the calculator's default assumptions are necessary to match the latest science, including recent US EPA findings published in October 2023.

Currently, the calculator assumes that t 75% of methane emissions from organics in landfill is captured starting at Year 4, based on a stipulated assumption from a 1997 US EPA study. This value, which the EPA study itself identifies as a placeholder value in the absence of more data, has been repeatedly shown to be a severe underestimate by more recent work leveraging advanced data collection methodology in California, the US, and worldwide. A 2019 study by NASA JPL estimates that landfills' contribution to the state's methane emissions is double current estimates – approximately 41% of all methane point source emissions in California.[2] This conclusion is supported by a report published by the Maryland Department of Energy finding that emissions from landfills were "four times greater" than previous estimates and were the leading source of methane emissions (37%) in the state.[3] The updated estimates were facilitated by the use of direct measurements instead of models. The NASA JPL study, in particular, deployed specialized airborne imaging spectrometers attached to drones, which could rapidly map methane plumes.[4] Deploying this remote sensing technology significantly improved the determination of methane emissions associated with landfills. In exceptional alignment with these studies, in October 2023, EPA published its findings that 61% of methane generated by food waste in landfill is emitted to atmosphere (i.e., a GCE of only 39%).

With CARB's endorsement of EPA as standard-bearer for capture rate, this EPA-quantified value should immediately replace a previous, outdated estimate. It is critical that CARB utilize the findings of improved monitoring and analysis techniques from the last quarter-century to inform and update the default landfill GCE. **We strongly urge CARB to update its 75% methane landfill capture assumption in the LCFS Tier 1 Calculator to reflect this latest EPA-published value**, which clearly affirms that landfill GCE in use at the State and national levels are well below the current default assumption.

Updating the fugitive methane emission factor will more accurately reflect the avoided carbon emissions associated from biomethane produced from anaerobic digestion of landfill-diverted organic waste. A more

[1] https://ww2.arb.ca.gov/sites/default/files/2021-12/LCFS%2012_7%20Workshop%20Presentation.pdf
[2] Duren, R.M., Thorpe, A.K., Foster, K.T. *et al.* California's methane super-emitters. *Nature* **575,** 180–184 (2019). https://doi.org/10.1038/s41586-019-1720-3
[3] https://environmentalintegrity.org/wp-content/uploads/2021/06/MD-Landfill-Methane-Report-6.9.2021-unembargoed_with-Attachments.pdf
[4] Duren, R.M., Thorpe, A.K., Foster, K.T. *et al.* California's methane super-emitters. *Nature* **575,** 180–184 (2019). https://doi.org/10.1038/s41586-019-1720-3

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705 Palomar Airport Rd, Ste 200
Carlsbad, CA 92011 USA

accurate CI score for biomethane from organic waste digestion will accelerate the deployment of anaerobic digestion throughout the State for landfill-diverted organics. This in turn can help the state achieve its goals to reduce SLCP emissions, per SB1383. Ultimately, this simple calculator update to reflect the latest landfill monitoring techniques and data can have an outsized impact on minimizing fugitive emissions of SLCP at landfills. Neglecting to correct the Tier 1 default GCE will result in the continued undervaluation of biomethane from organic waste and severely dampened investment in critical climate mitigating infrastructure.

Conclusion

Climate change is a grave threat to our environment and our economy. California has set an ambitious climate strategy and laws to reduce greenhouse gas emissions. Maintaining and improving LCFS is essential to support the development of a robust supply of in-state, carbon-negative biomethane, helping to achieve the State’s targeted reductions in SLCP emissions and encouraging in-state economic development.

In particular, avoided methane crediting is a powerful tool as a market signal to encourage investment and advance California climate goals – and it’s efficacy hinges on its correct CI determination through GREET. Updates to LCFS that enable the most accurate avoided methane crediting on a lifecycle basis will incentivize investment in food waste diversion infrastructure in California – where its benefit is most keenly felt – and establish a strong pipeline of cost-effective, carbon-negative biomethane generation to support both the transportation sector under LCFS and ultimately non-transportation sectors as well.

We deeply appreciate your leadership in mitigating climate change and hope that our comments will help to make these excellent programs work even better in the future.

Respectfully,

Dr. Yaniv Scherson
Chief Operating Officer
Phone: 949.987.1118
Email: Yaniv.Scherson@anaergia.com

CC:
Steve Cliff, Executive Director
Rajinder Sahota, Deputy Executive Director for Climate Change and Research
Matt Botill, Division Chief

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Comment 52 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Sherry
Last Name	M Kerr
Email Address	sherrykerr@live.com
Affiliation	
Subject	large corporate farms

Comment

I am truly concerned about having more huge corporate farms moving into our state. (Missouri). And, paying them for the methane they produce would invite MORE to come to our state. 044.1
They are often owned by out of country people from China and other places that do not have our best interests at heart.
They raise animals in crowded, unhealthy, unnatural, conditions that are not humane..............
They are harmful to our water supply and harmful to the environment..........
Seems we can do a better job of raising animals on a smaller, more natural basis.............and more humane.

Respectfully,
Sherry Kerr

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-15 09:55:33

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Comment 53 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Claire
Last Name	Foster
Email Address	claire.foster@fidelisinfra.com
Affiliation	
Subject	Fidelis New Energy's Comment Letter Submission
Comment	Good afternoon, On behalf of Fidelis New Energy, LLC, please see attached the company's comment letter in response to the proposed amendments fo CARB's LCFS legislation. We applaud CARB's continued efforts to improve the LCFS program and maintain California's position at the forefront of climate positive legislation. Respectfully submitted, Fidelis New Energy, LLC
Attachment	www.arb.ca.gov/lists/com-attach/6136-lcfs2024-B2tSN1M0U3MAWQZ2.pdf
Original File Name	LCFS Program Proposed Amendments Letter for Submission.pdf

Date and Time Comment Was Submitted	2024-02-15 11:53:38

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FIDELIS NEW ENERGY
CLIMATE POSITIVE CARBON NEGATIVE
WWW.FIDELISNEWENERGY.COM

FIDELIS NEW ENERGY, LLC
109 NORTH POST OAK, SUITE 140
HOUSTON, TEXAS 77024
(832) 551-3300

Liane M. Randolph
Chair – Low Carbon Fuel Standard
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Proposed Amendments to the Low Carbon Fuel Standard

Dear Chair Randolph,

We appreciate the opportunity to provide feedback on the proposed Draft Amendments to the Low Carbon Fuel Standard.

Fidelis New Energy, LLC ("Fidelis") is an energy transition company driving decarbonization through investments in renewable fuels, low-carbon intensity products, and carbon capture and storage. Using proprietary technology and processes, Fidelis aims to develop, invest, and deliver climate positive and carbon negative infrastructure to reach carbon reduction and climate positive targets. Fidelis develops carbon negative sustainable aviation fuel, renewable diesel, renewable naphtha, clean hydrogen, and clean ammonia infrastructure; in addition to developing and operating CO2 capture units, pipelines, sequestration wells, and related transportation and sequestration infrastructure.

We applaud the California Air Resources Board's efforts to pursue means of ensuring the continued success of the low carbon fuels standard. Our comments on proposed changes to the Standard are as follows:

Fidelis Supports Expanding Definitions for Acceptable Biomass Waste Feedstocks

045.1 It is critical for CARB to adopt a broader biomass definition in not only the most recent LCFS legislative proposal, but all future policy rulings by the Agency. The proposed utilization of arbitrary terms such as "unmerchantable" and certain "diameter sizes" for secondary material unnecessarily limits the potential feedstock pool, in potentially counterfactual ways, ultimately limiting the adoption of carbon neutral and negative technologies.

045.2 Furthermore, it is unreasonable to qualify material based upon diameter. This is out of alignment with existing federal programs and would be a departure from industry norms. Tracking and classifying material eligibility based on material diameter is not practical for companies to pursue from an effort, in-field feasibility, and cost perspective. Anything that is deemed as incidental material should be permissible as biomass feedstock, regardless of size. This would be inclusive of larger diameter residues, sawmill residues, and other to-be-defined materials.

One telling example would be the application of woody biomass generated as debris resulting from a natural disaster, such as a hurricane. In Louisiana, roughly 2 million tons of debris are generated per parish due to hurricane damage. Material generated in this quantity, and this quality, are generally destined to be landfilled as a means of disposal/use. From this perspective, the material

FIDELIS NEW ENERGY
CLIMATE POSITIVE CARBON NEGATIVE
WWW.FIDELISNEWENERGY.COM

FIDELIS NEW ENERGY, LLC
109 NORTH POST OAK, SUITE 140
HOUSTON, TEXAS 77024
(832) 551-3300

is truly "unmerchantable". However, this hurricane debris - largely felled trees, large limbs and branches, fibrous industrial debris such as wooden planks and sidings from buildings, etc.- would then fall outside the identified diameter limitations currently proposed, limiting a positive utilization option and further impairing the local environment. Based on the current proposed biomass limitations, this hurricane debris would not be viewed as a usable feedstock, despite its utilization in fuel/power production being a greener alternative than the material going to landfill to decompose.

045.3 In Fidelis' experience, a common point of concern amongst stakeholders is the availably and longevity of biomass supply. Focusing narrowly on specific forestry residuals, such as fire mitigation clearings, will restrict the longevity and sustainability of biomass management industries, and pits various regions of the US against one another, rather than focusing on the scientific benefits of biomass management in general. For the bioeconomy to flourish, all available biomass opportunities must be accessible to producers for credit generation including management actions necessary to maintain a healthy ecosystem, such as thinning. It is vital that the legislation considers the economic and environmental benefits of utilizing biomass uniquely to all regions and not through a narrow consideration of biomass impacts specific to certain regions, such as fire management areas. This is important because fire management and mitigation only applies as a main driver for biomass in a few western states while it is not directly applicable for most of the available biomass in the United States.

Louisiana is one of the most prolific managed forestry regions in the world, with roughly 290 million tons per year of pulpwood and forest residuals harvested every year across the entire region. Pulpwood, sometimes referred to as "pre-commercial thinnings" or "secondary residuals", is a byproduct of prudent forestry management generated in to ensure healthy forest stands and state, local, and private habitat management.

Though there are some market outlets for this material today, the utilization of forestry management byproducts would not result in market distortion for these products. In fact, a market for this material is necessary to continue supporting proper timberland forestry management whereby the historical offtake demand for this material at pulp and papermills is significantly receding. With the closure of the papermills, there currently exists few viable markets for low-grade or waste timber in the Southeast, resulting in an increase of forest biomass thinnings left to decay on the forest floor where it is converted into CO2 that is released into the atmosphere. Without a healthy market for pulpwood and low-grade fiber in the area, forestry management on hardwood stands would no longer be economically feasible, reducing the ability to properly manage forests. This would result in unhealthy and low-quality timber stands that would take decades to recover, in addition to unmanaged ecosystems that will impair local wildlife. Projects participating in the LCFS program would provide a viable and sustainable market for low-grade hardwood and softwood fiber. This in turn would allow foresters to effectively manage the region's forest resources. Effective forestry management practice results in positive environmental impacts such as: increased carbon stocks stored in living large older trees and improved habitats for endangered species.

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109 NORTH POST OAK, SUITE 140
HOUSTON, TEXAS 77024
(832) 551-3300

Forestry suppliers would comply with operational integrity requirements, as many of these documentation and planning practices are industry standard today. For example, in Louisiana, a forestry management plan precedes harvests with the express purpose of supporting suspected and known endangered species on the sites. In forestry managed areas, plans are reviewed by biologists, academics, agency staff, and the public (in the case of state-owned land). All forestry management operations are currently documented. This documentation covers all harvest and thinning operations and includes property descriptions, dates of treatment(s), employed contractors, current stand conditions, volumes, and future planned activities. Supporting the low-grade wood market in the region allows forest managers to appropriately maintain forest stand health as well as habitats of endangered species found on the managed properties.

Guided by a life-cycle emissions analysis approach, Fidelis recognizes the climate-positive opportunity to utilize a wide variety of potential biomass sources, including pulpwood, as a renewable fuel feedstock, providing an alternative use for byproduct materials.

Fidelis Supports Scoping Feasible Traceability and Certifiability Procedures

045.4 Letters of attestation are an appropriate means of providing feedstock certification that aligns with the 7 priorities identified by CARB in its recent LCFS proposal, as well as appropriately fitting the maturity of the upstream biomass industry.

In terms of establishing a chain of custody for traceability purposes, bills of lading ("BOLs") are a tool used by multiple sectors today to trace material movements along their supply chains. Whether it be forestry management materials, landfill diversion, ag residues, or other material groups, BOLs provide a means of tracing the supply chain of custody for biomass to be used by BECCS facilities from the point of origin to final user. As a legally binding document, BOLs provide a complete description of shipments and parties involved, including:

- The quantity, value, and weight of the cargo.
- A complete description of items within the cargo, and its freight classification.
- The shipping and receiving parties as well as their signatures and the shipping date.
- Location of origin and destination

By tracking and documenting these components, BOL's ensure that there is oversight from point of origin to transport vehicle, to staging destination (if applicable) to end-user. In doing so, this document creates a receipt for the products, and generates a traceable supply chain for BECCS facilities.

Depending on the type of biomass material being utilized and the scale of the BECCS facility, the length and structure of the supply chain will vary. BOL's will allow these variances to be captured. Two examples that help demonstrate this difference are:

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- Residues sourced from a local mill and trucked to the BECCS facility.
    - In the case of mill residues and chips, the point of origin would be the mill where the materials were generated as a secondary waste in the milling process and loaded for transit. It is at this point that the residues would become a secondary product eligible as a feedstock for usage under CARB's LCFS, as well as other programs, given they are a waste stream and were not purposefully generated as a fuel or feedstock.
    - A single BOL would be generated in this instance: at the loading of materials onto a truck at the local mill, to be delivered to the BECCS facility and signed by the receiving personnel on site with specific details around the batch (volume, product, quality, etc.).
    - Because these feedstocks are a processing residue resulting from the production of primary materials such as finished lumber, furniture, pallets, barrels, etc., it is an undue burden upon the mill owner to trace residues upstream of the facility. Furthermore upstream actions were not intended for the utilization or consumption of these residual fibers. Should these fibers not be utilized, mills would landfill the product, leading to CO2 emissions in the decomposition process.
- Pulpwood, and other byproducts and residues, sourced from managed forestry stands.
    - In the case of this example, this could include but would not be limited to: wood fiber of low grade quality and various diameters, material falling within a pulp classification, limbs/tops/slash/bark, or other low-grade material that would be harvested, potentially in-woods chipped, and/or left on the forest floor.
    - In the case of forestry management material, the point of origin would be where this pulpwood and low-grade fiber would be collected, and potentially chipped, and loaded into trucks at the timber stand where the material was harvested as part of established forestry management practices and loaded for transit.

045.4 cont Tracking BOLs from point of origin to the end-user will enable the certifiability of the material utilized for the benefit of BECCS facilities, increasing oversight and transparency across the supply chain.

Fidelis Supports More Aggressive CI Benchmark Carbon Intensities and GHG Targets

We applaud the California Air Resources Board's efforts to implement more stringent carbon intensity benchmarks to support the continued success of the low carbon fuels standard.

The Low Carbon Fuel Standard has doubled the volume of low carbon fuels over the past ten years, diversified the fuel supply mix in California, and has overperformed compliance targets. This

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HOUSTON, TEXAS 77024
(832) 551-3300

overwhelming success of the program supports long term aggressive carbon intensity benchmark as well as near term strengthening measures. Fidelis encourages CARB to adopt the compliance
045.5 targets as modeled in the February workshop of 30% by 2030, 45% 2035, 65% by 2040, and 90% by 2045, along with a one-time step down in 2025 of an incremental 5%. Through these compliance targets, CARB will enable continued investment and development of low carbon fuels and deliver material reductions in transportation emissions.

As noted on the LCFS program dashboard, 35% (4.7 million) of the 13.4 million credits cumulatively banked from the program's inception were generated in the four-quarter period ending in Q3 2022.[1] Based on the rapid accumulation of credits, Fidelis applauds CARB for considering an acceleration mechanism to adjust compliance targets based on the performance of the LCFS market. This acceleration mechanism will ensure market certainty for industry to develop and deploy the required low carbon fuel infrastructure and ensure that emissions are rapidly, but feasibly, reduced to deliver both climate and air quality improvements to Californians. Furthermore, implementing an automatic acceleration mechanism allows the LCFS program to be more dynamic, send a positive market signal to renewable sector investors, and reach its decarbonization targets faster.

045.6 Furthermore, Fidelis supports the proposed auto-acceleration structure applied when the trigger criteria have been met (with limitations noted below). As such, all future years of the program schedule should be impacted accordingly. Rather than sending a one-time signal and holding the program at the new target for an additional period (i.e., a "freeze"), we believe that impacting all future years in the program sends a strong and consistent market signal. This will further encourage projects and investments in the decarbonization sector and allow the LCFS program to accelerate its progress towards California's GHG reduction goals.

To maintain an active level of oversight on the program's acceleration, Fidelis supports a limit on the number of consecutive auto-accelerations that can be implemented. Fidelis recommends that CARB be required to provide their approval on a third program auto-acceleration, if both trigger criteria are satisfied and there have been two consecutive prior auto-acceleration periods implemented.

In addition to these future compliance targets, Fidelis supports CARB's consideration of a one-time stepdown in the benchmark carbon intensity near term to address the rapid accumulation of excess credits. Of the 13.4 million credits in the cumulative bank, 4.7 million excess credits were added to the cumulative bank in the four-quarter period ending in Q3 2022. With the average
045.7 quarterly deficit generation over this period being 5.1 million credits, the credit generation was outpacing deficits by almost an entire quarter of expected deficit generation. Fidelis recommends that CARB implements the proposed 5% stepdown in 2025 to address this growth. This step down will provide market confidence in credit pricing, enabling near term investments required to support the strengthened carbon intensity requirement.

[1]Data Source: CARB (February 2023) LCFS Dashboard (https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard)

FIDELIS NEW ENERGY, LLC
109 NORTH POST OAK, SUITE 140
HOUSTON, TEXAS 77024
(832) 551-3300
WWW.FIDELISNEWENERGY.COM

Fidelis Supports Adopting Intrastate Jet Fuel as Deficit Generator

Through the LCFS program, California has been the global leader in the deployment of low carbon fuels. The incentivization of SAF in the Inflation Reduction Act has encouraged significant deployment of SAF facilities and alternative Jet fuel generating credits in the LCFS market since 2019. Fidelis encourages California to continue leading the deployment of alternative jet fuel (SAF) at scale by making conventional Jet Fuel a deficit generating fuel when used on intrastate
045.8 flights. This amendment will directly incentive the utilization of alternative jet fuel at scale, resulting in decreased greenhouse gas emissions and improved air quality.

Respectfully submitted,

Fidelis New Energy, LLC

Comment Log Display

Here is the comment you selected to display.

Comment 54 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Goldie
Last Name	Potter
Email Address	Copperhead4656@gmail.com
Affiliation	Protect Pomme de Terre
Subject	Incentivizing CAFOS in the Midwest
Comment	This is endangering the family farm and all water quality in the state of Missouri. Please stop incentivizing CAFOs by claiming their methane is a renewable resporce. It is just like all the waste they want to dump in our rivers--POLLUTION. Please stop. 046.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-15 12:46:28

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

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Comment 55 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Don
Last Name	Gilstrap
Email Address	dgilstrap@chevron.com
Affiliation	
Subject	Chevron Comments on Intrastate Jet
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6150-lcfs2024-B2RQPgZiBCELf1U6.pdf
Original File Name	Chevron Comments on 2024 LCFS Rulemaking (intrastate jet).pdf
Date and Time Comment Was Submitted	2024-02-15 14:16:46

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Don Gilstrap
Manager, Fuels Regulations

February 14, 2024

Rajinder Sahota
Deputy Executive Officer – Climate Change and Research
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Ms. Sahota:

Re: Intrastate Fossil Jet Proposal

Chevron appreciates the opportunity to review and comment on the subject Low Carbon Fuel Standard rulemaking proposal.

Chevron is a major refiner and marketer of petroleum products and renewable fuels in the state of California and a regulated party under the Low Carbon Fuel Standard (LCFS). Chevron is also an international producer of lower carbon intensity fuels with a global integrated procurement, distribution, and logistics network and 11 biorefineries in the U.S. and Europe.

Chevron is submitting multiple letters on key topics under the 2024 LCFS rulemaking. Following are our comments on the proposal to introduce LCFS deficits for intrastate fossil jet fuel consumption.

<u>Key Messages</u>

- Adding deficits for intrastate fossil jet consumption will not encourage faster adoption of alternative jet fuel.
- Designating refiners and importers as the first reporting entities creates an impractical framework for compliance.
- Measuring intrastate jet fuel consumption is more complex than one might expect.
- CARB has not proposed critical definitions or verification protocols to enable compliance.

<u>CARB's Proposal</u>

CARB proposes to remove the exemption for fossil jet fuel under the LCFS, unless that fuel is demonstrated to have been used for interstate or international flights. The intent is to assign deficits to fossil jet fuel used on intrastate flights, defined as taking off from a California airport and landing at another California airport. The rationale for this proposal is that "California must reduce GHG emissions from aviation." However, CARB has proposed refiners and importers of jet fuel as the first reporting parties for fossil jet fuel, treating jet fuel in the same way that gasoline and diesel fuel are treated. There are several problems with this proposal.

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6001 Bollinger Canyon Rd, San Ramon, CA 94583
925 842 8903
dgilstrap@chevron.com

Fossil Jet Deficits Would Have No Effect on AJF Growth

The proposed deficits will add a new cost to air transportation within the state of California. However, the credits needed to satisfy this new obligation are far more likely to come from established fuels under the LCFS: ethanol, biodiesel, renewable diesel, RNG, and electric vehicles. While Alternative Jet Fuel (AJF), commonly referred to as Sustainable Aviation Fuel, qualifies as an opt-in fuel under the LCFS, the proposed deficits do nothing to improve the economics of its use.

047.1 The market-based structure of the LCFS is a critical element of the program's success to date. Credits generated by one fuel can be used to satisfy the deficits from another, even if it is not a direct substitute. This has enabled the rapid growth of fuels like renewable diesel and renewable natural gas, which play a large role in compliance with the deficits from both gasoline and diesel. Adding deficits for fossil jet fuel will not drive growth in AJF because the fundamental hurdle is that AJF is more expensive to produce than renewable diesel. A fossil jet obligation will not change the compliance value of AJF. Credits from fuels that are more economic would satisfy the new obligation.

Further, demand for AJF is growing without the proposed changes. The apparent logic is that adding deficits for intrastate jet will boost demand for AJF, but demand is not the problem. In the Initial Statement of Reason for this rulemaking, CARB describes emission reduction targets set by several airlines, who are pursuing increased AJF use to meet those targets. CARB also discusses the conversion of multiple California refineries to produce bio-based fuels, including AJF. This is all happening without the proposed fossil jet deficits, which will do nothing to improve the economics of those efforts.

The LCFS is already doing its part to encourage AJF adoption through the ability to opt in and generate credits. If CARB is looking to increase the incentive for AJF, it is worth considering an approach proposed by alternative jet fuel producers in their comments during the 2018 rulemaking[1].

047.2
> *Another benchmarking approach that would be more consistent with ARB's regulatory authority would be to establish a fixed benchmark standard for conventional jet fuel. This would be consistent with conventional jet fuel's LCFS exemption and would appropriately recognize the difference between CARB's regulatory authority over diesel and gasoline and its authority to provide a voluntary incentive in the aviation sector. Rather than a curve, such an approach would establish a fixed benchmark. It would logically be fixed at the CA-GREET 3.0 carbon intensity score that ARB determines for conventional jet fuel for 2010.*

This approach recognizes the global nature of jet fuel as compared to gasoline and diesel, while adding a competitive incentive for AJF. There is logic in this proposal and it would be far more effective than adding deficits for approximately 10% of the jet fuel consumed in the state.

The Proposed Approach Is Not Practical

CARB has proposed to include fossil jet fuel in the LCFS in the same manner as gasoline and diesel with certain uses exempted. The intent is to obligate only intrastate jet but executing this will be extremely problematic. Designating refiners and importers as the first reporting entities

[1] https://www.arb.ca.gov/lists/com-attach/119-lcfs18-WjsHawdgV1sEclUn.pdf

will bring all fossil jet fuel produced in the state into the program, meaning that CARB will be regulating interstate and international commerce. This is because:

047.3

- Refiners and importers will not have the information needed to separate intrastate jet fuel use from interstate and international use.
- This will require reporting all produced and imported jet fuel.
- The LCFS obligation for this fuel will then have to be passed through the supply chain until it reaches the aircraft operators.
- Aircraft operators (airlines, shipping companies, small aircraft owners) are the only parties who will have the information necessary to determine intrastate use versus exempt uses.

There are numerous points in the supply chain where title transfer can take place. This includes, but is not limited to, refinery gates, pipeline transactions, truck deliveries from terminals, in-tank transfers, and sales from airport storage (see Figure 1). At none of these points will the division between intrastate and interstate/international use be known. The LCFS obligation must ultimately be transferred to the aircraft operators who are the only parties that could segregate and report the intrastate and exempt volumes. For multiple reasons, the segregation will be challenging to do accurately, with the likely outcome that some of the LCFS burden will be placed on jet fuel used for interstate and international flights.

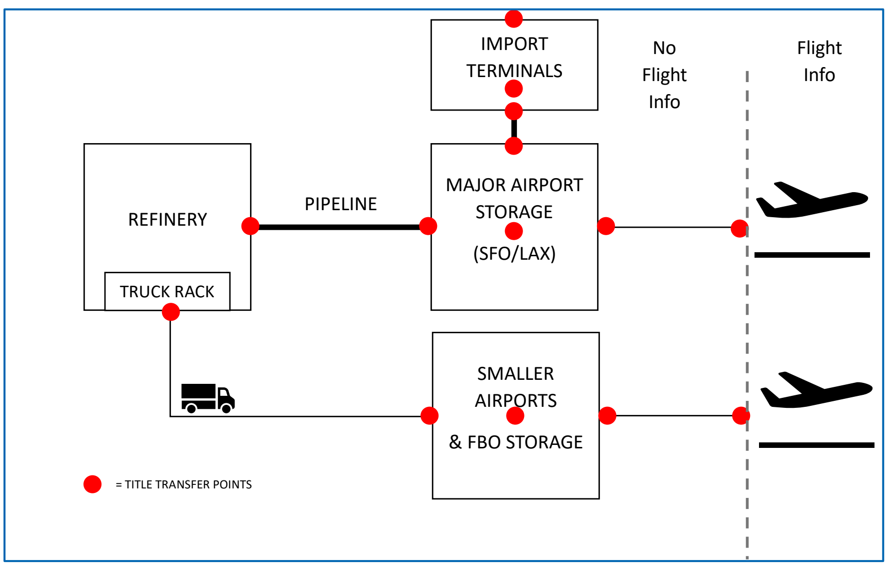

Figure 1. Jet fuel supply chain title transfer points

This adds a significant volume of additional reporting under the LCFS to track jet fuel production and import, purchase and sale, and ultimate consumption, only to have 90% (per CARB's estimate) of the fuel in question ultimately reported as exempt. This would also require changes to hundreds of contracts between parties involved in the jet fuel supply chain in California. Chevron alone has dozens of contracts related to jet fuel supplied on pipelines, via truck deliveries, terminal storage locations, and airport storage within California.

To further complicate the proposed approach, not all intrastate flights will have been fueled within California. It is common practice for aircraft to fuel at one airport (which could be outside California) and not refuel until multiple legs of a flight have been completed. This means an aircraft could fuel outside California, make multiple stops within the state, and refuel again out-of-state. So, CARB's proposal will not only end up regulating interstate/international use but will also exclude a portion of intrastate use.

047.3 cont While regulating intrastate jet fuel will not address CARB's goal of growing AJF use, if CARB chooses to proceed with this concept, it would be much more practical to designate the aircraft operators as the first reporting entity and avoid the excessive additional reporting activity and unavoidable inaccuracies described above.

Tracking and Reporting Intrastate Use Will Be Challenging

Designating aircraft operators as the first reporting entities will reduce the administrative burdens of the program but challenges with accuracy will remain. It is likely that aircraft operators will have to create new accounting and reporting systems to accurately measure and record fuel consumption for any California intrastate leg of a flight. Requiring that intrastate consumption be reported will add a significant, labor-intensive burden for aircraft operators.

047.4 A simple multiplier based on miles traveled between California airports and assumed fuel consumption could reduce the effort needed. However, aircraft size and type would have to be considered. This would lead to establishing multiple factors and clear guidelines from CARB on how to apply them, adding significant additional work for both aircraft operators and CARB staff.

This all assumes that this new obligation applies to a few large airlines and shipping companies. CARB must consider the added burden for small aircraft operators that fuel at fixed base operators (FBOs). It would be impractical to expect individual aircraft owners to understand and comply with this obligation under the LCFS. Even if the obligation belongs to a fuel supplier or the FBO itself, small aircraft owners would have a role to play in tracking and reporting intrastate jet fuel consumption.

More Specific Guidelines Are Needed

The minimal regulatory amendments made in this proposed rulemaking do not provide sufficient guidelines for compliance.

047.5

- An exemption is proposed for fossil jet fuel used for interstate or international flights but no definition is provided for these types of flights.
- No method is provided for measuring jet fuel use.
- § 95500(c)(1)(A) requires verifiers to include the transaction type "Fossil Jet Fuel Used for Intrastate Flights" in the scope of their review but it is not clear when this transaction type would be used and no parameters are given for verifying its use.
- As written, the proposed regulation requires parties to report production, import, purchase, sale, and all other transaction types that could apply to fossil jet fuel.
- No method is given for then reporting the portion of that fuel that is exempt based on interstate or international use.

Conclusion

CARB should remove the proposed introduction of deficits for intrastate jet fuel use. It does not address the intended goal of growing AJF. Instead, it introduces a confusing accounting burden into the California jet fuel supply chain and increases the cost of air travel without a corresponding benefit. Further, the burden will almost certainly increase the costs of interstate and international jet fuel use for flights that depart from California. To improve crediting for AJF under the LCFS, CARB could consider the 2018 proposal to use a fixed benchmark for AJF crediting. Absent that, it would be more effective to pursue an incentive program outside the LCFS to provide more direct encouragement for AJF growth.

Thank you for the opportunity to comment on these matters. If you have any questions regarding our comments, please contact me at (925) 842-8903 or DGilstrap@chevron.com.

Sincerely,

Comment Log Display

Here is the comment you selected to display.

Comment 56 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Don
Last Name	Gilstrap
Email Address	dgilstrap@chevron.com
Affiliation	
Subject	Chevron Comments on Biogas & Hydrogen
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6151-lcfs2024-VjVUOlYyVXAHcwFu.pdf
Original File Name	Chevron Comments on 2024 LCFS Rulemaking (biogas & H2).pdf
Date and Time Comment Was Submitted	2024-02-15 14:20:04

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Don Gilstrap
Manager, Fuels Regulations

February 14, 2024

Rajinder Sahota
Deputy Executive Officer – Climate Change and Research
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Ms. Sahota:

Re: Biogas & H2 Proposals

Chevron appreciates the opportunity to review and comment on the subject Low Carbon Fuel Standard rulemaking proposal.

Chevron is a major refiner and marketer of petroleum products and renewable fuels in the state of California and a regulated party under the Low Carbon Fuel Standard (LCFS). Chevron is also an international producer of lower carbon intensity fuels with a global integrated procurement, distribution and logistics network and 11 biorefineries in the U.S. and Europe.

Chevron is submitting multiple letters on key topics under the 2024 LCFS rulemaking. Following are our comments on the proposed amendments related to biogas and hydrogen.

Key Messages

- The 50% capacity limit on Hydrogen Refueling Infrastructure (HRI) credits will stall investment.
- Chevron supports book-and-claim accounting for hydrogen.
- The deliverability requirement and carbon intensity (CI) threshold for pipeline hydrogen are counterproductive.
- Reversing crediting for avoided methane runs counter to the goals of the LCFS and could cause backsliding.
- New deliverability requirements for biogas are unnecessary and will inhibit biogas investment.

HRI Crediting

048.1 The rationale that limiting HRI crediting to 50% of capacity will encourage wider scale growth is flawed. The current LDV HRI program does not have a capacity constraint, yet it has still fallen short of hitting the 2.5% obligation maximum each quarter due to the economic, technological, and permitting challenges of building hydrogen infrastructure. Shell's recent announcement that

Chevron Products Company
A Division of Chevron U.S.A., Inc.
6001 Bollinger Canyon Rd, San Ramon, CA 94583
925 842 8903
dgilstrap@chevron.com

048.1 cont they will close several stations is illustrative of the challenges faced in this space[1]. For heavy- and medium-duty (MHD) fueling stations, these challenges are only amplified due to the high capital requirements, lack of available fueling technology, and large land use requirements. Chevron urges CARB to remove the capacity limit and continue with a 15-year crediting window to encourage growth. If there is a capacity constraint and a shorter pathway length, then the prospect of lower returns would likely limit program participation.

048.2 Chevron requests that CARB work with industry to develop a realistic solution to differentiate reporting between light-duty and MHD vehicles for HRI crediting purposes. Since these are public access locations, there are little to no means for tracking hydrogen vehicle size to identify if the vehicular weight is less than 8,500 lbs, or within 8,501 lbs to 14,000 lbs GVWR. Also, unlike CNG, separate nozzles are not used for light duty vs. MHD vehicles today. The newly developed NREL heavy duty fueling protocol may allow for separate nozzles for fueling, however it will take many years for the industry to transition.

<u>Hydrogen Book-and-Claim</u>

048.3 The proposal to allow book-and-claim accounting for dedicated hydrogen pipelines is a constructive addition to the LCFS. However, imposing carbon intensity (CI) and deliverability constraints are unnecessary. There is no rationale for treating the CI of hydrogen shipped via pipeline differently than hydrogen shipped by truck. This only serves to encourage inefficiency in the supply chain. The market will reward lower-CI hydrogen without the need for these constraints.

CARB's expressed intent is to align with practices being established under the Inflation Reduction Act (IRA). This is unnecessary and counterproductive. The IRA includes arbitrary carbon intensity thresholds set by Congress, and the Treasury department is just beginning to establish organizational capability in this space. By contrast, the LCFS program is far more advanced and mature than these new measures and operates well as a technology-neutral and market-based approach. This is evidenced by CARB's focus on CI as the vehicle for GHG reduction, as opposed to providing credit for only certain technologies.

<u>Tier 1 Hydrogen Calculator</u>

048.4 Chevron applauds CARB's work to establish a simplified Tier 1 calculator for hydrogen pathways. This will greatly increase speed to market implementation. CARB's incorporation of feedback from industry is appreciated as well. This enables a more accurate and realistic approach from the beginning.

<u>Avoided Methane Crediting</u>

048.5 Chevron disagrees with the sunsetting of avoided methane crediting for biogas pathways under the LCFS. This is a demonstrated, significant reduction in greenhouse gas emissions that would otherwise be released to the atmosphere. Additionally, limiting incentives for biogas and renewable natural gas producers to reduce methane emissions is inconsistent with the Subnational Methane Action Coalition's statement of purpose and the 2021 Global Methane Pledge.

048.6 It is encouraging, however, that CARB has set a timeline that will avoid near-term stranded investments and allow for the establishment of new policies to encourage biogas use in other

[1] California's Hydrogen Economy Dealt A Hammer Blow By Shell's Exit (forbes.com)

sectors. If new programs do not arise to direct biogas and renewable natural gas to stationary sectors, we urge CARB to revisit this proposal in a future rulemaking to avoid backsliding.

Biogas Deliverability Requirements
While we appreciate the reasonable implementation timeline for the newly proposed
048.7 deliverability requirements, this also has the potential to deter growth and cause potential backsliding. The current approach to book-and-claim accounting is practical, aligns with other U.S. policies, and provides the most effective means of reducing GHG emissions, which are global in nature.

Thank you for the opportunity to comment on these matters. If you have any questions regarding our comments, please contact me at (925) 842-8903 or DGilstrap@chevron.com.

Sincerely,

Comment Log Display

Here is the comment you selected to display.

Comment 58 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Dan
Last Name	Evans
Email Address	Dan@promusenergy.com
Affiliation	Promus Energy
Subject	Comments on Proposed Low Carbon Fuel Standard Amendments
Comment	Please see attached comments.
Attachment	www.arb.ca.gov/lists/com-attach/6171-lcfs2024-UyMAdAFvUG5RIIIh.pdf
Original File Name	Promus Energy Comments on the Proposed Low Carbon Fuel Standard Amendments 2.15.24.pdf
Date and Time Comment Was Submitted	2024-02-15 16:52:10

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 15th, 2024

The Honorable Liane Randolph
Chair California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Chair Randolph:

As a developer of dairy digester RNG and biogas to electricity projects for EV charging in West Coast states, Promus Energy appreciates the opportunity to comment on the proposed changes to the CA Low Carbon Fuel Standard (LCFS). Promus values CARB's serious consideration and incorporation of feedback provided by us and other stakeholders as revisions to the LCFS program have been carefully crafted over the last several years.

Promus is pleased with CARB's proposed changes that will support the LCFS credit market and send the long-term market signals investors need to fund low carbon intensity (CI) fuel development projects.

Carbon Intensity Target Adjustments and Impact on Credit Prices:

We support incorporation of a one-time 5% "step down" in the CI target in 2025. 049.1

- This step down, and the subsequent anticipated increase in LCFS credit pricing, would jumpstart investment in low-CI projects and bolster the confidence lenders need to fund these projects.

However, Promus is concerned that CARB's analysis shows credit prices will dip to levels around $76 by 2030.

- Prices dipping this low by 2030 after their projected increase in 2025 makes it difficult for lenders to have sufficient confidence that low CI fuels projects will produce strong enough financial returns in the near term. While anticipated credit prices in 2025-2027 are at levels that support low CI fuels projects, these prices do not stay high long enough to generate attractive returns on project investments and inspire lender confidence.
- 049.2 Promus urges CARB to consider ways to minimize or eliminate the dip in credit prices by 2030, such as by setting a greater than 30% CI reduction target by 2030 sufficient to restore and stabilize healthy credit pricing. BTR's analysis presented during the May 2023 LCFS workshop indicated that a 2030 CI reduction target of greater than 30% will be required to prevent the credit bank from growing again within just a few years after the one-time step down. Preventing renewed growth of the credit bank is essential to supporting healthy LCFS credit market dynamics. Promus supports a CI reduction of 35% by 2030 to ensure strong short- to medium-term credit prices needed to spur investment in low CI fuels projects.[1]

[1] https://ww2.arb.ca.gov/sites/default/files/2023-05/BTR_052323.pdf

Clarification Needed for Biomethane Avoided Emissions Crediting:

049.3 Promus appreciates that CARB is extending up to three ten-year crediting periods for biomethane avoided emissions crediting for projects that break ground before 2030. However, we ask that CARB clarify a few points:

- Will the three ten-year crediting periods for avoided emissions crediting also extend to biomethane to electricity for EV charging pathways, or will they only apply to biomethane to
049.4 CNG, LNG, and Hydrogen pathways? Certainty for these crediting periods is essential for the financeability of biomethane to electricity projects and the reduction of electricity CI for EV charging.
- The following statement in the Proposed Regulation Order that describes the three ten-year crediting period suggests that a project needs to be certified by 2030 for it to be eligible: "The Executive Officer may renew crediting periods for fuel pathways certified before January 1,
049.5 2030, for up to three consecutive 10-year crediting periods."[2] However, this conflicts with statements later in that section and in other documents that suggest that the project must only have broken ground by 2030 to be eligible for the three ten-year crediting period. Could you please clarify the eligibility requirements?

We appreciate the opportunity to provide feedback on the proposed changes to the LCFS program.

Thank you for your consideration.

Sincerely,

Dan Evans, President
Promus Energy LLC
1201 Third Ave., Suite 320
Seattle, Washington 98101
dan@promusenergy.com
206.300.0835

[2] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appa1.pdf, Page 166

Comment Log Display

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Comment 59 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Simon
Last Name	Brandler
Email Address	simon@brimstone.energy
Affiliation	Brimstone
Subject	Brimstone comments on LCFS amendments
Comment	Please find our comments attached. Thank you.
Attachment	www.arb.ca.gov/lists/com-attach/6174-lcfs2024-AWNQJFI6V2kLfgN3.pdf
Original File Name	Brimstone LCFS Letter 2.15.pdf
Date and Time Comment Was Submitted	2024-02-15 18:16:42

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 15, 2024

Matthew Botill
California Air Resources Board (CARB)
1001 I Street
Sacramento, CA 95814

Re: Brimstone's Comments on the Proposed Low Carbon Fuel Standard Amendments

Dear Mr. Botill:

050.1 Brimstone appreciates the opportunity to comment on the proposed amendments to the Low Carbon Fuel Standard (LCFS). Brimstone supports California's climate change goals, including achieving carbon neutrality and net-negative greenhouse gas emissions no later than 2045. Currently, the LCFS provides one of the only regulatory markets in the world for carbon removal. This is a critical element of the program, and we strongly support the inclusion of carbon removal via direct air capture (DAC) as a credit-generating pathway under the LCFS.

050.2 Because carbon removal is so critical to achieving California's goals, we further encourage CARB to develop additional carbon removal protocols as it implements SB 905, including mineralization of carbon dioxide from the atmosphere and ocean. LCFS amendments should accommodate new carbon removal pathways, if and when they are adopted in the future. We accordingly urge CARB to consider 15-day changes to the LCFS proposal that would allow new carbon removal pathways to be included in the program, provided they meet the additionality, permanence, and other requirements of existing CCS Protocol.

About Brimstone

Brimstone is a California-based company, headquartered in Oakland, with a carbon-negative process for making ordinary portland cement. Cement has nearly the same greenhouse gas impact as all the world's cars on the road today, and it has traditionally been one of the most difficult materials to decarbonize – until now.

Our process produces ordinary portland cement from calcium silicate rocks, which do not contain CO_2, rather than limestone. It avoids any process emissions associated with producing portland cement and produces a magnesium byproduct that passively mineralizes CO_2 from the ocean or air and permanently stores it as magnesite rock.

Brimstone is upending the conventional wisdom that CO_2 process emissions are a necessary outcome of cement production and that carbon capture and sequestration (CCS) and associated high costs and/or subsidies are required to decarbonize the traditional process. We are also proving that carbon removal and direct greenhouse gas emission reductions at their source can, and should, go together, and need not be considered tradeoffs.

LCFS amendments should allow mineralization or other potential new carbon removal or DAC protocols to be used if they are adopted separately

050.2 cont We encourage CARB to allow the utilization of diverse carbon removal solutions that extend beyond existing CCS Protocols to be included in the LCFS. Specifically, we ask that CARB consider broadening definitions and references to CCS, DAC and the CCS Protocol to make clear that new carbon removal protocols may be developed and added to the CCS Protocol, and that if/when they are, projects utilizing those protocols would be eligible to generate credits under the LCFS, just like DAC projects currently can do.

As described above, approaches like Brimstone's that utilize natural carbon mineralization pathways offer highly efficient, enduring, and scalable methods of carbon removal. Strategies to remove carbon from the ocean may require less energy than removing carbon from the air, or in the case of mineralization, offer greater efficiencies for carbon removal and sequestration. Broadening the definition of eligible DAC projects and related CCS references to encompass additional promising carbon removal strategies by reference that may be adopted by the Board in the future will help to unleash solutions with significant potential for a widespread impact, which will be needed to achieve California's carbon neutrality objectives.

Conclusion

Thank you again for the opportunity to comment on the proposed LCFS amendments. We look forward to working with you and other stakeholders through the LCFS amendment process, SB 905 implementation, and other forums to keep the state on track to meet and exceed its climate goals. Please do not hesitate to reach out if you have any questions about Brimstone or these comments.

Thank you,

Simon Brandler
VP of Policy & Public Affairs
Brimstone

Comment Log Display

Here is the comment you selected to display.

Comment 60 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Diane
Last Name	Brost
Email Address	Dianebrost@att.net
Affiliation	
Subject	Factory Farm Gas in California's Fuel Standards
Comment	

Dear Board Members,
I'm against including factory farm gas in California's Low Carbon
Fuel Standard. This will not be a positive solution for our
climate
crisis. One of the main reasons to nix factory farm gas from the
standard is that it will encourage more large factory farms,
making
051.1 it harder for small family farms to prosper while these corporate
farms push down market prices with overproduction. More issues
with
this bill include the fact that multinational large meatpackers
will be paid for their pollution, and the bill will create
incentives via government subsidies to support anaerobic digesters
for factory farm gas.
This would add more factory farms which will lead to more methane,
more water and air pollution, more corporate consolidation. I'm in
the Midwest and know this will not lead to less carbon release in
our atmosphere. Please strike this portion of the amendments.
Thank you for allowing comments.

Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-15 18:51:11

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 61 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name D.

Last Name Zink

Email Address zmail@sunintherain.com

Affiliation

Subject DISASTER POTENTIAL FROM BIOGAS

Comment

There are already enough uncontrolled releases of methane from
multiple major sources in multiple major countries, from unmanage
landfill gas to fracking and pipeline release. Methane is much
more damaging to atmospheric protection of the planet than CO2.
Concentrated manure is a preventable source, and this process is
poorly captured. Pipeline losses will also apply to "biogas". In
052.1 addition to environmental impacts, community planning for emergenc
situations is usually under-assessed and under-developed. These
become gigantic explosion risks, whether or not the methane is
intended to be collected.

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-16 05:48:39

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Comment 65 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	alex
Last Name	oscoy
Email Address	oscoy55@yahoo.com
Affiliation	
Subject	METHANE/BIOGASSES
Comment	METHANE/BIOGASSES; LESS THAN IS WAY MORE THAN! VEGAN, A NOUN, IE. SOMEONE WHO TRULY CARES FOR PLANET EARTH AND AI ON ITS INHABITANTS.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:04:24

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 66 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Lorraine
Last Name	Lowry
Email Address	Lmurphy_2006@hotmail.com
Affiliation	
Subject	Factory Farm Gas
Comment 054.1	If we don't get this horrible pollution under control control soor this planet will never recover
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:13:18

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 67 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	ALIX
Last Name	SCHREK
Email Address	OSCOY56@YAHOO.COM
Affiliation	
Subject	NOT SUSTAINABLE METHANE
Comment 055.1	California has more industrial dairies than any other state, polluting our rivers, depleting our groundwater, and emitting disastrous greenhouse gasses. Now, factory farm polluters claim they are environmentally friendly because they produce "biogas." Even worse, they are using our tax dollars to fund this harmful greenwashing.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:13:51

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Comment 68 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Heidi
Last Name	Taylor
Email Address	hmephd@gmail.com
Affiliation	
Subject	FOIE GRAS PRODUCTION
Comment	Please stop!
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:16:35

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Comment Log Display

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Comment 69 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	robert
Last Name	brixner
Email Address	dratted@aol.com
Affiliation	
Subject	Pure air
Comment	YOU said - you PROMISED - to GET SOMETHING POSITIVE DONE! Start LIVING UP TO IT!!!
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:22:26

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 71 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Toby
Last Name	Malina
Email Address	toby@elfelf.com
Affiliation	
Subject	Level the playing field
Comment 058.1	Low carbon fuel standards should apply to all industries. We can't pick and choose to whom standards apply as we attempt to save our planet.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:19:52

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 72 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Linda
Last Name	Bartlett
Email Address	blinkmimi@gmail.com
Affiliation	
Subject	Biogas
Comment 059.1	Stop greenwashing by producing harmful Biogas.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:31:01

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Comment Log Display

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Comment 73 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Lacey
Last Name	Levitt
Email Address	laceylevitt@gmail.com
Affiliation	
Subject	end current Low Carbon Fuel Standard (LCFS) policies that reward factory far polluters
Comment 060.1	Please end current Low Carbon Fuel Standard (LCFS) policies that reward factory farm polluters. Investing in biogas means investing in even more factory farm pollution.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:30:59

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

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Comment 75 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Claudia A
Last Name	Peters
Email Address	cloudcw@aol.com
Affiliation	
Subject	Factory Farming
Comment	This is not only harmful to animals, which should be your top priority, it increases pollution and increases carbon in the air. 061.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:39:16

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 76 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Pegalee
Last Name	Benda
Email Address	riverwolf@comcast.net
Affiliation	
Subject	Rights for animals
Comment 062.1	Gas is cruel!
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:42:28

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

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Comment 77 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Phoenix
Last Name	Giffen
Email Address	phoenixgiffen@gmail.com
Affiliation	
Subject	Protect Mother Earth!
Comment	There is no Planet B!
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:49:17

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Comment Log Display

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Comment 78 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Emily
Last Name	Watson
Email Address	ewatson975@gmail.com
Affiliation	
Subject	Factory Farming and the allegiance to disregard

Comment

I often wonder what kind of human has the gall, emotional paralysis, and substantial lack of compassion that they are able t bear witness to the horrendous living conditions and ultimately, barbaric death these sentient beings are subjected to.

One might argue, "they don't know any different." To that I ask, i you grew up with debilitating physical abuse in your house, would you think that was normal and you would be fine because you don't know any better?

If we are being honest with ourselves, the answer would be no.

What if our babies, as soon as they are born, are taken from us. Chained to a dog house until they are sold to be killed and we are then raped of the nutrients our body made specifically for our offspring so someone else could get money.

Money. For what? To drive a stupid fancy car? To buy a big house you eventually take for granted? To tell people you have x amount of dollars so you can make yourself feel a little better about being you?

It's trafficking at the most basic level.you have advocated for this. You have sold yourself and your basic human beliefs for paper.

Take a step back and think about what factory farming really is ar then look at yourself in the mirror in a quiet room and sit with the fact that YOU have killed, abused, and neglected your fellow beings so YOU could have money. How sad of an existence is that really?

How cheap your soul is to be bought so easily and at the disregarded suffering of others. Think of your most beloved relative who as a child, you thought hung the moon. What would the think if they walked beside you everyday and watched what you did to animals.

It's a shame, really. We all used to have compassion, empathy, ar respect for all those around us. I dream of a time when we get bac to that. Sure, there are populations who consume meat and that is choice we all have the right to bare. What's wrong with doing it the right way and having pride in what you contribute to the worl Where has the pride gone?

064.1 End factory farming. It's what's good for all of us and something we collectively can be so proud to be a part of.

Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:33:08

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 80 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name LAURIE

Last Name Pueschel

Email Address bluewingedbreath@gmail.com

Affiliation

Subject Get Rid of Factory Farms and all the extras that come with it

Comment

Factory farming is the one of the biggest atrocities of modern day living.

065.1 We vegans. vegetarians have proven meat is not a necessity at all in the human diet. STOP playing around with regulations that pretend to show you care about the environment. Humans are as much as animals a connecting power to the environment. We are not seperate but a part or partner to it. I have a sort of PTSD from watching a few slaughterhouse videos to help keep me on my track o meatless diet and compassion for our fellow sweet animals like the cows, sheep, goats, pigs, ducks, turkeys, and chickens etc. Man is in a state of CONFUSION in the walls of confinement of buildings, roads, etc. Only an old time native American Indian can tell you what it feels like to know the spiritual tie to the land they were so proudly apart of. Simple living was a direct connection to trut at all times and to all places in time. They could feel the energy from the earth entering their being as some of us awakened can now too. Their intuition was outstanding and their ability to communicate with ancestors.

Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 08:53:31

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Comment Log Display

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Comment 81 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	David
Last Name	Jallo
Email Address	Dgjallo@yahoo.com
Affiliation	
Subject	Stop Support For Dairy Farm Biogas Greenwashing
Comment 066.1	I want to express my opposition to the dairy industry receiving support for its biogas production. These incentives support an industry built on pollution and cruelty. It's a classic example o greenwashing and does not benefit the environment. Biogas capture is inefficient, costly and does not mitigate atmospheric warming gas production. Ending dairy operations is the most effective way to stop their destructive effects. Please do not support their damaging activities.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 09:00:03

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 82 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Donovan
Last Name	Prahl
Email Address	donovan.p@bushmillsethanol.com
Affiliation	
Subject	Public Comment for Proposed Low Carbon Fuel Standard
Comment	Public Comment for Proposed Low Carbon Fuel Standard Amendments. See Attached document.
Attachment	www.arb.ca.gov/lists/com-attach/6277-lcfs2024-VDdQN1E8AjgEZARr.pdf
Original File Name	California Public Comment.pdf
Date and Time Comment Was Submitted	2024-02-16 09:07:33

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

BUSHMILLS ETHANOL
BUSHMILLS ETHANOL, INC. • 17025 HWY 12 NE • ATWATER, MN 56209 • PHONE: 320-974-8050 • FAX: 320-974-0805
02-14-2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

As a renewable fuel producer and participant in CARB's LCFS program, my team and I value the partnership and mission shared with you and your state to reduce the carbon intensity of transportation fuels.

I am writing to share our company's perspective on two key program areas for your consideration. These requests address the topics of **firm rotation** and **less intensive verification**.

Firm Rotation

The existing regulations within the LCFS verification program stipulate a mandatory rotation of audit firms every six years to assess participants' carbon intensity (CI) and fuel quantities compliance.

Our request is that CARB amend the mandatory firm rotation regulation to include an exception for licensed CPA firms. Of the 30 approved LCFS verification bodies, there are only four licensed CPA firms.

067.1 ***An approved verification body, that is also a licensed CPA firm, exceeds the standards in place for verification bodies and is already subject to additional oversight on the entity's quality control system in accounting and auditing practices through the required AICPA peer review process.***

Due to the increased regulatory oversight, we suggest a CPA firm not be subject to the audit firm rotation but would instead adhere to a Lead Verifier rotation after six consecutive years.

A licensed CPA firm differs from other consulting agencies by adhering to more rigorous standards and oversight at a state and national level. If a verification body were to violate a Lead Verifier rotation requirement, it would put the firm license at risk. The firm

license is required for all services provided by the firm, not just the LCFS verification services, thereby ensuring adherence to requirements.

Licensed CPA firm requirements

- A licensed CPA firm must be comprised of over 50% of the ownership being licensed CPAs.
    - To earn the accreditation to be a CPA, one must pass a rigorous four-part CPA exam, accumulate education hours, and in many states, one must fulfill 1-2 years of work experience.

- 3-year peer review audit
    - Each licensed CPA firm must enroll in an approved peer review program with reviews conducted every 3 years. The peer review requirement is a requirement of the American Institute of Certified Public Accountants (AICPA) and is an external review of a firm's quality control system in accounting and auditing practices. CPA firms' peer review results can be found on AICPA's website under the Peer Review Public File Search.

- State Boards of Accountancy (SBOA) are found in each state's statute to aid state governments in the licensing and regulation of the public accounting profession.
    - SBOAs provide further oversight on CPA firms by evaluating CPA licensees' examinations and regulatory oversight to ensure a firm is practicing within their statutory scope.

The audit quality and efficiency improve as the auditor becomes more familiar with our company's processes. In addition, with the limited number of firms available as verification bodies and a five-year lookback period in place, it is proving difficult to identify a quality verification body that is not also working with our facility in other consulting capacities. The number of people available with the proper expertise to assist us in design and development of projects and to reserve for verification purposes has proven even more limiting, which is also why we request a Lead Verifier rotation rather than a full firm rotation.

Less Intensive Verification

Regarding less intensive verification, we noted in Appendix E staff's proposal for less intensive verifications for when electricity is used as a transportation fuel, allowing verification bodies to skip site visits if they visited the site in the last two years and issued a positive verification statement.

The rationale for this proposed change states, "there is little change of operation from reporting period to reporting period thus reducing the benefit of annual site visits." Additionally, staff rationale states, "There is no or little risk to the integrity of the LCFS program to allow for less intensive verification services without a site visit in the annual verifications for the following two years. This should reduce the cost of verification services which is often passed on to program participants.”

Currently, the proposed language limits this allowance for less intensive verifications to QFTR third-party verification bodies for fuel reporting entities only reporting electricity transactions.

We agree with the staff’s stated rationale, but **we request for less intensive**
067.2 **verification to be extended as an option for verification bodies on all validations**
and annual verifications for any reporting entities.

In CARB’s MRR program (section 95130), less intensive verification is applied without prejudice to verification services by accredited verification bodies.

We agree with staff that less intensive verification leads to little to no risk to the integrity of the LCFS program and that there is little change in operation from reporting period to reporting period, while also providing cost savings to verification providers and passed on to our company as program participants.

We acknowledge the importance of adhering to CARB’s specified conditions that necessitate comprehensive verification services. These conditions include the issuance of an adverse verification statement or a qualified positive verification statement in the preceding year and the occurrence of a change in operational control of the reporting entity in the previous year.

Thank you for your time and consideration. Please reach out to us if you have any questions.

Sincerely,

Comment Log Display

Here is the comment you selected to display.

Comment 85 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Cara
Last Name	O'Neill
Email Address	ocara2015@yahoo.com
Affiliation	
Subject	FACTORY FARMS BIO GAS
Comment	I AM SOOOO DISAPPOINTED THAT CALIF THE"MOST" FACTORY FARMS ALL OF WHICH PRODUCE BIO GAS IF THAT IS THE CASE WE NEED TO CHANGE IT FACTORY FARMS ARE BARBAIUC BIO GAS IS DEADLY 068.1 CARA O'NEILL
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 09:02:59

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

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Comment 86 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Rich
Last Name	Dandolo
Email Address	rdandolo@aol.com
Affiliation	The public
Subject	Immoral use of tax payer money.
Comment	Please stop using my tax payer money to fund Factory Farming expenses of any kind. Thank you. 069.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 09:08:05

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Comment Log Display

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Comment 87 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Lisa
Last Name	Winningham
Email Address	lwinning1@verizon.net
Affiliation	
Subject	Biogas
Comment 070.1	Biogas from CAFOs is neither clean nor naturally renewable. It's not a replacement for clean solar, water, wind, and geothermal energy. It does not solve the environmental degradation or the human and other animal suffering caused by factory farming. This Earth Day, we must reject biogas in favor of energy and agricultural changes that can actually build a sustainable, just future.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 09:15:31

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 88 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jeremy
Last Name	Mall
Email Address	jeremymall@yahoo.com
Affiliation	

Subject	ZEVs

Comment

Please refrain from using the term "ZEV" or, at the very least, refrain from blanketly including electric vehicles in your definition. The California Low Carbon Fuel Standard is a complete well to wheel GHG emission program. The California power grid is far from zero emissions (even if you exclude all the uncontrolled burn emissions from forest fires caused by downed power lines). Electricity from the California power grid is the baseline source of fuel for most electric vehicles and thus, they are not "zero emission vehicles" per the very foundations of your policy.

071.1 If CARB wishes to include some electric vehicles in this definition, it should limit the vehicles to only those using hard-wired renewable power to refuel their vehicles as per CARB guidance on the use of renewable electricity.

I have doubts that even the vehicles mentioned above should qualif as a ZEV as GHG emissions from battery production and the production of solar panels are also not "zero emission" but I wil concede that one could interpret those as outside the scope for "fuel" within LCFS policy but CARB should further give guidance that the materials used to generate, store, or utilize fuel are outside the scope of the AB 32 policy.

CARB could choose to change this definition to zero tailpipe emission vehicles but it should refrain from using the "ZEV" acronym which is marketing tool for electric vehicle manufacturer and irrelevant to a well to wheel GHG emission policy. It is confusing to LCFS stakeholders and general population.

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-16 09:18:44

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Comment 89 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Sondra
Last Name	BUSTOS
Email Address	sondrambustos@gmail.com
Affiliation	
Subject	Factory farms
Comment 072.1	Stop investing in factory farm gas!
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 09:28:53

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 90 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Maura
Last Name	Lucus
Email Address	mclucus@aol.com
Affiliation	
Subject	Factory farm gas rewards
Comment 073.1	Please stop rewarding factory farms for their pollution. Biogas is unsustainable and unnecessary. Stop investing in factory farm gas.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 09:27:00

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Comment Log Display

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Comment 92 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Margaret
Last Name	Webb
Email Address	Mikiwebb@att.net
Affiliation	
Subject	Biogas
Comment 075.1	Please stop the many abuses of factory farms including biogas as helpful to the environment!
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 09:36:21

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 94 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Gloria
Last Name	Boyd
Email Address	gboyd805@charter.net
Affiliation	Mrs.
Subject	Destruction of all living things
Comment	Stop killing our planet and our children
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 09:50:00

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

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Comment 86 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Louise
Last Name	Gray
Email Address	louisegray1@hotmail.com
Affiliation	
Subject	Do Not Invest In Biogas

Comment

California has more industrial dairies than any other state so it is polluting rivers, depleting groundwater, and emitting disastrou greenhouse gasses!!

I experienced a NATIONWIDE food recall of California vegetables du to urine and feces run off from cows, into nearby vegetable farms

077.1

Now, factory farm polluters claim they are environmentally friendl because they produce "biogas."

Even worse, they are using tax dollars to fund this harmful greenwashing because the fact is Biogas is unsustainable and unnecessary--it does not reduce the dairy industry's environmental footprint!!

Investing in biogas means investing in even more factory farm pollution.

Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 09:45:22

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 97 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Karen
Last Name	Neumeier
Email Address	k.neumeier@comcast.net
Affiliation	
Subject	Funding for factory farms
Comment	Stop these horrible travesties to animals...despicable treatment
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 09:57:30

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Comment 88 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Geralyn
Last Name	Gulseth
Email Address	gpirategirl@yahoo.com
Affiliation	
Subject	Comment on low carbon fuel standard
Comment 079.1	Please adopt rules that do not reward pollution producing factory farms. We need to take reasonable steps to fight climate change now. Please end policies that encourage pollution
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 10:09:09

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 101 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Veronica
Last Name	Michael
Email Address	veromich@comcast.net
Affiliation	
Subject	Factory Farm Gas
Comment 080.1	Stop Public Funding For Factory Farm Gas
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 10:23:21

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 102 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Rozae
Last Name	Nichols
Email Address	rozae@floraanimalia.com
Affiliation	
Subject	Gas killing Farm Animals 081.1
Comment	We urge you to end this process of killing Fsrm Animas
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 10:35:23

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 103 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name Briana

Last Name Anderson

Email Address bnanderson0220@gmail.com

Affiliation

Subject Comment on proposed low carbon fuel standard amendments

Comment

To whom it may concern,
I am a lifelong Missouri resident with a long family history of small farmers. I have seen the harm inflicted by factory farms in my state, and I am fully aware of the negative impacts of factory farms on the environment, public health, animal welfare, and local economies. Nobody in Missouri wants these harmful farms - we want to support local small farms with regenerative practices.
When I learned that the CARB wants to include factory farm gas in
082.1 its Low Carbon Fuel Standard, I became so confused. The science is very clear that methane is not a climate-friendly gas. Everyone is aware that factory farms are nothing but harmful. Allowing factory farms to sell the methane created by housing massive numbers of cows and hogs as a supposedly "carbon negative fuel" is a completely harmful and misguided idea. Please consider the negativ consequences of this proposal and scrap it. We can do better.
Thank you for your time,
Briana

Attachment

Original File Name	
Date and Time Comment Was Submitted	2024-02-16 10:32:39

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 92 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Marisa
Last Name	Landsberg
Email Address	marisalandsberg@verizon.net
Affiliation	
Subject	Factory Farm
Comment 083.1	Please stop investing in factory farm gas.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 10:48:17

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 105 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Wendy
Last Name	Allen
Email Address	wendy38677@aol.com
Affiliation	
Subject	Factory farms
Comment	A heinous process that has tortured countless innocent animals. Please stop funding this cruel slaughter of animals.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 10:59:30

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 106 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Lionel
Last Name	Friedberg
Email Address	lionelfriedberg9@gmail.com
Affiliation	
Subject	Factory Farm Gassing
Comment	The abomination of euthanization by heat and carbon dioxide is beyond cruel and barbaric and has no place in a civilized society in the 21st century.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 11:03:08

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 108 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Armond
Last Name	Matevosian
Email Address	amatevosian@outlook.com
Affiliation	
Subject	Constantly beholden to money and industry

Comment

```
It's sad to see the state of affairs of politicians and governmen
officials of today.  Constantly beholden to corporate and industr
bribery, corruption, and lobbying.  Always looking the other way.
Always doing their bidding.

How have you all reached this point in your lives? How much is
enough for you all to actually finally have a conscience and do t
right thing?  I assume you all have children, family, pets,
etc...does it not register with any of you regarding what you are
leaving behind?

Sad.  Do the right thing for once in your lives.  Just once.
```

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-16 11:08:00

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Comment 109 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Pamela
Last Name	Maxfield
Email Address	humcotherapist@gmail.com
Affiliation	
Subject	Stop Investing In Factory Farm Gas!
Comment 087.1	Biogas is unsustainable; I am against funding this harmful practice!
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 11:20:34

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 110 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Debbie
Last Name	Meeks
Email Address	deborah.meeks@shell.com
Affiliation	
Subject	Shell Comments on LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6342-lcfs2024-WyhTPVA0VmkCaAQq.pdf
Original File Name	Shell.Letter.15FEB24.2.pdf
Date and Time Comment Was Submitted	2024-02-16 11:22:44

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Shell USA
West Corporate Relations
1121 L Street, Suite 700

Sacramento, CA 95814

February 15, 2024

Ms. Rajinder Sahota
Deputy Executive Director – Climate Change and Research
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Shell USA, Inc. Comments on Proposed 2024 Low Carbon Fuel Standard Amendments

Dear Ms. Sahota,

Shell USA, Inc. (Shell) appreciates the opportunity to provide comments on the subject proposed amendments to the Low Carbon Fuel Standard (LCFS). Shell shares a legacy of energy innovation with California that spans over a century, and we appreciate CARB's commitment to incentivizing investments in clean energy. In addition to marketing traditional fuels and electric vehicle charging we deliver low-carbon fuels such as biofuels, renewable natural gas (RNG) and hydrogen. Shell and its affiliates provide secure energy today and look ahead to the evolving energy needs of California and the nation. We are proud to work with our customers and the state to provide a viable energy system that relies, in part, on the regulatory constructs including the LCFS.

Shell respectfully submits these comments for the purpose of helping develop a robust regulatory structure. As always, we welcome the opportunity to answer any questions you may have.

GENERAL COMMENTS

Intrastate Fossil Jet Fuel – More Needs to Be Done Before It Can Become a Deficit Generator

The proposed regulations require fuel importers and producers to determine (a) what is intrastate aviation and (b) how and where the purchasers (i.e. the airlines) consume jet fuel.

088.1 Fuel importers and producers cannot comply because in large part they aren't able to track where their jet fuel is consumed. Accordingly, fuel importers and producers cannot provide any information regarding what portion of their jet fuel is interstate vs. intrastate. Fuel importers and producers only know the amount of jet fuel delivered to storage facilities.

In our view, the language related to intrastate fossil jet fuel should be removed until these issues can be properly vetted.

Eliminate Limitations on Book-and-Claim Accounting for Hydrogen

088.2 As you know, Shell has been very active in developing hydrogen projects in the state, and we are concerned that limiting book-and-claim accounting for hydrogen will constrain growth. This undermines California's immediate need to significantly increase hydrogen as detailed in the 2022 Scoping Plan Update. The LCFS program includes CI benchmarks, and these should be used as the singular determining factor to drive CI reductions and the credit values.

Facilities with an EPA Pathway Should be Exempt from Additional Sustainability Criteria

088.3 Shell appreciates that the proposed amendments do not place arbitrary caps on crop-based feedstocks given that there is no evidence currently suggesting that these feedstocks are resulting in deforestation or adverse land use change. CARB's goal is to prohibit bringing new land into agricultural production for biofuel feedstocks. However, this is currently addressed in the EPA Renewable Fuel Standard. The EPA requires that crop-based feedstocks come from existing agricultural land cleared or cultivated prior to December 19, 2007. If the feedstock was grown outside the United States or Canada then the EPA will require entities to map and track to ensure that this requirement is met (See, 40 CFR 80.1454(c)). However, for feedstock coming from a crop grown in the United States or Canada, the EPA checks when it issues its Renewable Volume Obligation that the 2007 baseline amount of agricultural land in the United States or Canada has not been exceeded (See, 40 CFR 80.1454(g)).

Program Streamlining

The LCFS program has expanded over the years, and it is understandable that some inefficiencies have come about. For CARB and the State to reach its ambitions in a timely manner Shell recommends working with regulated entities to streamline the program. Like many other organizations Shell has a list of suggestions for improving the efficiency of the program that we would appreciate discussing at the appropriate time.

SPECIFIC COMMENTS

Below is a list of items related to the updated regulation language for consideration.

Section 95486.1 Generating and Calculating Credits and Deficits Using Fuel Pathways

088.4 Subparagraph (g): This section essentially punishes operations by way of a four- or five-to-one deficit for inaccurately predicting CI over a 24-month period. Shell urges CARB to reconsider the severe deficit requirement for pathway holders that exceed their CI in a 24-month period. This new obligation would cause a punitive deficit four times the amount of the annual excess CI generated plus an invalidation of excess credits, effectively resulting in a penalty of five times the amount of the annual excess CI generated. This scheme punishes operations and will deter investment in clean fuels development.

Section 95486.3 Generating and Calculating Credits for ZEV Fueling Infrastructure Pathways

Subparagraph (a) Medium- and Heavy-Duty Hydrogen Refueling Infrastructure (MHD-HRI) Pathways: Here, Shell merely seeks clarification.

088.5 With regard to subparagraph (D)(1) Shell asks that CARB confirm that this only applies when subparagraph (D) is met. In other words, "Any station built as a required mitigation measure pursuant to the California Environmental Quality Act…is not eligible for MHD-HRI crediting" if it "is permitted to operate prior to January 1, 2022, or..."

088.6 Subparagraph (4)(F): This language needs some flexibility because it does not account for the reality that operators, despite good faith efforts, may not be able to comply with the 24-month operability requirement[1]. Shell requests a mechanism to seek a variance or waiver from the Executive Officer from the 24-month operability requirement for good cause shown.

Section 95488.6 Fuel Pathway Application Requirements and Certification Process

088.7 The Tier 1 Calculator for Hydrogen is a valuable addition to the program for both applicants and CARB staff as it reduces complexity and time. Shell asks that the calculator include "process energy," displacing natural gas, for book-and-claim. If it isn't included, this will force applicants to submit a Tier 2 pathway to get credits for the process energy utilized, which is counter to the goal of promoting low CI fuels.

Section 95488.10 Maintaining Fuel Pathways

088.8 Subparagraph (b): Shell is concerned with the language, "the Executive Office *may* perform credit true up" and requests this is changed to "*shall* perform." Further, the language should be clear that credit true ups go back to a facility's startup date and include the approval of both temporary and provisional pathways from startup. Clarity and certainty regarding the rules are important to encourage investments needed to achieve implementation of the important low carbon fuels infrastructures.

Appendix B: CA-GREET4.0 Supplemental Document - Modifications Incorporated in CA-GREET 4.0

088.9 A backhaul energy intensity was added to ocean tanker transport for Brazilian sugarcane. The language indicates this is based on data provided by fuel suppliers; however, this does not apply to all fuel suppliers. Shell requests that pathways should determine whether a backhaul is included and this can be confirmed through the verification process.

In conclusion, Shell appreciates the opportunity to engage in the LCFS rulemaking. It is more important than ever that the state maintains its leadership in the clean energy space as other states actively seek to adopt similar programs. Stabilizing the market and careful consideration to changes are critical to continued success of the LCFS program. Thank you for your consideration of our input and thank you for your hard work and leadership of this important program.

Sincerely,

Steve Lesher/dem

Steve Lesher
Manager of Corporate Relations, U.S. West Coast
Shell USA, Inc.

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[1] It has been Shell's experience in building and operating both light-duty and heavy-duty stations there are certain conditions that are beyond the control of the operator. For example, local permitting delays, unavailability of renewable hydrogen, etc.

Comment Log Display

Here is the comment you selected to display.

Comment 101 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Liza
Last Name	Tucker
Email Address	liza@consumerwatchdog.org
Affiliation	Consumer Watchdog
Subject	Proposed Low Carbon Fuel Standard Amendments
Comment	Please find Consumer Watchdog's public comment on proposed amendments to CARB's Low Carbon Fuel Standard. Many Thanks, Liza Tucker Consumer Advocate Consumer Watchdog
Attachment	www.arb.ca.gov/lists/com-attach/6355-lcfs2024-WzdcOVw7ACAFXAd3.pdf
Original File Name	LCFS Public Comment From CWD.pdf
Date and Time Comment Was Submitted	2024-02-16 11:50:11

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 16, 2024

Liane Randolph, Chair
California Air Resources Board
And Members of the Board
1001 I Street
Sacramento, CA 95814

RE: Public Comment on LCFS Rulemaking – Don't accelerate the LCFS Program

Madame Chair and Board Members,

089.1a Consumer Watchdog urges the California Air Resources Board to reject the proposed acceleration of carbon intensity standards under the Low Carbon Fuel Standard (LCFS) Program.

089.1b Gasoline prices in California are too high and the expansion of the LCFS will add more than 50 cents per gallon to the cost of California gasoline by 2026, according to CARB's own estimates (CARB SRIA page 57 here: https://ww2.arb.ca.gov/sites/default/files/2023-09/lcfs_sria_2023_0.pdf

California gasoline prices have consistently been $1.20 more than American gas prices, despite the fact that state environmental fees and extra taxes add only 70 cents more per gallon. The burden on working families in California is too much. Currently, the LCFS adds only 10 cents per gallon to a gallon of gas as part of the added fees. Quintupling that amount is unfair to drivers and will have dubious environmental benefits as the proposed acceleration of carbon intensity requirements is structured.

Ratcheting down Carbon Intensity reduction targets for transportation fuels is a noble goal. If the board adopts the staff recommendation, however, it will cause irreparable pain to consumers at the pump while facilitating continued, unacceptable damage to the environment.

The Low Carbon Fuel Standard (LCFS) program is meant to cut greenhouse gas emissions. It does this by mandating reductions in the average carbon intensity of transportation fuels sold in California. The program requires companies that sell gasoline and diesel fuels to purchase LCFS credits that CARB awards to cleaner fuel alternatives, including credits generated from biofuels and from non-combustion alternatives like electric vehicles.

089.2 By prioritizing biofuels over electrification, CARB has created a monster that is sucking up unreasonable subsidies at the expense of drivers, creating incentives for refiners to decrease

6330 San Vicente Blvd. Suite 250 Los Angeles, CA 90048
Tel: 310-392-0522 • Fax: 310-392-8874
www.ConsumerWatchdog.org

needed refining capacity, and aiding deforestation in the Amazon by propping up soybean farming.

CARB policies have brought a flood of renewable diesel into California's market by assigning overly generous Carbon Intensity scores on the premise that renewable diesel is far less carbon polluting than it is in reality.

One of the main beneficiaries has been big oil refiners who have converted two of their refineries to cash in on the renewable diesel gold rush CARB has created. The refiners have found a way to decrease gasoline inventories, so they can jack up gas prices from a tighter market. A history of the California oil refining market, where five oil refiners make 98% of the gasoline, shows that oil refiners have looked for ways to create a tighter market so they can charge more for gasoline.[1] CARB has given Marathon and Phillips 66 the incentive to take 13% of the state's gasoline refining capacity offline to produce renewable diesel.

The manufacture of renewable diesel, which earns more LCFS credits than any other project type, is particularly dangerous as it involves the use of highly [flammable methanol] to break up vegetable oils and animal fats. Worker overexposure can cause neurological damage. Two refineries, Marathon and Phillips 66, are on the verge of completing their conversions to make

[1] Memos from West Coast oil refiners from the 1990s, released by United States Senator Ron Wyden (D-Ore.), show that reducing refining capacity to maximize profits is a deliberate business strategy. An internal Chevron memo, for example, stated: "A senior energy analyst at the recent API [American Petroleum Institute] convention warned that if the U.S. petroleum industry doesn't reduce its refining capacity, it will never see any substantial increase in refinery margins." It then discussed how major refiners were closing down refineries. Not surprisingly, subsequent oil company profit reports show each dramatic gasoline price spike over the last decade has been mirrored by a corresponding corporate profit spike. An internal memo from Mobil discussed how the oil giant worked to "keep down" a smaller refiner, Powerine, from opening up its refinery as way to increase its profits by calling for increased environmental protections on the refiner. Then the memo talks about a Plan B of buying up the refiner's production should it open. Buying up other competitors' output and preventing new production are hardly the hallmarks of a competitive market. Similarly, a Texaco memo warned that "supply significantly exceeds demand year-round. This results in very poor refinery margins and very poor refinery financial results. Significant events need to occur to assist in reducing supplies and/or increasing the demand for gasoline." In the subsequent years, California's refineries consolidated and contracted. In 2005, our consumer group teamed up with Sen. Barbara Boxer (D-Calif.) and Attorney General Bill Lockyer in getting Shell Oil to reverse its decision to bulldoze its Bakersfield refinery, and to instead sell it. Internal documents showed that the refinery was making among the highest profits of all Shell refineries. That indicated the company wanted to make supplies even tighter, driving prices artificially higher. Nonetheless, Shell continued to lean on Flying J, the new owner, who eventually shuttered the refinery. For example, leaders of the United Steel Workers local at the refinery charged Shell with "trying to shut down our plant" by shutting off pipelines and demanding payment 30 days in advance. The union memo to members said Shell had refused an offer of eight days' advance payment. The erasure of the Big West refinery took 2% of the state's gasoline and 6% of diesel offline. Oil refiners in California have systematically shut down refiners and refineries as a way of maximizing their profits. See the following memos from Chevron, Texaco, and Mobil:
https://consumerwatchdog.org/wp-content/uploads/2023/12/Chevron-5103.pdf
https://consumerwatchdog.org/wp-content/uploads/2023/12/Texaco-5104.pdf
https://consumerwatchdog.org/wp-content/uploads/2023/12/Mobil-5105.pdf

renewable diesel full tilt in the Bay Area at Marathon's Martinez refinery and Phillips' Rodeo refinery. Marathon's Martinez refinery has already experienced two large fires. The manufacturing process is energy-intensive and renewable diesel combustion still produces both planet-cooking carbon dioxide and nitrogen oxide, a critical component of photochemical smog that is damaging to public health.

Biodiesel has a limited use for certain trucks but cannot be used for most vehicles that consumers drive. Based on credit generation data from the CARB LCFS Dashboard and average annual LCFS credit prices from UC Davis, about $17 billion worth of LCFS credits were issued from 2013 through 2022, with about 80% going to biofuels, and only about 20% going to EVs and electrification that produce zero emissions. The program's funding for electrification has played an important role in helping local governments and other public actors relying on the sale of credits afford projects that move them away from fossil fuels. But these benefits are being overshadowed by the harms being done by the program's primary beneficiaries, the biofuels industry.

The preponderance of projects the LCFS supports still produce planet-damaging and toxic emissions rather than moving far more quickly to a zero-emissions transportation structure via electrification. Both Marathon and Phillips 66 are investing in U.S. soybean processing plants as their renewable diesel requires large amounts of soybean oil that is rapidly becoming a preferred feedstock. Almost all the renewable diesel produced in America is consumed in California because of the LCFS program. Most of it is from out of state or imported from South American countries that are home to tropical rainforest that extends across several of them.

Phillips 66 plans to produce renewable diesel using soy bean oil from Argentina, the world's largest exporter of soybean oil, according to the Union of Concerned Scientists. "This one huge facility could potentially consume about half Argentina's soybean exports and 20 percent of global exports," according to UCS senior scientist Jeffrey Martin. Demand for soy and palm oil is displacing communities and leading to the slashing and burning of South American rainforests, according to Rainforest Rescue. "This deforestation is accelerating climate change by releasing billions of tons of CO_2 into the atmosphere — by some estimates, deforestation has a greater impact on the climate than the world's entire fleet of motor vehicles," the organization reports. "Moreover, arable land is scarce, and its use for fuel crops is contributing to rising food prices and world hunger."

The LCFS has been the nation's primary driver of factory farm biogas development, according to Food & Water Watch. Big Oil and Big Ag behemoths such as Chevron, BP, Shell, Smithfield, Perdue, and Tyson have invested heavily in a national methane production network from livestock waste that generates revenue from so-called "clean energy" renewable biogas under credit trading schemes such as the LCFS.

Such systems are in fact giant sources of pollution featuring vast manure lagoons that increase methane emissions, shoot pollutants such as ammonia and hydrogen sulfide into the air, and sicken communities.

CARB staff appears to have discounted such criticism in preparing its recommendation. When a
089.3 scientist and former CARB fuel chief criticized CARB's relationships to gas lobbyists, staff was barred from speaking with him by CARB's lead climate executive, Rajinder Sahota, according to an article in Capital & Main.

As UCS senior scientist Jeremy Martin, writes, "In my feedback over the last 2 years, I argued CARB should cap support for bio-based diesel made from vegetable oil and phase out credits for avoided methane pollution to wind down what has become, in effect, a poorly run offset program. Bio-based diesel and manure biomethane generate a lot more credits than an accurate assessment of their climate benefits would support and are causing additional problems to boot. Unfortunately, the official proposal ignores the oversupply of low value credits and focuses almost exclusively on increasing demand by accelerating the pace of the program. This won't work—and will make the LCFS needlessly costly for California drivers, while postponing the needed reforms that would restore the stability of the LCFS."

The technical complexity of biofuels policy makes it hard for consumers to understand what they are being asked to pay for, and industry benefits from the opacity. Financially disinterested experts have articulated substantial problems with the program's performance, which staff has ignored.

A vote for the staff proposal is a vote to ask California drivers to pay an additional 50 cents per gallon of gasoline to support biofuels that contribute to air pollution, increase food prices, and increase deforestation in the Amazon. CARB must ensure that the transition away from fossil fuels results in a zero-carbon emissions economy not an economic bonanza for biofuels polluters.

Sincerely,

Jamie Court

Jamie Court
President, Consumer Watchdog

Liza Tucker
Consumer Advocate, Consumer Watchdog

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Comment 102 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Adam
Last Name	Aranyos
Email Address	aaranyos@duck.com
Affiliation	
Subject	Urgent Call for Ethical and Environmental Reforms in California’s Agriculture

Comment

Dear Governor Newsom and Members of the California Air Resources Board,

I am reaching out to express my profound concern not only about th environmental impact of factory farming in California but also about the inherent cruelty to animals that these industrial practices perpetuate. The support for biogas production from industrial dairies under the Low Carbon Fuel Standard (LCFS) policies, while intended to promote renewable energy, inadvertentl endorses and sustains these harmful and inhumane practices.

The state of California has long stood as a beacon of progress in environmental protection and ethical standards. However, the
090.1 continued financial incentives for biogas as a byproduct of factor farming practices are in stark contradiction to these values. Beyond the significant issues of water pollution, groundwater depletion, and greenhouse gas emissions, the system of factory farming inflicts tremendous suffering on countless animals. These sentient beings are confined in overcrowded, unnatural conditions, deprived of their basic instincts and welfare, all in the name of efficiency and profit.

Supporting biogas production under the current LCFS policies not only overlooks but also financially rewards the environmental degradation and animal cruelty inherent in the factory farming model. This approach detracts from the urgent need to shift towar more sustainable and humane agricultural practices. It sends a misleading message that we can mitigate climate change without addressing the root causes of these crises, including the ethical treatment of animals.

I implore you and the CARB to reconsider the implications of supporting biogas production within the LCFS. This is a pivotal moment to align our environmental policies with a broader vision o sustainability that includes animal welfare. We must end the cycle of cruelty and environmental harm by investing in alternatives tha respect animal rights and contribute to a healthier planet.

I urge you to take a stand against the greenwashing of factory farming and to lead the way in adopting policies that promote genuine sustainability, respect for animal life, and the wellbein of our communities. The upcoming review of LCFS policies presents an invaluable opportunity to correct our course and commit to a future that values all forms of life and the integrity of our environment.

Thank you for considering this critical issue. I trust in your leadership to make decisions that reflect our shared values of compassion, sustainability, and justice.

Sincerely,
Adam Aranyos

Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 12:13:12

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Comment Log Display

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Comment 99 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Vasu
Last Name	Murti
Email Address	vasumurti@netscape.net
Affiliation	
Subject	stop public funding for factory farm gas
Comment	The Democratic Party platform should support: Animal Rights, Defending the Affordable Care Act, Ending Citizens United, Ending Marijuana Prohibition, Giving Greater Visibility to Pro-Life Democrats, Gun Control, Net Neutrality, Raising the Minimum Wage t $15 an Hour, Responding to the Scientific Consensus on Global Warming, and a Sustainable Energy Policy. Democrats for Life of America, 10521 Judicial Drive, #200, Fairfax, VA 22030, (703) 424-6663
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 12:28:44

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Comment 104 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jesse
Last Name	Nowicki
Email Address	jnowicki@rpmgllc.com
Affiliation	
Subject	Comments on Proposed LCFS Program
Comment	Please see attached.
Attachment	www.arb.ca.gov/lists/com-attach/6364-lcfs2024-B3VXIVY6AjYCWwFi.pdf
Original File Name	RPMG Comment Letter - LCFS Proposed Amendments February 2024.pdf
Date and Time Comment Was Submitted	2024-02-16 12:33:53

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

RPMG™
1157 Valley Park Drive, Ste. 100
Shakopee, MN 55379

February 14, 2024

Liane Randolph, Chair
CARB Board Members
California Air Resource Board

Re: 45-day Amendment Package of Proposed Changes to the Low Carbon Fuel Standard

Chair Randolph and Board Members,

RPMG Inc. (RPMG) is a biofuel marketing company representing our owner and marketing partner ethanol facilities located throughout the Midwest. Our member facilities provide both ethanol and distillers corn oil (DCO) as essential inputs to California's low carbon fuels market in material quantities. Since the Program's inception over a decade ago, RPMG has supported California's clean transportation fuel policy, and worked diligently with CARB staff to improve the administration of the Program. RPMG looks forward to the approval and use of E15 in California. This logical next regulatory step for lowering the carbon intensity of California's gasoline supply will also provide further reduction in criteria air pollutants, thus achieving the dual goals being sought by CARB. The amount of ethanol used in California is not a function of LCFS incentives, but rather is a function of the State and Federal air quality rules requiring the use of Reformulated Gasoline and an Oxygenate. Ethanol's role in California's gasoline market is firmly established and has been since the mandated phaseout of MTBE. Under these air quality requirements, there is already a mandate for ethanol that is independent of the LCFS. The LCFS incents lower carbon ethanol *per gallon*, but the existing fuel regulations dictate the *total volume* consumed.

Our member facilities are continually investing in lower carbon technologies, innovating production methodologies and ways to reduce carbon emissions to the atmosphere. These technologies include corn kernel fiber ethanol, wholistic facility efficiency upgrades, waste heat recovery, and Carbon Capture and Storage (CCS).

RPMG appreciates the opportunity to comment on this important rulemaking effort. Our comments below reflect the issues directly impacting RPMG and our member plants. They are presented in order of importance. We respectfully request the Board direct staff to continue working on the following identified issues. Given the importance, and frequency at which LCFS amendments occur, it is critical to take the time now to correct these deficiencies.

Sustainability Requirements for Crop-Based Feedstocks [§ 95488.9(g)]

092.1 RPMG is fundamentally opposed to the proposal in § 95488.9(g) *Sustainability Requirements for Crop-Based Feedstocks* based on several significant practical, policy, and technical issues highlighted for your consideration.

092.1 cont Despite the title of this newly drafted section, there is nothing proposed that clearly defines or expresses what CARB's expectations regarding sustainability are, in theory or practice. Instead, CARB has outsourced this concept. This regulatory sustainability model was not workshopped, nor presented in any draft fashion to stakeholders over the previous two years of informal rulemaking efforts.

It is clear through reviewing transcript of the September 2023 CARB Board hearing and stakeholder feedback at the informal workshops, that questions and concerns have been raised and debated regarding a potential increase in crop-based feedstocks for Renewable Diesel from virgin materials. That dialogue does not reconcile with what is written as proposed regulatory text. Staff's proposal is too broad and far-reaching to be adopted on its first pass.

Set to begin in 2028, the proposed sustainability requirements unilaterally require *all* crop-based feedstocks used for *all* fuel pathways (liquid, gaseous, electric) indiscriminate of vehicle class or engine technology be certified. The requirement imposed on the marketplace is to 'maintain continuous' certification by a yet-to-be determined, yet-to-be vetted and yet-to-be CARB-approved certification system. The requirement's goal of demonstrating *all* agricultural-based feedstocks is farmed, harvested, and developed in a "sustainable" manner without elaboration stands in contrast to practical regulations. As proposed, without obtaining this TBD certification, all biofuel pathways will be assigned an uneconomic carbon intensity value equivalent to fossil diesel. Low carbon fuel producers have responded to the signals of the LCFS program to reduce carbon emissions quantified in the fuel products they supply to California. The introduction of this section in this manner, as written and without even a definition of 'sustainability', is disingenuous toward the investments made and common goals we seek to achieve in mitigating impacts to the environment we all share and will not achieve its implied purpose.

From a technical perspective, and as has been pointed out by numerous LCFS stakeholders, this regulation already includes overly conservative Indirect Land Use Change (iLUC) values on all crop-based feedstock. iLUC is a sufficient mechanism for deterring high biodiverse land conversion within the supply chains of fuels delivered to California complying with the LCFS. It is important to note that an increased volume of ethanol used in California will not result in an increase of acreage used for feedstock production. To institute further, undefined, Sustainability certification requirements to these same crop-based feedstock supply chains ignores this pre-existing function of the regulation. It also infringes upon, and compounds, the conservative fundamental mechanics of performing a well to wheel lifecycle analysis.

The LCFS lives within a Federal Clean Air Act framework of fuel regulations. Underpinning this California program is the USEPA's Renewable Fuel Standard (RFS). Crop-based feedstocks are an integral part of U.S. domestic and global agricultural commodity markets. The RFS rightfully administers a feedstock aggregate compliance approach for domestic agriculture feedstocks under § 80.1454 (c)(1)(i). The domestic agricultural community has testified and commented on the complexities of commercial grain commodity markets in numerous federal, international, and regional fuel regulation proposals. RPMG points CARB staff to the public record comments submitted to USEPA for the RFS program on this issue for in-depth

092.1 cont resource review [1]. Given the crop-based feedstock sustainability requirements are not aligned with other policy frameworks, and as such are not needed, RPMG recommends § 95488.9(g), as proposed, be removed in its entirety.

From an authority perspective, CARB's proposal outsources the standard to an external certification body. The most prevalently used Sustainability certification standards in use at this time were mandated by directives and legal frameworks in foreign countries, and then developed by non-governmental organizations. RPMG understands the importance of sustainability, but developing a California legally binding requirement overseen by foreign non-governmental organizations and private entities is an abdication of authority, nor does it ensure domestic feedstocks meet the unknown definition of "sustainable." As written, there is no defined means of mitigating those risks should this proposed language be adopted. Should a satisfactory certification standard not be available, or the accepted standard changes, all crop-based fuels pathways in the LCFS program would default to a CI for fossil diesel.

The reasoning for this third-party auditing per the ISOR is based on the fact auditing has been done in other biomass-based energy programs. The introduction of more certification requirements is tantamount to more Audit Burden. There has not been any indication or case made that this proposal will result in emission GHG reductions, while forcing additional audit requirements, upstream to a U.S. domestic and global farmer stakeholder community that was not represented in the rulemaking process. This additional Audit Burden will only serve to increase costs, time demands, and superfluous recordkeeping without providing any benefit to the environment or to the LCFS carbon credit marketplace. There would be no economic incentive to put these additional requirements in place – for any fuel supply chain. It also further exacerbates a distinct increased demand for capable subject matter experts in field, available, and accredited auditors. The LCFS is already complicated, this proposal compounds that complexity several fold. Audit Burden, and stakeholder burn-out, are real issues, especially as clean fuel programs expand in a patchwork fashion across the continent, each with unique requirements. Cost benefit considerations are necessary yet haven't been discussed. RPMG recommends CARB take the time to have that conversation before instituting these requirements.

092.2 The debate for what constitutes "sustainable" activity or behavior is an important conversation. RPMG recommends we take the time to have that conversation before instituting requirements of this magnitude without even expounding upon what the time and cost requirements will be, nor the impact on national and international fuel markets. It is fundamentally necessary in RPMG's opinion to remove this proposed section in its entirety at this time. For these reasons RPMG is opposed to this new mandate as currently proposed.

[1] https://www.regulations.gov/comment/EPA-HQ-OAR-2005-0161-3210

<u>Verification Body Rotation Requirements</u> [§ 95503]

092.3 RPMG remains opposed to the existing mandated verifier firm rotation which requires verifiers to be on a six-year rotation and must suspend all services for three years following the rotation before providing any further verification services. RPMG has warned of the impact of this requirement in previous amendment packages[2,3]. We are revisiting this issue as the verification component of the Program has matured and pathway holders are getting close to the mandated rotation timeline. RPMG requests that CARB reverse this early policy decision.

Partner or lead verifier rotation is a sufficient alternative. RPMG strongly believes mandated firm rotation is in conflict to CARB's and stakeholders' mutually beneficial desire to leverage efficiencies amongst existing stakeholder verification programs. CARB has historically stated their interest in incorporating a firm rotation requirement is to ensure "fresh eyes" and impartiality among firms. The stated benefits of mandated rotation by CARB can be achieved at the partner or lead verifier level. RPMG believes the program's detailed accreditation and CARB approval of verification plans and sampling strategies are sufficient to ensure impartiality.

CARB further elaborates this requirement has been successfully demonstrated through administering the Mandatory Reporting Rule (MRR) under Cap-and-Trade. RPMG maintains there are crucial differences between Cap-and-Trade and LCFS. Required firm rotation does not adequately allow for a regulated entity to consider a verification body's basic knowledge of an industry or individual business practices. This will result, without question, in a loss of engagement efficiency and overall dissatisfaction of the verification experience. Regulated entities have commercial operations to manage. Excessive time spent on repeated and recurring introductions of a new auditor to those operations is not an effective use of enterprise resources, and it will amount to a loss in productivity and increased costs—costs not considered by CARB.

A firm rotation requirement is not only problematic for regulated parties but also for verifiers. Verifiers are already required to become accredited and incur the associated cost of undergoing the necessary training and travel. Once accredited, the verifier experiences a forced reduction in revenue in off years due to loss of clients which results in a necessitation of higher base fees. This inflated cost structure ultimately makes its way to California fuel consumers, undermining program cost containment efforts. For all of these reasons, RPMG urges CARB to incorporate a partner rotation requirement in lieu of a firm rotation requirement for LCFS verifiers.

<u>Indirect Accounting Mechanisms</u> [§ 95488.8 (i) & (h)]

092.4 RPMG recommends that the proposed amendments for indirect accounting for low-CI electricity, biomethane and low-CI hydrogen be expanded to allow the use of indirect accounting mechanisms to all pathway types for process energy, e.g. liquid biofuel production. All other pathway holders must have

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[2] Microsoft Word - RPMG LCFS Proposal Comment Letter 4.23.18 - Update 2.docx (ca.gov)

[3] Microsoft Word - RPMG LCFS 15-day Comment Letter 7-5-18 v5.docx (ca.gov)

direct connections from renewable or low-CI process energy in order to reduce the CI score. The following is suggested language to § 95488.8 (h) as well as removing the language regarding direct connection § 95488.8 (h)(1)(B).

> § 95488.8. Fuel Pathway Application Requirements Applying to All Classifications.
>
> (1) Low-CI electricity must be supplied from generation equipment under the control of the pathway applicant *or subject to a firm power purchase agreement (PPA) from generating equipment within the same balancing authority as the facility.*

The ISOR describes this preferential treatment as assistance and states this is necessary because there has been very little interest in indirect accounting renewable electricity ZEV pathways under the current rule. It may be true this accounting method has not been widely used in ZEV pathways, but it is a very narrow view of the fuel landscape. The 2022 Scoping Plan update clearly outlines a significant role for liquid biofuels through 2045. By tipping the scale, the proposed regulation is not "allowing the market to determine how the carbon intensity of California's transportation fuels will be reduced."[4] Not only is this a violation of technology neutrality, an original fundamental tenet of the LCFS, it leaves significant carbon reduction out of the program. Liquid biofuel producers have the capacity, both technical and capital, to greatly reduce their carbon intensity scores with the correct regulatory signals.

Credit True Up After Annual Verification [§ 95488.10 (b)]

RPMG strongly supports this aspect of the regulatory package.

Per the current regulation, fuel pathways that achieved additional carbon reductions demonstrated with a lower verified CI score had their additional generated credits assigned to the Program's buffer account. Under the proposed regulations, the fuel pathway holder that has a lower verified operational CI may perform a credit true up and the additional credits are assigned to the pathway holder.

092.5 Entities reporting lower verified CI scores have not been able to claim the additional credits due to the prohibition of retroactive credit claims in the regulation (95486(a)(2)). The addition of the proposed credit true up is an added benefit for the pathway holder, the program, and the environment as it provides the incentive to continue to lower greenhouse gas emissions.

RPMG also believes the credit true up proposal supports improved regulatory compliance and administrative efficiency. Today's system of subjecting pathway holders to both administrative adjustments and potential enforcement action for any CI exceedance, without the counterbalance of receiving additional credits for all incremental CI reductions is a scheme that is punitive in both directions. This newly proposed language is an incentive and will thus encourage pathway holders to improve CI

[4] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/fsorlcfs.pdf?_ga=2.118890249.1658159364.1707157899-1753130937.1706029505

scores without having to reapply for incremental production efficiency changes in their CI Scores. This administrative efficiency will also benefit CARB's pathway staff.

092.6 One additional note on this issue is that the proposed regulations need more clarification for entities utilizing Temporary CI scores. RPMG requests CARB provide further guidance document(s) to provide instructions on completing a credit true up for pathway holders who may have Temporary CI scores and certified or provisionally certified CI scores within the same compliance year.

<u>New Automatic Deficit Obligation Penalty</u> [§ 95486.1 (g)]

Beginning in 2025, it is proposed that a fuel pathway holder for a non-provisional fuel pathway generates a non-linear deficit obligation following a verified CI exceedance. If a verified CI exceedance does occur, pathway holders will face an automatic deficit obligation of a 4:1 ratio. RPMG understands this new section is intended to work in conjunction with the True Up provisions noted above. While we are supportive of the True Up change because it fairly addresses overcompliance, we oppose the current proposal for Deficit Obligation as it is unnecessarily punitive. If a pathway holder overperforms they receive a 1:1 credit, but if there is an underperformance, then the penalty is 4:1. An objective of the LCFS has always been to ensure that the environmental integrity of the market remains whole. Therefore, requiring a 1:1 adjustment of any deficit obligation before an enforcement action is initiated remains an appropriate remedy.

092.7

This two-step process would be a more balanced approach to pathway holders seeking to recertify under the new CA-GREET 4.0 model update required by the regulation. Each, and every, pathway will be updated in short order, and therefore each LCFS stakeholder will be tasked with the same decision of how much Margin of Safety to apply. With the current 4:1 vs 1:1 risk/reward structure, it can be imagined that more conservative CI scores will be requested. This will lead to a market lag in actual credit generation, a deferred return on investment, and potential unintended market consequences such as the impacts to the new Auto Acceleration Mechanism based on credit-deficit numbers that may not accurately reflect market conditions in real-time.

<u>Tier I/II Applications</u> [§ 95488.6 (a) & 95488.7 (a)]

All Tier 1 and Tier 2 applications must contain data consisting of the most recent 24-month period of operation, or at least three months of operation for provisional fuel pathway applications. Additionally, it is proposed that an application does not have more than three months between the end of the reported data period and date of its submission. RPMG understands that Tier 1 and Tier 2 applications with the most up-to-date operational data are essential. The proposed also states that if a pathway application cannot be validated, it must be resubmitted with the "most recent operational data".

092.8 RPMG recommends CARB clarify this "most recent operational data" requirement as it is unclear what time period is actually being sought or allowed. For example, if an application is resubmitted in January, does the provision require October through December data, or just a data period that is within three months of the resubmitted application (July-September). If the applicant must resubmit operational data, the time and expense to gather the data is costly and time-consuming. CARB providing application approvals within an adequate time would ensure the application has up-to-date information and the responsibility is put on CARB rather than the applicant.

<u>Tier 1 Calculator and Instruction Manual</u>

In reviewing the proposed CA-GREET 4.0 Starch and Fiber Ethanol T1 Calculator and Instruction Manual, RPMG encourages CARB to refine the following sections of the calculator and instruction manual:

1. A summary line should be added to the Site-Specific Input tab to aid in user reconciliation of aggregated monthly entries and Verifier reference in summarization detail.
2. The default value option for feedstock transport should be expanded to include more regions of biofuel production in addition to the present 9 state region identified. Identifying and producing records for harvest sites and collection sites is labor intensive. Without the option of a default value, certain applicants may choose simply not to participate due to this impediment. At the very least, the demonstration of feedstock transport mileage where a default value is not an option should be limited to a one-time Validation and not an on-going data collection exercise.
3. This iteration of the CA-GREET 4.0 T1 calculator should consider secondary and alternative energy directed to and allocated for co-product processing energy. For example, if an alternative energy source is consumed to operate only the drum dryer to bake Dried Distiller's Grain with Soluble, 092.9 the entry field for co-products should be broadened to capture this alternative energy source emission factor for the relevant allocated proportion and not simply default to the assumed primary process energy emission factor as the only option for calculation.
4. RPMG proposes all CA-GREET 3.0 Standard Methods and CARB designated Protocols, used by pathway holders since the last amended regulation effective for 2019, be provided to the public in an accessible online library or website. This will help all applicants to be able to access the same information and provide awareness of existing Standard Methods and Protocols developed after the adoption and issuance of T1 Calculator materials.
5. We noted the Emission Factor for Fiber Enzymes has been modified transitioning from 1,207 grams CO_2e per pound in CA-GREET 3.0 to 525 grams CO_2e per pound in CA-GREET 4.0. Staff has been explained this change is attributable to assuming a 50% moisture content of Enzymes received and used, and that the EF now compensates for this rate of moisture inclusion. RPMG recommends documenting the rational and basis for this change. Further RPMG recommends that CARB affirm in program guidance or Instruction Materials that if the moisture content of a received Fiber Enzyme formulation is greater than 50%, a pathway applicant can approach CARB for an Operating Condition to allow the use of an alternatively modified moisture compensated Emission Factor and they do not need to pursue a T2 pathway application.
6. RPMG and our affiliated producer pathway holders support the incorporation of the Pathway Summary into the CA-GREET 4.0 T1 Calculator. The presence of Operating Conditions within the Pathway Summary should be relied upon for both formal pathway and Operating Condition

acceptance and thereafter for Annual Fuel Pathway Reporting (AFPR) re-affirmation. Having all Operating Conditions singularly incorporated here will simplify the report submission and Verification process for all stakeholders. This should be clearly expressed in AFPR guidance and instruction for reporting expectations.

7. The CA-GREET 4.0 SFE T1 Calculator applies an emission factor for "Evaporative Emissions." It is not clearly identified in LCFS CA-GREET 4.0 material what this emission factor represents. When consulted directly, Staff explained it is meant to consider emissions of Volatile Organic Compound (VOCs) assumed in the production profile of ethanol plants. However, all U.S. domestic ethanol production facilities are obliged to implement and comply with Leak Detection and Repair (LDAR) mandates overseen by USEPA. Adherence to LDAR makes the presence of this additional assumed emission factor unnecessary and results in an arbitrary inflation of the CI score result. This emission factor should be removed from the CA-GREET 4.0 SFE T1 Calculator.

In addition to the comments outlined above, RPMG supports the comments submitted by our industry partners including Renewable Fuels Association (RFA), Growth Energy, ACE Ethanol LLC, and Christianson PLLP.

In Closing

RPMG would like to again highlight the benefits that our industry has made to California's GHG programs and thank CARB for the opportunity to contribute toward the improvement of this regulatory proposal. We would also reiterate that with a regulatory structure which promotes innovation the biofuels industry can continue to lead the way in terms of reducing the Carbon Intensity of the biogenic liquid fuel market that will remain in the state for years to come. RPMG looks forward to continuing these conversations and is available to clarify any suggestion provided in this letter. Please contact me with any questions or comments at (952) 465-3255 or jnowicki@rpmgllc.com.

Thank you,

Jesse Nowicki
Regulatory and Compliance Specialist
RPMG Inc.

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Comment 101 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Eric
Last Name	Sherman
Email Address	eric@bangzoomstudios.com
Affiliation	
Subject	Stop Funding Factory Farm Gas
Comment 093.1	Factory farms are cruel and inhumane. And they should not be funde with taxpayer dollars. I'm against factory farms and don't want my hard earned money supporting them.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 14:24:03

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Comment 106 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Cristin
Last Name	Reno
Email Address	Cristin.reno@oberonfuels.com
Affiliation	Oberon Fuels
Subject	Oberon Fuels Comments on Proposed LCFS Amendments 2024
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6383-lcfs2024-AG8FYVUxUXABaFI8.pdf
Original File Name	Oberon Fuels Comments on CARB LCFS Regulations 2024.pdf
Date and Time Comment Was Submitted	2024-02-16 14:28:52

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845 15th ST, SUITE 103 #49216, SAN DIEGO, CA 92101
619.255.9361 WWW.OBERONFUELS.COM

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814
Via Online Submission

Comments on Proposed Low Carbon Fuel Standard Amendments

Dear California Air Resources Board (CARB) Low Carbon Fuel Standard Program Staff:

Thank you for the opportunity to provide comments in response to the draft amendments to the Low Carbon Fuel Standard.

As background, Oberon is an innovative California company founded in San Diego 13 years ago with a focus on decarbonizing the global LPG/propane industry while laying the foundation for renewable hydrogen. We are accomplishing this today by producing renewable dimethyl ether (DME) at our Brawley, California production facility. Oberon's rDME® brand fuel can be made from various in-state waste streams (*e.g.*, dairy manure biogas, waste water treatment biogas), which can enable smaller, often stranded, biogas suppliers to participate in the LCFS program and produce low carbon DME.[1] Oberon's rDME fuel can reduce the carbon footprint of transportation when used as a: 1) blending agent with Liquid Petroleum Gas (LPG)/propane; 2) hydrogen carrier to power the growing fuel-cell electric vehicle and stationary source market; and 3) diesel substitute. This range of creative applications that clean fuels, such as DME, can support is underscored in the recently adopted 2022 Scoping Plan Update—DME along with other clean alternatives to petroleum are a key part of the solution if the state is to reach its legislatively-mandated greenhouse gas reduction targets.

Responses to Draft Amendments

094.1 Oberon strongly supports the proposed amendment package and urges adoption. In the 'Other Comments' section below we offer suggestions for further clarity where the draft amendment may benefit from a more fulsome consideration of rapidly developing technology and commercial practices.

We also express our gratitude for your engagement and support for DME and we note with pleasure the inclusion of DME on *Table 4. Energy Densities and Conversion Factors for LCFS Fuels and Blendstocks*.

[1] The California Air Resources Board has estimated dairy biogas-based DME made by the Oberon process has a carbon intensity of -278. rDME® is a trademark of Oberon Fuels, Inc.

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619.255.9361 WWW.OBERONFUELS.COM

Other Comments

- **Program Stringency**

094.2 While we believe that the proposed 5% step-down in stringency will help to course-correct the market, it simply does not go far enough considering the size of the cumulative credit bank, which is anticipated to increase its rate of growth as new clean fuel projects that have been or are being constructed bring more clean fuels to market. The step-down should be increased by at least 7%, which, for perspective, translates into a 2030 target of at least 32% reduction in the CI relative to the 2010 baseline. While a 7% step-down will still leave many credits in the cumulative credit bank, this single adjustment will translate into millions of additional tons of GHG emission reductions that would've otherwise gone unaddressed.

- **Avoided Methane Crediting**

094.3 CARB's draft regulatory language is silent on avoided emissions credits from feedstocks other than dairy, swine, and organics diverted from landfill. While we believe the current Tier 2 process is sufficient for a user to develop and CARB to approve avoided emissions credits for feedstocks such as poultry manure, project developers and users may benefit from further regulatory clarity.

- **Livestock Offset Protocol**

094.4 The Livestock Offset Protocol (LOP) uses methane conversion factors taken from Chapter 10 of the 2006 Intergovernmental Panel on Climate Change ("IPCC") entitled *Emissions from Livestock and Manure Management* ("Chapter 10"). Section 10.4 of Chapter 10 (pp. 35 – 52) provides these factors for many types of livestock in addition to dairy and swine, including poultry (both layers and broilers) and beef cattle. CARB may amend the LOP or create a separate LOP for the LCFS to add user clarity for other feedstocks.

- **Biomethane Crediting – Book-and-Claim**

094.5 CARB should expand the exemption to the deliverability requirements beyond hydrogen to include use in fuel production where biomethane is an intermediate feedstock if the finished fuel is physically delivered into California.

With appropriate limits and the verification and validation procedures CARB already has in place, we believe there is an opportunity to incentivize investments that deliver substantial reductions in greenhouse gas emissions while retaining the critical oversight and compliance that has been foundational to the success of the program.

845 15th ST, SUITE 103 #49216, SAN DIEGO, CA 92101
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- **Book-and-Claim of Low-CI Hydrogen**

094.6 We recognize that meeting California's ambitious goals for deploying large scale hydrogen projects will need to incorporate low carbon intensity hydrogen carriers such as DME. We ask that CARB consider adding explicit language or clarity around the opportunity to apply Book-and-Claim for renewable hydrogen pathways that involve an intermediate step or use of hydrogen carrier-molecules. This approach is fundamental to rapidly ramping up the use of renewable hydrogen as envisioned by the Scoping Plan and the ARCHES effort.

- **Credit True-up**

094.7 The proposal includes true-up provisions where verified operational CI's are drawn on to potentially adjust the credits based on certified CI's. The proposal indicates that a shortfall (i.e., a verified operational CI that is higher than the certified CI upon which project credits were generated) will result in a penalty the applies a multiplier to the shortfall. Further, the language indicates that in the event the operationally verified CI is lower than the certified CI (i.e., it failed to generate as many credits as it could have) the Executive Offer (EO) "may" make the appropriate adjustment (true-up) by awarding additional credits to the applicable fuel reporting entity. The word "may" should be deleted. If the operationally verified CI, including an affirmative verification statement, is lower than the certified CI that was the basis for credit generation, the EO "must" award the supplemental credits supported by the underlying documentation.

094.8 The concept of adjustment to credits based on operationally verified CI's is sound. However, limiting the proposal to certified CI's is a significant oversight. The proposal should be carried over and applied to temporary and provisional CI's as fuel providers may rely on these CI's for months, or even years, as a more refined pathway is evaluated and subsequently approved.

Recommendations for Future Action

Oberon encourages CARB to ensure there continues to be a market for low-CI liquid and gaseous fuels as they are an important decarbonization tool, especially in sectors that are hard to decarbonize. Oberon recommends that CARB send a clear policy signal that biofuels (e.g., biomethane, renewable propane, renewable DME) are necessary and effective decarbonization strategies in these other sectors (e.g., residential, commercial, industrial) and are fundamental to the state meeting its ambitious GHG reduction targets.

As the state transitions out of combustion in the transportation space gaseous and liquid fuels will continue to support the industrial, commercial, and residential sectors with escalating pressure to drive down GHG emissions. One approach for doing so is stronger signals and incentives for the production and use of low-CI fuels in those sectors.

Expanding the LCFS or creating a LCFS-like structure to help facilitate decarbonization of other gasoline-, diesel-, fossil natural gas-, and propane-fueled applications in residential, commercial, and industrial markets is an opportunity that merits attention. Doing so would reward investments and use of cleaner fuels by these legacy sectors that are not anticipated to be electrified for many decades. In the last year new domestic and international policies have been established to apply the LCFS approach beyond transportation fuels such as Vermont's Clean Heat Standard, the Canadian Clean Fuel Regulation, and the EU ETS II which cover both transportation and non-transportation fuel. Policy expansion, as signaled in the Initial Statement of Reasons for the proposed LCFS amendments, will support additional reductions in greenhouse gas emissions by further accelerating the market development of low carbon fuels such as renewable DME.

Thank you for your time and consideration. Please do not hesitate to contact me at cristin.reno@oberonfuels.com with any questions.

Sincerely,

Cristin Reno
Manager, Regulatory Affairs
Oberon Fuels

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Comment 107 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Kristen
Last Name	Lowry
Email Address	Lowrykristen@yahoo.ca
Affiliation	
Subject	Factory Farm Gas
Comment	As a nation, we have to do better for our country & our planet
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 14:35:46

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 108 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Heather
Last Name	Dziedzic
Email Address	heather@americanbiogascouncil.org
Affiliation	American Biogas Council
Subject	American Biogas Council Comments on the Proposed Amendments to the LCFS
Comment	Attached please find the American Biogas Council's comments on the proposed amendments to the LCFS. Thank you!
Attachment	www.arb.ca.gov/lists/com-attach/6390-lcfs2024-WjtRNQZkWVVVMAVq.pdf
Original File Name	ABC_CommentLetter_LCFS_Feb2024.pdf
Date and Time Comment Was Submitted	2024-02-16 14:58:58

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February 16, 2024

Chair Liane Randolph and Members of the Board
California Air Resources Board
1001 I St.
Sacramento, CA 95814

AMERICAN BIOGAS COUNCIL

RE: American Biogas Council Comments on the Proposed Amendments to the Low Carbon Fuel Standard

Dear Chair Randolph and Members of the Board,

The American Biogas Council (ABC) appreciates the opportunity to comment on the proposed amendments to the Low Carbon Fuel Standard (LCFS). The ABC is the voice of the U.S. biogas industry dedicated to maximizing carbon reduction and economic growth using biogas systems. We represent more than 400 companies in all parts of the biogas supply chain that are leading the way to a better future by maximizing all the positive environmental and economic impacts biogas systems offer when they are used to recycle organic material into renewable energy and soil products.

Biogas systems protect our air, water, and soil by recycling organic material, like food waste and manure, into renewable energy and soil products. Biogas systems are, at their heart, a biological means to capture methane that would otherwise be emitted into the atmosphere for use as a renewable fuel. This process specifically decreases baseline methane emissions by converting methane back into carbon dioxide. All of this is an effort to protect our air, water, and soil – crucial parts of the solution to the challenges the California Air Resources Board (CARB) seeks to address. The scientifically-based design of the LCFS recognizes the benefits of projects that collect biomethane that would otherwise be emitted to the atmosphere making it available for use in transportation. As a result, millions of gallons of petroleum-based diesel fuel have been replaced with clean biomethane over the past several years delivering substantial reductions in greenhouse gas (GHG) emissions as well as other co-benefits (e.g., reductions in emissions of particulate matter). Furthermore, in August 2023, CARB announced that in Q1 2023 clean fuels replaced more than 50% of the diesel used in the state for transportation purposes, equating to nearly two billion gallons of avoided fossil diesel use in 2022.[1] This further underscores the success of the program and continued need for the LCFS to deliver GHG reductions from the transportation sector.

Over the past year and a half, CARB staff have held numerous public workshops to gather feedback on potential changes to the program, where ABC participated, and we are pleased to see that the rulemaking is nearing completion. The ABC would like to underscore the importance of concluding this rulemaking as soon as possible. Any further delay to the rulemaking diminishes the necessary signal the market needs to facilitate and encourage continued investments in clean fuels. Without a strong policy signal, the state risks missing opportunities to further reduce GHG emissions from transportation fuels. Thus, the ABC urges CARB staff and the Board to finalize this rulemaking no later than the end of Q2 2024.

Strengthening Carbon Intensity (CI) Targets

The ABC applauds CARB and is encouraged to see that the proposed amendments aim to set more ambitious carbon intensity (CI) targets. A strong CI reduction target is a critical component for driving down GHG emissions in the transportation sector, reducing reliance on petroleum fuels, and transitioning to electric vehicles where feasible. However, we believe that there is both room and need to go further. Using the numbers from CARB's Quarterly Summary Report and averaging the rate of credit growth over the past five available quarters, it shows that the current scale-up in the production of clean fuels will continue to generate credits with the cumulative bank likely eclipsing 25 million by the end of 2024.[2] The proposed increase in stringency falls short of what the market can deliver, and as a result, is missing an opportunity to deliver

[1] California Air Resources Board, *For the first time 50% of California Diesel Fuel is replaced by clean fuels*. August 23, 2023. https://ww2.arb.ca.gov/news/first-time-50-california-diesel-fuel-replaced-clean-fuels
[2] California Air Resources Board, *LCFS Data Dashboard Figure 3 – Quarterly Summary Report*. https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard

1126 I Street SE, Washington DC 20003 | 202-640-6595
team@americanbiogascouncil.org | www.americanbiogascouncil.org

millions of additional tons of reductions in GHG emissions called for in statute and further underscored in the update to the state's Scoping Plan as approved by the Board in December 2022.

The ABC believes that there are two key adjustments that CARB can make to the stringency as part of the 15-day change process that do not require new economic or environmental analysis as they fall within the scope of the work CARB has already included in the Initial Statement of Reasons (ISOR). Specifically, by increasing the step-down as well as pulling forward the effective date for triggering the Auto Acceleration Mechanism (AAM) CARB can "recapture" reductions in GHG emissions that will otherwise be lost with the current proposal. Doing so will also send a clear, supportive market signal to continue investments in clean fuels that would otherwise be constrained by the current proposal. The description below provides additional detail on these two recommendations.

096.1 While we believe that the proposed 5% step-down in stringency is good start at course-correcting the market, it simply does not go far enough considering the size of the cumulative credit bank, which is anticipated to increase its rate of growth as new clean fuel projects that have been or are being constructed bring more clean fuels to market. Within the boundaries of staff's existing environmental and economic analysis, the step-down must be increased by <u>at least</u> 7%, which, for perspective, translates into a 2030 target of at least 32% reduction in the CI relative to the 2010 baseline. While a 7% step-down (20.75% CI target) will still leave many credits in the cumulative credit bank, this single adjustment will translate into millions of additional tons of GHG emission reductions that would've otherwise gone unaddressed. ABC would like to emphasize that a 7% step down should be the minimum considered, and that it is possible, based on recent modeling by ICF, for CARB to be more aggressive with the step-down, noting that a step-down of 11.25% (25% CI target) is feasible, and would sufficiently address the excess credits in the cumulative credit bank.[3]

096.2 As designed, the first year that the AAM could impact program stringency is 2028---four years from now! The concept and need for the AAM is to respond to clear overperformance of the program and to send an unambiguous market signal to investors that the program is nimble and will respond to opportunities to deliver additional GHG reductions rather than "add to" an excessively large credit bank that is at odds with the objectives of the program. Waiting four years is too long, and the ABC recommends pulling the date for triggering the AAM forward. The AAM should be based on 2025 data with the trigger assessment occurring in May 2026, and the AAM being applied in 2027 providing the applicable conditions are met, thus increasing the program stringency for 2027. Relying on 2025 as the first eligible year for triggering the AAM is appropriate as one of the main objectives of the step-down is to bring the program into balance. Therefore, assessing the impact of the step-down on the market based on 2025 data, including the cumulative bank and the rate of credit to deficit generation, is aligned with the principles of the program. With this approach, the AAM could theoretically increase the stringency of the program in 2027 and 2029 (i.e., triggered twice prior to 2030 providing the conditions for the triggering the AAM are satisfied), better ensuring that potential emission reductions are not left on the table in the event the program continues to overperform following the Board's adoption of the amendments. 096.3 Furthermore, it is important to note that the proposed 3:1 ratio (i.e., cumulative bank/average quarterly deficits) that would trigger the AAM is likely inadequate. For example, in 2022, a year where there is general stakeholder consensus that the LCFS was overperforming, the AAM would not have triggered using CARB's current proposal. Updated ICF modeling shows that changing the cumulative credit bank to average quarterly deficit ratio threshold from 3 to 2.5 or lower would position the AAM to be more responsive to overperformance of the program, thus delivering additional reductions in GHG emissions.[4]

Avoided Emission Crediting

The proposed amendments seek to phase out avoided emission pathways for projects that break ground after December 31, 2029, for biomethane used as a transportation fuel through 2040 and for biomethane used to produce hydrogen through 2045. 096.4 While we understand that CARB's intention here is to begin to transition biomethane away from the transportation sector, the underlying rational is being construed by some as science-driven rather than a policy decision concerning the phase out of combustion in transportation. ABC does not support the phaseout of avoided emission credits.

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[3] ICF, *Analyzing Future Low Carbon Fuel Targets in California*. February 2024. https://static1.squarespace.com/static/5b57ab49f407b4a7ffa44ffa/t/65cd3c74d1a72f445cdc7a7e/1707949173143/ICFReport2024.pdf

[4] ICF, *Analyzing Future Low Carbon Fuel Targets in California*. February 2024. https://static1.squarespace.com/static/5b57ab49f407b4a7ffa44ffa/t/65cd3c74d1a72f445cdc7a7e/1707949173143/ICFReport2024.pdf

Avoided methane emissions are a critical part of science-based, life cycle assessments, and their inclusion in carbon intensity scores is consistent with internationally recognized standards of carbon accounting. The science is robust and recognizes that the baseline includes methane emissions that would otherwise be released into the atmosphere. As stated in our previous comment letters to CARB, recognizing avoided methane emissions and its role as a short-lived climate pollutant, while incentivizing its removal from the atmosphere, has proven highly successful in supporting the reduction of millions of metric tons of carbon dioxide equivalents. We strongly encourage CARB to continue its longstanding commitment to a science-driven framework that utilizes proven science including Argonne National Laboratory's GREET model. In the event CARB maintains its plans to phase out eligibility for avoided methane in vehicle fuels, we encourage CARB to be clear that it is a policy decision associated with CARB's efforts to transition biomethane into non-vehicle sectors (e.g., residential, commercial, and industrial uses). CARB should be explicit that the policy decision to discontinue recognition and eligibility of avoided methane emissions in vehicle pathways should not be interpreted as a departure from the established rigorous science of accounting for the benefits of avoiding methane emissions which continues to be appropriate for non-vehicle sectors. ABC does, however, recognize that avoided emission credits for biogas to electricity projects remain, and applaud CARB for recognizing the value of these projects by proposing to retain this aspect of the program.

Book-and-Claim and Deliverability Requirements

Book-and-Claim has allowed the LCFS to evolve by supporting investments in clean fuels that have helped the program remain one of the most influential and successful transportation decarbonization policies in the country. To date, CARB's approach to indirect accounting in the program has been pivotal in its success, including its principles of driving GHG emissions down, facilitating investments and production of clean fuels, and in supporting increased clean fuel options for consumers.

While CARB's proposal clearly outlines recommendations related to book-and-claim for biomethane as directed to end use
fuel consumption and hydrogen production, it does not adequately address biogas and biomethane as directed to electricity
production. There are three key areas that CARB should address to ensure that biogas and biomethane can support
electricity production in support of transportation decarbonization. The first is to allow biogas to electricity projects to utilize
book-and-claim anywhere in the Western Electricity Coordinating Council (WECC), as is already the case in Oregon under
096.5 their Clean Fuels Program. Currently, the LCFS requires electricity to be physically delivered to California. This would
eventually result in regulatory consistency for projects with the same feedstock (i.e., biomethane) once the deliverability
requirements for that fuel are realized. Second, biogas-to-electricity projects where electricity generation and biogas
production are not co-located should be eligible to participate in the LCFS. This is in-line with the California Renewable
Portfolio Standard's (RPS) treatment of "directed biogas" and allows greater project penetration by supporting optimal siting
096.6 of both the biomethane source and the electricity generator rather than forcing co-location. Third, notwithstanding the
preceding constraints, there are clear guidelines and requirements for how electricity, as a LCFS fuel, can utilize book-and-
claim to move electricity from point of generation to end use. There is not, however, clear information on how biogas or
096.7 biomethane can utilize book-and-claim to move RNG to electricity generation. ABC recommends that CARB provide
clarification that biomethane may utilize book-and-claim in this context. Further, we recommend that book-and-claim for
096.8 biomethane to electricity remain unconstrained by timeline restrictions proposed for biomethane to end use and biomethane
to hydrogen production. We believe this is appropriate to support zero-emission vehicle aspirations beyond 2030.

The ABC is also requesting CARB provide further guidance on the proposed deliverability requirements. The proposed
amendments aim to adopt the California RPS requirement of ensuring biomethane injected into a common carrier pipeline
physically flows towards California 50% of the time. This referenced RPS framework does not, however, provide clarity on
096.9 how those biomethane molecules can be traced to California, how a 50% average flow toward California may be modeled,
nor expected geographical indications of regions anticipated to remain eligible for book-and-claim accounting. Moreover,
limiting book-and-claim to physical deliverability requirements risks the LCFS becoming a less effective decarbonization
program and undermines California's interest in rapidly ramping up the production and use of renewable hydrogen—a
foundational principle in establishing ARCHES, which is at odds with CARB's proposal, to implement deliverability
requirements for hydrogen projects utilizing biomethane.

It remains to be seen if and how the proposed deliverability requirements can be harmonized with the California Public Utilities Commission's (CPUC) SB 1440 program, as suggested. It has been clear over the past year that CARB was exploring potential deliverability requirements. However, throughout that process an actionable plan outlining the strategy and evidence necessary for imposing delivery requirements never emerged. Rather, stakeholders continued to raise concerns about the lack of a feasible plan which continues with the ambiguity of the proposed amendments. Therefore, the

ABC recommends that the deliverability requirement language be removed from the proposal to allow for further stakeholder engagement in support of a clear and actionable plan for consideration in a subsequent rulemaking.

True-up Provisions

The proposal includes true-up provisions where verified operational CI's are drawn on to potentially adjust the credits based
on certified CI's. The proposal indicates that a shortfall (i.e., a verified operational CI that is higher than the certified CI upon
which project credits were generated) is subject to a "penalty" that is 4 times the spread for the applicable volume of fuel. The
096.10 rationale for a 4X spread is unclear as a smaller spread (e.g., 2X) serves as a significant disincentive to producers for being
overconfident in their analysis. Further, the language indicates that in the event the operationally verified CI is lower than the
certified CI (i.e., it failed to generate as many credits as it could have) the Executive Offer (EO) "may" make the appropriate
adjustment (true-up) by awarding additional credits to the applicable fuel reporting entity. The word "may" should be deleted.
096.11 If the operationally verified CI, including an affirmative verification statement, is lower than the certified CI that was the basis
for credit generation, the EO "must" award the supplemental credits supported by the underlying documentation.

The concept of adjustment to credits based on operationally verified CI's is sound. However, limiting the proposal to certified
CI's is a significant oversight. The proposal must be carried over and applied to temporary and provisional CI's as fuel
096.12 providers may rely on these CI's for months, or even years, as a more refined pathway is evaluated and subsequently
approved by CARB.

Temporary CI's have been an important option under the program, but applicants can be reluctant to use them given the heavy credit discounting relative to facility-specific provisional CI's. Correcting for any under (or over) crediting while a temporary CI is used will help streamline and simplify the program as well as send a stronger signal to the market that investments in clean low-CI fuels will be rewarded. Further, including temporary CI's as part of the true-up process will reduce the pressure on CARB from developers to process LCFS applications quickly which has been an ongoing and growing challenge under the program. The concept of adjusting the awarding of credits based on operationally verified CI's is a key principle that supports innovation and must be reflected from project initiation, where a temporary CI is used, throughout the project's lifetime to properly account for and reward the associated reductions in greenhouse gas emissions. Credits should be awarded based on real-world operational experience and therefore adjusted accordingly when the temporary CI which is applied understates the benefits.

New Markets

As the technology in the transportation sector continues to evolve and advance towards lower carbon alternatives, ABC members are following suit and are ready to serve these new markets, such as alternative jet fuel (AJF), low-CI hydrogen, as well as exploring opportunities where biomethane can be utilized outside of transportation. As these markets continue to grow, the ABC asks CARB to remain mindful of the success of the historical framework of the program and to continue to apply it to newer pathways and technologies, including the use of avoided emissions and book-and-claim.

If CARB's goal is to transition biomethane out of the vehicle sector, the ABC strongly encourages CARB to ensure there
continues to be a market for low-CI biomethane as it is an important decarbonization tool, especially in sectors that are hard
to decarbonize. For example, the CPUC's SB 1440 program creates a biomethane procurement mandate for the state's
largest utilities, however, the program excludes dairy biomethane due to the credit it currently receives in the LCFS.[5] With
CARB's intention of phasing out all biomethane crediting for transportation fuel by the end of 2040, it makes sense for the
CPUC to integrate dairy biomethane into the SB 1440 program which will allow for more market choice and volumes of
renewable fuel for utilities to procure. The industrial sector is also another area where biomethane can help significantly
reduce emissions, particularly at facilities that are large natural gas users and where electrification is not currently feasible.
However, there isn't one, all-encompassing policy that drives biomethane, and other low-CI clean fuels, towards that use
case. Thus, the ABC recommends that CARB, starting with the 2024 amendments to the LCFS, send a clear policy signal
096.13 that biomethane is a necessary and effective decarbonization strategy in these other sectors (e.g., residential, commercial,
industrial) that are fundamental to the state meeting its ambitious GHG reduction targets.

[5] California Public Utilities Commission, *Decision Implementing Senate Bill 1440 Biomethane Procurement Program: R.13-02-008*, page 4. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M453/K954/453954308.PDF

The ABC would also like to extend its support for CARB's proposal of eliminating the exemption for intrastate fossil jet fuel from the program starting in 2028. This will allow for continued and increased momentum for AJF production and use and will
096.14 help drive down GHG emissions in the aviation sector. Furthermore, the 2022 update to the Scoping Plan calls for 80% of aviation fuel demand in 2045 to be met by AJF.[6] The growth of AJF use is a new market opportunity for biomethane as it can be an important input for the fuel, helping it achieve lower CI's. The magnitude of ambition the state has called for will require the industry to significantly scale-up production and use of AJF, and for that reason, the ABC requests that CARB begin to
096.14 think about the framework and guardrails needed to achieve the 80% goal set forth in the Scoping Plan and leverage all of the tools available to the vehicle market, such as book-and-claim and avoided emissions accounting, to make this goal a reality.

Conclusion

The LCFS continues to be a flagship policy that drives investments in low carbon fuels and is delivering millions of tons of reductions in greenhouse gases to meet California's statutory commitments. The program is also protecting communities throughout the state by transitioning from petroleum to much cleaner fuels, including biomethane. The LCFS is the hallmark of effective environmental policy in that it: 1) sets clear, science-based targets; 2) establishes clear regulations for program implementation; and 3) provides the market with the flexibility to innovate. There is a clear reason that other states and nations model their efforts on California's LCFS. The ABC and its hundreds of members are proud to help build on this success story and are committed to CARB's efforts to continue to drive down emissions from transportation fuels.

Thank you for the opportunity to comment on the proposed amendments, and we look forward to engaging with CARB staff on these topics.

Sincerely,

Patrick Serfass
Executive Director

About the American Biogas Council

The American Biogas Council is the voice of the US biogas industry dedicated to maximizing carbon reduction and economic growth using biogas systems. We represent more than 400 companies in all parts of the biogas supply chain who are leading the way to a better future by maximizing all the positive environmental and economic impacts biogas systems offer when they recycle organic material into renewable energy and soil products. Learn more online at www.AmericanBiogasCouncil.org, Twitter @ambiogascouncil, and LinkedIn.

[6] California Air Resources Board, *2022 Scoping Plan Update*, page 73. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

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Comment 105 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Tank
Last Name	Conner
Email Address	sheepy_bah@hotmail.com
Affiliation	
Subject	Low Carbon Fuel Standard (LCFS)
Comment 097.1	Please end current Low Carbon Fuel Standard (LCFS) policies that reward factory farm polluters. No greenwashing.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 15:06:09

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Comment 110 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Dyan
Last Name	Osborne
Email Address	dyan3926@att.net
Affiliation	
Subject	Animal Abuse
Comment	Just stop it. All of it. Go vegan! 🌱
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 15:41:01

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 111 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Perri
Last Name	Glass
Email Address	perriglass@hotmail.com
Affiliation	
Subject	Factory farming
Comment	Factory farms are disastrous for the environment and the animals imprisoned within. What don't you understand? Environmental degradation and extreme animal abuse are unacceptable. Human greed such as this is totally repugnant.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 16:22:29

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Comment 112 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	ROMONA
Last Name	WILLIAMS
Email Address	romonajoyce@aol.com
Affiliation	The Williams Family
Subject	Stop Factory Farm Fueling In California
Comment 100.1	Dear Sir, To who it may concern The population of factory farm gas has to be stop. We want California to be a safe, clean and healthy state.Please do so right now!!!! Sincerely, Romona Williams
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 16:30:03

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Comment 113 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Bill
Last Name	Magavern
Email Address	bill@ccair.org
Affiliation	Coalition for Clean Air
Subject	CCA comments on LCFS amendments
Comment	letter attached
Attachment	www.arb.ca.gov/lists/com-attach/6414-lcfs2024-VjUFYAdnBQlVMAlm.pdf
Original File Name	CCA Comments to CARB on LCFS 2.16.24.pdf
Date and Time Comment Was Submitted	2024-02-16 16:42:10

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COALITION FOR CLEAN AIR

February 16, 2024

California Air Resources Board
1001 I Street,
Sacramento, California 95814
Via Electronic submittal

Re: Amendments to the Low Carbon Fuel Standard

To the Air Resources Board:

The Coalition for Clean Air has long supported the Low Carbon Fuel Standard as an essential tool for reducing harmful emissions from the transportation sector, California's largest source of both air and climate pollution. The LCFS supports both the end goal of achieving zero-emission transportation and the interim goal of substituting low carbon renewable fuels for gasoline and diesel during the current period when we still have combustion vehicles on the road. Because of the magnitude of our air pollution and climate crises, we now need the LCFS to both work harder, through greater stringency, and work smarter, by incenting the cleanest fuels and avoiding harms to communities.

Having participated in the September 28 Board hearing and reviewed the December 19 Initial Statement of Reasons, we support both major and minor revisions to the staff proposal. **Most importantly, we are concerned that the absence of a cap on crop-based biofuels jeopardizes the success of the entire LCFS.**

We support the following amendments to the LCFS:

1. **Limit crediting of crop-based biofuels.**
CARB should establish guardrails to prevent incentivizing conversion of crop lands to fuel production, which exacerbates already-existing food shortages in much of the world. While biofuels made from wastes can provide a net climate benefit, using productive land to produce fuel is detrimental to the climate, because carbon-absorbing natural land
101.1 elsewhere will be converted into crop production.

At a minimum, CARB should immediately cap lipid biofuels at 2020 levels, to avoid being swamped with soy-based diesel fuels that are shuffled in from other states, depress LCFS credit values and provide no additional benefit to our climate, because they are

660 South Figueroa Street, Suite 1140
Los Angeles, California 90017

1107 Ninth Street, Suite 630
Sacramento, California 95814

www.ccair.org

already required for compliance with the Federal Renewable Fuel Standard. Ultimately, these fuels should be phased out of the LCFS.

2. **Increase the stringency of the program, and add an acceleration mechanism.** Meeting California's greenhouse gas emission caps under SB 32 and AB 1279 will require more rapid progress in phasing out petroleum fuels in the transportation sector, our largest source of climate-changing emissions. Alongside CARB's regulations and incentives for deploying cleaner engines, and the state's as-yet unrealized targets for reducing vehicle miles travelled, the LCFS provides a vital tool for curbing transportation emissions, as reiterated by the 2022 Scoping Plan Update, which calls for a 94% reduction in petroleum use and identifies the LCFS as a key route to that goal. Therefore, we support the proposed standard of a 30% reduction in fuel CI by 2030, and
101.2 90% by 2045, with inclusion of an automatic acceleration mechanism as a backstop to
101.3 assure that the market in cleaner fuels stays at a robust level.

3. **Remove the exemption for aviation fuel by 2026 for both intrastate and interstate flights.** Conventional jet fuel should be held to the same standard as other petroleum-based transportation fuels. California currently lacks a comprehensive plan for decarbonizing aviation fuels, and including conventional aviation fuel as a deficit generator under the
101.4 LCFS would help to spur innovation in cleaner fuels and equipment. Cleaning up aviation fuels and equipment will also help protect the health of workers and communities who are most exposed to the emissions from this sector.

4. **Use utilities' base residential LCFS credits to promote equity in zero-emission personal mobility and deployment of clean medium and heavy-duty vehicles.** LCFS base residential credit proceeds generated by EDUs from electricity used as a
101.5 transportation fuel should be used to effectively and equitably hasten the adoption of zero-emission electrified transportation, with a focus on disadvantaged and low-income communities. We and our allies are submitting a separate letter on this topic.

5. **Maximize the benefits of the proposed medium- and heavy-duty fast charging infrastructure program by increasing flexibility to better support the deployment of necessary infrastructure.** CARB regulations, which we support, require a transition to zero-emission engines in buses, trucks and other medium and heavy-duty vehicles. That transition is essential to solving our air pollution and climate crises, and infrastructure challenges are probably the biggest single obstacle to success. Therefore, we support the proposed creation of an infrastructure crediting mechanism for medium and heavy-duty refueling for zero-emission vehicles, both battery-electric and fuel-cell electric.

101.6

But the success of the MHD-FCI provision will be constrained by the geographic limitation to projects *"Located within one mile of a reading or pending electric vehicle Federal Highway Administration Alternative Fuel Corridor or on or adjacent to a* *property used for medium or heavy-duty vehicle overnight parking, or has received capital funding from a State or Federal competitive grant program that includes location evaluation as criteria."* We recommend removing these geographic restrictions, as they will undercut program effectiveness, delay deployment, and increase costs for charging and grid upgrades.

6. **Allow crediting in the marine sector.**
101.7 We urge CARB to allow credits for zero-emission transportation fuels used for ocean-going vessels, and to simplify the process for credits for shore power installations serving electrified harbor craft and for dispensing green hydrogen. The marine sector is a substantial source of emissions in much of the state, and the LCFS can spur conversion to cleaner fuels and support CARB's regulations of ocean-going vessels and commercial harbor craft.

7. **Phase out crediting of oil projects.**
101.8 California should be planning a transition away from fossil fuels, so allowing credits for oil projects provides a perverse incentive to perpetuate the very problem that the LCFS seeks to solve. These credits should be phased out sooner than the 2040 date proposed by the ISOR.

CARB should regulate methane emissions from large dairies.
101.9 This issue is not included within the four corners of the LCFS rulemaking but is related. Dairies are the largest California source of methane, a potent short-lived climate pollutant. CARB should require the large dairies to reduce their emissions of both manure and enteric methane. The regulations should also strive to protect local communities from the adverse impacts of large-scale dairy production.

We look forward to continued discussions as the Board considers the LCFS amendments.

Respectfully,

Bill Magavern

Bill Magavern
Policy Director
Coalition for Clean Air

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Comment 114 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Amy
Last Name	Hamilton
Email Address	ozarksoilhealth@gmail.com
Affiliation	
Subject	methane incentive
Comment	As a nation we spend an inordinate amount of money on corn and bea agriculture and helping confinement feeding operations. Our agricultural policies are having far reaching effects on invasive species. Cattle, goat and sheep producers are having a tough time competing with subsidized CAFO production and invasive are taking over as grassland farmers go out of business.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 16:51:28

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Comment 115 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Margot
Last Name	McMillen
Email Address	margotmcmillen@gmail.com
Affiliation	
Subject	LCFS2024
Comment	As a person that lives near a giant swine confinement, I protest the building of any more of these factory facilities. This one has devastated my neighborhood and forced many people to move away. Because of the ventilation systems that must be engaged at all times, the collection of methane from this system is incomplete so that much methane escapes. Other pollution includes water pollutio after the effluent is spread on fields. Our stream team finds excess nitrogen in the streams every spring. Building more of thes giant facilities will only mean more pollution. Don't be fooled by promises that they will produce power that can be used. They don't

103.1

Attachment	
Original File Name	

Date and Time Comment Was Submitted	2024-02-16 17:19:18

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Comment 116 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Joanne
Last Name	Hedge
Email Address	hedgegraphics@earthlink.net
Affiliation	Sustainability advocate, Glendale
Subject	CA Biogas is not "good" 104.1
Comment	Growing research & investigations of Big Dairy & corporate agricultural complicity in polluting air, water, and land add up t greater climate impacts at a time when we require less, and way less! Consumers are finding dairy alternatives due to lacto intolerance & legitimate investigations of inhumane treatment of cows & calves.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 17:53:43

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Comment 117 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Darlene
Last Name	Powell
Email Address	Darlene.powell@comcast.net
Affiliation	
Subject	Carbon fuel standard
Comment 105.1	Please lower the carbon fuel standard. Sincerely Nancy Mccormick
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 18:04:45

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Comment Log Display

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Comment 118 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Felena
Last Name	Puentes
Email Address	fpuentes19@att.net
Affiliation	
Subject	Stop
Comment	Stop the gas 106.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 18:10:29

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Board Comments Home

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Comment 119 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nancy
Last Name	Mccormick
Email Address	7riannon@gmail.com
Affiliation	
Subject	Low carbon fuel standard
Comment 107.1	Please consider the low carbon fuel standard. Thank you Nancy Mccormick
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 18:09:13

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 120 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Marcia
Last Name	Nelson
Email Address	marcianelson1220@aol.com
Affiliation	Farm Sanctuary
Subject	Factory Farm Gas
Comment	STOP INVESTING IN FACTORY FARM GAS WITH TAXPAYER MONEY!!!!!! 108.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 18:39:47

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Comment 121 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Catherine
Last Name	Santos
Email Address	catesanto@gmail.com
Affiliation	
Subject	Stop Public Funding for Factory Farm Gas
Comment	End current Low Carbon Fuel Standard (LCFS) policies that reward factory farm polluters! 109.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 19:27:18

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Comment 122 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mary
Last Name	Moreno
Email Address	cperezmoreno@yahoo.com
Affiliation	Connie's Crooked Creations
Subject	Stop using valuable resources
Comment	We cannot continue to pay for farmers to abuse our water systems.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 19:43:09

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Comment 123 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Pati
Last Name	Tomsits
Email Address	patito12@att.net
Affiliation	
Subject	Stop Public Funding For Factory Farm Gas
Comment	Stop investing in factory farm gas! 111.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 20:21:54

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 124 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ellen
Last Name	Riegelhuth
Email Address	eriegelhuth@yahoo.com
Affiliation	
Subject	Investing in biogas means investing in even more factory farm pollution.

Comment

Please END current Low Carbon Fuel Standard (LCFS) policies that reward factory farm polluters!

112.1

Thank YOU!🙏

Best Regards,
Ellen Riegelhuth

Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 20:24:47

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Comment 125 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Wayne
Last Name	Johnson PhD
Email Address	waynezorro@gmail.com
Affiliation	
Subject	Low Carbon Gas
Comment	For the sake of the environment. Shut down the dairy industry California.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 20:41:25

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Comment 126 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	C
Last Name	s
Email Address	csoragha@hotmail.com
Affiliation	
Subject	Low Carbon
Comment	Please consider this amendment now and help protect our children and communities!! 114.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-16 20:44:35

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Comment 127 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Tera
Last Name	Martinez
Email Address	teram888@gmail.com
Affiliation	
Subject	Consider proposed low carbon fuel standard amendments for Farms
Comment	Please consider the use of low carbon fuel for Farms. 115.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-17 00:15:52

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Comment 128 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	John
Last Name	Pasqua
Email Address	Johnpasqua57@gmail.com
Affiliation	
Subject	Biogas 116.1
Comment	End the greenwashing.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-17 01:01:52

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Board Comments Home

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Comment 129 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ted
Last Name	Myers
Email Address	emiltonmyers@verizon.net
Affiliation	
Subject	Factory Farm Gas
Comment	This one of the leading contributors to global warming. Want a planet? Stop all high-methane, like cow and pig manure from entering the atmosphere. Sincerely, Ted Myers
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-17 01:34:00

117.1

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Board Comments Home

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Comment 126 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Denise
Last Name	Vandermeer
Email Address	somulk@aol.com
Affiliation	
Subject	Biogas
Comment	Please do not use public funds to support biogas projects. These projects create more factory farms which produce more climate damage not less. 118.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-17 06:16:08

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Board Comments Home

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Comment 127 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name K L

Last Name Johnson

Email Address pineridgelj@outlook.com

Affiliation MRCC

Subject California Air Resources Board

Comment

119.1 I understand wanting to make air quality better; however, capturing methane gas from farms would exacerbate another problem which is factory farming of animals. This practice abuses farm animals and increases corporate takeover of family farms of US citizens by Chinese and Brazilian corporations and/or governments

It's a horrible idea that only increases corporate profits at the expense of humane farming practices in the US by family farmers.

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-02-17 07:25:19

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Comment 128 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mary
Last Name	Jones
Email Address	mrsjonesworld@yahoo.com
Affiliation	Protect Pomme de Terre
Subject	California low carbon fuel standard amendment

Comment

Hello.
My name is Beth Jones. I'm with a Midwest grassroots organization
called PROTECT POMME DE TERRE. Pomme de Terre is our local lake ar
river that is at risk of being polluted with waste water from a B
BEEF processing facility that thinks they can do whatever they war
to our land and water ways with no consequences. In the past year
they have found out that we at Protect Pomme de Terre will not
stand for it. This California law is ruining our Midwestern
aquaphers. They have already destroyed Iowa. We in Missouri sit or
one of the biggest and most pristine aquaphers in The country. We
will NOT STAND BY AND WATCH FACTORY FARMS DESTROY IT! If Californ
120.1 wants to make methane then they should move all the factory farms
out there and let them continue to destroy Californians
environment. See how the people out there that like that methane
also like the mess that creates it. Thank you very much for your
time.

Attachment

Original File Name	
Date and Time Comment Was Submitted	2024-02-17 07:49:05

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Comment 133 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Bernard
Last Name	Fenner
Email Address	bernard.fenner@ductor.com
Affiliation	
Subject	Ductor Americas Inc - Comments on the Proposed Low Carbon Fuel Standard Amendments

Comment

Dear Mr. Botill:

Thank you for the opportunity to comment on the Proposed Low Carbo
Fuel Standard (LCFS) Amendments and updated Life Cycle Analysis (LCA) and Documentation. The LCFS is one of the most powerful climate change policies in the world, uniquely supporting a wide array of innovative, low-carbon fuel production pathways. Its success has proven a model for similar programs that are emerging in other states and countries. We strongly encourage the Californi
Air Resources Board (CARB) to amend the program in a manner that protects and builds on its successful, technology-neutral and science-based approach to ensure the program continues to drive innovation and greenhouse gas reductions for decades into the future.

Find attached Ductor Americas' Comments on the Proposed Low Carbon
Fuel Standard Amendments

Best regards, Bernard

Attachment	www.arb.ca.gov/lists/com-attach/6505-lcfs2024-VDBXJFIwUXZQOQh6.pdf
Original File Name	Ductor comments_LCFS Amendments_Feb 2024_final.pdf
Date and Time Comment Was Submitted	2024-02-17 08:05:32

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

DUCTOR®

February 16, 2024

Matthew Botill
California Air Resources Board
1011 I Street
Sacramento, CA 95814

Subject: Comments on the Proposed Low Carbon Fuel Standard Amendments

Dear Mr. Botill:

Thank you for the opportunity to comment on the Proposed Low Carbon Fuel Standard (LCFS) Amendments and updated Life Cycle Analysis (LCA) and Documentation. The LCFS is one of the most powerful climate change policies in the world, uniquely supporting a wide array of innovative, low-carbon fuel production pathways. Its success has proven a model for similar programs that are emerging in other states and countries. We strongly encourage the California Air Resources Board (CARB) to amend the program in a manner that protects and builds on its successful, technology-neutral and science-based approach to ensure the program continues to drive innovation and greenhouse gas reductions for decades into the future.

Ductor offers the following high level comments, which are elaborated on further below. Additionally, we appreciate the opportunity to comment on the updated lifecycle analysis models and documentation, including revised Tier 1 calculators, which we will comment on separately.

- The LCFS has proven one of the most powerful programs in the world for reducing potent short-lived climate pollutants. It can similarly be applied to reduce even more potent nitrous oxide (N_2O) emissions, which have yet to be addressed in California's otherwise comprehensive climate change framework. ***We encourage CARB to leverage the LCFS to account for avoided N_2O emissions and enable reductions from this potent source of greenhouse gas emissions.***
- Protecting technology neutrality and enabling innovation is central to the success of the LCFS. ***We recommend minor changes to clarify provisions related to biogas pathways from poultry litter.*** This includes:
  - ***Creating a definition of "waste" that includes poultry litter***, including from layer, broiler, and turkey operations.
  - ***Clarifying language related to crediting for avoided methane emissions*** from manure and organic waste pathways.
  - ***Adding language to clarify applicability of crediting for avoided N_2O emissions for organic waste pathways.***

121.3
- Avoided methane crediting and book-and-claim access for biogas projects are central to enabling biogas projects and associated emissions reductions. ***We urge CARB to avoid restricting avoided methane crediting or biogas book-and-claim accounting in the program.***
- The proposed targets and structure of the auto acceleration mechanism (AAM) are insufficient to reverse the accumulation of credits in the market. We urge 15-day changes that would:
  - ***Increase the stringency of the step down*** to levels needed to restore healthy market conditions,
  - ***Apply the step down as soon as the regulation takes effect*** (e.g., Q3 2024),
  - ***Increase the 2030 target to levels needed to achieve the state's climate change goals, and no less than 40%,*** and
  - ***Move the AAM forward a year and remove the restriction against applying it in consecutive years.***

About Ductor

Ductor was founded in 2009 with the ambitious aim of creating a solution that would help solve today's environmental challenges in the energy and agriculture sectors. Today, we build, own, and operate turnkey microbiological facilities, turning organic resources from the agricultural sector into sustainable fertilizers and biogas. With two plants in Mexico and Germany and numerous projects in the pipeline, we are living up to our purpose and unlocking bio-resources to make food sustainable and energy clean.

Ductor's technology transforms nitrogen-rich organic resources from agriculture, aquaculture, and other organic sources into energy and fertilizers. We specialize in feedstock that cannot be used directly in conventional anaerobic digestion and biogas facilities. This feedstock is fed into the Ductor pre-process, where an IP-protected consortium of microorganisms and the IP-protected Ductor process converts them via fermentation and subsequent ammonia recovery into organic and sustainable liquid nitrogen fertilizer. The feedstock is further processed via anaerobic digestion to generate biogas, which is upgraded to pipeline quality. The digestate is further processed into additional fertilizing and soil-improving products.

Ductor's technology targets the poultry sector, which is growing globally to meet the increasing demand for meat and egg products. Driven by population growth, urbanization, and rising incomes, global per-capita consumption of poultry meat increased from 3.1 kg to 15 kg between 1964 and 2013, while global per-capita consumption of eggs grew from 4.7 kg to 9.2 kg. The poultry sector generates a large quantity of litter consisting of manure, egg wash water, waste bedding, waste food, and feathers. The amount of litter depends on the frequency of the removal of litter, which varies from country to country. According to the USDA, as much as 1.4 billion tons of manure is produced annually by the 9.8 billion head of livestock and poultry in the United States. Sustainable and alternative treatment options for this growing waste stream are needed to address environmental and emissions impacts associated with poultry litter management, storage, and land application.

Reducing N_2O emissions a missing piece of California's climate framework, should be supported through LCFS

California has correctly emphasized targeted efforts to reduce emissions of methane and other potent short-lived climate pollutants,[1] and has recognized the LCFS as a critical element to achieving these reductions in the agricultural sector.[2] Yet very little has been done to address even more potent N_2O emissions. While methane is about 30 times more potent than CO_2 over 100 years,[3] for example, N_2O is about 10 times worse still – about 300 times more potent than CO_2 over 100 years. Methane, as a short-lived climate pollutant, dissipates from the atmosphere in about a decade, but N_2O is a long-lived gas whose potent warming impacts will persist for over a century once it reaches the atmosphere.

The majority of N_2O emissions in California comes from the agricultural sector (specifically, fertilizer use/soils and manure management),[4] and according to the 2022 Climate Change Scoping Plan, CARB envisions few if any N_2O emissions reductions through mid-Century.[5] In fact, the Scoping Plan modeling shows agricultural N_2O becoming one of the largest sources of greenhouse gas emissions in the state in the future.[6] Fortunately, agricultural N_2O emissions can be readily addressed through improved manure management practices (especially at egg laying and poultry farms) and greater use of sustainable agricultural practices, including the use of renewable fertilizers, organic farming, and other strategies.

The state can enable significant reductions in agricultural N_2O emissions by accounting for avoided N_2O emissions in LCFS pathways and taking additional steps to support markets for renewable fertilizers and organic agriculture.

121.1 There is already a precedent for considering N_2O emissions within LCFS pathways. CARB currently accounts for avoided N_2O emissions associated with composting food scraps in their Tier 1 Organic Waste (OW) calculator. Excluding similar considerations for agricultural feedstocks appears arbitrary, especially given the critical role N_2O emissions play in the agricultural sector.

Clearly support poultry-based pathways in the LCFS

California has more than 10 times as many head of poultry (egg laying hens, broiler chickens and turkeys) than dairy cows and more than 200 times more poultry head than swine.[7,8] Yet, while the LCFS acknowledges dairy and swine pathways, it does not currently reference poultry-based pathways. Biogas pathways from poultry litter provide significant opportunity to support additional biogas supplies, while serving to improve nitrogen management associated with

---

[1] CARB (2017) Final Short-Lived Climate Pollutant Reduction Strategy, California Air Resources Board, March.
[2] CARB (2022) Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target, California Air Resources Board, March.
[3] And more than 80 times worse than CO_2 over 20 years.
[4] https://ww2.arb.ca.gov/sites/default/files/2023-12/ghg_inventory_scopingplan_2000-21n2o.pdf
[5] CARB (2022) 2022 Scoping Plan for Achieving Carbon Neutrality, California Air Resources Board, December.
[6] For example, compare Figures 2-5 and 4-19 in the 2022 Scoping Plan.
[7] https://www.statista.com/statistics/196085/top-us-states-by-number-of-chickens/
[8] https://www.nass.usda.gov/Quick_Stats/Ag_Overview/stateOverview.php?state=CALIFORNIA

poultry operations. These pathways support efforts to address water quality issues and reduce potent N_2O emissions, while also reducing methane and creating new supplies of renewable fertilizers to support organic farming, broader sustainable agricultural practices, and additional N_2O reductions from crop management and soils.

While poultry-based pathways (Figure 1) and avoided N_2O emissions are included in the GREET 4.0 model,[9] they are not referenced in the regulation or regulatory documents. Directly incorporating poultry litter-based pathways, avoided N_2O emissions, and renewable fertilizer co-products into the regulation will clarify the opportunity for poultry-based pathways and allow these projects to come on-line more quickly in support of the state's climate change and environmental goals. Specifically highlighting N_2O emissions will provide an important signal that the state is committed to reducing these emissions, alongside other greenhouse gas emissions.

1.3) Assumptions for Anaerobic Digestion of Animal Waste

Source of Assumptions: U.S.

U.S.

	Beef	Dairy Cow	Dairy Heifer	Swine	Layer	Broiler and Turkey
121.2 Share of Livestocks	0.0%	0.0%	0.0%	0.0%	75.0%	25.0%

Figure 1. Snapshot of CA GREET4.0 RNG Tab. The yellow cells indicate inputs. A red box is drawn around "Layer" (poultry), and "Broiler and Turkey" livestock categories.

Accordingly, we urge CARB to consider minor changes to clarify and elevate opportunities for these pathways, including the following:

- Create a definition of "waste" to clarify the new definition of "organic waste."[10] The definition of waste should be broad enough to include animal wastes and manures. Waste could refer to materials with limited immediate use, requiring disposal, originating from forestry, agriculture, livestock, municipalities, or industries.

- Ensure equal treatment for all organic waste pathways as it relates to avoided methane crediting and align the regulation with the organic waste Tier 1 calculator, which includes credit for avoided N_2O, with the following changes to § 95488.9:

  (f) Carbon Intensities that Reflect Avoided Methane and Nitrous Oxide Emissions from ~~Dairy and Swine~~ Animal Manure or Organic Waste ~~Diverted from Landfill Disposal~~.

    (1) A fuel pathway that utilizes biomethane from ~~dairy cattle or swine~~ animal manure digestion may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that:

[9] CARB (2023). Biomethane from Anaerobic Digestion of Organic Waste (Calculator). Avoided N_2O emissions are included for Food Scrap pathways.
[10] "Organic Waste" is defined as material that meets both the LCFS definitions of "biomass" and "waste." However, there is no definition in the regulation for "waste."

121.2 cont (A) A biogas control system, or digester, is used to capture biomethane from manure management on ~~dairy cattle and swine~~ farms that would otherwise be vented to the atmosphere as a result of livestock operations from those farms.

(B) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane.

(2) A fuel pathway that utilizes an organic waste ~~material~~ may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary diversion from decomposition in a landfill or other reference case and the associated fugitive methane and nitrous oxide emissions, provided that:

(A) The organic waste ~~material~~ that is used as a feedstock would otherwise have been disposed of by landfilling or in a manner in which decomposition emissions in the reference case can be quantified and verified, and the diversion is additional to any legal requirements for management of the organic waste, including ~~for~~ the diversion of organics from landfill disposal.

(B) Any degradable carbon that is not converted to fuel is subsequently treated in an aerobic system or otherwise is prevented from release as fugitive methane. Upon request, the applicant must demonstrate that emissions are not significant beyond the system boundary of the fuel pathway.

(C) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the avoidance or capture and destruction of biomethane.

(D) Credit for avoided nitrous oxide reflected in the CI calculation shall reflect the quantity of avoided nitrous oxide emissions, including decomposition emissions in the reference case, and is subject to approval by the Executive Officer and verification requirements in §95500.

- Update the reference in § 95488.1(d)(2) as follows:
  - Biomethane from sources other than those listed under the Tier 1 classification in (c)~~(5)~~(4), above;

Avoid restricting avoided emissions crediting or biogas book-and-claim accounting

121.3 We strongly oppose any restrictions to avoided emissions crediting, including avoided methane or N_2O, or book-and-claim accounting of biomethane pathways. These elements are critical to supporting biomethane projects from manure and organic waste resources and emissions

reductions from the most potent climate forcers, including methane and N_2O. Additionally, book-
121.4 and-claim accounting of biomethane is necessary to bring additional volumes of biomethane to
California and displace fossil-based natural gas, almost all of which comes from outside the
State, and is itself acquired and delivered via similar book-and-claim procedures.

121.5 We urge CARB to maintain existing provisions for book-and-claim accounting of biomethane
and avoided emissions, with the minor amendments proposed above, to support a growing
organic waste biomethane market with the associated carbon, SLCP and N_2O emissions benefits.
Additionally, we urge CARB to allow book-and-claim accounting of biomethane to power plants
to generate LCFS credits for electric vehicle charging, in order to advance the State's zero
121.6 emission vehicle (ZEV) goals, provide equitable treatment between electricity and hydrogen-
based fuel pathways, and support a shift of biomethane from CNG vehicles to ZEVs and
stationary sources.

Strengthen targets to restore the health of the program and ensure its ongoing success

In previous comments, we have consistently supported the following elements of a strengthened program:

- An immediate step-down in carbon intensity sufficient to reverse the trend of an accumulating bank of excess credits that is serving to dampen credit prices and restrict investment in new clean fuel pathways,
- A strengthened 2030 target, in-line with Scoping Plan targets and the ICF analysis, of at least 40%, and
- A responsive AAM that would automatically strengthen the program should the market continue to out-perform regulatory requirements, and therefore support additional low carbon fuel volumes and emissions reductions.

We appreciate that the regulatory proposal includes elements of these objectives. However, we
note that based on external analysis from ICF and others, and as indicated by the market
response following release of the regulatory proposal (credits are now trading at their lowest
level since the regulation was last amended), the targets appear insufficient to achieve these
outcomes. We encourage changes that would align with the objectives listed above, including (1)
121.7 strengthening the step-down and applying it as soon as the regulation takes effect, (2)
121.8 strengthening the 2030 target, to at least 40% in-line with the Scoping Plan and ICF analysis, and
121.9 (3) allowing the AAM to be more responsive to the market, including allowing it to be triggered
based on 2025 market data and to be triggered in consecutive years if needed.

Conclusion

We very much appreciate your work, and the work of other CARB staff, to engage stakeholders throughout this process. We understand the wide array of issues related to the LCFS program that are under consideration for amendments, and we appreciate your efforts to strengthen the program and advance California's climate change and related objectives.

Thank you for your consideration of these comments, and please do not hesitate to reach out with any questions.

Sincerely,

Bernard C. Fenner
CEO Ductor Corporation, President Ductor Americas, LLC

Ductor Americas, Inc
1200 18th Street NW
Suite 700
Washington, District of Columbia
20036

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Here is the comment you selected to display.

Comment 130 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name Nancy

Last Name Rasmussen

Email Address gnras@yahoo.com

Affiliation

Subject Proposed Low Carbon Fuel Standard Amendments

Comment

Please stop encouraging CAFOs, which is what this proposal will do 122.1
Missouri and the nation need small farmers who care about the land, our communities and our country. Giving preference to large corporations who are often foreign owned and do not care for anything but making money is wrong. Please wake up to what pride of ownership and pride of caring for our land and communities is all about. You are supposed to represent those who elected you, and not those paid to lobby for corporate interests. Please have the courage to stand up and actually represent the people of Missouri rather than multinational corporations.

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-17 12:25:36

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Comment 131 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Desiree
Last Name	Mitchell
Email Address	sfsonshine@aol.com
Affiliation	
Subject	No Factory Farm funding
Comment	Please do NOT use taxpayer dollars to pay for ANYTHING for farms that harm the environment, especially oil or gas that pollutes our air. Gas should be a thing of the past and certainly not something that taxpayers purchase without our approval. Most Californians do not want to spend our taxes funding factory farms in any way. Than you for considering those who pay here in the Golden State.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-17 12:50:24

123.1

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Comment 132 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jason
Last Name	Linn
Email Address	jalinn@calpoly.edu
Affiliation	
Subject	end current Low Carbon Fuel Standard (LCFS) policies that reward factory farm polluters!
Comment	end current Low Carbon Fuel Standard (LCFS) policies that reward factory farm polluters! 124.1
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-17 12:58:38

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Comment 133 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Lucinda
Last Name	Mayoral
Email Address	lucinda_mayoral@live.com
Affiliation	
Subject	Protect our environment and food supply by ending factory farming

Comment

Instead of investing in factory farming biogas, invest in sustainable humane certified farms and dairies. As a progressive and forward-thinking state, Californians are aware of the significant body of research that shows large scale factory farms, dairies and feedlots lead to environmental damage, lower quality food and milk, and unnecessary cruelty to the sentient beings who
125.1 nourish us. California should be following the example of the various farms within our state and country who truly care about th environment by utilizing regenerative practices while providing a high-quality food supply and treating the animals who feed us with the care they deserve. See Niman Ranch, Clover, Force of Nature, Rancho Llano Seco, Stemple Creek Farm, Hart Dairy, Organic Pasture Dairy, etc. Let's truly be a forward-thinking state by ending factory farming once and for all. Thank you.

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-17 13:36:01

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Comment 134 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Diana
Last Name	Ekholm
Email Address	Diana.shycoff@yahoo.com
Affiliation	
Subject	Public funding for factory farm gas
Comment	To whom it may concern, 126.1 I am writing to expressly ask you vote against public support for factory farming gas. Factory farms are the biggest contributor to pollution of all water ways. Thank for your consideration, Diana Ekholm
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-17 18:08:46

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 139 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Laura
Last Name	Berland-Shane
Email Address	laura@blueplanetsystems.com
Affiliation	Blue Planet Systems
Subject	Blue Planet Comments on the Proposed Low Carbon Fuel Standard Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6579-lcfs2024-BmRUPgRwBDIHXgR0.pdf
Original File Name	Blue Planet LCFS comments 2.17.24.pdf
Date and Time Comment Was Submitted	2024-02-17 18:20:25

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 17, 2024

Matthew Botill
California Air Resources Board (CARB)
1001 I Street
Sacramento, CA 95814

Re: Blue Planet Comments on the Proposed Low Carbon Fuel Standard Amendments

Dear Mr. Botill:

Blue Planet Systems Corporation (Blue Planet) appreciates the opportunity to comment on the proposed amendments to the Low Carbon Fuel Standard (LCFS). Blue Planet supports CARB's initiatives to advance California's climate change goals, including supporting development of key carbon capture, utilization and storage (CCUS) and direct air capture (DAC) technologies through the LCFS. We encourage CARB to expand their CCUS definition to allow for other permanent, non-geologic approaches to carbon sequestration to support state goals around deep decarbonization, carbon neutrality and achieving the Scoping Plan objectives.

About Blue Planet

Blue Planet is a California company developing technology and products related to economically sustainable carbon management. Our goal is to solve the carbon capture problem by converting CO_2 into high-value building materials. Our technology can be deployed at a wide array of difficult-to-decarbonize industries, including cement and facilities involved in any number of transportation pathways participating in the LCFS – including ethanol, renewable gasoline/diesel, hydrogen, biogas, electricity, or direct air capture. Importantly, our technology captures not only CO_2, but also particulate matter, NO_x, SO_x and other pollutants hazardous to surrounding communities. We are currently constructing and beginning operations of a plant in Pittsburg, California on the Sacramento Delta, and our carbon-sequestered aggregate has been utilized at San Francisco International Airport, where carbon-sequestered concrete is specified.

Blue Planet's technology produces coarse and fine limestone aggregates made from sequestered CO_2 utilizing the carbon mineralization process. It fosters lower-cost carbon capture, including from direct air capture or other carbon removal pathways, by avoiding the need to purify and enrich captured CO_2 before use, reducing the cost and energy needs associated with carbon capture. It is also fully scalable and can be applied to any facility in any part of the state where concrete is utilized, regardless of its proximity or access to a geological sequestration site.

Carbonate mineralization offers a significant and permanent carbon storage and utilization solution

Almost all of earth's carbon – about 99 percent – is stored naturally through the process of mineralization in limestone rock. Trillions of tons of CO_2 have been safely and naturally stored as carbonate mineral for over 100 million years. As described previously in comments to CARB related to the Scoping Plan,[1] and validated in peer-reviewed research,[2] the mineralization process permanently stores carbon in rock, which can then be used in concrete and stored in our built environment. Just as very high heat (~1500^{o}C) is necessary break limestone into its constituent elements (CaO and CO_2) to make cement, similar conditions would be required to release captured CO_2 once it has been mineralized back to limestone.

Additionally, since concrete is the most widely used building material on earth, every year California (and the world) use enough rocks in concrete that we could store all emissions from major industrial sources in our buildings and roads. Compared to geological sequestration, which only entails cost,[3] carbon capture and conversion – in particular carbon storage in concrete – provides a value-added market that can make carbon capture cost effective without additional public subsidy.

While several technical, legal, and economic questions remain related to geologic sequestration, many of which CARB and other agencies will address through implementation of SB 905 (Caballero, Chapter 359, Statutes of 2022), carbonate mineralization offers a fully scalable, permanent carbon storage solution, ready for deployment today. Through the SB 905 process, we also hope CARB will consider developing new CCS Protocols, including for carbonate mineralization. We appreciate the state repeatedly already recognizing this opportunity, including:

- In the Final 2022 Scoping Plan Update, CARB discusses the role of carbon capture and carbonate mineralization in the context of decarbonizing cement and other sector transitions, stating "Direct air capture and carbon mineralization have high potential capacity for removing carbon..."[4]

- The CEC identifies carbonate mineralization, including carbon storage in aggregates, as one of the most promising strategies for decarbonizing the cement sector:[5]

> Capturing carbon from industrial processes and then utilizing it in a product is considered one of the essential components for mitigating CO_2 emissions since it can achieve net negative emissions, especially for sectors that are unable to achieve zero emissions. For example, carbon capture and utilization appear to be a pathway to achieve significant decarbonization of the cement industry where 60 percent of the carbon dioxide is from process emissions… For instance, carbon capture and utilization in the cement industry has recently emerged with

[1] https://www.arb.ca.gov/lists/com-attach/73-sp22-kickoff-ws-UTMGbFElVGJQCQd3.pdf

[2] For example, see: Xi, F., Davis, S., Ciais, P. et al. Substantial global carbon uptake by cement carbonation. Nature Geosci 9, 880–883 (2016). https://doi.org/10.1038/ngeo2840

[3] Unless it is used for enhanced oil recovery, which is unlikely in California given prohibitions included in SB 905 (Caballero, Chapter 359, Statutes of 2022) and SB 1341 (Limón, Chapter 336, Statutes of 2022).

[4] CARB (2022) 2022 Scoping Plan for Achieving Carbon Neutrality, California Air Resources Board, November 16, pg. 221. https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp.pdf

[5] See pg. 10 at: https://esd.dof.ca.gov/Documents/bcp/2223/FY2223_ORG3360_BCP5441.pdf

sustainable techniques to use carbon emissions in concrete production. Some emerging utilization techniques, such as mineral carbonation, includes adding carbon into cement to enhance the concrete's compressive strength. With almost 4 billion tons of construction aggregate produced in North America, mineral carbonation could be the most efficient route to CO_2 utilization.

LCFS amendments should allow use of additional CCUS strategies as new CCS Protocols are developed

The LCFS is a critical program for advancing California's climate objectives, and likely the most important program to advance CCUS and carbon dioxide removal, both of which will be necessary to achieve California's goals of carbon neutrality and achieve and maintain net-negative greenhouse gas emissions. Indeed, the Final Scoping Plan identifies a significant role for CCUS to play in decarbonizing transportation fuel pathways and supporting carbon dioxide removal, both in 2030 and through 2045. We hope CARB will recognize the promising role that CCUS in aggregates and concrete – as well as other emerging CCUS and carbon dioxide removal strategies – can play in helping to achieve carbon neutrality and net-negative emissions in California and make further amendments to the LCFS to allow new protocols to be deployed as they are developed and adopted.

Unfortunately, while the regulatory language already references the CCS Protocol, in several instances the language also references geologic sequestration, CO_2 transport by pipeline, or other items that seem unnecessary to utilizing the current CCS Protocol in the program and serve to limit eligibility of potential new protocols as they are developed. **We hope you will consider 15-day changes to remove references in the regulation related to CCUS that serve to limit potential new CCUS and Carbon Dioxide Removal Protocols from being utilized in the future, and clarify that future protocols would be eligible under the LCFS, should they be developed and adopted.** In particular, we urge the following changes:

- Update the definition of "Carbon capture and sequestration (CCS) project" in § 95481(a) to remove language limiting the potential use of non-geologic sequestration projects:

  "Carbon capture and sequestration (CCS) project" means a project that captures or removes CO_2 by an eligible entity specified in section 95490(a) of this subarticle~~,~~ ~~transports the captured CO_2 to an injection site, and injects~~ and permanently sequesters the captured CO_2 pursuant to the Carbon Capture and Sequestration Protocol and as specified by section 95490 of this subarticle.

127.1

- Clarify that new protocols added to the CCS Protocol will be eligible to generate credits under the LCFS and similarly remove limiting language related to potential CCUS Protocols in § 95490:

  (a) Eligibility. The following entities are eligible to submit applications and, if approved, receive credits associated with net GHG reductions from CCS projects, in accordance with following protocol or any subsequent version, which ~~is~~ are incorporated herein by reference and ~~is~~ referred to as the "CCS Protocol" hereafter.

  Industrial Strategies Division, California Air Resources Board. August 13, 2018. Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard.

127.1 cont

(1) Alternative fuel producers, petroleum refineries, and oil producers that capture CO_2 on-site, including at the location of the production of hydrogen used as an intermediate input, and ~~geologically~~ permanently sequester CO_2 either on-site or off-site.

(2) An entity that employs direct air capture to remove CO_2 from the atmosphere using chemical and/or physical separation and ~~geologically~~ permanently sequester the CO_2.

(A) Direct air capture and sequestration projects must be physically located in the United States.

(B) If CO2 derived from direct air capture is converted to fuels, it is not eligible for project-based CCS credits. However, applicants may apply for fuel pathway certification using the Tier 2 pathway application process as described in section 95488.7.

(3) An entity that employs a technology to capture or remove and permanently sequester CO_2 from the atmosphere in accord with the provisions of the "CCS Protocol" or any subsequent version or protocol.

(b) General Requirements.

(1) Projects and fuel pathways claiming CCS credits must comply with the CCS Protocol. To be considered in compliance with the CCS protocol, a project must be issued executive orders and meet all the requirements throughout the project life in accordance with the permanence requirements of the CCS protocol.

(2) Credit determination for any project that utilizes CCS must be performed in accordance with the accounting requirements of the CCS protocol.

(3) Except for direct air capture and sequestration projects or other projects as deemed appropriate, credits must be prorated based on the volumes delivered to California.

(c)(2)(B) An engineering drawing(s) or process flow diagram(s) that illustrates the project and clearly identifies the system boundaries, relevant process equipment, mass flows, including the quantity of CO_2 injected into pipeline or delivered by other modes of transport for CO_2 ~~injection~~ sequestration, and energy flows necessary to calculate the CCS credit;

(c)(2)(G) Executive orders issued pursuant to the permanence requirements of the CCS protocol, certifying the sequestration site or method as capable of permanently storing CO_2 and authorizing ~~operation and~~ credit generation.

(g)(2) Energy use and chemical use data for the carbon capture facility and CO_2 ~~injection~~ sequestration facility;

- Also remove limiting language in § 95489(e)(1)(D)(1):

CO_2 capture from existing anthropogenic sources at refineries, or at hydrogen production facilities that supply hydrogen to refineries, and subsequent ~~geologic~~ sequestration;

Support maintaining project-based crediting for CCS projects

Blue Planet strongly supports exempting CCS projects from the proposed phase out of project-
127.2 based crediting for petroleum projects. We agree with the rationale for this proposal presented
in the ISOR.

Quickly enabling a wide array of CCUS projects and protocols will accelerate California's climate change goals

Now is the time to fully enable CCUS as a solution to ensure the California stays on track to achieve its Scoping Plan objectives. By incorporating the changes referenced above to avoid presuming geologic sequestration remains the only CCS Protocol available in California and preserving project-based crediting opportunities for CCS projects, the LCFS can continue provide a strong signal for investment in CCUS and DAC projects. The next step is to develop new CCS Protocols, as referenced in SB 905 and through implementation of that legislation, and incorporate CCUS into the Cap-and-Trade program. We look forward to continuing to engage in all of these forums.

Thank you for your consideration of these comments, and please do not hesitate to reach out if you have any questions about Blue Planet, our technology, or the recommendations and comments offered in this letter.

Thank you,

Laura Berland-Shane
Vice President, Government Affairs
Blue Planet Systems Corporation

Comment Log Display

Here is the comment you selected to display.

Comment 136 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jessie
Last Name	Melendrez
Email Address	jessieboy2feathers@hotmail.com
Affiliation	
Subject	Factory farming.
Comment	Factory farming is not healthy for humans and is torture for animals and dangerous for employees as the stress for rapid meat production makes employees make careless mistakes that end up in death and limb loss.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-17 19:45:22

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 137 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mariquita
Last Name	West
Email Address	mqqwest@gmail.com
Affiliation	

Subject	Stand firm to fight climate change

Comment

Dear California Air Resources Board,

129.1 Please do not slither backwards on low carbon fuel standards. You have been par tof California's leadership in fighting climate change.
Do Not Give Up Now!
Our kids depend on you.

Sincerely,
Mariquita West
Los Gatos, CA 95031

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-17 21:26:55

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 138 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Guadalupe
Last Name	Sanchez-Luna
Email Address	kidtrail@aol.com
Affiliation	
Subject	biogas
Comment	We need a healthier California!! It is not a wise decision to kee using our tax dollars to invest in biogas when it is polluting the air we breath. You have the opportunity to adopt new rules and sto rewarding factory farms for polluting our air. I hope you will mak an intelligent choice.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-17 21:31:59

130.1

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 139 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Shannon
Last Name	Speigner
Email Address	shannonspeigner@gmail.com
Affiliation	
Subject	Animals & land
Comment	I support the humane treatment of animals and a cleaner environment.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-18 01:08:51

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Comment Log Display

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Comment 140 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Anne
Last Name	Schedeen
Email Address	aschedeen@gmail.com
Affiliation	
Subject	Quickly fix the Low Carbon Fuel Standard

Comment

Dear California Air Resources Board,

Time to turn this unjust, LCSF policy around. What was the reaso
for ever making such a decision in the first place? Whatever it
was, allowing big corps to defile Californias environment looks to
132.1 be a deal which never should have even been considered.

The people of this state stand behind you in any and all your
efforts to get rid of the LCSF legacy. The time is now.

Sincerely,
Anne Schedeen
Cathedral City, CA 92234

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-18 04:13:17

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 141 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Shirley
Last Name	Lindquist
Email Address	sahl@llbbl.com
Affiliation	
Subject	California gas
Comment	Don't let California california-cate our farms here in the Midwest
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-18 07:16:31

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 142 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ivan
Last Name	Light
Email Address	ihlight607@gmail.com
Affiliation	Inverness Ridge Association
Subject	low carbon fuel standard amendments

Comment

134.1 Eliminate avoided methane crediting for fuel derived from livestoc
manure.

134.2 - Oppose Proposed LCFS Amendment Loophole to Allow Petroleum
Projects with Carbon Capture & Storage Past the 2040 Phase-out.

I recommend a number of measures, to wit:
134.3 Conduct and incorporate a full life cycle assessment of all air
pollution and greenhouse gas (GHG) emissions for all pathways, anc
their implications for environmental justice communities.

134.4 - Create ZEV multipliers to boost electric school bus and electric
public transit bus and rail system deployments.

134.5 - Eliminate credit generation from factory farm gas projects that
would have happened anyway due to other programs or investments.

134.6 - Include intrastate jet fuel as a deficit generator and include
California's share of the fuel used in interstate and internationa
flights.

134.7 - Allow credits for zero-emission transportation fuels used for
ocean-going vessels, and simplifying the process for credits for
shore power installations serving electrified harbor crafts and fo
dispensing green hydrogen.

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-02-18 08:49:13

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 143 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Daniel
Last Name	Medrano
Email Address	d.medrano87@yahoo.com
Affiliation	
Subject	factory farm energy pollution
Comment 135.1	factory farm biogas is unsustainable. it does not reduce the dairy industry's environmental footprint. In fact, investing in biogas helps maintain and expand factory farms. Investing in biogas means investing in more factory farm pollution
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-18 09:23:24

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 144 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Norm
Last Name	Sendler
Email Address	nordicup@msn.com
Affiliation	

Subject	Environmental Efficiency

Comment

I'd like to introduce a new term / measure when considering energy
"Environmental Efficiency". For example, the average, grid-scale
solar / storage operation has an Environmental Efficiency of 1.1
MWh / acre. A large nuclear plant, with a large "safety barrier",
has an Environmental Efficiency of ~40 MWh / acre. And a next-gen
136.1 natural gas fired generating station has an Environmental
Efficiency of ~80 MWh / acre.

In other words, while a 24,000 MWh / day natural gas generating
station might sit on a half-square mile of land, a similar solar /
storage operation would require ~40 square miles of land; obscenel
abusive and low Environmental Efficiency.

And that does not include any of the raw materiel / rare earths
mining, production in highly polluting countries such as China, no
the poor performance and accelerated life-time performance
degradation.

Then there is the human rights issue, but that might be better
captured in a separate category.

The point being there is "no free lunch"; miles and miles of virg
lands and waters are being abused, animals of land, sea and air ar
being murdered and all for the whimsy of politicians in DC and
Davos.

Remember, fossil fuels, such as natural gas, are simply Mother
Nature's stored solar energy; she's a very clever Lady.

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-18 11:11:49

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 145 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Chris
Last Name	Gilbert
Email Address	chris@gilbertbiz.com
Affiliation	
Subject	get rid of loopholes and misguided credits in current and proposed LCFs rules

Comment

137.1 - Eliminate avoided methane crediting for fuel derived from livestock manure.

137.2 - Oppose Proposed LCFS Amendment Loophole to Allow Petroleum Projects with Carbon Capture & Storage Past the 2040 Phase-out.

137.3 - Eliminate credit generation from factory farm gas projects that would have happened anyway due to other programs or investments.

Plus:

137.4 - Conduct and incorporate a full life cycle assessment of all air pollution and greenhouse gas (GHG) emissions for all pathways, anc their implications for environmental justice communities.

137.5 - Create ZEV multipliers to boost electric school bus and electri public transit bus and rail system deployments.

137.6 - Include intrastate jet fuel as a deficit generator and include California's share of the fuel used in interstate and internationa flights.

137.7 - Allow credits for zero-emission transportation fuels used for ocean-going vessels, and simplifying the process for credits for shore power installations serving electrified harbor crafts and fo dispensing green hydrogen.

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-02-18 12:29:32

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 150 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Robbi
Last Name	Buchholtz
Email Address	rbuchholtz@dakotaethanol.com
Affiliation	Dakota Ethanol
Subject	comments on proposed 2024 LCFS amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6675-lcfs2024-BWFSNQBqV2sEdgJj.pdf
Original File Name	Dakota Ethanol comment letter on 2024 proposed LCFS amendments.pdf
Date and Time Comment Was Submitted	2024-02-18 13:01:34

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

46269 SD Hwy 34
PO Box 100
Wentworth, SD 57075
605.483.2679
Fax 605.483.2681

February 16, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

As a renewable fuel producer and participant in CARB's LCFS program, my team and I value the partnership and mission shared with you and your state to reduce the carbon intensity of transportation fuels.

I am writing to share our company's perspective on two key program areas for your consideration. These requests address the topics of **firm rotation** and **less intensive verification**.

<u>Firm Rotation</u>
The existing regulations within the LCFS verification program stipulate a mandatory rotation of audit firms every six years to assess participants' carbon intensity (CI) and fuel quantities compliance.

Our request is that CARB amend the mandatory firm rotation regulation to include an exception for licensed CPA firms. Of the 30 approved LCFS verification bodies, there are only four licensed CPA firms.

> ***An approved verification body, that is also a licensed CPA firm, exceeds the standards in place for verification bodies and is already subject to additional***
> 138.1 ***oversight on the entity's quality control system in accounting and auditing practices through the required AICPA peer review process.***
>
> ***Due to the increased regulatory oversight, we suggest a CPA firm not be subject to the audit firm rotation but would instead adhere to a Lead Verifier rotation after six consecutive years.***

A licensed CPA firm differs from other consulting agencies by adhering to more rigorous standards and oversight at a state and national level. If a verification body were to violate a

Lead Verifier rotation requirement, it would put the firm license at risk. The firm license is required for all services provided by the firm, not just the LCFS verification services, thereby ensuring adherence to requirements.

Licensed CPA firm requirements

- A licensed CPA firm must be comprised of over 50% of the ownership being licensed CPAs.
    - To earn the accreditation to be a CPA, one must pass a rigorous four-part CPA exam, accumulate education hours, and in many states, one must fulfill 1-2 years of work experience.

- 3-year peer review audit
    - Each licensed CPA firm must enroll in an approved peer review program with reviews conducted every 3 years. The peer review requirement is a requirement of the American Institute of Certified Public Accountants (AICPA) and is an external review of a firm's quality control system in accounting and auditing practices. CPA firms' peer review results can be found on AICPA's website under the Peer Review Public File Search.

- State Boards of Accountancy (SBOA) are found in each state's statute to aid state governments in the licensing and regulation of the public accounting profession.
    - SBOAs provide further oversight on CPA firms by evaluating CPA licensees' examinations and regulatory oversight to ensure a firm is practicing within their statutory scope.

The audit quality and efficiency improve as the auditor becomes more familiar with our company's processes. In addition, with the limited number of firms available as verification bodies and a five-year lookback period in place, it is proving difficult to identify a quality verification body that is not also working with our facility in other consulting capacities. The number of people available with the proper expertise to assist us in design and development of projects and to reserve for verification purposes has proven even more limiting, which is also why we request a Lead Verifier rotation rather than a full firm rotation.

Less Intensive Verification

Regarding less intensive verification, we noted in Appendix E staff's proposal for less intensive verifications for when electricity is used as a transportation fuel, allowing verification bodies to skip site visits if they visited the site in the last two years and issued a positive verification statement.

The rationale for this proposed change states, "there is little change of operation from reporting period to reporting period thus reducing the benefit of annual site visits." Additionally, staff rationale states, "There is no or little risk to the integrity of the LCFS program to allow for less intensive verification services without a site visit in the annual verifications for the following two years. This should reduce the cost of verification services which is often passed on to program participants."

Currently, the proposed language limits this allowance for less intensive verifications to QFTR third-party verification bodies for fuel reporting entities only reporting electricity transactions.

138.2 We agree with the staff's stated rationale, but **we request for less intensive verification to be extended as an option for verification bodies on all validations and annual verifications for any reporting entities.**

In CARB's MRR program (section 95130), less intensive verification is applied without prejudice to verification services by accredited verification bodies.

We agree with staff that less intensive verification leads to little to no risk to the integrity of the LCFS program and that there is little change in operation from reporting period to reporting period, while also providing cost savings to verification providers and passed on to our company as program participants.

We acknowledge the importance of adhering to CARB's specified conditions that necessitate comprehensive verification services. These conditions include the issuance of an adverse verification statement or a qualified positive verification statement in the preceding year and the occurrence of a change in operational control of the reporting entity in the previous year.

Thank you for your time and consideration. Please reach out to us if you have any questions.

Sincerely,

Robbi Buchholtz

Robbi Buchholtz
CFO

Comment Log Display

Here is the comment you selected to display.

Comment 148 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Daniel
Last Name	Loftis
Email Address	Daniel_loftis@hotmail.com
Affiliation	
Subject	No more factory farms
Comment	Stop allowing these factory farms. They are bad for everyone except corporations You know they are bad yes they build wealth for companies and create jobs instead of small family owned farms. Daniel Loftis
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-18 17:44:57

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 153 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Asher
Last Name	Goldman
Email Address	asher@generatecapital.com
Affiliation	Generate Capital
Subject	Generate Capital Comments on Amendments to LCFS
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6713-lcfs2024-BmFRMgNsAjQAdFMy.pdf
Original File Name	Generate Capital Comments on LCFS_vF.pdf
Date and Time Comment Was Submitted	2024-02-18 21:02:26

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

GENERATE

February 20th, 2024

Matt Botill
Chief, Industrial Strategies Division
California Air Resources Board
1001 I Street, Sacramento, CA 95814

Mr. Botill and CARB Staff,

I am pleased to write to you on behalf of Generate Capital, PBC ("Generate") regarding the current rulemaking process to update and strengthen the Low Carbon Fuel Standard ("LCFS"). Generate is a leading sustainable infrastructure company based in San Francisco. Generate builds, owns, operates, and finances infrastructure solutions for clean energy, transportation, water, waste, agriculture, and smart cities. Founded in 2014, Generate partners with technology and project developers to deliver affordable, reliable, and sustainable resources to over 2,000 customers, companies, communities, school districts and universities.

The LCFS has been a model climate policy. It has enabled the private sector to deploy billions of dollars into climate solutions to decarbonize California's transportation sector. The current amendments to the policy continue that leadership. In particular, by providing carbon intensity ("CI") reduction targets through 2045, the agency is allowing investors like us to have the policy certainty needed to deploy patient, long-term capital into climate solutions and the companies that build them.

As participants in this market, we agree with many of the updates CARB is proposing in this process. At the same time, there remain a handful of key topics where we would like to see amendments to the proposed regulation. In particular, the key areas on which we will provide commentary include:

- The changes to the diesel baseline and its impact on credit supply and demand;
- The CI step-down and the 2030 CI reduction target;
- The design of the Auto-Acceleration Mechanism ("AAM"), and;
- The treatment of Renewable Natural Gas ("RNG").

We look forward to discussing these and other aspects of the LCFS program with CARB staff as may be helpful to finalize the rulemaking process. Thank you for all of your hard work to ensure California continues to be a leader in the fight against climate change.

Sincerely,

Asher Goldman

Asher Goldman
Vice President
Generate Capital

140.1 Changing the diesel baseline reduces the ambition of the LCFS program and lessens the impact of the changes CARB is proposing; the CI reduction targets should be increased to counteract the change in the baseline

For the past several years, the conversation around potential LCFS amendments has focused on changing the CI targets in terms of percent reductions relative to the 2010 baseline. While the Initial Statement of Reasons ("ISOR") did adjust those CI reduction targets, it also meaningfully changed the 2010 CI baseline for diesel. While we are aware that this value does periodically change due to updated modeling, this instance was larger than any previous change.[1] As shown in Figure 1, by moving the 2010 baseline for diesel from 100.45 g/MJ to 105.76 g/MJ, the resulting CI targets shift up.

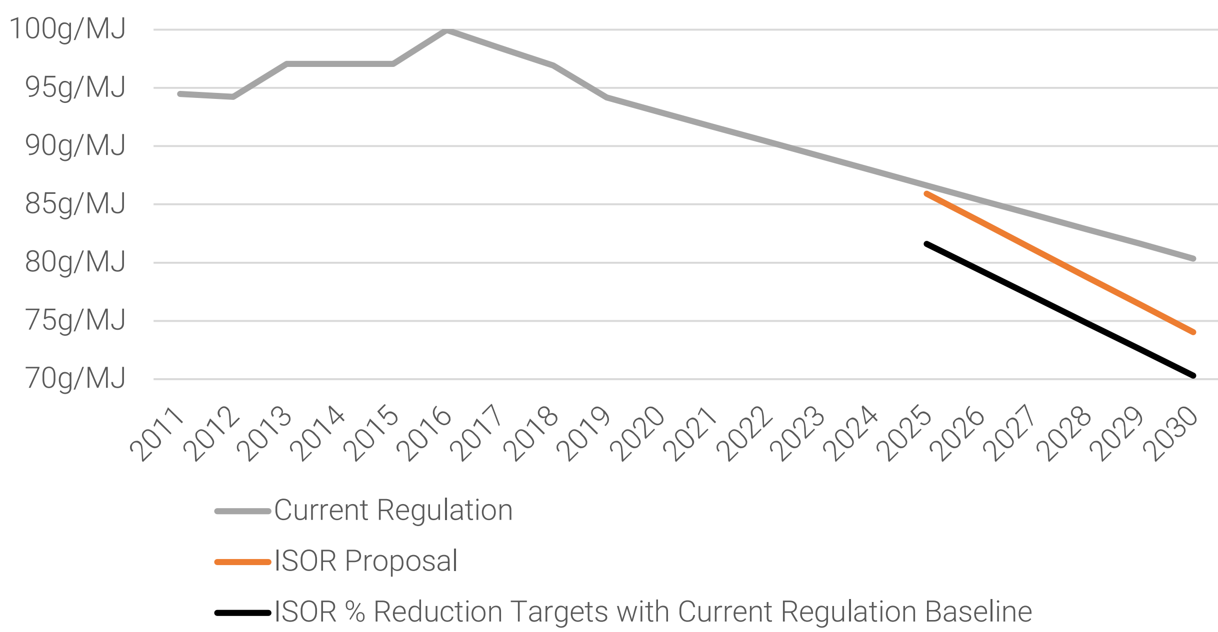

Figure 1: LCFS carbon intensity benchmarks for diesel fuel under different baseline values

The impact of this is significant. As CARB is aware, the volume of fossil diesel fuel used in California has fallen dramatically over the past several years; Q2 2023 had just 40% as much fossil diesel as Q2 2018.[2] With this change in baseline, fossil diesel will generate more deficits on a per-unit basis and diesel-replacements will generate more credits per unit. However, due to the declining fossil diesel volume, these per-unit increases do not cancel out in aggregate. Our modeling suggests that the credit bank will be 12.5M MT larger in 2030 than it would be with the baselines currently in effect (i.e., 100.45 g/MJ for diesel). **The outcome of this would be a reduced credit price, lower investment in climate solutions, and higher emissions levels.**

140.1 cont **To account for this change, we suggest that CARB adjust the CI reduction targets to make them ~3% more stringent.** This is particularly important for the CI step-down planned for Q1 2025; as can be seen in Figure 1, the baseline change practically undoes the impact of the step-down for the diesel pool.

[1] California Air Resources Board. *Proposed Amendments to the Low Carbon Fuel Standard*. December 2023. "Table 2. LCFS Carbon Intensity Benchmarks for 2011 to 2045 for Diesel Fuel and Fuels Used as a Substitute for Diesel Fuel". Page 65.
[2] California Air Resources Board. *LCFS Quarterly Data Spreadsheet*. January 2024.

In order to promote investment into climate solutions for California's transportation sector at the speed and scale needed, CARB must move the step-down to Q3 2024 and increase its magnitude, and increase the 2030 CI reduction target to between 32% and 35%

Generate is highly supportive of CARB providing the market with a long-term signal to reach deep levels of decarbonization via the 90% CI reduction target in 2045. This is precisely the type of policy certainty needed for investors such as Generate to make long-term investments into infrastructure projects needed to achieve the goals of the LCFS and the Scoping Plan. At the same time, we would like to see greater action in the near-term. In order to stimulate investment and infrastructure development in the next several years – a critical period to avoid exhausting our carbon budget – CARB should further the LCFS program's aims through 2030.

In the days following the publication of the ISOR, the market price of credits fell 22%, reaching the lowest levels since July 2016.[3] This reaction is the market unequivocally stating that the targets included in the ISOR are insufficient. At the current credit price – and those seen over the last two years – the market cannot support meaningful levels of investment into the decarbonization solutions needed to achieve the goals of the LCFS program or the Scoping Plan. We have experienced this first-hand: the low credit price environment has forced us to pause making new investments into LCFS-linked projects and companies. At a time when there are economic, social, and public health imperatives to accelerate our pace of decarbonization, the outcome of the most recent proposal would be lower investment, fewer projects, and greater emissions; in other words, this would be a missed opportunity.

140.1 cont Throughout the rulemaking process, Generate has consistently proposed 30% as the minimum viable 2030 target, a view reinforced with each successive LCFS data release. However, the change to the diesel pool's 2010 baseline value means that the significance of each "percent reduction" value using the updated baseline is actually ~3% less than it would have been under the prior rules; we should think of the proposed 2030 target as only 27%. Therefore, the proposed reduction target should be increased to between 32% and 35% for 2030.

140.2 Given the credit surpluses seen over the last two years, the step-down in the CI reduction schedule is critical. As CARB is likely aware, most market participants believe that 2024 will have a large number of excess credits produced, causing the bank to build rapidly – our modeling shows 11M more credits produced than deficits in 2024. In order to promote a stable market – one which avoids whiplash as we go from large quarterly surpluses to quarterly deficits – moving the step-down into 2024 and avoiding that bank build is crucial. In public workshops, CARB staff discussed the possibility of a 7/1/2024 step-down to the CI targets.[4] **We strongly support moving the step-down to 7/1/2024.** If CARB determines that Q1 2025 is the earliest that the step-down can be implemented, then we believe a much more aggressive step-down is warranted, as is shown in Table 1.

There are multiple ways of incorporating a mid-year CI change. CARB could implement a 7/1/2024 step-down and then have regular tightening on 1/1/2025. If CARB staff feels this is too aggressive, they could include a 7/1/2024 step-down and keep that CI reduction target through the 2025 calendar year. This moderated route may be attractive in that it avoids the projected 2024 credit bank growth without adjusting the CI target twice in six months. A third version of this would be to implement a smaller step-down on 7/1/2024 and then a larger step-

[3] Argus Media. *CA LCFS Spot Price.* Accessed February 2024.

[4] California Air Resources Board. *Public Workshop: Auto-Acceleration Mechanisms and Step Down Benchmark Considerations*. May 2023.

down on 1/1/2025; for example, CARB could opt for a 18.75% target for the second half of 2024 to mitigate (but not eliminate) the bank build in that year, and then have a second manual change to 22% in for 2025.

Step Down Timing	Step Down Magnitude	2030 Target
Q3 2024, CI targets held through 12/31/2025	21.50%	32%
Q3 2024, CI targets held through 12/31/2025	22.50%	30%
Q1 2025	21.50%	35%
Q1 2025	23.00%	32%
Q1 2025	24.00%	30%

Table 1: Generate recommendations for CI reduction schedule

Considering each of the aspects in concert with one another, Generate's **primary recommendation is for CARB to implement the step-down on 7/1/2024 to 21.50% below the 2010 baseline and maintain that target through 12/31/2025, alongside a 32% 2030 CI reduction target.** We have also prepared alternative designs if CARB wants to keep the 30% 2030 target and/or the Q1 2025 timing of the step-down, though the appropriate step-down magnitude increases if those elements of the ISOR proposal are retained.

The core rationale behind the recommendations above is that each of those designs would enable Generate and our competitors to build the climate solutions necessary to achieve CARB's policy goals, while ensuring that the LCFS program maintains a sensible credit bank to buffer price volatility. Building a market with reasonable, stable pricing allows investors like Generate to confidently deploy capital into projects that are needed for the scale of decarbonization which California is targeting; a market with significant volatility – as we have seen over the past several years – is not helpful to our goal of building infrastructure and deploying zero emission vehicles, meaning that investment happens more slowly, if at all. The four recommended designs would each motivate private capital to rapidly and efficiently decarbonize California's fuel system.

<u>The Auto-Acceleration Mechanism will promote a healthy, stable investment environment by continuously calibrating the LCFS's ambition</u>

We applaud CARB for including the AAM in the rulemaking proposal. The AAM will allow the market to expediently self-correct such that investors like us can have confidence to continue to deploy capital into the technologies needed for this program to continue its success in driving decarbonization of California's transportation sector. While we are excited about the inclusion of the AAM, there are several key points where CARB can improve the design to ensure that the mechanism functions as intended.

140.3 *Implementation of the AAM should be moved up by a year to reflect the mechanism's ongoing structure as proposed in the ISOR.*

CARB's proposed timeline for implementing the AAM currently has 2028 as the first year in which the AAM can amend CI reduction targets. If we treat the step-down planned for Q1 2025 as a manual iteration of the AAM (caused by 2023 overperformance) and apply CARB's logic on suspending the AAM the year after it activates, 2024 should be ineligible for AAM activation but 2025's performance should be able to trigger the mechanism. A 2025 triggering would impact CI targets in 2027, one year prior to when the ISOR currently proposes. We recommend adjusting the implementation timeline accordingly.

140.4 *The 75% bank-to-deficit trigger is too high and would allow for the types of market dislocations such as we have seen over the past two years.*

The proposed design for the AAM includes a trigger when the ratio of a given year's ending credit bank divided by the total deficit production in that year exceeds 75%. The issue with this is that a 75% bank-to-deficit ratio would be quite high in other commodity markets (where that metric is often referred to as the stock-to-use ratio).[5] Over the past 30 years, typical stock-to-use ratios in commodity markets have been below 40% and often under 10%.[6] To this point, in 2022 – a year in which the credit bank expanded by 55% and credit pricing fell by 54% – the AAM would not have been triggered under the proposed design with the bank-to-deficit ratio at "only" 71%.[7]

To support stable pricing in the LCFS market – and thereby allow investors to properly underwrite long-term investments into infrastructure projects – CARB would be well served to adjust the threshold for triggering the AAM to a bank-to-deficit ratio of 50%. This would allow the AAM to capture periods such as 2022 and adjust the targets of the program accordingly.

<u>While CARB has made progress in its proposed changes to RNG's treatment under the LCFS, there are additional amendments needed regarding avoided methane crediting and true ups to ensure private capital will target and prevent methane emissions</u>

CARB has shown leadership in arriving at a productive policy determination on RNG's treatment under the LCFS program. LCFS is fundamentally a technology-neutral policy which asks the market to determine the best and fastest way to decarbonize transportation. Avoiding prescriptive policy choices is key to allowing the market to do this efficiently and efficaciously. By protecting this ethos through this rulemaking, CARB is giving confidence to investors and project developers that their technology will not suddenly be eliminated from LCFS eligibility.

140.5 We endorse the comments from Amp Americas, the RNG Coalition, and the American Biogas Council on CARB's proposals regarding RNG.

CARB should condition phasing out avoided methane crediting on regulation of methane emissions.

Generate views preventing the emissions from agricultural methane to be no more or less valuable than preventing any other type of greenhouse gas emission, adjusted for global warming potential. The methane emitted is real, and solutions are needed to mitigate those emissions. While it is tempting to exclude certain emissions from our inventory, the climate

[5] Zulauf, et al. University of Illinois. *Stock-to-Use Ratios of US Corn, Soybeans, and Wheat Since 1960.* June 2021.
[6] Ibid
[7] California Air Resources Board. *LCFS Quarterly Data Spreadsheet*. January 2024.

does not care what laws we pass or what emissions we choose to ignore, only what gases we put into it. As such, we suggest that CARB amend the proposal phasing out avoided methane
140.6 crediting by 2040 for projects breaking ground in 2030 or later to be conditioned on direct regulation of these methane emissions. This would ensure that emissions do not suddenly increase in 2040 as the existing operating model for projects falls away.

140.7 *True ups to credit production are welcome and should be extended to Temporary Pathways, but the 4x penalty for overproduction will be an impediment to investment and to decarbonization.*

The clarity CARB has provided on "true ups" for RNG is valuable. This will better reflect the actual GHG impact made by each project, ensuring projects are not over- or under-compensated for the climate impact they make. With that said, we would like to see two changes to the draft language. First, as the RNG Coalition notes in their letter, it is unclear why CARB has changed its approach from what was discussed at public workshops regarding true ups for projects utilizing Temporary Pathways. As with latter pathways, the idea is only to correctly allocate value based on real-world climate impact. Second, it is unclear why CARB has proposed a 4x penalty for overproduction of LCFS credits. As staff is likely aware, conditions outside of the control of an investor or an operator can materially impact an RNG project's output and thereby its LCFS
140.8 credit production. For example, warmer conditions than normal can increase an anaerobic digester's output, resulting in over-production of credits. CARB's proposed 4x penalty is overly harsh and aims to prevent something outside of any operator's control. Instead, we suggest a bidirectional true up, with penalties only for intentional misrepresentations, fraud, or consistent and egregious overproduction.

<u>Closing Comments</u>

In summary, we are pleased with the process CARB has undergone over the past two years and with many of the policies CARB has included in the proposed regulation. With that said, we would like to see CARB continue to push the market to decarbonize California's transportation system faster. In particular, we would like CARB to consider the following proposals:

- Amending the timing of the step-down to 7/1/2024 and updating the step-down's magnitude to a minimum of 21.50%;
- Increasing the 2030 CI reduction target to at least 32%;
- Using an AAM design that will trigger at a 50% bank-to-deficit ratio and beginning the AAM one year earlier than proposed, and;
- Conditioning the phase out of avoided methane crediting for RNG on regulation of methane emissions and adjusting the design of credit production true ups.

Generate appreciates the opportunity to provide commentary and suggestions and looks forward to collaborating with CARB. Should you have any questions about the information contained herein, please do not hesitate to contact us.

Comment Log Display

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Comment 154 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Travis
Last Name	Lane
Email Address	tlane@calgren.com
Affiliation	Calgren
Subject	Re: Proposed Amendments to the Low Carbon Fuel Standard

Comment

February 18, 2024
The Honorable Liane Randolph
Chair, California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Proposed Amendments to the Low Carbon Fuel Standard

Dear Chair Randolph:

As you may recall from your visit to our facilities several years ago, Calgren has been producing low carbon intensity renewable fuels in Pixley, California since 2008, shortly before the LCFS start date of January 1, 2010. While others in the renewable fuels industry have occasionally questioned the wisdom of California's LCFS, both in the courts and otherwise, we have been among your strongest and most consistent supporters from the very start. In addition, we remain especially proud of the fact that we have been able to bring well-paid jobs and economic activity to an impoverished area of our great state.

With that background, we offer the following constructive comments to the 45-day language to amend the LCFS:

1. We are disappointed that the proposed changes fail to leve playing field for in-state producers of biomethane.

In 2022 and 2023, CARB staff recommended that Book and Claim accounting for biomethane that is undeliverable to California be phased out. The changes now proposed have abandoned that approach and treat all out-of-state projects, even those that cannot possibly deliver into California, the same as we California producers.

To give but one example of the uneven playing field, California biomethane producers face ever increasing standards for injection into California's pipeline system; California's biomethane injection standards are far more stringent than biomethane producers face in any other state. Yet biomethane producers in those more lenient states may use the same Book and Claim accounting without having to meet the same injection standards. In earlier comments to CARB, we suggested that out-of-state producer: be required to meet California's injection standards to use Book and Claim, a concept we continue to support. California gets the vast majority of its pipeline natural gas from out-of-state, yet there is no mandatory testing of that gas as it enters our state. Hence a biomethane producer is actually (and no doubt inadvertently) encouraged to locate outside California's borders. That is at odds with the Independent Statement of Reasons (ISOR) provided in support of the proposed regulatory changes.

As noted above, CARB staff took a slightly different tack in recommending a sensible restriction - that Book and Claim for out-of-state biomethane producers injecting into pipelines that d not serve California be phased out. The proposed changes to the LCFS have abandoned this sensible approach in favor of applying t same restrictions to in-state producers as are applied to out-of-state producers. Frankly, we think both requirements shoul apply, i.e. that out-of-state biomethane producers that wish to u Book and Claim accounting both meet California's biomethane quali standards and demonstrate deliverability into California.

In addition to cleaning up California's environment and encouragi in-state commercial activity, another of CARB's laudable goals is to encourage enactment of LCFS-type regulations in other states (ex., page 15 of the ISOR). Those goals are actually (and, again, no doubt inadvertently) thwarted by CARB's willingness to award California carbon credits for renewable fuel that is already in u in those other target states.

In fact, we now take this argument one step farther. Ultimately, LCFS costs get passed on to California residents via higher vehic fuel costs. We applaud that willingness to pay what it takes to help clean up the air we breathe. But awarding LCFS credits for biomethane that cannot be delivered into California forces Californians to pick up the tab to help clean the air in other geographic regions. That's inappropriate.

It is a fact that new biomethane projects can achieve pipeline injection much quicker if they are out-of-state. While we don't agree with the logic, we have heard that one reason to initially award LCFS credits for out-of-state biomethane projects that cann deliver into California was to encourage the growth of in-state biomethane production. If so, that goal has been achieved; California biomethane producers are now capable of meeting California's current, commercially attractive biomethane demand.

Continuing to offer LCFS credits for undeliverable biomethane is both unwarranted and detrimental to California biomethane producers.

2. The proposed carbon intensity benchmarks should be stricte sooner, perhaps even this year.

LCFS credits have recently been trading below $60 per MT. As CARB has heard from all quarters, that is too low. In fact, the recent announcement that CARB would delay adoption of the LCFS changes to "re-evaluat[e] the carbon intensity benchmarks" caused the spot price of carbon credits to jump almost 10%. That is a clear sign that the proposed step-downs need to be more aggressive.

We have consistently endorsed both a stronger step-down and the adoption of an Automatic Acceleration Mechanism (AAM). We hereby urge that the AAM triggers be moved up. As proposed, the mechanism cannot be triggered earlier than 5/15/2027. That is too late.

3. Section 95482(g) prohibits dairy projects breaking ground 12/31/2029 from generating credits by supplying CNG vehicles after 12/31/2040.

It is difficult to see how this proposed change squares with the goal stated on page 4 of the ISOR of promoting investment in disadvantaged, low-income and rural communities. In California, those are the areas that have benefited from dairy digesters. Terminating credit generation for CNG vehicles before attractive alternatives are available is likely to halt all dairy digester projects that would otherwise break ground after 12/31/2029. For that reason, it is also likely to thwart the separate goal of supporting methane emissions reductions, also appearing on page 4 of the ISOR. In addition, using the LCFS in this manner to pick winners and losers is likely to make it more difficult for other jurisdictions to adopt LCFS-type programs, a goal that is stated on page 15 of the ISOR. We fervently believe that the capture of methane from dairies should be supported, for the overwhelmingly valid reasons stated beginning on page 29 of the ISOR and in

SB1382, not thwarted as in this proposed change.

4. Section 95486.1(g) assesses a penalty of four times the a(credit shortfall should a valid pathway holder receive a verified pathway higher than its certified pathway.

The change proposed in Section 95486.1(g) is at odds with the accurate statement in Section 95488.4 that CIs will inherently var and should not be penalized for such natural variance. It also potentially treats pathway holders worse than petroleum refiners, who have from January 1st through April 30th of each year to acquire Carryback Credits to satisfy prior year credit deficiencie under Section 95486(a)(5). As written, the corrective procedure of Section 95486(a)(5) is available to obligated parties, but it is not clear that it is available to pathway holders. On page 29 of Appendix E, Purpose and Rationale for Low Carbon Fuel Standard Amendments, the rational for the change to Section 95486.1(g) includes the statement that mechanisms exist to retroactively provide credits to fuel pathway holders when the verified operational CI is lower than the certified CI, but Section 95486(a)(5) is not mentioned. Pathway holders should either not be subject to the proposed penalty or should have a similar opportunity to acquire Carryback Credits.

The success of the LCFS is due in no small part to the enthusiast: support of California producers such as Calgren. We believe in CARB's goals and intend to continue to be among your most ardent supporters. If the comments above are adopted, we sincerely believ those shared goals will be greatly advanced.

Thanks again for all your far-sightedness.

Very truly yours,

Travis Lane, CEO

Attachment www.arb.ca.gov/lists/com-attach/6718-lcfs2024-WjldOgNuAzcEcFUw.pdf

Original File Name	Calgren CARB Comments 2-18-24.pdf
Date and Time Comment Was Submitted	2024-02-18 21:48:02

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 18, 2024

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Chair, California Air Resources Board
1001 I Street
Sacramento, CA 95814

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11704 Road 120 • P.O. Box E • Pixley, CA 93256
Office Phone 559-757-3850 • Fax 559-757-3852

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CALGREN
Renewable Fuels

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Comment 151 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name		Greg
Last Name		Rosas
Email Address		thesro15@yahoo.com
Affiliation		
Subject		Stop public funding for factory farm gas
Comment	142.1	I support an end to funding for factory farm gas.
Attachment		
Original File Name		
Date and Time Comment Was Submitted		2024-02-19 01:31:41

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Comment 156 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	William
Last Name	Brieger
Email Address	will.brieger@gmail.com
Affiliation	Climate Action California
Subject	Comments on proposed LCFS amendments (lcfs 2024)
Comment	Thank you for all of the work you are doing to move this regulati forward. Please see attached.
Attachment	www.arb.ca.gov/lists/com-attach/6744-lcfs2024-AWIFb101VWtXMAh8.pdf
Original File Name	Climate Action California LCFS comments.docx.pdf
Date and Time Comment Was Submitted	2024-02-19 08:26:06

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 19, 2024

Liane Randolph, Chair
Members of the Board
California Air Resources Board
via electronic submittal

Re: Comments on the Proposed Amendments to the Low Carbon Fuel Standard and Initial Statement of Reasons, released December 19, 2023

Dear Chair Randolph and Board Members,

We are pleased to comment on the continued refinement of the Low Carbon Fuel Standard Program (LCFS), on behalf of Climate Action California, with more than 12,000 supporters around the nation.

We support the further lowering of the carbon intensity standard (CI)—provided that the new standard can be paired with the gradual reduction of crop-based fuels, as discussed below. This approach will continue to reward innovative fuels as it supports California's ultimate goal to eliminate greenhouse gas emissions (GHG) emissions from the transportation sector.

We suggest four improvements to the program that were not included or adequately addressed in the proposal.

1. <u>Crop-based fuels</u>

   The Initial Statement of Reasons (ISOR), like the existing LCFS regulation, recognizes that widespread land use change is a potential adverse effect of making fuel from crops. Yet the proposed solution largely ignores the central point: that *somewhere* in the world, financial incentives for biofuels will stimulate conversion of forest/grassland carbon sinks into new crop land.

In section 95488.9 subd. (g), the proposal requires that a fuel producer using crop- and forest-based feedstocks certify that the feedstock was not grown on *specific* land forested at any time after 2008. That requirement completely ignores the central concept of land use change, which is that growing enough food to feed the human population is a zero-sum game. This means that growing corn for fuel in Iowa results in the destruction of forest in Brazil to grow more food. Indeed, this is exactly what is happening. The ten-fold expansion of ethanol use in the US in recent years is reflected in expanded corn production on tens of millions of acres just in this country. And that expanded demand for corn, along with other fuel crops, is mirrored by extensive deforestation and planting of crops in the tropics.[1] Under the proposal that would still be allowed. Only one type of land conversion – cutting down a forest to grow fuel crops on the exact same acres – would not be rewarded with LCFS credits.

The Global Trade Analysis Project (GTAP) model that the LCFS currently employs discounts that effect with the explicit assumption that when food crops are diverted to fuel, instead of planting additional acres, people will simply eat less.[2] This is an unproven assumption—that people will watch their family go hungry rather than planting crops or buying food. Given that large uncertainty, the safer assumption is that the world's growing population will continue to demand food. That is exactly why LCFS recognizes the principles of land use change. The proposed certification process ignores the fact that crops are commodities, grown and sold in a global marketplace.

Most important for the LCFS update, research since the LCFS and GTAP model were adopted, increasingly indicates that emissions from land use change are significantly underestimated. As summarized in a recent brief from *Nature Climate Change*:

> Under current land-use regulation, carbon dioxide emissions from biofuel production exceed those from fossil diesel combustion. Therefore, international agreements need to ensure the effective and globally comprehensive protection of natural land before modern bioenergy can effectively contribute to achieving carbon neutrality.[3]

[1] E.g., J. Albert, Human Impacts Outpace Natural Processes in the Amazon, Science (1/27/2023) Vol. 379, Issue 6630.

[2] A second explicit, but dubious, assumption is that yields per acre will increase, but somehow emissions per acre will not change.

[3] L. Merfort et al., Nature Climate Change, Volume 13 | July 2023 | 610–612, 610 https://www.nature.com/articles/s41558-023-01711-7

Furthermore, land use change models used in Europe show that many crop-based renewable fuels have a *higher carbon intensity than petroleum fuels.* Based on modeling conducted by the LCFS team as part of the 2015 rulemaking[4] as well as in more recent academic research[5], emissions associated with producing crop-based biofuels are highly uncertain and are likely, in fact, be greater than fossil fuels on a full life cycle basis.

Given the uncertainties with land use change calculations, CARB should wind down crediting for all crop-based fuels by 2030, or sooner. The precautionary principle should apply.

143.1

Unwinding of problematic aspects of the LCFS program especially important for fuels that all agree will never aid in the realization of California's long-term vision of carbon neutral transportation. Crop-based liquid fuels support internal combustion (IC), and as such can fairly be viewed as prolonging the use of carbonaceous fuels and IC technology. Regardless of the precise CI, they will never support the deep reductions called for by both statute and the 2022 Scoping Plan Update.

2. Waste palm oil

The proposed amendments appropriately forbid fuel derived from palm oil feedstocks, recognizing that palm oil production is associated with significant adverse land use changes. CARB should be wary, however, of producers' claims that certain palm oil is waste. This is an expansive, lucrative end run around the prohibition. CARB does not have the enforcement reach to effectively check claims relating to commodity trades in distant countries; claims that certain oil is a waste product are extremely difficult to verify. Given the great risk of adverse land use change, the regulation should clarify that "derived from palm oil or palm derivatives" includes waste palm oil. That allows for a

143.2 simple chemical test – in California – for the presence of palm oil.

95482 subd. (f) should be amended to read:

> **Transportation fuel derived from palm oil or palm derivatives including waste palm oil is ineligible for LCFS credit generation. Any volumes of transportation fuel derived from palm oil or palm derivatives reported through the LCFS**

[4] https://ww3.arb.ca.gov/regact/2015/lcfs2015/lcfslSappi.pdf

[5] Lark et al., Environmental outcomes of the US Renewable Fuel Standard, PNAS 2022 Vol. 119 No. 9, available online at https://www.pnas.org/doi/10.1073/pnas.2101084119 . See also, https://www.wri.org/insights/us-renewable-fuel-standards-emissions-impact

program must be assigned the ULSD carbon intensity found in Table 7-1 of the LCFS regulation.

3. “Innovative” petroleum production

We were alarmed to read that the proposal enables specified petroleum development projects to earn credits for pumping oil from the ground until 2040.

The Initial Statement of Reasons (ISOR) says that the amendments’ goals, in concert with the 2022 Scoping Plan Update, include the following:

> The objective is to send clear, long-term market signals to support investment in low-carbon fuel production and technologies that are needed to achieve deep emissions reductions in the transportation sector while supporting the broader portfolio of zero-emission vehicle regulations and climate statutes. Another goal is to align the crediting opportunities in the LCFS with the fuel and technology pathways identified in the 2022 Scoping Plan Update. (ISOR, p.9)

Petroleum production, even using novel methods, will never lead to “deep emission reductions,” nor will it support “the broader portfolio of zero-emission vehicle regulations and climate statutess.” This ill-considered sop to the petroleum industry should be ended immediately.[6] It is impossible to see how continuing to incrementally reward petroleum production investments through 2039 aligns with California’s overarching goals.

143.3

Section 95489, subd. (c) should therefore be amended to read:

> ***Credits for Producing and Transporting Crudes using Innovative Methods*. Until December 31, 2025, credits may be generated for crude oil that has been produced or transported using innovative methods and delivered to California refineries for processing. Beginning January 1, 2026, no further credits may be generated under this paragraph (c).**

4. Avoided Emissions Crediting

Whenever an enterprise’s unregulated emissions are accepted as part of the environmental baseline, the LCFS counts capturing those emissions to produce fuel as “avoided emissions.” For example, fuels made with captured methane emissions yield extremely low CI scores, creating an especially lucrative stream of LCFS credits. As a result, a constituency is formed or strengthened against ever regulating the emissions in the first place.

[6] If the intent was to somewhat appease the petroleum industry, after legal challenges to the LCFS by the industry’s trade association and a raft of lawsuits by its ethanol-producing allies, we now know conclusively that appeasement failed.

Consistent with that thinking, landfills outside of California that are too small to be covered by EPA methane capture requirements, but big enough to be included in California's landfill methane regulation, are treated as if they were in California. Out-of-state landfill gas is scored like any other fuel, based on lifecycle emissions. To reward its capture in the first place as "avoided emissions" would make it harder for that other state to ever follow California's lead in controlling landfill methane beyond the federal requirements.

The same logic applies to biogas from dairies. Livestock emissions—both enteric and manure related—could be regulated. By treating all captured methane as "avoided emissions" California is creating an ever-stronger constituency against regulating livestock, which are by far the largest anthropogenic methane source in the state. While captured biogas can be used as a fuel, and earn a CI score better than fossil fuels, it should not be credited with avoided emissions. Such calculations should be phased out by 2025.

Section 95488.9, subd. (f)(3)(A) should be amended to read as follows:

143.4 **Crediting Periods. Avoided methane crediting for dairy and swine manure pathways as described in (f)(1) above, and for landfill diversion pathways as described in (f)(2) above, is limited to three consecutive 10 years crediting periods, counting from the quarter following Executive Officer approval of the application. The pathway holder must formally request each subsequent crediting period for the project through the LRT-CBTS. <u>Beginning January 1, 2025, the Executive Officer shall not approve or renew any avoided methane crediting for dairy and swine pathways.</u>**

Conclusion

We appreciate this chance to comment on the Low Carbon Fuel Standard amendments. Thank you for all of the work you and the staff do to protect Californians from air pollution and the worst impacts of climate change.

Sincerely,

Will Brieger

Will Brieger, Director
Climate Action California

Comment Log Display

Here is the comment you selected to display.

Comment 156 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Laura
Last Name	Verduzco
Email Address	laurav@chevron.com
Affiliation	Chevron Corporation
Subject	Feedback on newly proposed LCFS calculators
Comment	Please find attached Chevron's feedback on the newly proposed LCFS calculators.
Attachment	www.arb.ca.gov/lists/com-attach/6750-lcfs2024-BjQBN1dkAGcLUlcx.pdf
Original File Name	2024 Feedback on LCFS calculators.pdf
Date and Time Comment Was Submitted	2024-02-19 08:48:47

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 19, 2024

LCFS staff
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear CARB staff:

Subject: Feedback on newly proposed LCFS calculators

Dear CARB staff:

First of all, I would like to thank you for your work in the new LCFS calculators. The new versions of the calculators will help the industry streamline the pathway applications process for low carbon energy projects. In particular, we appreciate the new hydrogen calculator, building separate calculators for biodiesel and HEFA, and increasing the number of feedstocks that can be specified in the biodiesel calculator. I would also like to thank you for incorporating some of our previous comments into the new versions of the calculators.

Second, I would like to point out a few opportunities for improvement in the calculators that we reviewed:

- Consistency of by-product credit calculation in the HEFA calculator:
  - Light hydrocarbon used as H2 feedstock gets full displacement credit for natural gas displaced.
  - Light hydrocarbon used for alternate use gets energy allocation credit. Chevron continues to believe that the displacement method is the most appropriate approach to account for renewable propane and renewable fuel gas from hydrotreating lipids. That is because the
144.1 renewable propane/fuel gas is routed to the refinery's fuel gas system where it ***displaces fossil hydrocarbons and purchased natural gas*** that is used as make-up to the refinery's fuel gas system. Further, the allocation includes ILUC which appears to be different than what CARB has done in the past (ILUC wasn't included when applying energy allocation).
  - Light hydrocarbon to renewable propane sales gets energy allocation credit, but not on the ILUC piece. Again, renewable propane to non-transportation sales would most likely be displacing fossil propane or fossil natural gas (e.g., for home heating) and therefore would be appropriate to credit with a displacement method.
- LHV versus HHV calculations in the HEFA calculator:

When calculating by-product credits in the "pathway summary" tab applying the first two methods
144.2 above, it appears that the light hydrocarbons are expressed in a HHV-basis, and they are not converted to a LHV basis prior to applying the emission factors, which are expressed in an LHV-basis. We advise you to ensure that the heating values are consistently calculated on the same basis.

Our Family of Brands
Chevron Products Company
A Division of Chevron U.S.A., Inc.
6001 Bollinger Canyon Rd, San Ramon, CA 94583
925 842 8903
dgilstrap@chevron.com

- It would be helpful to put together a document explaining the logic behind major changes in emissions factors such as the following:
144.3
    - The emissions factor for UCO increased from 95 to 123 gCO_2e/MJ.
    - The natural gas emissions factor changed from 72,230 to 75,496 $gCO_2e/MMBTU$.

- "Manure-to-Biogas (LOP Inputs)" Tab –
    - L1.(1-6).14 Retention Time and Drainage – Required Annual Lagoon/Digester Cleanout
144.4
        - After production, many facilities remove excess water but do not fully cleanout the lagoon/digester to keep the microbes active. The requirement to cleanout the system annually in September per the calculator is inconsistent with many baseline scenarios. We request that the lagoon/digester cleanout be optional, and if one occurs, it should be modeled in the month when the cleanout takes place.

Thank you very much in advance for addressing our concerns.

Best regards,

Laura Verduzco, D.Sc.

Chevron Corporation

Comment Log Display

Here is the comment you selected to display.

Comment 154 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Marti
Last Name	Thomas
Email Address	bullion-ironing0l@icloud.com
Affiliation	

Subject Stop California from Incentivizing MORE Factory Farms in the Midwest!

Comment

There are many negative consequences that come from this illogical
and counterintuitive proposal, and here are two of the big ones:
Incentivizing by commoditizing factory farm pollution and paying
145.1 factory farm corporations for the methane they produce would fuel
MORE factory farms, causing MORE methane and greenhouse gases, MOR
water and air pollution, and MORE corporate consolidation.
This proposal would create additional overproduction of pork and
dairy, pushing market prices even further down for independent
family farms. Currently, overproduction of pork and dairy and
resulting low prices have been devastating for independent family
farm livestock producers.

In this climate crisis we must do all we can to protect our land &
water resources & the air we breath. Corporate Farms have no
145.2 interest in doing this, they ravage the land & take all the water
then walk away with profits leaving these areas devastated. As
well as causing harm to family farmers & we all suffer from their
destruction!
Please stop helping them!

Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-19 08:47:19

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 155 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Susan
Last Name	Wrasmann
Email Address	swras@fidmail.com
Affiliation	
Subject	Including factory farm gas in California Low Carbon Fuel Standard

Comment

I grew up in California's central valley in the 50s and 60s but I now live in the Midwest in the heart of factory farming. In addition to the below reasons, I will add that so called "green biogas" is anything but. It is methane, a dangerous greenhouse gas that is just as harmful to the atmosphere as the fossil kind. Thes farms also harm water quality and property values by their concentrated feeding operations production of concentrated odors and runoff. Please deny this misguided attempt to export your own emissions through carbon credits. Here's what it will do:
Incentivize more corporate factory farms, harming family farmers, rural communities, and our environment.
Create more corporate consolidation in the U.S. livestock industry.
146.1
Commoditize methane production, which would fuel more methane producing practices.
Create additional overproduction of commodities, pork and milk, increasing supply and further pushing down market prices paid to independent family farms.
Pay foreign multinational meatpackers, like Chinese-owned Smithfield and Brazilian-owned JBS, for their pollution.
Create incentives for the public (taxpayer dollars through government subsidies) to fund anaerobic digesters to capture factory farm gas.

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-02-19 09:17:53

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 160 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Michael
Last Name	Caprio
Email Address	mcaprio@republicservices.com
Affiliation	Republic Services
Subject	Low Carbon Fuel Standard - 45 Day Proposed Rule
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6762-lcfs2024-BnQFZl0sVnBXM1Q4.pdf
Original File Name	Republic Services Comment Letter - 45 day LCFS Rule.pdf
Date and Time Comment Was Submitted	2024-02-19 10:30:48

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

REPUBLIC SERVICES

Sustainability in Action

February 16, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Republic Services Comment Letter Regarding Proposed Changes to California's Low Carbon Fuel Standard (LCFS)

Staff of the California Air Resource Board:

Republic Services is committed to sustainability and shares the California Air Resource Board (CARB) mission of taking action to improve the communities we serve. Through our climate leadership initiative, we are on track to meet our science-based target goals of 35% reduction in Scope 1 and 2 emissions and working toward improvements in circular economy and renewable energy goals. We are proud of our electric vehicle (EV) fleet deployment in California and the contributions of these vehicles to the LCFS program goals.

It is important that changes to the LCFS program properly align incentives with fleet and infrastructure transition timelines. Our review of the draft regulation indicates that staff has arrived at the proper balance between supporting investments in low carbon fuels that have been made over the past decade while continuing to incentivize participation and investment in ZEV fleets.

Our comments are brief and related to verification of quarterly fuel transaction reports.

Section 95500(c)1E - Verification of Quarterly Fuel Transaction Reports

Republic Services welcomes improvements that enhance the integrity of the LCFS and continuation of processes serving to validate credits that are part of the program. It is clear CARB views third party verification (3PV) of EV credit pathways as an essential addition to the program. However, our view is that the proposed rule may create an unnecessary administrative and financial burden on EV participants.

147.1 Our proposal would be for CARB to re-evaluate the 3PV requirements as they apply to EV pathways and simplify the administrative responsibilities of participants in the program. We believe that CARB can obtain the level of confirmation they are seeking while ensuring that the 3PV process does not unduly burden entities that are pro-actively pursuing the emissions reduction goals that have been set forth.

REPUBLIC SERVICES

Sustainability in Action

For example, our EV charging is reported through BP and Shell's software platforms who review our data for accuracy and consistency relative to consumption data. Verifying our data through an established review process will continue to promote the integrity of the LCFS and correspondingly reduce our administrative burden. While there are reduced requirements below the 6,000 credit level under §95500(c)(2)(B), our expenses related to a 3PV utilizing the two year deferment could still outstrip proceeds from credit revenue.

It will be important to arrive at a suitable level of oversight considering the requirements and expense related to EV infrastructure installation, the premium associated with EV vehicle purchases and record keeping associated with utility projects. A balance of flexibility in 3PV site visit requirements while maintaining integrity to the program will be critical to incentivizing early and long-term participation in the EV space. The 3PV requirements as proposed may disincentivize participation in the program for early adopters and impact rates to customers which in turn would hinder the goals of reducing GHG emissions through the LCFS.

A potential means of achieving these goals is the implementation of a desktop remote audit every 2-3 years with site visits being subsequently required if discrepancies beyond a defined threshold
147.1 cont are identified. Our organization is willing to explore the concept of two-way data access (ie. API – Application Programming Interface). This construct and platform is in use with utility incentive programs we are currently involved in and has proven to be a very suitable replacement for time consuming and costly field verifications.

Considering the number of charging centers that will require 3PV in the near term and certainly the extended term, it seems inefficient to have this verification process be in person versus other more streamlined methods that are currently in use. As a point of reference, at full buildout Republic alone will have an estimated 35-40 charging centers that under the current draft language would cost $10,000 each per quarter to comply. Our company would rather place those funds towards infrastructure and EV purchases versus in person 3PV that could be accomplished in a more efficient manner.

We appreciate your consideration of our requested changes and look forward to continued dialogue on the LCFS final rulemaking. We commend CARB leadership and staff on the overall draft regulation that has been put forth and appreciate the opportunity to participate.

Very Best Regards,

Mike Caprio

Mike Caprio
Director of Government Affairs – CA

Comment Log Display

Here is the comment you selected to display.

Comment 161 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jasmin
Last Name	Ansar
Email Address	jasmin@theclimatecenter.org
Affiliation	The Climate Center
Subject	Comments on Proposed LCFS Amendments 2024 - TCC
Comment	Here are the comments on the Proposed LCFS Amendments 2024 from th Climate Center.
Attachment	www.arb.ca.gov/lists/com-attach/6770-lcfs2024-B2FcM1I9UWMDaVIN.pdf
Original File Name	Final TCC letter LCFS 2024 (1).pdf
Date and Time Comment Was Submitted	2024-02-19 10:57:03

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024
Cheryl Laskowski
Low Carbon Fuels Standard Program
California Air Resources Board
1001 I Street Sacramento,
California 95814

Re: Comments on Proposed Low Carbon Fuel Standard Amendments 2024

Dear Dr. Laskowski,

Thank you for the opportunity to offer our input regarding 2024 Proposed Low Carbon Fuel Standard (LCFS) Amendments. We appreciate the workshops and meetings and all the staff work that has culminated in these proposed amendments.

We urge you to change critical aspects of the Proposed LCFS Amended program that undermine California's climate goals and that directly harm historically disadvantaged, low income and frontline communities.

We urge CARB to:

1. **End the flawed policy of giving credits for "avoided methane emissions" in 2024 and limit the LCFS carbon intensity scores to no less than zero.**
2. **Cap lipid-based biofuels since they lead to tropical deforestation and result in food insecurity as they compete with land for food production.**
3. **End the crediting of Carbon Capture and Storage projects that use captured carbon for enhanced oil recovery as this conflicts with statewide prohibitions in SB 1314 (Limón 2022) and SB 905 (Caballero 2022).**

148.1 1. **End the flawed policy of giving credits for "avoided methane emissions" in 2024 and limit the LCFS carbon intensity scores to no less than zero.**

Under the current LCFS regulations, producers of livestock biomethane are given a large negative carbon intensity score, since it is assumed that anaerobic digesters capture all the emitted methane. However, a recent study[1] by Food and Water Watch, as outlined in their report 'The Proof is in the Pluming' (January 2024), reveals substantial methane leaks originating from these anaerobic digesters. The plumes of leaked methane are so large that, by Carbon Mapper's definition, the digesters qualify as super-emitters. This is deeply troubling, underscoring the direct contradiction between the current flawed LCFS carbon intensity assignments and California's Clean Energy and Air Quality objectives.

This policy distortion results in an inequitable and socially inefficient distribution of credits favoring compressed natural gas (CNG) trucks over zero-emission vehicles (ZEV), granting more credits to methane-based, polluting hydrogen than to zero-emission green hydrogen, and allocating LCFS credits to large Concentrated Animal Feeding Operations (CAFOs) over smaller more sustainable farms.

Since the economic value of LCFS credits increases with a more negative carbon
intensity measure, it is imperative for California to reevaluate its practice of awarding
148.1 cont credits for "avoided methane emissions." The existing flawed accounting method, which
assigns a carbon intensity range of -102.79 to -790 for factory farm gas, makes no
sense compared to the carbon intensity of zero for an electric car powered by solar
panels. This calls for a thorough reconsideration of the current approach. To ensure the
148.2 alignment of incentives with environmental priorities, CARB must discontinue its
practice of crediting dairy biogas in the LCFS.

The current CARB proposal is to continue with negative crediting of dairy biogas used directly in the LCFS until 2040[2] and until 2045 if used for hydrogen fuel cells.

This provision must be changed and the crediting for avoided methane emissions discontinued this year.

2. **Cap lipid-based (vegetable oil) biofuels since they lead to tropical
148.3 deforestation and global food insecurity, resulting from competition for
land with food production**

[1] https://storymaps.arcgis.com/stories/4b708bdc0d2d419ba34cb352ca79b6e3

[2] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf

A recent insightful blog post[3] by Dr. Jeremy Martin from the Union of Concerned Scientists, emphasizes the critical need for a cap on lipid-based biofuels to stabilize and strengthen California's Low Carbon Fuel Standard.

Currently the LCFS market is in crisis with low credit prices due in part to a surplus of credits resulting from the excessive use of these biofuels. The interaction between the LCFS and the Federal Renewable Fuel Standard (RFS) intensifies the influx of biofuels into California contributing to the surplus of credits. In addition, increases in the consumption of biofuels, such as soy oil, intensifies the competition for land resources used for food production, thereby worsening global food insecurity and raising food prices. Unchecked growth in the biofuel market poses a significant risk of increasing global deforestation, especially as there are limits on waste oil collection and reuse, necessitating expanded production of soy oil and other oil substitutes like palm oil.

148.3 cont Dr. Martin argues that increasing the stringency of the LCFS, as proposed by CARB, is unlikely to alleviate these adverse effects and may, in fact, lead to more detrimental outcomes. He highlights the urgency of transitioning away from vegetable oils to more scalable feedstocks. We strongly agree and support the implementation of a cap[4] on the use of vegetable oils to provide better incentives to move the LCFS toward feedstocks that do not have such harmful impacts on tropical forests and food production.

148.4

3. **End the crediting of Carbon Capture and Storage projects that use captured carbon for enhanced oil recovery, as this conflicts with statewide prohibitions in SB 1314 (Limón 2022) and SB 905 (Caballero 2022).**

As explicitly stated clearly in SB 1314[5] (Limón 2022):

> **SECTION 1.** The Legislature finds and declares that the purpose of carbon capture technologies and carbon capture and sequestration is to facilitate the transition to a carbon-neutral society and not to facilitate continued dependence on fossil fuel production.

This legislation unequivocally recognizes the incompatibility of enhanced oil recovery (EOR) with California's carbon neutrality policies. SB 905 (Caballero 2022), addressing carbon sequestration, also prohibits the use of carbon capture and storage for EOR.

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[3] https://blog.ucsusa.org/jeremy-martin/a-cap-on-vegetable-oil-based-fuels-will-stabilize-and-strengthen-californias-low-carbon-fuel-standard/

[4] https://theicct.org/wp-content/uploads/2022/08/lipids-cap-ca-lcfs-aug22.pdf

[5] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220SB1314

148.4 cont EOR poses harm[6] to nearby communities, causing toxic air pollution, impairing groundwater, and presenting a risk of blowouts. In line with these legislative prohibitions, CARB should exclude EOR projects both inside or outside California from receiving LCFS credits.

To fulfill CARB's commitment to integrating environmental justice[7] into its rulemaking, policy development, and implementation activities, including the LCFS, it is critical to disallow EOR from receiving LCFS credits. This action will provide essential safeguards for historically disadvantaged, low income, and frontline communities.

Finally, we wish to point out that Professor Michael Wara[8] and colleagues from Stanford University presented modeling results in the May 31st CARB LCFS Virtual Community meeting that clearly showed CARB can improve the integrity of the LCFS by eliminating credits for avoided methane by 2024 and putting a cap on crop-based biofuels. These are the prescribed changes 1 and 2 that are recommended in this letter. Furthermore, the modeling results show that these changes to the program will not adversely affect the LCFS credit price. Indeed, the concluding bullet from the Stanford presentation reads:

> *"Stanford modeling suggests EJ scenario could achieve ARB goals while lowering impacts to EJ communities and potentially improving climate outcome"*

It is perplexing to note that this important result and presentation did not get consideration in any of CARB's LCFS proposals. We urge CARB to incorporate these important findings and act on them to improve the climate and community impact outcomes for California.

Thank you for the opportunity to provide feedback and comments on the 2024 LCFS proposals.

Respectively Submitted,

Ellie Cohen
Chief Executive Officer
The Climate Center

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6 https://www.cleanwateraction.org/sites/default/files/docs/publications/EOR%20Risk%20and%20Oversight%20Factsheet_0.pdfhttps://www.cleanwateraction.org/sites/default/files/docs/publications/EOR%20Risk%20and%20Oversight%20Factsheet_0.pdf

7 https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf

8 https://ww2.arb.ca.gov/sites/default/files/2023-05/Stanford%20Presentation.pdf

Comment Log Display

Here is the comment you selected to display.

Comment 162 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	John
Last Name	Duff
Email Address	john@sorghumgrowers.com
Affiliation	National Sorghum Producers
Subject	Sorghum comments regarding the proposed amendments
Comment	Thank you for the opportunity to comment on this important matter We greatly appreciate ARB's continued willingness to lead change i this area and are especially grateful for continued improvement of the CA-GREET model. We would also like to provide additional data for this effort. The data we are providing are attached. We also continue to be in close contact with the Argonne National Laboratory, providing this information to them when appropriate, a well. Thank you again for the opportunity to comment, and please d not hesitate to let me know if you have additional questions.
Attachment	www.arb.ca.gov/lists/com-attach/6777-lcfs2024-ViUBclY6UmxXMFcl.pdf
Original File Name	Summary of Sorghum Inputs for CARB.pdf

149.1

Date and Time Comment Was Submitted	2024-02-19 12:03:20

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

SORGHUM CROP INPUTS AND GREENHOUSE GAS MODELING ASSUMPTIONS
Prepared by National Sorghum Producers
February 16, 2024

Background

Over the past 15 years, a large amount of sorghum crop input data have been collected. The sources for these data are highly varied and include statistically significant surveys of sorghum farmers, biodiversity programs with wildlife NGOs, lifecycle analyses conducted at land grant universities as well as extension hybrid trials. This document summarizes this information and provides it in reference form for future citations as all this information is publicly available. Figure 1 includes an overview of the data sources and Figure 2 includes a data summary.

Figure 1. Data Sources.

Data Source	Abbreviation	Years Covered	Relevance
SGS North America[1]	SGS	2008-2011	Statistically significant third-party survey of sorghum farmers
Strategic Marketing Research & Planning (first survey)[2]	SMRP1	2017-2019	Statistically significant third-party survey of sorghum farmers
Strategic Marketing Research & Planning (second survey)[3]	SMRP2	2019-2021	Statistically significant third-party survey of sorghum farmers
Strategic Marketing Research & Planning (third survey)[4]	SMRP3	2021-2023	Statistically significant third-party survey of sorghum farmers
Sustainable Environmental Consultants[5]	SEC	2020-2022	Data for biodiversity program with key wildlife NGO
Kansas State University[6]	KSU	2011	Third-party lifecycle analysis
Land Grant University Extension Hybrid Trials[7]	Trials	2008-2022	Fifteen years of scientific trials at seven universities across 31 locations and 5,181 observations

[1] https://www.sorghumcheckoff.com/wp-content/uploads/2022/08/The-Carbon-Footprint-of-Sorghum-1.pdf
[2] https://www.sorghumcheckoff.com/wp-content/uploads/2022/08/2020-Carbon-Footprint-Study-1.pdf
[3] https://www.sorghumcheckoff.com/wp-content/uploads/2022/08/2022-Carbon-Footprint-Study-1.pdf
[4] https://www.sorghumcheckoff.com/wp-content/uploads/2024/01/SMRP3.pdf
[5] https://www.sorghumcheckoff.com/wp-content/uploads/2022/10/EP-ALL-Supply-Chain-Report_2020_V3.pdf
https://www.sorghumcheckoff.com/wp-content/uploads/2023/09/EP-Sorghum-Checkoff-Executive- Summary_2021-V2.pdf
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[6] https://www.sorghumcheckoff.com/wp-content/uploads/2023/10/nelson_diesel_work_ksu.pdf
[7] https://csucrops.com/sorghum/
https://krex.k-state.edu/handle/2097/16531
https://cropwatch.unl.edu/varietytest/sorghum
https://clovissc.nmsu.edu/research/trails.html
https://extension.okstate.edu/search-results.html?q=Grain+Sorghum+Performance+Trials
https://extension.sdstate.edu/sorghum-trial-results
https://ccag.tamu.edu/extension/soil-crop-sciences/grain-sorghum-hybrid-trial-results/

Figure 2. Data Summary.

Assumption	Unit	SGS	SMRP1	SMRP2	SMRP3	SEC	KSU*	Trials**	Average
Diesel	btu/bu	6,943.52	4,402.79	3,520.59	5,159.58	5,500.35	4,287.30	-	4,969.02
Gasoline	btu/bu	497.36	-	-	-	-	-	-	497.36
Natural Gas	btu/bu	0.00	-	-	-	-	-	-	0.00
Electricity	btu/bu	39.11	-	-	-	-	-	-	39.11
Nitrogen	g/bu	411.93	405.62	416.56	413.82	392.04	423.35	394.13	408.21
Phosphorus	g/bu	99.24	119.37	115.05	208.33	-	175.07	83.67	133.45
Potassium	g/bu	20.24	18.09	10.12	-	-	0.00	0.36	9.76
Herbicide	g/bu	27.23	-	-	-	-	7.77	-	17.50

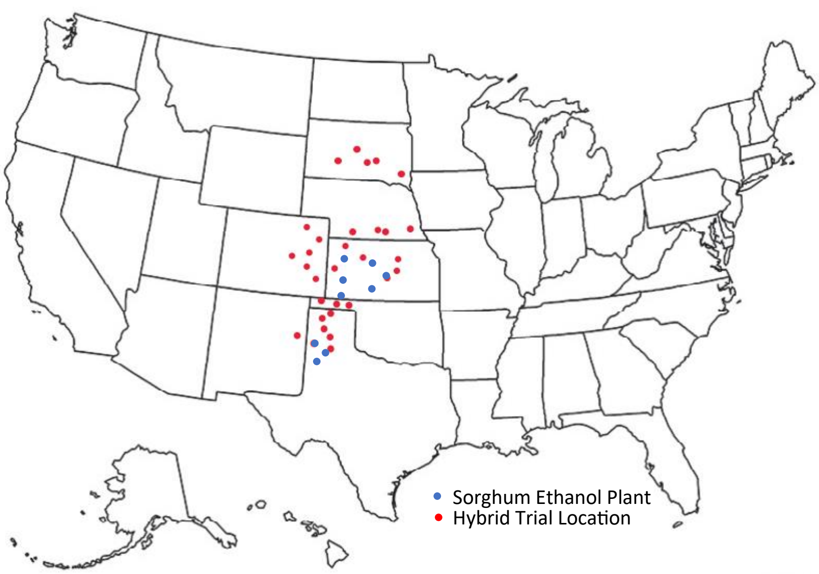
*Given this study was an LCA, it was assumed that it covered the equivalent of one acre.

**Given these were land grant university hybrid trials, it was assumed that each observation covered the equivalent of one acre.

Base Assumptions

The total area covered by the seven data sources was 173,384.28 acres. Note, however, that KSU and Trials were much lower. KSU was a lifecycle analysis, so it was assumed that it covered the equivalent of one acre. Similarly, Trials included 15 years of scientific hybrid trials at seven universities across 31 locations and 5,181 observations, so it was assumed that each observation covered the equivalent of one acre. With both KSU and Trials, this is a reasonable assumption as these values will scale. Figure 3 includes a map of the 31 locations represented in Trials overlaid with sorghum ethanol plants for reference. Each of the six other data sources were also based on production within the confines of this region, which includes more than 85 percent of U.S. sorghum area and produces 100 percent of U.S. sorghum ethanol.

Figure 3. Trials and Sorghum Ethanol Plant Locations.



Energy Inputs

Average diesel usage in British thermal units per bushel across the seven data sources was 4,969.02. In SGS, SMRP1, SMRP2, SMRP3 and SEC, diesel usage was calculated using fuel consumption data from Virginia Cooperative Extension[8] per this equation:

$$D = [\sum (N_{share} * N_{diesel} + R_{share} * R_{diesel} + C_{share} * C_{diesel} + R + P + S + H)] / n$$

Where D is average diesel usage in British thermal units per bushel, N_{share} is the percentage of acres in no-till systems, N_{diesel} is the amount of diesel used in no-till systems, R_{share} is the percentage of acre in reduced till systems, R_{diesel} is the amount of diesel used in reduced till systems, C_{share} is the percentage of acres in conventional till systems, C_{diesel} is the amount of diesel used conventional till systems, R is the amount of residual diesel used, P is the amount of diesel used for planting, S is the amount of diesel used for spraying and H is the amount of diesel used for harvesting. Diesel usage was given in KSU, and residual diesel, gasoline, natural gas and electricity usage were given in SGS. For each fuel type, energy usage associated with field activities, trucking and storage are included in the combined value.

Fertilizer Inputs

Average nitrogen, phosphorus and potassium applications in grams per bushel were 408.21, 133.45 and 9.76, respectively. If applicable, these values were given in all seven data sources.

Herbicide Inputs

Average herbicide usage across the seven data sources was 17.50 grams of active ingredient per bushel. Pesticide usage was given in SGS in gallons per acre. To convert to grams of active ingredient, a weighted average active ingredient factor was calculated based on the pesticide program assumed by the GREET model. This program includes atrazine,[9] metalochlor,[10] acetochlor[11] and cyanazine.[12] This is a realistic program and results in a calculated pesticide usage value for SGS near that of GREET. Pesticide usage in active ingredient volume was given in KSU.

Nitrous Oxide Emissions

Given the U.S. sorghum ethanol industry is located entirely in a dry climate as defined by the 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories,[13] we have undertaken a significant amount due diligence to confirm the assertion that dry climates will see lower nitrous oxide (N_2O) emissions. According to the 2019 refinement, “dry climates occur in temperate and boreal zones where the ratio of annual precipitation:potential evapotranspiration < 1.” Figure 4 includes a map of the relationship between precipitation and potential evapotranspiration overlaid with sorghum ethanol plants for reference. According to USGS,[14] geographies to the left of the blue line lost more moisture to evapotranspiration than they received from precipitation on average from 1971 through 2000.

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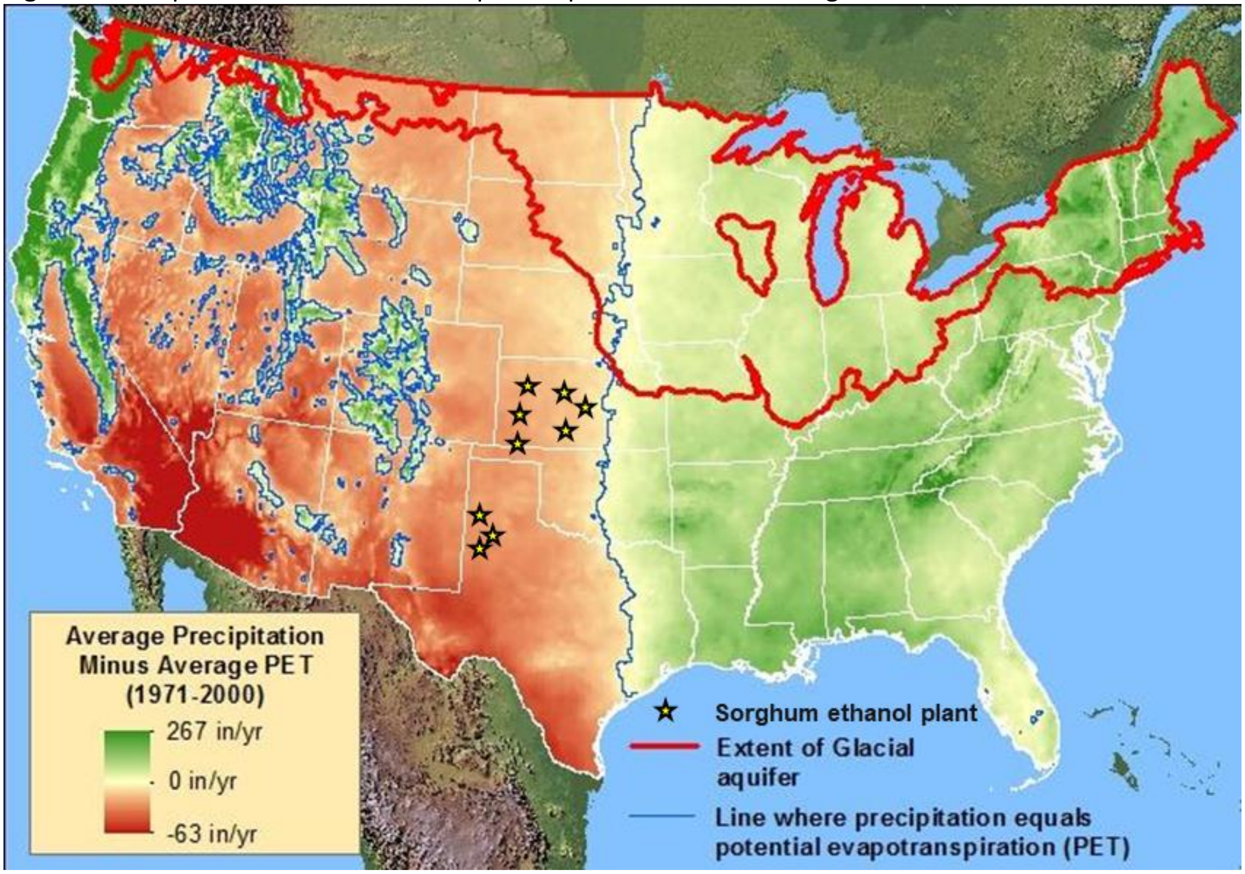
8 https://vtechworks.lib.vt.edu/bitstream/handle/10919/47472/442-073_pdf.pdf
9 https://www.syngenta-us.com/current-label/aatrex_4l
10 https://www.syngenta-us.com/current-label/dual_magnum
11 https://cs-assets.bayer.com/is/content/bayer/Warrant_Herbicide_Bayer1p_Labelpdf
12 https://www3.epa.gov/pesticides/chem_search/ppls/000352-00470-19990115.pdf
13 https://www.ipcc-nggip.iges.or.jp/public/2019rf/pdf/4_Volume4/19R_V4_Ch11_Soils_N2O_CO2.pdf
14 https://www.usgs.gov/media/images/map-gridded-values-1971-2000-avg-precipitation-minus-avg-pet

Figure 4. Precipitation and Potential Evapotranspiration as well as Sorghum Ethanol Plant Locations.



The 2019 refinement goes on to reference a map of dry climates: "cf. Figure 3A.5.1 in Chapter 3 of Vol. 4 provides a map subdividing wet and dry climates based on these criteria." This map[15] can be found in Figure 5. Note that much of western North America is now considered a dry climate by IPCC. Available scientific literature confirms the assertion that dry climates will see lower N_2O emissions. According to the 2019 refinement, the N_2O emissions factor should be 0.0050 in dry climates. In the 2006 guidelines[16] the default factor was double, or 0.0100 for all climates. For the wheat-based rotations common to the U.S. Sorghum Belt, Dusenbury, Engel, Miller, Lemke and Wallander (2008) suggested a 0.0023 emissions factor compared to the IPCC default mean of 0.0125.[17] Gehl, Haag, Warren, Sharma and Tomlinson (2020) reached a similar conclusion in a long-term study of sorghum fields in western Kansas, where the emissions factor was found to be 0.0026.[18] Based on the 2019 refinement and the support provided by these studies, we recommend emissions factors of 0.0050, matching the refinement.

Conclusion

The sources for the data presented in this document are highly varied and include statistically significant surveys of sorghum farmers, biodiversity programs with wildlife NGOs, lifecycle analyses conducted at land grant universities as well as extension hybrid trials. They are all publicly available, third-party

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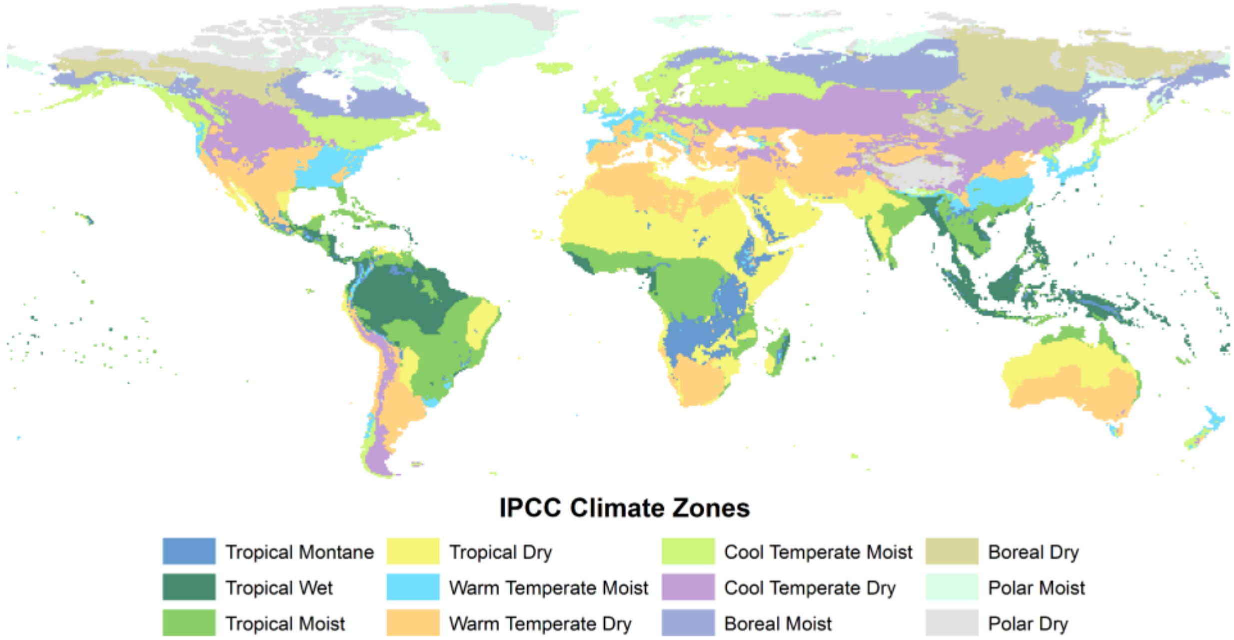
[15] https://www.ipcc-nggip.iges.or.jp/public/2019rf/pdf/4_Volume4/19R_V4_Ch03_Land%20Representation.pdf
[16] https://www.ipcc-nggip.iges.or.jp/public/2006gl/pdf/4_Volume4/V4_11_Ch11_N2O&CO2.pdf
[17] https://pubmed.ncbi.nlm.nih.gov/18389938/
[18] https://newprairiepress.org/kaesrr/vol6/iss5/10/

Figure 5. Map of Major Climate Zones According to the 2019 IPCC Refinement.



sources covering a broad geography and 15 growing seasons. We will provide additional guidance on how calculations and assumptions in this document were made upon request.

Comment Log Display

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Comment 163 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ryan
Last Name	Huggins
Email Address	legal@pinespire.com
Affiliation	PineSpire
Subject	Improvements for proposed amendments to Forklifts in LCFS
Comment	please see attached comments.
Attachment	www.arb.ca.gov/lists/com-attach/6778-lcfs2024-BnZWOQNsAjRQJQZ2.pdf
Original File Name	PineSpire_LCFS Rulemaking comments Feb 2024.pdf
Date and Time Comment Was Submitted	2024-02-19 12:17:32

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

PINESPIRE™

February 19, 2024

California Air Resources Board
Low Carbon Fuel Standard Program
Docket: lcfs-wkshp-feb23-ws

Re: Comments on Proposed Amendments to LCFS Regulation

PineSpire appreciates the opportunity to provide the following perspective on the proposed amendments to the LCFS Program in the Proposed Regulation Order as well as the Purpose and Rationale for LCFS Amendments and other associated documents.

Summary of Issues

We have provided specific examples and issues to consider in the implementation of proposed changes below, and summarized the main issues for your consideration:

- The proposed changes to CI targets, proposed AAM, and updates to pathway evaluations are steps in the right direction, but do not go far enough to create a sustainable, viable marketplace.
- The proposed reduction of the EER in forklifts is not reflective of the forklift fleet in California or the remaining gap of electric conversion. This change would make participation of forklifts financially infeasible in light of additional proposed amendments.
- We support the move to metering of forklifts; however, we urge CARB to consider the many complications of developing and deploying devices that can accomplish this and to allow a gradual timeline to transition from estimation method to metering.
- The proposal to shift credit generation from forklift owner to operator would not resolve the issues that currently create complex registrations. Further work is needed to find a solution that supports accuracy as well as aligning the incentives with the entity making the investment in the hardware.

Strengthen Carbon Intensity (CI) Targets and Auto-Acceleration Mechanism (AAM)

150.1 PineSpire appreciates CARB's recognition of the importance of strengthening CI standards to provide long-term stability and viability to the LCFS program. However, as currently proposed and as evidenced in the market value trends, the proposed updates to CI targets and the AAM are not strong enough to achieve those goals and maintain a viable marketplace. PineSpire strongly suggests accelerating the proposed
150.2 targets and speed at which the AAM functions.

Oppose the EER reduction for Forklifts as Untenable

150.3 The proposed reduction in EER, paired with metering requirements, will make it untenable for nearly all forklifts to participate. Unlike other EV chargers that have built in 'smart' capabilities and other financial incentives (i.e. fees for charging) to measure energy usage, the incremental cost to install metering devices, connect to the cloud, and extract energy usage data from forklift chargers, would very likely exceed the value of the credits if the EER is reduced as proposed.

PineSpire recommends CARB remove Class III lift truck eligibility to address the issues in the analysis instead of cutting the EER for all lift trucks. This would be a more accurate and precise adjustment than the proposed 50% reduction, which is unclear how it was calculated. Furthermore, it would be more aligned with the previous analysis and methodology used to develop the forklift EER.

PineSpire has concerns about the EER analysis and provides the following perspectives that may not have been included:

150.4

- California Specific Industries: The ITA data is a nationwide value that does not reflect the unique and very significant agriculture industry in California, which traditionally relies on propane due to varied indoor-outdoor working environments and seasonal demands for non-stop operations. It is not clear that this dataset is reflective of the sales and industries in California.

150.5

- Class V Lift Truck Replacement: Class V lift truck replacement is still relatively low because electric lift truck options that can effectively replace Class V trucks are a relatively recent technological advancement. The Class V truck is critical to several industries, particularly agriculture and food processing (as mentioned above). The proposed amendments focus on lift truck capacity as a metric for prevalence of internal combustion lift trucks, which overlooks the wide-spread use of internal combustion Class V trucks that typically have a capacity of 5,000lbs-6,000lbs. The current methodology and data provided do not account for the importance of conversion in this sector.
- Electric lift trucks are still being heavily innovated and evolving quickly, which keeps the cost of adoption higher (compared to the drop in prices in electric cars, for example). For example, many higher capacity electric forklifts were originally a conversion of an internal combustion machine, which came with the performance issues of a retrofit. Companies have now invested in developing electric options from the ground up, making them more efficient and effective at replacing the internal combustion option. However, this research and development, as well as innovations in battery chemistry, has kept the upfront cost of electric lift trucks significantly higher than their internal combustion alternatives.

Effectively eliminating the ability of these lift trucks to participate through the reduced EER, paired with metering requirement, erodes the financial return on investment needed to encourage low carbon equipment choices. Further, it discourages participation in the LCFS program by a wide range of critical California businesses.

Metering Implementation

150.6

PineSpire understands CARB's goal to move forklifts towards increased accuracy and into alignment with other EVs by requiring metering of the energy usage. However, we urge CARB to be aware of the significant time and resources required to make this shift, and to provide adequate lead time for the transition. An abrupt transition would likely disenfranchise the vast majority of forklift owners from the opportunity to participate for several quarters; PineSpire recommends CARB to continue to allow participation of e-forklifts through the estimation method during a reasonable transition timeline.

To support this request, we have summarized some of the forklift-specific limitations on data collection that set this vehicle class apart from other types of equipment in the LCFS program:

Current limitations:

- Nascent technologies: The data collection industry for forklifts is in its early stages, unlike the more established on-road EV charger technology. Current telematics solutions remain under development to be able to reliably deliver the level of data and detail that would be required for LCFS reporting. Additional time is needed to deploy and scale financially viable solutions across the California forklift fleet.
- Unique Aspects of Forklift Metering: Typical metering solutions seen in other vehicle classes are unlikely to apply to most forklift operations for several reasons.
    - Unlike other vehicle classes, the cost of implementing energy measurement must show a reasonable return on investment solely from LCFS credits, as there are no fees for charging in this vehicle class.
    - Existing telematics solutions are prohibitively expensive, with upfront costs in the many hundreds of dollars per unit and ongoing monthly subscription fees. Additionally, some require costly technician site visits for manual data downloads. High upfront costs, ongoing fees, and limited functionality currently make the financial justification for adopting the telematics technology challenging.

150.6 cont

    - Installing metering on the AC side is prohibitively expensive as it requires electricians, downtime to operations, and more costly hardware. As mentioned, forklift chargers are frequently distributed throughout facilities, not on a single AC circuit. And the AC circuits have the potential to serve other non-charging usage, thus requiring submetering.

Implementation challenges:

These implementation challenges are based on our experience deploying meters across forklift chargers at a range of facilities in Oregon.

- Hardware: Current monitoring options may require essential hardware modifications to accommodate the diverse range of forklift chargers, unlike the more standardized EV charger hardware. For example, there is a wide range of voltage and frequencies at which forklift chargers operate, both of which have the potential to 'fry' electric components of meters. Ensuring safety and functionality of new hardware, as proven in a range of test environments, is key before requiring widespread deployment.
- Connectivity: Reliable data connectivity requires site-specific troubleshooting and ongoing refinement. Additionally, successful implementation requires working with individual facilities to ensure all use of connectivity technology is secure. The one-off nature of this issue requires more time to implement than a universally designed charging network.
- Software complexity: Frequent software updates are needed to comply with varying state reporting and registration requirements, while maintaining historical data accuracy. This translates to significant lead times and resource allocation for the engineering and manufacturing updates of measurement devices.
- Evaluation burden: Developing hardware quotes, connectivity plans, and completing ROI analyses require time and resources for each individual site and its equipment team. This would be further complicated by the changes the proposed Amendments may have on LCFS values and the associated

150.6 cont financial analysis. Allowing entities time to put together this information, after other proposed amendments have been addressed and their market impact demonstrated, is appropriate.

Additional Considerations:

- Consistency with other CARB regulations: Fleet owners and operators are simultaneously responsible for complying with other CARB regulations, such as the proposed Zero Emission Forklift rule. CARB's zero-emission rules typically rely on a phased-in approach for adoption and implementation, as an acknowledgment of the cost and resources required for compliance. This phase-in approach also ensures a smoother transition for all parties by providing a more gradual 'ramp up' of metering. Using a phased-in approach with metering in the LCFS would be consistent and appropriate.
- Agriculture and Processing Industry Issues: Agricultural, food processing, wine, and beverage industries have several operational constraints relevant to developing hardware, connectivity solutions, and deploying meters. For example, many post-harvest and food processing facilities operate equipment within environments with a high level of dust that may require specific hardware enclosure designs. Similarly, cold storage facilities may challenge typical hardware specifications and require time to adapt specifications. Additionally, during harvest/post-harvest seasons (which can last one to two quarters), many facilities operate around the clock and do not have staff resources nor fleet down-time that would be required to deploy meters. Many of these facilities are large and forklift charging equipment is dispersed at many locations; it is common for facilities not to have reliable Wi-Fi reach throughout these dispersed locations, meaning that additional time and cost is required to deploy routers solely for use by energy measurement devices.

PineSpire represents dozens of agricultural and food processing businesses across California, responsible for thousands of acres of farmland, and millions to billions of dollars of food production. If CARB has specific questions for these types of facilities, we are happy to put you in touch with facility managers to discuss further.

Forklift Credit Generator: Owner <> Operator

PineSpire represents many forklift rental companies, with thousands of locations and several thousand forklifts across their fleets. We understand CARB's concerns with the complications of registering rental
150.7 forklifts for each location where they are used, however we have serious concerns about the disenfranchisement of credit generators under the proposed changes. If CARB has additional questions on this issue you'd like to gather information on, we are happy to facilitate conversation(s) with rental fleet owners.

Concerns with proposed changes, including Operator providing energy usage data:

- Investing in electrification: Rental fleet owners are continually investing in maintaining and updating their electric rental fleet, including upgrading to expensive lithium batteries, updating charger hardware, and purchasing newer forklifts. These investments by rental fleet owners increase the likelihood of fleet managers to use electric equipment as rentals, often serving as a stepping-stone for purchasing electric. Changing the credit generator to the operator would also contradict the draft Zero Emission Fleet (ZEF) regulations, which place extensive requirements on rental fleet owners.

- 150.7 cont Long-term commitment vs. short-term rentals: Participating in the LCFS program requires sustained resource investment (understanding the program, compiling registration information, regular reporting updates, etc.). Rental forklifts are frequently a short-term business solution for operators. The long-term investment in the purchase, maintenance, repairs of a rental forklift is made by the rental fleet owner, therefore the long-term benefits that come from the LCFS program should also accrue to the owner.
- Data Management: In the current framework, the "credits generator" is the facility owner (i.e., the rental operator) who may not have permission to add metering to chargers or forklifts, even in the rare long-term rental case where it makes financial sense. This mismatch creates issues with the ability to implement metering, access data, and reporting for most rental forklifts as proposed under the amendment.
- Does not achieve CARB's stated goal of eliminating registration burdens: The reality of forklift ownership and operation is that a significant portion of all facilities operate both owned and rented equipment simultaneously. For example, the majority of rental lift trucks come with a rental charger that would not be picked up by the fleet operator's metering. We recommend reconsidering options for modifying registration requirements that better align with the realities of mixed-fleet ownership, and metering implementation. We do appreciate there are a range of scenarios of ownership and operation, however we caution against moving ahead with updates that would not reduce the registration burdens.

Updates to eTRU registration

150.8 PineSpire strongly supports the proposed updates to eTRU credit generation to align with the realities of eTRU operations and ownership. TRUs are more similar to on-road EVs, moving continually from site to site and frequently not having a direct contractual relationship with their charging location, therefore the proposed changes are the most practical solution to enable wider participation in this sector.

Multi-Family Residential

150.9 PineSpire supports the proposed updates to the classification of multi-family residential charging as commercial in order to align with how these chargers are often financed and deployed, and making these LCFS incentives more widely accessible.

Thank you for your consideration of our comments.
Sincerely

Ryan Huggins
Partner
PINESPIRE

Comment Log Display

Here is the comment you selected to display.

Comment 164 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Paul
Last Name	Rozenberg
Email Address	prozenberg@suburbanpropane.com
Affiliation	Suburban Propane
Subject	Comments on the Proposed LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6779-lcfs2024-UCNWJQdkUXdRJVAy.pdf
Original File Name	Suburban Propane - Comments on Proposed LCFS Amendments.pdf
Date and Time Comment Was Submitted	2024-02-19 12:25:18

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

240 Route 10 West
P.O. Box 206
Whippany, NJ 07981-0206

www.suburbanpropane.com

Paul M. Rozenberg
Senior Manager
Government Affairs & Corporate Communications

prozenberg@suburbanpropane.com
(p) 973.503.9915
(c) 862.217.9643

February 19, 2024

VIA ELECTRONIC SUBMISSION
Chair Liane Randolph
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Comments on the Proposed Low Carbon Fuel Standard Amendments

Dear Chair Randolph:

Suburban Propane writes with regard to the Proposed Amendments to the Low Carbon Fuel Standard (the "Proposed Amendments"). Suburban Propane has served customers for more than 95 years and is the nation's third-largest propane retailer with operations in 42 states. In California, we currently have 266 employees at 71 locations, serving more than 55,000 customers.

Suburban Propane supports the Low Carbon Fuel Standard (LCFS) program and believes its technology-neutral, market-driven approach makes it one of the most effective policies in the country in reducing carbon emissions in the transportation sector. Given that the carbon intensity of California's transportation fuel pool decreased faster than CARB initially forecast and the state of the credit market, we understand the need to tighten carbon intensity (CI) benchmarks and reform the LCFS.

However, there are two specific provisions in the Proposed Amendments that we urge the Board to change: increase the flexibility of the Automatic Acceleration Mechanism by accelerating the CI benchmark reduction proportional to how much the credit bank exceeds the proposed trigger threshold up to one full year; and remove the biomethane credit phaseouts.

Automatic Acceleration Mechanism

As currently drafted, the Proposed Amendments create an Automatic Acceleration Mechanism (AAM) that tightens the annual CI benchmarks if two conditions are met: "(1) when the pool of outstanding credits (the credit bank) exceeds three quarters of average annual deficits generation, and (2) when the number of credits generated each year exceeds the number of deficits generated each year."[1] If those conditions are met, the AAM "would advance the entire benchmark schedule by one compliance period, increasing the stringency of the regulation for all subsequent years relative to what it otherwise would have been."[2]

151.1 Requiring acceleration of the benchmark reduction schedule by an entire year gives CARB too little room to maneuver. If the credit bank just barely reaches the threshold required to trigger the AAM, the benchmark reduction schedule leaps forward by an entire year, instead of considering a minor adjustment to maintain the credit market's stability. This could lead to CARB overtightening the benchmark reduction schedule, leading to a saturation of deficits and more market volatility.

Instead, we recommend the AAM create more flexibility by allowing CARB to proportionally accelerate the benchmark reduction schedule based on how much the credit bank exceeds the trigger threshold, up to the CI benchmark for the following year. This would help maintain the stability of the credit market and thwart any potential overcorrection, which contributes greatly towards supporting long-term investment in transportation decarbonization.

Biomethane Crediting

With a CI score as low as -532.74, biomethane, also known as renewable natural gas (RNG), is one of the most powerful tools in decarbonizing the transportation sector. The Initial Statement of Reasons for the Proposed Amendments acknowledges that "[b]iomethane has played a role in contributing to the overall decrease in carbon intensity of the transportation fuel pool" and [c]apturing methane from California's methane sources (e.g., landfills, dairies, and wastewater) is critical for achieving California's climate targets."[3]

However, notwithstanding the benefits RNG brings to California's transportation fuel pool, the Proposed Amendments seek to phase out crediting for RNG. As currently drafted, for projects that break ground after December 31, 2029, RNG pathways, along with avoided crediting, would be phased out after December 31, 2040. Fuel pathways for RNG with avoided methane used to produce hydrogen would be phased out after December 31, 2045.

151.2 Phasing out RNG pathways is shortsighted and stymies the LCFS's effectiveness by removing a carbon-negative fuel source from the program. CARB argues for the phaseout because natural gas transportation fuel demand "is only about 3% of overall natural gas demand in California, and achieving deep GHG reductions will have to include displacing fossil gas in sectors of the economy beyond transportation."[4]

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[1] See https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appe.pdf.
[2] *Id.*
[3] See https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf.
[4] *Id.*

151.2 cont

This type of reasoning is antithetical to the spirit of the LCFS program, which is to incentivize the increased use of low-carbon energy sources and spur innovation in the production of even lower carbon transportation fuels. According to the U.S. Department of Energy, since the beginning of the LCFS in 2011, natural gas fuel consumption in California's transportation jumped from approximately 211.5 million gasoline gallon equivalents (GGEs) in 2011 to 403.7 million GGEs in 2021.[5] If those gallons were replaced with carbon-negative RNG, it would accelerate the decarbonization of the transportation sector. Further, the availability of RNG pathways under the LCFS led to increased production of RNG. In fact, the potential of securing more LCFS credits was one of the factors that led Suburban Propane to invest in RNG. We created a new subsidiary, Suburban RNG, specifically to acquire assets and increase production of RNG.

Phasing out these pathways removes a key low-carbon and carbon-negative energy source from the LCFS. We ask that CARB remove the RNG pathway phaseout provisions from the Proposed Amendments.

Conclusion

For the reasons above, we urge the Board to consider two changes to the Proposed Amendments: increase flexibility of the Automatic Acceleration Mechanism by accelerating the CI benchmark reduction schedule proportional by how much the credit bank exceeds the trigger threshold, up to one full year; and remove the biomethane pathway phaseout. We would appreciate the opportunity to discuss these changes, as well as other ways to reduce greenhouse gas emissions, with CARB staff. Thank you for your consideration.

Sincerely,

/s/ Paul M. Rozenberg

Paul M. Rozenberg
Sr. Manager, Government Affairs &
Corporate Communications
Suburban Propane

[5] See https://afdc.energy.gov/states/ca.

Comment Log Display

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Comment 165 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	James
Last Name	Lavelle
Email Address	jim@usredcapital.com
Affiliation	US Renewable Energy Development Capital,
Subject	Comments on the Proposed Amendments to the Low Carbon Fuel Standard
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6780-lcfs2024-UicBdFEiVGIDYQJh.pdf
Original File Name	usredcarbletter02192024.pdf
Date and Time Comment Was Submitted	2024-02-19 12:24:54

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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USRED

February 19, 2024

Chair Liane Randolph and Members of the Board
California Air Resources Board
1001 I St.
Sacramento, CA 95814

Subject: **Comments on the Proposed Amendments to the Low Carbon Fuel Standard**

Dear Chair Randolph and Members of the Board:

US Renewable Energy Development Capital, Inc. ("USRED") are investors in and advisors to bioenergy and renewable power project development companies in the United States. The purpose of my letter to you today is to offer USRED's input on proposed amendments to the California Low Carbon Fuel Standard.

Strengthen Carbon Intensity (CI) Targets

152.1 - We are in favor of a strong CI reduction target for driving down GHG emissions in the transportation sector, reducing reliance on petroleum fuels, and transitioning to electronic vehicles where feasible.

-

Don't Phase Out Avoided Emission Credits

- We do not support the phase out of avoided emission credits.
152.2 - Avoided methane emissions are a critical part of science-based, life cycle assessments, and their inclusion in carbon intensity scores is consistent with internationally recognized standards of carbon accounting.

-

Clarify and Support Book-and-Claim and Delivery Requirements

152.3 - We recommend that CARB allow biogas to electricity projects to utilize book-and-claim anywhere in the Western Electricity Coordinating Council (WECC), as is already the case in Oregon under their Clean Fuels Program.
152.4 - We believe CARB should allow biogas-to-electricity projects, where electricity generation and biogas production are not co-located, should be eligible to participate in the LCFS
152.5 - We feel that CARB should provide clarification that biomethane may utilize book-and-claim.
152.6 - We recommend that book-and-claim for biomethane to electricity remain unconstrained by timeline restrictions.

152.7 - We request that the deliverability requirement language be removed from the proposal to allow for further stakeholder engagement in support of a clear and actionable plan for consideration in a subsequent rulemaking.

True-up Provisions Should be Formalized

152.8 - We believe the proposal must be carried over and applied to temporary and provisional CI's as fuel providers may rely on these CI's for months, or even years, as a more refined pathway is evaluated and subsequently approved by CARB.

152.9 - Credits should be awarded based on real-world operational experience and therefore adjusted accordingly when the temporary CI which is applied understates the benefits.

New Markets Are Evolving Requiring CARB's On-Going Pathway Inclusion

152.10 - We feel CARB should remain mindful of the success of the historical framework of the program and continue to apply it to newer pathways and technologies, including the use of avoided emissions and book-and-claim.

152.11 - We ask that CARB begin to think about the framework and guardrails needed to achieve the 80% goal set forth in the Scoping Plan and leverage all of the tools available to the vehicle market, such as book-and-claim and avoided emissions accounting, to make this goal a reality.

152..12 As an active member of the American Biogas Council (ABC) we are in support of and agreement with ABC's positions on all matters pertaining to State of California Low Carbon Fuel Standard policies and practices. Thank you for your consideration.

Sincerely,

James Lavelle

Chief Executive Officer

Comment Log Display

Here is the comment you selected to display.

Comment 167 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Andrew
Last Name	Cullen
Email Address	andrew.cullen@penske.com
Affiliation	

Subject	Comments on Proposed Low Carbon Fuel Standard Amendments

Comment

Dear California Air Resources Board:

Thank you for the opportunity to provide comments on the Californi
Air Resources Board (CARB) Proposed Low Carbon Fuel Standard (LCFS
Amendments. Penske Truck Leasing Co., L.P. ("Penske") is a nationwide leader in low-emission transportation with a company-wide commitment to a comprehensive transition to zero-emission vehicles (ZEVs). We share CARB's greenhouse gas reduction goals and federal air quality objectives; therefore, we are excited to offer our expertise and insights into these propose
amendments.

Please see our attached comments responding to the draft LCFS amendments, including changes in EV third party verification, infrastructure crediting, and forklift reporting criteria. Our comments underscore the challenges and opportunities inherent in the transition to ZEVs, and we hope to continue partnering with agencies to streamline requirements and goals across multiple programs to better support this critical technology.

Sincerely,
Andrew Cullen
Senior Vice President - Fuels and Facility Services, Penske

Attachment	www.arb.ca.gov/lists/com-attach/6791-lcfs2024-UCBSMVM8WHgEaQBl.pdf
Original File Name	Penske LCFS Program Changes Comment Letter_February 2024.pdf
Date and Time Comment Was Submitted	2024-02-19 13:57:27

Board Comments Home

Andrew Cullen
Senior Vice President – Fuels and Facility Services

February 12, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Comments on Proposed Low Carbon Fuel Standard Amendments

Dear California Air Resources Board:

Thank you for the opportunity to provide comments on the California Air Resources Board (CARB) Proposed Low Carbon Fuel Standard (LCFS) Amendments. Penske Truck Leasing Co., L.P. ("Penske") is a nationwide leader in low-emission transportation with a company-wide commitment to a comprehensive transition to zero-emission vehicles (ZEVs). We share CARB's greenhouse gas reduction goals and federal air quality objectives; therefore, we are excited to offer our expertise and insights into these proposed amendments.

Fundamentally, Penske is committed to zero-emission transportation technology, a commitment reflected by our significant investments over the last five years in numerous medium- and heavy-duty (MHD) electrification demonstration and deployment projects. As a rental and leasing company, Penske plays a unique role in accelerating the greater adoption of zero-emission vehicles by enabling fleets to test, iterate, and ultimately adopt ZEVs. Penske understands the necessity of collaboration for success, having worked closely with agencies such as CARB, the California Energy Commission (CEC), national utilities, major vehicle manufacturers, charging infrastructure manufacturers and developers, battery providers, and customers in the deployment and operation of new battery-electric transportation services across the entire supply chain.

We believe there are very few, if any, large transportation providers doing more than Penske to advance zero-emission and infrastructure technology. Penske currently operates one of the largest commercial fleets of MHD ZEVs and offroad ZEVs in the United States; our fleet includes battery electric powered trucks and offroad equipment from multiple OEMs, including Freightliner, Volvo, Navistar, Ford, Roush, Kalmar, Orange EV, and many others. These ZEVs operate on a nationally growing network of electric vehicle (EV) charging infrastructure. In addition to our current sites, we are actively working to equip our owned sites throughout the country with charging equipment that will allow us to comprehensively advance our shared zero-emission goals.

Penske's ever-expanding familiarity with ZEVs, coupled with our comprehensive and incomparable understanding of charging infrastructure and real-world commercial fleet applications, uniquely positions us to be a resource for CARB. Our front-line experience on the availability, use, and application of ZEVs allows us to serve as a partner in CARB efforts to amend the LCFS regulations.

On behalf of the entire Penske team, we want to thank CARB and your staff for the time to hear our comments, insights, and concerns while advancing effective regulations and programs that both address real-world concerns while also achieving critical zero-emissions progress.

Recently, CARB released draft language for LCFS amendments. Based on our experience as a leader in commercial ZEVs, Penske offers the following comments for consideration as your agency amends the regulation.

Penske Transportation Solutions
2675 Morgantown Road
Reading, PA 19607

Tel 610 775 6406
Fax 610 775 6330
andrew.cullen@penske.com
gopenske.com

![Penske logo]

Andrew Cullen
Senior Vice President – Fuels and Facility Services

Electric Vehicle (EV) Third Party Verification

Penske is supportive of the need for validated, auditable LCFS pathways. The long-established third-party verification (3PV) requirements have allowed for the liquid and gaseous low carbon fuel markets to thrive by developing trust between producers and counterparties. The strength of the LCFS is built on consistency and transparency of the program, ensuring confidence by participants in the validity of claims made in the program. However, existing 3PV rules were written specifically for liquid and gaseous low carbon fuels. We ask that any proposed changes develop approaches that are also specific to EVs, to allow for continued growth in that critical sector.

153.1 Penske encourages CARB to reconsider proposed 3PV requirements related to electricity pathways. The existing 3PV framework will create an undue administrative burden on ZEV operators participating in the LCFS program, if implemented as written. In turn, this will slow growth in a unique sector with immense potential to propel the state towards its greenhouse gas (GHG) reduction goals. Current 3PV rules hinder participants' ability to participate in the program and invest in further electrification by burdening them with outsized administrative costs. Specifically, the proposed changes would require electric fuel supply equipment (FSE) owners to verify quarterly an annual data through third party verifiers, site visits, and other requirements originally designed with large volume fuel production facilities in mind. Fleets, the LCFS program, and the state of California will all benefit by addressing 3PV for electricity in a manner that is tailored to the practicalities of the EV market. Without a structure that either aligns with existing documentation or considers the expense associated with a facility-based 3PV approach, CARB risks decreased EV participation in the program.

153.2 To ease this burden, this rule change could be an opportunity to synchronize with existing and planned audit and reporting structures for fleet electrification. For example, the CEC is currently developing Proposed Regulations for Electric Vehicle Charger Inventory, Utilization, and Reliability Reporting. A recent workshop walked through the CEC's draft proposal to require select operators of EV charging stations to report the number, utilization, and reliability of charging stations to the CEC. Validated, reliable charging data under one California regulation, alongside validated utility data that is regulated by the California Public Utilities Commission (CPUC), could serve as an important and streamlined mechanism for verifiable LCFS EV reporting. Similarly, as CARB determines how to implement Senate Bill 253 (California Climate Corporate Data Accountability Act) protocols should align and be streamlined to support holistic GHG reporting and LCFS accounting requirements. By aligning LCFS 3PV with existing and planned audit and reporting structures, CARB can help ensure EV participation in the LCFS program.

With regard to specific requirements in the proposed verification structure, a streamlined process is recommended for electric FSE that report only under Lookup Table pathways. In this case, verification could be limited to:

1) Confirmation that the FSE are operational through review of completed building permits, utility permission to operate, or site photographs. This would eliminate the need for costly site visits while providing verification that FSE has been installed.
2) Verification of charging data through review of charge session data in a charger management portal and/or review of the associated utility meter data. This would allow for confirmation of the accuracy of the reported data (charging energy).
3) Sites that generate 6,000 credits per year or more. Proposed rules would allow for deferral of initial verification requirements for two years but would not eliminate these requirements or reduce the frequency of the verification requirement. Alternatively, CARB could set a lower threshold for exemption from verification requirements, recognizing that per-site verification costs could easily exceed $10,000 per year. At current LCFS credit prices, these verification costs would represent an additional administrative cost of

Penske Transportation Solutions
2675 Morgantown Road
Reading, PA 19607

Tel 610 775 6406
Fax 610 775 6330
andrew.cullen@penske.com
gopenske.com

PENSKE

Andrew Cullen
Senior Vice President – Fuels and Facility Services

ten percent or more for sites generating less than 2,000 credits per year. Establishing this lower threshold for exemption and allowing for reduced frequency of reporting for sites falling under the 6,000 credit threshold would balance administrative costs with verification.

Zero Emission Vehicle (ZEV) Infrastructure Crediting

Penske is supportive of expanded eligibility for ZEV infrastructure crediting, which allows for increased public and private investment in low carbon fuels. Given the high cost of EV charging equipment, installation, and vehicle
153.3 investment, infrastructure funding support is essential to keep the program on track toward GHG reduction goals. We encourage CARB to continue supporting incentives which expand the availability of low carbon transportation charging options for fleets across the state. In developing these incentives, we especially encourage CARB to consider the unique needs and access points of the MHD ZEV sector.

Presently, even with existing rebates and incentive programs, the pathways for MHD fleets and operators to access ZEVs are difficult, especially for smaller fleets. Many small businesses do not have the capacity to take advantage of incentive programs or the capital to invest in new refueling infrastructure. Further, a transition to ZEVs requires a fundamental shift in business operations, as businesses must consider new challenges, such as including charging time in operation schedules, ensuring charging is accessible enroute, and solving for the inherent inconsistencies associated with emerging technologies. By aligning infrastructure, vehicles, and maintenance into a publicly available package without significant upfront costs, short-term rental and leasing offer a critical avenue for small businesses to affordably incorporate ZEVs into business operations. Thus, as CARB continues to support incentives to expand low carbon transportation charging options, we encourage CARB to recognize the unique needs of the MHD ZEV sector. Specifically, we encourage CARB to consider supporting infrastructure serving multiple fleets through publicly available rental and lease offerings as publicly accessible infrastructure, a practice that aligns with other funding agencies. In doing so, we believe the LCFS can more comprehensively be a major force of change incentivizing the essential transition to low carbon options.

Changes to Forklift Reporting Criteria

Forklifts have been an important participant in the LCFS and continue to provide valuable GHG reductions for California. By ending the estimation methodology reporting technique, CARB improves the accuracy of credit generation, but creates an additional cost burden to install "direct metering" equipment at existing participants facilities. The cost of this additional metering equipment may decrease participation in the program and eliminate a
153.4 revenue source that was part of the fleet's procurement plan. It is understood that better quantification methods are necessary for forklifts, and we propose an intermediary step be taken to allow for a transition period of three (3) years to phase out the use of the estimation methodology for already registered FSE, rather than requiring an immediate transition. Such an intermediary measure would allow for continued recognition of emissions reductions from EV forklifts that were procured and registered under the current program requirements. We further propose that any changes to forklift reporting criteria be aligned with CARB's proposed Zero-Emission Forklift Regulation, allowing companies to onboard new ZEVs and infrastructure that could also meet the goals of the LCFS quantification on the
153.5 same timeline. The proposed Zero-Emission Forklift Regulation has scheduled phaseouts of MY 2025 forklifts beginning in 2028, aligning with the suggested transition period of three (3) years. This would allow fleets the ability to support LCFS goals while strategically preparing for the Zero-Emission Forklift Regulation in a way that causes minimal disruption to operations and maximizes adoption and emissions reductions.

Penske Transportation Solutions
2675 Morgantown Road
Reading, PA 19607

Tel 610 775 6406
Fax 610 775 6330
andrew.cullen@penske.com
gopenske.com

Andrew Cullen
Senior Vice President – Fuels and Facility Services

Conclusion

Penske is appreciative of the opportunity to comment on CARB's proposed LCFS amendments. CARB's GHG reduction and zero-emission goals deeply resonate and align with our own, and we hope we can be a source of value as these programs and regulations are adopted. Our experience underscores the challenges and opportunities inherent in the transition to ZEVs, and we hope to continue partnering with agencies to streamline requirements and goals across multiple programs to better support this critical technology.

We believe zero-emission rentals and leasing enable more rapid rollouts of ZEVs via lower-risk leasing, maintenance, outsourcing, and charging efforts. These market--leading efforts will also help define and refine secondary market pathways, residual value calculations, and long- term maintenance planning. We share CARB's goals of lower GHGs and emissions and hope our experiences provide insight into more effective LCFS revisions. Thank you for this opportunity to comment on the proposed regulation amendments. We look forward to engaging CARB on the issues raised herein.

Sincerely,

Andrew Cullen
Senior Vice President – Fuels and Facility Services, Penske
andrew.cullen@penske.com

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Comment 168 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	James
Last Name	Duffy
Email Address	duffje@msn.com
Affiliation	Former LCFS Branch Chief
Subject	Restore Balance to the LCFS
Comment	Please see attached comment letter.
Attachment	www.arb.ca.gov/lists/com-attach/6792-lcfs2024-AWUGdQdgVmMHeAZZ.pdf
Original File Name	Duffy_LCFS_45-day_Comments.pdf
Date and Time Comment Was Submitted	2024-02-19 14:13:51

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 19, 2024

Liane Randolph, Chair
Members of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Chair Randolph and Members of the Board,

I retired from the California Air Resources Board (CARB) two years ago. During my 13-year career at CARB, I worked almost exclusively on the Low Carbon Fuel Standard (LCFS), including over a year as Branch Chief overseeing the program.[1] I helped develop and enthusiastically support the LCFS. A strong LCFS is critical to helping California achieve its zero emission transportation goals. I begin this letter with five high-level recommendations for the Board to consider, two of which are described in much greater detail in attachments. I then convey my thoughts on the history of the LCFS, the power of special interests over the program, and the importance of thoughtfully considering the rapidly increasing cost of the regulation to low-income Californians. I finish the letter by briefly describing several focused recommendations. I do hope that you will read this letter in its entirety and please feel free to reach out if you have questions or would like to further discuss comments that resonate with you.

154.1 First and foremost, I highly encourage the Board to cap and ultimately phase out the use of crop-based diesel and aviation fuel in California. The use of crops such as corn and soy as feedstock to produce liquid diesel and aviation fuel is not a sustainable means of reducing GHG emissions and may actually increase emissions as compared to fossil fuels. Moreover, using crops to produce biofuels is expensive and exacerbates tropical deforestation and global hunger. **In fact, a portion of the GHG emission reductions that CARB is attributing to crop-based biofuels directly results from the most food insecure populations in the world eating less.** CARB's promotion of these fuels is not in line with its reputation as a global leader in environmental policy. For further discussion, please see Attachment A.

154.2a Second, rather than simply claiming that all potentially significant impacts are unavoidable, require staff to think creatively and reevaluate which impacts can be mitigated or avoided through LCFS requirements. Throughout the Draft Environmental Impact Analysis (EIA), CARB frequently made the determination that the impacts associated with expected compliance responses are Potentially Significant and Unavoidable. Based on this determination, CARB staff will request that the Board issue a Statement of Overriding Considerations. CEQA places the burden on the approving agency to affirmatively show that it has considered feasible mitigation and alternatives that can lessen or avoid identified impacts through a statement of findings for each identified significant impact. I do not believe that CARB has adequately demonstrated that they have considered feasible mitigation and alternatives that could lessen or avoid

[1] I am writing this comment letter on my own behalf as a private citizen.

154.2b

several potential impacts on air quality. Moreover, there are several faulty assumptions in CARB’s analysis that result in the overestimation of GHG and air quality benefits of the Proposed Amendments in the Draft EIA. These faulty assumptions also lead to the incorrect conclusion that the Proposed Amendments scenario is more cost effective and provides more air quality benefits than Alternative 1.[2] For further discussion, please see Attachment B.

154.3

Third, direct staff to immediately begin a rulemaking for dairy methane. Avoided methane crediting for dairies is unique under the LCFS. No other industry is treated as if their methane pollution is naturally part of the baseline and then lavished with large financial incentives for simply reducing their own pollution.[3] Oil companies are not awarded large LCFS incentives for avoiding methane emissions at oil fields and refineries. Instead, they are regulated and penalized for their emissions. Likewise, landfill operators are not awarded large, avoided methane incentive for capturing methane escaping from landfills, rather they are regulated and required to do so. Excessively rewarding an industry for poor historic environmental performance is troubling in the least and furthermore, doing so only through a transportation fuels program distorts the market against the consideration of less costly and more sustainable methane mitigation options. Every effort should be made to regulate methane emissions from the dairy industry and limit any subsidies to the bare minimum necessary to resolve the problem. As it is, avoided methane crediting for dairies acts as an LCFS offset program, allowing oil companies to generate or purchase large amounts of credits while displacing very little or no fossil fuel.[4] It is no wonder that oil companies are investing heavily in dairy digesters, as it allows them to comply with the LCFS, make a profit doing so, and retain their market share for fossil fuels.

154.4

Fourth, I recommend resetting the LCFS price cap and encourage the Board to set credit multipliers for high priority fuels and projects. Currently the price cap for LCFS credits is $253 and by 2045 will likely be more than $400. As shown in Table 1 later in this document, the pass-through cost increases substantially over time if the credit price is at or near the ceiling. To help prevent excessive pass-through costs in the latter years of the program, I recommend resetting the price cap to $200 and removing the annual inflation adjustment. Moreover, if the Board believes that $200 is not sufficient to incentivize high priority fuels or emission reduction projects, then the Board should adopt credit multipliers that are specific to those fuels or projects. Using credit multipliers will allow the Board to fine tune the regulation to provide extra incentive for high priority fuels and projects without unnecessarily overcompensating other credit generators in the program. Some stakeholders will hypocritically cry out “blasphemy” at such a suggestion and that the LCFS must be “fuel neutral” or that credit multipliers will create an “unlevel playing field”. The truth of the matter is that transportation fuels

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[2] Alternative 1 includes a limit on total credits from diesel fuels or sustainable aviation fuel produced from virgin oil feedstocks and a complete phase out of light-duty battery electric forklifts from the program.

[3] At an LCFS credit price of $200, dairy digester gas generates approximately $80 per MMBtu in value from the LCFS and currently receives about $40 per MMBtu in value from the federal Renewable Fuel Standard. The commodity price for natural gas is approximately $5 per MMBtu.

[4] Much of the current dairy gas is not displacing fossil fuel, but rather displacing landfill gas.

policy in California has never been a level playing field because the LCFS subsidy is allowed to stack on top of federal subsidies. This is particularly true for the heavy-duty and aviation sector where the LCFS stacking on the RFS, Biodiesel Blenders Tax Credit, and 40B tax credit for sustainable aviation fuel creates an unlevel playing field tilted heavily toward renewable diesel, biodiesel, sustainable aviation fuel, and renewable natural gas. A relatively low, fixed price cap with credit multipliers for high priority fuels and projects will allow the Board to truly establish a level playing field and equitably promote California's zero-emission transportation goals.

154.5 Finally, I highly encourage you to follow the recommendation made by Earthjustice to hold a non-voting Board hearing prior to the Board vote. Staff made significant changes to the proposal at the last minute that were not discussed at workshops or informational Board hearings, nor were they included in modeling that staff performed for the ISOR and Draft Environmental Impact Analysis.[5] Moreover, staff have been surprisingly non-transparent in the amount of information included in the rulemaking materials, which is a change from prior LCFS rulemakings.[6] It is so important to provide stakeholders with the opportunity to convince Board members, as a group and in a public setting, to change course prior to the voting meeting. I strongly urge you not to shortcut this process.

Before providing detailed comments, I believe it is important to understand the history of the LCFS and the power that wealthy special interests have exerted over the program. Throughout these comments, I urge the Board to adopt many of the recommendations from the Environmental NGO and Environmental Justice Communities. Industrial stakeholders will lead you to believe that these recommendations are a radical departure from the history and philosophy of the LCFS. The truth is that most of the LCFS provisions and credit generating opportunities that the environmental community wants to eliminate, phaseout, or amend were not allowed in the original regulation. Under the original LCFS regulation adopted in 2009,

- Dairy projects did not receive avoided methane credit and would have been assessed approximately the same carbon intensity as landfill gas,
- RNG projects (e.g., landfills and dairies) were not allowed to "deliver" biomethane to California using an accounting ledger,
- Oil producers and petroleum refiners could not receive credit for emission reduction activities at their facilities,
- Offset credit could not be generated for direct air capture (DAC),
- Credit could not be generated by unused hydrogen stations and EV chargers,
- Credit could not be generated by forklifts,
- Alternative jet fuel could not participate as an opt-in credit generator,

[5] Confirmed by email with CARB staff.

[6] When contacted by stakeholders to provide more comprehensive data, assumptions, and calculations that were relied upon in making the determination that the Proposed Amendments scenario is superior to each of the Alternative scenarios, staff refused to provide the information, requiring at least one stakeholder to submit a Public Record Act request. Unfortunately, this information will not be available in time to inform comments during the 45-day period.

- Average Midwest corn ethanol did not generate credits but rather generated deficits in year one of the regulation, and
- Soy biodiesel and renewable diesel were only marginally better than fossil diesel and included a very large land use change penalty that more accurately reflected the likelihood that using soy oil to produce fuel indirectly contributes to tropical deforestation.

The original LCFS was designed to radically transform California's transportation sector by helping fund the transition from internal combustion to zero emission vehicles and accelerate the commercialization of advanced renewable biofuels, primarily produced from waste cellulosic feedstock. Over the next 10 years this vision slowly changed and the LCFS was revised to provide additional and unnecessary support to landfills and first generation crop-based biofuels, to mitigate the methane problem created by the dairy industry itself, to provide support for big oil to reduce emissions from their own facilities and more easily comply with their Cap-and-Trade obligations, and to provide support for direct air capture, a technology that has no direct relationship to transportation fuels. Many of us have witnessed this transition from an innovative regulation into a swag bag for venture capitalists, big oil, big agriculture, and big gas, increasingly coming at the expense of low- and moderate-income Californians. The LCFS is an extremely complicated program, which provides powerful special interest groups with a distinct advantage, as they can afford to pay for lawyers, lobbyists, former CARB staff, and research designed to promote their self-interests. Unfortunately, the same cannot be said for the lower-income consumer of gasoline. Powerful special interest groups will argue that changes to the regulation were objective, data driven, and made to reflect evolving science. I disagree. I believe many were subjective policy and modeling decisions, made not with the best interest of the California consumer and California's long-term transportation goals in mind, but rather with the intent to placate these powerful special interests and to achieve policy outcomes outside of transportation decarbonization. At this point, the LCFS gravy train has gained so much momentum that the only recourse from the staff's perspective is to quickly ramp up the targets, risking large costs to low-income gasoline consumers and public backlash. However, there is another option. Restoring many aspects of the original regulation would better focus the program on achieving California's long-term zero-emission transportation goals and at a much lower cost to the California consumer.

154.6 **Do not ignore the problem of pass-through cost to gasoline consumers.** In both 2015 when CARB readopted the regulation and in 2018 when the targets were extended to 2030, staff estimated the maximum pass-through cost of the amendments to consumers of gasoline and transparently conveyed this information to the public. For the current rulemaking, CARB staff provided similar calculations and rationale in the SRIA.[7] The estimation of pass-through cost uses the target CI reduction (converted to deficits generated per gallon of gasoline) multiplied by the estimated future market price for credits.[8] A basic rule of thumb says that a 1 percent reduction in carbon intensity at $100 credit price adds slightly more than 1 cent to the cost of gasoline. So, in late 2023

[7] See pages 55-59

[8] See the discussion and calculation for pass-through cost on pages 48-50 of the 2018 SRIA.

with a target CI reduction of 11.25 percent and a credit price of $75, the pass-through was a modest 9 to 10 cents per gallon. Table 1 below shows future estimates of the pass-through cost under the amended regulation at a range of reasonable credit prices. These costs are in addition to the pass-through cost for the Cap-and-Trade program which could exceed $1 per gallon in 2030 and reach $1.50 per gallon in 2035.[9] **To put the pass-through cost in perspective, at a $200 credit price, the LCFS could cost gasoline car drivers approximately $250 a year in 2025, rising to whopping $1150 a year by 2045.[10]**

Table 1: Estimated LCFS Pass-Through Cost to Gasoline ($ per gallon)

Year	Percent CI Reduction	$150 Credit Price	$200 Credit Price	Credit Price at Ceiling[11]
2025	18.75	$0.30	$0.41	$0.54
2030	30	$0.49	$0.65	$0.95
2035	52.5	$0.85	$1.13	$1.84
2040	75	$1.22	$1.62	$2.90
2045	90	$1.46	$1.94	$3.84

However, in the current staff report, staff disavowed this calculation of pass-through cost and focused instead on total fuel costs to all California consumers.[12] CARB staff wrote "retail fossil fuel prices are strongly influenced by many factors beyond LCFS credit prices (e.g., global events, holiday weekends, seasonal fluctuations, refinery disruptions and decisions about production that affect supply, refinery pricing decisions, seasonal fuel blends, taxes) and fossil fuel producer pricing strategies are complex and reflect local and regional market conditions…Predicting how LCFS credit price changes impact these complex pricing strategies and the per gallon gasoline and diesel prices paid at the pump in the future by consumers is beyond the scope of this work."

I reached out to Danny Cullenward, Senior Fellow with the Kleinman Center for Energy Policy and Vice Chair of California's Independent Emissions Market Advisory Committee, to get his take on the change in CARB's approach. Here is an excerpt from his response: "With respect to how much of the cost impact is passed through to consumers, I appreciate that it is difficult to assess this kind of question empirically, but I've also been skeptical of views that claim a substantial portion is paid for by the refiners. I don't see the reasoning for why refiners would choose to pay much or any of the total cost, especially not when operating in islanded market (for CARBOB) that is designed, in part through the free allocations to in-state producers in the cap-and-trade program, to be relatively hostile to refined product imports. I'd also flag that arguments that refiners may be exercising market power — e.g. the "mystery gasoline surcharge" identified by Severin Borenstein, and the broader concerns around "price gouging" issues that led to the new oversight function at the CEC — would suggest conditions under which refiners would pass 100% of the costs through. Point is, the market

---

[9] See Cap and Trade workshop: slide 34 of November 16, 2023 workshop presentation

[10] Estimates assume 15,000 miles annual driving in a vehicle getting 25 miles per gallon.

[11] The credit price at the price ceiling was estimated assuming inflation of 3% in 2023 and 2% for all future years.

[12] See middle of page 82 to top of page 84 of the ISOR

structure for CARBOB in particular would suggest more market power for refiners, rather than less, and that implies most or all of the costs getting passed through."

Data reported by refiners to the California Energy Commission under SB 1322 further supports the likelihood that the full cost of the LCFS (and Cap-and-Trade) is being passed on to consumers. As indicated in this data, California refiners reported an LCFS cost of 9 to 10 cents per gallon of gasoline in late 2023, the same as the maximum pass-through cost calculated above.

In the staff report, CARB also wrote "the program has a price ceiling to ensure credit prices do not go unchecked. This further ensures that the cost pass-through is managed and unnecessary costs of the program are not passed on to consumers." Table 1 above shows estimated pass-through costs at the price ceiling. I'll leave it up to the Board to decide if the price ceiling provides appropriate management of costs.

CARB's about-face and focus in the ISOR on total fuel costs to all California consumers instead of pass-through costs is a diversion and reminds me of an old joke:

> Question: Why did CARB paint the elephant's toenails red?
> Answer: So they could hide the elephant in a cherry tree!

The calculation of total fuel cost to all California consumers results in an average cost per mile travelled that encompasses both the higher cost to gasoline consumers and the lower cost to ZEV owners. Focusing on this metric rather than the pass-through cost to gasoline completely misses the point for two reasons. First, the total fuel costs to all California consumers does not isolate the effects of the LCFS, but rather encompasses the effects of all transportation policies in California including the ACC and ACT regulations, which are the most important policies driving the adoption of EVs. Second, because EVs are disproportionally being purchased by wealthier individuals, consumers of gasoline will increasingly become, on average, lower and lower income. Through higher prices of gasoline at the pump, gasoline consumers pay the cost of subsidizing the alternative fuels and projects that receive LCFS credit, and over time, this cost per gallon of gasoline is expected to grow substantially. It is important to understand and acknowledge this regressive nature of the LCFS. **CARB should not be avoiding the discussion of pass-through costs, but rather should be considering all possible**
154.6 cont **means to minimize the pass-through cost while preserving those credit generating opportunities that achieve real, additional emission reductions and/or accelerate the transition to zero emission transportation in California.** In voting on these amendments, you as Board Members are deciding how much you believe future California gasoline consumers should be paying for subsidies to combustion biofuels that exacerbate global hunger and may not reduce GHG emissions at all, for subsidizing dairies to mitigate their own pollution, for subsidizing out-of-state landfill and dairy gas projects, for helping oil companies reduce their Cap-and-Trade obligation through implementing non-innovative emission reduction projects, and for subsidizing out-of-state direct air capture projects which don't help California achieve AB32 GHG reduction goals. As an example, if you approve the amendments as written and credit

prices increase to $200[13], lipid-based biofuels will generate approximately $3 billion of LCFS subsidy in 2025 and out-of-state landfills and dairy digesters will likely generate about $1 billion. Are the benefits of renewable diesel and biodiesel worth this cost to California gasoline consumers? Should California gasoline consumers continue to foot the bill for out-of-state RNG projects to the tune of a billion dollars per year? Could we better use $4 billion each year on projects that help achieve California's long-term zero-emission transportation goals? Balancing the cost of the LCFS against the desire to achieve emission reductions and placate powerful special interests presents many difficult choices, which do not go away by trying to hide the elephant.

Fortunately, there are many actions that CARB can take to reduce the pass-through cost to consumers of gasoline. These actions involve limiting credit generation that does not advance California's long-term zero-emission transportation goals, eliminating excessive credit generation, eliminating LCFS subsidies that do not result in additional global GHG emission reductions beyond what would already occur through other State and Federal programs, and minimizing the potential for credit price spikes. Cutting out unnecessary and ineffective credit generation will allow for less stringent targets and lower pass-through costs, without sacrificing real, additional GHG reductions achieved by the program. In addition to a cap on crop-based biofuels and resetting the price cap, I outline several recommended actions in the discussion below.

Eliminate double counting of emission reductions from direct air capture (DAC): In several provisions of the LCFS regulation amendments (e.g., book-and-claim electricity, book-and-claim RNG, book-and-claim hydrogen, renewable or low-CI process energy), the regulation text prohibits generating LCFS credits if the RECs or environmental attributes are "being claimed in any other voluntary or mandatory program with the exception of (insert list of programs where stacking is allowed)". However, such language is conspicuously absent from section 95490 for DAC or other CCS projects. It is public knowledge that Oxy 1PointFive is already preselling future emission reductions in the voluntary carbon market for its first DAC project and intends to bundle DAC emission reductions with crude oil being marketed as "carbon neutral crude" or "net zero oil". See:

154.7
- 1PointFive announces agreement with Airbus for purchase of 400,000 tonnes of carbon removal credits
- Amazon makes first investment in direct air capture climate technology | Reuters
- Oxy teams with Macquarie to deliver the world's first carbon-neutral oil from Permian basin to India

While I agree that the LCFS value for CCS and DAC should stack with Federal 45Q tax credit, generating LCFS credit for emission reductions that are also sold to other entities in the voluntary carbon market and/or bundled with crude as "net zero oil" is a clear instance of double or maybe even triple counting of emission reductions. If your

[13] After the previous rulemaking to adjust targets in 2018, credit prices quickly increased to $200 and remained at this level for nearly two years. See figure 4 of the LCFS Dashboard.

intention is to allow double or triple accounting, then that should be transparently stated and discussed in a public forum.

154.8 Remove Enhanced Oil Recovery (EOR) as an Eligible Sequestration Method: California SB 1314 prohibits the use of EOR as a sequestration method for CCS projects in California. Section 1 of SB 1314 reads "The Legislature finds and declares that the purpose of carbon capture technologies, and carbon capture and sequestration is to facilitate the transition to a carbon-neutral society and not to facilitate continued dependence upon fossil fuel production." CO_2 EOR is a tertiary oil production method that is only used when oil field production has declined to the point that it is no longer profitable to continue producing using secondary production methods such as waterflood. As such, use of EOR results in the recovery of oil that otherwise would not be produced. The LCFS program should not be providing incentive to squeeze additional oil from these fields. Let's leave this oil in the ground! Out of consistency with California requirements, I strongly encourage the Board to remove EOR as an eligible sequestration method under the LCFS. This can be done by setting a grandfather date (e.g., 2028) after which projects using EOR cannot be certified.

154.9 Place a cap on out-of-state DAC projects: Based on press releases, DAC projects are expected to be massive, resulting in credit generation of up to one million MT annually for each project. At a credit value of $200, a single out-of-state project may result in approximately $200 million leaving the California economy annually, while providing no jobs for Californians, displacing no fossil fuels in California, resulting in no air pollution benefits to California communities, and not even counting toward California's AB32 emission reduction goals. Therefore, not only will Californians be paying for a large out-of-state project that provides no immediate benefit to the state, but they will also have to pay again for separate emission reductions that do count toward the State's goals. In effect, these DAC projects would act as "LCFS offsets", allowing oil companies to comply with the LCFS without affecting their fossil fuel sales. Credit generation for out-of-state DAC projects should either be quickly phased out through a grandfather date or tightly capped as is done in the Cap-and-Trade program for offsets. If left uncapped, a proliferation of DAC projects[14] could result in repeated triggering of the Auto-Acceleration Mechanism leading quickly to excessive pass-through costs to California consumers.

154.10 Stop receiving new petroleum project applications in 2025 and phase out crediting by 2030: The innovative crude and refinery investment projects that have been approved to date are certainly not innovative and are excessively subsidized. These projects should not be credited through the LCFS. All projects certified under the innovative crude provision are for solar electricity, which is cost effective without LCFS credit value. Likewise, the refinery investment credit project certified for the Chevron refinery in Richmond is providing approximately 60,000 credits annually for a hydrogen plant upgrade that Chevron was planning to do before the LCFS was even adopted.[15] These

[14] Oxy 1PointFive has announced a goal of completing 70 DAC projects by 2035.
[15] See https://ccpulse.org/2014/07/31/richmond-approves-stalled-modernization-plan-at-chevron-refinery-2/

are certainly not additional emission reductions. In effect, the LCFS is subsidizing oil companies to meet their Cap-and-Trade obligation.

154.11 <u>Stop overcompensating dairy digester projects:</u> It is my understanding that capital financing for dairy digester projects is commonly paid off in ten years, after which only maintenance and operating costs remain. While dairy digester operators may reasonably argue that they need full avoided methane credit for the first ten years while paying of capital costs, having full avoided methane credit for the next twenty years is gross overcompensation. **Moreover, after paying off capital costs for the digester, it is no longer appropriate to assume a baseline of methane emissions to the atmosphere.** With avoided methane crediting, a dairy digester project generates approximately $70 to $125 per MMBtu in total value from the LCFS, RFS, and gas sales.[16] The operating and maintenance costs for a digester project are about $25 per MMBtu ($35 per MMBtu if trucking of the gas is required).[17] In other words, digester projects getting avoided methane credit are generating about 100 to 400 percent annual profit after paying off the digester. To avoid this needless overcompensation, I recommend assigning a fixed CI value of zero g/MJ for the remaining 20 years of LCFS crediting.[18] At a CI value of 0 g/MJ, the dairy digester project would generate a combined value of approximately $40 to $60 per MMBtu, which is much more in line with the operating and maintenance costs.

154.12 <u>Do not allow dairy projects to get more credit for increasing the herd size:</u> Avoided methane credit should be capped based on the historic herd size before LCFS certification. This would prevent dairy projects from receiving additional credit for growing the herd size and exacerbating local air quality problems.

154.13 <u>Apply biomethane deliverability requirements for all biomethane pathways:</u> In a last-minute revision, staff decided to grandfather all RNG projects that break ground prior to 2030 from proposed deliverability requirements, and projects breaking ground in 2030 or later will only be affected by deliverability requirements starting in 2040. I recommend the Board direct staff to revert to the original concept discussed in workshops and apply deliverability requirements for all pathways starting in 2028. As an exception, I recommend that dairy digester projects that break ground prior to 2025 be allowed to complete their first 10-year crediting period under current deliverability requirements. These dates will provide sufficient time for out-of-state RNG projects that do not meet the deliverability requirements to contract with fleets outside of California and continue receiving value from the RFS. This timing will also allow these digester operators sufficient time to work with their own state legislatures to provide additional funding if necessary to avoid potential stranded assets. Gasoline consumers in

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[16] At an LCFS credit price of $100 to $200, dairy digester gas generates approximately $40 to $80/MMBtu in value from the LCFS, $26 to $40/MMBtu in value from the federal Renewable Fuel Standard, and about $5/MMBtu for the gas for a total value of approximately $70 to $125/MMBtu.

[17] See calculation details at https://asmith.ucdavis.edu/news/digester-update

[18] This recommendation should be made together with a phase out of book-and-claim accounting for landfill gas.

California have jump started the dairy digester industry in these states, they shouldn't be asked to fund these projects in perpetuity.

Quickly phase-out book-and-claim accounting for landfill gas: Landfills do not need LCFS credit as the RFS incentive for these projects is already excessive. Moreover, over 98 percent of the landfill gas generating credit under the LCFS is from out-of-state sources. Producing landfill gas for transportation is estimated to cost approximately $10
154.14 per MMBtu[19] but these projects currently receive about $40 per MMBtu in incentive from the RFS. In other words, the LCFS providing incentive for these projects does not result in additional global GHG reductions, only more profits. I recommend eliminating book-and-claim accounting for landfills in 2028, which will provide sufficient time for out-of-state landfill gas operators to find a different purchaser for their gas.

Phase out crediting for light-duty and heavy-duty forklifts: Staff took a step in this direction by reducing the EER for light-duty forklifts but should go a step further and set
154.15 phase out dates of 2030 for light-duty forklifts and 2040 for heavy-duty forklifts. With limited exceptions, all forklifts will be required to be zero-emission by 2040.[20]

Return to the Board if the Auto-Acceleration Mechanism (AAM) is triggered repeatedly: The AAM is designed to automatically increase the stringency of the program if there is a chronic excess of credit leading to a buildup of the credit bank and reduction of credit prices. In discussing the rationale for the AAM, CARB wrote "The existence of an AAM is expected to decrease market volatility and increase market confidence, which will promote low-carbon technology investments." However, in the staff report, CARB staff made no effort to assess the impact of this mechanism on the credit price or even qualitatively discuss the implications as part of the scenario analysis. For example, in the Proposed Amendments scenario, CARB staff estimate average credit prices ranging from $76 to the price cap, but they do not discuss whether this large volatility in the
154.16 market is reasonable given the addition of the auto-acceleration mechanism to the proposal. Will the AAM effectively set a credit price floor that is well above $76? Will unexpected credit generation result in multiple triggers of the AAM and unexpectedly high pass-through costs? Because of the uncertainty surrounding the impact of the AAM on credit price and pass-through cost, I recommend requiring that a rulemaking be initiated if the AAM is triggered twice in any six-year period. Moreover, this rulemaking should be completed before a third acceleration is allowed. Repeated triggering of the AAM indicates market conditions that staff and the Board did not anticipate when approving these amendments. Staff should be required to investigate and return to the Board with amendments to establish new compliance targets and address the cause(s) of the market imbalance, if necessary.

Address the potential for the AAM to overcorrect the market: I suggest not allowing an acceleration to occur in either 2031 or 2032 as the rate of CI decline for the benchmarks

[19] See https://www.erm.com/globalassets/documents/mjba-archive/issue-briefs/rngeconomics07152019.pdf
[20] See workshop materials for the forthcoming Zero-Emission Forklifts Regulation.

is already doubling and an acceleration that occurs in either of these years would quadruple the rate of target CI decline. Here are the scenarios of concern:[21]

154.17

- The AAM is triggered in May of 2030. This trigger has occurred because the market is generating too many credits based on an annual benchmark decline through 2030 of 2.25 percent. In 2031, the rate of benchmark decline is already scheduled to double to 4.5 percent. An acceleration in 2031 would quadruple the rate of benchmark decline to 9 percent.
- The AAM is triggered in May of 2031. Again, this trigger has occurred because the market is generating too many credits based on an annual benchmark decline through 2030 of 2.25 percent. In 2031, the benchmark has already declined by 4.5 percent, which may itself correct the market. However, in 2032, an acceleration will occur increasing the target CI reduction another 9 percent.

Either of these scenarios may result in an overcorrection with the credit price going to the ceiling, at which it may be stuck for many years. Under the above scenarios, credit price at the ceiling will result in a pass-through cost of approximately $1.30 per gallon of gasoline. Such a pass-through cost would be politically untenable for the program.

Withhold LCFS credits for violating other State and Federal requirements: Apparently, CARB has not been too serious about holding credit generators responsible for complying with other State and Federal requirements, as there do not appear to be any enforcement actions taken against entities for non-LCFS violations.[22] If the Board is truly intent on requiring regulated parties to comply with these requirements as a condition for generating LCFS credits, then I recommend that the Board direct staff to make the following amendments:

154.18

- Clearly define what types of State and Federal requirements (e.g., environmental, safety, labor, tax) are of concern and the repercussions for violating these requirements.
- Require regulated parties to report all violations and require third-party verification bodies to verify compliance with this reporting requirement.
- Investigate regulated parties with violations and withhold credits from entities with serious and/or repeated notices of violation.

If you have read this far, I do thank you for engaging with me😊.

Best regards,
Jim Duffy

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[21] I wrote these scenarios assuming that the AAM has not already been triggered prior to 2030. If the AAM has previously been triggered, then the years of concern will advance by one year. In other words, I suggest not allowing an acceleration to occur in either of the two years following the transition from a 2.25% rate of decline to a 4.5% rate of decline.

[22] See LCFS Enforcement webpage for a listing and description of settlements and account balance adjustments since the inception of the program.

Attachment A: Cap on Crop-based Biofuels

I most strongly urge the Board to **cap and ultimately phase out the use of crop-based diesel and aviation fuel in California**. The use of crops such as corn and soy as feedstock to produce liquid diesel and aviation fuel is not a sustainable means of reducing GHG emissions and may increase emissions as compared to fossil fuels. Moreover, using crops to produce biofuels is expensive and exacerbates tropical deforestation and global hunger. CARB's promotion of these fuels is not in line with its reputation as a global leader in environmental policy.

<u>If the rest of the world follows California's example, the demand for virgin vegetable oil will be enormous:</u> Just last year CARB issued a news release celebrating the accomplishment that the LCFS has resulted in renewable diesel and biodiesel replacing 50% of diesel. CARB often prides itself on providing an example for the world to follow. **So, what would happen if the rest of the world follows California's lead and replaces over 50% of its diesel fuel with renewable diesel and biodiesel?** Currently, the world annually produces 200 million metric tons of vegetable oil, a majority from the tropical countries of Indonesia, Malaysia, and Brazil. Replacing 50% of diesel worldwide would require an additional 600 million metric tons, necessitating a fourfold increase in worldwide production of vegetable oil. It doesn't take a scientist to know that the impact of such an increase in vegetable oil production on agricultural commodity prices, global hunger, tropical deforestation, and biodiversity would be enormous, especially in a world that is expected to add another 2 billion people by 2050. **Which leads me to ask: Are you really being a leader if the world would be much better off not following?**

<u>Crop-based biofuels are not sustainable:</u> Many studies, including work performed by CARB[23], show that full life cycle emissions, including emissions from increased fertilizer application and land use change (LUC), are significant, highly uncertain, and appreciably or entirely negate the carbon benefit of using biogenic feedstock. In fact, a recent assessment of GHG emissions resulting from corn ethanol production in the U.S. found that total life cycle emissions for corn ethanol exceed those of gasoline.[24] And a recent Model Comparison Exercise conducted by the US Environmental Protection Agency highlights the deep uncertainty underlying the modeled climate benefits attributed to soybean oil-based biofuels.[25] Another recent research study published in Nature Sustainability shows that the pace of tropical deforestation has more than doubled over the first two decades of this century, the same time period over which biofuel production has significantly increased in response to state and federal policies.[26] This study also shows that most (82%) of the forest carbon loss is at some stages associated with large scale commodity or small-scale agricultural activities, particularly in Africa and Southeast Asia.

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[23] See 2015 LCFS Rulemaking document at [Microsoft Word - APPENDIX I-iLUC_FINAL_ks.docx (ca.gov)]

[24] Lark et al., Environmental outcomes of the US Renewable Fuel Standard, PNAS 2022 Vol. 119 No. 9.

[25] See https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf

[26] Feng, et al., Doubling of annual forest carbon loss over the tropics during the early twenty-first century, Nature Sustainability, **5**, pages444–451 (2022)

Producing crop-based biofuels increases food prices and exacerbates global hunger: As indicated by the research quoted above and multiple other research studies[27,28], diverting crops from human and animal feed markets to produce biofuels results in an increase in agricultural commodity prices as compared to the counterfactual without biofuel production. This increase in food prices results in increased hunger, especially amongst the most vulnerable populations of the world. According to Tom Hertel, professor at Purdue University and author of several studies on LUC impacts of biofuels (including original modeling work performed for CARB's LCFS), **"reduced food consumption is an important market-mediated response to increased biofuels production. While lower food consumption may not translate directly into nutritional deficits among wealthy households, any decline in consumption will have a severe impact on households that are already malnourished"**.[29] The biofuel industry wrongly claims that the LUC CI penalty for crop-based biofuels negates any food price increases and food consumption impacts and therefore CARB does not need to impose any additional limits on biofuel consumption beyond the current LUC CI penalty. However, according to Hertel et al., if food consumption were held constant in the CARB LUC model (instead of allowing food consumption to decrease as is done in the actual LCFS modeling), twice as much forest conversion to agriculture would be predicted and the LUC CI penalty would increase by 40%. **In essence, a portion of the emission reductions attributable to crop-based biofuels under the LCFS is the result of the most food insecure populations in the world eating less.**

Crop-based renewable diesel, biodiesel, and aviation fuel is an extremely expensive means of reducing GHG emissions: Renewable diesel, biodiesel, and aviation fuel receives monetary incentives from the federal RFS, the federal Biodiesel Blenders Tax Credit, and the California LCFS. These incentives stack and adding the incentive values of these three programs resulted in a total societal cost in 2023 of nearly $4 per gallon and a GHG cost effectiveness (or ineffectiveness) of more than $600 per metric ton of GHG emission reduction, a value that greatly exceeds any reasonable estimate of the social cost of carbon.[30] Considering that emission reductions from crop-based biofuels are highly uncertain, one can only conclude that policies incentivizing these biofuels are a costly and risky means of spending limited consumer dollars on climate change mitigation. Moreover, because of the RFS volume mandate, renewable diesel and biodiesel would have been produced and consumed in the U.S. without the LCFS incentive. Stacking the smaller LCFS incentive on top of the larger federal incentives merely results in the shuffling of the lowest CI renewable diesel, biodiesel and ethanol to California. **Essentially, California consumers are paying a significant cost to support combustion fuels that achieve very little real global GHG reduction,**

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[27] See Economics of Biofuels | US EPA

[28] See The impact of the U.S. Renewable Fuel Standard on food and feed prices (theicct.org)

[29] Hertel et al., Effects of US Maize Ethanol on Global Land Use and Greenhouse Gas Emissions: Estimating Market-mediated Responses, Bioscience, Vol. 60 No. 3, 2010.

[30] Cost effectiveness estimated by dividing the total incentive value by the estimated GHG emission reduction for soy renewable diesel under the LCFS.

money that would be much better spent helping California transition to zero emission transportation.

In conclusion, emissions associated with producing crop-based biofuels are highly uncertain and may, in fact, be greater than fossil fuels on a full life cycle basis. Moreover, these fuels are very expensive and exacerbate tropical deforestation and global hunger. Because of these issues, the European Union has taken steps to restrict the use of biofuels produced from food and feed crops, and mainstream environmental organizations such as International Council on Clean Transportation, Natural Resources Defense Council, Union of Concerned Scientists and Earthjustice, as well as UC Davis Institute for Transportation Studies are urging CARB to limit the use of vegetable oil-based biofuels under the LCFS.[31,32] **Promoting the use of these fuels is not in line with California's role as a global leader in environmental policy, and I highly encourage the Board to direct staff to cap and ultimately phase-out the use of crop-based biofuels in California**.

Postscript: In lieu of a cap on crop-based biofuels, CARB could acknowledge that the RFS and Biodiesel Blenders Tax Credit are responsible for setting the total volumes of ethanol and biomass-based diesel consumed in the US, and only award LCFS credit for achieving reductions in excess of RFS requirements. For example, the RFS requires a CI reduction of 50 percent for biomass-based diesel to qualify for RINS. The LCFS could have a separate benchmark table for biomass-based diesel that starts at a 2010 baseline CI of 54.88 g/MJ (i.e., a 50 percent reduction) and declines to a 2045 CI target of 5.29 g/MJ (i.e., a 90 percent reduction from the 2010 baseline CI). Likewise, the RFS requires a CI reduction of 20 percent for ethanol to qualify for RINS. The LCFS could have a separate benchmark table for ethanol that starts at a 2010 baseline CI of 79.32 g/MJ (i.e., a 20 percent reduction) and declines to a 2045 target CI of 7.93 g/MJ. The major advantage of this approach as compared to a volume cap is that it doesn't create two separate markets for credits and can be seamlessly incorporated into the LRT-CBTS without major modifications to the software.

[31] See comment letters from ICCT, NRDC, UCS, and Earthjustice.

[32] See ITS Research Report "Driving California's Transportation Emissions to Zero", Carbon Neutrality Study 1: Driving California's Transportation Emissions to Zero – University of California Institute of Transportation Studies (ucits.org), pages 392-396.

Attachment B: Comments on the Draft Environmental Impact Analysis

Throughout the Draft EIA, CARB frequently makes the determination that the impacts associated with expected compliance responses are Potentially Significant and Unavoidable. Based on this determination, CARB staff will request that the Board issue a Statement of Overriding Considerations. CEQA places the burden on the approving agency to affirmatively show that it has considered feasible mitigation and alternatives that can lessen or avoid identified impacts through a statement of findings for each identified significant impact. I do not believe that CARB has adequately demonstrated that they have considered feasible mitigation and alternatives that could lessen or avoid several potential impacts on air quality and agricultural and forest resources. For example:

154.19
- Trucking of biofuel feedstock and finished product, trucking of manure or food and green waste to a centralized digester, trucking of biomethane from digesters to the pipeline injection point, trucking of hydrogen from production facilities to dispensing stations, and trucking of carbon dioxide from the capture facility to the sequestration point are all reasonably foreseeable compliance responses resulting in local air quality impacts. As an example, the conversion of the Paramount refinery to renewable diesel production by World Energy results, by their own calculations, in an estimated 125 tpy increase of NOx emissions for transport of feedstock and finished product.[33] These emissions could be mitigated by requiring these LCFS participants to use zero emission trucks as a condition for generating credit.

154.20
- Converting biogas to electricity using internal combustion generators is a reasonably foreseeable compliance response resulting in local air quality impacts that could be avoided by requiring LCFS participants to use non-combustion alternatives such as fuel cell generators as a condition for generating credit. In fact, CARB staff in the air quality calculations assumed that dairy electricity projects would use fuel cells even though the regulation does not require it. I suggest making it official.

154.21
- Continued siting of new fuel production facilities in overburdened communities is a reasonably foreseeable compliance response which exacerbates entrenched air quality problems that could be avoided by requiring LCFS participants to site all new production facilities in locations receiving a CalEnviroScreen score of "X" or lower as a condition for generating credit.

154.22
- Continued methane leaks from dairy digester projects are reasonably foreseeable and could be avoided by requiring LCFS participants to employ periodic leak detection and repair at digester facilities and transport equipment.

154.23
- Increasing dairy herd size to generate additional LCFS credit is a reasonably foreseeable compliance response resulting in local air quality impacts that could be mitigated by capping avoided methane credit based on the historic herd size before initial LCFS certification.

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[33] See page 2-41 of the AltAir EIR
https://www.paramountcity.com/home/showpublisheddocument/8001/637811424787470000

- 154.24 Increased biofuel feedstock production is a reasonably foreseeable compliance response resulting in land use change and global hunger impacts that are not being mitigated or avoided by the existing land use change CI penalty. Future impacts could be avoided by placing a cap on use of crop-based feedstocks to produce biofuels.

The Board should require staff to take a step back and think creatively when determining which potentially significant impacts can be mitigated or avoided rather than simply claiming that all impacts are unavoidable.

Moreover, there are several faulty assumptions in CARB's analysis that result in the overestimation or inaccurate portrayal of GHG and air quality benefits of the Proposed Amendments. These faulty assumptions also lead to the incorrect conclusion that the Proposed Amendments scenario is more cost effective and provides more air quality benefits than Alternative 1. These faulty assumptions include:

- 154.25 CARB staff are not using the latest data on tailpipe PM emissions from vehicles consuming renewable diesel. The ISOR and Draft EIA attribute health benefits to increased use of renewable diesel in California, especially associated with reduced PM2.5. This is based on a 2011 analysis, and ignores a more recent 2021 study prepared for CARB that looks at the NOx and PM from Biodiesel and Renewable Diesel Emissions in Legacy and New Technology Diesel Engines. The key finding in this more recent study is that air quality benefits from older engines are not observed in new technology diesel engines, which are now required in California for the on-road fleets. This undercuts one of the main justifications offered to reject limits on renewable diesel and results in an inaccurate portrayal of the criteria pollutant emission benefits of the proposed amendments in the Draft EIA. Ironically, because renewable diesel does offer PM reductions in older trucks that are still in use elsewhere in the US, concentrating most of US renewable diesel in California does not help Californians but it does harm others across the United States, many of whom reside in overburdened communities. A large percentage of renewable diesel currently consumed in California originates from a region of Louisiana known as Cancer Alley. Residents of Cancer Alley suffer from the additional pollution emitted by newly constructed or expanded renewable diesel refineries but do not benefit from the reduced tailpipe emissions that would occur if the renewable diesel were consumed locally instead of being shipped to California.

- 154.26 CARB incorrectly attributes 100 percent of the GHG emission reductions associated with consuming biofuels to the LCFS. Setting aside the argument that the CI values CARB calculates for crop-based biofuels are highly uncertain and likely significantly underestimated, CARB staff have changed the assumptions they use in attributing GHG emission reductions to the LCFS for biofuel. In the rulemaking for the 2018 amendments (see Attachment F page F-14), staff acknowledged that the federal Renewable Fuel Standard (RFS) and Biodiesel Blenders Tax Credit are primarily responsible for driving the production of biofuels. Through its design, the RFS essentially creates a volume mandate for biofuels, and therefore the total volume produced in the United States is effectively fixed by the RFS. In other words, if the LCFS ended today, the same amount of biofuel would be produced in the US. Because of this, the LCFS subsidy does not result in more production of biofuel beyond that incentivized by the RFS and blenders tax credit, but rather provides incentive to incrementally reduce the CI and shuffle the lowest CI production to California. Under the RFS, corn ethanol is required to achieve a 20 percent CI reduction and biomass-based diesel is required to achieve a 50 percent CI reduction to qualify for the subsidy. Therefore, in the 2018 LCFS rulemaking, staff gave credit to the federal programs for a CI reduction of 20 percent for corn ethanol and 50 percent for biomass-based diesel, and only gave credit to the LCFS for CI reduction in excess of these values. For example, under these more appropriate assumptions, the LCFS took some credit for lower CI of fuels made from used cooking oil and tallow which have CI reductions of about 60 to 80 percent but took no credit for emission reductions from fuels made from soy and canola oil which have CI reductions of about 50 percent. Conversely for the 2024 amendments, staff appears to be crediting the LCFS for the full CI reduction (see page 38 of ISOR), effectively ignoring the contribution of the federal programs. This change in assumption results in an overestimation of the GHG benefits of the Proposed Amendments scenario in the Draft EIA.

154.27

- CARB staff makes a flawed assumption that inflates the GHG and criteria pollutant benefits associated with displacing fossil diesel. In the GHG and air quality analysis presented by CARB, staff assume that a reduction in the consumption of fossil diesel in California will result in a proportional reduction in oil production in California. Staff then attribute the reduced criteria pollutant and GHG emissions associated with the oil production decline to the LCFS (see page B-1 of the SRIA for equations). I see several issues with this logic.

    - First, CARB totally disregards the fact that crude production in California is in terminal decline and has been for the past 40 years (see page 7). CARB's calculations assume a static baseline at 2019 crude production levels, rather than a dynamic baseline that accounts for the long-term historical rate of decline in production. In other words, CARB assumes that crude production in California would remain constant at 2019 levels without CARB regulations, when it will likely decline to near zero by 2045 based exclusively on naturally declining production from quickly maturing oil fields. If we want to understand the benefits or costs of an action or regulation, it should be measured against counterfactual case where the action or regulation did not happen. In either world, California oil production is dropping.
    - Second, even if CARB properly assumes a declining baseline for the calculations, I don't see evidence for a relationship between California oil production and fossil fuel demand in California, especially given the fact that California crude makes up only 25 percent of oil supply to California

refineries. Changes to the “rate of oil production decline” in California are largely the result of global oil price, California wholesale NG price, and approval of new well drilling. In other words, California oil production declines more rapidly when global crude prices are low and NG prices are high, and oil production declines less rapidly when crude prices are high and NG prices are low.[34] Changes in California fossil fuel demand will not significantly affect this dynamic because these changes are too small to significantly affect global oil prices. California refineries will much more likely respond to reduced demand for fossil fuels by reducing crude imports first, as is clearly evident by dramatically reduced imports during the pandemic (see the LCFS Dashboard Figure 8 which shows that imports of crude oil declined by nearly 100 million barrels between 2019 and 2020 while California production declined by only 6 million barrels). Moreover, if there were a link between California crude production and fossil fuel demand in California, one would expect to see California crude production increase after the pandemic in response to the rebound in gasoline and diesel consumption. Instead, California crude production continued its relatively steady annual decline and imported crude volume increased.

- Third, CARB is assuming that a reduction in fossil fuel demand will result in a proportional reduction in refining capacity in California. Although this is probably the strongest assumption CARB makes, it is in no way assured. California refiners may simply respond to reduced demand in California by exporting excess production, especially given the legal fights and costs associated with cleanup that will ensue after shutdown. In other words, will California refineries continue to operate and sell barely profitable fuels to satisfy increasing consumption in Asia or will they shut down and incur extremely expensive cleanup costs?

- CARB staff is significantly underestimating criteria pollutant emissions at renewable diesel, renewable gasoline, and sustainable aviation fuel production facilities. Staff assumes that these facilities have similar emissions to a simple oil
154.28 refinery and estimate emission factors of 0.058 and 0.022 tons per million DGE for NOx and PM2.5 emissions respectively.[35] Environmental Impact Reports for the AltAir and Phillips 66 refinery conversions indicate emission factors of 3 to 4 times these values. For the AltAir facility, data indicates emission factors of 0.152 and 0.090 tons per million DGE for NOx and PM2.5 emissions respectively.[36]

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[34] California oil producers have been injecting steam to recover oil for over 50 years and the remaining oil is getting much harder to extract as indicated by the increasing amount of steam injected per barrel of oil produced. The rate of California oil production is largely dependent on the amount of steam that the oil field operators can afford to inject. During periods like 2011 – 2014 when global crude prices were high (above $100 per barrel) and NG prices low, oil companies could afford to inject more steam and oil production remained nearly constant (see figure 2 on page 8 and figure 6 on page 10). When global crude prices dropped in 2015, California oil production resumed its decline.

[35] See page B-2 of https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appc-1.pdf

[36] See pages 2-37 through 2-46 for estimated project emissions for the AltAir facility https://www.paramountcity.com/home/showpublisheddocument/8001/637811424787470000

For the Phillips 66 facility, data indicates emission factors of 0.249 and 0.082 tons per million DGE for NOx and PM2.5 emissions respectively.[37]

- CARB staff assume that all future dairy to electricity projects will use fuel cell electric generators even though there is no requirement that project operators use fuel cells rather than combustion generators.[38] This assumption results in extremely low NOx and PM2.5 emission factors for these projects and therefore underestimates potential emissions.

- As discussed previously, CARB appears to be allowing future CCS and DAC projects to receive LCFS credit for emission reductions that will also be sold to other entities in the voluntary carbon market and/or through the marketing of zero-emission crude oil. If this is the case, the GHG emission reductions claimed for the LCFS in the Draft EIA are significantly overestimated as the same emission reductions are also being sold to parties not participating in the LCFS.

The net result of all these assumptions is that CARB is significantly overestimating the criteria pollutant and GHG reduction benefits associated with biofuel production and consumption, dairy electricity projects, as well as CCS and DAC projects, which results in an inaccurate portrayal of the benefits of the amendments in the Draft EIA.

Finally, CARB did not update the CATS model, rerun the Proposed Amendments scenario, and update the economic and air quality analyses between the submission of the SRIA to DOF in September and release of the rulemaking package in January.[39]
154.29 During this period, a few changes were made to the proposed amendments. The most significant of these changes were to grandfather all pre-2030 dairy and swine projects from the proposed phaseout of avoided methane and to grandfather all pre-2030 RNG projects from the proposed deliverability requirements. Therefore, the economic and air quality analyses presented in the ISOR and Draft EIA do not reflect the actual LCFS amendments proposal.

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[37] See Stationary Source Table 1 on PDF page 119 for estimated project emissions for the P66 facility https://www.contracosta.ca.gov/DocumentCenter/View/72908/Appendix-B--Air-Quality-and-GHG-Emissions-Technical-Data-PDF

[38] See pages B-2 and B-3 at https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appc-1.pdf

[39] Confirmed by email with CARB staff on 1/26/2024.

Comment Log Display

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Comment 169 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Alli
Last Name	McIntosh
Email Address	alli@skynrg.com
Affiliation	
Subject	Comments on Proposed Changes to the LCFS Regulation
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6794-lcfs2024-VWdRZ1NgUzRSeQMz.pdf
Original File Name	2024-02-19 SkyNRG Comments on Proposed Changes to the LCFS Regulation.pdf
Date and Time Comment Was Submitted	2024-02-19 14:26:04

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 19, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814
Via Online Submission: https://ww2.arb.ca.gov/rulemaking/2024/lcfs2024

Comments on Proposed Changes to the LCFS Regulation

Dear California Air Resources Board (CARB) Low Carbon Fuel Standard Program Staff:

Thank you for the opportunity to provide comments in response to the draft proposed changes to the Low Carbon Fuel Standard (LCFS) and associated Initial Statement of Reasons (ISOR) published on December 19, 2023. We appreciate CARB hosting workshops and soliciting stakeholders' input on a variety of forward-looking concepts for the future of the LCFS. Taking decisive action to bolster the LCFS market will help ensure the long-term viability of the program and the accomplishment of the state's carbon reduction objectives. SkyNRG Americas ("SkyNRG") is pleased to be able to provide comments on several areas of proposed LCFS policy.

Since 2009, SkyNRG has been building sustainable aviation fuel (SAF) production capacity to support the aviation industry's 2050 net-zero commitments. SkyNRG will be among the first producers of SAF and renewable diesel (RD) at scale from cellulosic feedstocks such as biomethane. Together with our existing technology partners, our production process converts biomethane to SAF and RD at an integrated production facility. SkyNRG's plans necessitate withdrawing biogas from common carrier pipelines on a book-and-claim basis, similar to producers of hydrogen, compressed natural gas (CNG), or liquid natural gas (LNG). Beginning in 2019, SkyNRG has invested in the development of dedicated SAF production facilities in the U.S. and Europe to support the aviation industry's transition to SAF from fossil jet fuel. Critically, SAF is one of the few cost-effective and scalable tools for decarbonizing aviation in the near- to medium-term. As such, SAF is one of few viable solutions for mitigating aviation emissions in the foreseeable future.

While aviation emissions currently comprise a relatively small percentage of California's total greenhouse gas (GHG) footprint, its share of the state's emissions inventory will increase through 2035 and beyond as road transportation modes electrify. The aviation sector is one of the most difficult industries to decarbonize due to unique operational and safety requirements that necessitate energy dense-fuels, highlighting the critical role of low carbon liquid fuels for the future of the aviation sector.

SAF is an essential contributor to achieving Governor Newsom's goal of 20% clean fuels for the aviation sector by 2030. However, delaying supportive low carbon policies now will jeopardize the industry's ability to scale SAF production in the timeframe needed to meet the Governor's goal. SAF production facilities can take five to seven years to move from development to operation; consequently, construction of new projects (or expansions of existing facilities) must begin now to enable availability of these solutions by 2030.

Strengthen the 2030+ CI Targets

The LCFS has been extremely successful in encouraging market investment in low carbon fuels and lowering transportation fuel pool emissions in the past decade. To help ensure a healthy LCFS credit

market that can keep pace with these investments, we strongly support CARB's plans to strengthen the
existing emission targets for 2030 and beyond. As such, CARB should revise the 2030 compliance target
155.1 to achieve at least a 35% reduction in GHG emissions for diesel and gasoline and implement more
stringent carbon intensity (CI) targets for jet fuel. We encourage CARB to make an appropriate
adjustment to reflect the strong market supply scenario to ensure development of novel markets, like
SAF.

We support the introduction of an auto-acceleration mechanism (AAM) to strengthen CI reduction
targets and respond to growth in the low carbon fuels sector. By recognizing and rewarding
overperformance in the program, California benefits from the latest in low carbon fuel technologies. As
155.2 the rule is currently written, it is essential that the AAM functions properly in tandem with the CI
adjustment. Private industry has signaled that it is ready to exceed stated goals well ahead of the
established targets. Considering the achievement of 2024 goals in 2022 and strong credit bank builds
each quarter, we believe the AAM should not be restricted to an every-other-year frequency. This allows
the AAM to respond to market conditions as they emerge rather than potentially two years behind
schedule.

CARB Should Expand, Not Restrict, Book-and-Claim Opportunities for Biomethane

As we have stated in previous comments to CARB, expanding opportunities for biomethane to be used as an input for additional transportation fuels such as SAF and RD will be critical to achieving the more stringent targets introduced during previous workshops. The share of LCFS credits generated for biomethane-based fuel, primarily renewable CNG, has steadily grown over the last decade thanks in large measure to the ultra-low CI scores attainable for feedstocks such as dairy and livestock wastes. This trend may be unsustainable long-term, however, if biomethane opportunities are not encouraged beyond their current applications due to the limited scale of on-road heavy duty natural gas vehicle (NGV) fleets. Existing LCFS regulations heavily incentivize the use of biomethane in renewable CNG and LNG applications, and for renewable hydrogen production, by offering the flexibility of indirect accounting of biomethane injected into pipeline systems connected, sometimes at great distance, to downstream production or dispensing locations (referred to as "book-and-claim"). This is a highly effective way to rapidly decarbonize transportation fuels, and we encourage this to be expanded to SAF and RD as it has been applied to other transportation fuel end uses like, hydrogen, CNG and LNG.

The U.S. biomethane industry has evolved with existing regulatory programs at both the federal and
state levels that reasonably recognize that most sources of biomethane do not justify co-location of fuel
production. To accommodate this challenge, book-and-claim accounting is an indispensable ingredient
155.3 to incentivizing the development of biomethane resources and unlocking their emission reduction
potential to materially reduce emissions.

Under the current regulations, SkyNRG (and others) would be unable to participate in the expansion of biomethane resources because there are no provisions allowing book-and-claim accounting for offsite biomethane utilized as feedstock to produce SAF and RD. We are discouraged that CARB introduced deliverability requirements for biomethane that restrict availability of this valuable feedstock, rather than expanding its availability. Geographic and deliverability limitations would almost certainly stifle investment in biomethane resources and reduce opportunities for the state to achieve its LCFS-specific climate goals. Respectfully, we believe that CARB's stated goal to harmonize book-and-claim policies for low-CI electricity and biomethane limits growth because it fails to recognize the fundamental difference of biomethane as a feedstock.

Additionally, we take issue with the Renewables Portfolio Standard (RPS) deliverability requirements that are specific to electricity generation. In the proposed rule and accompanying ISOR, CARB staff explains intentions to align deliverability of biomethane in the LCFS with the California Energy Commission's (CEC) RPS by requiring common carrier pipelines to physically flow toward California 50% of the time on an annual basis. Considering the RPS requirements are specific to electricity generation, we take issue with relying on this standard for biomethane as a transportation fuel or feedstock. Given the variety of uses of this valuable low-CI feedstock, the RPS alignment is limiting the potential for biomethane to reduce CI of other hard-to-decarbonize sectors, like aviation. Considering the goal of growing SAF's share of California's aviation fuel supply, these unique characteristics need to be considered. By allowing the book-and-claim of biomethane feedstocks, CARB ensures a steady supply of SAF to meet its programmatic goals. Electricity and SAF do not compete for the same investments, resources, or customers. Neither is advantaged over the other under the current regulatory regime, so harmonizing requirements would at best be an unnecessary change, and at worst, it could severely disrupt both existing and future investments.

155.3 cont

Earlier this year, the U.S. Environmental Protection Agency (EPA) recognized the potential for biomethane as a feedstock in the production of renewable fuels. In its 2023 rulemaking, the EPA established a regulatory framework allowing the use of biomethane as a "biointermediate," paving the way for producers like SkyNRG to make renewable, low carbon fuels like SAF and RD from products derived from biomethane under book-and-claim accounting (once finalized). Critically, the EPA's regime leverages indirect accounting of pipeline injection and offtake at separate points consistent with LCFS book-and-claim procedures. In CARB's ISOR for the proposed rule change, the need to align with federal support for SAF proliferation is specifically highlighted as a guiding principle of the rule change. The LCFS program has long been compatible with federal incentives, including the Renewable Fuel Standard (RFS) and numerous tax credits. The creation of additional federal incentives through the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA) only increases the opportunity for the LCFS program to align with and leverage federal investments to accelerate decarbonization. While the SAF market is growing, these incentives are greatly needed and have outsized impacts in supporting the industry's maturation. CARB should ensure that the LCFS program aligns with the treatment of SAF feedstocks under the RFS to avoid creating a bifurcated RNG market.

155.3 cont

In summary, we implore CARB to expand eligibility for book-and-claim of all sources of biomethane as feedstock to produce transportation fuels like SAF and RD. Doing so will create new opportunities to utilize biomethane to make low, or even negative, CI transportation fuels that are suitable for sectors that are hard to decarbonize. This will directly contribute to Governor Newsom's ambitious goals for expanded production and use of low carbon, renewable aviation fuels. With appropriate oversight (including the verification and validation procedures CARB already requires), we believe that any compliance risks can be effectively managed as they are today for CNG, LNG, and hydrogen production. By recognizing the potential of RNG as an SAF and RD feedstock, CARB acknowledges its strong value to a maturing industry and instills confidence in investment communities. Failing to expand book-and-claim eligibility for biomethane feedstocks is a critical issue that may significantly negate California's ability to benefit from the next generation of low carbon fuels.

Further Study on Changes to Avoided Methane Emissions Credits is Necessary

As SkyNRG works to build SAF production capacity, the company will continue to explore a wide range of biomethane feedstock opportunities from organic waste streams, including food waste, yard and landscaping waste, industrial and wastewater sludge, and a variety of animal wastes. Many untapped waste streams are novel as it relates to LCFS pathways, but nonetheless can readily be converted to transportation fuels through technologies that are commercially proven and readily suitable for producing low carbon fuels from biomethane pathways.

155.4 CARB should encourage the capture and productive repurposing of emissions from organic waste streams processed through anaerobic digestion, regardless of the source of the waste stream. To this end, CARB should avoid making changes in the present amendments that limit opportunities to include avoided emissions in CI calculations. We do not believe that a premature sunset is appropriate in achieving LCFS success. Therefore, we believe that this warrants further study from CARB to avoid any unnecessary consequences as currently proposed.

The GHG emission reductions resulting from CNG fleets being the default for many medium- and heavy-duty applications are attributed, in part, to the incentives of the LCFS and has resulted in improved air quality for constituents. SAF is at a similar crossroads. By allowing for avoided methane crediting for biomethane as a feedstock, CARB has the potential to see SAF become the default fuel for aviation, much like the transition in the CNG fleet space. Biomethane has continued potential to reduce GHG emissions in California, and recognizing its potential as a feedstock is essential to the continued success of the program.

155.5 We further implore CARB to study the success of Europe's Renewable Energy Directive (RED), which has long recognized the avoided methane benefits when assessing the lifecycle CI of various RNG pathways. The RNG to SAF pathway presents a unique opportunity to scale-up low carbon fuels in the aviation sector to align with California's recently stated goals of obligating jet fuel within the LCFS.

Fossil Jet Participation in LCFS

155.6 Inclusion of fossil jet in the LCFS is a first step in recognizing the impact of aviation on the state's GHG emissions and the benefits of SAF for the state's climate ambitions. Given current technologies and feedstocks, SAF represents a major opportunity to decarbonize this hard-to-abate sector. With the encouraging language in the proposed rule, SkyNRG further encourages CARB to expand the scope of fossil jet regulation to include int**er**state flights.

Current regulations under the LCFS are already regulating interstate fossil fuel for on-road vehicles refueling in California before leaving the state. It was through this scheme that the state has benefited from immense growth in liquid fuel innovation and the current boom in RD production and end use. This major paradigm shift in fuel technology was due in part to visionary leadership by CARB staff. By expanding the scope of fossil jet regulation in the LCFS, the state could further benefit from similar growth in the SAF sector. Furthermore, by regulating all fossil jet fuel uplifted in California, CARB would benefit from a streamlined regulatory process and reduced risk of legal challenge.

155.7 Additionally, we support accelerating the obligation to 2025 instead of 2028. CARB states that the proposal to delay the elimination of the exemption for fossil fuel jet fuel until 2028 is meant to provide "sufficient time for potential producers of alternative jet fuel to add capacity for the anticipated increased demand of alternative jet fuel." However, such a delay is unnecessary, and we urge CARB to consider an earlier implementation date. We note that British Columbia has already added an obligation for all fossil jet fuel beginning in 2026, coupled with a volumetric SAF mandate beginning in 2028. Given that CARB is only proposing an obligation for jet fuel and not an actual SAF requirement, consistent with the LCFS, there is technically no need for lead time to increase SAF production capacity because the structure of the LCFS program allows for compliance via credits generated outside of aviation, credits which are readily available today. In addition, CARB has already provided a five-year window for growth since making SAF an opt-in credit generator in 2019, during which time SAF volumes recorded under the LCFS have increased five-fold, despite a global pandemic and the continued regulatory disadvantages for SAF producers under both the LCFS and the Cap-and-Trade program. Nevertheless, SAF continues to lag far behind similar ground transportation fuels under the LCFS. This gap should not be misinterpreted as a signal that the SAF market or SAF technologies are insufficiently mature to support an obligation for aviation, but rather should serve as evidence that the lack of an LCFS obligation for aviation has steered producers toward more lucrative opportunities serving road transportation.

Thank you for the opportunity to comment on the proposed changes to the LCFS. SkyNRG applauds CARB staff for taking action to drive innovation and growth of low carbon fuel technologies. Through careful consideration of impacts of this rule change to a developing industry, we believe SAF can take the LCFS to new heights. We look forward to continuing the legacy of emissions reductions spurred on by this groundbreaking regulation.

Sincerely,

John Plaza
President & CEO
SkyNRG Americas, Inc.

Comment Log Display

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Comment 170 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mary
Last Name	Solecki
Email Address	msolecki@ajw-inc.com
Affiliation	
Subject	AJW comments on LCFS proposed amendments
Comment	Please see attached file for AJW comments. Thank you.
Attachment	www.arb.ca.gov/lists/com-attach/6795-lcfs2024-BTdVZwAxBGUDNwk5.pdf
Original File Name	240220 AJW LCFS Amendments_AAM_Comment Letter.pdf
Date and Time Comment Was Submitted	2024-02-19 15:03:14

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

ENHANCING OPPORTUNITIES FOR INNOVATORS

February 19, 2024

Chair Randolph and Members of the Board
California Air Resources Board
1001 I St.
Sacramento, CA 95814

RE: AJW Comments on the Proposed Amendments to the Low Carbon Fuel Standard

Dear Chair Randolph and Members of the Board,

AJW appreciates the opportunity to submit comments on the proposed amendments to the Low Carbon Fuel Standard (LCFS). AJW applauds the California Air Resources Board (CARB) and is encouraged to see that the proposed amendments are designed to increase overall program stringency and set forth a blueprint to achieve 90% reduction in carbon intensity (CI) of California's transportation fuels by 2045. First and foremost, a strong carbon intensity target is critical to ensure that the LCFS continues to drive down greenhouse gas (GHG) emissions in the transportation sector and decrease the state's reliance on fossil-based fuels.

More specifically, AJW would like to provide the following comments on the Auto Acceleration Mechanism (AAM). Throughout 2023, AJW engaged in a stakeholder process to develop and socialize the concept of an acceleration mechanism – a self-adjusting tool that would complement existing mechanisms to avoid credit shortfalls, a strong 2030 CI target, and a one-time step-down in program stringency. An AAM would aim to keep innovation, investment, and emission reductions on track when there is sustained overperformance of the program. From that stakeholder process, AJW developed a white paper with recommendations for CARB on how to successfully design and implement the mechanism.[1] AJW is
156.1 pleased to see that much of what was proposed by CARB staff is aligned with the recommendations in our white paper and strongly supports the overall concept and inclusion of the mechanism into the LCFS. However, with the benefit of weighing and modeling the proposed design details against the 2030 target and step-down as proposed by staff, we are updating our recommendations on a few design elements.

As proposed in the draft regulation, the first year that the AAM could influence program stringency is 2028 (triggered from 2026 data), but a fundamental principle of the mechanism is to be able to respond to overperformance of the program in a timely manner. We have observed quick market reactions to CARB's Standardized Regulatory Impact Assessment (SRIA) and initial proposal. This stands at odds with the implicit year of waiting before the first proposed AAM assessment. The additional year that staff proposed is presumably designed to allow for the market to fully adjust to the new LCFS targets after implementation in 2025, but this stepped approach does not appear necessary with the immediacy of market response. Thus, **AJW recommends that CARB pull forward the date for triggering the AAM by one year.** In the event the cumulative credit bank continues to grow in 2025, in spite of the step-down and new compliance targets, we believe it is appropriate for a first assessment in 2026, with a change in
156.2 benchmark in 2027. In fact, 2025 is the most important year for CARB to consider, as it will be imperative to make any adjustments to the compliance target before an oversized credit bank deters further investment into alternative fuels and vehicles. Using this approach, the AAM could potentially be utilized in 2027 and 2029, which will yield more opportunities for potential emission reductions and still give

[1] AJW White Paper on Designing an Acceleration Mechanism. Submitted in response to CARB's May 23, 2023, LCFS Workshop. https://ww2.arb.ca.gov/form/public-comments/submissions/3701

ample lead time for deficit and credit generators to adjust their operations to anticipate a stricter compliance curve.

156.3 Additionally, AJW encourages CARB to reassess the proposed threshold when considering the credit bank to average quarterly deficit ratio formula, which is currently proposed at 3.0 (i.e., three quarters of credits in the credit bank). This, when combined with the threshold of 1.0 for the credit generation to deficit generation formula (i.e., credits are continuing to contribute to a growing cumulative bank), is an overly conservative proposal as it would not allow for the AAM to trigger in situations where there is general consensus on the overperformance of the program. For example, looking at recent LCFS history, this 3:1 ratio the AAM would not have been triggered even in 2022 despite most stakeholders observing that the LCFS was overperforming and needed adjustments to program stringency to course correct. After backcasting recent LCFS activity, **we are instead recommending the average quarterly deficit ratio should be 2.0.** The impact of this threshold would mean that the credit bank is able to cover one-half a year of deficits. Today, that would mean that credit production would need to fall by 50% to create that level of demand. Given this, a threshold of 2.0 appears ample, when taken in combination with the consideration of whether credits are continuing to outperform deficit generation.

Backcasting Recent LCFS Activity with CARB-Proposed AAM Triggers							
Year	Formula	Trigger	2018	2019	2020	2021	2022
Cumulative Credit Bank	(B)		8,918,202	8,439,052	8,343,187	9,568,451	15,393,990
Total Credits	(C)		11,310,472	14,934,921	15,364,400	20,186,741	26,871,733
Total Deficits	(D)		12,366,566	15,487,415	15,488,232	18,864,647	21,233,457
Credit Bank to Avg Quart Deficit	(B/ (0.25 x D)	>3.0	2.885	2.180	2.155	2.029	2.900
Annualized Credits to Deficits	(C/D)	>1.0	0.91	0.96	0.99	1.07	1.27

156.4 Lastly, AJW recommends increasing the size of the step-down. A 5% step-down is a good start at beginning to address the size of the cumulative credit bank, however, it does not go far enough. The cumulative credit bank is anticipated to increase its rate of growth throughout 2024 and a 5% step-down will not sufficiently address the problem considering current market conditions. Thus, as stated in previous AJW comment letters, **we encourage staff to increase the step-down to at least 7%** while staying within the boundaries of the existing environmental and economic analysis. Even though a 7% step-down will not completely resolve the problem of the cumulative credit bank, this one-time adjustment will set the program down a path of course correction – one where hopefully the AAM will not be required to make continuous adjustments.

AJW supports CARB's work to improve the LCFS and ensure its long-term viability. We encourage CARB staff to address the recommendations listed above and for the Board Members to adopt the finalized amendments. Doing so will accelerate technological innovations and investments in fuel decarbonization options, increase LCFS credit availability, and secure market stability for years to come.

Sincerely,

Mary Solecki
Partner
AJW, Inc

Comment Log Display

Here is the comment you selected to display.

Comment 171 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Tadashi
Last Name	Ogitsu
Email Address	ogitsu@mac.com
Affiliation	
Subject	Questions and comments for 2023 LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6796-lcfs2024-AXBcL1w4WHhSIFA5.pdf
Original File Name	Questions and comments for LCFS 2023 Amendment Feb 19 2024.pdf
Date and Time Comment Was Submitted	2024-02-19 15:30:18

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Questions/Comments to LCFS 2023 Amendment

Name: Tadashi Ogitsu
Affiliation: Lawrence Livermore National Laboratory
Title: Staff scientist, PhD in Materials Science

Disclaimer

Opinions expressed in this document are entirely my own and nothing to do my employer. This study was conducted exclusively during my personal time.

Questions/Comments:

I would like to hear the CARB's responses to the following questions and comments at the hearing on 3/21/2024.

In page SRIA – 16, "3. Fuel Pool Demand, d) Light-Duty Zero Emission Vehicles", it is stated that

Highlight is from commenter

"*By 2031, staff assumed that BEVs would no longer have a substantial range or **charging-time disadvantage** compared to gasoline-powered LDVs and would therefore achieve 100% of the ICE vehicle VMT*."

157.1

1. 5 min charging of 80kWh battery (size of battery used in long range BEVs such as Tesla Model 3/Y) requires 1MW even without considering Joule heating loss and if energy loss is taken into consideration, it will require 10MW electricity supply capacity with 90% energy loss (explained later).
   i. **Question 1-1**: Can CARB elaborate how charging time disadvantage is going to be resolved?
   ii. **Comment 1-1**: 90% loss means that the effective CI will be 10X of the CI of grid electricity, therefore, if the grid cannot achieve 1/10 of current CI by 2031, CO_2 emission from electricity used by BEVs will increase.
   iii. **Question 1-2:** Majority's adaptation of BEVs will require more than 1000 such DCFCs. 1000 of 10MW DCFC will require 10GW low CI on-demand electricity supply. Could CARB explain how are we going to realize this?
   iv. **Comment 1-2:** Solar and wind are NOT on-demand power supplies. Nuclear power plant is baseload (constant output). Therefore, significant amount of buffering capacity (temporal storage) is needed for our future low CI power supplies. DCFC must rely on such a buffer.
   v. **Question 1-3:** Could CARB explain what is the assumed buffering method to address intermittency of solar and wind or inflexibility of nuclear? How much does the solution cost per household?
   vi. **Comment 1-3:** Please keep in mind, $/kWh of stationary battery is about 100X of underground hydrogen storage.

2. LDV hydrogen fuel cell vehicles have been available from 2014 in California, which have always been capable of 5 min charging for 300+ mile driving range. I assume CARB is aware of this fact.
    i. **Question 2-1:** is CARB LCFS standard ***technology agnostic*** and focusing on decarbonizing transportation sector?
157.2
    ii. **Comment 2-1:** assuming the CARB's answer to 2-1 is yes (LCFS is technology agnostic) and considering the CARB's awareness on relevance of charging time and driving range for public acceptance, it is extremely puzzling that CARB assumes overwhelmingly higher rate of public acceptance of BEV over FCEV such as seen in Figures 3, 4, 10.
    iii. **Question 2-2:** could CARB elaborate *why there is no mentioning of LDV-FCEVs* in the section 3 Fuel Pool Demand, d) Light-Duty Zero Emission Vehicle (page 16)?

In the followings, I will provide information relevant to above questions and comments. In my view, these are the critical factors perhaps in the blind spot of CARB staffs.

1. Specification of DCFC necessary to achieve 5 min charging of a long range BEV

Currently, the industry leading long range BEVs can be represented by Tesla Model 3/Y long range models that use 80kWh battery. In order to charge 80kWh of electricity in 5 min, the DCFC must be able to provide at least 80 kWh x 60/5 = 960 kW, which is about 1MW. This does not include energy loss due to Joule heating. In the past, a Tesla expert informed me that current state of art Tesla Supercharger has very impressively low 6% energy loss to achieve one hour charging. In order to achieve 5 min charging, 12 times higher current needs to pass through the circuit. Assuming the resistance of circuit (DCFC and the BEV) is the same, the corresponding Joule heating loss becomes 144 times higher since Joule heating loss goes I^2R (current square multiplied by resistance). 144 x of 6 percent is 864%.

In order to reduce the Joule heating, resistance of the circuit, *R*, must be reduced significantly. I'm not aware of any conductor that offer orders of magnitude lower resistivity than copper. Therefore, I assume reducing *R* by 100x will require 100x larger diameter of cable. Or else, we will need supercoducting material which is affordable and does not consume significant amount of electricity to keep operational.

I must therefore conclude that 5 min charging of 80kWh battery in 2031 at DCFCs that are ubiquitously available for general public is extremely unlikely to take place..

The other possibilities: a significant improvement on the vehicle efficiency, in other words, significant reduction on the required size of battery. Factors of consideration: air drag (major source of loss on highway) and air conditioning (nonnegligible loss in cold winter/hot summer).

Air drag is proportional to (drag coefficient) x (cross sectional area) x velocity^2 . Unfortunately it is extremely unlikely that drag coefficient could be reduced by 100x. Needless to say the cross section of car cannot be reduce by order of magnitude since the driver and passengers need to fit into the car.

Air conditioning: it is said that about 20% of driving range will be reduced by using air conditioning when it is hot (90~100F) or cold (20-30F). In other words, 80% was used to move the BEV. Let's say the vehicle efficiency (moving) gets 100x efficient, we still use 0.2 x 80kWh = 16kWh for air conditioning. Unless battery consumption for air conditioning can be reduce by order(s) of magnetite, total vehicle efficiency cannot be improved that much.

2. Common misconception about the well-to-wheel efficiency of BEV and FCEV

It is often argued that the well-to-wheel efficiency of BEV is much higher than that of FCEV. This argument completely ignores the cost for necessary amount of storage to address intermittency of solar and wind. One can download the supply and demand time profile data in California from caiso.com and simulate how much storage may have been necessary if we are to eliminate fossil power plant by, for example, installing more solar. All what one has to do is integrate demand over one year (or multiple years), then adjust solar supply data in such a way that total demand matches with total supply. Then calculating cumulative loss/gain between supply and demand over the period will give you the ballpark estimate on the necessary storage.

Next is to estimate the cost of storage. This is very simple: look up $/kWh values of available storage solutions and multiply it with the necessary storage capacity. One may also consider the round trip efficiency (RTE). I usually use 0.4 for hydrogen and 0.8 for stationary battery. Then, we may normalize the cost for per-household (about 13M household in California). At last, we need to take the lifetime of such storage solutions to estimate how much all of us need to pay. I used 30 years for hydrogen underground storage and 10 years for stationary battery.

With this, one can estimate the cost/household/year for each storage solutions.

My conclusion was hydrogen underground storage will cost about one hundred dollar per household per year. Stationary battery will naturally cost more than two orders of magnitude higher than hydrogen underground storage, which is not affordable for majority.

Take home message: claimed high well-to-wheel efficiency of BEV (over FCEV) is ***<u>economically unattainable</u>*** with intermittent power sources such as solar/wind.

I had series of debates on this issue with Mr. Michael Liebreich, who popularize the notion that LDV-FCEV is inefficient compared to BEV therefore governments should not support H2 station deployment. I had pointed him out that the claimed high well-to-wheel efficiency of BEV is economically unattainable due to intermittency of solar and wind.

His response to my comment was overproduction.

I hope CARB staffs understand critical flaw in his argument. Overproduction means system waste either produced electricity or the production capacity *by design*. One cannot claim high well-to-wheel efficiency, while the underlying infrastructure is designed to waste significant portion of produced electricity or the production capacity. Hydrogen solution, while RTE (round trip efficiency) may be much lower, enable us to fill the supply-demand gap created by intermittency of solar and wind and/or inflexibility of nuclear (constant output) in an affordable way for majority.

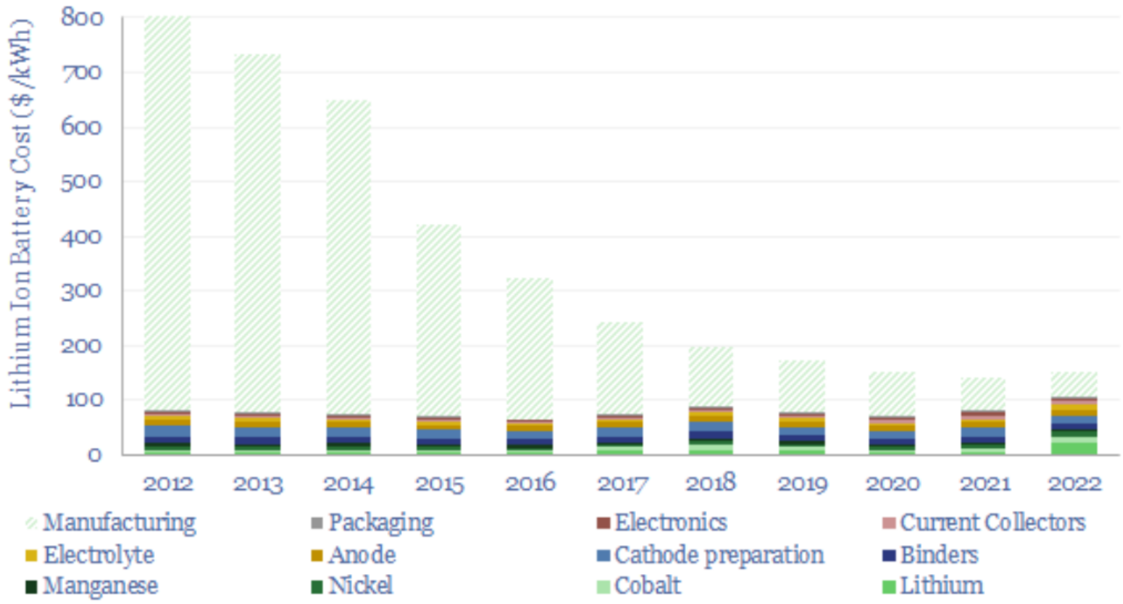
Can innovation bring the cost of battery down to resolve this issue?

Most likely no. The reason is the cost of material necessary for these storage solutions.

Amount of materials necessary for gas (or liquid) storage is proportional to the surface area (R^2), while that for battery is proportional to the volume (R^3). Therefore, for the limit of large storage size, gas storage offers greater economy than stationary battery as witness in about two order of magnitude difference in $/kWh values between hydrogen underground storage and stationary battery.

I also hear some people arguing mass production will reduce the cost of battery. Please remember, it is usually the process cost that could be reduced significantly by mass production. Material cost depends on accessibility and abundance of the chemical species. The material cost could be increased as the consequence of mass production (demand exceeds supply).

For instance, according to https://thundersaidenergy.com/2023/11/18/grid-scale-battery-costs-kw-or-kwh/, recent trend of cost breakdown looks as below. As you can see, manufacturing cost decreased significantly to the point that material cost became dominant. On the other hand, material cost has not come down (as expected). Therefore, I conclude that significant reduction of $/kWh value of stationary battery is very unlikely to take place.



Lithium ion battery costs breakdown between materials and manufacturing

Figure 1: Cost breakdown of battery from https://thundersaidenergy.com/2023/11/18/grid-scale-battery-costs-kw-or-kwh/

At last, I highly encourage the CARB staffs to revisit The Periodic Table and look for the combination of chemical species that could be used to store energy via electrochemical process. What are the abundance of such chemical species?

I hope you do not overlook the first candidate, hydrogen, which is the most abundant chemical species in the universe and is known to produce electricity via electrochemical process with oxygen (fuel cell). One can produce hydrogen out of water (electrolysis). These processes do not produce any harmful chemical species.

Lithium is after hydrogen and helium. Is there any reason to ignore hydrogen?

3. Business sustainability of DCFC and the area coverage of LDV-BEV

It is well known that 90% of charging of BEVs is done at home overnight. In other words, DCFC business market size will be less than 10% of the gas stations. This indicate that number of DCFC stations that is profitable will be about 10% of number of gas stations. Could the area coverage of LDV be kept in a similar level with the current gasoline car and gasoline stations?
We know that the area coverage can be retained with hydrogen fuel cell cars due to the quick fueling time and long driving range that are comparable to gas cars. LDV-FCEV will rely on hydrogen fueling stations so it is very likely that hydrogen fueling station business could simply replace gas stations.

Comment Log Display

Here is the comment you selected to display.

Comment 172 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Spencer
Last Name	Reeder
Email Address	spencer.reeder@audi.com
Affiliation	Audi of America, Inc.
Subject	Resubmittal for Audi of America: LCFS Amendment comments
Comment	**NOTE: This is a re-submittal, the version of our comments submitted earlier today was an incomplete earlier draft. Please se attached version and use this one (labelled "final") as the one fo consideration (and posting to the public server). This submittal should supersede those submitted by me on behalf of Audi of Americ earlier today. thank you.
Attachment	www.arb.ca.gov/lists/com-attach/6798-lcfs2024-AmNXJFE0VG5WDwNg.pdf
Original File Name	Audi_Comments_LCFS_ISOR_20Feb2024_final.pdf
Date and Time Comment Was Submitted	2024-02-19 15:45:51

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Audi of America, Inc. • 1950 Opportunity Way • Reston, VA 20190

California Air Resources Board (CARB)
1001 I Street
Sacramento, CA 95814

20 February 2024

Subject: Comment Submittal on **Proposed Amendments to the Low Carbon Fuel Standard** as outlined in the Staff Report: Initial Statement of Reasons (ISOR), March 21, 2024

Audi of America

1950 Opportunity Way
Reston, VA 20190
+1 248 754-5000
www.audiusa.com

Audi of America (Audi) welcomes the opportunity to submit comments to CARB on the evolution of this important climate policy. California's Low Carbon Fuel Standard (LCFS) is a vital tool that uniquely leverages market incentives to drive reductions in Greenhouse Gas (GHG) emissions.

To maximize the potential of achieving this core environmental objective, the entities within the primary LCFS value chains, those that can indeed react to the market signal, need to have an explicit participatory role in the program. Program design should be aligned accordingly.

The LCFS can and should serve as a key mechanism in accelerating the transition to zero emissions technologies. Audi views the continued evolution of this fuels policy as vital to supporting our company's goal of completely transforming our vehicle portfolio to plug-in battery electric vehicles (BEVs) over the next decade. In fact, Audi launches its last new internal combustion engine vehicle in 2026. Thus, we are counting on programs like California's LCFS to increasingly leverage the market mechanism it created to support the transition to all-electric vehicles, particularly in the light duty segment which dominates the state's roadways.

What makes the LCFS policy particularly powerful is its ability to incentivize the *utilization* of zero-emission battery electric vehicles (i.e., more eVMT and more GHG reductions) and not just the initial sale of those vehicles.

Thus, an LCFS policy framework that facilitates automakers serving as LCFS base credit generators, alongside electric utilities, indeed provides that direct incentive that will drive further technology innovation, new consumer-facing programs, and further strengthen the market pull for deploying more BEVs, and more *utilization* of those BEVs, in the state of California.

Incentives are important!

In the LCFS ISOR, refenced in the above Subject line, CARB states, "The State is working to rapidly increase the numbers of zero-emission vehicles on the road…"

As was noted in the recent LA Times investigation by Russ Mitchell, demand for EVs from California's vehicle buyers is starting to show signs of weakening.[1] While Audi remains bullish on the long-term prospect of the BEV market here in California, purchase incentives, like that previously provided under the LCFS **Clean Fuels Reward (CFR)** program are becoming even *more* crucial to bringing in hesitant mainstream vehicle buyers into the BEV market. While there are no doubt multiple factors that influence consumer demand, there is ample evidence that purchase incentives drive increased consumer consideration in EVs and ultimately increased sales.

As was noted in the LA Times piece, "…federal incentives have become scarcer and harder to understand." This directly impacts consumer demand.
A reliable, simple, and widely available purchase incentive is sorely needed.
A restructured light-duty CFR would certainly help in this regard. Again,
gauging the need for an incentive against California's stated objective to,
"rapidly increase the number of zero emission vehicles on the road" points
158.1 towards a reconsideration of a light-duty CFR.

Automakers are uniquely well positioned to carry forward a revamped CFR that is much more effective, resilient to credit price fluctuations, and with dramatically lower overhead costs by virtue of our existing expertise in administering these sorts of programs. We look forward to working with CARB to revamp a future CFR that, as noted above, will be increasingly necessary to meet the challenge of achieving higher rates of EV adoption.

Stringency

Audi supports CARB's interest in exploring LCFS design elements that will
158.2 underpin a market incentivizing LCFS credit price. This is most directly and
favorably impacted by ensuring sufficient program stringency and we would
encourage CARB to consider increasing stringency mechanisms accordingly.

[1] https://www.latimes.com/environment/story/2024-02-15/falling-ev-sales-raise-worries-over-california-climate-plan

Cross-Subsidization

158.3 We would respectfully ask CARB to examine the principle of rate class cross-subsidization in the staff proposal; namely, to explore the validity of taking resources (LCFS credits) generated by and within the residential light-duty vehicle segment and transferring those assets over to another rate class (commercial) and different vehicle class altogether. This asset transfer should be examined both within the context of existing deposits of LCFS credits (and credit sales revenues) generated by residential light-duty EV charging as well as any future residential credit generation.

This takes on additional importance when examining the extent of the need to accelerate light-duty EV adoption, as CARB's staff note, "…with just over 20 years to transition from today's significant fossil fuel usage to a future of clean fuels and technology."

A reminder of First Principles

To enable the aforementioned rapid transition, the private sector must continue to be incentivized to innovate and improve both the customer-facing attributes of EVs as well as the core low-carbon "fuel" technology that sits at the core of an EV.

As CARB notes, the top-level objective of the LCFS program is, "…to decrease the carbon intensity of California's transportation fuel pool and provide an increasing range of low-carbon and renewable alternatives, which reduce petroleum dependency and achieve air quality benefits."[2] This is echoed by the Purpose statement of regulation itself, "…[to] reduce the full fuel-cycle, carbon intensity of the transportation fuel pool used in California,…"[3]

It is now abundantly clear that battery electric vehicles are the dominant technology pathway for the light duty segment in California[4] and the principal path for further advances and further decarbonization (more eVMT) depends on investments in new innovations in battery system design (chemistry, core format, thermal management, power electronics, etc.).

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[2] https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard
[3] https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf
[4] https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics/new-zev-sales

In other words, the LCFS program offers the *potential* for a unique and increasingly powerful incentive to automakers to offer more (and more capable) EVs in California – to advance and accelerate the most foundational and "first principle" elements of the LCFS policy. LCFS base credit generation, alongside our electric utility partners, creates the additional market pull to accelerate these advances and deploy more EVs in the state.

Data and Methodology Validation

158.4 There is the additional benefit realized by CARB connected to the data submittals it requires of automakers to generate LCFS credits. Those data allow CARB to check and validate the methodology and algorithms it uses to award LCFS residential EV charging credits in the first place. Without automaker participation, those valuable data submittals would not be available. These data are widely recognized as vital to the program given the understanding that EV usage and charging behaviors continue to evolve rapidly.

Use of Credit Proceeds

In addition to the opportunity of launching a revamped CFR as described above, automakers will also be central to implementing other programs identified by CARB staff in the ISOR (and elsewhere) as important to supporting transportation electrification, such as, "smart" managed EV charging programs (including demand response), improvements in EV charging convenience and efficiency, Vehicle-to-Home and Vehicle-to-Grid technologies, approaches for mitigating battery degradation, etc. All of these programs have a clear and central role for automakers and thus justify a significant allocation of base credits to fund these activities alongside those allocated to the electric utilities for similar purposes.

158.5

The current structure, restricting automakers to Incremental Credit generation only, with the low and decreasing market value of those class of credits (along with the proposed increased costs to register those credits), will lead to automakers abandoning the LCFS program altogether.

158.6 Audi supports annual reporting to CARB around the use of LCFS credit proceeds by automakers commensurate with the requirements of other LCFS credit generators.

Conclusion

Audi again appreciates the opportunity to provide input into the proposed LCFS Amendments.

We view the program design choices CARB is considering not an “either/or” proposition, but rather, an opportunity to maximize program efficacy and decarbonizing potential. By aligning the intrinsic incentive that LCFS credit generation provides with the entities that sit directly within the core value chain of delivering the key enabling technologies.

This can be achieved by a considerate apportionment of base credit generation opportunities, combined with a sufficient program stringency and design that supports a robust credit market. This will allow CARB to realize the core environmental outcomes of the LCFS program while achieving its other stated program objectives.

In addition to the above comments, Audi of America supports the comments submitted by the Alliance for Transportation Innovation (AFAI).

Thank you again for the opportunity to comment on this important policy.

Sincerely,

W. Spencer Reeder
Director, Government Affairs & Sustainability
Audi of America, Inc.

Comment Log Display

Here is the comment you selected to display.

Comment 173 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nathalie
Last Name	Hoffman
Email Address	Nathalie.Hoffman@weaver.com
Affiliation	Weaver
Subject	Validation & verification rotation requirements
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6809-lcfs2024-USYBYgdnVHEFZgR2.pdf
Original File Name	Weaver - LCFS Amendment Comment Letter - 02.19.24 - FINAL.pdf
Date and Time Comment Was Submitted	2024-02-19 18:01:08

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 19, 2024

Chair Lianne Randolph
California Air Resources Board ("CARB")
1001 I Street
Sacramento, CA 95814
Via Online Submission

Re: Comment on proposed LCFS Amendment

Dear Chair Randolph and CARB LCFS staff,

Weaver and Tidwell, L.L.P. ("Weaver") appreciates the opportunity to comment on the proposed amendment to the LCFS, as set forth in the ISOR dated December 19, 2023, and appended documents, including Appendix E: Purpose and Rationale for Low Carbon Fuel Standards Amendments (updated January 2, 2024), hereafter referred to as the "Proposed Amendment".

Originally founded in 1950, Weaver is a full- service public accounting firm offering assurance, tax and advisory services. The firm has six offices in California, seven in Texas, as well as offices in Washington, D.C., New York, Oregon, Louisiana, Oklahoma, and virtually. With more than 1,700 employees, Weaver is ranked among the top 35 public accounting firms in the U.S. by Inside Public Accounting.

Weaver's Energy Compliance Services ("ECS") group is dedicated to helping businesses navigate compliance with evolving regulations. Transportation fuels regulations governed by CARB, the U.S. EPA, Environment and Climate Change Canada, and other governing agencies are a substantial focus of the practice. We help companies of all sizes understand their regulatory requirements and maintain compliance. We have over 120 professionals within the ECS practice that have a wide variety of backgrounds, including accounting, business, chemistry, engineering and law.

Weaver is an LCFS verification body accredited by CARB and has two dozen accredited lead verifiers on staff. In addition to consulting and validation/verification services under the LCFS, we provide advisory services to many clients in connection with the U.S. Renewable Fuel Standard and to the fuels sector in general. For example, we assist many clients with EPA attest engagement services in the U.S. with over 200 clients served annually in this capacity. We are one of the select few firms approved by EPA to provide Quality Assurance Plan ("QAP") services, and we assist many clients with registration and engineering reviews. Weaver completes EPA-approved QAP procedures for over 150 renewable fuel facilities on a quarterly basis.

Weaver also maintains a related advisory practice focusing on the fuel sector, which provides consulting, reporting and EPA Moderated Transaction System (EMTS) assistance, and due diligence and compliance audit services to a broad-based array of clients, including major oil companies, independent refiners, biofuel and biogas producers, and product marketers, distributors, and importers.

Given our experience as an accounting firm and our in-depth knowledge of the LCFS, as well as our extensive experience in performing attest and QAP engagements, Weaver is well-qualified to provide comment on the validation and verification provisions of the LCFS.

Specifically, we comment here on the verification body/verifier rotation requirements set forth in §95500 (g) entitled "*Verification Body and Individual Verifier Rotation Requirements".* Subsection (g*)* currently requires a fuel pathway applicant to use a different verification body and individual verifier(s) to perform validation and verification services after six consecutive years of such services. However, our clients and other market participants have expressed to us that this provision is highly disruptive and expensive. We therefore recommend that, instead of requiring a change of verification body and individual verifiers after six years, CARB amend 95500 (g) as follows:

159.1 "(g) ***Lead Verifier and Independent Reviewer*** *Rotation Requirements.* An entity that is required to contract for validation or verification must not use the same **lead verifier or independent reviewer** to perform validation and verification services under this subarticle for a period of more than six consecutive years. [Emphasis added.]

The six-year period **for such lead verifier or independent reviewer begins on the execution date of the Notice of Verification Services for validation or verification services for the entity required to contract for such services under this subarticle and ends on the date the final verification statement for such entity is submitted for such validation or verification**. The six-year limit does not reset upon a change in ownership or operational control of the entity required to contract for validation or verification services. [Emphasis added.]

The entity may re-engage **a previous lead verifier or independent reviewer** only after three years, except in the case of a set-aside of a validation or verification statement as specified in section 95501. An entity required to contract for validation or verification services must, in time for the next verification, replace a verification body that has a suspended or revoked Executive Order pursuant to MRR section 95132(d), and included by reference in section 95502(a)." [Emphasis added.]

In support of our position, we refer to the rotation requirements for auditors contained in Chapter 11, Securities and Exchange Commission (SEC), § 210.2-01, Qualifications of accountants, of Title 17 of the U.S. Code of Federal Regulations (CFR), Commodities and Securities Exchanges. The mission of the SEC is three-fold: protecting investors, maintaining fair, orderly, and efficient markets, and facilitating capital formation. The first two are analogous to the purpose of the LCFS validation and verification requirements.

Like LCFS validations and verifications, SEC audits are typically accomplished by a team whereby you have a lead partner, Engagement Quality Reviewer, and team of accountants. Please note that "Section 210.2–01 is designed to ensure that auditors are qualified and independent of their audit clients both in fact and in appearance". While everyone in an accounting firm is required to be independent of SEC audit clients, lead partners are required to rotate off a client's auditing team after five years, not the entire firm. A "lead partner" for purposes of § 210.2-01 is defined as the "lead or coordinating audit partner having primary responsibility for the audit or review", and therefore occupies a role analogous to a LCFS lead verifier. This same five year rotation requirement applies to the Engagement Quality Reviewer, with this role being similar to that of an independent reviewer under the LCFS validation and verification requirements.

It is essential to the functioning of the U.S. system of capitalism that auditors are independent and are perceived to be independent. Therefore, if CARB were to adopt a rotation requirement analogous to the SEC's in its LCFS validation and verification provisions, it can be confident that verification bodies and individual verifiers will similarly be independent and be perceived to be independent in exercising their roles in the verification process.

Weaver appreciates this opportunity to comment on the proposed amendment to the LCFS. If you should have any questions, please feel free to contact Wade Watson at wade.watson@weaver.com or (832) 320-3262.

Weaver and Tidwell, L.L.P.

WEAVER AND TIDWELL, L.L.P.

Comment Log Display

Here is the comment you selected to display.

Comment 174 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Charles
Last Name	Purshouse
Email Address	cpurshouse@camcorng.com
Affiliation	
Subject	Camco comments on Proposed LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6814-lcfs2024-WmhcalxvWT4FXFI+.pdf
Original File Name	2024_LCFSRegChangesCamcoComments.pdf
Date and Time Comment Was Submitted	2024-02-19 19:00:23

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

camco

February 19, 2024

Ms. Rajinder Sahota
Deputy Executive Director – Climate Change and Research
California Air Resources Board
1001 I Street
Sacramento, CA 95812

RE: Proposed 2024 LCFS Amendments

Dear Ms Sahota,

Thank you for the opportunity to comment on the Proposed Low Carbon Fuel Standard Amendments, published on December 19, 2023. Camco is a developer and operator of low carbon fuel projects, with a focus on biogas to RNG and biogas to EV projects.

160.1 Camco supports the changes ARB have made from earlier regulatory text to remove deliverability requirements and crediting period renewals for biogas projects beginning before 2030. The proposals as previously drafted would have restricted the development and operation of projects producing biogas for use in the transportation sector. However, we are concerned about ARBs proposed 2030 deadline for biogas to CNG and EV projects which would only be able to account for their avoided emissions benefits until 2040. Provided there are no applicable regulations requiring methane capture on dairy and swine farms, digester projects should be eligible to receive credit for avoided emissions. As a leader in developing programs and policies to lower emissions, California's exclusion of these projects from 2030 and the requirement to physically deliver gas, sends a signal to other jurisdictions, which have launched or are in the process of launching LCFS programs, to exclude these types of projects as well.

160.2 We support the introduction of a credit true-up mechanism under 95488.10(b). For developers and operators of low CI fuel projects, the current regulatory language provides little flexibility to account for variability in project operations and feedstock supply and increases the administrative burden on regulators and operators by requiring repeated adjustments to a projects' CI score. For reasons outlined below, we would like to see the credit true-up concept extended to also include the periods between a project starting and receiving a provisional CI score and between a provisional CI score and certified CI score.

Project developers are seeing waiting times of between 18 and 24 months from project commencement to provisional CI approval. Even using book-and-claim this can result in a low-CI project foregoing a year's worth of LCFS credits. Allowing credit true-ups through the provisional and initial certification would reduce pressure on staff and developers to process applications and updates as quickly as possible and reduce uncertainty for project owners and developers and LCFS credit counterparties. ARBs penalty mechanism as proposed under 95486.1(g) would discourage projects from over

Camco International Group, Inc.
333 Perry Street, Ste 301
Castle Rock, Colorado 80104
Phone: 720-279-2408
www.camcorenewables.com

crediting and in the event a project over credited and was unable to surrender sufficient credits to match its over credited amount the credit buffer account could be used to ensure the program's environmental integrity.

If ARB does not agree with a true-up for projects undergoing provisional and initial certification we suggest that it considers doubling the book-and-claim period from three quarters to six quarters for projects that have received provisional pathways but have not yet received final certified pathways. Oregon, for example, permits electricity projects to use up to a six-quarter book-and-claim period.

160.3 Currently there is no temporary pathway for electricity generated from dairy or swine manure. The LCA inputs for this type of project are very similar to biomethane CNG and LNG from dairy and swine manure, which received a temporary pathway of -150 in the 2018 updates. As of January 2024, there were 24 dairy manure-to-electricity Tier 2 pathways with certified CIs of between -353 and -790. It should be possible for ARB staff to follow the methodology outlined in Appendix E: Purpose and Rational for LCFS Amendments, page 74 and determine a pathway of -330 gCO2/MJ for electricity from dairy and swine manure. Project owners commencing new manure to electricity projects may have to wait two years for provisional CI pathway approval resulting in significant lost revenues (see previous comment). Permitting these projects to use a temporary pathway while waiting would help to mitigate this impact, remove a disincentive to generate electricity versus CNG from animal waste and support the continued growth of the EV sector.

As always, we welcome the opportunity to have further dialogue with ARB staff on changes to the LCFS program so that it can continue to drive emissions reductions in California's transportation sector and provide a model for the country as a whole.

Sincerely,

Charles Purshouse
Vice President, Camco International Group, Inc.

Comment Log Display

Here is the comment you selected to display.

Comment 175 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Susan
Last Name	Mayer
Email Address	artersa@att.net
Affiliation	
Subject	No BIOGAS State Subsidies for Factory Farms! 161.1
Comment	PLEASE: Do not use MY TAX DOLLARS to subsidize inhumane factory farming!
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-19 20:51:11

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Comment 176 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Fred
Last Name	Ghatala
Email Address	fghatala@advancedbiofuels.ca
Affiliation	Advanced Biofuels Canada Association
Subject	Support for LCFS inclusion of jet fuel
Comment	Please find included comments from Advanced Biofuels Canada on the subject rulemaking.
Attachment	www.arb.ca.gov/lists/com-attach/6819-lcfs2024-UTBXM1QzBTULUgJh.pdf
Original File Name	ABFC_CARB_LCFS comments_Jet Fuel_Inclusion_February 20 2024.pdf
Date and Time Comment Was Submitted	2024-02-19 20:05:15

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Advanced Biofuels Canada
Biocarburants avancés Canada

February 20, 2024

California Air Resources Board
1001 I Street Sacramento, CA 95814

RE: Support for LCFS inclusion of jet fuel; suggestions for aligning with British Columbia's approach

Dear California Air Resources Board,

Advanced Biofuels Canada is the Canadian national trade association for advanced biofuels and renewable synthetic fuels. ABFC members produce a portfolio of liquid low-carbon fuels (including alternative jet fuels), sustainable feedstocks, and intermediary products. Our members operate over 34 billion litres of low carbon fuel production capacity globally and are significant suppliers to renewable and low carbon fuel regulations in Canada, the US, and worldwide. Many of our members have operations in both the United States and Canada.

Regarding the subject consultation:

162.1 **ABFC is strongly supportive of CARB's proposal to remove the exemption for intrastate fossil jet fuel use under the LCFS.** Including intrastate jet fuel as a debit-generating fuel under the regulation is an important step towards encouraging more Alternative Jet Fuel (AJF) use in California.

162.2 **ABFC suggests that California expand its ambition towards jet fuel and, to the extent possible, align with the approach enacted in British Columbia that (1) obligates all jet fuel sold under the regulation, (2) prescribes minimum volumetric AJF use requirements, and (3) prescribes carbon intensity (CI) reduction requirements for jet fuel.**

The British Columbia regulations containing the jet fuel requirements are located here: Order in Council 699/2023 (gov.bc.ca)

To summarize, British Columbia's updated LCFS statute:

- Was approved on December 11, 2023 and enacted on January 1, 2024.
- Requires 1% AJF by volume in 2028, 2% in 2029, 3% in 2030.
- Requires a 2% CI reduction from a fossil jet baseline of 88.83 gC02e/MJ in 2026, 4% in 2027, 6% in 2028, 8% in 2029, and 10% in 2030.

We note that the CI reduction requirements for jet fuel are lower than that of gasoline and diesel fuels. Gasoline has a 5% renewable content requirement and a 30% CI reduction requirement by 2030 (below 2010 levels); diesel has a 4% renewable content requirement and is subject to the same 30% CI reduction requirement by 2030. (We note that the CI reduction requirements for any fuel can be met by overcompliance in other fuel types).

162.3 **Addressing aviation emissions should be a strong area of regional collaboration under the Pacific Coast Collaborative.** ABFC recognizes that California and British Columbia are members of the Pacific Coast Collaborative[1] and are leading LCFS jurisdictions in North America. Aligning on clear and stringent approaches to addressing emissions from petroleum jet fuel is an opportune area of continued policy collaboration.

Thank you for this opportunity to provide comments.

Yours truly,

Advanced Biofuels Canada

[1] The Pacific Coast Collaborative, British Columbia, Washington, Oregon, California, and the cities of Vancouver, Seattle, Portland, San Francisco, Oakland, and Los Angeles are working together to build the low carbon economy of the future. We share ambitious goals for reducing greenhouse gas emissions at least 80 percent by 2050.

By connecting jurisdictions at the regional level — and connecting states and provinces with cities in the region — the Pacific Coast Collaborative (PCC) facilitates collaboration on issues that cross borders and jurisdictional boundaries, such as grid integration, a comprehensive electric vehicle charging network, and responding to ocean acidification. We pool policy and technical expertise, share strategies to curb greenhouse gas emissions while growing the economy, and work together to implement them. (Accessed at: pacificcoastcollaborative.org/)

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Comment 177 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jim
Last Name	Stewart
Email Address	drjimstewart@gmail.com
Affiliation	
Subject	Eliminate avoided methane crediting for fuel derived from livestock manure.

Comment

163.1 - Eliminate avoided methane crediting for fuel derived from livestock manure.

163.2 - Oppose Proposed LCFS Amendment Loophole to Allow Petroleum Projects with Carbon Capture & Storage Past the 2040 Phase-out.

163.3 - Conduct and incorporate a full life cycle assessment of all air pollution and greenhouse gas (GHG) emissions for all pathways, anc their implications for environmental justice communities.

163.4 - Create ZEV multipliers to boost electric school bus and electri(public transit bus and rail system deployments.

163.5 - Eliminate credit generation from factory farm gas projects that would have happened anyway due to other programs or investments.

163.6 - Include intrastate jet fuel as a deficit generator and include California's share of the fuel used in interstate and internationa flights.

163.7 - Allow credits for zero-emission transportation fuels used for ocean-going vessels, and simplifying the process for credits for shore power installations serving electrified harbor crafts and f(dispensing green hydrogen.

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-02-19 21:20:55

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

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Comment 174 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Don
Last Name	Gilstrap
Email Address	dgilstrap@chevron.com
Affiliation	
Subject	Chevron Comments on Biofuel Guardrails
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6825-lcfs2024-WjIcMIl2AicDd1M8.pdf
Original File Name	Chevron Comments on 2024 LCFS Rulemaking (guardrails).pdf
Date and Time Comment Was Submitted	2024-02-19 22:57:19

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Don Gilstrap
Manager, Fuels Regulations

February 19, 2024

Rajinder Sahota
Deputy Executive Officer – Climate Change and Research
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Ms. Sahota:

Re: Crop-based Fuels Guardrails

Chevron appreciates the opportunity to review and comment on the subject Low Carbon Fuel Standard rulemaking proposal.

Chevron is a major refiner and marketer of petroleum products and renewable fuels in the state of California and a regulated party under the Low Carbon Fuel Standard (LCFS). Chevron, through its Renewable Energy Group subsidiary, is an international producer of lower carbon intensity fuels with a global integrated procurement, distribution, and logistics network and 11 biorefineries in the U.S. and Europe. to help California reduce transportation greenhouse gas emissions particularly in the hard-to-electrify heavy-duty sectors. As the second largest domestic producer of biodiesel and renewable diesel, our company uses waste fats, oils, and greases as well as virgin crop-based feedstocks.

Chevron is submitting multiple letters on key topics under the 2024 LCFS rulemaking. Following are our comments on the crop-based fuels guardrails proposed.

Key Messages

- Eligibility for RFS credit generation is a reliable alternative to the proposed LCFS sustainability criteria.
- Data related to land use in the United States contradicts the theoretical concerns voiced by advocates for a crop-based fuels cap.
- Indirect land use factors are already in place to address theoretical concerns about international impacts.

A Cap on Crop-based Fuels is Not Needed

164.1 Chevron appreciates that the proposal does not seek to implement an unnecessary and over-reaching cap on crop-based fuels. There are effective measures already in place that provide for proper balance in feedstock usage. These measures include the federal Renewable Fuel Standard (RFS) and the new tax incentive structure in the Inflation Reduction Act, that will transition the federal biodiesel tax credit from the existing $1/gal for all eligible biodiesel to a sliding scale incentive based on the fuel's carbon intensity. Further, the LCFS already provides appropriate 'guardrails' through life cycle analysis that incorporates direct and indirect land use

Chevron Products Company
A Division of Chevron U.S.A., Inc.
6001 Bollinger Canyon Rd, San Ramon, CA 94583
925 842 8903
dgilstrap@chevron.com

change (LUC) factors in products' carbon intensity (CI) scores. These LUC scores provide a conservative view of the potential impact from the use of agricultural feedstocks in fuel production. Illustrating the conservative nature of these factors, Figure 1 below shows that potential land-use change impacts have been declining for decades.

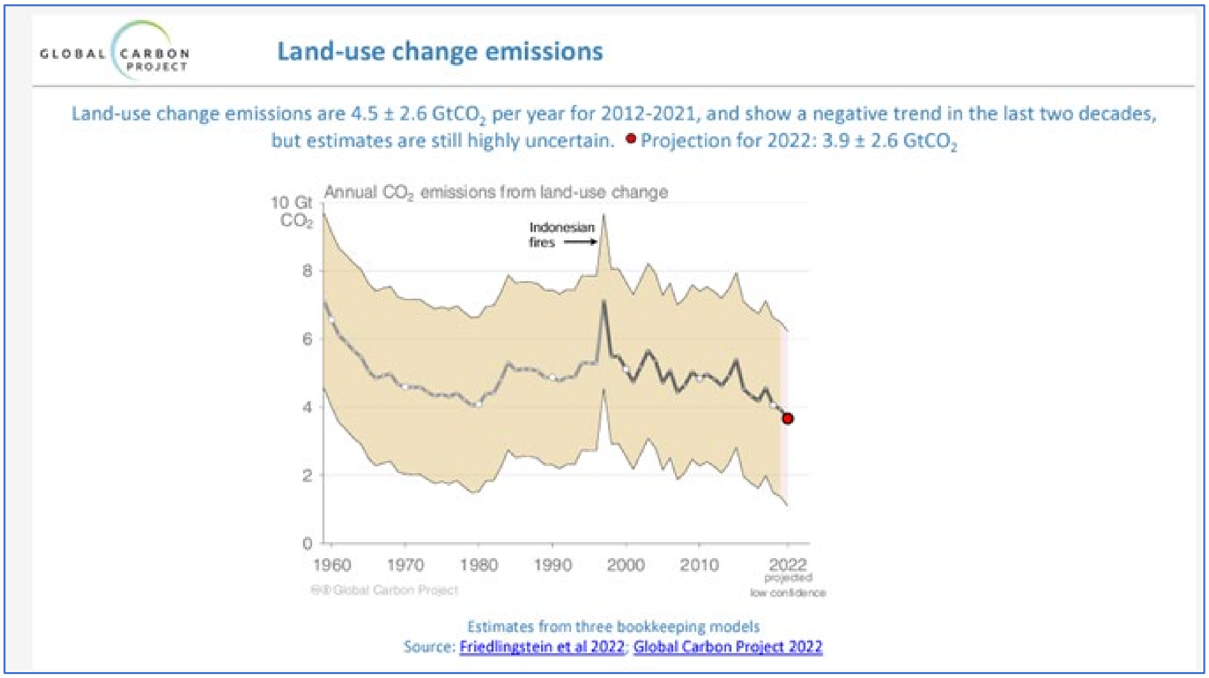

Figure 1, [1]

<u>The RFS Includes Traceability Requirements</u>

It is important to note that the federal Renewable Fuel Standard (RFS) offers safeguards against potential adverse effects owing to land use change. Efforts to include similar traceability
164.1 cont requirements in the LCFS would be duplicative of federal requirements. The RFS requires that land must have been in productive use as of December 19, 2007, to demonstrate that land use has not changed because of the RFS. Biofuel producers sourcing crop-based feedstock in the U.S. and Canada are not required to submit traceability documentation to the point of origin so long as the total crop acreage in a given year does not exceed total acreage determined in 2007 (the first year of compliance for the RFS). In setting the annual renewable volume obligations, U.S. Environmental Protection Administration (EPA), in collaboration with the U.S. Department of Agriculture (USDA), determines the amount of crop acres each year. In no year since the RFS was established has crop acreage exceeded that of 2007. The RFS requires "map and track" traceability requirements for biofuel producers sourcing crop-based feedstocks cultivated outside of the U.S. and Canada. Crop-based biofuels that participate in the LCFS also participate in the RFS and would be subject to federal traceability.

[1] https://globalcarbonbudget.org/wp-content/uploads/GCP_CarbonBudget_2022_slides_v1.0.pdf

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6001 Bollinger Canyon Rd, San Ramon, CA 94583
925 842 8903
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164.3 In addition, the RFS prohibits the use of certain feedstocks and fuels derived from these feedstocks from participating in the program. The RFS defines what feedstocks may be considered sources of renewable biomass and what fuels derived from renewable biomass may be eligible to participate. Through this process, fuels derived from certain feedstocks, such as palm oil and palm oil derivatives, are ineligible to generate biomass-based diesel RINs. Relying on the federal definition of renewable biomass, and the eligibility of fuels derived from these feedstocks to participate in the program, would preclude the need for an exhaustive list of eligible feedstocks under the LCFS program.

If CARB implements any new guardrails, then to avoid conflicts with the national program, any fuels participating in the RFS program should be exempted.

Specified Source Feedstock Attestations Are Unnecessary

Both the RFS and LCFS currently require significant documentation for feedstock sourcing, including detailed chain-of-custody records, in addition to third-party audits. The RFS specifically requires point of origin documentation for these feedstocks. Additional attestation requirements are duplicative.

164.4 As written, these new requirements have the potential to add considerable burden to feedstock supply chains. It is not clear which feedstock producers, distributors, or users would be required to maintain attestations or which operating conditions require them. It should also be made clear that this would be a recordkeeping requirement only and not akin to a product transfer document. We urge CARB to forego these added requirements or at least work more closely with feedstock producers and suppliers to clarify the purpose and nature of these new requirements.

U.S. Crop Acreage is Declining

There is little evidence that biofuels policies are linked with land use change in the United States. Recent USDA research indicates that total crop acreage has declined since 2007, illustrating that land use change owing to biofuel production is not occurring. Modest expansion of corn and soybean acres has been facilitated by the conversion of hay and wheat acres and land coming out of the conservation reserve program.[2]

[2] https://www.epa.gov/system/files/documents/2022-03/biofuel-ghg-model-workshop-cropland-patterns-2022-02-28.pdf

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925 842 8903
dgilstrap@chevron.com

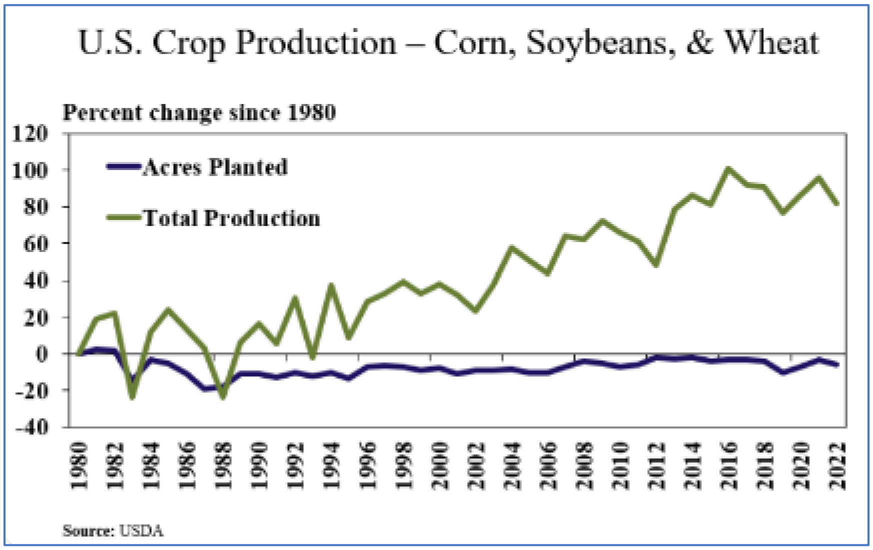

Figure 2 [3]

The 2022 Census of Agriculture recently released by USDA concludes that the U.S. has lost 21 million acres between 2017 and 2022 and lost 63 million acres since 1997. According to America's Farmland Trust, urbanization is a leading cause of lost crop acreage in the U.S. [4] Meanwhile, yields from U.S. soybean cultivation (the leading crop-based feedstock used to produce biomass-based diesel) have increased, indicating that more crops may be produced for a given area of land. According to the USDA, soybean yields, measured by bushels per acre, expanded by 35% between 1989 and 2020.[5] In summary, the United States grows more crops on less land every year.

[3] https://www.nass.usda.gov/AgCensus/
[4] https://theworld.org/stories/2020-08-07/us-lost-11-million-acres-farmland-development-past-2-decades)
[5] http://soystats.com/u-s-yield-production-yield-history/

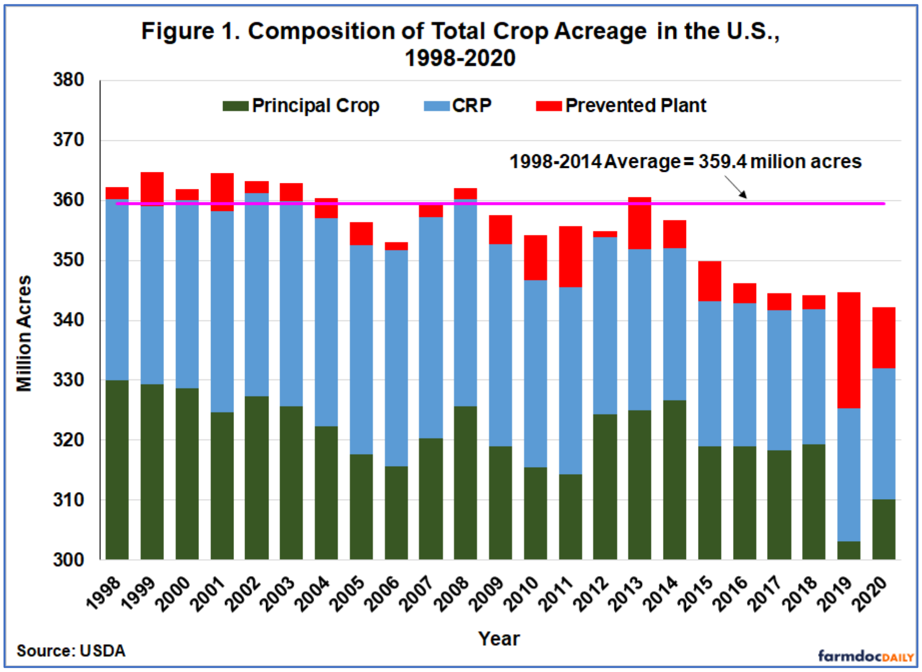

Figure 3 [6]

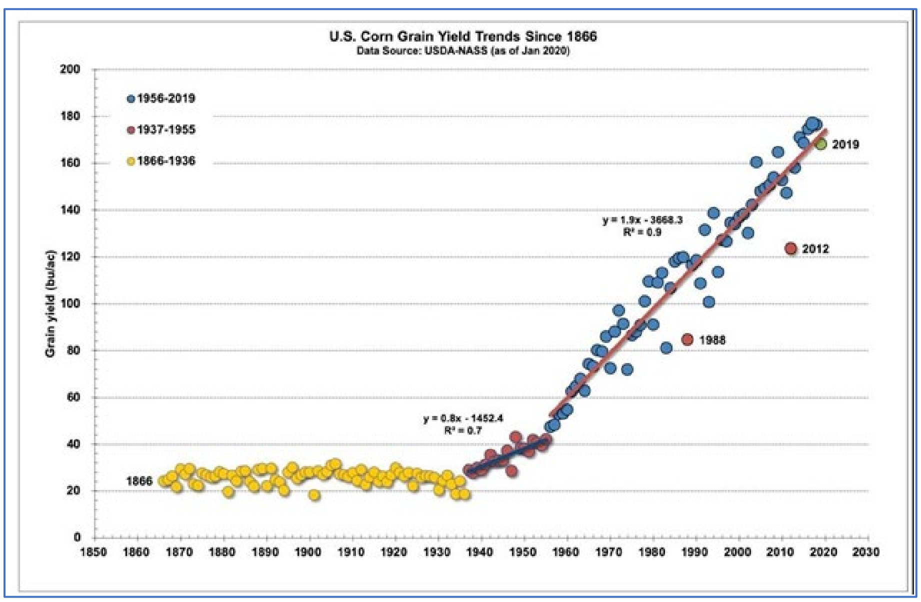

Figure 4, [7]

[6] https://farmdocdaily.illinois.edu/2021/06/estimating-total-crop-acres-in-the-us.html
[7] https://twitter.com/AlecStapp/status/1615384716361728000/photo/1

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925 842 8903
dgilstrap@chevron.com

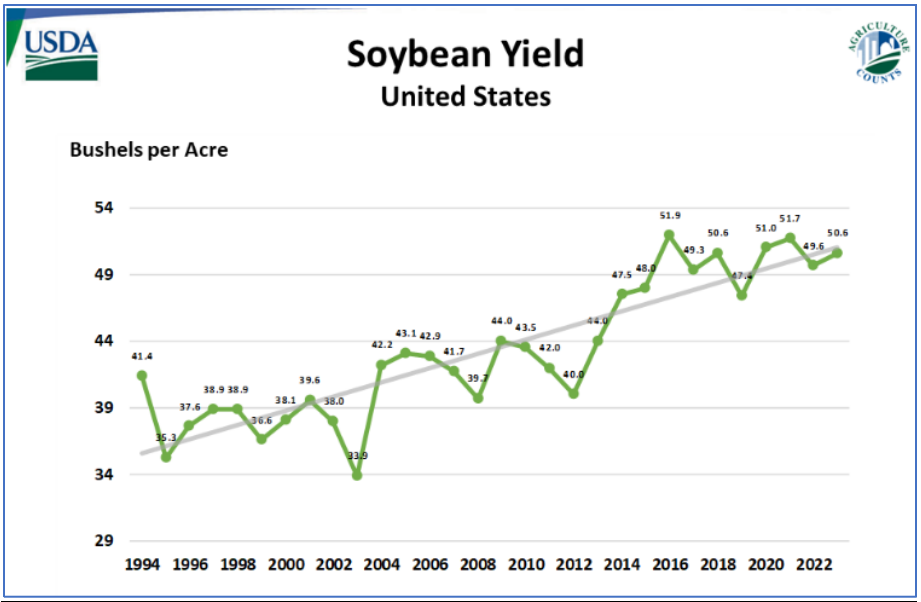

Figure 5, [8]

<u>Conclusion</u>

Additional traceability requirements are unnecessary under the LCFS program. As nearly all crop-based biofuels produced or imported into the U.S. participate in the federal RFS program, the aggregate compliance approach under the RFS offers effective assurance that biofuels policy is not linked to land use change. This approach also requires traceability requirements for feedstock sourced outside of the U.S. and Canada and imported biofuels produced from these feedstocks. Data provided in these comments demonstrates that crop land in the U.S. is declining owing largely to urbanization while yields on many crops are expanding. Thanks to agricultural innovations and smart farming practices we can grow more feedstocks on a diminishing amount of land to meet both biofuel and food demands.

Sincerely,

[8] USDA - National Agricultural Statistics Service - Charts and Maps - Soybeans: Yield by Year, US

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A Division of Chevron U.S.A., Inc.
6001 Bollinger Canyon Rd, San Ramon, CA 94583
925 842 8903
dgilstrap@chevron.com

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Comment 175 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Don
Last Name	Gilstrap
Email Address	dgilstrap@chevron.com
Affiliation	
Subject	Chevron Comments on Technical Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6826-lcfs2024-VjUHaVl2ACUAdFM8.pdf
Original File Name	Chevron Comments on 2024 LCFS Rulemaking (technical).pdf
Date and Time Comment Was Submitted	2024-02-19 22:58:42

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Don Gilstrap
Manager, Fuels Regulations

February 19, 2024

Rajinder Sahota
Deputy Executive Officer – Climate Change and Research
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Ms. Sahota:

Re: Technical Amendments

Chevron appreciates the opportunity to review and comment on the subject Low Carbon Fuel Standard rulemaking proposal.

Chevron is a major refiner and marketer of petroleum products and renewable fuels in the state of California and a regulated party under the Low Carbon Fuel Standard (LCFS). Chevron is also an international producer of lower carbon intensity fuels with a global integrated procurement, distribution, and logistics network and 11 biorefineries in the U.S. and Europe.

Chevron is submitting multiple letters on key topics under the 2024 LCFS rulemaking. Following are our comments on the technical amendments proposed.

Key Messages

- The Automatic Acceleration Mechanism (AAM) should not act as a substitute for future rulemakings.
- The pathway true up language does not address fundamental process issues with fuel pathway applications.
- Sunsetting project-related credits runs counter to the goals of the LCFS.

Periodic Rulemakings Are Necessary to the Health of the LCFS

165.1 Understanding that CARB is introducing the AAM to enable the LCFS to adjust more rapidly to strong performance, it is important that CARB continues to conduct rulemaking's every few years to allow technical adjustments in the recognition of improvements and modeling. Since the original proposal for rulemaking changes in 2022, there have been several legislative bills and executive orders passed affecting the transportation market in California alone, not to mention the hundreds of policy proposals made nationally and internationally. The assumptions made by CARB regarding the future of the transportation market, including both the vehicle market and fueling, should be continually reviewed. It would also be valuable to establish more frequent stakeholder engagement to hear concerns and recommendations well ahead of preparing for the next rulemaking.

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A Division of Chevron U.S.A., Inc.
6001 Bollinger Canyon Rd, San Ramon, CA 94583
925 842 8903
dgilstrap@chevron.com

The Credit True Up Language Needs Adjustment

Chevron supports the addition of true up language under §95488.10(b) as a means of recognizing demonstrated carbon intensity reduction. However, this language fails to address the extended period that often occurs between approval of a temporary pathway for a facility and the approval of a provisional pathway. Currently, it often takes several months or even years to move from temporary status to an approved provisional pathway. Fuel Pathway Reports are not required until a provisional pathway has been approved. Because the true up language was written so adjustments are only made after verification of an annual pathway report, the loss of credits incurred during extended operation under a temporary pathway is not addressed.

CARB's public comments on this topic indicate that it was not CARB's intention to leave the temporary pathway period out of the True Up process. This unintentional oversight can be remedied with small changes to the new language (see below). CARB may prefer to include separate equations for the two true up types as well. It would also be appropriate to replace the word "may" with "shall" in the first sentence.

165.2

(a) Credit True Up after Annual Verification or Application Validation. Beginning with the 2025 annual Fuel Pathway Report data reporting year, the Executive Officer ~~may~~ shall perform credit true up for a fuel pathway that has a lower verified operational CI upon receiving a positive or qualified positive verification statement for the associated annual fuel pathway report and quarterly fuel transactions reports, notwithstanding the prohibition on retroactive credit generation in section 95486(a)(2). A true up will also be performed for provisional pathway applications that receive a positive or qualified positive validation report. To implement this true up, the Executive Officer will calculate an equivalent number of credits representing the difference between the reported CI and the verified or validated operational CI from annual Fuel Pathway Reports and Provisional Pathway Applications for each fuel pathway code reported with non-liquid transaction types and with the following liquid fuel transaction types "Production in California," "Production for Import," and "Import" during a compliance year, and place those credits in the account of each appropriate fuel reporting entity after August 31 for the prior compliance year. For true ups from temporary pathways to provisional pathways, the true up shall apply to all quarters reported since the first approval of the temporary pathway. The credits will be calculated according to the following equation:

Process Issues Still Remain

While the true up language addresses a major symptom of the extended time it takes to approve fuel pathways, there are several procedural changes needed. CARB considers exportability of the LCFS to other jurisdictions to be a critical goal. Unfortunately, the complexity of the LCFS and the resources required to support the program are frequently cited by states reluctant to implement similar programs. Fuel pathway applications are one of the most resource-intensive elements, involving a significant number of handoffs between parties and considerable delays with each step. Considerable time could be saved if CARB's completeness
165.3 review and duplicative engineering review were eliminated. Applicants could have their pathway materials validated prior to submittal to CARB and the CARB-approved verifiers should be trusted to do the bulk of the analysis needed to ensure accuracy and completeness. We urge CARB to conduct a comprehensive review of the pathway application process with producers to

look for opportunities for streamlining, including measures that emphasize third-party review of applications. CARB staff are currently over-burdened, and certifying third-party engineering firms to review and endorse pathway applications would not only free up constrained staff resources, but also allow for the work to adapt to the growth rate of low-carbon industries.

Project-Related Credits Encourage Real GHG Reduction

165.4 Chevron opposes the phaseout of project-related credits proposed in this rulemaking. This is a counterproductive approach to targeting greenhouse gas reduction in transportation. While recognizing that reduced reliance on fossil fuels is a stated goal of the state, eliminating recognition of emission reductions in the production of those fuels while still part of the transportation fuel mix misses an opportunity to achieve real incremental change during the transition. Emission reductions today have a cumulative effect that should not be discouraged. Further, project-related crediting has not presented a threat to alternative fuel growth since its introduction but has incentivized several projects explicitly focused on emissions reduction.

The Proposed Penalties for CI Variations are Extreme

165.5 CARB has proposed to quadruple the penalization of carbon intensity scores that exceed the previously approved level. The language proposed makes no allowance for unplanned events that may impact a facility's score and would penalize good-faith operations that happen to see moderate changes in energy inputs and outputs. The LCFS already contains provisions to adjust credit balances based on such exceedances and CARB has the authority to pursue enforcement actions should a producer's actions demonstrate irresponsible behavior or ill intent. The proposed language seems intended to punish good actors for unplanned impacts, given that CARB already has sufficient authority to take action against bad actors.

Further Improvements to Verification Procedures Are Encouraged

165.6 CARB has proposed to allow credit generators for electric vehicle charging to forego site visits following a positive or qualified positive verification result. This is a disproportionate allowance given to a single credit source. CARB should extend this same allowance to all producers who receive a positive or qualified positive result. Now that the LCFS has several years of verification history, such a change is warranted. This is particularly true given the limited number of available verification firms and the growing number of LCFS and Cap-and-Trade style programs in place. This is another critical factor in the exportability of the program.

165.7 Limited rotation requirements for verifiers would also improve the flexibility of the LCFS. The LCFS already contains conflict of interest criteria that exceed those of other programs. We believe the rotation requirement to be unnecessary. Absent removal of the requirement, we recommend that CARB provides an exemption for CPA firms that provide verification services. Such firms are subject to considerable licensing requirements that exceed the independence goals of the LCFS. This would reduce the burden on regulated parties and encourage more firms to apply for CARB certification.

Thank you for the opportunity to comment on these matters. If you have any questions regarding our comments, please contact me at (925) 842-8903 or DGilstrap@chevron.com.

Sincerely,

Comment Log Display

Here is the comment you selected to display.

Comment 176 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Charles
Last Name	Davidson
Email Address	charlesdavidson@me.com
Affiliation	Sunflower Alliance/Rodeo Citizens Assoc
Subject	Concerns Regarding LCFS Eligibility and Claims by the Phillips 66 and Marath

Comment

From: Charles Davidson, Sunflower Alliance and the Rodeo Citizens Association. Hercules, CA
To: California Air Resources Board (CARB)
Date: February 20, 2024
Re: Concerns Regarding LCFS Eligibility and Claims by the Rodeo Phillips 66 and Martinez Marathon Refineries

Dear Chair Liane Randolph, CARB Members, and Hon. Dr. Steven Cliff,

I write to express urgent concerns about claims made by the Phillips 66 San Francisco Refinery in Rodeo and the Martinez Marathon Refining Company regarding their renewable diesel projects' eligibility under CARB's Low Carbon Fuel Standard (LCFS) Their claims misrepresent the eligibility criteria and carbon greenhouse gas footprint requirements of renewable diesel, but als exploit regulatory loopholes, potentially violating CARB regulations. Specifically, these LCFS violations regard both the use of virgin food oil non-waste feedstock for renewable diesel ar the fact that renewable diesel refining is profoundly energy intensive.

Existing lax GHG auditing by CARB, allows the refineries to misuse generous State and Federal low-carbon subsidies for projects that are financially dependent on using unearned LCFS certifications. For LCFS-accredited CO2 greenhouse gas reduction projects for renewable diesel, there is an urgent need for rigorous guardrails and pre- and post-project per barrel GHG auditing.

KEY ISSUES:
1.   Misallocation of LCFS Exemptions: Both refineries are inappropriately claiming LCFS tailpipe GHG exemption allowances fo renewable diesel from virgin food oils, traditionally reserved for waste-based feedstocks. Tailpipe CO2 emissions from fuel combustic represents 75% of total lifecycle GHGs, whether from renewable diesel or petroleum diesel. Removing tailpipe GHG emissions from LCFS GHG accounting for virgin food oil feedstock, promotes a massive, unjust food-to-fuels conversion pipeline. According to CARB's own documents, tailpipe CO2 exemption allowances should onl be reserved for rendered waste fats, oils and greases (ie, FOGs), not virgin food oils, because:

The CO2 emitted from vehicles during [used cooking oil] biofuel combustion is considered carbon neutral...as the carbon released was uptaken from the atmosphere within a short timeframe by the plant that produced the oil. [A. Low Carbon Fuel Standards (LCFS) p.19. CARB.
https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pd

2. Lack of Carbon Intensity Reduction Evidence: There is no substantial evidence to demonstrate a reduction in carbon intensit per barrel of renewable diesel produced (compared to the pre-project petroleum baseline). Instead, both project's Environmental Impact Reports (EIRs) clearly demonstrate a large (post-project) increase in per barrel hydrogen production and the resultant large increase in per barrel GHG emissions. (1)

3. Inadequate CARB Oversight: The refineries' claims have been locally approved without sufficient scrutiny, despite public comment on these matters. The mere fact of CARB not auditing these GHG-related discrepancies in LCFS qualification scoring, highlight critical oversights in CARB's lifecycle GHG assessment capabilitie for renewable diesel projects dependent on substantial GHG-reduction subsidies.

IMPLICATIONS:
The Phillips 66 Rodeo Renewed Project and Marathon's Martinez Renewable Fuels Project, being among the largest hydrogen-based renewable diesel initiatives globally, involve significant financial and reputational stakes. Yet, both refineries' environmental claims stand on shaky ground, with potential loopholes allowing continued use of high-emission petroleum-refining processes.

What has been lost amongst the public promotion of renewable diese and the Rodeo Renewed Project, is that Phillips 66's Environmenta Impact Report maintains a little-known backdoor loophole that wil allow the refinery to continue to use their high GHG-emitting, massive bottom-of-the-barrel petroleum-refining Delayed Coker complex.

RECOMMENDATIONS:
Reevaluate LCFS Eligibility: CARB must closely examine and rectif

the misapplication of LCFS exemptions for high-GHG virgin food oil-sourced renewable diesel, that is extremely expensive, requir subsidies and always has critical supply constraints that make its unrestricted use for transportation fuel a potential national security issue

Implement Rigorous GHG Accounting: It's imperative to introduce stringent, project-specific GHG accounting, hydrogen accounting ar auditing measures to ensure the veracity of claimed environmental benefits and prevent greenwashing.

Promote Transparency and Sustainability: By addressing these issues, CARB can reinforce its commitment to environmental stewardship and truly sustainable energy solutions.
I trust CARB will take these concerns seriously, ensuring that LC certifications and subsidies genuinely contribute to reducing GHG emissions and advancing sustainable practices.

Sincerely,

Charles Davidson

PS: FOOTNOTES
1) INCREASE IN REFINERY-LEVEL CO2 GHG EMISSIONS PER BARREL:
% Increase, estimated based on EIR-provided information, relative increase from petroleum baseline, ie, refinery-wide, yearly Mt CO divided by yearly product amount. (Mt CO2; million tons of CO2e GHGs).

Phillips 66: ~54-76% (relative increase from baseline) -- (2.147 / 2.171 Mt CO2 = 0.99) ÷ [(67/105 bpd = 0.64)-to-(67/120K(capacity) bpd = 0.56) = ~ (1.54-to-1.76)/1.00
Marathon: ~77% (relative increase from baseline) -- (2.169 / 1.14 MtCO2= 0.53) ÷ (48K / 160K(capacity) bpd = 0.3) = 0.53 / 0.3 = ~ 1.77/1.00

LIMITATION OF RENDERED WASTE FEEDSTOCK SUPPLY: By 2030, the combined renewable diesel feedstock needs of Phillips 66 and Marathon, alone, will be 97.3 % of CARB's projected amount of tot California waste oil (FOG) feedstock available, until 2045 (neith including, nor considering, CARB's ambitious SAF aviation target goals).

CONSEQUENCES OF THE ABOVE LIMITATIONS: If the renewable diesel fr only the Phillips 66 and Marathon were combined, ~ 43% of ALL US soybeans would go to renewable diesel (or fungible edible food-quality alternatives, IF there were no waste FOGs used in their manufacture). This would equal an area planted entirely wit soybeans, row-by-row, the size of the State of Michigan planted border-to-border. "To produce 100 percent of 2022 US diesel fuel consumption in the transportation sector would require more than 160 million metric tons (MMT) of feedstock, which is 10 times US production of vegetable oils in 2022 or 80 percent of global vegetable oil production in 2022" Everything You Wanted to Know About Biodiesel and Renewable Diesel. (Jan. 10, 2024) The Union o Concerned Scientists.
https://blog.ucsusa.org/jeremy-martin/all-about-biodiesel-and-ren

SUPPLY INSTABILITY EXACERBATING THE ABOVE LIMITATIONS: Foreign sources of soybeans have profoundly decreased since the war in th Ukraine began and most recently, because the collapse of soybean production in Argentina (a major global soybean producer) due to drought. Specifically, noting that "in the 2022/23 season, Argentina had a historical crop failure caused by hot, dry conditions enhanced by a third consecutive La Niña. The USDA estimated Argentina's 2022/23 production at 25 million metric ton the smallest since 1999/00, with a 43% drop from the previous yea Local sources such as the Buenos Aires Grains Exchange went even lower, putting last year's production at 21 million metric tons." Beginning over one year before the invasion of Ukraine and since, the rate of inflation for global virgin food oils has increase at faster rate than all other major food items.

In stating their reasons for limiting renewable diesel production the Union of Concerned scientists state the following need "to be realistic about where they come from, and limit feedstocks to sustainable resources used at a reasonable scale to avoid turning helpful tool into a harmful dead end. The realistic potential for biofuel conversions is quite small because of the limited availability of suitable feedstocks. Exaggerated hype about potential for refinery conversions to biofuel production amounts greenwashing that distracts from more scalable solutions."
[Everything You Wanted to Know About Biodiesel and Renewable

Diesel. Also, see: The overlooked hub of South American: New Trase data on Argentina's soy supply chain highlights how indirect soy supply in South America could be hiding deforestation in global supply chains. Soy. (Aug. 11. 2022) https://trase.earth/insights/argentina-the-overlooked-hub-of-south

SUMMARY: Virgin food oil supply is becoming increasingly limited for various geopolitical, climate change, market structure and other reasons. The first step towards limiting the misuse of valuable virgin food resources is limiting their being misused for LCFS accreditation and government subsidies. The method to achieve LCFS truthfulness would be a loophole-free auditing of lifecycle CO2 GHGs for renewable diesel, on a per barrel basis with the full accounting of hydrogen production metrics and tailpipe emissions.

CC: ATTACHMENT [SAME AS ABOVE TEXT]

Attachment	www.arb.ca.gov/lists/com-attach/6829-lcfs2024-UzUBbgdoBzUCaAhX.docx
Original File Name	FINAL *** California Air Resources Board (CARB) Date- February 20, 2024 Re Regarding LCFS Eligibility and Claims by Phillips 66 and Marathon Refining D Randolph .docx
Date and Time Comment Was Submitted	2024-02-20 00:17:32

From: Charles Davidson, Sunflower Alliance and the Rodeo Citizens Association. Hercules, CA
To: California Air Resources Board (CARB)
Date: February 20, 2024
Re: Concerns Regarding LCFS Eligibility and Claims by the Rodeo Phillips 66 and Martinez Marathon Refineries

Dear Chair Liane Randolph, CARB Members, and Hon. Dr. Steven Cliff,

I write to express urgent concerns about claims made by the Phillips 66 San Francisco Refinery in Rodeo and the Martinez Marathon Refining Company regarding their renewable diesel projects' eligibility under CARB's Low Carbon Fuel Standard (LCFS). Their claims misrepresent the eligibility criteria and carbon greenhouse gas footprint requirements of renewable diesel, but also exploit regulatory loopholes, potentially violating CARB regulations. Specifically, these LCFS violations regard both the use of virgin food oil *non-waste* feedstock for renewable diesel and the fact that renewable diesel refining is profoundly energy intensive.

Existing lax GHG auditing by CARB, allows the refineries to misuse generous State and Federal low-carbon subsidies for projects that are financially dependent on using unearned LCFS certifications. For LCFS-accredited CO2 greenhouse gas reduction projects for renewable diesel, there is an urgent need for rigorous guardrails and pre- and post-project *per barrel GHG auditing*.

KEY ISSUES:

1. **Misallocation of LCFS Exemptions: Both refineries are inappropriately claiming LCFS tailpipe GHG exemption allowances for renewable diesel from virgin food oils**, traditionally reserved for waste-based feedstocks. Tailpipe CO2 emissions from fuel combustion represents 75% of total lifecycle GHGs, whether from renewable diesel or petroleum diesel. Removing tailpipe GHG emissions from LCFS GHG accounting for virgin food oil feedstock, promotes a massive, unjust food-to-fuels conversion pipeline**.** ***According to CARB's own documents, tailpipe CO2 exemption allowances should only be reserved for rendered waste fats, oils and greases (ie, FOGs), not virgin food oils***, because:

   The CO_2 emitted from vehicles during [used cooking oil] biofuel combustion is considered carbon neutral…as the carbon released was uptaken from the atmosphere within a short timeframe by the plant that produced the oil. **[A. Low Carbon Fuel Standards (LCFS). p.19. CARB. https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf]**

2. **Lack of Carbon Intensity Reduction Evidence:** There is *no substantial evidence* to demonstrate a reduction in carbon intensity per barrel of renewable diesel produced (compared to the pre-project petroleum baseline). Instead, both project's Environmental Impact Reports (EIRs) clearly demonstrate **a large (post-project) increase in *per***

***barrel* hydrogen production and the resultant large increase in *per barrel* GHG emissions. (1)**

3. **Inadequate CARB Oversight:** The refineries' claims have been locally approved without sufficient scrutiny, despite public comment on these matters. The mere fact of CARB not auditing these GHG-related discrepancies in LCFS qualification scoring, highlights critical oversights in CARB's lifecycle GHG assessment capabilities for renewable diesel projects dependent on substantial GHG-reduction subsidies.

IMPLICATIONS:

The Phillips 66 Rodeo Renewed Project and Marathon's Martinez Renewable Fuels Project, being among the largest hydrogen-based renewable diesel initiatives globally, involve significant financial and reputational stakes. Yet, both refineries' environmental claims stand on shaky ground, with potential loopholes allowing continued use of high-emission petroleum-refining processes.

What has been lost amongst the public promotion of renewable diesel and the Rodeo Renewed Project, is that Phillips 66's Environmental Impact Report maintains a little-known backdoor loophole that will allow the refinery to continue to use their high GHG-emitting, massive bottom-of-the-barrel petroleum-refining Delayed Coker complex.

RECOMMENDATIONS:

166.1 **Reevaluate LCFS Eligibility:** CARB must closely examine and rectify the misapplication of LCFS exemptions for high-GHG virgin food oil-sourced renewable diesel, that is extremely expensive, requires subsidies and always has critical supply constraints that make its unrestricted use for transportation fuel a potential national security issue

166.2 **Implement Rigorous GHG Accounting:** It's imperative to introduce stringent, *project-specific GHG accounting, hydrogen accounting and auditing measures* to ensure the veracity of claimed environmental benefits and prevent greenwashing.

Promote Transparency and Sustainability: By addressing these issues, CARB can reinforce its commitment to environmental stewardship and truly sustainable energy solutions.

I trust CARB will take these concerns seriously, ensuring that LCFS certifications and subsidies genuinely contribute to reducing GHG emissions and advancing sustainable practices.

Sincerely,

Charles Davidson

PS: FOOTNOTES
1) INCREASE IN REFINERY-LEVEL CO2 GHG EMISSIONS PER BARREL:
% Increase, estimated based on EIR-provided information, *relative increase from petroleum baseline*, ie, refinery-wide, yearly Mt CO2, divided by yearly product amount. (Mt CO2; million tons of CO2e GHGs).

<u>Phillips 66: ~54-76%</u> (relative increase from baseline) — (2.147 / 2.171 Mt CO2 = 0.99) ÷ [(67/105 bpd = 0.64)-to-(67/120K(capacity) bpd = 0.56) = ~ (1.54-to-1.76)/1.00
<u>Marathon: ~77%</u> (relative increase from baseline) — (2.169 / 1.145 MtCO2= 0.53) ÷ (48K / 160K(capacity) bpd = 0.3) = 0.53 / 0.3 = ~ 1.77/1.00

LIMITATION OF RENDERED WASTE FEEDSTOCK SUPPLY: By 2030, the combined renewable diesel feedstock needs of Phillips 66 and Marathon, alone, will be 97.3 % of CARB's projected amount of total California waste oil (FOG) feedstock available, until 2045 (neither including, nor considering, CARB's ambitious SAF aviation target goals).

CONSEQUENCES OF THE ABOVE LIMITATIONS: If the renewable diesel from only the Phillips 66 and Marathon were combined, ~ 43% of ALL US soybeans would go to renewable diesel (or fungible edible food-quality alternatives, IF there were no waste FOGs used in their manufacture). This would equal an area planted entirely with soybeans, row-by-row, the size of the State of Michigan planted border-to-border. "To produce 100 percent of 2022 US diesel fuel consumption in the transportation sector would require more than 160 million metric tons (MMT) of feedstock, which is 10 times US production of vegetable oils in 2022 or 80 percent of global vegetable oil production in 2022" Everything You Wanted to Know About Biodiesel and Renewable Diesel. (Jan. 10, 2024) The Union of Concerned Scientists.
https://blog.ucsusa.org/jeremy-martin/all-about-biodiesel-and-renewable-diesel/]

SUPPLY INSTABILITY EXACERBATING THE ABOVE LIMITATIONS: Foreign sources of soybeans have profoundly decreased since the war in the Ukraine began and most recently, because the collapse of soybean production in Argentina (a major global soybean producer) due to drought. Specifically, noting that "in the 2022/23 season, Argentina had a historical crop failure caused by hot, dry conditions enhanced by a third consecutive La Niña. The USDA estimated Argentina's 2022/23 production at 25 million metric tons, the smallest since 1999/00, with a 43% drop from the previous year. Local sources such as the Buenos Aires Grains Exchange went even lower, putting last year's production at 21 million metric tons." Beginning over one year before the invasion of Ukraine and since, the rate of inflation for global virgin food oils has increase at a faster rate than all other major food items.

In stating their reasons for limiting renewable diesel production the Union of Concerned scientists state the following need "to be realistic about where they come from, and limit feedstocks to sustainable resources used at a reasonable scale to avoid turning a helpful tool into a harmful dead end. The realistic potential for biofuel conversions is quite small because of the limited availability of suitable feedstocks. Exaggerated hype about potential for refinery conversions to biofuel production amounts to greenwashing that distracts from more scalable solutions." [Everything You Wanted to Know About Biodiesel and Renewable Diesel. Also, see: The overlooked hub of South American: New Trase data on Argentina's soy supply chain highlights how indirect soy supply in South America could be hiding deforestation in global supply chains. Soy. (Aug. 11. 2022) https://trase.earth/insights/argentina-the-overlooked-hub-of-south-american-soy]

SUMMARY: Virgin food oil supply is becoming increasingly limited for various geopolitical, climate change, market structure and other reasons. The first step towards limiting the misuse of
166.3 valuable virgin food resources is limiting their being misused for LCFS accreditation and government subsidies. **The method to achieve LCFS truthfulness would be a loophole-free auditing of lifecycle CO2 GHGs for renewable diesel, on a per barrel basis with the full accounting of hydrogen production metrics and tailpipe emissions.**

Comment Log Display

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Comment 177 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Eddy
Last Name	Nupoort
Email Address	enupo@nelhydrogen.com
Affiliation	Nel Hydrogen
Subject	Written comment on the inclusion of MHD-HRI stations in the LCFS
Comment	Find attached the written comment from Nel Hydrogen to the propose inclusion of MHD-HRI stations in the proposed LCFS amendment. Best regards Eddy Nupoort Nel Hydrogen
Attachment	www.arb.ca.gov/lists/com-attach/6832-lcfs2024-VzkCYQRpAg4AcVQm.pdf
Original File Name	NEL_written-comment-LCFS-amendment-public-hearing_20-02-2024.pdf
Date and Time Comment Was Submitted	2024-02-20 04:14:53

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Nel Hydrogen
2389 Verna Court
San Leandro, CA 94577
E info@nelhydrogen.com
W www.nelhydrogen.com

Att.: **California Air Resources Board (CARB)**
Topic: **Written comment to the *"Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments"***

February 20, 2024

Nel Hydrogen (NEL) appreciates the opportunity to provide input to the CARB on the *"Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments"* (LCFS)[1].

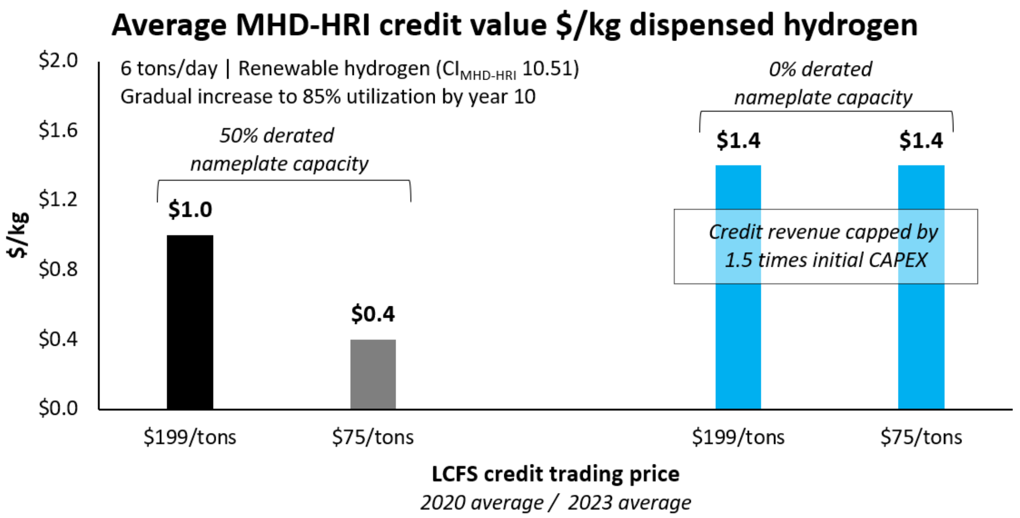
NEL is a leading manufacturer of hydrogen production and fueling equipment and have delivered equipment and provides services to multiple stations in California offering fueling to both Light Duty Vehicles (LDV) and Heavy Duty Vehicles (HDV) on a daily basis.

Foremost NEL would like to complement the CARB for proposing inclusion of both Medium and Heavy Duty Vehicles (MHD) in the LCFS regulation, in addition to the current LDVs only.

Whereas the CARB proposed inclusion of MHD into the LCFS[2] provides a good basis – NEL would like to convey some concerns regarding the following proposed new mechanisms:

167.1
- 50% derating of Nameplate capacity for Shared MHD-HRI stations
- Capping of cumulative credit value at 1.5 times initial capital expenditure.
- Shortening of Crediting Period from 15 years to 10 years.

The impact of the above mechanisms will significantly reduce the achievable credit value per kg hydrogen dispensed, as illustrated in the graph below.



The graph shows calculations of MHD-HRI credit value per kg hydrogen dispensed for a 6 tons/day Shared MHD-HRI station using renewable hydrogen. The average LCFS trading price during 2020 of $199/tons[3] and the average during 2023 of $75/kg are used as they represent the all-time high and low during the past 10 years. Station is assumed operated for 10 years, and with a gradual annual increase of utilization reaching 85% by year 10.

[1] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_notice.pdf
[2] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appa-2.pdf
[3] Based on LCFS credit trading prices as reported on www.arb.ca.gov/fuels/lcfs/credit/lrtcreditreports.htm

Nel Hydrogen
2389 Verna Court
San Leandro, CA 94577
E info@nelhydrogen.com
W www.nelhydrogen.com

167.1 cont The 50% derating of Nameplate capacity results in an average credit value of only $0.4 - $1.0 per kg of hydrogen dispensed during the 10 years Crediting Period.

Without derating of the capacity, the average credit value would be $1.4/kg, almost regardless of the credit trading price, as the value is capped by the cumulative credit revenue limit of 1.5 times the initial capital expense for the MHD-HRI station.

In 2020 a California Energy Commission report[4] assessed that an average LCFS credit value of ~$3/kg in 2030 ($150/tons CI=35) would bring hydrogen dispensed costs within the range of $6-8/kg required for gasoline price parity in LDVs.

However, achieving diesel price parity for MHD vehicles will require an even lower cost of hydrogen dispensed, likely in the range of $4-5/kg. Achieving MHD diesel price parity in 2030 would thus require an LCFS credit value higher than the $3/kg sufficient for LDVs.

As shown in the credit value calculations above, the cap on cumulative credit revenue on 1.5 times the initial CAPEX indirectly limits the maximum credit value to only $1.4/kg – and the 50% derating reduces this even further down to between $0.4 to $1/kg. The proposed 10 years Crediting Period, compared to the current 15 years, also reduces the overall credit value generated.

As a result, the achievable credit value $/kg will most likely not be sufficient for enabling MHD-HRI stations to achieve diesel price parity by 2030.

According to the LCFS amendment Appendix E[5] the CARB rationale for the 1.5 times CAPEX limit, 10 years crediting period and the derating of capacity, is to incentivize a sufficient number of stations to accommodate anticipated MHD hydrogen fuel demand.

Deployment of sufficient number of stations is definitely needed to accommodate MHD vehicle deployments. However, if the potential LCFS credit value does not enable diesel price parity, this will negatively impact the attractiveness of MHD vehicles and may challenge the actual vehicle deployments and emission reductions achieved.

NEL would therefore encourage CARB to:

- Consider removing the 50% Nameplate Capacity derating for Shared MHD-HRI stations
- Consider either removing or increasing the cumulative credit value cap of 1.5 times initial capital expenditure
- Consider keeping the 15 years Crediting Period as in the current LCFS regulation
- Aim of the above should be to enable credit values ($/kg) where diesel price parity is within reach for MHD-HRI stations

Thank you for considering the input from NEL.

Best regards
Eddy Nupoort
Director of Sales and Business Development

Nel Hydrogen Inc.
Cell: (916) 841 7262
E-mail: enupo@nelhydrogen.com

[4] https://efiling.energy.ca.gov/getdocument.aspx?tn=233292
[5] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appe.pdf

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Comment 178 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Bryan
Last Name	Sievers
Email Address	bsievers@roesleinae.com
Affiliation	Roeslein Alternative Energy
Subject	Comments on Proposed Amendments to Low Carbon Fuel Standard
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6835-lcfs2024-VyVVMlYyVloCZ1M8.docx
Original File Name	RAE_CommentLetter_LCFS_Feb2024_EXECUTED.docx
Date and Time Comment Was Submitted	2024-02-20 06:32:11

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

ROESLEIN ALTERNATIVE ENERGY, LLC
9200 Watson Rd. Suite 200, St. Louis, MO 63126
(314) 729 - 0055
www.roesleinae.com

February 20, 2024

Chair Liane Randolph and Members of the Board
California Air Resources Board
1001 I St.
Sacramento, CA 95814

RE: Roeslein Alternative Energy Comments on the Proposed Amendments to the Low Carbon Fuel Standard

Dear Chair Randolph and Members of the Board,

Roeslein Alternative Energy (RAE) appreciates the opportunity to comment on the proposed amendments to the Low Carbon Fuel Standard (LCFS). Biogas systems protect our air, water, and soil by recycling organic material, like food waste and manure, into renewable energy and soil products. Biogas systems are, at their heart, a biological means to capture methane that would otherwise be emitted into the atmosphere for use as a renewable fuel. This process specifically decreases baseline methane emissions by converting methane back into carbon dioxide. All of this is an effort to protect our air, water, and soil – crucial parts of the solution to the challenges the California Air Resources Board (CARB) seeks to address. The scientifically based design of the LCFS recognizes the benefits of projects that collect biomethane that would otherwise be emitted to the atmosphere making it available for use in transportation. As a result, millions of gallons of petroleum-based diesel fuel have been replaced with clean biomethane over the past several years delivering substantial reductions in greenhouse gas (GHG) emissions as well as other co-benefits (e.g., reductions in emissions of particulate matter). Furthermore, in August 2023, CARB announced that in Q1 2023 clean fuels replaced more than 50% of the diesel used in the state for transportation purposes, equating to nearly two billion gallons of avoided fossil diesel use in 2022.[1] This further underscores the success of the program and continued need for the LCFS to deliver GHG reductions from the transportation sector.

Over the past year and a half, CARB staff have held numerous public workshops to gather feedback on potential changes to the program, where RAE participated, and we are pleased to see that the rulemaking is nearing completion. RAE would like to underscore the importance of concluding this rulemaking as soon as possible. Any further delay to the rulemaking diminishes the necessary signal the market needs to facilitate and encourage continued investments in clean fuels. Without a strong policy signal, the state risks missing opportunities to further reduce GHG emissions from transportation fuels. Thus, RAE urges CARB staff and the Board to finalize this rulemaking no later than the end of Q2 2024.

Strengthening Carbon Intensity (CI) Targets

RAE applauds CARB and is encouraged to see that the proposed amendments aim to set more ambitious carbon intensity (CI) targets. A strong CI reduction target is a critical component for driving down GHG emissions in the transportation sector, reducing reliance on petroleum fuels, and transitioning to electric vehicles where feasible. However, we believe that there is both room and need to go further. Using the numbers from CARB's Quarterly Summary Report and averaging the rate of credit growth over the past five available quarters, it shows that the current scale-up in the production of clean fuels will continue to generate credits with the cumulative bank likely eclipsing 25 million by the end of 2024.[2] The proposed increase in stringency falls short of what the market can deliver, and as a result, is missing an opportunity to deliver millions of additional tons of

[1] California Air Resources Board, *For the first time 50% of California Diesel Fuel is replaced by clean fuels*. August 23, 2023. https://ww2.arb.ca.gov/news/first-time-50-california-diesel-fuel-replaced-clean-fuels
[2] California Air Resources Board, *LCFS Data Dashboard Figure 3 – Quarterly Summary Report*. https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard

reductions in GHG emissions called for in statute and further underscored in the update to the state's Scoping Plan as approved by the Board in December 2022.

Roeslein Alternative Energy believes that there are two key adjustments that CARB can make to the stringency as part of the 15-day change process that do not require new economic or environmental analysis as they fall within the scope of the work CARB has already included in the Initial Statement of Reasons (ISOR). Specifically, by increasing the step-down as well as pulling forward the effective date for triggering the Auto Acceleration Mechanism (AAM) CARB can "recapture" reductions in GHG emissions that will otherwise be lost with the current proposal. Doing so will also send a clear, supportive market signal to continue investments in clean fuels that would otherwise be constrained by the current proposal. The description below provides additional detail on these two recommendations.

While we believe that the proposed 5% step-down in stringency is a good start at course-correcting the market, it simply does not go far enough considering the size of the cumulative credit bank, which is anticipated to increase its rate of growth as new clean fuel projects that have been or are being constructed bring more clean fuels to market. Within the boundaries of staff's
168.1 existing environmental and economic analysis, the step-down must be increased by at least 7%, which, for perspective,
translates into a 2030 target of at least 32% reduction in the CI relative to the 2010 baseline. While a 7% step- down (20.75% CI target) will still leave many credits in the cumulative credit bank, this single adjustment will translate into millions of additional tons of GHG emission reductions that would've otherwise gone unaddressed. RAE would like to emphasize that a 7% step down should be the minimum considered, and that it is possible, based on recent modeling by ICF, for CARB to be more aggressive with the step-down, noting that a step-down of 11.25% (25% CI target) is feasible, and would sufficiently address the excess credits in the cumulative credit bank.[3]

As designed, the first year that the AAM could impact program stringency is 2028---four years from now! The concept and need for the AAM is to respond to clear overperformance of the program and to send an unambiguous market signal to investors that the program is nimble and will respond to opportunities to deliver additional GHG reductions rather than "add to" an excessively large credit bank that is at odds with the objectives of the program. Waiting four years is too long, and RAE recommends pulling the date for triggering the AAM forward. The AAM should be based on 2025 data with the trigger assessment occurring in May 2026, and the AAM being applied in 2027 providing the applicable conditions are met, thus increasing the program stringency for 2027. Relying on 2025 as the first eligible year for triggering the AAM is appropriate as
168.2 one of the main objectives of the step-down is to bring the program into balance. Therefore, assessing the impact of the step-
down on the market based on 2025 data, including the cumulative bank and the rate of credit to deficit generation, is aligned with the principles of the program. With this approach, the AAM could theoretically increase the stringency of the program in 2027 and 2029 (i.e., triggered twice prior to 2030 providing the conditions for the triggering the AAM are satisfied), better ensuring that potential emission reductions are not left on the table in the event the program continues to overperform following the Board's adoption of the amendments. Furthermore, it is important to note that the proposed 3:1 ratio (i.e., cumulative bank/average quarterly deficits) that would trigger the AAM is likely inadequate. For example, in 2022, a year where there is
168.3 general stakeholder consensus that the LCFS was overperforming, the AAM would not have triggered using CARB's current
proposal. Updated ICF modeling shows that changing the cumulative credit bank to average quarterly deficit ratio threshold from 3 to 2.5 or lower would position the AAM to be more responsive to overperformance of the program, thus delivering additional reductions in GHG emissions.[4]

Avoided Emission Crediting

The proposed amendments seek to phase out avoided emission pathways for projects that break ground after December 31, 2029, for biomethane used as a transportation fuel through 2040 and for biomethane used to produce hydrogen through 2045. While we understand that CARB's intention here is to begin to transition biomethane away from the transportation sector, the underlying rational is being construed by some as science-driven rather than a policy decision concerning the phase out of
168.4 combustion in transportation. RAE does not support the phaseout of avoided emission credits.

[3] ICF, *Analyzing Future Low Carbon Fuel Targets in California*. February 2024. https://static1.squarespace.com/static/5b57ab49f407b4a7ffa44ffa/t/65cd3c74d1a72f445cdc7a7e/1707949173143/ICFReport2024.pdf

[4] ICF, *Analyzing Future Low Carbon Fuel Targets in California*. February 2024. https://static1.squarespace.com/static/5b57ab49f407b4a7ffa44ffa/t/65cd3c74d1a72f445cdc7a7e/1707949173143/ICFReport2024.pdf

168.4 cont

Avoided methane emissions are a critical part of science-based, life cycle assessments, and their inclusion in carbon intensity scores is consistent with internationally recognized standards of carbon accounting. The science is robust and recognizes that the baseline includes methane emissions that would otherwise be released into the atmosphere. As stated in our previous comment letters to CARB, recognizing avoided methane emissions and its role as a short-lived climate pollutant, while incentivizing its removal from the atmosphere, has proven highly successful in supporting the reduction of millions of metric tons of carbon dioxide equivalents. We strongly encourage CARB to continue its longstanding commitment to a science-driven framework that utilizes proven science including Argonne National Laboratory's GREET model. In the event CARB maintains its plans to phase out eligibility for avoided methane in vehicle fuels, we encourage CARB to be clear that it is a policy decision associated with CARB's efforts to transition biomethane into non-vehicle sectors (e.g., residential, commercial, and industrial uses). CARB should be explicit that the policy decision to discontinue recognition and eligibility of avoided methane emissions in vehicle pathways should not be interpreted as a departure from the established rigorous science of accounting for the benefits of avoiding methane emissions which continues to be appropriate for non-vehicle sectors. RAE does, however, recognize that avoided emission credits for biogas to electricity projects remain, and applaud CARB for recognizing the value of these projects by proposing to retain this aspect of the program.

168.5

Book-and-Claim and Deliverability Requirements

Book-and-Claim has allowed the LCFS to evolve by supporting investments in clean fuels that have helped the program remain one of the most influential and successful transportation decarbonization policies in the country. To date, CARB's approach to indirect accounting in the program has been pivotal in its success, including its principles of driving GHG emissions down, facilitating investments and production of clean fuels, and in supporting increased clean fuel options for consumers.

While CARB's proposal clearly outlines recommendations related to book-and-claim for biomethane as directed to end use fuel consumption and hydrogen production, it does not adequately address biogas and biomethane as directed to electricity production. There are three key areas that CARB should address to ensure that biogas and biomethane can support electricity production in support of transportation decarbonization. The first is to allow biogas to electricity projects to utilize book-and-claim anywhere in the Western Electricity Coordinating Council (WECC), as is already the case in Oregon under their Clean Fuels Program. Currently, the LCFS requires electricity to be physically delivered to California. This would eventually result in regulatory consistency for projects with the same feedstock (i.e., biomethane) once the deliverability requirements for that fuel are realized. Second, biogas-to-electricity projects where electricity generation and biogas production are not co-located should be eligible to participate in the LCFS. This is in-line with the California Renewable Portfolio Standard's (RPS) treatment of "directed biogas" and allows greater project penetration by supporting optimal siting of both the biomethane source and the electricity generator rather than forcing co-location. Third, notwithstanding the preceding constraints, there are clear guidelines and requirements for how electricity, as a LCFS fuel, can utilize book-and- claim to move electricity from point of generation to end use. There is not, however, clear information on how biogas or biomethane can utilize book-and-claim to move RNG to electricity generation. RAE recommends that CARB provide clarification that biomethane may utilize book-and-claim in this context. Further, we recommend that book-and-claim for biomethane to electricity remain unconstrained by timeline restrictions proposed for biomethane to end use and biomethane to hydrogen production. We believe this is appropriate to support zero-emission vehicle aspirations beyond 2030.

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Roeslein Alternative Energy is also requesting CARB provide further guidance on the proposed deliverability requirements. The proposed amendments aim to adopt the California RPS requirement of ensuring biomethane injected into a common carrier pipeline physically flows towards California 50% of the time. This referenced RPS framework does not, however, provide clarity on how those biomethane molecules can be traced to California, how a 50% average flow toward California may be modeled, nor expected geographical indications of regions anticipated to remain eligible for book-and-claim accounting. Moreover, limiting book-and-claim to physical deliverability requirements risks the LCFS becoming a less effective decarbonization program and undermines California's interest in rapidly ramping up the production and use of renewable hydrogen—a foundational principle in establishing ARCHES, which is at odds with CARB's proposal, to implement deliverability requirements for hydrogen projects utilizing biomethane.

168.11

It remains to be seen if and how the proposed deliverability requirements can be harmonized with the California Public Utilities Commission's (CPUC) SB 1440 program, as suggested. It has been clear over the past year that CARB was exploring potential deliverability requirements. However, throughout that process an actionable plan outlining the strategy and evidence necessary for imposing delivery requirements never emerged. Rather, stakeholders continued to raise concerns about the lack of a feasible plan which continues with the ambiguity of the proposed amendments.

Therefore, RAE recommends that the deliverability requirement language be removed from the proposal to allow for further stakeholder engagement in support of a clear and actionable plan for consideration in a subsequent rulemaking.

True-up Provisions

The proposal includes true-up provisions where verified operational CI's are drawn on to potentially adjust the credits based
on certified CI's. The proposal indicates that a shortfall (i.e., a verified operational CI that is higher than the certified CI upon
which project credits were generated) is subject to a "penalty" that is 4 times the spread for the applicable volume of fuel. The
168.12 rationale for a 4X spread is unclear as a smaller spread (e.g., 2X) serves as a significant disincentive to producers for being
overconfident in their analysis. Further, the language indicates that in the event the operationally verified CI is lower than the
certified CI (i.e., it failed to generate as many credits as it could have) the Executive Offer (EO) "may" make the appropriate
168.13 adjustment (true-up) by awarding additional credits to the applicable fuel reporting entity. The word "may" should be deleted.
If the operationally verified CI, including an affirmative verification statement, is lower than the certified CI that was the basis
for credit generation, the EO "must" award the supplemental credits supported by the underlying documentation.

The concept of adjustment to credits based on operationally verified CI's is sound. However, limiting the proposal to certified CI's is a significant oversight. The proposal must be carried over and applied to temporary and provisional CI's as fuel providers may rely on these CI's for months, or even years, as a more refined pathway is evaluated and subsequently approved by CARB.

168.14 Temporary CI's have been an important option under the program, but applicants can be reluctant to use them given the heavy credit discounting relative to facility-specific provisional CI's. Correcting for any under (or over) crediting while a temporary CI is used will help streamline and simplify the program as well as send a stronger signal to the market that investments in clean low-CI fuels will be rewarded. Further, including temporary CI's as part of the true-up process will reduce the pressure on CARB from developers to process LCFS applications quickly which has been an ongoing and growing challenge under the program. The concept of adjusting the awarding of credits based on operationally verified CI's is a key principle that supports innovation and must be reflected from project initiation, where a temporary CI is used, throughout the project's lifetime to properly account for and reward the associated reductions in greenhouse gas emissions. Credits should be awarded based on real-world operational experience and therefore adjusted accordingly when the temporary CI which is applied understates the benefits.

New Markets

As the technology in the transportation sector continues to evolve and advance towards lower carbon alternatives, RAE is following suit and are ready to serve these new markets, such as alternative jet fuel (AJF), low-CI hydrogen, as well as exploring opportunities where biomethane can be utilized outside of transportation. As these markets continue to grow, the RAE asks CARB to remain mindful of the success of the historical framework of the program and to continue to apply it to newer pathways and technologies, including the use of avoided emissions and book-and-claim.

If CARB's goal is to transition biomethane out of the vehicle sector, RAE strongly encourages CARB to ensure there continues
to be a market for low-CI biomethane as it is an important decarbonization tool, especially in sectors that are hard to
decarbonize. For example, the CPUC's SB 1440 program creates a biomethane procurement mandate for the state's largest
utilities, however, the program excludes dairy biomethane due to the credit it currently receives in the LCFS.[5] With CARB's
intention of phasing out all biomethane crediting for transportation fuel by the end of 2040, it makes sense for the CPUC to
168.15 integrate dairy biomethane into the SB 1440 program which will allow for more market choice and volumes of renewable fuel
for utilities to procure. The industrial sector is also another area where biomethane can help significantly reduce emissions,
particularly at facilities that are large natural gas users and where electrification is not currently feasible. However, there isn't
one, all-encompassing policy that drives biomethane, and other low-CI clean fuels, towards that use case. Thus, RAE
recommends that CARB, starting with the 2024 amendments to the LCFS, send a clear policy signal that biomethane is a
necessary and effective decarbonization strategy in these other sectors (e.g., residential, commercial, industrial) that are
fundamental to the state meeting its ambitious GHG reduction targets.

---

[5] California Public Utilities Commission, *Decision Implementing Senate Bill 1440 Biomethane Procurement Program: R.13-02-008*, page 4. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M453/K954/453954308.PDF

Roeslein Alternative Energy would also like to extend its support for CARB's proposal of eliminating the exemption for intrastate
168.16 fossil jet fuel from the program starting in 2028. This will allow for continued and increased momentum for AJF production and
use and will help drive down GHG emissions in the aviation sector. Furthermore, the 2022 update to the Scoping Plan calls for
80% of aviation fuel demand in 2045 to be met by AJF.[6] The growth of AJF use is a new market opportunity for biomethane as
it can be an important input for the fuel, helping it achieve lower CI's. The magnitude of ambition the state has called for will
require the industry to significantly scale-up production and use of AJF, and for that reason, the ABC requests that CARB begin
168.17 to think about the framework and guardrails needed to achieve the 80% goal set forth in the Scoping Plan and leverage all of
the tools available to the vehicle market, such as book-and-claim and avoided emissions accounting, to make this goal a reality.

Conclusion

The LCFS continues to be a flagship policy that drives investments in low carbon fuels and is delivering millions of tons of reductions in greenhouse gases to meet California's statutory commitments. The program is also protecting communities throughout the state by transitioning from petroleum to much cleaner fuels, including biomethane. The LCFS is the hallmark of effective environmental policy in that it: 1) sets clear, science-based targets; 2) establishes clear regulations for program implementation; and 3) provides the market with the flexibility to innovate. There is a clear reason that other states and nations model their efforts on California's LCFS. RAE is proud to help build on this success story and is committed to CARB's efforts to continue to drive down emissions from transportation fuels.

Thank you for the opportunity to comment on the proposed amendments, and we look forward to engaging with CARB staff on these topics.

Sincerely,

Chris Roach
President, Renewables

[6] California Air Resources Board, *2022 Scoping Plan Update*, page 73. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

Comment Log Display

Here is the comment you selected to display.

Comment 178 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mark
Last Name	Stoermann
Email Address	mstoerm@newtrient.com
Affiliation	Newtrient LLC
Subject	Newtrient LLC Comments on the Proposed Amendments to the Low Carbon F Standard

Comment

Newtrient appreciates the opportunity to comment on the proposed amendments to the Low Carbon Fuel Standard (LCFS). Newtrient was founded by leading milk cooperatives and organizations, representing 20,000 dairy farmers producing approximately half of the nation's milk supply.

Newtrient applauds the leadership the California Air Resources Board (CARB) is taking on climate change and appreciates being a part of this important dialogue surrounding potential changes to the Low Carbon Fuel Standard (LCFS). The dairy industry has answered the call to action and is embracing environmental responsibility - from family farms in California, to farms across America. By installing and utilizing biogas systems, farms are offering practical solutions to the challenges CARB seeks to address.

Two programs directed by the California Department of Food and Agriculture (CDFA) have been particularly vital to the progress California has made. According to the 2023 CARB Mid-Year Data Update report on the cumulative progress of the California Climate Investments Program (CCIP), the Dairy Digester Research and Development Program (DDRDP) and the Alternative Manure Management Program (AMMP) have received a total of $309.1 million in funding and have reduced 23.2 million MTCO2e. The funding for these programs represents 1.86% of the California Climate Investments program as of May 31, 2023, but the GHG reductions from these two programs represent 23.69% of the total for all California Climate Investments programs .

In December of 2022, researchers at UC Davis published the study, Meeting the Call: How California is Pioneering a Pathway to Significant Dairy Sector Methane Reduction in which they stated "...analysis shows that continued implementation and commitment to the incentive-based climate smart solutions that are currently driving voluntary dairy methane reduction in California should, by 2030, achieve the full 40 percent reduction in dairy methane sought by state regulators without the need for direct regulation."

With our support of CARB and the LCFS in mind, Newtrient would lik

> to offer the attached Comments on the proposed amendments to the Low Carbon Fuel Standard.

Attachment	www.arb.ca.gov/lists/com-attach/6836-lcfs2024-BTdXZVBhUTAEMgM7.pdf
Original File Name	240208 -Newtrient-LCFS-Comments.pdf
Date and Time Comment Was Submitted	2024-02-20 06:52:16

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Chair Liane Randolph and Members of the Board California Air Resources Board
1001 I St.
Sacramento, CA 95814

RE: Newtrient LLC Comments on the Proposed Amendments to the Low Carbon Fuel Standard

Dear Chair Randolph and Members of the Board,

Newtrient appreciates the opportunity to comment on the proposed amendments to the Low Carbon Fuel Standard (LCFS). Newtrient was founded by leading milk cooperatives and organizations, representing 20,000 dairy farmers producing approximately half of the nation's milk supply. Newtrient delivers solutions to environmental and economic challenges, including advancing manure management technologies and products. Through a team of credible technical experts in manure management systems, nutrient recovery, renewable energy, and environmental asset markets, Newtrient helps dairy farms and the dairy industry reduce its environmental footprint.

Newtrient applauds the leadership the California Air Resources Board (CARB) is taking on climate change and appreciates being a part of this important dialogue surrounding potential changes to the Low Carbon Fuel Standard (LCFS). The dairy industry has answered the call to action and is embracing environmental responsibility - from family farms in California, to farms across America. By installing and utilizing biogas systems, farms are offering practical solutions to the challenges CARB seeks to address.

Two programs directed by the California Department of Food and Agriculture (CDFA) have been particularly vital to the progress California has made. According to the 2023 CARB Mid-Year Data Update report on the cumulative progress of the California Climate Investments Program (CCIP), the Dairy Digester Research and Development Program (DDRDP) and the Alternative Manure Management Program (AMMP) have received a total of $309.1 million in funding and have reduced 23.2 million $MTCO_2e$. The funding for these programs represents 1.86% of the

California Climate Investments program as of May 31, 2023, but the GHG reductions from these two programs represent 23.69% of the total for all California Climate Investments programs[1].

There are 78 subprograms listed in the 2023 CARB Mid-Year Data Update report on the cumulative progress of the California Climate Investments Program as of May 31, 2023. Only one of these subprograms, the DDRDP, has produced a GHG reduction at a cost of less than $10 per $MTCO_2e$. The DDRDP program has the largest GHG reductions of any single subprogram (22.1 million $MTCO_2e$) and represents the single most effective program in the overall strategy to achieve the ambitious climate goals set by the State of California.

In December of 2022, researchers at UC Davis published the study, *Meeting the Call: How California is Pioneering a Pathway to Significant Dairy Sector Methane Reduction* in which they stated "…analysis shows that continued implementation and commitment to the incentive-based climate smart solutions that are currently driving voluntary dairy methane reduction in California should, by 2030, achieve the full 40 percent reduction in dairy methane sought by state regulators without the need for direct regulation."[2]

With our support of CARB and the LCFS in mind, Newtrient would like to offer the following suggestions for improving the proposed amendments to the Low Carbon Fuel Standard:

Strengthening Carbon Intensity (CI) Targets

Newtrient applauds CARB and is encouraged to see that the proposed amendments aim to set more ambitious carbon intensity targets. A strong CI reduction target is a critical component for driving down (GHG) emissions in the transportation sector, reducing reliance on petroleum fuels, and transitioning to electric vehicles where feasible. However, we believe that there is both room and a need to go further. Using the numbers from CARB's Quarterly Summary Report and averaging the rate of credit growth over the past five available quarters, it shows that the current scale-up in the production of clean fuels will continue to generate low carbon

[1] California Climate Investments Program: *2023 CARB Mid-Year Data Update* (May 31, 2023), (https://ww2.arb.ca.gov/sites/default/files/auction-proceeds/cci_2023mydu_cumulative_statistics.pdf)
[2] Kebreab, Ermias, Ph.D., Mitloehner, Frank, Ph.D., and Sumner, Daniel A., Ph.D., Meeting the Call: California is Pioneering a Pathway to Significant Dairy Methane Reduction (December 2022), available at: https://clear.ucdavis.edu/news/new-report-california-pioneering-pathway-significant-dairy-methane-reduction

fuel standard credits with the cumulative bank likely eclipsing 25 million by the end of 2024.[3] The proposed increase in stringency falls short of what the market can deliver, and as a result, is missing an opportunity to deliver millions of additional tons of reductions in greenhouse gas emissions called for in statute and further underscored in the update to the state's Scoping Plan as approved by the Board in December 2022.

Newtrient believes that there are two key adjustments that CARB can make to the stringency as part of the 15-day change process that do not require new economic or environmental analysis as they fall within the scope of the work CARB has already included in the Initial Statement of Reasons (ISOR), specifically, by increasing the step-down as well as pulling forward the effective date for triggering the Auto Acceleration Mechanism (AAM) CARB can "recapture" reductions in GHG emissions that will otherwise be lost with the current proposal. Doing so will also send a clear, and supportive market signal to continue investments in clean fuels that would otherwise be constrained and subdued by the current proposal. The below description provides additional detail on these two recommendations.

169.1 While we believe that the proposed 5% step-down in stringency is a good start at course correcting the market, it simply does not go far enough considering the size of the cumulative credit bank, which is anticipated to increase its rate of growth as new clean fuel projects that have been or are being constructed bring more clean fuels to market. Within the boundaries of staff's existing environmental and economic analysis, the step-down must be increased by at least seven percent (7%), which, for perspective, translates into a 2030 target of at least 32 percent (32%) reduction in the CI relative to the 2010 baseline. While a 7% step-down will still leave many credits in the cumulative credit bank, this single adjustment will translate into millions of additional tons of greenhouse gas emission reductions that would've otherwise gone unaddressed.

169.2 As designed, the first year that the AAM could impact program stringency is 2028---four years from now! The concept and need for the AAM is to respond to clear overperformance of the program and to send an unambiguous market signal to investors that the program is nimble and will respond to opportunities to deliver additional GHG reductions rather than "add to" an excessively large credit bank that is at odds with the objectives of the program. Waiting four

[3] California Air Resources Board, LCFS Data Dashboard Figure 3 – Quarterly Summary Report. https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard

years is too long, and Newtrient recommends pulling the date for triggering the AAM forward.
169.2 cont The AAM should be based on 2025 data with the trigger assessment occurring in May 2026, and the AAM being applied in 2027 providing the applicable conditions are met, thus increasing the program stringency for 2027. Relying on 2025 as the first eligible year for triggering the AAM is appropriate as one of the main objectives of the step-down is to bring the program into balance. Therefore, assessing the impact of the step-down on the market based on 2025 data, including the cumulative bank and the rate of credit to deficit generation, is aligned with the principles of the program. With this approach, the AAM could theoretically increase the stringency of the program in 2027 and 2029 (i.e., triggered twice prior to 2030 providing the conditions for the triggering the AAM are satisfied), better ensuring that potential emission reductions are not left on the table in the event the program continues to overperform following the Board's adoption of the amendments.

Avoided Emission Crediting

169.3 The proposed amendments seek to phase out avoided emission pathways for projects that break ground after December 31, 2029, for biomethane used as a transportation fuel through 2040 and for biomethane used to produce hydrogen through 2045. Newtrient believes that this is inconsistent with the incentive-based approach outlined in SB 1383 and currently being implemented in California. Moreover, eliminating or phasing out the avoided methane crediting in the dairy sector would lead to an inability to meet the state's targeted methane reduction goals and result in significant dairy methane emissions leakage. Avoided methane crediting is a key component of dairy methane reduction incentives that has achieved significant reductions to date and as stated previously, is one of the most effective tools to meet California's GHG goals.

According to a UC Davis analysis:

> . . . misguided efforts to change course by forced coercion to pasture-based operations, direct regulation of dairy farms, or limitation on dairy digesters incentives will not only fail to achieve the desired greenhouse gas emissions reductions but will exacerbate the problem by causing significant emissions leakage. Revenue streams that incentivize investment in biogas capture and beneficial use are critical. Phasing out of avoided methane crediting in the dairy sector would jeopardize existing projects, making them

169.3 cont uneconomic in the long-term, and dry up investment capital for the additional digester projects sought by CARB to achieve the state's ambitious and aggressive targets.[4]

The ultra-low carbon indices within the dairy Anaerobic Digestion (AD)/Biogas sector are real and well-vetted within the national laboratory-developed Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model. As such, anyone who values science must appreciate their role in meeting GHG and climate goals, and not selectively replace them with non-scientific reasoning.

The low carbon intensity of these projects arises from a combination of well-to-wheels carbon gains plus the methane offsets from baseline methane emissions from manure management, storage, and application. Methane offsets from baseline emissions are a legitimate accounting practice as baseline, pre-AD/biogas systems emissions exist, and are largely removed through the installation of the AD/biogas system.

CARB has carefully and correctly set the boundaries of animal agriculture and clearly defines the baseline scenario of California dairies by providing a diagram of the LCFS boundaries and indicating the project related components in the Compliance Offset Protocol for Livestock Projects Capturing and Destroying Methane from Manure Management Systems Adopted: November 14, 2014.

Some groups misrepresent the dairy industry and, as in the case of the comments submitted and made during public input sessions, misrepresent the benefits of the use of anaerobic digestion and renewable energy production on dairy farms. Anaerobic digestion systems have scientifically supported GHG reductions. By calling the scientifically supported GHG reductions achieved by AD systems "artificially inflated," they show that they are not willing to discuss the science and the significant impact of AD on reducing GHG emissions from farms, but instead label and denigrate these projects with their own unscientific opinions.

Revenue streams that incentivize investment in biogas capture and beneficial use are critical. Phasing out of avoided methane crediting in the dairy sector would jeopardize existing projects, making them uneconomic in the long-term, and dry up investment capital for the additional

[4] Kebreab, Ermias, Ph.D., Mitloehner, Frank, Ph.D., and Sumner, Daniel A., Ph.D., Meeting the Call: California is Pioneering a Pathway to Significant Dairy Methane Reduction (December 2022), available at: https://clear.ucdavis.edu/news/new-report-california-pioneering-pathway-significant-dairy-methane-reduction

169.3 cont digester projects sought by CARB to achieve the state's ambitious and aggressive targets.

Avoided methane emissions are a critical part of science-based, life cycle assessments, and their inclusion in carbon intensity scores are consistent with internationally recognized standards of carbon accounting. The scientific evidence for this is robust and recognizes that the baseline includes methane emissions that would otherwise be released into the atmosphere. Recognizing methane and its role as a short-lived climate pollutant, while incentivizing its removal from the atmosphere, has proven highly successful in supporting the reduction of millions of metric tons of carbon dioxide equivalents. We strongly encourage CARB to continue its longstanding commitment to a science-driven framework that utilizes proven science including Argonne National Laboratory's GREET model.

169.4 In the event CARB maintains its plans to phase out eligibility for avoided methane in vehicle fuels, we encourage CARB to be clear that it is a policy decision associated with CARB's efforts to transition biomethane into non-vehicle sectors (e.g., residential, commercial, and industrial uses). CARB should be explicit that the policy decision to discontinue recognition and eligibility of avoided methane emissions in vehicle pathways should not be interpreted as a departure from the established rigorous science of accounting for the benefits of avoiding methane emissions which continues to be appropriate for non-vehicle sectors.

Book-and-Claim and Deliverability Requirements

Book-and-Claim has allowed the LCFS to evolve by supporting investments in clean fuels that have helped the program remain one of the most influential and successful transportation decarbonization policies in the country. To date, CARB's approach to indirect accounting in the program has been pivotal to its success, including its principles of driving greenhouse gas emissions down, facilitating investments and production of clean fuels, and in supporting increased clean fuel options for consumers.

169.5 Newtrient is requesting CARB provide further guidance on the proposed deliverability requirements. The proposed amendments aim to adopt the California Renewable Portfolio Standard (RPS) requirement of ensuring biomethane injected into a common carrier pipeline physically flows towards California 50% of the time. This referenced RPS framework does not, however, provide clarity on how those biomethane molecules can be traced to California, how a 50% average flow toward California may be modeled, nor does it provide the expected geographical regions that will remain eligible for book-and-claim accounting. Moreover, limiting

169.5 cont book-and-claim to physical deliverability requirements risks the LCFS becoming a less effective
decarbonization program and undermines California's interest in rapidly ramping up the
production and use of renewable hydrogen—a foundational principle in establishing California's
initiative to accelerate renewable hydrogen projects and the necessary infrastructure now
known as the ARCHES program---despite CARB proposing to implement deliverability
requirements for hydrogen projects utilizing biomethane five years later than projects using
biomethane for CNG vehicles.

It remains to be seen if and how the proposed deliverability requirements can be harmonized
with the California Public Utilities Commission SB 1440 program, as suggested. It has been clear
over the past year that CARB was exploring potential deliverability requirements. However,
throughout that process an actionable plan outlining the strategy and evidence necessary for
imposing delivery requirements never emerged. Rather, stakeholders continued to raise
concerns about the lack of a feasible plan which continues with the ambiguity of proposed
amendments. Therefore, Newtrient recommends that the deliverability requirement language
be removed from the current amendments to allow for further stakeholder engagement to
support a clear and actionable plan for consideration in a subsequent rulemaking.

True-up Provisions

The proposal includes true-up provisions where verified operational CI's are drawn on to
potentially adjust the credits based on certified CI's. The proposal indicates that a shortfall (i.e.,
a verified operational CI that is higher than the certified CI upon which project credits were
generated) is subject to a "penalty" that is 4 times the spread for the applicable volume of fuel.
169.6 The rationale for a 4X spread is unclear as a smaller spread (e.g., 2X) serves as a significant
disincentive to producers for being overconfident in their analysis. Further, the language
indicates that in the event the operationally verified CI is lower than the certified CI (i.e., it
failed to generate as many credits as it could have) the Executive Offer (EO) "may" make the
169.7 appropriate adjustment (true-up) by awarding additional credits to the applicable fuel reporting
entity. The word "may" should be deleted. If the operationally verified CI, including an
affirmative verification statement, is lower than the certified CI that was the basis for credit
generation, the EO "must" award the supplemental credits supported by the underlying
documentation.

The concept of adjustment to credits based on operationally verified CI's is sound. However,
169.8 limiting the proposal to certified CI's is a significant oversight. The proposal must be carried
over and applied to temporary and provisional CI's as fuel providers may rely on these CI's for

169.8 cont months, or even years, as more refined pathways are evaluated and subsequently approved by CARB.

Temporary CI's have been an important option under the program, but applicants can be reluctant to use them given the heavy credit discount relative to facility-specific provisional CI's. Correcting for any under (or over) crediting while a temporary CI is used will help streamline and simplify the program as well as send a stronger signal to the market that investments in clean low-CI fuels will be rewarded. Further, including temporary CI's as part of the true-up process will reduce the pressure on CARB from developers to process LCFS applications quickly which has been an ongoing and growing challenge under the program. The concept of adjusting the awarding of credits based on operationally verified CI's is a key principle that supports innovation and must be reflected from project initiation, where a temporary CI is used, throughout the project's lifetime to properly account for and reward the associated reductions in greenhouse gas emissions. Credits should be awarded based on real-world operational experience and therefore adjusted accordingly when the temporary CI which is applied understates the benefits.

New Markets

As the technology in the transportation sector continues to evolve and advance towards lower carbon alternatives, Newtrient members and the rest of the dairy industry and are ready to serve these new markets, such as alternative jet fuel (AJF), low-CI hydrogen, as well as exploring opportunities where biomethane can be utilized outside of transportation. As these markets continue to grow, Newtrient asks CARB to remain mindful of the success of the historical framework of the program and to continue to apply it to these newer pathways and technologies, including the use of avoided emissions and book-and-claim.
If CARB's goal is to transition biomethane out of the vehicle sector, Newtrient strongly encourages CARB to ensure there continues to be a market for low-CI biomethane as it is an important decarbonization tool, especially in sectors that are hard to decarbonize. For example, the CPUC's SB 1440 program creates a biomethane procurement mandate for the state's largest utilities, however, the program limits dairy biomethane due to the credit it currently receives in the LCFS.[5] With CARB's intention of phasing out all biomethane crediting for transportation fuel by the end of 2040, it makes sense for the CPUC to integrate dairy

[5] California Air Resources Board, *2022 Scoping Plan Update*, page 73. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022- sp.pdf

biomethane into the SB 1440 program which will allow for more market choice and volumes for utilities to procure. The industrial sector is also another area where biomethane can help significantly reduce emissions, particularly at facilities that are large natural gas users and where electrification is not currently feasible. However, there isn't one, all-encompassing policy that drives dairy biomethane, and other low-CI clean fuels, towards that use case. Thus, Newtrient recommends that CARB, starting with the 2024 amendments to the LCFS, send a
169.9 clear policy signal that dairy biomethane is a necessary and effective decarbonization strategy in these other sectors (e.g., residential, commercial, industrial) that are fundamental to the state meeting its ambitious GHG reduction targets.

Conclusion

Over the past year and a half, CARB staff have held numerous public workshops to gather feedback on potential changes to the program, where Newtrient participated, and we're pleased to see that the rulemaking is nearing completion. Newtrient would like to underscore the importance of concluding this rulemaking as soon as possible. Any further delay to the rulemaking diminishes the necessary signal the market needs to facilitate and encourage continued investments in clean fuels. To continue the significant and unprecedented progress made by CARB and the dairy industry of California under the guidance and support of the CDFA, Newtrient urges CARB staff and the Board to finalize this rulemaking no later than the end of Q2 2024.

Thank you for the opportunity to comment on the proposed amendments, and we look forward to engaging with CARB staff on these topics.

Sincerely,

Mark Stoermann
Chief Operating Officer
Newtrient LLC

Newtrient, LLC
10255 West Higgins Road, Suite 900 • Rosemont, IL 60018-5616 **www.newtrient.com**

Comment Log Display

Here is the comment you selected to display.

Comment 179 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Kim
Last Name	Dupre
Email Address	duprekk@gmail.com
Affiliation	
Subject	LCFS Public Comments

Comment

I'm speaking today as a resident of rural America, one who has
lived in the shadow of factory farms and biogas digesters. Despit
170.1 all the promises from DNR, local elected officials, and experts
over the years that this farm/biogas digester wouldn't hurt our
water quality or way of life....that has not aged well in Emerald,
Wisconsin.

I watched several in my neighborhood lose their drinking water -
the Town Hall's well which originally had nitrates at 6.9 ppm just
a few years ago - now has nitrates consistently near 40 ppm and ha
spiked to 52 and 62 ppm.

This farm keeps getting larger. We've seen the implementation of
biogas digesters become a rationale for increasing herd sizes....
yet our drinking water is not getting cleaner - but actually much
worse. The biogas digester exploded and burned up after a few
years and wasn't replaced, but the damage was already done, and ou
water has not improved.

My neighbors watched the nitrates rapidly increase over the same
time in their private wells, many of which don't drink their water
anymore - some won't even give it to their pets. Well drillers
have said "we can dig you a well, but we can't guarantee you
drinkable water." One neighbor experienced that firsthand when
selling his home - a new well 200 feet deep well was still testing
at 17 ppm for nitrates. He had to install a reverse osmosis syste
to get the property sold - but then the new family, with small
children, moved away within a year because they were concerned
about the water quality.
E.coli has also been found in several wells in our neighborhood
over the years - which made turning on my faucet every day a "crap
shoot" in my mind. That led to the heartbreaking decision my
husband and I finally made to leave our acreage in Wisconsin for
safer spaces in Minnesota - a place where we can drink the water
and serve it to family and friends without fear.

Clean water is the only driver of economic development in rural
areas. No one wants to locate a home, subdivision, or business if
clean drinking water is not available. To incentivize manure
production over milk production is damaging to our environment.
There is no way our soils can absorb that concentrated nutrient

170.1 cont

load from digestate when they are already 5-6x higher in phosphoru
than what is recommended by University of Wisconsin for growing
crops. TMDLs are common in many agricultural parts of Wisconsin -
green rivers, streams, and lakes by the 4th of July. Nitrates in
groundwaters are still rising per a 10-year study in St. Croix
County, Wisconsin.

I make the analogy that this feels like these energy companies hav
come in and raided our kitchens, make a disastrous mess, and
leaving us to clean it up and deal with the consequences.

As a resident of the St. Croix River Valley for over 25 years (a
Wild & Scenic River, part of the National Park System), I ask that
you look at the long-term picture - plan for the next generation
and not just the next years' dollars.

As a farmer's daughter, I get that farming has changed....but what
has not, or will EVER change, is our need for clean drinking
water.

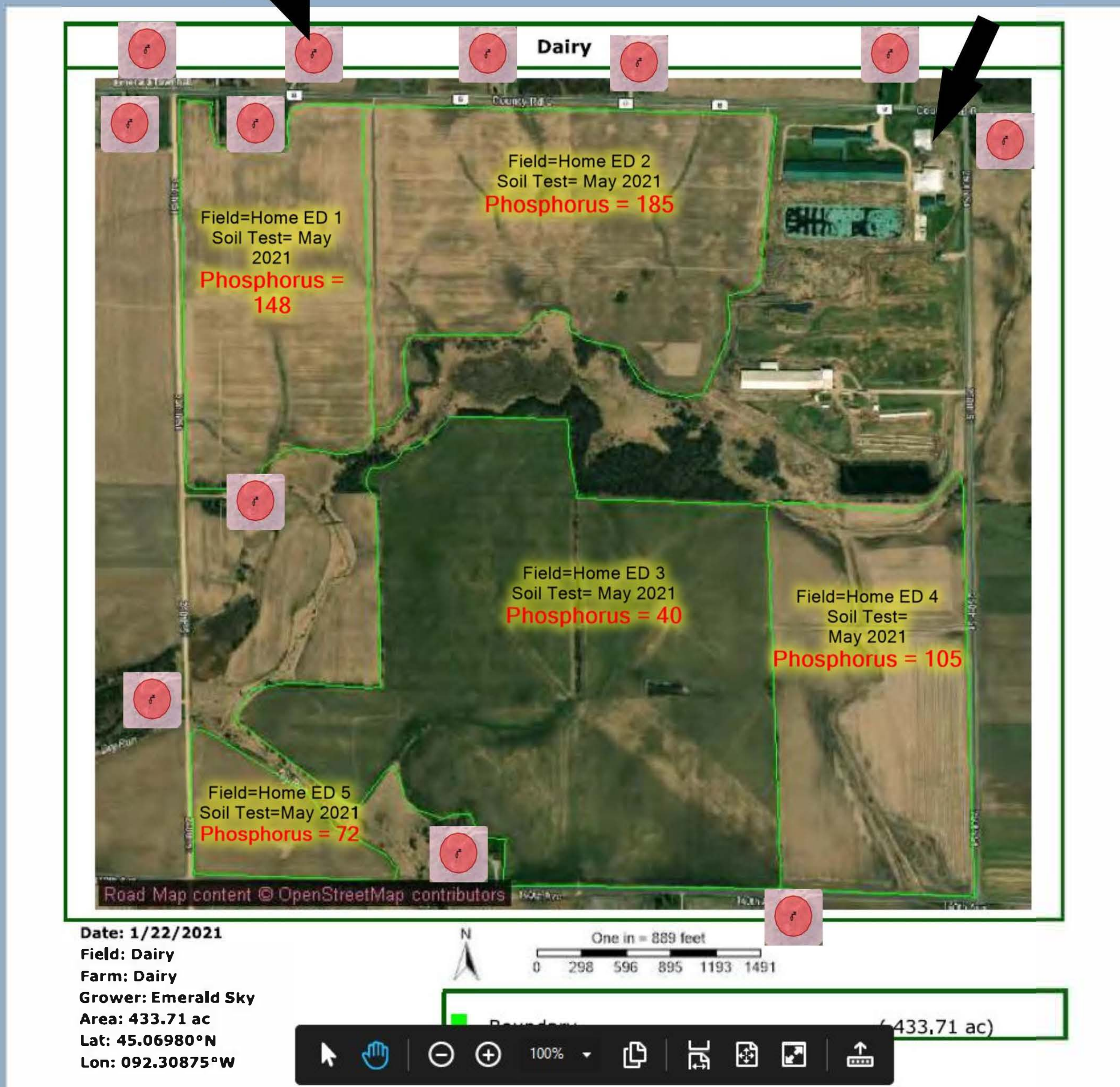
Attachment	www.arb.ca.gov/lists/com-attach/6837-lcfs2024-BWBVIABIUFxVO1U6.jpg
Original File Name	ESD_Home_PhosSoilTests2021.jpg
Date and Time Comment Was Submitted	2024-02-20 07:17:18

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Emerald Town Hall
Nitrates=52 mg/l in May 2022
5x higher than Public Health
safety standard

= Drinking water well

Emerald Sky Dairy
production area



Note 1: Soil test Phosphorus levels for most agronomic crops in Wisconsin are considered "excessively high" at 35+ ppm. Once levels reach 200 ppm - DNR must give written permission to continue with manure spreading since it takes over 50 years of NO spreading to resture the soil.

"Optimum" soil P levels are generally between 16 ppm and 25 ppm and are considered (interpreted) by UW-EX as "economically and environmentally the most desirable soil test category." Further, "the Wisconsin program defines the critical level as the cutoff between the optimum and high soil test levels. If the nutrient supply drops below the critical level, growers face economic losses from reduced yields or poor crop quality.

If the supply exceeds the critical level, there is an increased risk of mobile nutrients moving into the groundwater and surface water. In addition, there is no profit in applying nutrients that will not be used."

Comment Log Display

Here is the comment you selected to display.

Comment 180 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Neil
Last Name	Koehler
Email Address	neil.koehler@kbe-llc.com
Affiliation	Renewable Fuels Association
Subject	Renewable Fuels Association comments on proposed LCFS Amendments
Comment	RFA comments attached.
Attachment	www.arb.ca.gov/lists/com-attach/6838-lcfs2024-USMCYIY2V1sLbgFu.pdf
Original File Name	RFA Comments on CARB LCFS Ammendments 02-20-24.pdf
Date and Time Comment Was Submitted	2024-02-20 07:21:26

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

RENEWABLE FUELS ASSOCIATION

February 20, 2024

The Honorable Liane Randolph
Chair
California Air Resources Board
1001 I St
Sacramento, CA 95814

Re: Proposed Low Carbon Fuel Standard Amendments

Dear Chair Randolph and Members of the Board,

The Renewable Fuels Association (RFA) appreciates the opportunity to comment on the proposed amendments to the Low Carbon Fuel Standard (LCFS). The RFA is the leading trade association for America's ethanol industry. Our mission is to drive growth in sustainable renewable fuels and bioproducts for a better future.

The RFA supports the LCFS and looks forward to continued engagement in this process to strengthen and extend the program beyond 2030. The RFA is also working around the country in collaboration with other stakeholders to develop and implement clean fuel programs in other states.

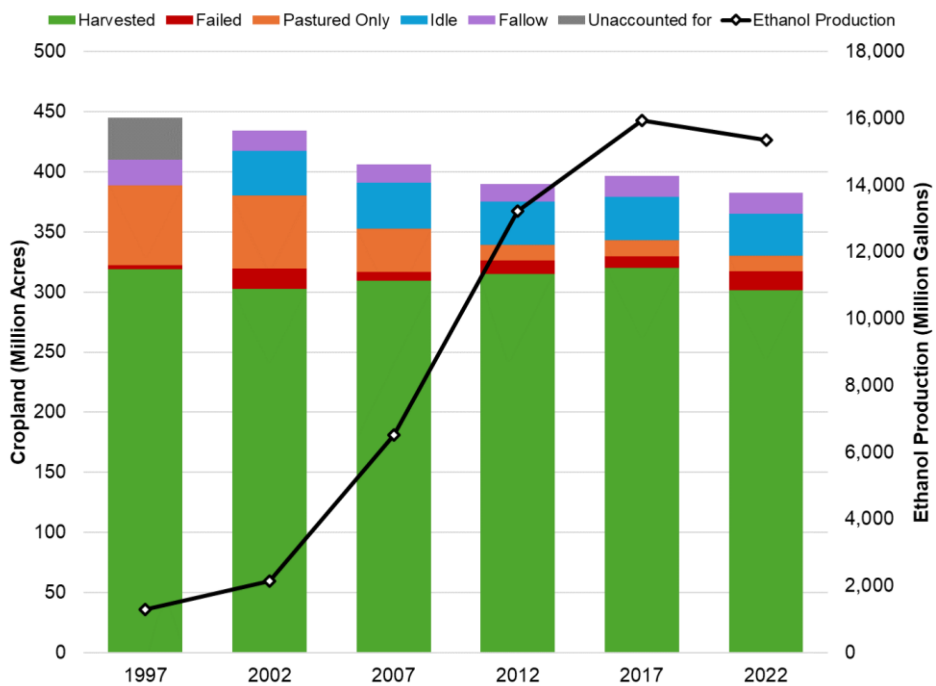
The RFA has commented extensively over the last two years during the California Air Resources Board's (CARB) process of modifying and updating the LCFS program. We will not reiterate those comments here, but are attaching them to this letter, in order to enter them into the public record for the LCFS rulemaking and to encourage further refinement of the LCFS. To date, most of our substantive comments have not received adequate responses from staff. Our comments here address new items introduced in the rulemaking package and some further elaboration of earlier comments.

The proposed sustainability requirements for crop and forestry feedstocks are vague, overreaching, and unnecessary for U.S.-produced biofuel feedstocks.

171.1 The proposed amendments to the LCFS released at the end of 2023 include a sustainability certification program which is a new concept that has never been introduced or discussed at any public workshop or hearing during the two years of the LCFS modification process. It is problematic from a public process perspective to introduce a concept with wide-ranging policy implications and cost burdens to feedstock and clean fuel producers with no corresponding clear justification or demonstrated benefits of such a program.

In CARB staff's Initial Statement of Reasons, the rationale for a feedstock certification program is a stated concern over deforestation or adverse land use change resulting from a rapid increase in biofuel production. As was documented in the RFA comments of August 8, 2022, the total acreage of cropland in the U.S. has steadily declined for decades, including since the beginning of both the federal Renewable Fuel Standard (RFS) in 2005 and the LCFS in 2011. This was reinforced by the 2022 Census of Agriculture released by USDA just last week, which showed that the amount of cropland in the U.S. fell by an additional 14 million acres, or 4%, since the prior Census in 2017. The decline in cropland area has occurred even as ethanol output increased substantially from the modest volumes of the early 2000s (Figure 1).

Figure 1: U.S. Cropland Area Compared to Ethanol Production



Sources: U.S. Dept. of Agriculture, Census of Agriculture (cropland area); U.S. Energy Information Administration (ethanol production)

As also documented in our prior comments, significant increases in biofuel production have been made possible by continuous crop yield and biofuel production efficiency improvements. From 1997 to 2022, three-quarters of the increase in U.S. corn production was attributable to rising yields, while only one-quarter came from higher acreage, based on an RFA analysis of Census data.[1]

It should be emphasized that the RFS already contains provisions to protect against any expansion of cropland for biofuel feedstock production from a 2007 baseline.

[1] https://ethanolrfa.org/media-and-news/category/blog/article/2024/02/ag-census-confirms-cropland-decline-adoption-of-environmental-practices

171.1 cont Imposing a third-party verification system for feedstock certification places an extreme audit burden on feedstock suppliers and biofuel producers without any clearly defined benefit. The audit report summaries would need to be designed so that their publication does not result in the disclosure of sensitive or confidential business information.

It is difficult to understand what is being proposed, as even the term "sustainability" is not defined in the proposed amendment. Moreover, the requirement that the certification system include social criteria could take it far afield from being an environmental safeguard and could introduce subjectivity regarding the criteria that are included.

This provision needs extensive stakeholder engagement and analysis before being considered for inclusion in any amendment to the LCFS program. At least for U.S.-sourced feedstocks and biofuel production, there is no substantiable reason to impose this vague, yet cumbersome system.

Consistency across transportation fuel technologies is another issue with the sustainability provisions in the LCFS proposed amendments. If feedstocks for biofuels are to be examined across yet-to-be-defined sustainability criteria, then so should other raw materials and technologies. For instance, with the projections for a massive increase in new electric vehicles, what are the sustainability considerations for the corresponding massive increase in the amount of mining for lithium, cobalt and other metals involved in battery production?

A precedent close to what is being suggested for sustainability requirements is the Land Use and Biodiversity (LUB) provisions of Canada's recently adopted Clean Fuel Regulation (CFR). Based on analysis provided to Environment and Climate Change Canada, the agency implementing the CFR, the U.S. was granted feedstock recognition on November 9, 2023, certifying that U.S. feedstocks comply with the LUB criteria covering all bio-based diesel and ethanol shipped to Canada from the U.S. If California moves ahead with any feedstock certification program, there should be a provision comparable to the Canadian CFR to designate all U.S.-produced biofuels as being in compliance with the program so long as aggregate cropland acreage in the U.S. does not expand beyond a given baseline.

The RFA and many other stakeholders have commented repeatedly on the need to develop farm level crediting for carbon-reducing agricultural practices such as cover cropping, no till, and lower carbon inputs. There is a tremendous opportunity to incentivize carbon reductions in agricultural production which would meaningfully contribute to lower carbon intensity from the biofuels that continue to be a critically important contributor to the success of the LCFS. Any consideration of sustainability certification should include the opportunities for farm level crediting of lower-carbon farming practices.

171.2 **Higher blends of ethanol are an immediate option for maximizing carbon intensity reductions, lowering criteria emissions, and reducing consumer costs in the LCFS. Concurrent with adoption of LCFS amendments, CARB should initiate a rulemaking to certify E15 blends in California.**

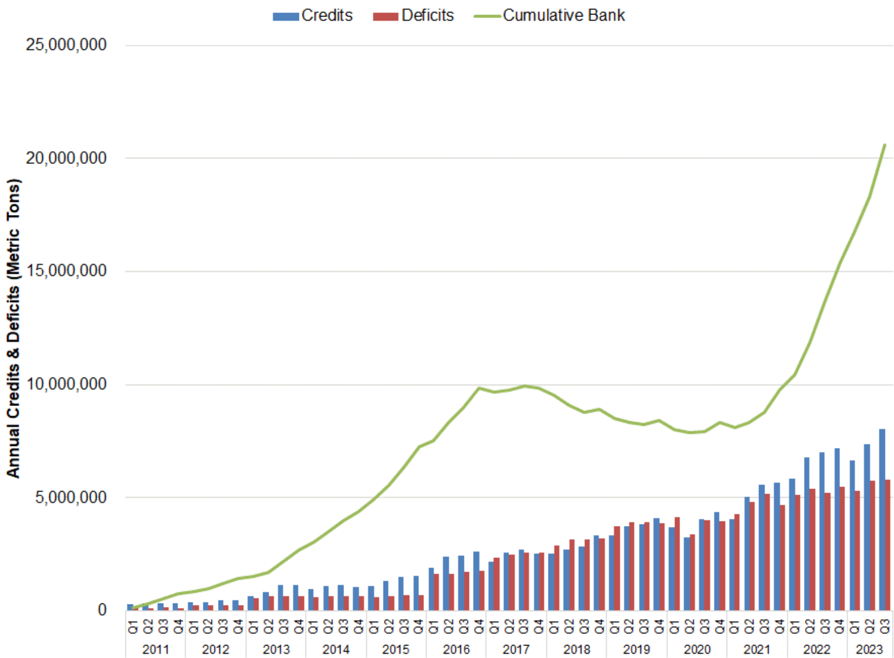
With Montana's approval of E15 in December of 2023, California is now the only state not recognizing the blend as a legal fuel. Decarbonizing the liquid fuels that will be in the market for decades to come is a critically important complement to electrification in achieving the goals of the CARB Scoping Plan. Science informs us that time is of the essence to achieve maximum GHG reductions now. E15 is the leading opportunity under the LCFS to immediately and significantly further reduce GHG emissions while at the same time reducing criteria pollutant emissions and consumer costs. Higher ethanol blends in California will not lead to substantial increases of ethanol in the California fuels market, but rather utilize existing supplies to displace more petroleum as gasoline consumption in California declines, meeting both decarbonization and petroleum displacement goals.

Ethanol has been a workhorse of the LCFS program generating one-quarter of the credits program to date. Opening the LCFS to higher blends of ethanol supports a more stringent compliance curve resulting in greater GHG and criteria pollutant reductions. A vehicle emissions study co-funded by CARB demonstrated remarkable air quality benefits when increasing the blend of ethanol from 10 to 15 percent. E15 as the standard fuel in California would result in an additional annual reduction of two million metric tons of GHGs while reducing the cost of gasoline to consumers.

RFA is part of the broad coalition of clean fuel suppliers who have documented through analysis by ICF that carbon reductions of over 40 percent by 2030 are readily achievable. E15 is a significant contributor to these additional carbon reductions. The ICF analysis has been shared with CARB Board members and staff.

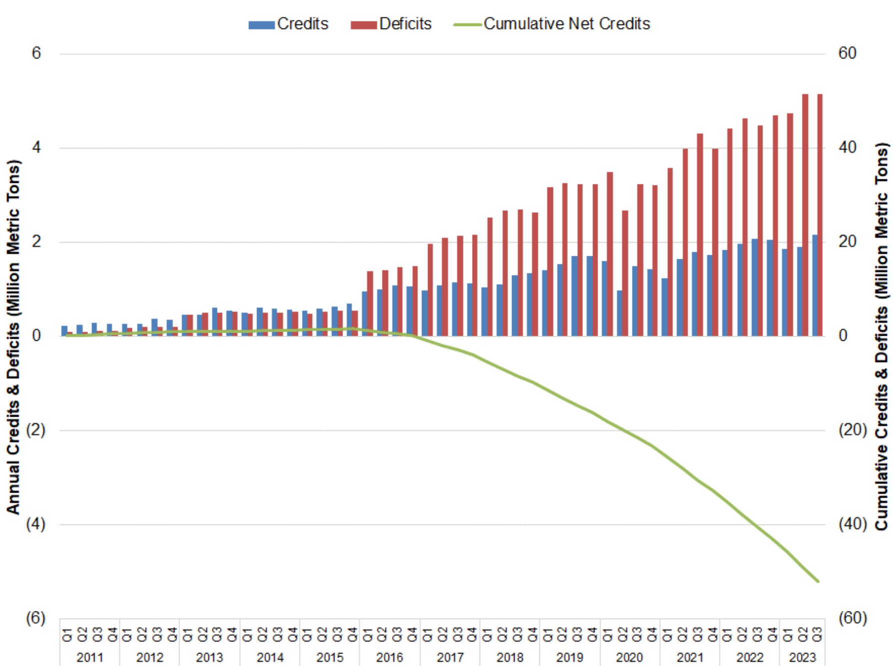
Additional credit generation in the gasoline pool is critical in the near term to reverse the growing and alarming trend of large deficit balances in the light duty transportation sector. Figure 2 and Figure 3, which are updated from prior RFA comment letters, show the credit surpluses in the overall LCFS program due to large credit generation from RNG and bio-based diesel (now 60 percent of total diesel consumption) contrasted with the large deficits in the gasoline pool, where ethanol is limited to ten-percent blends (E10) and petroleum continues to be the dominant source of fuel.

Figure 2: Total California LCFS Credits and Deficits for All Fuels



Source: California Air Resources Board

Figure 3: Net Credits (Deficits) Generated by Gasoline, Ethanol and Charging of On-road Electric Vehicles, Excluding Heavy-duty Vehicles



Source: RFA Analysis of California Air Resources Board data

171.2 cont The Department of Finance was correct in responding to the SRIA by questioning the assumption that E10 would be the standard ethanol blend through 2045 when the consequence is greater dependence on liquid petroleum fuel, which runs counter to stated CARB policy. The response by CARB to the Department of Finance in defending the E10 assumption was misleading. The Multimedia Working Group (MMWG) process evaluating E15 blends has been ongoing for over three years and is nearly complete, merely waiting for finalization by CARB staff to then refer to the Environmental Policy Council for a final recommendation.

Due to California leading underground tank policies, all underground tanks in California are legally required to be compatible with E15 and higher blends as of January 1, 2024. Virtually all the cars on the road are approved by EPA for E15 use and virtually all the new dispensers sold are warrantied for at least E15 blends. With E15 approval by CARB, fuel marketers will have the option of providing a lower cost and cleaner fuel choice to consumers.

CARB has expressed interest in leveraging federal support in meeting LCFS and climate neutrality goals. The Inflation Reduction Act (IRA) of 2022 allocated $500 million to the High Blend Infrastructure Incentive Program (HBIIP) to support the building of new infrastructure for the distribution of higher blends of both ethanol and biodiesel produced from agricultural products. The first round of $50 million in HBIIP funding is committed with $450 million still available over the next several years. This program is available to California businesses to invest in new infrastructure for dispensing E15 and higher ethanol blends.

SB 32, which extended the goals of California's groundbreaking AB 32 legislation, is clear in the mandate for CARB to adopt rules and regulations to "achieve the maximum technologically feasible and cost-effective greenhouse gas emissions reductions." California's exemption from the Clean Air Act to implement its own clean air programs is predicated on the state's regulations going further than the federal government on improving air quality and human health. Expeditiously approving E15 use in California is consistent and necessary for CARB to comply with both state and federal clean air policies.

As commented by the RFA from the beginning of this process, E15 certification should be part of the current LCFS rulemaking. We respectfully ask that the CARB Board direct staff to expedite the simple gasoline specification change allowing for (not mandating) E15 to facilitate greater emissions reductions, petroleum displacement and cost savings as soon as possible to advance the success of the LCFS program.

171.3 **Allowing the Auto Acceleration Mechanism (AAM) to be triggered as early as 2026 and to apply to consecutive years would be more effective in supporting a robust LCFS.**

RFA supports the AAM and the conditions proposed to trigger a pulling forward of the compliance schedule by one year. The current proposal prohibits the AAM from starting before 2027 and being triggered in two subsequent years, requiring a one-year break before it can be triggered again even if in that subsequent year the conditions are met. To support a robust LCFS compliance curve, we support the AAM implementation in 2026 and dropping the skip-year requirement. Carbon markets are efficient in responding to supply/demand imbalances. Delaying implementation of the AAM until 2027 or a waiting an extra year if the market is out of balance will create inefficiencies and undermine the objective of the LCFS to maximize carbon emission reductions.

Indirect accounting for low carbon intensity hydrogen production through
171.4 **purchase power agreements (PPAs) should be extended to the production of all low- to zero-carbon biofuels.**

In the interest of both technology neutrality and maximizing renewable electricity production and carbon emission reductions, the use of PPAs for book-and-claim accounting should be extended beyond just hydrogen. RFA supports the concepts for PPA accounting to ensure new or expanded capacity, delivery to local balancing authorities and quarterly matching. Extending these concepts to biofuel producers supports further increases in renewable electricity production and further decreases in the carbon intensity of liquid biofuels.

RFA reiterates its support in prior comments for book-and-claim accounting to also be extended to the use of biogas delivered to a pipeline for displacing fossil natural gas in the production of liquid biofuels. This could be subject to the same additionality, deliverability and balancing measures being proposed under the PPA construct.

The LCFS and Scoping Plan have an overarching objective to maximize carbon reductions as quickly as possible to achieve carbon neutrality no later than 2045. Appropriately and consistently extending indirect accounting for both renewable electricity and biogas for liquid biofuel production is a valuable and necessary tool in achieving the state’s aggressive climate targets.

The carbon intensity of ethanol is falling faster than any other low carbon fuel supplied to California and RFA ethanol producers have committed to zero carbon ethanol production before 2050. While RFA supports the LCFS, the current proposed amendments to the LCFS program are falling short of maximizing technologically feasible and cost-effective greenhouse gas emission reductions that are possible when utilizing higher blends of ethanol and indirect accounting for renewable process energy incorporation in ethanol production.

171.5 **The proposed credit true-up for entities achieving a lower verified operational CI is a reasonable step to recognize GHG emissions reductions that have been achieved. However, the deficit multiplier for a verified CI exceedance is disproportionate.**

RFA supports the proposal to allow credits to be placed in the account of a fuel reporting entity that achieves a lower verified operational CI for a fuel pathway, as this will provide additional incentive to reduce GHG emissions. However, the proposed measure to allocate deficits to entities with a CI exceedance is disproportionate to the treatment of entities achieving a lower verified operational CI and is unnecessarily punitive, as the number of deficits is four times the difference between the verified operational fuel pathway CI and the reported CI, multiplied by the quantity of fuel. A more equitable treatment of these mirror-image cases would be merited, and the deficit multiplier should be eliminated or greatly reduced.

171.6 **The requirement that there be rotation of verification bodies/individual verifiers every six years should be revised.**

The prohibition against the same verification body or individual verifier performing validation and verification services for more than six consecutive years is not newly proposed, but the January 1, 2026 date when entities that are required to use these services would start having to change providers is fast approaching and would occur during the timeframe covered by the proposed amendments. Such changes would be disruptive and costly, and CARB's objectives can be accomplished through less-rigid means. Specifically, it would be sufficient to require that the person(s) leading the verification organization's services for a client be rotated every six years.

Thank you again for the opportunity to submit these comments. RFA looks forward to working with CARB staff and other stakeholders to strengthen and extend the successful LCFS program.

Sincerely,

Scott Richman

Chief Economist

ATTACHMENTS

RENEWABLE FUELS ASSOCIATION

June 6, 2023

Ms. Cheryl Laskowski, Branch Chief
Transportation Fuels Branch
California Air Resources Board
1001 I St
Sacramento, CA 95814

Re: Low Carbon Fuel Standard Workshop May 23, 2023

Dear Ms. Laskowski,

The Renewable Fuels Association (RFA) appreciates the opportunity to comment on the workshop regarding the consideration of potential Acceleration Mechanisms to the Low Carbon Fuel Standard (LCFS) program held on May 23, 2023. The RFA supports the LCFS and looks forward to continued engagement in this process to strengthen and extend the program beyond 2030. The RFA is also working around the country in collaboration with other stakeholders to develop and implement LCFS and other clean fuel programs in other states.

The RFA has commented extensively on the key issues of the LCFS modifications in our letter of August 8, 2022, following the July 27, 2022 LCFS workshop, our letter of December 20, 2022, following the November 9, 2022 LCFS workshop, and our letter of March 15, 2023 following the February 22, 2023 workshop. These new comments should be considered in combination with the earlier comments and are responsive to CARB staff's request at the most recent workshop for stakeholder input on the topics of a potential stepdown in the compliance curve and acceleration mechanisms.

A stepdown in the compliance curve in 2024 is the single most important step CARB can take to strengthen the LCFS.

The LCFS program's outstanding success has resulted in overcompliance, ballooning the credit bank and undercutting credit prices. This is dampening new investment in low- to zero-carbon fuels. A stepdown of at least five percent from the current compliance curve will send the right long-term price signal, while also facilitating a significant strengthening of the 2030 target from the scheduled 20 percent to greater than 40 percent. The RFA is working with a broad coalition of fuel providers who have commissioned ICF to demonstrate both a central and higher ambition case to CARB on what the clean fuels industry is prepared to deliver by way of carbon intensity reductions.

Higher blends of ethanol are a cost-effective and immediate option for maximizing carbon intensity reductions in the LCFS. CARB should include E15 approval in the upcoming LCFS rulemaking package.

At the most recent workshop, the CARB presentation identified the objectives of the new LCFS rulemaking: to support increased low-carbon fuel supply, provide long-term price signals and increase regulatory clarity to support deeper transportation decarbonization, and to leverage new federal programs with complementary LCFS policies.

Consistent with these objectives, CARB should include with the rulemaking an approval of E15 as a legal fuel in California. If E15 had been used in California in 2022 rather than E10, that alone would have allowed the LCFS compliance target to be nearly 2 percent lower. Migration of the market to E15 over the course of this decade would enable a 2.5 percent reduction of the current 2030 target against the 2010 baseline, based on a combination of the expected improvement in ethanol's carbon intensity and the forecast decrease in finished gasoline consumption resulting from the Advanced Clean Cars II regulation. (Please see our calculations at the bottom of this comment letter.)

When the E10 cap is removed from the CATS model, the model immediately selects usage of E15 as a cost-effective way to achieve additional carbon reductions. California and Montana are the only two states not recognizing E15 as a legal fuel. The recently passed IRA includes billions of dollars to support the significant lowering of the carbon intensity of ethanol through CCS, climate smart ag and other efficiency improvements. Not including E15 certification in the current LCFS rulemaking would be inconsistent with the stated goals of the LCFS, sending a contradictory and confusing message to the market on what carbon reduction goals are possible.

It is also important to note that increasing the ethanol blending rate will not result in large increases in ethanol consumption in California but will displace larger volumes of fossil energy use and increase the market share of renewable liquid fuels as overall gasoline volumes decline rapidly with continued electrification. Projected out to 2045 when California has committed to carbon neutrality, there will still be billions of gallons of liquid fuels in the market and these fuels must be ultra-low to zero carbon to achieve that goal. In the gasoline pool, ethanol is the only commercially available fuel that meets this test. Even in emerging renewable gasoline blends, ethanol will still be needed to help raise octane, dilute sulfur, increase oxygen content and provide other desirable properties (e.g., Chevron's new renewable gasoline blend contains 15% ethanol[1]).

[1] https://www.chevron.com/-/media/chevron/newsroom/2023/Q2/renewable-gasoline-blend-factsheet-may-2023.pdf

A properly constructed Acceleration Mechanism is helpful for sending a consistent market signal for innovation and investment in additional supplies of low carbon fuels.

The current low credit prices under the LCFS are clearly inhibiting new investment in low carbon fuel production. The long period of time (up to three years) to update the LCFS given the regulatory process in California is creating uncertainty as to the longer-term trajectory of the program. In combination with an immediate stepdown of the LCFS program in 2024, an Acceleration Mechanism could address this problem. RFA generally agrees with the concepts presented by AJW and believes that an acceleration formula should incorporate ratios of credit and deficit generation as well as ratios of such generation to the overall size of the credit bank.

It is critically important for CARB to move quickly and concisely in strengthening the LCFS program. Timely and accurate modelling and scenario development, with input from the coalition of stakeholders that are supporting the ICF analysis, is an important and valuable tool in this regard.

Ethanol is a top generator of credits in the LCFS program, accounting for three of every 10 credits generated since the program's inception. But constraining ethanol's use to E10 is sacrificing additional carbon reductions possible today. We urge CARB to include E15 approval as part of the regulatory package for the current LCFS modifications under consideration, which will allow the ethanol industry to help displace more fossil fuel in California and lower carbon emissions now.

An accurate modelling of ethanol's benefits and an integration of CARB fuels policy to incentivize higher ethanol blends will result in immediate reductions of GHG emissions and criteria pollutants while lowering the cost of compliance to obligated parties and California consumers.

RFA looks forward to working with CARB staff and other stakeholders to strengthen and extend the successful LCFS program.

Sincerely,

Scott Richman
Chief Economist

	Based on 2022 Estimates			2030 Projection		
	Actual	**If E15 Used**	**Difference**	**If E10 Used**	**If E15 Used**	**Difference**
Volumes (Mil Gal)						
Finished Gasoline	13,700	13,918	218	9,700	9,854	154
CARBOB in:						
E10	12,330			8,730		
E15		11,830			8,376	
Total	12,330	11,830	-500	8,730	8,376	-354
Ethanol in:						
E10	1,370			970		
E15		2,088			1,478	
Total	1,370	2,088	718	970	1,478	508
Carbon Intensity (gCO2e/MJ)						
CARBOB	101.7			101.7		
Ethanol	59.2			35.0		
Gasoline CI Benchmarks/Targets (gCO2e/MJ)	89.5			79.6		
Revised 2010 Baseline	99.4					
Energy Density (MJ/Gal)						
CARBOB	119.53					
Ethanol	81.51					
LCFS Credits (Deficits) (Mil MT)						
CARBOB	-18.0	-17.3	0.7	-23.1	-22.2	0.9
Ethanol	3.4	5.2	1.8	3.5	5.4	1.8
Finished Gasoline Total	-14.6	-12.1	2.5	-19.6	-16.8	2.8
Addl. Gas CI Benchmark Reduction due to E15						
g CO2e/Gal Gasoline	-1,066	-870	196	-2,020	-1,706	314
MJ/Gal Gasoline	116	114		116	114	
Addl. CI Benchmark Reduction (gCO2e/MJ)			1.6			2.5
Reduction as Percentage of:						
2010 Baseline			**1.6%**			**2.5%**
Annual Benchmark/Target			**1.8%**			**3.1%**

Note: Excludes E85 since volume would not be expected to change due to E15 adoption

RFA
RENEWABLE FUELS ASSOCIATION

March 15, 2023

Ms. Cheryl Laskowski, Branch Chief
Transportation Fuels Branch
California Air Resources Board
1001 I St
Sacramento, CA 95814

Re: Low Carbon Fuel Standard Workshop February 22, 2023

Dear Ms. Laskowski,

The Renewable Fuels Association (RFA) appreciates the opportunity to comment on the workshop on potential changes to the Low Carbon Fuel Standard (LCFS) program held on February 22, 2023. The RFA supports the LCFS and looks forward to continued engagement in this process to strengthen and extend the program beyond 2030. The RFA is also working around the country in collaboration with other stakeholders to develop and implement LCFS and other clean fuel programs in other states.

The RFA commented extensively on the key issues of the LCFS modifications in our letters of August 8, 2022 (in response to the July 27, 2022 LCFS workshop) and December 20, 2022 (regarding the November 9, 2022 workshop). These new comments should be considered in combination with the earlier comments and are responsive to CARB staff's request at the most recent workshop for stakeholder input on specific topics.

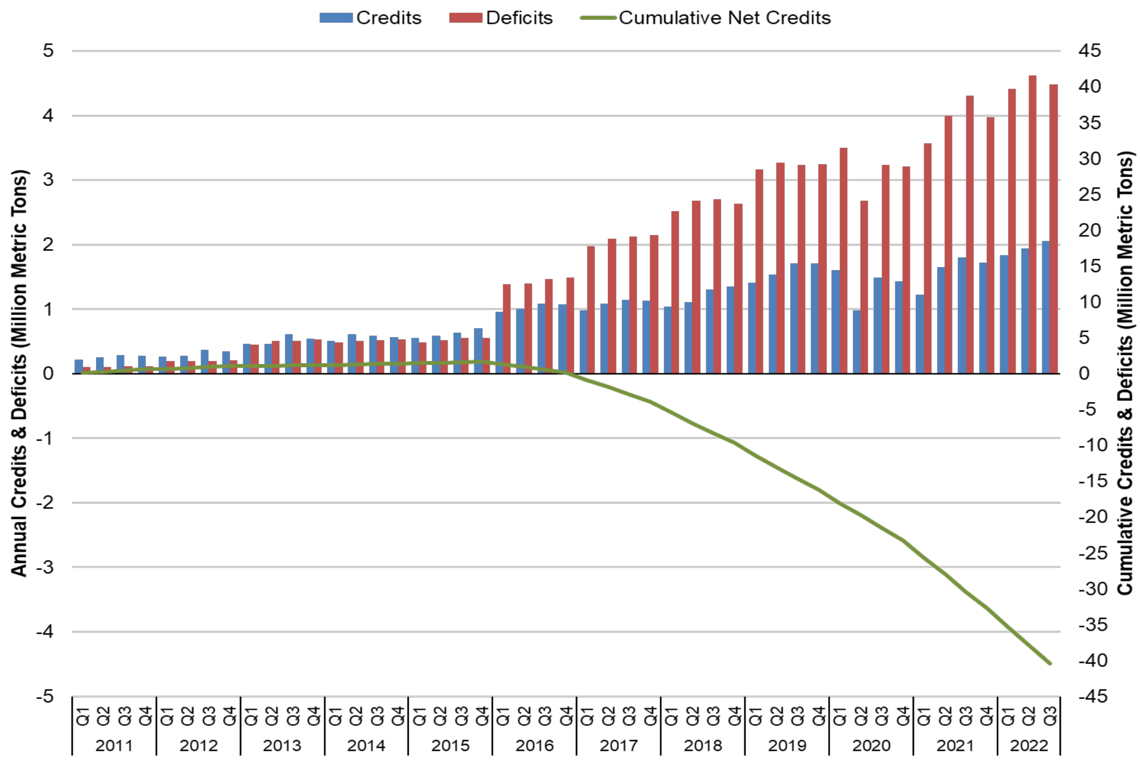
Since the earlier workshops were considered informal workshops, and the February workshop is considered the first formal workshop for the proposed LCFS modifications rulemaking, we are including the earlier comments with this comment letter to ensure that they are included in the formal rulemaking record.

Higher blends of ethanol are necessary to meet the goals of the newly adopted CARB Scoping Plan.

The CARB presentation at the last workshop identified the current *Decade of Action* to achieve the near-term statewide goal of achieving a 48% reduction of GHG emissions below 1990 levels by 2030 and a rapid transition away from fossil fuels in the transportation sector. In addition to aggressive electrification goals, higher blends of low- to zero-carbon ethanol are a critical component of achieving the 2030 targets on the path to carbon neutrality by 2045. CARB has all the data to support the immediate approval of E15 for use in California. Migrating all E10 to E15 in California today would result immediately in approximately 2 million metric tons annually of additional GHG reductions while also reducing criteria pollutants and toxics, all at a lower cost to California consumers.

As RFA has commented before, while the overall LCFS program has resulted in a significant credit surplus (currently over 13 million metric tons with the most recent third quarter report of 2022), the deficit generation in the gasoline pool continues to grow rapidly with a current deficit balance of 40 million metric tons and accelerating as shown below.

LCFS Credits/Deficits Associated with Finished Motor Gasoline and Onroad EV Charging
Q1 2011-Q3 2022



The RFA and a preponderance of stakeholders support both strengthening the 2030 carbon reduction target to at least 30 percent and a stepdown of the current compliance curve starting in 2024. Without addressing the growing deficit generation in the gasoline pool, such a robust strengthening of the compliance curve will not be possible. With a greater inclusion of higher ethanol blends in the California gasoline supply, RFA believes that the 2030 target reduction could be moved to as much as 35 percent. Oregon has strengthened their Clean Fuels Program compliance target to 37 percent by 2035, and the modelling to support this includes both a transition of gasoline blends to E15 and significant growth in the E85 market.

Beyond 2030, intermediate blends above 15 percent and continued growth of E85 are needed to further displace fossil fuels and achieve carbon neutrality. The Scoping Plan includes a large volume of "bio-based gasoline" in achieving carbon neutrality. Ethanol is the only commercially practical and affordable "bio-based gasoline" substitute in the market today, and the LCFS and other CARB policies must clear unnecessary regulatory hurdles to its increased use. Simply stated, by not encouraging higher blends of low- and zero-carbon ethanol in the transportation market today, CARB would be abdicating its own stated goal of maximizing GHG reductions as soon as possible.

Further modify the CATS model to better reflect current and projected ethanol economics, carbon intensities and volumes.

RFA appreciates the revisions in version two of the CATS model that were partially responsive to our comments on carbon intensities and carbon capture and sequestration (CCS), but we believe further revisions would more appropriately reflect the current market and future trends in the ethanol industry.

The updated CATS model incorporates the average carbon intensity (CI) of ethanol in the market today and assumes that CI improvements will continue in the future. Yet, it also assumes that the CI of ethanol produced at facilities using CCS will remain at a constant 35 gCO_2e/MJ through 2045. Given trends in agricultural practices and in the processing of both corn starch and corn fiber ethanol, which were well documented in the RFA comment letter of December 20, 2022, it is reasonable to expect substantial reductions in the CI of ethanol over the next two decades. Accordingly, for ethanol produced using CCS, the model should be modified to assume the CI will decline to zero CI by 2045. This is consistent with recent research and the 2021 pledge by RFA's producer-members to ensure that ethanol achieves net zero lifecycle GHG emissions, on average, by 2050 or sooner.[1]

Additionally, the CATS model baseline should reflect rapid adoption of E15 starting in 2024 for the reasons discussed above, and CARB should consider loosening the binding constraint on E85 usage. RFA would also draw attention to the comments in our December 20, 2022 letter regarding corn price, ethanol conversion costs, E85 infrastructure costs and corn distillers oil, which have not yet been addressed or, in the case of conversion costs, were adversely revised in the latest version of CATS, apparently without referencing available survey-based data.

Regarding E85, the CATS model assumes a 2022 volume of 49 million gallons of E100 equivalent, which translates to approximately 62 million gallons of E85, a volume similar to that reported for 2021. While CARB has not yet published E85 sales for 2022, our market sources would suggest that the E85 number is closer to 100 million gallons. The success of the LCFS and attractive pricing of E85 in California (selling for $1.50 to

[1] https://ethanolrfa.org/pledge

$2.00 per gallon less than gasoline) has resulted in approximately 60-percent increases in E85 demand annually over the last two years. The CATS model should be adjusted to the actual number for E85 sales in 2022. E85 is an extremely effective GHG reduction strategy in California and should be further incentivized in the LCFS program.

RFA is available to provide CARB staff with information on the topics raised regarding the CATS model. With updated and more accurate assumptions, CATS will "choose" more low- to zero-carbon ethanol as one of the most cost-effective ways to lower GHG emissions now and out to 2045 and reduce the pervasive LCFS deficits generated by the gasoline pool.

An Acceleration Mechanism is appropriate for sending a consistent market signal for innovation and investment in new supplies of low carbon fuels.

The current low credit prices under the LCFS are clearly inhibiting new investment in low carbon fuel production. The long period of time (up to three years) to update the LCFS given the regulatory process in California is creating uncertainty as to the longer-term trajectory of the program. Some form of an Acceleration Mechanism could address this problem.

Of the concepts advanced by CARB, RFA believes that a mechanism based on some ratio of credit to deficit generation on an annual basis would be the preferred approach for triggering a compliance mechanism. This is a preliminary assessment, and we look forward to working with CARB staff and other stakeholders in building longer-term market certainty into the LCFS modifications.

It is critically important for CARB to move quickly and concisely in strengthening the LCFS program. Timely and accurate modelling and scenario development through the CATS model and other analyses is a valuable tool in this regard.

Ethanol has generated the single largest volume of credits in the LCFS program, accounting for roughly four of every 10 credits generated since the program's inception. But constraining ethanol's use to 10 percent blends is sacrificing additional carbon reductions possible today. We urge CARB to move quickly to adopt regulations approving E15, which will allow the ethanol industry to help displace more fossil fuel in California and lower carbon emissions now.

An accurate modelling of ethanol's benefits and an integration of CARB fuels policy to incentivize higher ethanol blends will result in immediate reductions of GHG emissions and criteria pollutants while lowering the cost of compliance to obligated parties and California consumers.

RFA looks forward to working with CARB staff and other stakeholders to strengthen and extend the successful LCFS program.

Sincerely,

Scott Richman
Chief Economist

August 8, 2022

Ms. Cheryl Laskowski, Branch Chief
Transportation Fuels Branch
California Air Resources Board
1001 I St
Sacramento, CA 95814

Re: Low Carbon Fuel Standard July 7th , 2022 Workshop

Dear Ms. Laskowski,

The Renewable Fuels Association (RFA) appreciates the opportunity to comment on the workshop on potential changes to the Low Carbon Fuels Standard (LCFS) program held on July 7, 2022. The RFA supports the LCFS and looks forward to continued engagement in this process to strengthen and extend the program beyond 2030. The RFA is also working around the country in collaboration with other stakeholders to develop and implement similar programs in other states.

These comments update many of the RFA comments in our letter of January 7, 2022, following the December 2021 LCFS workshop, and are responsive to CARB staff's request at the most recent workshop for stakeholder input on specific topics.

The integrity of the LCFS depends on maintaining technology neutrality.

The hallmark of success of the LCFS is its market-based, technology-neutral approach that is driven by the carbon intensity scores of all fuels whether generating credits or deficits. The RFA supports California's goal of carbon neutrality by 2045. This is an aggressive, but achievable goal that will require a broad portfolio of low- and zero-carbon fuel solutions. The LCFS is a centerpiece policy in California's decarbonization efforts and modifying and extending the LCFS regulation beyond 2030 is necessary to achieve carbon neutrality. Any new policies that are introduced to incentivize new innovations and technology development should be equitably available to all low carbon fuels.

A cap on crop-based biofuels is not necessary, would be inconsistent with the technology-neutral design of the LCFS, and would chill investment in lower-carbon fuel technologies.

During the workshop, CARB staff noted that some stakeholders had expressed concern about the LCFS increasing demand for lipid-based feedstocks for biofuels. While this discussion was focused primarily on lipid-based feedstocks for renewable diesel and biodiesel, RFA believes capping any low-carbon fuels under the LCFS is contrary to the successful market-based and technology-neutral design of the LCFS. The inclusion of substantial land use change emissions factors in the program's carbon intensity scoring framework already serves to constrain the use of certain feedstocks and biofuels under the LCFS. And as discussed in these comments, and as documented in studies and data analysis, the iLUC factor in the LCFS for corn ethanol is overstated and should be adjusted downward. The use of ethanol is also already constrained by federal and state regulations that allow only 15% ethanol (E15) to be used in conventional light-duty automobiles.

California is one of only two states that does not yet allow the sale of E15. If some LCFS stakeholders feel it is necessary to take credit generation pressure off lipid-based biofuels like renewable diesel, the easiest and fastest way to do that would be to approve the use of E15.

Further, capping the use of certain feedstocks (like corn) for ethanol production would have no impact whatsoever on consumer food prices or food price inflation rates. Indeed, it has been very well established that the primary driver of food price inflation is energy price inflation (i.e., since energy is used at every step in the food production supply chain). Thus, programs like the LCFS that encourage greater use of lower-cost, lower-carbon alternatives to petroleum play a role in fighting the effects of petroleum market volatility on food inflation. Capping the use of biofuels would only exert more pressure on petroleum markets, drive petroleum prices higher, and spur additional food price inflation.

U.S. ethanol production peaked in 2018 at approximately 16 billion gallons. The pandemic, structural marketplace changes (e.g., more fuel-efficient cars, higher gas prices, higher sales of electric vehicles and increased working from home) have suppressed gasoline consumption and by extension, the usage of ethanol. The EIA forecasts only negligible growth in domestic ethanol production and consumption between 2023 and 2030 and increases in corn productivity (i.e., yield per acre), are generally expected to outpace any increases in the use of corn for ethanol over the next decade.

Meanwhile, modest increases in ethanol production combined with the allowance to sell higher blends can help accelerate the decline in gasoline consumption in California that will be necessary to achieve carbon neutrality by 2045. Given the volume of petroleum fuels that will continue to be in use in 2040 and beyond, accelerated carbon removal is essential in achieving carbon neutrality. This is fully recognized in California's Draft 2022 Scoping Plan.

Ethanol has the unique ability to combine low carbon fuel production with carbon removal through CCS. Two ethanol plants in the US have already commercialized CCS, and the industry is poised for widescale adoption of CCS as long as the appropriate federal and state policy signals remain in place. Capping crop-based biofuels in the LCFS would send the wrong signal to a biofuels industry that is making significant investment in low- and zero-carbon technologies and represents the most immediate and economic path to CCS.

US farmers have supported the significant growth in biofuel production while continuing to supply growing food, feed, and fiber markets. We are attaching to this letter an RFA presentation that goes into more detail on this topic. In summary, due to productivity gains in agricultural production and processing, U.S. farmers have easily satisfied demand growth in all market segments on less crop acreage than in 2007 when the RFS2 regulations were implemented.

Feed corn is the primary feedstock for U.S. ethanol. The production process converts the starch in the corn kernel to ethanol, while concentrating the feed value in the form of high protein feed (DDGS) and the industry continues to fraction off more valuable components of the corn kernel such as corn oil that is an ultra-low carbon input for renewable diesel production and fiber that can be converted to cellulosic ethanol.

Processes to further concentrate the protein for higher value protein markets also increases the corn oil yield. Today, there is over 150 million gallons per year of cellulosic corn fiber ethanol delivered to California and this amount could grow significantly over the next several years with the right market signals provided by the LCFS in California and similar programs in other states. Capping crop-based biofuel production would be the wrong market signal for an industry that continues to grow and innovate in meeting food, feed, fiber, and fuel markets.

RFA supports CARB staff's consideration of stronger LCFS compliance curves before and after 2030.

Strengthening the compliance curves is appropriate to harmonize the LCFS with the goal of carbon neutrality by 2045, and it sends the long-term market signal necessary to encourage the significant new investment in innovative technologies required to meet decarbonization goals. In the early years of the LCFS, political and market uncertainty resulted in low LCFS credit pricing which dampened investment in lower carbon fuels. But following the "readoption" of the LCFS in 2015, credit prices reacted in a way that stimulated investment and growth in low-carbon fuels. From 2018 through the first half of 2021, credit prices held steady around $200 per metric ton, stimulating new investments in growing supplies of lower carbon biofuels, electrification, and refinery improvements. In the last year, credit prices have dipped to below $100 per metric ton, and there is a real risk of not attracting sufficient new investments for the large volumes of low carbon fuels needed to meet future compliance targets. Prices have drifted lower due to the success of the program, with projections of over-compliance and a significant build in the credit bank balance over the next several years absent a significant adjustment to the compliance curve.

Specifically, RFA supports strengthening the 2030 target from a 20 percent reduction to between a 25 and 30 percent reduction. We would suggest that post 2030 targets be set in a linear fashion to be close to 100 percent reductions by 2045. Quickly moving to a steeper and longer-term compliance curve will send a strong market signal that the ultimate success of the LCFS depends on continued innovation and new investments. RFA members have committed to achieving net-zero carbon ethanol production by 2050. A recent study by Informed Sustainability Consulting identified five distinct pathways to net-zero corn ethanol based on a set of 28 emissions reduction actions that were considered. It concluded that "the industry can achieve net-negative (carbon intensity) ethanol by adopting near term technologies and expanding best practices in corn farming." [1]

However, if CARB were to proceed with an ill-advised cap on crop-based biofuels, it would not be feasible to substantially strengthen the compliance curve—and CARB's vision of achieving carbon neutrality by 2045 would be put in grave danger.

Higher ethanol blends are necessary to meet a more aggressive LCFS compliance schedule and carbon neutrality goals.

Higher blends of low-carbon ethanol in the current gasoline pool represent the nearest term and most affordable path for immediate reductions of GHG emissions from the light duty fleet. Higher ethanol blends are also necessary to meet the longer term need to decarbonize the liquid fuels that will be in the California transportation system for decades to come.

The University of California's Institute of Transportation Studies report, "*Driving California 's Transportation Emissions to Zero"* (April 2021) clearly documented this challenge and pointed repeatedly to the need for the LCFS and complementary policies to drive the substantial volume of liquid fuels remaining in the system to near zero carbon. To date, ethanol has contributed approximately 30 percent of all LCFS credits, with the vast majority from 10 percent ethanol blends (E10).

Complementary policies to allow for higher blends of ethanol, E15-E100 are a critical component to the future success of the LCFS. Even with ethanol contributing the single largest share of LCFS credits in the program, limiting ethanol to a 10 percent blend has swamped the gasoline pool with net deficits. The first chart shown below is for all fuels showing a net credit surplus of nearly 10 million metric tons to date as reported by CARB.

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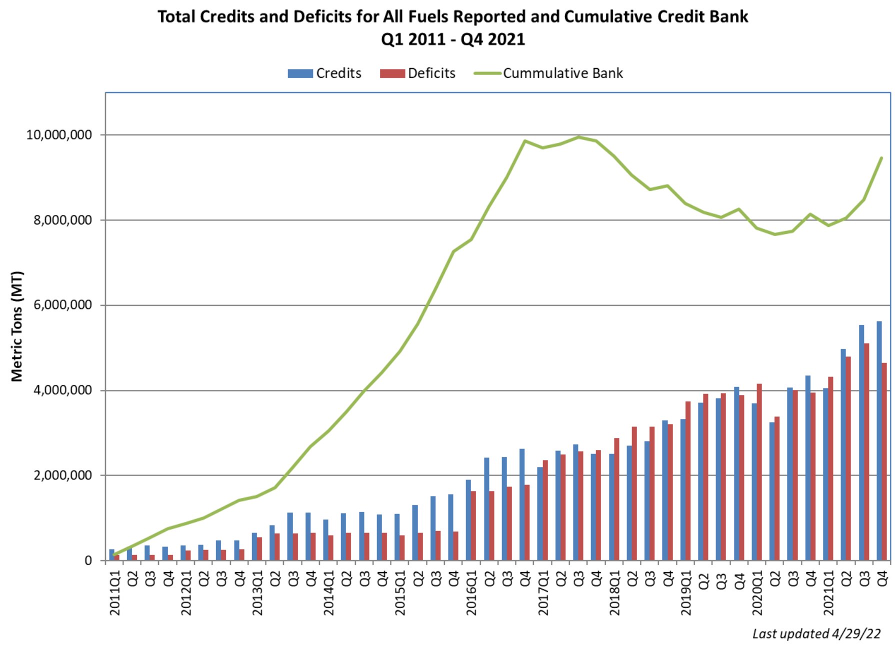
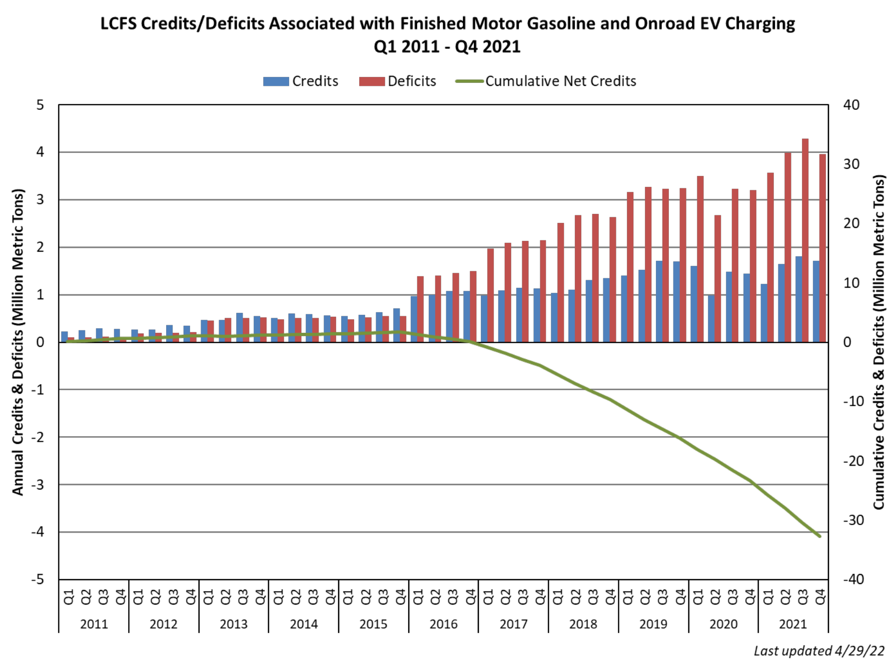
[1] *Pathways to Net-Zero Ethanol: Scenarios for Ethanol Producers to Achieve Carbon Neutrality by 2050;* Emery, I., February 2022; https://ethanolrfa.org/file/2146



However, looking at the gasoline pool separately, as shown in the chart below, a different picture emerges. Ethanol and electricity combined (i.e., the only current replacements for gasoline) are not even close to covering the deficits generated by CARBOB, resulting in a large and growing net deficit of over 30 million metric tons program to date.



Source: California Air Resources Board. Included CARBOB, ethanol and electricity for on-road light and medium duty vehicles

The rapid growth of renewable diesel has provided the excess credits in the program to cover the gasoline deficits. This is not sustainable, as new supplies of renewable diesel are needed to further displace conventional diesel and gasoline substitutes will need to cover gasoline deficits in a transportation system moving toward carbon neutrality. Also, as mentioned above, if some LCFS stakeholders feel it is necessary to take credit generation pressure off lipid-based biofuels like renewable diesel, the easiest and fastest way to do that would be to approve the use of E15.

Achieving carbon neutrality will only be possible with the widespread deployment of low to zero carbon ethanol at blends above 10 percent, along with electrification and other bio-based gasoline substitutes. An important first step is to immediately approve the use of E15 in California. The LCFS should also work in tandem with other CARB polices to encourage, require, or incentivize future ICE engines that can run on very high levels (i.e., 85-100 percent) low to zero carbon biofuels. The Advanced Clean Car Regulation should require that all ICE engines sold starting in 2026 are flex fuel (FFV) capable.

Biofuel producers should qualify for book and claim credits for RNG in the pipeline utilized to substitute for natural gas in the biofuel production process.

This modification to the LCFS would be consistent with the principles of technology neutrality and further incentivizing private investment in low carbon fuels. It is also analogous with the book and claim accounting that is currently allowed for hydrogen producers utilizing pipeline RNG in the manufacturing process of hydrogen for fuel. To ensure fairness, consistency, and neutrality across all low carbon fuel pathways, CARB should allow all low-carbon fuel producers to use the same accounting procedures. Combining RNG for process fuel with carbon capture and sequestration (CCS) projects that are now in the planning stages at many ethanol facilities, moves the industry to the production of ultra-low to zero to negative carbon ethanol. The right policy support from the LCFS facilitates this valuable contribution in meeting the state's climate goals.

RFA strongly supports allowing low-carbon fuel producers to incorporate site-specific agricultural factors and inputs into fuel pathways.

A significant portion (roughly half) of the full life cycle carbon intensity of ethanol is from the agricultural production of the feedstocks. With the increasing employment of no-till, cover cropping, and other modern precision agricultural practices, farmers have quantified the ability to significantly lower the carbon intensity of feedstock production while also increasing soil carbon levels. These practices result in carbon scoring well below the current averages employed in the CA-GREET model. Currently, the CA-GREET model treats agricultural feedstock production practices as "one size fits all" and does not allow ethanol producers to incorporate lower-carbon agricultural practices into their pathway carbon intensity scores. Allowing fuel producers to provide site specific input agricultural data will further incentivize carbon efficient agricultural practices, resulting in lower carbon ethanol production and contributing to a more successful LCFS. More detailed recommendations for recognizing soil carbon sequestration and other carbon efficient ag practices within CA-GREET are provided in a comment letter from the Low Carbon Fuels Coalition, which was signed and endorsed by RFA. We look forward to working with CARB staff and other agricultural and academic stakeholders to systematically address CARB's questions regarding verification and permanence.

A combination of a high concentration of low to zero carbon ethanol combined with more efficient engines is an opportunity to define new Energy Economy Ratios (EERs).

The high-octane rating of ethanol combined with a higher-compression ratio internal combustion engine offers a significant fuel efficiency improvement and lifecycle carbon intensity reduction. However, the LCFS currently does not provide any opportunity to recognize and encourage these GHG benefits. The use of a high-octane fuel with higher renewable content in a plug-in hybrid with a higher compression ratio engine qualifies as a ZEV and represents an opportunity for defining a new EER. Specifically, our analysis has shown that the use of a high-octane (98 RON) blend containing 30 percent ethanol in a high-compression ratio engine would result in a drivetrain energy efficiency improvement of 11 percent, equating to an EER of 1.11. We encourage CARB to include an EER for high-octane fuels used in high compression ratio engines in both conventional and plug-in hybrid vehicles.

The land use change (LUC) values used by CARB to determine CI scores should conform to updated analytical and empirical data.

A recent analysis by a collaboration of researchers from Environmental Health Engineering, MIT, Tufts, and Harvard concluded that a LUC (direct and indirect) emissions value for corn ethanol of 3.9 g/MJ represents the most credible evolution of the science on the topic.[2] Oregon's Clean Fuels Program uses the Argonne GREET model values of 7.8 g/MJ. These lower values are supported by recent analyses of land use patterns by Purdue University, the U.S. Departments of Energy and Agriculture, University of Illinois, and other institutions. Both values are well below California LCFS value of 19.8 g/MJ, which has not been updated since 2014.

The Argonne GREET model is the basis for the entire life cycle analysis in the LCFS, so it is consistent to use Argonne GREET for land use change values as well. Argonne updates its model regularly (typically on an annual basis) to incorporate the best

[2] *Carbon Intensity of Corn Ethanol in the United States: State of the Science:* Scully, M. et al., January 2021; https://iopscience.iop.org/article/10.1088/1748-9326/abde08

science on all variables. Additionally, in the interest of technology neutrality and with the rapid increase in battery-electric vehicles, the land use impacts of mineral extraction for battery production should also be evaluated [3], along with the land use implications of expanded wind and solar electricity generation [4].

There are several other data sources and studies that should be considered in the analysis of crop-based biofuels.

Responsive to CARB staff's request for other data sources and studies to take into consideration, following are other important and recent studies that should be reviewed on the topics of ethanol's climate and land use change impacts.

- *Retrospective Analysis of the U.S. Corn Ethanol Industry for 2005-2019; Implications for Greenhouse Gas Emission Reductions;* Lee, U et al., May 2021; https://onlinelibrary.wiley.com/doi/10.1002/bbb.2225. The study, conducted by Argonne National Laboratory researchers, found that the carbon intensity of corn ethanol shrank by 23% over the 2005-2019 timeframe, from 58 to 45 gCO2e/MJ (not including the land use change value of 7.4 gCO2/MJ). By 2019, corn ethanol reduced lifecycle emissions by 44-52% compared to gasoline. The researchers determined that corn ethanol reduced transportation related greenhouse gas (GHG) emissions by a cumulative 544 million metric tons CO2e over the study timeframe. Notably they demonstrated that there has been a "downtrend in simulated (land use change) emissions" that the stated "is a result of better developed and calibrated economic models and better modeling of GHG emissions."

- *GHG Emissions Reductions due to the RFS2: A 2020 Update*; Unnasch, S. & Parida, D., February 2021; https://ethanolrfa.org/file/748. The Renewable Fuel Standard (RFS) as expanded in 2007 has resulted in significant reductions in GHG emissions, with cumulative carbon dioxide savings of 980 million metric tons to date. Most of the savings have been associated with the use of ethanol.

- *The California Low Carbon Fuel Standard: Incentivizing Greenhouse Gas Mitigation in the Ethanol Industry*; Lewandrowski, J., Hohenstein, B., & Pape, D., November 2020; https://www.usda.gov/sites/default/files/documents/CA-LCFS-

[3] See, for example, International Energy Agency. "*The Role of Critical Minerals in Clean Energy Transitions.*" May 2021. The report shows highly variable EV carbon intensity based on the minerals used. Mining and processing of cobalt sulfate, for example, is four times more carbon intensive than mining and processing of zinc. https://www.iea.org/reports/the-role-of-critical-minerals-in-clean-energy-transitions

[4] A recent study published in Nature, for example, found that the land cover changes, including indirect effects, associated with significant expansion in solar "…will likely cause a net release of carbon ranging from 0 to 50 gCO_2/kWh [0-180 g CO2/MJ], depending on the region, scale of expansion, solar technology efficiency and land management practices in solar parks." See: van de Ven, DJ., Capellan-Pérez, I., Arto, I. *et al.* The potential land requirements and related land use change emissions of solar energy. *Sci Rep* **11,** 2907 (2021). https://doi.org/10.1038/s41598-021-82042-5

Incentivizing-Ethanol-Industry-GHG-Mitigation.pdf. The assessment, which was conducted by researchers from the USDA and ICF, concluded that the value of credits toward California's Low Carbon Fuel Standard (LCFS) provides a strong financial incentive for ethanol facilities to implement GHG-reducing technologies and practices. A series of interviews with ethanol facility managers indicated that the LCFS and other policies, including the RFS, were large drivers of decisions to proceed with plant upgrades, such as process efficiency improvements, process energy modifications, changes to co-product production, and enzyme enhancements.

- *Response to Comments from Lark et al. Regarding Taheripour et al. March 2022 Comments on Lark et. al. Original PNAS Paper*; Taheripour, F. et al., May 2022; https://greet.es.anl.gov/publication-comment_environ_outcomes_us_rfs2. Researchers from the Department of Energy's Argonne National Laboratory, Purdue University, and the University of Illinois system thoroughly assessed the paper by Lark et al. "Environmental Outcomes of the US Renewable Fuel Standard," and they refuted key findings of the work. They showed that indirect land use change was overestimated, and land transitions were misinterpreted; additionally, there were significant issues with the calculation of GHG emissions associated with purported land use change. The authors concluded, "The overestimated emission factors and overestimated land conversion in Lark et al. led to overestimated [land use change] emissions for corn ethanol."

- *A Cautionary Tale: A Recent Paper's Use of Research Based on the USDA Cropland Data Layer to Assess the Environmental Impacts of Claimed Cropland Expansion*; Pritsolas, J. & Pearson, R., June 2021; https://ethanolrfa.org/file/1833/SIUE-Rebuttal-on-USDA-CDL-Use.pdf. A study by Zhang et al. assessed the environmental impacts of cropland expansion in the Midwest between 2008 and 2016, building on previous research that used the USDA Cropland Data Layer (CDL) to estimate the conversion of grassland to cropland. A review of the two studies determined, "The cropland expansion claimed … has a high potential of being false change due to poor classification certainty in the earlier CDL." This occurred since the earlier CDLs underestimated cropland area and grossly overestimated non-cropland area, but both were mapped more accurately as the CDL improved over time. The reviewers pointed out that the USDA has warned about "very low classification accuracy" of pasture and grass-related land cover categories in the CDL.

- *Response to "How Robust Are Reductions in Modeled Estimates from GTAP-BIO of the Indirect Land Use Change Induced by Conventional Biofuels?"*; Taheripour, F., Mueller, S., & Kwon, H., May 2021; https://www.sciencedirect.com/science/article/abs/pii/S0959652621016504. The paper was a response to criticisms by Malins et al. regarding the Global Trade Analysis Project model for biofuel analysis (GTAP-BIO) and the Carbon

Calculator for Land Use Change from Biofuels Production (CCLUB). The authors compared early versus recent results of GTAP-BIO, discussed the treatment of cropland pasture, the yield-to-price elasticity and harvest frequency in the model, and they commented on the CCLUB emissions model. They asserted that as data and models have improved over time, estimates of the emissions associated with induced land use change from biofuels have decreased. It was noted that in the past, the "exclusion of market mediated responses, poor characterization of agricultural supply responses, poor reflection of real-world data, and using models and data not well-suited for addressing ILUC-related questions contributed to over-estimation of land use changes due to biofuels".

- *Effects of Ethanol Plant Proximity and Crop Prices on Land-Use Change in the United States*; Yijia, L., Miao, R., & Khanna, M., December 2018; https://onlinelibrary.wiley.com/doi/10.1093/ajae/aay080. The analysis showed that land use is inelastic to changes in corn ethanol production capacity. A 1% increase in the effective ethanol capacity in a county led to an increase in corn acreage in that county by about 0.03% to 0.1%, and an increase in total acreage of only 0.02% to 0.03%. The effect of the corn price and aggregate crop price on acreage change from 2008 to 2012 was more than twice as large. The results implied that the effect of changes in corn price on land use was largely at the intensive margin rather than at the extensive margin. Corn prices are influenced by a number of factors, not only ethanol, and it was noted that the effect of crop prices on land use was largely reversed as a result of the downturn in prices after 2012 and was close to negligible by 2014 relative to 2008.

- *Carbon Calculator for Land Use Change from Biofuels Production: Users' Manual and Technical Documentation*; Dunn, J. et al., December 2017; https://greet.es.anl.gov/files/cclub-manual-r4. The Carbon Calculator for Land Use Change from Biofuels Production calculates carbon emissions from land use change for ethanol production pathways, including corn ethanol. It is used in connection with Argonne National Laboratory's GREET model. For corn ethanol, land use change emissions were estimated to be 7.8 g CO_2e/MJ.

- *Lessons Learned from US Experience with Biofuels: Comparing the Hype with the Evidence*; Khanna, M., Rajagopal, D., & Zilberman, D., March 2021; https://www.journals.uchicago.edu/doi/pdf/10.1086/713026. The paper reviews projections that were made about the impacts of biofuels during the initial expansion in the 2000s and presents empirical evidence and modeling results about the effects of increased production on crop and fuel prices, land use change and GHG emissions. Biofuels were one of several significant factors that contributed to the increase in agricultural commodity prices through 2012, but the impact has dissipated over time. Regarding indirect land use change, the authors concluded that "the high initial estimates of the effect of biofuels on ILUC were driven largely by stringent model assumptions and have not been supported by either recent models (that have more advanced features) or the empirical evidence that has emerged over time."

- *Economic Impacts of the U.S. Renewable Fuel Standard: An Ex-Post Evaluation*; Taheripour, F., Baumes, H., & Tyner, W., June 2020; https://www.frontiersin.org/articles/10.3389/fenrg.2022.749738/full. The GTAP-BIO model was used to evaluate the extent to which the RFS and other factors affected commodity markets in the medium to long run, focusing on two time periods: 2004-2011 and 2011-2016. The analysis determined that coarse grain prices were 0.6% higher during the first time period and 0.9% higher during the second period due to the RFS. This was supplemented with a partial equilibrium model, which determined that on a short-term basis the price of coarse grains was 6.7% higher during the second period due to the RFS. Overall, the study concluded that the RFS made major contributions to the agriculture sector, raising U.S. annual farm incomes by $1.4 billion in the first period and by $2.4 billion in the second period. In both periods, the long-run effects of biofuel production and policy on food prices were negligible.

- *Food Versus Fuel: An Updated and Expanded Evidence*; Filip, O. et al., August 2019; https://www.sciencedirect.com/science/article/pii/S0140988317303742. The study was segmented into three time periods, centering around the commodity price escalation that occurred during the second half of the 2000s. The analysis determined that ethanol did not affect agricultural commodity prices prior to June 2008, that it explained approximately 15% of the variance in corn prices and 5% of the changes in other commodity prices from July 2008 to February 2011, and that it contributed to approximately 10% of the variance in commodity prices from March 2011 to May 2016. The authors concluded that the results served as an ex-post correction of early studies that found biofuels had more substantial effects.

- *The Impact of Ethanol Industry Expansion on Food Prices: A Retrospective Analysis*; Informa Economics IEG, November 2016; https://ethanolrfa.org/file/975/Retrospective-of-Impact-of-Ethanol-on-Food-Prices-2016.pdf. A retrospective statistical analysis determined that retail food prices were not impacted in any demonstrable way by the expansion of U.S. corn ethanol production under the RFS. In fact, the study found that food price inflation actually slowed during the "ethanol era." While corn prices were positively impacted by ethanol expansion, the link between corn prices and consumer food prices was shown to be weak.

Making higher blends of ethanol available to consumers promotes equity.

Ethanol reduces GHG emissions, criteria pollutants[5] and lowers cost to the consumer. Life cycle modelling has clearly demonstrated that ethanol reduces GHG emissions compared to gasoline by approximately 50 percent. Corn fiber ethanol production reduces GHG emissions by roughly 70 percent and as discussed, the ethanol industry continues to drive ethanol production toward net zero carbon offering an affordable and viable path for decarbonization in transportation alongside vehicle electrification.

The recent emissions testing on E15, sponsored and supported by CARB, showed significant reductions in most criteria pollutants compared to E10. This can help improve the air quality today in front line communities that have a disproportionate exposure to today's air pollution.

Historically, ethanol has sold at a discount to gasoline. Currently, E85 is typically selling in California at over a $2/gallon discount (or more) to regular gasoline.[6] E85-capable vehicles (flex fuel vehicles) cost the manufacturer just $50-100 more to produce than conventional gasoline-powered vehicles and are significantly less to produce (and purchase) than current electric vehicles. Providing policy support for E15 and flex fuels like E85 helps meet California's ambitious environmental goals while providing consumer choice and lower cost options for California citizens.

RFA applauds CARBs commitment to support the exportability of the LCFS.

Many other jurisdictions across the country are now considering LCFS type programs and California is the leader. The successful policy framework of the LCFS is an excellent model for developing new programs outside of California, but its attractiveness to other jurisdictions depends on maintaining a technology neutral, market-based structure. RFA believes that protecting the integrity of a performance based standard and working on incorporating site specific agricultural inputs improves the exportability of the LCFS program.

RFA urges CARB staff to move expeditiously to make these modifications to the LCFS. The most recent UN IPCC report and subsequent COP 26 meeting in Glasgow make alarmingly clear the imperative of further reducing GHG emissions immediately. The recent rash of extreme heat events, wildfires and flooding around the world are painful reminders of the consequences of the climate crisis and the urgency to act now.

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[5] See, for example, the results of recent emissions testing supported by CARB and conducted by the University of California Riverside. https://ww2.arb.ca.gov/resources/documents/comparison-exhaust-emissions-between-e10-carfg-and-splash-blended-e15

[6] See, for example, https://twitter.com/EthanolRFA/status/1554149931325300741?cxt=HHwWioC9hZvIuZErAAAA

The cumulative impacts of not reducing GHG emissions as soon as possible can be catastrophic. When coupled with the ongoing decrease in the carbon intensity of ethanol, higher ethanol blends like E15 and flex fuels like E85 present a practical and cost-effective opportunity for both immediate and long-term GHG reductions under the LCFS.

RFA looks forward to working with CARB staff and other stakeholders to strengthen and extend the successful LCFS program.

Sincerely,

Kelly S Davis

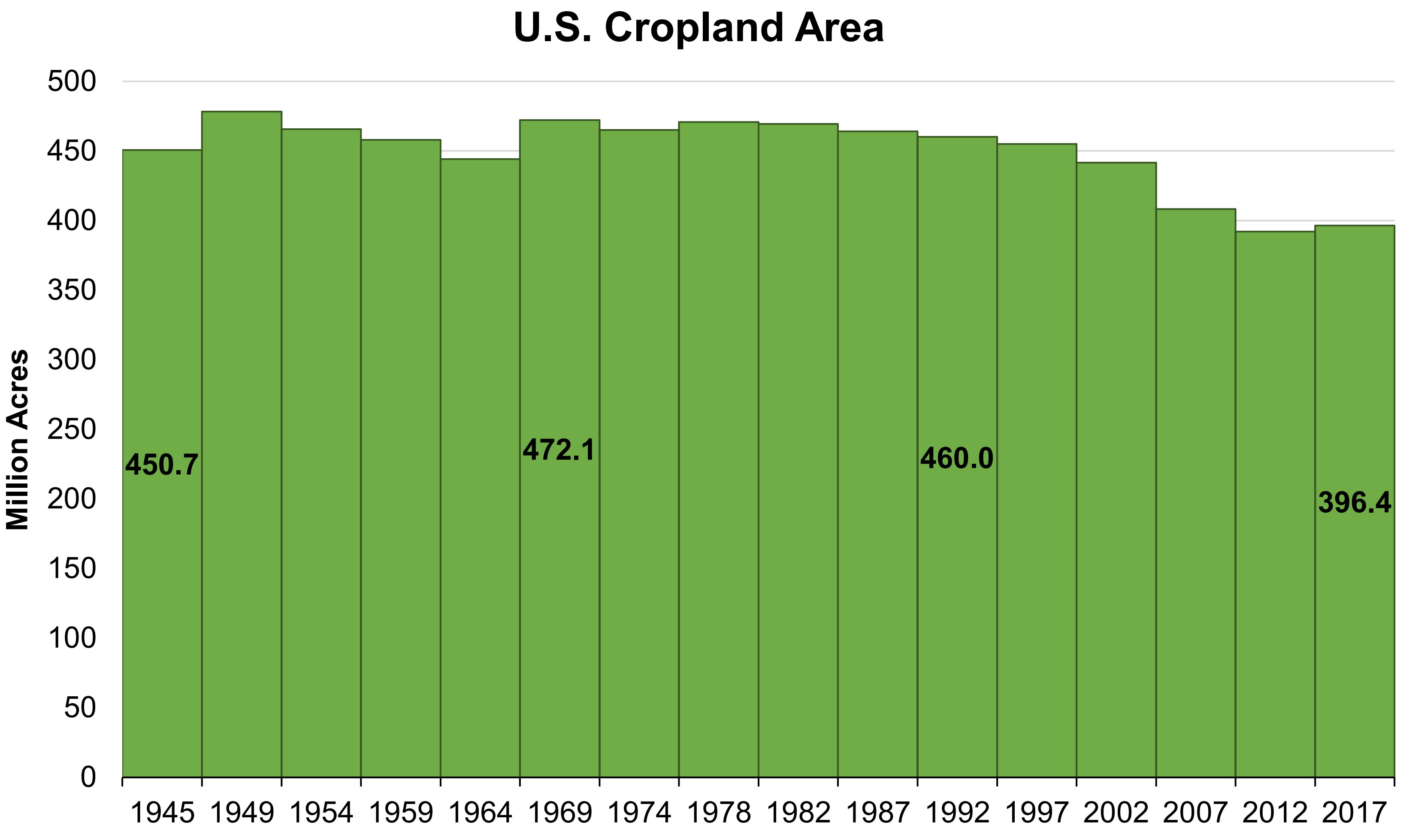
Kelly Davis
VP of Regulatory Affairs

Thinking Clearly About Agricultural Land Use, Productivity Gains, and the Impact of Ethanol Expansion

Renewable Fuels Association

July 2022

The amount of U.S. land dedicated to crop production continues to shrink

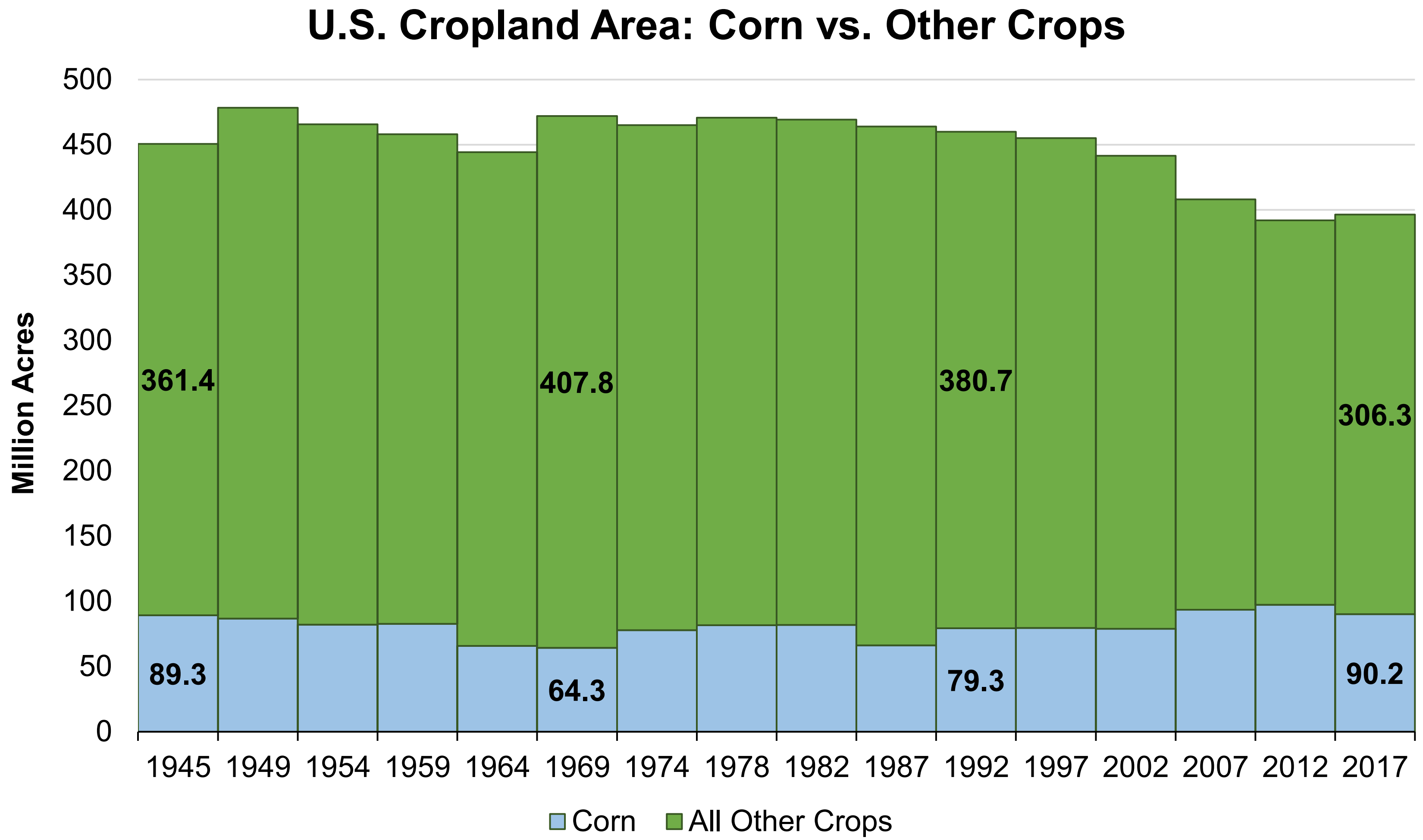


- Since the late 1960s, U.S. land dedicated to crop production has continued to shrink.
- Between 1969 and 2017, U.S. cropland fell 16%, or 76.7 million acres—an area the size of New Mexico, our fifth-largest state.
- U.S. cropland has remained under 400 million acres since 2008.

Source: USDA Census of Agriculture (2022 data not yet available)

RENEWABLE FUELS ASSOCIATION

Total cropland is shrinking, even as corn acreage is flat or slightly increasing

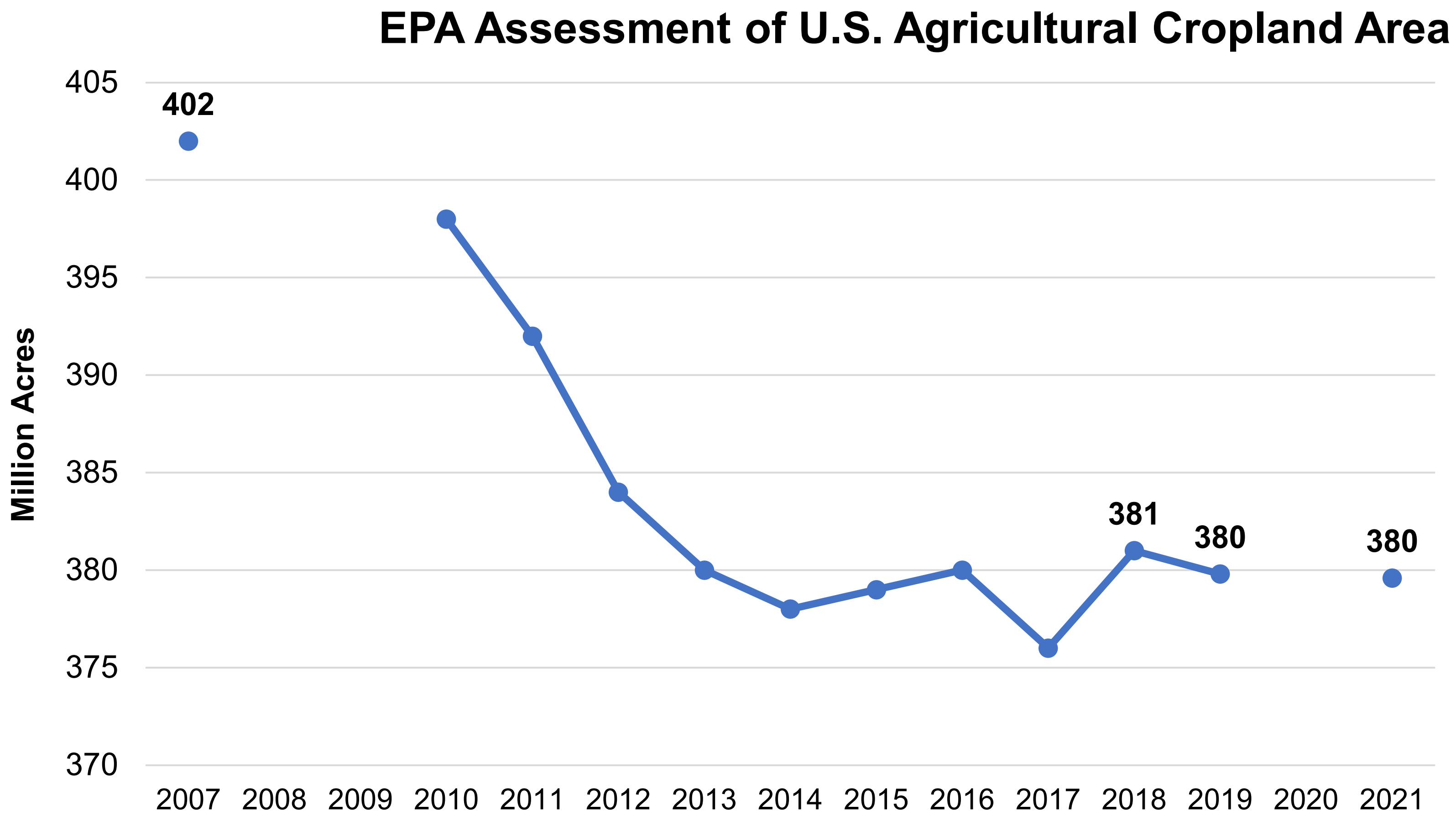


- In recent years, corn has accounted for roughly 20% of U.S. cropland.
- Acres planted to corn in 2017 were nearly identical to the amount of land planted to corn in 1945 (less than 1 million acres difference).
- Acres planted to wheat, cotton, oats, sorghum, barley and other crops have trended lower as increased yields and lower demand have reduced land requirements.

Source: USDA Census of Agriculture (2022 data not yet available)

RENEWABLE FUELS ASSOCIATION

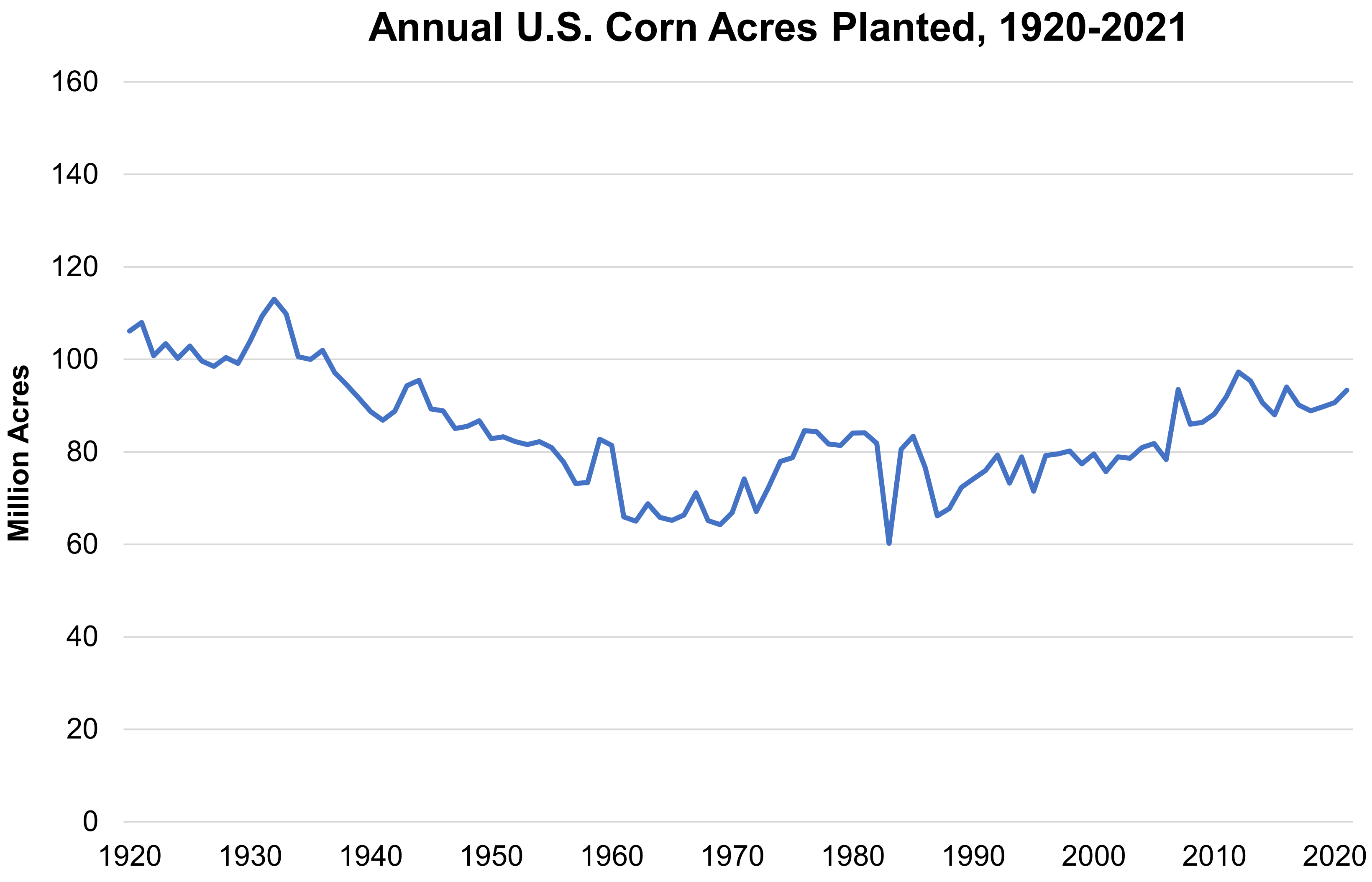
EPA data show nearly 25-million-acre reduction in agricultural cropland since 2007



- The 2007 law establishing the expanded RFS **prohibits** ethanol producers from using corn or other feedstocks from new cropland “cleared or cultivated” after 2007.
- To ensure compliance, U.S. EPA tracks agricultural cropland area annually using USDA data. The data show **no expansion** of U.S. cropland from 2007 levels.
- In fact, U.S. EPA analysis shows a **decrease** in agricultural cropland of 20-25 million acres (roughly 6%) between 2007 and 2017-2021.

Source: U.S. EPA

Fewer corn acres today than in 1920s-1930s

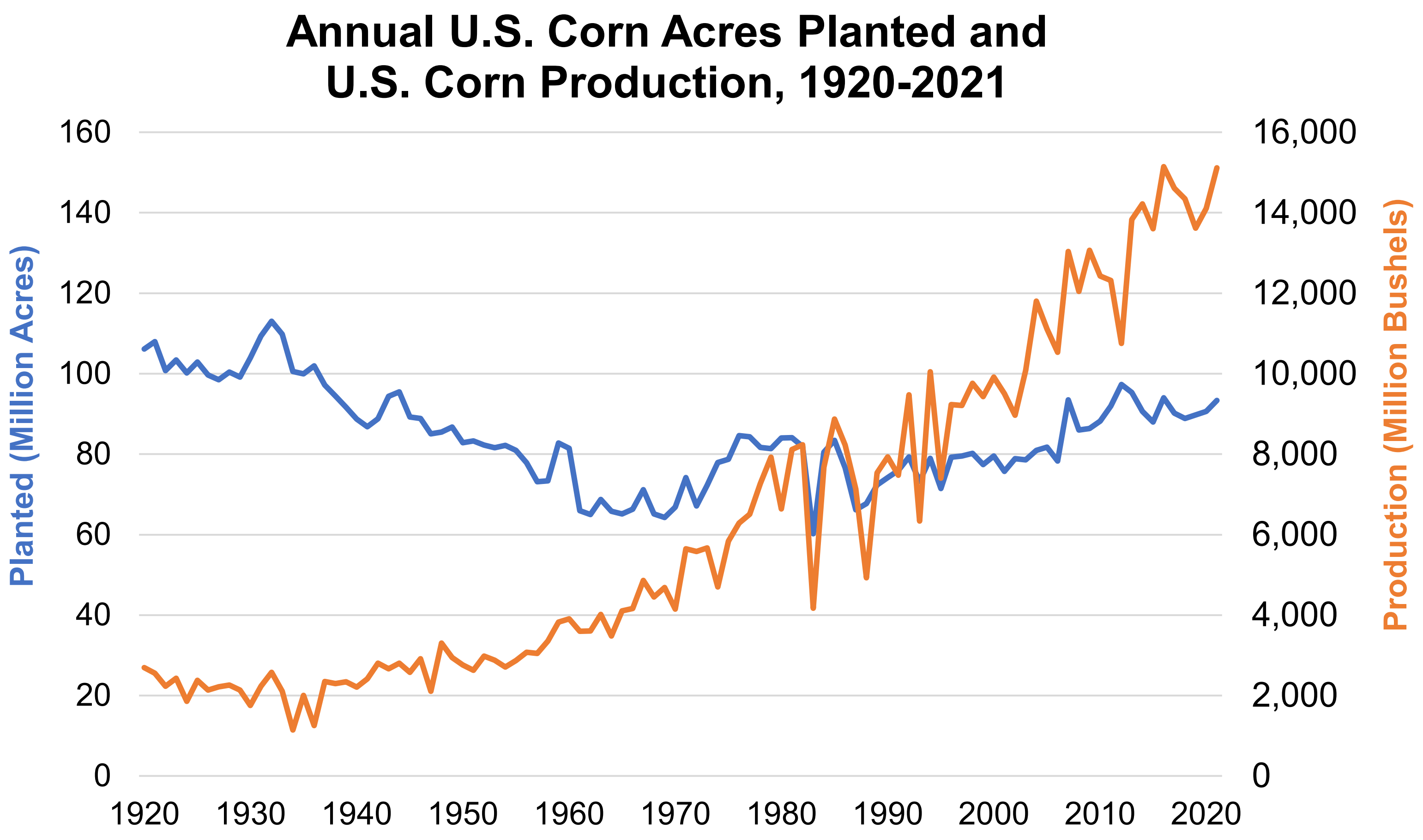


Source: USDA

- Over the past 100 years, acres planted to corn have averaged less than 85 million annually.
- Corn acres were well over 100 million in the 1920s and 1930s, peaking at 113 million in 1932.
- Corn acres have generally been in the 85 to 95-million-acre range since the RFS was expanded in 2007, as profitability returned to corn farming.
- Corn acres have been trending downward since 2012, as stocks were rebuilt and prices gravitated lower.

RFA
RENEWABLE FUELS ASSOCIATION

Corn acreage trending downward, while production up nearly 600% since 1920s

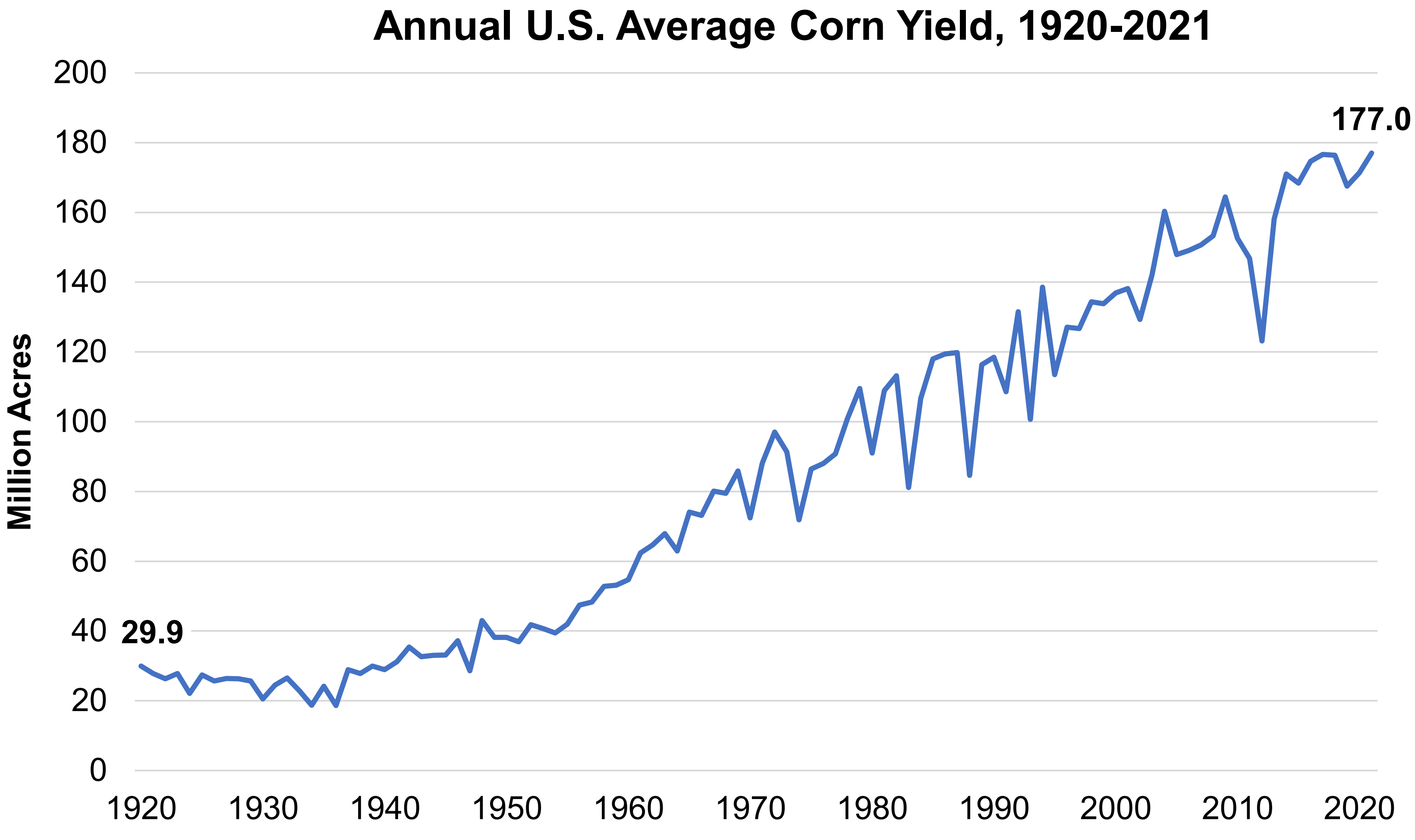


- While corn acres have been relatively flat over the past century, corn production has increased **six-fold**.
- In the 1920s-1940s, annual corn production averaged roughly **2.3 billion bushels** and planted acres averaged 98 million.
- In the 2000s, annual corn production averaged **11 billion bushels** from 82 million acres.
- Since 2010, annual corn production has averaged **13.7 billion bushels** on an average of 92 million planted acres.

Source: USDA

RENEWABLE FUELS ASSOCIATION

Corn output per acre continues to trend higher; up nearly 600% over past century

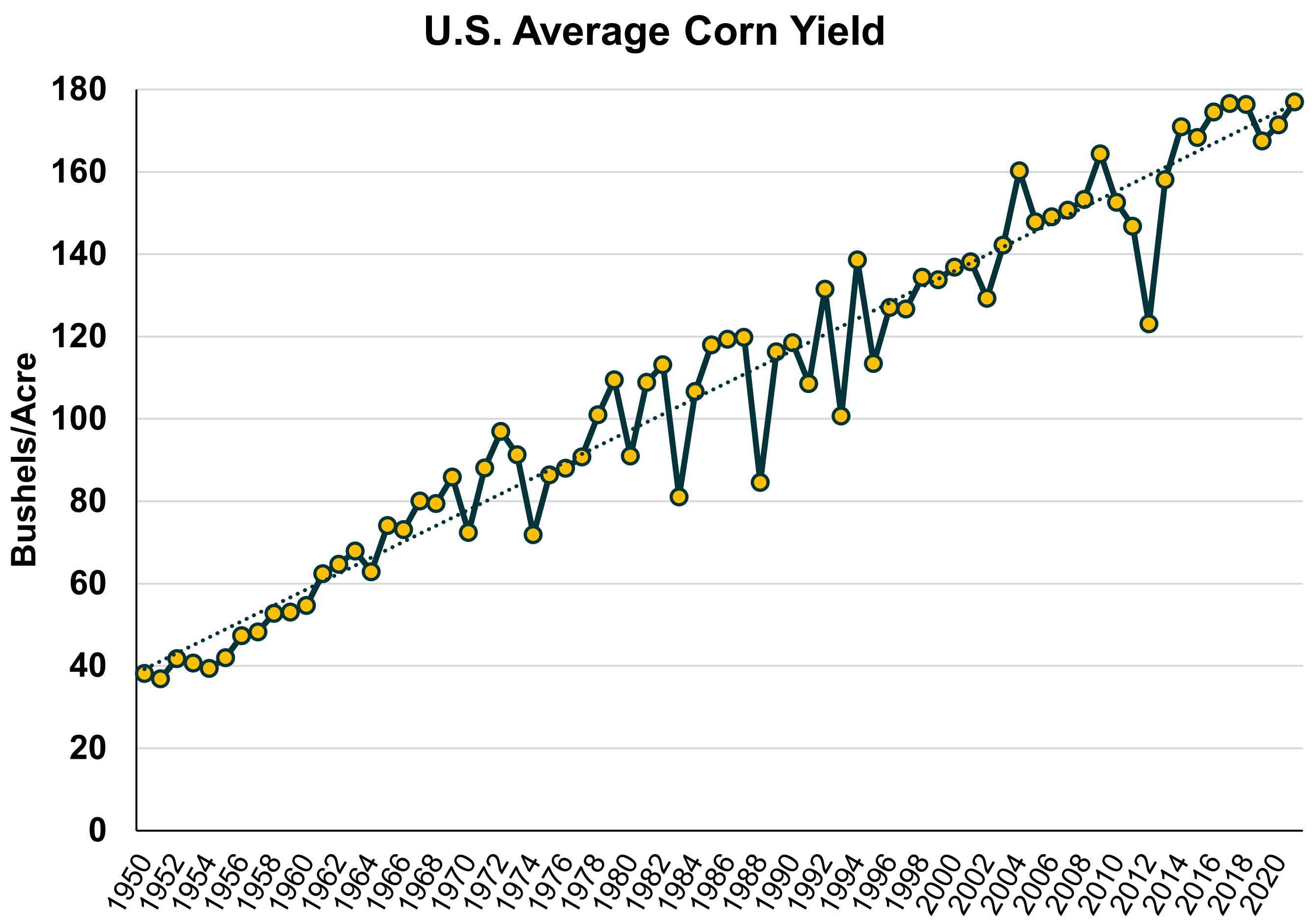


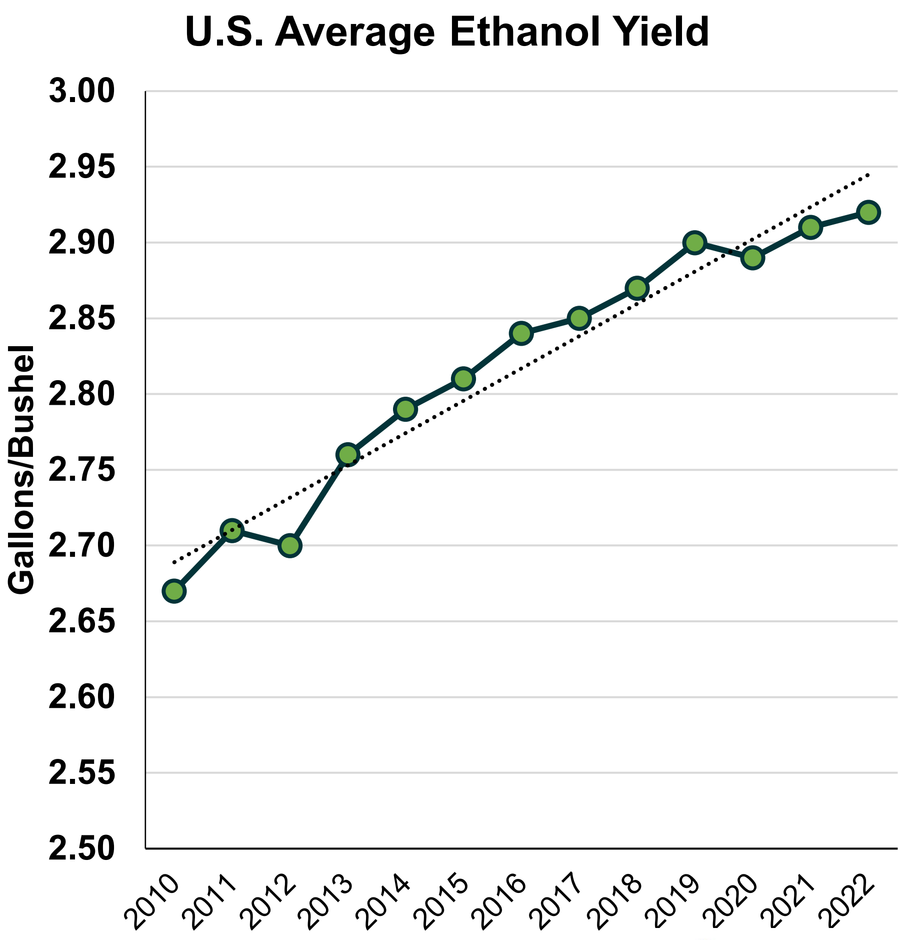
Source: USDA

- The average amount of corn produced per acre ("yield") has increased nearly **600%** over the past 100 years.
- A new record average yield of **177.0 bushels per acre** was established in 2021. Each bushel of corn weighs 56 pounds.
- Since 1970, yields have grown an average of **2.8% per year**.

RENEWABLE FUELS ASSOCIATION

Ethanol biorefineries are also seeing gains in productivity and output per unit of input





Source: USDA, RFA

RENEWABLE FUELS ASSOCIATION

RENEWABLE FUELS ASSOCIATION

December 20, 2022

Ms. Cheryl Laskowski, Branch Chief
Transportation Fuels Branch
California Air Resources Board
1001 I St
Sacramento, CA 95814

Re: Low Carbon Fuel Standard Workshop November 9, 2022

Dear Ms. Laskowski,

The Renewable Fuels Association (RFA) appreciates the opportunity to comment on the workshop on potential changes to the Low Carbon Fuel Standard (LCFS) program held on November 9, 2022. The RFA supports the LCFS and looks forward to continued engagement in this process to strengthen and extend the program beyond 2030. The RFA is also working around the country in collaboration with other stakeholders to develop and implement LCFS and other clean fuel programs in other states.

The RFA commented extensively on the key issues of the LCFS modifications in our letter of August 8, 2022, following the July 27, 2022, LCFS workshop. These new comments should be considered in combination with the earlier comments and are responsive to CARB staff's request at the most recent workshop for stakeholder input on specific topics.

RFA supports strengthening the current LCFS compliance schedule before and after 2030, in conjunction with other regulatory improvements that will make more stringent targets achievable.

The RFA supports both strengthening the 2030 carbon reduction target to 30 percent and steepening the trajectory of the compliance curve starting in 2024. At the workshop the staff presentation outlined that over-compliance with the program has resulted in LCFS carbon credit pricing of around $60 per metric ton, chilling investments in new technologies and innovations.

The science as summarized in the most recent UN IPCC report points to the urgent need to make immediate and large-scale reductions in GHG emissions in this decade to avoid catastrophic consequences of climate change. Approving E15 as a legal fuel and further incentivizing flex fuels like E85 (through the value of carbon credits) provides a significant new opportunity for credit generation, supporting a much stronger carbon reduction compliance curve. However, without complementary action (e.g., E15 approval and promotion of E85 and flex fuel vehicles), more stringent future LCFS requirements may be very difficult to achieve.

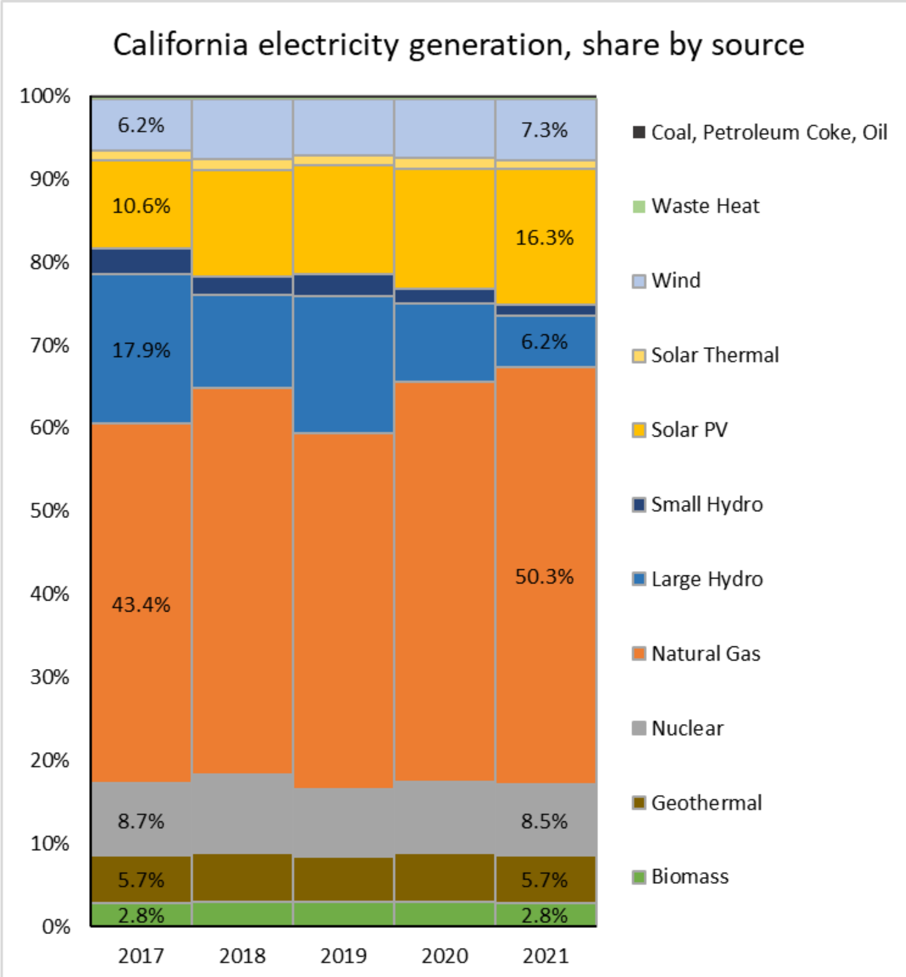
Modify The CATS model to better reflect current and projected ethanol economics, carbon intensities and volumes.

RFA appreciates the release of the CATS model and believes that with the proper assumptions, the model could be a helpful tool for understanding technically and economically viable strategies for improving the LCFS program. Unfortunately, the model was not made available in a timeframe and manner sufficient to facilitate in-depth stakeholder review and input.

Based on the posted CARB Presentation, CATS Model Technical Documentation, CATS Summary Inputs and Supplemental FAQ Documentation, RFA submits for consideration the following comments:

- The CATS model assumes a static 66 gCO_{2e}/MJ (g/MJ) carbon intensity (CI) for ethanol without carbon capture and sequestration (CCS) and a 35 g/MJ CI for ethanol with CCS. The average CI for ethanol in the California market today is 58 g/MJ and has steadily fallen since the inception of the LCFS.[1] The actual values in the market should be used as the starting point and there should be a curve representing the decreasing CI over time for ethanol. RFA members are committed to net zero carbon ethanol production no later than 2050 and have outlined concrete plans and pathways to achieve this result.[2] Using a declining future trend for ethanol CI would be consistent with both the historical (observed) trend analysis and the model's treatment of electricity, where a declining CI over time is built into the CATS model assumptions. Notably, the model's assumed declining CI for electricity is not necessarily consistent with recent observed trends in California's electricity generation. As shown in the chart below (based on data from the California Energy Commission), the share of California electricity generated from natural gas has increased in recent years, while increases in the solar and wind share of generation have been largely offset by decreases in hydro-electric generation.

[1] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries
[2] https://d35t1syewk4d42.cloudfront.net/file/2146/Pathways%20to%20Net%20Zero%20Ethanol%20Feb%202022.pdf



- The CATS model assumes an E10 blend in conventional gasoline. Given the significantly lower CI of ethanol relative to CARBOB, and the results of the recent CARB-supported emissions study showing significant criteria pollutant reductions from increasing the blend to E15, the model should run a scenario on higher blends. E15 represents a key strategy for an early acceleration of the LCFS compliance curve.

- E85 represents another significant opportunity for carbon reductions from the light duty vehicle fleet. Given the lower CI of E85 and the fuel's distinct price advantages, California E85 volumes have been increasing at an annual growth rate of approximately 50-60 percent in recent years. From the Technical Documentation, the CATS model is assuming additional costs associated with bringing E85 to market relative to E10 to be reflected by D6 RIN prices ($1.13 per gallon in the model). This assumption is greatly overstated given the modest costs of converting existing E10 distribution to E85. We are happy to work with staff to better understand these costs.

- Market prices are used for modelling biofuels, but for electricity the social marginal cost is used; however, the document referenced in the footnote states that "the marginal cost is vastly lower than current rates." With the need to more than double total electrical production in California to meet state climate objectives and the assumption that the grid CI is dropping, market pricing with some escalation over time seems to be a more appropriate assumption. This would also be more consistent with the treatment of other alternative fuels in the CATS model.

- For ethanol with CCS, the CATS model assumes that the CO2 captured would be used or stored in oil and gas fields qualifying for the $60 per metric ton 45Q federal tax credit. As a matter of fact, most of the announced ethanol CCS projects will be geologically sequestering the CO2 and qualifying for the higher $85 per metric ton 45Q credit. The model should be adjusted accordingly.

- A $7 per bushel corn price assumed in the CATS model is not a representative long-term price for corn. Current corn prices around $6.50 per bushel are at a multi-year high due to the Russia-Ukraine war and general worldwide commodity price inflation. USDA forecasts that prices will fall to $4.30 per bushel by 2026 and then remain at that level as shown in the U.S. Feed Grains file in the recent USDA Baseline Projections.[3]

- The model's conversion cost for ethanol appears to be higher than actual observed costs. Typical operating costs for ethanol producers are in the public domain and should be used to validate or modify the results of the regression analysis. For example, the Center for Agricultural and Rural Development (CARD) provides weekly updated margin reports that document corn ethanol conversion costs.[4]

- Corn distillers oil from ethanol producers is a coproduct of the production process and is an inedible corn oil (ICO). Consequently, it should not be included on the list of virgin oils. The distillers oil extracted at dry mill ethanol plants is strictly an industrial product and has no human food application. The FAQ supplement stated that it was not included as a waste oil because it had alternative uses as a feed. The same is true of the tallow and used cooking oil, which also have feed market opportunities.

[3] https://www.usda.gov/oce/commodity-markets/baseline
[4] https://www.card.iastate.edu/research/biorenewables/tools/hist_eth_gm.aspx

It is critically important for CARB to move quickly and concisely in strengthening the LCFS program. Timely and accurate modelling and scenario development through the CATS model and other analyses is a valuable tool in this regard.

Ethanol has generated the single largest volume of credits in the LCFS program, accounting for roughly four of every 10 credits generated since the program's inception. But constraining ethanol's use to 10 percent blends is sacrificing additional carbon reductions possible today. We urge CARB to move quickly to adopt regulations approving E15, which will allow the ethanol industry to help displace more fossil fuel in California and lower carbon emissions now.

An accurate modelling of ethanol's benefits and an integration of CARB fuels policy to incentivize higher ethanol blends will result in immediate reductions of GHG emissions and criteria pollutants while lowering the cost of compliance to obligated parties and California consumers.

RFA looks forward to working with CARB staff and other stakeholders to strengthen and extend the successful LCFS program.

Sincerely,

Kelly S. Davis
VP of Regulatory Affairs

Comment Log Display

Here is the comment you selected to display.

Comment 181 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nasser
Last Name	Kutkut
Email Address	nkutkut@smartchargetech.com
Affiliation	Smart Charging Technologies LLC
Subject	Proposed Low Carbon Fuel Standards Regulations and Its Impact on Bank Size and Credit Pric
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6839-lcfs2024-UiEBZFciUl4BawZj.pdf
Original File Name	SCT Letter to CARB - LCFS Credit Bank & Step-down Schedule.pdf
Date and Time Comment Was Submitted	2024-02-20 07:24:31

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 19, 2024

California Air Resources Board
1001 Street
Sacramento, CA, 95814

SUBJECT: Proposed Low Carbon Fuel Standards Regulations and Its Impact on Bank Size and Credit Prices

Dear Respected Members of the California Air Resources Board,

We are writing this letter to share with you some of our concerns regarding the proposed LCFS regulation as it relates to the growing credit bank size, its impact on credit prices, and the ability to reach CARB's emission reduction goals.

First and foremost, we would like to thank the CARB team for putting in the effort to update the LCFS regulations, which are intended to help move the fuel pool mix toward being cleaner and more diversified. We would like to recognize that ensuring the alignment of the proposed regulations with California's goals, as well as having minimal impact on all of California's stakeholders, cannot be easy.

172.1 That being said, we strongly feel that the proposed regulation, as it stands, would fall short of achieving CARB's goals in terms of diversifying the fuel pool mix as well as providing support for the LCFS credit prices. In fact, we have run some simulation scenarios using CARB's input file and incorporated the proposed step-down CI values as well as any potential trigger of the Automatic Acceleration Mechanism (AAR). We have also included some plausible scenarios that may alleviate these limitations. Note that we have only focused on the period of 2024 through 2030 as we strongly believe that the market will not price future projections past this time frame.

1- Scenario 1 – Proposed Regulation: 5% CI Step-down in 2025 and AAR in 2028

We believe that CARB underestimated the growth of renewable diesel (RD) and biomethane, which has led to a large credit bank and depressed credit prices. As of Q3 2023, renewable diesel filled almost 60% of the state's liquid diesel pool and generated roughly 50% of all new LCFS credits. In fact, we expect 80% of the diesel complex to be made up of RD by early 2025. This has undermined the LCFS's support for electrification and more scalable low-carbon fuels. The LCFS credit current prices saw high 50's, which did not inspire much in terms of investment. As the bank continues to grow, prices will continue to drop.

While stepping down the CI target by 5% in 2025 should create more demand for LCFS credits, this will not be enough to curb the rapid growth of the LCFS credit bank and its downward pressure on credit prices. We have used CARB's input file, along with the present CARB data (Q3 2023), to model the size of the bank throughout Q4 2030, as shown in Fig. 1. We assumed that the AAR will be triggered in 2027 and the CI target will be updated in 2028. Under this scenario, the credit bank will grow to 91 million credits by Q4 2030. As the bank continues to grow, prices will continue to drop. It is important to note that current RD capacity utilization is in the high 60% and low 70%, and capacity in the pipeline is expected to double; the bottleneck is how quickly paperwork can get signed to have the fuel find its way into California.

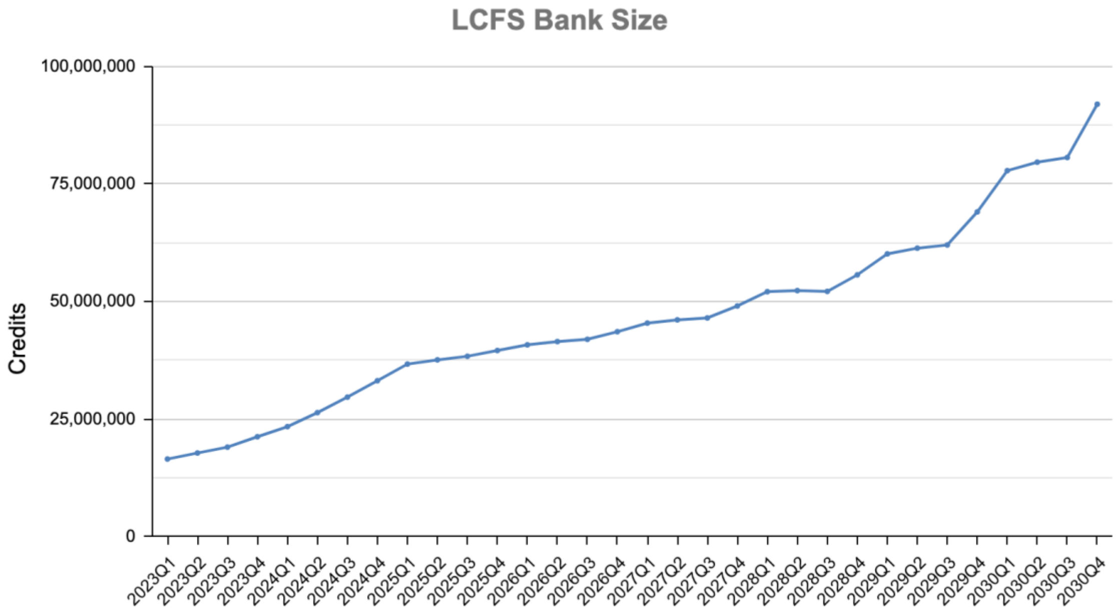


Fig. 1: Projected Bank Size Under Current Proposed Regulations (AAR in 2028)

2- **Scenario 2 – Incoming legislation + Stronger step-down to 21%**

In this scenario, we propose stepping down the CI target to **21% in 2025** while keeping the same rules in the proposed regulation. Under this scenario, the AAR isn't triggered until 2030, and the resulting credit bank will be shown in Fig. 2.

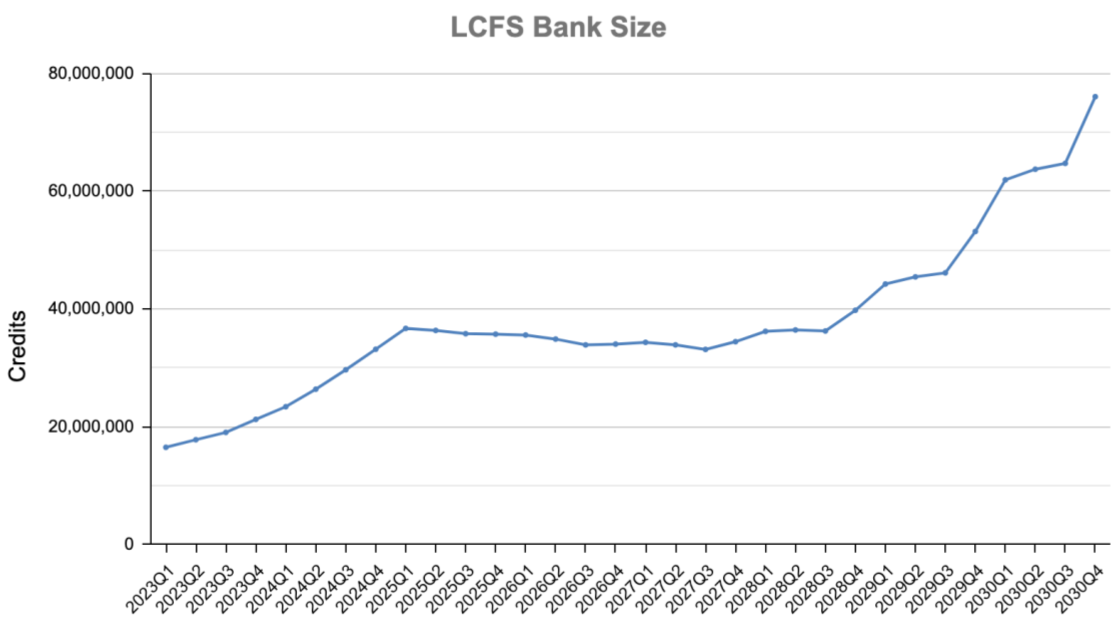


Fig. 2: Stronger step-down in 2025 to 21%

The impact of this would initially be positive between 2025 and 2028 as it would draw down the bank almost immediately. This may send a signal to the market, which can result in supporting LCFS credit prices. This change in CI step-down CI schedule can be easily implemented, allowing CARB to maintain the proposed regulation. CARB can then monitor the bank and assess whether a stronger action would be needed. However, it is important to note that the draw on the bank is relatively weak, so its impact on price levels may not be sufficient. The model predicts that the bank will resume rising in late 2028 and reach almost 77 million by the end of 2030.

3- **Scenario 3 – Incoming legislation + Stronger step-down to 23.5%**

In this scenario, we propose a bigger step down to 23.5% by 2025. This larger step down would quickly draw down the bank and correct prices. While the bank would rise starting in 2029, the size of the bank will be below the projected levels by the end of 2024. In addition, as the number of deficits grows, the bank's acceptable size can also become larger. In addition, the AAR may be triggered in subsequent years (past 2030) to address growing bank size and falling prices.

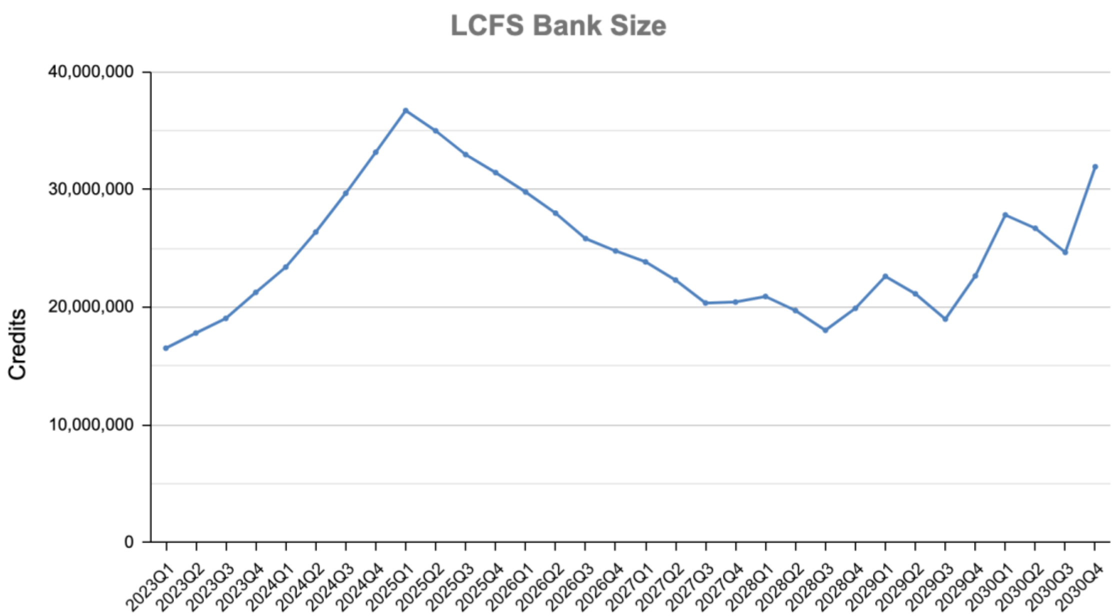


Fig. 3: Stronger step-down in 2025 to 23.5%

172.1 cont In summary, the current proposed regulation, as is, will not result in any measurable impact on the rapid growth trajectory of the credit bank and will almost eliminate any clean fuel technology, other than renewable diesel, from being competitive. We have presented some alternatives that may help stabilize the growth in the credit bank and stabilize LCFS credit prices. CARB can also put caps on RD and other biofuels to help other clean technologies get established and allow investments to flow into them.

We are committed to helping California reach its target CI reduction goals and hope the board will push CARB to address the above concerns to ensure the success of the LCFS program.

Respectfully,
/s/
Nasser Kutkut, PhD
CEO
Verdant Energy Services LLC

Comment Log Display

Here is the comment you selected to display.

Comment 182 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mireille
Last Name	Ferdinand-Hercule
Email Address	mireille.ferdinand-hercule@valero.com
Affiliation	
Subject	Diamond Green Diesel LLC's Comments on 2024 Proposed LCFS Amendments
Comment	Please find the attached comments for Diamond Green Diesel.
Attachment	www.arb.ca.gov/lists/com-attach/6840-lcfs2024-BzVQZINgBGcFXFRk.pdf
Original File Name	2020 02 19 Diamond Green Diesel - Comments on 2024 Proposed LCFS Amendments.pdf
Date and Time Comment Was Submitted	2024-02-20 07:31:17

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

DIAMOND GREEN DIESEL

February 20, 2024

Ms. Rajinder Sahota
Deputy Executive Officer – Climate Change and Research
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Submitted electronically through CARB Portal

RE: Comments of Diamond Green Diesel, LLC on 2024 Proposed Low Carbon Fuel Standard Amendments

Dear Ms. Sahota:

Diamond Green Diesel, LLC ("DGD"), a joint venture between subsidiaries of Darling Ingredients Inc. and Valero Energy Corporation, submits these comments regarding the 2024 proposed Low Carbon Fuel Standard ("LCFS") amendments. DGD is a leading producer of renewable diesel in the United States, with a total production capacity of approximately 1.2 billion gallons annually. We are also well underway on a project to upgrade approximately half of the new Port Arthur facility's production capacity to produce sustainable aviation fuel ("SAF"). Upon commissioning of this project, currently planned for early 2025, we are poised to become one of the largest SAF producers in the world.

As one of the nation's leading producers of renewable diesel and as a trailblazer in SAF production, we are proud to have played a leading role in helping California achieve the LCFS goal of reducing the carbon intensity of the transportation fuel pool. Our growth owes much to the strong market signals created by the LCFS, and we look forward to helping CARB continue to improve the program so that it can remain the premiere market-based regulatory program supporting innovation in low-carbon fuels. With that goal in mind, we offer the following comments.

Feedstock Considerations

DGD appreciates that CARB does not propose to implement a cap on biofuels made form crop-based feedstocks, because doing so would have been impractical to implement, could have created market uncertainty, and may have led to legal challenges. However, DGD has some concerns regarding the proposed specified source feedstock attestation letter requirement because they will increase the annual verification burden for pathway holders without
173.1 any associated "value add" to the program. If it is the intent of the provision that upstream suppliers be held accountable through the pathway holder, then it is duplicative of the currently effective provisions requiring chain of custody documentation. CARB should consider an approach consistent with the International Sustainability and Carbon Certification ("ISCC") requirements.[1]

[1] International Sustainability and Carbon Certification, *ISCC EU 201 System Basics*, at pp. 25-28, available at: https://www.iscc-system.org/wp-content/uploads/2024/01/ISCC_EU_201_System_Basics_4.1_January2024.pdf ("The collecting point is the first element that must be individually certified. Points of origin can be covered under the certificate of the collecting point but may also receive an individual or group certification.")

Diamond Green Diesel LLC • One Valero Way • San Antonio, Texas 78249-1616
Post Office Box 696000 • San Antonio, Texas 78269-6000 • Telephone (210) 345-2000

DIAMOND GREEN DIESEL

Likewise, DGD requests that CARB provide greater clarity on the definition of "crop-based" and "forestry-based" biofuels. Currently, it is unclear which feedstocks Subsection 94588.9(g)(1) would apply to. DGD reiterates its
173.2 previous comment that distiller's corn oil ("DCO") used to make renewable diesel is inedible and not fit for human consumption.[2] Additionally, it is produced as a byproduct of the ethanol production process. Because corn is not grown to provide DCO, it should not be considered a "crop-based" biofuel, subject to additional sustainability requirements that are ostensibly designed to inhibit land-use change.

To address these issues, DGD suggests that CARB schedule workshops with the affected parties for any sustainability requirements, as was previously done with the CI stringency and AAM provisions. There are numerous international approaches to supply chain declarations that CARB can study and more seamlessly implement, with
173.3 appropriate stakeholder feedback. At a minimum, CARB should reconsider the length of time allowed for verification and/or allow for less intensive verifications, as has been done with fuel reporting entities reporting only electricity transactions. The recent announcement to postpone the Board's consideration of the rule may provide an opportunity to further develop this issue.

Feedstock Emission Factors

a. Feedstock Emission Factor for Tallow Rendering

The emission factor for tallow rendering used in the draft HEFA Tier 1 calculator is almost 2.5x the value in Argonne's GREET 2022 model (286 gCO2e/lb oil vs 119 gCO2e/lb oil). The draft HEFA Tier 1 calculator and CA-GREET 4.0 appear to use the same values for energy consumption in the tallow rendering process as CA-GREET 3.0, which
173.4 was based on GREET 2016. Since the publication of GREET 2016, Argonne has updated their tallow rendering data and emission factors multiple times based on updated industry data. CARB should update the tallow rendering values in CA-GREET 4.0 to reflect the most current Argonne GREET 2022 model, to ensure consistency with the other feedstocks and processes that CARB has updated in CA-GREET 4.0.

b. Feedstock Emission Factor for UCO Rendering

Similarly, CA-GREET 4.0 uses a UCO rendering emission factor of 87 gCO2e/lb oil, compared to Argonne GREET
173.5 2022's UCO rendering emission factor of 81 gCO2e g/lb. CARB should update CA-GREET 4.0 consistently with GREET 2022 to reflect current industry practices for all feedstock and fuel production processes, regardless of technology.

Increasing Stringency of Annual Carbon Intensity Benchmarks

In light of CARB's recent announcement that the Board hearing on the proposed amendments will be postponed pending staff's reconsideration of the proposed carbon intensity benchmarks, DGD will reserve specific comments regarding the stepdown and AAM at this time and will look forward to participating in the workshops planned for mid-April. DGD agrees in principle with the near-term step down in order to send a clear message that CARB is committed to using the LCFS to promote transportation decarbonization and to help stabilize the unprecedentedly high credit bank.

[2] Comments of Diamond Green Diesel LLC on February 2023 CARB LCFS Revisions Workshop, March 13, 2023.

DIAMOND GREEN DIESEL

173.6 Additionally, we note that the proposal to extend the program for ZEV infrastructure credits to medium- and heavy-duty ZEVs could potentially work counter to the proposed increased stringency of the targets. Because vehicle manufacturers and fleet owners face regulatory mandates to transition the medium- and heavy-duty vehicle fleets to ZEV technology, incentives already exist for affected parties to provide for infrastructure to support these technologies. Providing additional incentives in the form of LCFS credits may lead to credit price dilution, thus further weakening the credit market and reducing incentives for development of all low-carbon transportation fuels. It is not clear that CARB has modeled both of these phenomena in conjunction, and staff may not have a clear indication of how the market will emerge and continue to drive innovation and investment in low-carbon transportation fuels.

We greatly appreciate your consideration of our comments. If you have any questions or would like to discuss any of the points discussed in this letter, please do not hesitate to contact us.

Sincerely,

Sandra Dudley
Chairman and President

Diamond Green Diesel LLC • One Valero Way • San Antonio, Texas 78249-1616
Post Office Box 696000 • San Antonio, Texas 78269-6000 • Telephone (210) 345-2000

Comment Log Display

Here is the comment you selected to display.

Comment 183 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Dawn
Last Name	Caldwell
Email Address	dawnc@renewablefuelsne.org
Affiliation	Renewable Fuels Nebraska
Subject	Low Carbon Fuel Standard Comments
Comment	See Uploaded File.
Attachment	www.arb.ca.gov/lists/com-attach/6842-lcfs2024-B2QBZl0uU2IGbFU2.pdf
Original File Name	CARBLCFSCommentsFeb24.pdf
Date and Time Comment Was Submitted	2024-02-20 08:11:36

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

RENEWABLE FUELS NEBRASKA

Ensuring the growth of the renewable fuels industry in Nebraska

February 20, 2024

California Air Resources Board

1001 I St.

Sacramento, CA 95814

Re: Comments from Renewable Fuels Nebraska on California's Low Carbon Fuel Standard

Chair Randolph and Members of the California Air Resources Board,

I write today to urge you to reconsider proposed changes to the Low Carbon Fuel Standard.

Specifically: On behalf of the hundreds of thousands of farmers, ranchers, producers,
and workers here in Nebraska who help feed and fuel the world — and for the sake of
our shared goal of reducing greenhouse gas emissions — we respectfully request for
174.1 you to adopt a more technology-neutral, market-based approach that ensures that
biofuels can contribute on a level-playing field to a cleaner, more efficient energy
future in California and across the country.

In addition to general concerns that the proposed changes as currently envisioned would pick winners and losers among renewable energy alternatives, there are several specific factors to note as you continue the regulatory process.

These include our inability to provide more detailed comments with regard to the
sustainability requirement proposal for crop- and forest-based biofuels without more
174.2 information. Details such which third-party verifiers would be involved and what
information said third-party verifiers would require are necessary, both to ensure
equitable application in the real world and to ensure that interested stakeholders are
able to provide informed feedback as soon as possible.

More broadly, the proposed changes to the Low Carbon Fuel Standard risk doubling down on California's inexplicable decision to effectively reject cleaner fuels and lower emissions through the failure to permit the use of E15.

174.3

For instance, if E15 had replaced E10 in California cars as recently as 2022, the Golden State would have enjoyed an additional greenhouse gas savings of 2.2 billion metric tons (CO2e) that year alone.[1] And California residents could have joined drivers

[1] Letter from Renewable Fuels Association, October 3, 2023.

[1] Renewable Fuels Association study, April 2023.

174.3 cont nationwide in saving an average of more than 25 cents per gallon when filling up their tanks.[2]

Yet, despite the substantial greenhouse gas emissions benefits associated with E15 — and the significant financial savings to consumers — California continues to abstain from this commonsense step towards a better and cleaner energy future. And that hurts California residents from all walks of life both financially and environmentally.

We urge CARB to reconsider its approach towards the Low Carbon Fuel Standard before it makes the same kind of mistake again.

And we remain committed to working with you and other dedicated stakeholders to pave a better path forward that appropriately balances strident goals and the incredible technologies available to us today to help achieve them.

Sincerely,

Dawn Caldwell

Dawn Caldwell

Executive Director

Renewable Fuels Nebraska

dawnc@renewablefuelsne.org

Comment Log Display

Here is the comment you selected to display.

Comment 184 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Amanda
Last Name	Parsons DeRosier
Email Address	Amanda.DeRosier@gceholdings.com
Affiliation	Global Clean Energy
Subject	Comments on Proposed LCFS Amendments 2024

Comment

February 20, 2024

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Chair Randolph and Honorable Members of the Board,

Thank you for your continued dedication to enhancing air quality i the Golden State through the proposed updates to the Low Carbon Fuel Standard Program (LCFS). We commend your decision to further encourage and not restrict the use of crop-based feedstocks withi the proposed LCFS amendments under consideration.

The proposed accounting requirement for crop-based feedstocks, to trace their origin and undergo independent certification, aligns with the California Air Resources Board's commitment to ensuring crop-based feedstocks do not contribute to adverse impacts associated with land use change or limiting food supply. This proactive approach addresses concerns raised by the Environmental Justice Advisory Committee (EJAC) regarding "expanse of global deforestation, unsustainable land conversion, or adverse food supply impacts."

Our company, Global Clean Energy, stands ready to assist CARB in achieving this important goal. As a California-based renewable fu innovator with offices in Torrance and a renewable fuels producti facility in Bakersfield, we work tirelessly to ensure renewable fuels that we produce can have the lowest possible carbon intensity. What sets us apart is our focus on producing ultra-low carbon renewable fuels using Camelina sativa (camelina), a crop that alleviates the foregoing concerns.

Unlike other renewable fuel feedstocks, camelina is nonfood. Camelina is quick to mature, is tolerant to drought, promotes biodiversity, sequesters carbon as it is grown, and provides soil health benefits similar to those of cover crops. Importantly, camelina does not displace food crops when grown. Instead, it gro on existing farmland during the fallow between crop cycles -

providing a new revenue source to farmers and rural agricultural communities while also strengthening our domestic energy supply. With these unique traits, camelina has the potential to be the lowest carbon intense renewable fuel feedstock on the market.

Labeled as an "Intermediate Crop," camelina falls under a new classification of biofuel and renewable fuel feedstocks. "Intermediate Crops" act as harvestable cover crops that can reach maturity during an idle or fallow period on existing farmland, which does not cause land use change or adversely impact food supply. Intermediate crops like camelina can help California and our nation reach our renewable fuel and SAF goals responsibly through biomass.

As you endeavor to create an accounting mechanism to track feedstocks to their point of origin and develop the independent feedstock certification process recommended within your proposed LCFS rule, we encourage you not to recognize the importance of emerging crops like camelina. By incentivizing the further adoptic of "Intermediate Crops" like camelina among growers and renewable fuel producers, we can help ensure land use change is prevented, soil health is protected, and renewable fuel feedstock demand can be met responsibly.

As new crops, education and incentives are vital to ensure "Intermediate Crops'" continued adoption and future success. Recognizing that newer feedstocks lack the resources of traditiona commodities like soy or corn, we recommend that accounting rules should not place "Intermediate Crops" like camelina at a financia disadvantage as they establish themselves within the market.

As experts in this emerging field of "Intermediate Crops" we stanc ready to work with CARB staff and others to lend data and provide guidance in the development of an accounting mechanism addressing GHG and air pollution emissions associated with feedstock production pathways.

We look forward to working together to ensure Intermediate Crops are supported while these accounting criteria are developed. Thank you for taking the time to consider our comments.

Sincerely,

Amanda Parsons DeRosier
Vice President of Public Affairs and Investor Relations
Global Clean Energy   www.GCEholdings.com

Attachment	www.arb.ca.gov/lists/com-attach/6843-lcfs2024-VjAAb10yUGIDaVUK.pdf
Original File Name	FINAL GCE LCFS Letter Letterhead.pdf
Date and Time Comment Was Submitted	2024-02-20 08:21:59

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Amanda Parsons DeRosier
Vice President of Public Affairs and
Investor Relations

February 20, 2024

Clerk of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Chair Randolph and Honorable Members of the Board,

Thank you for your continued dedication to enhancing air quality in the Golden State through the proposed updates to the Low Carbon Fuel Standard Program (LCFS). We commend your decision to further encourage and not restrict the use of crop-based feedstocks within the proposed LCFS amendments under consideration.

175.1

The proposed accounting requirement for crop-based feedstocks, to trace their origin and undergo independent certification, aligns with the California Air Resources Board's commitment to ensuring crop-based feedstocks do not contribute to adverse impacts associated with land use change or limiting food supply. This proactive approach addresses concerns raised by the Environmental Justice Advisory Committee (EJAC) regarding "expanse of global deforestation, unsustainable land conversion, or adverse food supply impacts."

Our company, Global Clean Energy, stands ready to assist CARB in achieving this important goal. As a California-based renewable fuel innovator with offices in Torrance and a renewable fuels production facility in Bakersfield, we work tirelessly to ensure renewable fuels that we produce can have the lowest possible carbon intensity. What sets us apart is our focus on producing ultra-low carbon renewable fuels using Camelina sativa (camelina), a crop that alleviates the foregoing concerns.

Unlike other renewable fuel feedstocks, camelina is nonfood. Camelina is quick to mature, is tolerant to drought, promotes biodiversity, sequesters carbon as it is grown, and provides soil health benefits similar to those of cover crops. Importantly, camelina does not displace food crops when grown. Instead, it grows on existing farmland during the fallow period between crop cycles - providing a new revenue source to farmers and rural agricultural communities while also strengthening our domestic energy supply. With these unique traits, camelina has the potential to be the lowest carbon intense renewable fuel feedstock on the market.

Labeled as an "Intermediate Crop," camelina falls under a new classification of biofuel and renewable fuel feedstocks. "Intermediate Crops" act as harvestable cover crops that can reach maturity during an idle or fallow period on existing farmland, which does not cause land use

2790 Skypark Drive, Suite 105, Torrance, CA 90505 Amanda.DeRosier@GCEHoldings.com

change or adversely impact food supply. Intermediate crops like camelina can help California and our nation reach our renewable fuel and SAF goals responsibly through biomass.

As you endeavor to create an accounting mechanism to track feedstocks to their point of origin and develop the independent feedstock certification process recommended within your proposed LCFS rule, we encourage you to recognize the importance of emerging crops like camelina. By incentivizing the further adoption of "Intermediate Crops" among growers and renewable fuel producers, we can help ensure land use change is prevented, soil health is
175.2 protected, and renewable fuel feedstock demand can be met responsibly.

As new crops, education and incentives are vital to ensure the continued adoption and future success of "Intermediate Crops" like camelina. Recognizing that newer feedstocks lack the resources of traditional commodities like soy or corn, we recommend that accounting rules should not place "Intermediate Crops" like camelina at a financial disadvantage as they establish themselves within the market.

As experts in this emerging field of "Intermediate Crops" we stand ready to work with CARB staff and others to lend data and provide guidance in the development of an accounting mechanism addressing GHG and air pollution emissions associated with feedstock production pathways.

We look forward to working together to ensure Intermediate Crops are supported while these accounting criteria are developed. Thank you for taking the time to consider our comments.

Sincerely,

Amanda Parsons DeRosier
Vice President of Public Affairs and Investor Relations
Global Clean Energy | www.GCEholdings.com

Comment Log Display

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Comment 185 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Lisa
Last Name	Hanke
Email Address	lhanke@ecoengineers.us
Affiliation	EcoEngineers
Subject	EcoEngineers Comments on 2024 Proposed LCFS Amendments
Comment	Letter
Attachment	www.arb.ca.gov/lists/com-attach/6845-lcfs2024-UGJQZlJhWT5SCwBs.pdf
Original File Name	2024 LCFS Amendments Comments EcoEngineers .pdf
Date and Time Comment Was Submitted	2024-02-20 08:50:20

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

EcoEngineers appreciates the opportunity to submit comments regarding the Proposed Low Carbon Fuel Standard Amendments.

EcoEngineers is one of the nation's leading auditing, verification and consulting firms for renewable fuel and clean energy technologies. We are accredited under the EPA Renewable Fuel Standard (RFS), the California Low Carbon Fuel Standard (LCFS) and the Washington and Oregon Clean Fuel Standards. We are also accredited by the American National Standards Institute (ANSI) National Accreditation Board (ANAB), in accordance with the International Organization for Standardization (ISO) standards ISO/IEC 17029:2019 and we are in the process of becoming accredited by the Canadian Government for the Clean Fuel Standard. We appreciate the opportunity to share some of our thoughts and comments on the proposed amendments.

EcoEngineers strongly supports the advancement of policies, regulations and programs that address the global reduction of greenhouse gas (GHG) emissions across all sectors. The LCFS program continues to be a vital tool that can assist California and the US in meeting their climate reduction goals. This program serves as an example to jurisdictions around the world looking to decarbonize their transportation fuel sector and as such, should continue to strive towards ambitious targets while closely considering market dynamics.

EcoEngineers presents the following comments on the Proposed Low Carbon Fuel Standard Amendments.

1- Compliance, Program Benchmarks, and Credit Generation

176.1 Strengthening the carbon intensity benchmarks throughout 2045 and including fossil jet fuel are 176.2
necessary steps to ensure continued reductions in GHG emissions while providing industry with the regulatory certainty required to develop and grow low carbon fuel alternatives.

The inclusion of a "step-down" mechanism is a key element of this proposal. If implemented
176.3 correctly, the mechanism could help stabilize the credit market. EcoEngineers recommends CARB
implement a more active "step-down" mechanism that annually balances rates of production with

requirements. EcoEngineers also suggests including a “step-up” mechanism that can address potential credit surpluses.

Finally, EcoEngineers recommends that CARB provide clarity as to the stackability of CORSIA and
176.4 LCFS credits. Similar to US Renewable Fuel Standard RINs, CORSIA credits in conjunction with
LCFS credits would help facilitate uptake of SAF. This will also provide industry with additional
clarity as they develop capital intensive SAF projects.

2- Equity-Focused Improvements

Even with the “step-down” mechanism as proposed, current EcoEngineers’ modeling shows credit prices in the near term will remain within the current range. The main factor driving price outlook is the near-term oversupply of credits versus the schedule, primarily from renewable diesel. Historic data and refinery planning indicate that renewable diesel use will continue to grow with current credit pricing till 2030. However, the modeling also shows a potential undersupply of credits toward the end of the decade without improvements in electric vehicle (EV) sales.

EcoEngineers believes that zero emission vehicle (ZEV) (includes battery electric vehicles (BEV)
and fuel cell electric vehicles (FCEV)) uptake is a critical element of the LCFS program. There is
clear evidence that point-of-sale and home charging economic incentives for ZEV purchases
increase ZEV uptake. EcoEngineers suggests that CARB implement vehicle based LCFS ZEV credit
accounting in conjunction with infrastructure credits. By having an accounting system based off
vehicular data, OEMs would eventually be able to discount their ZEV sale prices by future LCFS
credit generation. This would be similar to the approach adopted by the USEPA in the proposed
176.5 RFS eRIN rules.

The proposed focus and increased investment on increasing the accessibility of ZEVs in disadvantaged, low-income, rural, and tribal communities coupled with the expansion of ZEV crediting to the medium and heavy-duty sector will be positive additions to the LCFS program.

3- Fuel Pathway Applications and CI Determination

EcoEngineers fully supports updating LCA modeling tools and emission factors to ensure the
176.6 modeling is reflective of the most up-to-date scientific, evidence-based information. The update
of the GREET model will help ensure the LCFS remains at the forefront of science-based GHG
reductions including the addition of a Tier 1 Calculator for hydrogen.

EcoEngineers also supports sustainability requirements for crop and forestry-based feedstock.
176.7 These requirements should be clearly defined, and sufficient time should be given to ensure
industry can incorporate the necessary changes to meet the requirements.

4- Verification Program

EcoEngineers supports the proposed addition of third-party verification on hydrogen and
176.8 electricity data types and deferral thresholds as well as on applications for project-based
crediting. Third-party verification continues to be a reliable method of validating applicant
information to ensure the integrity of the program.

February 20, 2024

Thank you once again for the opportunity to comment on the proposed amendments and please do not hesitate to contact me for more details. We look forward to continuing to work with the LCFS on implementing a successful program.

Sincerely,

Lisa Hanke,

Director, Regulatory Engagement
EcoEngineers

Comment Log Display

Here is the comment you selected to display.

Comment 186 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Carol
Last Name	Tjiong
Email Address	carol.tjiong@frionaindustries.com
Affiliation	
Subject	CARB LCFS Rulemaking Comments
Comment	Please see attached comments from Hereford Ethanol Partners, L.P.
Attachment	www.arb.ca.gov/lists/com-attach/6846-lcfs2024-UWNVY1xvUzQLIwg4.pdf
Original File Name	2024.02.20 CARB 2024 Rulemaking LCFS Comments Submitted by HEP.pdf
Date and Time Comment Was Submitted	2024-02-20 09:01:48

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Hereford Ethanol Partners, L.P.

4300 CR 8
Hereford, TX 79045

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814
RE: Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

As a renewable fuel producer and participant in CARB's LCFS program, my team and I value the partnership and mission shared with you and your state to reduce the carbon intensity of transportation fuels.

I am writing to share our company's perspective on several key program areas for your consideration. These requests address the topics of **CCS protocols, Low-CI Electricity, LCFS modeling & crop-based biofuels, and Verification**.

Fuels Produced Using Carbon Capture and Sequestration

177.1 We support and encourage CARB to approve fuel pathway applications from entities utilizing the CCS Protocol dated August 13, 2018 so that they may receive credits associated with net GHG reductions from CCS projects.

Low-CI Electricity

CARB Staff proposes to update language in Sections 95488(i)(1), 95490(b)(8), and 95491(d)(4)(D) related to modifications to book-and-claim accounting of low-CI electricity to produce hydrogen used as a transportation fuel and for process electricity in direct air capture projects. The rationale in Appendix E states that the process of capturing CO2 directly from the atmosphere has higher electricity demand, which makes it financially challenging and may drive the need for additional electricity load. The proposal permits low-CI electricity with quarterly demonstration of trackable deliverability to be used for hydrogen production for hydrogen used as a transportation fuel as well as at a direct air capture facility, which aligns with the requirement for renewable or low-CI process energy (section 95488.8(h)(1)(C)). On page 34 of the ISOR, CARB staff also recommends allowing for power purchase agreements but can only be from new or expanded capacity for low CI hydrogen production.

177.2 We would like to highlight that adding the process of carbon capture from controlled, high CO2 concentration sources (e.g. fermentation vessels at an ethanol plant) also require a higher electricity demand and may also need additional electricity load, which makes it financially challenging. Therefore, we **request CARB treat all CO2 capture and sequestration activities similarly and allow the book-and-claim accounting for low-CI electricity or the expanded use of PPAs for carbon capture facilities with fuel pathways claiming CCS credits by producers of alternate transportation fuels**.

LCFS Modeling & Crop-Based Biofuels

To reduce the risk that rapid expansion of biofuel production and biofuel feedstock demand could result in deforestation or adverse land use change, CARB staff are proposing additional guardrails on the use of crop-based feedstocks for biofuel production. CARB staff are proposing to require pathway holders to track crop-based and forestry-based feedstocks to their point of origin and require independent feedstock certification to ensure feedstocks are not contributing to impacts on other carbon stocks like forests. As crop-based biofuel producers may have field level information to comply with this provision, we **request that**

177.3 **LCFS modeling be granular and allow the inclusion of on-the-farm carbon accounting and factor lower carbon intensity grain associated with climate smart and regenerative agriculture farming practices.**

Verification - Firm Rotation

The existing regulations within the LCFS verification program stipulate a mandatory rotation of audit firms every six years to assess participants' carbon intensity (CI) and fuel quantities compliance.

Our request is that CARB amend the mandatory firm rotation regulation to include an exception for licensed CPA firms. Of the 30 approved LCFS verification bodies, there are only four licensed CPA firms.

An approved verification body, that is also a licensed CPA firm, exceeds the standards in place for verification bodies and is already subject to additional

177.4 ***oversight on the entity's quality control system in accounting and auditing practices through the required AICPA peer review process.***

Due to the increased regulatory oversight, we suggest a CPA firm not be subject to the audit firm rotation but would instead adhere to a Lead Verifier rotation after six consecutive years.

A licensed CPA firm differs from other consulting agencies by adhering to more rigorous standards and oversight at a state and national level. If a verification body were to violate a Lead Verifier rotation requirement, it would put the firm license at risk. The firm license is required for all services provided by the firm, not just the LCFS verification services, thereby ensuring adherence to requirements.

Licensed CPA firm requirements

- A licensed CPA firm must be comprised of over 50% of the ownership being licensed CPAs.
  - To earn the accreditation to be a CPA, one must pass a rigorous four-part CPA exam, accumulate education hours, and in many states, one must fulfill 1-2 years of work experience.

- 3-year peer review audit
  - Each licensed CPA firm must enroll in an approved peer review program with reviews conducted every 3 years. The peer review requirement is a requirement of the American Institute of Certified Public Accountants (AICPA)

and is an external review of a firm's quality control system in accounting and auditing practices. CPA firms' peer review results can be found on AICPA's website under the Peer Review Public File Search.

- State Boards of Accountancy (SBOA) are found in each state's statute to aid state governments in the licensing and regulation of the public accounting profession.
    - SBOAs provide further oversight on CPA firms by evaluating CPA licensees' examinations and regulatory oversight to ensure a firm is practicing within their statutory scope.

The audit quality and efficiency improve as the auditor becomes more familiar with our company's processes. In addition, with the limited number of firms available as verification bodies and a five-year lookback period in place, it is proving difficult to identify a quality verification body that is not also working with our facility in other consulting capacities. The number of people available with the proper expertise to assist us in design and development of projects and to reserve for verification purposes has proven even more limiting, which is also why we request a Lead Verifier rotation rather than a full firm rotation.

Less Intensive Verification

Regarding less intensive verification, we noted in Appendix E staff's proposal for less intensive verifications for when electricity is used as a transportation fuel, allowing verification bodies to skip site visits if they visited the site in the last two years and issued a positive verification statement.

The rationale for this proposed change states, "there is little change of operation from reporting period to reporting period thus reducing the benefit of annual site visits." Additionally, staff rationale states, "There is no or little risk to the integrity of the LCFS program to allow for less intensive verification services without a site visit in the annual verifications for the following two years. This should reduce the cost of verification services which is often passed on to program participants."

Currently, the proposed language limits this allowance for less intensive verifications to QFTR third-party verification bodies for fuel reporting entities only reporting electricity transactions.

We agree with the staff's stated rationale, but **we request for less intensive verification to**
177.5 **be extended as an option for verification bodies on all validations and annual**
verifications for any reporting entities.

In CARB's MRR program (section 95130), less intensive verification is applied without prejudice to verification services by accredited verification bodies.

We agree with staff that less intensive verification leads to little to no risk to the integrity of the LCFS program and that there is little change in operation from reporting period to reporting period, while also providing cost savings to verification providers and passed on to our company as program participants.

We acknowledge the importance of adhering to CARB's specified conditions that necessitate comprehensive verification services. These conditions include the issuance of an adverse verification statement or a qualified positive verification statement in the preceding year and the occurrence of a change in operational control of the reporting entity in the previous year.

Thank you for your time and consideration. Please reach out to us if you have any questions.

Sincerely,

Don Gales
CEO

Comment Log Display

Here is the comment you selected to display.

Comment 187 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Rosalie
Last Name	Barcinas
Email Address	Rosalie.Barcinas@sce.com
Affiliation	SCE
Subject	SCE Supports LCFS Regulation Amendments with Modifications
Comment	SCE supports the proposed amendments to the LCFS regulation with the following modifications, which are discussed in detail in the attachment: (1) combine the separate holdback project lists proposed for equity and nonequity projects; (2) specify that utilities have discretion to select the most appropriate projects for their customers and require the large investor-owned utilitie (IOUs) to fund at least three program options; (3) retain the 10% administrative cost cap for Holdback programs because 5% is insufficient; (4) align the administrative cost cap for the statewide Clean Fuel Reward Program with other large utility incentive programs; (5) update vehicle eligibility for the Statewide Clean Fuel Reward Program to conform to CARB's goals; ar (6) reject the 1-mile requirement for capacity credits in favor o greater flexibility.
Attachment	www.arb.ca.gov/lists/com-attach/6847-lcfs2024-ViVQNVYyWFQCZ1I9.pdf
Original File Name	SCE Comments LCFS Amendment Comments.Feb20.24.pdf

Date and Time Comment Was Submitted	2024-02-20 09:07:30

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

SOUTHERN CALIFORNIA EDISON®

An *EDISON INTERNATIONAL®* Company

February 20, 2024

BY ONLINE SUBMITTAL

California Air Resources Board
1001 I Street
Sacramento, CA 95814

ATTN: Liane Randolph, Chair
Steven S. Cliff, Ph.D., Executive Officer

Re: *SCE Support for Low Carbon Fuel Standard Regulation Amendments with Some Proposed Modifications and Clarifications*

Southern California Edison (SCE) appreciates the opportunity to comment on the California Air Resources Board's (CARB's) staff proposal to amend the Low Carbon Fuel Standard (LCFS) regulation (Proposed Amendment), which CARB posted on December 19, 2023. The LCFS Regulation has been instrumental in helping California move towards a decarbonized economy and SCE appreciates staff's willingness to consider and collaborate on opportunities to strengthen and provide clarity within the regulation.

178.1 Among other things, SCE supports the Proposed Amendment's recommendations to: (1) establish an automatic acceleration mechanism (AAM); (2) adjust the minimum contribution of
178.2 large investor-owned utilities (IOUs) towards the Clean Fuel Reward program to 50% of their base residential credit proceeds; (3) list and provide detailed examples of pre-approved uses for 178.3
utility Holdback credit proceeds; and (4) include Vehicle Grid Integration (VGI) and workforce development as pre-approved Holdback projects. 178.4

178.5 SCE also understands the need for a brief postponement of the public hearing to consider the amendments, given the number of items that require staff's attention and time to address. However, to ensure the timely implementation of important modifications to stringency, the statewide Clean Fuel Reward program, and utility Holdback project requirements, SCE requests that the extension not extend beyond the end of Q2 2024.

In addition to SCE's general support, SCE proposes that CARB (1) combine the separate holdback project lists proposed for equity and nonequity projects; (2) specify that utilities have discretion to select the most appropriate projects for their customers and require the large investor-owned utilities (IOUs) to fund at least three program options; (3) retain the 10% administrative cost cap for Holdback programs because 5% is insufficient; (4) align the administrative cost cap for the statewide Clean Fuel Reward Program with other large utility incentive programs; (5) update vehicle eligibility for the Statewide Clean Fuel Reward Program to conform to CARB's goals; and (6) reject the 1-mile requirement for capacity credits in favor of greater flexibility.

I. CARB Should Combine the Separate Holdback Project Lists Proposed for Equity and Non-equity Projects

As mentioned above, SCE appreciates the staff's proposed amendments expanding the list of LCFS Holdback projects and activities but recommends that the final amendments do not contain separate lists for (1) Holdback Credit Equity Projects - for projects that are for the primary benefit of or primarily serving a defined list of underserved individuals and/or communities[1] and (2) Other Holdback Projects – for activities are not considered as equity Holdback projects.[2] As currently drafted, the Other Holdback funding list limits the IOUs' spending on non-equity projects to three project types: (1) vehicle grid integration (VGI), (2) investments in grid-side distribution infrastructure necessary for EV charging, and (3) hardware and software that decrease the costs of or avoid updates to infrastructure, including load management software or outlet splitting. Such limits are not consistent with broader CARB objectives and may contribute to confusion. For example: because VGI projects are found only on the "Other Holdback (aka non-equity)" list of projects in the proposed draft language, the proposed amendment, if adopted, would not authorize the IOUs to use LCFS funds to support a VGI program that could minimize charging costs for a low-income EV driver or equity
178.6 communities.

SCE therefore supports the "one list" approach that a CalETC and the other IOUs' shared with CARB staff. CalETC's proposal proposes to authorize the IOUs to use LCFS holdback funds for any pre-approved LCFS Holdback projects for all types of customers and communities. To meet the proposed equity spending requirements, SCE supports a proposal to require the utilities to demonstrate that they distributed the funds to one of the defined underserved individuals or communities (*e.g.*, rebates issued as part of an income-qualified program, or public charging stations installed in a rural community, etc.). This streamlined approach enables utilities to deploy any of the projects and solutions when and where they are best for their service areas, while maintaining the requirement for utilities to direct funding to equity-focused activities.

II. CARB Should Specify that Utilities Have Discretion to Select the Most Appropriate Holdback Program Option(s) for their Customers and Require the Large IOUs to Fund At Least Three Program Options

California has a diverse mix of electric utilities, with differing customer needs and requirements.
178.7 There are the large IOUs, like SCE, and smaller publicly owned utilities that serve customers across the state. Because individual utilities will have different needs and require different solutions to ensure an affordable and equitable transition to electrified transportation for their

[1] Proposed Amendments to LCFS Regulation, § 95483(c)(1)(A)(5)(a)
[2] Proposed Amendments to LCFS Regulation, § 95483(c)(1)(A)(5)(b)

178.7 cont customers, CARB should update the LCFS Regulation's *Restrictions on Use of Holdback Credits* section[3] to clarify that CARB does not require or prefer any particular program option, so long as the large IOUs use LCFS credit revenues for multiple categories to support their diverse customer classes.

Specifically, SCE requests that CARB's final amendment clearly state that "utilities have discretion to select the most appropriate Holdback program option(s) for their customers, within the established requirements." Additionally, the regulation should require the "large IOUs to use their Holdback credit revenues to fund a minimum of three program options." Using funding for at least three program options will ensure that the IOUs meet diverse customer needs.

III. CARB Should Retain the 10% Administrative Cost Cap for Holdback Programs Because 5% Is Insufficient

178.8 The Proposed Amendments propose to reduce the allowed administrative costs on utility Holdback programs from 10% of total portfolio costs to 5%. This reduction in allowable administrative costs on utility Holdback programs will make it extremely difficult, if not impossible, to administer these programs given that these programs are designed to reach the most underserved individuals and communities. As Table 2 below shows, while SCE was able to operate its Clean Fuel Reward Program (CFRP) Rebate in years 2017-2020 with administrative costs at 5% or below, the moment SCE converted its program to a used EV rebate program with a targeted low-income rebate in 2021, SCE's administrative costs nearly tripled. While some of the 14% administrative cost in 2021 is the product of a combination of close-out costs from CFRP and launch costs from SCE's Pre-Owned EV Rebate (POEV), it required just under 11% administrative costs to implement POEV in 2022.

Table 2: SCE's LCFS Holdback Program Administrative Costs over Time

	2017	2018	2019	2020	2021	2022
Administrative Costs	$461,428	$339,590	$489,074	$1,678,204	$1,091,169	$1,002,251
Total LCFS	$10,554,478	$14,881,205	$28,876,538	$32,210,342	$8,037,704	$9,274,919
Administrative % of Total	4%	2%	2%	5%	14%	11%

SCE files the data in Table 2, which is public, in April of each year with both CARB and the California Public Utilities Commission (CPUC). While SCE has not compiled its calendar 2023 report, the administrative costs for SCE's LCFS Holdback programs from Q1-Q3 of 2023 were 8-9%. The targeted requirements of utility Holdback programs necessarily make them more expensive to operate than broad, unrestricted incentive programs. Thus, CARB should reject the Proposed Amendment's 5% cap and instead retain the 10% allowable administrative costs for utility Holdback programs, as authorized in the current version of the LCFS Regulation.

[3] Proposed Amendments to LCFS Regulation, § 95483(c)(1)(A)(5)(a -b).

IV. CARB Should Align the Administrative Cost Cap for the Statewide Clean Fuel Reward Program with Other Large Utility Incentive Programs

As the Program Administrator for the statewide Clean Fuel Reward Program since 2019, SCE can attest that not only is reducing the allowable administrative costs on the statewide Clean Fuel Reward from 10% to 5% an impediment to operating the program, but also does not comport to cost controls on other large utility programs. For example, the IOUs energy efficiency program portfolios, which have administered billions of dollars of incentive funds throughout the state with oversight from the CPUC, are operated under guidelines established in the Energy Efficiency Policy Manual (Version 6 published in April 2020 at this link). As shown in Table 3 below, Appendix C of the Energy Efficiency Policy Manual lists the cost caps (hard requirements) and targets that the CPUC established for the operations of these programs.

178.9

Table 3: Energy Efficiency Policy Manual APPENDIX C Cost Category Caps

Budget Categories	**Cap**	**Target**
Utility program administrative costs	10%	
Third-party / Gov't partnership administrative costs		10%
Marketing & outreach costs		6%
Direct implementation non-incentive (DINI) costs		20%
Evaluation, measurement & verification (EM&V) costs	4%	

In addition to being separate from ME&O costs, administrative costs, as defined in the Energy Efficiency Policy Manual, explicitly exclude third party implementer fees, ME&O costs, and also exclude *direct implementation non-incentive (DINI) costs* (which include activities such as software licenses, rebate processing, contractor training, etc.). By comparison, the Statewide Clean Fuel Reward program currently counts *all* of these costs towards its 10% Administrative and ME&O cost cap.

When the CPUC authorized SCE to administer the Statewide Clean Fuel Reward program in Resolution E-5015, it found that "A 10% cap of administrative funds is generally within the range of spending for other customer programs the utilities implement," and ordered SCE to "administer no more than 10% of the total Clean Fuel Reward program budget on administrative and marketing, education, & outreach spending, which must include all administrative spending related to the Clean Fuel Rewards program."

A 10% administrative cap on utility LCFS programs aligns utility LCFS programs with other similar utility programs and ensures the programs can operate as effectively as they will need to in order to help the state achieve its ambitious transportation electrification objectives.

V. CARB Should Update Vehicle Eligibility for the Statewide Clean Fuel Reward Program to Conform to CARB's Goals

178.10 SCE, as the Program Administrator for the statewide Clean Fuel Reward Program, supports CARB's proposed amendments to transition the statewide program from an incentive for all new passenger EVs to one that will support the adoption of electric MDHD vehicles in the coming decade. However, it is necessary that CARB make minor changes to the vehicle eligibility in the draft amendments to ensure that that next iteration of the program can effectively implement CARB's ambitious plans for the commercial vehicle sector.

178.11 For example: in *Appendix E: Purpose and Rationale of Proposed Amendments for the Low Carbon Fuel Standard Requirements,* CARB Staff states that the "Clean Fuel Reward will change from a universal new light-duty EV rebate to be focused on new and used rebates for medium- and heavy-duty trucks" because this " will jumpstart the transition for a harder to transition segment." However, the draft amendments define the Clean Fuel Reward as "a statewide program established by EDUs to provide a reduction in price on purchases or leases for new medium- or heavy-duty electric vehicles." SCE believes that CARB unintentionally omitted the word "used" from the draft amendments and recommends CARB add it to the final language.

178.12 Additionally, the definitions for *medium-or-heavy duty vehicle* in the draft amendments need updating to align with CARB's intentions. While CARB defines medium-duty vehicle in the Definitions and Acronyms as "MDV means a vehicle that is rated between 8,501 and 14,000 pounds GVWR," there is no accompanying definition for HDV, though HDV is reference in several locations throughout the Regulation as the acronym for *heavy-duty* vehicle. CARB should add the weight classification for completeness.

178.13 More significantly, that the combination of defining MDV and HDV solely by weight class and the proposed definition of the Clean Fuel Reward as "a statewide program established by EDUs to provide a reduction in price on purchases or leases for new medium- or heavy-duty electric vehicles" means that the program may be required to provide incentives for *all* vehicles that have a GVWR greater than or equal to 8,501, which includes many passenger vehicles such as the Rivian line of products, the extended range Ford F-150 Lightning, the electric Chevrolet Silverado, and the electric Hummer. Based on CARB Staff's published rationale, the Clean Fuel Reward should only provide incentives for these vehicles if the purchaser obtained them for *commercial* use. This distinction is important not only for the goals of the Clean Fuel Reward, but also the operations of the program, as implementing a program that is accessible to all commercial customers plus a narrow segment of the retail (passenger vehicle) market would be administratively challenging. Therefore SCE, as the Clean Fuel Reward Program Administrator, recommends that CARB revise the definition for the Clean Fuel Reward program as follows:

> *"Clean Fuel Reward" is a statewide program established by EDUs to provide a reduction in price for new* ***and/or used commercial*** *electric vehicles, greater than or equal to 8,501 GVWR, that are not subject to the High Priority and Federal Fleets requirements as specified in, title 13, California Code of Regulations, section 2015(a)(1) in California. The Clean Fuel Reward is funded exclusively through LCFS proceeds generated by EDUs from electricity fuel.*

For the avoidance of doubt, SCE also recommends that CARB add *commercial vehicle* to the definitions in the LCFS Regulation now that the CCFR is explicitly incentivizing them. HVIP is an established and well understood definition that SCE recommends CARB adopt for the LCFS Regulation Definitions and Acronyms section:

> *"Commercial vehicle" for the purposes of this program means any vehicle used by a business, public or governmental agency, or non-profit to carry people, property, or hazardous materials.*

VI. CARB Should Reject the 1-Mile Requirement for Capacity Credits in Favor of Greater Flexibility

SCE commends Staff for including the new capacity crediting (FCI) provision for public and shared-private medium-duty and heavy-duty (MDHD) charging stations. The MDHD FCI provision is critical in assisting the deployment of these charging stations by allowing developers to recover a portion of their LCFS crediting potential while their utilization grows as the electric MDHD vehicle market matures. However, SCE is concerned that the requirement that these sites be located within one mile of an Alternative Fuel Corridor (AFC) creates incentives for developers to impose arbitrary constraints on the electric grid that may stall overall MDHD vehicle electrification.

178.14

An examination of SCE's public-facing Grid Needs Assessment (GNA) Load Capacity maps illustrates this point. In 2025, SCE expects to have a total of 12,921MW of carry capacity available on its system over a total of 4,285 circuits, with 75% of that carrying capacity located within one mile, and 95% of the capacity located within ten miles, of the AFC routes. However, MDHD charging stations are much larger than typical interconnection requests – usually greater than 5MW and often greater than 10MW. When applying this filter, only 36% of SCE's available circuit capacity is located withing one mile of AFC routes for circuits that can handle at least 5MW of additional load, and that value increases to only 45% when the radius is expanded to ten miles.

Because incentives drive market participant behavior, SCE is concerned that the strict geographic restrictions proposed in the draft amendments for MDHD FCI credits will cause developers to attempt to locate sites in areas that do not have immediately available circuit capacity. This scenario creates undue costs on SCE's ratepayers and delays the deployment of critical MDHD charging infrastructure that is necessary to achieve the state's decarbonization targets. For this reason, SCE recommends that CARB reject the 1-mile requirement and allow for greater flexibility in allowable locations for sites seeking to claim MDHD FCI credits.

Thank you for considering SCE's comments and recommendations.

Sincerely,

/s/ *Rosalie Barcinas*

Rosalie Barcinas

Director, Electrification & Customer
Services Policy, Regulatory Affairs Southern
California Edison

Comment Log Display

Here is the comment you selected to display.

Comment 188 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mark
Last Name	Neuburger
Email Address	mneuburger@counties.org
Affiliation	California State Association of Counties
Subject	California State Association of Counties (CSAC) - Letter of Concern
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6848-lcfs2024-AGNQJVExWGgBWFI+.pdf
Original File Name	CSAC Letter - CARB 2.20.24.pdf
Date and Time Comment Was Submitted	2024-02-20 09:39:36

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

California State Association of Counties®

February 20, 2024

California Air Resources Board
1001 Street
Sacramento, CA, 95814

Subject: Concerns on the proposed Low Carbon Fuel Standards Rulemaking

Dear Members of the California Air Resources Board:

On behalf of the California State Association of Counties (CSAC), representing all 58 counties in the state, I write to express concerns on the regulatory proposal by the California Air Resources Board (CARB) to regulate jet fuel under the Low Carbon Fuel Standard (LCFS) program.

CSAC is committed to environmental stewardship and recognizes airports' critical role in a balanced transportation system. We are proud of our county airports' advances towards reducing their carbon emissions. Although we recognize how these proposed regulations support the State's broader goals for sustainability and environmental protection, the proposal to regulate jet fuel usage presents several challenges that could disproportionately affect county airports. Many county airports are not equipped with the infrastructure necessary for Sustainable Aviation Fuel (SAF) and Jet A blending, nor do they have the financial resources to undertake such significant upgrades. Implementing these upgrades will negatively impact their operations and services, exposing them to be in violation of federally mandated grant assurances and Federal Aviation Administration (FAA) policy.

We recognize and appreciate California's leadership in adopting SAF. However, we are concerned that the proposed regulations do not account for the significant infrastructure upgrades required for SAF and Jet A blending, particularly at general aviation airports. The logistics of transportation and storage for SAF, which differ from conventional jet fuel, pose additional challenges. Implementing this proposal could impose substantial operational burdens on county airports, potentially disrupting the progress toward our state's sustainable aviation future.

179.1

County airports play a vital role in the state transportation system and support numerous ancillary industries, it is imperative to consider the operational implications of this regulation carefully, not to mention the risk of losing federal entitlement monies by being in violation of federal grant assurance policies. We must avoid creating an aviation environment within our State where regulatory compliance costs undermine the viability of county airports. County airports are a vital part of the transportation system and delivery of emergency fire services in communities across California.

We urge CARB to reconsider this proposal, given the unique circumstances of county general aviation airports. Instead of a one-size-fits-all approach, we advocate for a strategy that includes grants for infrastructure upgrades and a phased implementation plan that allows county airports to transition to SAF usage without compromising their federal obligations and operational or financial stability.

In conclusion, we respectfully request that CARB preserve the existing opt-in approach for SAF, collaborate with county airports to address the complexities of SAF integration and focus on realistic policies that facilitate a smooth transition to a greener aviation future in California.

Thank you for your attention to this critical matter.

Sincerely,

Mark Neuburger
Legislative Advocate
California State Association of Counties

Comment Log Display

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Comment 189 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Alexandria
Last Name	Reed
Email Address	alexandria.reed@gm.com
Affiliation	
Subject	Low Carbon Fuel Standard: 2024 Proposed Amendments
Comment	General Motors LLC (GM) appreciates the opportunity to offer comments on CARB's Low Carbon Fuel Standard (LCFS) Proposed Amendments for 2024. Please see the attachment.
Attachment	www.arb.ca.gov/lists/com-attach/6849-lcfs2024-AjBTZQQ3BGNWD1Vl.pdf
Original File Name	2024 02_CARB LCFS Regulatory Updates_GM FINAL.pdf
Date and Time Comment Was Submitted	2024-02-20 09:51:28

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

GENERAL MOTORS

February 20, 2024

Clerks' Office
California Air Resources Board
1001 I Street
Sacramento, CA 95814
(submitted electronically via https://ww2.arb.ca.gov/applications/public-comments)

RE: Low Carbon Fuel Standard: 2024 Proposed Amendments

General Motors LLC (GM) appreciates the opportunity to offer comments on CARB's Low Carbon Fuel Standard (LCFS) Proposed Amendments for 2024.

If you have any questions, please contact me at +1-202-775-5071.

Sincerely,

Hon. David Strickland
Vice President
Global Regulatory Affairs and
Transportation Technology Policy
General Motors LLC

EXECUTIVE SUMMARY

General Motors LLC ("GM"), headquartered in Detroit, MI, is a global automotive manufacturer committed to positively impacting the communities where its customers live and work. As of December 2023, GM employs roughly 163,000 employees, operates 120 facilities, delivers over 2 million vehicles annually, and works with more than 5,000 suppliers.[1]

GM is focused on advancing toward a zero emissions future that is inclusive and accessible to all.[2] Battery Electric Vehicles ("BEVs") are key enablers of our vision for a world with Zero Crashes, Zero Emissions, and Zero Congestion.[3] GM regularly reports on sustainability metrics,[4] and endeavors to track and report emissions inventory.[5] GM has set science-based targets consistent with the goals of the Paris Agreement to support this vision.[6]

GM appreciates the opportunity to provide its insight as a BEV manufacturer to CARB's Proposed Amendments to the Low Carbon Fuel Standard, particularly on aspects of the proposal related to EV charging. This proposal clearly signals CARB's intention to further pursue reductions in carbon-based fuel impacts to the environment by incentivizing BEV deployment lower carbon intensity electricity. GM generally supports CARB's proposed updates to the LCFS framework, with recommendations on specific aspects of the revised program.

GM supports CARB's framework proposal to tighten carbon intensity stringency, adopt an acceleration mechanism and introduce a step down in stringency for 2025.

The LCFS program is among the most successful regulatory programs, delivering significant reductions in carbon intensity of fossil fuels and promoting adoption of lower carbon intensive transportation modes. As such, the market is oversupplied with credits, thereby reducing their value and potential to reinvest in California's EV infrastructure development. CARB's plan to
180.1 increase stringency for the LCFS market will tighten market conditions, thereby bolstering the market and further decreasing carbon intensity in liquid fuels.

The proposed amendment to require a 30% reduction in carbon intensity benchmarks by 2030 is appropriate for market compliance conditions. Adding additional flexibility to the regulation with the adoption of a near-term step-down and an automatic acceleration mechanism will strengthen the LCFS market long-term. Using two credit market ratio signals as the triggers for the acceleration mechanism is appropriate to address the specific problem that the proposal is intended to address.

Credits generated from light-duty electric vehicles should be reinvested into the still developing light-duty electric vehicle market.

While California leads the US in EV sales having reached 25% market share, the EV transition is
180.2 far from complete. Substantial progress is needed to meet CARB's complementary regulatory

[1] https://www.gm.com/company/usa-operations
[2] https://news.gm.com/company/about-us
[3] *Id*.
[4] https://www.gmsustainability.com/esg-resources-and-downloads.html
[5] https://www.gmsustainability.com/data-center.html
[6] https://www.gmsustainability.com/_pdf/resources-and-downloads/GM_2021_SR.pdf (pages 11, 16-17)

180.2 cont programs, which will require 51% ZEV sales in 2028 leading to 100% by 2035 under Advanced Clean Cars II. Infrastructure access for light-duty vehicles must be addressed to achieve EV market growth to meet regulatory and climate expectations. Funding generated from residential EV credit generation should be directed to the light-duty EV market by investing in infrastructure deployment, vehicle incentives and public education.

GM recommends that CARB reinstate Clean Fuel Rewards for light-duty EV adopters. Light-duty EV adopters represent the best opportunity for reducing carbon intensive transportation applications, including the harder to transition used vehicle market. Residential light-duty EV charging funds the Clean Fuel Reward program and this program is highly incentivizing to light-duty EV purchasers as it is available at the time of purchase as an “on the hood” incentive. It is paramount that the Clean Fuel Reward program is mechanized reliable for light-duty vehicle purchasers. We urge CARB to reconsider its proposal to allocate the Clean Fuel Reward to medium and heavy duty electric vehicles.

GM looks forward to reviewing details on CARB’s proposal to add third-party verification provisions to electricity transaction types.
GM recognizes and supports provisions designed to enhance integrity of regulatory programs, while streamlining regulatory compliance and costs. Based on CARB’s proposed regulatory text, CARB’s expectation for how third-party verification should be managed for metered residential EV charging are unclear.

180.3

In §95500(c)(1) Applicability, entities submitting Quarterly Fuel Transaction Reports are expected to obtain the services of an accredited verification body, including required site visits. It would be ideal to understand CARB’s expectations for a “site” under this verification requirement, as this definition could be widely interpreted as it pertains to residential EV credit generation and may require considerations to address consumer privacy protections. Finally, third-party verifiers for regulatory programs tend to slow market conditions due to limited accreditors, at least in the near term. We look forward to working with CARB to come to a practical solution for both parties to demonstrate validity of EV residential charging events for the final amendment update.

INCORPORATION BY REFERENCE

180.4 GM contributed to the development of comments through the Alliance for Automotive Innovation and provides its support for the positions established therein.

CONCLUSION

GM supports CARB’s proposed framework for the 2024 updates to the low carbon fuel standard. As a one of the key stakeholders in low carbon electricity within the LCFS program and its administration, GM would be glad to provide further support for any of the above topics and looks forward to continued collaboration on the development of the LCFS program.

Comment Log Display

Here is the comment you selected to display.

Comment 190 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jordan
Last Name	Garfinkle
Email Address	jordan.garfinkle@bloomenergy.com
Affiliation	Bloom Energy
Subject	Comments of Bloom Energy - Proposed Amendments to the Low Carbon Fuel Standard
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6850-lcfs2024-WzhSO1U5BzkGZQln.pdf
Original File Name	Comments of Bloom Energy_2.20.24.pdf
Date and Time Comment Was Submitted	2024-02-20 09:49:43

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Bloomenergy

February 20, 2024

Chair Liane Randolph and Members of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Comments of Bloom Energy - Proposed Amendments to the Low Carbon Fuel Standard

Dear Chair Randolph,

Bloom Energy appreciates the opportunity to submit comments in response to the December 19, 2023 Staff Report regarding proposed amendments to the Low Carbon Fuel Standard (LCFS). Acknowledging the complexity and far-reaching nature of the program, we thank the Air Resources Board for steady management over the years while balancing a broad range of interests and stakeholders.

Bloom Energy is a manufacturer of solid oxide fuel cell (SOFC) technology that utilizes an electro-chemical process to power non-combustion microgrids as well as high efficiency electrolyzer systems designed to convert renewable electricity into renewable "green hydrogen." Bloom Energy's solid oxide fuel cells and electrolyzers are designed in a modular fault-tolerant format that provides mission critical reliability with no downtime for maintenance. The company has installed over 1000 of its non-combustion solid oxide fuel cell systems for customers in thirteen U.S. states as well as in Japan, South Korea, India and Italy. Bloom Energy's emission reducing systems have proven resilient through outages caused by hurricanes, winter storms, earthquakes, forest fires, and other extreme weather and natural disasters.

Bloom Energy's modular design, high efficiency, and ability to utilize biogas without the significant upgrading required for pipeline injection, allows for smaller and remotely located biogas projects to make the most efficient use of this valuable form of renewable energy, producing more electricity for equivalent volumes of biogas than other available technologies. Its electrochemical process produces far fewer criteria pollutants than competing technologies that rely on combustion. Our SOFCs also require virtually no water during operation, mitigating water supply concerns in many areas across the country.

Based on our experience developing projects that consume or generate renewable fuels, we offer the following comments on a few key aspects of the proposal and Staff Report.

Avoided Methane Crediting

Bloom Energy does not support a phaseout of avoided emission credits for biogas to electricity projects, and commends CARB for recognizing the value of these projects by proposing to retain this aspect of the program.

181.1

Converting biogas into electricity through scalable, efficient, non-combustion technologies provides outsize environmental benefits by eliminating methane emissions and generating reliable clean, firm, renewable electricity. As a short-lived climate pollutant and potent greenhouse gas, methane is a core contributor to climate change and often a difficult pollutant to mitigate. Phasing out avoided methane credits would have the unintended consequence of leaving small or remote methane sources

Bloom Energy Corporation
4353 North First Street, San Jose, CA 95134
408 543 1500
www.bloomenergy.com

181.1 cont undeveloped, creating stranded resources that emit methane with no mitigation options. Because small or remote farms or digesters are not biomethane project candidates due to their size and distance from pipelines for injection, in many cases biogas-to-electricity is the only viable option for emissions reductions. In addition, non-combustion biogas-to-electricity projects that supply EV chargers directly serve CARB's goal of improving air quality by reducing vehicle tailpipe emissions through increasing market penetration of Zero Emission Vehicles (ZEVs). As noted in the Staff Report, "[r]educing criteria pollutants and toxic emissions from fuel combustion in line with California's air quality goals requires deploying ZEVs and ensuring the availability of fueling infrastructure to support ZEV deployment."[1] Supporting extremely low carbon intensity (CI) renewable energy to power ZEVs serves both climate and local air quality objectives.

As highly efficient, non-combustion and modular electricity generation systems, fuel cells meet the needs of these small/remote sources. Developing biogas to electricity projects in these locations would deliver critical methane reductions and valuable clean, firm electricity that can be delivered to meet transportation energy demand around the clock. Avoided methane credits are critical to leveraging these resources and developing such projects. And the carbon benefits are not just theoretical; as of this writing, Bloom has three operational non-combustion solid oxide fuel cell biogas-to-electricity projects operational at dairy farms in California. The first project, located in Kerman, CA, received a CARB-certified CI score of -790, the lowest CI score in the history of the LCFS program.[2]

Book-and-Claim

181.2 Currently, biogas-to-electricity projects under the LCFS must physically wheel the power into California, while RNG projects may be located anywhere in North America and utilize book-and-claim accounting to demonstrate use for LCFS compliance. We acknowledge CARB's proposal to limit book-and-claim accounting for RNG starting in 2040 but that is a long time away. We believe that the most efficient, cost-effective way to ensure that the LCFS program enables the most beneficial projects is to maintain a level playing field for pathways that rely on the same feedstock. A major step towards aligning requirements for projects with the same feedstock, and unlocking the untapped emissions reductions of biogas-to-electricity, would be to allow such projects to utilize book-and-claim accounting anywhere in the Western Electricity Coordinating Council (WECC), as is already the case in Oregon under their Clean Fuels Program. This, coupled with the proposed sunset for national book and claim available for RNG projects, would eventually result in regulatory consistency for projects with the same feedstock.

181.3 Additionally, Bloom recommends changes that allow biogas-to-electricity projects to qualify when electricity generation and biogas production are not co-located. This is in-line with the California RPS's treatment of "directed biogas" and allows greater project penetration by supporting optimal siting of both the RNG source and the electricity generator rather than requiring co-location. Specifically, where electricity generation is used for on-site EV charging, the project should be permitted to utilize directed biomethane as a power generation fuel provided that the biogas source and the electricity generator are located within the WECC. This additional flexibility would allow many more biogas to electricity projects to participate and would provide for greater deployment of biomethane-fueled microgrids at EV charging stations, which, as noted above, would further CARB's efforts to promote vehicles with zero tailpipe emissions. Of course, this would also bolster California's efforts to address the significant grid capacity

[1] California Air Resources Board. *Public Hearing to Consider the Proposed Amendments to the Low Carbon Fuel Standard*, *Staff Report: Initial Statement of Reasons*. December 19, 2023.
[2] Application No. B0490, available at: https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0490_cover.pdf

issues associated with large scale deployment of charging infrastructure across the State by enabling renewable generation to be deployed where it is most needed, rather than where the fuel is generated.

Consideration of Total Environmental Impact

Furthermore, Bloom Energy encourages CARB to reward market participants in the LCFS Program for achieving environmental results beyond carbon reductions. Environmental benefits such as reduced criteria air pollutant emissions in particular warrant consideration as part of the calculation methodology.

181.4 An increasing body of research has found the economic and health benefits associated with reducing NOx and PM emissions often exceed the economic and health benefits of reducing GHG emissions on a per ton basis.[3] Currently, while biogas combustion narrowly serves LCFS program objectives, the associated air pollution runs counter to CARB's broader new and long-standing air quality goals. Alternatively, non-combustion biogas-to-electricity projects meet LCFS objectives while also reducing local air pollution and furthering air quality objectives.

Over the past several years, research has shown that local combustion-related air pollutants are far more harmful to human health and the environment than previously understood. Some key findings that demonstrate the need for clean energy programs to value these impacts include:

- Combustion related air pollution may be as harmful to human lungs as smoking cigarettes;[4]
- Combustion related air pollution increases preterm birth risk;[5]
- Particulate matter (PM) is the largest environmental health risk factor in the nation, and the resulting health impacts are borne disproportionately by disadvantaged communities.[6]

This information is not new to CARB. In fact, the benefits of reduced criteria pollutant emissions are well documented in the Staff Report. To the extent that the proposed amendments do already reduce these emissions, the report states, "[t]he total statewide health benefits derived from criteria emissions reductions is estimated to be approximately $5 billion, with $4.9 billion resulting from reduced premature cardiopulmonary mortality and $85 million resulting the reductions in other adverse health impacts."[7]

The following table shows the different environmental impacts of non-combustion via a solid oxide fuel cell versus combustion uses of biogas.

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[3] Institute for Policy Integrity, New York University School of Law, "*How States Can Value Pollution Reductions from Distributed Energy Resources*" July 2018 available at https://policyintegrity.org/publications/detail/how-states-can-value-pollution-reductions-from-distributed-energy-resources

[4] Wang M, Aaron CP, Madrigano J, et al. *"Association Between Long-term Exposure to Ambient Air Pollution and Change in Quantitatively Assessed Emphysema and Lung Function." JAMA.* 2019;322(6):546–556. doi:10.1001/jama.2019.10255 Aubrey, Allison. Air Pollution May Be As Harmful To Your Lungs As Smoking Cigarettes, Study Finds. NPR. 13 August 2019. https://www.npr.org/sections/health-shots/2019/08/13/750581235/air-pollution-may-be-as-harmful-to-your-lungs-as-smoking-cigarettes-study-finds

[5] Mendola, P. et al. *"Air pollution and preterm birth: Do air pollution changes over time influence risk in consecutive pregnancies among low-risk women?"* International Journal of Environmental Research and Public Health, 2019. https://pubmed.ncbi.nlm.nih.gov/31547235/

[6] Tessum et al. *"Inequity in consumption of goods and services adds to racial–ethnic disparities in air pollution exposure." PNAS March 26*, 2019 116 (13) 6001-6006; first published March 11, 2019 https://doi.org/10.1073/pnas.1818859116

[7] California Air Resources Board. *Public Hearing to Consider the Proposed Amendments to the Low Carbon Fuel Standard*, *Staff Report: Initial Statement of Reasons*. December 19, 2023.

Table 1: Comparison of NO_x and SO_2 Emissions

	g/MMBtu		
	Non-combustion SOFC[1]	**Engine[2]**	**% reduction**
NO_x	0.402	385.55	99.9%
SO_2	0.00039	0.27	99.8%

1. From source testing
2. AP-42 Chapter 3 Section 2 for 2SLB engines

58,000 MMBtu/year of biogas equates to roughly a 1 MW Bloom solid oxide fuel cell system, or 7,900 MWh/year. Using the emissions factors above for an illustrative biogas-to-electricity project and utilizing the corresponding emissions for EPA's Co-Benefits Risk Assessment Health Impacts Screening and Mapping Tool (COBRA),[8] results in $1.3 to $3M of air quality driven health benefits for non-combustion fuel cell over combustion-based generation or flaring. The illustrative 1 MW Bloom project in the above example emits roughly 3,000 MT CO_2e/yr. At the midpoint of the COBRA health benefits calculation ($2.4M), the additional air quality-driven health benefits of the project equate to roughly $800/MT. While the LCFS credit market generally values carbon abatement at anywhere from ~$50 to ~$200/MT, it does not value air quality benefits at all.

In order to value these significant benefits, Bloom strongly encourages CARB to include a mechanism that appropriately considers criteria air pollutant emission reductions when evaluating electrical generation from biogas and natural gas, across all pathways. One possibility is to include an LCFS credit multiplier such that, when utilizing the same fuel, a project that does not exacerbate air quality issues generates more credits than one that does. Under this model, we recommend setting an emissions threshold of <0.1g/MWh NO_x and <0.01g/MWh SO_2, below which projects receive a credit multiplier of 1.5.[9] At current and expected LCFS credit prices, this results in far less additional value than the $800/MT shown above and would be a modest but direct acknowledgement of the societal benefits of improved air quality.

Tier 1 Calculator for Biogas-to-Electricity

For certain fuel pathways the LCFS currently provides Tier 1 CI calculators that help to streamline the application review and validation process. As part of the proposed amendments, Staff proposes to update the calculators to increase usability and further reduce administrative burden on applicants and agency staff. Additionally, the proposed amendments would create a new Tier 1 CI calculator for hydrogen. While
181.5 the Staff Report justifies the existing Tier I option due to extensive experience reviewing certain pathways,
no such claim can be made of hydrogen, which is relatively new and still emerging. This acknowledges the benefits of streamlining without risking the integrity of an existing and robust process.

Bloom supports both of these proposals and the Tier 1 calculators in general. Additionally, we respectfully request that a Tier 1 calculator or other streamlining option be made available for biogas-to-electricity projects. Given the fact that this option is already available for RNG, this would help to provide equal treatment for pathways dependent on the same feedstock.

[8] https://www.epa.gov/cobra

[9] Note that the emission rates shown in Table 1 are represented in terms of grams per MMBtu.

GREET Model Treatment of CO2 Storage

With the emergence of various forms of above ground permanent CO_2 storage, such as manufacturing
181.6 products (including concrete, plastics, etc.) from captured CO_2, we encourage CARB to broaden the
definition of permanent CO_2 storage beyond the limited "underground" storage definition currently used.
This will incentivize more projects to capture and sequester CO_2, thus achieving even lower carbon
intensities and furthering CARB's goals of aggressive decarbonization of the transportation sector.

A Broader Clean Fuels Standard Will Support Industrial and Commercial Sector Decarbonization

Notwithstanding all of the above, Bloom Energy also wishes to point out that a broader Clean Fuels Standard is necessary to support industrial and commercial sector decarbonization. These sectors have proven hard-to-decarbonize and remain a significant source of GHG emissions that must be addressed to achieve the State's carbon neutrality goals. As the adopted 2022 Scoping Plan recognizes, changes in fuel use are also critical to reducing GHG emissions from these sectors and biomethane use in these sectors is critical to meeting both 2030 and 2045 Scoping Plan goals.

CARB could and should expand the LCFS program outside of transportation or use the LCFS program as an
example to develop and adopt a broader Clean Fuels Standard that would complement the LCFS. Such a
standard could impose a decreasing, rate-based target on regulated entities, allowing these sectors to
achieve emission reductions in a technology neutral manner by choosing between electrification,
procuring low- and zero-carbon and carbon-negative fuels, and/or improving energy efficiency. Such a
181.7 standard would achieve significant reductions at least cost by enabling compliance flexibilities and
harnessing technological innovation. The current LCFS program is providing critical support to the RNG
market. Because a significant amount of RNG usage today is occurring in the transportation sector, the
LCFS program holds continued importance as the State explores opportunities to incentivize RNG use in
other sectors. Competitive pricing and availability of supply will be critical when looking to expand RNG
usage to other hard-to-abate sectors. For these reasons, Bloom Energy continues to recommend that
discussions about the potential expansion of LCFS or the potential development of a broader standard
should happen in parallel with ongoing support provided to the RNG market through the current LCFS.

Bloom Energy appreciates the opportunity to provide comment on this important proceeding. Please do not hesitate to contact the undersigned if we can provide additional information. We look forward to further engagement as stakeholders collaborate to strengthen the LCFS program.

Sincerely,

/S/Jordan Garfinkle

Jordan Garfinkle
Senior Manager, Policy
Bloom Energy Corporation

jordan.garfinkle@bloomenergy.com
www.bloomenergy.com

Comment Log Display

Here is the comment you selected to display.

Comment 191 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Krysta
Last Name	Wanner
Email Address	krysta@westernpga.org
Affiliation	Western Propane Gas Association
Subject	LCFS Proposed Amendments
Comment	Please see attached letter.
Attachment	www.arb.ca.gov/lists/com-attach/6851-lcfs2024-Am4HYlE2BCQAWQdr.pdf
Original File Name	LCFS Letter 2.20.2024 WPGA.pdf
Date and Time Comment Was Submitted	2024-02-20 10:01:27

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

WPGA®
WESTERN PROPANE GAS ASSOCIATION

1107 9TH ST, SUITE 540, SACRAMENTO, CA 95814
P: (916) 447-9742 | F: (916) 447-9740
WESTERNPGA.ORG | USECALIFORNIAPROPANE.COM

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814
VIA ONLINE SUBMISSION

RE: Low Carbon Fuel Standard Potential Amendments

The Western Propane Gas Association (WPGA) is pleased to submit its comments in response to the Low Carbon Fuel Standard (LCFS) proposed amendments. Aligned with our recent meeting with CARB staff on February 1, 2024, the focus of our letter is on the value of renewable propane as an eligible fuel for LCFS.

As mentioned in our previous letters, we would like to thank CARB staff for recognizing the value of renewable propane in decarbonizing "hard-to-electrify" segments of California, and for justly calculating a lower Carbon Intensity (CI) of conventional propane under the GREET4.0 proposed model (Lookup Table Pathways, Pg 24)[1].

<u>CORRECTING CI OF CONVENTIONAL PROPANE IN GREET MODEL</u>
However, WPGA also supports adjusting the baseline CI for propane further based upon corrected assumptions and modeling. Please see our letter submitted on April 29, 2023[2] for detailed CI calculations.

In short, WPGA proposes that CARB update its modelling of the CI for conventional propane within the lookup table to result in **80.06 gCO2eq/MJ** due to corrections on:

182.1
- Upstream combustion emissions – from a CI of 64.84 to 64.58 (determined by existing GREET 2021 model updates for school buses),
- Assumptions regarding refining source – from 75% oil/25% natural gas mixture for conventional propane to 59.5% oil/40.5% natural gas within California per Argonne National Laboratory reporting[3], and
- Transport distance for delivery – fewer than 100 miles traveled for final delivery, based upon industry reporting and best practices.

<u>AIR & WATER QUALITY BENEFITS OF TRANSITIONING TO PROPANE</u>
The current CI of renewable propane ranges from half- to one-quarter of the CI of California's current electric grid – and new sources keep going lower still. Like traditional propane, renewable propane has no methane and therefore does not suffer leakage issues or fugitive GHG emissions like natural gas. Likewise, it does not run the risk of groundwater or soil intrusion from spills like liquid fuels or degrading electronic waste, such as batteries or solar panels.

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[1] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/lut_update_2023_2.pdf
[2] WPGA, Comment Letter, RE: GREET4.0 – Propane Carbon Intensity Calculation, Submitted to CARB April 29, 2023
[3] Backes, S. E., Beath, J., Sebastian, B., & Hawkins, T. R. (2020, September). Sources of Propane Consumed in California. Chicago; Argonne National Laboratory.

There would be a significant air quality benefit to transitioning from fuels with significant air emissions like CARBOB (California gasoline blend), natural gas, and diesel to the no-SOx, no-black-carbon, and ultra-low-NOx solution of renewable propane. To meet 2022 Scoping Plan goals and other emission reduction mandates such as the State Implementation Plan (SIP), renewable propane serves as the bridge fuel to meet timeline goals in fuel sectors where using electric technology is not yet affordable nor feasible. It is the perfect fuel for hard to decarbonize areas and sectors of the state, like off-road and heavy-duty transportation. Renewable propane can be prioritized in underserved communities where electric infrastructure is not afforded to them or where service is intermittent due to power shutoffs or natural disasters.

TRANSPORTATION EMISSIONS AND BOOK & CLAIM

Acknowledging that the transportation of fuel is included in the CI, ideally renewable propane production would be in California. There are already facilities in the state producing renewable propane, with additional sources coming rapidly online. One of them is Global Clean Energy, which utilizes the energy-rich cover crop camelina seed; currently qualified as an LCFS compliant fuel. While many renewable diesel and sustainable aviation fuel (SAF) plants produce renewable propane, it is currently being utilized onsite to lower the CI of other existing LCFS-compliant fuels. This limits the amount of renewable propane on the market.

182.2 WPGA proposes that CARB apply its Book & Claim and avoided emissions reporting to renewable propane. While renewable propane is currently only deliverable in California by truck or rail, CARB, through amendments, has the capacity to generate enhanced distribution and use of renewable propane. Given renewable propane's low CI score, CARB could, through adopting its Book & Claim and avoided emissions framework, play an instrumental role in lowering the CI score in California and increasing production to offset fuels with larger air quality or GHG emissions footprints.

182.3 Similar to its provisions pathway for renewable biomethane, CARB could develop a provisional pathway for avoided emissions for renewable propane.

- One pathway would involve booking propane produced outside of California, and exchanged for renewable propane produced in California, allowing a lower CI score to and to avoid the added CI for transmission.
- A second proposed provisional pathway would account for reduced or nominal CI additions for renewable propane shipped by rail or truck, as renewable propane should not be excluded by a failure of useful infrastructure.

CARB has a unique potential to both stimulate renewable propane production and demand, while lowering CI scores and improving environmental justice communities, all by providing for Book & Claim and avoided emissions accounting for renewable propane. Through this process, CARB can ensure the best available fuel for particular communities and uses, while at the same time lowering the CI score of the fuel utilized.

STREAMLINE PATHWAY APPROVAL PROCESS FOR DELIVERY MODELS

Alongside Book & Claim efforts, there are other steps that CARB can take that would improve the supply and usage of renewable propane within California.

182.4 WPGA proposes that CARB adopt a streamlined approval process for the following additional delivery models of fuel:

1) Pathways that would incentivize production of electricity used in the charging of battery electric vehicles: Currently, renewable and conventional propane can be used in fast-

182.4 cont charging mobile or stationary applications to charge battery electric vehicles across many classes. Offering a streamlined pathway to incorporate the delivery of already-approved renewable propane to these charging applications is directly in line with existing LCFS intent and will provide greater reliability for electric vehicle charging networks within California.

2) Updated GREET model (and/or pathways) that incorporate the usage of renewable fuels or technologies within the transportation of renewable propane for delivery. In-state transportation emissions could further be reduced by using renewable propane to fuel the vehicles involved in transportation and delivery. WPGA is working with vendors to bring ultra-low-NOx renewable propane-powered Autogas vehicles to the California market to supplant diesel. CARB could create a streamlined process to incorporate those reductions in the CI of transportation within the CI of the fuel itself.

CONCLUSION

With approximately 15% of all propane used in transportation being renewable today, the industry has a goal of reaching 100% renewable propane across California's propane transportation market by 2035 or sooner. WPGA remains committed to transitioning its fuel within California and bringing additional resources to the non-transportation markets served by our members.

WPGA appreciates the opportunity to submit feedback on the LCFS potential amendments. We will continue engaging with CARB staff to support a path for the continued development of renewable propane.

Sincerely,

Krysta Wanner

Krysta Wanner
Manager of Government Affairs, WPGA
krysta@westernpga.org

Comment Log Display

Here is the comment you selected to display.

Comment 192 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Esabella
Last Name	Rojas
Email Address	erojas@lachamber.com
Affiliation	Los Angeles Area Chamber of Commerce
Subject	LAACC Opposition to Jet Fuel Proposal
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6852-lcfs2024-Uz9VMgZmBDQLbgVa.pdf
Original File Name	LAACC_ CARB Letter_.pdf
Date and Time Comment Was Submitted	2024-02-20 10:03:12

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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LOS ANGELES AREA
CHAMBER OF COMMERCE

February 13, 2024

Liane M. Randolph, Chair
California Air Resources Board
P.O. 2815
Sacramento, CA 95812

Re: Opposition to California Air Resources Board Proposal to Regulate Jet Fuel

Dear Board Chair Randolph,

The Los Angeles Area Chamber of Commerce is writing to share our serious concern and opposition to the recent California Air Resources Board (CARB) proposal to regulate jet fuel under its Low Carb Fuel Standard (LCFS) program.

The Los Angeles Area Chamber of Commerce represents the interests of a broad spectrum of organizations across the private, non-profit, academic and public sector, including the business community, job creators, and innovators in the Los Angeles region. Our mission is to design and advance opportunities and solutions for a thriving regional economy that is inclusive and globally competitive. As the oldest and largest business association in the region, the Chamber has a long standing history of convening business leaders, communities, and policy makers to promote a vibrant economy.

The U.S. airline industry plays a vital role in California's economy. Furthermore, the industry is committed to reducing its climate impact and achieving "net zero" carbon emissions by 2050. Transitioning to Sustainable Aviation Fuels (SAF) is core to this commitment, and the industry has pledged to work with governments and other stakeholders to make three billion gallons of SAF available in the United States by 2030. Achieving these goals requires new and additional policy incentives, streamlined permitting processes, and close collaboration among airlines, fuels industry, manufacturers, environmental organizations and governments, among others.

With respect to SAF, California has established itself as an early leader in attracting investment, production, and use of SAF through the existing Low Carbon Fuels Standard (LCFS) Program, which provides an opt-in credit for SAF that helps reduce the price difference between SAF and conventional jet fuel. This voluntary regulatory structure has been successful in enabling the growth of the SAF market in California and across the country. CA has the most viable market for SAF today in the United States and as airlines increase their demand for SAF the market continues to grow.

350 S. Bixel St. | Los Angeles, CA 90017 | P: 213.580.7500 | F: 213.580.7511 | lachamber.com

Aviation accounts for 2.6% of the US GHG emissions but 5% of US GDP and 4.1% of CA's GDP. There are 380 thousand employees of US Commercial aviation firms based in California, with an overall economic impact of $194 billion[1]. Aviation is critical to driving California's economy and it's rank as the 5th largest economy in the world, enabling $114 Billion in annual trade flows and underpinning the of many of the rest of California's biggest economic drivers such as agriculture, tourism, manufacturing, banking, technology and small business. Ensuring a healthy and vibrant aviation industry is essential to California's future, and leveraging CARB's early leadership on SAF can enable California leadership in the emerging SAF production industry, creating new jobs and economic development opportunities.

With this context, we express our serious concern with a new proposal by the California Air Resources Board (CARB) to regulate jet fuel as an obligated fuel under the LCFS Program. CARB's proposed changes to the LCFS program include a proposal to eliminate the existing exemption for conventional jet fuel use for flights within the state of California. This proposed change is unlikely to result in increased SAF production, availability, or use in California, but would lead to higher jet fuel prices. The primary impediment to increased SAF production and availability in California remains the higher cost of SAF for producers and buyers relative to conventional jet fuel and renewable diesel. The CARB proposal would not meaningfully address this fundamental challenge and therefore unlikely to meaningfully increase SAF supply or use.

183.1 The proposal seeks to regulate jet fuel and reduce emissions from aviation, both of which are pre-empted under federal law a fact that CARB recognized when it exempted jet fuel in 2018.[2]. Aviation has unique circumstances, that go beyond considerations of interstate commerce, for the safe operation and maintenance of aircraft that the federal government has recognized in the EPA's Clean Air Act and the jurisdiction of the FAA. These statutory authorities establish clear and broad federal authority for regulating jet fuel and aircraft engine emissions that pre-empts California from regulating jet fuel under the LCFS program.

Moving forward with eliminating the fossil jet fuel exemption and implementation of a new obligation will likely result in litigation that will be lengthy, costly and do nothing to advance the mission of more SAF production and uplift. Engaging in litigation will divert resources from the state and the aviation industry that would be better spent enabling greater SAF production. Our mutual interest is to increase SAF production, availability, and use and the most effective way to accomplish this is to continue the positive,

[1] The Economic Impact of Civil Aviation on the U.S. Economy, State Supplement, US Department of Transportation, November 2020

[2] CARB stated that "[s]ubjecting aircraft fuels to annual carbon intensity standards would raise federal preemption issues" *available at* https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/isor.pdf?_ga=2.259407882.1202437490.1641231788-253234234.1573227006

collaborative approach represented by the existing “opt-in” mechanism developed by CARB and the aviation community.

Based on these considerations, we urge CARB to reconsider and withdraw the proposal to remove the exemption for jet fuel for intrastate flights and instead preserve the existing opt-in approach for SAF and partner with the aviation sector and stakeholders across the emerging SAF ecosystem on new policies and approaches to rapidly increase the availability of SAF in California. We urge CARB to focus on the ultimate goal – how to get more SAF into planes in California by reducing barriers to production, availability and use.

For more information, please contact Elissa Diaz at ediaz@lachamber.com.

Sincerely,

Maria S. Salinas

Maria S. Salinas
President & CEO

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Here is the comment you selected to display.

Comment 193 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Lisa
Last Name	Whelan
Email Address	lisa@iowacci.org
Affiliation	Iowa Citizens for Community Improvement
Subject	Reform the LCFS

Comment

Iowa Citizens for Community Improvement urges the Air Reso
Board to grant the recent Petition for Rulemaking to Exclude All Fuels Derived from Biomethane from Dairy and Swine Manure and amer the LCFS accordingly. Iowa CCI is a statewide organization with a communication base of 15,000 everyday Iowans working to win socia environmental, economic and racial justice. We want to reform our food and farm systems to work for farmers, workers, eaters, and tl planet. Amending the LCFS to exclude fuels from methane captured from factory farms is an important step toward this critical reform.

The current flaws in the LCFS, such as "avoided methane cı and inaccurate life cycle assessments, not only enable pollution but disproportionately harm low-income communities and communitie of color. Factory farms, predominantly situated in these marginalized areas, inflict severe damage on air, water, public health, rural economies, and overall quality of life.

We urge you to consider and prioritize the following refo the LCFS:

1. Eliminate "avoided methane crediting" in 2024.
2. Address inaccuracies in the Life Cycle Assessment that ignore associated up and downstream greenhouse gas emissions from factor farm gas production.
3. Remove the 10-year "grace period" for factory farm gas producers.
4. Stop double counting by allowing factory farm gas projects pai for and claimed by other programs to sell LCFS credits as well.

We are extremely concerned that the LCFS, which the ARB a with the intention to reduce greenhouse gases from California transportation fuels, will perversely incentivize more and larger hog and dairy confinements in Iowa. Over the last several decades the number of permitted livestock facilities has increased dramatically from 722 (93% hog) in 2001 to over 10,000 in 2017. Bu recently, the Iowa legislature exempted confinement operations fr a permitting requirement for operations greater than 8,500 animal units if an operation installs an anaerobic digester system to capture biogas. The Cedar Rapids Gazette reports that nine Iowa dairies have applied for permits for anaerobic digesters, seven a expanding herd sizes as part of the process, and two are utilizin the exemption because their herd sizes will exceed 8,500 animal units.

The LCFS program has drawn significant interest from fact in California and other states with many factory farms taking advantage of lucrative LCFS credits. We do not want to see your transportation fuel policy entrench and enrich corporations like Iowa Select, Smithfield, Tyson, JBS, and Prestage Farms at the expense of our communities, land, air, and water. Even worse, we are extremely concerned that the value of LCFS credits for biomethane from hog and dairy waste will incentivize expansions a even more confinement operations. Right now, Iowa agricultural runoff is contributing approximately 30 percent of the nitrogen load feeding the Gulf Dead Zone off the coast of Louisiana, and that amount has been increasing. And this runoff is polluting ou drinking water as well. Turning Iowa factory farms into sources credits to offset California transportation fuel emissions will inevitably generate more incentives to increase more manure which will further degrade our communities and water quality.

We hope that you recognize the consequences that your pol choice has inflicted and will inflict. We urge you to amend the LCFS to stop utilizing out-of-state factory farms as a source of offsets for your pollution trading scheme. We also ask that, at a minimum, you amend the LCFS to correct the over-valuation of manure-based credits to include all climate pollution associated with the factory farm system and ensure that credits from non-additional reductions do not continue.

Instead of pitting our states and residents against each should be working together to implement real solutions that prote our communities, our farmers, our workers, and our planet. Thank you for considering these comments.

Attachment	www.arb.ca.gov/lists/com-attach/6853-lcfs2024-UGJWYFxvBGMFLQQ2.docx
Original File Name	2024.2.20 CCI comment letter - CA LCFS.docx

Date and Time Comment Was Submitted	2024-02-20 10:06:31

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Iowa Citizens for Community Improvement
We talk. We act. We get it done.

2001 Forest Avenue
Des Moines, IA 50311
Ph 515-282-0484
www.iowacci.org
Facebook/iowacci

To: California Air Resources Board
1001 I Street
Sacramento, CA 95814

From: Lisa Whelan, Iowa CCI Executive Director on behalf of Iowa CCI members

Date: February 20, 2024

Re: Reform the LCFS

184.1 Iowa Citizens for Community Improvement urges the Air Resources Board to grant the recent Petition for Rulemaking to Exclude All Fuels Derived from Biomethane from Dairy and Swine Manure and amend the LCFS accordingly. Iowa CCI is a statewide organization with a communication base of 15,000 everyday Iowans working to win social, environmental, economic and racial justice. We want to reform our food and farm systems to work for farmers, workers, eaters, and the planet. Amending the LCFS to exclude fuels from methane captured from factory farms is an important step toward this critical reform.

The current flaws in the LCFS, such as “avoided methane crediting” and inaccurate life cycle assessments, not only enable pollution but disproportionately harm low-income communities and communities of color. Factory farms, predominantly situated in these marginalized areas, inflict severe damage on air, water, public health, rural economies, and overall quality of life.

I urge you to consider and prioritize the following reforms to the LCFS:

184.2 1. Eliminate "avoided methane crediting" in 2024.
184.3 2. Address inaccuracies in the Life Cycle Assessment that ignore associated up and downstream greenhouse gas emissions from factory farm gas production.
184.4 3. Remove the 10-year "grace period" for factory farm gas producers.
184.5 4. Stop double counting by allowing factory farm gas projects paid for and claimed by other programs to sell LCFS credits as well.

184.6 We are extremely concerned that the LCFS, which the ARB adopted with the intention to reduce greenhouse gases from California transportation fuels, will perversely incentivize more and larger hog and dairy confinements in Iowa. Over the last several decades, the number of permitted livestock facilities has increased dramatically from 722 (93% hog) in 2001 to over 10,000 in 2017. But recently, the Iowa legislature exempted confinement operations from a permitting requirement for operations greater than 8,500 animal units if an operation installs an anaerobic digester system to capture biogas.[1]

[1] Iowa Code § 459.206(2)(c).

184.6 cont The Cedar Rapids Gazette reports that nine Iowa dairies have applied for permits for anaerobic digesters, seven are expanding herd sizes as part of the process, and two are utilizing the exemption because their herd sizes will exceed 8,500 animal units.[2]

The LCFS program has drawn significant interest from factory farms in California and other states with many factory farms taking advantage of lucrative LCFS credits. We do not want to see your transportation fuel policy entrench and enrich corporations like Iowa Select, Smithfield, Tyson, JBS, and Prestage Farms at the expense of our communities, land, air, and water. Even worse, we are extremely
184.6 concerned that the value of LCFS credits for biomethane from hog and dairy waste will incentivize expansions and even more confinement operations. Right now, Iowa agricultural runoff is contributing approximately 30 percent of the nitrogen load feeding the Gulf Dead Zone off the coast of Louisiana, and that amount has been increasing.[3] And this runoff is polluting our drinking water as well.[4] Turning Iowa factory farms into sources of credits to offset California transportation fuel emissions will inevitably generate more incentives to increase more manure which will further degrade our communities and water quality.

We hope that you recognize the consequences that your policy choice has inflicted and will inflict. We urge you to amend the LCFS to stop utilizing out-of-state factory farms as a source of offsets for your pollution trading scheme. We also ask that, at a minimum, you amend the LCFS to correct the over-valuation of manure-based credits to include all climate pollution associated with the factory farm system and ensure that credits from non-additional reductions do not continue.

Instead of pitting our states and residents against each other, we should be working together to implement real solutions that protect our communities, our farmers, our workers, and our planet. Thank you for considering these comments.

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[2] Cedar Rapids Gazette, Nine Iowa dairies get digester permits since new law, seven plan expansion, December 3, 2021, available at https://www.thegazette.com/agriculture/nine-iowa-dairies-get-digester-permits-since-new-law-seven-plan-expansion/.

[3] Chris Jones, Grading on a Curve, May 6, 2021, available at https://cjones.iihr.uiowa.edu/blog/2021/05/grading-curve.

[4] Associated Press, Des Moines faces extreme measures to find clean water, July 4, 2021, available at https://apnews.com/article/des-moines-business-environment-and-nature-b7f1e431a601dfb6536452d743012948.

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Comment 194 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Lasse
Last Name	Moelgaard-Nielsen
Email Address	las@umwelt.energy
Affiliation	Umwelt Energy
Subject	Comments to Proposed Low Carbon Fuel Standard Amendments
Comment	Umwelt Energy appreciates the opportunity to provide feedback on the CARB's proposed amendments to the LCFS regulation. As detailed in the attached, our comments pertain to Section 95482(d)(2) of the LCFS.
Attachment	www.arb.ca.gov/lists/com-attach/6855-lcfs2024-Wy5ROlQiUGZXPVcj.pdf
Original File Name	Umwelt Energy - CARB LCFS Comments_signed 02.20.2024.pdf
Date and Time Comment Was Submitted	2024-02-20 10:13:05

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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VIA ELECTRONIC DELIVERY
Clerks' Office,
California Air Resources Board
1001 I Street,
Sacramento,
California 95814

UMWELT
energy

Umwelt Energy ApS
Bryghusgade 8, 3
1473 Copenhagen
Denmark

CVR/CNR: DK43722824
umwelt.energy

20 February 2024

Comments to Proposed Low Carbon Fuel Standard Amendments

Umwelt Energy ApS ("**Umwelt Energy**") appreciates the opportunity to provide feedback on the California Air Resources Board's ("**CARB**") proposed amendments to the Low Carbon Fuel Standard ("**LCFS**") regulation.

As detailed below, our comments pertain to Section 95482(d)(2) of the current LCFS regulation, which exempts ocean-going vessels from the LCFS.

In particular, these comments propose the basis for revisions to the regulatory text, so fuels for ocean-going vessels — as a minimum — are treated the same way as aviation fuels.

We believe revisions are warranted, as they would significantly incentivize the scale-up of Californian low-carbon fuels, which are regarded as the most promising pathway to decarbonize the maritime sector, a significant (indirect) contributor to California's emissions.

Umwelt respectfully requests that CARB include these proposed revisions in its forthcoming LCFS amendments.

➢ Background: Umwelt Energy

Umwelt Energy develops industrial-scale e-fuel projects in green industrial hubs that further the green energy transition by enabling deep decarbonization of hard-to-abate industries. We believe that addressing emissions from all sectors, including maritime shipping, is crucial to achieving California's ambitious climate goals.

Our projects combine renewable power generation, the production of green hydrogen via electrolysis, and e-fuel synthesis plants. Using proven technologies that can operate flexibly on-grid or off-grid, the e-fuels we produce include green methanol, ammonia, and kerosene, with off-takers primarily in the maritime and aviation sectors. In addition to serving as feedstock for e-fuels, our projects can help local communities by decarbonizing heavy Californian industry like the glass, steel, and cement[1], which are major contributors to in-state greenhouse gas ("**GHG**") emissions. Hence not only do our projects reduce emissions directly in California, but they also reduce California's GHG footprint outside the state.

➢ California as World-Leading on Climate ctions

"185.1" Umwelt Energy currently have projects in different stages of development in the US, with several projects specifically located in California. However, regulatory hurdles, including limitations within the LCFS, hinder our ability to contribute fully to the state's ambitious climate goals.

A critical shortcoming is the current exemption for ocean-going vessels from the LCFS. This exclusion undermines California's potential for comprehensive GHG reduction, considering the global shipping industry's 2-3% share of global emissions[2]. As California ascends to become the world's fourth-largest economy while simultaneously claiming the "*most ambitious set of climate goals*

[1] California's seven cement plants are major contributors to the state's greenhouse gas emissions, spewing out 7.8 million metric tons of carbon dioxide equivalent in 2019 alone. This accounts for a staggering 8.8% of all industrial sector emissions, highlighting the urgent need for cleaner alternatives in this critical industry (https://ww2.arb.ca.gov/events/second-workshop-sb-596-cement-sector-net-zero-emissions-strategy#:~:text=The%20seven%20cement%20plants%20currently,sector%20GHG%20emissions%20in%20California.)

[2] https://www.globalmaritimeforum.org/getting-to-zero-coalition

"185.1 cont." *of any jurisdiction in the world*[3] this inconsistency becomes particularly glaring.

Thousands of ships traverse the world's oceans, transporting goods to and from California, virtually all reliant on fossil fuels that generate significant GHG emissions. Overlooking these emissions, with their undeniable Californian footprint, is counterproductive. While the latest LCFS amendment addresses important areas, it fails to consider this major contributor to the state's climate challenge.

Therefore, we urge CARB to include ocean-going vessels within the LCFS scope. This crucial step would not only align with the state's climate goals but also incentivize the adoption of clean e-fuels in the maritime sector, ultimately contributing to a cleaner future for California and beyond.

"185.2"

➢ Low Carbon Fuels for the Maritime Sector

Ocean-going vessels are undeniable contributors to climate change and local air quality concerns, not just through their 2-3% share of global GHG emissions, but also by spewing significant air pollutants. While geographically, much of this occurs outside California's immediate jurisdiction, the impacts of climate change and degraded air quality transcend borders, significantly affecting the state.

Including ocean-going vessels within the LCFS presents a unique opportunity to leverage California's leadership role in environmental progress. Such a bold move would not only address a significant source of emissions directly linked to California's economy and environment, but also set a powerful precedent for stricter regulations on a global scale. This precedent could pave the way for the wider adoption of cleaner technologies and practices, driving meaningful change in a problem with undeniable global implications.

Furthermore, incorporating ocean-going vessels into the LCFS aligns with the rising tides of stricter regulations being implemented by both the European Union (EU) and the International Maritime Organization (IMO). By taking this step,

[3] https://ww2.arb.ca.gov/news/california-releases-final-2022-climate-scoping-plan-proposal

UMWELT energy

California would not only be leading by example but also aligning itself with the progressive efforts of these influential bodies, potentially accelerating the pace of positive change in the maritime sector.

As an example, bio-methanol and e-methanol hold significant potential as future shipping fuels. They have emerged as a major pathway for achieving maritime decarbonization goals and offer one of the most promising solutions for reducing emissions in the marine industry.

Methanol is an organic chemical used in various products and as a fuel. When burned, it produces lower amounts of CO_2, particulate matter, and sulfur emissions compared to heavy fuel oil ("**HFO**") or marine gas oil ("**MGO**"). Naturally, CO_2 is emitted as well in the process (1.4 kilograms per kilogram of methanol versus 3.1 kilograms per kilogram of fuel oil[4]. However, as the bio-methanol and e-methanol is produced from captured biogenic or unavoidable CO_2, and for e-methanol, combined with green hydrogen generated from renewable electricity sources, these fuels ultimately represent carbon-neutral fuels.

Leading shipping companies, including A.P. Møller-Maersk, CMA CGM, COSCO, Methanex Waterfront Shipping, and Stena, have already chosen marine methanol as the near-term low carbon future fuel[5]. Therefore, California also needs to support the immediate development of a greener future for the maritime sector by making these low-carbon intensity fuels available at a competitive price. This can be achieved by including ocean-going vessels in the LCFS program.

Additionally, deploying bio-methanol and e-methanol as a marine fuel dramatically lowers emissions of sulfur oxides, nitrogen oxides, and particulate matter compared to HFO or MGO.

"185.3" ➢ Leveraging the Amendment to the Intrastate Aviation Fuel Precedent

[4] https://www.man-es.com/discover/methanol-fueled-ships
[5] https://www.methanol.org/wp-content/uploads/2023/05/Marine_Methanol_Report_Methanol_Institute_May_2023.pdf

The proposed amendment to include intrastate sustainable aviation fuel ("**SAF**") in the LCFS sets a crucial precedent for holding all transportation sectors accountable for emissions reduction. Exempting ocean-going vessels creates an inconsistency that undermines California's leadership in environmental action and sends a message of unequal treatment of GHG emitters.

Expanding the LCFS to encompass – as a bare minimum - intrastate marine fuels for ocean-going vessels demonstrates policy coherence and continuity. It builds upon the established framework for regulating intrastate fuel sources and sends a clear message of comprehensive decarbonization efforts across all transportation modes.

In addition, the 2028 start date for SAF LCFS regulation reflects anticipation of technological advancements and infrastructure development for cleaner fuels. Similarly, including ocean-going vessels in the LCFS incentivizes investments in low-carbon intensity fuel production and infrastructure, is alligned with expected advancements in the timeframe of technological advancements for low-carbon marine fuels.

"185.4"

- Benefit of including ocean-going vessels to section 95482(d)(2)

Incentives created by including ocean-going vessels to the LCFS could spur the development and adoption of clean technologies like bio-methanol and e-methanol, generating economic opportunities across the state of California. This shift away from fossil fuels wouldn't just benefit the environment, but also enhance the competitiveness of Californian fuel infrastructure, ports and shipping companies through their leadership in sustainability.

In addition, including ocean-going vessels in the LCFS creates a fair environment for players who invest in green technologies. Companies choosing cleaner fuels would gain a competitive edge in the global market, accelerating the transition towards a sustainable maritime industry, which ultimately reduce the climate impact on California.

"185.5" We must also address, that communities living near Californian ports and heavy industries suffer disproportionately from air pollution. By including ocean-going vessels in the LCFS, California can demonstrate its commitment to environmental justice, ensuring all communities benefit from cleaner air and a healthier environment.

As the world's fourth-largest economy with ambitious climate goals, California has a unique responsibility to address its maritime emissions. A phased approach starting with vessels operating within Californian waters can lay the groundwork for broader inclusion.

- Final Remarks

California can cement its global leadership in climate action by including ocean-going vessels in the LCFS. This bold step would not only address a significant source of emissions directly linked to the state, but also set a powerful precedent for stricter regulations, incentivize clean technologies, and ultimately contribute to a cleaner future for California.

- Align with ambitious climate goals: Including ocean-going vessels in LCFS aligns with California's commitment to tackling all sectors contributing to emissions.
- Leverage California's economic power: Incentivize investments in low-carbon fuels like bio-methanol and e-methanol, generating economic opportunities across the state and strengthening the competitiveness of California.
- Level the playing field: Create a fair environment for players who invest in clean technologies, accelerating the transition towards a sustainable maritime industry with tangible benefits for California's climate impact.
- Address environmental justice concerns: Protect communities disproportionately impacted by air pollution from ocean-going vessels and demonstrate California's commitment to environmental justice and ensuring cleaner air for all.
- Build upon existing framework: Leverage the precedent set by including amendments to intrastate SAF in the LCFS, demonstrating policy coherence and continuity toward comprehensive decarbonization.

Umwelt Energy stands ready to contribute to this critical initiative by developing low-carbon e-fuels projects for the maritime sector. We urge CARB to seize this opportunity to make a meaningful impact on California's future by including ocean-going vessels in the LCFS.

oooOOOooo

Thank you for your consideration of our comments. Please do not hesitate to contact me Lasse Moelgaard-Nielsen (las@umwelt.energy), if you have any questions.

I want to stress in closing that we would be pleased to meet or otherwise engage with your staff on any aspect of our comments.

Lasse Mølgaard-Nielsen
Lasse Moelgaard-Nielsen
Project Director, U.S
Umwelt Energy

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Comment 195 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Dean
Last Name	Taylor
Email Address	Dean@calETC.com
Affiliation	Calif Electric Transportation Coaliton
Subject	CalETC comments on Proposed 2024 LCFS amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6856-lcfs2024-UjFQN1Y7UGYKeFU2.pdf
Original File Name	CalETC comment letter on proposed LCFS amendments Feb 20, 2024 vF.pdf
Date and Time Comment Was Submitted	2024-02-20 10:17:24

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Honorable Chair Liane Randolph and Honorable Board Members California Air Resources Board
1001 I Street
P.O. Box 2815
Sacramento, CA 95812

Re: Proposed Amendments to the Low Carbon Fuel Standard Regulation

Submitted to https://ww2.arb.ca.gov/applications/public-comments

Dear Chair Randolph and Honorable Board Members:

CalETC appreciates this opportunity to SUPPORT the Low Carbon Fuel Standard (LCFS) regulation and provide feedback for CARB Board member consideration. As discussed in detail below, CalETC largely supports the proposed draft regulation order ("draft order"), however, we are urging CARB to make some modifications to ensure that the utilities will be able to effectively administer the programs funded by LCFS proceeds. These changes are critical to ensuring the success of the LCFS program.

CalETC is a non-profit association committed to the successful introduction and large-scale deployment of all forms of electric transportation including plug-in electric vehicles of all weight classes, transit buses, port electrification, off-road electric vehicles and equipment, and rail. Our board of directors includes Los Angeles Department of Water and Power, Pacific Gas and Electric, Sacramento Municipal Utility District, San Diego Gas and Electric, Southern California Edison, Northern California Power Agency, and the Southern California Public Power Authority. Our membership also includes major automakers, manufacturers of zero-emission trucks and buses, developers and operators of charging stations and other industry leaders supporting transportation electrification. CalETC supports and advocates for the transition to a zero-emission transportation future to spur economic growth, fuel diversity and energy independence, ensure clean air, and combat climate change. This letter is submitted on behalf of the CalETC board of directors and covers issues specific to the utility interests in LCFS.

Over the past few years, the CalETC board has worked closely with the CARB LCFS staff to provide suggested amendments to the LCFS regulations. We appreciate the tremendous effort and accessibility of CARB staff during the extensive public process regarding this regulation.

I. Executive Summary of CalETC Utility Comments

CalETC requests specific changes to the draft order to ensure that the utilities will be able to
effectively administer programs funded by LCFS proceeds. These changes include: (1) ensuring that
"186.1" the cap on administrative costs for both holdback programs and the statewide California Clean
Fuel Reward (CCFR) program is clearly defined and set at a reasonable amount; (2) simplifying and
"186.2" clarifying the language in the proposed regulation pertaining to utility "holdback" (holdback)
"186.3" programs; (3) clarifying that Publicly Owned Utilities must spend 50% of holdback funds on equity
"186.4" projects, as opposed to 75%; (4) clarifying that San Diego Gas and Electric is a "medium-sized"
"186.5" utility under the regulation; (5) making edits to the regulation that will assist smaller utilities,
"186.6" potentially allowing them to participate in LCFS; (6) modifying the utility reporting requirements to
better track deployment of funds to impacted communities, align with the reporting framework
required by the California Public Utilities Commission (CPUC), and simplify reporting for smaller
"186.7" utilities; (7) requesting that the regulation allow the Executive Officer to approve certain
modifications to the CCFR that can improve program responsiveness and efficacy; and (8)
"186.8" requesting implementation assistance on the Credit Clearance Market (CCM). All of these
modifications are discussed in Section II, below.

CalETC supports many provisions in the draft order including, but not limited to: (1) the current program design with utilities generating the "base" LCFS residential credits; (2) the provision of more credits to the utility holdback programs; and (3) the establishment of a statewide medium-and-heavy-duty electric vehicle rebate program for new and used vehicles. A detailed description of the rationale behind CalETC's support positions is included in Section III, below.

II. CalETC Requests the Following Important Changes to the Draft Order

CalETC respectfully requests that the following changes be made to the Draft Order:

186.1 *(1) CalETC opposes the proposed 5% cap on administrative costs for both holdback programs and the statewide California Clean Fuel Reward and recommends that the cap remain at 10%*

Based on how utilities currently track and report program administrative costs, the reduction of allowable administrative costs for utility holdback programs from 10% to 5% in the proposed amendments will make it extremely difficult, if not impossible, to administer these programs. Given their focus on addressing the most underserved individuals and communities, utility holdback programs are necessarily more expensive to operate than broad, unrestricted incentive programs given higher levels of customer support and additional expenses like income verification needed to ensure the funding is reaching the people that most need it. Additionally, smaller utilities may only be able to implement a portfolio of small programs that will never benefit from the economies of scale that larger programs achieve. While there is an option in the Regulation that allows the utilities to exceed the administrative cost caps with advanced approval from the Executive Officer, this is likely to create administrative challenges for CARB and utility staff if each utility must make a request each year that they expect to exceed the proposed 5% cap.

CalETC acknowledges, however, that there may be differences in how CARB Staff and the electrical distribution utilities (EDUs) interpret "administrative costs" as this is not a defined term in the Regulation. While CARB Guidance 20-03 does provide some insight into what might be considered administrative costs, it appears to be inclusive only of the utility's administrative staff costs (salary, benefits, training, travel, etc.) and does not mention other program-specific costs that have typically been reported as "administrative costs" in past and current utility LCFS programs to CARB and the CPUC . These include critical program activities such as third-party administrative costs, rebate processing fees, applicant and income verification costs, website licenses and fees, and other direct, but non-incentive, program costs. It has been customary for the IOUs to report all these additional costs as "administrative costs" to both CARB and the CPUC in their annual LCFS reports based on the history of discussion in various CPUC Decisions and their experience with other customer programs.[1]

So, while it may be possible to implement utility Holdback programs with a 5% administrative cost cap under the narrow definition considered in Guidance 20-03, CalETC recommends that, with the exception of small EDUs that have annual electricity sales of less than 2000 GWh, the cap on equity holdback administrative costs should revert to 10% as allowed in the current Regulation, and that the definition should be expanded to include all associated program administrative costs, with the exception of start-up costs and education and outreach costs. Start-up costs, defined as set-up costs that occur before any incentives can be paid, are already excluded from the CCFR. Because costs before program launch are almost 100% administrative, it is nearly impossible to meet any administrative cap in the year a program is being set up. For small EDUs, CalETC proposes that they are not subject to a cap on administrative costs. To this end, CalETC has proposed a definition of EDU Program Administrative Costs in the Appendix that should be included in the Definitions and Acronyms section of the Regulation.

For small EDUs, CalETC proposes that they are not subject to a cap on administrative costs, or are subject to a higher cap, such as 20%. While Small EDUs are able to design and implement programs specifically tailored to their community needs, administrative costs for these EDUs may naturally result in a higher percentage of costs due to the small scale of programs and the utility's limited staff resources, particularly if the definition of administrative costs is expanded. The 2000 GWh exemption makes sense as a natural break in utility sizes when looking at 2022 CEC data on total electricity sales. While there is a process for EO approval of administrative costs exceeding 10%, the process would place yet another administrative burden on small EDUs to go through the process annually and require additional LCFS Staff time. Furthermore, the process requires a contract with a community-based organization, which is limiting. Many small EDU equity projects incorporate partnerships and collaboration with a CBO without a formal contract.

[1] See D.14-12-083, D.20-12-027, and CPUC Resolution E-5015.

To further illustrate how other program operating costs are different than the definition of administrative costs in Guidance 20-03, consider the investor-owned utilities (IOUs) energy efficiency program portfolios, which have administered billions of dollars of incentive funds throughout the state with oversight from the CPUC, are operated under guidelines established in the Energy Efficiency Policy Manual[2]. As shown in the Table below, Appendix C of the Energy Efficiency Policy Manual lists the cost caps (hard requirements) and targets that the CPUC established for the operations of these programs.

Appendix C Table: Energy Efficiency Policy Manual APPENDIX C Cost Category Caps

Budget Categories	Cap	Target
Utility program administrative costs	10%	
Third-party / Gov't partnership administrative costs		10%
Marketing & outreach costs		6%
Direct implementation non-incentive (DINI) costs		20%
Evaluation, measurement & verification (EM&V) costs	4%	

In addition to being separate from ME&O costs, administrative costs, as defined in the Energy Efficiency Policy Manual, explicitly exclude third party implementer fees, and also exclude direct implementation non-incentive (DINI) costs (which include activities such as software licenses, rebate processing, contractor training, etc.). CalETC's request to expand the definition of administrative costs to include things such as third-party implementer costs and DINI costs while imposing a cap of 10% is more conservative than the requirements of the Energy Efficiency Policy Manual while still allowing the utilities the budgets needed to effectively operate their LCFS-funded programs.

CalETC has confirmed with CARB staff that ME&O costs for holdback are not included as part of administrative costs in any LCFS guidance document. In addition, as noted above, the CPUC does not include ME&O as part of administrative costs for other programs, including current LCFS programs. We recommend that ME&O should be excluded from administrative costs in the new LCFS regulation to reduce uncertainty and improve clarity. See the Appendix for our proposed amendments.

With this expanded definition of administrative costs, CalETC also recommends that the allowable cost cap for the statewide Clean Fuel Reward, which currently includes ME&O costs, be reverted to 10% from the 5% that is in the proposed regulation. While CARB Staff have expressed reasonable concerns that the potential size of the Clean Fuel Reward could allow for very large administrative and ME&O budgets, it should be noted that these same concerns were addressed when the CPUC authorized the utilities to implement the Clean Fuel Reward in 2019, finding that "a 10% cap of administrative funds is generally within the range of spending for other customer programs the utilities implement," and ordered SCE in Resolution E-5015 to "administer no more than 10% of the total Clean Fuel Reward program budget on administrative and marketing, education, &

[2] Version 6 located at 6442465683-eepolicymanualrevised-march-20-2020-b.pdf (ca.gov)

outreach spending, which must include all administrative spending related to the Clean Fuel Rewards program." The CPUC found that including ME&O in the 10% cap was reasonable for a program of this size; the potential scale of the Clean Fuel Reward is no larger today than it was in 2019 and the same rationale should apply today. Further, we do not believe that either the Clean Fuel Reward or holdback programs will grow so large in the near term that the administrative costs will be too large . CARB will be doing another LCFS rulemaking in a few years and should closely monitor administrative costs and address if there is a problem.

Therefore, the proposed amendment's 5% cap should be rejected, and instead should revert to 1) the 10% allowable administrative costs for utility equity holdback programs, excluding startup costs and ME&O, as this is currently accepted by both CARB and the CPUC, 2) the 10% cap on allowable combined administrative and ME&O costs for the Clean Fuel Reward programs, as authorized in the current version of the LCFS Regulation and concurrent CPUC Resolutions, and 3) a more expansive definition of administrative costs that explicitly excludes ME&O should be added to the regulation. CalETC has provided recommended language for the relevant sections of the Regulation in the Appendix that implement these recommendations. Additional details on administrative costs should continue to be in an updated guidance document.

186.2 *(2) CalETC recommends simplifying and clarifying the language in the proposed regulation pertaining to utility holdback programs*

CalETC supports the staff's efforts to develop a recommended list in the proposed regulation of activities for holdback projects to make it easier for all stakeholders (e.g., the CPUC, CARB Staff, municipal utility governing boards, and utility program developers) to have a clear understanding of how CARB intends utility LCFS Holdback funds to be used. While we appreciate that many new project types have been included in the proposed amendments at the recommendation of CalETC and its members, several updates to the Holdback project list in the proposed amendments are needed for the sake of simplicity and to provide clarity on what is or is not considered a holdback equity project while also providing consistency of interpretation through the regulation itself.

The proposed amendments contain two lists: one which CARB Staff has indicated must be used for equity projects and another which are "good ideas" for non-equity projects. However, this makes it unclear if a utility could implement a project on the "equity" list – such as deploying charging stations at a multifamily property – as part of its non-equity project spending, and it also implies that a project on the "good ideas" list – such as optimized EV charging – could not be considered as counting towards a utility's equity spending requirements even if that project was directly reducing the energy bill of a low-income customer. Further uncertainty exists around the incentivization of medium- and heavy-duty (MDHD) vehicles: should projects supporting MDHD electrification only be considered equity projects if the vehicles are domiciled, or fueling located in, impacted communities, or always be considered equity projects since the pollutants from these vehicles disproportionately impact equity communities (i.e., disadvantaged rural, tribal and low-income communities) regardless of where they are domiciled or fueled?

CalETC recommends that the two lists be consolidated into one and that project spending be considered towards the utilities' equity allocation compliance requirements if it benefits the communities and individuals defined in the equity holdback section. To ensure that the utilities are only deploying projects that CARB supports for equity communities and individuals, CalETC recommends that the single project list must be used for equity projects and may be used for non-equity projects in addition to other non-equity projects that further transportation electrification in California as defined by 95491(e)(5). This approach is more straightforward, minimizes opportunity for conflicting interpretations, and provides certainty on expectations around CARB's priorities while still allowing flexibility for utilities to propose non-equity programs that are best suited to their specific service areas and customers. CalETC also recommends that any project that furthers the deployment of electric MDHD vehicles be considered as an equity project, as the electrification of trucking almost always benefits low-income individuals and disadvantaged communities with criteria pollutant and GHG reductions even when the primary charging / ownership location is outside of the disadvantaged community, low-income community, tribal area, or rural area (*See* CalETC's comments on the definition of rural in bullet 8 below).

Additionally, CalETC recommends several smaller changes to the proposed regulation below with proposed amendments in the Appendix:

1. The regulation should include a requirement for large IOUs (SCE and PG&E in CalETC's comments below) to utilize their holdback credit revenues to fund a minimum of three program options as there are increasingly diversified needs in transportation electrification over large service areas. Including this requirement to fund a minimum of three program options will help ensure that the large IOUs consider the diverse needs of their customers and are not compelled by stakeholders to focus on a single project.
2. While we agree with the proposed regulation's deletion of broad-based ME&O (e.g., television and radio), the regulation, rather than Guidance Document 20-03, should clearly allow ME&O for specific projects.
3. The project list should explicitly allow for upgrades to electric panels, which are prerequisites to transportation electrification for many customers living in older buildings that have not had recent updates. Upgrades to panels can have other benefits but are primarily to enable transportation electrification.
4. For simplicity and clarity, the project list should be consolidated on the recommended projects for electric mobility solutions as there are two list items that appear to overlap regarding mobility alternatives.
5. The project list should preserve a narrowly-focused project category for direct multilingual education and outreach serving equity communities. The preservation of this category is not intended to include general marketing or advertising. It is only intended to allow for multilingual education and outreach to equity communities.
6. The list of agencies that may be consulted in the creation of workforce development projects should be expanded to include other pertinent entities, such as California Community Colleges, community-based organizations, and publicly-owned utilities (POUs) Governing Boards.
7. CalETC thanks CARB Staff for harmonizing the definitions of equity communities and individuals in the proposed amendments with those detailed in AB 841 and CPUC Decision

D.20-12-027. However, the language requires a slight modification. AB 841 defines this as "a community located on lands belonging to a federally recognized California Indian tribe."[3] The proposed amendments include "state and federally recognized".

8. The definition of "rural" needs to be updated as the U.S. Census Bureau no longer reports rural percentages for census tract population. The Census Bureau now defines rural as "all population, housing, and territory not included within an urban area."[4]
9. "Off Road Vehicle" should be defined for clarity because it is not obvious that vessels, aircraft, and other transportation qualify under that term. CalETC has provided recommended edits to this section of the proposed amendments in the Appendix to this letter.

186.3 *(3) CalETC requests clarification that POUs must spend 50% of holdback funds on equity projects, as opposed to 75%*

CalETC notes a discrepancy between the proposed LCFS requiring 75% of holdback funds for equity projects compared to Appendix E "Purpose and Rationale for Low Carbon Fuel Standards Amendments," which calls for 50% for POUs. We recommend that POUs have a 50% requirement for equity holdback. We understand there are almost 30 POUs that have opted into LCFS and potentially another fifteen could opt in. The POUs are very diverse and represent specific and limited territories within the State, with a wide variety of populations, EV densities, rural/urban splits, percentages of DACs and community needs. POUs are also uniquely in tune with local needs. Designing and implementing effective transportation electrification programs for low-income, rural and/or disadvantaged communities can be challenging, and the uptake and timing of projects is difficult to predict. In addition, there will be natural fluctuations in program spending year-to-year, and an annual requirement of 50% allows for better planning to maximize the impact of equity spending. In addition, we recommend the 50% equity requirement for the three small IOUs (instead of the 75% in the proposed LCFS). These small IOUs are not opted into LCFS, and a 75% equity holdback requirement creates practical challenges at start up that make it difficult for them to opt-in to LCFS.

186.4 *(4) CalETC requests clarification that San Diego Gas and Electric is a "medium-sized" utility under the regulation*

CalETC notes that the regulatory package has conflicting information regarding the size of San Diego Gas and Electric (SDG&E) and its requirements under CCFR and holdback programs. Specifically, in *Appendix E: Purpose and Rationale of Proposed Amendments for the Low Carbon Fuel Standard Requirements*, CARB staff states, "San Diego Gas & Electric is re-defined to have a comparable contribution to the statewide program to similarly sized public utilities." However, this change is not in the proposed regulation. In discussion with CARB staff, we understand that

[3] Bill Text: CA AB841 | 2019-2020 | Regular Session | Amended | LegiScan at 1601.(e)(5)

[4] See https://www.census.gov/programs-surveys/geography/guidance/geo-areas/urban-rural.html

that they intend to categorize SDG&E as the same size as Los Angeles Department of Water and Power based on their similar total 2022 electricity sales (annual GWh). CalETC supports these two utilities having the same contribution to the CCFR in the final LCFS, as their size is very similar, and SDG&E is substantially smaller than the two large IOUs. This change will allow SDG&E to have more meaningful holdback programs.

CalETC may have further comments on the definition of EDUs based on annual GWhs in the future, as we understand that staff plans to propose amendments to these definitions (e.g., improved data, new thresholds for large, medium, and small EDUs) in an upcoming 15-day comment period.

186.5 *(5) CalETC requests edits to the regulation that will assist smaller utilities, potentially allowing them to participate in LCFS*

CalETC requests the LCFS include a program to encourage small EDUs who have not opted-into LCFS to do so and expand programs by small EDUs who have recently opted in. There are over 50 EDUs in California, and we understand from staff that about thirty have opted in to LCFS. Our proposal would support approximately twenty small rural utilities who cover about one percent of California.

We propose that the LCFS have new regulatory language that allows the CCFR Steering Committee to work with the Executive Officer to design one-time grants to incent the small, mostly rural EDUs that have not yet opt into the LCFS to opt-in and also to provide additional funding to EDUs that have recently opted in. The goal of the program would be to have almost all California utilities participate in the LCFS and provide holdback programs to provide better coverage in underserved areas.

Specifically, we request funding for our recommended program to come from funds that non-opt in EDUs have been providing to the CCFR since 2020 per Section 95486.1 (c) (1) (A) paragraph 2.[5] Our informal survey of these small EDUs found that they often only have a handful or a few hundred EVs which is not enough to justify a program. Under our proposal, a start-up grant would be enough for a small EDU to start or expand a basic program to help their customers and CARB would provide approvals and oversight to the CCFR Steering Committee and Program Administrator. Our recommended amendment is in the Appendix.

186.6 *(6) CalETC requests the regulation modify the utility reporting requirements to better track deployment of funds to impacted communities, align with the reporting framework required by CPUC, and simplify reporting for smaller utilities*

CalETC appreciates the areas where CARB Staff have made efforts to harmonize the regulatory and reporting requirements of the LCFS Regulations with other regulatory bodies, such as the

[5] All base credits for any EDU that is not eligible to receive base credits pursuant to this provision will be allocated to the Clean Fuel Reward program pursuant to section 95486.1(c)(1)(A) paragraph 2.

CPUC. One such area was increasing the equity allocation requirement of utility Holdback programs for the Large IOUs from 50% to 75%. Yet, while increasing the equity requirement to 75% appears to align with the CPUC's requirements in D.20-12-027, CARB and the CPUC currently measure this metric in very different ways. CARB counts percent of proceeds earned in a calendar year, which was clarified by guidance document 20-03 to include percent of proceeds either spent or encumbered (i.e., budgeted or set aside) to an equity program. The CPUC, however, counts spending that occurs during the calendar year, regardless of when the credits were earned. This is subtle but, as a result, the IOUs are often reporting entirely different data to demonstrate compliance to each agency in their annual reports[6].

Tracking compliance against the percentage of annual proceeds creates many operational difficulties. For example, if the combination of on-road EV charging and credit prices-- both of which are beyond the utilities' control – evolve over a year such that a utility generates double the proceeds it expected to generate, then a utility may be faced with two options to maintain compliance based on percent of annual proceeds: double the spending of its in-market programs or encumber those funds, without actually spending them, in some combination of those programs. The first may not be practical as it is difficult to increase operational capacity of a program in real time; the second achieves compliance but it does not necessarily allow the utility to assess where it should best allocate its holdback funds in the coming calendar year as they will have been encumbered to a specific program for the sake of compliance.

Tracking on how LCFS proceeds are actually returned to Californians, is a more effective metric to track how LCFS dollars actually flow to benefit underserved communities over time and is consistent with the metric used by the CPUC to ensure compliance[7]. However, in recognition that the balance between equity and non-equity spending may necessarily vary in a given year, the regulation should specify that any "underspend" in annual equity spending will carry over to the next calendar year(s) in the form of increased equity spending requirements.[8] The recommended language has been provided in the Appendix as part of the updates to the holdback program section.

Compliance based on spend, when coupled with the rollover of any "underspending" on equity in a given year, also helps smaller utilities, by providing an option, to save up holdback proceeds for several years to accumulate a large enough bank to implement a program without "pre-deciding" how to allocate their funds into a program until they are ready to spend them, in addition to the option of saving up for large equity spending projects through the rollover provision. Further, compliance based on spend makes it easier to account for the reality of utility programs, which often have both equity and non-equity recipients, as the utilities can

[6] See Decision D.14-12-083 Ordering Paragraph 4, requiring reporting on annual expenditures.

7 Decision D.20-12-027 Ordering Paragraph 1

[8] For example, if a large IOU spent $10 million in one year, $7.5 million of that would be required for equity. However, if only $7 million was spent on equity (70%), the $500,000 underspend would be added to the following year's compliance such that they would need to spend 75% plus $500,000.

simply report how much of the annual spend went to each type of recipient in a calendar year, rather than managing set asides in intra-program budgets.

Therefore, CalETC recommends that the utility holdback project equity allocation requirements be updated to percent of annual spend rather than percent of annual proceeds. Further, CalETC proposes that if a utility underspends on equity projects in a given year, the amount that it underspends will be carried forward to the next year. This aligns the LCFS Regulation's requirements with the obligations that the CPUC has already placed on the IOUs, improves tracking of how LCFS funding is actually being deployed into impacted communities, and simplifies accounting for CARB, CPUC, and utility staff. CalETC has proposed language that would implement these recommendations in the Appendix to this letter as part of its other recommendations for updates to the holdback section.

186.7 *(7) CalETC requests that the regulation allows the Executive Officer to approve certain modifications to the CCFR that can improve program responsiveness and efficacy*

The LCFS is a powerful tool for incentivizing the adoption of low carbon technologies to support the technologies called for in the 2022 Scoping Plan. Because the Scoping Plan calls for the adoption of new zero emission technologies, the LCFS regulatory framework must allow for some flexibility in response to changing market conditions and needs. As such, CalETC respectfully requests that the final regulation allow the Executive Officer to make modifications to the electricity provisions of the LCFS, including the ability to add tools other than rebates or new technologies (such as financing assistance) to the statewide Clean Fuel Reward program if requested by the Clean Fuel Reward Steering Committee. CalETC also respectfully requests that such exception requests to the Executive Officer be handled expeditiously, and staff be adequately resourced to handle these exceptions.

186.8 *(8) CalETC requests implementation assistance on the Credit Clearance Market (CCM)*

CalETC's members include large EDUs who will be impacted by the CCM. We respectfully ask for a guidance document (or, if appropriate, a user guide or FAQ) on the mechanics of the CCM. For example, what do deficit/credit holders functionally do once a CCM / Advanced Crediting phase is declared? Also, given the proposed increase from ten million to thirty million credits in the CCM, we request further discussion regarding possible practical issues down the road if only a small number of EDUs are trying to transact such a large volume in a mandatory compressed timeframe.

III. CalETC largely supports the proposed order

CalETC applauds CARB's efforts to amend this important and complicated regulation. In particular, CalETC supports the following provisions of the proposed order:

(1) CalETC supports the continued allocation of base residential charging credits to the electric distribution utilities (EDUs) which fund important statewide and individual utility programs

CalETC strongly supports the continued allocation of the residential base credits generated by electricity used to fuel electric vehicles to the electric utilities. This is appropriate and leads to the most efficient, equitable, and market-stimulating distribution of the proceeds.

1. *The utilities are subject to extensive regulatory oversight, ensuring that the proceeds are spent in a manner that aligns with the state's goals.*

The electric utilities are subject to extensive reporting and compliance requirements, ensuring that the distribution of LCFS proceeds is open and transparent. Furthermore, the utilities have a duty to serve all customers, including populations that have been slower to adopt EVs including those residing in disadvantaged communities (DAC), low-income renters and multi-unit dwellings (MUD). Residents of DACs and MUDs are utility customers, and as such the utilities are incentivized to assist those customers in transitioning to electric transportation. The electric utilities can use the proceeds gained from base residential credits to establish holdback programs that enable charging at MUDs, for renters, and in equity communities. Similarly, utilities can leverage credits generated across the entire customer base to fund programs incentivizing adoption in DACs and low-income communities. Utilities are the only entity able to use credits generated from residential light-duty EV charging to support heavy-duty or off-road vehicle electrification, an increasingly urgent issue in decreasing the transportation sector's air pollution and greenhouse gas emissions.

California's electric utilities are uniquely positioned to support and enable additional load from electric vehicles because electric vehicle load is flexible and when used off peak makes more efficient use of the electric system which puts downward pressure on electric rates for all other customers. Because of this, California's electric utilities are the only entities that have the primary goal of ensuring accessible infrastructure and affordable electricity, making them uniquely positioned to receive and manage base residential credits.

2. *The electric utilities have been a long-time partner in the state's decarbonization efforts and are by definition located in California.*

Unlike other entities, the electric distribution utilities (EDUs) must always be located locally, within California, to provide a critical and essential service. The size of utilities varies dramatically, with the larger utilities having the staff and resources necessary to work cohesively with the other EDUs to efficiently run statewide programs. Some examples of efforts to collectively enable market transformation include programs in energy efficiency, renewable energy and most recently, the California Clean Fuel Reward. The utilities are equipped to handle the very large-scale proceeds generated by the LCFS. They are experienced, efficient administrators and have a long history of designing large-scale, stable successful programs and have shown they can quickly implement statewide and individual utility programs.

Additionally, all Californians have an electric utility provider and are used to working with their utility to support their energy needs. This name recognition and familiarity is necessary for getting reluctant customers to adopt new technologies. Finally, the electric utilities have provided service to their customers for decades and will continue to serve their territories for many decades to come, providing the stability needed to positively contribute to the wholesale market transformation required by the switch to electrified transportation.

3. *Electric utilities are able to implement programs that address the needs of all aspects of electric vehicle adoption and at the scale needed to support CARB's scoping plan.*

Unlike other important players in the electric vehicle industry, electric utilities can administer programs involving all aspects of the transportation electrification ecosystem. The utilities can provide rebates for chargers, rates designed to incentivize adoption, vehicle incentives, grid upgrades to support increased beneficial electrification, and have decades of experience implementing programs targeted to benefit lower-income and disadvantaged customers. Having the ability to address all aspects of electric vehicle adoption allows for flexibility in how the money is spent. Furthermore, a properly designed program can afford the utilities the ability to act quickly and to adjust program design when external factors change. This is increasingly important as state, local and federal funding sources and tax breaks tend to shift over time.

Electric utilities also provide service to all electric vehicle segments and classes. The utilities serve light, medium- and heavy-duty vehicles, individually owned vehicles, last-mile vehicles, and fleets. With the increase of electrification, upgrades to the electric grid will be necessary. Utilities will need information about the location of all electric vehicles so that they can adequately upgrade the grid and provide vehicle/grid integration services. Finally, serving all vehicle classes allows the electric utilities to provide programs for both the light-duty and medium-and-heavy-duty sectors. This allows the utilities to utilize the funding from the sectors that are first to electrify (light-duty) to incentivize and support the sectors that are harder to electrify (e.g., medium-and-heavy-duty).

Allowing the utilities to receive the residential base credits also supports individual utility programs which are necessary for meeting local needs and hard-to-reach markets such as medium- and heavy-duty EVs, off-road EVs and infrastructure for renters (homes, apartments, etc.) that are identified in the Scoping Plan, Advanced Clean Cars, and Advance Clean Fleets. Individual utility programs can be nimble and respond to the complex, ever-changing incentive landscape for EV and infrastructure incentives.

4. *Keeping the current structure prevents a complicated system where both utilities and non-utilities receive base residential credits.*

The current structure supports large-scale, statewide programs linked to the State's equity and climate goals. Diluting the credits coming to utilities makes both individual utility and large-scale statewide programs very difficult to implement and harder for CARB to regulate. Also, the current structure enables and funds active utility involvement, especially for small POUs, and encourages more small EDUs to join LCFS and create custom programs to support their customers. The current LCFS is a well-crafted system that allows site-hosts, automakers, charging providers and utilities to all receive LCFS credits.

CalETC also supports the proposed provision requiring entities "generating credits from electricity to use all credit proceeds to further transportation electrification efforts in California and include in their annual compliance report an itemized summary of efforts and costs associated with meeting this requirement." Ensuring that all the proceeds from the electricity LCFS credits are put back into programs and projects that incentivize the adoption of transportation electrification is essential to effectuating the goals of CARB's Scoping Plan.

(2) CalETC supports staff's proposal for EDUs to spend more of their LCFS proceeds on holdback programs

Under the proposed order § 95483(c)(1)(A)(2), the required contribution to CCFR and remaining allocation to holdback programs would be changed as follows:

EDU Category	Holdback Allocation (%)	
	Proposed	Previous
Large Investor-owned Utilities	50	33
Large Publicly Owned Utilities	75	55
Medium Investor-Owned Utilities	75	75
Medium Publicly Owned Utilities	90	75
Small Publicly Owned Utilities and Small Investor-owned Utilities	100	98

CalETC strongly supports these changes, with the exception discussed above regarding San Diego Gas and Electric. Funding from base residential credits for holdback programs and CCFR are directly linked. With the proposed regulation increasing holdback funding percentages, the percentages allocated to the CCFR will decrease. This change is appropriate because the proposed CCFR is for the much smaller market of medium- and heavy-EVs vs. the larger light-duty market in the current CCFR.[9] Similarly, removing very small EDUs from contributing to the CCFR is appropriate because a two percent contribution is not meaningful and results in administrative inefficiencies for both the CCFR Program Administrator and the very small EDUs.

(3) CalETC supports the proposed shift in the California Clean Fuel Reward (CCFR) from being a reduction in the purchase or lease price of new light-duty electric vehicles (EVs) to being a reduction in the purchase of lease prices of new electric medium- and heavy-duty EVs

CalETC supports CARB's proposed amendments that will transition the statewide Clean Fuel Reward program from an incentive for all new passenger EVs to one that will support the adoption of electric MDHD vehicles in the coming decade. We also agree that the new Clean Fuel Reward

[9] The California Energy Commission anticipates that the adoption of medium- and heavy-duty vehicles as follows: 27,000 by 2025, 155,000 by 2030 and 377,000 by 2035. *See* Assembly Bill 2127 Second Electric Vehicle Charging Infrastructure Assessment Revised Staff Report.

should be in line with the needs of CARB's Scoping plan - and primarily benefiting equity communities - and believe the new proposal[10] achieves this goal. However, as the Clean Fuel Reward Program Administrator (SCE) has commented, minor updates to the vehicle eligibility in the proposed amendments are needed to ensure that that new Clean Fuel Reward program can effectively implement CARB's ambitious plans for the commercial vehicle sector.

For example, in *Appendix E: Purpose and Rationale of Proposed Amendments for the Low Carbon Fuel Standard Requirements*, CARB Staff states that the "Clean Fuel Reward will change from a universal new light-duty EV rebate to be focused on new and used rebates for medium- and heavy-duty trucks." However, the proposed amendments define the Clean Fuel Reward as applying only to new vehicles. CalETC believes that "used" was accidentally omitted from the proposed amendments and has provided recommended language that includes used vehicles in the Appendix to this letter.

Additionally, CalETC is concerned that definitions for medium-or-heavy duty vehicle in the proposed amendments do not necessarily align with CARB's stated intentions. Defining these solely by weight class, as the current proposed amendments do, means that the Clean Fuel Reward program may be required to provide incentives for all vehicles that have a GVWR greater than or equal to 8,501, which includes many passenger vehicles such as the Rivian line of products, the extended range Ford F-150 Lightning, the electric Chevrolet Silverado, and the electric Hummer to name few. Based on CARB Staff's published rationale, CalETC believes these vehicles should be incentivized by the Clean Fuel Reward only if they are purchased for use as commercial vehicles. CalETC agrees with the Program Administrator's proposal that the definition of Clean Fuel Reward be updated to specify that it is for commercial vehicles only, and the Regulation should also include a definition for commercial vehicle in the Definitions and Acronyms section for clarity and completeness. For consistency, CalETC proposes that the LCFS Regulation adopt the same definition for commercial vehicles utilized by the Hybrid and Zero-Emissions Truck and Bush Voucher Incentive Project (HVIP). Both these definitions are included in the Appendix to this letter, and CalETC believes that these minor modification to the proposed amendments will empower the new Clean Fuel Reward program to be a vital tool in the state's efforts to decarbonize heavy-duty trucking.

CalETC appreciates the opportunity to provide comments on this important regulation. If you have any questions, please do not hesitate to contact me at any time.

[10] "Clean Fuel Reward" is a statewide program established by EDUs to provide a reduction in price on new light-duty EV purchases or leases for new medium- or heavy-duty electric vehicles that are not subject to the High Priority and Federal Fleets requirements as specified in, title 13, California Code of Regulations, section 2015(a)(1) in California.

Best,

Laura Renger
Executive Director

cc: Rajinder Sahota
Matthew Botill
Jordan Ramalingam
Jacob Englander

Appendix

New or updated Defined Terms to be added to the Regulation's Definitions and Acronyms

[New term] "EDU Program Administrative Costs" are all costs associated with implementing LCFS-funded programs incurred by an EDU to pay for its staff, 3rd party implementers, non-incentive implementation costs (rebates processing, application verification, etc.) websites, application portals, and other direct program costs required to operate the program. EDU Program Administrative Costs do not include marketing, education and outreach costs.

[Updated term] "Clean Fuel Reward" is a statewide program established by EDUs to provide a reduction in price ~~on new light duty EV~~ ~~purchases or leases~~ for new and/or used commercial medium- orheavy-duty electric vehicles that are not subject to the High Priority and Federal Fleets requirements as specified in, title 13, California Code of Regulations, section 2015(a)(1) in California. The Clean Fuel Reward is funded exclusively through LCFS proceeds generated by EDUs from electricity fuel.
[New term] "Commercial vehicle" for the purposes of this program means any vehicle used by a business, public or governmental agency, or non-profit to carry people, property, or hazardous materials.[11]

"Rural Area" means a census tract ~~with~~ ~~*at least 75 percent of its population*~~ *identified as* ~~*rural*~~ *non-urban* *by the latest US Census data.*

[new term] "Off road vehicle" is a piece of equipment that is moved over distances in order to transport goods or people from one physical location to another and is not primarily operated on roads established for automotive transport (e.g. fields, waterways, construction sites, airports, airways, etc.).

Recommendations for edits to the holdback program

5. *Restrictions on Use of Holdback Credits.* Documentation of adherence to the following restrictions must be included inthe annual report submitted pursuant to section 95491(e)(5)(A).

    a. *Holdback Credit Equity Projects.* Effective January 1,202~~2~~5, at least 75 percent ~~in year one, 40 percent in year two, and 50 percent in subsequent years~~ of holdback credit ~~proceeds~~ annual spending for large and medium investor owned EDUs and 50 percent of holdback credit annual spending for all other EDUs must be used to support transportation electrification for underserved individuals and communities. Any project from sections 95483(c)(5)(a)(i), (viii), or (xi)

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[11] HVIP FY22-23 Implementation Manual, Definitions, page 52 HVIP-FY22-23-Implementation-Manual.pdf (californiahvip.org)

shall be considered a holdback credit equity project; all other projects described in this paragraph may be considered holdback credit equity projects provided they are for the primary benefit of or primarily serving disadvantaged communities and/or low-income communities and/or rural areas or low-income individuals eligible under California Alternative Rates for Energy (CARE) or Family Electric Rate Assistance Program (FERA) or the definition of low-income in Health and Safety code section 50093 or the definition of low-income established by a POU's governing body or a community in which at least 75 percent of public school students in the project areaare eligible to receive free or reduced-price meals under the National School Lunch Program, or a community located on lands belonging to a ~~state and~~ federally recognizes California Indian tribe.

If an EDU fails to spend the required percentage on equity projects in a calendar year, the shortfall of spending, in dollars, will be added to their total equity spending requirement for the following year.

~~a.~~

~~b.~~ EDUs must use their holdback credits to implement additional projects that further transportation electrification efforts in California. Project costs may include incentives; infrastructure installation; administration; marketing, education, and outreach (ME&O); evaluation; and other cost categories as needed. Equity projects as defined in this paragraph must be selected from the options of projects listed in i-x below. Non-equity projects may be selected from the options on this list or any alternative provided the EDU meets the requirements of 95491(e)(5) without further CARB approval. The large investor-owned utilities must implement at least three different holdback projects. Equity holdback project options are listed below: ~~These projects may include:~~

~~i. Electrification and battery swap programs for school or transit buses.~~

~~ii.~~ i. Electrification of drayage trucks as well as other medium-, heavy-duty, or off-road vehicles including school and transit buses.

~~iii.~~ ii. Investment in public EV charging infrastructureand EV charging infrastructure in multi-family residences.

~~iv.~~ iii. ~~Investment in electric mobility solutions, suchas EV sharing and ride hailing programs.~~

~~v. Multilingual marketing, education, and outreach designed to increase awareness and adoption of EVs and clean mobility options and including information about: the environmental, economic, and health benefits of EV transportation; basic maintenance and charging of EVs; electric rates designed to encourage EV use; and local, state, and federal incentives available for purchase of EVs.~~

~~vi.~~ [*Revised Subsection v. renumber as iii*] Multilingual ~~marketing, education, and outreach~~ community education events located within communities listed in 95483(c)(1)(A) designed to increase awareness and adoption of EVs and clean mobility options, and outreach in coordination with community-based organizations, including but not limited to neighborhood canvasing, community listening sessions, and needs assessments, focused in communities listed in 95483(c)(1)(A), to inform the development of projects and programs tailored to community needs. ~~including information about: the environmental, economic, and health benefits of EV transportation; basic maintenance and charging of EVs; electric rates designed to encourage EV use; and local, state, and federal incentives available for purchase of EVs.~~ Education and outreach do not include general marketing or advertising campaigns.

~~vii.~~

~~viii.~~ ~~Iv~~iv. Additional rebates and incentives ~~for low-income individuals~~ beyond existing local, federal and State rebates and incentives ~~including the Clean Fuel Reward~~ for: purchasing or leasing new or previously ownedEVs; installing EV charging infrastructure in residences, including panel and service upgrades; ~~promoting use of public transit andother clean mobility solutions;~~ and offsetting costs for residential or nonresidential EV charging.

v. Investing in, or promoting the ~~Promoting~~ use of, ~~and additional incentives foruse of~~ public transit and other clean mobility solutions~~, via charging equipment or infrastructure for the following categories~~ such as:

I. EV sharing and ride hailing programs,

II. Electrification of public transit and school buses, including battery swap programs, and

III. Use or ownership of neighborhood electric vehicles, eBikes, eScooters, eMotorcycles, and other micromobility solutions.

IV. Charging equipment or infrastructure for any of the above.

vi. Re-skilling and workforce development for transportation electrification and electric vehicle infrastructure applications, developed in coordination with the California Workforce Development Board, ~~or~~ local workforce development agencies~~.~~, a community-based organization, a California Community College, or a workforce strategy adopted by the Board of a POU.

vii. Investments in grid-side distribution infrastructure necessary for ~~medium- and heavy-duty~~ EV charging.

viii. Transportation Electrification projects that are identified in, or consistent with, a Community Emission Reduction Plan created in response to AB 617.

ix. Support for vehicle-grid integration with projects such as:

I. Encouraging the optimization of EV charging through education in the following areas: peak demand, rate pricing, grid emergencies, potential power shutoffs, infrastructure deferral, renewable integration, and/or other signals and grid needs to provide grid and customer benefits.

II. Providing program incentives to encourage driver participation in monitored/managed charging, demand response, or vehicle-to-load / vehicle-to-grid applications.

III. Supporting the deployment and installation of bidirectional charging equipment.

IV. Other innovative approaches to promoting and managing EV charging and discharging that provides benefits to customers and the grid.

x. Hardware and software that decrease the cost of or avoid updates to infrastructure, including load management software or outlet splitting

~~vii.~~xi. Alternatively, EDUs, in coordination with local environmental justice advocates, local community-based organizations, and local municipalities, may develop and implement other projects that promote transportation electrification in disadvantaged and/or low-income communities and/or rural areas or for low-income individuals. These alternative projects are subject to approval by the Executive Officer. Applications submitted to theExecutive Officer must include, and will be evaluated for approval based on, a complete description of the project, demonstration that the project promotes transportation electrification in disadvantaged and/or low-income communities and/or rural areas orprovides increased access to electric transportation for low-income individuals, and evidence that the project was developed in coordination with local environmental justice advocates, local community-based organizations, and local municipalities.

b. ~~*Additional Reporting Requirements for Holdback Credit Equity Projects.* As part of annual reporting required pursuant to section 95491(d)(3)(A)5., EDUsmust include a discussion on how their portfolio of holdback credit equity projects is consistent with the findings and recommendations of the SB 350 Low-Income Barriers Study, Part B report prepared by CARB (rev. Feb. 2018), incorporated herein. This discussion must include, as applicable, a description of how the projects: support increased access to clean transportation and mobility options; consider, and to the extent feasible, either complement or buildupon existing CARB, other State, or local incentive projects to diversify and maximize benefits from statewide investments; demonstrate partnership and support from local community-based organizations; and meet community-identified clean transportationneeds.~~

~~b. *Other Holdback Projects.* Holdback projects that arenot specified in subsection 95483(c)(1)(A)6.a. mustfollow the requirements specified in 95491(e)(5). Below are examples of pre-approved uses for these other holdback credit proceeds:~~

~~i. Investments in grid-side distribution infrastructure necessary for EV charging.~~

~~ii. Support for vehicle-grid integration with projects such as:~~

~~I. Encouraging the optimization of EV charging through education in the following areas: peak demand, rate pricing, grid emergencies, potential power shutoffs, infrastructure deferral, renewable integration, and/or other signals and grid needs to provide gridand customer benefits.~~

~~II. Providing program incentives to encourage driver participation in monitored/managed~~

~~charging, demand response, or vehicle-to-load / vehicle-to-grid applications.~~

~~III. Supporting the deployment and installation of bidirectional charging equipment.~~

~~IV. Other innovative approaches to promoting and managing EV charging and discharging that provides benefits tocustomers and the grid.~~

~~iii. Hardware and software that decrease the costof or avoid updates to infrastructure, including load management software or outlet splitting.~~

b. Administrative Costs of Holdback Credit Equity Projects. With the exception of EDUs with annual sales of less than 2000 GWh, EDU Program administrative costs to support the ~~development and~~ implementation of holdback credit equity projects excluding start-up costs (those costs associated with setting up the program and incurred prior to issuing incentives),must not exceed 10~~5~~ percent of total spending on holdback credit equity projects annually unless the EDU contracts with a community-based organization, and the exceedance is approved in advance by the Executive Officer. The request for administrative cost exceedance for a calendar year must be submitted by September 30~~th~~ of the prior year. The request must include, and will be evaluated for approval based on, a complete description of the equity projects planned by the EDU, an estimate of total administrative costs relative to total spending on the projects, and evidence that the community-based organization is a non-profit organization focused on serving disadvantaged and/or low-income groups.
Within 30 days of receiving a request for higher administrative costs, the Executive Officer will inform the EDU of its decision in writing. If the request is rejected the Executive Officer will provide a rationale for the decision. If the rejection is due to insufficient information, the EDU may resubmit the request after addressing the deficiencies identified in the Executive Officer decision.

Recommended amendments on Administrative cost

§95483(c)(1)(A)(4) Combined ~~A~~administrative and marketing, education and outreach costs, excluding start-up costs (those costs associated with setting up the program and incurred prior to issuing rewards), to support any Clean Fuel Reward program funded by LCFS credit proceeds may not exceed ~~5~~10 percent of LCFS credit proceeds contributed to the Clean Fuel Reward program annually, unless approved in advance by the Executive Officer.

§95483(c)(1)(A)(4)(a) A request to exceed ~~5~~ 10 percent administrative and marketing education and outreach costs must be submitted by the administrator of the Clean Fuel Reward program to the Executive Officer by September 30 of the prior year.

Recommended amendments for a new Small EDU program
[New provision – exact location TBD] §95483(c)(1)(A) XXXX Proceeds from non-opt-in EDU base credits that were allocated to the Large EDUs beginning with the deposit of Q2 2019 credits through the deposit of Q2 2024 credits and the transferred to the Clean Fuel Reward program pursuant to section 95483 (c)(1)(A) may be transferred by the Clean Fuel Reward Program Administrator to small EDUs opted in to the LCFS program by March 31, 2025. Any base credit proceeds reallocated in this manner must be spent by the recipient small EDU in accordance with sections 95491 (e)(5) and 95483 (c)(1)(A).The Executive Officer must approve the Clean Fuel Reward Program Administrator's plan for distribution of previously unallocated base credit proceeds prior to any transfers.

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Comment 196 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nancy
Last Name	Young
Email Address	nyoung@gevo.com
Affiliation	Gevo, Inc.
Subject	Gevo's Comments on the LCFS Amendments Proposal
Comment	Please find attached the comment letter from Gevo, Inc. on CARB's LCFS proposal. Thank you.
Attachment	www.arb.ca.gov/lists/com-attach/6858-lcfs2024-BTdUYgc0B2AHXlA3.pdf
Original File Name	2024 Gevo LCFS Rulemaking Comments_2-20-24.pdf
Date and Time Comment Was Submitted	2024-02-20 10:39:10

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

345 Inverness Drive South
Building C, Suite 310
Englewood, CO 80112

T 303-858-8358
F 303-858-8431
gevo.com

February 20, 2024

VIA ELECTRONIC FILING
Submitted via LCFS Comments Upload Link

The Honorable Liane M. Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Gevo, Inc.'s Comments on "Proposed Amendments to the Low Carbon Fuel Standard"

Dear Chair Randolph:

Thank you for the opportunity to comment on the California Air Resources Board's (CARB) Proposed Amendments to the Low Carbon Fuel Standard (LCFS).

Gevo, Inc.'s (Gevo) mission is to produce low-carbon, renewable energy-dense liquid hydrocarbons for drop-in transportation fuels such as gasoline, jet fuel, and diesel. Gevo's alcohol-to-hydrocarbons production process uses a combination of decarbonization technologies and sustainably farmed feedstock to produce fuels with substantially reduced carbon intensity (CI) compared to fossil fuel equivalents. We broke ground on our first alternative jet fuel (AJF)/sustainable aviation fuel (SAF)[1] production facility, "Gevo Net-Zero 1" (NZ1), in Lake Preston, South Dakota, in September 2022. This facility will use a three-part strategy to produce low-CI SAF: 1) use locally-sourced corn feedstock from farmers engaged in sustainable agriculture to both reduce on-farm greenhouse gas (GHG) emissions and sequester CO_2 in the soil; 2) decarbonize the fuel production process by replacing conventional fossil fuel inputs with wind energy, renewable natural gas, and green hydrogen; and 3) use carbon capture and sequestration (CCS) technology to reduce emissions from the production process further. The Gevo approach is aimed at decarbonizing every step in our SAF's life cycle,

[1] Gevo typically uses the term "sustainable aviation fuel" or "SAF" to refer to our fuel. This fuel meets the definition of "alternative jet fuel" (AJF) as set forth in the LCFS regulations. Accordingly, our references to SAF in this comment letter should be deemed synonymous with AJF.

which we track all the way from the farm field through to the aircraft using our Verity Tracking platform.

Gevo intends to submit a Tier 2 LCFS Provisional Pathway application for the SAF, renewable diesel, and renewable naphtha fuels produced at the NZ1 facility, utilizing our field corn starch feedstock and alcohol-to-jet (ATJ)/alcohol to hydrocarbons production process.

I. Overview of Gevo's Comments

Gevo greatly appreciates the role that the LCFS is playing in reducing GHG emissions by incentivizing the replacement of fossil fuels with low-carbon alternatives. We currently are participating in the LCFS through our production of renewable natural gas (RNG) and, given our prospective SAF offtake agreements with major airlines operating in California, we expect to deliver SAF into the state from our NZ1 facility and sequential net-zero SAF facilities in the future. Our comments on the current LCFS proposal are focused accordingly. Although we provide detailed comments below keyed to specific sections of the proposal, we note the following by way of summary:

187.1
- Gevo strongly supports CARB's intent to strengthen the overall compliance curve. CARB's analysis clearly shows that this is needed to support California's emission goals. While we support CARB's proposal of a 30% reduction in fuel CI by 2030 and a 90% reduction in fuel CI by 2045 from a 2010 baseline at a minimum, as detailed below, we believe CARB can and should adopt an even more aggressive curve.

187.2
- Gevo also supports CARB's proposal for a CI stepdown in 2025 and for adoption of an Automatic Acceleration Mechanism (AAM). However, as detailed below, we urge CARB to consider a significantly greater stepdown than the 5% that has been proposed and to further strengthen the AAM.

187.3
- In various places in the proposed regulations, CARB proposes to enumerate certain feedstocks and/or production processes, rather than retaining the feedstock- and technology-neutral approach that has typically been taken under the LCFS. In our comments, Gevo raises concerns with these proposed changes, as they imply unnecessary barriers to feedstock and technological innovation.

187.4
- Gevo supports the "true-up" concept for all pathways, although, as detailed below, we recommend that this be expanded to include true-ups between temporary and provisional pathways.

187.5
- While Gevo supports CARB's recognition of the important role that crop-based biofuels play in reducing GHG emissions and we are committed to strong

sustainability and tracking provisions, we have significant concerns regarding CARB's current open-ended proposal to require third-party "sustainability certifications" for crop-based feedstocks. In our comments below, we encourage CARB to convene a stakeholder process to flesh out an appropriately tailored approach to sustainability certifications for feedstocks that would include crediting the emissions reductions from climate-smart agriculture.

187.6
- Gevo strongly supports avoided methane crediting recognizing RNG project benefits that reduce global methane emissions regardless of location or end use. In our comments, Gevo recommends changes to the current RNG proposals so the LCFS can continue to deliver emissions benefits and maintain project developer and investor confidence in continuing to advance these important methane abatement projects.

- Gevo also provides comments on several compliance-related and administrative provisions set forth in the proposal.

Also, in addition to providing our own comments, Gevo is a member of and supports
187.7 and incorporates by reference the comments of the Coalition for Renewable Natural Gas
(RNG Coalition) and the Low Carbon Fuels Coalition (LCFC).

II. Gevo's Detailed Comments on the Proposal

<u>§ 95484 "Annual Carbon Intensity Benchmarks" (i.e., Compliance Curve), Stepdown, and Automatic Acceleration Mechanism</u>

a. Gevo supports strengthening the overall compliance curve

CARB affirmed rigorous emissions reduction goals in the 2022 Scoping Plan update.
CARB's analyses and that of various outside parties, including ICF,[2] have confirmed not
only that the LCFS is a critical tool for emissions reduction in the State, but that the
LCFS carbon intensity (CI) benchmarks and compliance curve therefrom must be
strengthened to in order for the State's emissions goals to be met. Accordingly, Gevo
187.8 supports CARB's proposal to update the annual CI benchmarks through 2030 and
establish more stringent post-2030 benchmarks in alignment with the 2022 Scoping
187.9 Plan. Notably, the analysis undertaken by ICF demonstrates that CARB could go even

[2] ICF's prior analysis, captured in the report, "Analyzing Future Low Carbon Fuel Targets in California," was previously submitted to CARB by the Low Carbon Fuels Coalition. *See* Letter from the Low Carbon Fuel Coalition to CARB Chair, Liane Randolph (Sept. 28, 2023) (attaching the ICF report).

187.9 cont. farther, as ICF's LCFS analysis found that a 2030 target for the program greater than 40% is achievable, when all low carbon fuels are allowed to contribute fully under the program's technology-neutral, performance-based design.[3] Thus, while supporting CARB's benchmarks/compliance curve proposal, we urge CARB to view the proposed targets as a minimum, and to continue to consider ways to further advance emissions reduction through LCFS emissions targets.

187.10 cont.

b. The proposal for a stepdown in 2025 and for the auto accelerator mechanism are warranted and support California's emissions reduction goals, though CARB should further strengthen these proposed mechanisms

In addition to adjusting the overall compliance curve, CARB has also proposed a near-term, one-time 5% stepdown of the CI benchmark in 2025 and an Automatic Acceleration Mechanism (AAM). While Gevo supports the adoption of these mechanisms, we urge CARB to adopt a greater stepdown than proposed and to further strengthen the AAM.

The LCFS is clearly a successful program, exceeding its initially projected carbon reductions through what CARB has referred to as "overperformance." Although the LCFS has supported the production of a greater quantity of low-carbon fuels during a certain timeframe than originally projected, Gevo notes that labelling this phenomenon as "overperformance" is a bit of a misnomer. In actuality, given the State's aggressive carbon emissions reduction and climate goals, and the challenges associated with meeting them, the situation might better be referred to as underperformance of the CI targets and implementing mechanisms. As CARB has recognized, because the volume of low-carbon fuel has exceeded projections, the credit prices have been reduced and the credit bank is unduly large, thereby threatening continuing success. Implementing an appropriately calibrated near-term CI stepdown and automatic acceleration mechanism alongside the compliance curve/benchmarks revisions can address this. Indeed, a near-term CI stepdown can provide near-term market improvements while the accelerator mechanism will provide California with the tools to monitor the LCFS program and adjust it when needed. In addition, the accelerator mechanism will also help meet the State's interest in spurring additional emissions reductions from SAF by supporting expansion of SAF production (and other renewable fuels) by providing investors and industry with confidence that the LCFS can support the crediting of additional gallons without the long delays that would be required by future rulemakings.

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[3] ICF, "Analyzing Future Low Carbon Fuel Targets in California," (September 2023).

187.11 While Gevo supports adoption of these mechanisms, we are concerned that setting the stepdown at the proposed 5% level will be insufficient to achieve the intended results. As established in the ICF report accompanying comments submitted by the Low Carbon Fuels Coalition,[4] a stepdown in 2025 of at least 6.5% appears necessary to ensure that the LCFS credit bank does not continue to build. And that analysis also shows that a stepdown of at least 10.5% in 2025 likely is needed to ensure that the credit bank reverses and is drawn down to the level necessary to continue to incentivize LCFS-driven emissions reductions, i.e., with the credit bank holding approximately two to three quarters' worth of deficits. By contrast, ICF's analysis indicates that if CARB retains the proposed 5% CI stepdown for 2025, the credit bank will build in 2025, 2026, and 2027, with the credit bank reaching 45-50 million credits in 2027. In turn, this would trigger the AAM in 2028 and again in 2030, and yet the AAM would not be able to sufficiently adjust to correct the imbalance.

187.12 While ICF's analysis demonstrates that a greater 2025 stepdown is needed, it also demonstrates that this should be done in tandem with an adjustment to the proposed threshold for triggering the AAM so the AAM will be triggered when the credit bank is more than 2.5 times greater than the quarterly deficits generated in a given year. These changes would result in a tighter credit-deficit balance and would provide sufficient flexibility to respond to market conditions in the near-term future (pre-2030), while enabling California to achieve its long-term GHG reduction targets. Accordingly, Gevo recommends that CARB revise the stepdown and AAM proposals consistent with this analysis.

§95481(a): Revised Definitions of "Renewable Diesel" and "Renewable Naphtha"

187.13 Gevo is concerned about the proposed revision to the definition of "renewable diesel" and the proposed definition of "renewable naphtha" in the LCFS package. CARB's proposals would import specific feedstocks and production pathways (i.e., hydrotreated lipids and biocrudes or from gasified biomass that is converted using the Fischer-Tropsch process and portions from co-processing) into these definitions. As written, the proposed definitions would presumably exclude feedstocks and production pathways that are not enumerated. We urge CARB to reconsider this approach and to instead revert to the technology and feedstock neutral approach for these definitions.

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[4] See, ICF "Analyzing Future Low Carbon Fuel Targets in California: Response to Staff Report," February 2024, available at https://www.lcfcoalition.com/comment-letters-reports (tagged there as "ICF Analysis: Updated Results for Accelerated Decarbonization, Initial Statement of Reasons (ISOR) Case").

187.13 cont.

With specific respect to Gevo, our production process – the alcohol-to-hydrocarbons conversion process – apparently would be excluded from these definitions, as would our feedstock, corn starch (or other such biomass not expressly included in the proposed definitions).[5] Yet, renewable diesel and renewable naphtha are hydrocarbon fuels that are produced alongside our SAF (i.e., alternative jet fuel) in alcohol-to-hydrocarbons production facilities. There is no rational reason for excluding such truly renewable naphtha and diesel from the CA-LCFS program and to do so would unnecessarily limit the effectiveness of the LCFS. Moreover, by enumerating specific technologies and feedstocks (and in this case, so few), CARB would be creating an administrative barrier to the types of innovations the State wants to encourage, as regulatory revisions would have to be made each time a new feedstock or production process (or new combination thereof) were introduced. Accordingly, as noted, we urge CARB to make these definitions neutral as to non-petroleum feedstocks and production processes.

§95488.1(d)(4): Tier 2 Classification

187.14

As discussed above with respect to the proposed renewable diesel and naphtha definitions, we believe it is critical that CARB include – or not appear to exclude – the alcohol-to-hydrocarbon conversion process from LCFS eligibility. While Gevo understands that the Tier 2 pathway classification is not limited to the production processes listed in this section of the proposed regulation, we are concerned that the omission of the alcohol-to-hydrocarbon conversion process might be misread as an exclusion. Therefore, for clarification and transparency, we suggest revising the language associated with Tier 2 classification to explicitly mention alcohol-to-hydrocarbon conversion technology, as follows (proposed addition underlined and bolded, while the strikethroughs are in CARB's proposal):

> *(4)Drop-in fuels (~~renewable~~ biomass-derived hydrocarbons using processes such as gasification and pyrolysis, synthetic hydrocarbons,* ***and alcohol to hydrocarbon conversion****) except for renewable ~~diesel~~ hydrocarbon fuels produced from feedstocks described in section 95488.1(c)(3). This category includes fuels produced from low carbon feedstocks co-processed with fossil feedstocks in petroleum refineries;*

§95488.8(h)(2): Renewable or Low-CI Process Energy

In this section of the LCFS package, CARB has proposed the following physical limitation on biogas/biomethane: "Biogas or biomethane must be physically supplied directly to

[5] In addition to our NZ-1 facility, Gevo is planning additional facilities that would employ the alcohol-to-hydrocarbons process and there are other companies that also use such processes.

the production facility. The applicant must submit the attestation set forth below in section 95488.8(i)(2)(C)2."

The proposed requirement for physical delivery of biogas or biomethane, i.e., RNG, to a production facility would add significant cost burden and environmental impact as truck transport of RNG apparently would be required to decarbonize thermal energy. In addition to unduly burdening RNG suppliers like Gevo, it would be counterproductive to the State's emissions reduction goals.

187.15

To avoid these results, we encourage CARB to allow for biogas or biomethane to be supplied as process energy using the book-and-claim provisions under the regulation. This will bring the CA-LCFS into alignment with the recent changes in the Renewable Fuel Standard (RFS) Biogas Regulatory Reform – which now allows for biogas to be delivered via commercial natural gas pipelines and used to decarbonize thermal demands.

CARB recognizes the benefits of the book-and-claim approach and provides for book-and-claim of biomethane for hydrogen production/use in a production facility. As CARB has confirmed that book-and-claim approaches work well under the LCFS, such an approach should be authorized for natural gas thermal heating.

§95488.9(b) Temporary Fuel Pathways

187.16 Gevo applauds CARB's proposal to include alternative jet fuel (i.e., SAF) temporary pathways in Table 8. This will allow new ATJ production facilities to send initial batches of fuel to the State while awaiting approval of a provisional pathway.

187.17 We respectfully request that CARB expand the ATJ temporary pathways to include corn starch feedstock processed using an alcohol-to-hydrocarbon production process. As noted above, the alcohol-to-hydrocarbon pathway is well established, with multiple ATJ/SAF facilities using this production process coming online. Inclusion of the corn starch feedstock to alcohol-to-hydrocarbon process as a temporary ATJ pathway will further incentivize its production, helping to meet the State's emissions reduction goals and will avoid the delay that would be occasioned by deferring its addition until later.

§ 95488.10(b): "Credit True Up after Annual Verification"

187.18 Gevo supports a credit true up in the LCFS program for all pathways and believes it should be expanded to also include true ups between temporary pathways and provisional pathways.

Temporary LCFS pathways offer production facilities an opportunity to generate LCFS credits while awaiting full provisional pathway approval. While these temporary pathways are vital to supporting the start-up and build out of new production facilities, the credits generated are much more conservative than actual carbon intensity reductions the fuel is offering to California.

187.18 cont. *Example: RNG Pathways*

We note that the RNG temporary pathway score of -150 CI for swine and dairy manure biomethane projects is more than 50% higher than the actual CI of Gevo's operating facility. Provisional pathways undergo the same rigorous validation and verification process as operational pathway CI scores undergo. By allowing "true ups" between temporary and provisional CI's, CARB would be supporting the successful start-up of these production facilities and recording actual GHG emission savings as part of the program.

A significant amount of capital is invested to ensure the success of methane emissions abatement through RNG projects. RNG projects are critically important because they mitigate methane (a potent GHG) from entering the atmosphere that would normally be released through standard agricultural operations. Yet the lack of a true-up mechanism between temporary and provisional pathways results in significantly discounting the real emissions reduction value of an RNG project simply due to regulatory process and associated timelines, thereby disincentivizing such projects. By contrast, a true-up mechanism would allow operators like Gevo to be rewarded for the entirety of their project and the real-world climate value these projects bring, thereby supporting and promoting investment in climate mitigating projects like Gevo's.

§ 95488.9(g): "Sustainability Requirements for Crop-Based and Forestry-Based Feedstocks"

Gevo is committed to providing low-carbon, sustainable SAF, which starts at the field and goes all the way into the aircraft. As noted, we plan to source sustainably-grown, low-CI field corn from the Lake Preston, South Dakota area and use Verity Tracking to measure and verify carbon intensity and all farm activities to the field level. The Gevo Growers' Program is already enrolling farmers under our $30 million USDA Climate-Smart Commodities grant, which allows us to pay farmers more for implementing climate-smart agriculture practices such as cover crops, reduced tillage, organic fertilizers, and nutrient management.

187.19 These practices are critical to producing sustainable feedstock. In addition to sequestering carbon in soil, they provide significant additional ecosystem benefits such as better soil health, better water quality, higher water use efficiency, more resilient crops, and long-term land fertility. These practices are a significant component of Gevo's approach to sustainable SAF production and we fully support crediting them under the LCFS.

Gevo also supports and is committed to fully meeting appropriate sustainability criteria.
187.19a Unfortunately, what CARB has proposed misses the mark. CARB has not set out specific sustainability requirements that it would expect to be met, instead deferring to unspecified third-party schemes. CARB's failure to set out specific requirements calls into question not only how one might comply, but also whether CARB has the legal and regulatory authority to import into the LCFS undefined substantive provisions within outside schemes.

Indeed, the provisions under (1)(B) are too vague to be implemented appropriately and consistently across production facilities and by various certification bodies. For example,
187.20 the provision that "the certification must consider environmental, social, and economic criteria" could be interpreted in a variety of ways. It is unclear from the proposed language which specific environmental, social, and economic criteria would be deemed essential for the CA-LCFS program and how they might align with program goals. Further, CARB's failure to establish clear criteria calls into question why the current analytical, science-based methodologies used by CARB are assumed to be insufficient to provide the necessary controls on crop-based (and forestry) feedstocks to ensure environmental integrity.

Moreover, it is unclear why crop and forestry-based fuels are being singled out for meeting social and economic criteria, which have implications for any fuel pathway
187.21 participating in the program. These additional criteria have the potential to add substantial administrative burden to both farmers and fuel producers, potentially creating barriers to participation in the LCFS, and as such should be carefully considered in the context of what the program hopes to achieve with these criteria.

187.22 Accordingly, we implore CARB to remove this section from the rulemaking and continue to mature the development of specific program requirements with multi-stakeholder input and workshop feedback to align whatever substantive requirements CARB might impose with specific LCFS goals and to make the provisions practicable. Critically, this stakeholder input must bring farmers and others who work in agriculture to the table. Farmers are more often than not omitted from the development of program standards,
187.23 despite being the most critical actors in implementation of those standards. Specifically, while we are members of and work with the Roundtable on Sustainable Biomaterials (RSB) and the International Sustainability and Carbon Certification (ISCC) initiative, in our experience, despite being well intentioned regarding stakeholder input, these entities have not actively included farmers in the development of standards and only seem to consult such stakeholders after standards have already been formalized, if at all.

187.24 Notably, in establishing specific sustainability criteria that are expected to be met for crop-based feedstocks, CARB should include provisions that allow for climate-smart agriculture practices to be credited under the LCFS. These practices represent significant additional effort on the part of the farmer to implement and are a departure from business-as-usual feedstock production. Moreover, these practices can bring significant GHG emissions reductions, as recognized by the U.S. Department of Agriculture, the National Academy of Sciences, the IPCC, and others.[6][7][8] Hence, they should be incentivized through crediting to drive adoption of these important practices.

187.25 By focusing in on what the State of California seeks to achieve through additional sustainability criteria, and delineating those criteria with appropriate inputs, CARB can ensure that program requirements are fit for purpose, clear, transparent, applied fairly across feedstocks and fuel production processes, properly credit GHG emissions reductions from agricultural feedstocks, and align with LCFS-specific program goals. And such a process need not take long, as CARB could set up a process with a specified time frame (e.g., six months) as it has in other instances where program requirements need to be refined.

Biomethane Projects

187.26 Gevo applauds CARB for progressing the LCFS to encourage the mitigation of GHG emissions, increase the production and consumer optionality of clean fuels, and facilitate investments of such clean fuels. To continue to meet those objectives, Gevo urges CARB to continue its progressive stance on biomethane projects, rather than create limitations for methane avoidance projects. Accordingly, Gevo recommends that CARB continue to support biomethane projects that benefit the climate, regardless of location, pipeline flow directionality or end-use, thereby providing a level playing field

187.27 for projects that provide the same GHG mitigating practices. Much like carbon capture and sequestration (CCS) is not limited by its location in the U.S. and is judged by the

[6] J. Rosenfeld, J. Lewandrowski, T. Hendrickson, K. Jaglo, K. Moffroid, and D. Pape, 2018. A Life-Cycle Analysis of the Greenhouse Gas Emissions from Corn-Based Ethanol. Report prepared by ICF under USDA Contract No. AG-3142-D-17-0161. September 5, 2018.

[7] National Academies of Sciences, Engineering, and Medicine. 2019. Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Washington, DC: The National Academies Press. doi: https://doi.org/10.17226/25259.

[8] Nabuurs, G-J., R. Mrabet, A. Abu Hatab, M. Bustamante, H. Clark, P. Havlík, J. House, C. Mbow, K.N. Ninan, A. Popp, S. Roe, B. Sohngen, S. Towprayoon, 2022: Agriculture, Forestry and Other Land Uses (AFOLU). In IPCC, 2022: Climate Change 2022: Mitigation of Climate Change. Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change, P.R. Shukla, J. Skea, R. Slade, A. Al Khourdajie, R. van Diemen, D. McCollum, M. Pathak, S. Some, P. Vyas, R. Fradera, M. Belkacemi, A. Hasija, G. Lisboa, S. Luz, J. Malley, (eds.)]. Cambridge University Press, Cambridge, UK and New York, NY, USA. doi: 10.1017/9781009157926.009.

fact that GHG emissions are removed from the atmosphere, these same principles should be applied to biomethane projects throughout the U.S., without the limitations proposed in the current round of LCFS revisions and as outlined below.

Book-and-Claim and Deliverability Requirements

§ 95488.8. Fuel Pathway Application Requirements Applying to All Classifications.

§ 95488.8.(i)(2)(B)(1) Book-and-Claim Accounting for Pipeline-Injected Biomethane Used as a Transportation Fuel

187.27 cont.

Gevo urges CARB to continue to expand book-and-claim and deliverability requirements within the LCFS in general, and to not place book-and-claim (or other) restrictions on biomethane projects. CARB's proposals in the LCFS package that would place restrictions on biomethane projects risk the LCFS program's ability to decarbonize through biomethane projects. In particular, Gevo opposes CARB's proposal for biomethane projects breaking ground after December 31, 2029, which would mandate that "[s]tarting January 1, 2041…the entity…must demonstrate that the…pipelines along the delivery path physically flow from the initial injection point toward the fuel dispensing facility at least 50 percent of the time on an annual basis." Instead of singling out certain biomethane projects for such restrictions, Gevo supports consistency in LCFS pathways and believes biomethane projects be evaluated and credited on the science-based merits of GHG emissions reduction, rather than the project location or directionality of biomethane flow in U.S. pipelines.

Gevo supports CCS projects across the U.S. for the GHG reducing merits and believes this same concept should apply to existing and future biomethane projects. In the same way that carbon dioxide does not have to be transported and injected into California's geologic pore space to provide value to the climate, biomethane projects should not be geographically limited. In sum, Gevo supports the expansion of book-and-claim accounting mechanisms, rather than restrictions, promoting the tangible reductions in GHG reductions that result from this type of program flexibility.

Crediting Periods – Avoided Methane Emissions

§ 95488.9(f): "Carbon Intensities that Reflect Avoided Methane Emissions from Dairy…Manure…"

§ 95488.9(f)(3)(A) Crediting Periods

187.28

As noted, Gevo strongly believes that RNG projects that remove methane, a potent GHG, from the atmosphere should not be limited in their eligibility or approval within the LCFS program, for existing or future projects. To realize the level of emissions

187.28 cont. benefits needed to meet California's climate targets, all projects that bring demonstrable emissions benefits should continue to be credited on a performance basis. Thus, Gevo urges CARB to decline to adopt the limits on the crediting periods that it has proposed under the LCFS.

Missing Data Provisions

§ 95491.2. Measurement Accuracy and Data Provisions.

CARB, like many regulatory bodies, has recognized the use of "reasonable temporary methods" to address data gaps, recognizing that operational realities result in such gaps and can be reliably filled in alternative ways. Accordingly, Gevo urges CARB to continue to allow those participating in the LCFS to be able to use "a reasonable temporary
187.29 method," rather than being shoehorned into the limited data substitution tactics specified under 95491.2(b)(2)(B)'s Table 13. CARB has not provided a reasoned basis for eliminating the "reasonable temporary method" option, which provides needed flexibility to Gevo and others with current and anticipated pathways in locations that are remote and with intermittent communication outages. While Gevo typically does not experience significant outages, we appreciate flexibility in filling in for missing data periods using the data immediately before and after an outage period, which has been established as a statistically valid approach to addressing such data gaps. And such flexibility is important for RNG and other renewable fuel facilities because such operations tend to have variability in operations. For example, Gevo's RNG facility has variability due to cow herd counts, associated manure volumes, drastic changes in weather conditions that can drive utility usage, and cold weather events that can cause occasional freezes/shutdowns.

The data immediately before and after an outage is able to account for such operational variability and would be expected to be more accurate than averages across a 30-day before/after-, year-to-date- or two-year- period, as would be required under 95491.2(b)(2)(B)'s Table 13. As another example, the amount of natural gas Gevo uses in the summer is nominal to what Gevo will use in the winter on a 0-degree Fahrenheit day. In such cases, incorporating averages outside of the missing data period as apparently would be required under Table 13 often would not align accurately with actual operations.

Thus, Gevo advocates for maintaining flexibility in approach and supports the current approach of being able to use a "reasonable temporary method." Gevo currently documents our "reasonable temporary" methods thoroughly and has confirmed their reliability. Indeed, this approach allows for unique downtime events to be addressed with realistic data directly before and after the event. Additionally, being forced to utilize Table 13 would be expected to negatively – and unduly – impact Gevo's CI score as the substituted values would not be representative of operational events around

187.29 cont. each missing data event. Due to the operational parameters described above, the values that would fall in the 10th or 90th percentile or the highest and lowest values in a given year or two would be *too* conservative to reflect actual operations. This would have a significant negative impact on Gevo's actual CI score by forcing much higher or lower values compared to real operating values during missing data events.

Lastly, Gevo believes even if we were able to resort to an "Executive Office approved alternate method," this would pose a significant burden on not only Gevo, but on CARB, as CARB will be called on to review each unique method for approval. Gevo is also concerned that this proposed approach will unnecessarily delay pathway certification. In our experience, verifiers are well qualified to ensure that data substitution under "reasonable temporary" methods are robust. Accordingly, we encourage CARB to retain this option for data substitution.

§ 95491.2(b)(2)(C) Force Majeure Events

187.30 Gevo respectfully requests that CARB provide more definition and specificity around "Force Majeure Events," especially regarding what might be deemed a "facility shutdown" or "disruption drastically affecting production." As noted above, alternative fuel production facilities can face shutdowns and disruptions (and typically more frequently than their petroleum-based counterparts) given the expected variability in bio-feedstocks and processing conditions. Thus, to the extent that CARB seeks to impose further requirements for what it defines as "shutdowns" and "disruptions," it will be critical to Gevo and other alternative fuel producers that these terms are fleshed out and understood.

Overall, Gevo believes the types of events CARB is implying in this section are already captured in shutdown logs provided to the verification body along with the data captured during the events (typically null or zero values). Thus, it seems unnecessary and unduly burdensome to require special reporting for such events within 90 days, given the remote nature and geographic location of many alternative fuel facilities and especially given that production during these events is minimal to zero, which is readily captured in the reported dataset(s).

Tier 1 CI Calculator for Dairy and Swine Manure Biomethane: Retention Time and Drainage

Gevo reasserts here the comments we submitted on July 12, 2023, regarding the proposed changes to the "Biomethane from Anaerobic Digestion of Dairy and Swine Manure" Tier 1 calculator. As before, CARB has proposed a change regarding the "Retention Time and Drainage" instructions for Tier 1 calculators. Currently, an applicant can select from the options that are applicable to their farms in the "Manure-to-Biogas (LOP Inputs)" tab without having to select a particular month where the system is completely emptied. CARB has now proposed a standardized requirement that: "If there is no regular storage/treatment system clean schedule, must select 'System Emptied in This Month' each September. The applicant only needs to select one 'System Emptied in This Month' for each year."

187.31 Gevo appreciates what we perceive to be CARB's approach to standardize the Tier 1 Calculator's inputs for swift processing. Nonetheless, we are concerned that by setting this specific "System Emptied" timeframe, this requirement can result in a forced increase in the CI of a project, causing a penalty to farms that retain a certain level of volatiles in their storage system throughout the year. Accordingly, we urge CARB to retain the current approach rather than adopting this amendment.

In any event, although the proposal appears to seek to standardize, and only apply to, Tier 1 applications, to the extent CARB proceeds with the proposed change, we respectfully request that CARB continue to assess site-specific optionality in Tier 2 applications. This will ensure unnecessary penalties aren't assessed for farm-specific circumstances in which the farm does not completely empty their storage systems in any year.

Removal of "business days" and overall shortening of response timelines

187.32 In several sections of the rulemaking proposal, CARB has proposed shortening the fuel pathway applicant response timeline from "business" days to "calendar" days, effectively reducing the amount of time allowed for responses. In some sections response time has been reduced even further (for example: reduction from 15 business days to 14 calendar days). This includes sections:

- §95488.5(c) Completeness Check for lookup table fuel pathway applications
- §95488.7(d) Certification process for Tier 2 pathway applications

Although the proposed changes might seem trivial to CARB, in application the reduction in response times will put significant additional strain on compliance program staff dedicated to supporting LCFS pathway compliance. And yet there is no compelling reason for CARB to make these changes. Accordingly, we recommend that CARB maintain the current regulatory language and timelines, including specifying "business" days and providing appropriate and needed time for fuel applicant response.

Tier 1 and Tier 2 application data interval requirements

187.33 With respect to the proposed application data intervals, Gevo recommends specifying a six (6) month timeline, rather than a three (3) month timeline as outlined below.

The LCFS proposal has added language in the following sections:

- *§95488.6(a)(1) "Tier 1 applications must not have an interval of greater than 3 months between the end of the reported operational data month and the date of submission"*
- *§95488.7(a)(1) "Tier 2 applications must not have an interval of greater than 3 months between the end of the operational data month and the date of submission."*

187.33 cont.

The process to collect data, prepare the Tier 1 or 2 calculator and supporting documentation package is significant and, in our experience, requires the support of dedicated internal staff resources and outside consultants. Imposing a three-month timeframe on the preparation and submission of an LCFS application package will cause a significant cost burden and may not be feasible for all projects. In addition, there does not appear to be a compelling reason for limiting the intervals to only three months. Thus, Gevo recommends that CARB specify six (6) month timelines instead.

III. Conclusion

Thank you for the opportunity to comment on the "Proposed Amendments to the Low Carbon Fuel Standard." Please let us know if you have any questions regarding our comments. We look forward to continuing to participate in this program with our RNG and as Gevo begins commercial scale production of SAF and other biofuels.

Respectfully,

Kent Hartwig
Director of State Government Affairs

Nancy N. Young
Chief Sustainability Officer

Gevo, Inc.

Comment Log Display

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Comment 197 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Dean
Last Name	Taylor
Email Address	Dean@CalETC.com
Affiliation	
Subject	EVCA-CalETC joint comments on proposed 2024 LCFS
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6859-lcfs2024-VDEAcFAyWGoKIQVm.pdf
Original File Name	EVCA-CalETC comment letter on proposed LCFS amendments Feb 20, 2024 vF.pdf
Date and Time Comment Was Submitted	2024-02-20 10:47:03

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

Honorable Chair Liane Randolph and Honorable Board Members California Air Resources Board
1001 I Street
P.O. Box 2815
Sacramento, CA 95812

Re: SUPPORT Proposed Amendments to the Low Carbon Fuel Standard Regulation

Submitted to https://ww2.arb.ca.gov/applications/public-comments

Dear Chair Randolph and Honorable Board Members:

The Electric Vehicle Charging Association (EVCA) and CalETC appreciate this opportunity to SUPPORT the Low Carbon Fuel Standard (LCFS)regulation and provide feedback for the California Air Resources Board (CARB) Board member consideration. This letter largely supports the proposed draft regulation order and provides some suggested modifications for consideration. We also appreciate the tremendous effort and accessibility of CARB staff during the extensive public process leading up to this hearing.

EVCA is a not-for-profit trade organization of twenty leading EV charging industry member companies and two zero-emission autonomous fleet operators. The association was established in 2015 to comprehensively represent the entire EV charging value chain and provide a collective industry voice for decision makers.

CalETC is a non-profit association committed to the successful introduction and large-scale deployment of all forms of electric transportation including plug-in electric vehicles of all weight classes, transit buses, port electrification, off-road electric vehicles and equipment, and rail. Our board of directors includes Los Angeles Department of Water and Power, Pacific Gas and Electric, Sacramento Municipal Utility District, San Diego Gas and Electric, Southern California Edison, the Northern California Power Agency, and the Southern California Public Power Authority. Our membership also includes major automakers, manufacturers of zero-emission trucks and buses, developers and operators of charging stations and other industry leaders supporting transportation electrification. CalETC supports and advocates for the transition to a zero-emission transportation future to spur economic growth, fuel diversity and energy independence, ensure clean air, and combat climate change. Please note that the views and comments reflected in this letter represent the positions of the CalETC board of directors and some, but not all, of the members of CalETC.

Over the past 10 years, the LCFS has been tremendously successful in supporting the transition from petroleum to cleaner transportation fuels including electric fuel. Clean low-carbon fuels have replaced a percentage of petroleum and, in doing so, have reduced climate change pollutants as well as a myriad of air and toxic pollutants that adversely impact communities. The LCFS has served as a catalyst for billions of dollars of investments in clean fuels and infrastructure.

The most recent Intergovernmental Panel on Climate Change (IPCC) report along with countless studies cannot be clearer on what science tells us. We must act decisively with an amplified focus on mitigation if we are to limit the most severe impacts of climate change—impacts that will be disproportionately borne by those least equipped to adapt. The Governor and the Legislature's leadership to address the threat that climate change poses to the health of Californians and the economy is emphatic and reflected in a series of actions including statutorily mandated greenhouse gas reduction targets and an unprecedented budget commitment.

The 2022 update to the Scoping Plan is the state's response to the need for a holistic strategy to achieve legislatively mandated greenhouse gas reduction targets including achievement of carbon neutrality by 2045. The 2022 Scoping Plan is built on science and robust analysis, presenting an irrefutable case for ramped-up mitigation and public investment relying heavily on strengthening programs that have been effectively implemented for years. In short, there is no path to achieve the state's climate goals without strengthening the LCFS.

We have been participating in staff workshops for several years and have had several constructive conversations with staff in that time. We very much appreciate their accessibility and commitment to LCFS.

For a summary of our comments, please see the Executive Summary, immediately below. Thank you again for the opportunity to provide CalETC's feedback on this important program.

Executive Summary of CalETC's Comments

EVCA and CalETC largely support the proposed amendments to the LCFS (also referred to as draft regulation order). However, we have many significant concerns and requests for amendments. A summary of our support positions and requests for changes is as follows:

188.1 1. EVCA and CalETC recommend the hearing on the new LCFS be no later than 2nd Quarter 2024,
188.2 2. EVCA and CalETC support the proposed carbon intensity targets in Table 1 (e.g., 30% in 2030 and 45% in 2045),
188.3 3. EVCA and CalETC appreciate the proposal to extend the existing Fast Charge Infrastructure (FCI) program for light duty EVs at public charging locations, but the proposed size and rules governing this program are inadequate to meet California's needs for 83,000 public DC fast chargers by 2035 needed to support the Advanced Clean Cars II (ACC II) regulation,
188.4 4. EVCA and CalETC appreciate the proposal to create a new FCI program for medium-, and heavy-duty EVs (eMHDVs) at public, fleet, and shared depot locations but the proposal includes several limiting parameters that will undercut its effectiveness in supporting

California's Advanced Clean Truck (ACT) and Advanced Clean Fleet (ACF) requirements. EVCA and CalETC oppose the geographic limits and prescriptive site limits and specifications included in the proposed LCFS. A larger, more flexible program is needed to meet industry needs, accelerate deployment, reduce costs, and align with California's truck electrification ambitions,

188.5 5. EVCA and CalETC oppose the proposed requirements for parties to pay for visits to individual charging stations by third-party verifiers to check for accuracy at public and private charging stations for light -, medium-, and heavy-duty EVs and incremental residential credits when reviewing quarterly fuel transaction reports. Instead, we recommend parties pay for desk-top reviews by third-party verifiers at central data locations that do not duplicate existing accuracy regulations established by the California Department of Food and Agriculture's Division of Measurement Standards and the California Public Utilities Commission (CPUC) and that generators of small numbers of non-residential credits be exempted from these requirements,

188.6 6. EVCA and CalETC recommend at least an immediate 7% step down in carbon intensity (CI) to better account for historical overcompliance and push the market to greater levels of emission reduction and attract the private capital needed to meet state requirements and goals,

188.7 7. EVCA and CalETC support the proposed automatic acceleration mechanism but recommend that the mechanism can be triggered as soon as 2027,

188.8 8. EVCA and CalETC continue to recommend the new LCFS create a level playing field for emerging transportation electrification end-uses in airports, agriculture, mining, marine, aviation, and recreation by adding conservative default EER of 2.0. while excluding certain end-uses such as golf carts and indoor sweeper/scrubbers that are already electric,

188.9 9. EVCA and CalETC support the proposal for all sizes of electric forklifts to remain in LCFS,

188.10 10. EVCA and CalETC support expanding LCFS to new sectors. We support expanding LCFS to include new types of transportation (e.g., sea and air transport). Including new types of transportation will further necessitate increasing the stringency of LCFS. The Low Carbon Fuel Standard is a successful tool for decarbonizing transportation and should be expanded to other types of transportation given the climate crisis.

EVCA- CalETC Comments on the January 2024 LCFS Draft Regulation Order

EVCA and CalETC appreciate this opportunity to comment on the proposed LCFS amendments. Our comments focus on the electricity-related provisions.

188.1 *1. EVCA and CalETC recommend the hearing on the new LCFS be no later than the 2nd Quarter 2024.*

The first CARB workshop on amending the current LCFS was in late 2020. We previously recommended the new LCFS go into effect in January 2023 if not sooner. The market participants need a new LCFS in effect by the end of this year at the latest.

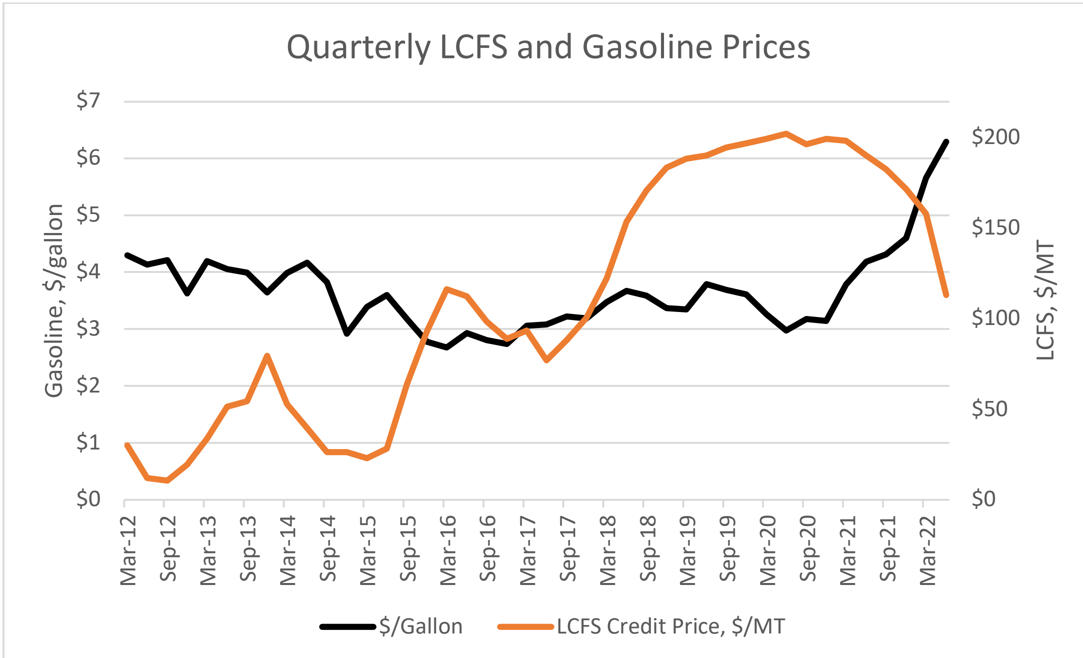
188.2 *2. EVCA and CalETC support the proposed carbon intensity targets in Table 1 (e.g., 30% in 2030 and 45% in 2045).*

EVCA and CalETC applaud staff for aligning the proposed Table 1 requirements with CARB's Scoping Plan vision and providing industry and stakeholders with the certainty needed for LCFS to be successful to planners, implementers, and investors.

Currently the LCFS is overperforming as the carbon intensities are too easy for the market to meet, leading to low credit prices that are undermining investment in electric cars, trucks, buses, and charging infrastructure, as well as infrastructure for other low-carbon fuels. Multiple models support increasing the stringency of the LCFS to a minimum 30 percent reduction in carbon intensity by 2030. It is essential that the stringency be increased expeditiously and be implemented as soon as possible to ensure the LCFS continues to contribute substantially to the state's clean air, climate change, and zero-emission transportation requirements and goals. The LCFS has been a highly successful program as part of a broad package of regulations and incentives to address climate change. For the LCFS program to continue to be successful, the annual compliance requirements on regulated parties should be strengthened and extended. Currently, the LCFS credit market suffers from credit oversupply issues. When the 2030 standard was adopted, the CARB Board made it clear the standard could be adjusted if market circumstances called for adjustment. CARB must expeditiously address this market supply issue; increasing the overall stringency of the LCFS regulation is one way to accomplish this.

While there are impacts to retail gasoline prices from LCFS compliance, the correlation between LCFS prices and gasoline prices is not nearly as significant as global macroeconomic factors that play a much larger role in price swings of this global commodity. The impact of increased LCFS stringency on gasoline prices is overshadowed by other factors. This makes it difficult to determine how the regulated oil industry is responding to increased stringency in LCFS with respect to consumer pricing of gasoline and diesel. The graph below[1] does not show a direct, quantifiable link between quarterly LCFS prices and the price of gasoline. Further, as gasoline faces competition from low-carbon fuels in the next decade, it is likely that any price impact between LCFS stringency and gasoline prices will be further muted.

[1] https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMM_EPM0_PTE_SCA_DPG&f=M



188.3 3. *EVCA and CalETC appreciate the proposal to extend the existing Fast Charge Infrastructure (FCI) program for light duty EVs at public charging locations but the proposed size and rules governing this program are inadequate to meet California's needs of 83,000 public DC fast chargers by 2035 to support ACC II.*

The proposed LCFS would create a new light duty vehicle FCI program 2026-2030 where the cap on prior quarter deficits is 0.5% (instead of the current 2.5% cap) and limit FCI projects to disadvantaged communities (DACs) are rural areas only instead of the entire state like the current light duty (LD) FCI.

EVCA and CalETC support the following aspects of an FCI program. The current FCI program (which ends in 2025) is a well-designed program that has been effective in helping attract capital to build public DC fast charge stations in California by helping to de-risk investment and, if not for the pandemic, would have been even more successful. One of its most attractive aspects is that it results in charging plazas and refueling stations being able to exit the FCI program and transition to traditional LCFS credits. Put another way, both FCI and hydrogen refueling infrastructure (HRI) capacity credits decrease over time as the utilization of the stations increases and the station generates more traditional LCFS credits.

Recommendations. The proposed LD-FCI program has limits, caps and rules that are very different than the current program and that are inadequate to support the infrastructure needed for the ACC II regulation. In summary, we recommend the existing light duty FCI program be continued to 2035 with only a few modifications to the existing program.

- Changes to the existing program that we support. The proposed regulation makes the LD FCI credit life 10 years instead of five years and the formula for calculating LD FCI credits to be linear rather than exponential. Both of these changes make LD FCI have rules that align with the proposed LD HRI. The proposed regulation removes requirements on connectors and raises the minimum charger kW from 50 to 150 kW.
- Keep the existing program rather than the proposed changes. The existing LD FCI program has a 2.5% cap on prior quarter deficits, but the proposed regulation lowers this to 0.5%. The existing LD FCI does not have geographic limits on public DCFC locations, but the proposed regulation does. The existing regulation caps sites at 2.5 MW with exceptions allowed up to 6 MW, but the proposed regulation caps sites to 1 MW and four connectors per site which encourages 250 kW chargers. We discuss these issues in detail below.
- Other recommended changes. The proposed LD FCI should allow applicants to have zero carbon electricity just like the proposed LD HRI does, and few exceptions should be allowed for DCFC projects in cities and towns that serve apartments and condominiums with DCFC located at curbside or in public, private and non-profit parking lots outside of the apartment or condominium. We discuss these recommendations in detail below.

Keep in the new LD FCI the current 2.5% cap on prior quarter deficits: The CARB Scoping Plan, ACC II, and the AB 2127 report by the California Energy Commission (CEC) all call for or inherently require rapid build-out of DCFC infrastructure to support the light duty vehicle electrification for all use cases. However, the 0.5 percent cap for light duty FCI in the proposed LCFS does not reflect the widespread demand and need for fast charging to meet state requirements.

With the adoption of the ACC II regulation requiring 100 percent of new vehicle sales be battery EVs, fuel cell EVs and plug-in hybrid EVs with 50-mile all-electric range in 2035, California is requiring a dramatic increase in sales of light-duty ZEVs. The rapid deployment of ZEVs accessible to all Californians and the success of ACC II depends upon substantially more access to ZEV fueling infrastructure than currently exists. Therefore, it is counter to the state's ZEV requirements and goals and the commensurate need to build out sufficient fueling infrastructure to reduce the capacity credit generation cap to 0.5 percent for the LD FCI program and 0.5 percent for the LD HRI program. This is particularly true in 2026-2035, when the state anticipates massive ZEV sales increases and a commensurate build out of public fueling infrastructure. It is too early to declare "mission accomplished" on light duty electric vehicle charging. In the technology adoption life cycle, we are now past the early adopters and into the mainstream of car buyers. These buyers tend to be more risk-adverse and more concerned with the availability of charging infrastructure. It is crucial that we continue to maintain a 2.5% cap to create a positive charging experience for these mainstream customers and use the FCI program to build infrastructure in advance so that we can continue to advance the ACC II towards 100 percent of new car sales.

While an increase in battery EV sales will likely lead to greater utilization of DCFC in a manner that reduces the need for FCI credit generation in certain areas, DCFC usage is not uniform across the state; regrettably, a more restrictive cap on light-duty FCI credits will adversely affect DCFC deployment opportunities in communities with less favorable station economics, which may include rural, low-income, and disadvantaged areas of the state which need more DCFC than a 0.5 percent cap can provide.

Moreover, light-duty FCI credits are also critically important for supporting ongoing operating costs for fast chargers and help enhance station reliability. With charging experience topics emerging as a state and national priority, EVCA and CalETC assert that maintaining broad pathways for light-duty FCI credits will be important for driving consumer confidence in EVs and charging technology – particularly at stations that have yet to achieve robust levels of utilization.

According to the modeling done by Southern California Edison using the Bloomberg New Energy Finance model, the impact of a ten percent cap on prior quarter deficits for capacity credits (light-, medium and heavy duty for both FCI and HRI programs) to the overall LCFS out to 2030 is manageable and the lower cap in the proposed LCFS is not needed.[2] Furthermore, as shown by the CEC (with the National Renewable Energy Lab), 37,000 public DCFC will be needed to support 8 million EVs in 2030,[3] and 83,000 public DCFC will be needed to support the nearly 14 million EVs expected in 2035 under the ACC II regulations.[4] In fact, data from the CEC and NREL confirm that substantially more DC fast chargers will be needed than the Governor's prior Executive Order.[5] CARB's new LCFS should be aligned with the needs of ACC II. Absent further analysis from CARB demonstrating materially adverse effects from preserving the current light-duty FCI credit structure, EVCA and CalETC recommends that CARB maintain the size of the light-duty credit pool at 2.5 percent of prior quarter deficits.

Keep in new FCI the eligibility of LD FCI sites statewide. The proposed regulation's limit on LD capacity credit generation to fueling infrastructure located in low-income, rural, or disadvantaged communities (DAC) does not align with the state's efforts to reduce impacts in those communities, nor does it ensure benefits to those communities. While there may be situations where a low-income or disadvantaged community benefits from fueling infrastructure located in the community, alternatively some communities may prefer that the preponderance of fueling

[2] See SCE's letter December 21, 2022 on the LCFS workshop docket, pages 12-13.
[3] Figure 1. Final AB 2127 report from the California Energy Commission (CEC) 2020.
[4] Comments by NRDC on ACC II regulation, page 5.
[5] Governor's Executive Order is 10,000 DC fast chargers by 2025.

infrastructure be primarily located outside the community to limit the traffic flow within the community. DAC residents travel beyond their communities and benefit from DC fast chargers outside of the DACs. Also, there may be fueling infrastructure facilities that serve light-, medium-, and heavy-duty ZEVs. And as explained above, the need is so great to meet ACC II that public DCFC are needed in all parts of the state.

The proposed regulation has a restriction that effectively limits LD FCI stations to rural areas because it limits FCI stations to be no closer than ten miles from an existing DCFC station. We oppose this because it is not workable to develop LD FCI stations and check federal maps (e.g., Alternative Fuel Data Center) on a daily, monthly, or even quarterly basis to see if the planned station remains within ten miles of some other public DCFC station.

If our recommendation for no geographic restrictions is not acceptable, we recommend the new LCFS use the term "rural area" instead and it be defined to align with the new definition used by the US Census Bureau. Specifically, we recommend the following edits to Section 95481: "Rural Area" means a census tract ~~with at least 75 percent of its population~~ identified as ~~rural~~ non-urban by the latest US Census data. This definition aligns with the United States Treasury Department and Internal Revenue Service (IRS) guidance on station eligibility for the 30C alternative fuel vehicle fueling property tax credit, which was designed to support the deployment of EV charging infrastructure in non-urban (rural) communities across the US and updated in the Inflation Reduction Act.[6] The U.S. Department of Energy has also published a clear mapping tool that shows which census tracts meet IRS definition of non-urban census tracts.[7] The federal definition of non-urban census tracts is easily understood, stable, and remains in effect through 2030 until the Census Bureau updates determinations of urban and non-urban areas.[8]

We also recommend that the FCI program should be slightly modified in order to address the "chicken and egg" infrastructure problem associated with placing public-access DCFC in cities and towns to serve EV drivers who live in apartments and condominiums and where the DCFC is placed in locations such as curbside of a street or in public, non-profit or private parking lots. Building charging at multifamily residences is a well-recognized challenge and placing level 2 chargers on site is not always attractive or in many cases even possible. CARB has an opportunity with this LD FCI program to address this problem by encouraging DCFCs at nearby locations that will work not only for residents of apartments and condominiums but also for

[6] https://www.irs.gov/pub/irs-drop/n-24-20.pdf
[7] https://experience.arcgis.com/experience/3f67d5e82dc64d1589714d5499196d4f/page/Page/
[8] https://www.irs.gov/pub/irs-drop/n-24-20.pdf and https://www.census.gov/programs-surveys/geography/guidance/geo-areas/urban-rural.html

residents of single-family homes in denser urban areas where off-street parking is limited. We recommend the following three changes to the proposed regulation:

- The 24-7 requirement for public access should, at minimum, be slightly modified so that non-profit and private locations in our proposal do not run into problems with rights-of-way laws. For example, a site such as a church or a bank needs to close their parking lot for at least one day a year in order to not lose their property rights. Ideally, CARB should also accommodate, through an exception process, other times that access could be blocked for a few hours (e.g., neighborhood festivals).
- CARB should allow less than 150 kW chargers through an exception process (applications to the Executive Officer). An example: adding two 25 kW DC fast chargers curbside is possible next to underground vault transformers in an urban area.[9] While this may not be a common application, it is a worthy experimental program that could be easily added to the new LCFS.
- Finally, if CARB keeps the proposed geographic restrictions in the proposed LCFS, we recommend that the geographic restriction be lifted for our proposal above to serve those EV drivers who mostly live in apartments and condominiums anywhere in California.

Keep in the new FCI the current rules allowing a 2.5 MW per site cap with exceptions allowing up to 6 MW and more chargers per site. Also, encourage 150 kW rather than 250 kW chargers. To reach the infrastructure needs of ACC II charging sites discussed above much larger than 1 MW sites limited to four connectors per site are needed. The NEVI minimum standards, which CARB uses to justify the increase to 150 kW, state that four ports are the *floor* not the ceiling for eligible NEVI sites.[10] If CARB's intent is to align with NEVI, then CARB should not artificially cap site size if we are trying to build larger sites that EV drivers want. Further, CEC and Caltrans are strongly encouraging NEVI applicants to build corridor sites on I-5 and I-15 that exceed four ports per site. CARB should better align with CEC/Caltrans plans for rural/corridor charger buildout and not artificially restrict site size.[11] We strongly recommend returning to the current rules allowing 2.5 MW per site with exceptions to go higher and the only limit on chargers per site would be based on a 150-kW charger minimum. Charging developers are fast moving to 350 kW which also shows that 1 MW is an inadequate cap. Further, charging developers need flexibility to meet consumer demand and the different use cases at DCFC sites where they may want or need 150 kW chargers.

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[9] Conversation with Marvin Moon, deputy General Manager, Pasadena Water and Power.

[10] https://www.federalregister.gov/documents/2023/02/28/2023-03500/national-electric-vehicle-infrastructure-standards-and-requirements

[11] See slides 18 -19 of staff presentation at https://www.energy.ca.gov/event/funding-workshop/2023-11/pre-application-workshop-gfo-23-601-californias-national-electric

Align the new LD FCI more closely with the proposed LD HRI program. We support having the 2026 – 2030 LD FCI program be more closely aligned with the 2026 to 2030 LD HRI program in the proposed regulation, and three recommendations make this alignment closer: 1) keeping the 2.5 MW per site cap in the current LD FCI and not lowering it to 1 MW is very similar to the proposed HRI, 2) allowing use of zero carbon intensity electricity in the FCI formula which is the same as zero CI hydrogen allowed in the proposed HRI formula, and 3) removing the limit of four charging connectors per site. (See our detailed explanation in the next section on this topic).

Extend the new LD FCI to 2035. We recommend that this program extend to 2035 and not sunset in 2030. We are in a challenging phase of light duty EV adoption as the market needs to capture more skeptical mainstream buyers to meet the "hockey stick" ramp inherent in the ACC II requirements. The light duty FCI remains a very elegant and desirable tool to address the chicken-and-egg problem of how to accelerate EV infrastructure and EV adoption. Without the changes we recommend to the light duty FCI the pace of DCFC build-out could dramatically slow which makes meeting ACC II much more challenging. Now is not the time to scale back this program. CARB can take a no-regrets approach to supporting the light-duty fast charging market by adopting a 2.5% cap with no geographic restrictions. While the addition of more credits into the market can lower credit prices several factors can counter this including the new acceleration mechanism.

188.4 *4. EVCA and CalETC appreciate the proposal to create a new FCI program for eMHDVs at public, fleet, and shared depot locations but the proposal includes several limiting parameters that will undercut its effectiveness in supporting California's ACT and ACF requirements. EVCA and CalETC oppose the geographic limits and prescriptive site limits and specifications included in the proposed regulation. A larger, more flexible program is needed to meet industry needs, accelerate deployment, reduce costs, and align with California's truck electrification ambitions.*

The FCI program, as demonstrated by the existing FCI for light duty EV charging, is an incredibly elegant tool to solve the "chicken and egg" problem that EVs and EV infrastructure face. We truly thank CARB for creating an FCI to 2030 for eMHDVs and support the addition of fleets and shared depot locations as eligible, as well as the addition of more corridors. However, as proposed the MHD FCI is simply not workable for most industry use cases (e.g., shared charging depots and fleets for drayage, short-haul, and delivery trucks), especially in the near term with uncertainty around utilization and truck deployment timelines. It also does not meet the infrastructure needs of CARB's ACT and ACF regulations.

The proposed new FCI program for MHDVs, which starts when the new LCFS begins and ends December 31, 2030, includes a 2.5% cap on prior quarter deficits and restricts FCI locations to public truck stops and shared depots within one mile of existing and pending corridors on the federal highway administration map as well as locations that are "on or adjacent to a property used for medium or heavy-duty vehicle overnight parking or has received capital funding from a State or Federal competitive grant program that includes location evaluation as criteria." It allows projects built after January 1, 2022, to earn credits once the new LCFS begins, limits how many credits a single firm can earn per quarter, requires the minimum charger size to be 250 kW and for public chargers requires acceptance of "all major fuel, credit, or debit cards." "Private" fleets would not receive as much FCI credit as public truck stops and shared depots. In addition, its rules focus on encouraging 1 MW chargers at truck stops for long-distance travel because the proposal only allows ten chargers per site and has a 10 MW per site cap not just for truck stops but for fleets and shared depots too.

In summary our recommendations are:

1. Remove the geographic restrictions completely; if that is not acceptable, expand the corridor boundary from one mile to five, clarify language around parking, and consider local funding along with state and federal when determining eligibility,
2. Remove the cap of ten chargers per site, and if that is not acceptable, remove this for shared depots and fleets or raise this to 100 chargers per site,
3. Lower the 250-kW charger minimum size to 150 kW, and if that is not acceptable, apply a 150-kW minimum only to shared depots and fleets. If lowering the 250-kW charger minimum is not acceptable, we request that LCFS exempt projects that began design and construction after Jan. 1, 2022, and before the start date of the new LCFS from the 250-kW charger size requirement,
4. Increase the cap the proposed 2.5% of prior quarter deficits on MHD FCI to 5%,
5. Increase the 10 MW cumulative charger nameplate capacity credit generating cap for sites to at least 15 MW or alternatively allow an exception by the Executive Officer for up to 24 MW,
6. Allow zero carbon intensity electricity just like the proposed HRI program,
7. Change the requirement for payment to be done by all major fuel cards to a single fuel card,
8. Include land costs for new sites as an eligible cost, as these stations are extremely difficult to site and new locations are often needed,
9. Clarify what is meant by networking requirements, and
10. Clarify that "private MHD-FCI stations" includes fleets owned by entities in the government, private and non-profit sectors.

Geographic restriction. The market will necessarily prioritize public truck stops in the most heavily trafficked freight routes. Adding additional geographic restrictions will undermine the program, slow charger deployment, and increase costs. EV charging infrastructure for trucks has different siting requirements than other types of liquid or gaseous fueling infrastructure. EV charging can be located closer to the point where vehicles are domiciled and used, which may not be on or near highway corridors for many of the vehicle fleets that must be electrified.

It is difficult and expensive to find suitable sites for truck charging due to scarcity of land in urban areas (owning or 10-year leases), zoning restrictions, lease restrictions and, most importantly, the challenge in finding 5-20 MW (sometimes more) of grid capacity.[12] The Venn diagram overlap of these needs is small. Restricting FCI to sites within one mile of a corridor is unnecessary and exacerbates the challenges around infrastructure buildout. Expanding eligibility to a limited subset of sites with overnight parking will help in some cases, but greenfield sites with overnight parking will also be needed given fleet operational needs and constraints. Similarly, expanding eligibility to sites that have won specific state or federal grants is directionally helpful but insufficient to cover the broad array of sites the state will need to meet electrification goals.

As broad an area as possible would be helpful to expand opportunities as many shared depots and public access trucks stops will need between 5-20 MW.[13] Many types of trucks will need shared depots which need to be closer to where the vehicles are domiciled. For example, short-haul trucks or trucks operated by independent-owner operators, which often need shared depots, are often not domiciled near corridors. Truckers who operate local routes need safe overnight parking with full charge in the morning with schedulable charging sessions for top-ups during the day. The focus on corridors in the proposed MHD-FCI may make sense for long-haul trucks, but the proposed LCFS's seeming focus on long-haul trucks versus other segments such as drayage, short-haul and delivery trucks is inappropriate given ACF and the nascent stage of the electric truck market. While single user fleets and shared depots have been added as eligible locations in the proposed FCI, their locations are not concentrated near corridors according to developers.[14]

Retaining the one-mile requirement could unintentionally trigger additional utility upgrades because developers will be incentivized to prioritize corridor proximity over existing grid capacity when making siting decisions. This then brings additional costs and delays with the energization and grid upgrade process. Removing the one mile from corridor restriction will open up locations where fleet needs intersect with existing grid capacity, resulting in faster and lower cost infrastructure deployment.

It is important to note that the financial incentives of the proposed FCI MDHD program are not enough to incentivize building the charging infrastructure at a

[12] As an example of the challenge of finding available grid capacity see Southern California Edison's new tool. https://drpep.sce.com/drpep/

[13] See Figure ES-1 at https://www.nationalgrid.com/document/148616/download Much more is needed after 2035.

[14] Conversations with Forum Mobility, EV Realty, Carbon Solutions and Tesla.

location that is not likely to see sufficient utilization. As with the light duty FCI program, developers will continue to build in locations that are expected to see utilization as the market matures. The geographic limits are therefore unnecessary from the standpoint of avoiding stranded assets. We recommend completely eliminating the geographic restriction to maximize the benefits of this program. However, if CARB must put a restriction in this new 2024 LCFS, we recommend expanding the corridor boundary from one mile to five from the existing and pending corridors in the Federal Highway Administration map.[15] We also recommend clarifying the language to explicitly allow greenfield sites with overnight parking to support evolving fleet operations, and we recommend consideration of local funding sources (e.g., local air districts) in addition to state and federal as a trigger for eligibility. Overly restricting location for MHD-FCI sites will create adverse impacts on the grid, delay deployment, adversely impact meeting the ACT and ACF regulations and increase overall cost.

In order to address the siting challenges and considerations outlined above, we recommend completely striking section §95486.3 (b)(1)(B)2. Alternatively, increase flexibility with the following changes to the proposed LCFS:

2. *Located within ~~one mile~~ five miles of a ready~~ing~~ or pending electric vehicle Federal Highway Administration Alternative Fuel Corridor or on or adjacent to a property that allows ~~used for~~ medium or heavy-duty vehicle overnight parking at the time credits are claimed, or has received capital funding from a local, State or Federal competitive grant program. ~~that includes location evaluation as criteria.~~*

Ten chargers per site. The proposed regulation caps the numbers of chargers at an applicant's site at 10 chargers.[16] This is a huge problem that will severely restrict the usefulness of this important program. Many depots being designed around the state today serve upwards of one hundred trucks. At larger sizes, economies of scale deliver lower costs. Artificially restricting the size of eligible depots will not only slow deployment, but also raise costs – both of which are counter to the state's interest.

Also, the proposed limit on ten chargers per site and 10 MW per site implies the proposed MHD FCI is designed to encourage 1 MW chargers. The challenge with this is threefold. First, 1 MW chargers do not yet exist at broad commercial levels. Secondly, there are no trucks currently commercially available that can take 1 MW. Third, there is actually a strong policy interest in charging as low and slow as possible: doing so will maximize the utilization of the existing distribution network and thereby minimize rate impacts.

[15] https://hepgis-usdot.hub.arcgis.com/apps/5c4d9e173301473688468fc7cf6dbe19/explore

[16] "The number of FSEs. The total number for all FSEs claiming MHDFCI credit owned by a single applicant within ¼ mile of an MHD-FCI site cannot exceed ten. The nameplate power rating (kW), connector type(s), and model for each FSE. The total nameplate power rating for all FSEs claiming MHD-FCI credit owned by a single applicant within ¼ mile of an MHD-FCI site cannot exceed 10 MW."

The requirement in the proposed regulation for claiming credits on not more than ten chargers per site was never workshopped nor mentioned in our conversations with staff last year. For many large government, non-profit, and private fleets and for most shared depots, much larger sites are needed. For example, many developers are building sites with upwards of one hundred chargers – larger sizes bring down costs and make key reliability functions, such as security and technical support staff, economically viable. There is a trade-off between speed of charging and cost, and this is something that market participants should decide.

Minimum charger capacity. Instead of the requirement for a 250-kW minimum capacity for a DC fast charger, we recommend affording more flexibility to industry by setting a 150-kW minimum, and if that is not acceptable, have a 150-kW minimum only for shared depots and fleets. This supports the State's interest in helping electrify Class 2b to Class 8 trucks that are included in ACT and ACF regulations and in better utilizing grid resources with lower and slower charging. Higher capacity fast charging that seeks to replicate liquid fueling times for combustion vehicles is neither necessary nor desirable in all cases, and unduly increases costs and grid impacts. In addition, there is a lot of variation between Class 2b and 8 trucks in use cases for charging times. An analogy is how CNG trucks found early success with cherry picker trucks (Class 5), transit buses (Class 7), and garbage trucks (Class 7). Similarly, with a shift to 150-kW minimums MHD FCI can better serve many use cases and classes of trucks. For example, small independent truckers will be heavily reliant on shared depots that offer many different kW levels so they can slowly charge overnight or top-off during the day. Our members tell us that their customers are price sensitive. Forcing super-fast charging in all circumstances, regardless of whether it can be served by cheaper and less impactful alternatives, is the equivalent of eliminating level 1 home charging and requiring DCFC for light-duty EV home charging. CARB should provide flexibility to charging developers and their customers instead of picking a certain technology.

As stated above, some fleet consumers and shared depot customers prefer the lower costs associated with 150-kW charging. While we understand the desire to ensure a positive customer charging experience, we do not believe our recommendation will negatively impact public truck stops because the developers and operators of these locations will be subject to market pressures to do what their customers want and will naturally gravitate toward higher kW as this is demanded. If this approach is not acceptable to CARB, we recommend allowing only private and shared fleets to have a minimum DC charger size of 150 kW in order to save costs and provide customers with choices.

In addition, we recommend that the 250-kW requirement for chargers not be applied to stations that began development prior to the start of the new LCFS. (Note: the proposed LCFS allows stations that started development in 2022 to be eligible for FCI.) Doing so would be very expensive for a developer who already has stations (typically with 180 kW chargers) under development and would require re-engineering the project and potentially starting again in the queue for energization of the location by the local utility.

Cap on prior quarter deficits. The MHD-FCI program is limited to 2.5% of the previous quarter deficits. At 2025 deficit levels, we estimate this would support as little as 635 MW of capacity from MHD FCI credits, depending on utilization, uptime, and other assumptions.[17] According to the CEC's AB 2127 analysis, the state will need about 2,900 MW of charging from eMHDVs by 2025 and 11,600 MW of charging from eMHDVs by 2030.[18] Additional support is needed to attract the scale of private capital required, particularly at this nascent stage of the market with less than 1,000 MHD trucks and vans on the road and with both fleets and OEMs citing infrastructure as a primary limiting factor.

We recommend increasing the 2.5% cap on prior quarter deficits, particularly in the early years of the program, to kickstart the zero-emission truck market especially for near-term trucks applications in the drayage, short-haul, medium-haul, and delivery segments. As momentum builds, CARB might consider reducing the cap in a future rulemaking. We recognize that there are tradeoffs and that the "right" cap depends on perspective. However, we are at a critical launch point for both ACT and ACF and believe a higher cap – we recommend 5% based on the above need - is warranted to begin deploying a network that will enable the market to take off. Solving the chicken-and-egg infrastructure problem by using FCI to build infrastructure in advance of vehicle adoption is critical to the success of ACF, ACT and the Scoping Plan.

California will need to deploy charging infrastructure in advance of vehicle deployment to keep pace with the need to install over 50 MHD chargers per day every day through 2030.[19] MHD FCI is a crucial tool to encourage charging

[17] This calculation was derived leveraging the formulas from Appendix A-2 Proposed Regulation Order, section § 95486.3.(b)(2)(G) and section § 95486.3.(b)(5)(G) with the following assumptions: previous quarter deficits = 8,082,115 MT (based on CARB CATS model 2025 forecast); shared MHD-FCI charging site model selection; 85% uptime; and 5% utilization.

[18] The California Energy Commission's AB 2127 report uses the HEVI-load model to forecast the number of depot and public chargers required for MHD charging under the AATE3 primary scenario. This forecast predicts the number of chargers and their respective power ratings that will be required in 2025 and 2030, as seen in Appendix-H, Table H-1. The sum of the total MHD charging capacity based on this forecast was calculated to be 2,900 MW and 11,600 MW by 2025 and 2030, respectively, by taking the sum-product of the number of chargers and their respective power rating.

[19] Based on the more recent CEC AB 2127 report available at: https://www.energy.ca.gov/publications/2023/second-assembly-bill-ab-2127-electric-vehicle-charging-

infrastructure deployment in advance of vehicles – thereby removing a frequently cited barrier to electrification overall and ACF in particular. Encouraging the early adopters (e.g., shared depots and some fleets) to build the infrastructure to accommodate full electrification is critical even if the initial vehicle deployments are lower. This will help expedite the time frame for increasing the fleet's adoption rate of electric trucks. In the near future, turnaround time for new electric truck orders will be measured in weeks and the lack of infrastructure will delay adoption. Helping fleets move early will allow them to quickly add to their fleet after gaining comfort with the technology.

As mentioned above, the state will need about 11,600 MW of MHD charging by 2030 but we estimate the proposed MHD-FCI will only provide about 600 MW. The chart below also illustrates the size of the need for DC charging infrastructure and the pace of installation needed.[20] As for the impact of our recommendation on credit prices, see our points above in the LD-FCI section.

Table 27 - HEVI-LOAD Infrastructure Results for 112,000 BEVs in 2030 and 289,000 BEVs in 2035[105]

Charger Power Level	2030			2035		
	Number Chargers (% Depot / % Public)	Charging Energy (%)	Charging Time (%)	Number Chargers (% Depot / % Public)	Charging Energy (%)	Charging Time (%)
19; 25 kW	9,509 (100 / 0)	2.74	21.69	24,638 (100 / 0)	2.29	19.94
50; 75 kW	12,174 (87 / 13)	7.56	37.45	31,529 (88 / 12)	6.46	36.38
100; 150 kW	33,558 (96 / 4)	29.15	2.42	90,599 (97 / 3)	27.34	2.85
225; 250; 300 kW	12,257 (82 / 18)	20.17	23.71	31,362 (85 / 15)	19.10	24.40
350; 450; 500 kW	9,882 (83 / 17)	18.92	9.20	25,190 (86 / 14)	18.19	10.10
750; 900; 1,000; 1,050 kW	1,112 (0 / 100)	7.77	5.46	2,499 (0 / 100)	8.88	6.25
1,200; 1,400; 1,600 kW	1,498 (0 / 100)	13.69	0.07	3,809 (0 / 100)	17.73	0.09
Total	79,990 (88 / 12)	100	100	209,626 (90 / 10)	100	100

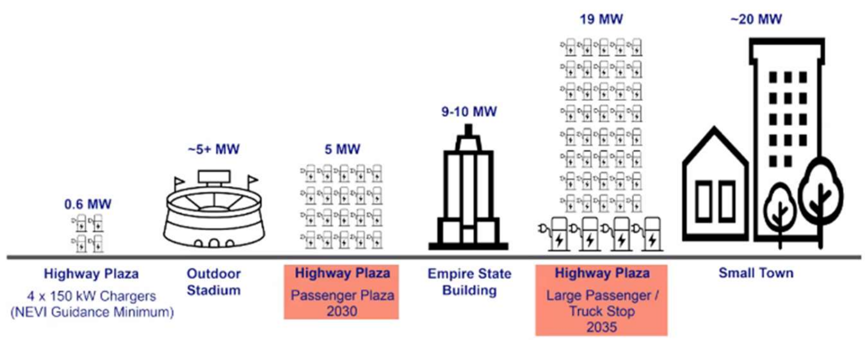
infrastructure-assessment, to support medium- and heavy-duty plug-in electric vehicles, California will need about 109,000 depot chargers and 5,500 public chargers for 155,000 vehicles in 2030, and 256,000 depot chargers and 8,500 public chargers for 377,000 vehicles in 2035. **For 2030:** 114,500 chargers divided by 2146 days (from today) = 53 chargers a day through 2030 needed. What is the baseline of current chargers? 2000? that would bring it to fifty-two chargers a day. **For 2035:** 264500 chargers divided by 3972 days - 67 chargers a day; if we assume a baseline of 2000, then 66 a day through 2035.

[20] https://ww2.arb.ca.gov/sites/default/files/2022-01/Draft_2022_State_SIP_Strategy.pdf

10 MW cap per location. We recommend either raising the MW cap on cumulative nameplate charging capacity eligible for credit claiming per location to 15 MW or alternatively, allowing up to 24 MW with Executive Officer approval. The later recommendation is 4 times the current LD-FCI which is capped at 2.5 MW per location with up to 6 MW with Executive Officer approval. In addition, this approach is similar to the MHD HRI provisions which are five times larger than the current LD HRI. The chart below also helps illustrate the MW size of MHDV charging.[21]

Infrastructure – Readying for Future Deployments

Figure 21. Comparative Peak Loads for Illustrative Sites and Other Major Users[35]



Source: Electric Highways: Accelerating and Optimizing Fast-Charging Deployment for Carbon-Free Transportation (2022 – National Grid, Calstart, RMI)

Allow zero carbon intensity (CI) electricity just like the proposed HRI program. The proposed regulation gives preferential treatment to hydrogen stations over electric vehicle charging stations when assigning the CI for capacity credits. Hydrogen stations utilizing the HCI pathway receive a CI of the "Company-wide weighted average CI for dispensed hydrogen during the quarter or 0 g/MJ, whichever is greater." DCFC stations utilizing the FCI receive a CI of the "California average grid electricity carbon intensity" regardless of whether the EV charging company is utilizing 0 CI RECs for the rest of their charging. We encourage CARB in the new LCFS to harmonize Hydrogen refueling and EV charging by allowing EV charging FCI capacity credits to be generated off of a 0 CI if the company is using renewable energy credit (REC) matching for the rest of their charging.

Payment. We recommend a slight change to the payment requirements. We support the requirements for all major credit and debit cards for publicly accessible chargers but oppose the requirement for all major fuel cards to work for payment. Fuel cards for gasoline / diesel stations do not have this interoperability of station branded

[21] See Figure 21 at https://www.nationalgrid.com/document/148616/download

payment cards. For example, a Shell branded refueling station card does not work with every other brand of gasoline/diesel stations. The same is true for light duty EV charging stations even though there are a few peer-to-peer agreements. For at least ten years, the light duty EV charging industry has tried to achieve payment interoperability between the cards offered by charging station brands but has not succeeded and nor has CARB's Electric Vehicle Equipment Supply Standards required this. In addition, we seek clarification that providing contactless payment is sufficient and there is no need for the older technologies (chip cards, magnetic swipe cards or toll-free phone numbers).

Networked chargers. CARB proposes a networking and communication requirement we request clarification around the data to be shared and the rationale. The proposed language states "Each FSE must be networked and capable of monitoring and reporting its availability for charging." This can be read to require public reporting of availability, which would not necessarily be relevant for shared chargers such as those found in multi-fleet charging depots with defined customers and reservations.

Other provisions we support: We support both HRI and FCI credits for MHDVs lasting 10 years as one way to make the two programs more similar and fairer. We support having fewer credits for single user fleets and appreciate CARB proposing to include this use case as eligible to generate credits as they also face challenges and risks in developing DCFCs.

188.5 *5. EVCA and CalETC opposes the proposed requirements for parties to pay for visits to individual charging stations by third-party verifiers to check for accuracy at public and private charging stations for light -, medium-, and heavy-duty EVs and incremental residential credits when reviewing quarterly fuel transaction reports. Instead, we recommend parties pay for desk-top reviews by third-party verifiers at central data locations that do not duplicate existing accuracy regulations established by the California Department of Food and Agriculture's Division of Measurement Standards and the California Public Utilities Commission (CPUC) and that generators of small numbers of non-residential credits be exempted from these requirements.*

The proposed regulation requiring site hosts to pay for third party verifiers for metered incremental residential credits, non-residential, and FCI credits for charging of light duty EVs and eMHDVs will result in high costs and a chilling of market development by site hosts, automakers, and charging developers. Section 95501 (b)(3) seems to indicate that site visits to each facility with a charging station is required (we see no mention of risk assessments or sampling affecting the number of site visits in the proposed regulation). We believe this requirement represents a massive time investment and cost for extraordinarily little benefit.

Metered electricity fuel credit generators are widely distributed, unlike other fuel providers that generate LCFS credits. Electricity is also economically regulated, unlike other transportation fuels. While there are approximately 10,000 gasoline / diesel stations in California, electricity is fundamentally different, with already 10,000 public DCFC, about 90,000 public level 2 charging stations, many thousands of fleet charging stations, and nearly one million residential charging stations. Soon these numbers will need to grow by a factor of eight or nine, as the ACC II, ACT, ACF and other regulations ramp up their compliance requirements. The sheer number of charging stations and their distributed nature makes travel to even a fraction of these an exorbitant cost.

Additionally, this requirement is not needed as EDUs have meter accuracy requirements that cover tens of millions of meters in private and commercial locations and a process to deal with inaccuracy complaints.[22] Moreover, the California Department of Food and Agriculture's Division of Measurement Standards (DMS) regulates EV chargers for metering accuracy as well as many other consumer protection requirements,[23] and inspections to enforce this regulation are conducted by each California county's Department of Weights and Measures and paid through device registration fees paid to the counties.[24] Adding a requirement for site hosts to pay for third-party verification for data that is already aligned with the proposed measurement accuracy requirements in §95491.2(a)(1)(B) in Appendix A-2 Proposed Regulation Order[25] may cause smaller fleets or properties like multifamily residences to forego participating in the LCFS program and the sectors CARB more broadly wishes to support. We recommend that the new LCFS does not require site visits to the charging stations and defers to existing CPUC and DMS metering accuracy regulations.

Requiring third party verification for residential metered charging is particularly concerning, as there are already hundreds of thousands of EVs being reported to CARB in order to generate incremental residential LCFS credits with kWh measurement via EV telematics or a charging station. Conducting site visits to even a fraction of those sites will be tremendously expensive. It is also unclear how the verifier would check the EV's telematics data and engage with the EV owner. We see

---

[22] Utility Meters are certified to ANSI C12 standards by Nationally Recognized Testing Labs (NRTLs). Here is a SMUD example on meter accuracy. For example, https://www.smud.org/-/media/Documents/Going-Green/EVs/Engineering-Specification-T017---Electric-Vehicle-Chargers-Rev-0---3-6-18.ashx. And https://www.smud.org/-/media/Documents/Rate-Information/Rates/Rule-2-17.ashx Utilities have processes to respond to high bill complaints and this can be escalated to the CPUC's Consumer Affairs Branch: https://www.cpuc.ca.gov/consumer-support/file-a-complaint/utility-complaint.

[23] https://www.cdfa.ca.gov/dms/pdfs/regulations/EVSE-OAL_EndorsedLetter-and-FinalText.pdf

[24] https://www.cdfa.ca.gov/dms/docs/publications/2023/2023_Combined_BPC.pdf

[25] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appa-2.pdf

no corresponding benefit and recommend that site visits by a verifier to the EV or residential charger not be required.

EVCA and CalETC propose that for incremental residential credits, FCI credits, and non-residential charging of light, medium- and heavy-duty EVs, that the only requirement is for desk top reviews to be done by third-party verifiers to check the accuracy of the calculations, except where a risk-based assessment reveals a reasonable concern about accuracy.

EVCA and CalETC appreciate that the proposed regulation allows for a deferment in verification for small entities with fewer than 6,000 credits per year, but we do not think this goes far enough for the many small locations that are just entering LCFS. We recommend that any entity with fewer than 2,000 credits per year be exempted from all verification and that those applicants with 2,001 to 6000 metric tons of credits per year be eligible for deferment of paying for a verifier to visit the central data location. Our intent is to avoid a chilling impact that verification requirements will have on recent and new sites and to have a better cost -benefit ratio for these sites. Fleets, workplaces, multifamily buildings, grocery stores, small utilities and other businesses are often just one or two locations and only generating a handful to a few thousand credits per year.[26] We believe our proposal is reasonable to prevent the costs of verification from removing the financial benefits of generating credits or even discouraging the adoption of charging stations so needed to make ACC II, ACT, ACF, Innovative Clean Transit, Clean Miles Standard, Zero-Emission Airport Shuttle and other regulations effective.

Also, as noted below, we are recommending that many emerging EVs in agriculture, airports, mining, and recreation be allowed to be in LCFS immediately. We recommend these new TE end-uses be subject to the same deferment and exemption thresholds as listed above, and any site visits be determined by a risk-based assessment that considers whether there is a reasonable risk of inaccuracy from the meter or charging equipment itself rather than the calculations and reporting.

Finally, CARB staff indicated that base residential credits should not count toward a 6,000-credit cap for deferment of verification (or our proposed 2,000 credit cap for exemption). However, the current regulation language simply references credits in the LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS). Almost all of the utilities' LCFS credits come from base residential credits calculated by CARB (and therefore not subject to verification). However, the current LCFS LRT-CBTS does not differentiate between a utilities base residential credits and other metered credits.

[26] Medium and heavy-duty trucks and buses are often generating several thousand credits annually when they are starting out.

CARB should clarify that only credits subject to verification count towards the credit cap for deferment or exemption.

We recommend that CARB avoid the creation of duplicative reliability requirement as part of the proposed verification provisions on electricity. The CEC is in the process of drafting a reliability standard for publicly funded charging stations pursuant to AB 2061 (Ting). We recommend that CARB work closely with the CEC to understand how the CEC's reliability standards would affect Level 2 charging stations and DC fast chargers participating in the LCFS. It is important for CARB and CEC to align these standards, as harmonizing technical requirements for reliability will result in a more consistent charging experience across the state.

188.6 6. *EVCA and CalETC recommend at least an immediate 7% step down in carbon intensity (CI) to better* account for historical overcompliance and push the market to greater levels of emission reduction.

EVCA and CalETC support the proposed immediate "step down" in stringency to deliver additional near-term pollutant reductions. The step down in 2024 and the proposed automatic acceleration mechanism would not replace the need for increasing the overall stringency of the program as proposed in Table 1 (e.g., 30 percent reduction in CI by 2030). Rather, the stringency and step-down provisions would complement the increased compliance requirement on traditional high-carbon fuels industry both in the near- and mid-term. That said, we remain concerned about overcompliance creating an oversupply of credits that limit motivation for additional low carbon fuels investment and recommend at least a 7% step down instead of 5%. For additional details regarding this position, please see the letter submitted by AJW on this topic.

188.7 *7. EVCA and CalETC support the proposed automatic acceleration mechanism but recommend that the start date for the mechanism be 2027 instead of 2028.*

The LCFS includes several features designed to mitigate excessive costs for the petroleum industry by ensuring against potential shortages of credits. These features include:

- Unlimited banking
- No expiration date on credits
- Fungible use of credits to mitigate deficits irrespective of the deficit-generating fuel
- Credit clearance mechanism (CCM) with a price cap
- Mechanism to pull utility electric vehicle credits forward if the CCM is activated, and
- Ability to carry over deficits in the event credits are unavailable.

From the LCFS program's inception, minimal attention has been directed at effectively protecting clean fuel providers by providing some certainty and market stability against the potential for a market glut of LCFS credits and very low credit prices. Specifically, the results of the current LCFS continue to stifle investment in electrification of the transportation sector, investment in charging infrastructure, and investment in all clean fuels. This is likely due to exceeding the CI reduction compliance targets resulting in a significantly reduced credit value and adding to a growing credit bank that now stands at over twenty million credits.[27] The historical response to market perturbation and glut of credits, which unfortunately means the full emission reduction benefits of the LCFS are not being realized, has been to implement amendments that increase the stringency of the program. However, anticipating the magnitude of innovation associated with developing progressively cleaner fuels and vehicles, like electricity fuel and electric vehicles, is exceedingly difficult. The market has consistently exceeded the CI reduction targets under the program and waiting for a new round of amendments has resulted in missed opportunities to reduce millions of tons of climate change pollutants and accelerate the transition to a zero-emission transportation future. In short, the problem is a suboptimal stringency requirement without a timely mechanism to correct it resulting in suboptimal climate change and other pollutant reductions, investment in innovative solutions, and/or investment by low carbon fuel providers. For these reasons, we support the adoption of an acceleration mechanism.

The acceleration mechanism will dynamically respond in the event of future sustained and significant innovation supporting a rapid escalation in credit generation by further tightening the stringency. Together with the proposed CI targets in Table 1, the acceleration mechanism in the new LCFS will provide greater certainty for clean fuel providers and customers, and better ensure that opportunities to deliver additional reductions of climate change pollutants, traditional (e.g., ozone-forming pollutants, PM2.5) air pollutants, and toxic emissions are not foregone. We believe the acceleration mechanism proposed in this regulation utilizes transparent metrics that trigger adjustments to the program's stringency and the necessary certainty for clean fuel providers to plan accordingly. An acceleration mechanism keeps innovation, investment, and emission reductions accelerating faster than they would otherwise. By incorporating a responsive acceleration mechanism into the regulation, the program will provide the market with a clearer signal that investments in clean fuels will be rewarded, and that California will not leave climate change pollutant reductions "on the table" in the future.

CARB, with the credit clearance market and other features listed above, provided price and risk certainty to the oil industry. We believe that now is the time for CARB

[27]https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/dashboard/quarterlysummary/Q3%202023%20Data%20Summary_013124.pdf

to adopt an acceleration mechanism, which would provide similar certainty to the low-carbon fuels industry, consumers, and society.

We support the proposed details of the acceleration mechanism except we recommend that the start date of the acceleration mechanism be 2027 instead of 2028 for the reasons that are provided in the letter submitted by AJW on this topic.

188.8 8. *EVCA and CalETC continue to recommend that the new LCFS create a level playing field for emerging transportation electrification end-uses in airports, agriculture, forestry, mining, marine, aviation, and recreation by adding a conservative default EER of 2.0, while excluding certain end-uses such as golf carts and indoor sweeper/scrubbers that are already electric.*

While LCFS supports many types of transportation electrification, it does not support emerging EVs used in agriculture, airports, mining, forestry, rail, warehouses, water transportation and recreation. This needs to be fixed so these hard-to-reach applications of EVs can easily participate in LCFS. The last 10 years have shown that these emerging EV industries do not have the wherewithal to develop the current LCFS requirement for a scientific study needed in a Tier 2 pathway to prove their Energy Economy Ratio (EER) which is their efficiency compared to gasoline or diesel. To solve this problem, we propose the new LCFS allow these industries to use a conservative default EER that is much less than other EVs. If they want a more realistic EER, these industries can do the full scientific study and the process outlined in Section 95488.7 (a)(3): *Tier 2 Pathways for EER-Adjusted Carbon Intensity*.

In other words, EVs which do not have an EER in the proposed Table 5 should be able to receive a default, conservative EER of 2.0 and allow them to compete with other low-carbon fuels which already earn LCFS credits. However, to address staff's concerns about applications that are mostly electric, we further propose that CARB does not allow this default EER for golf carts, indoor mobile sources such as walk-behind and ride-on sweepers, scrubbers and burnishers, airport heating and air conditioning units, conveyer belts and lawn and garden equipment. We believe this is a realistic compromise to the current situation that still provides an incentive for emerging TE industries to apply for a better EER via the Tier 2 pathway process. The Low Carbon Fuel Standard is a successful tool for accelerating the market for ZEVs and should be expanded to include all ZEVs given the climate crisis and the state's very ambitious regulations.

188.9 *9. EVCA and CalETC support the proposal for all sizes of electric forklifts to remain in LCFS.*

Previously, CalETC expressed many concerns with the staff's proposal to remove most electric forklifts from LCFS because this proposal was arbitrary. We argued that many fuels and end-uses of low-carbon fuel technologies are regulated and/or already exist in the market (not just electric forklifts), and that any criteria for removal of a fuel or technology from LCFS eligibility should be fuel and technology neutral, transparent, support the state's requirements and goals to decarbonize transportation fuel and the transportation sector, complementary to existing regulations, and approved by the CARB Board.

The new proposal to keep all sizes of electric forklifts in LCFS but grant different EERs to forklifts with different lift capacities is an acceptable compromise. We also support the proposed LCFS provisions to remove estimation of kWh for electric forklifts and require metering and third-party verifiers.

We appreciate the opportunity to comment on these important changes to the LCFS regulation. Thank you for your consideration.

Regards,

Reed Addis
Governmental Affairs
Electric Vehicle Charging Association

Laura Renger, Executive Director
California Electric Transportation Coalition

cc: Rajinder Sahota
Matthew Botill
Jordan Ramalingam
Jacob Englander

Comment Log Display

Here is the comment you selected to display.

Comment 198 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Evan
Last Name	Rosenberg
Email Address	evan.rosenberg@srectrade.com
Affiliation	SRECTrade
Subject	SRECTrade Comments on Proposed LCFS Amendments
Comment	See attachment
Attachment	www.arb.ca.gov/lists/com-attach/6860-lcfs2024-UiFRJQNnADACcFcl.pdf
Original File Name	SRECTrade LCFS Comments_2.20.2024.pdf
Date and Time Comment Was Submitted	2024-02-20 10:42:17

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

SRECTrade
AN XPANSIV COMPANY

February 20, 2024

Rajinder Sahota
California Air Resources Board
1001 I St.
Sacramento, CA 95814

RE: SRECTrade Comments on Proposed Low Carbon Fuel Standard (LCFS) Amendments

Dear Ms. Sahota:

SRECTrade appreciates the opportunity to comment on the Proposed LCFS Amendments. SRECTrade is the largest aggregator of EV charging stations under the LCFS, helping the nation's leading EV charging networks, EV fleet operators, and others participate in and benefit from this valuable incentive program.

We appreciate your consideration of our comments:

189.1

1. **Increase the 2030 carbon intensity reduction targets to at least 40%**. SRECTrade supports the findings in the analysis conducted by ICF which indicated that a target above 40% target is achievable based on expected carbon intensity reductions.[1] LCFS has long been a powerful driver of low carbon fuels precisely because of the clear, consistent market signal it provides. However, the transportation fuel economy has outperformed expectations set during the last rulemaking in 2018. CARB now has an opportunity to challenge the entire sector yet again, and in doing so align with the ambitious goals set by the 2022 Scoping Plan.

189.2

2. **Modify the auto-acceleration mechanism (AAM) to be triggered in consecutive years.** The AAM will be a valuable tool to adjust carbon intensity targets to market conditions without the need of a rulemaking. The triggers for the AAM should be attuned to prevailing market conditions and not be unnecessarily restricted.

189.3

3. **Phase-in the implementation of forklift metering requirements to give fleet operators time to install metering solutions**. SRECTrade supports aligning reporting requirements for forklifts with other electricity applications and strongly encourages CARB to provide fleet operators at least one year to install metering solutions. During the one-year phase-in period, fleet operators should be able to continue to use the estimation methodology by demonstrating that they are in the process of installing metering solutions. SRECTrade also encourages CARB to consider a broad variety of reporting technologies for forklifts, including vehicle telematics.

189.4

4. **Grant verification bodies discretion to conduct site visits when verifying quarterly fuel transactions reports for EV charging**. SRECTrade is supportive of expanding the scope of third-party verification to include electricity transactions. However, site visits can be costly given the volume of charging stations and may provide little to no benefit to the

[1] ICF Resources, L.L.C. (2023). *Analyzing Future Low Carbon Fuel Targets in California*. Available here.

verification of quarterly fuel transactions if the data collection process is centrally managed. SRECTrade recognizes that not all EV charging applications or underlying technologies are the same, therefore a verifier should be given the discretion to determine whether a site visit is necessary and be required to document the decision in the verification report.

189.5 5. **Remove the U.S. Commodity Futures Trading Commission registration requirement for Clearing Service Providers operating spot exchanges**. SRECTrade supports CARB's efforts to enable a robust cleared spot market for LCFS credits. Exchange-traded spot markets create transparent marketplaces with better price discovery and confidence with secured clearing and settlement. The current requirement that a Clearing Service Provider (CSP) maintain a derivative clearing organization license is prohibitive for operators of spot exchanges where no such licenses are required or relevant. The requirement should be removed or clarified so that it only applies to futures exchange operators.

Sincerely,

Evan Rosenberg
Director, Strategy and Business Development
SRECTrade, Inc.
(415) 651-7781
Evan.Rosenberg@SRECTrade.com

About SRECTrade
SRECTrade provides management and transaction solutions for renewable energy and clean fuel programs across North America. SRECTrade's parent company, Xpansiv, provides market infrastructure to rapidly scale the world's energy transition. Xpansiv operates CBL, the largest

energy certificates.

Comment Log Display

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Comment 199 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Julie
Last Name	Busse
Email Address	busse@ncga.com
Affiliation	National Corn Growers Association (NCGA)
Subject	National Corn Growers Association Comments on the Proposed Amendments the LCFS
Comment	Attached, please find the National Corn Growers Association (NCGA)'s comments on the proposed amendments to the LCFS. Thank yo for the opportunity to provide this feedback.
Attachment	www.arb.ca.gov/lists/com-attach/6861-lcfs2024-VmQCMFFgBWQANAc3.pdf
Original File Name	240220 NCGA - LCFS 2024 Rulemaking Comments (Final).pdf
Date and Time Comment Was Submitted	2024-02-20 10:58:50

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Chair Liane Randolph and the Members of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: National Corn Growers Association (NCGA) Comments on the Proposed Amendments to the Low Carbon Fuel Standard

Dear Chair Randolph and Members of the Board,

The National Corn Growers Association (NCGA) values the opportunity to provide comments on the proposed amendments to the Low Carbon Fuel Standard (LCFS).

NCGA represents 40,000 dues-paying corn growers and more than 300,000 farmers who contribute to corn promotion programs nationally. Along with its 50 affiliated state associations and checkoff organizations, NCGA works to protect and advance the interests of corn growers. NCGA recognizes CARB staff's leadership in continuing to refine the LCFS program to support California's ambitious climate goals and serve as an example to encourage similar programs elsewhere.

NCGA would like to provide the following comments in response to the proposed amendments to the LCFS:

190.1 **2030 Target**

NCGA is encouraged to see CARB's proposal of a 30% reduction in carbon intensity (CI) by 2030. This target can be reached at an accelerated pace through the implementation of fuel blends with up to 15% ethanol (E15) in California. NCGA urges CARB to adopt E15 due to the
190.2 immediate benefits it can help achieve as a lower carbon and lower cost fuel which is readily available. Ethanol has a low-CI and can help reduce greenhouse gas (GHG), criteria, and toxic pollutant emissions. Compared to E10, E15 can reduce annual GHG emissions by 2 million metric tons.

Notably, California is the last state that has not approved E15 despite gasoline-ethanol blends having a long history of being used in the state.[1] Today, almost all gasoline sold in California

[1] Montana Becomes 49th State to Approve the Sale of E15

WWW.NCGA.COM
NATIONAL OFFICE
632 Cepi Drive
Chesterfield, MO 63005
(636) 733-9004
WASHINGTON, DC OFFICE
20 F Street NW, Suite 900
Washington, DC 20001
(202) 628-7001

uses blends of up to 10% ethanol (E10). As California looks to electrify much of its transportation, higher ethanol blends are a complementary solution, especially for hard-to-abate sectors and heavy-duty applications. California has long been a leader in championing progressive climate policies, with the LCFS being one of them. With more jurisdictions looking to introduce their own clean fuels programs, the lack of approval for E15 in California will be a significant obstacle to exporting the program as E15 helps garner agricultural support.

The ethanol industry and CARB have invested significant resources in conducting the proper analyses to get E15 approved in California. Among these efforts is the Multimedia Evaluation (MME) of E15, which is in the final stages.[2] In the Tier II Report for the MME, the ethanol industry and CARB jointly funded vehicle emission testing conducted by the University of California Riverside which found significant air quality improvements (see results in the table below).[3] Throughout the MME process, ethanol stakeholders have been responsive and collaborative with CARB to ensure the evaluation could move at a quick pace.

190.2 ctd

E15 is a readily available and affordable solution which can swiftly enable additional CI reductions in the LCFS. Approving E15 in California will allow for the LCFS to be even more ambitious in setting targets and achieving California's transportation decarbonization goals.

Pollutant	Reduction %	Statistical significance
NOx	3%	Not significant
THC	5%	Significant
NMHC	8%	Marginally significant
CO	17%	Significant
CO_2	1%	Marginally significant
PM	18%	Significant
Solid Particle	12%	Significant

Figure 1, E15 Tier II Report – Vehicle Emission Testing Results, UC Riverside

Sustainability Requirements

NCGA asks CARB to reconsider the proposal for crop-based biofuel sustainability requirements. Requiring credit generators to track feedstocks back to their point of origin will impose an extensive regulatory burden with unclear benefits. Despite this proposal adding more responsibility and costs to farmers, it does not address our members' requests for on-farm credits to reward better agricultural practices. Our members are already dedicated to improving their agricultural practices by continuing to advance and incorporate increased efficiencies in land, water, and energy use. [4] In working towards these goals, U.S. corn growers are committed to reducing GHG emissions per bushel by 13% from 2020 to 2030.[5]

190.3 We suggest CARB take a step back from the proposed framework and instead explore a more sophisticated approach that would balance on-farm crediting with sustainability tracking and low carbon ag practices. Also, CARB should be weighing the incremental benefit of this additional

[2] California Multimedia Evaluation of E11-E15 Gasoline-Ethanol Blends Tier I Report
[3] California Multimedia Evaluation of E10 - E15 Gasoline Ethanol Blends Tier II Report (p. 10-11, 29).
[4] NCGA Sustainability Report, Page 3.
[5] NCGA 2030 Corn Environmental Sustainability Goals

data against information that is already collected and reported. For instance, Argonne's Feedstock Carbon Intensity Calculator examines the CI variations of different farming practices for growing crops used for biofuel production.[6] This tool uses data from key farming inputs from the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) fuel-cycle model. In understanding the data and resources that are already available, this can better inform CARB's concerns in verifying sustainability standards while preventing duplicative efforts and reporting for credit generators.

Figure 2, NCGA's 2030 Goals

NCGA appreciates the opportunity to provide feedback on the proposed amendments for the LCFS. We look forward to continuing our engagement with CARB both in the completion of this rulemaking and those to come.

Sincerely,

Harold Wolle, Jr.
President, National Corn Growers Association

[6] Argonne Feedstock Carbon Intensity Calculator

Comment Log Display

Here is the comment you selected to display.

Comment 200 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Tom
Last Name	Hance
Email Address	thance@gordley.com
Affiliation	US Canola Association
Subject	Low Carbon Fuel Standard Proposed Amendments
Comment	Attached are comments submitted on behalf of the US Canola Association
Attachment	www.arb.ca.gov/lists/com-attach/6862-lcfs2024-UCVRJFU3UWMAWQQp.pdf
Original File Name	USCA - CARB - LCFS Proposed Amendments - Comments - 2024 Feb (002).pdf
Date and Time Comment Was Submitted	2024-02-20 11:16:59

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

U.S. Canola Association
600 Pennsylvania Ave., SE, Suite 300
Washington, DC 20003
Phone (202) 969-8113

February 20, 2024

California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Submitted electronically via: Submit Public Comments to CARB | California Air Resources Board

Re: Proposed Low Carbon Fuel Standard Amendments

California Air Resources Board:

The U.S. Canola Association (USCA) appreciates the opportunity to comment on the California Air Resources Board's (CARB) Proposed Low Carbon Fuel Standard Amendments issued on December 19, 2023.

The U.S. Canola Association (USCA) is a non-profit commodity organization whose mission is to increase domestic canola production and promote the establishment and maintenance of conditions favorable to growing, marketing, processing and utilization of U.S. canola. Canola has multiple uses and markets and is one of numerous feedstocks used to produce clean burning, renewable biomass-based diesel (BBD) and is a potential feedstock for sustainable aviation fuel (SAF).

The BBD industry is an important market for canola producers, utilizing approximately 1.2 billion pounds of canola oil in 2021. The BBD market provides a valuable outlet for surplus canola oil not utilized for food production.

Consistent with the intent of the LCFS, BBD from canola provides significant benefits to our national energy security, the environment, and the economy. Canola BBD contributes to the expansion and diversification of U.S. fuel and energy production, reduces emissions and improves air quality, and provides jobs and additional economic benefits, especially in rural communities. The canola and BBD industry have provided these benefits without significant disruption or adverse impacts to consumers.

Currently, U.S. canola production is primarily in the Northern Plains and Pacific Northwest region of the country. It is predominantly a Spring planted crop harvested in the Fall and grown as part of a beneficial crop rotation on diversified farms that grow five or more different crops. Canola production has grown modestly, but steadily over the past few decades, reaching over 2.3 million acres in 2023. There is potential for continued expansion of canola production in the U.S., including as a winter and double crop option in the Pacific Northwest, Great Plains, and

Southeast regions. This winter canola and double crop production provides additional vegetable oil feedstock from existing cropland and fallow land.

Crop-Based Biofuels Sustainability Criteria

191.1 The USCA believes CARB can utilize existing programs and data sources, such as the federal Renewable Fuel Standard (RFS) and USDA crop production data and statistics, to certify that feedstocks grown in North America that are used in the production of BBD are produced sustainably and meet CARB's proposed criteria.

The proposed amendments state that CARB staff are proposing additional guardrails on the use of crop-based feedstocks for biofuel production. Specifically, CARB staff are proposing to require pathway holders to track crop-based and forestry-based feedstocks to their point of origin and require independent feedstock certification to ensure feedstocks are not contributing to impacts on other carbon stocks like forests. The USCA does not believe that CARB needs to impose additional feedstock tracking and certification requirements. There is no evidence to suggest that deforestation is occurring in the U.S. due to land being converted to agricultural production. Expanded agricultural production is occurring through yield increases, improved agronomic practices, double cropping and use of previously fallow land that benefits environmentally from having "cover" crops.

The federal RFS already includes protections against land conversion to cropland for biofuel feedstock production. To be eligible for the RFS, feedstocks have to come from land that was non-forested and in production prior to December 19, 2007. EPA set a national baseline for eligible cropland in 2007 of 402 million acres. If cropland in subsequent years exceeds that baseline, biofuel producers would be required to track and trace where its feedstocks were grown. There is also a threshold of 397 million acres which, if exceeded, would trigger investigation and reassessment of the aggregate compliance program. Neither of these thresholds have been exceeded since 2007. We would also note that the most recent Census of Agriculture data released by USDA on February 13, 2024 shows a 2% decline of total farmland in the United States since 2017. We believe CARB could utilize the existing federal protections and monitoring of land conversion instead of imposing additional, unnecessary compliance burdens.

The USCA urges you to recognize that fuels produced and certified under the federal RFS meet CARB's proposed sustainability criteria. Additional requirements would place an unnecessary burden on the fuel and feedstock providers as well as on CARB's staff and resources for LCFS implementation and enforcement. This additional burden would increase costs without providing any additional environmental benefit.

We would also point out that, as noted in the proposed amendments issued in December, the California LCFS already accounts for land use change emissions in its life cycle methodologies. Additional certification requirements would be redundant and create unnecessary burdens and expenses that could increase costs and reduce the amount of renewable fuel available to achieve the LCFS targets.

Again, the USCA appreciates the opportunity to comment on the Proposed Low Carbon Fuel Standard Amendments and looks forward to supporting your efforts to implement an effective LCFS program.

Sincerely,

Andrew Moore
President
c/o U.S. Canola Association
600 Pennsylvania Ave., SE
Suite 300
Washington, DC 20003
202-969-8113
info@uscanola.com

Comment Log Display

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Comment 201 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nancy
Last Name	Pauken
Email Address	npauken@yahoo.com
Affiliation	

Subject	Stop rewarding mono-cropping, and factory farming/ranching

Comment

192.1 What we need to stop is pollution, whether it be from private jets yachts, McMansions, golf courses, the military, industry and factory farming. The predatory class, industry and the military cause the vast majority of the pollution that poisons us and our environment, yet they are all exempt from the ridiculous "carbon" standards foisted on the rest of us, and yet our tax dollars subsidize what little mitigation is actually done toward cleanup. There is no reason why Air Force One should run 24-7, which create gawd-knows how much pollution.

If anyone in government or our regulatory agencies (mostly staffed by a revolving door of executives and lobbyists), actually cared about us (they don't), our tax dollars would subsidize regenerative, humane, organic, biodynamic, local, small-scale farming and ranching, which would go a long way to restoring the soil and cleaning up the environment. And, we would severely punish industrial polluters, where the executives would be criminally prosecuted and spend time with rank and file criminals in prison, and not some Club Fed where they play golf all day.

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-02-20 11:03:55

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Comment 202 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	DENIZHAN
Last Name	BAYTUG
Email Address	dbaytug@gmail.com
Affiliation	EMC Cement

Subject Suggested LCFS Amendments (2024)

Comment

Dear Board:

We are thankful for the opportunity offer-up our suggestions towards deploying the LCFS to meet the aims of SB 596 (Becker), namely empowering the deployment of zero-carbon low-energy electrification technologies.

The Annex demonstrates that with minimal rule changes, the LCFS could be easily innovated to support Title XVII by way of example If you require the Annex in Word format, please advise.

Thank you again for the opportunity to submit.

Yours faithfully

Denizhan Baytug
Corporate Counsel   EMC Cement BV

Attachment www.arb.ca.gov/lists/com-attach/6864-lcfs2024-VzIFbIIwWFRSNwZn.pdf

Original File Name	EMC_CA_Letter_CARB_Re LCFS 2024 changes_02.20.24_ex.pdf
Date and Time Comment Was Submitted	2024-02-20 11:17:09

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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INTENDED FOR DOCKET PUBLICATION

EMC Cement

Mark Sippola, Chief Cap 'n' Trade Program, Chief Climate Change Program
Rachel Gold, Supervisor Climate Change Program, Evaluation Branch
Mihoyo Fuji, Lead for SB596, Staff Air Pollution Specialist
Haley Hamza, Climate Change Program Evaluation Branch

California Air Resources Board
1001 I Street, Sacramento, California 95814

BY EMAIL ONLY
(hyperlinks below in blue)

February 20, 2024

Innovating the Low Carbon Fuel Standard Regulation ("LCFS") for SB596

Dear California Air Resources Board:

We write in response to CARB's invite, encouraging "members of the public to bring to the attention of staff in advance of the hearing any suggestions for modification of the proposed regulatory action", our having noted that despite SB596's clear mandate—and Senator Becker's address to the UNFCCC at COP 26 heralding its purpose—nonetheless SB596 is not mentioned once in the documentation supporting CARB's proposed regulatory action. Even Appendix D, Attachment A ("Environmental and Regulatory Setting For the Proposed Low Carbon Fuel Standard Regulation") fails to mention SB596.

Context in Brief

This letter is sequential to our public letters to CARB dated 09.04.23 (**here**|PDF **here**) and 11.01.23 (**here**|PDF **here**). By our November 2023 letter, we requested an LCFS rule-innovation having in mind SB596's clear and present impetus, in the context of the *energy paradox* identified by the U.S. EIA (**here**) and California's energy supply.

We believe a fair reading of California's *primary* statutes confirms that CARB shoulders a number of specific duties formed from express demands over cement and concrete's decarbonization. Moreover, the LCFS has evolved into a flexible tool to deliver legislators' Climate Action priorities. Our November 2023 request was made in that context only and this letter demonstrates *why*. After all, by comparing our own EPD (**here**) with the PCA's (**here**), at its intended capacity EMC California would save >1.87 TWh energy annually, across LCA Zones A1-A3. That's before energy-intensive CCS is factored-in that will *at least* double those savings!

Purpose and Structure of this Letter

We respect the work and commitment of CARB in meeting its statutory duties. Having noted the many comments made already in this 45-day process, it is clear there is a sense of urgency. For example, we note the exhortations per the January 11, 2024 letter endorsed by over 2,600 individuals (**here**):

> "The world has changed a lot since the implementation of the LCFS in 2009. Unlike the 2000s, we have a north star goal for our climate and the air we breathe: zero emissions transportation. Continuing to invest the billions in revenue from the LCFS into harmful and polluting biofuels that end up combusted, instead of electric vehicles powered by clean energy, hampers our efforts to fight the climate crisis while enriching oil companies and industrial agriculture."

We agree: much *has* changed since 2009! So, what is the "North Star goal"? This letter will not engage in pages of legal argument to assert our answer, as we believe the opportunity speaks for itself. Instead, the purpose of this letter is to lay-out the basis for the annex that sets out our "suggestions for modification of the proposed regulatory action". **First**, we set out a succinct compendium to record various Californian legal sources having in mind Title XVII's 2021 innovations (per 42 U.S. Code §16513, **here**) and the DOE LPO's recent rule changes (**here**) in the context of California's §38561.2 Health and Safety Code (b)(6) set out below at line number 73. **Second**, we set out a brief digest. **Finally**, we set out a brief conclusion.

Californian Code: A Succinct Compendium *(grouped thematically)*

The Global Warming Solutions Act of 2006 (AB32), required California reduce its greenhouse gas emissions to 1990 levels by 2020. This has been missed. The current 2030 target is 40% below 1990 levels.

CARB Statutory authority per AB32/Global Warming Solutions Act of 2006 (**here**):

- 38510. The State Air Resources Board is the state agency charged with monitoring and regulating sources of emissions of greenhouse gases that cause global warming in order to reduce emissions of greenhouse gases.
- 38560. The state board shall adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions from sources or categories of sources, subject to the criteria and schedules set forth in this part.

Macro CO2 Reduction Targets:

- Executive Order S-3-05: 1 of 2006 (**here**):

  That the following greenhouse gas emission reduction targets are hereby established for California: by 2010, reduce GHG emissions to 2000 levels; by 2020, reduce GHG emissions to 1990 levels; by 2050, reduce GHG emissions to 80 percent below 1990 levels;

- Executive Order B-30-15 of 2019 (**here**):
  1. A new interim statewide greenhouse gas emission reduction target to reduce greenhouse gas emissions to 40 percent below 1990 levels by 2030 is established in order to ensure California meets its target of reducing greenhouse gas emissions to 80 percent below 1990 levels by 2050.
  2. All state agencies with jurisdiction over sources ofgreenhouse gas emissions shall implementmeasures, pursuant to statutory authority, to achieve reductions of greenhouse gas emissions to meet the 2030 and 2050 greenhouse gas emissions reductions targets.

LCFS enabling:

- Executive order S-01-07 for LCFS (**here**):

  WHEREAS greenhouse gas ("GHG") emissions pose a serious threat to the health of California's citizens and the quality of the environment; and

  WHEREAS Assembly Bill 32 (Chapter 488, Statutes of 2006) requires a cap on GHG emissions by 2020, mandatory emissions reporting, identification of discrete early action measures, achievement of the maximum technologically feasible and cost-effective emission reductions from sources, and authorizes the development of a market-based compliance program; and

  WHEREAS California's dependence on a single type of transportation fuel whose price is highly volatile imperils our economic security, endangers our jobs, and jeopardizes our industries; and

  WHEREAS alternative fuels can provide economic development opportunities and reduce emissions of greenhouse gases, criteria pollutants, and toxic air contaminants.

LCFS (**here**):

- § 95481. Definitions and Acronyms.

  (150) "Transportation Fuel" meansany fuel used or intended for use as a motor vehicle fuel or for transportation purposes in a non-vehicular source.

- § 95484. Annual Carbon Intensity Benchmarks.

  (f) Carbon Intensity Benchmarks for Biomass-Based Diesel Fuel. The benchmark for diesel fuel, set forth in section 95484(c), applies to biomass-based diesel fuel is used or intended to be used in any:

  (1) light-, medium-, or heavy-duty vehicle;

  (2) off-road transportation application;

  (3) off-road equipment application;

  (4) locomotive or commercial harbor craft application; or

  (5) non-stationary source application not otherwise specified in subsections (1) through (4) above.

SB 596:

- Generally, see, CARB (**here**):

  "In September 2021, Governor Newson signed Senate Bill 596 (Becker), which requires CARB, by July 1, 2023, to develop a comprehensive strategy for the cement sector in California to achieve a greenhouse gas (GHG) emissions intensity 40% below baseline levels by 2035 and net-zero GHG emissions by 2045. The bill also requires CARB to establish interim targets for reductions in the GHG intensity of cement used within the state relative to the average GHG intensity of cement used within the state during the 2019 calendar year, with the goal of reducing the GHG intensity of cement used within the state to 40% below the 2019 average levels by December 31, 2035."

- Bill (**here**):

  (a) The Legislature finds and declares all of the following:

  (1) Climate change is an urgent threat to the health and well-being of California's residents and economy.

  (2) California is a global leader on climate action and has committed to achieve carbon neutrality as soon as possible, and no later than 2045, in line with the latest climate science.

  (3) Achieving this objective will require advance planning, coordination, outreach, and development of a robust set of policies tailored to the needs and opportunities of every major emitting sector, including cement and concrete.

  (5) A wide range of commercially available technologies and practices exist to reduce and remove emissions of greenhouse gases throughout the lifecycle of cement and concrete production and use, but these technologies and practices face a series of market and regulatory barriers hindering their deployment.

  (6) Implementing complementary strategies to both reduce the greenhouse gas intensity of cement production and grow the demand for low-carbon concrete will also reduce air pollution and improve public health in California communities.

  (7) Positioning California's cement and concrete sector to thrive in a low-carbon economy will enhance the sector's long-term competitiveness, support high-quality jobs, and enable resilient infrastructure development.

  (b) It is the intent of the Legislature that attaining net-zero or net-negative emissions of greenhouse gases from the cement and concrete sector in a manner that enhances California's competitiveness, supports high-paying jobs, improves public health, and aligns with local community priorities becomes a pillar of the state's strategy for achieving carbon neutrality.

- Statute: Section 38561.2 Health and Safety Code (**here**)

  (b) In developing the comprehensive strategy pursuant to subdivision (a), the state board shall do the following:

  (1) Define a metric for greenhouse gas intensity and evaluate the data submitted by cement manufacturing plants to the state board for the 2019 calendar year and other relevant data about emissions of greenhouse gases for cement that was imported into the state to establish a baseline from which to measure greenhouse gas intensity reductions.

  (2) Assess the effectiveness of existing measures, identify any modifications to existing measures, and evaluate new measures to overcome the market, statutory, and regulatory barriers inhibiting achievement of the objectives described in this section.

  (3) Identify actions that reduce adverse air quality impacts and support economic and workforce

development in communities neighboring cement plants.

(4) Include provisions to minimize and mitigate potential leakage and account for embedded emissions of greenhouse gases in imported cement in a similar manner to emissions of greenhouse gases for cement produced in the state, such as through a border carbon adjustment mechanism.

(6) Prioritize actions that leverage state and federal incentives, where applicable, to reduce costs of implementing greenhouse gas emissions reduction technologies and processes and to increase economic value for the state.

(7) Evaluate measures to support market demand and financial incentives to encourage the production and use of cement with low greenhouse gas intensity, including, but not limited to, consideration of all of the following measures:

(A) Measures to expedite the adoption for use in projects undertaken by state agencies, including the Department of Transportation, of Portland limestone cement and other blended cements.

(B) Measures to provide financial support and incentives for research, development, and demonstration of technologies to mitigate emissions of greenhouse gases from the production of cement with the objective of accelerating industry deployment of those technologies.

(C) Measures to facilitate fuel switching.

(D) Measures to create incentives and remove obstacles for energy efficiency improvements and waste heat recovery at cement manufacturing facilities.

Academic:

Farrell, A. E; Sperling, D.; Arons, S.; Brandt, A.; Delucchi, M.; et al. (2007). A Low-Carbon Fuel Standard for California Part 1: Technical Analysis. UC Berkeley: Transportation Sustainability Research Center (**here**), at p.175:

"Jackson (2005) evaluated two applications at ports: the use of shore power instead of ships' engines for electricity and heat (a practice called "cold ironing") and the use of electric-drive cranes instead of diesel-powered cranes. Two truck-related electric applications were also evaluated: electric truck refrigeration units (e-TRUs) instead of diesel-powered devices, and the supply of electricity at truck stops as a substitute for engine idling. Large off-road vehicles include airport ground service equipment, electric forklifts (class 1 and 2), and tow tractors/industrial tugs. Small off-road vehicles include small electric lawn and garden equipment, electric golf carts, electric sweepers/scrubbers, burnishers, electric forklifts (class 3), electric personnel and burden carriers, and turf trucks. Jackson (2005) does not consider light rail, high-speed rail, electric freight rail, electric trolley buses, electric boats, electric bikes, commercial walk-behind mowers, riding mowers, leaf-blowers or other applications."

Digest

"If CCUS is applied on an industrial scale, the power demand of cement manufacturing will increase significantly. As described, carbon capture technologies will require high power consumption to e.g. supply consumables like oxygen, pump solvents, operate power driven separation devices like membrane or cryogenic units and purify and compress the CO_2 in order to meet the required conditions of downstream processes. **Therefore, CCUS will *increase* power consumption by 50 to 300% at plant level.**"

ECRA | State of the Art Cement Manufacture: Current Technologies & Future Development (2022) | **here**

This letter's purpose is not to set out the *minutiae* of Title XVII's requirements. Instead, let us focus on this gnawing simplicity: an EMC plant delivering 1mn tonnes annual CO_2 abatement will likely yield upwards of 1.87 TWh savings when compared to a PCA-declared cement plant (**here**). This is equivalent to more than 375,000 Californian apartments that on average each use 5 MWh/yr (**here**). Even if CCS only *doubled* the energy needs of Portland cement production as it stands now (which is likely *conservative* according to ECRA's conclusion above), that number would balloon to 750,000 Californian apartments.

To assert our request, we had noted especially the assorted text as highlighted per the Compendium section above. Simply: on our reading, the LCFS is a powerful wide-ranging Climate Action tool, now modified through the years. It now includes provision for CCS (and DAC) and (separately) also fuels made from such CCS systems. Per our 11.01.23 letter, as the rules are currently formulated a DAC plant can be installed anywhere on the planet to make its LCFS claim. Having in mind the controlling statutes empowering CARB—and that the primary legislation has been *turbocharged* per SB596—we assert the following points in support of our request:

- Noting our LCA diagram and EPD for California (**here**), in transportation terms an EMC plant can be justified also as a *transportation device* per LCA boundaries A2–A3. For example, as our LCA diagram confirms, Zone A3 is an all-electric *linear* transportation device. It will span over 1000 ft and hence will be of a dimension similar to the guide-rails of a portside crane.
- All of our Zone A3 could be powered by diesel. Indeed, when in 2014 we were asked by Cameroon's government to investigate an EMC installation there, such are the limitations of West African electricity supply, any such EMC plant would have used diesel across its entire A3 transportation device so as to cause both the necessary drying and processing. Instead, we demurred.
- Just like a portside crane, our Zone A3 plant is *captive*. It does not move from its intended site. Only the intended substrate is transported: again, just like a portside crane.
- §95483(c)(4) LCFS (**here**) rewards the usage of electric forklifts. LCFS Credits flow directly to the "fleet owner". Clearly, a forklift is also *captive*: it is not intended to move beyond its operation site.
- The LCFS' definition of "transportation fuel" speaks for itself and *per se* has no requirement for a device to be non-stationary. Per lines 25–26 above, the term "non-vehicular" is expressly included. UC Berkeley's 2007 technical report confirms non-vehicular equipment, including leaf blowers.
- Further, that same definition places no restriction for such *equipment* only to cause *transport*. Equally, that same definition makes no attempt to rank transport as the fuel's primary purpose. Simply put: the "transportation fuel" definition is agnostic in all such regards.
- In confirmation of such agnosticism, per lines 30–31 above, the LCFS expressly introduces the terms "off-road transportation application" and "off-road equipment application".
- The highlight at line 88 confirms the inclusion of portside electric cranes: *i.e.,* yet another type of wholly *captive* device.

Conclusion: Zero CO2 | Low Energy | Electrification

> "Though going from an 80% reduction to a 100% reduction might seem incremental, the effort to decarbonize the economy gets harder the closer we get to 100%. To deliver on the much more ambitious goal, CARB needs more technologies in the mix. The "net-zero" part is acknowledgement that, for some sectors of the economy, such as air travel, we won't have cost-effective solutions to cut emissions...CARB realized the technologies weren't sufficiently developed and needed government support to get there...any entity that captures and sequesters a ton of CO2 from the air (which traded at an average price of $160 in 2018), can claim a credit from California. And because it doesn't matter where the CO2 is captured and stored, any entity in the world can apply for the credit."
>
> **Akshat Rathi, Quartz** | A Tiny Tweak in California Law is Creating a Strange Thing: Carbon-Negative Oil (2019) | **here**

Per line 73 above, §38561.2(b)(6) expressly includes the word "prioritize". To such ends, our LCA diagram confirms A3's processing of raw material is impossible unless it is *transported*. Simply: transport is both inherent and necessary in absolute terms to an EMC's production. Today, the LCFS is a wide-ranging Climate Action toolkit. However, it has always comprised the means to directly deliver the *electrification* of legacy fossil-fuel transportation and equipment *applications*. Equally, a Portland cement plant is a legacy application that is both fossil-fuel intensive and requiring its substrate to be transported in a linear fashion by its installed equipment system. Further, vast quantities of cement are used in California's transport infrastructure on which its economy depends. Concrete may not be a product used to power trucks, but without it? Concrete is a vital transportation *material*, whose decarbonization is now a statutory demand.

Our 11.21.23 letter noted that ECRA's CCS cost estimate (~€100/t) is corroborated by Canada's IISD report (**here**). Moreover, the glaring scale of the energy savings we have set out here, is such that the more CCS is progressed in California, the greater California's need for a low-energy solution such as ours. At the very least, and using ECRA's most conservative CCS energy-forecast, 1mn tonnes of electric CCS bolted to a Californian Portland cement plant can only be offset—in energy terms—by 1mn tonnes EMC *Californian* CO_2 abatement (an energy-saving equaling the needs of some 750,000 apartments *upwards*).

This letter demonstrates that the LCFS supports a variety of devices carrying, to whatever degree, some sense of a transportation *dynamic*. A leaf blower transports only a "substrate" (*i.e.*, leaves). A forklift truck is captive. A portside crane transports a variety of loads only within the confines of a rail-system set within the range of an EMC plant's length. Both are captive. Hence, whether a device is "non-stationary" is a red herring. There is no doubt that a hook-up towed conveyor used in (say) forestry management is an "*off-road equipment application*". However, that machine is likely sitting entirely stationary when doing its job — during which the only aspect delivering transportation will be the conveying *mechanism* itself.

SB596 compels innovation. Our future is only about *delivery*. Respectfully therefore, having in mind especially §38561.2(b)(6) and Title XVII, we repeat our request for an LCFS rule-innovation that favors SB596 industrial low-energy *electrification*. We fully accept any new rule must be open equally to others also delivering those same benefits in an SB596 setting. To such ends, we believe the innovations we have suggested could be easily implemented and require minimal change to California's existing code, while being linked expressly to the aims of SB596. Further, the suggestions we have made are designed also to concord with Title XVII, moreover so that only innovative *electrification* technologies may qualify under the LCFS (with the credits generated tied to verified carbon mitigation). Nevertheless, if it is demonstrated objectively that the LCFS cannot be innovated no matter the reasons as suggested by us here, then we would welcome any alternate rule-change given §38561.2(b)(7)'s express requirements, per lines 76–86 above which includes energy-efficiency improvements and "*Measures to facilitate fuel switching*".

Sincerely

Atle Lygren | C.E.O. EMC Cement BV

ENC: Annex

ANNEX

NOTES

The ***New Definitions*** suggested below are taken from 10 CFR 609.2 (here), duly modified.

The terms "ASTM", "Executive Officer", "Primary Product", "Verification Body" are already set out in §95481 and do **not** require modification in the setting as suggested below.

193.1 ***New Definitions:***

"Commercial Technology" means a technology in general use in the commercial marketplace in the United States at the time the application is made to the Executive Officer. A technology is in general use if it is being used in three or more facilities that are in commercial operation in the United States for the same general purpose as the proposed project, and has been used in each such facility for a period of at least five years. The five-year period for each facility shall start on the in-service date of the facility employing that particular technology or, in the case of a retrofit of a facility to employ a particular technology, the date the facility resumes commercial operation following completion and testing of the retrofit.

"New or Significantly Improved Technology" means an electrical technology which produces a Primary Product and is intended to reduce both the generation of high-temperature heat and the greenhouse gas emissions associated from cement production, which that at the time the application is made to the Executive Officer either:

(i) Has only recently been developed, discovered, or learned; or

(ii) Involves or constitutes one or more meaningful and important improvements in productivity or value, in comparison to Commercial Technologies in use in the United States;

provided, always, such technology may still be considered a "New or Significantly Improved Technology" if no more than 6 projects employ the same or similar technology as another project, provided no more than 2 projects that use the same or a similar technology are located in the same region of the United States.

193.2 ***§95483(c)(5) ("For Electricity Used as a Transportation Fuel") amended as follows:***

(5) *Other Electric Transportation Applications.* For electricity supplied to a transportation application not covered in subsection (1) through (5) above, any entity can apply to the Executive Officer to be ~~the fuel reporting entity and~~ the credit generator:

(A) and the fuel reporting entity for electricity supplied as long as it meets the requirements of section 95488.7(a)(3) and 95491;

(B) for any New or Significantly Improved Technology that is not a Commercial Technology at the time the application is made to the Executive Officer, as long as:

1. the deployment of any such New or Significantly Improved Technology meets the reasonable requirements as may be stipulated by Executive Officer;
2. the Primary Product is ASTM compliant; and
3. the carbon mitigation delivered by any such New or Significantly Improved Technology is verifiable by a Verification Body including for the purposes of the Executive Officer meeting the requirements of §95486(a)(3)(A).

Comment Log Display

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Comment 203 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Robert
Last Name	Hambrecht
Email Address	rhh@allotropepartners.com
Affiliation	Allotrope Partners LLC
Subject	CARB LCFS Rulemaking Comment Letter
Comment	See attached. Thank you for the opportunity to comment on these important issues.
Attachment	www.arb.ca.gov/lists/com-attach/6865-lcfs2024-AmNVMABlWWkFXARn.pdf
Original File Name	ACDC CARB Comment Letter Feb 20 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 11:36:58

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

To: California Air Resources Board

Thank you for the opportunity to comment on the LCFS rule making process. We recognize CARB's long-established leadership in addressing the climate crisis across a broad landscape of innovative policies such as the LCFS program and the State's Cap and Trade program, which implemented stringent forestry offset protocols now being emulated by programs outside of California. We appreciate the opportunity to contribute to the dialog, in particular regarding the forestry practices embedded in the LCFS program.

Allotrope Cellulosic Development Company (ACDC) is a California-based project development company developing a forest residues and agricultural waste derived cellulosic ethanol plant in California. In partnership with a well-regarded, established technology partner as well as other important industry partners, ACDC's plant will produce carbon negative ethanol, which is a critical piece of making Sustainable Aviation Fuel possible. Developing such plants will support many key elements of California's overall strategy to address climate change while lowering the risk of catastrophic wildfire and creating numerous related environmental benefits.

The CARB 2022 Scoping Plan for Achieving Carbon Neutrality establishes a goal of managing and treating 2.3 million acres per year of Natural Working Lands (NWL), a goal that it acknowledges is "ambitious." [1] Near the end of the document, the Scoping Plan addresses "considerations" that "must be addressed when implementing" the plan, one of which is that achieving the ambitious goal of treating 2.3 million acres of NWL will require "significant changes" in forest management.[2] Scoping Plan strategies to scale forest management include expanding biomass processing infrastructure and streamlining permitting in collaboration with State and local agencies.[3] As a project developer working to build a commercial scale cellulosic ethanol plant in Northern California utilizing forest biomass, we contribute to carbon neutrality while improving forest management and expanding biomass processing infrastructure.

Forestry residues from harvests and fire management activities are materials that, at present, are typically left in the woods post-harvest, resulting in heightened fire risk and, ultimately, in emissions/pollution, be it from wildfire, open pile burning or via decomposition. Alternatively, removing this material and utilizing it to manufacture carbon negative cellulosic ethanol meaningfully contributes to combating climate change, while also resulting in improvements in air quality and a reduction in particulate matter, due to the elimination of open pile burning, or wildfires in the worst-case scenario.[4]

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[1] California Air Resource Board - 2022 Scoping Plan for Achieving Carbon Neutrality, November 16, 2022 (the Scoping Plan) at pp. 98 & 99.
[2] Scoping Plan at p. 262 ("Increasing forest management to the degree included in the Scoping Plan Scenario will require significant changes to wood-processing infrastructure, workforce capacity, permitting processes, technical assistance, and other operational constraints.")
[3] Scoping Plan at p. 252.
[4] See Springsteen, Christofk, Eubanks, Mason, Clavin and Storey, "Emissions reductions from woody biomass waste for energy as an alternative to open burning."
https://www.hcd.ca.gov/community-development/disaster-recovery-programs/ndrc-attachment-f/docs/aw_article_pcapcd_20120321.pdf

Cellulosic biofuel projects using forest and agricultural waste biomass offer a variety of benefits to the California communities where they are located, including significant direct employment opportunities[5] and indirect job creation as the biomass supply chain needed to support the ethanol plant grows to meet increased biomass demand. Our first plant requires 300,000 metric tons of forest residue annually, which will support an estimated 25,000 acres of annual forest treatments, advancing sustainable forest management activity at scale and increasing the carbon stock of those forests while reducing the risk of catastrophic fire. Our project supports the long-term growth of forest carbon stocks and also improves the overall water supply. Furthermore, the resulting biofuel produced will have a negative carbon intensity, will displace fossil fuels and will support the long term decarbonization of the State's economy. This project is fully aligned with CARB's approach to Natural and Working Lands that "holistically fosters ecosystem health, resilience, provision of overall climate function, and other co-benefits."[6]

The key operational challenge as a biofuel developer in California is securing a long-term supply of state LCFS and federal Renewable Fuel Standard (RFS) qualified forest biomass. Existing federal rules preclude the use of federal forest biomass and thus require that we source forest biomass from private or State forests only. To that end, we are concerned with the language in the proposed LCFS amendments that makes forest residue biomass derived from private land clearcuts ineligible. If approved, this would result in the elimination of an important, immediately available feedstock that is presently left in the woods, eliminating a critical long-term supply source required to advance renewable fuels projects that also advance broader CARB goals.

Our long-term aim is to add residue from emerging forest management activities to the existing residues, further increasing sustainable long-term biomass contracts for expansion and additional facilities. We are eager to see sustainable solutions that allow for the long-term utilization of additional material and we urge CARB (and other state entities) to support
194.1 continued funding for CalFrame and to support proposed avoided emissions credit programs to help create the appropriate economic structures that support more forest management work and additional residue utilization. We also see opportunity to work with federal authorities to lift the ban on biomass from federal lands. While such longer-term forest management enhancements are developed, we believe that working with existing operations to use waste streams presently left in the woods provides significant value to the forest ecosystem and supports the transition to broader forest management activities.

It's important to note that in California clearcutting is tightly restricted by State regulations in the California Forest Practice Rules, which are set forth in Title 14 of the California Code of Regulations (CCR) at Chapters 4, 4.5 & 10. Specifically, 14 CCR Section 921.3(c) establishes narrow circumstances under which clearcutting may be employed, as well as detailed rules regarding the extent and manner in which it may be used. And it can only "be used when

[5] Each ACDC plant will generate over 500 temporary jobs during construction and fifty well-paid permanent jobs.
[6] Scoping Plan at p. 243.

justified and explained in the plan and found in conformance by the Director" with the requirements of the rule.[7] Given the tightly regulated permitting of clearcutting, there is no chance that allowing the forest residual materials that remain after a clearcut to be utilized as biomass feedstock will create any incentive for additional clearcutting. Instead, it will deliver the many environmental and climate benefits noted above, and thereby improve the overall environmental impact of the limited usage of clearcutting that is allowed today in the State.

194.2 We therefore propose that the language in § 95488.8. Fuel Pathway Application Requirements Applying to All Classifications. section (g) Specified Source Feedstocks (1) (A) subsection 3 be amended to read as follows:

> "~~*Small-diameter, non-merchantable*~~ *Any forestry residues and byproducts removed as part of a forest fire fuel reduction,* ~~*last*~~ *stand improvement or slash/tops from a treatment (including harvests)* ~~*where no clear cutting occurred;*~~ *from forest lands that meet applicable federal, state or local regulations; Municipal solid waste that is diverted from landfill disposal;".*

We respectfully submit that in California any residue from pre-2008 plantations[8] that meets the current California Forest Practice Rules requirements should be eligible for the LCFS program. We note that CARB took a similar approach when it aligned the 2015 Compliance Offset Protocol for U.S. Forest Projects with the requirements of the California Forest Practice Rules.[9] California's Forest Practice Act regulations are the most stringent in the United States[10] and set a standard that assures sustainability, a long term increase in the carbon balance of forests and assures that these forests will not be converted to plantations for energy crops as there are minimum stand age and minimum diameter requirements in place. While other jurisdictions may not be as stringent as California, by aligning its climate and forest management regulations it
194.3 will strengthen the State's leadership role in both areas.[11]

As we seek long term feedstock agreements with forest landowners in the region, we recognize that, while all landowners in California adhere to California Forest Practice Act (CFPA) standards, their forest management practices do vary in practice. When analyzed at a landscape scale, over the longer time frames appropriate for forest and carbon management, CFPA standards assure a growing carbon stock in these regions as well as a healthier and more fire resilient ecosystem. As such, we respectfully submit that the focus should be on landscape scale improvements to forestlands and that compliant clear-cutting practices on individual small

[7] 14 CCR Section 921.3(c)(1).
[8] We believe the definition of pre-existing plantation proposed in Section 95488.9 is appropriate as it is largely consistent with federal definitions used for eligibility requirements for federal RINs.
[9] See Section 5.2.1(e)(1)(D) regarding forest projects in California.
[10] See Goldstein, Crandall and Kelly, "The cost of doing business": Private rights, public resources, resulting diversity of state-level forestry policies in the U.S. Table 1 demonstrates, for instance, that California is the only state that requires licensing for foresters and timber harvest plans/permits before harvest as well as notification requirements before harvest.
[11] Another option would be to do as CARB did in the 2015 Forest Offset Protocol and carve out a specific set of rules for California. Compare Section 5.2.1(e)(1) with Section 5.2.1(e)(1)(D).

stands of pre-existing plantations should be seen within that larger context and not result in the elimination of an important source of feedstock for the biofuels industry in California.

Sincerely,

Robert Hambrecht
Partner
Allotrope Cellulosic Development Company, LLC

Comment Log Display

Here is the comment you selected to display.

Comment 204 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Helen
Last Name	Kemp
Email Address	hkemp@3degreesinc.com
Affiliation	3Degrees Group Inc.
Subject	3Degrees Comments on LCFS
Comment	Please see the attached file for our feedback on the proposed LCF regulation. Thank you!
Attachment	www.arb.ca.gov/lists/com-attach/6866-lcfs2024-UmFTMQFlUGQLfwZj.pdf
Original File Name	3Degrees Comments on LCFS 2024 Formal Rulemaking.pdf
Date and Time Comment Was Submitted	2024-02-20 11:39:16

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

3Degrees 235 Montgomery St., Suite 320
San Francisco, CA 94104

February 20, 2024

The Honorable Liane M. Randolph, Chair
California Air Resources Board
1001 I St.
Sacramento, CA 95814

RE: 3Degrees Comments in Response to Proposed Amendments to the Low Carbon Fuel Standard Regulation

Dear Chair Randolph and Air Resources Board (ARB) Staff,

Thank you for the opportunity to provide comments in response to the Proposed Amendments to the Low Carbon Fuel Standard (LCFS) Regulation published December 19, 2023 (updated January 2, 2024). 3Degrees Group Inc. ("3Degrees") is a global climate and clean energy solutions provider and is a strong supporter of the LCFS program. We participate in the program as a designated reporting entity on behalf of a variety of opt-in parties with light-duty electric vehicle (EV) chargers, electric forklifts, hydrogen forklifts, and heavy-duty EV fleets. We are also an active fuel pathway developer.

3Degrees appreciates the time and effort that Staff has put into engaging the public and crafting these updates to the program over the last few years. Our recommendations for the LCFS proposed rule are outlined below. Under each heading, we have organized our comments in order of what we view as the key priorities for this formal rulemaking process.

I. Carbon Intensity (CI) Reduction Targets and Credit Market Mechanisms

195.1a **ARB should impose a more stringent near-term carbon intensity reduction schedule to ensure long-term credit price stability.**

The LCFS program has been highly effective at achieving emissions reductions, and we understand that the final target for this rulemaking needs to be feasible as well as effective. The low carbon fuel industry has consistently exceeded the expectations of this program and with the right market signals, the total decarbonization of the transportation sector could be within reach. However, our market analysis shows that the proposed 30% CI target (§ 95484) is too low to provide the near-term price indicators that are necessary to spur the substantial industry investment in lower-CI projects, fuels, and vehicles required to reach the program's long-term goals.

In our comments during the informal rulemaking process, 3Degrees advocated for at least a 35% CI reduction by 2030 and 90% by 2045 in order to align with the ambition of the 2022 Scoping Plan and other decarbonization objectives in California. With credit prices dropping from ~$67 to ~$55 since the publication of the proposed rule, the market reaction to the proposed CI schedule has evidenced a lack of confidence that the near-term target of a 30% reduction by

2030 will require more than minimal additional credit generation to attain. We therefore reiterate our support for at least a 35% target by 2030.

Our market analysis shows that under the proposed rule the credit bank will continue to grow until it peaks in 2030, followed by a sharp drawdown, potentially depleting the bank by as early as 2034. The auto-adjustment mechanism (AAM) would be triggered twice, making the CI reduction target in 2030 38% and reaching 90% reduction in 2043. We expect that prices will only begin to rise once the bank begins to draw down.

While lower near-term prices may achieve the objective of reducing total program costs, the post-2030 targets will only be achievable through significant investments in the low carbon fuel sector this decade. Low credit prices will not send an adequate market signal to drive the necessary investment. We are generally supportive of the AAM (§ 95484(b)) and 2025 step-down adjustment (§ 95484(d) - Table 1, footnote b), though we would suggest that the AAM should be able to be triggered earlier, in 2026. This design would lead to fewer surplus credits through the late-2020s and likely result in the higher prices needed to drive investment, thus mitigating pricing volatility with a smoother path towards more ambitious targets.

195.1b

II. Changes to Forklift Crediting

195.2 **3Degrees urges ARB to not phase out technology (e.g., zero-emission (ZE) forklifts) or fuel types from the program via energy economic ratio (EER) adjustments.**

Staff's proposal to adjust the EER for forklifts with lift capacities less than 12,000 kg (§ 95486.1(a) - Table 5) to decrease credit generation opportunities for this technology introduces unnecessary regulatory risk to the LCFS program. In the Initial Statement of Reasons (ISOR), Staff explains that this adjustment is based on a re-evaluation of the forklift baseline; because ZE forklifts have replaced many combustion-fuel forklifts in the State, Staff is assuming that approximately 50% of new ZE forklifts purchased will be replacing older ZE forklifts, effectively neutralizing overall ZE forklift adoption rates. However, not only is this crediting limitation ill founded, it sets a precedent for the reduction of other credit generation opportunities that could threaten the ability to meet program targets, especially in the long-term.

In conjunction with the LCFS, other California policies aimed at decarbonizing vehicle types and fuels, such as the Advanced Clean Cars II Regulation, Advanced Clean Trucks Regulation, and Advanced Clean Fleets Regulation, will inevitably lead to similar situations in which some portion of ZEV purchases for those equipment types will be made to replace existing ZEVs. However, depending on the vehicle type, this does not necessarily mean that older ZEVs will be retired. For example, used light-duty ZEVs with a lower price point may replace fossil fuel vehicles that would not otherwise have been retired. The need for ARB to account for this kind of market dynamic while balancing decarbonization goals against program operability underscores the importance of establishing clear criteria for equipment phase outs.

Arbitrarily halving the EER, defined in the regulation as "the dimensionless value that represents the efficiency of a fuel as used in a powertrain as compared to a reference fuel used in the same powertrain," should not be used as the method to discount forklift credit generation, or that of other technologies or fuels. If ARB must phase out any credit generation opportunity, this should only occur via a well-defined, data-driven methodology that accurately accounts for market saturation and other relevant factors. As noted in our comments during the workshop phase of this rulemaking, the LCFS should provide an off-ramp or other provision geared at a smooth and predictable transition out of the program. A lack of clarity on how other equipment types will be treated under the LCFS as they gain traction may result in reduced investment in these technologies, making it more difficult for the Program to achieve its long-term goals.

195.3 **A metering requirement for forklift credit generation calculations should be phased-in so that industry has time to adjust their equipment and processes.**

While 3Degrees understands the benefits to data accuracy that metering provides, in order for the LCFS program to have an effective metered solution in place, facilities with e-forklifts need sufficient lead time to plan, pay for and install the external meters that are required to measure electrical dispensation into their fleets. The LCFS's estimation methodology has been a cornerstone of the forklift credit generation process and businesses have relied on not needing meters for participation in the program for many years. Changing this rule without some provision of an offramp for estimation, coupled with any reduction to the forklift EER as discussed above, would be significantly disruptive to many current participants.

Should ARB move forward with an immediate metering requirement, we respectfully request that Staff consider a delayed effective date for forklifts that are currently registered in the program. This would allow time for owners of fueling supply equipment (FSE) to acquire the capital, engineering reviews, permits, and equipment necessary to comply.

III. Third-Party Verification Requirements

195.4 **ARB should provide clarification within the new verification provisions for hydrogen and electricity transaction types to ensure that site visit requirements are feasible.**

With the introduction of new third-party verification requirements for certain hydrogen and electricity crediting types, it is imperative that ARB does not take a one-size-fits-all approach to the site visit obligation. Although the sampling plan mechanism as described in the proposed rule would reduce the number of FSE that must be surveyed for a particular site, it would not be reasonable to expect individual site visits for the thousands of disparate sites containing FSE, particularly for designated entities. Furthermore, conducting site visits of all metered residential charging poses practical and privacy implications for homeowners that may outweigh assurances gained by a visual inspection of the meter.

The proposed text states that verifiers must "annually visit each facility; and, if different from the fuel production facility, the central records location for which the records supporting an application or report subject to verification are submitted" (§ 95501(b)(3)). We request that ARB make a revision to this section such that in the case of designated reporting entities or entities with more than a certain number of registered FSE, verifiers need only visit the designated reporting entity's central location for recordkeeping plus a subset of facilities based on a carefully-crafted sampling plan. This would be a typical set of requirements for verification bodies to come to a *reasonable* level of assurance - the standard for a positive verification statement - as opposed to seeking an *absolute* level of assurance by visiting every parking lot in the state with a registered FSE. While we understand that ARB desires to apply verification requirements equally to all reporting entities throughout the LCFS program, the nature of EV charging equipment is such that the verification process could require multiple months of continuous travel to achieve 100% visitation of all sites with registered FSE. This impractical requirement would pose serious issues for verification bodies and designated entities alike. In addition, we ask ARB staff to exempt residential charging from site visit requirements. Failing to make these changes would discourage EV participation in the program, especially for entities with a large number of distributed FSE.

We further recommend that § 95500(c)(1)(E)(1) be revised to state, "EV Charging except as specified under 95491(d)(3)(A) *and 95491(d)(3)(B)*" (new text in italic). This captures both the metered and non-metered residential charging provisions under the exemption.

IV. Other Proposed Amendments

195.5 **The deficit generation penalty for exceeding a predetermined CI score will disproportionately penalize the biogas sector and should be adjusted down.**

According to the proposed rule, beginning in 2025, exceeding the CI score of a fuel pathway will result in both deficits being generated and a claw-back of credits, and the number of deficits per volume of fuel will be 4x the difference between the verified CI and the reported CI (§ 95486.1(g)). If this full penalty is enforced, many well-intending pathway operators will observe large swings in performance, particularly in digester-derived fuels processing organic wastes and newly-certified pathway operations that will likely have unavoidably variable CIs.

The proposed combination of credit clawback and 4x deficit generation effectively creates a 5x penalty for CI deviations. Combined with the fact that the LCFS regulation does not allow for retroactive credit generation for overperformance, this creates an incentive for projects with variable CI scores and/or operations to implement a dramatic safety factor that significantly reduces the benefits of the program for these projects. These projects provide real greenhouse gas benefits as compared to sending those organic materials to landfills, and the proposed penalty may discourage these projects from being built, effectively limiting California's realized greenhouse gas emissions reductions.

We propose either (1) reducing the 4x deficit generation policy and replacing with a 1x deficit penalty or (2) implementing a carve-out for all categories of digester-derived pathways that exceed their certified CI only as a result of organic variability in digester performance. A reduced deficit penalty would be a fairer and cleaner means of ensuring that participants make best efforts to meet assigned CI scores. Additionally, accounting for the operational differences that digester projects face as compared to other LCFS activities is critical to maintaining the equitable treatment of fuels within the program.

195.6 **ARB should continue to allow site-specific data to be used in the Tier 1 calculator for Renewable Electricity from Dairy and Swine Manure.**

In the Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure Instruction Manual (DSM Manual), we ask that ARB revert to the original language requiring that site-specific data take precedence over values from Table A.9 of the Compliance Offset Protocol - Livestock Projects (LOP) as an input to the calculator for solid separation equipment. This change made by ARB in Table 2, L1.(1-6).13, Fraction of Volatile Solids Sent to Anaerobic Storage/Treatment System, and similar language in L4.5 and L4.6 of the Proposed Tier 1 Simplified Calculators, will lead to less precise calculations and an underrepresentation of emission reductions achieved.

Pathways that rely on site-specific values result in a far more accurate CI score than the default. Further, the LOP generally prioritizes site-specific data, also in favor of accuracy. 3Degrees has generated CI projections based on this site-specific data which now may suffer a material deterioration of their CI due to this modification of the DSM Manual. If ARB is not willing to revise the Tier 1 instructions, then we support maintaining the ability to utilize site-specific values for solid separation equipment inTier 2 applications as a reasonable alternative.

195.7 **We encourage ARB to add electric ground support equipment (eGSE) as an eligible credit-generating technology.**

3Degrees recommends that ARB use this rulemaking opportunity to explicitly include eGSE as an eligible credit-generating technology type under the LCFS. eGSE are eligible for crediting under the programs in both Oregon and Washington, and incorporating eGSE into the LCFS would serve to incentivize an industry that is in the early stages of electrification. This would help ensure that the California LCFS remains a driving force for new technologies to transition away from fossil fuels. An EER for eGSE can be easily developed using a similar methodology to that of electric cargo handling equipment (eCHE). This category of electric off road equipment charging should, in line with other clean fuels programs, assign the owner of the FSE as the fuel reporting entity and the credit generator.

195.8 **3Degrees recommends aligning the minimum charging capacity requirement for light-duty fast charging infrastructure (LD-FCI) crediting eligibility with current technological capabilities.**

The proposed minimum charging capacity requirement of 150 kW for LD-FCI (§95486.2(b)(1)(D) and (b)(7)(A)) is higher than currently technically feasible for most EVs to charge. While this capacity standard may be forward-looking, 50 kW would be a more appropriate minimum in line with today's technological capabilities. We suggest a gradual increase in the requirement, for example, ARB could institute a 100 kW minimum in a few years, followed by 150 kW once EV technology has evolved to reliably charge at this level.

3Degrees appreciates this opportunity to provide feedback and we look forward to continuing to work with ARB on the success of the LCFS program. Please reach out with any questions or for further discussion.

Sincerely,

/s/ Helen Kemp

Helen Kemp
Senior Associate, Regulatory Affairs
hkemp@3degrees.com

Comment Log Display

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Comment 205 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Brian
Last Name	Jennings
Email Address	bjennings@ethanol.org
Affiliation	American Coalition for Ethanol
Subject	Comments on 2024 Proposed Amdts to Calif LCFS
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6867-lcfs2024-UDFXMlQwU19SNwBv.pdf
Original File Name	ACE Comments Calif LCFS Proposed Amendments 2.20.24.pdf
Date and Time Comment Was Submitted	2024-02-20 11:46:04

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

american coalition for ethanol

February 20, 2024

Liane Randolph
Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: 2024 Proposed Low Carbon Fuel Standard Amendments

Dear Chair Randolph:

On behalf of the members of the American Coalition for Ethanol (ACE), I appreciate the opportunity to comment on the California Air Resources Board (CARB) 2024 proposed amendments to the Low Carbon Fuel Standard (LCFS). Our comments will focus specifically on the proposed "sustainability criteria" for crop-based biofuels, the need to approve E15 use in California, and the importance of E85 and flexible fuel vehicles (FFVs).

Crop-Based Sustainability Criteria

Over the past several years, ACE has been leading the effort to ensure ethanol producers and farmers are part of the climate solution. Our work involves development and advocacy for new LCFS policy in Midwest states and validation of the real-world greenhouse gas (GHG) reductions modern-day corn and ethanol production can deliver at scale. The farmer and locally owned ethanol plants which comprise the grassroots membership of ACE are investing in a variety of strategies and technology innovations to supply California with low-carbon ethanol and believe a properly designed and administered LCFS policy incentivizing climate-smart agriculture practices can support increased use of ethanol.

196.1 Nevertheless, we do not support CARB's sweeping "sustainability criteria" approach to regulate ethanol producers and farmers. The broad and burdensome proposal to require pathway holders to track crop-based feedstocks to their point of origin and obtain independent third-party certification will only serve to discourage participation in the LCFS. Instead, we offer a scientifically driven alternative based on real-world farm practices.

Earlier this year, the United States Department of Agriculture (USDA) made a $25 million investment in a Regional Conservation Partnership Program (RCPP) led by ACE. This USDA RCPP project is designed to unlock corn ethanol access to LCFS markets and new tax incentives based on the adoption of climate-smart agricultural practices which reduce GHG emissions.

The USDA funding will help farmers adopt reduced tillage, nutrient management and cover crops on nearly 100,000 acres across 167 counties surrounding 13 ethanol facilities partnering with ACE to implement the project in the 10-state region of Illinois, Indiana, Iowa, Kansas, Minnesota, Missouri, Nebraska, Ohio, South Dakota and Wisconsin. The sites were strategically chosen to provide our project's scientific team with statistically significant data regarding the GHG effect of conservation practices in different soil types and climates.

american coalition for ethanol

ACE and our partners will accomplish three important objectives with this funding support from USDA. First, we will incentivize farmers in 10 states to adopt conservation practices. Three-fourths of the funding will go toward farmer adoption of practices. Second, our team of soil scientists and agronomists will monitor, measure and verify how the conservation practices adopted by the farmers reduce GHG emissions from corn production. The data they collect will be shared with the U.S. Department of Energy who will use it to pressure test existing models such as the Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model to address real and perceived 'information gaps' which currently prevent farmers and ethanol producers from adequately monetizing climate-smart ag practices. Third, our ultimate objective is to empower ethanol producers and farmers with modeling and calculator tools to earn higher tax credits and premium prices in clean or low carbon fuel markets based on climate-smart ag practices.

Our partners, including 13 ethanol companies and team of technical experts, are currently making plans to ensure farmers in the 167 counties are aware of their eligibility and we hope to execute contracts for initial conservation practices following the 2024 fall harvest. This larger project is based on ACE's existing South Dakota RCPP, where we have more than 15,000 acres in seven counties under contract for climate-smart ag practices. Given the progress we have already made with the South Dakota RCPP project, we are in a good place to hit the ground running on this 10-state project.

196.2 While we may share CARB's goal for better understanding the GHG impacts farming practices have on crop-based biofuels, we disagree feedstocks such as corn must be tracked to their point of origin. Rather, some of the models CARB and other regulators use today to penalize corn ethanol for land use change (LUC) and farm-level practices can be improved and modified to assign carbon credits based on climate-smart agriculture practices. Specifically, we believe the GREET model developed by U.S. Department of Energy's Argonne National Laboratory should be used to assign carbon credits from climate-smart ag practices. GREET currently estimates nitrous oxide emissions from fertilizer use, contains a module for estimating LUC penalties through the Carbon Calculator for Land Use Change from Biofuels (CCLUB), and features a relatively new Feedstock-Carbon Intensity Calculator (FD-CIC) module estimating soil carbon emissions and sequestration credits for practices such as conservation tillage and cover crops on corn production.

Scientists and modelers indicate precipitation, soil type, and temperature are essential factors used to determine the GHG benefits of climate-smart agriculture practices. These same modelers and market regulators such as CARB are reluctant to assign carbon credits for farm-level practices without more locally verified data upon which to validate the GHG benefits. Our USDA RCPP project includes an experienced team of scientists from land-grant universities and the U.S. Department of Energy's Sandia National Lab who have developed a proven mechanism to collect data from farmers in the 167 counties. Our scientific team will be able to assess the real-world carbon sequestration and reductions in carbon dioxide, methane, and nitrous oxide emissions from the climate-smart practices and validate them at a high confidence level required by modelers and market regulators.

The result of this USDA RCPP project will be the establishment of a non-proprietary, scientifically verified tool such as a modified GREET for ethanol producers and farmers to use to document the carbon intensity benefits of changes in agricultural practices that are validated with on-farm data at production level scale.

In short, our USDA RCPP project will establish an alternative to CARB's proposed burdensome and costly quantification and verification protocols that would discourage farmers and ethanol producers from reaping maximum benefits from these practices in the future.

The economic potential of capitalizing on climate-smart farming practices to produce corn ethanol for clean fuel markets or new tax incentives is significant. Through the 13 partner ethanol facilities, there's the potential to remove over 2,679,843 metric tons of CO_2 per year, or the equivalent of taking 596,346 cars off the road annually. Across the 10-state project area, this could amount to over $500 million per year in estimated maximum value from clean fuel markets — a $266 per acre benefit for farmers based on the three-year average LCFS carbon credit price. This potential economic value is similar to what the carbon benefits could be worth under a properly implemented 45Z tax credit. To learn more about this project, visit ethanol.org/usda-rcpp.

E15

196.3 Though technically related to CARB's "Advanced Clean Cars" (ACC) proposed amendments, we must take this opportunity to implore you to once and for all approve the use of E15 in California. Afterall, allowing E15 will help reduce the carbon intensity of the state's gasoline supply and also cut emissions of criteria pollutants. In fact, the Center for Environmental Research and Technology at the University of California Riverside found that replacing E10 with E15 in California will significantly improve air quality.[1] It should also be noted E15 is EPA-approved for nearly all vehicles on the road and offers meaningful cost savings, but Californians are currently paying more at the pump because CARB has not yet approved E15.

E85 and Flexible Fuel Vehicles (FFVs)

196.4 While E15 is not yet allowed for use in California, the availability of E85 enables the state to significantly reduce GHG emissions and save drivers of Flexible Fuel Vehicles (FFVs) substantial money at the pump. We specifically reinforce comments and concerns submitted to CARB from Pearson Fuels on January 15, 2024. Pearson is the largest distributor of E85 in California, supplying more than 350 fueling locations and planning more than 150 additional locations in the next 24 to 36 months.

In its January 15 comment letter, Pearson noted E85 use continues to rise in California but the number of FFVs declined from 2021 to 2022 by nearly 4 percent. As Pearson noted, "absent specific federal or state policy changes to motivate automakers to manufacture FFVs, we expect the FFV population will further shrink as automakers reduce model offerings. This will remove a key tool in the state's push to reduce carbon emissions, scale down petroleum usage, and offer consumers affordable fuel." We urge CARB to work with other state agencies, automakers, and the federal government to incentivize manufacturers to produce more FFVs and convert existing gasoline-operated internal combustion engines to operate on E85.

Thank you for your time and consideration of these comments.

[1] https://ww2arb.ca.gov/resources/documents/comparison-exhaust-emissions-between-e10-carfg-and-splash-blended-e15

Sincerely,

Brian Jennings, CEO
American Coalition for Ethanol

5000 S. Broadband Lane, Suite 224 Sioux Falls, SD 57108 605-334-3381 ethanol.org

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Comment 206 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Andrew
Last Name	Dick
Email Address	Andrew.Dick@electrifyamerica.com
Affiliation	Electrify America
Subject	Electrify America comments on LCFS Proposed Amendments
Comment	Thank you for the opportunity to comment. Please find our letter attached.
Attachment	www.arb.ca.gov/lists/com-attach/6868-lcfs2024-UTRUPlA0V2dXJQl7.pdf
Original File Name	Electrify America Comments on 2024 LCFS Amendments 45-Day.pdf
Date and Time Comment Was Submitted	2024-02-20 12:04:06

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Rajinder Sahota
California Air Resources Board (CARB)
1001 I Street
Sacramento, California 95814

RE: Electrify America comments on Proposed Low Carbon Fuel Standard (LCFS) Amendments

Dear Ms. Sahota:

Electrify America appreciates the opportunity to comment on the Proposed Low Carbon Fuel Standard Amendments. Electrify America is the nation's largest open network of DC fast chargers for electric vehicles (EVs), with over 3,900 ultra-fast chargers across 887 locations around the country, and over 1,100 chargers across more than 250 locations open to the public in California.

The electric vehicle sector is at a critical time in California. The market for new electric vehicles was highly successful in 2023, with approximately one quarter of new vehicles deployed in the state being electric. The result has been a surge in demand for public charging that necessitates a rapid expansion of charging infrastructure. In November 2023, Electrify America reported to CARB that dozens of stations in the state are experiencing above 40% utilization, with multiple sites exceeding 50% utilization for the quarter. At 50% utilization, all charging ports at a station are in use, on average, more than 12 hours per day. Now, more than ever, it is critical that California support the installation of additional charging ports to meet the rising customer demand for clean vehicles.

The LCFS has historically been one of the State's most powerful tools for supporting clean transportation in California, including electric vehicle charging infrastructure deployment. As a leading charging infrastructure developer, Electrify America can attest that every dollar generated from LCFS credits goes directly back into operations and efforts to expand access to affordable, reliable EV charging. As highlighted in the SRIA, the LCFS is poised to add nearly $100 billion in value to the EV ecosystem over the next two decades.[1]

However, at a time when charging infrastructure and the EV market more broadly needs to expand rapidly to achieve California's clean air, climate change, and transportation electrification goals, LCFS credits have rapidly declined in value, with credit generation substantially exceeding deficits over the past several years, leading to a reduction in credit prices. Specifically, after many years of relative stability, the excess of banked credits began

[1] SRIA, Table 24.

increasing rapidly around Q3 2021, more than doubling to a total of over 18 million banked credits by Q2 of last year. Furthermore, independent analysis by ICF demonstrates that the proposed amendments to the program may be insufficient to reverse this trend, resulting in a protracted situation of credit oversupply and low credit values that reduces a critical funding stream for development and operations of charging infrastructure.[2]

197.1 The most important thing CARB can do to stabilize the program is quickly amending the LCFS to appropriately strengthen targets, reverse the trend of accumulating excess credits, and return the program to a state where it continues to drive investments in a broad array of low carbon fuels and infrastructure, including EV charging. To achieve these goals, and based on the analysis by ICF,[3] we believe that a 40% reduction target by 2030 is the minimum necessary to stabilize the credit market and ensure that the LCFS program supports a successful transition to electric transportation in California. Given that sentiment and premise, we appreciate your consideration of our comments below.

197.2 **CARB should propose 15-day changes to align with findings from the ICF analysis**

Electrify America has participated in the coalition group working with ICF to analyze market appetite for low carbon fuels and associated appropriate targets for the LCFS. We support the overarching finding of the analysis, that a 2030 target of greater than 40% is appropriate and can be readily supported by the market. A target of at least 40% by 2030 is likely necessary to align with California's climate change goals and Scoping Plan outcomes, as well, which calls for a 40-48% reduction in greenhouse gas emissions by 2030. Given the fact that transportation fuel pathways account for about half of California's greenhouse gas emissions, LCFS targets that align with statewide greenhouse gas reductions are reasonable.

In fact, at least as it relates to electricity-related pathways, we have reason to believe that the assumptions in the ICF analysis are conservative. For example, while the assumptions assume minimum compliance with the Advanced Clean Cars II sales, in fact, EV sales in California consistently outperform regulatory requirements, and we expect that to continue into the future. Already, zero emission vehicle sales comprise about a quarter of California's new vehicle market, a market share not anticipated until the 2026 model year under the Advanced Clean Cars II rules. We also anticipate further innovation and efforts to reduce the carbon intensity of electricity used as transportation fuel in California. For example, Electrify America's network in California is backed by 100% renewable electricity. We expect others will increasingly do the same, reducing the carbon intensity of power for EV charging well below the grid average, and delivering additional LCFS credits into the market.

[2] ICF (2024) Analyzing Future Low Carbon Fuel Targets in California: Response to Staff Report, ICF Resources, LLC, February.

[3] ICF (2023) Analyzing Future Low Carbon Fuel Targets in California: Initial Results for Accelerated Decarbonization, Central Case, ICF Resources, LLC, June. https://ww2.arb.ca.gov/system/files/webform/public_comments/4306/Analzying%20Low%20Carbon%20Fuel%20Targets%20-%20Central%20Case%20Draft%20FINAL%20%28submit%29.pdf

Following the release of the Proposed Amendments, ICF conducted additional analysis to incorporate updated market data, evaluate CARB's proposed targets, and adjust assumptions into the scenario analysis to reflect prevailing assumptions from CARB. Their analysis reinforces
197.3 their earlier findings that CARB's proposed targets are too low, and that the step-down and auto acceleration mechanism as proposed in the 45-day regulatory package are insufficient to flatten or reverse the credit bank and restore market conditions that support ongoing investments in EV charging and other low carbon fuels.

Electrify America supports the findings of the ICF analysis and urges CARB to propose 15-day changes to the regulation that would do the following:

- 197.4 Increase the step-down to 20-25%, and have it take effect as soon as the regulation does in 2024.
- 197.5 Increase the 2030 target to at least 40%, in line with Scoping Plan targets.
- 197.6 Modify the AAM so that it:
    - Would be triggered when banked credits exceed 2-2.5 times quarterly deficits.
    - Can apply to calendar year 2025 data, potentially be triggered in 2026, and the compliance schedule can be potentially pulled forward in starting in 2027.
    - Can be triggered in consecutive years if market conditions warrant.

Comments on additional elements of the Proposed Amendments

Electrify America offers the following comments on other aspects of the Proposed Amendments:

- 197.7 We support the proposed capacity crediting provisions for zero emission vehicle infrastructure, including shifting FCI crediting proposals to medium and heavy-duty vehicles (MHD-FCI) and targeted deployments for light-duty vehicles (LD-FCI).
- 197.8 We support amendments to clarify that the owner of EVSE at multi-unit dwellings that is not serving a dedicated or reserved parking space is eligible to generate credits.

Thank you again for the opportunity to comment on the Proposed Amendments. We appreciate CARB's efforts to support the transition to EVs in California and look forward to continuing to work with CARB through the LCFS amendment process and in other forums to advance the State's transportation electrification and climate change goals. Please do not hesitate to reach out with any questions.

Sincerely,

DocuSigned by:
Andrew Dick
5A2AF58306B0487...

Andrew Dick
Business Development Manager, Incentives

Comment Log Display

Here is the comment you selected to display.

Comment 207 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Paul
Last Name	Wilkins
Email Address	pwilkins@eh2.com
Affiliation	Electric Hydrogen
Subject	Electric Hydrogen Comments on Proposed 2024 LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6869-lcfs2024-AGVUPgZiAjIFd1cl.pdf
Original File Name	Electric Hydrogen LCFS Comments Final .pdf
Date and Time Comment Was Submitted	2024-02-20 12:16:35

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

SUBMITTED ELECTRONICALLY

Tuesday, February 20, 2024

California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

RE: Electric Hydrogen Comments on Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

Thank you for the opportunity to provide comments regarding the proposed low carbon fuel standard amendments. Electric Hydrogen respectfully submits the following comments and proposed amendments, which are intended to facilitate the adoption of green hydrogen production at scale, as a transportation fuel as well as a feedstock in the production of transportation fuels for conventional and low and zero-carbon liquid transportation fuels (including sustainable aviation fuel, power-to-liquids, and renewable diesel).

With significant facilities, management groups, and employees in California and Massachusetts, Electric Hydrogen manufactures the world's most powerful electrolyzers for critical industries to produce low-cost green hydrogen. Our 100 MW electrolyzer plant is designed to load follow variable renewable energy resources and enable customers to efficiently convert renewable electrical energy into clean molecular energy in the form of hydrogen. Electric Hydrogen's mission is to achieve cost parity with fossil fuels in a timeframe that matters. Put another way, the company exists to make green hydrogen an economic inevitability, giving hard to decarbonize industries, like heavy-duty transportation, aviation, and maritime transport, a viable and cost-effective solution to meet their urgent net-zero climate objectives.

Green hydrogen is a necessary tool in the energy transition to a net-zero economy. The 2022 California Scoping Plan for Achieving Carbon Neutrality notes that for California to achieve its net-zero goal by 2045, California will have to increase green hydrogen production 1700-fold.[1]

Within the transportation sector, green hydrogen has multiple applications for helping lower GHG emissions. In addition to green hydrogen used as a transportation fuel in fuel cell electric vehicles (FCEVs), hydrogen is a necessary feedstock in both conventional petroleum fuels and many low and zero-carbon liquid transportation fuels including renewable diesel, sustainable aviation fuel (SAF), power-to-liquids (PtL), and maritime fuels including methanol and ammonia.

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[1] California Air Resources Board. *2022 Scoping Plan for Achieving Carbon Neutrality.* December 2022, page 8. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

Enabling the adoption of green hydrogen as both a transportation fuel in FCEVs as well as a feedstock in other transportation fuels can drive emissions reductions in both the near and long-term. Low and zero carbon liquid transportation fuels for heavy duty and long-haul transportation applications such as aviation and maritime shipping will be needed for the foreseeable future. CARB's scoping plan calls for meeting 80% of aviation fuel demand in 2045 with sustainable aviation fuel and power-to-liquids—fuels that require hydrogen as a feedstock in their production.[2] The scoping plan acknowledges the role that low-carbon liquid fuels will play for the foreseeable future and calls for continued state support: "the state must continue to support low-carbon liquid fuels during this period of transition and for much harder sectors for ZEV technology such as aviation, locomotives, and marine applications."[3]

Leveraging the LCFS to incentivize liquid transportation fuel producers to switch from gray to green hydrogen can also help the green hydrogen industry scale and in turn reduce the cost of green hydrogen which will enable greater adoption of FCEVs in medium and heavy-duty transportation. California's existing annual hydrogen production capacity is approximately 1.83 million metric tons. However, only about 5000 metric tons (less than 0.3% of current production capacity) is used to fuel FCEVs.[4] While the FCEV market for green hydrogen is expected to grow in the coming years, it will remain small compared to the market for green hydrogen as a feedstock in liquid transportation fuels. Ensuring that developers producing green hydrogen for the FCEV market as well as the liquid transportation fuel market can benefit from LCFS eligibility would accelerate green hydrogen adoption, reduce emissions, and reduce the cost of green hydrogen creating a virtuous cycle enabling greater adoption of FCEVs.

To enable the LCFS eligibility of green hydrogen as a feedstock in liquid transportation fuels, Electric Hydrogen recommends the following three amendments to the LCFS staff draft.

- Allow book-and-claim delivery of low-CI electricity for electrolytic hydrogen production used as a feedstock in liquid transportation fuel.
- Allow book-and-claim delivery of low-CI hydrogen in dedicated hydrogen pipelines outside of California for transportation fuel sold into the California market.
- Allow delivery of low-CI electricity via book-and-claim for electrolytic hydrogen production in the Renewable Hydrogen Refinery Credit Program.

198.1 **Allow book-and-claim delivery of low-CI electricity for electrolytic hydrogen production used as a feedstock in transportation fuel.**

§ 95488.8. subsection (i)(1) restricts the use of book-and-claim delivery of low-CI electricity to electrolytic hydrogen used in FCEVs. This provision artificially limits the market for LCFS

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[2] California Air Resources Board. *2022 Scoping Plan for Achieving Carbon Neutrality.* December 2022, page 73. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

[3] California Air Resources Board. *2022 Scoping Plan for Achieving Carbon Neutrality.* December 2022, page 190. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

[4] Justin Bracci, Adam Brandt, Sally M. Benson, Gireesh Shrimali and Sarah D. Saltzer, *"Pathways to Carbon Neutrality in California: The Hydrogen Opportunity",* Stanford Center for Carbon Storage and Stanford Carbon Removal Initiative, February 2022, page 2.

eligible green hydrogen to less than 0.3% of California's current hydrogen market. Refineries and other fuel production facilities that produce the lion's share of hydrogen in this State (whether conventional, SAF, renewable diesel, or power-to-liquids) typically lack both the land and the solar/wind resources necessary to produce the hundreds of megawatts or gigawatts of renewable generation required to turn grey hydrogen production into green hydrogen production. Without amendment, this restriction will unnecessarily limit growth of the green hydrogen market and miss an important opportunity for California to drive emissions reductions in the transportation sector. It is also inconsistent with CARB's scoping plan which, as noted previously, calls for continued state support for low and no-carbon liquid transportation fuels to decarbonize hard to decarbonize transportation modes including aviation, maritime, and heavy and medium duty transportation.

Extending the ability to utilize book-and-claim delivery of low-CI electricity in hydrogen production for liquid transportation fuels would also create a level playing field with hydrogen produced from renewable natural gas (RNG). § 95488.8 subsection (i)(2) of the staff draft allows for the utilization of book-and-claim delivery of RNG, including for RNG used in the production of a liquid transportation fuel. This allowance applies to production of any kind of liquid transportation fuel including both conventional gasoline and diesel as well as low and zero-carbon liquid transportation fuels.

Electric Hydrogen respectfully requests that CARB amend the current staff draft to allow for book-and-claim delivery of low-CI electricity for hydrogen used as a feedstock in any liquid transportation fuel. This approach would maximize the potential for green hydrogen adoption and emissions reductions and match the treatment CARB has extended to RNG. However, if CARB is concerned with extending this policy to green hydrogen used in conventional gasoline and diesel refineries, CARB should at a minimum allow for book-and-claim delivery of low-CI electricity in green hydrogen production used as a feedstock in low and no-carbon liquid transportation fuels including sustainable aviation fuels, power-to-liquids fuels, and renewable diesel.

198.2 **Allow book-and-claim delivery of low-CI hydrogen in dedicated hydrogen pipelines outside of California.**

§ 95488.8 subsection (i)(3) restricts the use of book-and-claim delivery of low-CI hydrogen in dedicated hydrogen pipelines to pipelines physically connected to California. California currently has only 17 miles of dedicated hydrogen pipelines. However, nationwide there are about 1600 miles of dedicated hydrogen pipelines, of which about 1300 miles are concentrated in the Gulf Coast.[5] This existing hydrogen pipeline infrastructure network serves a variety of industrial customers, including both conventional and low-carbon fuel producers selling liquid transportation fuels into the California market. This restriction limits the ability of these fuel producers to utilize green hydrogen to lower the carbon intensity of their liquid transportation fuels. The optimal policy would be to allow book-and-claim delivery of low-CI hydrogen in any dedicated hydrogen pipeline serving as a feedstock in any fuel. However, if CARB is concerned

[5] Justin Bracci, Adam Brandt, Sally M. Benson, Gireesh Shrimali and Sarah D. Saltzer, *"Pathways to Carbon Neutrality in California: The Hydrogen Opportunity",* Stanford Center for Carbon Storage and Stanford Carbon Removal Initiative, February 2022, page 25.

with extending this policy to hydrogen used in conventional gasoline and diesel refineries, CARB should at a minimum allow for book-and-claim delivery of low-CI hydrogen in dedicated hydrogen pipelines when that low-CI hydrogen is used as a feedstock in low and no-carbon liquid transportation fuels such as sustainable aviation fuels, power-to-liquids fuels, and renewable diesel.

198.3 **Allow delivery of low-CI electricity via book-and-claim for electrolytic hydrogen production in the Renewable Hydrogen Refinery Credit Program.**

§ 95488.10 subsection (f) prohibits the delivery of low-CI electricity via book-and-claim for electrolytic hydrogen production in the Renewable Hydrogen Refinery Program. Requiring onsite renewable electricity generation restricts the program to pilot scale projects thereby limiting the efficacy of the program in reducing emissions.

California currently has 20 hydrogen production facilities with 1.83 million metric tons of annual hydrogen production capacity. The median production capacity of the fleet is 226,517 metric tons per year.[6] To fully decarbonize the hydrogen supply at the median-sized facility would require 1.3 GWs of electrolysis capacity assuming a 100% utilization rate and a plant efficiency of 50 kWh/kg H2. A more realistic utilization rate of 50% would increase the requirement to 2.6 GWs of electrolysis capacity. To meet even the 50% utilization rate would require an oversizing of the renewable generation capacity relative to the electrolysis capacity. Hence, to decarbonize even half of the median hydrogen production facility in California would require renewable generation on the scale of the Alta Wind Energy Center in Kern, County, which is the largest wind farm in the United States.

Requiring onsite renewable generation to decarbonize even a portion of a refinery's hydrogen production requires more land than refineries have available onsite. Allowing for the delivery of low-CI electricity via book-and-claim for electrolytic hydrogen production would allow refineries to utilize this program to lower emissions. Without this amendment, this program will likely continue to be underutilized.

<u>Conclusion:</u>

EH2 is committed to helping California meet its climate goals. We appreciate CARB's consideration of the three proposed amendments, and we look forward to continuing to work with CARB on this critically important effort.

Sincerely,

Paul Wilkins

Paul Wilkins
Vice President for Policy and Government Engagement

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[6] Justin Bracci, Adam Brandt, Sally M. Benson, Gireesh Shrimali and Sarah D. Saltzer, *"Pathways to Carbon Neutrality in California: The Hydrogen Opportunity",* Stanford Center for Carbon Storage and Stanford Carbon Removal Initiative, February 2022, page 3.

Comment Log Display

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Comment 208 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jo
Last Name	Thapa
Email Address	jthapa@ajw-inc.com
Affiliation	AJW Inc
Subject	Comments on the Proposed Amendments to California's Low Carbon Fuel Standard

Comment

```
Hello,
I am submitting comments on behalf of DTE Vantage to Chair Randolp
and Members of the California Air Resources Board. DTE Vantage
appreciates the opportunity to provide the agency with these
comments and commends CARB for its efforts and dedication to this
program and amendment process.

DTE Vantage welcomes any opportunity to meet with the agency or
provide any follow-ups should there be any questions regarding the
outlined recommendations. Thank you for your time and
consideration.

Best,
Jo
On behalf of DTE Vantage
```

Attachment www.arb.ca.gov/lists/com-attach/6870-lcfs2024-ADJVZ1ZnAGFSZgAw.pdf

Original File Name	240220_DTE Vantage Draft Comments LCFS Proposal vSubmission.pdf
Date and Time Comment Was Submitted	2024-02-20 12:08:15

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

DTE VANTAGE

February 20, 2024

The Honorable Liane Randolph
Chair, California Air Resources Board
Low Carbon Fuel Standard Program
1001 I Street
Sacramento, CA 95814

RE: December 19, 2023, Proposed Amendments to California's Low Carbon Fuel Standard

Dear Chair Randolph and Members of the California Air Resources Board,

DTE Vantage (DTE) appreciates the opportunity to provide written feedback on the proposed amendments to California's Low Carbon Fuel Standard (LCFS) program. DTE is a developer, owner, and operator of biomass, co-generation, and landfill gas electricity facilities in California and nationally, supplies renewable natural gas (RNG) to the state, and participates in the LCFS program.

Our company has invested millions of dollars in California's decarbonization goals, in part due to the strong market signal provided by the LCFS program. By spurring investment and innovation, the LCFS has been and can continue to be a critical tool for achieving the state's objectives to reduce the carbon intensity of the transportation sector, while continuing to set a leading example for other states and jurisdictions to follow to drive performance-based emission reductions in the transportation space.

We appreciate the California Air Resources Board's (CARB) efforts to engage stakeholders as it considers changes to the program and respectfully submit the following comments for your consideration.

199.1 **Further Increasing the Stringency of the Program Will Accelerate California's Transportation Decarbonization Goals**

199.2 CARB has an opportunity in this amendment process to enhance the market signal to low carbon fuels and drive further greenhouse gas (GHG) emissions reductions by increasing the program's stringency. DTE strongly supports CARB's efforts to strengthen the LCFS program in this proposal. We are encouraged by the Agency's proposal to increase the 2030 carbon intensity (CI) targets from 20% to 30% by 2030, with a one-time 5% reduction in 2025. However, we urge the Agency to consider even more stringent reduction goals to support California's ambitious climate targets and address the current LCFS market imbalance.

DTE Vantage's internal modeling suggests that the currently proposed changes to the LCFS program are not sufficient to address the growing credit bank. In fact, we predict that the credit bank could increase to over 80MM credits by 2030 absent additional changes to the latest proposed rules. Failing to curb the growing credit bank could undermine necessary investments in low carbon fuels and unwind the clean fuels market needed for California to meet its goals. If the credit bank swells to 2x - 4x its current size, credit pricing may decrease to the point that further decarbonization investments are no longer incentivized and existing projects may be forced to shut down for economic reasons. Our recommended actions will establish a more robust LCFS program that will continue to drive innovation and accelerate GHG emissions reductions.

To CARB's credit, the LCFS program has overperformed in recent years, creating greater reductions than required, and leading to a significant oversupply of credits. The cumulative LCFS credit bank now stands at ~20.6 million surplus credits, while LCFS prices continue to decline, hovering around $65 per ton in January 2024. We encourage CARB to target at least a 40% CI reduction by 2030 to correct its course and address the credit surplus.

Additionally, due to the size of the current credit bank and the ongoing credit surplus, we believe that CARB's proposed 5% step-down in 2025, while helpful, is unlikely to impact the market at the scale needed. DTE encourages the Agency to consider increasing the step-down provision's size to 10% to appropriately address the current state of credit and deficit creation. A decisive step-change reduction in 2025 would provide a signal of strong intent by the Agency to support both short- and long-term investment to meet California's climate goals.

Finally, we applaud CARB's proposal to integrate an auto-acceleration mechanism to increase the stringency of the annual CI targets of the program when triggered by clear criteria. However, like our recommendations above regarding the CI reduction target and the step-down mechanism, we encourage CARB to be more ambitious in its proposal to ensure the greatest progress in achieving the goals of the LCFS. We recommend the agency adopt the auto-acceleration mechanism earlier, as soon as 2025, to allow triggering as early as 2026 and ensure the current surplus is addressed promptly and efficiently. There is no rationale for delaying the implementation of the acceleration mechanism given its triggering criteria, however substantial risk exists if the mechanism is delayed resulting in further growth of the credit bank.

199.3 **CARB's Proposed Remedy of a 4x Penalty for CI Exceedance is Excessive and will Disproportionately Impact Agriculture Facilities**

DTE Vantage incorporates by reference the comments submitted by the RNG Coalition dated February 20, 2024, which reflect our stance on CARB's proposed penalty for CI exceedance.

"We continue to support a full true up to verified actual CI performance for all pathways (temporary, provisional, and fully certified). Dairy Manure Digesters (and other biological systems) experience substantial increases and decreases in gas production due to weather, livestock herd changes, and other uncontrollable factors that are not present in other fuel pathways. Because the carbon intensity of the gas from these systems is calculated against a quantity of avoided methane emissions, these variations in biogas production necessarily result in outsized changes in the digester pathways' carbon intensity (CI) scores every year. Under the current structure of the LCFS (prior to the changes proposed in this rulemaking), all dairy digesters pathways experience the following negative impacts:

1. Substantial underestimation of greenhouse gas benefit (and associated lost revenue) during the project startup (temporary pathway) period.
2. Substantial risk of underestimation of greenhouse gas benefit (and lost revenue) each year during annual verification.
3. Substantial risk of LCFS enforcement, resulting in fines or potential pathway cancellation, due to no fault of the pathway holder.

These consequences are an unavoidable outcome of CARB's overly conservative approach to dairy digester pathways (and some other pathways with biological feedstocks) under the current LCFS structure. As we will describe below, no amount of careful management, conservative pathway assumptions, or other actions can fully protect a digester under the Current Rule—and the Proposed Rule's changes alleviate some, but not all, of these concerns."[1]

DTE Vantage understands CARB's focus on program integrity and the importance of recouping excess credits created by CI scores, adjusted during reviews. However, imposing a 4x penalty for adjustments not resulting from misconduct is unwarranted and unfair. DTE agrees with a party refunding excess credits received (despite the fact that CARB does not award additional credits when a review finds that a lower CI score was warranted) but opposes the 4x penalty. This punitive provision is not justified by any history of problems with the program, and the existing documentation and 3rd party review requirements already provide adequate protection for the program. DTE strongly encourages CARB to eliminate this multiplier penalty. Conversely, providing a true up mechanism whereby excess credits are refunded back to CARB and additional credits are awarded following a review showing that a lower CI score was warranted would be an acceptable solution to the inherent variability in dairy manure digester pathways. DTE Vantage is in agreement with the system proposed by the Coalition for Renewable Natural Gas' comment letter dated 2/20/2024.

199.4 **Reconsider Proposed Concepts Related to Phasing Out Avoided Methane Crediting and Aligning Deliverability Requirements of Biomethane as a Transportation Fuel with RPS and CPUC 1440 Program**

DTE Vantage remains highly concerned with CARB's proposed changes to phase out avoided methane crediting and remove book-and-claim accounting for out-of-state biomethane.

We strongly urge CARB to reconsider its proposed changes to eliminate RNG pathways that rely on book-and-claim delivery mechanisms for pathways associated with projects that break ground on or after January 1, 2030. As identified in previous comment letters in response to the CARB

[1] RNG Coalition's Comments on Low Carbon Fuel Standard Initial Statement of Reasons dated 2/20/2024

LCFS workshops on 2/22/23 and 5/23/2023, DTE's primary areas of concern with this proposal are as follows:

- At present time, there are insufficient outlets available in other markets and end uses to absorb RNG that would otherwise supply the LCFS transportation market.
- Because CARB is proposing to remove the option of a fuel that competes well in the market to continue to enter the fuel mix, credits that otherwise would be generated from out-of-state RNG will presumably be replaced by more expensive alternatives. Thus, the agency's proposal will make compliance more expensive for Californians.

We also urge the agency to continue its avoided methane crediting methodology to preserve and promote meaningful GHG emission reductions for pathways associated with projects that break ground on or after January 1, 2030. Clean fuel providers made significant investments in dairy RNG projects based on the avoided methane crediting construct, which are mitigating fugitive methane emissions on farms. California's SB 1383 targets a 40% reduction in total methane emissions and a 40% reduction in dairy and livestock emissions. To meet these goals, we recommend that CARB reconsider eliminating avoided methane crediting of the LCFS program.

Conclusion

In summary, DTE Vantage appreciates the opportunity to provide the agency with these comments and commends CARB for its efforts and dedication to this program and amendment process. As the Agency looks to finalize this rulemaking, we strongly encourage CARB to implement the following changes:

- At least a 40% CI reduction target in 2030,
- Increase the step-down provision to 10% in 2025,
- Effectuate the auto-acceleration mechanism in 2025,
- Implement symmetrical CI true up mechanism for pathways known to have inherent variability,
- Continue to allow RNG pathways that rely on book-and-claim delivery mechanisms and avoided methane crediting methodology to promote meaningful GHG emissions reductions.

We would welcome the opportunity to meet with the agency should there be any questions regarding our recommendations. Thank you for your consideration of our comments.

Sincerely,

Philip O'Niel

Vice President – DTE Vantage

Comment Log Display

Here is the comment you selected to display.

Comment 209 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Catherine
Last Name	Garoupa
Email Address	catherine@calcleanair.org
Affiliation	EJAC + CVAQ
Subject	EJAC Low Carbon Fuel Standard Recommendations
Comment	Please see the attached document.
Attachment	www.arb.ca.gov/lists/com-attach/6871-lcfs2024-UTQHawBgWGgAWQdr.pdf
Original File Name	EJAC LCFS Comments_2.20.24.docx.pdf
Date and Time Comment Was Submitted	2024-02-20 12:22:27

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Tuesday, February 20, 2024
California Air Resources Board
1001 I Street
Sacramento, CA 95814
By email: isd@arb.ca.gov, LCFSWorkshop@arb.ca.gov + *submitted via online portal*

To Whom It May Concern:

Attached are the Environmental Justice Advisory Committee's comments from our final 2022 Scoping Plan recommendations, along with the 8 point resolution adopted and discussed during our 2023 and 2024 meetings. While the recommendation language points to the 2022 Scoping Plan, many of the recommendations remain relevant to the rulemaking process, as well as providing foundational context for the resolution. We look forward to receiving direct responses to these recommendations and are hopeful that staff and the board will work to substantively integrate equity considerations into the Low Carbon Fuel Standard.

Sincerely,

Martha Dina Argüello, EJAC Co-Chair, Physicians for Social Responsibility-Los Angeles

Dr. Catherine Garoupa, EJAC Co-Chair, Central Valley Air Quality Coalition

Non-Fossil Fuel Energy Generation	Type of Activity
"CARB should" is implied at the start of every recommendation.	

		Biogas	
200.1	NF41	CARB must acknowledge the significant environmental justice and sustainability concerns around biogas and particularly biomethane, including: (1) the incentivizing of ongoing and expanded, massive dairies and their associated impacts to the air, water, odor, and well-being of local communities; (2) the perpetuation of a polluting natural gas industry via sustained gas infrastructure; and (3) the improper accounting of emissions and emissions reductions from dairies in the state's credit schemes, which additionally allows ongoing oil and gas emissions.	Action/ Analysis
200.2	NF42	CARB and other state agencies must regulate livestock methane starting in 2024 instead of relying solely on incentives to yield dairy methane reductions, and do so in a manner that advances co-equal benefits to local air and water quality, odor, and community well-being.	Interagency Coordination
200.3	NF43	CARB must commit in the Scoping Plan to examining the life cycle impacts of dairy biogas to ensure the state is relying on the most accurate assessments of the technologies and fuels making up California's long term GHG reduction strategy. If a rulemaking is not already underway, the Scoping Plan must commit to addressing the problems and impacts of dairy biogas in a dedicated Low Carbon Fuel Standard (LCFS) rulemaking. LCFS Pathways certifications for dairy biogas should be paused until the conclusion of the rulemaking.	Action/ Analysis
200.4	NF44	Increase LCFS stringency to at least 30%–35% to meet the Governor's stated goal. This will force a more rapid removal of NOx- and black carbon-emitting internal combustion engine (ICE) powered stationary and mobile sources.	Action
200.5	NF45	Exclude polluting fuels like biogas, biofuels, and factory farm gas from the LCFS and any other definition of clean, renewable, and/or zero-carbon energy.	Action
200.6	NF46	Regulate dairies to limit methane instead of producing factory farm gas that benefits oil and gas companies and artificially delays progress to zero emission transportation.	Action
200.7	NF47	The SB 1383 moratorium on regulation expires in 2024, and as the Scoping Plan is a five-year plan, it must include a plan to begin regulating emissions from dairies in 2024. In the alternative, direct the upcoming LCFS rulemaking to address these issues, and pause certification of LCFS pathway applications that include these polluting fuels until the completion of the 2024/2025 rulemaking.	Action
200.8	NF48	Ensure that materials used to produce transportation fuels do not incentivize feedstocks and production practices that result in air quality and water quality degradation. Fuels derived from livestock and dairy manure must be excluded from the LCFS, and the LCFS must be reformed to ensure that its implementation does not negatively impact low-income communities, communities of color, and areas already suffering environmental degradation including areas that are in nonattainment status for state and federal air quality standards.	Action
200.9	NF49	A dramatic increase in alternative fuel production must not come at the expense of a transition to clean electricity, global deforestation, unsustainable land conversion, environmental justice, or adverse food supply impacts, to name a few examples. Staff must continue to monitor scientific findings on these topics to ensure that California	Action

	policies, such as the LCFS, send appropriate market signals and do not result in unintended consequences. AB 32 Environmental Justice Advisory Committee, Draft Recommendations, F1E. *ejacrecsrevised.pdf* (ca.gov).	
NF50 200.10	Accelerate the reduction and replacement of fossil fuel production and consumption in California. AB 32 Environmental Justice Advisory Committee, Draft Recommendations, F3. *ejacrecsrevised.pdf* (ca.gov).	Action
200.11 NF51	Incentivize private investment in new non-polluting and zero-carbon fuel production in California.	Action / Investment
NF52	Invest in the infrastructure to support reliable refueling for transportation such as electricity.	Investment
NF53	Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program, including eliminating eligibility for offsets that result in either the perpetuation or increase in local air or water pollution.	Action
NF54 200.12	Initiate a public process focused on options to increase the stringency, integrity, and scope of the LCFS: • Evaluate and propose accelerated carbon intensity targets pre-2030 for LCFS. • Evaluate and propose further declines in LCFS post-2030 carbon intensity targets to align with the Final 2022 Scoping Plan. • Consider integrating opt-in sectors into the program. • Provide capacity credits for electrolytic hydrogen and electricity for heavy-duty fueling. • Evaluate and ensure full life cycle emissions from all LCFS pathways and each LCFS project, including all upstream and downstream • Evaluate and ensure that credits issues pursuant to the LCFS are based additional GHG emission reductions and were not already accounted for through other state or federal funding and incentive programs • Ensure that LCFS pathways and projects do not disproportionately impact communities of color, low-income communities, or communities already disproportionately burdened by environmental degradation and do not conflict with efforts to ensure that regions attain state and federal air quality standards. • Reevaluate the carbon intensity value of livestock and dairy gas based on a full life cycle analysis, an analysis of additionality for each project, and relevant regulatory programs. • Evaluate whether to remove livestock and dairy gas from the LCFS based on the role of the LCFS in incentivizing herd concentration near pollution-burdened communities and in pollution-burdened regions, accurate GHG emissions analyses, and conformity with additionality requirements.	Action / Analysis /
NF55 200.13	Monitor for and ensure that raw materials used to produce low-carbon fuels or technologies do not result in unintended consequences, including allowing for ongoing	Action / Analysis

	pollution in low income communities, communities of color, and environmentally burdened regions and communities.	

Fossil Fuel Industry and Transportation		Type of Activity
	"CARB should" is implied at the start of every recommendation.	
F1	**Transportation / Reducing Vehicle Miles Traveled (VMT)**	
F1E 200.14	**Send a strong signal that CARB plans to amend the Low Carbon Fuel Standard (LCFS) to reflect serious climate and sustainability concerns.** CARB must be clear about the very limited supply of sustainable, carbon-free liquid and gaseous fuels and avoid using them in any sectors where it is feasible to implement solutions that are zero-emission for both air pollution and GHGs. CARB has previously identified these environmental sustainability concerns in the 2018 CARB LCFS Environmental Assessment. Previous PATHWAYS modeling included a biofuels module that chose to exclude purpose-grown crops because of their harmful environmental impacts and climate risks and further limited the biomass used to in-state production in addition to California's population-weighted share of total national waste biomass supply. Without intervention, the majority of renewable diesel and sustainable aviation fuel produced in the state will come from food crop and food system oils, predominantly soybean oil. A chief substitute for soybean oil is palm oil, whose production has been linked to significant deforestation and associated carbon sink loss. After a decade of studies, the European Parliament has voted to restrict use of soybean oil as a feedstock, by providing that it would no longer be counted toward the quota for first-generation biofuels. Belgium has already banned soybean oil-based biofuels as of 2022. Although soy is currently the main feedstock concern, distiller's corn oil is a growing concern as well, with the production of ethanol causing major problems in the corn growing states. At the public EJAC meeting on July 25, 2022, Dr. Maureen McCue from Physicians for Social Responsibility-Iowa described significant environmental problems caused by ethanol (using the Iowa experience because Iowa is the largest producer of ethanol in the U.S), including deforestation, soil and nutrient loss, pollinator extinction, and rising food costs. Additional market disruption results from the fact that distiller's corn oil was has long been used in animal feed, before large amounts of it were diverted to produce biodiesel. The Scoping Plan should make clear that California fuels policy will assess and refrain from supporting fuels associated with soy, corn, and any other feedstocks, either due to CI impacts from ILUC, other environmental harms, or food system disruptions. At the very minimum, CARB should commit to establishing a cap on the availability of the LCFS subsidy for feedstocks such as soybean oil that carry the highest risks of market disruption or Indirect Land Use Change emissions, based on such factors as feedstock availability and California's proportional share of the distillate fuel market; the availability of LCFS credits should be limited in order to deter production of volumes and types of biofuel that are inconsistent with California's climate planning trajectories. (Malins and Sandford. 2022. *Animal, vegetable or mineral (oil)?* Cerulogy. https://theicct.org/wp-content/uploads/2022/01/impact-renewable-diesel-us-jan22.pdf.)	Action

	(“Soy oil set to follow palm as crop faces biofuel feedstock restrictions,” *Biofuels International* July 14, 2022, *available at* https://biofuels-news.com/news/soy-oil-set-to-follow-palm-as-crop-faces-biofuel-feedstock-restrictions/. See Malins, C. *Risk Management: Identifying high and low ILUC-risk biofuels under the recast Renewable Energy Directive*; Cerulogy, 2019; 4, 14. http://www.cerulogy.com/wp-content/uploads/2019/01/Cerulogy_Risk-Management_Jan2019.pdf; Belgium to ban palm- and soy-based biofuels from 2022. Argus Media, Apr. 14, 2021. https://www.argusmedia.com/en/news/2205046-belgium-to-ban-palm-and-soybased-biofuels-from-2022.) (*Final Environmental Analysis Prepared for the Proposed Amendments to the Low Carbon Fuel Standard and the Alternative Diesel Fuels Regulation*, California Air Resources Board: Sacramento, CA, 2018. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/finalea.pdf) (Mahone et al., 2020. Achieving Carbon Neutrality in California: Pathways Scenarios Developed for the California Air Resources Board, California Air Resources Board, Energy and Environmental Economics, Inc., footnote 2 at 19-20, *available at* https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf).	
F4	**Carbon Capture and Storage (CCS) and Carbon Capture Use and Sequestration (CCUS) on Refineries, ‘Blue Hydrogen’ or ‘Low-carbon Hydrogen)**	
F4.1 200.15 200.16 210.17 200.18	Do not consider any engineered carbon removal for fossil fuel infrastructure in the 2022 Scoping Plan. a. Revisit the LCFS CCS Protocol to clarify the application of rigorous eligibility and application review criteria specific to different types of fossil fuel infrastructure. Currently, the protocol lacks adequate assessment criteria to evaluate the addition of carbon capture technology to different types of CCS capture facilities, as defined in the LCFS CCS Protocol Section A.2(19). Despite inclusion in the system boundary under Section B.1, the substantive Sections B.2 (Quantification of Geologic Sequestration of CO2 Emissions Reductions), and the entirety of Section C (Permanence Requirements for Sequestration), there must be no question which provisions apply to what types of capture facilities themselves, not only injection and sequestration sites. b. Additionally, the permissibility of weak financial assurance instruments in Section C.7 (Financial Responsibility) is unsupportable. c. Revisit regulations governing the Refinery Investment Credit program, title 17, CCR, section 95489(e), which currently fails to consider the range of risks necessary to protect refinery communities; additionally, amend the regulations to reflect initial assessments and findings from the first examples of CCS projects on fossil fuel infrastructure across the globe. d. Do not authorize LCFS credits for CCS infrastructure in EJ communities that would increase net criteria pollution; knowingly incentivizing projects that would increase net criteria pollutant emissions as described in section 95489(e)(1)(c), perpetuates and worsens a long legacy of environmental racism.	Action

EJAC Resolution re: the Low Carbon Fuel Standard

WHEREAS, the Low Carbon Fuel Standard (LCFS) has exacerbated and entrenched air, water, and odor pollution in communities most impacted by environmental injustices;

WHEREAS, The LCFS has worsened environmental injustice issues across the state, nation, and world by increasing and entrenching pollution on the frontlines of industrial agribusiness;

WHEREAS, California Air Resources Board (CARB) has the authority to regulate methane emissions from livestock as soon as January 1, 2024, pursuant to Health and Safety Code section 39730.7(b).

WHEREAS, the LCFS has exacerbated and entrenched harmful pollution in frontline oil refinery communities;

WHEREAS, the LCFS has exacerbated and entrenched harmful pollution from tailpipes by incentivizing combustion fuels;

WHEREAS, the LCFS has exacerbated and entrenched harmful pollution to global communities from deforestation and using food for fuels;

WHEREAS, the LCFS has exacerbated and entrenched harmful pollution in communities near and regions containing large dairies and other confined animal feeding operations by incentivizing the production, storage, and land application of wet manure;

WHEREAS, insofar as the LCFS reduces carbon emissions from the transportation sector, the provision of LCFS credits for carbon removal such as direct air capture eliminates the possibility of reducing commensurate carbon emissions and co-pollutant emissions from the transportation sector through the LCFS;

WHEREAS, insofar as CARB's goal for carbon removal is to be carbon negative, issuing LCFS credits for carbon removal such as direct air capture (DAC) ensures that it will not be carbon negative but rather offset continued burning of fossil fuels;

WHEREAS, the provision of LCFS credits for direct air capture harms frontline communities both directly with harms and risks from capturing and storing the carbon, and indirectly from displaced renewable deployment that could reduce emissions from fossil fuel power plants, as well as from foregone reductions in transportation sector emissions;

Therefore, be it resolved that the EJAC recommends that the CARB board direct staff to address the above risks, threats, and harms to environmental justice communities by incorporating the following changes, referenced throughout as the "Comprehensive EJ Scenario" into the Low Carbon Fuel Standard through the current rulemaking:

1. Conduct and incorporate a full life cycle assessment of all air pollution and greenhouse gas (GHG) emissions for all pathways, and their implications for environmental justice communities.
2. Conduct a full accounting of GHG and air pollution emissions associated with pathways relying on the production of fuel from livestock and dairy manure.
3. Eliminate avoided methane credits effective January 1, 2024.
4. Eliminate credit generation for pathways relying on the production of fuel from livestock and dairy manure for emissions reductions that otherwise would have occurred or were legally or contractually required to occur.
5. Cap the use of lipid biofuels at 2020 levels pending an updated risk assessment to determine phase out timelines for high-risk, crop-based feedstocks.
6. Prohibit enhanced oil recovery as an eligible sequestration method.
7. Do not issue LCFS credits for carbon removal projects such as Direct Air Capture.
8. Consider the inclusion of intrastate jet fuel and marine fuels as a deficit generator and provide analysis of this option as part of the LCFS.

Be it further resolved that the EJAC recommends that CARB formally consider the Comprehensive EJ Scenario as a regulatory alternative in the LCFS rulemaking process.

Be it further resolved that the EJAC recommends that CARB reform the LCFS to strengthen the Low Carbon Fuel Standard's support for zero emission vehicles including mass transit vehicles, drayage duty trucks, and heavy duty trucks.

Be it further resolved that the EJAC recommends that CARB immediately initiate formal rulemaking for the regulation of livestock methane pursuant to Health and Safety Code section 39730.7(b).

Comment Log Display

Here is the comment you selected to display.

Comment 210 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Andy
Last Name	Foster
Email Address	andy.foster@aemetis.com
Affiliation	Aemetis, Inc.
Subject	Comments on LCFS/ISOR
Comment	Please find attached comments from Aemetis, Inc. on CARB's propose amendments (Proposed Rule) to the LCFS and associated ISOR. Thank you for your consideration.
Attachment	www.arb.ca.gov/lists/com-attach/6872-lcfs2024-VzRSNVUmAjMKU1Mj.pdf
Original File Name	CARB_Proposed Rule_Aemetis Comments_Final 02202024.pdf
Date and Time Comment Was Submitted	2024-02-20 12:26:38

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

The Honorable Liane Randolph
Chair, California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Chair Randolph,

As one of California's leading renewable fuels producers, Aemetis is pleased to submit comments to the California Air Resources Board (CARB) in response to the Proposed Amendments (Proposed Rule) to the Low Carbon Fuel Standard (LCFS) and associated Initial Statement of Reasons (ISOR). We appreciate the leadership you have shown as Chair to address the critical environmental issues of our time and look forward to working closely with you and the CARB staff to advance the next stage of California's landmark LCFS program.

Headquartered in Cupertino, California, Aemetis owns and operates a 60 mgy renewable fuel ethanol plant in Keyes, California, has eight (8) operating dairy biogas digesters (with an additional 40 digesters planned), operates 36 miles of biogas pipeline (with 24 additional miles permitted), and has an operating RNG gas conditioning unit and PG&E gas interconnection. Aemetis is also in the final permitting and engineering phase to build a 78 mgy sustainable aviation fuel (SAF) and renewable diesel (RD) facility in Riverbank, California. Finally, in 2023 Aemetis was granted a characterization well permit for the eventual construction of a 1 million ton per year carbon capture and underground sequestration well (CCUS) at the Riverbank facility.

In short, Aemetis has clearly shown a commitment to the production of low or below zero carbon intensity fuels that will help California achieve its ambitious goals as set forth in the LCFS and other climate and air quality policies and programs. Aemetis plans to invest an additional $1.3 billion in production facilities to capture methane, produce sustainable aviation fuel, and sequester carbon dioxide in California.

LCFS credits are a significant portion of the revenues for a wide variety of renewable energy, carbon capture, and energy efficiency projects. A failure of the LCFS price to be near the price cap is directly correlated with a failure to attract lenders and institutional investors.

201.1 If CARB wishes to attract new investment utilizing the LCFS program, then an ambitious mandate that allows the LCFS price cap to be reached quickly and thereby establish a stable LCFS credit market price is the best way to quickly create confidence in the LCFS program. Any mandate short of a clear price signal that the excess credit bank will be quickly reduced to less than 10 million "excess credits" by year-end 2025 is telling the market that there will always be too many credits – so the price should be low for many years to come.

20400 Stevens Creek Blvd., Suite 700, Cupertino, CA 95014 Main (408) 213-0940 Fax (408) 252-8044
www.aemetis.com

As the rapidly accelerating surplus of LCFS credits weighs heavily on the market and market price for credits, we fear that without immediate and dramatic action by CARB, the LCFS will lag well behind the goals envisioned in the ISOR, and the atmosphere for investment in low or below zero carbon projects in California will shift to other states or regions that promise a more fitting economic return. At the present time, California already has a number of well-established sectors that can rapidly advance the LCFS in the near term. Rather than trading existing low or below zero carbon intensity fuels for technologies that will likely take longer to develop wider market acceptance and implementation, CARB can take immediate action to support both the near- and longer-term goals of the LCFS. We urge CARB to avoid
201.1 cont. making false choices or trading today's low or below zero carbon intensity fuels for tomorrow's promise of better solutions. It is not only possible to have both, but also imperative for the overall success of the LCFS.

To that end, we are concerned that the proposed carbon intensity (CI) compliance curve is inadequate in stimulating the market and needs to be significantly strengthened to draw down the excess credit bank which recently hit a new high of over 20 million surplus credits, with ICF forecasting that the program will have an excess credit bank of more than 30 million LCFS credits by the end of 2024.

The LCFS price was $218 in August 2020, driving investment interest in renewable projects by institutional investors that has now almost disappeared as the LCFS credit price crashed to about $60 in 2023 and recently hit a seven year low at only $55.

Without immediate action by CARB, the LCFS credit price will continue to decline, and investment will stall further. <u>A 2025 target of 25% or greater CI reduction below the 2010 Baseline is needed to address the LCFS credit oversupply issue. This step-down should be implemented in Q3 or Q4 of 2024.</u>

Without immediate and meaningful action this year, investors and obligated parties have little or no incentive to accelerate the implementation of low or below zero carbon intensity fuels in California, which will not only damage existing and planned development, but it will also remove the sense of urgency needed to achieve meaningful carbon reduction in the state's transportation matrix.

Aemetis also encourages CARB to adopt a more aggressive CI reduction target than the 30% by 2030 that was put forward in the January 2, 2024, *Proposed Amendments to the LCFS*. <u>We support a 40% CI</u>
201.2 <u>reduction target by 2030</u>. Extensive quantitative modeling by ICF Resources concludes that implementing this strategy would increase the current approximate $55 credit price to $100-$120 by the end of 2025 and maintain at least that price through 2030.

Additional RNG-related changes are needed to improve investor confidence and increase the pace of methane emissions abatement. We strongly urge CARB to implement the following items that are critical to the near and long-term success of RNG as a fuel or feedstock:

- <u>We support a full true-up to verified actual CI performance for all pathways (temporary,</u>
201.3 <u>provisional, and fully certified)</u>. Dairy Manure Digesters experience substantial increases and decreases in gas production due to weather, livestock herd changes, and other factors that are not present in other fuel pathways. Because the carbon intensity of the gas from these systems is calculated against a quantity of avoided methane emissions, these variations in biogas production necessarily result in outsized changes in the digesters' carbon intensity (CI) scores every year. Under the current structure of the LCFS (prior to the changes proposed in this rulemaking), <u>all</u> dairy digester pathways experience the following negative impacts:

1. Substantial underestimation of greenhouse gas benefit (and associated lost revenue) during the project startup period.
2. Substantial risk of underestimation of greenhouse gas benefit (and lost revenue) each year during annual verification.
3. Substantial risk of LCFS enforcement, resulting in fines (NOV) or potential pathway cancellation, due to weather patterns and at no fault of the pathway holder.

201.3 cont.

Currently, pathway approvals require 18 months or more which imposes severe financial hardships on finished projects and those in planning stages. A full credit true-up would allow completed projects to apply their actual CI performance retroactively to the start of operations and thus eliminate the need to store gas. We support the *Proposed Amendment's* inclusion of a "Credit True Up" after Annual Verification. ***However, the Proposed Amendment's true up language requires re-drafting as it appears to not allow true ups during the temporary pathway period.***

When implemented properly, such a concept can ensure that the LCFS program correctly accounts for the full GHG benefits all fuel pathways produce.

201.4

- The Auto Acceleration Mechanism should be allowed to trigger as early as 2026 using data from 2025. This would dynamically respond in the event of future sustained and significant underestimation of CI reduction targets by further tightening the overall stringency of the program, complement existing mechanisms to avoid credit shortfalls, and better ensure that opportunities to deliver additional reductions of carbon and air pollutants are not foregone.

201.5

- We support the revised Tier 1 calculators and urge improving pathway processing times by utilizing the Tier 1 application as the norm for dairy RNG project applications, not the exception. The current initial review delay of over one year has put existing project capital repayment in jeopardy, and if this persists, will stymie future investment in RNG and other zero or below zero carbon projects. Today, each $4 million completed project must endure an 18- to 24-month administrative review to fully certify the project's LCFS pathway. Given the urgent nature of climate change and the need for methane abatement, this delay is completely unacceptable. Certification should be performed in less than a six-month window, as is the norm with most Tier 1 applications.

201.6

- We strongly oppose the phase-out of avoided methane crediting for dairy RNG projects. Given the importance of LCFS crediting in project viability, it is unwise and irresponsible to propose an arbitrary phase-out of avoided methane crediting without a detailed plan for developing a supporting replacement policy. At current LCFS credit prices, a framework without avoided methane crediting may not even cover operating costs for existing agricultural-based projects. Absent some new market that covers the cost of operations, existing digesters will not continue operating after their avoided methane crediting periods expire, leaving the state with billions of dollars of stranded biomethane capture assets and resulting in methane returning to California's environment or, much worse, the cancellation of projects before they are built.

201.7 Finally, Aemetis strongly encourages CARB to approve 15% ethanol blended gasoline (E-15) in California in 2024. E-15 was first approved by the US EPA in 2012, and California remains the only US State not to adopt an E-15 gasoline blend.

201.7 cont. Over the past 12 years, billions of miles have been driven utilizing E-15, and no notable safety, environmental, or vehicle damage concerns have been presented. In 2023, the US EPA approved E-15 for year-round use. California has performed all of the required air and road testing required to adopt E-15, and yet CARB inexplicably refuses to approve the use of E-15.

Beyond the environmental attributes of renewable E-15 (higher octane, lower tailpipe emissions), E-15 will reduce prices at the pump for California residents as ethanol consistently sells at a discount to gasoline. Californians continue to suffer from higher gasoline prices than most states, which creates economic and environmental harm - especially to marginalized and disadvantaged communities. While Aemetis supports CARB's push for increased adoption of ZEVs and alternative fuel vehicles, longer than anticipated adoption rates require interim steps that can provide immediate GHG reductions. E-15 will allow California to pursue aggressive ZEV adoption over the next decade while reaping the benefits of lower tailpipe emissions today. No action on E-15 keeps gasoline prices artificially high and causes more pollution than necessary.

As the world leader in environmental policy, it seems out of character for California to be the laggard as the only US state to support a 90% petroleum gasoline mandate. We urge CARB to fully approve an E-15 gasoline blend immediately. Otherwise, Californians will endure yet another summer of record setting gasoline prices, economic hardship, and increased air pollution.

We appreciate the opportunity that CARB has provided for input on the Proposed Rule/LCFS, and the ongoing dialogue that you have encouraged through workshops, meetings, and written comments. We strongly support the efforts that you and the CARB staff have made to include feedback from all interested parties, and we look forward to working together as this important next step is taken to achieve net carbon neutrality.

Sincerely,

Andy Foster
President
Aemetis, Inc.
andy.foster@aemetis.com

Comment Log Display

Here is the comment you selected to display.

Comment 211 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Holly
Last Name	Mayton
Email Address	maytonholly@johndeere.com
Affiliation	Deere & Co.
Subject	Comments on Proposed CA LCFS Amendments from John Deere
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6873-lcfs2024-BTcGMAMwVTUDKwAw.pdf
Original File Name	2023.02 Deere Comment on CARB LCFS Amendments_Final.pdf
Date and Time Comment Was Submitted	2024-02-20 12:33:38

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Deere & Company
One John Deere Place Moline, IL 61265

Dr. Cheryl Laskowski
Branch Chief, Low Carbon Fuel Standard
California Air Resources Board
1001 I Street, Sacramento, CA 95815

Re: 2024 Proposed Amendments to the Low Carbon Fuel Standard Regulation

Dear Dr. Laskowski,

Deere & Company ("John Deere") appreciates the opportunity to submit these comments in response to the proposed Low Carbon Fuel Standard (LCFS) amendments, published in January 2024, to the California Air Resources Board (CARB).

John Deere's customers play a critical role in producing crop-based feedstocks for California's liquid biofuels and can directly contribute to measurable reductions in carbon intensity (CI) of the state's overall energy mix. The U.S. renewable fuels sector provides thousands of jobs to rural communities, enhances U.S. energy security, provides cleaner-burning transportation fuels to U.S. consumers, and generates additional value for farmers. It is John Deere's hope that, backed by strong clean fuels policies like California's LCFS program, farmers can continue to add positively to our nation's economy and play a key role in reducing emissions within the transportation sector.

202.1 Respectfully, John Deere opposes the "***Sustainability Requirements for Crop-Based and Forestry-Based Feedstocks***" in CARB's latest proposal. These deforestation-focused requirements would create broad, inequitable administrative burdens for the agricultural sector without significant benefits towards the stated goal of minimizing CI associated with biofuel feedstock production. For example, most of the crop-based feedstocks for fuel ethanol used in California are produced by U.S. corn farmers[1], where corn production efficiency improvements have drastically out-paced growth in corn acreage. Specifically, average bushel per-acre yield has seen a 400% increase since the mid-1900s while total harvested acres of corn have increased by less than 25%, according to USDA data[2].

The California LCFS could more effectively meet its sustainability goals by recognizing voluntary farm emissions reductions that contribute to the reduced CI of fuels, allowing biofuel producers to use field-level CI data in their fuel pathways, and enabling farmers to receive a fair share of the economic value generated.

Deere recommends that CARB add voluntary incentives for farmers to leverage sustainable practices and utilize field-level data that demonstrate a reduction in CI instead of the proposed mandatory certification

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[1] California State Energy Profile, U.S. Energy Information Administration (2023). www.eia.gov/state/analysis.php?sid=CA
[2] USDA, Economic Research Service, National Agricultural Statistics Service (2023). www.ers.usda.gov

laid out in the "***Sustainability Requirements.***" Deere believes the certification requirement for crop- and forestry-based feedstocks is an inefficient and inequitable approach to reducing overall CI of crop-based biofuels and fails to acknowledge and leverage the major technological innovations that characterize today's agriculture operations:

202.2 A. **Efficiency and equity for farmers:** Any sustainability requirements of biofuel feedstock growers should be voluntary and incentive-based, rather than mandatory. Productive engagement and buy-in from farmers that produce crop-based biofuels feedstocks are essential to the success of clean fuels programs and standards. This will only come with meaningful and fair incentive structures that allow farmers to receive compensation from lowering their operation's CI, given that they are already pressed for time and resources throughout the growing season without additional documentation burdens.

Mandatory certifications created by disparate and disconnected sustainability and clean fuels programs ultimately place a burden on farmers without any apparent benefits. Instead, CARB should incentivize traceability and field-level certification of growing practices, rather than mandating sustainability certifications. Several other active and proposed low carbon fuel programs around the world have adopted a strategy that allows farmers to certify their operations by utilizing the same technology and data that already support their decision-making in the field. Importantly, creating demand for field-level data will also increase the adoption of precision technology and sustainable farm management practices, resulting in many benefits including reduced greenhouse gas (GHG) emissions. There are significant opportunities for digital agricultural technologies to improve nitrogen use efficiency and water quality, while restoring soil health and contribute to the overall[3].

202.3 B. **Appropriate use of technology:** Precision technologies and data have made demonstrable contributions to GHG emissions measurement and reduction of U.S. agriculture,[4] with significantly greater emissions reductions still possible[5]. John Deere brings a unique perspective on the use of technology and data, as the leader in precision agriculture equipment and technologies. In 2020, John Deere introduced its Smart Industrial Operating Model to accelerate the delivery of scaled analytics and provide high-quality, usable data, while protecting the proprietary interests of producer customers. Today, John Deere's farm data management system, Operations Center™, has enabled agricultural producers to digitize their operations on more than 388 million acres globally (e.g. digital record of planting rate, fuel use efficiency, fertilizer application, and yield variability within a field).

As more acres are digitally engaged, Deere is focused on empowering farmers with data-driven insights on key sustainability metrics, including nitrogen use efficiency and field-level GHG emissions. The necessary data for voluntary sustainability programs can be verified using the John

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[3] Khanna, et al. (2022). doi.org/10.1111/agec.12733; MacPherson, et al. (2022). doi.org/10.1007/s13593-022-00792-6 Balasundram, et al. (2023). doi.org/10.3390/su15065325
[4] Balafoutis, et al. (2017). doi.org/10.3390/su9081339; Kazimierczuk, et al. (2023). doi.org/10.1021/acsengineeringau.3c00031
[5] Northrup, et al. (2021). doi.org/10.1073/pnas.2022666118

Deere Operations Center today[6]. For example, farmers can opt-in to sharing tillage intensity and cover crop data from their operations with a third party directly via APIs. CARB's approach should ensure that current farm data systems like Operations Center are considered acceptable sources of data to increase accuracy, reduce verification costs, and allow farmers to more easily provide necessary data to meet sustainability goals, if they choose.

We appreciate the opportunity to be an active participant as CARB continues implementation of the LCFS and considers program changes. John Deere supports maintaining a pathway-neutral low carbon fuel program without limits or caps on crop-based feedstocks in California. We also reiterate our offer to work collaboratively with CARB on ways to ensure farmers are included as part of the solution to meet the State of California's climate goals.

For questions or for further information regarding John Deere's comments, please contact John Rauber, Director & Counsel, Federal Affairs at rauberjohnw@johndeere.com.

Thank you for your consideration on this important issue.

[6] John Deere and Cargill Partner To Expand Regenerative Ag Practices. (2023)

Comment Log Display

Here is the comment you selected to display.

Comment 212 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Steve
Last Name	Forde
Email Address	steve.forde@adm.com
Affiliation	ADM
Subject	ADM Comments to LCFS Proposed Amendments
Comment	Attached, please find comments as submitted by ADM.
Attachment	www.arb.ca.gov/lists/com-attach/6874-lcfs2024-VzZdP1Q4UFwGbAhr.pdf
Original File Name	ADM LCFS Comments February 20 2024 FINAL.pdf
Date and Time Comment Was Submitted	2024-02-20 12:37:24

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

77 West Wacker Drive
Suite 4600
Chicago, Illinois 60601

312-634-8100

February 20, 2024

Re: Comments on the December 19, 2023 LCFS Proposed Amendments

Submitted electronically

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Thank you for affording our company and other stakeholders the opportunity to comment on proposed amendments to California's Low Carbon Fuel Standard (LCFS). The LCFS has been a landmark policy in greenhouse gas (GHG) reductions, enabling the renewable fuels industry to grow with direction and purpose. The biofuels sector has been a significant contributor to the development of this landmark lower-carbon policy, and likewise, companies such as ADM have led the way in producing fuels that have helped the state reach its goals and sustain its progress on GHG reductions in transportation.

ADM's Low-Carbon Legacy and Commitment to Sustainability

Long before adoption of the LCFS, ADM had significant interest in and contributions to low-carbon energy policy. For more than a century, we have transformed crops into products that serve the energy and food security needs of a growing world. Renewable fuels are a vital part of our business. We first produced ethanol in 1978 and added biodiesel production in 2006. Today in the U.S., we manufacture more than 1.4 billion gallons of corn-based ethanol per year at seven plants in five locations. We also produce or market more than 400 million gallons of biodiesel per year from four North American ADM-owned facilities and one for which we market product. Globally, we also produce biodiesel at facilities in Europe and Brazil. These facilities produce biomass-based diesel from a variety of feedstocks, including soy and canola. Collectively, our current biofuel production operations directly support nearly 4,000 jobs, and indirectly support tens of thousands more. We also are growing our capacity, with additional soybean crush capability now online in Spiritwood, North Dakota, as part of a partnership with Marathon Petroleum to provide feedstock for its renewable diesel operations.

Sustainability is a foundation of ADM's purpose and a pillar of our growth strategy, and we applaud CARB's interest in sustainable fuel production throughout the history of the program, including its most current proposed amendments. With global scale and a value chain that stretches from more than 200,000 farmers to customers, ranging from multinational companies to startups, ADM is a leader in supporting the production of sustainable solutions in categories encompassing food, fuel, and industrial and consumer products.

Our company has made significant global sustainability commitments, updated, published, and highlighted each year in our annual Corporate Sustainability Report. The most recent report is attached for your review. Highlights from last year's report, covering January 1 through December 31, 2022, include:

- Achieving 100% traceability across direct and indirect soybean suppliers in Argentina, Brazil, and Paraguay.
- Disclosing GHG emissions from land use change.
- Introducing a goal to increase low-carbon energy usage to 25% of total energy use by 2035.
- Launching our regenerative agriculture program, re:generations™, and enrolling more than 2 million North American acres in regenerative agriculture programs – which leverage the land's ability to

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Suite 4600
Chicago, Illinois 60601

312-634-8100

sequester carbon, enhance biodiversity, and help protect and preserve soil and water – in the initiative's inaugural year. We aim to enroll 4 million acres globally by 2025.
- Committing to work with the Science-based Targets Initiative (SBTi) to align ADM's carbon reduction targets with ambitious goals to limit the average rise of global temperatures to 1.5 degrees Celsius.

These metrics indicate the very real progress made by ADM, indicative of the positive change that the entire renewable fuels industry is undertaking.

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Suite 4600
Chicago, Illinois 60601

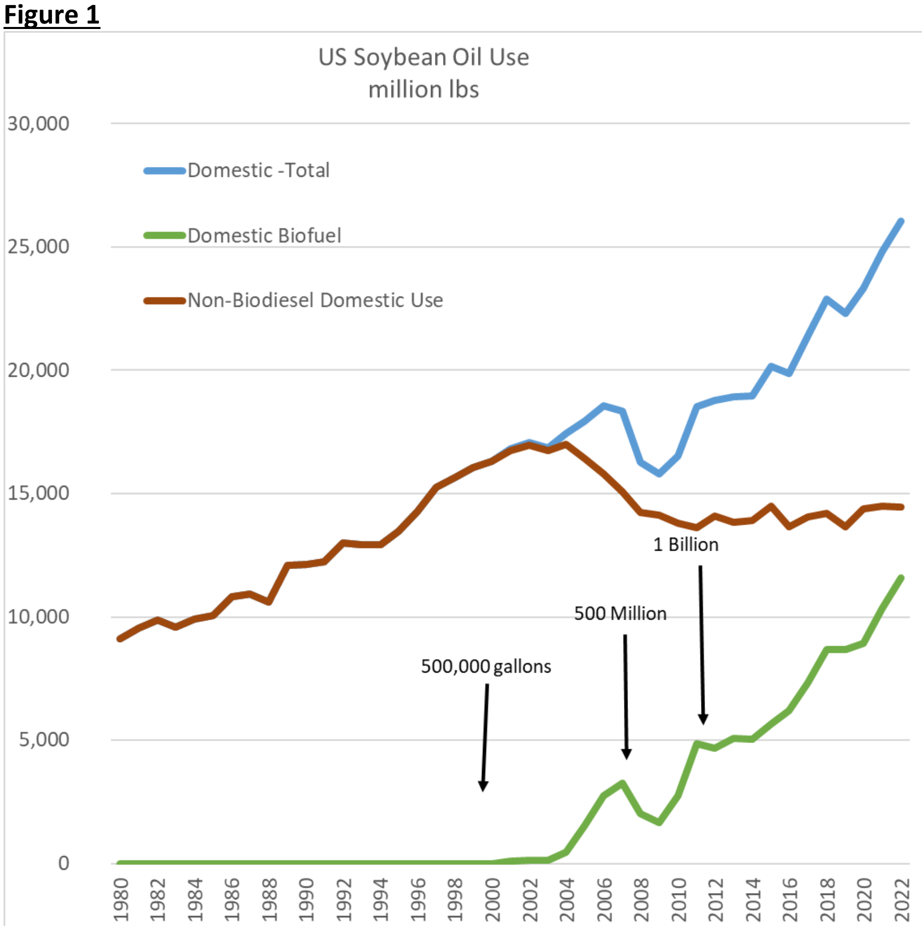
312-634-8100

The Biofuels Industry Promotes Food *and* Fuel

Producers such as ADM have the skill, technology, and vision to make the most efficient use of an entire agricultural crop. Indeed, we and our counterparts in the agricultural and biofuels sectors are focused on promoting both food and fuel. Corn and oilseeds like soybeans and canola produce high-protein feed and oil. The protein is used for animal feed and other food products. The oil is used for food ingredients and preparation and a range of industrial uses, including biofuels.

Looking specifically at oilseeds, feedstocks which are driving growth of lower-carbon biodiesel into the California market, U.S. demand over the next five years is forecast to grow 10%. A corresponding growth in vegetable oil supply will occur in tandem. Because per-capita fats and oils consumption across the globe is decreasing, lipid-based biofuels are actually recovering the value of the product that would otherwise had been lost (see Figure 1). This is a benefit to farmers, consumers, and the environment, as more biofuel is being consumed in our transportation system. Said another way, without demand for the oil via biofuels, either farmers would see less profitability or the price of soy protein meal for pork, chicken, and turkeys would have to increase – leading to food inflation.

Figure 1



Source: USDA – Oil Crops Data Yearbook - 2023

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Suite 4600
Chicago, Illinois 60601

312-634-8100

Further Analysis of Crop-Based Fuels Sustainability Criteria

Given the reality of food and fuel, ADM applauds CARB's decision not to implement a cap on crop-based biofuels in these most recently proposed amendments to the program. Data regularly makes clear that crop-based biofuels do not negatively impact the production of human or animal nutrition. Rather, crop-based fuels such as ethanol and biodiesel produce both food and fuel at affordable prices. And as stated earlier, the biofuels industry has led the way in meeting the LCFS program's goal of reducing GHG and other emissions over time. A cap would be a significant course reversal, for the state, consumers, and the environment.

203.1 While CARB's decision not to propose a cap is promising, significant questions remain regarding its proposed sustainability criteria for crop-based fuels. Given that this proposal had not been previously considered or publicly discussed, we appreciate the additional workshop to be conducted this spring on a number of issues, including sustainability criteria. All stakeholders should be afforded the opportunity to engage and understand how such criteria would be implemented and administered.

The workshop will be instructive in more fully exploring a number of important factors seemingly not yet considered by CARB. For example, existing standards and protocols already achieve the goals these new criteria aim to achieve. Two of the primary crops grown in the U.S. are covered by the U.S. Soybean Assurance Protocol or the U.S. Corn Assurance Protocol. In addition, under the U.S. Renewable Fuel Standard (RFS), sustainability criteria as proposed by CARB are met and in some cases exceeded. The RFS law has been in place for nearly two decades, well exceeding CARB's proposal that applicable sustainability certification programs be in place for at least two years before satisfying these proposed requirements. Additionally, under the RFS:

- Fuel feedstocks must not be sourced from agricultural land cleared or forested after Dec. 19, 2007;
- Environmental, social, and economic criteria are taken into account in developing annual fuel volumes under the program;
- Transparent public review of and comment on proposed annual volumes and changes to the rule are central to the continual development of the program. Proposed changes, public comment, and associated documents are posted on the U.S. Environmental Protection Agency's (EPA's) website to review by stakeholders and the general public.
- Scientific experts within EPA and associated technical advisory panels provide regular input into changes to the program.
- A rigorous audit program via EPA, including high standards, training to ensure competency, and transparency to the public, is maintained.

On each of these and more points, the comprehensive RFS meets or exceeds sustainability certification criteria as proposed by CARB. Moreover, recognizing the RFS in this manner would avoid the burden of duplicative criteria and reporting, allowing the program to stand on firm, proven ground as it pertains to sustainability while ensuring that biofuels producers and feedstock providers are held to account.

As stated, we look forward to a workshop focused on this matter in order for stakeholders in the program to understand key drivers, definitions, implementation planning, and finer points of the requirements not covered in adequate depth as part of the proposed amendments. Key participants in these sessions would be farmers and those who work closely with them, as providing our agricultural community certainty and a straightforward, reliable manner of compliance is critical to their continued growth and success.

77 West Wacker Drive
Suite 4600
Chicago, Illinois 60601

312-634-8100

Finally, ADM welcomes discussions on our global scope of work, including with accrediting bodies currently developing and deploying sustainability models.

203.2 **Protecting and Promoting North American Feedstocks**

The proposed sustainability criteria noted above would place U.S. and Canadian crop-based feedstocks at a disadvantage versus feedstocks coming from other markets, as the RFS recognizes and provides rigorous review of feedstocks from these two countries as part of the program. As mentioned, establishing duplicative criteria would be a burden not only to fuel producers, but also to domestic U.S. and Canadian farmers who fully participate in feed and fuel production. All of this would occur with no commensurate sustainability benefit.

203.3 Further to the point of protecting North American feedstocks, the rise of international used cooking oil (UCO) feedstock imported into the U.S. market has skyrocketed in recent years, after the establishment of more incentives for their use in producing lower-carbon fuel. Much of this UCO also is leveraged for LCFS compliance in the California market, and on a level playing field, this is appropriate. Still, this influx of UCO from overseas raises questions about its sourcing and, at a minimum, calls for greater scrutiny to ensure integrity of the LCFS program and the fuels consumed in the state.

203.4 Finally, North American-grown feedstocks such as corn, soy, and canola are expected to face expanding global competition, including Chinese agriculture which is improving its own production and crop yields, and will be able to supply more feed and fuel to our domestic markets in the coming years. Our industry will lead the way on domestic food and energy security.

Conclusion

As amendments to the LCFS are finalized and implemented, we ask that CARB continue partnering with the agricultural industry as we grow, evolve, and supply California consumers with food and fuels in a sustainable manner. The LCFS program is a key policy to further catalyze our and others' sustainability efforts and associated learnings. A robust LCFS sends a clear signal to the market and supports continued investments in lower carbon feedstocks as well as carbon reduction efforts, including regenerative agriculture practices such as cover crops and improved water and fertilizer management practices.

Thank you for the opportunity to share these comments as the CARB staff and Board complete work on amending the LCFS. We further associate ourselves and align with comments submitted by the California Advanced Biofuels Alliance, Clean Fuels Alliance America, National Oilseed Processors Association, and Growth Energy. Please do not hesitate to contact me or our Vice President – State Government Relations Greg Webb (webb@adm.com) with any questions.

Respectfully,

Greg Morris
Senior Vice President
President, Ag Services and Oilseeds
ADM

Comment Log Display

Here is the comment you selected to display.

Comment 213 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ryan
Last Name	Clink
Email Address	ryan.clink@hexagongroup.com
Affiliation	
Subject	LCFS Amendments Response
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6875-lcfs2024-BmVdOgNwV2YGXwNv.pdf
Original File Name	CARB LCFS 2 20.pdf
Date and Time Comment Was Submitted	2024-02-20 12:39:19

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

VIA E-EMAIL

February 20, 2024

The Honorable Liane Randolph
Chair, California Air Resources Board
1001 I St, Sacramento, CA 95814
Sacramento, California 95814

Re: Low Carbon Fuel Standard

Dear Chair Randolph,

As Senior Vice President of Legal and Government Affairs of the Hexagon Group ("Hexagon"), I am writing to express support for the key proposed amendments to the Low Carbon Fuel Standard (LCFS) and urge the adoption of two additional amendments that will allow the state of California to achieve climate and clean air goals more effectively. We would like to further provide our support for the letters provided by Natural Gas Vehicles for America (NGVA) and California Renewable Transportation Alliance (CRTA). As we respect your time, we will not repeat those arguments here, but incorporate those arguments by reference.

Hexagon is a global leader in clean energy systems and solutions. Hexagon enables the storage and conversion to clean energy in a wide range of mobility, industrial and consumer applications. Further, Hexagon Purus, a business area of Hexagon, is a world leading provider of complete vehicle systems and battery packs for hydrogen fuel cell electric and battery electric vehicles including hybrid mobility applications on light, medium and heavy-duty vehicles, transit buses, ground storage, distribution, maritime, rail, and aerospace. Most importantly, as an alternative fuel company, we are focused across all divisions on displacing diesel and gasoline in transportation and bringing, "clean air everywhere." We do this by leveraging all available alternative fuels, including propane and natural gas, electric and hydrogen. Notably, we have been instrumental in the transportation-related emissions reductions of Amazon, UPS, Waste Management, and many other fleets.

We believe the LCFS is well positioned to encourage billions of dollars of investment into the transportation sector of California but must remain fuel-neutral and supportive of all technologies to do so. Currently, there is a strong bias for zero tailpipe emission vehicles, which is not conducive to carbon reduction of the highest polluting sectors of transportation. Among other reasons, this is because the heavy-duty sector requires internal combustion engines to continue to move volumes of goods cost efficiently in the near term. There is not a sufficient infrastructure in place now or within the next five years to meet the electricity or hydrogen fueling demands of the heavy-duty market[1]. Therefore, we have the following recommendations.

204.1 1. **Increase stringency of carbon intensity (CI) targets for heavy-duty (HD) vehicles.** Increasing CI stringency for heavy duty vehicles will result in the accelerated adoption of CNG engines by fleets currently using diesel engines. Diesel power not only perpetuates the use of higher CI scored fuels, but they are responsible for driving demand for biodiesel which is overproduced and harms LCFS credit prices[2]. If CARB can drive more bio based RNG (landfill and

[1] Electric Vehicle Charging Infrastructure Assessment - AB 2127 (ca.gov)
[2] A Cap on Vegetable Oil-Based Fuels Will Stabilize and Strengthen California's Low Carbon Fuel Standard - Union of Concerned Scientists (ucsusa.org)

dairy/swine) to displace fossil CNG, the CI of California will continue to drop as fugitive methane becomes more valuable to collect and use. Furthermore, this increased reduction will pave the way for hydrogen and electric infrastructure to catch up to the demands of future zero emission vehicles.

204.2 **2. Cap lipids-based biodiesel production volumes.**

Biodiesel and renewable diesel incentives have been an overwhelming success for the LCFS program. Unfortunately, there are situations when too much of a good thing can be bad. The overproduction of biodiesel can easily be viewed as one example.

"Over the last decade, BBD fuels have grown from 0.4% of California's diesel blend in 2011 to 32% in 2021 and this growth is poised to accelerate in coming years. Vegetable oil, waste oil, and animal fats are lipid compounds that can be readily converted to BBD. Although BBD can also be produced from cellulosic

feedstocks such as agricultural and forestry residues, lipid-based feedstocks are the primary materials used to produce fuel for the state's BBD market. These feedstocks will be increasingly drawn from the rest of the United States and the world to meet growing demand. Increased consumption of lipid-based biofuels raises food prices, sustainability issues, and fraud concerns and could undermine the efficacy of the LCFS[3]."

Currently, LCFS credit prices are almost 1/3 of what they were only 3 years ago. This rapid decline not only instills fear in investors, but also undermines future adoption of LCFS standards by other states like New Mexico, who recently adopted an LCFS program but has not yet put it into practice.

Conclusion

There is no more effective and immediate step we can be taking to address climate change now than to aggressively and rapidly reverse emissions of fugitive methane from all sectors, including society's organic waste streams through renewable natural gas (RNG) projects. For all other avenues within the LCFS, there should be a tiered value structure for different volumes of positive CI fuels entering California. Limiting credit values of different production methodologies allows CARB to push for the most efficient CI scored production methodologies and get the most value out of the marketplace. The LCFS must remain fuel-neutral, driven by CARB's science-based analysis, capable of incentivizing real-world investment, and focused on performance-based GHG outcomes. Remaining true to these core concepts will ensure California leads the world in rapid transportation sector decarbonization.

We thank CARB for the chance to comment and appreciate your commitment to keeping California's air clean.

Ashley Remillard

Ashley Remillard
SVP Legal and Government Affairs

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[3] Setting a lipids fuel cap under the California Low Carbon Fuel Standard (theicct.org)

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Here is the comment you selected to display.

Comment 214 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Monte
Last Name	Shaw
Email Address	mshaw@iowarfa.org
Affiliation	
Subject	Comments to CARB regarding potential changes to the Low Carbon Fuel Standard
Comment	See attachment for full comments from Iowa Renewable Fuels Association.
Attachment	www.arb.ca.gov/lists/com-attach/6876-lcfs2024-UjEHYF0uBTRQCVd6.pdf
Original File Name	CARB - LCFS Amendments Comments.pdf
Date and Time Comment Was Submitted	2024-02-20 12:39:19

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Iowa Renewable Fuels Association

February 20, 2024

Dr. Cheryl Laskowski
Branch Chief, Transportation Fuels
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
Via electronic submission

RE: IRFA Comments on Proposed LCFS Amendments

Iowa Renewable Fuels Association (IRFA) appreciates the opportunity to provide comments to CARB regarding potential amendments to the Low Carbon Fuel Standard (LCFS) ("Proposed Amendments" or "Proposal"). The IRFA is the independent state trade association representing ethanol, biodiesel, renewable diesel, and renewable natural gas producers from across Iowa. In total, Iowa has 42 ethanol refineries capable of producing over four and half billion gallons annually, accounting for about a thirty percent of the United States total ethanol production. Iowa is also the largest biodiesel producing state, with 10 plants capable of producing around four hundred million gallons annually or roughly twenty percent of the United States total biodiesel production. Ultimately, California is a major market for each of these low carbon, renewable fuel segments.

Biofuels have been among the largest contributors to the success of the LCFS program to date and are poised to continue to do so with appropriate updates to the program. This includes but is not limited to what third-party verifiers will be looking for or even who are the approved third-party verifiers. In our view, CARB has not provided the public and regulatory community notice or the opportunity for stakeholders to comment on the validity of these new requirements.

205.1

Furthermore, we believe crop-based biofuels, which again currently provide the majority of credit-generating fuels for the LCFS program, are being singled out for more stringent criteria. This is all on top of not allowing crop-based biofuels the ability to include on-farm activities such as cover crops or no till practices that increase sustainability while dramatically lowering crop-based biofuels carbon intensity (CI) score. How is this following the spirit of "technology neutrality" if only crop-based biofuels are penalized and treated unfairly?

205.2 To further proof this point, ethanol gets lumped in with other crop-based and forestry-based biofuels with worse LUC penalties like palm oil proving the unfair application of said sustainability requirements that heavily penalize U.S. corn ethanol. In fact, the benefits of ethanol are routinely proven including recently by [IFP Energies]

nouvelles (IFPEN) which found that “compact” plug-in hybrids that run on E85 (85% ethanol, 15% gasoline), are comparable in carbon neutrality to electric vehicles when accounting for all emissions in connection with the vehicle and its battery as well as the energy used across production, distribution and combustion. Finally, as U.S. airlines look to move to sustainable aviation fuel (SAF), crop-based biofuels like ethanol are one of the few feedstocks that are readily available and in needed quantities to meet this growing demand.

The LCFS has been a major national driver in low carbon fuel use and the push toward net zero energy. However, if the proposed changes are made, we would see a major step backwards from achieving our goal while pushing U.S. energy production away for new energy sources overseas. It would also raise questions about the stability of the LCFS program that could undermine future investments in technologies designed to help reduce carbon emissions from not just on-road vehicles, but aviation as well.

As it stands today, IRFA and its members firmly believe California’s LCFS should encourage, not prohibit, low carbon options for the consumers and while keeping the program truly technology neutral. I think we all can agree that we should let science decide the best route forward. However, this can only be done when there is a level-playing field without the scales being pushed down in favor of one particular technology or energy source.

If you have additional questions, please contact me at mshaw@IowaRFA.org or 515-252-6249. Also, if you or any of your staff would ever be interested in touring an Iowa biofuel production facility, visit an Iowa farm and other aspects of the biofuels supply chain in Iowa, IRFA and its members would love to host you.

Sincerely,

Monte Shaw

Monte Shaw
Executive Director
Iowa Renewable Fuels Association

Comment Log Display

Here is the comment you selected to display.

Comment 215 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nataley
Last Name	Williams
Email Address	nwilliams@catf.us
Affiliation	CATF
Subject	CATF Comment Letter_CARB LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6878-lcfs2024-UzAGYVAlBzIBWFIx.pdf
Original File Name	CATF Comment Letter_CARB LCFS Amendments.pdf
Date and Time Comment Was Submitted	2024-02-20 12:46:26

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Liane Randolph
Chair, California Air Resources Board
1001 I St
Sacramento, CA 95814

Clean Air Task Force
114 State Street, 6th Floor
Boston, MA 02109

P: 617.624.0234
F: 617.624.0230

Re: CATF Comments on CARB's Proposed Low Carbon Fuel Standard Amendments

Dear Chair Randolph,

Thank you for the opportunity to comment on CARB's proposed amendments to the Low Carbon Fuel Standard (LCFS). Clean Air Task Force (CATF) is a global nonprofit organization working to safeguard against the worst impacts of climate change by catalyzing the rapid development and deployment of low-carbon energy and other climate-protecting technologies. These comments convey our concerns regarding the proposal's treatment of biomethane crediting and bio oil-based fuels, and we recommend constructive actions CARB can take to address these concerns.

Biomethane Crediting Provisions

LCFS credits generated under pathways utilizing biomethane from dairy and swine manure provide valuable incentives to invest in technologies like anaerobic digesters, which can be an effective tool for managing methane emissions from manure. More than half of methane emissions in California are from the livestock sector, with 25% of total methane coming from manure,[1] a consequence of California's predominant large herd production systems and their manure management. While CATF recognizes the need to provide incentives for anaerobic digesters, we are concerned about the LCFS locking in very lengthy crediting periods despite a lack of robust scientific literature on a number of critical topics.

206.1 • Farming Management Practices. There are uncertainties about the current LCFS policy's impacts on farming management practices, such as the risk of subsidies accelerating the rate of consolidation of livestock herds, driving an increase in herd size, and leading to changes in manure management practices.[2] CARB has publicly stated that it has a lack of evidence that the implementation of LCFS is contributing to dairy farm consolidation and increased herd size.[3] However, the UC Davis analysis[4] referenced by CARB used a "cows per farm" statistic, and the study's author advises that further analysis using data from the USDA's Census of Agriculture[5] (released in February 2024) would be better to answer this question. Furthermore, because LCFS subsidies benefit dairies outside of

[1] https://ww2.arb.ca.gov/sites/default/files/2022-03/final-dairy-livestock-SB1383-analysis.pdf

[2] UCLA_Emmett_CA_Dairies_1ccc FINAL 1.23.pdf

[3] https://ww2.arb.ca.gov/sites/default/files/barcu/board/mt/2023/mt092823.pdf

[4] Are Manure Subsidies Causing Farmers to Milk More Cows? | Aaron Smith (ucdavis.edu)

[5] https://www.nass.usda.gov/AgCensus/

California, analysis of the impacts on farming management practices should also consider farms outside the state.

Clean Air Task Force
114 State Street, 6th Floor
Boston, MA 02109

P: 617.624.0234
F: 617.624.0230

- Increased Methane Emissions. Some changes in manure management, such as transitioning from land application to long-term storage,[6] may increase methane emissions. In addition, increases in herd sizes may also lead to an increase in methane from enteric emissions. Critically, enteric emissions are currently not
206.2 included in the LCFS's lifecycle emissions analysis for biomethane from manure. [7] While CARB does not account for these upstream emissions, if there is an increase in enteric emissions as a direct effect of LCFS policy, progress toward meeting the SB 1383 target for livestock methane emissions reductions may be negatively affected.

Given the long-term commitment in the proposed LCFS amendments to fully credit avoided methane emissions and the lack of robust scientific data about the current LCFS policy's holistic impacts on farming management practices and subsequent methane emissions, CATF strongly recommends CARB take the following actions:

206.3 1. CARB should investigate the avoided methane crediting mechanisms, their potential to affect farm management practices, and the implications of resulting shifts in those practices. CARB should support research that uses data from the 2022 census (just released in mid-February 2024[5]) to investigate whether LCFS policies are accelerating the rate of consolidation in dairies participating in the LCFS in California and outside the state. Further analysis should evaluate if there is a correlation between farmers' intention to expand (based on permitting asks to increase herd size) and participation in the LCFS program. Note that because the LCFS benefits farms outside California, a simple comparison between California versus other states may represent a study bias, and the study design should account for that. These analyses would address some of the concerns around the LCFS credits supporting the deployment of anaerobic digesters in livestock farms. This could be achieved by convening an external working group comprised of experts that meet to review new science and data regarding the impacts of LCFS policy on farm management practices.

206.4 2. CARB should ensure that the final rulemaking documents explicitly provide for the possibility of adjusting crediting periods for avoided methane if future research or data indicates that the LCFS is leading to negative climate consequences such as additional methane emissions (e.g., from enteric or digestate management due to changes in farm management practices) or negative health consequences.

206.5 3. CARB should account for potential unintended increases in emissions at the farm level (from manure management and/or digestate management) and potential risk to accelerate rate-of-farm consolidation in the amendment

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[6] Aguirre-Vilegas and Larson, 2017. Available at Evaluating greenhouse gas emissions from dairy manure management practices using survey data and lifecycle tools (sciencedirectassets.com).
[7] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/tier1-dsm-im.pdf?_ga=2.237395968.1206035128.1708095436-333494751.1695223517

Appendix D, attachment B, Summary of Environmental Impacts and Mitigation Measures. The goal is to have these issues clearly mapped by CARB and added to the broader discussion of reduction in methane emissions from the dairy sector.

Clean Air Task Force
114 State Street, 6th Floor
Boston, MA 02109

P: 617.624.0234
F: 617.624.0230

Sustainability Concerns Regarding Bio-Oil Based Fuels

CATF has submitted its detailed comments to the docket (see joint comments submitted by CATF and Pacific Environment on February 20, 2024) regarding our concerns about the risks that the LCFS amendments will result in unsustainable consumption of vegetable oil-based biofuels. Below is a high-level summary of the concerns and recommendations conveyed in that comment letter.

Concerns:

- Without adequate safeguards, strengthening and extending LCFS carbon intensity benchmarks will likely accelerate the rapid growth in demand for bio-oil based biofuels, directly and indirectly impacting food markets and increasing emissions from land use changes;

- Including intrastate fossil jet fuel in the LCFS is an important policy signal for decarbonizing the aviation sector, but the current proposal will further increase demand for bio-oil based fuels, given that refining and hydrotreating bio-oils is currently the only commercially viable alternative to fossil jet fuel at scale; and

- The only proposed sustainability requirement for crop-based biofuels is third-party certification that the feedstocks are derived from land that has not been forested since 2008, which is too narrowly scoped to serve as an effective constraint on climate-damaging land use change.

Given these risks, we recommend the following:

206.6 1. CARB should limit the volume of first generation vegetable oil-based fuels that are eligible to generate credits under the program;

206.7 2. CARB should assess on an annual basis the direct and indirect market impacts from fuels obligated under the proposed sustainability requirements; and

206.8 3. CARB should extend the sustainability requirements beyond crop oils to used cooking oil and waste oils.

Conclusion

Thank you for considering the concerns and recommendations expressed above. If you have any questions or would like to discuss these topics further, please contact CATF's U.S. State Climate and Energy Program Director, Jeremy Tarr, at jtarr@catf.us.

Comment Log Display

Here is the comment you selected to display.

Comment 216 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Kye
Last Name	Whitmore
Email Address	kwhitmore@UCSUSA.org
Affiliation	Union of Concerned Scientists
Subject	1,350 Public Comments, Notice of Public Hearing to Consider Proposed LCFS Amendments

Comment

```
February 20, 2024

Dear Recipient,

I am submitting public comments from members of the 'Union of
Concerned Scientists' in response to the Notice of Public Hearing
to Consider Proposed Low Carbon Fuel Standard Amendments. Enclosed
are 1,350 messages, 138 of which came from UCS Science Network
members who are pursuing advanced degrees in science, public,
economics, and engineering.

Thank you for your consideration.

Sincerely
Kye Whitmore
Western States Campaign Coordinator
Union of Concerned Scientists
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Attachment	www.arb.ca.gov/lists/com-attach/6879-lcfs2024-VCEHb1Y+V2sGblQL.pdf
Original File Name	Union of Concerned Scientists, LCFS Feb 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 12:52:02

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

West Coast
500 12th St., Suite 340
Oakland, CA 94607
510-843-1872

Midwest
200 E. Randolph St., Suite 5151
Chicago, IL 60601
312-578-1750

February 20, 2024

California Air Resources Board
1001 I Street, Sacramento, CA 95814

Dear Recipient,

I am submitting public comments from members of the Union of Concerned Scientists in response to the *Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments*. **Enclosed are 1,350 messages, 138 of which came from UCS Science Network members who are pursuing advanced degrees in science, public, economics, and engineering. Of the 1,350 comments, 92 were individualized messages 1,258 signed on to the message below**:

> *I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards.*

207.1

> *Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.*

207.2

> *I urge the California Air Resources Board to ensure that changes to the LCFS place a cap on vegetable oil-based fuels and reflect our commitment to a sustainable future. Thank you for considering my views on this crucial matter.*

Thank you for your consideration.

Sincerely

Kye Whitmore
Western States Campaign Coordinator
Union of Concerned Scientists

Signers of the letter above:

Susan Abby, mssueabby@aol.com, 94122

Ryan Acebo, racebo@outlook.com, 94602

Frank Ackerman, ackermanjay@icloud.com, 94595

Alberto Acosta, aacosta756@att.net, 91505

Steven Acosta, koisgae@yahoo.com, 90011

carlos acuna, nadase@adelphia.net, 92243

Lisa Adair, lildnky@yahoo.com, 93023

James Adams, jsadams.4910@yahoo.com, 95827

EVA ADAMYAN, violetaarsenyan@att.net, 90027

Elizabeth Adan, eliz_adan1@yahoo.com, 95608

Julie Adelson, jpadelson@gmail.com, 90731

Steven Aderhold, sladerhold@gmail.com, 92028

Alfonso Aguirre Luna, abraxas0909@gmail.com, 90041

Jessica Ainsworth, jessica_ainsworth@hotmail.com, 94103

Cy Airo, cyairo@comcast.net, 95662

Katherine Aker, kathiaker@icloud.com, 91042

frederick akers, rickakers1@aol.com, 95340

Theron Akers, theronaak@aol.com, 92683

Judy Ann Alberti, judyann2007@earthlink.net, 94705

Rory Alden, roryalden@yahoo.com, 94704

Frances Alet, fmalet@sbcglobal.net, 91302

David Alexander, daabigyin@gmail.com, 93908

ann allen, ann5cats@comcast.net, 94903

Nikki Alvarado, alvni1218@yahoo.com, 91356

Linda Alvarado, ccastlegifts@aol.com, 93301

Cristina Amarillas, clamarillas@gmail.com, 95405

Scott Ames, thirstyrunner@earthlink.net, 95427

William Ames, billames37@yahoo.com, 94903

Kate Amon, kateamon@yahoo.com, 94536

Jon Anderholm, xunbio@hotmail.com, 95421

Barbara Anders, lrnncrv@aol.com, 95076

Evette Andersen, evette.andersen@gmail.com, 95945

Stephen Anderson, tangosteve@earthlink.net, 93063

CAROL ANDERSON, cmutrux@att.net, 95966

Joan Andersson, joanandersson200@gmail.com, 94708

Gail Angevine, gailangevine@yahoo.ca, 90732

Judith Antin, judith@cabodevelopmentgroup.com, 90077

Patricia Appel, appel.patti@gmail.com, 92651

Susaan Aram, mermaidlaguna@aol.com, 92629

Bonnie Arbuckle, trancegoddess2001@yahoo.com, 95367

Ken Arconti, kenarconti@yahoo.com, 95060

Suzette Ariza, sariza3@hotmail.com, 95255

Jim Armbruster, armbr@cox.net, 92026

John Armstrong, armstrong@calcentral.com, 95006

Maris Arnold, Maris1000@aol.com, 94703

james ashcraft, jammic1949@gmail.com, 95825

Chris Ashton, chrashton@gmail.com, 92119

Cathy Asmus, cathyasmus@gmail.com, 94122

Tom Atha, athatl@yahoo.com, 91801

Ed Atkins, hearthdance@yahoo.com, 95006

Trina Aurin, trina_dk@yahoo.com, 92610

John Aviani, siegavi@gmail.com, 96067

Julio Aviles, grapes.02-maggots@icloud.com, 90042

Julie B, julie.baas@yahoo.com, 91406

A B, ra3ajw@sbcglobal.net, 94086

Jill B., jknjl127@yahoo.com, 94109

m. baca, marisabaca@sbcglobal.net, 94536

Mark Bachelder, markbachelder@yahoo.com, 94960

Susanne Bader, susannes_bader@hotmail.com, 95945

Linda Bailey, lindajbailey1960@gmail.com, 95983

Arlene Baker, baker_eliz@yahoo.com, 94952

Gail Bakewell, g722bakewell@gmail.com, 95608

Patricia Baldwin, patriciachristianbaldwin@yahoo.com, 92377

Barbara Ballenger, baballenger1@gmail.com, 91361

sharon bambridge, zdz@gmx.com, 00000

joyce banzhaf, joycebanzhaf@gmail.com, 95060

Soraya Barabi, musiclover2478@yahoo.com, 90025

Benjamin Barajas Jr, bbarajasjr@yahoo.com, 92399

LARA BARBIR, barbirla@vcu.edu, 92626

Scott Barlow, scott_w_barlow@yahoo.com, 94087

Judith Barnett, jabarnett@sbcglobal.net, 91356

Marguerite Barragan, miggleb@gmail.com, 95076

Elaine Barrett, tabbysmom@sbcglobal.net, 92103

Tim Barrington, tim_barrington@hotmail.com, 95112

paula Barsamian, pa0la421@yahoo.com, 95062

Tim Bartell, timdoggiedreams@sbcglobal.net, 91602

Marilyn Barthelow, sue_barthelow@yahoo.com, 95602

Henning Bauer, hlb9@outlook.com, 94132

Miriam Baum, miriambaum@aol.com, 91701

Loren Bauman, lorendbpa@gmail.com, 94526

Gary Baxel, ba.catselos@gmail.com, 92234

Susannah Baxendale, susannahbaxendale@gmail.com, 90232

Joyce Beattie, jycbyt@gmail.com, 94306

David Beaulieu, dbeaulieu50@icloud.com, 90026

Paul Bechtel, elcapa@verizon.net, 92373

SHARI BECKER, copychik@aol.com, 91307

Gary Beckerman, rocksnfr@comcast.net, 93460

Nicole Beeck, whole_woman@yahoo.com, 95112

Julie Beer, rutledgesteve@yahoo.com, 94306

Richard Bejarano, rbejarano@ca.rr.com, 92530

Ana Belle, anabelle7_95051@yahoo.com, 95051

Doug Bender, alfabender@verizon.net, 90277

Douglas Benedict, douggieb@verizon.net, 90405

Elaine Benjamin, ebalpine@flash.net, 91901

Travis Benneian, tjbenneian@gmail.com, 92532

Jon Benneian, acide.noir@gmail.com, 90026

Molly Bennett, pastrygrl83@hotmail.com, 93446

Barbara Bennigson, bbennigson@aol.com, 94301

Richard Bentley, rbentley@ucsd.edu, 92102

Christine Berger, nerthuschild@gmail.com, 94610

Cheryl Berkey, cheryl@berkeyresearch.com, 92129

Leah Berman, mysofteyes@yahoo.com, 95003

Adam Bernstein, adambern@aol.com, 90012

Sherry Berry, oakskt5@yahoo.com, 93003

John Bertaina, jedward294@currently.com, 95139

Mark Beseda, mpb55@sbcglobal.net, 95209

Ann Betz, betzovich@gmail.com, 91767

Samantha BeuMaher, sambeumaher@gmail.com, 92040

Alice Bidasha, afsb0314@gmail.com, 95648

Barbara Bills, barbarabills51@gmail.com, 95667

Mark Bishop, marbis99@hotmail.com, 95050

Ian Bixby, bixbyi@yahoo.com, 90814

C Blackburn, bcd2fam@gmail.com, 91711

Hill BLACKETT, hblackett@friedmanspring.com, 94530

Robert Blackey, rblackey@csusb.edu, 91711

Carolyn Blackman, carolynblackmanslo@gmail.com, 93401

Patricia Blackwell-Marchant, patmarchant@comcast.net, 94552

Rollin Blanton, rollin.blanton@gmail.com, 91104

Natalie Blasco, justnat@xtra.co.nz, 96007

Joan Bleu, joansbleu@yahoo.com, 91941

Patricia Blevins, seaglass103@sbcglobal.net, 95118

Steve Bloom, sbloom@pixar.com, 94122

Ronald Bogin, bogin@sbcglobal.net, 94530

Constantine Bogios, costabass@hotmail.com, 94597

Nicholas Bogle, design@nickbogle.com, 94924

Stephen Bohac, stephenbohac56@gmail.com, 95383

Kate Bolton, katebolton@sonic.net, 94952

Mike Bonar, mikenb@sbcglobal.net, 94044

Michael Bordenave, mbordenave1016@gmail.com, 93728

Nancy Borelli, nancyborelli@gmail.com, 93012

Elaine Borseth, driveelectric92007@gmail.com, 92007

Diane Boss, dianeboss@aol.com, 93108

Vic Bostock, care4animals@hotmail.co.uk, 91001

Adriane Bosworth, bosdesign7@gmail.com, 94523

Jason Bowman, xyamuchax@yahoo.com, 95823

Candy Bowman, canbowring@yahoo.com, 95667

KAREN BOWMAN, laptops_rangers_0n@icloud.com, 91942

Ernest Boyd, ernestboyd@gmail.com, 94087

Patricia Bradford, pbradford@me.com, 94924

Stacy Braslau-Schneck, stacy@wagntrain.com, 95125

Bonnie Breckenridge, bbreck66@gmail.com, 92105

Douglas Breidenbach, wdbarch@att.net, 91401

Joan Breiding, liteuptheroom@yahoo.com, 94117

Gayle Brenenstall, thrifts_wearing.0d@icloud.com, 91767

John Brennan, jb96094@gmail.com, 96094

nathan brenner, nathanbren2003@gmail.com, 92037

Barry Brenner, bcreative@ca.rr.com, 90046

Lisa Breslauer, lbreslauer@gmail.com, 95695

Cathleen Brew, cathleenbrew@gmail.com, 95355

Pam Brigg McKown, pambrimck@gmail.com, 94530

Wm Briggs, megamax2@roadrunner.com, 90254

Joanne Britton, jmbritton@ymail.com, 92115

bob brixner, dratted@aol.com, 94611

Blaise Brockman, fatherblaise@holyangelsarcadia.org, 91007

Pat Brooks, pbrooks2042@gmail.com, 94703

Dale Brooks, 58brookwoodchevy@gmail.com, 91335

Michael Brown, mcbrown32@yahoo.com, 92707

Max Brown, mbrown2@dc.rr.com, 92264

Byron Brown, byb88@earthlink.net, 94530

Bob Brown, rapidoroberto@gmail.com, 94599

Caroline Brown, cmb128@sonic.net, 95448

Ben Brucker, bbrucker2@gmail.com, 92624

George Budd, earshot21@sbcglobal.net, 90056

Nancy Bukowski, nancybukow45@live.com, 95608

Kathryn Bumpass, kathrynb@mail.fresnostate.edu, 93405

Sharon Bunch, ssbunch10@gmail.com, 94611

Barbara Burke, bbconsultant@bluetiehome.com, 95531

Bonnie Burke, b_margay@yahoo.com, 92160

Kenneth Burke, kennethburke@prodigy.net, 92705

Ruth Burman, rumbu@comcast.net, 94070

Bruce Burns, everytingcrash@yahoo.com, 95060

Judy Burris, jabrs27@gmail.com, 91360

David Burtis, dbsorbit@earthlink.net, 94515

DonaldDon Bush, dabush0235@sbcglobal.net, 90066

Greg C, gac37@hotmail.com, 92701

Carlo Calabi, carlo7@sbcglobal.net, 94508

Jesse Calderon, ohjesse14@yahoo.com, 91706

Timothy Callahan, bonolatim@dslextreme.com, 91001

Laurel Cameron, ledwards1209@yahoo.com, 90277

Allan Campbell, allanlc16@gmail.com, 95132

Cecilia Canales, cecilia@msjdominicans.org, 91011

Elaina Caner, ecaner89@gmail.com, 92626

HC Cannon, ccannon707@yahoo.com, 95436

Jhene Canody, jcanody@yahoo.com, 94121

Julissa Cardenas, julissacard@gmail.com, 91763

Len Carella, lmc567@comcast.net, 94118

David Carlson, dnjcarlson@yahoo.com, 92009

Rita Carlson, timrita@suddenlink.net, 95502

Thomas Carlton, tomcarlton2001@yahoo.com, 90232

Beverly Carman, beverlycarman@hotmail.com, 90064

Sheila Carnegie, sheilac99@sonic.net, 94901

Gina Carollo, gfc223@yahoo.com, 92103

Anjanette Caron, anjanette_caron@yahoo.com, 91803

James Carpenter, we2carps@aol.com, 94619

Catherine Carr, clctruth@att.net, 95476

Kermit Carraway, kcarrawa@aol.com, 95602

Anthony Carreon, 925livin@gmail.com, 94509

Valerie Carrick, bonaparte0916@gmail.com, 91762

Stephen Carrillo, scarrillo@earthlink.net, 94706

Joe Catania, jcatania222@gmail.com, 93728

Peter Catizone, petercat@comcast.net, 95018

Patricia Cauthen, JACNPAC@PACBELL.NET, 95821

Bobbie Cavazos, richnbobbie04@yahoo.com, 95338

Robert Celeste, bcandjc2002@yahoo.com, 94536

Rick M Cerutti, rmceruttibuilders@comcast.net, 94901

Carina Chadwick, carina.chadwick@gmail.com, 91390

Richard Chamberlain, rh_chamberlain@hotmail.com, 94518

Daniel Chandler, dwchandl@yahoo.com, 95570

Paul Chapman, pchapman5@gmail.com, 94705

danielle charney, shineshuge@gmail.com, 90405

Phyllis Chavez, chavez_art@yahoo.com, 90405

Jason Chinn, jpchinn@sbcglobal.net, 95425

AJ Cho, amenoartemis@gmail.com, 94579

Martin Christopherson, martinchristopherson71@gmail.com, 95747

Elaine Chung, echungg2003@yahoo.com, 94539

Victor Citrin, vscitrin@aol.com, 91766

frank clark, phranquec@gmail.com, 94531

Darrell Clarke, darrell@dclarke.org, 91103

Robyn Class, robyn.class@yahoo.com, 92866

Sarada Cleary, sdcleary2010@hotmail.com, 92056

Robert Clover, rclover@me.com, 93402

Jacqueline Cochrane, jackieco2@yahoo.com, 90278

Shiela Cockshott, shiela9@cal.berkeley.edu, 94002

Lynette Coffey, siabykatz@yahoo.com, 96019

Natalie Cohen, ncohen@usc.edu, 91106

Anne Cohen, ancohen2@gmail.com, 94903

David Coleman, redandcurly@sbcglobal.net, 95426

Linc Conard, lincconard@gmail.com, 91107

yuko p conniff, info@detroitstzencenter.com, 90036

Thomas Conroy, trconoy@yahoo.com, 90266

Lynda Cook, opiecook@gmail.com, 91351

Craig Cook, craigecook@hotmail.com, 95401

Karen Cornell, cornellkl@me.com, 95667

Theresa Corrigan, lioness1@sbcglobal.net, 95820

Deborah Cosentino, deborahcosentino@yahoo.com, 95864

Ettie Councilman, ettiejco@verizon.net, 90808

Frank Cox, frnkcox6@gmail.com, 94903

John Crahan, jscrahan@hotmail.com, 90045

Scott Crass, scrass@csulb.edu, 90804

Brian Crawford, brian@briancrawford.info, 94960

William Crist, raconis79@comcast.net, 94044

Nanette Cronk, nanettecronk@gmail.com, 96161

Dustin Crook, dcrook1@socal.rr.com, 92708

Alvin Crown, acrown405@gmail.com, 90405

Kurt Cruger, cruginator@gmail.com, 90803

Kermit Cuff, tierno23@yahoo.com, 94041

Susanna Cummings, srcummingss@gmail.com, 95469

Kevin Curtis, houseofcurtis@netscape.net, 92832

Elizabeth Cutter, recutter@att.net, 93643

Lll D, msldill@yahoo.com, 94706

Jill Dahlman, jilldahlman@yahoo.com, 95670

Dennis Daigle, daiglem@comcast.net, 94531

Emily Damm, edamm673@hotmail.com, 95630

Courtney Daniels, heyshug@gmail.com, 91403

Mark Dankowski, mark.sensiblesolar@gmail.com, 95448

Jessica Dardarian, jessicadardarian@gmail.com, 95630

Denise Dardarian, marchharemadness@hotmail.com, 90046

Robert Davenport, ridport@aol.com, 90712

Ryan Davis, ryansdavis@yahoo.com, 91502

CARLA H DAVIS, CMOUSE1945@AOL.COM, 94925

Donald Davis, don@dondavis.net, 91302

Ellen Davis, ellentd@aol.com, 90025

Daniel Davis, drdavis0391@gmail.com, 92562

James Dawson, james-dawson@sbcglobal.net, 95618

Theo Dawson, theo@dawson-west.org, 91342

Janet De Lu, newjerseydreamer@gmail.com, 95065

Glen Deardorff, guitarride@gmail.com, 94546

Yves DeCargouet, countzero100@gmail.com, 95458

Terri Decker, firefox8565@sbcglobal.net, 96001

Daysha Deen, dayshadeen@yahoo.com, 91737

Javier Del Valle, jdelvalle@dvacommercialre.com, 90640

Diane Demee-Benoit, diane_demee_benoit@yahoo.com, 94925

Ken Densmore, densmoreken@gmail.com, 94925

Sheila Desmond, sdesmond342@gmail.com, 95682

Vivian Deutsch, duodeutsch@aol.com, 91302

Karla Devine, kjdevine99@yahoo.com, 90266

G Devine, brokeneye3@gmail.com, 91001

Amy Dewey, amyd@alumnae.mills.edu, 94610

Mark Dickson, mark@economic.com, 95033

Heidi Dietz, heidi310@yahoo.com, 94501

Barbara Dincau, barbaradincau@me.com, 93003

Larry Dinger, larrdd@hotmail.com, 95677

M Susan Ditzler, sditzler@sbcglobal.net, 93923

Sheila Dixon, sdixon429@comcast.net, 94521

Andrea Dixon, andreasdixon@gmail.com, 92373

Timothy Dobbins, sfbigcelt@sbcglobal.net, 94117

Gary Dobson, gdobson@sbcglobal.net, 93444

Gene Dongieux, gdongieux@gmail.com, 93013

Gregory Dorais, analyticalagnostic@yahoo.com, 94553

Ann Dorsey, aedorsey@hotmail.com, 91325

Larry Dorshkind, mail@dorshkind.com, 94061

Soraya Dosaj, soraya_d@sbcglobal.net, 91401

ROB DOUCETTE, diner-tactic0v@icloud.com, 90293

Paulette Doulatshahi, pdoulatshahi@hotmail.com, 90293

KELLY DOYLE, kellydoylecmt@gmail.com, 94965

Joshua Dubansky, dubansky@gmail.com, 96161

Serge Dumont, sdumont47@yahoo.com, 94903

Jeff Duncan, jeff.duncan4@aol.com, 90077

Kerry duncan, duncankerry9@gmail.com, 92260

B. E., barerickson@gmail.com, 91361

Geoffrey Eargle, geoear@gmail.com, 95841

Robert Earl, earl19@bobearl.net, 95519

Jonathan Eden, edenjonathan@hotmail.com, 94707

Rick Edmondson, rickedmon@yahoo.com, 94526

Jane Edwards, jpedwards@ca.rr.com, 90623

Dennis Eicholtz, deicholtz@mac.com, 95926

Kevin Eisenstaedt, kevinonroscoe@hotmail.com, 94102

Hilary Eisma, prattprattprattandpratt@gmail.com, 95503

Lowell Eliason, leliason@csulb.edu, 90630

Cheryl Elkins, cejewelryonline@cox.net, 92105

Jane Ellis, JEllisMA@msn.com, 94710

Margaret Emerson, margaretemerson@att.net, 95521

Laurel Emsley, rowdy205@sbcglobal.net, 93923

Marilyn Eng, mreng5@yahoo.com, 91765

Bruce England, bkengland@gmail.com, 94043

walter erhorn, waltererhorn@cox.net, 91979

Mark Escajeda, mark.escajeda@gmail.com, 95445

Chelsea Esse, yochelsea@dslextreme.com, 94623

Joseph Evelyn, jevelyn@aol.com, 91011

Esther Faber, bellinghamesther@yahoo.com, 95456

Donna Fabiano, dlfabiano@yahoo.com, 95436

Rita Fahrner, ritakell@comcast.net, 94110

James Fairley, jamesfairley2@gmail.com, 94709

Tobias Fairman, ophion34@gmail.com, 91740

Dominick Falzone, dominickfalzone1212@gmail.com, 90005

Valerie Fannin, osdawesa@aol.com, 95973

P Feinblatt, pepi1655@att.net, 91104

Thomas Feldman, tom@clearfiremedia.com, 91011

Reed Fenton, reefen@aol.com, 91406

Frank Ferguson, taxguy777@yahoo.com, 91326

Fr. JOHN FERNANDES, usmcbamboo@sbcglobal.net, 94577

Kathleen Fernandez, kfernandez2576@gmail.com, 92887

Asano Fertig, asanof@comcast.net, 94702

Stephen Fessant, sfpeasant@yahoo.com, 94609

Aixa Fielder, aixafielder@gmail.com, 90028

Thomas Filip, s2gesfan@yahoo.com, 93020

Allyson Finkel Finkel, allyson.finkel@gmail.com, 92688

Stephen Fitch, sfitchphd@gmail.com, 91362

Marcia Flannery, marciaflannery@gmail.com, 94609

Robert Flasher, rangerdude333@hotmail.com, 94708

Marla Flores-Jauregui, senorajauregui68@yahoo.com, 95823

c Foglietta, jcfoglietta@yahoo.com, 93420

Susie Foot, bongoboycd@sbcglobal.net, 95519

Jean Fordis, jean.fordis@me.com, 94022

Kim Forrest, kim_forrest@comcast.net, 93923

Scott Forrest, hmbscott@mac.com, 94019

Nicole Fountain, nicmasterflash@yahoo.com, 95648

John Fowler, johannsebastianfowler@gmail.com, 90405

Michelle Fox, michellefox612@gmail.com, 90241

Jim Franzi, jim@jimfranzi.com, 95629

Forest Frasieur, frforest@sbcglobal.net, 94510

Marivee Frayer, mariveedf@hotmail.com, 95006

Cary Frazee, cxfrazee@gmail.com, 95503

Nancy Freedland, nhamorah@verizon.net, 92314

Linda Freeman, lindaf121@hotmail.com, 95991

elaine frey, ekfrey52@yahoo.com, 93907

Adrian Fried, adriannovato@gmail.com, 94947

Mary Fryer, marykittner@att.net, 94116

Thomas Fukuman, nobachi2007@gmail.com, 90504

Marinel Fuller, mjadfuller@comcast.net, 92270

Gilda Fusilier, gfusilier@comcast.net, 95831

joe Futterer, taojoe@fastmail.com, 90290

Michael Gabriel, mikegabriel@outlook.com, 94114

Querido Galdo, querido@queridomundo.com, 95445

barbara Gale, babyeiya91436@yahoo.com, 91436

Rachel Galgoul, rgalgoul@yahoo.com, 94117

Nina Gallardo, luckystar82@att.net, 92324

David Gallardo, gingerr007@yahoo.com, 91803

Mark Gallegos, wstcstltn@hotmail.com, 90063

Vicki Gallegos, VERYANNOID@GMAIL.COM, 93534

Jillian Gallery, jilliangallery@gmail.com, 90740

Richard Gallo, rg198995076@yahoo.com, 95062

Gina Garcia, greenginagplus3@gmail.com, 90405

Jorge Garcia, jgarcia45@hotmail.com, 94102

Ked Garden, kedz2garden@gmail.com, 91945

Jan Gardner, jangardner3@cox.net, 90274

Michael Garitty, garitty@nccn.net, 95959

Cherie Garrett, dreamlover505@hotmail.com, 93012

alvaro garza, garlicy2@sbcglobal.net, 95354

David Gassman, dfgassman@aol.com, 94610

Darrell Gauff, dgauff@yahoo.com, 95405

Dave Geare, dgeare@sbcglobal.net, 95502

Madelaine Georgette, studiogeorgette@mac.com, 94595

Alexis Georgiou, Alexis_Georgiou_1987@hotmail.com, 95054

William Gerharter, cords_katana0v@icloud.com, 90631

Britani German, britanig106@hotmail.com, 93727

Christopher Geukens, cgeukens@gmail.com, 91343

luciano giampa, lou@bayareaoffices.com, 94595

Pamela Gibberman, pgibberman@gmail.com, 91402

David Gieseker, gieseker@gmail.com, 90066

Robert Giles, robert_reed_giles@msn.com, 92029

Holly gilzow, gilzo001@cougars.csusm.edu, 92057

Dana Ginn, dginn92591@gmail.com, 92591

Mark Ginsburg, mginsbur@gmx.edu, 95062

Mark Giordani, magiordani@aol.com, 91303

Joe Glaston, vidiot49@yahoo.com, 92240

MaryAnne Glazar, maryanneglazar48@gmail.com, 94611

Robert Glover, reg93618@yahoo.com, 93726

James Goethel, jimbag71@yahoo.com, 92115

Gary Goetz, gag888@hotmail.com, 93950

Ken and Donna Gold, gramadonna@keppandbeeze.com, 93012

Martha Goldin, honmgret@gmail.com, 94118

Alan Gonzalez, astroboyatblast@hotmail.com, 90815

Theresa Gonzalez, lthrchick@hotmail.com, 95030

Watson Gooch, wpgooch111@gmail.com, 93402

Patricia Goodson, spiritlady13@gmail.com, 95423

William Goodson, whg3md@att.net, 94118

Kevin Goodwin, kmgoodwin365@gmail.com, 93308

Narayan Gopinathan, ngopinathan@g.ucla.edu, 90024

Marc Gordon, marc.gordon@me.com, 95370

Elliot Gordon, elliotg1@cox.net, 92604

Carol Gordon, thecarolanngordon@gmail.com, 90027

Norman Goss, ensemblegzf@hotmail.com, 91202

Arthur Gould, arthurgould.cello@gmail.com, 95945

Kris Grabow, kristine.louise.g@gmail.com, 95003

Greg Grady, gregjie@att.net, 94930

Steve Graff, stevegraff12@hotmail.com, 90025

Kelly Gram, kgkelly@sbcglobal.net, 95125

Bonnie Grand, bvgan@sonic.net, 95446

Faith Grant, faithagrant@aol.com, 91361

Barbara Graper, barbie1pob@gmail.com, 93465

Caryn Graves, caryn@lmi.net, 94702

James Gray, jimgray101@aol.com, 92270

Robert Grealish, bgrealish22@gmail.com, 94112

Jamie Green, Springhead.jg@gmail.com, 93004

Janice Greenberg, ghawk24@gmail.com, 94595

Cynthia Greenleaf, drleafy@yahoo.com, 94706

Anne Gregory, xagregoryx@yahoo.com, 94303

Probyn Gregory, probyngregory@gmail.com, 91042

Michelle Grimes, mjlgrimes@hotmail.com, 92115

Alexis Grone, alexis.grone@gmail.com, 92058

Gary Groth-Marnat, garygm9898@gmail.com, 93117

Melodi Gulsen, melodi2727@yahoo.com, 92831

Karen Guma, guma@sonic.net, 94952

Karen Gutfeld, k1a2g3@duck.com, 91204

Genevieve Guzman, genny.guzman@gmail.com, 91604

Maria Guzman, mariaguzeman@aol.com, 93311

Perry Gx, perrygxx@gmail.com, 92780

Amber H, kou_puuwai@hotmail.com, 94089

Jim H, hancockfin@aol.com, 92037

l Haage, lhaage@hotmail.com, 94618

Dale Haas, dfredhaas@gmail.com, 92115

Kenneth Haber, haberphoto@gmail.com, 91001

Ian Haddow, 2ianhaddow@gmail.com, 94131

Sharon Hafner, srhafner@suddenlink.net, 95501

Thomas Hagler, tmhagler@gmail.com, 94061

James Haig, james@meta-balance.com, 94901

Ellen Hall, ellenbh@sbcglobal.net, 94044

Judith Hall, judithyhall@gmail.com, 93923

Holly Hall, hahall51@verizon.net, 92592

Timothy Hall, mccajor@earthlink.net, 90024

Gary Hamel, hrttohrt@aol.com, 93445

Frederick Hamilton, fhami38130@gmail.com, 91739

Vince Hangman, vhangman@yahoo.com, 94559

Jim Hanley, jimhanley23@gmail.com, 95407

Jan Hansen, firepig1948@gmail.com, 92122

Janet Hansen, jmariehansen@hotmail.com, 93160

Joseph Hardin, joehardin@earthlink.net, 90405

Nathan Harling, nathan.x.h@gmail.com, 94061

Nicole Harmon, djhngh@aol.com, 92234

Charesa Harper, charleighh78@yahoo.com, 94558

Laurel Harris, laurel.harris@gmail.com, 94573

Robert F Harris, rfharris3@comcast.net, 94025

JOHN HARRIS, johnharri9@att.net, 94565

David Harris, open7oceans@gmail.com, 93001

Michael Harrop, michaeljharrop+ucsusa@gmail.com, 92505

Leilani Hart, lmhart4769@gmail.com, 92078

Lucy Hart, lusineharutyunyan@yahoo.com, 91316

Nancy Hartman, bikegirlnancy@aol.com, 94549

Penny Hartman, pennyandco@comcast.net, 95476

Richard Haskell, haskell@g.hmc.edu, 91711

Melanie Hassel, melanie.hassel@gmail.com, 94805

Phyllis Hatch, phatch317@aol.com, 95054

Susan Hathaway, susanhathaway0@yahoo.com, 90660

Steven Hayashi, sj.hayashi@yahoo.com, 95032

Noah Haydon, noahhaydon@gmail.com, 94015

shelby Hebert, shelbysinbox@gmail.com, 95926

Ross Heckmann, rosss.heckmann@gmail.com, 91006

Donine Hedrick, doninehedrick@comcast.net, 95616

Laura Hefner, festerhefner@gmail.com, 90717

Jennifer Heggie, jdheggie@gmail.com, 94112

Janet Heinle, janetheinle@yahoo.com, 90403

Bridgett Heinly, kbmdogs@att.net, 92107

Charles Heinrichs, cwheinrichs@hotmail.com, 96097

Cynthia Hellmuth, crhellmuth@yahoo.com, 94510

Karen Hellwig, khellwigrn@sbcglobal.net, 90056

Miranda Helly, mihelly@att.net, 94612

Tom Helm, tomhelm@sonic.net, 95409

Martin Henderson, beechcleener@gmail.com, 93117

Nancy Henderson, sersuave2003@yahoo.com, 94563

Lucy Henderson, hndrsnlucy@gmail.com, 94563

Sandra Hendricks, scubasandy@yahoo.com, 95685

Alice Hendrix, 2cachers@gmail.com, 95662

Anne Henkes, ahenkes@pacbell.net, 94015

Charlene Henley, charlenehenley01@gmail.com, 95136

Kevin Henry, k@severian.com, 93923

Teresa Hensley, teresanagano@gmail.com, 92543

Martha Henze, M_Henze@outlook.com, 92071

Jean Hepner, 4chiennuit@gmail.com, 94062

Michael Herbert, michaelscottherbert@yahoo.com, 91739

Laura Herndon, herndonlaura0@gmail.com, 91505

Martha Herrero, mail@marthaherrero.com, 92627

Ebba Herritt, ebbaviolin@gmail.com, 95926

Louise Herschelle, leela77@yahoo.com, 94901

Susanne Herting, sbherting@gmail.com, 94619

Steven Hibshman, shibshman@yahoo.com, 94404

Mary Hicklin, mary@virgomoon.com, 92040

Janine Hicks, jhicksdc@yahoo.com, 91326

Percy Hicks-Severn, percyhsevern@yahoo.com, 91320

NANCY HIESTAND, nancya0624@aol.com, 95616

Julie Higgins, juliehg@mcn.org, 95460

Alison Hill, alisonrhill@comcast.net, 94549

Debra Hill, dhill3030@att.net, 95501

Carol Hilton, hiltonsmith1@cox.net, 92056

Bill Hilton, billhilton@mac.com, 94087

lynn hoang, spacecadetnova_2000@yahoo.com, 92833

Zora Hocking, zhocking@msn.com, 95401

Steven Hoelke, hoelke@alumni.caltech.edu, 91711

Julie Holguin, lakerjulie32@gmail.com, 90027

Barbara Hollis, bchollis@yahoo.com, 94904

Celeste Hong, celestehong13@gmail.com, 90027

Michael Horowitz, human23x2@icloud.com, 94602

Carol Horowitz, chorowit@earthlink.net, 90025

Theresa Horrigan, proteanpress@gmail.com, 94108

deanna horton, dlh@dmsgs.com, 93923

Martin Horwitz, martin7ahorwitz@yahoo.com, 94122

Jennifer Houseal, jenniferhouseal@yahoo.com, 91401

Sherrie Howell, sherriehowell1@comcast.net, 94588

Sally Howlett, sahowlett@lmi.net, 94703

Rich Hughes, richhughessf@gmail.com, 94112

Walter Huitema, huitemaw@mac.com, 90604

Peter Humphries, p_humphries@hotmail.com, 95123

Mark Hurst, mwhurst@hormail.com, 94563

Jeffrey Hurwitz, jahurwitzhome@cs.com, 94121

Stephen Hutchinson, shutchin@sbcglobal.net, 91202

Melissa Hutchinson, melhutch236@gmail.com, 93950

Herbert Hwang, herb_hwang@sbcglobal.net, 94019

Thomas Hyde, ozhyde@sbcglobal.net, 95405

Jinx Hydeman, earthwoman69@gmail.com, 92679

Alan Ibrahim, alan.ibrahim@gmail.com, 94040

Lara Ingraham, laraingraham@gmail.com, 90038

Lou Insprucker, lainsprucker@gmail.com, 91011

Michael Ireland, michael-ireland@att.net, 95321

Kent Iverson, ks_iverson@yahoo.com, 95476

Christina Jackson, cjackson998@cox.net, 91942

Karen Jacques, threegables1819@gmail.com, 95811

Gina Jager, ginacjager@gmail.com, 94538

Edna Jamati, ekjamati@gmail.com, 94301

Robert Jardine, rljardine@gmail.com, 95014

Michael Jenkins, eradbami@cox.net, 92115

Mark Jenne, markjenne@aol.com, 92007

Victoria Jensen, vicster@init-6.com, 90405

Jennifer Jerlstrom, 7146996083@charter.net, 90620

Adam Joe, adam.joe@ucsf.edu, 94546

James Johnson, porcine14@aol.com, 93065

Louise Johnson, lcjsew@aol.com, 95350

Deanna Johnson, dee32johnson@gmail.com, 95618

CLiff Johnson, gemsun9@gmail.com, 94019

Shawn Johnson, shawninbarca@gmail.com, 92024

Joyce Johnson, dogsknitter@proton.me, 95404

Nathan Johnson, nrj9995@gmail.com, 94501

Evelyn Johnson-Todd, 08_shire_foggy@icloud.com, 93727

Philip Johnston, wendover76@cruzio.com, 95066

Michael A. Johnston, PLUTO_OF_THE_UNDERWORLD@HAUNTEDMANSION.COM, 92176

Jan Jones, jan@metrostation.com, 94530

Rev. Allan B. Jones, allan8838@att.net, 95404

Jeffrey Jones, jjones11749@aol.com, 91423

Alena Jorgensen, aj.1156@yahoo.com, 91780

Leslie Joyce, lkjoyce.R40@gmail.com, 92071

lee juskalian, drbig@me.com, 93110

Linda K, lbkour@aol.com, 92109

S. K., sklngmn@aol.com, 94015

Martin Kaliski, martymech@aol.com, 94710

natasha kaluza, natashakaluza@hotmail.com, 94803

Joan Kaplan, joankap@earthlink.net, 91001

adam kaplan, adamkaplan@cox.net, 92651

Joyce Karel, jokarel@cox.net, 92103

Anand Karipineni, kak7757@prodigy.net, 94538

Paul Katz, paulkatz@flash.net, 95004

Daniel Katzman, dankatzman@yahoo.com, 94517

Andrea Kaufman, andykaufman@comcast.net, 95446

Murray Kaufman, murraykaufman430@gmail.com, 92612

Michael Kavanaugh, mkavanau@yahoo.com, 94116

James Kawamura, kawamurakzextion@aol.com, 92336

Kevin Kearney, kmktunes@gmail.com, 92585

ROBERT KEATS, bobswave@earthlink.net, 93101

Kaija Keel, kaijakeel@gmail.com, 90049

Marjory Keenan, marjkeenan44@gmail.com, 94703

Cheri Keisner, c144p@outlook.com, 95587

Theresa Kellgreen, tesakell@sbcglobal.net, 95005

Kristian Kelly, kriskguitar@gmail.com, 95476

Alice Kelly, alicemarykelly@gmail.com, 95018

Lisa Ann Kelly and Family, bluesunflowersb@gmail.com, 93101

Michael Kemper, mckemper84@gmail.com, 94109

Jeffrey Kent, jeffreykent@kentsbromeliad.com, 92084

Faye Keogh, fkeogh@grubbco.com, 94705

Nareg Keshishian, naregkeshishian23@gmail.com, 91367

LaVive Kiely, kielykids@gmail.com, 94127

Sue King, sdk831@yahoo.com, 94588

Karen Kirschling, kumasong@icloud.com, 94117

Linda Klein, kleinjohnson@sbcglobal.net, 90245

Priscilla Klemic, pklemic@gmail.com, 91401

Diana Kliche, klichediana@gmail.com, 90804

George F. Klipfel II, gklipfel@msn.com, 92234

Basey Klopp, bklopp@gmail.com, 92024

Cassandra Klyman, cklyman@sbcglobal.net, 90068

Sue Knight, shartling88@hotmail.com, 90804

Robin Knill, morepaws@sbcglobal.net, 95959

Lotti Knowles, lottiluwho@gmail.com, 91505

John Knox, jtimothyknox@msn.com, 91914

Cindy Koch, ck55@verizon.net, 90807

Carol Kommerstad, cmkr@cox.net, 93108

Robert Konuch, robert.konuch@icloud.com, 91364

Blanche Korfmacher, blanchek@sbcglobal.net, 94132

Richard Kornfeld, Richard.Kornfeld@education.vic.gov.au, 91101

Evie Kosower, ekosower@cox.net, 92105

Rick Koury, rickmx767@yahoo.com, 95032

cheryl kozanitas, cherylkoz44@gmail.com, 94403

Kathy Kramer, kathy@kathykramerconsulting.net, 94806

Kevin Krywko, kevinkrywko@cox.net, 92069

Francine Kubrin, fkubrin@gmail.com, 90049

Tom Kunhardt, tt101@mac.com, 94602

Michael Kutilek, kuti3058@sbcglobal.net, 95112

Lisa Kutner, lisakutner@hotmail.com, 92103

Elijah L., Infectedtitan97@gmail.com, 90255

Roxanne LaChapelle, lach.learn@sbcglobal.net, 92867

J. Spencer Lake, j.spencerlake@yahoo.com, 92109

rene lambert, lambrene7@gmail.com, 94703

John Lampe, jvlampe@earthlink.net, 94070

carlyn lampert, carlynlampert@gmail.com, 91607

Beth Lander, bkland113@cox.net, 92115

Gary Landgrebe, gary@seraphina.com, 95073

Dennis Landi, zipcode90003@yahoo.com, 90706

Edward Landler, edlandler@roadrunner.com, 90065

John Landmann, jsport2004@yahoo.com, 92122

Catherine Lanzl, caclwax@yahoo.com, 92024

Paul Lapidus, plapidus@ebold.com, 95004

Kenneth Lapointe, incredistical@outlook.com, 90031

Mary LaRiviere, mlariviere1234@outlook.com, 90620

Stephanie Larro, stephanielarro@gmail.com, 91367

R. Dene Larson Jr, theowl63@yahoo.com, 94117

M. F. Lasack, custommerry@yahoo.com, 94541

J Lasahn, jacqueline@sacred-ceremony.com, 94530

Andrew Lawrence, adl@saber.net, 94118

Jennifer Lawson, jennifer@intelligent-rain.com, 94925

Peter Lee, peterboothlee@hotmail.com, 94118

Elizabeth lee, sootfive48@gmail.com, 92407

Sandra Lee, sklee9942@gmail.com, 94928

Vicki Leeds, vickiml10008@gmail.com, 94956

Trudy Leek, jodee147@gmail.com, 95401

Lola Leeman, lolaleeman@students.berkeley.net, 94702

Andrea Lehman, adlehman@att.net, 92122

Bill Leikam, wcleikam@gmail.com, 94040

Pat Lenz, pamblenz@gmail.com, 92240

Jim Leske, gooddogsaretrained@yahoo.com, 91343

M. Virginia Leslie, mvleslie@att.net, 95035

Julie Levenbach, julie@sierra-aikido.org, 94303

Sandra Levine MD, sacljunk@gmail.com, 94903

Lacey Levitt, laceylevitt@gmail.com, 92120

David Levy, david@meanwhile.org, 94133

Jaclyn Lewis, mauijoy99@aol.com, 92835

Nicolas Liberal, majingoku22@yahoo.com, 91737

Yehudit Lieberman, yehudit@yehudit.net, 94523

Sharon Lieberman, sjlieby@mcn.org, 95412

Lauren Linda, laulind714@gmail.com, 92637

Grania Lindberg, granialindberg@gmail.com, 94559

Connie Lindgren, scubapiratesurfer@rocketmail.com, 95521

Johanna Lindsay, jolindsay@comcast.net, 94539

Maxine Litwak, mglitwak@umich.edu, 94949

Cindy Loomis, Lkinikia@aol.com, 90403

Denise Louie, denise_louie_sf@yahoo.com, 94131

Blaze Lovejoy, nianaster@gmail.com, 90034

Cody Low, KAJSAINGELSSON@GMAIL.COM, 90046

Lorraine Lowry, lmurphy_2006@hotmail.com, 95688

Erik Loyer, erikcloyer@gmail.com, 91355

Matthew Lubs, matthew_lubs@yahoo.com, 90245

Janie Lucas, janielucas@att.net, 94110

Mary Luckey, mickiluckey@gmail.com, 94610

Carol Luery, cluery@gmail.com, 95864

CARL LUHRING, carlluhring@hotmail.com, 92081

Nancy Lund, nslund@earthlink.net, 94510

Kate Lunn, kate1213.kl@gmail.com, 93433

Alexandria Luostari, alexandria.luostari@gmail.com, 90064

John Lyman, lymanconstinc@aol.com, 91016

W Lynch, wslynch@mac.com, 90049

James Lynn, fullertonbear@gmail.com, 95006

MARSHA LYON, lyonmarsha65@gmail.com, 92116

Jane Lyon, mountan6@gmail.com, 94931

David Lyons, onrust8@gmail.com, 95540

Steve M, industrialwtr@gmail.com, 94403

Carla Macchello, Cmacchello@sbcglobal.net, 94087

Kristy Madden, junebugtyme@yahoo.com, 91311

Scott Madia, smadia25@aol.com, 95407

Mario Magpale, mariomagpale@hotmail.com, 93550

Pat Magrath, phatmcass@gmail.com, 92649

Eva Malhotra, emalhotra@malhotralaw.com, 91024

John Mangan, jmangan751@hotmail.com, 95665

Clarissa Manges, clarissa.manges@charter.net, 92506

John Manning, johnrmanning@gmail.com, 94121

Amira Mansour, amiramansour@earthlink.net, 92612

Leo Mara, provega350@gmail.com, 94550

Martin Marcus, abba_eama@yahoo.com, 92120

Mel Marcus, earthmamamel@hotmail.com, 90808

Michael Margulis, mmargu@mcn.org, 91354

Steve Mark, luckydogster@gmail.com, 90720

Kevin Markoe, kevshell8322@att.net, 95076

R Marks, dobro4me@yahoo.com, 94022

Sally Marone, sallymarone@gmail.com, 94550

Autumn Marr, hannahsue@hotmail.com, 95616

Michael Marrelli, micmusic@gmail.com, 94110

Sheryl Marsh, MTASJ@aol.com, 92056

Ben Martin, benmartin12@stanfordalumni.org, 94040

Nancy Martin, ncmartin@comcast.net, 94303

Stephen Martin, steve7890@gmail.com, 94564

Glenn Martin, ghm@igc.org, 94110

Linda Martin, linda@lindamartindesign.com, 92021

Tyson Martin, tysonjmartin@gmail.com, 91505

Christy Marx, marxcauses@christymarx.com, 96093

julie mascarenhas, c.j.l.mascarenhas@gmail.com, 95060

Mark Masi, markmasi@gmail.com, 90265

Pearly Masters, pearly.masters@gmail.com, 94402

Martha Masura, tilegal@sonic.net, 95465

Rene Maurice, rene.r.maurice@gmail.com, 91447

michele may, mishame1953@gmail.com, 95485

Dana May, obscureeng@yahoo.com, 92840

Felix Mbuga, fmbuga@icloud.com, 95035

Mary McAuliffe, mcpuff05@yahoo.com, 90028

Karen McCaw, mccaw.karen@yahoo.com, 90043

Karen McCaw, karen.mccaw@ca.rr.com, 90043

Lydia Mccloskey, lydiamccloskey9@gmail.com, 94541

Douglas McCormick, mfiinsure@cox.net, 92679

Pamela Mcdonald, plmatdhs@yahoo.com, 92505

Kerri McGoldrick, mcgoldrick.kerri@gmail.com, 94546

William McGrath, oye.billy@gmail.com, 94087

Caephren McKenna, caephren@gmail.com, 94609

Joy McMahan, joymcmahan@hotmail.com, 91361

Cynthia McMath, cynmcm@yahoo.com, 95415

Martha McNamee, jolehmmc@hotmail.com, 94595

Dorothy McQuown, dr.dorothym@yahoo.com, 94941

Axel Meier, toax12@sonic.net, 94606

Barbara Meislin, purpleladybythebay@earthlink.net, 94920

Mariana Mellor, mcns.777@gmail.com, 91360

Richard Mercer, sail.rick@yahoo.com, 94901

Evan Merz, evanxmerz@yahoo.com, 95125

Barbara Mesney, graymez@yahoo.com, 90066

Twyla Meyer, tmmacc15@aol.com, 91767

Cindy Meyers, awakened2007@hotmail.com, 95076

Hildy Meyers, hmeybsan@verizon.net, 92648

David Michaels, dmichaels52@hotmail.com, 95370

Eric Michelsen, elmichelsen@yahoo.com, 92009

Mary Jane Mikuriya, mikuriya@aol.com, 94107

Jack Miller, trustedadvisor@jdmillercpa.com, 94590

John Miller, zenmastermiller@gmail.com, 92618

Nancy Miller, sistergh1976@gmail.com, 93455

Victoria Miller, vemiller0426@gmail.com, 91436

Melva Mills, mlearner39@gmail.com, 95818

Jack Milton, nospray@omsoft.com, 95616

Helene Minniti, hminniti@yahoo.com, 91351

Andrew Mittelman, aj.mittelman@gmail.com, 95065

Elizabeth Mittermiller, beemitt@gmail.com, 92037

William Mittig, wpmittig@gmail.com, 95338

Robert Mizar, mizar2@msn.com, 94923

Jane Moad, janemoad11@gmail.com, 95405

Nelson Molina, hippieteacher@hotmail.com, 90620

Maria Molund, maria.molund@gmail.com, 90019

Gary Monahan, yrag622@gmail.com, 91506

Gary Mononi, mononi.gary@gmail.com, 94930

Dana Monroe, danamonroe@cox.net, 91950

RICHARD MONROE, richmonroe@aol.com, 98006

Davis Montalvan, dmmd001@yahoo.com, 90275

Shannon Montoya, cancermoon74@yahoo.com, 94928

Hugh Moore, hmpeace1@yahoo.com, 90006

william mora, williamgm2000@yahoo.com, 87701

Lynn Morales, lynnmmorales@yahoo.com, 93402

Henry Morgen, hjmla@sbcglobal.net, 90019

Patricia Morton, pamorton@ix.netcom.com, 90039

Sue Mossman, syl1@humboldt.edu, 95518

Archie Mossman, archiemoss@gmail.com, 95518

Lauren Mueller, babyred1407@yahoo.com, 91786

Kenny Mullen, kennymullen@gmail.com, 95403

Glenn Mullins, nascar8160@hotmail.com, 90620

Erica Munn, ericamunn@hotmail.com, 90028

Ilana Murphy, murphetrics@hotmail.com, 94122

Brigid Murphy, bamvetm@yahoo.com, 91710

Joan Murray, jsmurray24@gmail.com, 90066

Joseph Muscat, jymuscat@yahoo.com, 94030

charles myers, chuckmm@aol.com, 95403

Edward Myers, emiltonmyers@verizon.net, 90403

Jane Nachazel-Ruck, antjn4tprch@sbcglobal.net, 90026

H. S. Nadler, s510nadler@earthlink.net, 94947

Rikke Naesborg, rikke_rn@yahoo.com, 93023

Nikki Nafziger, nikkinashmusic@gmail.com, 94590

Kenneth Nahigian, appalonius@netzero.net, 95827

Jaime Nahman, jnahman@verizon.net, 90290

Tem Narvios, winevitable@sbcglobal.net, 94134

Raquel Narvios, ssalino@sbcglobal.net, 94134

Utkarsh Nath, utkarsh.nath@yahoo.com, 94555

Greg Nelson, forestsump@aol.com, 90732

Brad Nelson, bwnssurfn7@hotmail.com, 93035

C. C. Nettles, ccnettles43@hotmail.com, 94605

Alice Neuhauser, apntrc@msn.com, 90266

Christine Ney, cmney70@gmail.com, 92807

Carol Ng, carolng38@yahoo.com, 90026

stu nichols, bigstu1948@outlook.com, 91606

Steven Nielsen, kcee@pacbell.net, 95403

Jeffrey Nigh, janigh@comcast.net, 94127

Jack M Nilles, jnilles@icloud.com, 90049

Lena Nilsson, lnilsson1@yahoo.com, 92651

ben nitzan, bennitzan@yahoo.com, 94018

Jason Nolasco, jro.nolasco@gmail.com, 90706

Viktoria Norberg, viktorianorberg@aol.com, 92374

Elizabeth Novak, beth@spottswoode.com, 94574

Mary Novasic, mnovasic949@aol.com, 94118

Maria Nowicki, mnowicki45@yahoo.com, 94116

Carlos Nunez, cakeflip444@yahoo.com, 91335

Miguel Oaks, oakshere@yahoo.com, 90038

Abraham Omorenimwen Oboruemuh, abraomorenimwen@yahoo.com, 92505

mary oconnell, marymmoc@yahoo.com, 94123

Dennis Oliver, doliver923@yahoo.com, 95451

Christine O'Neill, christine.oneill@live.com, 94523

Steve Ongerth, intexileiww@gmail.com, 94801

Linda Ono, lono08@comcast.net, 94080

James Orr, james.orr@orrenterprises.us, 93726

Robert Ortiz, r77ortiz@hotmail.com, 94945

Greg Orzech, chiphera@comcast.net, 94015

Dale Osborn, tg.dale@gmail.com, 92130

Dyan Osborne, dyan3926@att.net, 94513

Linda Ostro, lostro@pacbell.net, 94595

Hillary Ostrow, hillaryostrow@yahoo.com, 91316

Cindy Owens, clowens3@yahoo.com, 95628

Ron P, larana762@hotmail.com, 91762

Jim P, peckos@me.com, 95125

Meera P, payment-broth0w@icloud.com, 94539

Ernest Pacheco, erniepacheco@cwa9412.org, 94544

Jordan Paetsch, jpaetsch@gmail.com, 90015

Vic PAGLIA, lifters_helices0x@icloud.com, 92663

VICTOR PAGLIA, vic_paglia@hotmail.com, 92663

Michelle Palladine, mpalladine@earthlink.net, 92262

Matthew Palmer, mattpalm@gmail.com, 90808

Bonnie Pannell, touchpeace@gmail.com, 94525

Rich Panter, rpanter@gmail.com, 94947

Melina Paris, melinaparis9@gmail.com, 90275

Benjamin Park, benbe83@hotmail.com, 90046

Jennifer Parker, alpengoose@gmail.com, 96161

Mitch Parkinen, mjp623@sbcglobal.net, 94553

Caryl Parrish, cparrish@prodigy.net, 92009

Oliver Parrish, zorbodor@gmail.com, 95614

Ronald Partridge, raturon@sbcglobal.net, 93063

John Pasqua, johnpasqua57@gmail.com, 92025

Russell Pasqualetti, rkpasqual@icloud.com, 95459

Rashid Patch, rashid_patch@yahoo.com, 94621

Riddhi Patel, riddhipatel1011@gmail.com, 93311

lynne pateman, lpateman@me.com, 90068

Carol Patton, carol.patton@comcast.net, 94708

Lisa Patton, lapatton729@hotmail.com, 94115

James and Tamaira Patton, james.patton@comcast.net, 94024

Mary Anne Paul, maryannepaul@hotmail.com, 95076

Lee Paxton, lpaxton2001@yahoo.com, 90068

Richard Payne, rkpayne1@mac.com, 95448

Bonnie Payne, bonnieapayne@comcast.net, 95448

Clydell Peairs, pritiandclydell@yahoo.com, 94544

Juliet Pearson, juliet@mybougiebottle.com, 95949

Jeffrey Pekrul, jp89149@gmail.com, 94114

M Pelfrey, pelf2006@googlemail.com, 92804

Linda Penrose, ljpenrose@gmail.com, 90275

Deborah Peri, 4deviperi@gmail.com, 95060

Greg PERKINS, gregperkins1@verizon.net, 90814

Janet Perlman, jperlman@berkeley.edu, 94705

Martin Perlman, arroyowaves@gmail.com, 91932

Jim Perry, scarab@sonic.net, 95403

Susan Peters, scpeters39@gmail.com, 94901

David Peterson, pete23152@aol.com, 92116

John Petrak, j_petrak@yahoo.com, 95139

Carolyn Pettis, forkare2@yahoo.com, 91350

Sue Phalen, suephalen@comcast.net, 95370

Valerie Phillips, goskival@yahoo.com, 95611

Craig And Nancy Phillips, caphillips22644@gmail.com, 95005

Ellen Phillips, parrotfreak@att.net, 94704

Claudia Piaseckyj, claudia_piaseckyj@hotmail.com, 91306

Judith Pickles PhD, jpickles@mac.com, 90405

Donna Pielaszczyk, donnap13@sonic.net, 95472

Christine Pielenz, christinepielenz@icloud.com, 94019

Carol Pierce, farmbabe@mac.com, 93023

April Pinheiro, mrs.pinheiro@yahoo.com, 94566

Tom Pitman, thomaspitman@gmail.com, 91506

Raymond Plasse, raymattecc@yahoo.com, 91307

Daniel Podell, dcpodell@yahoo.com, 95404

barbara poland, catsdogsnroses@hotmail.com, 91214

Debra Polansky, debrapolansky8@gmail.com, 95603

Alice Polesky, askalice@pacbell.net, 94107

Bret Polish, brednjam1@yahoo.com, 91335

Stephen Pollaine, spollaine@yahoo.com, 95465

Jackie Pomies, jbpomies@yahoo.com, 94122

samuel popailo, samuel_popailo@yahoo.com, 90046

Kathy Popoff, kathy_popoff@yahoo.com, 90732

Elizabeth H Porter, betsyhartporter@yahoo.com, 94611

Keith Porter, keith@burmaoaks.com, 95945

shirley porter, shirley@burmaoaks.com, 95945

Elisabeth Potts, ejpotts47@gmail.com, 95060

Jon Povill, jpovill@gmail.com, 90290

Kathleen Powell, kit.mom@hotmail.com, 94590

Laurel Powers, jrhilljr1@comcast.net, 94952

Jerami Prendiville, Jerami@rebar-vfx.com, 93012

Lynne Preston, bluelynne@sbcglobal.net, 94110

Marilyn Price, mprice@the-acorn.com, 94941

David Prina, rangerdprina@yahoo.com, 93907

Louis Priven, loupriven@aol.com, 90049

Nora Privitera, noraprivitera@comcast.net, 94602

Karen Profet, kprofet@kprofet.com, 90266

Bill Prothero, prothero@ucsb.edu, 93105

Lauren Prust, lauren.prust@gmail.com, 92126

Robert Q, info@robertquarrick.com, 94510

April Quigley, galadrl2@aol.com, 95531

vanessa quintero, nessaangel15@aol.com, 94572

Kelly Radimer, snapdrygon@hotmail.com, 94568

Francesca Rago, bah000224@hotmail.com, 94523

Mary Ragsdale, maryfrap7@yahoo.com, 95366

Antonia Raikes, tnrgeorge1@aol.com, 90066

Don Rake Rake, rakedon1@yahoo.com, 95765

Grace ramirez, twotonetia@yahoo.com, 95502

Hank Ramírez, latinleo@sbcglobal.net, 92116

Rudy Ramp, rampturn@tidepool.com, 95521

Walter Ramsey, walter.ramsey@sbcglobal.net, 94561

Peter Randolph, peter.randolph@cox.net, 92029

Louise Rangel, prefierofrio@gmail.com, 93060

Michael Ranger, casca2525@yahoo.com, 90210

Dorri Raskin, bunnyraskin@gmail.com, 91326

Thomas Ray, tfr22@comcast.net, 94945

JAMES REAMY, jrsk8s@aol.com, 92111

Maryellen Redish, mredish@aol.com, 92262

Penny Redman, redman.penny@icloud.com, 95814

Diane Reed, diane.f.reed@sbcglobal.net, 94804

Robert Reed, robtsreed@gmail.com, 92651

Pamela Reed, artfusion@mac.com, 94590

James Rees, jerees@aol.com, 94546

Catherine Regan, cregan44@comcast.net, 94608

Jennifer Regoli, genofear@yahoo.com, 95817

Gregory Reichert, gregoryareichert@gmail.com, 94601

Susan Reichle, carpecircus@gmail.com, 95327

F. Carlene Reuscher, carlene-r@roadrunner.com, 92626

Debra Reuter, debireuter@gmail.com, 95687

erich rex, erichrex@hotmail.com, 94066

Barbara Rhine, barbrhine@pacbell.net, 94618

Genevieve Riber, gennyriber@gmail.com, 92103

Nancy Richards, nancyr@sonic.net, 95404

Gwen Richards, ladygwen242@gmail.com, 93101

Carol Richardson, csrterp@yahoo.com, 94606

Adele Richman, zuzu08902@yahoo.com, 94595

Erica Richter, ericajrichter@gmail.com, 94070

Ellen Riegelhuth, eriegelhuth@yahoo.com, 94595

Dale Riehart, dale@daleriehart.com, 94107

Shari Riffe, shari.riffe@sbcglobal.net, 94523

Felix Rigau, flix@yahoo.com, 94123

Carol Rigrod, crigrod@yahoo.com, 91316

Ben Rigrod, jackrayes2@yahoo.com, 91316

Ronald Ringler, ronald.ringler@gmail.com, 92530

Susanne Risso, srisso53@gmail.com, 96052

Tony Robbins, arobbins@sfsu.edu, 94122

Megan Robbins, meganrobbins@sbcglobal.net, 94923

John Robbins, john_d_robbins@yahoo.com, 94087

Steven Roberson, saganblue@yahoo.com, 95747

Jacquelyn Roberts, love.violet524@yahoo.com, 93561

John Robey, steve.robey@gmail.com, 94708

Kate Robin, katerobin@mac.com, 90049

Chuck Rocco, crocco1250@aol.com, 93065

Priscilla Rocco, dementedgardensprite@gmail.com, 92626

Beverly Rockabrand, bjrockabrand@gmail.com, 94109

Steve Roddy, sidingwen@yahoo.com, 94118

BRENDA RODRIGUEZ, brenda_1174@yahoo.com, 91345

Kevin Roe, kevinjr1@aol.com, 95005

Christina Roe, rustydustyvintage@yahoo.com, 93705

Jim and Connie Rogers, jrogers@garlic.com, 95020

Lilith Rogers, lilithrogers1@gmail.com, 95472

Susan Roland, sronthebay@gmail.com, 95642

Sheri Rollison, sherirollison@comcast.net, 94945

Van Rookhuyzen, vanrookhuyzen@comcast.net, 94102

Greg Rosas, thesro15@yahoo.com, 94546

Mary Rose, mrose1126@aol.com, 94702

John Rose, jnbrose2@gmail.com, 93117

Stephen Rosenblum, pol1@rosenblums.us, 94301

Carolyn Rosenstein, kenterway@msn.com, 90067

Steve Rosin, steve.rosin@gmail.com, 91106

Donald Rothberg, redmountain@donaldrothberg.com, 94703

D. Rowe, dianamite920@gmail.com, 90403

Rina Rubenstein, houseofrina@hotmail.com, 90018

Cynthia Rudolph, cynthiabrudolph@gmail.com, 94005

Christoph Ruegg, quitethere1@yahoo.com, 91604

Michael Russell, cardcat57@gmail.com, 93060

Donna Russell, dbr3705@yahoo.com, 95618

Kathleen Russler, katr_22@yahoo.com, 95123

Peter Rutherford, pbr90266@yahoo.com, 90266

Robert Rutherford, drjakekt@sonic.net, 95448

Ellen Ryan, ellenryan3843@gmail.com, 95503

ravi s, qfg@yahoo.com, 90095

C S, carco2@aim.com, 90808

PETER SAID, pfsaid@cal.berkeley.edu, 91730

Mark Salamon, marksalamon@aol.com, 94403

Joe Salazar, joesalazar19@yahoo.com, 95407

NATALIJA SALE, hbnatydred@msn.com, 90740

Jack Salem, djsalemla@gmail.com, 90049

Dalia Salgado, adthdfyr@aol.com, 90017

Sean San José, seansanjova@yahoo.com, 94112

Michele Sanderson, qstarspectrum7@aol.com, 94595

Valerie Sanfilippo, valerie.sanfilippo@icloud.com, 92111

Michele Santoro, fashionpanther@gmail.com, 95616

Angelina Saucedo, asaucedo22@hotmail.com, 90640

Laura Saunders, tolsaunders@yahoo.com, 94107

Charles Saylan, csaylan@earthlink.net, 90045

Russell Scalf, rscalf@sonic.net, 94702

Robert Schaff, rschaff@pacbell.net, 94903

J. Schaffell, jschaffell@gmail.com, 94598

Carol Schaffer, cschaff@aol.com, 94806

Roberta Schear, bschear@sonic.net, 94618

Barbara Schell, bschell761@gmail.com, 92101

NANCY Schelling, nschelling@roadrunner.com, 92240

Alan Schenck, aschenck771@gmail.com, 95003

Bob Schildgen, bob.schildgen@gmail.com, 95412

Elizabeth Schlaff, beth.schlaff@gmail.com, 90272

Henry Schlinger, hschling@hankschlinger.com, 91201

Fred Schloessinger, fredleosch@gmail.com, 92646

Eugenie Schlueter, emschl@sbcglobal.net, 91105

Nancy Schmidt, nanfran48@gmail.com, 92395

Paul Schmidt, p.a.schmidt@sbcglobal.net, 92603

George Schneider, grs92138@gmail.com, 92105

Rick Schulte, rickschulte@cox.net, 91941

Ellen Schulz, ellenjanes@hotmail.com, 94949

Linda Schulz, lrschulz@verizon.net, 93532

Jeanne Schuster, jeanneschuster@aol.com, 91791

Ron Schutte, ras356@cox.net, 92103

Nancy Schwartz, nancygraceschwartz@yahoo.com, 92117

Barry Schwartz, barryschwartz1@mac.com, 94559

Andrea Scott, andrea.scott@theagencyre.com, 94507

Rob Seltzer, rsscpa@earthlink.net, 90265

Christine Sepulveda, simianchrissy@gmail.com, 91786

Stephen Serafino M.S., sfserafino@gmail.com, 93012

Elliott Sernel, esernel@pacbell.net, 92262

Mariam Shah-Rais, yatrika@shivaloka.com, 90035

Donna Sharee, dsharee@earthlink.net, 94112

Charles Sharpe, chipsharpe@sbcglobal.net, 95524

al shayne, afshayne@gmail.com, 90036

Gabriel Sheets, arkangyl_g@hotmail.com, 95338

John Shell, jhshelljr@aol.com, 91344

Victoria Shepherd, vshepherd45@yahoo.com, 91201

David Sherertz, ddsherertz@gmail.com, 94703

PHILIP SHERMAN, jpsherman@live.com, 95814

James Sherrel, yetinsyny@comcast.net, 95628

Marilyn Shirey, mshirey@comcast.net, 95831

Judy Shively, jashively01@gmail.com, 92101

S Shoup, ixbalam@turbonet.com, 92061

Jerry Shuper, jshupharm@yahoo.com, 95818

Wayne Sibilia, oneisone58@gmail.com, 93401

Nancy Sidebotham, nannystu@sonic.net, 94605

Marc Silverman, dhalgrn@pacbell.met, 90068

Gary Simmons, teetime33@msn.com, 92562

Philip Simon, philsim75@aol.com, 94903

Hilary Simonetti, hsimonetti@dc.rr.com, 92234

Bruce Sims, ODDLOTS1947@ATT.NET, 92027

Tony Sirna, tony@citizensclimate.org, 94705

Darcy Skarada, dskarada@gmail.com, 95451

michael skinner, skinnermp@gmail.com, 92649

Carole Sky, CaroleSky@gmail.com, 94591

Marianne Slaughter, twobirderz@gmail.com, 93010

Kevin slauson, ksslauson@yahoo.com, 94501

Cathy Sleva, csleva@me.com, 90740

Diane Smith, dsmith@csjla.org, 91423

Julie Smith, raynjulie1048@sbcglobal.net, 93402

Cynthia Smith, bloomabilities2001@yahoo.com, 92691

Glenn Smith, glenntrumpet@gmail.com, 95959

Jerel Smith, jerel@cruzio.com, 95006

Leslie Smith, leslie@leslieplatosmith.com, 94611

Judith Smith, judithsmith313@gmail.com, 94601

Aleta Smith, espresso43@yahoo.com, 95946

Tower Snow, tower.snow@gmail.com, 94515

TREVOR SNOW, trevorjosephsnow@gmail.com, 90039

Joel Sokolsky, esthersfolks@sbcglobal.net, 94595

Richard Solomon, risolom@gmail.com, 94611

Betty Songer, capacbet@aol.com, 93013

Brent Spencer, blamar59@aol.com, 90740

Jane Spini, janespini@hotmail.com, 95521

A. Srinivasan, tintenbear@gmail.com, 91001

James Stamos, jstamos@alum.mit.edu, 95070

elizabeth standard, estandard1@icloud.com, 91601

Norm Stanley, norman720@yahoo.com, 92399

Garry Star, gstar42@hotmail.com, 91362

Mary Starzel, mbstarzel@gmail.com, 93420

Wayne Steffes, camerashy@shasta.com, 96001

Carl Stein, sfcarl@hotmail.com, 94103

Richard Stein, fossilfree@gmail.com, 92620

Cindy Stein, cinfish65@yahoo.com, 91320

Neal Steiner, nrspacific@yahoo.com, 90034

Kat Stephens, kat9433@gmail.com, 95409

John Steponaitis, steponaj@gmail.com, 94109

Roberta Stern, rozydeco50@hotmail.com, 94618

janet stillman, janetstillman@yahoo.com, 94110

Robert Stine, zv75@yahoo.com, 94117

Rick StJohn, rinsfcausa@gmail.com, 94109

Ari Stocking, arianna@insynccom.com, 94903

Polly Stone, polly_stone@comcast.net, 94952

Ellen Straw, ekstraw@verizon.net, 91722

Laura Strom, fogfairy@netscape.net, 90034

Stephen Stroud, scstroud@gmail.com, 91101

Carey Suckow, c_suckow@yahoo.com, 94114

Tad Sullivan, tadsulli@earthlink.net, 92625

Penelope Suter, psuter@ymail.com, 93304

Erin Suyehara, efly13@yahoo.com, 90503

Linda Sward, glmsward@att.net, 93631

Robert Sykes, bobkyoko@gmail.com, 93908

Geoffrey and Linda Symcox, symcox@history.ucla.edu, 91105

Gregory Tabat, greg@exceptional.org, 92704

Robert Taft, robertaft31@gmail.com, 93901

Michael Talbot, talbot.nkt@gmail.com, 94901

Akiko Tamano, atamano323@gmail.com, 92129

Binh Tang, overrice@gmail.com, 91311

Donald Taylor, cplii@sbcglobal.net, 95628

Simone Tejero Mills, simtom3@yahoo.com, 91104

Debbie Tenenbaum, debbietenenbaum@aol.com, 94703

Noah Tenney, noahten@earthlink.net, 94606

Leonie Terfort, lterfort@icloud.com, 94941

Jeff Thayer, scubapong@yahoo.com, 92117

Bonnie Thompson, bthompson.xyz@gmail.com, 93402

Brenda Thompson, bthompson@mail.sdsu.edu, 91942

Doug Thompson, doug@powerofplants.com, 92256

Greg Thomson, gregothomson@mac.com, 94965

Hannah Thorner, hmthorner@gmail.com, 94707

Daniel Tiarks, dtiarks@sbcglobal.net, 90046

Teresa Tillman, tctillman@aol.com, 94618

Susan Titus, susanlee448@att.net, 95819

JOHN TITUS, jjtitus@gmail.com, 95776

Erh-Yen To, sea11wa@yahoo.com, 95835

Jerry Tobe, tagchai@gmail.com, 90034

Kevin Todd, ordofratrumkaramazovus@gmail.com, 93427

Lisa Toller, jaderabbit365@gmail.com, 83792

Michael Tomczyszyn, mtomczyszyn@hotmail.com, 94132

Andy Tomsky, andytomsky@yahoo.com, 92029

Ava Torre-Bueno, avatb3@gmail.com, 92105

Anthony Totaro, ajtotaro@comcast.net, 94568

Lana Touchstone, lanatouchstone@hotmail.com, 94591

Karen Toyohara, spboersma@gmail.com, 91941

Nancy Treffry, nancytreffry@gmail.com, 95004

Linda Trevillian, linda-in-alhambra@sbcglobal.net, 91803

Charles Tribbey, cltquest@gmail.com, 93449

Martin Tripp, recn@sbcglobal.net, 91390

Darrell Trombley, trillionairechrist@aol.com, 92264

Laurel Tucker, tsva1@earthlink.net, 91711

R.G. Tuomi, rgtuomi@yahoo.com, 91362

Anthony Tupasi, improvant@yahoo.com, 94122

Nolan Turner, nolan_turner@yahoo.com, 95123

Elizabeth Turner Wallace, eltwallace@gmail.com, 92679

Myrna Tuttle, revmom13@gmail.com, 93110

Meadow Two Feathers, adoptfromashelter@gmail.com, 92705

Eric Uhrhane, uranium+ucs1@gmail.com, 94122

Susan Urang, theonlydrsooz@gmail.com, 95126

Sylvia Vairo, sylviavairo@yahoo.com, 95062

Antonio Valdez, x100net@yahoo.com, 92801

Ellen Van Allen, ellenlea@sonic.net, 95404

Dona van Bloemen, donavanb03@yahoo.com, 90405

Jill Van Cise, jlkrnvncs@hotmail.com, 90057

Arlene Van Craeynest, acvancraeynest@gmail.com, 94947

Sara Van Dusen, svdusen@hotmail.com, 94303

Kathleen Van Every, KatMVanE2@gmail.com, 93422

Judith Van Herik, jxv4@psu.edu, 95949

Sandra Van Horn, smilesandcats2@gmail.com, 92637

victoria vance, victoriavvance@yahoo.com, 95524

John Varga, jlvarga9@gmail.com, 92270

Vance Vaughan, vance@berkeley.edu, 94707

Carolyn Vaughan, carolyncvaughan@gmail.com, 91206

Joan Velvick. Velvick, jvelvick@msn.com, 92683

Shellie Vermeer, svermeer1@att.net, 92653

Paul Vesper, pontiffp@comcast.net, 94703

Lizzie Vierra, lizzievie@aol.com, 92627

Carmela Vignocchi, stellacarmela@yahoo.com, 93433

James Voight, vavavoight@aol.com, 92109

Susan von Schmacht, svonschmacht@sbcglobal.net, 95076

Jacqueline Vrooman, jacquelinevrooman@gmail.com, 91792

Don W, dw333@reninet.com, 95503

Ellen Wade, mldwade@sbcglobal.net, 92107

James Walker, james_r_shoffet@yahoo.com, 95519

Greg Walker, walker@citrus.ucr.edu, 92507

Patrice Wallace, patricewallace@cruzio.com, 95060

Barry L Wallace, barryofca@yahoo.com, 92346

Paul Waller, psw20@icloud.com, 91367

Susan P. Walp, susanwalp@gmail.com, 91103

Jennifer Walters, cooljen@msn.com, 90247

Ernie Walters, ernwalt@aol.com, 94587

Gabriele Wampfler, gwampfler2@earthlink.net, 94062

Virginia Ward, virward@sbcglobal.net, 94591

Ann Wasgatt, wasgatta@gmail.com, 95678

Lee Wasserwald, wasserwald@verizon.net, 90401

diana waters, dianawaters09@gmail.com, 90503

Melissa Waters, msimply3@aol.com, 92677

Linda Watkins, linda.watkins44@gmail.com, 94118

Anita Watkins, watanita@gmail.com, 94611

Richard Watson, rwatson35@hotmail.com, 90807

Virginia Watson, virginiawatson5@gmail.com, 90026

Susan Watts-Rosenfeld, susanmwr@aol.com, 92506

Helen Webb, helweb857@yahoo.com, 92373

Ellen Webster, ellenweb@earthlink.net, 91711

Alice Weigel, awiggle@sbcglobal.net, 95076

Linda Weiner, lindawiner@aol.com, 94110

Jonathan Weinstock, jstock522@yahoo.com, 94710

Lynne Weiske, movieblonde@hotmail.com, 90048

Joanna Welch, jfwelch22@gmail.com, 95501

R Wells, rockywells18@gmail.com, 90020

David Wendt, w6547green@astound.net, 94596

Tina Wener, wenertina@gmail.com, 93442

Margaret Wessels, margaretwess@hotmail.com, 95003

Juanita Westberg, jj4short@gmail.com, 92345

Anne Westbrook, annewestbrook@alum.mit.edu, 94024

Ansel Wettersten, awawd@mac.com, 94109

Dave Whipple, dwhipple@statconcorp.com, 93940

Mindi White, ammaze@aol.com, 90046

Ree Whitford, reewhitford@gmail.com, 94558

Helene Whitson, helenewhitson@comcast.net, 94709

Barbara Whyman, b.whyman@yahoo.com, 93001

Reynold Wiggins, rwig123@yahoo.com, 94019

Stewart Wilber, s.wilber@mindspring.com, 94114

Carol Wiley, desertlily1@verizonl.net, 92394

Arlene williamson, spiritwing7643@gmail.com, 94544

Susan Williard, dancegirl@earthlink.net, 94122

Eleanor Wilson, platydudette@yahoo.com, 93060

Martha Wilson, mvw618@gmail.com, 95618

Anthony A. WILSON, Lonewolf113191966@Gmail.com, 95336

Janis Wilson-Pavlik, janiswp23@aol.com, 93924

Liz Winterhawk, winterhawk@animalconsultations.com, 96067

Anita Wisch, awisch629@aol.com, 91355

Anita Wisch, Nitababe44@aol.com, 91355

W Wittl, wjwittl@cox.net, 93105

Jessica Wodinsky, jwad@ucla.edu, 90066

Scott Wolf, theroamingwolf@yahoo.com, 95926

Charles Wolfe, cawolfe@verizon.net, 91342

Jean Wolman, jwolman@sbcglobal.net, 94024

Ivan Womboldt, iwomboldt@dc.rr.com, 92264

Samuel Wong, samtheveggieman@msn.com, 91792

George Wood, george@radiowood.com, 95482

Alan Wortman, alan.wortman@outlook.com, 94062

Gerrit Woudstra, gwo.woudstra@hccnet.nl, 91126

Pam Wright, pasapdub@aol.com, 91107

Victoria Wu, thevicwu@gmail.com, 95112

Blake Wu, skbkms@mail.com, 94549

Dana Wullenwaber, odonata22@sbcglobal.net, 96001

Darlene Wyatt, dpwyatt352@gmail.com, 91945

Aimee Wyatt, photochk611@gmail.com, 93023

Benjamin Wynne, wynnealanwynne@aol.com, 96101

C. Yee, c-yee@sbcglobal.net, 95822

Steven Yellin, yellin@slac.stanford.edu, 94025

Dan Young, dyoungmail@aol.com, 92262

Lowell Young, lowell_young_95338@yahoo.com, 93720

J Yudell, turtleshmertle@gmail.com, 90409

Barry Zakar, bzakar30@gmail.com, 94591

Rudy Zeller, goforgoalrudy2@yahoo.com, 94510

Stephen Zelman, zeltunes@yahoo.com, 91367

R. Zierikzee, inor@earthlink.net, 94118

Joan Zierler, kahblue@gmail.com, 90230

pam zimmerman, pzimmer946@comcast.net, 95404

Amy Zink, adzink29@hotmail.com, 94606

Alex Zukas, alexzukas@yahoo.com, 92115

Arleen Zuniga, zuniga.arleen@gmail.com, 95446

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

West Coast
500 12th St., Suite 340
Oakland, CA 94607
510-843-1872

Midwest
200 E. Randolph St., Suite 5151
Chicago, IL 60601
312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

As a California resident, I believe it is critical that California not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Richard Dawson
rcdawson@att.net
90026

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

West Coast
500 12th St., Suite 340
Oakland, CA 94607
510-843-1872

Midwest
200 E. Randolph St., Suite 5151
Chicago, IL 60601
312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

As a Senior living in Los Angeles, I'm writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does NOT rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses SIGNIFICANT tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Hilary Hilary
hilaryoung@gmail.com
90026

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

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312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

207.3

I believe that the most effective way to effect carbon in the atmosphere is a carbon tax with proceeds divided equally to every man woman and child plus a border tax of the same magnitude on products from other countries that do not have a carbon tax. Even with that, we need every known measure and some as yet unknown, to be instantly applied. Hence I am writing to provide input on the most effective way to support the proposed to amendments to the Low Carbon Fuel Standard (wayLCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Wilms Hoffmann
wilmahoffmann@icloud.com
94070

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

As an American citizen and taxpayer and long-time health care provider I am deeply concerned and desire to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Mha Atma S Khalsa
earthactionnetwork@earthlink.net
90035

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am a proud and happy electric vehicle owner. The whole thing thrilled me so much, I ditched my gas-powered lawnmower and bought a cordless electric mower. I went green in areas where it is obtainable for most. I will address the rest of my living space as appliances die. Now, I see that somehow soybean oil diesel has made the cut as environmentally friendly. What! This is far from the truth, so I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Julie Kanoff
jkanoff@sbcglobal.net
95819

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. Let’s be smart(er) with our ‘science’!

Sincerely,

Peter Lambert
1petermlambert@gmail.com
95682

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

Regarding the proposed amendments to the Low Carbon Fuel Standard (LCFS): Allowing a large increase in vegetable-oil-based diesel will result in deforestation due to a greater market for imported vegetable oil. Deforestation harms the environment by both disrupting the forest ecosystem and by contributing to global warming. In addition, diverting vegetable oil to use as fuel instead of food risks impacting food security in vulnerable communities.

Sincerely,

Elaine Lee
wejunk@sbcglobal.net
95051

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

Soybean based diesel oil is causing environmental harm. I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

George Leone
georgelleone@gmail.com
93422

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

IMMEDIATELY PLACE CAP ON VEGETABLE OIL-BASED FUELS! I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

David Perry
dperry2@gmail.com
94306

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

The production of soybean oil creates a significant amount of greenhouse gas emissions and is therefore not an effective alternative to petroleum. I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Ravid Raphael
rraphael@twodancers.net
93111

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

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312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am a mother and a grandmother who is very concerned about the future of our environment. I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Linda Waldroup
lindawaldroup@yahoo.com
94595

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

As a California diesel consumer for transportation, I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. My exploration of biodiesel over the past two decades has convinced me that it is a useful adjunct and not a base for a sustainable transportation future. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. As California's consumption of soybean oil-based diesel increases, it fuels the rapid expansion of palm oil cultivation to replace what we use for fuel. California's consumption of soybean oil for fuel is projected to reach 1.3 million metric tons this year, equivalent to 10 percent of the worldwide trade in soybean oil, which will distort the market.

Sincerely,

Douglas Walter
dawalter@dcn.org
95616

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I appreciate what you are trying to do but this amendment will do more harm than good for our environment and not help with climate change at all. We're better off focusing on electric vehicles and public transportation. I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Marie J Salerno
marie@mjsalerno.com
94904

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

As a nurse, I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Judy Schultz
heyjudenf@gmail.com
94115

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

ATTENTION! I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Jonathan Bailin
jonathan4web@gmail.com
90066

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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200 E. Randolph St., Suite 5151
Chicago, IL 60601
312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am providing input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Mark Bartleman
mbartleman86@gmail.com
92651

[Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. We have had an electric vehicle since 2014 and are amazed by the advances in the technology. They great to drive and own.

Sincerely,

Wendy Bernstein
clangford@earthlink.net
94706

Union of Concerned Scientists

Headquarters	Washington, DC	West Coast	Midwest
Two Brattle Square, 6th Floor	1825 K St. NW, Suite 800	500 12th St., Suite 340	200 E. Randolph St., Suite 5151
Cambridge, MA 02138	Washington, DC 20006	Oakland, CA 94607	Chicago, IL 60601
617-547-5552	202-223-6133	510-843-1872	312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. In November I bought a fully electric car. We need to look at the future and the planet. We are leaving behind for the next generations. Please do the right thing.

Sincerely,

Alain Berrebi
berrebi555@gmail.com
90012

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. Insofar as the soybean source is Brazil, this implies deforestation, another major concern. Off subject perhaps, but similarly using corn to produce ethanol by fermentation is a terrible environmental idea (rationale is purely political). Fermentation produces CO2 and the energy content is reduced by 20%

Sincerely,

Rich Blish
richard.blish@gmail.com
95070

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing in regard to the proposed amendments to the Low Carbon Fuel Standard (LCFS). In particular, I urge CARB to reevaluate the amount of subsidies provided to vegetable-oil based diesel and instead focus the program toward supporting vehicle electrification and green hydrogen. California should not be reliant upon soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. Also overlooked in this process are programs to support the production of green hydrogen. While manufacturers are ramping up production of electric vehicles, the promise of hydrogen fuel cell transportation solutions (non-polluting and much more convenient for consumers) will stall without government support for clean hydrogen production and distribution.

Sincerely,

Richard Bradus
bradusr@sonic.net
94115

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. As a person of faith, I pray you will use your authority to protect Creation in this way.

Sincerely,

Diane Brenum
dbrenum@gmail.com
94602

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing regarding the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Catherine Brown
chb@waterhouses.us
95616

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

Please know my concern regarding proposed amendments to the Low Carbon Fuel Standard (LCFS). As a Californian I find it critical that California not rely on soybean oil-based diesel to reach our idealistic yet responsible environmental standards. Moving vegetable oil from food to fuel poses major environmental harm through tropical deforestation. Any flood of vegetable oil-based diesel in California also undermines support LCFS provides for transportation electrification.

Sincerely,

Gail Camhi
gailcamhi24@aol.com
94949

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant climate impacts and environmental harm through tropical deforestation and increased demand for ag land. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. LCFS should focus support on electrification, use of waste products/used oils, and e-fuels (watch those hydrogen lifecycle emissions and GWP of leaks though!).

Sincerely,

John Chamberlin
johnnie@elaw.org
94960

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I respectfully ask that you support the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Jan Charvat
jch@cox.net
91901

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
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617-547-5552

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1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my deep concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does NOT rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation! The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification??

Sincerely,

Gail Cheda
gailsendstuff@gmail.com
93401

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. I have added solar panels and a battery to my home and look forward to getting an electric plug in car. We desperately need to move away from oil-based fuels that dirty our air and take away land for fuel burning. We can do so much better using solar energy.

Sincerely,

Laura Chinn-Smoot
violaura@sonic.net
94121

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my great concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is absolutely critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses some very significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the needed support the LCFS provides for transportation electrification. Electrification really is the best route-especially with our public transportation. That would leave fewer vehicles on the road. Upgrade our transportation from LNG, and filthy fossil fuels to electricity, add more buses & trains, and schedule them to arrive in a timely manner, maybe even add more stops. This would greatly improve our air, soil, and water quality. Thank you for caring about us.

Sincerely,

Kate Considine
dragonstorm7998@duck.com
93030

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

West Coast
500 12th St., Suite 340
Oakland, CA 94607
510-843-1872

Midwest
200 E. Randolph St., Suite 5151
Chicago, IL 60601
312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. It is time to stop tearing up the world's productive land to produce oil for transportation. Get off the carbon-based fuel madness, and support green electrical programs that are really sustainable.

Sincerely,

Charles Coston
costoncj@gmail.com
94087

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The unprecedented expansion and magnitude of soybean oil-based diesel used in California is harming people, accelerating tropical deforestation, and undermining the state's climate policies. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. You Board members can mitigate the impact of California's fuel consumption on sensitive ecosystems by aligning our climate action with sustainable practices by capping soybean oil-based diesel and refocusing the LCFS on electric vehicles.

Sincerely,

Chris Eaton
ceaton7777@gmail.com
90041

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
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617-547-5552

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To: California Air Resources Board

I am to the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Linda Elkind
linda@elkind.org
94304

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. Time is running out. Let California do what it does best--show the world how to get things done.

Sincerely,

Luann Erickson
erickson.luann@gmail.com
95670

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, and an owner of a diesel vehicle, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Paul Eusey
cre8tiv369@yahoo.com
95969

Union of Concerned Scientists

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Two Brattle Square, 6th Floor
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is CRITICAL that California DOES NO RELY ON SOYBEAN OIL-BASED DIESEL to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Mark Feldman
happeevegan@gmail.com
95401

Union of Concerned Scientists

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Two Brattle Square, 6th Floor
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on non-waste soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation and raises food costs for the world's poor. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

DAVID FORSTER
derforster@yahoo.com
94539

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
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617-547-5552

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Lynn Franks

Sincerely,

Lynn Franks
laf32@sbcglobal.net
95818

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

Clean air and environment are very important to me. I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Jeffery Garcia
jeffery@mcn.org
95460

Union of Concerned Scientists

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Two Brattle Square, 6th Floor
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. Please do not include soybean oil-based fuel as an option. This crop has wrought social and environmental devastation in South America. Thank you.

Sincerely,

Diane Gifford-Gonzalez
giffordgonzalez@gmail.com
95060

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

You can do so much more to protect the health of Californians and the future of all children and grandchildren. Be on the side of humanity, please. I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Julie Harris
jrhjrh13@gmail.com
94803

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. There are two reasonable alternatives, both based upon Hydrogen: fuel cells and combustion. The residual exhaust is WATER. These are both very attractive for truck transportation and can be phased in over at 7-10 year period, thus not forcing an instantaneous change. The key is that the market in California is so large, if we require this, the rest of the country will follow and in time, the world. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

James Harris
jharris@stanford.edu
94305

Union of Concerned Scientists

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Two Brattle Square, 6th Floor
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To: California Air Resources Board

vEGETABLE OILS ARE CARBON BASED!! I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Chris Hays
chris@chrishays.com
91011

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am concerned about the proposed amendments to the Low Carbon Fuel Standard (LCFS). I'm a California native and recognize the leadership our state provides to the rest of our nation. California must not rely on soybean oil-based diesel to reach our environmental standards. Shunting vegetable oil from food to fuel causes significant environmental harm through tropical deforestation. All of the vegetable oil-based diesel flowing into California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Thomas Hazelleaf
cheapcruiser2003@yahoo.com
90740

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
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To: California Air Resources Board

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Sincerely,

Jessica Heiden
jlhiowa2@yahoo.com
95503

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Realign the LCFS with California's environmental goals and global responsibility by capping on vegetable oil-based diesel. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Richard Hill
r.e.hill@att.net
95628

[Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. soybean oil-based diesel will produce carbon dioxide and other greenhouse and polluting byproducts when combusted. That's elementary chemistry. More CO2 in the atmosphere is increasing the risk of catastrophic climate disruption. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Stanley Hutchings
stan.hutchings@gmail.com
94960

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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To: California Air Resources Board

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Sincerely,

Nancy Ihara
nancyihara@gmail.com
95521

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing with deep concern the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible and necessary environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. We need electric transportation, with solar charging stations to support it. We need this soon, not later.

Sincerely,

Lori Jirak
lorih@mcn.org
92036

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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Sincerely,

Cynthia King
cintiaking@gmail.com
93015

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident and as a public health professional and environmental advocate for 40+ years, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Nancy Kingston
nxkingston@cox.net
92692

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I'm writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it's critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Betty Kissilove
cacaogal@gmail.com
94122

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does NOT rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical DEFORESTATION. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Evan Jane Kriss
samesamejane@gmail.com
94965

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
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617-547-5552

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To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. All fuels for vehicles in California need to be sustainably created and we must rapidly shift to an all electrified fleet of commercial and personal cars and trucks. Long haul trucks need to replace diesel with electric ones where possible as soon as feasible. Air transportation needs to convert to more sustainable and truly renewable fuels such as green hydrogen from renewably sourced electricity.

Sincerely,

Tim Laidman
tim@timlaidman.com
94530

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
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To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel is not sustainable. It poses significant environmental harm through tropical deforestation and the cost and energy required to import soybean oil from afar. Please consider the negative effects of this proposed amendment and focus on electrifying vehicles.

Sincerely,

Barbara Lamb
blamb@pacific.net
95494

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am VERY concerned about the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Nancy Levy
nancylevy@aol.com
94301

Union of Concerned Scientists

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Sincerely,

Amy Longanecker
alwilliams0630@gmail.com
92111

Union of Concerned Scientists

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. Michael Lueras 90272 U.S.A.

Sincerely,

Michael Lueras
bebopper55@gmail.com
90301

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

West Coast
500 12th St., Suite 340
Oakland, CA 94607
510-843-1872

Midwest
200 E. Randolph St., Suite 5151
Chicago, IL 60601
312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. Electrifying transportation has the additional benefit of decreasing air pollution, with immediate health benefits for people living near roadways, especially those overburdened by high truck traffic.

Sincerely,

Cynthia Mahoney
cam8ross@comcast.net
94526

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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To: California Air Resources Board

I write to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Marcus Maloney
maloney_marc@yahoo.com
95841

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

Vegetable oil is not the answer. Please amend the Low Carbon Fuel Standard (LCFS)so that vegetable based oils are not diverted from use as food to use as fuel. California should not rely on soybean oil-based diesel to reach our environmental goals. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. Vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Elizabeth Mather
elizabet.mather@sbcglobal.net
92129

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

Please avoid taking a step backward in California's to clean up its fuel, air and water! I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Wendy McCobb
wmccobb@proton.com
93024

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

WE MUST GO STRONGLY TOWARD WHATEVER WILL HELP US SAVE LIFE EARTH !!!!! I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Howard Miller
mmmhunify@aol.com
93003

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am deeply concerned about the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Sharon Morris
skmorris101@gmail.com
94577

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern about the proposed amendments to the Low Carbon Fuel Standard (LCFS). I am a California resident and a physician - it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Judith Murphy
judithamurphy@prodigy.net
94028

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. The Democratic Party platform should support: Animal Rights, Defending the Affordable Care Act, Ending Citizens United, Ending Marijuana Prohibition, Giving Greater Visibility to Pro-Life Democrats, Gun Control, Net Neutrality, Raising the Minimum Wage to $15 an Hour, Responding to the Scientific Consensus on Global Warming, and a Sustainable Energy Policy. Democrats for Life of America, 10521 Judicial Drive, #200, Fairfax, VA 22030, (703) 424-6663

Sincerely,

Vasu Murti
vasumurti@aim.com
94611

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
Washington, DC 20006
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my extreme concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I strongly believe it is critical that California does NOT rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significantly severe environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Karen Naifeh
karenaifeh@sbcglobal.net
94402

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California will not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Julie Neidich
jneidich@akeakamai.net
92694

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I strongly oppose the proposed amendments to the Low Carbon Fuel Standard (LCFS) concerning fuels made from vegetable oil. LCFS must stop promoting production and consumption of diesel made from vegetable oil that exceeds sustainable sources of waste oils and fats. It is worse than counterproductive for CARB policy to encourage the razing of tropical forests to grow vegetable oil for transportation fuel, as deforestation is a major driver of the climate crisis. The flood of vegetable oil-based diesel in California also undermines the our state's efforts to increase transportation electrification.

Sincerely,

Du Ng
ecrituncourriel-112@yahoo.com
95123

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

G. Orlowski
gigiao@aol.com
92010

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am expressing my concern about the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California not rely on soybean oil-based diesel to reach our ambitious but essential environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation and the resulting loss of carbon sequestration and loss of important wildlife habitat. The flood of vegetable oil-based diesel in California also undermines the impact the LCFS would otherwise have for expanding the electrification of vehicles.

Sincerely,

James Peugh
peugh@cox.net
92106

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

Low Carbon Fuel Standard (LCFS). As a California resident, it is critical that California does not rely on soybean oil-based diesel to reach our responsible environmental standards. Diverting vegetable oil from food to fuel poses environmental harm through tropical deforestation. Vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Margaret Phanes
maphanes@gmail.com
95242

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

In regard to the Low Carbon Fuel Standard (LCFS), as a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Cynthia Piontkowski
cynpiontko@yahoo.com
94116

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

My wife and I are commenting on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California residents, we believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Using vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Andrew Pohorsky
tompoho@gmail.com
95073

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I write to express my deep concern about and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Mary Proteau
proteaum@aol.com
90036

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

Hello, I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. It's important that we transition from oil and use more renewable energy sources, so we can put this dirty energy behind us please do the responsible thing and get us back on track to the renewable energy commitment.

Sincerely,

Isaac Ramirez
isaac2022rr@gmail.com
94587

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

TO: California Air Resources Board As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the Low Carbon Fuel Standards (LCFS) provides for transportation electrification. I urge the California Air Resources Board to ensure that changes to the LCFS place a cap on vegetable oil-based fuels and reflect our commitment to a sustainable future. Thank you for considering my views on this crucial matter. Sincerely, Christine Ramsay

Sincerely,

Christine Ramsay
cramsaymo@gmail.com
90266

Union of Concerned Scientists

Headquarters	Washington, DC	West Coast	Midwest
Two Brattle Square, 6th Floor	1825 K St. NW, Suite 800	500 12th St., Suite 340	200 E. Randolph St., Suite 5151
Cambridge, MA 02138	Washington, DC 20006	Oakland, CA 94607	Chicago, IL 60601
617-547-5552	202-223-6133	510-843-1872	312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I have been trying to educate myself about the way the Low Carbon Fuel Standard (LCFS) works in California and I am troubled by some of what I have learned. Iam writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard. As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Andrew Reich
andrewlreich@gmail.com
90004

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am deeply concerned with the Low Carbon Fuel Standard (LCFS) set by CARB. Biofuels as a clean energy alternative is a myth. The CO2 emissions from planting, fertilizing, harvesting, shipping and processing biofuels are far greater than the slight decrease in the emissions from burning. Your support of biofuels stands in the way of electrification, which is the only true path to zero emissions in the transportation sector. And with the subsidies you're offering to oil refineries, you're simply helping keep them in business. Furthermore, you're supporting U.S. farmers' shift from grow food crops to growing biofuel feedstocks. It's time to rethink the LCFS and stop the proliferation of biofuels in California.

Sincerely,

Dave Rhody
dave@rhodyco.com
94122

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I was born and raised in the Bay Area, and I'm very concerned about the LCSF standard and the other impacts and implications of biodiesel. I am writing to express my concern and to provide input on the proposed amendments to the LCFS. As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. There are also additional transportation emissions and land-use concerns. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Matt Richardson
richardson034@gmail.com
94123

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. In particular, please consider: 1) the economic interaction of the California regulations with federal regulations, to avoid devaluing federal regulations, and 2) the substitution of palm oil in the food supply, with all of its environmental harms, to replace soybean oil redirected to biofuel production for California.

Sincerely,

Bruce Richman
brich@alumni.caltech.edu
94087

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. God Loves You I Love You let's keep the Faith.

Sincerely,

Lewis Emmanuel Ruiz
ruiz.louis.manuel@gmail.com
95062

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am concerned and want to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Kathy Sabatini
ksabatin53@yahoo.com
95628

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

The letter below expresses my interest in this matter. ... I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Sandra Safran
SANDRASAFRAN@MAC.COM
95946

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am concerned. As a California resident, I know it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Louise Schwartz
alpschw1515@gmail.com
90077

Union of Concerned Scientists

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. My name is Alan Solomon. I live in southern California. I completely Agree with and strongly Support the above statement/petition Today and for many years and generations to come. Thank you for your time Today. Alan Solomon

Sincerely,

Alan Solomon
asolomon777@gmail.com
92260

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

West Coast
500 12th St., Suite 340
Oakland, CA 94607
510-843-1872

Midwest
200 E. Randolph St., Suite 5151
Chicago, IL 60601
312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I write to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Jane Sutton
jgsutton@gmail.com
92121

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I'M CONCERNED ABOUT THE proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident & TAXPAYER, I KNOW it is MORE THAN CRITICAL that California does NOT RELY IN soybean oil-based diesel to reach OUR responsible ENVIRONMENTAL STANDARDS. Diverting vegetable oil from food to fuel IS A SIGNIFICANT HARM VIA tropical deforestation. The DISGUSTING FLOOD of vegetable oil-based diesel in California ALSO UNDERMINES THE SUPPORT the LCFS provides for transportation electrification.

Sincerely,

Deborah Temple
deborahtemple@rocketmail.com
94901

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
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Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I was born and still live in California, and I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Olivia Teter
oliviateter@yahoo.com
94116

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

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1825 K St. NW, Suite 800
Washington, DC 20006
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Sincerely,

Barbara Warner
Bwarner2@cox.net
91977

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
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To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification. Plus food insecurity is already a big problem.

Sincerely,

bruce Waterman
vagary@att.net
94609

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

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510-843-1872

Midwest
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Chicago, IL 60601
312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a resident of Contra Costa County, which has recently approved two massive refinery conversions to biofuel production primarily utilizing soy oil, I am counting on you to reform the Standard that set Contra Costa County on that dangerous course in the first place. I believe it is critical that California not rely on soybean oil-based diesel to reach our ambitious environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Shoshana Wechsler
swechs@pacbell.net
94708

Union of Concerned Scientists

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

West Coast
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Oakland, CA 94607
510-843-1872

Midwest
200 E. Randolph St., Suite 5151
Chicago, IL 60601
312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

I am writing to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe California mustn't rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Joseph White
ranger352@yahoo.com
95614

Headquarters
Two Brattle Square, 6th Floor
Cambridge, MA 02138
617-547-5552

Washington, DC
1825 K St. NW, Suite 800
Washington, DC 20006
202-223-6133

West Coast
500 12th St., Suite 340
Oakland, CA 94607
510-843-1872

Midwest
200 E. Randolph St., Suite 5151
Chicago, IL 60601
312-578-1750

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

To: California Air Resources Board

We KNOW it is the mining, transport, and burning of fossil fuels that drive the climate crisis, and yet our Congress is mired in petty politics! I write to express my concern and to provide input on the proposed amendments to the Low Carbon Fuel Standard (LCFS). As a California resident, I believe it is critical that California does not rely on soybean oil-based diesel to reach our ambitious yet responsible environmental standards. Diverting vegetable oil from food to fuel poses significant environmental harm through tropical deforestation. The flood of vegetable oil-based diesel in California also undermines the support the LCFS provides for transportation electrification.

Sincerely,

Charlene Woodcock
charlene@woodynet.net
94709

Comment Log Display

Here is the comment you selected to display.

Comment 217 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Molly
Last Name	Armus
Email Address	marmus@foe.org
Affiliation	Friends of the Earth U.S.
Subject	FOE Comment - Proposed Low Carbon Fuel Standard Amendments
Comment	Please find attached a comment on behalf of Friends of the Earth U.S. and our members and supporters on the proposed Low Carbon Fue Standard amendments. Thank you for your consideration.
Attachment	www.arb.ca.gov/lists/com-attach/6880-lcfs2024-VDJUPVUxB3lWMwdo.pdf
Original File Name	FOE-Comment-CARB_LCFS_FINAL.pdf
Date and Time Comment Was Submitted	2024-02-20 12:47:19

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Friends of the Earth

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Comments in Response to the California Air Resources Board Rulemaking to Amend the Low Carbon Fuel Standard

Friends of the Earth U.S. (FOE), on behalf of our 120,000 members and supporters in California, welcomes this opportunity to provide comments in response to the California Air Resources Board's (CARB) rulemaking to amend the Low Carbon Fuel Standard (LCFS). We echo the calls of California-based organizations and individuals living near industrial dairy operations in California to reform the LCFS and immediately address the egregious environmental injustices in the program.

LCFS is driving the demand for manure biogas — or "factory farm gas" — by allowing concentrated animal feeding operations (CAFOs), or factory farms, to generate credits from installing and operating anaerobic digesters that can be sold to companies to pay for their pollution. It creates a perverse incentive for CAFO operators to generate as much methane — and therefore as much manure — as possible to capitalize on these hefty subsidies the program provides. As a result, the LCFS is exacerbating existing pollution and failing to mitigate animal agriculture's climate impacts by driving the growth of both factory farms and factory farm gas production across the United States.

To achieve California's environmental, public health, climate, and environmental justice objectives,
208.1 CARB must cease the incentives for factory farm gas and stop paying these industrial polluters to capture methane emissions in a dangerous, ineffective approach to address the climate crisis.

Industrial Animal Agriculture's Environmental & Health Impacts on Communities

Industrial animal agriculture operations are a major polluter of the rural communities in which they are located, which are disproportionately communities of color and low-wealth communities such as California's San Joaquin Valley.[1] Today's industrial-scale farms, housing thousands — or sometimes hundreds of thousands — of animals, generate as much as 1 billion tons of manure per year, which contaminates air, drinking water, and surface waters, directly impacting the health of the surrounding communities.[2]

Manure from industrial dairy and hog operations, the main beneficiaries of LCFS' incentives, is typically stored as liquid in giant manure lagoons and periodically applied to spray fields and contains

[1] Arbor J.L. Quist et al., *Disparities of industrial animal operations in California, Iowa, and North Carolina*, https://earthjustice.org/wp-content/uploads/quistreport_cafopetition_oct2022.pdf.
[2] U.S. Env't Prot. Agency, *Detecting and mitigating the environmental impact of fecal pathogens originating from confined animal feeding operations: Review* (Jan. 2005), https://nepis.epa.gov/Exe/ZyPDF.cgi/P10089B1.PDF?Dockey=P10089B1.PDF.

1100 15th Street, NW · 11th Floor · Washington, DC 20005
202.783.7400 · 202.783.0444 fax · 877.843.8687 toll free · www.foe.org
2150 Allston Way, Suite 240 · Berkeley, CA 94704
510-900-3150 · 510-900-3155 fax · 866.217.8499 toll free

pathogens, antibiotic-resistant bacteria, and heavy metals.[3] The sprayed, untreated waste can contaminate the soil and run off into waterways, causing harmful downstream effects.[4] The manure also emits hazardous gases and particulate matter, causing toxic air emissions and noxious odor.[5] Studies have shown that people living near factory farms face higher risk and severity of respiratory illnesses, digestive issues, headaches, and other serious health conditions.[6]

As mentioned above, these negative impacts disproportionately affect low-income communities and communities of color because of where CAFOs operate. One study found that of the 15,900 deaths from food production in the U.S., 80 percent, or 12,700 deaths, are attributable to industrial animal production, and the majority of deaths — 12,400 deaths each year — are attributable to ammonia acting as a PM2.5 precursor.[7] Environmental justice communities face a so-called "triple jeopardy" where their proximity to sources of air pollution, disproportionate disease burdens, and psychosocial stressors compound to diminish their quality of life.[8]

In addition to being a major polluter of rural communities, animal agriculture is the top source of U.S. climate changing methane emissions, accounting for 36% of total U.S. methane emissions.[9] Climate change also disproportionately affects communities of color, low-income communities, and other vulnerable populations, which are more likely to live in isolated rural areas, floodplains, coastlines, and other at-risk locations, putting them at risk of exposure to adverse climate change impacts and compounding the harm inflicted by factory farm pollution.[10]

Ultimately, the state of California should be doing so much more to protect these long-suffering communities from both industrial pollution and climate change. The very least it could do is stop rewarding the perpetrators.

Factory Farm Gas Production Fails to Address Environmental and Health Impacts on Communities and Creates New Problems

Not only does producing factory farm gas fail to address the aforementioned public health and safety concerns of communities, producing factory farm gas also generates additional environmental, public

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[3] *See,* Daniel Hellerstein et al., *Agricultural Resources and Environmental Indicators, 2019*, U.S. Dep't of Ag. Econ. Research Serv. (May 2019), https://www.ers.usda.gov/webdocs/publications/93026/eib-208.pdf; V. Blanes-Vidal, et al., *Residential Exposure to Outdoor Air Pollution From Livestock Operations & Perceived Annoyance Among Citizens,* 40 Env't Int'l 44 (2012) (exposure to animal waste odor is "a significant degradation in [rural residents'] quality of life").

[4] Rolf U. Halden & Kellogg J. Schwab, The Pew Comm'n on Industrial Farm Animal Production, *Environmental Impact of Industrial Farm Animal Production* (2008), https://law.lclark.edu/live/files/6699-environmental-impact-of-industrial-farm-animal. Carrie Hribar, Nat'l Ass'n of Local Bds. of Health, *Understanding Concentrated Animal Feeding Operations and Their Impact on Communities* 2-3 (2010), https://www.cdc.gov/nceh/ehs/docs/understanding_cafos_nalboh.pdf.

[5] J.Y. Son et al., *supra* note 1.

[6] *Id.*

[7] Nina Domingo et al., *Air Quality-Related Health Damages of Food*, 118 PNAS 1, 2 (2021), https://www.pnas.org/content/pnas/118/20/e2013637118.full.pdf.

[8] Fiona Ward et al., *Engaging communities in addressing air quality: a scoping review,* 21 Env't Health 1 (2022), https://doi.org/10.1186/s12940-022-00896-2.

[9] Quirin Schiermeier, *Eat less meat: UN climate-changes report calls for change to human diet*, Nature (Aug. 12, 2019), https://www.nature.com/articles/d41586-019-02409-7.

[10] *See,* U.S. Global Change Research Program, *Impacts of Climate Change on Human Health in the United States* 249 (2016), https://health2016.globalchange.gov/low/ClimateHealth2016_FullReport_small.pdf; California's Fourth Climate Change Assessment: Climate Justice Summary Report 36-48 (2018), https://health2016.globalchange.gov/low/ClimateHealth2016_FullReport_small.pdf.

health, and safety concerns for communities living near CAFOs and biogas plants. These include increased production of ammonia pollution from anaerobic digestion,[11] higher concentrations of nutrients digestate that contribute to water pollution,[12] increased disruption and pollution from new pipelines and trucks to transport manure or biogas through communities, and more toxic air pollution from biogas processing than is produced by fossil gas.[13]

For example, as petitioners point out in their *Petition for Rulemaking to Exclude all Fuels Derived from Biomethane from Dairy and Swine Manure from the Low Carbon Fuel Standard*, the Lakeview Dairy Biogas project in Kern County, California, uses two internal combustion engines to produce over 1,000 kW of electricity on-site.[14] Even with the required pollution control technology, this project emits 4.58 tons/year of NOx, 1.98 tons/year of PM10 (fine particulate matter), and 3.18 tons/year of VOC.[15] Compared to a natural gas combined cycle plant in a nearby town, the Lakeview digester project produces much higher levels of NOx, SOx, and VOC emissions per unit of electricity generated.[16] Meanwhile, communities in California's San Joaquin Valley, which are disproportionately Latino and low-income, already suffer some of the worst air and water quality in the country due in large part to the concentration of dairy factory farms. The California Air Resources Board acknowledges that 1,200 residents of the San Joaquin Valley die prematurely each year from PM2.5 pollution alone.[17] Producing and combusting manure biogas onsite leads to even worse air quality, exacerbating public health harms and environmental injustice.

The Low Carbon Fuel Standard is Flawed

The LCFS incorrectly assigns factory farm gas an extremely large negative Carbon Intensity (CI) score, one even better than electric vehicles powered by renewable electricity, and as result, it generates a large subsidy for the CAFOs and biogas operators.[18] This is because CARB gives participating CAFOs credit for both reducing methane emissions from manure under the assumption

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[11] *See,* Michael A. Holly et al., *Greenhouse Gas and Ammonia Emissions from Digested and Separated Dairy Manure during Storage and after Land Application*, 239 Agric., Ecosystems & Env't (2017), https://doi.org/10.1016/j.agee.2017.02.007; Thomas Kupper et al., *Ammonia and Greenhouse Gas Emissions from Slurry Storage – A Review*, 300 Agric., Ecosystems & Env't (2020), https://doi.org/10.1016/j.agee.2020.106963; Lowry A. Harper et al., *The Effect of Biofuel Production on Swine Farm Methane and Ammonia Emissions*, 39 J. Env't Quality (2010), https://doi.org/10.2134/jeq2010.0172.

[12] Katarzyna Chojnacka & Konstantinos Moustakas, *Anaerobic digestate management for carbon neutrality and fertilizer use: A review of current practices and future opportunities*, 180 Biomass and Bioenergy (2024), https://doi.org/10.1016/j.biombioe.2023.106991.

[13] Alarico Macor & Alberto Benato, *A Human Health Toxicity Assessment of Biogas Engines Regulated and Unregulated Emissions*, 10 Applied Sciences (2020), https://doi.org/10.3390/app10207048.

[14] Ass'n of Irritated Residents et al., *Petition for Rulemaking to Exclude All Fuels Derived from Biomethane from Dairy and Swine Manure from the Low Carbon Fuel Standard Program*, (Oct. 27, 2021), https://ww2.arb.ca.gov/sites/default/files/2022-01/2021.10.27%20Petition%20for%20Rulemaking%20AIR%20et%20al_.pdf.

[15] San Joaquin Valley Air Pollution Control District, Notice of Preliminary Decision – Authority to Construct (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf at 14.

[16] *Id.*

[17] Press Release, Cal. Air Resources Bd., Clean-Air Plan for San Joaquin Valley First to Meet All Federal Standards for Fine Particle Pollution (Jan. 24, 2019), https://ww2.arb.ca.gov/news/clean-air-plan-san-joaquin-valley-first-meet-all-federal-standards-fine-particle-pollution.

[18] Kiki Velez, *CARB Must Reform LCFS Program to Meet Climate Goals*, NRDC (Aug. 23, 2023), https://www.nrdc.org/bio/kiki-velez/carb-must-reform-lcfs-program-meet-climate-goals-0; Aaron Smith, *What's Worth More: A Cow's Milk or its Poop?*, AG Data News (Feb. 3, 2021), https://asmith.ucdavis.edu/news/cow-power-rising.

that wet, methane-generating manure is an unavoidable byproduct of livestock production, and for replacing fossil fuels with higher CI scores.[19]

208.2 This is flawed for a number of reasons. First, CARB completely disregards the greenhouse gas emissions from the underlying factory farming operations as well as the increased greenhouse gas emissions when operators use and dispose of the digester waste. Second, maintaining massive
208.3 quantities of liquid manure is not a given; it is a choice — one that the LCFS rewards and reinforces.
208.4 There are alternative manure management practices that have lower methane-emissions and are more sustainable.[20] Finally, the LCFS does not prohibit participants in the program from double-counting
208.5 the emissions reductions attributable to anaerobic digesters, with the same purported emissions reductions being counted toward multiple programs, inflating climate progress. Research has shown that the LCFS takes credit for the same emissions reductions as California's state-funded Dairy Digester Research and Development Program.[21]

The LCFS Creates Perverse Incentives

Due to factory farm gas' flawed CI score, the LCFS distorts the market for transportation fuels, boosting fuels derived from manure above truly renewable sources. Perversely, CAFO operators and energy companies are incentivized to produce more manure biogas, in the most methane-emission heavy manner, to receive the lucrative rewards from the false market that has been created. This is done either by consolidating farms, creating an even more unfair playing field for producers, by increasing herd sizes (and the pollution, public health risks, and animal cruelty that comes with expanding CAFOs), or by utilizing the worst (most methane-generating) manure management strategies.

These perverse incentives exacerbate extensive environmental and public health impacts frontline communities are already enduring from CAFOs and undermines the methane-reducing potential of anaerobic digesters.

Reform the LCFS Immediately

Failing to reform the LCFS will entrench our current, inherently unsustainable systems of industrial animal agriculture and fossil fuel energy. Without a change, industrial polluters will continue to reap lucrative benefits at the expense of frontline communities' health and safety, perpetuating the environmental injustice California seeks to address. As such, CARB should prioritize the following changes to the program:

208.1 1. Eliminate "avoided methane crediting" in 2024.
208.2 2. Fix the inaccurate Life Cycle Assessment that ignores upstream and downstream greenhouse gas emissions associated with factory farm gas production.
208.6 3. Eliminate the 10-year "grace period" for factory farm gas producers.
208.5 4. Eliminate credit generation from factory farm gas projects that would have happened anyway due to other programs or investments.

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[19] *Id.*

[20] It's worth noting that an even more effective approach to mitigating animal agriculture's impact on the climate is for methane emissions from industrial livestock facilities to be monitored, publicly disclosed, and regulated by the state.

[21] Phil McKenna, *Is California Overstating the Climate Benefit of Dairy Manure Methane Digesters?*, Inside Climate News (Dec. 30, 2023), https://insideclimatenews.org/news/30122023/milkingit-california-overstating-climate-benefit-dairy-manure-methane-digesters; Gabriel Petek, Legislative Analyst's Office, *Assessing California's Climate Policies—Agriculture* (Dec. 2021), https://lao.ca.gov/Publications/Report/4483.

We encourage CARB to change course and prioritize the well-being of Californians over industrial polluters and reform LCFS immediately. Thank you for your consideration.

Sincerely,

Molly Armus
Animal Agriculture Policy Program Manager
Friends of the Earth U.S.

Comment Log Display

Here is the comment you selected to display.

Comment 218 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jesse
Last Name	Holman
Email Address	senergyoilag@gmail.com
Affiliation	Senergy, LLC

Subject	Supplemental to Consider Innovative Production Method Lowers CI >60%

Comment

209.1

Please find a supplemental to a previous added comment #24, postec
2024-02-06 12:36:37, where we kindly request consideration of adding to CCR Section 95489(c)(1)(A), Chemistry Replace Steam, as an innovative
production method. This will incentive crude producers to stop using steam to extract heavy oil, reducing emissions in California's most disadvantaged communities while reducing overal fossil fuel demand.

Thank you, Jesse

Attachment	www.arb.ca.gov/lists/com-attach/6881-lcfs2024-WjkGYVUmV2ZXMgRs.pdf
Original File Name	CARBchemistrySupplement.pdf

Date and Time Comment Was Submitted	2024-02-20 12:45:00

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

SUPPLEMENT TO APPLICATION TO THE EXECUTIVE OFFICER

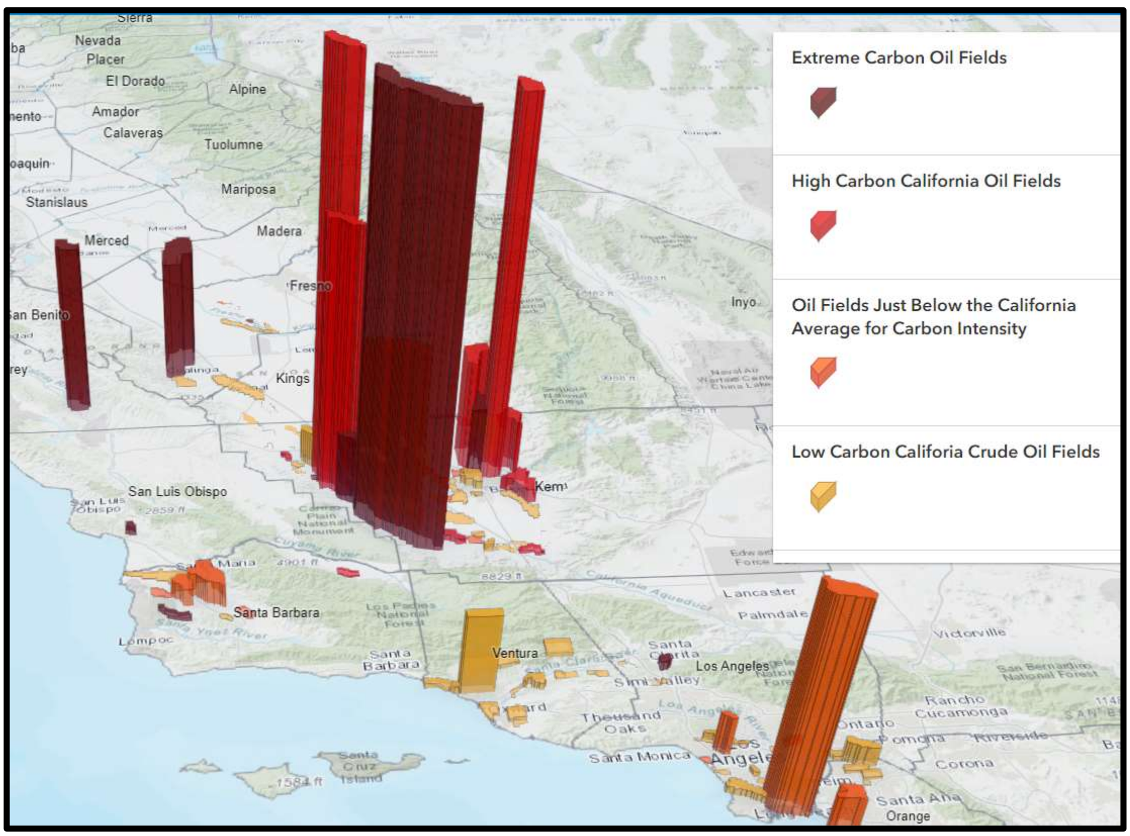
FOR LCFS CREDITS FOR USING INNOVATIVE METHODS FOR CRUDE

PRODUCTION OR TO AMEND §95849(c)(1)(A)

CYCLIC STEAM REPLACEMENT

CLEAN SURFACTANT ENERGY (CRSE) PROJECT

RENEWABLE AND BIODEGRADABLE SURFACTANT



Thermal Heavy Oil Fields, Kern County California

SUPPLEMENT TO APPLICATION TO THE EXECUTIVE OFFICER

FOR LCFS CREDITS FOR USING INNOVATIVE METHODS FOR CRUDE PRODUCTION OR TO AMEND §95849(c)(1)(A)

CYCLIC STEAM REPLACEMENT

CLEAN SURFACTANT ENERGY (CRSE) PROJECT

RENEWABLE AND BIODEGRADABLE SURFACTANT

Recognizing that CARB's world leading LCFS is designed to decrease the carbon intensity of California's transportation fuel pool, Senergy submitted its application for approval of credits for CRSE, an innovation that uses renewable chemistry to eliminate steam in production of crude oil. Senergy's application gives focus to the operational advantages of the innovation. This supplement describes externalities that merit attention in Staff's evaluation.

1. CRSE advances social justice in impacted communities in California.

Where oil is produced in California, the most impacted and least protected communities are near its source and bear the brunt of GHG emissions. Reducing that impact is the priority of CARB. CRSE immediately facilitates significant progress toward that equity goal.

2. CRSE brings economic advantages to disadvantaged communities.

Enabling production of clean oil provides increased local employment in communities that are presently under economic pressure. In turn, CRSE multiplies economic opportunity for local businesses. The CRSE innovation will redress long-standing inequities for communities which are otherwise disadvantaged by the loss of well-paying jobs.

3. CRSE enables decarbonizing around the clock.

Current accredited innovations that reduce emissions from steam do so only during daylight hours, in favorable weather. CRSE, by contrast, enables GHG reduction from the point source of oil production 24/7/365—without land use changes. This is a concrete example of how new technology is better than old technology.

4. CRSE ensures buy-in from the dirtiest industry in the state.

Forcing emission abatement on the oil industry has met with some resistance from recalcitrant operators, and too little active participation even by the most enlightened companies. Burning natural gas to generate steam remains economically attractive. The proposed credit will alter the calculation and incentivize adoption of the CRSE innovation.

CRSE abates emissions and maintains efficient production, eliminating any excuse to delay decarbonizing efforts. By accelerating the production of existing oil supplies, CRSE abbreviates oil production in California, *and* cleans up the fuel pool to advance the energy transition.

5. CRSE eliminates dirty oil in California.

As long as oil is produced in California, CARB should favor production of the *cleanest possible oil*. Awarding credits to companies that adopt efficient abatement measures incentivizes decarbonization. The marketplace will nudge every oil producer in the right direction. Even the most truculent oil producer can appreciate the cost-benefit analysis that will mandate implementation of this innovation.

6. Granting the CRSE application encourages further innovation.

By allowing credits for carbon abatement, CARB acts as a clearing house for the best and brightest advancements in abated emissions in oil production. The potential exists for upstream advancements like CRSE to encourage additional decarbonizing throughout the transportation fuel chain.

CONCLUSION

Senergy wants to express gratitude for everything CARB does to make California a better place to live and work. We remain ready to answer your tough questions about our product and process.

RESPECTFULLY SUBMITTED,

____

Jesse Holman, President, and CEO

Comment Log Display

Here is the comment you selected to display.

Comment 219 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Scott
Last Name	Hochberg
Email Address	shochberg@biologicaldiversity.org
Affiliation	Center for Biological Diversity
Subject	Comment from Center for Biological Diversity

Comment

```
Hello,

Please find attached comments on behalf of the Center for
Biological Diversity. Copies of the references cited in the commer
are available for download at the following link:
https://diversity.box.com/s/8jcli9f2vwyof9cbq1qx5sna1m0d0hsb

Thank you and please reach out if you have any questions.
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February 20, 2024

Chair Liane Randolph and
Members of the Board
California Air Resources Board
1001 I St.
Sacramento, CA 95814

RE: Proposed Low Carbon Fuel Standard Amendments

Dear Chair Randolph and Members of the Board:

The Center for Biological Diversity appreciates the opportunity to comment on CARB's proposed amendments to the Low Carbon Fuel Standard ("LCFS"). There are serious issues with the current iteration of the LCFS: it is misaligned with the California's electrification goals, worsens environmental injustices, and permits a credit excess from biofuels and other "false solutions" that undercuts the credit price. We offer several concerns and suggestions to improve the program in order to better address the state's climate goals and avoid reliance on false solutions that accelerate the climate crisis.

I. CARB Should Use the Time Until the Final Vote to Incorporate Feedback from the Board and the Public.

We appreciate that the Board recently delayed a final vote on the LCFS, given the volume of comments the Board has received. While we are generally skeptical of industry-led attempts to delay implementation of life-saving rules that the Board has adopted in recent years, there were good reasons to delay a vote on this particular proposal. The Board now has time to analyze and incorporate the changes requested in this comment letter, as well as the changes recommended by the Environmental Justice Advisory Committee ("EJAC"), many of which are not reflected in the current proposal.

The LCFS has been trending in the wrong direction in recent months. The current proposal
backtracks in important ways from what staff had outlined in September. For example, the new
210.1 proposal backslides on the previously announced avoided methane policy, allows retroactive
210.2 crediting for pathways that favor non-zero-emission fuels, and adds (inadequate) safeguards on
210.3 crop-based feedstocks. The Board now has time to consider the changes proposed here before the LCFS is finalized. It should use the coming months to revisit some of the fundamental assumptions currently baked into the program, which could have a tremendous impact on whether the program will help meet the state's climate goals.

II. Carbon Capture and Storage Threatens to Derail Climate Goals and CARB Must Respond Accordingly.

210.4

a. CARB must end LCFS credits to out-of-state projects conducting EOR associated with CCS.

CARB must remove its provision allowing credits to projects outside of California that produce oil using captured carbon dioxide ("CO_2"). This provision is at odds with California law. Closing this loophole would not only align with California law, but also reduce opportunities for fossil fuel production, and align with an EJAC recommendation.

In September 2022, Governor Newsom signed Senate Bill 905 (SB 905) into law.[1] Among other provisions, SB 905 prohibits operators in California from utilizing CO_2 from CCS operations in enhanced oil recovery ("EOR").[2]

It's easy to see why the legislature listened to communities in California and banned EOR associated with CCS. EOR involves the injection of fluids and/or gases (such as CO_2) underground to extract fossil fuels.[3] EOR threatens drinking water integrity, yet regulations on EOR activities are decades old and fall short of providing sufficient safeguards for groundwater.[4] In addition, all forms of EOR have some risk of blowouts that can result in leakage and/or surfacing of fossil fuels or injection fluids.[5] And throughout the EOR lifecycle—from construction to injection, production, and waste disposal—there are risks to the environment and communities from air, water, and noise pollution.[6] Adding to this is the contribution to climate change caused by extracting and using more fossil fuels via EOR. One study found that for each ton of CO_2 injected for EOR, 2.7 tons of CO_2 are eventually emitted from burning recovered oil.[7]

Yet while California decidedly took a stand against CCS-associated EOR within the State, CARB's LCFS door remains open to incentivizing this same harmful practice *outside* the State's borders. Under the LCFS CCS Protocol, applicable CCS projects are those "that capture carbon dioxide (CO_2) and sequester it onshore, in either saline or depleted oil and gas reservoirs, *or oil*

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[1] SB 905 (Caballero, 2022), https://leginfo.legislature.ca.gov/faces/billStatusClient.xhtml?bill_id=202120220SB905.
[2] *Id.* at Section 4(b), to be codified in Cal. Pub. Res. § 3132(b); *see also* Senate Bill 1314 (Limón, 2022) (also signed into law and prohibiting EOR using CO_2 derived from CCS operations).
[3] Clean Water Action, The Environmental Risks and Oversight of Enhanced Oil Recovery in the United States at 5 (Aug. 2017), https://www.cleanwater.org/sites/default/files/docs/publications/The%20Environmental%20Risks%20and%20Oversight%20of%20Enhanced%20Oil%20Recovery%20in%20the%20United%20States.pdf.
[4] *Id.*
[5] *Id.* at 13.
[6] *Id.* at 12.
[7] *Id.* at 23, *citing* Banks, Brian et al., *SaskPower's Carbon Capture Project – What Risks? What Rewards?*, Canadian Center for Policy Alternatives at 16-17 (2015) (noting that this calculation "does not even account for carbon dioxide losses in the course of the injection process: a substantial proportion returns to the surface with the oil.").

and gas reservoirs used for CO_2-enhanced oil recovery (CO_2- EOR).[8] Thus, non-California regulated entities conducting EOR will be compensated by CARB for causing environmental and community health damage elsewhere. This asymmetry is simply wrong and must be corrected by removal of CCS-related EOR from the LCFS.

Closing the out-of-state EOR loophole aligns with the EJAC's recommendation that CARB has yet to address in the LCFS revisions. The EJAC specifically directed CARB staff to "Prohibit enhanced oil recovery as an eligible sequestration method."[9]

The following are possible changes to remove CCS-related EOR:

A. Remove the bolded language below from the LCFS CCS Protocol:
   - The CCS Protocol applies to projects "that capture carbon dioxide (CO_2) and sequester it onshore, in either saline or depleted oil and gas reservoirs, **or oil and gas reservoirs used for CO_2-enhanced oil recovery (CO_2- EOR)."**

B. Update the following regulations:
   - In 17 Cal. Code Regs. section 95490(a)(1) (stating that eligible entities include "Alternative fuel producers, refineries, and oil and gas producers that capture CO_2 on-site and geologically sequester CO_2 either on-site or off-site"), make clear that, to be eligible, capture and sequestration of CO_2 does not include EOR.
   - In 17 Cal. Code Regs. section 95490(a)(2) (stating that "If CO_2 derived from direct air capture is converted to fuels, it is not eligible for project-based CCS credits. However, applicants may apply for fuel pathway certification using the Tier 2 pathway application process as described in section 95488.7."), make clear that CO_2 derived from direct air capture may not be used for EOR.

210.5 **b. CARB must not encourage continued and/or prolonged use of fossil fuels through its petroleum-plus-CCS phase-out loophole.**

CARB is seeking to "encourage existing petroleum facilities to deploy"[10] technologies like CCS and in doing so, to allow these fossil fuel projects to continue to generate credits beyond the phase-out date of December 31, 2040.[11] This amendment creates a dangerous loophole that relies on a so-called climate solution that is anything but; the result will be California incentivizing and perpetuating the climate catastrophe and the health and environmental harms that come with it.

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[8] CARB LCFS CCS Protocol at 7 (Aug. 13, 2018) (emphasis added). CCS projects are eligible for LCFS participation under the Tier 2 pathway. *See* 17 Cal. Code Regs. § 95488.1(d)(7)(B).
[9] EJAC, Recommendations to the California Air Resources Board (CARB) on the Low Carbon Fuel Standard Regulation Updates (version August 28, 2023), https://www.arb.ca.gov/lists/com-attach/1-lcfs2024-VjMFaQNjUGABWFA0.pdf.
[10] LCFS Proposed Amendments, Appendix E at page 88, Y.8, rationale for proposed §§ 95489(c)(1)(A)2 and 95489(e)(1)(D)1.
[11] LCFS Proposed Amendments, Appendix E at page 93, X.19, proposed for §§ 95489(c)(5), 95489(d)(5)(C), 95489(e)(5)(B), and 95489(f)(5)(B).

Encouraging fossil fuels and exempting their use from phase-out is reckless and derails California's efforts at climate leadership. The Intergovernmental Panel on Climate Change (IPCC) modeled pathway to the best chance of limiting warming to 1.5°C makes no use of fossil fuels with CCS or bioenergy with CCS and limited to no use of engineered CO_2 removal technologies.[12] CCS projects around the world have failed drastically—and repeatedly—to meet their GHG emission reduction promises.[13] For example, in July 2021, Chevron admitted that its self-described "world's biggest CCS project" failed to meet its five-year capture target and was seeking a deal to make up for millions of tons of CO_2 emitted.[14] In another example, the Petra Nova[15] CCS facility which was promised to capture 90 percent of the power plant's total CO_2 emissions only captured 7 percent.[16] Providing a phase-out exemption for fossil fuel projects in California invites failed and under-delivering polluting facilities to continue to pollute communities and the climate, all without any end in sight.

There is also a substantial energy penalty for the use of CCS that reduces any potential climate benefits—especially when that extra energy is sourced from fossil fuels.[17] An energy penalty is defined as the extra energy required to run a capture process or the amount of energy spent when compared to the energy generated.[18] The energy penalty of CCS increases the fuel requirement for electricity generation by 11-40%.[19] Thus, the installation of CCS and its concomitant energy penalty drives even more pollution, which is currently unaccounted for in CARB's Scoping Plan and, seemingly, in the proposed phase-out exemption.

[12] The IPCC-modeled pathway with the best chance of keeping warming at or below the target of 1.5°C makes no use of fossil fuels with CCS. IPCC, Summary for Policymakers in Global Warming of 1.5°C (2018) at 14, Section C.1.1., Figure SPM 3b (Pathway 1); *see also* IPCC SR1.5, at Ch. 2.3.3 and Table 2.SM.12.

[13] Institute for Energy Economics and Financial Analysis (IEEFA), *The Carbon Capture Crux: Lessons Learned* (Sept. 2022), https://ieefa.org/resources/carbon-capture-crux-lessons-learned.

[14] Bruce Robertson & Milad Mousavian, *If Chevron, Exxon and Shell Can't Get Gorgon's Carbon Capture and Storage to Work, Who Can?* IEEFA (April 26, 2022), https://ieefa.org/articles/if-chevron-exxon-and-shell-cant-get-gorgons-carbon-capture-and-storage-work-who-can.

[15] Petra Nova was shut down in 2020 due to plunging oil prices but will soon restore operations. Kevin Crowley, *The World's Largest Carbon Capture Plant Gets a Second Chance in Texas*, Bloomberg (Feb. 8, 2023), https://www.bloomberg.com/news/articles/2023-02-08/the-world-s-largest-carbon-capture-plant-gets-a-second-chance-in-texas#xj4y7vzkg.

[16] Ctr. for Int'l Envtl. L., *Confronting the Myth of Carbon-Free Fossil Fuels: Why Carbon Capture Is Not a Climate Solution*, 8 (2021), https://www.ciel.org/wp-content/uploads/2021/07/Confronting-the-Myth-of-Carbon-Free-Fossil-Fuels.pdf at 2.

[17] *See* Mark Z. Jacobson, *The Health and Climate Impacts of Carbon Capture and Direct Air Capture*, 12 Energy & Environmental Science (2019), https://pubs.rsc.org/en/content/articlelanding/2019/ee/c9ee02709b#!divAbstract.

[18] *Id*.

[19] *See* Kurt House, et. al., *The Energy Penalty of Post-Combustion CO_2 Capture & Storage and its Implications for Retrofitting the U.S. Installed Base*, Energy & Envtl. Sci. (Jan. 22, 2009), https://dash.harvard.edu/bitstream/handle/1/12374812/1239214136-mja188.pdf.

210.6 **c. Hydrogen using fossil fuels plus CCS must not be eligible for reducing the CI score or LCFS credits generally.**

As explained later in this comment, the only form of hydrogen that should be considered under any provision in the LCFS is "green hydrogen," or hydrogen made by splitting water into hydrogen and oxygen using 100% solar or wind energy, while adhering to the three pillars. Instead, CARB staff are proposing to allow "hydrogen as an intermediate input to alternative or petroleum fuel production is eligible for reducing the GHG emissions associated with fuel production if hydrogen production is equipped with" CCS.[20]

As reiterated throughout this comment letter, CARB should not be incentivizing and prolonging the use of fossil fuels *in any manner*. This includes fossil fuels plus CCS. Facilities using CCS do *not* capture 100% of their climate-harming emissions, they incur a high energy penalty (meaning more energy use and emissions), and fossil fuel production is rife with environmental and health harms. Phasing out fossil fuels should be a fundamental tenant of any climate-focused policy, but CARB insists on carving out ways for fossil fuels to continue, such as this hydrogen allowance. These carve outs must end.

210.7 **d. CARB must ensure capture-to-injection tracking of CO_2.**

While we do not support the false climate fix that is CCS, we do support CARB's proposal that "additional entities, such as CO_2 transporters, along the supply chain of a CCS project" register as joint applicants and include "how the captured CO_2 passes through the supply chain among various entities."[21] We agree that "it is crucial for CCS projects to track the CO_2 throughout the supply chain."[22] It is important to avoid double-counting and double credits, both at the LCFS level and to the extent this information can be used to avoid double-counting at the federal level with IRS 45Q tax credits, which is rife with this kind of fraud.[23]

We recommend that CARB staff prohibit applicants from claiming confidential business information (CBI) in their applications so that members of the public have insight into the joint applicants involved in the entirety of a CCS project.

210.8 **III. CARB Should Strictly Limit the Use of Crop-based Biofuels.**

210.3 **a. The proposed sustainability criteria for crop-based biofuels are woefully inadequate.**

The proposed LCFS amendments allow for the continued use and expansion of crop-based (lipid) biofuels despite evidence that they are unsustainable and a danger to environmental and

[20] LCFS Proposed Amendments, Appendix E at page 104, Z.2, proposed for § 95490(a)(2).
[21] LCFS Proposed Amendments, Appendix E at page 107, Z.6, proposed for § 95490(c)(1).
[22] *Id.*
[23] Taxpayers for Common Sense, "45Q Issue Brief – Nearly 90 Percent of Carbon Sequestration Tax Credits Based on Insufficient Reporting and Fraudulent Claims" (Feb. 2023), https://www.taxpayer.net/climate/45q-issue-brief-nearly-90-percent-of-carbon-sequestration-tax-credits-based-on-insufficient-reporting-and-fraudulent-claims/.

public health. The only effort CARB staff propose to address these concerns is to identify and implement a sustainability certification for crop-based biofuels, without defining the criteria that would make a crop-based biofuel viable for use under such a certification. A sustainability requirement that equates to satisfying a certification standard that has yet to be defined is meaningless, and it should not have been proposed without a certification standard already chosen for consideration.

In the absence of CARB-established sustainability criteria, we looked to general definitions of energy sustainability to establish governing principles for biofuels. The result was the following biofuels sustainability criteria: (1) the fuel must be produced using feedstock that is readily available and can be replenished; (2) collecting and processing the feedstock must not cause environmental and social harms; (3) procuring the feedstock must not result in significant land-use change or otherwise hinder land's natural ability to store and sequester carbon; and (4) the lifecycle greenhouse gas emissions from the fuel must be near zero relative to conventional jet fuel.[24] In applying these sustainability criteria, it becomes clear that no crop-based biofuel is sustainable.

210.9 **b. In permitting crop-based biofuels, CARB is allowing climate-damaging emissions.**

Relying on crop-based biofuels results in both direct and indirect land use change emissions that worsen the climate crisis, counter to their intended purpose. For example, in an analysis of 17 potential alternative-fuel pathways looking at different feedstocks, technologies, and world regions, researchers found that using virgin vegetable oil had the highest indirect land-use change emissions because of links to high deforestation and peat oxidation in southeast Asia, driven by palm expansion.[25] Though CARB staff are proposing to remove palm-derived fuels from eligibility under the LCFS, it must be noted that this does not eliminate the threat of CARB's sanctioning of crop-based biofuels leading to palm oil expansion. In the same study, it was found that producing biofuels from any vegetable oil in any region, including corn and soy in the U.S. context, would encourage palm oil expansion and associated peat oxidation in southeast Asia due to substitutions among vegetable oils and international trade.[26] Thus, high indirect land-use change emissions from virgin vegetable oil biofuel pathways undermine some, if not all, of the greenhouse gas savings from these fuels.[27]

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[24] Fleming, J., The Biofuels Myth: Why 'Sustainable Aviation Fuels' Won't Power Climate-Safe Air Travel (August 2022), Center for Biological Diversity, *available at:* https://biologicaldiversity.org/programs/climate_law_institute/pdfs/2022_The_Biofuels_Myth_Center_for_Biological_Diversity.pdf.
[25] Zhao, X. et al., Estimating induced land use change emissions for sustainable aviation biofuel pathways, 779 Science and the Total Environment (2021).
[26] Zhao, X. et al., Estimating induced land use change emissions for sustainable aviation biofuel pathways, 779 Science and the Total Environment (2021).
[27] Pavlenko, N. and Searle, S., Fueling flight: Assessing the sustainability implications of alternative aviation fuels, International Council on Clean Transportation (2021); Zhao, X. et al., Estimating induced land use change emissions for sustainable aviation biofuel pathways, 779 Science and the Total Environment (2021).

CARB staff state that, "[w]ith continued increased demands on biofuel crops the Proposed Amendments could contribute to increased direct and indirect land use change to accommodate new croplands," but go on to minimize this statement by stating that "the likelihood of this is at least partially (and potentially fully) accounted for by the LUC scores added to crop-derived pathways."[28] However, the reality is that the Proposed Amendments likely will yield additional direct and indirect land use change emissions without any guarantee that these emissions will be fully accounted for. So CARB staff are proposing guidance on crop-based biofuels that could lead to unforeseen climate-harming emissions.

210.10 **c. Crop-based biofuels pose a threat to communities and the environment.**

There could also be unforeseen harms to communities and the environment. One such harm is worsening water scarcity. A 2017 study found that increased production of crop-based biofuels heavily contributes to global water scarcity and is not the best option for bioenergy.[29] Meanwhile, a 2016 study found that biofuels rely on about 2-3% of the global water and land used for agriculture. Based on the food calories used for biofuel production, that amount could feed about 30% of the malnourished global population.[30] Just in the United States, about 140 million people could be fed with the resources for bioethanol, and about 10 million people could be fed with the resources for biodiesel, indicating the threat of crop-based biofuels to global food security.[31] Also, with increased production of crop-based biofuels, there is the potential for increased nutrient and pesticide runoff to surface waters and contamination of groundwater due to crop cultivation.[32]

Another harm from crop-based biofuels is the impact to communities from biofuel refining and resulting criteria pollutant emissions. Crop-based biofuels are most often produced using the Hydroprocessed Esters and Fatty Acids (HEFA) pathway, which reacts crop feedstock with hydrogen at high temperatures and pressures to form fuel.[33] Because of the high temperatures and extremely high pressures, runaway increases in temperature are common, which result in operators flaring refinery gases to bring conditions back under control. However, in doing so, toxic and smog-forming air contaminants are emitted such as particulate matter, sulfur dioxide, and hydrocarbons that worsen air quality. Because HEFA processes require more hydrogen than petroleum refining, it is expected that hydro-conversion-related flaring would be worse with

[28] Appendix D, p. 32.
[29] Gerbens-Leenes, P.W., Bioenergy water footprints, comparing first, second and third generation feedstocks for bioenergy supply in 2040, 59 European Water 373 (2017).
[30] Rulli, M.C. et al., The water-land-food nexus of first-generation biofuels, 6 Nature Scientific Reports (2016).
[31] Rulli, M.C. et al., The water-land-food nexus of first-generation biofuels, 6 Nature Scientific Reports (2016).
[32] National Research Council 2011. Renewable Fuel Standard: Potential Economic and Environmental Effects of U.S. Biofuel Policy. Washington, DC: The National Academies Press. https://doi.org/10.17226/13105.
[33] Van Dyk, S. et al., Potential synergies of drop-in biofuel production with further co-processing at oil refineries, 13 Biofuels Bioproducts & Biorefining 760 (2019).

HEFA refining, along with explosion and fire risk.[34] With refineries most often sited in low-income communities and communities of color,[35] environmental justice harms are exacerbated by the presence of HEFA refining and would worsen with crop-based biofuel expansion.

Biofuel refinery expansion is alluded to by CARB staff: "Potential compliance responses to the Proposed Amendments…include construction and operation of new facilities to produce renewable diesel, biodiesel, and AJF and collection and distribution of feedstock to supply these facilities, or replace existing petroleum refineries."[36] Indeed, attempts are already being made in the Bay Area, for example, to convert existing oil and gas refineries to HEFA refineries, [37] and where low-income communities and communities of color would bear the brunt of air-pollution exposure.

210.11

d. CARB should adopt the EJAC recommendation of a cap on crop-based biofuels.

Given the risks associated with crop-based biofuels, it is disappointing that CARB staff rejected the amendments in the Comprehensive Environmental Justice Scenario proposed by CARB's Environmental Justice Advisory Committee (EJAC). The proposal was to "[c]ap the use of lipid biofuels (commonly known as crop-based biofuels) at 2020 levels, about 855 million gallons, pending an updated risk assessment to determine phase out timelines for high-risk, crop-based feedstocks."[38] The EJ Scenario was rejected because it would purportedly result in higher volumes of fossil diesel being used than any of the other scenarios evaluated. However, capping the use of lipid biofuels could instead spur the development of less deleterious alternatives such as the use of true waste products in biofuel production such as municipal solid waste (mentioned in the amendments),[39] and push the needed transition to battery-electric in shipping and trucking,[40] all while preventing the expansion of crop-based biofuel harms. Instead, crop-based biofuels are treated as the unavoidable alternative to fossil fuels, locking in the threat to communities and the environment.

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[34] Karras, G., Changing Hydrocarbons Midstream: Fuel chain carbon lock-in potential of crude-to-biofuel petroleum refinery repurposing, Prepared for: National Resources Defense Council (2021).
[35] Donaghy, T. et al., Fossil fuel racism in the United States: How phasing out coal, oil, and gas can protect communities, 100 Energy Research & Total Science 103104 (2023).
[36] Appendix D, p. 25.
[37] *See e.g.*, Rodeo Renewed Project Draft Revised Environmental Impact Report, County File No. CDLP20-02040, State Clearinghouse No. 2020120330, October 2023.
[38] ISOR, p. 116.
[39] Appendix E, p. 66.
[40] Minjares, R. and Basma, H., Battery-electric trucks: The most affordable path to decarbonizing tractor-trailers, International Council on Clean Transportation (April 27, 2023), https://theicct.org/event/battery-electric-trucks-the-most-affordable-path-to-decarbonizing-tractor-trailers/.

210.12

IV. CARB Should Add Conventional Jet Fuel as a Deficit-Generator But Add Strong Guardrails on Crop-Based Biofuels.

CARB is proposing to add conventional jet fuel ("CJF") for intrastate flights as a deficit-generator, as opposed to its current status as an opt-in fuel.[41] In including aviation emissions in the LCFS, the Board must walk a fine line between eliminating the exemption for dirty jet fuel while not incentivizing the use of crop-based biofuels, which damage ecosystems and communities.[42]

First, we note that the current language on this issue is weaker than staff had previously suggested, which will delay the potential benefits achieved through this change. The current proposal includes only fuel from intrastate flights, rather than all fuel that is combusted in and over California by all flights, including interstate and international. And it delays implementation until 2028.[43] These limiting factors will needlessly slow the benefits that may come from a transition to a more sustainable aviation industry. CARB should explore whether it can accelerate the implementation of this change and include fuel combusted from international and interstate flights for the portion of their trips that occur within the state's boundaries. If the Board chooses not to explore these avenues in this rulemaking, it should revisit these options at its next opportunity.

Second, it is beyond time to end the unfair advantages given to CJF that perpetuate the industry's use of fossil fuels. Many state policies heavily subsidize the industry's use of carbon-based jet fuels, which works against the state's efforts at decarbonizing the sector and allows this fuel to be under-regulated. For example, fuel used in international flights are exempt from sales and use taxes in California, a practice that was estimated to cost state and local governments nearly $300 million in revenue in 2021-2022.[44] Commercial airlines are also exempt from the excise tax for jet fuel, a tax break that costs the state about $23 million each year.[45] The carveout in the Low Carbon Fuel Standard for conventional jet fuel saves the airlines an estimated $110 to $360 million each year[46] on the cost of that fuel.

Relatedly, the industry continues to push the false solution of so-called Sustainable Aviation Fuels. Rather than accept the true and full climate costs of aviation and invest more seriously in research for zero-emission technologies like electric aircraft, the industry has become enamored with false solutions like carbon offsets or flawed, short-term answers like SAFs. Many sources of SAF feedstock are likely unable to scale up to the industry-wide demand, and particularly

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[41] CARB, Staff Report: Initial Statement of Reasons (Dec. 19, 2023), p. 26, *available at*: https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf
[42] These are referred to as Alternative Jet Fuel in the program.
[43] ISOR at p. 26.
[44] CA Dept. of Tax and Fee Administration, Aircraft Jet Fuel - Frequently Asked Questions, *available at* https://www.cdtfa.ca.gov/taxes-and-fees/aircraft-jet-fuel-faq.htm .
[45] CA Dept. of Finance, Tax Expenditure Reports 2021-22, at p. 11, *available at* https://dof.ca.gov/wp-content/uploads/sites/352/Forecasting/Economics/Documents/2021-22-Tax-Expenditure-Report.pdf.
[46] State fuel use estimated using DoT T-100 data on available seat miles originating in state & DoT data on national airline fuel consumption for 2019.

problematic sources of biofuel feedstock like palm oil may create even more problems than they solve. Therefore, CARB should carefully regulate the feedstocks that receive credit for contributing to SAFs.

Third, while ending the exemption for CJF is a welcome first step, it needs to be paired with complementary policies that strictly limit the use of crop-based biofuels, as described above in Part III. The inclusion of CJF in the program at this juncture provides the Board an opportunity to ensure that included fuels meet true sustainability criteria going forward. Relying on crop-based biofuels results in both direct and indirect land use change emissions that worsen the climate crisis, counter to their intended purpose. The Board should therefore choose to allow only feedstocks that have little to no land use effects or indirect emissions, such as municipal solid waste.

In short, the promotion and subsidization of SAFs, without adequate regard for the lifecycle impact and other ecological consequences of different feedstocks, threatens to substitute one problem for a host of others. California should not be in the business of subsidizing an industry's transition to fuels that promote deforestation in other parts of the country and world. Because crop-based biofuels are simply not sustainable, CARB should only incentivize fuels that meet strict and transparent sustainability criteria—a goal the Board has not reached in its current proposal.[47]

210.13
210.14
V. CARB Should Limit the Incentives for Hydrogen and Restrict Crediting to Renewable-Fueled Hydrogen.

210.15
a. The LCFS should only allow hydrogen production that adheres to the three pillars.

According to CARB staff, "[p]otential compliance responses to the Proposed Amendments could include the construction of new or expanded hydrogen production facilities, using steam methane reformation, electrolysis, or gasification technologies."[48] This highlights a grave issue with the proposed amendments since, according to current best science, the cleanest way to produce hydrogen, without drawing much needed renewables from other uses, is to employ the three pillars—hourly matching, deliverability, and additionality—in the process of renewable-fueled electrolysis.[49]

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[47] *See infra*, Part III.
[48] Appendix D, p. 29.
[49] Ricks, Jenkins, *The Cost of Clean Hydrogen with Robust Emission Standards: A Comparison Across Studies,* Princeton University Zero-carbon Energy Systems Research and Optimization Laboratory (2023), available at https://subscriber.politicopro.com/f/?id=00000187-9bb4-daaa-a5e7-bfbfff120000; Dan Esposito et al., *Smart Design of 45V Hydrogen Production Tax Credit Will Reduce Emissions and Grow the Industry,* Energy Innovation Policy & Technology (2023); and Ben Haley, Jeremy Hargreaves, *Three-Pillars Accounting Impact Analysis,* Evolved Energy Research (2023), available at https://www.evolved.energy/post/45v-three-pillars-impact-analysis.

Specifically, hydrogen production should proceed where hydrogen generators are powered by *new* sources of zero-emissions electricity (additionality or incrementality) that directly supply the grid electrolyzers are connected to (deliverability), within the same hour that generators are running (hourly matching). This is reaffirmed by the IRS's proposed rulemaking in which hydrogen producers could only receive the Section 45V clean hydrogen production tax credit by adhering to the 3 pillars.[50] Yet, CARB staff's proposed amendments would allow the continued use of fossil gas, and the use of problematic feedstocks like dairy biogas and biomass, despite the emissions and environmental burdens these all carry. The only form of hydrogen that should be considered under any provision in the LCFS is "green hydrogen," or hydrogen made by splitting water into hydrogen and oxygen using 100% solar or wind energy, while adhering to the 3 pillars.

210.16 **b. The LCFS should only allow electrolytic hydrogen produced using renewable solar and wind energy.**

"Blue hydrogen" production, or steam methane reformation paired with CCS, and gasification or pyrolysis of biogenic resources (e.g. woody biomass and biogas) should be explicitly excluded because of their associated harms: CCS, on which blue hydrogen production relies, has proven to be ineffective, dangerous, and expensive,[51] with research showing that blue hydrogen can be worse for the climate than burning fossil fuels.[52] Woody biomass, as a feedstock (e.g. in gasification or pyrolysis) or energy source to make hydrogen, harms the climate,[53] communities, and ecosystems with significant emissions of CO_2[54] and criteria pollutants.[55] As the IPCC, the

[50] Section 45V Credit for Production of Clean Hydrogen: Section 48(a)(15) Election To Treat Clean Hydrogen Production Facilities as Energy Property, Proposed Rules, 88 Fed. Reg. 246, 89220-255 (Dec. 26, 2023)(to be codified at 26 C.F.R. Part 1)

[51] Taylor Kubota, *Stanford Study casts Doubt on Carbon Capture,* Stanford News (Oct. 25, 2019), https://news.stanford.edu/2019/10/25/study-casts-doubt-carbon-capture/, citing Mark Z. Jacobson, *The health and climate impacts of carbon capture and direct air capture*, 12 Energy Envt. Sci. 3567 (2019), https://pubs.rsc.org/en/content/articlelanding/2019/ee/c9ee02709b/unauth#!divAbstract; Clark Butler, IEEFA, *Carbon Capture and Storage Is About Reputation, Not Economics* at 4 (2020), https://ieefa.org/wp-content/uploads/2020/07/CCS-Is-About-Reputation-Not-Economics_July-2020.pdf; *CAN Position: Carbon Capture, Storage, and Utilization*, Climate Action Network Int'l at 9 (2021), https://climatenetwork.org/resource/can-position-carbon-capture-storage-and-utilisation/.

[52] Howarth, R.W. and Jacobson, M.Z., How green is blue hydrogen? 9 Energy Sci. Eng. 1676 (2021).

[53] Sterman, John et al., Does wood bioenergy help or harm the climate?, 78 Bulletin of the Atomic Scientists 128 (2022), DOI: 10.1080/00963402.2022.2062933, available at https://www.tandfonline.com/doi/full/10.1080/00963402.2022.2062933; Partnership for Pol'y Integrity, *Air pollution from biomass energy* (updated April 2011), available at https://www.pfpi.net/wp-content/uploads/2011/04/PFPI-air-pollution-and-biomass-April-2011.pdf.

[54] Sterman, John et al., Does replacing coal with wood lower CO2 emissions? Dynamic lifecycle analysis of wood bioenergy, 13 Env't Rsch. Letters 015007 (2018), DOI: 10.1088/1748-9326/aaa512, available at https://www.tandfonline.com/doi/full/10.1080/00963402.2022.2062933.

[55] Liu, Wu-Jun et al., Fates of chemical elements in biomass during its pyrolysis, 117 Chemical Reviews 6367 (2017), https://pubs.acs.org/doi/10.1021/acs.chemrev.6b00647; Yao, Zhiyi et al., Particulate emissions from the gasification and pyrolysis of biomass: Concentration, size distributions, respiratory

federal Environmental Protection Agency's Science Advisory Board, and other scientists have established, wood bioenergy should not be assumed to be carbon neutral;[56] Using methane to produce hydrogen increases methane leakage risk, with one biogas plant study finding that leaked methane can be as high as 14.9% of total methane production.[57] There is also a significant pollution burden from biogas facilities near communities.[58] The LCFS should no longer incentivize and subsidize feedstocks that harm the climate and pollute the same communities that have historically borne the pollution burden of our status quo energy portfolio.

c. Hydrogen will only have a limited role in a carbon-free future.

Ultimately, even hydrogen produced using clean, renewable energy should play only a limited role in a carbon-free future, given the risks it carries. First, hydrogen is a potent, indirect greenhouse gas with 100 times the warming power of CO_2 over a 10-year period and 33 times over 20 years.[59] As a small molecule, hydrogen is more leakage-prone than methane, posing climate risks across the production and supply chains. Also, transporting hydrogen through pipelines is more dangerous than transporting methane: it is more likely to explode, burns hotter, and is more corrosive to pipelines.[60] Further, hydrogen production from fossil gas and coal emits dangerous health-harming pollution.[61] And all forms of hydrogen production use massive amounts of water—much more than solar and wind per unit of energy produced—which will put

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deposition-based control measure evaluation, 242 Environmental Pollution 1108 (2018), https://doi.org/10.1016/j.envpol.2018.07.126; Saxe, Jennie Perey et al., Just or bust? Energy justice and the impacts of siting solar pyrolysis biochar production facilities, 58 Energy Research & Social Science 101259 (2019) https://doi.org/10.1016/j.erss.2019.101259; Pang, Yoong Xin et al., Analysis of environmental impacts and energy derivation potential of biomass pyrolysis via piper diagram, 154 Journal of Analytical and Applied Pyrolysis 104995 (2021), available at https://doi.org/10.1016/j.jaap.2020.104995.

[56] IPCC Task Force on National Greenhouse Gas Inventories, Frequently Asked Questions, available at https://www.ipcc-nggip.iges.or.jp/faq/faq.html, at Q2-10 (IPCC Guidelines do not automatically consider biomass used for energy as 'carbon neutral,' even if the biomass is thought to be produced sustainably); EPA Science Advisory Board, SAB Review of Framework for Assessing Biogenic CO2 Emissions from Stationary Sources (2019), at 2 (not all biogenic emissions are carbon neutral nor net additional to the atmosphere, and assuming so is inconsistent with the underlying science); Beddington, J. et al., Letter from scientists to the EU parliament regarding forest biomass (2018), available at https://empowerplants.files.wordpress.com/2018/01/scientist-letter-on-eu-forest-biomass-796-signatories-as-of-january-16-2018.pdf.

[57] Scheutz, Charlotte & Anders M. Fredenslund, Total methane emission rates and losses from 23 gas plants, 97 Waste Mgmt. 38-46 (2019), https://doi.org/10.1016/j.wasman.2019.07.029.

[58] Nicole, W., CAFOs and Environmental Justice: The Case of North Carolina, 121 Environmental Health Perspectives a182 (2013); Montford, K. and Wotherspoon, T., The Contagion of Slow Violence: The Slaughterhouse and COVID-19, 10 Animal Studies Journal 80 (2021); Domingo, N.G.G. et al., Air quality-related health damages of food, 118 PNAS e2013637118 (2021).

[59] Ocko, I.B. and Hamburg, S. P., Climate consequences of hydrogen emissions, 22 Atmos. Chem. Phys. 9349 (2022).

[60] Pipeline Safety Trust, Hydrogen Pipeline Safety, Summary for Policymakers (2023), https://pstrust.org/wp-content/uploads/2023/01/hydrogen_pipeline_safety_summary_1_18_23.pdf.

[61] Sun, P. et al., Criteria Air Pollutants and Greenhouse Gas Emissions from Hydrogen Production in U.S. Steam Methane Reforming Facilities, 53 Environ. Sci. Technol. 7103 (2019).

extra stress on water supplies in areas already suffering from climate crisis-charged drought.[62] At present, about one million Californians lack access to safe, clean, and affordable water adequate for human consumption,[63] begging the question of whether water should be diverted to hydrogen production.

Thus, the use of hydrogen should be limited to those sectors without a viable present-day
210.17 alternative, such as replacing existing dirty gray fossil-based hydrogen, crude oil refineries, or
steel manufacturing.[64] This would effectively exclude the sectors for which the proposed
amendments are most incentivizing hydrogen adoption: light-duty, medium-duty, and heavy-
duty transport. Through the Hydrogen Refueling Infrastructure (HRI) provision, for instance,
CARB is incentivizing the rapid buildout of hydrogen refueling infrastructure.[65] However,
210.18 resources would be better directed to other pursuits given that for light-duty vehicles, battery-
electric is readily available, energy efficient, and lower cost than the hydrogen fuel cell
alternative.[66] Likewise, for heavy-duty vehicles such as those in long-haul trucking, it has now
been shown that battery-electric is competitive and economically advantageous.[67] Whenever
direct electrification can be used instead of hydrogen, as with vehicles, it's the demonstrably
better choice. Electricity made from solar and wind is more efficient, lower cost, lower in CO_2
emissions, and a mature energy resource.[68] The LCFS should be incentivizing full electrification
210.17 rather than hydrogen which is projected to have only a limited role in a carbon-free future.[69]

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[62] DiFelice, M. and Murray, B., Exposing a New Threat to Our Water: Hydrogen Power, Food & Water Watch (2023), https://www.foodandwaterwatch.org/2023/02/07/hydrogen-water-use/.

[63] Pineda, Dorany et al., *'A ticking time bomb': Why California Can't provide safe drinking water to all its residents*, LA Times, Sept. 27, 2023, https://www.latimes.com/environment/story/2023-09-27/californias-struggle-for-clean-water-is-getting-harder (last visited February 8, 2024).

[64] *See e.g.*, Michael Liebreich, *The Clean Hydrogen Ladder (v.4.1)* (2021), available at https://www.linkedin.com/pulse/clean-hydrogen-ladder-v40-michael-liebreich/ ; see also, Michael Liebreich, *The Unbearable Lightness of Hydrogen*, BloombergNEF (2022), available at https://about.bnef.com/blog/liebreich-the-unbearable-lightness-of-hydrogen/, and Michael Barnard, *Chemical Engineer Paul Martin Reflects on Liebreich's Hydrogen Ladder & #Hopium—Part 1*, Clean Technica (2021)*(hydrogen is actually a decarbonization problem, not a decarbonization solution)*, available at https://cleantechnica.com/2021/09/01/cleantech-talk-chemical-engineer-paul-martin-reflects-on-liebreichs-hydrogen-ladder-hopium-part-1/.

[65] *See e.g.*, Appendix E, p. 30.

[66] Plötz, P., Hydrogen technology is unlikely to play a major role in sustainable road transport, 5 Nature Electronics 8 (2022).

[67] Phadke, A. et al., Why Regional and Long-Haul Trucks are Primed for Electrification Now, Lawrence Berkeley National Laboratory (2021), https://eta-publications.lbl.gov/sites/default/files/updated_5_final_ehdv_report_033121.pdf. Minjares, R. and Basma, H., Battery-electric trucks: The most affordable path to decarbonizing tractor-trailers, International Council on Clean Transportation (April 27, 2023), https://theicct.org/event/battery-electric-trucks-the-most-affordable-path-to-decarbonizing-tractor-trailers/.

[68] Hydrogen Science Coalition, https://h2sciencecoalition.com (last accessed: February 8, 2024).

[69] IPCC, Technical Summary Working Group III contribution to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change (2022), available at

210.19 **VI. CARB Should Remove Woody Biomass Feedstocks from the LCFS Program.**

CARB's proposed amendments to section 95488.8(g)(1)(A)1 on Specified Source Feedstocks adds "forestry residues" to the list of feedstocks, with some specifications: "Small-diameter, non-merchantable forestry residues removed for the purpose of forest fire fuel reduction or forest stand improvement and from a treatment where no-clear cutting occurred."[70]

We oppose the inclusion of woody biomass feedstocks, including forest and agricultural residues, in the LCFS program due to the significant greenhouse gas pollution, air pollution, degradation of forest ecosystems, and loss of forest carbon storage that come from producing biofuels and hydrogen from woody biomass. CARB's proposed specifications for forest residues are vague and will not meaningfully reduce harms.

210.19 **a. CARB should not include woody biomass, including forest and agricultural residues, as feedstocks in the LCFS program due to the harms to the climate, public health, and forest ecosystems.**

As detailed below, the production of biofuels and hydrogen from woody biomass releases large amounts of planet-heating CO_2 and toxic air pollutants, worsening the climate emergency and harming public health. While the GREET model incorrectly treats forest feedstocks as carbon neutral, scientific research clearly shows that combustion or gasification of trees and other forest material—including residues considered to be "waste"— leads to a net increase of carbon emissions in the atmosphere for decades to centuries. Biomass facilities often concentrate pollution in communities of color and low-income communities in California, worsening environmental injustice.[71] Adding CCS to biomass gasification, pyrolysis, or combustion would still result in significant climate and air pollution and threaten public and safety, given CCS has proven to be ineffective, unsafe, and energy-intensive. Incentivizing hydrogen and biofuels production from forest biomass risks increasing logging and thinning, which degrade wildlife habitat and result in a net loss of forest carbon storage and sequestration, at a time when we must be protecting forest carbon stores. Biofuel and hydrogen production from woody biomass are not part of a clean, just energy future and should not be included in the LCFS program.

i. Gasification and pyrolysis of biomass to produce hydrogen and biofuels produce large amounts of CO_2 and health-harming pollutants.

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https://www.ipcc.ch/report/ar6/wg3/downloads/report/IPCC_AR6_WGIII_TechnicalSummary.pdf; see also David Cebon and Johanne Whitmore, Hydrogen's role in the energy transition to 2050—Three evidence-based recommendations, The OECD Forum Network (2023), available at https://www.oecd-forum.org/posts/hydrogen-s-role-in-the-energy-transition-to-2050-three-evidenced-based-recommendations, and Michael Liebreich, The Unbearable Lightness of Hydrogen, BloombergNEF (2022), available at https://about.bnef.com/blog/liebreich-the-unbearable-lightness-of-hydrogen/.

[70] Appendix A-1 at 145.

[71] Center for Biological Diversity, Forest Biomass Energy is a False Solution (2021), https://www.biologicaldiversity.org/campaigns/debunking_the_biomass_myth/pdfs/Forest-Bioenergy-Briefing-Book-March-2021.pdf.

Gasification and pyrolysis are the primary processes being promoted to produce hydrogen and biofuels from woody biomass such as trees and agricultural materials. The gasification of biomass at high temperatures (800-1200°C) produces a "syngas" containing large amounts of CO_2, as well as methane (CH4), carbon monoxide (CO), and hydrogen (H_2), in addition to liquid hydrocarbons and tar, solid char and ash residues, and a wide array of air pollutants. The pyrolysis of biomass additionally produces pyrolytic oil and larger quantities of char. The biomass fuel, gasifier type, temperature, and gasifying agent (e.g., steam, air, oxygen, oxygen-enriched air) influence the composition of the syngas.[72] Biomass gasification and pyrolysis processes to produce hydrogen are still in the initial development phase, have not been demonstrated at any meaningful scale, are technically difficult, and expensive.

ii. Health-harming pollutants.

Biomass gasification and pyrolysis produce a wide range of health-harming pollutants including fine particulate matter, NOx, SOx, benzene, toluene and xylenes (BTEX), tars and soot, and persistent organic pollutants such as polycyclic aromatic hydrocarbons (PAHs) (e.g., naphthalene), polychlorinated dibenzo-*p*-dioxins and dibenzofurans (PCDD/Fs).[73] Importantly, gasification and pyrolysis of biomass are significant sources of fine particulate matter (PM 2.5) that can penetrate deeply into the lungs, even enter the bloodstream, and cause serious health problems.[74] Fine particulate matter pollution is linked to a higher risk of premature death, heart disease, stroke, and aggravated asthma.[75]

The formation of NOx precursors, including NH_3, HCN and HNCO, during biomass pyrolysis has been widely reported, where NOx damages the respiratory system and contributes to acid

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[72] Shayan, E. et al., Hydrogen production from biomass gasification; a theoretical comparison of using different gasification agents, 159 Energy Conversion and Management 30 (2018), https://doi.org/10.1016/j.enconman.2017.12.096.

[73] Partnership for Policy Integrity, Air pollution from biomass energy, https://www.pfpi.net/air-pollution-2/; Liu, Wu-Jun et al., Fates of chemical elements in biomass during its pyrolysis, 117 Chemical Reviews 6367 (2017), https://pubs.acs.org/doi/10.1021/acs.chemrev.6b00647; Yao, Zhiyi et al., Particulate emissions from the gasification and pyrolysis of biomass: Concentration, size distributions, respiratory deposition-based control measure evaluation, 242 Environmental Pollution 1108 (2018), https://doi.org/10.1016/j.envpol.2018.07.126; Saxe, Jennie Perey et al., Just or bust? Energy justice and the impacts of siting solar pyrolysis biochar production facilities, 58 Energy Research & Social Science 101259 (2019) https://doi.org/10.1016/j.erss.2019.101259; Pang, Yoong Xin et al., Analysis of environmental impacts and energy derivation potential of biomass pyrolysis via piper diagram, 154 Journal of Analytical and Applied Pyrolysis 104995 (2021), https://doi.org/10.1016/j.jaap.2020.104995.

[74] Yao, Zhiyi et al., Particulate emissions from the gasification and pyrolysis of biomass: Concentration, size distributions, respiratory deposition-based control measure evaluation, 242 Environmental Pollution 1108 (2018), https://doi.org/10.1016/j.envpol.2018.07.126.

[75] U.S. Environmental Protection Agency, Health and Environmental Effects of Particulate Matter, https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm.

rain, harming ecosystems.[76] Of the BTEX compounds produced during gasification and pyrolysis, benzene is a known human carcinogen, and toluene and xylenes damage the brain and nervous system, respiratory system, kidneys, and liver.

The formation of liquid tar is an inherent problem in biomass gasification. Tar contains toxic substances such as benzene, toluene, and naphthalene, while tar build-up also lowers energy efficiency, interrupts continuous operation, and increases maintenance costs of gasification processes.[77] Methods to clean tar from equipment would create large amounts of toxic wastewater, with resulting environmental and community harms.[78]

iii. Climate-heating CO_2.

Similar to biomass combustion, gasification and pyrolysis of biomass produce large quantities of CO_2 as well as methane emissions that worsen the climate emergency. Biomass-derived hydrogen and biofuels are often falsely promoted as being carbon neutral or carbon negative (i.e., meaning that they will lead to a net removal of CO_2 from the atmosphere) based on the inaccurate claims that woody biomass is a carbon neutral feedstock and/or that CCS can be used to capture the CO_2 emitted from the process. The claim that woody biomass is a carbon neutral feedstock has been thoroughly debunked,[79] given the lost carbon storage and sequestration from extracting biomass, and the significant CO_2 emissions during biomass processing and gasification, pyrolysis, or combustion.[80] For example, substantial upstream emissions are released from cutting and extracting trees and other vegetation which immediately ends their carbon storage and sequestration; the use of fertilizers and pesticides after cutting; transporting biomass often long distances in diesel trucks; and processing biomass through chipping and drying.[81] The combustion, gasification, and pyrolysis of trees and other forest material—

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[76] Chen, Hongyuan et al., A review on the NOx precursors release during biomass pyrolysis, 451 Chemical Engineering Journal 138979 (2022), https://doi.org/10.1016/j.cej.2022.138979.
[77] He, Quing et al., Soot formation during biomass gasification: A critical review, 139 Renewable and Sustainable Energy Reviews 110710 (2021), https://doi.org/10.1016/j.rser.2021.110710.
[78] Luo, Xiang et al., Biomass gasification: an overview of technological barriers and socio-environmental impact. In *Gasification for Low-Grade Feedstock* (2018): 1-15, https://www.intechopen.com/chapters/59423.
[79] Booth, Mary S, Not carbon neutral: Assessing the net emissions impact of residues burned for bioenergy, 13 Env't Rsch. Letters 035001 (2018), https://doi.org/10.1088/1748-9326/aaac88; Sterman, John et al., Does wood bioenergy help or harm the climate?, 78 Bulletin of the Atomic Scientists 128 (2022), https://doi.org/10.1080/00963402.2022.2062933.
[80] Climate Action Network International, Position: Carbon Capture, Storage, and Utilisation (January 2021), https://climatenetwork.org/resource/can-position-carbon-capture-storage-and-utilisation/; Fern, 2022, Six problems with BECCS, https://www.fern.org/fileadmin/uploads/fern/Documents/2022/Six_problems_with_BECCS_-_2022.pdf.
[81] *See, e.g.*, Roder, Mirjam et al., How certain are greenhouse gas reductions from bioenergy? Life cycle assessment and uncertainty analysis of wood pellet-to-electricity supply chains from forest residues, 79 Biomass and Bioenergy 50 (2015), DOI: 10.1016/j.biombioe.2015.03.030.

including residues considered to be "waste"— leads to a net increase of carbon emissions in the atmosphere for decades to centuries.[82]

Furthermore, CCS has consistently proven to be exceptionally ineffective, unsafe, expensive, and targets environmental justice communities.[83] CCS operations are very energy-intensive given the high energy requirements needed to separate, compress, transport, and inject CO_2, typically requiring at least 15-25% more energy, which results in increased greenhouse gas and air pollution emissions.[84] CCS projects around the world have consistently failed to meet their carbon-capture promises, often by large margins.[85] Moreover, 95% of CO_2 captured in the U.S. by CCS is used to pump oil and gas out of the ground in process called enhanced oil recovery,[86] worsening the climate emergency. CCS poses significant new health, safety, and environmental risks from toxic air pollution emitted from CCS facilities, earthquake risks from underground CO_2 injection, and the inevitable ruptures of CO_2 pipelines and leaks from underground CO_2 storage that can sicken and even kill people.[87] In short, putting CCS equipment on biomass gasification and pyrolysis facilities (BECCS) would still lead to significant CO_2 and co-pollutants emissions, endangering communities and the climate.

iv. Environmental injustice.

Biomass gasification and pyrolysis project proposals are targeting communities in the Central Valley already overburdened with pollution. For example, idled Central Valley bioenergy facilities in or near communities, such as the Madera biomass facility, are being proposed for

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[82] Booth, Mary S., Not carbon neutral: Assessing the net emissions impact of residues burned for bioenergy, 13 Env't Rsch. Letters 035001 (2018), https://doi.org/10.1088/1748-9326/aaac88; Laganiere, Jerome et al., Range and uncertainties in estimating delays in greenhouse gas mitigation potential of forest bioenergy sourced from Canadian forests, 9 GCB Bioenergy 358 (2017), https://doi.org/10.1111/gcbb.12327; Sterman, John et al., Does wood bioenergy help or harm the climate?, 78 Bulletin of the Atomic Scientists 128 (2022).

[83] Center for Biological Diversity, Carbon Capture and Storage is a False Solution for the Climate and Our Communities (2022), https://biologicaldiversity.org/campaigns/carbon-capture-and-storage/pdfs/CCS-explainer.pdf.

[84] Climate Action Network International, Position: Carbon Capture, Storage, and Utilisation (January 2021), https://climatenetwork.org/resource/can-position-carbon-capture-storage-and-utilisation/; IEEFA, The carbon capture crux: Lessons learned (Sept. 2022), https://ieefa.org/resources/carbon-capture-crux-lessons-learned.

[85] IEEFA, The carbon capture crux: Lessons learned (Sept. 2022), https://ieefa.org/resources/carbon-capture-crux-lessons-learned.

[86] Global CCS Institute, https://status22.globalccsinstitute.com/2022-status-report/appendices/.

[87] Pipeline Safety Trust, Regulatory and Knowledge Gaps in the Safe Transportation of Carbon Dioxide by Pipeline (2022), https://pstrust.org/wp-content/uploads/2022/10/CO2-Regulatory-and-Knowledge-Gaps-1.pdf; Dan Zegert, Huffington Post, "The Gassing of Satartia" (Aug. 2021), https://www.huffpost.com/entry/gassing-satartia-mississippi-co2-pipeline_n_60ddea9fe4b0ddef8b0ddc8f; Fowler, Sarah, 'Foaming at the mouth': First responders describe scene after pipeline rupture, gas leak, The Clarion-Ledger (February 27, 2020), https://www.clarionledger.com/story/news/local/2020/02/27/yazoo-county-pipe-rupture-co-2-gas-leak-first-responders-rescues/4871726002/.

conversion to biomass gasification or pyrolysis facilities to produce hydrogen, threatening to worsen environmental injustice for these communities.[88] Another recent proposal envisions a massive build-out of 50 to 100 biomass processing facilities—many of them biomass gasification and pyrolysis facilities—that would be concentrated in the Central Valley, paired with a polluting network of CO_2 pipelines, railcars, and trucking, and the injection of 100 million tons of CO_2 underground each year,[89] with inevitable harms from air pollution, water pollution, noise pollution, CO_2 leakage, earthquake risks, and ecosystem damage.

v. High water usage.

Biomass gasification to produce hydrogen has extremely high water usage. One recent study estimated that biomass gasification uses 306 kg water per kg of H_2 produced, which is orders of magnitude more than electrolysis production pathways estimated at 9 to 18 kg water per kg H_2.[90] This would put extra stress on water supplies in areas already suffering from climate crisis-charged drought.

vi. Forest ecosystem harms and lost forest carbon storage and sequestration.

Incentivizing the production and commodification of hydrogen and biofuels from woody biomass is likely to increase forest logging and thinning which degrade wildlife habitat and result in a net loss of carbon storage and sequestration from forests, at a time when we must be reducing deforestation and protecting forest carbon stores.[91] Logging and thinning trees releases their stored carbon to the atmosphere in a triple whammy for the climate: it increases overall carbon emissions, reduces the forest carbon sink, and requires massive public subsidies, taking resources away from truly low-carbon solar and wind energy.

210.20 **b. CARB's proposed specifications for forest residues are vague and will not meaningfully reduce harms.**

CARB's proposed specifications for forest residues are that they are "[s]mall-diameter, non-merchantable forestry residues removed for the purpose of forest fire fuel reduction or forest stand improvement and from a treatment where no-clear cutting occurred."[92] However well-intentioned, these specifications are too vague to limit forest degradation nor will they

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[88] Clean Energy Systems, Clean Energy Systems Enters Into An Agreement to Acquire the Madera Biomass Power Plant (Jul. 12, 2022), *available at* https://www.cleanenergysystems.com/clean-energy-systems-enters-into-an-agreement-to-acquire-the-madera-biomass-power-plant.
[89] LLNL and DOE, Getting to Neutral: Options for Negative Carbon Emissions in California (2019), *available at* https://livermorelabfoundation.org/2019/12/19/getting-to-neutral/.
[90] Mehmeti, Andi et al., Life cycle assessment and water footprint of hydrogen production methods: from conventional to emerging technologies, 5 Environments 24 (2018).
[91] Moomaw, William R. et al., Intact Forests in the United States: Proforestation mitigates climate change and serves the greatest good, Frontiers in Forests and Global Change (2019).
[92] Appendix A-1 at 145.

meaningfully reduce the significant harms to the climate, communities and forests detailed above.

Almost all forest logging and thinning projects are done under the justification that they will promote forest health and resilience and/or are needed for fuels reduction. Trees and other forest vegetation of any size can be lopped and masticated into “small-diameter” residues and called “non-merchantable.” Incentivizing the commodification of forest materials under the LCFS will lead to the removal of more biomass from the forest than would happen if these materials were not commodified, threatening forest ecosystems and forest carbon storage. Management practices should instead prioritize leaving residues in the forest to maintain soil organic carbon, retain vital nutrients in the ecosystem, and support wildlife habitat.[93]

Thank you for consideration of these comments.

Sincerely,

John Fleming, PhD, Senior Scientist
Scott Hochberg, Staff Attorney
Victoria Bogdan Tejeda, Staff Attorney
Shaye Wolf, PhD, Climate Science Director

Center for Biological Diversity
Climate Law Institute
1212 Broadway, Suite 800
Oakland, CA 94612
(510) 844-7100
jfleming@biologicaldiversity.org
shochberg@biologicaldiversity.org
vbogdantejeda@biologicaldiversity.org
swolf@biologicaldiversity.org

References available at: https://diversity.box.com/s/8jcli9f2vwyof9cbq1qx5sna1m0d0hsb

[93] Walmsley, J.D. et al., Whole tree harvesting can reduce second rotation forest productivity, 257 Forest Ecology and Management 1104 (2009); Buccholz, Thomas et al., Mineral soil carbon fluxes in forests and implications for carbon balance assessments, 6 GCB Bioenergy 305 (2014); Achat, David et al., Forest soil carbon is threatened by intensive biomass harvesting, 5 Scientific Reports 15991 (2015), https://www.nature.com/articles/srep15991; Achat, David et al., Quantifying consequences of removing harvesting residues on forest soils and tree growth – A meta-analysis, 348 Forest Ecology Management 124 (2015).

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Subject	Comments on Proposed LCFS Amendments

Comment

```
Good afternoon,

Please disregard the comment letter I submitted earlier today and
post the letter attached to this message. The earlier letter
contained a minor error that needed to be clarified.

Thank you for your kind assistance.

Shelby Neal
VP - Renewables & Energy Policy
```

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DARLING INGREDIENTS

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Proposed 2024 LCFS Amendments

Dear California Air Resources Board:

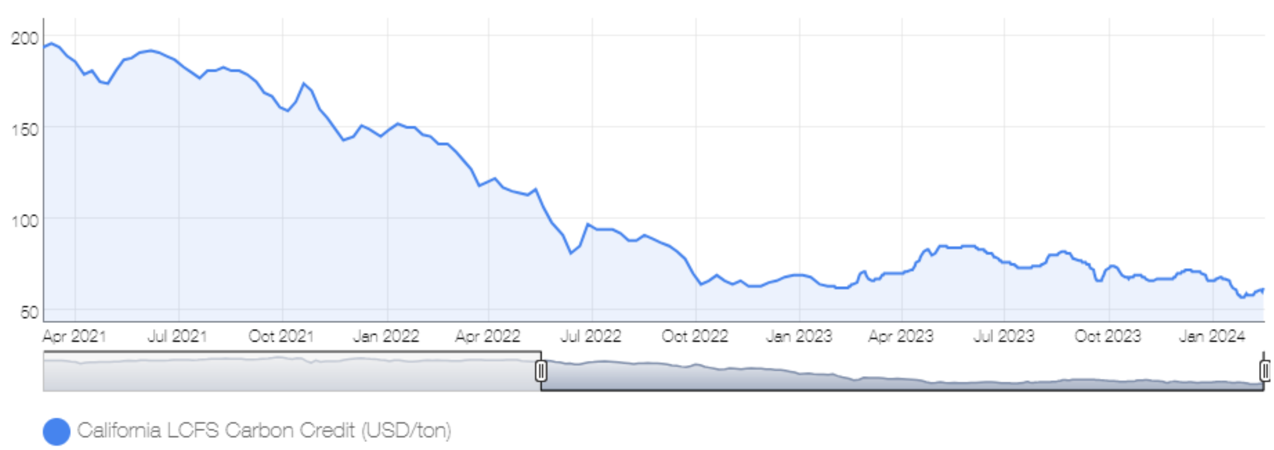
We are writing to provide comments on the Proposed 2024 Low Carbon Fuel Standard Amendments. Thank you for considering our views on this important issue.

Darling Ingredients is North America's largest purveyor of waste fats and oils and is a 50% owner of the nation's largest renewable diesel production facility through a joint venture. Most of the fat that Darling Ingredients processes from its North American factories (used cooking oil and animal fat) are used as feedstocks for domestically produced renewable diesel. We have collection, recycling, and processing operations at several locations in California[1]. According to CARB, our renewable diesel reduces greenhouse gasses (GHGs) by as much as 80%, particulate matter by 30%, NOx by 12%, and is sulfur and benzene free because it is produced from biological – rather than fossil – feedstocks. Renewable diesel is compatible up to 100% in all existing vehicles, equipment, and infrastructure and can be further processed into sustainable aviation fuel (SAF).

After reviewing the regulatory package, we have several comments we would like to share.

<u>Carbon Intensity (CI) Benchmarks</u>

Addressing the persistent decline in LCFS credit values demands more robust measures than have been included in the proposed regulatory package. While the amendments represent progress and a good faith effort to get the program back on track, a 5% step down in 2025 is simply not ambitious enough to
211.1 remedy the ongoing challenges linked to overcompliance and a historically high credit bank. The data depicted in the chart below unmistakably indicate that the credit market lacks confidence in the proposed amendments' ability to rebalance supply and demand effectively.



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[1] Fresno, Los Angeles, San Diego, San Francisco, Santa Ana, and Turlock.

To address this issue, stakeholders previously recommended that CARB implement the 5% step down beginning July 1, 2024 rather than January 1, 2025. We still believe this would be an effective policy response to help address the current problem. However, in addition, we recommend increasing the 2025 step down from 5% to at least 10.5%. This would help restore the credit bank to levels more consistent with historical averages. For the 2030 benchmark, we recommend a requirement of at least 35%. By implementing these measures, the program would be poised for stability and innovation both in the short and long term.

Exemption for Jet Fuel

Prior to the availability of sustainable aviation fuel (SAF), exempting jet fuel from the LCFS program seemed logical. However, the landscape has changed with new facilities coming online in the very near future. For example, our joint venture project, which will be capable of producing approximately 235 million gallons of SAF annually beginning by approximately the first quarter 2025, underscores the
emergence and wider availability of SAF. In light of this evolving reality, it is disconcerting that the
211.2 proposed amendments continue to exempt intrastate jet fuel until January 1, 2028. Such a delay would
prove severely counterproductive since urgent market signals are needed to capitalize on the
momentum the industry is currently experiencing.

Advancing the repeal of the exemption to January 1, 2025 would offer essential support urgently
needed to transition the aviation sector toward cleaner, more sustainable practices. Furthermore, we
advocate for exempting the obligation on all jet fuel, not solely intrastate, as continuing reliance on
211.3 petroleum jet fuel amidst cleaner alternatives is entirely unnecessary, especially for years 2025, 2026,
and 2027 when our joint venture alone could fulfill the entire SAF obligation for all three years.

Auto Acceleration Mechanism (AAM)

The AAM concept represents an innovative approach to managing the ambition of the LCFS, and we appreciate its integration into the proposed amendments. However, similar to the concerns expressed regarding the exemption of jet fuel, we fail to understand the reasoning behind postponing
implementation until 2028. Should CARB lean toward deferring implementation of the AAM, we
211.4 recommend considering 2027 as a more suitable timeline. The years spanning 2025 through 2027 stand
out as particularly unbalanced during credit bank modeling exercises, demanding more ambition than is
represented in the proposed amendments.

Credit True Up After Annual Verification

211.5 We strongly support the provision that allows the Executive Officer to perform a credit true up for a fuel
pathway that has a lower verified operational CI upon receipt of a positive verification statement for the
211.6 associated annual fuel pathway report. However, we fail to understand why CARB proposes to penalize
CI exceedances by four times the difference in credits between the verified operational fuel pathway CI and the reported CI. Obviously, the agency has regulatory options at its discretion currently, including issuing notices of violation and levying financial penalties. If staff believe an additional deterrent is needed, two times the exceedance would seem more than sufficient to deter such activity. Four times the exceedance is simply unfair to producers and will result in less accurate CI values as well as an entirely different set of administrative challenges.

CARB Leadership

We urge staff and the board to continue embracing CARB's historical role as the global leader on low carbon fuels policy. Under the tech-neutral California program, every alternative fuel and technology has been successful and significantly outperformed expectations. While we are encouraged and optimistic about the future of low carbon programs in other states, the reality is that most other jurisdictions are still in some phase of consideration or in a nascent stage of development. For this reason, continued strong leadership from CARB is needed to ensure continuity of innovation across the broad spectrum of technologies, especially sustainable aviation fuel.

Once again, thank you for considering our comments. If you should have any questions, please feel free to contact me at any time at shelby.neal@darlingii.com.

Sincerely,

Shelby Neal

Shelby Neal
VP - Renewables & Energy Policy

Comment Log Display

Here is the comment you selected to display.

Comment 221 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Roxana
Last Name	Bekemohammadi
Email Address	roxana@ushydrogenalliance.org
Affiliation	
Subject	Proposed 2024 LCFS Amendments

Comment

Dear California Air Resources Board,

We appreciate the opportunity to share our thoughts on California Air Resources Board's Low Carbon Fuel Standard amendments. The United States Hydrogen Alliance is a non-profit trade association dedicated to building the U.S. hydrogen economy. Our organization represents hydrogen companies actively deploying clean technologie across the country.

We are writing to share our perspective on several key program areas for your consideration. These requests address the light dut hydrogen refueling infrastructure pathway, low carbon intensity electricity, methane pyrolysis, along with recommendations for pyrolysis and renewable hydrogen definitions.

Regarding the new light duty hydrogen refueling infrastructure pathway, we believe the location restrictions to disadvantaged communities, low-income communities, and rural areas is overly limiting. While we respect the intent of these restrictions, we as for removal of the hydrogen refueling station location restrictio to allow alignment with traffic/use forecasts to ensure high usag and maximum societal benefit and to avoid applying a double standard for hydrogen, a zero emission fuel, in comparison to electricity.

New restrictions for low carbon intensity electricity require it t be supplied by new or expanded production, or within three years o a hydrogen production facility or air capture project's creation date. These restrictions resemble "additionality" or "incrementality," and is something the hydrogen industry is oppose to on all accounts. We suggest the removal of the new 100% renewable electricity requirement given the policy bias for electricity against hydrogen, as battery electric vehicles are no required to charge with 100% renewable electricity. Through California's Renewables Portfolio Standard, it is already require for retail electricity to be 100% renewable by 2045; with the gri already moving in this direction, this requirement seems redundan

For the definition of pyrolysis we suggest two amendments, the inclusion of both biomethane and solid carbon. We believe that solid carbon should be considered as a form of carbon capture and sequestration. Methane pyrolysis should also be included in a pathway for flexible access to low greenhouse gas methane sources to reduce both greenhouse gasses and the cost of hydrogen. We also suggest an amendment to the definition of renewable hydrogen to include pyrolysis in section two.

In section § 95490. Provisions for Fuels Produced Using Carbon Capture and Sequestration, we suggest adding the eligibility requirement below:
(3) "Hydrogen producers from methane pyrolysis that capture precombustion carbon in solid form and permanently store it or provide proof of permanent storage. 1kg of solid carbon is equivalent to 3.67kg of avoided carbon dioxide"

We at the United States Hydrogen Alliance thank you for your time and consideration. Please reach out to us if you have any questions.

Respectfully,

Roxana Bekemohammadi
Founder and Executive Director
United States Hydrogen Alliance

Attachment	www.arb.ca.gov/lists/com-attach/6885-lcfs2024-ViNQJVA5WWtXDlU5.pdf
Original File Name	USHA LCFS Letter_Signed_022024.pdf
Date and Time Comment Was Submitted	2024-02-20 12:58:39

Board Comments Home

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, California 95814

RE: Proposed 2024 LCFS Amendments

Dear California Air Resources Board,

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We are writing to share our perspective on several key program areas for your consideration. These requests address the light duty hydrogen refueling infrastructure pathway, low carbon intensity electricity, methane pyrolysis, along with recommendations for pyrolysis and renewable hydrogen definitions.

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USHA
UNITED STATES HYDROGEN ALLIANCE

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212.4

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> (3) "Hydrogen producers from methane pyrolysis that capture precombustion carbon in solid form and permanently store it or provide proof of permanent storage. 1kg of solid carbon is equivalent to 3.67kg of avoided carbon dioxide"

We at the United States Hydrogen Alliance thank you for your time and consideration. Please reach out to us if you have any questions.

Respectfully,

K. Bekemohammadi

Roxana Bekemohammadi
Founder and Executive Director
United States Hydrogen Alliance

Comment Log Display

Here is the comment you selected to display.

Comment 222 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nikita
Last Name	Pavlenko
Email Address	n.pavlenko@theicct.org
Affiliation	ICCT

Subject	ICCT Comments on LCFS Amendments

Comment	The attached PDF contains comments submitted by the International Council on Clean Transportation (ICCT). The ICCT is an independent nonprofit organization founded to provide unbiased research and technical analysis to environmental regulators. Our mission is to improve the environmental performance and energy efficiency of road, marine, and air transportation, in order to benefit public health and mitigate climate change. We promote best practices and comprehensive solutions to increase vehicle efficiency, increase the sustainability of alternative fuels, reduce pollution from the in-use fleet, and curtail emissions of local air pollutants and greenhouse gases (GHG) from international goods movement. The ICCT welcomes the opportunity to provide comments on the Air Resources Board's Proposed Low Carbon Fuel Standard amendments. We commend the agency for its technical analysis and interest in continuing to improve the effectiveness of one of its flagship climate programs. Based on the content of the Initial Statement of Reasoning (ISOR) document, the comments below offer a number of technical observations and recommendations for ARB to consider in aligning the program with the goals of the 2022 Scoping Plan.
Attachment	www.arb.ca.gov/lists/com-attach/6886-lcfs2024-AmsCZwFjACcAWQJu.pdf
Original File Name	ICCT LCFS Dec 2023 ISOR Comments.pdf
Date and Time Comment Was Submitted	2024-02-20 13:10:16

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

icct

www.theicct.org
communications@theicct.org
twitter @theicct

THE INTERNATIONAL COUNCIL ON CLEAN TRANSPORTATION
1500 K STREET NW | SUITE 650 | WASHINGTON DC 20005

February 20, 2024

RE: International Council on Clean Transportation comments on the **Proposed Low Carbon Fuel Standard Amendments**

These comments are submitted by the International Council on Clean Transportation (ICCT). The ICCT is an independent nonprofit organization founded to provide unbiased research and technical analysis to environmental regulators. Our mission is to improve the environmental performance and energy efficiency of road, marine, and air transportation, in order to benefit public health and mitigate climate change. We promote best practices and comprehensive solutions to increase vehicle efficiency, increase the sustainability of alternative fuels, reduce pollution from the in-use fleet, and curtail emissions of local air pollutants and greenhouse gases (GHG) from international goods movement.

The ICCT welcomes the opportunity to provide comments on the Air Resources Board's Proposed Low Carbon Fuel Standard amendments. We commend the agency for its technical analysis and interest in continuing to improve the effectiveness of one of its flagship climate programs. Based on the content of the Initial Statement of Reasoning (ISOR) document, the comments below offer a number of technical observations and recommendations for ARB to consider in aligning the program with the goals of the 2022 Scoping Plan.

We would be glad to clarify or elaborate on any points made in the below comments. If there are any questions, ARB staff can feel free to contact Nik Pavlenko (n.pavlenko@theicct.org) and Dr. Stephanie Searle (stephanie@theicct.org).

Stephanie Searle, PhD
ICCT Acting Deputy Director
International Council on Clean Transportation

Summary of Comments

The LCFS program is designed to diversify California's transportation fuel pool and support the state's broader climate targets of economy-wide decarbonization and reducing dependence on petroleum.[1] Since 2011, the LCFS has undergone numerous rounds of revisions that have raised the carbon intensity (CI) reduction target and trajectory, expanded the list of eligible fuel pathways, and supported the expansion of zero-emission fueling infrastructure. The California Air Resources Board (CARB) is now administering another round of revisions to better align the program with the state's 2022 Scoping Plan.[2] These revisions were developed with input from numerous public workshops and engagement with the Environmental Justice Advisory Committee (EJAC) and summarized in an Initial Statement of Reasoning (ISOR) document released in December 2023.[3]

In its latest amendments, CARB has proposed to increase the annual CI reduction target to 30% in 2030 and make other program changes such as setting deliverability requirements on biomethane, phasing out avoided methane emissions crediting beginning in 2030, expanding project crediting for medium and heavy duty zero-emission vehicles, and obligating the volume of fossil jet fuel consumed on intrastate flights. CARB has also proposed introducing an auto-acceleration mechanism (AAM) and step down in the near-term CI target to address low and fluctuating credit prices in recent years. These changes are intended to put California on a path towards its long-term climate goals including an 85% GHG emission reduction target by 2045 and a path towards carbon neutrality.[4] Though we applaud CARB's proposal to extend the LCFS targets, we are concerned with the lack of safeguards to mitigate unintended emissions and market distortions that could undermine the policy's intended effects.

Our analysis finds that the "Proposed Alternative" is insufficient because it does not implement policy safeguards necessary to avoid unintended consequences to the climate impacts and efficacy of the program that were identified by CARB staff during the 2022-2023 Scoping Plan process. Safeguards discussed in previous LCFS workshops such as limiting the contribution of crop-based biofuels were not incorporated in the ISOR proposal, while proposed other safeguards such as phasing out avoided methane emissions crediting and aligning biomethane deliverability requirements with other fuel pathways are pushed far into the future and will have little relevance to the program's operation for over a decade.[5] The Proposed Alternative overestimates the GHG emissions attributable to the proposals and diverges from

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[1] https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf
[2] Ibid.
[3] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf
[4] https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp-es.pdf
[5] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/LCFSpresentation_02222023.pdf; https://ww2.arb.ca.gov/sites/default/files/2022-11/LCFSPresentation.pdf

previous LCFS rulemakings. Due to the recent ramp up of the program's CI reduction trajectory, as well as potential interactions with the auto-acceleration mechanism, swift implementation of these safeguards is critically important to avoid unintended consequences of alternative fuel expansion.

Based on our review of CARB's "Proposed Alternative", we find that an alternative scenario is warranted. We recommend that this scenario incorporates elements of Alternative 1 and the Environmental Justice scenarios evaluated by CARB to safeguard against upstream emissions risk and align the LCFS with the goals of the 2022 Scoping Plan.

We recommend that CARB:

213.1

1) Set a cap on the volume of lipid-derived fuels credited under the LCFS program.

213.2

2) Phase out avoided methane emissions crediting for new projects within three years and align deliverability requirements for biomethane and bio-hydrogen pathways with the existing deliverability requirements for new electricity pathways.

213.3

3) Obligate jet fuel consumed within the California airspace starting in 2025, with a cap on lipid-based fuels crediting.

213.4

4) For pathways that utilize hydrogen as a feedstock such as e-fuels, subject the low-CI electricity used to produce the hydrogen to additionality and deliverability requirements consistent with the use of low-CI electricity for hydrogen, rather than low-CI electricity used as a process fuel.

213.5

5) Increase the scope of credit generation for transport electrification from charging infrastructure and fixed guideway public transit to simultaneously help the LCFS achieve equity goals and more ambitious target levels.

In the subsequent sections, we provide additional analysis and data from our review used to develop these recommendations.

The Proposed Approach Overestimates GHG Savings from Biomass-Based Diesel

Our analysis finds that the ISOR overstates the environmental benefits of the "Proposed Alternative." This is largely because the methodology attributes the GHG savings of existing federal biofuels policies to the LCFS program. Over the past decade, the federal Renewable Fuel Standard (RFS) program has been the primary driver for BBD production in the country.[6] Under the RFS, the EPA sets annual volume mandates for biofuels, based on an assessment of national production capacity, economics, and existing federal and state subsidies. External policies like the LCFS also influence EPA's volume projections. EPA has assessed what the 2023-2025 national biofuels market could look like in the absence of the RFS program in its supporting analysis to last year's volume rulemaking.[7] By comparing fuel volumes from scenario tables with and without an RFS in place, it found that BBD volumes would be reduced by half in a "no RFS" scenario - reflecting market conditions that operate independently of the RFS (e.g., ethanol as an oxygenate). Given that California makes up nearly half of the national BBD market,[8] we can infer that a substantial portion of this growth in volumes is driven by the federal RFS. We present the estimated share of biofuel volumes for each major feedstock category that are attributable to the RFS program in Table 1.

Table 1. Biofuel volumes projected to be consumed in the U.S. that are attributable to federal RFS program. Calculated from Tables 2.1.5-2 and 3.1-4 of 2023 RIA

Volumes attributed to federal RFS	**2023**	**2024**	**2025**
Cellulosic biofuel	59%	63%	68%
BBD	54%	50%	50%
Other advanced biofuels	21%	21%	21%
Conventional renewable fuel	5%	5%	6%

213.6 The Draft Environmental Impact Analysis[9] is also a departure from CARB's previous methodology. Previously, CARB only attributed emissions impacts beyond a 50% GHG reduction threshold to LCFS policy in updates to the 2018 LCFS rulemaking,[10]; i.e., emission reductions beyond the RFS' minimum emissions reduction threshold for BBD that could plausibly have been incentivized by the LCFS program. In the 2024 Draft Environmental Impact Analysis, CARB counted the full GHG reductions of BBD as fully attributable to the LCFS and has thus overstated them. For these reasons, it is likely

[6] https://theicct.org/wp-content/uploads/2022/01/impact-renewable-diesel-us-jan22.pdf
[7] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017OW2.pdf
[8] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017OW2.pdf
[9] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appd.pdf
[10] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/15dayattf2.pdf

213.6 that CARB has also overstated the benefits that the LCFS has on regional air quality and health outcomes. Developing a more accurate estimate would require additional modeling to disentangle the effects of the LCFS from other climate and federal biofuels policies.

Using the CATS model default inputs shared at the July 2023 workshop and assuming a 30% carbon intensity reduction target for 2030, ICCT modeled the compliance trajectory of the LCFS and estimated the GHG reductions by fuel pathway.[11] Based on this default data, we estimate that the LCFS would generate approximately 35 million cumulative tonnes of GHG reductions from virgin vegetable oils from 2024-2034, after which virgin vegetable oil begins to generate deficits. Using CARB's previous methodology of only counting the GHG reductions above 50% (which no soy oil-derived BBD pathway exceeds), approximately 6% of the cumulative 558 Mtonne CO_2e reduction calculated by CARB in its Draft analysis from 2024 through 2045 would thus not have been attributed to the LCFS, significantly narrowing the GHG savings gap between the Proposed Alternative and Alternative 1. While higher BBD growth could provide some GHG reductions in the near-term, these reductions are offset by its uncertain and significant upstream emissions impacts and inability to guide California on a path towards net-zero decarbonization. We discuss these impacts in detail below.

The LCFS is Creating Market Distortions with the National Renewable Fuel Standard

We note that the LCFS's continued reliance on BBD feedstocks will necessarily impact other states' ability to meet their own climate goals. Based on a modeling run of the CATS model based on CARB's default inputs published in summer 2023, the modeling suggests that BBD consumption could peak at 2.1 billion gallons in 2025, or more than 70% of the federally mandated BBD volume that year. Current trends in California suggest that California could be at risk of overtaking the volume of BBD mandated under the RFS, which could depress RIN credit prices or trigger the AAM. If the
213.7 renewable diesel boom in California pushes national BBD consumption beyond annual RFS mandates, this could have significant implications on RIN markets. Gerveni and Irwin have modeled the possibility of a "RIN cliff", where RIN prices fall to $0 per gallon if the BBD mandate becomes non-binding.[12] Because BBD is the marginal unit of compliance under the RFS, these price implications extend beyond the BBD RIN category. Without an increase in federal BBD mandates or a contraction in BBD supply,
213.7 the value of BBD in the U.S. could steeply drop. This risk is even more likely if the AAM is activated given that current CATS modeling projections may understate the level of BBD required for LCFS compliance.

[11] https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-meetings-and-workshops#:~:text=v0.2%20Technical%20Documentation-,CATS%20Example%C2%A0Inputs,-.
[12] https://farmdocdaily.illinois.edu/2023/05/is-the-us-renewable-fuel-standard-in-danger-of-going-over-a-rin-cliff.html

Furthermore, it is likely that the modeling used by CARB results in an under-estimate of LCFS-induced demand for virgin vegetable oils. The model baseline is tuned to 2022 consumption data and does not include the impact of the automatic-acceleration mechanism (AAM). We find that the model takes until 2025 to increase demand for BBD
213.8 to present-day 2023 consumption, and the model's inability to assess the AAM prevents us from evaluating how high near-term credit prices could further accelerate demand for BBD in the near-term.

Consumption of BBD in California far exceeds its share of the national distillate fuel market. While California made up approximately 7% of national diesel consumption in the transportation sector in 2021,[13] it consumed approximately 44% of all BBD. Its share of renewable diesel consumption is far higher. Based on data from the 2023-2025 RFS impact analysis and California quarterly reports, we calculate that 87% of renewable diesel volumes credited under the RFS were consumed in California in 2022. Even more staggering, the EIA reports that California comprised 99% of national renewable diesel consumption in 2021.[14] If CARB does not curtail unchecked BBD growth in these
213.9 current amendments, the LCFS will continue to draw BBD from other geographic regions into California. This trend will hamper the ability of other states to meet their own clean fuel standard (CFS) goals including Washington, Oregon, and the CFS newly announced in New Mexico.[15] Other state-level CFS programs in Minnesota and New York are currently under development.[16]

Supply Chain Certification of Crop-Derived Biofuels Fails to Address Indirect Land-Use Change Emissions

Over the past decade, BBD has exhibited the highest growth rate of all fuel pathways. BBD is on track to make up 46% of total credits in 2023, up from 8% in 2011.[17] Rapid growth in BBD consumption has also been followed by changes in the composition of the BBD feedstock market. Until 2021, nearly all BBD consumed in California was sourced from waste oil feedstocks such as used cooking oil (UCO), corn oil, and tallow that do not compete for land area across multiple economic markets. Although the California market was previously dominated by lower-CI BBD feedstocks, BBD derived from vegetable oils has made up a rapidly growing share of LCFS credits in recent years. Vegetable oil (primarily soybean oil) is projected to account for 17% of BBD

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[13] https://www.eia.gov/state/seds/data.php?incfile=/state/seds/sep_fuel/html/fuel_use_df.html&sid=US
[14] https://www.eia.gov/state/print.php?sid=CA
[15] https://www.env.nm.gov/wp-content/uploads/2024/02/2024-02-13-COMMS-Senate-passes-landmark-Clean-Fuel-Standard-Final.pdf
[16] https://www.dot.state.mn.us/sustainability/clean-transportation-fuel-standard-working-group.html; https://www.nysenate.gov/legislation/bills/2023/S1292
[17] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

volumes in 2023. Further, soy-BBD consumption more than doubled between 2021 and 2023 alone. We display the change in annual BBD volumes by feedstock category in Figure 1

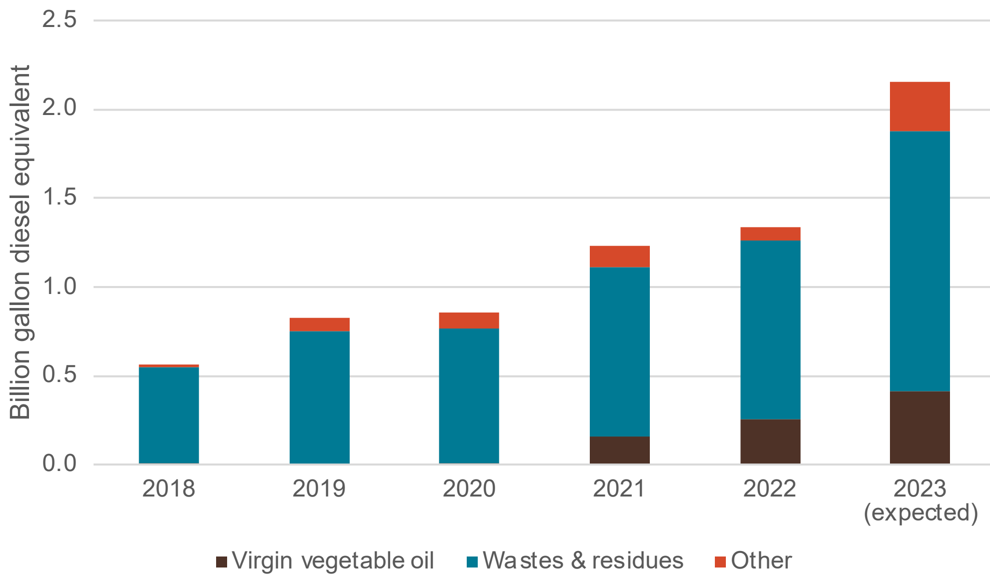

Figure 1. BBD volumes by feedstock category. Q1-Q3 2023 data is extrapolated through the end of the year.

There is no indication of this trend reversing or leveling off. EPA predicts that soybean crushing capacity could increase by more than 500 million bushels between 2022 and 2025,[18] equivalent to 770 million gallons in increased soybean oil BBD production. Industry associations including the American Soybean Association, National Farmers Union and Clean Fuels Alliance America are even more optimistic on soybean crush expansion. In comments submitted on the proposed 2023-2025 RFS volumes, these associations predicted that capacity commitments from soybean crushing facilities could result in 700-800 million gallons of additional BBD by the end of 2025.[19]

Gerveni and Irwin (2023) estimate that renewable diesel nameplate capacity could reach 7.4 billion gallons over the next decade, up from 4.1 billion gallons in 2023, and 0.8 billion gallons in 2020.[20] Similarly, the Energy Information Administration (EIA) estimates that RD capacity could more than double between 2023 and 2025 as a result of favorable state and federal biofuels policy and tax credits allocated under the Inflation

[18] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017OKN.pdf
[19] https://soygrowers.com/wp-content/uploads/2023/02/EPA-RFS-2023-2025-ASA-Comments.pdf; https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0427-0805; https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0427-0595
[20] https://farmdocdaily.illinois.edu/2023/03/overview-of-the-production-capacity-of-u-s-renewable-diesel-plants-for-2023-and-beyond.html

Reduction Act (IRA).[21] The majority of this growth will come from retrofits of existing refineries distributed along the U.S. West Coast, Gulf, and mountain regions.

The LCFS program's accelerating reliance on biomass-based diesel to meet the program's greenhouse gas targets is at odds with the emerging evidence on the market-mediated GHG emissions from growing biofuel demand using purpose-grown crops. The Draft Environmental Impact Analysis overlooks the magnitude of emissions uncertainty associated with crop-based biofuels production and overcounts emissions
213.10 reductions attributable to the LCFS program. This problem is particularly relevant to BBD fuels due to their significant upstream market and environmental impacts that are not well accounted for in supply chain (attributional) life-cycle assessment (LCA). Though CARB has evaluated the indirect land-use change (ILUC) emissions attributable to vegetable oil-derived fuels, recent studies suggest that these emissions may be understated, and the existing ILUC emission factor used in the LCFS may not be a sufficient safeguard.

We find that CARB's ILUC assessment may underestimate soy-BBD emissions significantly. When soybean oil is diverted from food, feed, and oleochemicals markets it
213.11 is often substituted with palm oil; [22] this greatly increases its upstream emissions impacts because palm oil is often grown on high-carbon stock land. In its recent RFS triennial review, EPA notes that there remains "potential for low-cost palm oil from ecologically sensitive areas in Southeast Asia to "backfill" diverted soybean oil from international vegetable oil markets." This risk is "especially [likely] if RFS program total biofuel mandates increase in the future".[23] Due to soy-palm substitution and pressure that soy expansion places on other markets, soy BBD's ILUC emissions may even exceed that of fossil fuel.

Despite years of dedicated research, ILUC modelers are no closer to reaching consensus around the upstream land-use impacts of biofuels production since the field emerged in the mid-2000s. Persistent scientific uncertainty and risk of deforestation has lead jurisdictions such as the European Union and United Kingdom to cap or limit the contributions of crop-based fuels within major fuels regulations.[24] In a 2022 report, the National Academies of Sciences, Engineering, and Medicine concluded that "substantial uncertainties remain on many key components of economic models used to assess [LUC] impacts" in their comprehensive review of LCA methodology.[25] The Carbon Offsetting and Reduction Scheme for International Aviation (CORSIA) incorporates LCA results from two different models in an attempt to account for the range of results across

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[21] https://www.eia.gov/todayinenergy/detail.php?id=55399
[22] https://www.sciencedirect.com/science/article/pii/S0301421518307924
[23] https://cfpub.epa.gov/ncea/biofuels/recordisplay.cfm?deid=353055 (p. IS-22)
[24] https://data.consilium.europa.eu/doc/document/PE-29-2023-INIT/en/pdf; https://assets.publishing.service.gov.uk/media/6424782560a35e00120cb13f/pathway-to-net-zero-aviation-developing-the-uk-sustainable-aviation-fuel-mandate.pdf
[25] https://nap.nationalacademies.org/catalog/26402/current-methods-for-life-cycle-analyses-of-low-carbon-transportation-fuels-in-the-united-states

different inputs and methodologies.[26] Although modeling of starch and sugar-based pathways have reached relative alignment for the purposes of CORSIA, ILUC modelers assessing oilseed based pathways found substantial differences across models ranging from 7 to 90 gCO_2e/MJ for various oilseed-derived biofuel pathways.[27] Depending on which model is used to assess ILUC emissions, some pathways were found to have higher emissions than the fossil fuel baseline.

The Environmental Protection Agency (EPA) released a technical modeling comparison document last year that highlights the persistent scientific uncertainty of ILUC modeling.[28] As part of the exercise, EPA compared five models including their modeling structure, spatial and temporal resolution, representation of land types, and trade dynamics. Despite harmonized inputs, the models varied greatly in their representation of global economic activity and, notably, their ILUC emissions estimates. The analysis concluded that “the variability of LUC estimates significantly influences variability in overall biofuel GHG estimates.” Further, EPA found that level of uncertainty is particularly high for soybean oil due to its fungibility with other vegetable oils including palm oil in other markets. We display EPA’s results from its corn ethanol and soybean biodiesel scenario runs across the five models in Figure 2. ILUC emissions for soybean biodiesel range between 9 and 280 gCO2e/MJ while ILUC emissions for corn range between -1 and 29 gCO2e/MJ. Removing the ADAGE model as an outlier, soybean biodiesel results range by 49 gCO2e/MJ, more than half the certified CI of fossil diesel in California.

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[26] https://www.icao.int/environmental-protection/CORSIA/Documents/CORSIA_Eligible_Fuels/CORSIA_Supporting_Document_CORSIA%20Eligible%20Fuels_LCA_Methodology_V5.pdf
[27] Ibid.
[28] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf

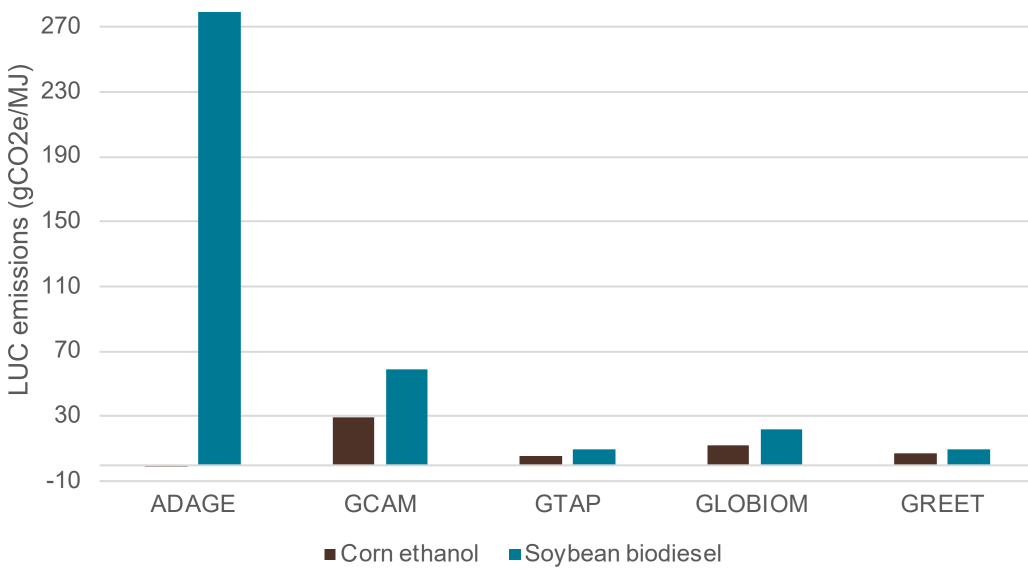

Figure 2. Land-use change emissions from EPA Modeling Comparison exercise

CARB uses a version of the Global Trade Analysis Project (GTAP-BIO) model in its 2015 ILUC assessment that modeled the impacts of demand shocks for crop-based biofuels on commodity prices and net global land conversion. Based on these modeling runs, CARB adopted an ILUC value of 29.1 gCO_2e/MJ for soy biodiesel. GTAP-BIO has been the subject of significant academic debate due to parametric assumptions such as its modeling of unmanaged forest land and high rates of yield intensification.[29] Most contentiously though, GTAP-BIO assumes that cropland expansion is likeliest to occur onto land parcels classified as "cropland pasture" and that this type of land conversion
213.12 sequesters rather than releases carbon.[30] This assumption conflicts with definitions used by the EPA that assume "cropland pasture" is land currently in a pasture state[31] and thus will result in soil organic carbon (SOC) loss when converted to cropland. As a result, the ILUC emissions adopted by CARB likely underestimate the upstream emission impacts associated with biofuel expansion.

CARB has acknowledged that "a rapid increase in oil crop demand for biofuel production could potentially add pressure to convert forested land or other land types into biofuel crop production." Rather than set a cap on high-risk feedstocks, CARB has proposed that biofuel producers adhere to a sustainability certification scheme (SCS) where independent auditors must track feedstocks to their point of origin and verify their environmental attributes to be certified. This proposal is aligned with other sustainability requirements set forth under the EU's Renewable Energy Directive (RED II) and

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29 https://theicct.org/wp-content/uploads/2023/09/ID-16-Briefing-letter-v3.pdf
30 https://www.sciencedirect.com/science/article/abs/pii/S0959652620307630
31 US EPA. "Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis," February 2010.

international CORSIA program. However, the SCS guardrail only applies to crop and forestry-based feedstocks; thus, excluding UCO supply chains with documented cases of fraud. Member States within the European Union have prosecuted several cases of UCO fraud, arising from UCO's high credit value under their implementation of the RED II.[32] In these examples, companies that were certified under SCSs forged the quantity of waste-based biofuel sold on the market or forged the makeup of these fuels entirely. An investigative report submitted to the European Commission found that the Dutch company Sunoil forged SCS certificates in 2020 of an unknown volume that credited crop-based biofuels as waste-based; the investigation is still underway.[33] Executives of the former company, Biodiesel Kampen, were arrested for fraud for falsely reporting the volumes of waste-oil fuel sold on the market. It is likely that employees may have also falsely labeled crop-based biofuel as waste-based to receive credit incentives.

The EU's experience has found that third-party verification schemes are an ineffective tool to address the environmental and social risks of biofuels. The European Anti-Fraud Office investigated a case involving numerous companies where 150,000 tonnes of virgin soy oil exported from the U.S. was fraudulently labeled as UCO to avoid anti-dumping fees and exploit national-level renewable energy incentives. A producer in the U.S., Greenworks Holdings LLC, also forged quality tests for UCO biodiesel and overstated production quantities to receive higher credit value under the federal Renewable Fuel Standard (RFS).[34]

While SCSs can help verify material and emission inputs across the fuel supply chain, supply chain certifications are fundamentally not suited to address the significant and uncertain environmental harm associated with market distortions from BBD demand.
213.13 Certification schemes, even if properly implemented, cannot measure or address ILUC. Thus, our analysis finds that it is critical that the volume of BBD feedstocks are capped at manageable levels. This exact threshold can be debated but should reflect a
213.14 feedstock's total availability accounting for competition from other sectors plus marginal growth in domestic production that is proportionate to California's share of the national distillate fuel market. Using this methodology, a previous ICCT analysis has suggested capping the contribution of lipid-based fuels, including vegetable and waste oils, at 1.2 billion gallons.[35] California has already far exceeded this supply threshold and is projected to produce 2.2 billion gallons of lipid-based BBD in 2023.

Although California has already exceeded its proportional share of domestic BBD supply, an energy or volume cap can help contain future unchecked growth in BBD markets. Given the substantial increase in BBD volumes since 2021 and difficulty associated with scaling down existing production, we recommend capping the

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[32] https://op.europa.eu/en/publication-detail/-/publication/ec9c1003-76a7-11ed-9887-01aa75ed71a1/language-en
[33] https://op.europa.eu/en/publication-detail/-/publication/ec9c1003-76a7-11ed-9887-01aa75ed71a1/language-en
[34] https://theicct.org/wp-content/uploads/2023/02/US-UCO-potential_fs_final.pdf
[35] https://theicct.org/wp-content/uploads/2022/08/lipids-cap-ca-lcfs-aug22.pdf

213.15 contribution at levels consistent with Alternative 1, which implements a roughly 2-billion-gallon cap on lipid-derived fuels starting in 2025. As explained above, the difference in emissions and implementation costs between this scenario and the Proposed Approach is substantially narrower than modeled by CARB, and this would reduce unintended climate impacts and market distortions. Further, we recommend that CARB extend the
213.15 SCS requirement to all feedstocks to mitigate fraud risk from UCO imports.

Implement livestock methane regulations and accelerate the phaseout of avoided methane emissions crediting

Avoided methane crediting has been used as a mechanism to comply with the state's Short-Lived Climate Pollutant (SLCP) strategy and precursor Senate Bill (SB) 1383 which requires that California reduce methane emissions 40% from 2013 levels by the year 2030. In place of developing binding regulations on in-state farms, previous CARB statements suggest that the LCFS is a sufficient incentive to meet the SLCP targets.[36] Notably, this methodological assumption is only applied to livestock and organic waste digester projects where methane capture is considered voluntary rather than legally required.[37] Livestock digester projects made up an estimated 90% of biomethane credit generation under the LCFS in 2023 while accounting for less than half of volumes (Figure 3).

Biomethane is consumed in a small number of natural gas vehicles (NGVs) that account for 5% of heavy-duty fuel consumption in the state.[38] NGV fuel consumption will decline in the coming decades due to the implementation of the Advanced Clean Trucks (ACT) and Advanced Clean Fleets (ACF) rulemakings that regulate a minimum share of zero-emission vehicles within California's medium and heavy-duty (MHDV) transportation fleet.[39] Despite its small role in the MHDV sector, biomethane crediting within the LCFS has accelerated in recent years. This has occurred while the delivered share of total volumes credited under the program have remained nearly constant. Biomethane is projected to make up 18% of LCFS credits and 5% of volumes in 2023, extrapolating from data from CARB's recently published Q3 report through the end of the year.[40]

The growing divergence between biomethane credits and volumes is due to the high LCFS incentive that biomethane receives when it is utilized as transportation fuel. When

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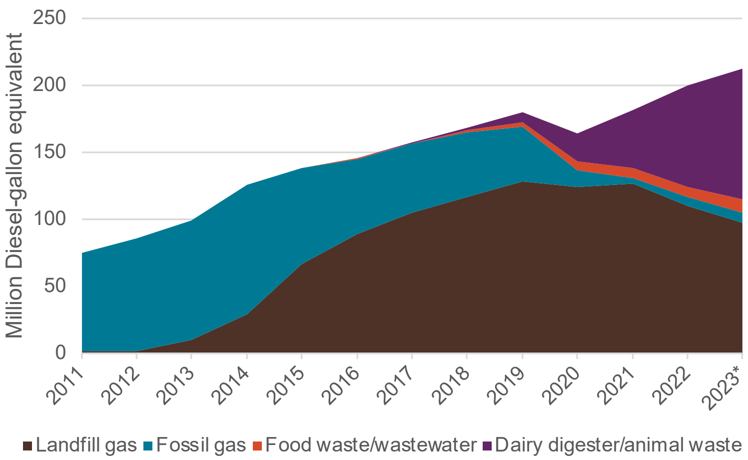
36 https://ww2.arb.ca.gov/sites/default/files/2022-01/LCFS%20Petition%20Response%202021.pdf
37 https://www.law.cornell.edu/regulations/california/17-CCR-95488.9
38 https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries
39 https://ww2.arb.ca.gov/our-work/programs/advanced-clean-fleets; https://ww2.arb.ca.gov/our-work/programs/advanced-clean-trucks/about
40 https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

assessing the lifecycle impact of some biomethane pathways, CARB assumes that methane emissions would be vented to the atmosphere in the absence of an LCFS policy signal. We illustrate growth in biomethane volumes and credits by feedstock in Figure 3.



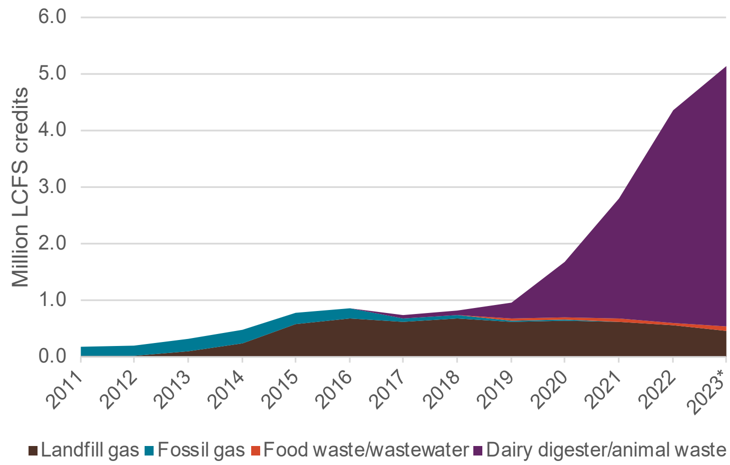


Figure 3. Share of CNG volumes by feedstock type (left); Share of CNG credits by feedstock type (right)

Rapid growth in livestock digester projects in California is motivated by its significant financial incentives. We find that active swine projects have an average CI of -406 gCO_2e/MJ while active dairy projects have an average CI of -285 gCO_2e/MJ based on data reported in the LCFS current pathways spreadsheet,[41]. This is equivalent to a $6.66/diesel-gallon equivalent(DGE) and $5.03/DGE credit value in 2023, respectively, assuming an $100/metric tonne credit price.[42] If biomethane is later converted to bio-hydrogen it receives an even higher credit incentive per volume of fuel due to hydrogen's 1.9x energy economy ratio (EER) in MHDV applications.[43] Using CARB's LCFS credit price calculator, we find that the value of bio-hydrogen could even exceed $5/kg assuming current credit prices, nearly double the tax incentive under the 2022 Inflation Reduction Act (IRA). We present common biomethane pathways, their average CI, and associated credit value in 2023 in Table 2. Pathways with negative emission CIs receive the highest LCFS credit value while pathways with higher average CIs such as landfills and wastewater plants receive a more moderate credit value.

[41] https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities
[42] https://ww2.arb.ca.gov/sites/default/files/2022-03/creditvaluecalculator.xlsx
[43] https://ww2.arb.ca.gov/sites/default/files/2020-07/2020_lcfs_fro_oal-approved_unofficial_06302020.pdf

Table 2. Average project CI value and credit values for certified biomethane pathways in 2023. Assumes $100/mt LCFS credit price

Feedstock pathway	Average CI (gCO_2e/MJ)	Credit value ($/MMBTU)	Credit value ($/DGE)
Landfill gas	62.6	$2.81	$0.36
Fossil NG	79.2	$1.05	$0.13
Wastewater	49.0	$4.24	$0.54
Food waste	-54.1	$15.11	$1.93
Organic waste	16.7	$7.64	$0.97
Swine manure	-406.2	$52.27	$6.66
Dairy manure	-285.2	$39.5	$5.03

Digester projects are also eligible for federal and state-level grant funding to reduce the cost of methane capture. The U.S. Department of Agriculture (USDA) offers loan financing under the Rural Energy for America Program (REAP) to cover up to 75% of eligible costs for energy projects.[44] Since 2015, the California Department of Food and Agriculture (CFDA) has awarded $227 million in funding for dairy digester projects concentrated in the Central Valley.[45] Dairy biomethane is also eligible for RIN credits, which have traded at a value of $2.50 per gallon ethanol equivalent ($4.1/DGE) over the last 5 years.[46] Between 2025 and 2027, the IRA 45Z tax credits will provide another funding stream of up to $1.00 per DGE for dairy biomethane consumed as a transportation fuel. In total, this amounts to a staggering incentive of ~$11-$12.50 per DGE for biomethane derived from dairy and swine digesters, assuming LCFS credit prices from Table 2 above.

The combination of high-value incentives from multiple overlapping policies and jurisdictions poses a particularly strong additionality risk for pathways certified with avoided methane emissions. Though CARB has generally avoided assessing the additionality of fuels delivered under the program, biomethane pathways pose a unique risk because of a combination of factors, namely 1) their very high negative emissions attributable to out-of-sector behavior, 2) the lack of meaningful deliverability requirements meaning that these fuels aren't necessarily consumed in California or in the transportation sector (as discussed in the subsequent section), and 3) the sheer size of the combined policy incentives for these fuels. While it can be argued that a biofuel consumed in California can benefit from a combination of policies to motivate its production and reduce its CI, that argument has less merit for crediting a unit of natural

[44] https://www.rd.usda.gov/programs-services/energy-programs/rural-energy-america-program-renewable-energy-systems-energy-efficiency-improvement-guaranteed-loans
[45] https://www.cdfa.ca.gov/oefi/DDRDP/docs/DDRDP_Program_Level_Data.pdf
[46] https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information

gas paired with the attributes of an out-of-state dairy farm. Given the accelerating role of these pathways in the LCFS and their out-of-scale contribution to the program, implementing guardrails in this rulemaking would help to ensure that the LCFS is not diluted by GHG reductions whose attribution to the program is difficult to demonstrate.

We find that numerous digester projects that upgrade biogas to renewable natural gas (RNG) were already capturing methane independently of the LCFS program. These producers receive negative emissions credits for simply diverting biogas feedstock from existing applications to the transport sector rather than capturing methane that would have otherwise been vented to the atmosphere. For example, ICCT submitted comments on FirstElement Fuel's LCFS pathway application that highlights the lack of additionality for biomethane-based project crediting.[47] The candidate dairy farms were previously producing electricity on-site with excess transmitted to the local electric grid. Project data indicates that the digester was installed in 2010, far before the facility began upgrading biogas to transportation fuel.[48] Despite this pre-existing baseline, the facility operators assumed that methane would be vented to the atmosphere under a counterfactual scenario in their pathway application, later approved by CARB. This counterfactual scenario is simply not credible, and neither are the GHG emission reductions credited to the LCFS for this pathway.

213.16 Biomethane capture in anaerobic digesters will remain an effective method to reduce methane emissions but it is critical to recognize that the LCFS is often not the driver of this step and digesters are often installed or were installed years ago for other reasons. Thus, phasing out avoided methane crediting in the LCFS as soon as possible will help to "right-size" the value of RNG pathways compared to their genuine effect of reducing lifecycle GHG emissions and displacing fossil fuel consumption. We recommend that CARB phase out avoided methane credits at the end of existing pathways' current 10-year crediting cycle and within three years for new applications to help prevent crediting biomethane pathways that are not additional. It generally takes up to 2 years for developers to plan and construct new digester projects,[49] so this timeline would offer flexibility to developers that anticipated negative emissions crediting within their project economics. Following a similar timeline, the IRA 45V tax credit has set a vintaging requirement that renewable energy generation facilities must be built no earlier than 3 years before the tax credit takes effect to avoid crediting projects that are non-additional.[50]

213.17 Using the Argonne National Lab Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies (GREET) Model, we estimate the emissions for dairy biogas to be approximately 19 gCO_2/MJ, assuming that the methane reductions and soil carbon

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[47] https://www.arb.ca.gov/lists/com-attach/980-tier2lcfspathways-ws-Vj8GY1c1ACcLUlc0.pdf
[48] https://martinenergygroup.com/wp-content/uploads/2022/08/2MCR_QualificationsStrengths_Final.pdf
[49] https://www.biogasworld.com/biogas-faq/#:~:text=For%20a%20moderate%20to%20large,have%20a%20functioning%20biogas%20plant.
[50] https://www.govinfo.gov/content/pkg/FR-2023-12-26/pdf/2023-28359.pdf

sequestration from digestate are not attributable to the LCFS (i.e. that a digester would still have been used in the counterfactual scenario).[51] This change still represents an approximately 80% GHG reduction relative to conventional, petroleum-derived fuels but more accurately reflects the emissions reductions from displacing fossil fuels.

213.18 Although capturing methane from dairy digesters is a laudable goal, there are other methods to meet the 40% reduction target of the SLCP. Changes to manure management practices and livestock diets can help reduce methane reduction at the source.[52] It may also be preferable to implement a regulation with a carbon border adjustment mechanism[53] to ensure that dairy products produced outside of California are treated consistently with those produced in-state. The EPA has detailed strategies that agricultural producers can pursue depending on the size of their operations and relative costs.

213.19 CARB's proposed phaseout dates of 2040 for biomethane and 2045 for bio-hydrogen are completely insufficient to prevent avoided methane credits from distorting the climate goals of the LCFS. Though the scenario modeling published by CARB indicates that these pathways will be phased out completely after 2040, this modeling does not take into account the opportunities for existing pathways to recertify for multiple, 10-year periods. For example, RNG pathways with avoided methane emissions credits that are certified before 2030 may qualify for up to three, 10-year credit periods. Furthermore, the Draft analysis does not evaluate the transition from dairy RNG pathways (which are separated in the results) to dairy biomethane electricity and dairy biomethane hydrogen pathways.

213.20 In summary we recommend that the phaseout of avoided methane emissions crediting takes effect by the end of the 10-year crediting period for certified projects and that avoided methane emissions credits are phased out for new projects within the next 3 years. These changes from the current ISOR proposal are critical to align the significant subsidies allocated to biomethane with its climate impact when consumed as a transport fuel.

Book-and-claim biomethane crediting sustains out-of-state and out-of-sector emissions crediting, diluting the LCFS's impact on California's transportation sector

By conflating methane reductions achieved under the SLCP strategy with the book-and-claim structure LCFS program, CARB has overstated the ability of biomethane to

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[51] Argonne National Lab, 2021 "Greenhouse Gases, Regulated Emissions, and Energy Use in Technologies Model",https://greet.es.anl.gov/; assuming 100% dairy cow-derived manure, California electricity grid mix, for renewable natural gas as an intermediate fuel.
[52] https://www.epa.gov/agstar/practices-reduce-methane-emissions-livestock-manure-management
[53] https://taxation-customs.ec.europa.eu/carbon-border-adjustment-mechanism_en

displace petroleum and achieve the state's broader decarbonization goals. Book-and-claim decouples fuel consumption from fuel production via the purchase and trade of environmental attributes; thus, it does not require any physical traceability of injected fuel. In many cases, RNG projects credited under the LCFS are located outside of California that have no direct impact on California's greenhouse gas (GHG) emissions or in-state agricultural practices. In other words, natural gas suppliers may gain revenue from LCFS credits for a unit of fossil gas produced and consumed in California (often in non-transportation uses) with an equivalent unit of renewable natural gas (RNG) produced across the country and injected into the national natural gas transmission grid.

Based on existing pathways certified under the LCFS, we find that **all** active landfill gas and swine digester projects credited under the LCFS are located outside of California while 48% of dairy digester projects and 83% of wastewater projects are located outside of the state based on CARB project data.[54] Similarly, CARB has found that, in 2022, the majority of RNG reported under the LCFS program came from "resources injected into the North American natural gas pipeline outside of California."[55]

We review the geographic makeup of biomethane derivative projects including bio-hydrogen and low-CI electricity in Figure 4. Out-of-state project crediting is particularly relevant for dairy manure projects that receive a highly negative CI under current LCFS methodology. We focus on dairy manure as a feedstock since dairy manure-derived biogas makes up the highest number of active biomethane, bio-hydrogen, and bio-electricity projects credited under the LCFS. We find that all dairy manure-derived bio-hydrogen projects are sourced from digesters located outside of California while roughly half of dairy biomethane projects are located outside of the state. We present the share of active dairy biomethane and derivative projects located within and outside California from CARB's pathways spreadsheet in Figure 4.

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[54] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/current-pathways_all.xlsx
[55] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf

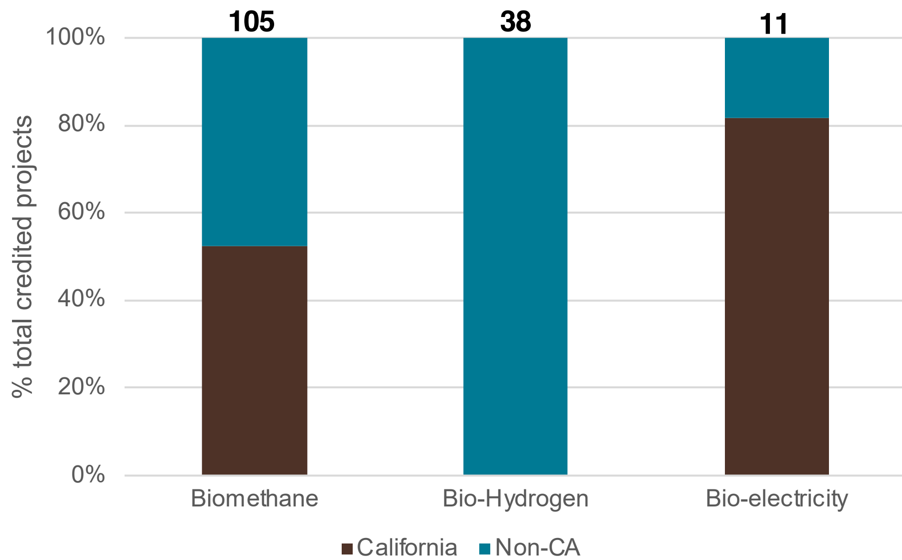

Figure 4. Share of dairy biomethane and derivative projects receiving LCFS credits located in and outside California. Total number of active projects are bolded at the top of each column.

213.21 CARB has proposed setting deliverability requirements on biomethane to better align project crediting with the state's methane reduction targets and address the recent rise in book-and-claim crediting. Deliverability requirements stipulate that biomethane must flow through "common carrier pipelines that physically flow within [or toward] California…50% of the time on an annual basis" beginning in 2041 for biomethane and 2046 for bio-hydrogen. The proposed language is consistent with deliverability requirements that biomethane-based electricity must adhere to under the state's Renewable Portfolio Standard (RPS); however, the ISOR does not specify how these requirements would translate to the natural gas grid and CARB has not provided further information on how it would be implemented and to what extent it would constrain the existing system. A simple geographic deliverability requirement will be more transparent, easier to implement, and is precedented from the deliverability requirements for low-CI electricity. 213.22 Drawing from an analysis conducted by the U.S. Department of Energy (DOE) for 45V tax credit implementation, we recommend that CARB limit geographic eligibility for biomethane to the states of Washington, Oregon, and California, as this would be roughly consistent with the geographic deliverability for electricity proposed for 45V.[56] Alternatively, CARB can reference geographic zones from the U.S. natural gas transmission network to set its deliverability boundaries.[57]

We note that the deliverability requirements for biomethane for hydrogen specifically are far less stringent than those for low-CI electricity derived hydrogen. Despite achieving a higher theoretical credit price than green hydrogen, green hydrogen made from low-CI electricity must satisfy a more rigorous series of requirements to ensure geographic

[56] https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen
[57] https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/index.html

deliverability, that low-CI electricity comes from new generation, and no double-
counting. In contrast, biomethane producers who sell their environmental attributes to
existing grey hydrogen producers must only demonstrate the retirement of
environmental attributes. Thus, a pathway that enables further use of existing natural
gas SMR technology generates higher credit values in the LCFS and has looser book-
213.23 and-claim requirements than a green hydrogen pathway that involves deploying new
electrolyzer technology. We recommend that CARB set deliverability requirements on
bio-hydrogen that are consistent with other biomethane pathways. That is, implemented
within the next three years and adherent to the same geographic boundaries.

The deliverability requirements proposed in the ISOR also fall short of initiating any
meaningful change to current operating conditions. This is due to significant
implementation delay and looser guidance granted to hydrogen producers. CARB has
noted that this delay is intentional to encourage a "rapid buildout of biomethane capture
projects" before the end of the decade to meet the state's methane reduction goals.
However, attributing biomethane capture to the LCFS program belies the reality that
majority of these emissions reductions occur out of state and outside the transportation
sector. Credited RNG volumes may also begin to exceed the quantity of natural gas
consumed in California's transportation sector, further stretching the plausibility of the
213.24 argument that RNG contributes to reducing California's transportation GHG emissions.
Previous ICCT analysis has found that RNG volumes credited under the LCFS
accounted for 98% of natural gas vehicle consumption in California in 2021.[58] As
demand for CNG declines even further, new RNG production will have no little to no
impact on displacing in-state petroleum consumption and meeting the goals of the 2022
Scoping Plan.

In summary, we recommend that CARB implement stronger deliverability requirements
213.25 for all pathways derived from biomethane within the next three years to prevent
subsidizing out of sector emission reductions within an in-state transportation policy. For
pathways that are already certified, we recommend that deliverability requirements take
effect at the end of the current 10-year crediting period.

Obligate fossil jet fuel as a deficit-generating fuel before 2028 and paired with a cap on lipid-based fuels

CARB has proposed obligating jet kerosene as a deficit-generating fuel beginning in
213.26 2028. This will increase crediting opportunities for sustainable aviation fuel (SAF) and
encourage economic growth in a budding California SAF market. Due to the small size
of the volume obligation, this growth will be limited. Without expanding the obligation
scope to cover all inter-state jet fuel, it will also require that other transport sectors

[58] https://theicct.org/wp-content/uploads/2023/05/california-rng-outlook-2030-may23.pdf

continue to shoulder the burden of decarbonizing the state's aviation emissions. If LCFS
213.27 amendments do not incentivize sufficient quantities of SAF, the aviation sector can source credits from sectors that over-comply with their annual CI reduction targets to meet annual compliance.[59]

California has signaled stronger support for SAF in earlier proposals that are notably less ambitious in the ISOR. In 2021, California legislature passed AB 1322 that set a 20% SAF blending target by 2030, approximately 1.5 billion gallons.[60] This bill was later vetoed by Governor Newsom on the grounds that the LCFS was already an effective policy lever to meet these goals.[61] Absent any proposed amendments, ICCT research has found that the LCFS alone is an insufficient tool to promote SAF uptake in California.[62] Study authors found that obligating intra-state aviation would only expand the LCFS program by 5% based on the quantity of deficits generated on intra-state flights. Pavlenko and Mukhopadhaya estimate that fuel consumed on intra-state flights accounts for roughly 6% of jet fuel uplifted in California.[63] At a maximum, that level of obligation would deliver a maximum of approximately 113 million gallons of SAF production by 2030 assuming that aviation obligations are met in-sector rather than through out-of-sector credits from renewable diesel or electric vehicle charger.

In comparison, CATS modeling suggests that jet fuel deficits will make up 1.8% of total deficits (0.76 million tonnes CO_2e) in 2030 under a 30% CI reduction target. Jet fuel makes up approximately 0.7% of deficits (0.23 Mt CO2e) under the baseline 20% CI reduction target. If jet fuel was obligated at an earlier date, this could generate an additional 2.6 million tonnes in CO_2e deficits between 2025 and 2027 under the proposed scenario. This corresponds to approximately 500 million gallons of cumulative SAF production, based on the average carbon intensity of SAF consumed in California in 2021.

If California were to obligate the entirety of jet fuel consumed over its airspace, this could motivate SAF production even further. We analyze what this obligation might look like based on routing data from California airports, using an updated version of the Global Aviation Carbon Assessment (GACA) model developed by Graver et al. (2020.)[64] Jet fuel consumed over the California airspace is approximately 3 times the magnitude of fuel consumed on intra-state flights (i.e., those that begin and end in California). We source jet fuel deficit quantities directly from the CATS model and calculate SAF production assuming a conversion ratio of 0.005 tonnes of offset CO_2e per gallon. Our estimates likely overstate SAF production by assuming that SAF credits fully offset the quantity of jet kerosene deficits. In practice, the quantity of SAF would be lower due to the relatively lower cost of using out-of-sector credits.

[59] https://theicct.org/wp-content/uploads/2023/01/ca-aviation-decarbonization-jan23.pdf
[60] https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB1322
[61] https://www.gov.ca.gov/wp-content/uploads/2022/09/AB-1322-VETO.pdf?emrc=7598b6
[62] https://theicct.org/wp-content/uploads/2023/01/ca-aviation-decarbonization-jan23.pdf
[63] Ibid.
[64] https://theicct.org/publication/co2-emissions-from-commercial-aviation-2013-2018-and-2019/

We review results from the August 2023 CATS model under a baseline (20% CI reduction, proposed (30% CI reduction), and proposed with expanded obligation the entire CA airspace scenario in Figure 5. These scenarios assume that jet fuel is obligated beginning in 2025, 3 years ahead of the published ISOR proposal. We find that near-term SAF production is significant under the proposed scenario (30% CI reduction) and increases to 198 million gallons in 2030 while SAF production gradually increases to 49 million gallons under the baseline scenario (20% CI reduction). Obligating the entirety of the CA airspace would result in far higher SAF production. We this obligation could result in 1.1 billion gallons of new SAF production in 2030.

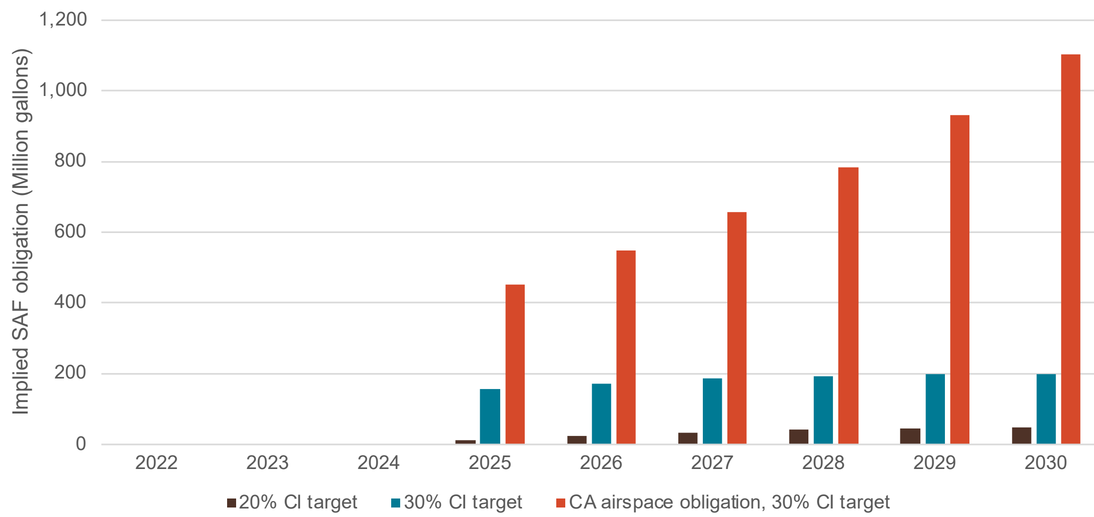

Figure 5. Estimated SAF production to offset jet kerosene deficit generation under three LCFS scenarios

Obligating jet fuel demand could help incentivize SAF production in California but would fall short of the legislative intent of AB 1322 across all scenarios. If CARB waits until 2028 to implement this obligation, this will reduce the cumulative production of SAF by 500 million gallons based on the proposed scenario and 1.66 billion gallons, assuming an obligation of the entire CA airspace.

213.28 While an increase in SAF can deliver public health and emissions reduction benefits, it is important that this growing fuel market does not exacerbate upstream emissions impacts from other transport sectors. SAF is often co-produced with renewable diesel at bio-refineries and thus is sourced from the same waste and virgin vegetable oil feedstocks. This increases demand for lipids that are already in limited supply and could exacerbate unintended emissions consequences associated with biofuel production. These risks include ILUC, plummeting RIN prices, and waste oil fraud as discussed above.

To summarize, though we support expanding the scope of the LCFS to include the aviation sector, we caution that it must be done without exacerbating the underlying problems in the LCFS. If aviation is obligated without a separate safeguard on lipid-
213.29 based fuels, this could undermine the GHG emission and public health benefits of regulating aviation emissions. Thus, we recommend that CARB obligate jet fuel consumed over the entire CA airspace to spur growth in nascent SAF markets and deliver public health benefits but only if this obligation is paired with a cap on the consumption of lipid-based fuels. We also recommend that this obligation take effect in 2025 to increase cumulative SAF output and signal earlier support for the production scale-up of advanced fuel pathways.

Establish criteria for low-CI electricity used to produce e-fuels consistent with criteria for green hydrogen production

In the proposed amendments to the LCFS, CARB staff propose new requirements for the attribution of low-CI electricity used as a transportation fuel, direct air capture, and for hydrogen used directly as a transport fuel. These requirements are a welcome change from the previous guidance for the crediting of low-CI electricity under the LCFS, and will help to ensure that low-CI electricity is not being diverted from existing uses by ensuring that it is new production, deliverable within the same grid region, and that renewable energy attributes are not double-claimed.

However, we note that as written, the current guidance will restrict the use of e-fuels made from low-CI electricity, as these are not included in the current language. Thus the proposal would effectively restrict low-CI electricity from being eligible for attribution unless it was supplied via a direct electricity connection. However, it is likely that as with most green hydrogen production, grid-connected projects will have greater economic
213.30 competitiveness due to a higher capacity factor.[65] Therefore, to provide more flexibility for e-fuel pathways based on converting green hydrogen into other fuels, we recommend that CARB treat these pathways' use of low-CI electricity consistent with green hydrogen and direct air capture. This will still maintain crucial safeguards on project vintage, deliverability and double-counting, while providing necessary flexibility for these projects to use renewable electricity supplied via the grid.

Expand Opportunities for ZEV crediting

The Proposed Alternative relies heavily on virgin vegetable oils and avoided emissions from biomethane to meet 2030 targets, despite these pathways' sustainability risks and the potential for over-attribution of GHG savings to the LCFS program. In CARB's Draft analysis, both Alternative 1 and the EJ scenario that scaled back reliance on these

[65] https://theicct.org/publication/fuels-us-eu-cost-ekerosene-mar22/

pathways were penalized for the lower GHG reductions attributable to these safeguards. However, we recommend that CARB instead pair these safeguards with expanded credit generation opportunities from ZEVs in order to complement CARB's existing strategies on ZEV deployment and equity while also maintaining its goals of more ambitious LCFS targets.

Currently, the LCFS greatly limits credit generation from fixed guideway public transit systems by limiting the energy-economy ratio multiplier of 4.6x to track lengths that were constructed after 2011. Despite these' systems high energy efficiency, potential to displace vehicle use and local air pollution, and contribution to local communities, their role in the LCFS to date has been minimal. For example, the BART system plays a crucial role in electric mobility in the Bay Area, but approximately 90% of its system predates 2011.[66] Extrapolating this under-crediting to the fixed guideway pathway as a whole, we find that there is substantial potential for credit generation to support public transit in California by applying the EER to all fixed guideway systems regardless of construction date. In July 2023 CATS modeling, we calculate approximately 6.2 Mtonnes of LCFS credits from fixed guideway systems would be generated from 2024-2045. Assuming a similar 90% relationship as in the BART system, applying the EER uniformly to all fixed guideway systems would increase the total credits over that time period to 26.3 Mtonnes—approximately 75% of the credits generated by virgin vegetable oils over that same time period. These credits could enable a virtuous cycle, enabling further capacity improvements for transit agencies and increasing ridership while displacing automobile use. Furthermore, these credits would allow CARB to set ambitious targets while implementing safeguards such as capping lipid-based fuels.

To help achieve California's long-term goals of electrification, using the LCFS to support the build-out of light and heavy-duty charging infrastructure is another opportunity to create a virtuous cycle. Lack of charging infrastructure remains a substantial barrier to EV adoption, particularly for low-income drivers or those living in multi-family housing.[67] There remain substantial further needs for charging infrastructure in California. For example, we estimate that Los Angeles will need more than 3,000 public fast charging stations by 2030 and San Francisco would require approximately 350. The proposed phasing down of light-duty fast charging infrastructure credits to 0.5% of the previous
213.31 year's deficits in the proposal occurs too soon.[68] Therefore, we propose maintaining the size of the LDV FCI infrastructure credits at 2.5% of previous year's deficits.

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[66] Bay Area Regional Transit, 2023. *Letter to Cheryl Laskowski. RE: Potential Updates to the Low Carbon Fuel Standard Program*

[67] https://theicct.org/publication/quantifying-the-electric-vehicle-charging-infrastructure-gap-across-u-s-markets/; https://theicct.org/publication/when-might-lower-income-drivers-benefit-from-electric-vehicles-quantifying-the-economic-equity-implications-of-electric-vehicle-adoption/

[68] https://theicct.org/publication/los-angeles-electric-vehicle-charging-infrastructure-needs-and-implications-for-zero-emission-area-planning/ and https://theicct.org/wp-content/uploads/2021/06/SF-EV-charging-infra-oct2020.pdf

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Comment 223 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Miles
Last Name	Heller
Email Address	hellermt@airproducts.com
Affiliation	Air Products
Subject	Comments regarding LCFS 45-day package
Comment	We appreciate the opportunity to provide this feedback. Please find our comments attached.
Attachment	www.arb.ca.gov/lists/com-attach/6887-lcfs2024-VDVRPlAjUFwEcgFz.pdf
Original File Name	Air Products Comments Draft LCFS Regulation final.pdf
Date and Time Comment Was Submitted	2024-02-20 13:04:39

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Air Products and Chemicals, Inc.
4000 MacArthur Boulevard, Suite 420, East Tower
Newport Beach, CA 92660

www.airproducts.com

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Comments submitted electronically

RE: Draft Low Carbon Fuel Standard (LCFS) 45-Day Comment Package

Dear Chair Randolph and fellow Board Members,

Air Products is pleased to provide comments in support of the California Air Resources Board (CARB) rulemaking for the Low Carbon Fuel Standard (LCFS). We support California's climate goals and Air Products stands ready to help the State facilitate the energy transition needed to meet these challenges. We are very appreciative that CARB has recognized the substantial role that hydrogen will play to decarbonize transportation by proposing many related improvements to the LCFS in the proposed 45-day package.

Air Products is the only U.S.-based global industrial gas company and the largest hydrogen producer globally, nationally, and in California. The company is a trusted hydrogen supplier for numerous markets, including transportation. Within California, Air Products safely operates 10 hydrogen production facilities, about 30 miles of hydrogen pipeline and currently supplies and operates a network of light-duty and heavy-duty hydrogen fueling stations, facilitating the transition to zero-emission transportation. Air Products has also been selected to be part of the California ARCHES LLC Hydrogen Hub Project.

We are committed to rapidly scaling and decarbonizing global hydrogen supplies to support decarbonization efforts internationally. Air Products has announced[1] that it will spend or at least $4 billion in additional new capital for the transition to clean energy over the next five years. Air Products had previously announced approximately $11 billion in clean energy investments, bringing its total recent commitment to clean energy investments targeting hard-to-abate economic sectors to $15 billion.

Summary: Key Areas of Support and Improvement

214.1 • We support the most ambitious carbon intensity (CI) reduction targets feasible and a robust stepdown of at least 7% prorated for 2024 to send a strong signal to the market once the rule is effective.

214.2 • We support the inclusion of the Auto-Acceleration Mechanism but believe the assessment should start in 2026 based on 2025 data.

[1] Air Products Announces Additional "Third by '30" CO2 Emissions Reduction Goal, Commitment to Net Zero by 2050, and Increase in New Capital for Energy Transition to $15 Billion

214.3 - We strongly support the inclusion of a technology-neutral CI-based book-and-claim approach for hydrogen but suggest that it be used for all transportation fuel regardless of where they are produced, if they are consumed in California consistent with standard LCFS treatment of fuels.
214.4 - We appreciate the extension of low-CI electricity book-and-claim to include process energy demand for the full hydrogen fuel value chain but believe the eligibility for all transportation in the current regulation should be maintained and the resource-shuffling and time-matching requirements should apply equally to both hydrogen and electricity.
214.5 - We support the additional time provided to hydrogen for the beneficial use of biomethane.
214.6 - We applaud the proposed extension of Hydrogen Refueling Infrastructure (HRI) crediting to medium and heavy-duty vehicles, along with additional time for light-duty vehicle stations and look forward to working on language with CARB to accommodate refueling stations that serve all vehicle types.
214.7 - We are very pleased with the inclusion of a Tier 1 Simplified Calculator for hydrogen and clarification that hydrogen plants that are not co-located with refineries are eligible under the project-based crediting provisions.

Program Stringency

We urge CARB to be as ambitious as possible in setting the new carbon intensity reduction targets between now and 2045 and align targets with levels no less than what is needed to achieve California's greenhouse gas targets and outcomes established in the 2022 Scoping Plan Update. Setting the target
214.8 at a 30% CI reduction by 2030 should be the minimum. If additional information becomes available from stakeholders or CARB analysis during the 45-day public comment period to support a larger CI reduction, then we urge CARB to make this change, provided it does not require restarting the rulemaking process and necessitate reissuing the 45-day package notice. CARB should be confident in setting ambitious standards, given the existing robust cost-containment provisions in the regulation, and provide regulated party protection, should low-carbon fuel supplies not develop as quickly as anticipated. As discussed in the 2022 Scoping Plan Update, a statewide carbon reduction target of 48% below 1990 levels by 2030 as well as carbon neutrality by 2045 creates decarbonization targets that need to be supported by the LCFS targets. The transportation sector and fuel production pathways are the largest component of statewide greenhouse gas emissions, accounting for about half of the state's climate footprint, so the LCFS needs to provide a proportional amount of the reductions toward the 48% reduction target.

214.9 We support including both the initial 2025 accelerated stepdown of at least 5% and automatic stringency 'ratcheting' mechanism conceptually as proposed in the 45-day package. Based on the most recently published banked credit balance of over 20 million metric tonnes (Q3 2023), a step down of at least 7% is more appropriate. In the ICF International comments submitted to CARB last year, a CI reduction level of between 20% and 25% may still have an associated credit bank build.[2] A stepdown in the range of 7% to 10% would result in a CI reduction target from 20.75% to 23.75% relative to the current target of 13.75% in 2025 – well within the range of ICF's predicted potential increase in banked

[2] See attachment at the following link: https://ww2.arb.ca.gov/form/public-comments/submissions/4306

credits. We also request that a prorated stepdown occur for the partial year of 2024, as soon as the rule is effective, to send the right signal to the market as early as possible.

The LCFS program is most effective when the credit pricing is consistently at a level that incentivizes the innovation and clean fuel supply needed to decarbonize the transportation sector. Enabling the program to make this adjustment automatically through the proposed Auto Acceleration Mechanism (AAM) would be very powerful for accelerating deployment of low carbon fuels. We believe that there will be a strong need for this mechanism in the future as many policies and funding streams outside of the LCFS will contribute to the decarbonization of transportation, which further depresses LCFS credit values. This will translate into reduced investments and less innovation in clean low-CI fuels. For example, there are substantial programs that support battery electric vehicles outside of the LCFS and provide significant incentives for the purchase and use of light duty battery electric vehicles[3]. Such programs will result in a substantial increase of credits in the LCFS program from the displacement of gasoline with electricity as a fuel. The stringency of the LCFS program will need to be tightened aggressively to sustain the important signal it provides to all clean fuels.

In terms of AAM design, we prefer that the trigger bring stability to the market without price volatility, and that the action taken be predictable and thereby more certainty as market participants project credit balance outlook and value. We support CARB's proposed AAM, but request that the implementation be set one year earlier than proposed to allow faster acceleration of the targets – providing increased stringency to the program if the 2025 stepdown fails to bring the program back in balance. The signal to the market has been diminished based on substantial overcompliance for many years and based on the current and growing bank balance, we foresee this trend continuing unless CARB sets an ambitious CI reduction target. To facilitate the most flexible and effective AAM, we request that
214.10 CARB change the reference year in 95484 (b) from 2027 to 2026 and reference years in 95484 (c), (d), (e), and (f) from 2028 to 2027.

Hydrogen Book-and-Claim Provisions

Air Products appreciates CARB's willingness to provide a 'book-and-claim' accounting approach for low-
214.11 CI hydrogen and we strongly support the provision's focus on a technology-neutral, CI-focused metric to establish eligibility for low-CI hydrogen. Focusing on CI is consistent with CARB's longstanding approach under the LCFS and the definition of clean hydrogen set in the Inflation Reduction Act (IRA). To advance the State's transportation decarbonization goals, meet greenhouse gas reduction targets and support the nascent low-carbon hydrogen market, it is essential to capture the CI attribute of hydrogen that is transported in multi-source/multi-use distribution systems, where lower-carbon hydrogen is comingled with conventionally produced hydrogen. A robust book-and-claim system for hydrogen will ensure that the low-carbon attributes of the hydrogen are retained and applied to end-uses where the most environmental benefit can be derived. This sends the necessary long-term signal for low-carbon hydrogen to play a meaningful role in decarbonizing transportation. CARB's design of such a system will serve as a model to other jurisdictions considering or implementing an LCFS program. It is important to get this right.

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[3] Volkswagen Environmental Mitigation Trust Fund, California Energy Commission EnergIIZE Infrastructure Funding Program and Clean Transportation Programs, and the National Electric Vehicle Infrastructure Program

214.12 To that end, one key improvement needed is to eliminate the requirement that eligible hydrogen must be supplied to California in a dedicated pipeline as proposed in §95488.8(i)(3)(A). This requirement places an unnecessary constraint on a nascent market and will stifle investments at a time when massive capital outlays are needed to bring low-carbon hydrogen to scale. There are no dedicated interstate hydrogen pipelines to California. As such, this requirement favors only in-state hydrogen pipelines and fails to recognize the value of using hydrogen as a feedstock to renewable fuels produced out of state and imported for use in California. These fuels are actively contributing to decarbonizing California's transportation energy and will become more important as sustainable aviation fuel is further incented in the regulation. In fact, 95488.8(i)(3) specifically indicates the intention that the low-CI hydrogen book-and-claim approach should be applied to hydrogen used in "Alternative Fuel Production", but this proposed eligibility requirement precludes alternative fuel facilities out of state from realizing these benefits. These renewable fuel facilities are located in fuel producing regions across North America, are connected to regional hydrogen pipelines, and are planning to lower their CI by utilizing low-CI hydrogen. For example, we believe that CARB would welcome out-of-state projects whereby a renewable fuel facility that consumes low-zero-carbon intensity hydrogen from a direct connection, delivers those renewable fuels to California. However, a specific geographic limitation directing that the hydrogen be supplied to
214.13 California would make such a project ineligible, consequently lowering the incentive for producing low-CI hydrogen and forgoing related emission reductions. We urge CARB to adopt a wider worldview that acknowledges the need for a multi-jurisdictional supply chain for low-carbon hydrogen capable in order to displace the existing, equally global fossil fuel supply chain and demonstrate California's leadership in driving decarbonization nationally. Promoting hydrogen energy infrastructure nationally and globally will drive down costs, promote wider adoption and achieve decarbonization more quickly if CARB does not put artificial barriers in place.

We find no statement in Appendix E as to the rationale behind this requirement. In fact, the rationale for providing a book-and-claim approach for low-CI hydrogen is expressly to "facilitate and spur the use of low-CI hydrogen in support of California's decarbonization efforts." Renewable liquid fuels have played, and will continue to play, a key role in California's decarbonization efforts – and there should be no distinction between those produced in-state or those imported. CARB should encourage the development of all low-CI hydrogen supply that help lower the CI of liquid fuels, provided that the fuels are consumed in California. This is consistent with science, the design of the LCFS, and delivers real reductions of greenhouse gas emissions. <u>We request that CARB modify §95488.8(i)(3)(A) as follows:</u>

214.14 *"Low-CI hydrogen is injected into a dedicated hydrogen pipeline physically connected to ~~California~~ <u>a distribution system or a production facility that provides transportation fuel to California."</u>*

§95488.8 (i)(3) also limits the use of a low-CI hydrogen book-and-claim approach to hydrogen used directly as a transportation fuel and hydrogen that is used to produce alternative fuels. As long as hydrogen is still an eligible feedstock for project-based crediting in §95489, low-CI hydrogen book-and-claim should be available to all transportation fuels consumed in California, including conventional fuels. <u>We request CARB make this improvement to enable more emission reductions across a broader array of transportation fuels and further spur investment in low-CI hydrogen. We recommend modified language in §95488.8(i)(3) as follows:</u>

"Book-and-Claim Accounting for Pipeline-Injected low-CI Hydrogen Used in FCV and ~~Alternative~~ Transportation Fuel Production. Indirect accounting may be used for low-CI

214.14 *hydrogen used in FCVs or to produce ~~alternative~~ transportation fuel for transportation purposes provided the conditions set forth below are met:…"*

We note that the low-CI hydrogen book-and-claim requirements are appropriately applied to low-CI hydrogen in the gaseous phase that is commingled in pipelines – including hydrogen conveyed as a liquid before pipeline injection as a gas. CARB has indicated in discussions that liquid hydrogen (or hydrogen derivatives like ammonia) of varying CIs that are mixed in transport and distribution systems can be volumetrically balanced, similar to other liquid alternative fuels like ethanol, renewable diesel, and biodiesel, and that this can be accommodated via the fuel pathway and existing accounting systems without amendment to the regulation. We request CARB clarify, consistent with past discussions with
214.15 staff, that a book-and-claim approach for commingled liquid hydrogen or liquid hydrogen derivatives in these systems is not needed, and that the necessary provisions are included in the existing regulations to enable such an approach.

We appreciate the explicit clarification in §95488.8(i)(3)(B) that biomethane book-and-claim can be used to reduce hydrogen CI but request CARB to confirm that other renewable feedstocks or production technologies can be used to lower the carbon intensity and produce eligible hydrogen as long as the proposed CI thresholds are validated via approved fuel pathways. We do not see this precluded in any way in the proposed language. Such feedstocks could include bio-offgases or renewable ammonia.

We note that §95488.8(i)(3)(C) safeguards against resource shuffling and encourages new projects that provide eligible hydrogen. We support this requirement but want to clarify that the term "expand" used in the provision is not narrowly interpreted to mean that every project must increase the amount of
214.16 hydrogen produced. Instead, we encourage an interpretation, that it refers to an expansion in the production of lower carbon hydrogen that meets the CI thresholds established in §95488.8(i)(3)(B). It is quite possible that existing facilities not producing eligible hydrogen will be modified to produce low-CI eligible hydrogen without a net increase in total hydrogen produced. We request that such projects are eligible consistent with past discussions with CARB staff.

Lastly, we note that the new low-CI hydrogen book-and-claim provision includes a requirement to report the contracted price of hydrogen to CARB in unredacted invoices. We support the need for
214.17 robust tracking of hydrogen volumes to ensure the quantity and environmental attributes of the hydrogen tracked via book-and-claim is verifiable but find no rationale for including hydrogen pricing. In fact, sharing information on the contracted hydrogen price creates the possibility of irreparable harm to both Air Products and its customers. Even in situations where data is published in an aggregated fashion, the limited supply of this hydrogen from a handful of entities would likely lead to competitors deducing this proprietary information and leveraging that information to their advantage in bidding processes. We urge CARB to strike the requirement to report this information in 95488.8(i)(3)(E).

Low-CI Electricity Book-and-Claim Provisions

Air Products strongly supports CARB's proposal in §95488.8(i)(1) to extend the existing book and claim
214.18 accounting approach for low-CI electricity to include the process energy associated with other components used to process and distribute hydrogen, like liquefaction and compression. By looking beyond just the production of feedstock hydrogen, this proposal will enable greater carbon reduction ambition in California policies. Extending book-and-claim provisions to process energy will not only

incentivize bringing more renewable production on-line but will also enable hydrogen to further lower its CI and help California decarbonize cars, trucks, buses, and other combustion-dependent equipment. While Air Products supports the extension of low-CI electricity book-and-claim to process energy demand in the hydrogen value chain, we do not believe that the use case of low carbon hydrogen produced in this manner to produce transportation fuel should be eliminated. Because hydrogen is an important feedstock in the manufacture of either renewable biofuels or conventional transportation fuels (under the project-based crediting provisions), and the expectation that these fuels will be used for decades, CARB should encourage all emission reductions possible in all fuels used for transportation in California. Substantive emission reductions can be encouraged, along with renewable electricity growth, by continuing to enable hydrogen CI to be lowered via low-CI electricity book-and-claim for all fuels used in California. We request retention of the end-use flexibility provided in the current regulation by modifying the following provisions as indicated:

214.19

Modify proposed provision 95488.1 (i)(1*): as follows:*

> *"… for hydrogen production ~~through electrolysis~~ and processing for transportation purposes (including hydrogen that is used in the production of ~~as~~ a transportation fuel), or for direct air capture projects, provided the conditions set forth below are met:…."*

Modify proposed provision 95488.8 (i)(1)(C) as follows*:*

> *"For direct air capture projects or for hydrogen used as a transportation fuel (including hydrogen that is used in the production of a transportation fuel), low-CI electricity must meet the following criteria: …"*

While the California Public Utilities Code is referenced in the regionality requirement provision §95488.8(i)(1)(C)(1), we understand that the initial clause of this provision "*The low-CI electricity must be supplied to the grid within the local balancing authority where the electricity is consumed"* is intended to apply to hydrogen production and associated renewable power outside of the state of California. Please add the parenthetical *"(or local balancing authority for hydrogen produced outside of California)"* similar to what is provided in 94488.8(i)(1)(A).

Lastly, while we are supportive of the new resource shuffling and quarterly time-matching requirements applied to the low-CI electricity book-and-claim provisions for hydrogen in §95488.8 (i)(1)(C)(3) and (4), respectively, we note that these same new requirements are not imposed on electricity used as a transportation fuel in 95488.8(i)(1)(A). We propose that both electricity and hydrogen supplied as transportation fuels should be treated equally with regards to eligibility and recordkeeping provisions and suggest that both fuel requirements be aligned with the new restrictive standards. Alternatively, hydrogen could retain the current eligibility and recordkeeping requirements that are already aligned with electricity supplied as a transportation fuel.

Biomethane Book-and-Claim

214.20 Air Products appreciates CARB's proposal to provide additional time to allow biomethane use for hydrogen in a book-and-claim scenario and enabling avoided methane crediting in the calculation of the CI. We do also note and appreciate that these new restrictions do not apply for projects initiated during the balance of this decade which incentivizes early action on projects that will accelerate decarbonization. However, we still believe that none of these requirements should be imposed for hydrogen supporting zero-emission solutions – even in 2045 as proposed. Eliminating these proposed requirements will not only continue to incent beneficial use of biomethane wherever it can be cost-effectively developed, but also help lower the CI of hydrogen to enable broad use of low carbon hydrogen across many transportation sectors, especially large off-road equipment like locomotives, marine, and aircraft, consistent with the 2022 Scoping Plan through 2045. The use of low-CI hydrogen in fuel cell vehicles is fully aligned with California's goals of phasing out combustion in the transportation sector. In fact, placing constraints on biomethane that is used to produce low-CI hydrogen for fuel cell vehicles advantages electricity over hydrogen even though both support zero emission transportation. We request that CARB not impose any new requirements for biomethane book-and-claim used in the production of hydrogen.

214.20 In a parallel concept to what is proposed in the 45-day package for hydrogen produced and processed using low-CI electricity, we request that CARB clarify that biomethane book-and-claim provisions can be used to displace fossil methane used both as a reactant in the stoichiometric conversion to hydrogen and for the thermal energy needed to catalyze the reaction. We believe that the combined reactant and thermal energy demand for fossil methane should be considered "production" for the purposes of biomethane book-and-claim provisions. Please confirm.

Hydrogen Refueling Infrastructure (HRI) Credits

214.21 Air Products strongly supports the expansion of crediting to medium and heavy duty (MHD) vehicles and continued crediting for light duty (LD) vehicles. The current HRI program, in combination with other California incentives, has been very effective in promoting the build-out of zero-emission vehicle infrastructure. It is important that CARB build on this success by expanding the program to the truck and bus markets. This expansion will complement CARB's ambitious goals under the Advanced Clean Truck (ACT) and Advanced Clean Fleet (ACF) regulations and help advance the state's goals for zero-emission vehicles in line with Executive Order N-79-20.

214.22 We previously supported the requirement that LD hydrogen refueling stations (HRS) be located in designated disadvantaged communities, as it is important to continue incentivizing the build out of LD hydrogen refueling stations beyond core market areas in the state to bring hydrogen Fuel-Cell Electric Vehicle (FCEV) accessibility to a larger share of the state's population. We also support CARB's proposal to extend location eligibility to other low income and rural areas, as this additional coverage will further promote accessibility and connectivity throughout the state.

214.23 Air Products appreciates the flexibility in provisions in 95484.2(a)(1), (a)(7), and 95486.3(a)(1) to allow the dispenser owner or designee to apply for HRI credits. However, we recommend that CARB add a provision for executive officer review and discretion to negate such an arrangement if said arrangement is found to circumvent the 1% deficit cap for a single entity or any other relevant provision for HRI crediting. A company applying for credit should not be able to exceed the deficit cap simply by diversifying the credit claims via multiple commercial arrangements and registered entities.

214.24 We support the proposed location requirements for MHD fueling stations as written but seek clarity that the 1-mile distance requirement is based on a radius for the proposed location relative to the criteria and not a 1-mile driving distance.

We appreciate CARB providing an option for private MHD stations to receive HRI credits in support of the Advanced Clean Fleets regulation and we support the lower credit cap for these stations. Providing some crediting for private stations, but a higher level of crediting for public stations, strikes a good balance in the two use cases and will drive investments in the infrastructure necessary for meaningful fleet conversion.

214.25 Consistent with past crediting windows, we believe that for both LD and MHD vehicles going forward, a full 15-year crediting period should be allowed. This will help ensure continued station support through 2045 in support of CARB's carbon neutrality goals.

Air Products believes that multi-modal stations which include fueling for both LD and MHD vehicles, utilizing shared compression, storage and dispensing equipment will play an important role in California's hydrogen fueling network. Clarity is needed in the regulation or in guidance as to how the provisions in the separate LD and MHD sections apply. We have drafted language that we believe provides an approach for stations with combined fueling capabilities (in italics below) and propose that it be added to the regulation. Moreover, there is a misalignment in the Energy Economy Ratio (EER) value split and the new HRI provisions as MD vehicles are coupled with LD vehicles in Table 5 for EERs, but are coupled with HD vehicles for the purposes of HRI crediting which apply a credit calculation
214.26 formula employing an HD EER. Please clarify what tracking or recordkeeping is necessary to assign the correct EER value for HRI crediting.

Proposed combined LD and MHD HRI crediting language – add new § 95486.3 (a)(7) as follows:

(7) Requirements to Generate HRI Credits for Combined ZEV/LD and MHD Hydrogen Refueling Stations.

Application for ZEV/LD-HRI crediting capacity to MHD-HRI Refueling Capacity must submit an application to the Executive Officer to generate additional credits based on the increased dispensing capacity and number of light-duty dispensing units at a MHD hydrogen HRI station. A hydrogen station that fuels ZEV/LD and MHD vehicles will follow the requirements of the current MHD section 95486.3 (a)(1) through (6) with the exception of subsections 95486.2(a)(3)(A), 95486.2(a)(7)(I), 95486.3(a)(4)(G), and 95486.3(a)(4)(G)1, and 95486.3(a)(5).

(A) Whenever section 95486.3(a)(7) is the HRI crediting pathway, calculation of estimated potential HRI Credits will be calculated as the sum of subsections 95486.2(a)(2)(F) and 95486.3 (a)(2)(F) for HRI pathway applications received on or before December 31, 2025. Beginning January 1, 2026, the Calculation of Estimated potential HRI credits will be calculated as the sum of subsections 95486.2(a)(7)(D) and 95486.3(a)(5).

(B) Whenever section 95486.3(a)(7) is the HRI crediting pathway, the estimated cumulative value of HRI credits generated for the station in the prior quarter must be less than the difference between 1.5 times the initial capital expenditure reported pursuant to section 95486.3(a)(6)(C)(1) and the total grant revenue or other funding for capital, operational and maintenance expenses reported pursuant to section 95486.3(a)(6)(C)5 and (C)6 in the prior quarter. The capital and operational expenditure cap may be additive for shared station equipment supporting LD and MHD fuel dispensing.

1. *The estimated value of HRI credits, for the purpose of this determination, shall be calculated using the number of ZEV/LD and MHD credit generated for the station in the quarter and the average LCFS credit price for that quarter published on the LCFS website. Credits will be calculated as the sum of 95486.2(a)(5) and 95486.3(a)(5) for the HRI pathway application.*

(C) Whenever section 95486.3(a)(7) is the HRI crediting pathway, calculations of HRI Credits for Combined ZEV/LD and MHD Hydrogen Refueling Stations will be calculated using the equations found in Sections 95486.2(a)(5) for the light-duty portion of the refueling station and 95486.3(a)(5) for the medium/heavy-duty portion of the refueling station for the HRI application received before December 31, 2030. These two credit calculations will be additive.

Section 95486.3.a(4)(H) caps HD HRI credits to initial eligible capital expenditure reported and cumulative value of MHD-HRI credits earned. CARB should ensure sure that on-site hydrogen production costs are not included in the capital calculation, which would create an unlevel playing field.
214.27 §95486.3 (a)(6)(B)(1) would create a situation that favors on-site hydrogen generation vs. the more efficient centralized hydrogen production and distribution approach. Operations and maintenance costs should be included in the MHD HRI payback metric as these are differential to the costs associated with electric vehicle charging.

214.28 It is our understanding that the grant revenue being referenced in 95486.3.a(4)(H) is related to specific grants or funding revenue related to station construction and station operations and maintenance costs. Please confirm that any value for the production of hydrogen upstream of the station provided by the Inflation Reduction Act under sections 45V or 45Q is not considered "grant revenue or other external funding" for the purposes of this calculation for HRI credits.

214.29 References in proposed §95486.3 (a)(4)(G) (see below) – should be (a) and not (b). The HRI section in Appendix A-2 inadvertently references the FCI provisions.

"(G) The estimated cumulative value of MHD-HRI credits generated for the station in the prior quarter must be less than the difference between 1.5 times the initial capital expenditure reported pursuant to section 95486.3(a)(6)(B)1 and the initial grant revenue or other funding reported pursuant to section 95486.3(~~b~~a)(6)(B)5 and section 95486.3(~~b~~a)(6)(B)6 in the prior quarter"

Hydrogen Tier 1 Simplified Calculator and CalGREET4.0 Model

214.30 Consistent with the proposed change to extend low-CI electricity book-and-claim to both production and process energy under 95488.8(i)(1), please update the Tier 1 simplified calculator to provide the necessary inputs and CI calculations to accommodate this proposal.

The emissions factor for liquid hydrogen storage and dispensing (cell E19 on CA-GREET4.0 sheet) is higher than the gaseous hydrogen factor. Does this result come from the CA-GREET4.0 model? Please provide more information on how that factor was determined. It's significantly higher than what we would expect for power consumption at a liquid hydrogen fueling station, so it is important to understand the assumptions behind the factor.

Air Products suggests that it would benefit all users of the model to build into the CA-GREET4.0 sheet, or the instruction manual, information on how to use the CA-GREET4.0 full model to calculate the emission factors given in the Tier 1 calculator. There would be two benefits to this: (1) increased awareness/confidence the Tier 1 calculator is consistent with CA-GREET4.0; and (2) providing a starting point for pathway applications which need to propose modifications to CA-GREET4.0 for Tier 2 applications of complex pathways. We recommend including this additional information.

We note the substantial decrease in the California average grid electricity CI used as a transportation fuel from a value of 93.75 gCO2e/MJ to 81 gCO2e/MJ in Table 7-1. A similar value should be applied as a default in the Tier 1 Simplified Hydrogen Calculator to grid connected electrolysis units that are deployed in California as this is incremental grid demand similar to direct supply of electricity to charging. This would place hydrogen and electricity supply to zero-emission vehicles on a more level playing field.

Intrastate Jet Inclusion as Deficit-Generating Fuel

214.31 Air Products is supportive of actions to further the state's decarbonization goals and stimulate additional credit demand in the LCFS program. To this end, we are supportive of including intrastate jet fuel as an obligation-generating fuel. This will spur demand for cleaner jet fuel and possibly hydrogen for aviation in the future consistent with Governor Newsom's target of 20% sustainable aviation fuels by 2030 and the full transition to clean aviation fuels by 2045 as presented in the 2022 Scoping Plan Update scenario.

Project-Based Crediting

214.32 Air Products appreciates CARB's amendments throughout §95489 to clarify that hydrogen production facilities not co-located with a petroleum refinery can generate credits under the refinery investment credit and renewable hydrogen provisions. This is an important clarification and provides equitable treatment between third-party hydrogen production and production embedded in refinery operations.

214.33 We urge CARB to reconsider retaining the opportunity for renewable hydrogen to be eligible for project-based crediting beyond 2040. While CARB anticipates a substantial phase-down of petroleum refining, it will be important to preserve some emission reduction opportunities for the refining capacity that remains, as recognized in the 2022 Scoping Plan Update, and preserving the renewable hydrogen option recognizing the role that hydrogen can play to ensure that residual petroleum refining helps meet CARB's decarbonization goals for the transportation sector. We note the exemption from phase-out provided for Carbon Capture and Sequestration (CCS) and renewable hydrogen has a similarly important role to play. There is still refining capacity anticipated in 2045 so enabling crediting to at least 2045 will continue to promote emission reductions at these facilities.

Additional Language and Technical Suggestions and Clarifications

- We appreciate the improvements proposed for the renewable hydrogen definition but suggest
214.34 some additional changes to ensure that all conversion technologies and potential feedstocks are captured, including renewable ammonia used as a feedstock to produce hydrogen.

> *"§95481 (a) "Renewable Hydrogen" means hydrogen derived from (1) electrolysis of water or aqueous solutions using renewable electricity; (2) catalytic cracking, partial oxidation, autothermal reforming, ~~oxidation~~ or steam methane reforming of biomethane or other biogenic or renewable feedstocks ~~hydrocarbons~~; or (3) thermochemical conversion of biomass, including the organic portion of municipal solid waste (MSW). Renewable electricity, for the purpose of renewable hydrogen production by electrolysis, means electricity derived from sources that qualify as eligible renewable energy resources as defined in California Public Utilities Code sections 399.11-399.36."*

- 214.35 There is a reference to hydrogen in the Low CI electricity as a fuel section – §95488.8 (i)(1)(A) - which was not deleted like other similar references. We believe this reference is no longer needed given the new section related to hydrogen as a fuel.

- 214.36 We request that CARB consider including information on how many credits are generated via smart charging and smart electrolysis in the quarterly summary spreadsheet posted on-line – distinct from other charging and electrolysis credit-generation pathways. This information will help the market understand the opportunity for incremental credit generation associated with these pathways.

- 214.37 95488.10 (a)(4) should acknowledge that low-CI electricity can also be used for process energy for hydrogen used as a transportation fuel – and not just for the "hydrogen production via electrolysis" – consistent with 95488.8(i)(1).

- 214.38 Air Products supports phasing down electric forklift crediting based on existing fleets that effectively transitioned to electrification where credits under the LCFS are understood to have little to no impact on the rate or magnitude of the transition (i.e., electrification is the baseline for new purchases/replacements and no longer should be considered an opt-in source eligible to generate LCFS credits). This is a durable principle that can be applied to other sectors when the transition is sustainable. However, we do not believe that adjusting the Energy Economy Ratio (EER) is a valid way to do this and are concerned about the precedent this will set for other vehicle classes. The CI targets in the LCFS regulation are anchored in the CI of the base fuels – gasoline and diesel. The EERs that are used in the credit generation calculation should likewise always be calculated relative to the conventional fuel vehicles that are being replaced. This helps ensure proper crediting for the vehicle turnover that is needed to comply with various ZEV regulations and mandates.

Air Products appreciates the opportunity to provide this feedback on the 45-day package and we would be happy to meet with CARB to discuss any of these topics further. Please feel free to contact me at hellermt@airproducts.com.

Respectfully,

Miles Heller
Director, Greenhouse Gas, Hydrogen, and Utility Regulatory Policy

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Comment 224 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ira
Last Name	Dassa
Email Address	ira.dassa@twelve.co
Affiliation	Twelve Benefit Corporation
Subject	Proposed LCFS Amendments
Comment	Please find attached Twelve's comments and our suggested revisions shown in redline, on pages 21 and 149-50 of Appendix A-1.1.
Attachment	www.arb.ca.gov/lists/com-attach/app-zip/6888-lcfs2024-UCRUJQNnVmkBcQht.zip
Original File Name	Twelve Comments.zip
Date and Time Comment Was Submitted	2024-02-20 13:06:59

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

twelve

February 20, 2024

Submitted electronically at https://ww2.arb.ca.gov/lispub/comm/bclist.php

Clerk's Office
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Twelve Benefit Corporation Comments on the Proposed Low Carbon Fuel Standard Amendments

Dear Sir/Madam:

Twelve Benefit Corporation (Twelve), based in northern California, appreciates the opportunity to comment on the above-referenced Low Carbon Fuel Standard (LCFS) rulemaking package issued by the California Air Resources Board (CARB).[1]

As detailed below, our comments address the following points:

215.1
- CARB should consider broadening the proposed definition of "renewable naphtha;"

215.2
- Some of the proposed revisions to the book-and-claim accounting provisions for low-carbon intensity (low-CI) electricity used for hydrogen production are unexplained, unwarranted, and short-sighted;

215.3
- Most importantly, CARB through this rulemaking should put in place regulatory provisions to foster the production and uptake of ultra-low carbon Power-to-Liquid Sustainable Aviation Fuel (PtL SAF) and other PtL fuels;

215.4
- The "physically connected to California" requirement should be eliminated from proposed subsection 95488.8(i)(3)(A); and

215.6
- In view of the proposed revisions to section 95490, CARB should revisit the system boundary for carbon capture and sequestration (CCS) projects when the carbon dioxide (CO_2) is captured at an alternative fuel production facility.

215.7
Please note that Twelve is also a signatory of the comment letter submitted by Infinium on behalf of various PtL fuel producers and airlines.

[1] Posted at https://ww2.arb.ca.gov/rulemaking/2024/lcfs2024.

614 Bancroft Way, Suite B, Berkeley, CA 94710

As we did in our July 3, 2023, submission to CARB on potential changes to the LCFS Program,[2] we first provide background information on our company and our groundbreaking carbon transformation™ technology, as well as a brief overview of PtL fuels, sometimes referred to as electrofuels or e-fuels, before setting out our detailed comments in Part II below.

I. Background

A. Twelve and Carbon Transformation

Founded in 2015 and headquartered in Berkeley, Twelve currently employs a staff of almost three hundred chemists, engineers, techno-economic experts, product developers, and other specialists, with the vast majority of our personnel working in one of our locations in the San Francisco Bay area. We are on a mission to eliminate global CO_2 emissions and build a fossil-free future.

Our proprietary carbon transformation technology takes captured CO_2 and, using only water and renewable energy, transforms it into synthesis gas (syngas), a combination of carbon monoxide and hydrogen. Once formed, the syngas is routed through an integrated Fischer-Tropsch reactor and then upgraded, ultimately resulting in our E-Jet® fuel – PtL SAF (or as CARB refers to it under the LCFS Program, alternative jet fuel) that meets the specifications in Annex A1 of ASTM International's D7566 Standard (*Standard Specification for Aviation Turbine Fuel Containing Synthesized Hydrocarbons*) – as well as our E-Naphtha™. We expect our E-Jet, which has been tested and validated under a grant from the U.S. Air Force,[3] to reduce lifecycle greenhouse gas (GHG) emissions by up to 90% in comparison to conventional, petroleum-based jet fuel.[4]

Last summer, we began constructing our first E-Jet plant in Moses Lake, Washington.[5] We selected Moses Lake in part because of the availability and abundance of low-carbon electricity in the state of Washington, including existing (especially hydropower) and new renewable energy sources. Over the next few years, we intend to develop commercial-scale fuel production plants in various locations around the country, and to supply our E-Jet and E-Naphtha to the global airline and chemical industries and other customers. As a California-based company, we hope to be able to arrange for uplift in the state of a sizable portion of the PtL SAF that we produce. Our ability to generate LCFS credits for our ultra-low carbon jet fuel

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[2] A copy of our earlier comment letter, which can be found at https://ww2.arb.ca.gov/system/files/webform/public_comments/4291/Twelve%20Letter%20to%20CARB%20on%20Indirect%20Accounting_filed%20070323.pdf, is attached.

[3] *See* https://www.af.mil/News/Article-Display/Article/2819999/the-air-force-partners-with-twelve-proves-its-possible-to-make-jet-fuel-out-of/.

[4] For more on Twelve and carbon transformation, our revolutionary electrochemical technology, please visit our website at twelve.co.

[5] The Moses Lake AirPlant™, which will transform biogenic CO_2 captured from an industrial source, will have a water electrolyzer operating alongside our CO_2 electrolyzer, but in the future, we may produce the clean hydrogen that is needed for the syngas via an alternative hydrogen production pathway (e.g., one of the non-water electrolysis pathways included in the U.S. Department of Energy's 45VH2-GREET Model), or we may opt to obtain the clean hydrogen from a supplier.

will, of course, be a key factor in whether this happens.

B. PtL Fuels in General

While technological approaches to the production of PtL fuels can vary, the common thread among all such fuels is the utilization of the same feedstocks: CO_2 that is either captured from an industrial source (e.g., an ethanol facility) or obtained from direct air capture; and a renewable source of electricity (e.g., solar, wind, hydropower) that is used to create clean hydrogen through the electrolysis of water (or perhaps through some other hydrogen production pathway). The national blueprint for transportation decarbonization, a multi-agency effort released by the federal government early last year, points out that PtL fuels represent "a viable pathway" to sustainable, low-carbon transportation fuels.[6] According to the U.S. Department of Energy (DOE), one of the federal agencies involved in that effort, PtL fuels "have dramatically smaller land, water, and [GHG] footprints compared to fossil fuels."[7]

Specifically in the context of the hard-to-abate aviation sector,[8] PtL SAF poses fewer land-related issues than most biomass-based SAF, is also advantageous from a water demand standpoint, and has been cited as "the only SAF technology that has the potential for unbounded production,"[9] an apt description given the ever-increasing amount of CO_2 in the Earth's atmosphere. For its part, Airbus, the commercial aircraft manufacturer, has referred to PtL SAF as an "exciting option" for fueling airplanes, one that "will be necessary to meet [expected SAF] demand,"[10] while the International Energy Agency recently asserted that e-fuels "made from biogenic or air-captured CO2 can potentially provide full emissions reduction,

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[6] *The U.S. National Blueprint for Transportation Decarbonization: A Joint Strategy to Transform Transportation*, at 55 (Jan. 2023), available at https://www.energy.gov/sites/default/files/2023-01/the-us-national-blueprint-for-transportation-decarbonization.pdf.

[7] DOE Bioenergy Technologies Office, "CO2 Reduction and Upgrading for e-Fuels Consortium," available at https://www.energy.gov/eere/bioenergy/co2-reduction-and-upgrading-e-fuels-consortium.

[8] As the Federal Aviation Administration (FAA) puts it, "decarbonization of the aviation sector is extremely challenging," and SAF is "critical to the long-term decarbonization of aviation." *See* FAA, *United States 2021 Aviation Climate Action Plan*, at 3, 21 (Nov. 2021), available at https://www.faa.gov/sites/faa.gov/files/2021-11/Aviation_Climate_Action_Plan.pdf.

[9] Rhodium Group, "Sustainable Aviation Fuels: The Key to Decarbonizing Aviation" (Dec. 7, 2022), available at https://rhg.com/research/sustainable-aviation-fuels/; *see also* World Economic Forum, *Clean Skies for Tomorrow: Delivering on the Global Power-to-Liquid Ambition*, at 10 (May 2022) (referring to PtL SAF's "high GHG reduction potential" compared to other types of SAF and indicating that the feedstocks "are theoretically unlimited"), available at https://www3.weforum.org/docs/WEF_Clean_Skies_for_Tomorrow_Power_to_Liquid_Deep_Dive_2022.pdf.

[10] Airbus, "Power-to-Liquids, explained" (July 15, 2021), available at https://www.airbus.com/en/newsroom/news/2021-07-power-to-liquids-explained; "Sustainable aviation fuels: A new generation of reduced emissions fuels," available at https://www.airbus.com/en/sustainability/respecting-the-planet/decarbonisation/sustainable-aviation-fuels.

making them the primary production pathway that is consistent with achieving [the global aviation sector's goal of] net zero emissions by mid-century."[11]

II. Twelve's Comments on the CARB Proposal

With the above background in mind, our detailed comments on CARB's proposed LCFS amendments follow.

A. CARB Should Consider Broadening the Proposed Definition of Renewable Naphtha

As an initial matter, we note that among the new definitions that CARB is proposing to add to section 95481(a) of the LCFS regulation is a definition of the term "renewable naphtha." The definition would provide, in relevant part, that the term "means naphtha that is produced from hydrotreated lipids and biocrudes, or from gasified biomass that is converted to liquids using the Fischer-Tropsch process."[12]

215.8 As indicated above, Twelve's Moses Lake plant and our future commercial-scale facilities will produce not only E-Jet but also an electrochemical, E-Naphtha. For this reason, Twelve recommends that CARB consider broadening the proposed definition of "renewable naphtha" so that it also encompasses the E-Naphtha to be produced at Twelve's facilities. We suggest the following possible revision to the first sentence of the proposed definition (underline to indicate additions and ~~strikeout~~ to indicate deletions):

> "Renewable Naphtha" means naphtha that is produced from hydrotreated lipids and biocrudes, ~~or~~ from gasified biomass that is converted to liquids using the Fischer-Tropsch process, or from captured CO_2, water, and low-CI electricity that are converted to liquids using electrolysis and the Fischer-Tropsch process.

215.9 While we offer this recommendation, we also acknowledge the proposed revision to section 95488.1(d)(4) that would identify "synthetic hydrocarbons" as drop-in fuels subject to Tier 2 pathway classification.[13] If PtL-based naphtha like Twelve's E-Naphtha is meant to be covered by this particular revision, we would appreciate CARB providing clarification to that effect.

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[11] International Energy Agency, *The Role of E-Fuels in Decarbonising Transport*, at 10, 24 (Jan. 2024), available at https://iea.blob.core.windows.net/assets/a24ed363-523f-421b-b34f-0df6a58b2e12/TheRoleofE-fuelsinDecarbonisingTransport.pdf. The International Civil Aviation Organization (ICAO) established net-zero carbon emissions by 2050 as the long-term global aspirational goal for international aviation in October 2022. *See* ICAO Assembly Resolution A41-21, ¶ 7, available at https://www.icao.int/environmental-protection/Documents/Assembly/Resolution_A41-21_Climate_change.pdf.

[12] Appendix A-1: Proposed Regulation Order (Appendix A-1) at 23.

[13] Appendix A-1 at 117.

B. Some of the Proposed Changes to the Indirect Accounting Provisions for Low-CI Electricity Used for Hydrogen Production Are Unexplained, Unwarranted, and Short-Sighted

Proposed section 95488.8(i)(1) would include a major revision to the language on book-and-claim accounting for low-CI electricity that is used in the production of hydrogen. Currently, this regulatory provision allows indirect accounting in two instances: (1) when the low-CI electricity is supplied as a transportation fuel (i.e., for use in an electric vehicle); and (2) when the low-CI electricity is used to make hydrogen via electrolysis, where that hydrogen is then used either as a transportation fuel (i.e., in a hydrogen fuel cell electric vehicle (FCV)) or in the production of another transportation fuel.[14]

CARB is proposing to restructure section 95488.8(i)(1) and the three subsections encompassed within it (i.e., existing subsections (A) and (B) and new subsection (C)), but most important to Twelve is the proposed deletion of the parenthetical in section 95488.8(1) that reads, "(including hydrogen that is used in the production of a transportation fuel)," along with the proposed insertion of the phrase "as a transportation fuel" in the italicized subheading for section 95488.8(i)(1). The deletion of the parenthetical (as well as the corresponding subheading insertion) is irksome and troubling because CARB offers absolutely no explanation or rationale for it – not in the ISOR, and not in Appendix E.[15]

To be sure, CARB has proposed to include in the introductory clause of what would be new section 95488.8(i)(3) language stating that indirect accounting may be used for low-CI hydrogen that is used "to produce alternative fuel for transportation purposes,"[16] but this new section would only apply to low-CI hydrogen injected into a dedicated hydrogen pipeline physically connected to California. We also observe that CARB has not proposed any changes to the introductory language of section 95488.8(i)(2), which allows indirect accounting for pipeline-injected biomethane that is used "to produce hydrogen for transportation purposes (including hydrogen that is used in the production of a transportation fuel)."[17] Yet under new subsection 95488.8(i)(1)(C), CARB is proposing to allow book-and-claim accounting for low-CI electricity only when it is used in direct air capture projects or in the production of hydrogen that is used as a transportation fuel. For unexplained reasons, CARB is seeking to eliminate book-and-claim
215.10 accounting for low-CI electricity when the electricity is used to make hydrogen that is then used in the manufacture of another transportation fuel (e.g., PtL SAF).

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[14] 17 CCR § 95488.8(i)(1); *see also* CARB, "Low Carbon Fuel Standard (LCFS) Guidance 19-01: Book-and-Claim Accounting for Low-CI Electricity," at 1-2 (Oct. 2023), available at https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-01_Revised_Oct2023_ADA.pdf; CARB, "LCFS Electricity and Hydrogen Provisions" (providing as an example the hydrotreating of renewable diesel), available at https://ww2.arb.ca.gov/resources/documents/lcfs-electricity-and-hydrogen-provisions.

[15] *See* Staff Report: Initial Statement of Reasons (ISOR) at 34; Appendix E: Purpose and Rationale of Proposed Amendments for the Low Carbon Fuel Standard Requirements (Appendix E) at 68-69.

[16] Appendix A-1 at 156.

[17] 17 CCR § 95488.8(i)(2); *see also* CARB, "Low Carbon Fuel Standard (LCFS) Guidance 19-05: Reporting and Recordkeeping for Natural Gas and Book-and-Claim Accounting for Biomethane," at 6 (Feb. 2024), available at https://ww2.arb.ca.gov/sites/default/files/2024-02/lcfsguidance_19-05.pdf.

Twelve maintains that this deletion is wholly unwarranted, and we respectfully request that CARB reverse itself or at the very least provide a thorough explanation detailing the rationale for why it believes this change is needed, especially given that CARB knows full well that hydrogen is an integral input in the production of SAF.[18] From our perspective, depriving fuel producers like Twelve of the ability to use indirect accounting for low-CI electricity used to make the electrolytic hydrogen that is essential to the production of PtL SAF is short-sighted and would be a huge misstep in that it would make the scale-up of ultra-low carbon PtL SAF even more challenging than it already is.

215.10 con't

It seems fairly clear from both the ISOR and Appendix E that CARB wants to prioritize hydrogen for the on-road vehicle sector, i.e., direct use of hydrogen as fuel for cars and trucks.[19] Twelve has no quarrel with hydrogen's use as a motor vehicle fuel in FCVs. What we vigorously object to is CARB tipping the scale on book-and-claim accounting for low-CI electricity and disadvantaging the aviation sector and PtL SAF producers, as CARB is clearly doing in the proposed rulemaking by limiting book-and-claim only to low-CI electricity that is used to produce hydrogen for use as a transportation fuel.

C. CARB Should Put in Place Regulatory Provisions To Foster the Production and Uptake of Ultra-Low Carbon PtL SAF and Other PtL Fuels

215.11 In our July 3, 2023, comment letter on potential changes to the LCFS Program, we recommended that CARB expand the indirect accounting rules for low-CI electricity under section 95488.8(i) by enabling book-and-claim accounting for low-CI electricity when it is used as a feedstock for the production of PtL transportation fuels. CARB appears not to have considered Twelve's proposal, but as noted above, in the context of the proposed Tier 2 classification updates in section 95488.1(d), CARB openly acknowledges that "there is a growing interest in producing synthetic fuels by combining hydrogen with captured CO_2."[20] In the ISOR, CARB states that "the proposed amendments, and the LCFS more broadly, are structured to encourage ongoing innovation and improvement in reducing the carbon intensity of transportation fuels as well as investment in innovative . . . carbon capture, *utilization*, and sequestration approaches."[21] In view of these statements, and considering that the PtL process is a prime example of carbon capture and utilization,[22] Twelve is submitting its proposal anew.

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[18] *See* ISOR at 34 (referring to "hydrogen used in the production of low-carbon transportation fuels such as renewable diesel and AJF").

[19] In this regard, it bears noting that earlier this month, Shell announced it was permanently closing all of its hydrogen light-duty vehicle fueling stations in California. *See* "Shell is Immediately Closing All of Its California Hydrogen Stations" (Feb. 9, 2024), available at https://insideevs.com/news/708156/shell-closes-california-hydrogen-stations/.

[20] Appendix E at 59.

[21] ISOR at 80 (emphasis added).

[22] *See, e.g.,* DOE, "Clean Fuels & Products Shot™: Alternative Sources for Carbon-based Products," available at https://www.energy.gov/eere/clean-fuels-products-shottm-alternative-sources-carbon-based-products; European Commission, "Questions and Answers on the EU Industrial Carbon Management Strategy" (Feb. 6, 2024), available at https://ec.europa.eu/commission/presscorner/detail/en/qanda_24_586.

In addition to our earlier submission, we are attaching to these comments a marked-up version of Appendix A-1.1 showing the textual regulatory revisions we are proposing today. These revisions are simple, straightforward, and narrowly tailored to "power-to-liquid fuel," a term that would be defined to mean transportation fuel that is produced from captured CO_2, water, and low-CI electricity. Allowing indirect accounting for low-CI electricity used in the production of PtL fuel would greatly incentivize the scale-up of these fuels, especially ultra-low carbon PtL SAF, which does not present the indirect land use change impacts or feedstock constraints that other types of SAF (e.g., crop-based SAF and waste oil- or animal fat-based SAF) do. Equally if not more important, extending book-and-claim to the low-CI electricity that is a feedstock (and not process energy) for PtL SAF production would ease the path to achieving the 90 percent jet fuel CI reduction in 2045 that CARB has proposed in Table 3,[23] a reduction level that Twelve fully supports and that CARB stresses "is necessary to accelerate decarbonization of the transportation fuels sector and support the State's broader climate goals."[24]

In Appendix E, CARB emphasizes that "the 2022 Scoping Plan Update includes consideration for *integrating other fuels into the LCFS program* and *highlights the importance of continuing to support low-carbon liquid fuels for sectors that are more difficult to transition to ZEV technology, such as aviation*,"[25] while in the ISOR, CARB explains that the 2022 update "anticipates a major shift away from fossil jet fuel by 2045, including 20% zero-emission aviation."[26] Twelve urges CARB to use the current rulemaking to enable book-and-claim accounting for the low-CI electricity that is essential to PtL SAF (and other PtL fuel) production and thereby facilitate the role ultra-low carbon PtL SAF can play in the decarbonization of California's aviation sector. Without indirect accounting for feedstock electricity, it will be very difficult for Twelve's E-Jet and the PtL SAF produced by other fuel producers to contribute to the state's goal, enshrined in section 38562.2(c) of the Health and Safety Code, of achieving an 85 percent reduction in anthropogenic GHG emissions (below 1990 levels) by 2045.

Please note that if CARB incorporates in the final rule the revisions we are seeking in this part of our comment letter, the feedback provided in Part II.B above becomes moot inasmuch as the recognition of book-and-claim accounting for low-CI electricity used to produce a PtL fuel would encompass both the electricity to make electrolytic hydrogen from water as well as, in Twelve's case, the electricity to electrolyze CO_2.[27]

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[23] *See* Appendix A-1 at 67 (Table 3 specifying for fossil jet fuel substitutes an average CI in 2019 of 94.17 gCO_2e/MJ, dropping to 10.57 gCO_2e/MJ in 2045, for an 88.78 percent reduction).

[24] ISOR at 24.

[25] Appendix E at 86 (emphasis added).

[26] ISOR at 26. CARB, in fact, foresees SAF accounting for at least 80 percent of aviation fuel demand in 2045. *See* CARB, *2022 Scoping Plan for Achieving Carbon Neutrality*, at 73, 206 (Dec. 2022), available at https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

[27] As we indicated in footnote 17 of our July 3, 2023, comment letter, Twelve's electrochemical technology is unique in that we also use electricity to transform the CO_2 molecule.

D. The Physical Connection Requirement Should Be Eliminated From Proposed Subsection 95488.8(i)(3)(A)

As mentioned above, CARB has proposed in section 95488.8(i)(3), which would be a brand new provision in the LCFS regulation, "to expand [the] use of indirect accounting to include low-CI hydrogen injected into a dedicated hydrogen pipeline, which can be either used directly in transportation, or used in alternative fuel production."[28] To Twelve's knowledge, nowhere in the rulemaking documents does CARB speak to the extent to which dedicated hydrogen pipelines currently exist in, or to use the phrasing of proposed subsection 95488.8(i)(3)(A), are "physically connected to California." As best we can tell, the state had only 16 miles of hydrogen pipeline as of late 2020.[29]

215.12 Due to this apparent paucity of in-state hydrogen pipeline infrastructure, Twelve recommends that CARB eliminate the "physically connected to California" requirement that is included in proposed subsection 95488.8(i)(3)(A). We note in this regard that while the ISOR and Appendix E mention the physical connection prerequisite, both are silent on the underlying rationale for it.[30] So long as pipeline-injected low-CI hydrogen meets all of the other conditions laid out in proposed subsections 95488.8(i)(3)(B)-(F), an entity should be allowed to avail itself of indirect/book-and-claim accounting. In Twelve's view, this would better "incentivize and spur increased development and supply of low-CI hydrogen by providing flexibility to hydrogen production facility siting and supply logistics" and "facilitate and spur the use of low-CI hydrogen in support of California's decarbonization efforts."[31]

Thus, book-and-claim accounting would apply to low-CI hydrogen injected into a dedicated hydrogen pipeline network irrespective of whether the pipeline network is physically connected to California. This should have the ultimate effect of encouraging out-of-state fuel producers that use dedicated hydrogen pipeline-supplied low-CI hydrogen in their fuel production process to export their low-carbon fuel to California, and also enable California to benefit to an even greater extent from low-CI hydrogen that is produced outside the state.

E. CARB Should Revisit the System Boundary for Carbon Capture and Sequestration Projects When the CO_2 is Captured at an Alternative Fuel Production Facility

Finally, Twelve notes that CARB is proposing various modifications to the provisions in section 95490 governing CCS. Assuming these modifications are adopted, CARB may need to amend its CCS Protocol, which is referenced in the eligibility provision of section 95490 and "applies to CCS projects that capture [CO_2] and sequester it onshore, in either saline or depleted oil and gas reservoirs, or [in] oil and gas reservoirs used for CO_2-enhanced oil recovery (CO_2-

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[28] Appendix E at 71.

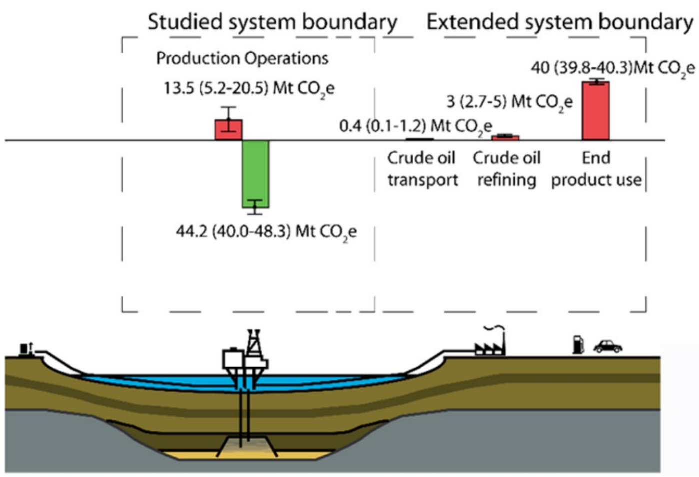
[29] *See* Congressional Research Service, *Pipeline Transportation of Hydrogen: Regulation, Research, and Policy*, at 5 (Mar. 2, 2021), available at https://www.everycrsreport.com/files/2021-03-02_R46700_294547743ff4516b1d562f7c4dae166186f1833e.pdf.

[30] *See* ISOR at 34; Appendix E at 71-73.

[31] Appendix E at 72.

EOR)."[32] Even if the Protocol would not need to be updated as a result of the approved LCFS amendments, Twelve maintains that CARB should review one specific aspect of it – CO_2
215.13 capture and sequestration in oil and gas reservoirs used for CO_2-EOR when the CO_2 was captured on-site at an alternative fuel production facility.

Currently, the CCS Protocol provides that irrespective of whether CO_2 is captured and sequestered in a depleted oil and gas reservoir or saline formation or captured and sequestered in an oil and gas reservoir used for CO_2-EOR, "the system boundary begins with carbon capture and ends with injection operations including CO_2 leakage. Any emissions downstream of the sequestration site (except entrained CO_2 in the case of CO_2-EOR) are excluded since they are associated with the downstream products rather than the CCS project."[33] Twelve urges CARB to revisit this system boundary for CO_2-EOR projects when the CO_2 is captured on-site at an alternative fuel production facility. More specifically, we believe the system boundary for such
215.14 CCS projects should be extended to include rather than exclude any GHG emissions associated with the downstream products, as depicted in the figure below. In other words, the emissions



associated with the transport, refining, and end-product use of the recovered oil should be reflected in the CI score of the Tier 2 fuel produced by the alternative fuel producer. In our view, only by including these emissions can there be a truly accurate CI score of the applicable alternative fuel.

* * *

Thank you for your consideration of our comments and proposed regulatory revisions. Please do not hesitate to contact me or my colleague, Ira Dassa (ira.dassa@twelve.co), if you have any questions.

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[32] CARB, "Carbon Capture and Sequestration Protocol Under the Low Carbon Fuel Standard," available at https://ww2.arb.ca.gov/resources/documents/carbon-capture-and-sequestration-protocol-under-low-carbon-fuel-standard.

[33] CCS Protocol at 21.

Sincerely yours,

Andrew Stevenson

Andy Stevenson
Vice President of Commercial
Twelve Benefit Corporation
andy.stevenson@twelve.co

Attachments

—twelve

July 3, 2023

Submitted via email to: LCFSWorkshop@arb.ca.gov

Dr. Cheryl Laskowski, Branch Chief
Transportation Fuels Branch
California Air Resources Board
1001 I St.
Sacramento, CA 95814

Re: Twelve Benefit Corporation Feedback on Potential Changes to the Low Carbon Fuel Standard

Dear Dr. Laskowski:

Although there is no longer an open feedback period for any of the informal public meetings and workshops that the California Air Resources Board (CARB) has held over the last several months on potential changes to the Low Carbon Fuel Standard (LCFS) Program, Twelve Benefit Corporation (Twelve) is taking this opportunity to submit these comments inasmuch as the formal rulemaking stage for the "Proposed LCFS Amendments" has yet to be reached.[1] To the extent specificity is needed pursuant to the introductory paragraph on CARB's "LCFS Meetings and Workshops" webpage, please consider this comment letter and the accompanying proposed regulatory language as referring to the virtual community meetings held on June 1 and June 2, for which the timeframe for feedback ended on June 14, 2023.[2]

As detailed below, our comments pertain to section 95488.8(i) of the current LCFS regulation. In particular, this letter proposes and discusses the basis for the attached revisions to the regulatory text. The revisions would enable indirect accounting mechanisms for renewable or low-carbon intensity (low-CI) electricity when it is used as a feedstock for the production of power-to-liquid (PtL) transportation fuels, sometimes referred to as electrofuels or e-fuels. We believe these revisions are warranted, as they would significantly incentivize the scale-up of these ultra-low carbon fuels, which are regarded as one of the most promising pathways, if not the most promising pathway to decarbonization of the aviation (and broader heavy-duty transportation) sector. Twelve respectfully requests that CARB include these proposed revisions in its forthcoming LCFS rulemaking package.

Before setting out our comments in Part II below, we first provide background information on Twelve and our groundbreaking carbon transformation™ technology, as well as a brief general overview of PtL fuels.

[1] *See* https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-11-1%20LCFS%20Amendments%20Admin%20Record%20Commencement%20Memo.pdf.

[2] *See* https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-meetings-and-workshops.

I. Background

A. Twelve and Carbon Transformation

Founded in 2015 and based in northern California, Twelve currently employs a staff of almost three hundred chemists, engineers, techno-economic experts, product developers, and other specialists, with the vast majority of our personnel working in one of our locations in Berkeley and Alameda. We are on a mission to eliminate global carbon dioxide (CO_2) emissions and build a fossil-free future.

Our patented carbon transformation technology takes captured CO_2 and, using only water and renewable electricity, transforms it into syngas, a combination of carbon monoxide and hydrogen. Once formed, the syngas is routed through an integrated Fischer-Tropsch reactor and then upgraded, ultimately resulting in our E-Jet® fuel – PtL sustainable aviation fuel (SAF, or as CARB refers to it under the LCFS Program, alternative jet fuel) that meets the specifications in Annex A1 of ASTM International's D7566 Standard (*Standard Specification for Aviation Turbine Fuel Containing Synthesized Hydrocarbons*). We expect our E-Jet, which has been tested and validated under a grant from the U.S. Air Force,[3] to reduce lifecycle greenhouse gas (GHG) emissions up to 90% in comparison to conventional, petroleum-based jet fuel.[4]

At the Paris Air Show last month, we publicly announced plans to begin construction of our first E-Jet plant in Moses Lake, Washington.[5] We selected Moses Lake in part because of the availability and abundance of low-carbon electricity in the state of Washington, including existing and new renewable sources. Over the next few years, we intend to develop additional fuel production plants in various other locations around the country. As a California-based company, we hope to be able to arrange for the uplift of a sizable portion of the PtL SAF we produce by aircraft in California.

B. PtL Fuels in General

While technological approaches to the production of PtL fuels vary, the common thread among all such fuels is the utilization of the same feedstocks: CO_2 that is either captured from an industrial source (e.g., an ethanol facility) or obtained through direct air capture; water, which is electrolyzed to produce hydrogen; and a renewable source of electricity (e.g., solar, wind, hydropower). The national blueprint for transportation decarbonization, a multi-agency effort released by the federal government earlier this year, points out that PtL fuels represent "a viable

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[3] *See* https://www.af.mil/News/Article-Display/Article/2819999/the-air-force-partners-with-twelve-proves-its-possible-to-make-jet-fuel-out-of/.

[4] For more on Twelve and our revolutionary CO_2 electrolysis technology, please visit our website at twelve.co.

[5] *See* https://www.commerce.wa.gov/news/twelve-announces-plans-to-scale-production-of-sustainable-aviation-fuel-made-from-co2-in-washington-state/.The Moses Lake plant will use biogenic CO_2 captured from an industrial point source, but our carbon transformation technology also converts CO_2 extracted from the air via direct air capture.

pathway" to sustainable, low-carbon transportation fuels.[6] According to the U.S. Department of Energy (DOE), one of the federal agencies involved in that effort, PtL fuels "have dramatically lower land, water, and [GHG] footprints compared to fossil fuels."[7] Specifically in the context of the hard-to-abate aviation sector,[8] PtL SAF poses fewer land-related issues than most biomass-based SAF, is also advantageous from a water demand standpoint, and has been cited as "the only SAF technology that has the potential for unbounded production,"[9] an apt description given the ever-increasing concentration of CO_2 in the Earth's atmosphere. For its part, Airbus, the commercial aircraft manufacturer, has referred to PtL SAF as an "exciting option" for fueling airplanes.[10]

With the above background in mind, our LCFS comments follow.

II. Indirect Accounting for Renewable or Low-CI Electricity is Warranted for PtL Fuels

Section 95488.8(i), which was added to the LCFS regulation as part of the 2018 rulemaking, makes clear that indirect accounting mechanisms for renewable or low-CI electricity can only be used under the Program in two instances: (1) when the electricity is used as a transportation fuel (i.e., in an electric vehicle); and (2) when the electricity is used to make hydrogen via electrolysis, where that hydrogen is then used either as a transportation fuel (i.e., in a fuel cell electric vehicle) or in the production of another transportation fuel.[11]

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[6] *The U.S. National Blueprint for Transportation Decarbonization: A Joint Strategy to Transform Transportation*, at 55 (Jan. 2023), available at https://www.energy.gov/sites/default/files/2023-01/the-us-national-blueprint-for-transportation-decarbonization.pdf.

[7] DOE Bioenergy Technologies Office, "CO2 Reduction and Upgrading for e-Fuels Consortium," available at https://www.energy.gov/eere/bioenergy/co2-reduction-and-upgrading-e-fuels-consortium.

[8] As the Federal Aviation Administration (FAA) puts it, "decarbonization of the aviation sector is extremely challenging." *See* FAA, *United States 2021 Aviation Climate Action Plan*, at 3 (Nov. 2021), available at https://www.faa.gov/sites/faa.gov/files/2021-11/Aviation_Climate_Action_Plan.pdf.

[9] Rhodium Group, "Sustainable Aviation Fuels: The Key to Decarbonizing Aviation" (Dec. 7, 2022), available at https://rhg.com/research/sustainable-aviation-fuels/; *see also* World Economic Forum, *Clean Skies for Tomorrow: Delivering on the Global Power-to-Liquid Ambition*, at 10 (May 2022) (referring to PtL SAF's "high GHG reduction potential" compared to other types of SAF and indicating that the feedstocks "are theoretically unlimited"), available at https://www3.weforum.org/docs/WEF_Clean_Skies_for_Tomorrow_Power_to_Liquid_Deep_Dive_2022.pdf.

[10] Airbus, "Power-to-Liquids, explained" (July 15, 2021), available at https://www.airbus.com/en/newsroom/news/2021-07-power-to-liquids-explained.

[11] 17 CCR § 95488.8(i)(1); *see also* CARB, "Low Carbon Fuel Standard (LCFS) Guidance 19-01: Book-and-Claim Accounting for Low-CI Electricity," at 1-2 (Dec. 2022), available at https://ww2.arb.ca.gov/sites/default/files/2022-12/19-01_updated%20for%20WREGIS%20changes_ADA.pdf; CARB, "LCFS Electricity and Hydrogen Provisions," available at https://ww2.arb.ca.gov/resources/documents/lcfs-electricity-and-hydrogen-provisions.

In its November 2018 Final Statement of Reasons (2018 FSOR), CARB reiterated what it had indicated at the outset of the 2018 rulemaking, that "[t]he CI of pathways for electricity supplied to vehicles, and hydrogen produced by electrolysis rely almost entirely on the source of the electricity, but no options exist under the current regulation for matching low-CI electricity to an EV or electrolysis load."[12] CARB then explained in the 2018 FSOR as follows:

> Pathways . . . for hydrogen produced by electrolysis use electricity as a feedstock. Staff views the flexibility for indirect accounting of low-CI electricity for these pathways as analogous to the flexibility that the LCFS has always offered to other biofuels in using a mass balance approach to allocation of finished fuel to various feedstocks. In this regard, electricity has historically been disadvantaged in the program by being limited to the regional grid CI. Additionally, these changes create consistency between the treatment of biomethane that is indirectly supplied through the common carrier pipeline, and renewable electricity that is supplied through the electrical grid.[13]

CARB went on to emphasize that it was not recognizing indirect accounting under the LCFS Program in any other instances (i.e., in instances other than the two specified in section 95488.8(i)(1)) in part because "[t]he GHG benefits of allowing indirect accounting for renewable or low-CI process energy are expected to be relatively small as most alternative fuel production does not rely extensively on electricity consumption."[14]

As indicated in the attached document, which shows the textual regulatory revisions we are proposing, Twelve maintains that indirect accounting for renewable or low-CI electricity should likewise be allowed in a third, specific and limited instance: when the electricity is used in the production of a PtL transportation fuel like Twelve's E-Jet. The language changes laid out in the attachment are simple, straightforward, and narrowly tailored. In addition to minor add-ons in section 95488.8(i), all of which are shown in redline, we are putting forward a proposed definition of the term "power-to-liquid fuel" to ensure the intended scope of the proposal is not exceeded.[15] Importantly, the conditions in subparagraphs (1)(A) and (B) would have to be met for indirect accounting to be allowed.

As with the existing authorized uses now contained in section 95488.8(i)(1), the CI value of any fuel producer's PtL fuel depends, as CARB put it in the 2018 FSOR, "almost entirely on the

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[12] 2018 FSOR at 172, quoting from the Initial Statement of Reasons (2018 ISOR) at III-95. In the 2018 ISOR, CARB proffered as the rationale for indirect accounting that "[s]upport for electricity decarbonization for electric vehicles allows for ultra-low carbon fuel pathways, which will help California better meet GHG emission reduction goals." 2018 ISOR at III-96.

[13] 2018 FSOR at 172. Elsewhere in the document, CARB stated that "[i]ndirect, or book-and-claim, accounting for renewable or low-CI energy is recognized under the LCFS only for feedstocks or when the input is used directly as a fuel, not process energy." *Id.* at 483.

[14] *Id.* at 173.

[15] We acknowledge that the term "low-CI electricity" is a defined term in the LCFS regulation (17 CCR 95481(a)(94)) and expressly includes "'an eligible renewable resource" as defined under the California Renewables Portfolio Standard Program. Nevertheless, insofar as the subtitles of subsection (i) and paragraph (1) each include the term "renewable," we recommend from a pure drafting standpoint that this term also be inserted elsewhere in section 95488.8(i)(1), as shown in the attachment.

source of the electricity." In a presentation at a recent Commercial Aviation Alternative Fuels Initiative event, Dr. Ian Rowe, who co-leads the DOE CO_2 Reduction and Upgrading for e-Fuels Consortium, confirmed this, pointing out that PtL fuels "can have a very low carbon intensity IF they are made with renewable electricity."[16] Moreover, as with electrolytic hydrogen production, electricity serves as a feedstock for PtL fuel production, not as process energy. Finally, indirect accounting in this additional instance is further justified by the fact that, separate and apart from the electricity being a feedstock rather than process energy, the GHG emission reductions that would result from the allowance of indirect accounting would be quite significant inasmuch as the fuel production process, once again as CARB put it in the 2018 FSOR, "rel[ies] extensively on electricity consumption." That, of course, is the whole premise behind the burgeoning PtL fuel industry – using electricity (from a renewable source) to ultimately transform CO_2 into an ultra-low carbon liquid fuel.[17]

From a public policy perspective, allowing indirect accounting for renewable or low-CI electricity used in the production of a PtL transportation fuel makes good sense in that it would significantly incentivize not only the scale-up of these promising liquid fuels, but also the much-needed development and utilization of renewable energy resources like solar, wind, and hydroelectric. It is undeniable that the LCFS Program is designed to reduce GHG emissions from the transportation sector, and Twelve's proposal would squarely further that purpose. That the proposal would also yield ancillary benefits for the electricity grid by supporting lower-CI stationary electricity generation should not be ignored or disregarded, particularly given that for a host of reasons, PtL fuel producers cannot always co-locate their facilities at a renewable electricity source or build a solar or wind farm as part of their fuel production facility.

* * *

Thank you for your consideration of our comments and proposed regulatory revisions. Please do not hesitate to contact me or my colleague, Ira Dassa (ira.dassa@twelve.co), if you have any questions. As a California-based company, and with the manufacture of the all-important CO_2 electrolyzer stacks that will be deployed at our first fuel production plant now taking place at our facility in Alameda, I want to stress in closing that we would be pleased to meet or otherwise engage with you or your staff on any aspect of our proposal.

[16] *See* Ian Rowe (DOE Bioenergy Technologies Office), "Emerging Technologies to Support the SAF Grand Challenge 2050 Goal: Routes to Achieving Net-Zero Fuels and E-Fuels," at slide 11 (June 16, 2023) (emphasis in original), available at https://caafi.org/resources/pdf/SAF_Virtual_Conf_June2023_Session_13_Ian_Rowe.pdf.

[17] Twelve's proprietary process is unique in that we use electricity not only to create electrolytic hydrogen for the syngas but, equally important, to electrolyze CO_2 via our revolutionary CO_2 electrolyzer technology. Under the current LCFS regulation, our understanding is that indirect accounting can be used for the water electrolysis step. (Note that in the future, we may opt to obtain green hydrogen from a supplier.) However, we are submitting this proposal because the novel CO_2 electrolysis step in our process does not appear to be encompassed within section 95488.8(i)(1), which we assume triggers the applicability of the section 95488.8(h) preclusion against indirect accounting mechanisms "[u]nless expressly provided elsewhere in [the LCFS regulation]." This, in turn, would affect the CI score of our E-Jet fuel.

Sincerely yours,

Andrew Stevenson

Andy Stevenson
Vice President of Project Development and Partnerships
Twelve Benefit Corporation
andy.stevenson@twelve.co

Attachment

cc: Liane M. Randolph, Chair
Dr. Steven C. Cliff, Executive Officer
Rajinder Sahota, Deputy Executive Officer
Anil Prabhu, Manager, Fuels Evaluation Section

§ 95481. Definitions and Acronyms.

(New (a)(120))

(120) "Power to Liquid Fuel" means a synthetic fuel that is produced from captured carbon dioxide, water, and renewable or low-CI electricity.

* * *

§ 95488.8. Fuel Pathway Application Requirements Applying to All Classifications.

* * *

(i) *Indirect Accounting for Renewable or Low-CI Electricity and Biomethane.*

(1) *Book-and-Claim Accounting for Renewable or Low-CI Electricity Supplied as a Transportation Fuel ~~or~~, Used to Produce Hydrogen, or Used to Produce a Power-to-Liquid Fuel.* Reporting entities may use indirect accounting mechanisms for renewable or low-CI electricity supplied as a transportation fuel ~~or~~, for hydrogen production through electrolysis for transportation purposes (including hydrogen that is used in the production of a transportation fuel), or for the production of a power-to-liquid fuel for transportation purposes, provided the conditions set forth below are met:

(A) Reporting entities may report renewable or low-CI electricity used as a transportation fuel or as an input to hydrogen or power-to-liquid fuel production delivered through the grid without regard to physical traceability if it meets all requirements of this subarticle.
The renewable or low-CI electricity must be supplied to the grid within a California Balancing Authority (or local balancing authority for hydrogen or power-to-liquid fuel produced outside of California) or alternatively, meet the requirements of California Public Utilities Code section 399.16, subdivision (b)(1). Such book-and-claim accounting for renewable or low-CI electricity may span only three quarters. If a renewable or low-CI electricity quantity (and all associated environmental attributes, including a beneficial CI) is supplied to the grid in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to grid electricity used as a transportation fuel or for hydrogen or power-to-liquid fuel production no later than the end of the third calendar quarter.
After that period is over, any unmatched renewable or low-CI electricity quantities expire for the purpose of LCFS reporting.

(B) Renewable or ~~L~~low-CI electricity can be indirectly supplied through a green tariff program (including the Green Tariff Shared Renewables program described in California Public Utilities Code Section 2831-2833) or other contractual electricity supply relationship that meets the following requirements:

1. Electricity is generated by, or supplied under contract to, the pathway applicant for all environmental attributes of the claimed electricity. In order to substantiate renewable or low-CI electricity claims, the applicant must make contracts available to the Executive Officer, upon request, to demonstrate that the electricity meets the requirements of this subarticle. Generation invoices or metering records are required to substantiate the quantity of renewable or low-CI electricity produced from the renewable assets. Monthly invoices must be unredacted copies of originals showing electricity sourced (in kWh) and contracted price;

2. All electricity procured by any LSE for the purpose of claiming a lower CI must be in addition to that required for compliance with the California Renewables Portfolio Standard (described in California Public Utilities Code sections 399.11-399.32) or, for hydrogen or power-to-liquid fuel produced outside of California, in addition to local renewable portfolio requirements;

3. Renewable energy certificates or other environmental attributes associated with the electricity, if any, are retired and not claimed under any other program with the exception

of the federal RFS, and the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800). Retirement of renewable energy credits for the purpose of demonstrating Green Tariff Shared Renewables procurement to the California Public Utilities Commission does not constitute a double claim.

*   *   *

APPENDIX A-1.1

Proposed Regulation Order

Proposed Amendments to the Low Carbon Fuel Standard Regulation

[Showing Twelve Benefit Corporation's Proposed Insertions on pp. 21 and 149-50]

[Note: This alternative version of the proposed amendments is provided to improve the accessibility and readability of the regulatory text. This version is not the authoritative version for this proposed rulemaking. **For the authoritative version that complies with Government Code section 11346.2, subdivision (a)(3), please see Appendix A-1**. The existing, original regulatory language currently adopted into the CCR is shown as plain, clean text, while the proposed amendments subject to comment in this rulemaking are shown in tracked changes (underline to indicate additions and ~~strikeout~~ to indicate deletions from the existing regulatory text). [Bracketed underline text] is placeholder text for these amendments' approval date. Vertical lines in the left margins and text balloons in the right margins are to flag where changes are proposed (both substantive and nonsubstantive) for ease of reference and are not part of the proposed amendments. Blank cells in Table 9 (section 95489) are a result of formatting in "No Markup" or "Clean" reviewing options and are not part of the proposed amendments. To review this document in a clean format (no underline or strikeout to show changes), please select "Simple Markup" or "No Markup" in Microsoft Word's Review menu, or accept all changes. You can also change the view to the original (originally proposed regulatory text prior to proposed modifications) by selecting "Original" or rejecting all tracked changes. Additionally, "Advanced Track Changes Options" will allow for further options regarding color and other markings. Instructions on using/viewing Track Changes can be found here]

Chapter 1. Air Resources Board

Subchapter 10. Climate Change

Article 4. Regulations to Achieve Greenhouse Gas Emission Reductions

Subarticle 7. Low Carbon Fuel Standard

Section 95488.6.	Tier 1 Fuel Pathway Application Requirements and Certification Process
Section 95488.7.	Tier 2 Fuel Pathway Application Requirements and Certification Process
Section 95488.8.	Fuel Pathway Application Requirements Applying to All Classifications
Section 95488.9.	Special Circumstances for Fuel Pathway Applications
Section 95488.10.	Maintaining Fuel Pathways
Section 95489.	Provisions for Petroleum-Based Fuels
Section 95490.	Provisions for Fuels Produced Using Carbon Capture and Sequestration
Section 95491.	Fuel Transactions and Compliance Reporting
Section 95491.1	Recordkeeping and Auditing
Section 95491.2.	Measurement Accuracy and Data Provisions
Section 95495.	Authority to Suspend, Revoke, Modify, or Invalidate
Section 95500.	Requirements for Validation of Fuel Pathway Applications; and Verification of Annual Fuel Pathway Reports, Quarterly Fuel Transactions Reports, Crude Oil Quarterly and Annual Volumes Reports, Project Reports, and Low-Complexity/Low-Energy-Use Refinery Reports
Section 95501.	Requirements for Validation and Verification Services
Section 95502.	Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers.
Section 95503.	Conflict of Interest Requirements for Verification Bodies and Verifiers

Proposed Regulation Order

Title 17, California Code of Regulations

Amend Sections 95481, 95482, 95483, 95483.2, 95483.3, 95484, 95485, 95486, 95487, 95486.1, 95486.2, 95488, 95488.1, 95488.2, 95488.3, 95488.5, 95488.6, 95488.7, 95488.8, 95488.9, 95488.10, 95489, 95490, 95491, 95491.1, 95495, 95500, 95501, 95502, 95503 of title 17, California Code of Regulations, to read as follows:

§ 95480. Purpose.

The purpose of this regulation is to implement a low carbon fuel standard, which will reduce the full fuel-cycle, carbon intensity of the transportation fuel pool used in California, pursuant to the California Global Warming Solutions Act of 2006 (Health & Safety Code [H&S], section 38500 et seq.).

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95481. Definitions and Acronyms.

(a) *Definitions.* For the purposes of sections 95480 through 95503, the definitions in Health and Safety Code sections 39010 through 39060 shall apply, except as otherwise specified in this section or sections 95482 through 95503:

~~(1)~~"Account Administrator" means the person who can establish and activate user accounts for the reporting party organization as well as upload data (but not necessarily "submit" reports) into the LRT-CBTS. Account administrators with "signatory authority" may submit Quarterly and Annual Reports; initiate and view all credit transfers and credit transfer activity; access the Credit Balance ledger for the organization; and select/authorize broker(s) to represent them.

~~(2)~~"Advanced Credits" means LCFS base electricity credits that are issued prior to the quarter in which credit-generating transactions have occurred. Advanced credits can only be sold via the Credit Clearance Market, and only retired for the purpose of meeting compliance obligation.

~~(3)~~"Advanced Credit Window" is the six-year period during which advanced credits can be issued and after which base credit issuances will be adjusted to account for advanced credits.

~~(4)~~"Adverse Validation Statement" and "Adverse Verification Statement" means a statement rendered by a verification body attesting that: (1) the verification body cannot say, with reasonable assurance, that the reported value is free of a material misstatement, or (2) the data submitted contain one or more correctable errors, or (3) both, and thus is not in conformance with the requirement to fix such errors pursuant to section 95501(b)(6). This definition applies to Adverse Validation Statements for fuel pathway applications and Adverse Verification Statements for Annual Fuel Pathway Reports, Quarterly Fuel Transactions Reports, Crude Oil Quarterly and Annual Volumes Reports, Low-Complexity/Low-Energy-Use Refinery Reports, and Project Reports. "Material misstatement" for each type of report is assessed pursuant to sections 95501(b)(9) through (11).

~~(5)~~"AEZ-EF Model" means the Agro-Ecological Zone Emissions Factor model (December 31, 2014),~~ posted at http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/lcfs_meetings.htm and~~ available for download at http://www.arb.ca.gov/fuels/lcfs/lcfs_meetings/aez-ef_model_v52.xlsm, which is incorporated herein by reference.

~~(6)~~"Aggregated Transaction Indicator" means an identifier for reported transactions that are a result of an aggregation or summing of more than one transaction in the LRT-CBTS. An entry of 'True' indicates that multiple transactions have been aggregated and are reported with a single Transaction Number. An entry of 'False' means that the transaction record results from one fuel transaction reported as a single Transaction Number.

~~(7)~~"Alternative Fuel" means any transportation fuel that is not CaRFG~~ or a~~, diesel fuel, or fossil jet fuel including those fuels specified in section 95482(a)(3) through (a)(13).

~~(8)~~"Alternative Jet Fuel" means a drop-in fuel, made from ~~petroleum or~~ non-petroleum sources, which can be blended ~~and used with~~into conventional ~~petroleum~~ jet fuel~~s~~ without the need to modify aircraft engines and existing fuel distribution infrastructure.

"Alternate Method" means the collection of data to support or replace a measurement required by this subarticle. An alternate method may include a calculated value based on accurate measurements of system inputs and outputs or based on a conservative calculation using previously collected quality assured data.

~~(9)~~"Animal Fat" means the inedible fat that originates from a rendering facility as a product of rendering the by-products from meat processing facilities including animal parts, fat and bone. "Yellow grease" must be reported under an applicable animal fat pathway if evidence is not provided to the verifier or CARB to confirm the quantity that is animal fat and the quantity that is used cooking oil.

~~(10)~~“Application” means the type of vehicle where the fuel is consumed in terms of LDV/MDV for light-duty vehicle/medium-duty vehicle or HDV for heavy-duty vehicle.

“Automatic Acceleration Mechanism” is a mechanism implemented pursuant to section 95484 which advances all annual carbon intensity benchmarks by one year when specified conditions are met.

~~(11)~~“Aviation Gasoline” means a complex mixture of volatile hydrocarbons, with or without additives, suitably blended to be used in aviation engines.

~~(12)~~“Avoided Cost Calculator” means the Excel-based spreadsheet model (May 22, 2018) produced by Energy and Environmental Economics, Inc. (E3) for use in demand-side cost-effectiveness proceedings at the California Public Utilities Commission (CPUC), which is incorporated herein by reference~~, and is available for download at http://www.cpuc.ca.gov/General.aspx?id=5267.~~..

~~(13)~~“Battery Electric Vehicle (BEV)” means any vehicle that operates solely by use of a battery or battery pack, or that is powered primarily through the use of an electric battery or battery pack but uses a flywheel or capacitor that stores energy produced by the electric motor or through regenerative braking to assist in vehicle operation.

~~(14)~~“Biodiesel” means a fuel as defined in California Code of Regulations, title 4, section 4140(a).

~~(15)~~“Biodiesel Blend” means biodiesel blended with CARB diesel.

~~(16)~~“Biogas” means the raw gaseous mixture comprised primarily of methane and carbon dioxide and derived from sources, including but not limited to, the anaerobic decomposition of organic matter in a landfill, lagoon, or constructed reactor (digester). Biogas often contains a number of other impurities, such as hydrogen sulfide, and it cannot be directly injected into natural gas pipelines or combusted in most natural-gas-fueled vehicles. It can be used as a fuel in boilers and engines to produce electrical power. The biogas can be refined to produce near-pure methane, which is sold as biomethane.

~~(17)~~“Bio-CNG” means biomethane which has been compressed to CNG. Bio-CNG has equivalent performance characteristics when compared to fossil CNG.

~~(18)~~“Bio-LNG” means biomethane which has been compressed and liquefied into LNG. Bio-LNG has equivalent performance characteristics when compared to fossil LNG.

~~(19)~~“Bio-L-CNG” means biomethane which has been compressed, liquefied, re-gasified, and re-compressed into L-CNG, and has performance characteristics at least equivalent to fossil L-CNG.

~~(20)~~"Biomass" means non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms, including: products, by-products, residues and waste from agriculture, forestry, and related industries; the non-fossilized and biodegradable organic fractions of industrial and municipal wastes; and gases and liquids recovered from the decomposition of non-fossilized and biodegradable organic material.

~~(21)~~"Biomass-based Diesel" means a biodiesel or a renewable diesel.

~~(22)~~"Biomethane" means methane derived from biogas, or synthetic natural gas derived from renewable resources, including the organic portion of municipal solid waste, which has been upgraded to meet standards for injection to a natural gas common carrier pipeline, or for use in natural gas vehicles, natural gas equipment, or production of renewable hydrogen. Biomethane contains all of the environmental attributes associated with biogas and can also be referred to as renewable natural gas.

~~(23)~~"Blendstock" means a component that is either used alone or is blended with another component(s) to produce a finished fuel used in a motor vehicle. Each blendstock corresponds to a fuel pathway in the ~~California-modified Greenhouse Gases, Regulated Emissions, and Energy use in Transportation version 3.0 (~~CA-GREET ~~3~~4.0~~)~~ model, ~~(August 13, 2018), which is incorporated herein by reference.~~[Date of adoption]. A blendstock that is used directly as a transportation fuel in a vehicle is considered a finished fuel.

"Book-and-Claim Accounting" is an indirect accounting system where a physical product and its environmental attributes can be separately traded. In the LCFS, the separated environmental attributes of low-CI electricity, biomethane or low-CI hydrogen may be matched under certain conditions to the use of grid electricity, fossil natural gas or hydrogen respectively.

"Break ground" means earthmoving and site preparations necessary for construction of the digestor system and supporting infrastructure that starts following approval of all necessary entitlements/permits for the project.

~~(24)~~"Brown Grease" means an emulsion of fat, oil, grease, solids, and water separated from wastewater in a grease interceptor (grease trap) and collected for use as a fuel feedstock. Brown grease must be reported under an applicable used cooking oil (UCO) pathway, i.e., reported as "unprocessed UCO" only if evidence is provided to the verifier or CARB to confirm that it has not been processed prior to receipt by the fuel production facility.

~~(25)~~"Business Partner" refers to the counterparty in a specific transaction involving the fuel reporting entity. This can be either the buyer or the seller of fuel.

"Byproduct" means a secondary product with marginal economic value outside its use in a biofuel pathway.

"California-modified Greenhouse Gases, Regulated Emissions, and Energy use in Transportation model (CA-GREET)" is a modified version of Argonne National Lab's Greenhouse Gases, Regulated Emissions, and Energy use in Transportation (GREET) model used to evaluate well-to-wheel GHG emissions in the LCFS. The CA-GREET model is periodically updated, and includes a version number suffix, e.g., CA-GREET4.0.

"California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB)" is gasoline blendstock that, when blended with ethanol, results in a finished gasoline which meets the requirements of California Reformulated Gasoline (RFG) Regulations

"Carbon capture and sequestration (CCS) project" means a project that captures CO_2 by an eligible entity specified in section 95490(a) of this subarticle, transports the captured CO_2 to an injection site, and injects and permanently sequesters the captured CO_2 pursuant to the Carbon Capture and Sequestration Protocol and as specified by section 95490 of this subarticle.

~~(26)~~"Carbon Intensity (CI)" means the quantity of life cycle greenhouse gas emissions, per unit of fuel energy, expressed in grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ).

~~(27)~~"Cargo Handling Equipment" means any off-road, self-propelled vehicle or equipment, other than yard trucks, used at a port or intermodal rail yard to lift or move container, bulk, or liquid cargo carried by ship, train, or another vehicle, or used to perform maintenance and repair activities that are routinely scheduled or that are due to predictable process upsets. Equipment includes, but is not limited to, rubber-tired gantry cranes, top handlers, side handlers, reach stackers, loaders, aerial lifts, excavators, tractors, and dozers.

~~(28)~~"CHAdeMO Connector" means a connector and communication protocol for vehicle DC charging initially developed in Japan during 2005-2009. It was first adopted into international standards IEC 61851-23/24 and IEC 62196-3 in 2014 and then into USA standard IEEE 2030.1.1 in 2015. Further updates to the protocol are managed by the CHAdeMO Association.

~~(29)~~"Clean Fuel Reward" is a statewide program established by EDUs to provide a reduction in price ~~on new light duty EV~~ purchases or leases for new medium- or heavy-duty electric vehicles that are not subject to the High Priority and Federal Fleets requirements as specified in, title 13, California Code of Regulations, section 2015(a)(1) in California. The Clean Fuel Reward is funded exclusively through LCFS proceeds generated by EDUs from electricity fuel.

~~(30)~~"Compressed Natural Gas (CNG)" means natural gas that has been compressed to a pressure greater than ambient pressure.

~~(31)~~"Conflict of Interest" means a situation in which, because of financial or other activities or relationships with other persons or organizations, a person or body is unable, or potentially unable, to render an impartial validation or verification statement on a potential client's LCFS data report, or the person or body's objectivity in performing validation or verification services is, or might be, otherwise compromised.

"Conservative" means reducing the estimated GHG reduction benefits of an operation or utilizing methods and factors that over-estimate energy usage or carbon intensity (90th percentile or highest value) or under-estimate produced fuel volumes (10th percentile or lowest value).

~~(32)~~"Contract Description Code" means the alphanumeric code assigned by an exchange to a particular exchange product that differentiates the product from others traded on the exchange.

~~(33)"Conventional~~ "Jet Fuel" means aviation turbine fuel including Commercial and Military Jet Fuel. Commercial Jet Fuel includes products known as Jet A, Jet A-1, and Jet B. Military Jet Fuel includes products known as JP-5 and JP-8.

"Co-product" means a product with significant market value that is produced alongside a main primary product.

~~(34)~~"Correctable Errors" means one or more errors that result from a nonconformance with this subarticle and are identified by the verification team as errors that affect data subject to validation or verification as specified in section 95500. Differences that, in the professional judgment of the verification team, are the result of differing but reasonable methods of truncation or rounding or averaging, where a specific procedure is not prescribed by this subarticle, are not considered errors.

"Credit Bank" is the total credits retained from previous crediting periods that have not been retired to demonstrate compliance.

~~(35)~~"Credit Generator" means a fuel reporting entity or a project operator that generates LCFS credit in the LCFS program.

~~(36)~~"Credits" and "Deficits" mean the units of measure used for determining a regulated entity's compliance with the average carbon intensity requirements in section 95484. Credits and deficits are denominated in units of metric tons of carbon dioxide equivalent (CO_2e), and are calculated pursuant to sections 95486.1(a), (c), 95486.2(a)(5) and (b)(5), 95489 and 95490.

~~(37)~~"Day" means a calendar day unless otherwise specified as a business day.

~~(38)~~"Deficit Generator" means a fuel reporting entity who generates deficits in the LCFS program.

~~(39)~~"Diesel Fuel" (also called conventional diesel fuel) has the same meaning as specified in California Code of Regulations, title 13, section 2281(b).

~~(40)~~"Direct Current Fast Charging" means charging an electric vehicle at 50 kW and higher using direct current.

~~(41)~~"Disadvantaged Communities" means communities that are defined by California Health and Safety Code section 39711(a) that are identified based on geographic, socioeconomic, public health, and environmental hazard criteria, and may include, but are not limited to, either of the following: (1) areas disproportionately affected by environmental pollution and other hazards that can lead to negative public health effects, exposure, or environmental degradation or (2) areas with concentrations of people that are of low-income, high unemployment, low levels of homeownership, high rent burden, sensitive populations, or low levels of educational attainment.

~~(42)~~"Distiller's Corn Oil" has the same meaning as "Technical Corn Oil."

"Distiller's Grains and Solubles" is a coproduct of ethanol production rich in protein and fiber, typically used for animal feed. DGS is subcategorized as Dry (DDGS), Modified (MDGS), or Wet (WDGS) based on the extent of moisture removal at an ethanol production facility.

~~(43)~~"Distiller's Sorghum Oil" has the same meaning as "Technical Sorghum Oil."

~~(44)~~"Drayage Trucks" means vehicles as defined in California Code of Regulations, title 13, section 2027(c).

~~(45)~~"E100," also known as "Denatured Fuel Ethanol," means nominally anhydrous ethyl alcohol.

~~(46)~~"Electrical Distribution Utility" means an entity that owns or operates an electrical distribution system, including:

~~(A)~~(1) a public utility as defined in the Public Utilities Code section 216 (referred to as an Investor Owned Utility, or IOU); or

~~1.~~(A) "Large Investor-owned Utility" means an IOU with annual load served equal to or more than 10,000 Gigawatt-hours (GWh) in 2017;

~~2.~~(B) "Medium Investor-owned Utility" means an IOU with annual load served of less than 10,000 GWh and equal to or more than 700 GWh in 2017;

~~3.~~(C) "Small Investor-owned Utility" means an IOU with annual load served equal to or less than 700 GWh in 2017.

or

~~(B)~~(2) a local publicly-owned electric utility (POU) as defined in Public Utilities Code section 224.3;

~~1.~~(A) "Large Publicly-owned Utility" means a California POU with annual load served equal to or more than 10,000 Gigawatt-hours (GWh) in 2017;

~~2.~~(B) "Medium Publicly-owned Utility" means a California POU with annual load served of less than 10,000 GWh and equal to or more than 700 GWh in 2017;

~~3.~~(C) "Small Publicly-owned Utility" means a California POU with annual load served of less than 700 GWh in 2017.

or

~~(C)~~(3) an Electrical Cooperative (COOP) as defined in Public Utilities Code section 2776.

~~(47)~~"Electric Cargo Handling Equipment (eCHE)" means cargo handling equipment using electricity as the fuel.

~~(48)~~"Electric Power for Ocean-going Vessel (eOGV)" means shore power provided to an ocean going vessel at-berth.

~~(49)~~"Electric Transport Refrigeration Units (eTRU)" means refrigeration systems powered by electricity designed to refrigerate or heat perishable products that are transported in various containers, including semi-trailers, truck vans, shipping containers, and rail cars.

~~(50)~~"Electric Vehicle (EV)," for purposes of this regulation, refers to Battery Electric Vehicles (BEVs) and Plug-In Hybrid Electric Vehicles (PHEVs).

"Emission Factor" is a measure of greenhouse gas emissions per unit of a specific product or activity (i.e., gCO2e/mile transported). Emission factors are used extensively in Tier 1 calculators to provide simplified results of more complex lifecycle analysis equations derived from the CA-GREET model.

"Emissions & Generation Resource Integrated Database (eGRID)" is the database maintained and published by the U.S. Environmental Protection Agency (EPA) that provides resource mix and emission data for electrical power generated in the United States.

~~(51)~~"Energy Economy Ratio (EER)" means the dimensionless value that represents the efficiency of a fuel as used in a powertrain as compared to a reference fuel used in the same powertrain. EERs are often a comparison of miles per gasoline gallon equivalent (mpge) between two fuels. EERs for fixed guideway systems are based on MJ/number of passenger-miles.

~~(52)~~“Environmental Attribute” means greenhouse gas emission reduction recognition in any form, including verified emission reductions, voluntary emission reductions, offsets, allowances, credits, avoided compliance costs, emission rights and authorizations under any law or regulation, or any emission reduction registry, trading system, or reporting or reduction program for greenhouse gas emissions that is established, certified, maintained, or recognized by any international, governmental, or non-governmental agency.

~~(53)~~“Executive Officer” means the Executive Officer of the California Air Resources Board, or his or her delegate.

~~(54)~~“Exchange” means a central marketplace with established rules and regulations where buyers and sellers meet to conduct trades.

~~(55)~~“Export” means transportation fuel reported in the LRT-CBTS program that is subsequently delivered outside of California and not used for transportation in California.

~~(56)~~“Feedstock First Collection Point” means the facility that aggregates and stores or treats feedstock materials collected from a point of origin. The first collection point may be upstream of the fuel production facility, or, if feedstocks are transported to the fuel production facility directly from the point of origin, the first collection point is the fuel production facility.

~~(57)~~“Feedstock Transport Mode” means the applicable combination of actual delivery methods and the distance through which the feedstock was transported to any intermediate entities and ending at a fuel production facility. The fuel pathway holder and any entity reporting the fuel must demonstrate that the actual feedstock transport mode and distance conforms to the stated mode and distance in the certified pathway.

~~(58)~~“Final Distribution Facility” means the stationary finished fuel transfer point from which the finished fuel is transferred into the cargo tank truck, pipeline, or other delivery vessel for delivery to the facility at which the finished fuel will be dispensed into motor vehicles.

~~(59)~~“Finished Fuel” means a fuel that is used directly in a vehicle for transportation purposes without requiring additional chemical or physical processing.

~~(60)~~“First Fuel Reporting Entity” means the first entity responsible for reporting in the LRT-CBTS for a given amount of fuel. This entity initially holds the status as the fuel reporting entity and the credit or deficit generator for this fuel amount, but may transfer either status pursuant to sections 95483 or 95483.1.

~~(61)~~“Fish Oil” means the fat that originates from fish processing operations as a product of rendering fat from residual fish parts.

~~(62)~~"Fixed Guideway System" means a system of public transit electric vehicles that can operate only on its own guideway (directly operated, or DO), or through overhead or underground electricity supply constructed specifically for that purpose, such as light rail, heavy rail, cable car, street car, and trolley bus.

"Food Scraps" is the organic portion of municipal solid waste (MSW) that consists of wastes derived from plants or animals for the explicit preparation for consumption by humans or other animals that is predominantly disposed by landfilling. This includes inedible waste from foods processed or consumed at residences, hospitality facilities (hotels, restaurants, amusement parks, stadiums, special events, etc.), institutions (hospitals, schools, prisons, etc.), and grocery stores. Food scraps do not include liquid wastes, fat/oil/grease (FOG) materials, or other by-products of industrial food processing, manufacturing, and distribution facilities.

"Forest" means land spanning more than 0.5 hectares with trees higher than 5 meters and a canopy cover of more than 10 percent, or trees able to reach these thresholds in situ. It does not include land that is predominantly under agricultural or urban land use.

"Fossil CNG" means CNG that is derived solely from petroleum or fossil sources, such as oil fields and coal beds.

~~(63)~~"Fossil Jet Fuel" means Jet Fuel that is derived solely from petroleum or fossil sources, such as oil fields and coal beds.

~~(64)~~"Fossil LNG" means LNG that is derived solely from petroleum or fossil sources, such as oil fields and coal beds.

~~(65)~~"Fossil L-CNG" means L-CNG that is derived solely from petroleum or fossil sources, such as oil fields and coal beds.

~~(66)~~"Fuel Pathway" means, for a particular finished fuel, the collective set of processes, operations, parameters, conditions, locations, and technologies throughout all stages that CARB considers appropriate to account for in the system boundary of a complete well-to-wheel analysis of that fuel's life cycle greenhouse gas emissions.

~~(67)~~"Fuel Pathway Applicant" refers to an entity that has registered in the Alternative Fuel Portal pursuant to section 95483.2 and has submitted an application including all required documents and attestations in support of the application requesting a certified fuel pathway.

~~(68)~~"Fuel Pathway Code" means the identifier in the LRT-CBTS that applies to a specific fuel pathway certified pursuant to sections 95488 through 95488.10.

~~(69)~~"Fuel Pathway Holder" means a fuel pathway applicant that has received a certified fuel pathway carbon intensity based on site-specific data, including a Provisional fuel pathway.

~~(70)~~"Fuel Production Facility" means the facility at which the fuel is produced. "Fuel Production facility" means, with respect to biomethane to vehicle fuel pathways, a facility at which fuel is upgraded, purified, or processed to meet standards for injection to a natural gas common carrier pipeline or for use in natural gas vehicles.

~~(71)~~"Fuel Reporting Entity" means an entity that is required to report fuel transactions in the LRT-CBTS pursuant to section 95483 or 95483.1. Fuel reporting entity refers to the first fuel reporting entity and to any entity to whom the reporting entity status is passed for a given quantity of fuel.

~~(72)~~"Fuel Transport Mode" means the applicable combination of actual fuel delivery methods, such as truck routes, rail lines, pipelines, and any other fuel distribution methods, and the distance through which the fuel was transported under contract from the entity that generated or produced the fuel, to any intermediate entities, and ending at the fuel blender, producer, importer, or provider in California. The fuel pathway holder and any entity reporting the fuel must demonstrate that the actual fuel transport mode and distance conforms to the stated mode and distance in the certified pathway.

"Fugitive Methane" is methane emitted atmospherically from leaks, venting or incomplete combustion. Fugitive methane sources may be quantified either using standard values or a site-specific energy balance of methane inside the fuel pathway system boundary.

"Full verification" means all verification services as provided in section 95501.

~~(73)~~"Green Tariff" means a program in which a retail seller of electricity offers its customers an opportunity to purchase electricity sourced from low-carbon intensity energy resources. This includes the Green Tariff Shared Renewables program established pursuant to California Senate Bill 43 (2013) and defined under the California Public Utilities Code sections 2831-2833.

~~(74)~~"GTAP" or "GTAP Model" means the Global Trade Analysis Project Model (December 2014), which is incorporated herein by reference, and is a software available for download at https://www.gtap.agecon.purdue.edu/resources/res_display.asp?RecordID=4577.

~~(75)~~"Heavy-Duty Vehicle" means a vehicle that is rated at or greater than 14,001 pounds gross vehicle weight rating (GVWR).

"Higher Heating Value (HHV)" is the quantity of heat energy produced by complete combustion of a fuel, including the heat of condensation for water vapor produced during combustion.

~~(76)~~“Holdback Credits” means the portion of base residential EV charging credits issued to an EDU that are not contributed by the EDU to the Clean Fuel Reward program.

~~(77)~~“Home Fueling” means the dispensing of fuel by use of a fueling appliance that is located on or within a residential property with access limited to a single household.

~~(78)~~“Hybrid Electric Vehicle (HEV)” means any vehicle that can draw propulsion energy from both of the following on-vehicle sources of stored energy: 1) a consumable fuel, and 2) an energy storage device, such as a battery, capacitor, or flywheel.

“Hydrogen Fueling Capacity Model” or “HyCap” means a tool developed by the National Renewable Energy Laboratory to determine the dispensing capacity of hydrogen stations with different configurations and size parameters to accommodate heavy-duty fueling demands.

~~(79)~~“Hydrogen Station Capacity Evaluator” or “HySCapE” means a tool developed by the National Renewable Energy Laboratory to determine the dispensing capacity of a hydrogen station, HySCapE Version 1.0 (August 13, 2018), which is incorporated herein by reference and available at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm~~http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.~~.

“Hydroprocessed Ester and Fatty Acid (HEFA) Fuel” is any lipid feedstock converted to transportation fuel with addition of hydrogen in the presence of a catalyst. HEFA fuels can include renewable diesel, renewable naphtha, renewable propane and alternative jet fuel.

“Gasification” means the non-combustion thermal decomposition of biomass or organic matter in the presence of limited oxygen, air, or steam to produce heat and a mixture of gases, including but not limited to carbon monoxide and hydrogen (syngas) and solid hydrocarbon products.

~~(80)~~“Import” means to bring a product from outside California into California.

~~(81)~~“Importer” means the person who owns the transportation fuel or blendstock, in the transportation equipment that held or carried the product, at the point the fuel entered California. For purposes of this definition, “transportation equipment” includes, but is not limited to, rail cars, cargo tanker trucks, and pipelines.

~~(82)~~“Independent Reviewer” means an accredited lead verifier, within a verification body, who (A) has not participated in conducting the LCFS validation or verification services for the client for the current application period or reporting period, and (B) provides an independent review of findings and services rendered to the client as required in section 95501. The independent reviewer is not required to meet the additional specified competency requirements in sections 95502(c)(4) and 95502(c)(5) that the verification team leader must meet.

~~(83)~~“Ineligible Specified Source Feedstock” means a feedstock specified in section 95488.8(g)(1)(A) that does not meet the chain-of-custody documentation requirements specified in section 95488.8(g)(1)(B).

~~(84)~~“Intermediate Calculated Value” means a value that is used in the calculation of a reported value but does not by itself meet the reporting requirement under section 95491.

~~(85)~~“Intermediate Facility” means a facility in a fuel supply chain, which is not the fuel production facility, that contributes site-specific data for determination of a fuel pathway carbon intensity. Intermediate facilities produce components of a fuel or intermediate chemical that may be further processed into a fuel. This term includes feedstock-processing facilities.

~~(86)~~“LCFS Credit Broker” is a person registered in the LRT-CBTS specifically to facilitate the transfer of LCFS credits between LRT-CBTS accounts.

~~(87)~~“Lead Verifier” means a person who has met all the requirements in section 95502 and who may act as either (A) the lead verifier of a verification team providing validation or verification services, or (B) as a lead verifier providing an independent review of validation or verification services rendered.

“Less intensive verification” means the verification services provided in interim years between full verifications; less intensive verification does not require a site visit, and only requires data checks and document reviews of a submitted report based on the analysis and risk assessment in the most current sampling plan developed as part of the most current full verification services. This level of verification may only be used if the verifier can provide findings with a reasonable level of assurance.

~~(88)~~“Life Cycle Greenhouse Gas Emissions” means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions, such as significant emissions from land use changes), as determined by the Executive Officer, related to the full fuel life cycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.

~~(89)~~“Light-Duty Vehicle” and “Medium-Duty Vehicle” mean a vehicle category that includes both light-duty (LDV) and medium-duty vehicles (MDV).

~~(A)~~(1) “LDV” means a vehicle that is rated at 8,500 pounds or less GVWR.

~~(B)~~(2) “MDV” means a vehicle that is rated between 8,501 and 14,000 pounds GVWR.

~~(90)~~"Liquefied Compressed Natural Gas (L-CNG)" means LNG that has been liquefied and transported to a dispensing station where it was then re-gasified and compressed to a pressure greater than ambient pressure.

~~(91)~~"Liquefied Natural Gas (LNG)" means natural gas that has been liquefied.

~~(92)~~"Liquefied petroleum gas (LPG or propane)" has the same meaning as defined in Vehicle Code section 380.

~~(93)~~"Load-Serving Entity" means any entity that (A) sells or provides electricity to end users located in California, or (B) generates electricity at one site and consumes electricity at another site that is in California and that is owned or controlled by the company. A load-serving entity does not include the owner or operator of a co-generator.

~~(94)~~"Low-Carbon Intensity (Low-CI) Electricity" means any electricity that is determined to have a carbon intensity that is less than the average grid electricity for the region, including but not limited to an "eligible renewable energy resource" as defined in Public Utilities Code sections 399.11-399.36 under the California Renewables Portfolio Standard Program.

~~(95)~~"Low-Complexity/Low-Energy-Use Refinery" means a refinery that meets both of the following criteria:

~~(A)~~(1) A Modified Nelson Complexity Score equal to or less than 5 as calculated in section 95489(d)(1)(A~~).~~), and

~~(B)~~(2) Total annual energy use equal to or less than 5 million MMBtu as calculated in section 95489(d)(1)(B).

"Lower Heating Value (LHV)" is the quantity of heat energy produced by complete combustion of a fuel, excluding the heat of condensation for water vapor produced during combustion.

~~(96)~~"Low-Income Communities" means census tracts with median household incomes at or below 80 percent of the statewide median income or with median household incomes at or below the threshold designated as low income by the Department of Housing and Community Development's list of state income limits adopted pursuant to Health and Safety Code section 50093.

~~(97)~~"Mandatory Reporting Regulation" or "MRR" means CARB's Regulation for the Mandatory Reporting of Greenhouse Gas Emissions as set forth in title 17, California Code of Regulations, chapter 1, subchapter 10, article 2 (commencing with section 95100).

~~(98)~~"Material Misstatement of Operational Carbon Intensity" means any discrepancy, omission, or misreporting, or aggregation of the three, identified in the course of verification services that leads a verification team to believe that the reported operational CI (gCO_2e/MJ) contains one or more errors that, individually or collectively, result in an overstatement or understatement more than 5.00 percent of the reported operational CI, or 2.00 gCO_2e/MJ, whichever absolute value expressed in gCO_2e/MJ is greater. Material misstatement is calculated separately for each operational CI. All correctable errors identified must be fixed prior to the completion of the verification services to receive a positive or qualified positive verification statement.

~~(99)~~"Material Misstatement of Low-Complexity/Low-Energy-Use (LC/LEU) Refinery Data" means any discrepancy, omission, or misreporting, or aggregation of the three, identified in the course of LC/LEU refinery report verification services that leads a verification team to believe that a LC/LEU Refinery Report contains one or more errors that, individually or collectively, result in an overstatement greater than 5.00 percent of the regulated entity's annual sum of quarterly reported volumes of CARBOB or diesel produced from crude oil. Discrepancies, omissions, or misreporting, or an aggregation of the three, that result in an understatement of the annual sum of quarterly reported volumes of CARBOB or diesel produced from crude oil submitted in the LC/LEU Refinery Report is not a LC/LEU refinery data material misstatement. Material misstatement is calculated separately, pursuant to section 95501(b)(11), for the annual volume of CARBOB production from crude oil and for the annual volume of diesel production from crude oil. All correctable errors identified must be fixed prior to the completion of the verification services to receive a positive or qualified positive verification statement.

~~(100)~~"Material Misstatement of Project Data" means a discrepancy, omission, misreporting, or aggregation of the three, identified in the course of project verification services that leads a verification team to believe that a Project Report contains one or more errors that, individually or collectively, result in an overstatement greater than 5.00 percent of the regulated entity's reported total greenhouse gas emission reductions. Discrepancies, omissions, or misreporting, or an aggregation of the three, which result in an understatement of total reported greenhouse gas emission reductions in the Project Report, is not a project material misstatement. Material misstatement is calculated separately, pursuant to section 95501(b)(10), for each Project Report. All correctable errors identified must be fixed prior to the completion of the verification services to receive a positive or qualified positive verification statement.

~~(101)~~"Material Misstatement of Quarterly Fuel Quantity" means any discrepancy, omission, or misreporting, or aggregation of the three, identified in the course of validation or verification services that leads a verification team to believe that the regulated entity's reported fuel quantity per fuel pathway code per quarter contains one or more errors that, individually or collectively, result in an overstatement or understatement greater than 5.00 percent. Material misstatement is calculated separately, pursuant to section 95501(b)(9), for each quarterly fuel quantity per fuel pathway code. All correctable errors identified must be fixed prior to the completion of the verification services to receive a positive or qualified positive verification statement.

“Missing Data” means a loss of reliable data for a period of time during which a piece of data is not collected, is invalid, or is collected while the measurement device is not in compliance with the applicable quality-assurance requirements, including calibration requirements.

~~(102)~~“Modified Nelson Complexity Score” means a Nelson Complexity Score that is calculated without including lube oil and asphalt capacity, as set forth in section 95489(d)(1)(A).

~~(103)~~“Motor Vehicle” has the same meaning as defined in section 415 of the Vehicle Code.

~~(104)~~“Multi-fuel Vehicle” means a vehicle that uses two or more distinct fuels for its operation. A multi-fuel vehicle (also called a vehicle operating in blended-mode) includes a bi-fuel vehicle and can have two or more fueling ports onboard the vehicle. A fueling port can be an electrical plug or a receptacle for liquid or gaseous fuel. For example, most plug-in hybrid electric vehicles use both electricity and gasoline as the fuel source and can be “refueled” using two separately distinct fueling ports.

~~(105)~~“Multi-family Residence” means a dwelling unit in a building that consists of at least four condominium dwelling units or at least three apartment dwelling units in which each unit shares a floor or ceiling on at least one side.

~~(106)~~“Natural Gas” means a mixture of gaseous hydrocarbons and other compounds, with at least 80 percent methane (by volume), and typically sold or distributed by utilities, such as any utility company regulated by the California Public Utilities Commission.

~~(107)~~“Nelson Complexity Score” means the commonly used industry measure of a refinery's ability to convert crude oils to finished fuels, taking into consideration the complexity of the technologies incorporated within the process and related capacities as compared to crude distillation.

~~(108)~~“Nonconformance” means the failure to use any method or meet any other requirement specified in this subarticle.

~~(109)~~“Ocean-Going Vessel” means a commercial, government, or military vessel meeting any one of the following criteria:

~~(A)~~(1) A vessel greater than or equal to 400 feet in length overall (LOA) as defined in 50 Code of Federal Regulations (CFR) § 679.2, as adopted June 19, 1996;

~~(B)~~(2) A vessel greater than or equal to 10,000 gross tons (GT ITC) pursuant to the convention measurement (international system) as defined in 46 CFR § 69.51-.61, as adopted September 12, 1989; or

~~(C)~~(3) A vessel propelled by a marine compression ignition engine with a per-cylinder displacement of greater than or equal to 30 liters.

~~(110)~~"On-road" means a vehicle that is designed to be driven on public highways and roadways and that is registered or is capable of being registered by the California Department of Motor Vehicles (DMV) under Vehicle Code sections 4000 et seq. - or DMV's equivalent in another state, province, or country; or the International Registration Plan. A vehicle covered under CARB's In-Use Off-Road Regulation, Code of Regulations, title 13, section 2449, is not covered under this definition.

~~(111)~~"OPGEE" or "OPGEE Model" means the Oil Production Greenhouse gas Emissions Estimator Version ~~2.0 (June 20, 2018~~3.0b (May 14, 2022) posted at ~~http://www~~https://ww2.arb.ca.gov/~~fuels~~resources/documents/lcfs/~~lcfs.htm~~-life-cycle-analysis-models-and-documentation, which is incorporated herein by reference.

"Operating Condition" is a specific requirement developed by CARB that dictates operational changes and conditions, and how operational data/other information must be gathered, kept, reported, or calculated for a fuel pathway or set of pathways.

"Operational Data Period" is the date range for site-specific data in a given fuel pathway application or annual report.

~~(112)~~"Opt-in Fuel Reporting Entity" means an entity that meets the requirements of section 95483.1 and voluntarily opts in to be a fuel reporting entity and is therefore subject to the requirements set forth in this subarticle.

~~(113)~~"Opt-in Project" means a project approved for generating LCFS credits by the Executive Officer pursuant to sections 95489 or 95490.

"Organic Waste" is material that meets both the LCFS definitions of "biomass" and "waste."

~~(114)~~"Over-the-Counter" means the trading of LCFS credits or contracts not executed or entered for clearing on any exchange.

~~(115)~~"Performance Review" means an assessment conducted by CARB of an applicant seeking to become accredited or reaccredited as a verification body or lead verifier pursuant to section 95502 of this subarticle. Such an assessment may include a review of applicable past sampling plans, validation and verification reports, validation and verification statements, conflict of interest submittals, and additional information or documentation regarding the applicant's fitness for qualification.

~~(116)~~"Petroleum Intermediate" means a petroleum product that can be further processed to produce CARBOB, diesel, or other petroleum blendstocks.

~~(117)~~"Petroleum Product" means all refined and semi-refined products that are produced at a refinery by processing crude oil and other petroleum-based feedstocks, including petroleum products derived from co-processing biomass and petroleum feedstock together. "Petroleum product" does not include plastics or plastic products.

~~(118)~~"Plug-In Hybrid Electric Vehicle (PHEV)" means a hybrid electric vehicle with the capability to charge a battery from an off-vehicle electric energy source that cannot be connected or coupled to the vehicle in any manner while the vehicle is being driven.

~~(119)~~"Positive Validation Statement" and "Positive Verification Statement" means a statement rendered by a verification body attesting that the verification body can say, with reasonable assurance, that the reported value is free of material misstatement, when applicable, and conforms to the requirements of this subarticle. This definition applies to Positive Validation Statements for fuel pathway applications and Positive Verification Statements for Annual Fuel Pathway Reports, Quarterly Fuel Transactions Reports, Crude Oil Quarterly and Annual Volumes Reports, Low-Complexity/Low-Energy-Use Refinery Reports, and Project Reports.

"Power-to-Liquid Fuel" means transportation fuel that is produced from captured CO_2, water, and low-CI electricity.

"Primary Product" is a product that a system is optimized to produce, and typically represents the highest economic value of all system product outputs.

~~(120)~~"Private Access Fueling Facility" means a fueling facility with access restricted to privately-distributed electronic cards ("cardlock") or is located in a secure area not accessible to the public.

"Private MHD-FCI charging site" means an EV fast charging site that can be limited to be available only to MHD EVs under single ownership.

"Private MHD-HRI station" means a hydrogen refueling station that can be limited to be available only to MHD FCEVs under single ownership.

~~(121)~~"Producer" means, with respect to any fuel, the entity that made or prepared the fuel.

~~(122)~~"Product Transfer Document (PTD)" means a document that authenticates the transfer of ownership of fuel from a fuel reporting entity to the recipient of the fuel. A PTD is created by a fuel reporting entity to contain information collectively supplied by other fuel transaction documents, including bills of lading, invoices, contracts, meter tickets, rail inventory sheets, Renewable Fuels Standard (RFS) product transfer documents, etc.

~~(123)~~"Project Operator" means an entity that registers an opt-in project in the Alternative Fuel Portal and has it approved for generating LCFS credits. A project operator must meet the requirements of sections 95483.1 and 95489 or 95490.

~~(124)~~"Public Access Fueling Facility" means a fueling facility that is not a private-access fueling dispenser.

"Pyrolysis" means the non-combustion thermal decomposition of biomass or organic matter by the addition of heat with little to no added oxygen, air, or steam, to produce a mixture of liquids, solid hydrocarbon products, and combustible gases, including but not limited to carbon monoxide, hydrogen, bio-oil, and biochar.

~~(125)~~"Qualified Positive Validation Statement" and "Qualified Positive Verification Statement" means a statement rendered by a verification body attesting that the verification body can say, with reasonable assurance, that the reported value is free of material misstatement, when applicable, and is in conformance with the requirement to fix correctable errors pursuant to section 95501(b)(6), but the data may include one or more other nonconformance(s) with the requirements of this subarticle, which do not result in a material misstatement. This definition applies to Qualified Positive Validation Statements for fuel pathway applications and Qualified Positive Verification Statements for Annual Fuel Pathway Reports, Quarterly Fuel Transactions Reports, Crude Oil Quarterly and Annual Volumes Reports, Low-Complexity/Low-Energy-Use Refinery Reports, and Project Reports.

~~(126)~~"Rack" means a mechanism for delivering motor vehicle fuel or diesel from a refinery or terminal into a truck, trailer, railroad car, or other means of non-bulk transfer.

~~(127)~~"Reasonable Assurance" means a high degree of confidence that submitted data and statements are valid.

~~(128)~~"Regulated Entity" means an entity subject to any requirement pursuant to this subarticle.

~~(129)~~"Renewable Fuel Standard" means the program administered by the United States Environmental Protection Agency, under 40 CFR Part 80: Regulation of Fuels and Fuel Additives, Subparts K and M.

~~(130)~~"Renewable ~~Hydrocarbon~~ Diesel" means a diesel fuel that is produced from ~~non-petroleum renewable resources but is not a mono-alkyl ester~~hydrotreated lipids and ~~which is registered as a motor vehicle fuel~~biocrudes, or ~~fuel additive~~

~~under 40 Code of Federal Regulations part 79~~from gasified biomass that is converted to liquids using the Fischer-Tropsch process. This includes the renewable portion of a diesel fuel derived from co-processing biomass with a petroleum feedstock.

~~(131)~~"Renewable Hydrogen" means hydrogen derived from (1) electrolysis of water or aqueous solutions using renewable electricity; (2) catalytic cracking, oxidation or steam methane reforming of biomethane or other renewable hydrocarbons; or (3) thermochemical conversion of biomass, including the organic portion of municipal solid waste (MSW). Renewable electricity, for the purpose of renewable hydrogen production by electrolysis, means electricity derived from sources that qualify as eligible renewable energy resources as defined in California Public Utilities Code sections 399.11-399.36.

"Renewable Naphtha" means naphtha that is produced from hydrotreated lipids and biocrudes, or from gasified biomass that is converted to liquids using the Fischer-Tropsch process. This includes the renewable portion of a naphtha fuel derived from co-processing biomass with a petroleum feedstock.

"Renewable Natural Gas (RNG)" is an alternate term for "biomethane."

~~(132)~~"Renewable Propane" means liquefied petroleum gas (LPG or propane) that is produced from non-petroleum renewable resources.

"Residue" is a secondary product with no significant economic value outside of its use as in a biofuel pathway that does not incur significant disposal or management costs.

~~(133)~~"Rural Area" means a census tract with at least 75 percent of its population identified as rural by the latest US Census data.

~~(134)~~"SAE CCS Connector" means a connector that supports both AC J1772 and DC Charging and created by the Society of Automobile Engineers, which is a standards development organization for vehicle technology.

"Shared MHD-FCI charging site" means an EV fast charging site that is available to at least two MHD EV fleets under different ownership, or to the public for at least 12 hours each day. The site must not have obstructions or obstacles precluding the fleet vehicles from entering site premises, and no registered equipment training shall be required for individuals to use the site.

"Shared MHD-HRI station" means a hydrogen refueling station that is available to at least two MHD FCEV fleets under different ownership, or to the public for at least 12 hours per day. The station must not have any obstructions or obstacles precluding the fleet vehicles from entering station premises and no registered equipment training shall be required for individuals to use the station.

~~(135)~~"Shore Power" means electrical power being provided either by the local utility or by distributed generation to ocean-going vessels at-berth.

~~(136)~~"Single-family Residence" means a building designed to house a family in a single residential unit. A single-family residence is either detached or attached including duplex or townhouse units.

~~(137)~~"Site-specific Data" and "Site-specific Input" means an input value used in determination of fuel pathway carbon intensity value, or the raw operational data used to calculate an input value, which is required to be unique to the facility, pathway, and feedstock. All site-specific inputs must be measured, metered or otherwise documented, and verifiable, e.g., consumption of natural gas or grid electricity at a fuel production facility must be documented by invoices from the utility.

~~(138)~~"Specified Source Feedstocks" means feedstocks that require the chain of custody evidence specified in 95488.8(g)(1)(B) to be eligible for a reduced CI associated with the use of a waste, residue, by-product or similar material. Specified source feedstocks are identified in section 95488.8(g)(1)(A).

~~(139)~~"Staff" means CARB personnel unless otherwise specified or dictated by context.

"Standard Value" is an input value established or developed by CARB, which may be used under specified conditions and is typically not subject to validation or verification.

~~(140)~~"Station Operational Status System (SOSS)" means a software database tool developed and maintained by California Fuel Cell Partnership to publicly monitor the operational status of hydrogen stations.

~~(141)~~"Steam Quality" means the ratio of the mass of vapor to the total mass of a vapor-liquid mixture of water at its saturation temperature.

~~(142)~~"Technical Corn Oil" means inedible oil recovered from thin stillage or the distiller's grains and solubles produced by a dry mill corn ethanol plant, termed distiller's corn oil (DCO), or other non-food grade corn oil from food processing operations.

~~(143)~~"Technical Sorghum Oil" means inedible oil recovered from thin stillage or the distiller's grains and solubles produced by a dry mill sorghum ethanol plant, termed distiller's sorghum oil (DSO), or other non-food grade sorghum oil from food processing operations.

"Temporary Method" means a method used when necessary for the avoidance of missing data or to comply with the missing data provisions of this subarticle. As described in section 95491.2(b)(2)(A) for reports other than fuel pathways, a temporary method may not be used for a time period longer than six months during a calendar year for a source that was affected by a loss of data. A measurement device used as part of a temporary method is not subject to the calibration requirements in section 95488.8(j)(1); however, the entity must be able to demonstrate to the reasonable assurance of the verification body that the temporary method provides data accuracy within ±5.00 percent or is conservative.

~~(144)~~"Total Obligated Amount (TOA)" means the quantity of fuel for which the fuel reporting entity is the eligible credit or deficit generator. The LRT-CBTS calculates the TOA for each fuel pathway code. TOA is calculated as the difference between the fuel reported using transaction types that increase the net quantity of fuel that generates credits or deficits in the LRT-CBTS and the fuel reported using transaction types that decrease the net quantity of fuel that generates credits or deficits in the LRT-CBTS. Transaction types that increase the TOA include: Production in California, Production for Import, Import, Purchased with Obligation, Gain of Inventory. Transaction types that decrease the TOA include: Sold with Obligation, Loss of Inventory, Export, Not Used for Transportation.

~~(145)~~"Total Amount (TA)" means the total quantity of fuel reported by a fuel reporting entity irrespective of whether the entity retained status as the credit or deficit generator for that specific fuel volume. TA is calculated as the difference between the fuel reported using transaction types that increase the net fuel quantity reported in the LRT-CBTS and fuel reported using transaction type that decrease the net fuel quantity reported in the LRT-CBTS. Transaction types that increase the TA include: Production in California, Production for Import, Import, Purchased with Obligation, Purchased without Obligation, Gain of Inventory. Transaction types that decrease the TA include: Sold with Obligation, Sold without Obligation, Loss of Inventory, Export, Not Used for Transportation.

~~(146)~~"Transaction Date" means the title transfer date as shown on the Product Transfer Document.

~~(147)~~"Transaction Quantity" means the amount of fuel reported in a transaction. A Transaction Quantity must be reported in units, provided in Table 4 and in the LRT-CBTS.

~~(148)~~"Transaction Type" means the nature of a fuel-based transaction as defined below:

~~(A)~~(1) "Production in California" means the transportation fuel was produced at a facility in California for use in California;

~~(B)~~(2) "Production for Import" means the transportation fuel was produced outside of California and imported into California for use in transportation.

~~(C)~~(3) “Import” means the transportation fuel was produced outside of California and later brought by any party other than its producer into California for use in transportation.

~~(D)~~(4) “Purchased with Obligation” means the transportation fuel was purchased with the obligation to claim credits or deficits in the LRT-CBTS from a separate fuel reporting entity;

~~(E)~~(5) “Purchased without Obligation” means the transportation fuel was purchased without obligation to claim credits or deficits in the LRT-CBTS from a separate fuel reporting entity;

~~(F)~~(6) “Sold with Obligation” means the transportation fuel was sold with the obligation to claim credits or deficits in the LRT-CBTS by a fuel reporting entity;

~~(G)~~(7) “Sold without Obligation” means the transportation fuel was sold without obligation to claim credits or deficits in the LRT-CBTS by a fuel reporting entity;

~~(H)~~(8) “Export” means any fuel reported in the LRT-CBTS that is subsequently delivered outside of California and is not used for transportation in California;

~~(I)~~(9) “Loss of Inventory” means the fuel entered the California fuel pool but was not used due to volume loss;

~~(J)~~(10)“Gain of Inventory” means the fuel entered the California fuel pool due to a volume gain;

~~(K)~~(11) “Not Used for Transportation” means a transportation fuel was reported with compliance obligation under the LCFS but was later not used for transportation purposes in California or otherwise determined to be exempt under section 95482(d);

~~(L)~~(12) “eTRU Fueling” means providing fuel to electric transport refrigeration units.

~~(M)~~(13) “eCHE Fueling” means providing fuel to electric cargo handling equipment.

~~(N)~~(14) “eOGV Fueling” means providing shore power to an ocean-going vessel at-berth.

~~(O)~~(15) “EV Charging--Grid” means providing electricity to recharge EVs using the California Average Grid Electricity Lookup Table pathway for a given year as specified in section 95488.5;

~~(P)~~(16) "EV Charging--Non-Grid" means providing electricity that has a carbon intensity lower than the average grid electricity and is obtained through an approved arrangement as specified in section 95488.8(h) or section 95488.8(i) to recharge EVs;

~~(Q)~~(17) "EV Charging--Smart Charging" means providing electricity that is eligible to generate credits under the smart charging provisions in section 95488.5 to recharge EVs;

~~(R)~~(18) "Fixed Guideway Electricity Fueling" means fueling light rail, heavy rail, cable car, street car, and trolley bus, or exclusive right-of-way bus operations with electricity;

~~(S)~~(19) "Forklift Electricity Fueling" means providing fuel to electric forklifts;

~~(T)~~(20) "Forklift Hydrogen Fueling" means providing fuel to hydrogen forklifts;

(21) "Fossil Jet Fuel used for Intrastate Flight" means jet fuel consumed during a flight that takes off and lands in California.

~~(U)~~(22) "Fuel Cell Vehicle (FCV) Fueling" means the dispensing of hydrogen at a fueling station designed for fueling hydrogen fuel cell electric vehicles;

~~(V)~~(23) "Fuel Cell Vehicle (FCV) Fueling--Smart Electrolysis" means the dispensing of hydrogen that is eligible to generate credits under the smart charging or electrolysis provisions in section 95488.5;

~~(W)~~(24) "NGV Fueling" means the dispensing of natural gas at a fueling station designed for fueling natural gas vehicles;

~~(X)~~(25) "Propane Fueling" means the dispensing of propane at a fueling station designed for fueling propane vehicles.

~~(149)~~"Transmix" means a mixture of refined products that forms when these products are transported through a pipeline. This mixture is typically a combination of two of the following: gasoline, diesel, or jet fuel.

~~(150)~~"Transportation Fuel" means any fuel used or intended for use as a motor vehicle fuel or for transportation purposes in a non-vehicular source.

~~(151)~~"Uncertainty" means the degree to which data or a data system is deemed to be indefinite or unreliable.

"Urban Landscaping Waste" is organic MSW material collected from landscaping activities, including leaves, grass, branches, and stumps.

~~(152)~~"Used Cooking Oil" (or UCO) means fats and oils originating from commercial or industrial food processing operations, including restaurants, that have been used for cooking or frying. Feedstock characterized as UCO must contain only fats, oils, or greases that were previously used for cooking or frying operations. UCO must be characterized as "processed UCO" if it is known that processing has occurred prior to receipt by the fuel production facility or if evidence is not provided to the verifier or CARB to confirm that it is "unprocessed UCO."

~~(153)~~"Validation" means verification of a fuel pathway application.

~~(154)~~"Validation Statement" means the final statement rendered by a verification body attesting whether the fuel pathway application is free of material misstatement, and whether it conforms to the requirements of this subarticle.

~~(155)~~"Verification" means a systematic, independent and documented process for evaluation of reported data against the requirements specified in this subarticle.

~~(156)~~"Verification Body" means an entity accredited by the Executive Officer that is able to render a validation or verification statement and provide validation or verification services to entities required to contract for validation or verification.

~~(157)~~"Verification Services" means services provided during validation or verification as specified in section 95501 beginning with the development of the validation or verification plan to submitting a validation or verification statement to CARB.

~~(158)~~"Verification Statement" means the final statement rendered by a verification body attesting whether the responsible entity's report is free of material misstatement, when applicable, and whether the report conforms to the requirements of this subarticle.

~~(159)~~"Verification Team" means all persons working for a verification body, including all subcontractors, to provide validation or verification services to an entity required to contract for validation or verification.

~~(160)~~"Verifier Review" means all reviews and services specified in section 95501 that a verifier conducts, except the material misstatement assessment under section 95501(b)(9) through (11). If some data sources are selected for data checks based on the sampling plan, the verifier will check for conformance with the requirements of this subarticle.

"Wastewater Sludge" is a residual, semi-solid byproduct generated from wastewater treatment processes that can serve as a feedstock for biogas production.

~~(161)~~"Yard Truck" An off-road mobile utility vehicle used to carry cargo containers with or without chassis; also known as utility tractor rig (UTR), yard tractor, yard goat, yard hostler, yard hustler, or prime mover. For the purpose of LCFS crediting an electric yard truck is considered a heavy-duty truck.

~~(162)~~"Yellow Grease" means a commodity produced from a mixture of: (A) used cooking oil, and (B) rendered animal fats that were not used for cooking. This mixture often is combined from multiple points of origin. Yellow grease must be characterized as "animal fat" if evidence is not provided to the verifier or CARB to confirm the quantity that is animal fat and the quantity that is used cooking oil.

(b) *Acronyms.* For the purposes of sections 95480 through 95503, the following acronyms apply.

"AEZ-EF" means Agro-Ecological Zone Emissions Factor model.

"AJF" means Alternative Jet Fuel.

"ASTM" means ASTM International (formerly American Society for Testing and Materials).

"AFP" means Alternative Fuel Portal.

"BEV" means battery electric vehicles.

"CA-GREET" means California-modified Greenhouse Gases, Regulated Emissions, and Energy use in Transportation model.

"CARB" means the California Air Resources Board ("Board").

"CARBOB" means California reformulated gasoline blendstock for oxygenate blending.

"CaRFG" means California reformulated gasoline.

"CCM" means Credit Clearance Market.

"CEC" means California Energy Commission.

"CFR" means Code of Federal Regulations.

"CHAdeMO" means Charge de Move, a DC fast charging protocol.

"CI" means carbon intensity.

"CNG" means compressed natural gas.

"DC" means Direct Current.

"DCO" means Distiller's Corn Oil or Technical Corn Oil.

"DSO" means Distiller's Sorghum Oil or Technical Sorghum Oil.

"eCHE" means Electric Cargo Handling Equipment.

“EDU” means Electrical Distribution Utility.

“EER” means energy economy ratio.

“eTRU” means electric transport refrigeration unit.

“eOGV” means Electric Power for Ocean-going Vessel.

“EV” means electric vehicle.

“FCV” means fuel cell vehicle.

“FPC” means fuel pathway code.

“FSE” means fueling supply equipment.

“gCO_2e/MJ” means grams of carbon dioxide equivalent per megajoule.

“GTAP” means the Global Trade Analysis Project model.

“GTSR” means the Green Tariff Shared Renewables program.

“GVWR” means gross vehicle weight rating.

“HySCapE” means Hydrogen Station Capacity Evaluator.

“H_2” means hydrogen.

“HDV” means heavy-duty vehicles.

“HDV-CIE” means a heavy-duty vehicle compression-ignition engine.

“HDV-SIE” means a heavy-duty vehicle spark-ignition engine.

“HEV” means hybrid electric vehicle.

“ICEV” means internal combustion engine vehicle.

“LUC” means land use change.

“LCA” means life cycle analysis.

“LCFS” means Low Carbon Fuel Standard.

“LDV” means light-duty vehicles.

“L-CNG” means liquefied compressed natural gas.

“LNG” means liquefied natural gas.

“LPG” means liquefied petroleum gas.

“LRT-CBTS” means LCFS Reporting Tool and Credit Bank & Transfer System.

“LSE” means Load-Serving Entity.

~~“LVP” means LCFS Verification Portal.~~

"MCON" means marketable crude oil name.

"MDV" means medium-duty vehicles.

"MMBtu" means million British Thermal Units.

"MRR" means Mandatory Greenhouse Gas Reporting Regulation.

"MT" means metric tons of carbon dioxide equivalent.

"NG" means natural gas.

"NGV" means a natural gas vehicle.

"OPGEE" means Oil Production Greenhouse gas Emissions Estimator Model.

"PHEV" means plug-in hybrid vehicles.

"RFS" means the Renewable Fuel Standard.

"RNG" means renewable natural gas or biomethane.

"SAE CCS" means Society of Automotive Engineers Combined Charging System, a DC fast charging protocol.

"SMR" means steam methane reformation.

"SOSS" means Station Operational Status System.

"UCO" means used cooking oil.

"TEOR" means thermally enhanced oil recovery.

"ULSD" means California ultra-low sulfur diesel.

"U.S. EPA" means the United States Environmental Protection Agency.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95482. Fuels Subject to Regulation.

(a) *Applicability of the Low Carbon Fuel Standard.* Except as provided in this section, the California Low Carbon Fuel Standard regulation, California Code of Regulations (CCR), title 17, sections 95480 through 95503 (collectively referred to as the "LCFS") applies to any transportation fuel, as defined in section 95481, that is sold, supplied, or offered for sale in California, and to any person who, as a fuel reporting entity defined in section 95481 and specified in section 95483, is responsible for reporting a transportation fuel in a calendar year. The types of transportation fuels to which the LCFS applies include:

(1) California reformulated gasoline ("gasoline" or "CaRFG");

(2) California diesel fuel ("diesel fuel" or "ULSD");

(3) Fossil compressed natural gas ("Fossil CNG"), fossil liquefied natural gas ("Fossil LNG"), or fossil liquefied compressed natural gas ("Fossil L-CNG);

(4) Bio-CNG, bio-LNG, or bio-L-CNG;

(5) Electricity;

(6) Compressed or liquefied hydrogen ("hydrogen");

(7) A fuel blend containing greater than 10 percent ethanol by volume;

(8) A fuel blend containing biomass-based diesel;

(9) Denatured fuel ethanol ("E100");

(10) Neat biomass-based diesel ("B100" or "R100");

(11) Fossil Jet Fuel;

~~(11)~~(12) Alternative Jet Fuel;

~~(12)~~(13) Propane; and

~~(13)~~(14) Any other liquid or non-liquid fuel.

(b) *Opt-In Fuels.* Each of the following alternative fuels ("opt-in fuels") is presumed to have a full fuel cycle, carbon intensity that meets the compliance schedules set forth in sections 95484(b) through (d) through December 31, 2030. A fuel provider for an alternative fuel listed below may generate LCFS credits for that fuel only by electing to opt into the LCFS as an opt-in fuel reporting entity pursuant to section 95483.1 and meeting the requirements of this regulation:

(1) Electricity;

(2) Bio-CNG;

(3) Bio-LNG;

(4) Bio-L-CNG;

(5) Alternative Jet Fuel; and

(6) Renewable Propane.

(c) *Exemption for Specific Fuels.* The LCFS regulation does not apply to:

(1) An alternative fuel that:

(A) is not a biomass-based fuel; and

(B) is supplied in California by all providers of that particular fuel for transportation use at an aggregated quantity of less than 420-million MJ (3.6 million gasoline gallon equivalent) per year;

A fuel reporting entity that believes it is subject to this exemption has the sole burden of proving to the Executive Officer's satisfaction that the exemption applies to the entity.

(2) ~~Conventional jet fuel~~Fossil jet fuel produced or imported before 2028 or used for interstate or international flights, or aviation gasoline.

(3) Any deficit-generating fuel used in military tactical vehicles and tactical support equipment as defined in title 13, CCR, section 1905(a) and CCR, title 17, section 93116.2(a)(38), respectively.

(4) Any credit-generating fossil CNG or fossil propane dispensed at a fueling station with total throughput of 150,000 gasoline-gallons equivalent or less per year. The exemption for fossil propane dispensing stations expires January 1, 2021, when the use of that fuel in heavy-duty or off-road applications becomes deficit generating. The exemption for fossil CNG dispensing stations expires January 1, 2024, when the use of that fuel in heavy-duty or off-road applications becomes deficit generating.

(d) *Exemption for Specific Applications.* The LCFS regulation does not apply to any transportation fuel used in the following applications:

(1) Locomotives not subject to the requirements specified in CCR, title 17, section 93117; and

(2) Ocean-going vessels, as defined in CCR, title 17, section 93118.5(d). This exemption does not apply to shore power provided to ocean-going vessels at-berth, nor to recreational and commercial harbor craft, as defined in CCR, title 17, section 93118.5(d); and

(3) Any deficit-generating fossil propane and CNG used in school buses purchased prior to January 1, 2020.

(e) Nothing in this LCFS regulation (Cal. Code Regs., tit. 17, §§ 95480 et seq.) may be construed to amend, repeal, modify, or change in any way the California reformulated gasoline regulations (CaRFG, Cal.Code Regs., tit. 13, §§ 2260 et seq.), the California diesel fuel regulations (Cal.Code Regs., tit. 13, §§ 2281-2285 and Cal. Code Regs., tit. 17, § 93114), or any other applicable State or federal requirements. A person, including the regulated entity as that term is defined in the LCFS regulation, who is subject to the LCFS regulation or other State and federal regulations, shall be solely responsible for ensuring compliance with all applicable LCFS requirements and other State and federal requirements, including the CaRFG requirements and obtaining any necessary approvals, exemptions, or orders from either the State or federal government.

(f) Transportation fuel derived from palm oil or palm derivatives is ineligible for LCFS credit generation. Any volumes of transportation fuel derived from palm oil or palm derivatives reported through the LCFS program must be assigned the ULSD carbon intensity found in Table 7-1 of the LCFS regulation.

(g) For projects that break ground after December 31, 2029, pathways for bio-CNG, bio-LNG, and bio-L-CNG used in CNG vehicles are ineligible for LCFS credit generation after December 31, 2040. Any volumes of bio-CNG, bio-LNG, and bio-L-CNG used in CNG vehicles reported through the LCFS program after December 31, 2040 must be assigned the ULSD carbon intensity found in Table 7-1 of the LCFS regulation.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95483. Fuel Reporting Entities.

The purpose of this section is to identify the first fuel reporting entities, subsequent fuel reporting entities, and the credit or deficit generator for each type of transportation fuel. The first fuel reporting entity is responsible for initiating reporting within the LRT-CBTS for a given amount of fuel and, by default, also holds the status as initial credit or deficit generator for the reported fuel quantity. The fuel reporting entities identified in this section are subject to the reporting requirements pursuant to section 95491 and to any other requirement applicable to a fuel reporting entity and credit or deficit generator under this subarticle.

(a) *For Liquid Fuels.* Liquid fuels in this subsection refer to fossil fuels (including CARBOB, gasoline, diesel, and ~~conventional~~fossil jet fuel), liquid alternative fuels (including ethanol as an oxygenate, biomass-based diesel, and alternative jet fuels), and blend of liquid alternative and fossil fuels.

(1) *Designation of First Fuel Reporting Entities for Liquid Fuels.* The first fuel reporting entity for liquid fuels is the producer or importer of the liquid fuel. For liquid fuels that are a blend of liquid alternative fuel components (including ethanol as an oxygenate, biomass-based diesel, or alternative jet fuels) and a fossil fuel component (including CARBOB, gasoline, diesel, ~~conventional~~fossil jet, or other fossil fuels), the first fuel reporting entity is the following:

(A) With respect to the alternative fuel component, the producer or importer of the alternative fuel component.

(B) With respect to the fossil fuel component, the producer or importer of the fossil fuel component.

(C) *Specifics for Alternative Jet Fuel.* For an alternative jet fuel or the alternative fuel portion of a blend with ~~conventional~~fossil jet fuel, the first fuel reporting entity is the producer or importer of the alternative jet fuel, which is delivered to a storage facility where fuel is stored before it is uploaded to an aircraft in California. ~~Conventional~~Fossil jet fuel produced or imported before 2028, including the ~~conventional~~fossil jet fuel portion of a blend, is not subject to the LCFS and must not be reported.

(2) *In the Case of Transfer of Fuel Ownership.* An entity transferring ownership of fuel is the “transferor” and an entity acquiring ownership of fuel is the “recipient.”

(A) *Transferring Status as Credit or Deficit Generator.* An entity can voluntarily transfer its status as a credit or deficit generator for a given amount of liquid fuel, with the ownership of the fuel, if the conditions set forth in subsections 1. through 4. below are met by the time ownership of fuel is transferred. If such a transfer occurs, the recipient also becomes the fuel reporting entity for the fuel while the transferor is still subject to reporting requirements pursuant to section 95491 and to any other requirement applicable to a fuel reporting entity under this subarticle.

1. The two entities agree by written contract that the recipient accepts all LCFS responsibilities of a fuel reporting entity and credit or deficit generator.

2. The transferor must provide the recipient a product transfer document that prominently states the information specified in section 95491.1(b)(1).

3. In the case of a deficit generating fuel, the transferor and recipient must meet the requirements specified in the subsection below:

a. By default, the ~~transferor's~~recipient's annual credit and deficit balance, as set forth in section 95485(b)(2), will be updated to include the $Deficits^{XD}_{Incremental20XX}$ as defined and set forth in section 95489(b).

b. By default, the recipient's annual credit and deficit balance, as set forth in section 95485(b)(2), will be updated to include $Deficits_{Base}^{XD}$, as defined and set forth in section 95489(b).

c. Paragraphs a. and b. above notwithstanding, the transferor and recipient of deficit generating fuels may, by the time the ownership is transferred, specify by written contract which party is responsible for accounting for the base deficit and incremental deficit in the annual credits and deficits balance calculation set forth in section 95485(b)(2).

4. The credit or deficit generator status cannot be passed to a downstream entity acquiring ownership of liquid fuel below the rack.

5. An entity acquiring ownership of fuel below the rack is not required to report the fuel transaction in the LRT-CBTS unless it is a fuel exporter pursuant to section 95483(a)(4)(C).

(B) *Retaining Status as Credit or Deficit Generator.* An entity can retain its status as a credit or deficit generator for a given amount of liquid fuel, while transferring the ownership of the fuel, if the conditions set forth in subsections 1. through 2. below are met by the time ownership of fuel is transferred. If such a transfer occurs, the recipient also becomes a fuel reporting entity for the fuel while the transferor is still subject to reporting requirements pursuant to section 95491 and to any other requirement applicable to a fuel reporting entity under this subarticle.

1. The two entities agree by written contract that the recipient accepts all LCFS responsibilities of a fuel reporting entity and the transferor retains the responsibilities as a fuel reporting entity and credit or deficit generator.

2. The transferor must provide the recipient a product transfer document that prominently states the information specified in section 95491.1(b)(2).

3. An entity acquiring ownership of fuel below the rack is not required to report the fuel transaction in the LRT-CBTS unless it is a fuel exporter pursuant to section 95483(a)(4)(C).

(3) *Transfer Period.* For all liquid fuels, the period in which credit or deficit generator status can be transferred to another entity, for a given amount of fuel, is limited to three calendar quarters. This means that, for example, if an entity receives title to a fuel along with credit or deficit generator status in the first calendar quarter, the status as credit or deficit generator for that amount of fuel can be transferred to another entity no later than the end of the third calendar quarter. After this period is over, the credit and deficit generator status for that amount of fuel cannot be transferred.

(4) *Designation of Fuel Exporter.* Entities responsible for reporting exports of fuel that has been previously reported in the LRT-CBTS are identified below:

(A) When the fuel is sold or delivered above the rack for export, the entity holding title to the fuel as it crosses the California border on its way toward the first point of sale/delivery is responsible for reporting the export in the LRT-CBTS.

(B) When the fuel is sold across the rack for export, the entity holding title to the fuel as the fuel crosses the rack is responsible for reporting the export in the LRT-CBTS.

(C) When the fuel is diverted out-of-state below the rack, the entity holding title to the fuel, as it crosses the California border, is responsible for reporting the export in the LRT-CBTS.

(b) *For Gaseous Fuels.* Gaseous fuels refer to natural gas fuels (including CNG, LNG and L-CNG), propane and hydrogen.

(1) *Designation of First Fuel Reporting Entities For Gaseous Fuels.* The first fuel reporting entity for different gaseous fuels is identified in subsections (A) through (E) below. For gaseous fuels, subsection (2) below provides entities the ability to contractually designate another entity as the first fuel reporting entity for a given amount of gaseous fuel.

(A) *Bio-CNG.* For bio-CNG, including the bio-CNG portion of a blend with fossil CNG, the first fuel reporting entity is the producer or importer of the biomethane.

(B) *Bio-LNG and Bio-L-CNG.* For bio-LNG and bio-L-CNG, including the biomethane portion of any blend with fossil LNG and L-CNG, the first fuel reporting entity is the producer or importer of the biomethane.

(C) *Renewable Propane.* For renewable propane, including the renewable propane portion of a blend with fossil propane, the first fuel reporting entity is the producer or importer of the renewable propane.

(D) *Fossil CNG, LNG, and L-CNG and Propane.* For fossil CNG, LNG, L-CNG, and propane, including the fossil portion of any blend with a renewable fuel component, the first fuel reporting entity is the entity that owns the fueling equipment through which the fossil fuel is dispensed to motor vehicles for transportation use.

(E) *Hydrogen.* The first fuel reporting entity for hydrogen is the entity that owns the fueling supply equipment ("hydrogen station owner") through which hydrogen fuel is dispensed to motor vehicles for transportation use. Notwithstanding the above, the first fuel reporting entity for hydrogen used in fuel cell forklifts is the forklift fleet owner.

(2) Subsections (1)(A) through (1)(E) above notwithstanding, an entity may elect not to be the first fuel reporting entity for a given gaseous fuel, provided another entity has contractually agreed to be the first fuel reporting entity for the fuel on its behalf. In such cases the two entities must agree by written contract that:

(A) The original first fuel reporting entity per subsections (1)(A) through (1)(E) above will not generate credits or deficits in the LCFS and will instead provide the amount of fuel dispensed, and other required information pursuant to sections 95483.2(b)(8), 95491 and 95491.1, to the contractually designated entity for the purpose of LCFS reporting and credit or deficit generation.

(B) The contractually designated entity accepts all LCFS responsibilities as the first fuel reporting entity and as a credit or deficit generator, as applicable.

(c) *For Electricity Used as a Transportation Fuel.*

(1) *Residential EV Charging.* For on-road transportation fuel supplied for electric vehicle (EV) charging in a single-family residence, or at dedicated or reserved parking at a multi-family residence, the following entities are the credit generators:

(A) *Base Credits.* The EDU or its designee is the credit generator for base credits for the portion of residential EV charging assigned to that EDU by the Executive Officer. The EDU may authorize a third party to sell the EDU's credits. The EDU or its designee must meet the requirements set forth in paragraphs 1. through ~~6. below~~5. Below, and ~~paragraphs 1. through 5. in section~~ 95491(~~d)(3)(A~~e)(5).

Within 30 days of the effective date of this subarticle for large and medium IOUs and POUs, or ~~by December 31, 2022 for small IOUs and POUs, or~~ within 30 days of opting into the LCFS program, whichever is later, each large or medium EDU seeking eligibility to generate base credits must demonstrate, by attestation or entrance into any applicable Clean Fuel Reward program (as defined in section 95481(a~~)(29~~)) governance agreement, its ability to contribute allocated credits to the Clean Fuel Reward program consistent with CPUC approval of Pacific Gas and Electric's, Southern California Edison's, and San Diego Gas and Electric's filing(s). The Executive Officer may revoke the eligibility of an EDU to generate base credits if it fails to make this required demonstration or if the EDU withdraws or has been removed as a party to the governance agreement. All base credits for any EDU that is not eligible to receive base credits pursuant to this provision will be allocated to the Clean Fuel Reward program pursuant to section 95486.1(c)(1)(A) paragraph 2. An EDU must submit any request to change their base credit generation eligibility status for the Clean Fuel Reward program to the Executive Officer by the September 30~~th~~ prior to the start of the effective credit generation year.

1. EDUs seeking eligibility to generate base credits must provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid;

~~1.~~2. Upon California Public Utilities Commission (CPUC) approval of Pacific Gas and Electric's, Southern California Edison's, and San Diego Gas and Electric's filing(s) to initiate a Clean Fuel Reward program, all opt-in EDUs must contribute a minimum percent of base credits for residential EV charging (or net base credit proceeds) to provide a Clean Fuel Reward funded exclusively by LCFS credit proceeds, as per the contribution tabulated below:

EDU category	***~~% Contribution in years 2019 through 2022~~***	***% contribution~~ in years 2023 and subsequent years~~***
Large Investor-owned Utilities	~~67~~50%	~~67%~~
Large Publicly-owned and Medium Investor-owned Utilities	~~35~~25%	~~45%~~
Medium Publicly-owned Utilities~~ and Medium Investor-owned Utilities~~	~~20~~10%	~~25%~~
Small Publicly-owned Utilities and Small Investor-owned Utilities	0%	~~2%~~

Deleted Cells

Deleted Cells

The Executive Officer will review the implementation of any Clean Fuel Reward program, including the actual credit value contribution of each utility to the program, and present a report to the Board by January 1, 202~~5~~7 with recommendations for further increasing utility contributions to the Clean Fuel Reward program.

~~2. The reward amounts for any Clean Fuel Reward program must be calculated based on the vehicle's battery capacity as tabulated below:~~

~~***Battery Capacity (kWh)***~~	~~***Reward %***~~
~~$C < 5$~~	~~0%~~
~~$C = 5$~~	~~38.9%~~
~~$5 < C < 16$~~	~~$\left(38.9 + \frac{(C-5)}{11} \times 61.1\right)\%$~~
~~$C \geq 16$~~	~~100%~~

~~where:~~

~~$Reward\ \%$ means the percentage of maximum reward a vehicle would receive under the Clean Fuel Reward program funded by LCFS credit proceeds. The maximum reward is the amount a vehicle with a battery capacity of 16 kWh or greater can receive; and~~

~~C means the rated battery capacity of the electric vehicle in kWh.~~

3. All proceeds from base credits issued pursuant to section 95486.1(c)(1)(A) paragraph 2. As well as any previously allocated funds for the Clean Fuel Reward by all large and medium EDUs must be contributed to ~~any~~the Clean Fuel Reward program.

4. Administrative costs, excluding start-up costs (those costs associated with setting up the program and incurred prior to issuing rewards), to support any Clean Fuel Reward program funded by LCFS credit proceeds may not exceed ~~10~~5 percent of LCFS credit proceeds contributed to the Clean Fuel Reward program annually, unless approved in advance by the Executive Officer.

   a. A request to exceed ~~10~~5 percent administrative costs must be submitted by the administrator of the Clean

Fuel Reward program to the Executive Officer ~~on~~by September 30 of the ~~following schedule:~~prior year.

~~i. For the first six calendar months of the program including the month in which the first issuance of reward takes place, a request must be submitted at least 30 days prior to the first reward issuance.~~

~~ii. For the period starting with the seventh calendar month of the program through December 31, 2021, the request must be submitted at least 30 days prior to the beginning of month seven.~~

~~iii. For calendar year 2022 and subsequent calendar years, the request must be submitted by September 30th of the prior year.~~

b. Request submitted to the Executive Officer must include, and will be evaluated for approval based on, a complete description for why higher administrative costs are necessary, a detailed list of expected administrative costs including a description of all efforts made to obtain competitive rates and minimize costs, and a detailed estimate of expected program proceeds. Within 30 days of receiving a request for higher administrative costs, the Executive Officer will inform the administrator of its decision in writing. If the request is rejected, the Executive Officer will provide a rationale for the decision. If the rejection is due to insufficient information, the administrator may resubmit the request after addressing the deficiencies identified in the Executive Officer decision.

~~5. *Reporting on Clean Fuel Reward Program Implementation.* By April 30th the administrator of the Clean Fuel Reward program funded by LCFS credit proceeds shall submit a report to the Executive Officer describing the disposition of LCFS Clean Fuel Reward program funds from the previous calendar year. The first such report covering a period from the start of the program until the end of 2020 must be submitted by April 30, 2021. This report must include:~~

~~a. The monetary value of LCFS credit proceeds received by the Clean Fuel Reward program; and~~

b. ~~A summary, detailed list, and explanation of administrative costs, including start-up costs, utility overhead costs, and costs for program-related marketing, education, and outreach activities.~~

~~6.~~5. *Restrictions on Use of Holdback Credits.* Documentation of adherence to the following restrictions must be included in the annual report submitted pursuant to section 95491(~~d)(3~~e)(5)(A~~)5.~~).

a. *Holdback Credit Equity Projects.* Effective January 1, 202~~2~~5, at least ~~30~~75 percent ~~in year one, 40 percent in year two, and 50 percent in subsequent years~~ of holdback credit proceeds must be used to support transportation electrification for the primary benefit of or primarily serving disadvantaged communities and/or low-income communities and/or rural areas or low-income individuals eligible under California Alternative Rates for Energy (CARE) or Family Electric Rate Assistance Program (FERA) or the definition of low-income in Health and Safety code section 50093 or the definition of low-income established by a ~~POU's governing body.~~ POU's governing body or a community in which at least 75 percent of public school students in the project area are eligible to receive free or reduced-price meals under the National School Lunch Program, or a community located on lands belonging to a state and federally recognizes California Indian tribe. These projects may include:

~~i. Electrification and battery swap programs for school or transit buses.~~

~~ii.~~i. Electrification of drayage trucks as well as other medium-, heavy-duty, or off-road vehicles including school and transit buses.

~~iii.~~ii. Investment in public EV charging infrastructure and EV charging infrastructure in multi-family residences.

~~iv.~~iii. Investment in electric mobility solutions, such as EV sharing and ride hailing programs.

~~v. Multilingual marketing, education, and outreach designed to increase awareness and adoption~~

~~of EVs and clean mobility options and including information about: the environmental, economic, and health benefits of EV transportation; basic maintenance and charging of EVs; electric rates designed to encourage EV use; and local, state, and federal incentives available for purchase of EVs.~~

~~vi.~~iv. Additional rebates and incentives for low-income individuals beyond existing local, federal and State rebates and incentives ~~including the Clean Fuel Reward~~ for: purchasing or leasing new or previously owned EVs; installing EV charging infrastructure in residences; ~~promoting use of public transit and other clean mobility solutions;~~ and offsetting costs for residential or nonresidential EV charging.

v. Promoting use and additional incentives for use of public transit and other clean mobility solutions, via charging equipment or infrastructure for the following categories:

I. EV sharing and ride hailing programs,

II. Electrification of public transit and school buses, including battery swap programs, and

III. Use or ownership of neighborhood electric vehicles, eBikes, eScooters, eMotorcycles, and other micromobility solutions.

vi. Re-skilling and workforce development for transportation electrification and electric vehicle infrastructure applications, developed in coordination with the California Workforce Development Board or local workforce development agencies.

vii. Investments in grid-side distribution infrastructure necessary for medium- and heavy-duty EV charging.

viii. Transportation Electrification projects that are identified in, or consistent with, a Community Emission Reduction Plan created in response to AB 617.

~~vii.~~ix. Alternatively, EDUs, in coordination with local environmental justice advocates, local community-based organizations, and local municipalities, may develop and implement other projects that promote transportation electrification in disadvantaged and/or low-income communities and/or rural areas or for low-income individuals. These alternative projects are subject to approval by the Executive Officer. Applications submitted to the Executive Officer must include, and will be evaluated for approval based on, a complete description of the project, demonstration that the project promotes transportation electrification in disadvantaged and/or low-income communities and/or rural areas or provides increased access to electric transportation for low-income individuals, and evidence that the project was developed in coordination with local environmental justice advocates, local community-based organizations, and local municipalities.

~~b. *Additional Reporting Requirements for Holdback Credit Equity Projects.* As part of annual reporting required pursuant to section 95491(d)(3)(A)5., EDUs must include a discussion on how their portfolio of holdback credit equity projects is consistent with the findings and recommendations of the SB 350 Low-Income Barriers Study, Part B report prepared by CARB (rev. Feb. 2018), incorporated herein. This discussion must include, as applicable, a description of how the projects: support increased access to clean transportation and mobility options; consider, and to the extent feasible, either complement or build upon existing CARB, other State, or local incentive projects to diversify and maximize benefits from statewide investments; demonstrate partnership and support from local community-based organizations;~~

~~and meet community-identified clean transportation needs.~~

b. *Other Holdback Projects.* Holdback projects that are not specified in subsection 95483(c)(1)(A)6.a. must follow the requirements specified in 95491(e)(5). Below are examples of pre-approved uses for these other holdback credit proceeds:

i. Investments in grid-side distribution infrastructure necessary for EV charging.

ii. Support for vehicle-grid integration with projects such as:

I. Encouraging the optimization of EV charging through education in the following areas: peak demand, rate pricing, grid emergencies, potential power shutoffs, infrastructure deferral, renewable integration, and/or other signals and grid needs to provide grid and customer benefits.

II. Providing program incentives to encourage driver participation in monitored/managed charging, demand response, or vehicle-to-load / vehicle-to-grid applications.

III. Supporting the deployment and installation of bidirectional charging equipment.

IV. Other innovative approaches to promoting and managing EV charging and discharging that provides benefits to customers and the grid.

iii. Hardware and software that decrease the cost of or avoid updates to infrastructure, including load management software or outlet splitting.

c. *Administrative Costs of Holdback Credit Equity Projects.* Administrative costs to support the development and implementation of holdback credit equity projects must not exceed ~~10~~5 percent of total spending on holdback credit equity projects annually unless the EDU contracts with a community-based organization, and the exceedance is approved in advance by the Executive Officer. The request for administrative cost exceedance for a calendar year must be submitted by September 30~~th~~ of the prior year. The request must include, and will be evaluated for approval based on, a complete description of the equity projects planned by the EDU, an estimate of total administrative costs relative to total spending on the projects, and evidence that the community-based organization is a non-profit organization focused on serving disadvantaged and/or low-income groups. Within 30 days of receiving a request for higher administrative costs, the Executive Officer will inform the EDU of its decision in writing. If the request is rejected the Executive Officer will provide a rationale for the decision. If the rejection is due to insufficient information, the EDU may resubmit the request after addressing the deficiencies identified in the Executive Officer decision.

d. Holdback credit proceeds must not be used for the following activities:

i. To meet compliance obligations under the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800), including the purchase of allowances, for electricity sold into the California Independent System Operator markets.

ii. To pay for the costs of MRR, the AB 32 Cost of Implementation Fee Regulation (California Code of Regulations, sections 95200-95207), or the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800), including the purchase of allowances.

iii. To pay for lobbying costs, employee bonuses, shareholder dividends, or costs, penalties, or activities mandated by any legal settlement, administrative enforcement action, or court order. This provision does not prohibit the use of holdback credits to pay costs, penalties, or liabilities associated with the Clean Fuel Reward program in the event that Clean Fuel Reward program funds are insufficient.

(B) *Incremental Credits.* Any entity, including an EDU, is eligible to generate incremental credits for improvements in carbon intensity of electricity used for residential EV charging. An entity that generates incremental credits must meet the requirements set forth in ~~paragraphs 2. through 7. in section 95491(d)(3)(A~~95491(e)(5), as applicable.

1. For metered residential EV charging, incremental credits for each FSE may be generated for one of the following:

   a. Low-CI electricity; or

   b. Smart charging. In the case of an entity claiming smart charging incremental credits, the credit generator must demonstrate the residence is enrolled in a Time-of-Use rate plan, if offered by the LSE serving the residence.

2. Multiple claims for incremental credits for metered residential EV charging associated with a single FSE ID will be resolved pursuant to the following order of preference:

   a. The Load Serving Entity (LSE) supplying electricity to the EV associated with the FSE ID and metered data has first priority to claim credits;

   b. The manufacturer of the EV associated with the FSE ID has second priority; and

   c. Any other entity has third priority.

3. For non-metered residential EV charging, the EDU is eligible to generate incremental credits for supplying low-CI electricity to the EVs in its service territory.

(C) *Advanced Credits.* Large POUs and Large IOUs that opt-in to the LCFS and are eligible to receive base credits per section 95483(c)(1)(A) are the credit generators for advanced credits.

(2) *Non-Residential EV Charging.*

(A) For electricity supplied for non-residential EV charging, including chargers at multi-family residences that are not limited to serving dedicated or reserved parking spaces, the owner of the FSE is eligible to generate the credits.

(B) Subsection (A) above notwithstanding, the owner of FSE may elect not to be the credit generator and instead designate another entity to be the credit generator if the two entities agree by written contract that:

1. The owner of FSE will not generate credits and will instead provide the electricity data to the designated entity for LCFS reporting pursuant to sections 95483.2(b)(8), 95491 and 95491.1.

2. The designated entity accepts all LCFS responsibilities as the fuel reporting entity and credit generator.

(C) An entity that generates credits for non-residential EV charging must meet the requirements set forth ~~in paragraphs 2. through 7. in~~ section 95491(~~d)(3)(A), as applicable.~~e)(5).

(3) *Fixed Guideway Systems.* For electricity supplied as transportation fuel to a fixed guideway system, the transit agency operating the system is the fuel reporting entity and the credit generator for electricity used to propel the system. Upon submittal to the Executive Officer of the transit agency's written acknowledgment that it will not opt in and generate credits under this provision, the EDU becomes eligible to generate the credits for the electricity, and must meet the requirements set forth in sections 95491(d)(3)(A), paragraphs 3. through 5.

~~(4) *Electric Forklifts.*~~

~~(A) For transportation fuel supplied to electric forklifts, the fleet owner is the fuel reporting entity and the credit generator for electricity supplied to a specified fleet.~~

~~(B) Subsection (A) above notwithstanding, the electric forklift fleet owner may elect not to be the credit generator and instead designate another entity to be the credit generator, if the two entities agree by written contract that:~~

~~1. The electric forklift fleet owner will not generate credits and will instead provide the electricity data to the designated entity for LCFS reporting pursuant to sections 95483.2(b)(8), 95491 and 95491.1.~~

2. ~~The designated entity accepts all LCFS responsibilities as the fuel reporting entity and credit generator.~~

3. ~~The EDU can generate credits for electricity supplied to electric forklift fleet in its service territory during a reporting period if not claimed by any other entity under paragraphs 1. and 2., above. The EDU must meet the requirements in section 95491(d)(3)(A), paragraphs 3. through 5.~~

~~(5)~~(4) *Electric Forklifts, Electric Transport Refrigeration Units (eTRU), Electric Cargo Handling Equipment (eCHE), Electric Power for Ocean-going Vessel (eOGV).*

(A) For electricity supplied to Electric Forklifts, eTRU, eCHE, or eOGV, the owner of the FSE is the fuel reporting entity and the credit generator.

(B) Subsection (A) above notwithstanding, the owner of the FSE may elect not to be the credit generator and instead designate another entity to be the credit generator if the two entities agree by written contract that:

1. The owner of the FSE will not generate credits and will instead provide the electricity data to the designated entity for LCFS reporting pursuant to sections 95483.2(b)(8), 95491 and 95491.1.

2. The designated entity accepts all LCFS responsibilities as the fuel reporting entity and credit generator.

(C) An entity that generates credits for Electric Forklifts, eTRU, eCHE, or eOGV must meet the requirements set forth in ~~paragraphs 2. through 7. in~~ section 95491(~~d)(3)(A), as applicable.~~e)(5).

~~(6)~~(5) *Other Electric Transportation Applications.* For electricity supplied to a transportation application not covered in subsection (1) through (5) above, any entity can apply to the Executive Officer to be the fuel reporting entity and the credit generator for electricity supplied as long as it meets the requirements of section 95488.7(a)(3) and 95491.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95483.1. Opt-In Entities.

(a) *Eligibility.* An entity that meets one or more of the following criteria may opt into the LCFS program, thereby becoming a credit generator.

(1) *Opt-in Fuel Reporting Entity.* An entity meeting any of the following criteria can opt into the LCFS program in a capacity of fuel reporting entity.

(A) A qualified fuel reporting entity who provides a fuel specified in section 95482(b) that meets the requirements of section 95483, wherever applicable;

(B) An out-of-state producer of oxygenate for blending with CARBOB or gasoline, or biomass-based diesel for blending with CARB diesel, who is not otherwise already subject to the LCFS regulation as an importer. An out-of-sate producer under this subsection may retain the ability to generate credits or deficits, for a specific quantity of fuel or blendstock, only if it opts in as a first fuel reporting entity and meets the requirements of section 95483, wherever applicable.

(C) An entity that is in the distribution/marketing chain of imported fuel and is positioned on that chain between the producer in subsection (B) above and the importer ("intermediate entity"). The intermediate entity is subject to the following requirements.

The intermediate entity must provide written documentation demonstrating all the following requirements to the Executive Officer's written satisfaction before opting into the LCFS:

1. The entity received ownership of the fuel for which the entity is claiming to generate LCFS credits;

2. Either:

a. The entity received the fuel reporting entity status from a producer that opted in under section 95483.1; or

b. The producer did not opt in under section 95483.1(a)(1).

3. The entity actually delivered the fuel or caused the fuel to be delivered to California for use in California;

The fuel delivered under subsection 3. is shown to have been sold for use in California or was otherwise actually used in California; and

4. The entity is not otherwise already subject to the LCFS regulation as a fuel reporting entity.

5. The demonstrations in paragraphs 1. through 4. above must be made for the specific quantity of fuel upon which the entity first elects to opt into the LCFS. For subsequent quantities of fuel for which the entity is claiming to be the fuel reporting entity pursuant to this subsection, the entity must retain documentation to support the demonstrations required in paragraphs 1. through 4., above, and must submit such documentation to the Executive Officer within 30 ~~calendar~~ days upon request.

(2) *Project Operators.* An entity that has a project approved for crediting or is applying for approval by the Executive Officer under section 95489 must apply to opt into the LCFS program as a credit generator.

(3) *Clearing Service Provider.*

(A) An entity providing clearing services in which it takes only a temporary possession of LCFS credits for the purpose of clearing transactions between two entities with registered accounts in LRT-CBTS, may apply to opt in as a clearing service provider if the following conditions are met:

1. The eligible entity must be a derivatives clearing organization as defined in the Commodities Exchange Act (7 U.S.C § 1a (9)) that is registered with the U.S. Commodity Futures Trading Commission pursuant to the Commodities Exchange Act (7 U.S.C. § 7a-1(a)).

2. The entity must register in the LRT-CBTS pursuant to section 95483.2(b).

3. The entity must be located in the United States, according to the registration information reported pursuant to section 95483.2(b).

(B) A clearing service provider cannot own credits but can hold LCFS credits up to five days for clearing purposes only.

(b) *Opting in Procedure.* The procedure for opting into and opting out of the LCFS for such a person is set forth as follows.

(1) Opting into the LCFS program becomes effective when the opt-in entity establishes an account in the LRT-CBTS, pursuant to section 95483.2. The opt-in entity may not report and generate credits and deficits based on transactions that precede the quarter in which the entity opted in.

(2) Establishing an account in the LRT-CBTS under subsection (b)(1) above means that the entity understands the requirements of the LCFS regulation and has agreed to be subject to all the requirements and provisions of the LCFS regulation.

(c) *Opting Out Procedure.* An opt-in entity may decide later to opt out of the LCFS program by following the following procedure:

(1) For opt-out to be effective, the opt-in entity must complete all actions specified below:

(A) Provide to the Executive Officer a 90-day notice of intent to opt out and a proposed effective opt-out date;

(B) Submit in the LRT-CBTS any outstanding quarterly fuel transactions or project reports up to the quarter in which the effective opt-out date falls and a final annual compliance report (covering the year through the opt-out date); and

(C) Identify in the 90-day notice any actions to be taken to eliminate any remaining deficits by the effective opt-out date.

(2) *Opt-Out Approval.* The Executive Officer shall notify the opt-in entity of the final "approval" status of the opt-out request. Any credits that remain in the opt-in entity's account at the time of the effective opt-out date shall be forfeited and the opt-in entity's account in the LRT-CBTS shall be closed.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95483.2. LCFS Data Management System.

The LCFS Data Management System refers to all the online systems responsible for LCFS data management and program implementation.

The LCFS Data Management System comprises ~~three~~two interactive and secured web-based systems: Alternative Fuel Portal~~,~~ and LCFS Reporting Tool and Credit Bank and Transfer System~~, and LCFS Verification Portal~~.

(a) *Alternative Fuel Portal (AFP).* The AFP supports fuel pathway applications, certifications, and verifications. It also handles the registration of fuel production facilities and opt-in projects~~.~~, except for the projects described in section 95489(c)-(f).

(1) *Eligibility.* Any person who intends to be a fuel pathway applicant or an opt-in project operator can request to establish an account in the AFP.

(2) *Requirements to Establish an Account in AFP.* To establish an account in the AFP, an entity must complete and submit the online AFP account registration form and provide the following:

(A) Organization name, address, state and country, Organization Federal Employer Identification Number (FEIN), company EPA ID, if available, facility location(s).

(B) A letter on company letterhead stating the basis for qualifying for an account pursuant to subsection (1) above. This letter must be signed by the company owner, a president, a managing partner, or a corporate officer. An electronic copy of the signed letter must be uploaded in the AFP.

(C) The registrant must designate a primary account representative and at least one alternate account representative. The primary account representative and the alternate account representative(s) must attest, as follows:

"I certify under penalty of perjury under the laws of the State of California as follows: I was selected as the primary account representative or the secondary account representative, as applicable, by an agreement that is binding on all persons who have the legal right to access the AFP account. I have all the necessary authority to carry out the duties and responsibilities contained in California Code of Regulations, title 17, sections 95480 et seq. on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Executive Officer or a court regarding the account."

(D) For each representative, name, title, relationship to the organization, business phone, e-mail address, username, and password.

(E) The account representatives can be changed by following steps set forth in subsection (B), (C), and (D) above. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous account representatives prior to the time and date when the Executive Officer receives the superseding information shall be binding on the entity.

(3) *Account Approval.*

(A) The account is established when the Executive Officer approves the application.

(B) Account registration application may be denied based on false, misleading, or missing information.

(4) *Account Management Roles and Duties*.

(A) The account representative is responsible for making any changes to the company profile within AFP.

(B) The account representative may designate users within the company who can access and manage the account.

(C) If any information required by section 95483.2(a)(2) changes, the entity holding the account must update the account to reflect the changes within 30 ~~calendar~~ days.

(b) *LCFS Reporting Tool and Credit Bank & Transfer System (LRT-CBTS).* The LRT-CBTS is designed to support fuel transaction reporting, compliance demonstration, credit generation, banking, ~~and transfers.~~ transfers, and additional verification processes described in section 95483.2(c).

(1) *Eligibility*. The following entities can request to establish an account in the LRT-CBTS:

(A) A fuel reporting entity;

(B) An entity opting into LCFS, pursuant to section 95483 or 95483.1; or

(C) An LCFS credit broker.

(2) *Deadline to Establish LRT-CBTS Account*.

(A) An entity responsible for reporting any transportation fuels pursuant to section 95483 must complete registration at least 30 days prior to the date for filing any required report.

(B) An opt-in entity can register anytime during a calendar year. All quarterly and annual reporting is then required, beginning with the quarter in which registration was approved, and continuing until any opt-out is completed.

(C) Any broker must register in LRT-CBTS prior to facilitating any LCFS credit trades.

(3) *Requirements to Establish an Account in LRT-CBTS.* A company owner, a president, a managing partner, or a corporate officer with legal binding authority must complete and submit the online LRT-CBTS account registration form and provide the following:

(A) Organization name, address, state and country, Organization Federal Employer Identification Number (FEIN), date and place of incorporation.

(B) A letter on company letterhead stating the basis for qualifying for an account pursuant to subsection (1) above. This letter must be signed by the company owner, a president, a managing partner, or a corporate officer. A signed pdf copy must be uploaded in the LRT-CBTS to complete the application process.

(C) The online LRT-CBTS registration form must designate a primary account representative and at least one alternate account representative. The primary account representative and the alternate account representative(s) must attest in writing, as follows:

"I certify under penalty of perjury under the laws of the State of California as follows: I was selected as the primary account representative or the secondary account representative, as applicable, by an agreement that is binding on all persons who have the legal right to control LCFS credits held in the account. I have all the necessary authority to carry out the duties and responsibilities contained in California Code of Regulations, title 17, sections 95480 et seq. on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Executive Officer or a court regarding the account."

(D) For each representative, name, title, relationship to the organization, business and mobile phone, e-mail address, username, and password.

(E) The account representatives can be changed by following steps set forth in subsections (B) through (D) above. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous account representatives prior to the time and date when the Executive Officer receives the superseding information shall be binding on the entity.

(F) A designated fuel reporting entity pursuant to section 95483(b) and (c) must also provide a written contractual agreement demonstrating it acquired the first fuel reporting entity status from another entity for each such entity.

(G) *Clearing Service Providers.* In addition to requirements specified in 95483.2(b)(3)(A) through (E), a clearing service provider requesting to establish an LRT-CBTS account must provide documents demonstrating their eligibility pursuant to section 95483.1(a)(3).

(4) *LCFS Credit Broker.* A broker may represent other LRT-CBTS account holders in LCFS credit transfers. To register a broker account, the broker must provide the following:

(A) Broker's organization name, address, state and country, Organization Federal Employer Identification Number (FEIN), date, and place of incorporation, if applicable.

(B) Broker's name, business and mobile phone, e-mail address, username, and password.

(C) Broker's statement attesting: “By submitting this broker registration application to the LCFS program for a broker account in the LRT-CBTS, I am submitting to the jurisdiction of the California courts. I certify under penalty of perjury that I have not been convicted of a felony in the last five years.”

(5) *Account Approval*.

(A) The account is established when the Executive Officer approves the application.

(B) Account registration application may be denied based on false, misleading or missing information.

(6) *Account Management Roles and Duties*.

(A) The account representative is responsible for making any changes to the company profile within LRT-CBTS.

(B) The account representative may designate users within the company who can access and manage the account.

(C) The account representative is responsible for meeting the reporting requirements as set forth in section 95491.

(D) If any information required by section 95483.2(b)(3) changes, the entity holding the account must update the account to reflect the changes within 30 ~~calendar~~ days.

(7) *Account Closure*.

(A) An LRT-CBTS account is subject to suspension or closure based on any of the following:

1. The account holder is no longer eligible to establish an LRT-CBTS account pursuant to section 95483.2(b)(1);

2. The account holder fails to comply with requirements of section 95483.2(b); and

3. The account holder intends to opt out pursuant to section 95483.1(c).

(B) The account holder must provide a notice of intent to the LRT-CBTS Administrator to close the account within 90 days after any condition in subsection (A) above. The entity must submit a final quarterly report for the quarter in which the notice was provided, submit a final annual report, and submit verification that any remaining deficits have been eliminated. The Executive Officer shall notify the entity of the final account closure. Any credits that remain in the entity's account at the time of the closure will be placed in the Buffer Account.

(C) Failure to provide notice pursuant to subsection (B) above will result in account closure and forfeit of any credits that remain in the entities account at the time of the closure.

(D) When an entity requests to reopen the LRT-CBTS account that was previously closed, the entity must follow the requirements as set forth in section 95483.2(b) to reopen the account.

(8) *Registration of Fueling Supply Equipment (FSE).* After establishing the LRT-CBTS account, fuel reporting entities for natural gas, electricity, propane, and hydrogen must register all fueling supply equipment in the LRT-CBTS using the FSE registration template available on the LRT-CBTS home page. The completed FSE registration template with supporting documents must be uploaded into the LRT-CBTS. Upon FSE registration, the applicant will receive a unique LCFS FSE ID that must be used for reporting fuel transactions in the LRT-CBTS pursuant to 95491. The following must be provided:

(A) *General Requirements.* All FSE registrations must include:

1. Federal Employer Identification Number (FEIN) for the entity registering, name of the facility at which FSE is situated, street address, latitude, and longitude of the FSE location.

2. Name and address of the entity that owns the FSE, if different from the entity registering the FSE.

(B) *Specific Requirements by Fuel Type.*

1. For CNG, FSE refers to a fueling station associated with a utility meter. A CNG station with multiple dispensers is considered a single FSE. Fuel reporting entities for CNG must provide the natural gas utility meter number at the FSE location, name of the utility company, and a copy of the most recent utility bill.

2. For LNG and propane, FSE refers to a fueling station. An LNG or propane station with multiple dispensers is considered a single FSE. Fuel reporting entities for LNG and propane must provide a unique identifier associated with the FSE used for their own fuel accounting or financial accounting or other purposes and copy of invoice or bill of lading for the most recent fuel delivery.

3. For non-residential EV charging, FSE refers to each piece of equipment capable of measuring the electricity dispensed for EV charging. Fuel reporting entities for non-residential EV charging for on-road applications must provide the serial number assigned to the FSE by the original equipment manufacturer (OEM) and the name of OEM. If there are multiple FSEs at the same location, each unique piece of equipment must be registered separately.

4. For residential metered EV charging, FSE refers to a piece of equipment or on-vehicle telematics capable of measuring the electricity dispensed for EV charging.

   a. Fuel reporting entities for metered residential EV charging using off-vehicle meters must provide the serial number assigned to the FSE by the OEM, the name of the equipment OEM, and the Vehicle Identification Number (VIN) for the vehicle expected to be charged at the location.

   b. Fuel reporting entities using vehicle telematics must provide the VIN.

   c. FSE registration is optional when reporting metered electricity to generate base credits.

d. Notwithstanding subsection (8)(A) above, location information and address is not required for residential charging.

5. Fuel reporting entities for fixed guideway systems are exempt from subsection (A)1. above. The LRT-CBTS will assign FSE IDs for reporting purposes based on the information provided in the LRT-CBTS account registration form.

6. For electric forklifts, eCHE, ~~or~~ eOGV, or eTRU, FSE refers to the facility or location where electricity is dispensed for fueling. If there are multiple FSEs capable of measuring the electricity dispensed at the facility or location, then it is optional to provide serial number assigned to each equipment by the OEM and the name of OEM.

~~7. For eTRU, FSE refers to each eTRU. Fuel reporting entities for eTRU fueling must provide the serial number assigned to the unit by the OEM and the name of the OEM.~~

~~8.~~7. For hydrogen, FSE refers to a fueling station. A hydrogen station with multiple dispensers is considered a single FSE. Fuel reporting entities for hydrogen must provide the station ID assigned by SOSS.

~~9.~~8. For transportation applications not covered in paragraphs 1. through 8. above, FSE refers to a fuel dispenser or a transportation equipment with the capability to measure the dispensed fuel in that equipment.

(c) ~~*LCFS Verification Portal (LVP).*~~*LRT-CBTS for verification.* The ~~LVP~~LRT-CBTS is ~~designed to support~~capable of supporting LCFS verification processes.

(1) *Eligibility.* Any entity providing verification services pursuant to section 95500 (Executive Officer accredited verification body) can request an account in ~~LVP~~LRT-CBTS.

(2) *Requirements to Establish an Account in ~~LVP~~LRT-CBTS.* A company owner, a president, a managing partner, a corporate officer, or any other person with binding legal authority must complete and submit the online ~~LVP~~LRT-CBTS account registration form and provide the following:

(A) Organization name, address, state and country, Organization Federal Employer Identification Number (FEIN), date and place of incorporation.

(B) The online ~~LVP~~LRT-CBTS registration form must designate a primary account representative and at least one alternate account representative.

The primary account representative and the alternate account representative(s) must attest in writing, as follows:

"I certify under penalty of perjury under the laws of the State of California as follows: I was selected as the primary account representative or the secondary account representative, as applicable, by an agreement that is binding on all persons who have the legal right to submit information on behalf of the verification body. I have all the necessary authority to carry out the duties and responsibilities contained in California Code of Regulations, title 17, sections 95480 et seq. on behalf of such persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any order or decision issued to me by the Executive Officer or a court regarding the account."

(C) For each representative, name, title, relationship to the organization, business and mobile phone, e-mail address, username, and password.

(D) The account representatives can be changed by following steps set forth in subsection (B) and (C) above. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous account representatives prior to the time and date when the Executive Officer receives the superseding information shall be binding on the entity.

(3) *Account Approval*.

(A) The account is established when the Executive Officer approves the application.

(B) Account registration application may be denied based on false, misleading or missing information.

(4) *Account Management Roles and Duties*.

(A) The account representative is responsible for making any changes to the company profile within ~~LVP~~LRT-CBTS.

(B) The account representative may designate users within the company who can access and manage the account.

(C) The account representative is responsible for meeting the requirements as set forth in section 95500 through 95502.

(D) If any information required by section 95483.2(c)(2) changes, the entity holding the account must update the account to reflect the changes within 30 ~~calendar~~ days.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95483.3. Change of Ownership or Operational Control.

If an entity or a facility registered in the LRT-CBTS~~, the AFP,~~ or the ~~LVP~~AFP undergoes a change of ownership or operational control, the following requirements apply.

(a) *CARB Notifications.* Within 30 days of the change of ownership or operational control, the previous owner or operator of the regulated entity or facility and the new owner or operator of the entity or facility must provide the following information to CARB:

(1) The previous owner or operator must notify CARB in writing of the ownership or operational control change, including the name of the new owner or operator and the date of the ownership or operational control change.

(2) The new owner or operator must notify CARB in writing of the ownership or operational control change, including the following information:

(A) Previous owner or operator;

(B) New owner or operator;

(C) Date of ownership or operator change;

(D) Name of new account representatives pursuant to section 95483.2 for the affected entity's account in the LRT-CBTS~~, AFP~~ or ~~LVP~~AFP.

(3) The first owner must give the Executive Officer direction regarding the disposition of net credits in the first owner's LRT-CBTS account and the certified fuel pathways associated with the first owner's AFP account.

(b) *Reporting Responsibilities.* The owner or operator of record at the time of a reporting or verification deadline specified in this subarticle has the responsibility for complying with the requirements of this subarticle, including submitting quarterly and annual reports, certifying that the reports are accurate and complete, obtaining verification services, and completing verification.

(1) Reported data must not be split or subdivided for a reporting period, based on ownership. A single reporting period data report must be submitted for the entity by the current owner or operator. This report must represent required data for the entire reporting period.

(2) Previous owners or operators are required to provide data and records to new owners or operators that is necessary and required for preparing quarterly and annual reports required by this article.

(c) *New Owner Responsible for Net Deficits.* The new owner, when filing the annual report, is responsible for demonstrating compliance pursuant to section 95485.

(d) *Bankruptcy.* Deficits constitute regulatory obligations under California law.

(e) *Fate of Credits After an Entity Dissolves.* The Executive Officer will place into the Buffer Account any net credits in the account of a party that dissolves or otherwise ceases to exist without notifying the Executive Officer pursuant to paragraph (3) of subdivision (a) of this section.

(f) *Fate of Deficits After an Entity Dissolves.* Prior to dissolution, a fuel reporting entity is responsible for retiring credits equal to any net deficits in its LRT-CBTS account and fulfill account closure requirements as set forth in section 95483.2(b)(7).

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95484. Annual Carbon Intensity Benchmarks.

(a) The Executive Officer's credit and deficit calculations, as described in Sections 95486 and 95486.1, will use the appropriate annual carbon intensity benchmarks set forth in Tables 1, 2, and 3 of this section.

(b) *Automatic Acceleration Mechanism.* Starting 2027, on May 15 of each year, the Executive Officer will announce on the LCFS website whether the Automatic Acceleration Mechanism has been triggered and the cumulative number of times that the Automatic Acceleration Mechanism has been triggered.

(1) The Automatic Acceleration Mechanism cannot be triggered in the calendar year that immediately follows an announcement that the Auto Acceleration Mechanism has been triggered.

(2) The Automatic Acceleration Mechanism is triggered when the conditions in both subparagraphs (A) and (B) below are met, and if it was not triggered in the immediately prior calendar year.

(A) The Credit Bank to Average Quarterly Deficit Ratio exceeds 3:

$$\frac{Credit\ Bank_{20xx}}{{}^{1}/_{4} \times Deficits_{20xx}} > 3$$

where:

$Credit\ Bank_{20xx}$ is the final credit bank for the program as calculated at the end of compliance year 20xx, the compliance year preceding the year for the current May 15 Automatic Acceleration Mechanism announcement; and

$Deficits_{20xx}$ is the total number of deficits generated under the program as calculated at the end of compliance year 20xx, the compliance year preceding the year for the current May 15 Automatic Acceleration Mechanism announcement.

(B) Credit Generation exceeds Deficit Generation:

$$\frac{Credits_{20xx}}{Deficits_{20xx}} > 1$$

where:

$Credits_{20xx}$ is the total number of credits generated under the program as calculated at the end of compliance year 20xx, the compliance year preceding the year for the current May 15 Automatic Acceleration Mechanism announcement; and
$Deficits_{20xx}$ is the total number of deficits generated under the program as calculated at the end of compliance year 20xx, the compliance year preceding the year for the current May 15 Automatic Acceleration Mechanism announcement.

(c) Updating the Benchmark Schedules. Starting January 1, 2028, the compliance year for which an average carbon intensity benchmark applies will also take into account the number of times the Automatic Acceleration Mechanism has been triggered pursuant to section 95484(b).

(1) An updated benchmark schedule will be posted to the LCFS website on May 15 for any year that the Executive Officer announces that the Automatic Acceleration Mechanism has been triggered.

(2) An updated benchmark schedule posted pursuant to 95484(c)(1) will override any prior benchmark schedules and will take effect January 1 of the calendar year after the Automatic Acceleration Mechanism was triggered.

~~(b)~~(d) *Benchmarks for Gasoline and Fuels used as a Substitute for Gasoline*. Starting in 2028 the defined average carbon intensity benchmarks for each future year will be advanced by one year each time the Automatic Acceleration Mechanism has been triggered pursuant to section 95484(b).

Table 1. LCFS Carbon Intensity Benchmarks for 2011 to 20~~30~~45 for Gasoline and Fuels Used as a Substitute for Gasoline.

Year	*Average Carbon Intensity (gCO_2e/MJ)*	~~*Year*~~	~~*Average Carbon Intensity (gCO_2e/MJ)*~~
2010	Reporting Only	~~2020~~	~~91.98~~
2011*	95.61	~~2021~~	~~90.74~~
2012	95.37	~~2022~~	~~89.50~~
2013**	97.96	~~2023~~	~~88.25~~
2014	97.96	~~2024~~	~~87.01~~
2015	97.96	~~2025~~	~~85.77~~
2016***	96.50	~~2026~~	~~84.52~~
2017	95.02	~~2027~~	~~83.28~~
2018	93.55	~~2028~~	~~82.04~~
2019****	-93.23	~~2029~~	~~80.80~~
2020	91.98		
2021	90.74		
2022	89.50		
2023	88.25		
2024	87.01		
2025[a,b]	80.55		
2026	78.32		
2027	76.09		
2028	73.86[δ]		
2029	71.63[δ]		
2030	69.40[δ]		
2031	64.94[δ]		
2032	60.48[δ]		
2033	56.02[δ]		
2034	51.55[δ]		
2035	47.09[δ]		
2036	42.63[δ]		
2037	38.17[δ]		
2038	33.71[δ]		

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Year	Average Carbon Intensity (gCO_2e/MJ)	~~Year~~	~~Average Carbon Intensity (gCO_2e/MJ)~~
2039	29.24 [δ]		
2040	24.78 [δ]		
2041	21.81 [δ]		
2042	18.83 [δ]		
2043	15.86 [δ]		
2044	12.88 [δ]		
20~~30~~45 and subsequent years	~~79.55~~9.91 [δ]		

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[δ] These CI targets may be accelerated by the Automatic Acceleration Mechanism pursuant to section 95484(b).
* The benchmarks for years 2011 and 2012 reflect reductions from base year (2010) CI values for CaRFG (95.85) calculated using the CI for crude oil supplied to California refineries in 2006.
** The benchmarks for years 2013 through~~o~~ 2015 reflect reductions from revised base year (2010) CI values for CaRFG (98.95) calculated using the CI for crude oil supplied to California refineries in 2010.
*** The benchmarks for years 2016 through~~o~~ 2018 reflect reductions from revised base year (2010) CI values for CaRFG (98.47).
**** The benchmarks for years 2019 through~~o~~ 2024~~30~~ reflect reductions from revised base year (2010) CI values for CaRFG (99.44~~).~~)
[a] The benchmark for years 2025 through 2045 reflect reductions from revised base year (2010) CI Values for CaRFG (99.15).
[b] The benchmark schedule in 2025 has been updated to include a 5% increase in stringency, achieving an 18.75% CI reduction compared to the 13.75% CI reduction specified in the 2018 adopted regulation.

~~(c)~~(e) *Benchmarks for Diesel Fuel and Fuels used as a Substitute for Diesel Fuel*. Starting in 2028 the defined average carbon intensity benchmarks for each future year will be advanced by one year each time the Automatic Acceleration Mechanism has been triggered pursuant to section 95484(b).

Table 2. LCFS Carbon Intensity Benchmarks for 2011 to 20~~30~~45 for Diesel Fuel and Fuels Used as a Substitute for Diesel Fuel.

Year	Average Carbon Intensity (gCO_2e/MJ)	~~Year~~	~~Average Carbon Intensity (gCO_2e/MJ)~~
2010	Reporting Only	~~2020~~	~~92.92~~
2011*	94.47	~~2021~~	~~91.66~~
2012	94.24	~~2022~~	~~90.41~~
2013**	97.05	~~2023~~	~~89.15~~
2014	97.05	~~2024~~	~~87.89~~
2015	97.05	~~2025~~	~~86.64~~
2016***	99.97	~~2026~~	~~85.38~~
2017	98.44	~~2027~~	~~84.13~~

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Year	*Average Carbon Intensity (gCO2e/MJ)*	~~*Year*~~	~~*Average Carbon Intensity (gCO2e/MJ)*~~
2018	96.91	~~2028~~	~~82.87~~
2019****	94.17	~~2029~~	~~81.62~~
2020	92.92		
2021	91.66		
2022	90.41		
2023	89.15		
2024	87.89		
2025[a,b]	85.93		
2026	83.55		
2027	81.17		
2028	78.79[δ]		
2029	76.41[δ]		
2030	74.03[δ]		
2031	69.27[δ]		
2032	64.51[δ]		
2033	59.75[δ]		
2034	54.99[δ]		
2035	50.23[δ]		
2036	45.47[δ]		
2037	40.71[δ]		
2038	35.95[δ]		
2039	31.19[δ]		
2040	26.44[δ]		
2041	23.26[δ]		
2042	20.09[δ]		
2043	16.92[δ]		
2044	13.74[δ]		
20~~30~~45 and subsequent years	~~80.36~~10.57[δ]		

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[δ] These CI targets may be accelerated by the Automatic Acceleration Mechanism pursuant to section 95484(b).
* The benchmarks for years 2011 and 2012 reflect reductions from base year (2010) CI values for ULSD (94.71) calculated using the CI for crude oil supplied to California refineries in 2006.
** The benchmarks for years 2013 through~~o~~ 2015 reflect reductions from revised base year (2010) CI values for ULSD (98.03) calculated using the CI for crude oil supplied to California refineries in 2010.
*** The benchmarks for years 2016 through~~o~~ 2018 reflect reductions from revised base year (2010) CI values for ULSD (102.01).
**** The benchmarks for years 2019 through~~o~~ 2024~~30~~ reflect reductions from revised base year (2010) CI values for ULSD (100.45).
[a] The benchmark for years 2025 through 2045 reflect reductions from revised base year (2010) CI Values for ULSD (105.76).
[b] The benchmark schedule in 2025 has been updated to include a 5% increase in stringency, achieving an 18.75% CI reduction compared to the 13.75% CI reduction specified in the 2018 adopted regulation.

~~(d)~~(f) *Benchmarks for Fuels used as a Substitute for ~~Conventional~~Fossil Jet Fuel.* Starting in 2028 the defined average carbon intensity benchmarks for each future year will be advanced by one year each time the Automatic Acceleration Mechanism has been triggered pursuant to section 95484(b).

Table 3. LCFS Carbon Intensity Benchmarks for 2019 to 20~~30~~45 for Fuels Used as a Substitute for ~~Conventional~~Fossil Jet Fuel.

Year	***Average Carbon Intensity (gCO₂e/MJ)***
2019*	~~89.37~~94.17
2020	~~89.37~~92.92
2021	~~89.37~~91.66
2022	~~89.37~~90.41
2023	89.15
2024	87.89
2025**,[a]	~~86.64~~85.93
2026	~~85.38~~83.55
2027	~~84.13~~81.17
2028	~~82.87~~78.79[δ]
2029	~~81.62~~76.41[δ]
2030	74.03[δ]
2031	69.27[δ]
2032	64.51[δ]
2033	59.75[δ]
2034	54.99[δ]
2035	50.23[δ]
2036	45.47[δ]
2037	40.71[δ]
2038	35.95[δ]
2039	31.19[δ]
2040	26.44[δ]
2041	23.26[δ]
2042	20.09[δ]
2043	16.92[δ]
2044	13.74[δ]
20~~30~~45 and subsequent years	~~80.36~~10.57[δ]

[δ] These CI targets may be accelerated by the Automatic Acceleration Mechanism pursuant to section 95484(b).

* The benchmarks reflect reductions from base year (2010) CI values for ~~conventional~~fossil jet fuel (89.37).

** The benchmark for years 2025 through 2045 reflect reductions from revised base year (2010) CI Values for fossil jet fuel (89.43).

[a] The benchmark schedule in 2025 has been updated to include a 5% increase in stringency, achieving an 18.75% CI reduction compared to the 13.75% CI reduction specified in the 2018 adopted regulation.

~~(e)~~(g) *Carbon Intensity Benchmarks for an Alternative Fuel Other Than a Biomass-Based Diesel Fuel Intended for Use in a Vehicle.*

(1) The Executive Officer will use the benchmarks for gasoline set forth in section 95484(~~b~~d) for credit and deficit calculations for any alternative fuel, other than biomass-based diesel fuel, if the alternative fuel is used or intended to be used in any single-fuel light- or medium-duty vehicle.

(2) The Executive Officer will use the benchmarks for diesel fuel set forth in section 95484(~~c~~e) for credit and deficit calculations for any alternative fuel, other than biomass-based diesel fuel, that is used or intended to be used in any single-fuel application not identified in section 95484(e)(1).

~~(f)~~(h) *Carbon Intensity Benchmarks for Biomass-Based Diesel Fuel.* The benchmark for diesel fuel, set forth in section 95484(~~c~~e), applies to biomass-based diesel fuel is used or intended to be used in any:

(1) light-, medium-, or heavy-duty vehicle;

(2) off-road transportation application;

(3) off-road equipment application;

(4) locomotive or commercial harbor craft application; or

(5) non-stationary source application not otherwise specified in subsections (1) through (4) above.

~~(g)~~(i) *Carbon Intensity Benchmarks for Transportation Fuels Intended for Use in Multi-Fuel Vehicles*.

(1) The Executive Officer's credit and deficit calculations involving alternative fuel provided for use in a multi-fueled vehicle use:

(A) the benchmarks for gasoline set forth in section 95484(~~b~~d) if one of the fuels used in the multi-fuel vehicle is gasoline; or

(B) the benchmarks for diesel fuel set forth in section 95484(~~c~~e) if one of the fuels used in the multi-fuel vehicle is diesel fuel.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95485. Demonstrating Compliance.

(a) *Compliance Demonstration*.

(1) A fuel reporting entity must demonstrate that it met its annual compliance obligation by submitting an annual compliance report, showing that it possessed and has retired a number of credits from its credit account that is equal to its compliance obligation.

(2) *Mandatory Retirement of Credits for the Purpose of Compliance.* At the time of annual compliance report submission, for a fuel reporting entity that possesses credits and has also incurred deficits, the LRT-CBTS will retire a sufficient number of credits so that:

(A) Enough credits are retired to completely meet the fuel reporting entity's compliance obligation for that compliance period, or

(B) If the total number of credits available in entity's account is less than the total number of deficits incurred, all the credits within entity's possession will be retired.

(b) *Calculation of Credit Balance and Annual Compliance Obligation*.

(1) *Compliance Period.* Beginning in 2011 and every year thereafter, the annual compliance period is January ~~1st~~1 through December 31~~st~~ of each year.

(2) *Calculation of Compliance Obligation and Credit Balance at the End of a Compliance Period.* The Executive Officer will calculate each LRT-CBTS account holder's compliance obligation and credit balance at the end of a compliance period as follows:

$$ComplianceObligation = Deficits^{Generated} + Deficits^{CarriedOver}$$

$$\begin{aligned} CreditBalance \\ &= \left(Credits^{Generated}\right. \\ &+ Credits^{Acquired} + Credits^{Released} + \left.Credits^{CarriedOver}\right) \\ &- \left(Credits^{Retired} + Credits^{Sold} + Credits^{OnHold}\right. \\ &+ Credits^{CCMPledge} + \left.Credits^{Adjustments}\right) \end{aligned}$$

where:

$Deficits^{Generated}$ are the deficits generated pursuant to sections 95486 and 95489 in the current compliance period;

$Deficits^{CarriedOver}$ are the deficits carried over from the previous compliance period and not deferred pursuant to section 95485(c);

$Credits^{Generated}$ are the credits generated pursuant to sections 95486 and 95489 in the current compliance period;

$Credits^{Aquired}$ are the credits purchased or otherwise acquired in the current compliance period, including carryback credits acquired pursuant to section 95486;

$Credits^{Released}$ are the credits released from the hold due to enforcement or administrative action;

$Credits^{CarriedOver}$ are the credits carried over from the previous compliance period;

$Credits^{Retired}$ are the credits retired within the LCFS in the current compliance period;

$Credits^{Sold}$ are the credits sold or otherwise transferred in the current compliance period;

$Credits^{OnHold}$ are the credits placed on hold due to enforcement or administrative action. While on hold these credits cannot be used for meeting an annual compliance obligation;

$Credits^{CCMPledge}$ are the credits pledged for the Credit Clearance Market and withheld from the ongoing LCFS market; and

$Credits^{Adjustments}$ are the credits adjusted or invalidated due to administrative or enforcement action.

(c) *Credit Clearance Market*.

(1) If a fuel reporting entity does not retire sufficient credits to meet its year-end compliance obligation under section 95485(a), that party must purchase its pro-rata share of credits in the Credit Clearance Market, if one occurs.

(A) *If the Credit Clearance Market occurs*, a fuel reporting entity that fails to comply with section 95485(a) is nevertheless in compliance if the party:

1. Retires all credits in its LRT-CBTS account;

2. Acquires its Pro-Rata Obligation in the Credit Clearance Market and retires that number of credits by August 31~~st~~ of the year subsequent to the compliance year in question; and

3. Retires the remaining balance of its annual obligation, with interest, within five years.

(B) *If no Credit Clearance Market occurs*, the Executive Officer will record any entity's unmet compliance obligation, and the fuel reporting entity will be deemed in compliance for that year, provided that it has retired all credits in its account, and retires credits equivalent to the Accumulated Deficits, with interest as explained in section 95485(c)(5) below, within five years.

(2) *Acquisition of "Clearance Market" Credits to Meet an Annual Compliance Obligation*.

(A) *Clearance Market Period.* The Clearance Market, if one occurs, will operate from June ~~1st~~1 to August 30~~th~~. A fuel reporting entity subject to section 95485(c)(1) must acquire credits pledged into the Credit Clearance Market to be retired toward compliance in the previous compliance year. Credits acquired for this purpose are defined as "Clearance Market" credits.

(B) *Use of Clearance Market Credits.* A Clearance Market credit can only be used for the purpose of meeting the fuel reporting entity's compliance obligation from an immediate prior year.

(C) A regulated entity that participates in the Credit Clearance Market for two consecutive years must submit a Compliance Plan to CARB, by August 31~~st~~ of that second consecutive year, detailing its plan to obtain sufficient credits to meet future annual compliance obligations within a five-year period.

1. *Compliance Plan Requirements.* Submitted Compliance Plans must include the following:

a. A detailed list of specific business initiatives, strategies, and actions that, if implemented, will achieve a positive credit balance within a five-year timeframe;

b. Quantification of anticipated LCFS credit generation and acquisition, and discussion of uncertainties and contingencies associated with each listed initiative, strategy, or action;

c. Quantification of anticipated annual credit shortage and uncertainties over the following five compliance years;

d. A target timeline for implementing all outlined provisions in the plan;

e. Data and underlying calculations used to arrive at emission reduction quantification and timelines;

f. Reference to management policies or practices applicable to implementing listed plan initiatives, strategies, and actions;

g. List of key roles or positions within the company involved in executing and completing implementation of provisions of the plan;

h. Data records, including written contracts and associated verbal or electronic records, and invoices used to demonstrate actions underway consistent with the submitted plan;

i. Any other information related to or supporting demonstration of plan requirements necessary to allow CARB to develop a general understanding of the approaches being taken to implement the plan.

2. *Compliance Plan Approval.* The Executive Officer shall approve each submitted compliance plan if it meets the requirements of section 95485(c)(2)(C) paragraph 1. If the Executive Officer determines that the requirements for approval have not been met, the Executive Officer will notify the regulated entity of which specific requirements of section 95485(c)(2)(C) paragraph 1 have not been met. The regulated entity must then submit additional information to correct deficiencies identified by the Executive Officer. If the regulated entity is unable to correct any deficiencies found with their plan within 45 days of the Executive Officer's receipt of the original plan, the plan will be denied on that basis, and the regulated entity will be informed in writing. At any point during the evaluation process, the Executive Officer may request in writing additional information or clarification from the regulated entity.

3. *Compliance Plan Implementation Reporting.* In addition to other reports required to be submitted by this subarticle, entities required to submit compliance plans must submit annual compliance plan implementation reports that clearly demonstrate actions taken and progress made to comply with the approved plan. The regulated entity must disclose and explain any deviations from the submitted plan in their compliance plan implementation report and identify the actions that will be taken to correct these deviations.

a. Annual compliance plan implementation reports must be submitted by April 30~~th~~ each year for a five-year period starting the calendar year after the plan was approved.

b. If a regulated entity's annual credit shortage in any given year is greater than the annual credit shortage that was approved in the original compliance plan, implementation reports that identify deviations from the approved compliance plan will be made public on the CARB website.

(D) Entities required to acquire credits in the Credit Clearance Market must complete payment to the seller before the credit transfer is initiated, unless the buyer and seller agree on other payment terms. All credit transfers must be completed on or before the final date of the Clearance Market Period.

(3) *Procedure for Selling in the Clearance Market.*

(A) *Call for Credits.* On the first Monday in April, the Executive Officer shall issue to all fuel reporting entities and credit generators a call for credits to be pledged for sale in the Clearance Market. When calling for credits, the Executive Officer will inform fuel reporting entities of that year's Maximum Price for Credits as determined in section 95487(a)(2)(D).

(B) *Pledging Credits for Sale into the Clearance Market.* Fuel reporting entities and credit generators pledging credits for sale into the Clearance Market must report to the Executive Officer in the Annual Compliance Report (on or before April 30~~th~~) the number of credits they are pledging for sale.

(C) *Advanced Credits.* If, for any compliance year, insufficient credits are pledged for sale into the Credit Clearance Market to fully clear outstanding deficits, the Executive Officer shall issue credits equal to the difference between the number of outstanding deficits and the number of credits pledged for sale in the Credit Clearance Market subject to the following:

1. Advanced credits will be issued to eligible Large IOUs and Large POUs that opt into the LCFS and are eligible to receive base credits per section 95483(c)(1)(A). Advanced credits will be allocated to eligible utilities based on their prorata share of base credits received in the most recent issuance. Advanced credits must be pledged for sale in the current Credit Clearance Market and may only be sold at the

maximum LCFS price per section 95487(a)(2)(D). A minimum portion of proceeds generated from the sale of advanced credits must be allocated using the 2023 and onward contribution percentages found in section 95483(c)(1)(A) paragraph 1. to the Clean Fuel Reward program.

2. The first such issuance of advanced credits will mark the start of the six-year “advanced credit window,” during which advanced credits can be issued and after which base credit issuances will be adjusted to account for advanced credits.

3. *Cumulative Advanced Credits.* The cumulative number of advanced credits issued during the advanced credit window shall not exceed ~~10~~30 million.

4. *Adjusting Future Issuance of Base Credits.* After the six-year advanced credit window is closed, total base credits issued every year will be adjusted downwards to account for advanced credits as per the following schedule. Base credit adjustment for each EDU will be pro-rated based on their share of total advanced credits received. Annual adjustments will be spread equally across each quarter.

Year	***Percent of total advanced credits***
Year 7	5%
Year 8	10%
Year 9	20%
Year 10	30%
Year 11	35%

where:

Year *n* refers to the n^{th} year from the first year the advanced credits were issued. For example, if the first advanced credits are issued in 2021, marking year 1, then the first year that base credit issuance will be adjusted would be 2027.

(D) *Calculation of the Maximum Price for Credits in the Clearance Market.* The maximum price for credits acquired, purchased or transferred via the Credit Clearance Market shall be set pursuant to section 95487(a)(2)(D).

(E) *Eligibility to Sell.* Only fuel reporting entities that demonstrated compliance pursuant to section 95485(a) for the prior year can pledge credits for sale into the Clearance Market. Fuel reporting entities that have an Accumulated Deficit obligation cannot pledge credits for sale into the Clearance Market.

(F) *Selling in the Clearance Market.* By pledging credits for sale in the Clearance Market, parties agree to the following provisions:

1. Parties pledging credits agree to withhold those credits from sale in the ongoing LCFS credit market until the Executive Officer determines whether a Clearance Market will occur and, if a Clearance Market will occur, until August 31~~st~~.

2. The Executive Officer will announce whether a Clearance Market will occur by May 15~~th~~ of each year.

3. If the Executive Officer announces that a Clearance Market will not be held that year, parties who have pledged credits to the Clearance Market shall be released from their agreement to withhold those credits from sale in the ongoing LCFS credit market.

4. If a Clearance Market does occur, parties agree to sell or transfer credits at or below the Maximum Price for the pertinent year, until the Clearance Market closes on August 30~~th~~.

5. Parties that have voluntarily pledged credits to sell into the Clearance Market cannot reject, based on credit pricing terms, an offer to purchase those pledged credits at the Maximum Price, provided they have not sold or contractually agreed to sell those pledged credits.

(4) *Clearance Market Operation.* The Executive Officer will inform each fuel reporting entity that failed to meet the Annual Compliance obligation under section 95485(a) of its pro-rata share of credits available into the Clearance Market by June ~~1st~~1.

(A) *Calculation of Pro-Rata Shares.* Each fuel reporting entity's pro-rata share of credits available in the Clearance Market will be calculated by the following formula:

Fuel reporting entity A's pro-rata share =

$$\left[\frac{(A's\ deficit)}{(total\ deficits)}\right] \times [lesser\ of: (pledged\ credits)\ or\ (total\ deficits)]$$

where:

$deficit$ refers to one fuel reporting entity's obligation for the compliance year that has not been met pursuant to section 95485(a);

$total\ deficits$ refers to the sum of all fuel reporting entities' obligations for the compliance year that have not been met pursuant to section 95485(a); and

$pledged\ credits$ means the sum of all credits pledged pursuant to section 95485(c)(3).

(B) *Publishing a List of Entities Participating in the Clearance Market.* On or before June ~~1st~~1, the Executive Officer will post the following information on the LCFS ~~web site~~website:

1. The name of each entity that did not meet the requirement of section 95485(a);

2. The name of each entity that has pledged to provide credits for sale in the credit clearance market and the number of credits that each party has agreed to provide and

3. The name of each entity that received advanced credits and the total number of advanced credits pledged for sale in the credit clearance market.

(C) *Submission of Amended Annual Compliance Reports.* Fuel reporting entities that purchased credits in the Clearance Market must submit to the Executive Officer an Amended Annual Compliance Report by August 31~~st~~ that accounts for the acquisition and retirement of their pro-rata share of Clearance Market credits, and for all deficits carried over as Accumulated Deficits.

(D) *Accumulated Deficits.* If, after purchasing its pro-rata share of credits and retiring those credits, a fuel reporting entity retains an unmet compliance obligation, the Executive Officer shall record remaining deficits from that compliance year in the entity's account.

(5) *Rules Governing Accumulated Deficits*.

(A) *Compound Interest on Accumulated Deficits.* Fuel reporting entities with an Accumulated Deficit will be charged interest to be applied annually to all deficits in a fuel reporting entity's account. Interest will be applied on Accumulated Deficit from previous compliance years in terms of additional deficits that must be retired pursuant to section 95485(c)(1)(A) at a rate of 5 percent annually, applied on each September ~~1st~~1.

(B) *Repayment of Accumulated Deficits.* Fuel reporting entities that participate in the Clearance Market in order to meet their compliance obligations must repay all deficits, plus interest no later than five years from the end of the compliance period in which any such deficit was incurred.

(C) *Restrictions on the Repayment of Accumulated Deficits.* Fuel reporting entities may repay Accumulated Deficits as part of a subsequent annual report. However, no repayment of any Accumulated Deficits is allowed unless the fuel reporting entity meets 100 percent of its current compliance obligation.

(D) *Prohibitions on Credit Transfers.* Fuel reporting entities that have an Accumulated Deficit obligation cannot transfer or sell credits to another fuel reporting entity.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95486. Generating and Calculating Credits and Deficits.

(a) *Generation and Acquisition of Transferrable Credits*.

(1) *Credit and Deficit Issuance.* Upon submission and acceptance of timely reports as required by this subarticle, the total number of credits and deficits generated will be issued in the LRT-CBTS account of the applicable credit or deficit generator. Once issued, credits may be retained indefinitely, retired to meet a compliance obligation, or transferred to other entities through the LRT-CBTS. The Executive Officer will issue the credits and deficits in the LRT-CBTS if:

(A) The credit or deficit generator met all the reporting requirements pursuant to this subarticle;

(B) The credit or deficit generator successfully reconciled the fuel quantity reported per FPC using transaction types Sold with Obligation and Purchased with Obligation with business partners by the quarterly reporting deadline, if required;

(C) The activity is not prohibited pursuant to section 95486(a)(2) or any other provision of this subarticle.

(2) *No Retroactive Credit Claim.* Unless expressly provided elsewhere in this subarticle, no credit generator may generate or claim credits retroactively for a period for which the reporting deadline has passed. Similarly, no

deficit generator may eliminate deficits retroactively for a period for which the reporting deadline has passed.

(3) *Buffer Account.* The Executive Officer may create an LRT-CBTS account under the control of the Executive Officer. In this account, the Executive Officer may place:

(A) An equivalent number of credits for any LCFS credits that could have been claimed (or deficits that could have been eliminated) if reported timely, if not for the prohibition on retroactive credit claims in section 95486(a)(2).

(B) ~~An~~Unless otherwise specified in section 95488.10(b), an equivalent number of credits representing the difference between the reported CI and the verified operational CI from annual Fuel Pathway Reports for each fuel pathway code reported with the following liquid fuel transaction types “Production in California”, “Production for Import”, and “Import” and all non-liquid fuel transaction types during a compliance year~~. These credits~~ will be placed in the buffer account after August 31~~st~~ for the prior compliance year and will be calculated according to the following equation:

$$Credits^{FPC}_{CI\ difference}\ (MT) = \left(Credits^{FPC}_{verified\ opertaional\ CI}\ (MT) - Credits^{FPC}_{reported\ CI}\ (MT)\right)$$

If $Credits^{FPC}_{CI\ difference} > 0$

where:

$Credits^{FPC}_{CI\ difference}$ is the number of credits representing the difference between the reported CI and verified operational CI for each fuel pathway code.

$Credits^{FPC}_{verified\ opertaional\ CI}$ is the number of credits calculated using $CI^{XD}_{verified\ opertional}$ instead of $CI^{XD}_{reported}$ in the equation in section 95486.1(a)(1). $CI^{XD}_{verified\ opertional}$ is determined by the Executive Officer on the basis of the annual Fuel Pathway Reports pursuant to section 95488.10 for each fuel pathway code; and

$Credits^{FPC}_{reported\ CI}$ is the number of credits calculated using equation in section 95486.1(a)(1) for each fuel pathway code;

(C) Contribution from CCS projects pursuant to the CCS Protocol.

(D) All net credits remaining in any deactivated LRT-CBTS accounts.

(E) The Executive Officer may retire credits in the Buffer Account to address the invalidation of credits, pursuant to section 95495, if the person responsible for the invalidated credits no longer exists or is otherwise unavailable to reimburse the program.

(4) The Executive Officer may, at the time of credit generation or credit transfer, assign a unique identification number to each credit. Credits are subject to review and audit by the Executive Officer or his designee, and credits may be invalidated or adjusted as necessary pursuant to section 95495.

(5) *Acquisition of "Carryback" Credits to Meet Obligation*.

(A) *Carryback Credit Acquisition Period.* A fuel reporting entity may acquire, via purchase or transfer, additional credits between January ~~1st~~1 and April 30~~th~~ ("carryback period") to be used for meeting the compliance obligation of the year immediately prior to the carryback period. Credits acquired for this purpose are defined as "carryback" credits. All carryback credit transfers must be completed in the LRT-CBTS pursuant to section 95487(b) by April 30~~th~~. In order to be valid for meeting the compliance obligation of the year immediately prior.

(B) *Use of Carryback Credits.* A carryback credit may be used for the purpose of meeting the compliance of an immediate prior year if all of the conditions below are met:

1. The credit was acquired during the carryback period;

2. The credit was generated in a compliance year prior to the carryback period;

3. A fuel reporting entity electing to use carryback credits must identify the number of credits it desires to use as carryback credits in its annual compliance report submitted to the Executive Officer no later than April 30~~th~~ of the year in which the carryback credits were obtained; and

4. A fuel reporting entity electing to use carryback credits must:

a. Acquire and retire a sufficient amount of carryback and other credits to meet 100 percent of its compliance obligation in the prior compliance year, or

b. Minimize its compliance shortfall by retiring all credits in its possession at the end of the previous compliance year, as well as all credits purchased during the carryback period that are eligible to be used as carryback credits.

(b) *Calculation of Credits and Deficits Generated.* The Executive Officer will calculate the number of credits and deficits generated within the LRT-CBTS using the methods specified in section 95486.1 and section 95489. The total credits and deficits generated are used in determining the overall credit balance for a compliance period, pursuant to section 95485. All credits and deficits are denominated in units of metric tons (MT) of carbon dioxide equivalent.

(1) All LCFS fuel quantities used for credit calculation using fuel pathways are in energy units of megajoules (MJ).

Fuel quantities denominated in other units, such as those shown in Table 4, are converted to MJ in the LRT-CBTS by multiplying by the corresponding energy density[1]:

Table 4. Energy Densities and Conversion Factors for LCFS Fuels and Blendstocks.

Fuel (units)	***Energy Density***
CARBOB (gal)	119.53 (MJ/gal)
CaRFG (gal)	115.83 (MJ/gal)
Diesel fuel (gal)	134.47 (MJ/gal)
LNG (gal)	78.83 (MJ/gal)
Fossil Jet Fuel (gal)	129.82 (MJ/gal)
CNG (Therms)	105.5 (MJ/Therm)
Electricity (KWh)	3.60 (MJ/KWh)
Hydrogen (kg)	120.00 (MJ/kg)
Dimethyl Ether (gal)	72.72 (MJ/gal)
Undenatured Anhydrous Ethanol	80.53 (MJ/gal)
Denatured Ethanol (gal)	81.51 (MJ/gal)
FAME Biodiesel (gal)	126.13 (MJ/gal)
Renewable Diesel (gal)	129.65 (MJ/gal)
Alternative Jet Fuel (gal)	126.37 (MJ/gal)

[1] Energy density factors are based on the lower heating values of fuels in CA-GREET~~3~~4.0 using BTU to MJ conversion of 1055.06 J/Btu.

Fuel (units)	Energy Density
Renewable Naphtha (gal)	123.36 (MJ/gal)
Renewable Gasoline (gal)	122.37 (MJ/gal)
Propane (LPG) (gal)	89.63 (MJ/gal)

(2) The total credits and deficits generated by a credit or deficit generator in a compliance period will be calculated as follows:

$$Credits^{Gen}(MT) = \sum_{i}^{n} Credits_i^{gasoline} + \sum_{i}^{n} Credits_i^{diesel} + \sum_{i}^{n} Credits_i^{jet} + \sum_{i}^{n} Credits_i^{projects}$$

$$Deficits^{Gen}(MT) = \sum_{i}^{n} Deficits_i^{gasoline} + \sum_{i}^{n} Deficits_i^{diesel}$$

where:

$Credits^{Gen}$ represents the total credits (a zero or positive value), in units of metric tons (MT), for all fuels and blendstocks determined from the credits generated under the gasoline, diesel, and fossil jet fuel annual carbon intensity benchmarks, and from opt-in projects, if applicable;

$Deficits^{Gen}$ represents the total deficits (a negative value), in MT, for all fuels and blendstocks determined from the deficits generated under either or both of the gasoline and diesel fuel annual carbon intensity benchmarks;

i is the finished fuel or blendstock index; and

n is the total number of finished fuels and blendstocks provided by a credit or deficit generator in a compliance period.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95486.1. Generating and Calculating Credits and Deficits Using Fuel Pathways.

(a) *General Calculation of Credits and Deficits Using Fuel Pathways.* LCFS credits or deficits for each fuel or blendstock for which a fuel reporting entity is the credit or deficit generator will be calculated according to the following equations:

(1) $Credits_i^{XD}/Deficits_i^{XD}(MT) = \left(CI_{standard}^{XD} - CI_{reported}^{XD}\right) \times E_{displaced}^{XD} \times C$

where:

$Credits_i^{XD}/Deficits_i^{XD}(MT)$ is either the number of LCFS credits generated (a zero or positive value), or deficits incurred (a negative value), in metric tons, by a fuel or blendstock under the average carbon intensity requirement for gasoline (XD = "gasoline"), diesel (XD = "diesel"), or fossil jet fuel (XD = "jet");

$CI_{standard}^{XD}$ is the average carbon intensity requirement of either gasoline (XD = "gasoline"), diesel (XD = "diesel"), or fossil jet fuel (XD = "jet") for a given year as provided in sections 95484(b), (c) and (d), respectively;

$CI_{reported}^{XD}$ is the adjusted carbon intensity value of a fuel or blendstock, in gCO_2e/MJ, calculated pursuant to section 95486.1(a)(2);

$E_{displaced}^{XD}$ is the total quantity of gasoline (XD = "gasoline), diesel (XD = "diesel"), or fossil jet fuel (XD = "jet") fuel energy displaced, in MJ, by the use of an alternative fuel, calculated pursuant to section 95486.1(a)(3); and

C is a factor used to convert credits to units of metric tons from gCO_2e and has the value of:

$$C = 1.0x10^{-6}\frac{(MT)}{(gCO_2e)}$$

(2) $CI_{reported}^{XD} = \frac{CI_i}{EER^{XD}}$

where:

CI_i is the carbon intensity of the fuel or blendstock, measured in gCO_2e/MJ, determined by a CA-GREET pathway or a custom pathway and incorporates a land use modifier (if applicable); and

EER^{XD} is the dimensionless Energy Economy Ratio (EER) relative to gasoline (XD = "gasoline"), diesel (XD = "diesel"), or fossil jet fuel (XD = "jet") as listed in Table 5. For a vehicle-fuel combination not listed in Table 5, $EER^{XD} = 1$ must be used unless an applicant is granted certification of an EER-adjusted CI value pursuant to section 95488.7(a)(3).

(3) $E_{displaced}^{XD} = E_i \times EER^{XD}$

where:

E_i is the energy of the fuel or blendstock, in MJ, determined from the energy density conversion factors in Table 4, except as noted in subsection (4) below.

(4) For Fixed Guideway Systems ~~and Forklifts~~:

$$E_{displaced}^{XD} = E_i$$

where:

E_i is the energy of the fuel used to propel fixed guideway systems~~, electric forklifts, and hydrogen fuel cell forklifts.~~. For fixed guideway system expansion beyond 2010~~, and for electric and hydrogen fuel cell forklifts with model year 2011 or later~~, the formula for displaced energy in section 95486.1(a)(3) may be used with Executive Officer approval.

Table 5. EER Values for Fuels Used in Light- and Medium-Duty, and Heavy-Duty Applications.

Light/Medium-Duty Applications (Fuels used as gasoline replacement)		***Heavy-Duty/Off-Road Applications (Fuels used as diesel replacement)***		***Aviation Applications (Fuels used as fossil jet fuel replacement)***	
Fuel/Vehicle Combination	***EER Values Relative to Gasoline***	***Fuel/Vehicle Combination***	***EER Values Relative to Diesel***	***Fuel/Vehicle Combination***	***EER Values Relative to ~~Conven-tional~~Fossil Jet Fuel***
Gasoline (incl. E6 and E10) Or E85 (and other ethanol blends)	1	Diesel fuel Or Biomass-based diesel blends	1	Alternative Jet Fuel	1
CNG/ICEV	1	CNG or LNG (Spark-Ignition Engines)	0.9		
		CNG or LNG (Compression-Ignition Engines)	1		
Electricity/BEV, or PHEV	3.4	Electricity/BEV or PHEV* Truck or Bus	5.0		
		Electricity/Fixed Guideway, Heavy Rail	4.6		
		Electricity/Fixed Guideway, Light Rail	3.3		

On-Road Electric Motorcycle	4.4	Electricity/Trolley Bus, Cable Car, Street Car	3.1	
		Electricity Forklifts with lift capacity <12,000 lbs.	1.9	
		Electricity Forklifts with lift capacity ≥12,000 lbs.	3.8	
		eTRU	3.4	
		eCHE	2.7	
		eOGV	2.6	
H2/FCV	2.5	H2/FCV	1.9	
		H2 Fuel Cell Forlifts with life capacity < 12,000 lbs.	1.1	
		H2 Fuel Cell Forklifts with lift capacity ≥12,000 lbs.	2.1	
Propane	1.0	Propane	0.9	

*BEV = battery electric vehicle, PHEV= plug-in hybrid electric vehicle, FCV = fuel cell vehicle, ICEV = internal combustion engine vehicle.

(b) *Credit and Deficit Generation Frequency Using Fuel Pathways.* Unless expressly provided elsewhere in this subarticle, credits and deficits for fuel transactions reported each quarter will be generated in LRT-CBTS accounts upon completion of the reporting period for the given quarter, if all the conditions set forth in section 95486(a)(1) are met.

(c) *Calculation of Credits for EV Charging Using Fuel Pathways*.

(1) *Base Credits to EDUs.* “Base Credit” refers to the credit generated by an EDU for electricity using carbon intensity values provided in the Lookup Table pathway for California Average Grid Electricity and the credit calculation in 95486.1(a).

(A) *Determining Quantity of Electricity.* For calculating base credits to EDUs, the quantity of electricity must be determined as follows:

1. *For Non-Metered Residential EV Charging.* The Executive Officer will use the following method to calculate the quantity of electricity used for non-metered residential charging:

$$Electricity^{EV}_{Non\ metered} =$$

$$N^{EV}_{Non\ metered} \times Electricity^{EV}_{Daily\ Average} \times T^{days}_{reporting\ period}$$

where:

$Electricity^{EV}_{Non\ metered}$ is the total estimated electricity use in kWh of non-metered residential plug-in electric vehicles assigned to the EDU for the reporting period;

$N^{EV}_{Non\ metered}$ is the total number of non metered residential EVs within a given EDU service area for the reporting period;

$Electricity^{EV}_{Daily\ Average}$ is the quantity in kWh of electricity used daily for residential charging of EVs, based upon the best data available to the Executive Officer, during the reporting period;

$T^{days}_{reporting\ period}$ is the total number of days in the reporting period.

2. Using the equation in subsection 1. above, the Executive Officer may also calculate, based upon the best data available, the quantity of non-metered electricity used in residential EV charging within service areas for which the EDU has not opted in or is not eligible to receive base credit per section 95483(c)(1)(A). The Executive Officer may then calculate credits generated from this quantity of electricity and assign these credits to Large IOUs and Large POUs that are eligible to receive base credits.

3. *For Metered Residential EV Charging.* The EDU may demonstrate the quantity of electricity for the purposes of calculating the base credits for metered charging at residences through timely submission of Quarterly Fuel Transaction Reports based on meter records.

(B) *Calculation of Base Credits.* The Executive Officer will use the quantity of electricity as determined in subsection (A) above to calculate the base credit using the Lookup Table pathway CI value for California Average Grid Electricity and the credit generation equation provided in section 95486.1(a).

(C) Credits calculated and generated pursuant to subsection (B) above are exempt from the credit generation requirements pursuant to sections 95486(a)(2) and 95486.1(b).

(2) *Incremental Credits for Residential EV Charging.* "Incremental Credit" refers to any credits generated in addition to the base credits generated by

an EDU pursuant to subsection (1)(B) above, for the same electricity, using the calculation in subsection (2)(B), below.

(A) *Quantity of Electricity*.

1. *Non-Metered Residential EV Charging.* The Executive Officer shall use the formula in 95486.1(c)(1)(A) for calculating the quantity of electricity eligible to generate incremental credits for each residence that has an electric vehicle that is not separately metered and is shown to receive low-CI electricity, and is not claimed by another generator of incremental low-CI electricity credits using metered data.

2. *Metered Residential EV Charging for Incremental Credits.* Any entity generating incremental credit for metered residential EV charging must supply the quantity of electricity through timely submission of Quarterly Fuel Transaction Reports based on meter records.

(B) *Calculation of Incremental Credits.* Incremental credits for residential EV charging, including either low-CI electricity or smart charging, and incremental credits for smart electrolysis pathways, must be calculated according to the following equation:

$$Credits_i(MT) = \left(CI_{grid\ average} - CI_{reported}\right) \times Electricity \times C$$

where:

$Credits_i(MT)$ is the number of incremental LCFS credits generated (a zero or positive value), in metric tons, for improvements in carbon intensity of electricity supplied to residential EV charging or for hydrogen production using electrolysis compared to the grid-average carbon intensity;

$CI_{grid\ average}$ is the carbon intensity of California Average Grid Electricity pathway certified by the Executive Officer for a given year, or the applicable region's average grid electricity for hydrogen imported to California;

$CI_{reported}$ is the adjusted carbon intensity of electricity, in gCO_2e/MJ, as calculated for a certified Tier 2 pathway or a Lookup Table pathway, including smart charging or smart electrolysis pathways;

$Electricity$ is the total quantity of either low-CI electricity supplied for EV charging, or electricity supplied for smart charging or smart electrolysis and reported by hourly windows, in MJ, determined from the energy density conversion factors in Table 4; and

C is a factor used to convert credits to units of metric tons from gCO_2e and has the value of:

$$C = 1.0x10^{-6} \frac{(MT)}{(gCO_2e)}$$

(d) *Calculation of Credits for Non-Residential EV Charging Using Fuel Pathways.* The base and incremental framework does not apply to non-residential EV charging. Only one entity per FSE may claim credits for non-residential metered EV charging.

(1) An entity may generate credits for Non-Residential EV charging using a carbon intensity for California Average Grid Electricity, Zero-CI Electricity, or Smart Charging pathway from the Lookup Table in section 95488.5, or a carbon intensity value certified through the Tier 2 pathway application process, and the credit calculation in 95486.1(a).

(e) *Calculation of Credits for Other Electricity used as Transportation Fuel Using Fuel Pathways.* An entity may generate credits for the non-EV charging applications listed in sections 95483(c)(3) to (6), which use electricity to displace conventional transportation fuel, using a carbon intensity for California Average Grid Electricity or Zero-CI Electricity from the Lookup Table 7-1 in section 95488.5, or a carbon intensity value certified through the Tier 2 pathway application process, and the credit calculation in 95486.1(a).

(f) *Calculation of Credits for Hydrogen Using Fuel Pathways*.

(1) An entity may generate credits for hydrogen used as a transportation fuel using a carbon intensity for hydrogen found in the Lookup Table in section 95488.5, or a carbon intensity value certified through the Tier 2 pathway application process, and the credit calculation in 95486.1(a).

(2) *Smart Electrolysis Pathways for Hydrogen Production.* An entity can generate incremental credits, in addition to credits generated under a pathway for electrolytic hydrogen produced using average grid electricity, for hydrogen using smart electrolysis pursuant to section 95488.5 and the incremental credit calculation in section 95486.1(c)(2)(B).

(g) *Calculation of Deficit Obligation for Verified CI Exceedance.* Beginning with the 2025 fuel transactions reporting year, a fuel pathway holder for a non-provisional fuel pathway generates a deficit obligation following a verified CI exceedance. A verified CI exceedance occurs if the verified operational CI of a fuel pathway for a given compliance period, pursuant to section 95488.10, exceeds the certified CI used for reporting that fuel pathway, and is calculated as specified below.

(1) The quantity of deficits generated by CI exceedance is calculated as four times the difference between the verified operational fuel pathway CI and the reported CI, multiplied by the quantity of fuel reported using that fuel

pathway during the applicable year. Deficits will be calculated using the following equation:

$$Deficits(MT) = \left(CI_{operational} - CI_{reported}\right) \times E \times C \times 4$$

where:
$Deficits(MT)$ is the number of calculated deficits from CI exceedance;

$CI_{operational}$ is the verified operational fuel pathway CI for a given compliance period;

$CI_{reported}$ is the certified CI in LRT-CBTS under which the fuel was reported;

E is the reported fuel under a given certified fuel pathway in Megajoules;

C is a factor used to convert credits/deficits to unit of metric tons from gCO_2e and has the value of:

$$C = 1 \times 10^{-6} \frac{(MT)}{(gCO_2e)}$$

(2) Any pathway holder generating deficits following a verified CI exceedance must satisfy the compliance demonstration requirements of section 95485 of this subarticle.

(3) A pathway holder that meets the exemption criteria specified in subsection 95488.10(a)(7)(C) will not generate deficits under this subsection.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and Western Oil and Gas Ass'n v. Orange County Air Pollution Control District, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95486.2. Generating and Calculating Credits for ZEV Fueling Infrastructure Pathways.

(a) *Hydrogen Refueling Infrastructure (HRI) Pathways*.

(1) *HRI Pathway Eligibility.* A hydrogen station owner or their designee identified in subsection 95483(b)(2) may submit an application to certify an HRI pathway subject to the following eligibility conditions:

(A) The proposed HRI must be located in California and open to the public.

(B) The HRI pathway application must be received on or before December 31, 2025.

(C) The following stations are not eligible for HRI crediting:

1. Any station receiving or spending funds pursuant to any settlement related to any California or Federal regulation enforcement; or

2. Any station built as a required mitigation measure pursuant to the California Environmental Quality Act.

(2) *HRI Application Requirements.* For each hydrogen refueling station, the station owner must submit an application in the LRT-CBTS containing the following information:

(A) Name and address of the owner of the proposed station.

(B) Contact person for the owner entity.

1. Name

2. Title or position

3. Phone number

4. Mobile phone number

5. Email address

(C) Name, street address, latitude, longitude and a location description for the proposed station.

(D) Expected daily permitted hours of operation for the station. If the daily permitted hours are less than 24 hours, the applicant must provide documentation from a permitting authority demonstrating that daily permitted hours for the station are limited.

(E) The station nameplate refueling capacity for the permitted hours of operation calculated using the HySCapE 1.0 model or an equivalent model or capacity estimation methodology approved by the Executive Officer. The applicant must submit a completed model with the application.

(F) The HRI refueling capacity for the station is the nameplate refueling capacity determined in subsection (E) above or 1,200 kg/day, whichever is less.

(G) The number of dispensing units at the station.

(H) Expected source(s) of hydrogen, CI value(s), and method(s) used for delivery.

(I) Expected date that the station will be operational.

(J) Justification for the station location and how the proposed location contributes in developing a hydrogen refueling station network to support ZEV adoption. The justification must include:

1. The role(s) the station location will play in the developing hydrogen station network;

2. The means by which the station contributes to robust growth of the statewide hydrogen fueling network;

3. Demonstration of potential for consistent and calculable hydrogen demand;

4. Demonstration that the proposed station capacity is an appropriate capacity based on documented, verifiable, and reproducible projections of daily hydrogen demand at the proposed location;

5. Calculation of the projected trajectory of annualized average station utilization (calculated as annual throughput divided by annual station capacity) at the proposed location; and

6. Demonstration that the proposed station location has been discussed with local authorities having jurisdiction and no early roadblocks have been identified.

(K) A signed attestation letter from the applicant attesting to the veracity of the information in the application packet. The attestation letter must be submitted as an electronic copy, be on company letterhead, be signed by an officer of the applicant with authority to attest to the veracity of the information in the application and to sign on behalf of the applicant, be from the applicant and not from an entity representing the applicant (such as a consultant or legal counsel), and include the following attestation:

I, an authorized representative of _______________ (applicant entity), attest to the veracity of the information submitted as part of the Hydrogen Refueling Infrastructure (HRI) application, attest that the proposed FSE is not receiving funds pursuant to any enforcement settlement related to any California or Federal regulation, and declare that the information submitted accurately represents the anticipated and intended design and operation of the hydrogen refueling station. Further, I understand and agree to each of the statements in the attached application. I am a duly authorized officer with authority to attest to the veracity of the information in the application and to sign on behalf of the respective applicant.

I understand that the following information in the HRI application will be made available on the LCFS ~~web site~~website: Name of the Applicant Entity, Station Name, Station Address, Number of Dispensing Units, HRI Refueling Capacity, and Effective Date Range for HRI Crediting.

By submitting this application, ____(applicant entity) accepts responsibility for the information herein provided to CARB. I certify under penalty of perjury under the laws of the State of California that I have personally examined, and am familiar with, the statements and information submitted in this document. I certify that the statements and information submitted to CARB are true, accurate, and complete.

______________________________ ______________________________ __________

Signature Print Name & Title Date

(L) CBI must be designated pursuant to the requirements described in section 95488.8(c).

(M) An application and supporting documents must be submitted electronically via the LRT-CBTS unless the Executive Officer has approved or requested in writing another format.

(3) *Application Approval Process*.

(A) The HRI application must be approved by the Executive Officer before the station owner may generate hydrogen refueling infrastructure credits. If estimated potential HRI credits from all approved stations exceed 2.5 percent of deficits in the prior quarter, the Executive Officer will not approve additional HRI pathways and will not accept additional applications until estimated potential HRI credits are less than 2.5 percent of deficits. HRI applications will be evaluated for approval on a first come, first served basis.

Estimated potential HRI credits will be calculated using the following equation:

$$Credits_{HRI}^{Potential} = Credits_{HRI}^{Prior\ qtr} \times \frac{Cap_{HRI}^{Approved}}{Cap_{HRI}^{Operational}}$$

where:

$Credits_{HRI}^{Potential}$ means the estimated potential HRI credits from all approved HRI stations;

$Credits_{HRI}^{Prior\ qtr}$ means the total HRI credits generated by operational stations in the prior quarter;

$Cap_{HRI}^{Operational}$ means the total HRI capacity of stations that were operational in the prior quarter; and

$Cap_{HRI}^{Approved}$ means the total HRI capacity of all approved stations, both operational and nonoperational.

(B) After receipt of an application designated by the applicant as ready for formal evaluation, the Executive Officer will advise the applicant in writing either that:

1. The application is complete, or

2. The application is incomplete, in which case the Executive Officer will identify which requirements of section 95486.2(a)(2) have not been met.

a. The applicant may submit additional information to correct deficiencies identified by the Executive Officer.

b. If the applicant is unable to achieve a complete application ~~within 180 days~~in the quarter of the Executive Officer's receipt of the original application, the application will be denied on that basis, and the applicant will be informed in writing. The applicant may submit a new application for the station.

3. At any point during the application evaluation process, the Executive Officer may request in writing additional information or clarification from the applicant.

(C) The Executive Officer will not approve an application if the Executive Officer determines, based upon the information submitted in the application and any other available information, that the application does not meet requirements in subsections 95486.2(a)(1) and (a)(2). The Executive Officer may reject an application if satisfactory justification is not provided for station location pursuant to subsection 95486.2(a)(2)(J). If the Executive Officer does not approve the application, the applicant will be notified in writing and the basis for the disapproval shall be identified.

(D) If the Executive Officer determines that the applicant and application have met all requirements for approval pursuant to subsections 95486.2(a)(1) and (a)(2), the Executive Officer will approve the application and provide an approval summary on the LCFS website including the station location and assigned identifier, number of dispensing units, HRI refueling capacity, and effective date range for HRI pathway crediting.

(E) *Crediting Period.* HRI crediting is limited to 15 years starting with the quarter following Executive Officer approval of the application.

(4) *Requirements to Generate HRI Credits.* To generate credits using HRI pathways the station must meet the following conditions. The station

owner must maintain, and submit to CARB upon request, records demonstrating adherence to these conditions.

(A) The station owner must update the HRI refueling capacity if different from the design HRI refueling capacity provided in the application. Any station design or operational information that deviates from the original application must be declared to the Executive Officer, and a new attestation must be submitted pursuant to 95486.2(a)(2).

(B) The station must be open to the public, meaning that no obstructions or obstacles exist to preclude vehicle operators from entering the station premises, no access cards or personal identification (PIN) codes are required for the station to dispense fuel, and no formal or registered station training shall be required for individuals to use the hydrogen refueling station.

(C) The station uses a public point of sale terminal that accepts major credit and debit cards.

(D) The station is connected to the Station Operational Status System (SOSS), is listed open for retail, and:

1. The station passed final inspection by the appropriate authority having jurisdiction and has a permit to operate.

2. The station owner has fully commissioned the station, and has declared it fit to service retail FCV drivers. This includes the station owner's declaration that the station meets an appropriate SAE fueling protocol.

3. At least three OEMs have confirmed that the station meets protocol expectations, and their customers can fuel at the station.

4. All dispensers installed in the hydrogen refueling station have undergone type evaluation according to the California Type Evaluation Program (CTEP) administered by the California Department of Food and Agriculture/Division of Measurement Standards (CDFA/DMS) and have either a Temporary Use Permit or a type approval Certificate of Approval issued by CDFA/DMS.

(E) The FSE registration must be completed pursuant to section 95483.2(b)(8) and the quantity of dispensed hydrogen must be reported as required in section 95491.

(F) Dispensed hydrogen meets the following CI and renewable content requirements on a company-wide, weighted average basis. The Executive Officer will consider all the stations registered by an entity with a unique FEIN in the LRT-CBTS for calculating the company-wide weighted average CI and renewable content.

1. CI of 150 gCO_2e/MJ or less before January 1, 2030, and 90 gCO_2e/MJ or less thereafter, and

2. Renewable content of 40 percent or greater before January 1, 2030, and 80 percent thereafter.

(G) The station must be operational within 24 months of application approval. If the applicant fails to demonstrate the operability within 24 months of approval then the application will be canceled. The applicant can reapply for the same station eligible only for 10 years of crediting.

(5) *Calculation of HRI Credits.* HRI credits will be calculated using the following equation:

$$Credits_{HRI}\ (MT) = (CI^{XD}_{standard} \times EER - CI_{HRI}) \times E_{H2} \times \left(Cap_{HRI} \times N \times UT - H2_{disp}\right) \times C$$

where:

$CI^{XD}_{standard}$ is the average carbon intensity requirement of gasoline (XD = “gasoline”) for a given year as provided in sections 95484(b);

EER is the dimensionless Energy Economy Ratio for H2/FCV relative to gasoline as listed in Table 5;

CI_{HRI} is the carbon intensity used for HRI crediting. Company-wide weighted average CI for dispensed hydrogen during the quarter or 0 g/MJ, whichever is greater;

E_{H2} is the energy density for hydrogen in MJ/kg as listed in Table 4;

Cap_{HRI} is the HRI refueling capacity for the station (kg/day);

UT is the the uptime multiplier which is the percentage of time that the station is available as reported to SOSS during the quarter;

$H2_{disp}$ is the quantity of hydrogen dispensed during the quarter (kg);

N is the number of days during the quarter;

C is a factor used to convert credits to units of metric tons from gCO_2e and has the value of:

$$C = 1.0x10^{-6} \frac{(MT)}{(gCO_2e)}$$

(6) *Reporting and Recordkeeping Requirements.* The following must be reported to the Executive Officer each quarter as set forth in section 95491 before credits will be issued to the LRT account associated with an approved HRI pathway.

(A) Station availability. This is the percentage of hours the station is available for fueling during the quarter relative to the permitted hours of operation for the station, as reported to the SOSS. Any period of time that SOSS reports that a portion of the station capacity is not available will count as a pro-rated amount of station availability, proportional to the percentage of the station capacity that remains available for fueling for this period of time.

(B) Company-wide, weighted average renewable content (percent) for dispensed hydrogen.

(C) Cost and revenue data. Provide a quarterly account of the following costs borne and revenues received by the station owner up through the most recent reporting quarter per station.

1. Total capital expenditures ($)

2. Total delivered cost ($) of hydrogen and average delivered cost ($/kg) for hydrogen

3. Total maintenance costs ($)

4. Total land rental cost ($)

5. Total grant revenue or other external funding received towards capital expenditures ($)

6. Total grant revenue or other external funding received towards operational and maintenance expenditures ($)

7. Total revenue ($) received from sale of hydrogen and average retail price ($/kg) for hydrogen sold

8. Other operational expenditures ($)

~~(7) *Applications for Expanded HRI Refueling Capacity.* Station owners who expand the capacity of a station and that is already generating HRI credits under the LCFS must submit an application to the Executive Officer to generate additional credits based on the updated capacity. Applications for expanded station capacity must be received before December 31,~~

~~2025 and do not extend the effective date range for the HRI crediting specified upon initial project approval in 95486.2(a)(3)(D). The application must include the following elements.~~

~~(A) In order to be eligible to generate HRI credits for expanded capacity, the station owner must demonstrate that station throughput in a reporting quarter is greater than or equal to 50 percent of the original approved HRI refueling capacity.~~

(7) ~~Updated~~ *Transition to Light-Duty Hydrogen Refueling Infrastructure (LD-HRI) Pathways.* Beginning January 1, 2026, a light-duty hydrogen station owner or designee may submit an application to certify an LD-HRI pathway. The LD-HRI pathway retains the requirements of the HRI pathway described in section 95486.2(a)(1-6), with the following amendments effective January 1, 2026:

(A) Subsection 95486.2(a)(1)(A) is amended. The proposed LD-HRI station must be located in California in a disadvantaged community, low-income community, or rural area and open to the public.

(B) Subsection 95486.2(a)(1)(B) is amended. The proposed LD-HRI pathway application must be received on or before December 31, 2030.

(C) Subsection 95486.2(a)(2)(E) is amended. The station nameplate refueling capacity ~~and updated HRI~~ for the permitted hours of operation calculated using the HyCap model or an equivalent model or capacity estimation methodology approved by the Executive Officer. The applicant must submit a completed model with the application.

~~(B)~~(D) Subsection 95486.2(a)(2)(F) is amended. The LD-HRI refueling capacity for the station is one-half the nameplate refueling capacity determined in subsection (C) above or 600 kg/day, whichever is less.

~~(C) If the sources of hydrogen and delivery methods stated in the original HRI application will change as a result of the added capacity, the station owner must disclose the new hydrogen sources and delivery methods.~~

~~(D) The station owner must maintain records demonstrating that any new equipment added as a result of the expansion in capacity, including storage and fueling dispensers, meet the requirements listed in 95486.2(a).~~

(E) Subsection 95486.2(a)(2)(J) is removed.

(F) Subsection 95486.2(a)(3)(A) is amended. If estimated potential LD-HRI credits from all approved stations exceed 0.5 percent of deficits in the most recent quarter data is available, the Executive Officer will not approve additional LD-HRI pathways and will not accept additional applications until estimated potential LD-HRI credits are less than 0.5 percent of deficits. LD-HRI potential credits are calculated separately from HRI potential credits described in this section.

(G) Subsection 95486.2(a)(3)(E) is amended. LD-HRI crediting is limited to 10 years starting with the quarter of Executive Officer approval of the application.

(H) Subsection 95486.2(a)(4)(G) is amended. If the applicant fails to demonstrate the operability within 24 months of approval and if the estimated potential LD-HRI credits exceed 0.5 percent of deficits in the most recent quarter for which deficit data is available, then the application will be canceled. The applicant may submit a new application for the same station the following quarter. The estimated value of LD-HRI credits, for the purpose of this determination, shall be calculated using the number of LD-HRI credits generated for the station in the quarter and the average LCFS credit price for that quarter published on the LCFS website.

(I) Subsection 95486.2(a)(4)(H) is added. The estimated cumulative value of LD-HRI credits generated for the station in the prior quarter must be less than the difference between 1.5 times the initial capital expenditure and the sum of total grant revenue or other external funding received towards capital, operational and maintenance expenditures in the prior quarter, reported pursuant to section 95486.2(a)(6)(C).

(J) Subsection 95486.2(a)(6)(C) is amended. Provide an annual account of the following costs borne and revenues received for the station. The cost and revenue account must be included in the annual report submitted pursuant to section 95491.

(K) Subsection 95486.2(a)(6)(C)1. is amended to include a breakdown of initial capital expenditure by equipment, labor, materials, fees and land ($). Costs for working capital and off-site facilities are not included.

(b) *DC Fast Charging Infrastructure (FCI) Pathways*.

(1) *FCI Pathway Eligibility.* An FSE owner or their designate identified in subsection 95483(c)(2)(B) may submit an application to receive an FCI pathway subject to the following eligibility conditions:

(A) The proposed FSE must be located in California and open to the public for charging.

~~(B) Upon an individual applicant's estimated potential FCI credits, calculated pursuant to section 95486.2(b)(3)(B), exceeding 0.5 percent of the deficits in the prior quarter, each additional site applied for by the applicant must meet the following requirements:~~

~~1. Charging equipment at the site must support at least two of the following three fast charging connectors: CHAdeMO, SAE CCS, and/or Tesla;~~

~~2. The site must have at least one FSE with a CHAdeMO connector protocol and at least one FSE with an SAE CCS connector protocol; and~~

~~3. No more than three-quarters of all FSE subject to this provision at the site can support only a single fast charging connector protocol.~~

~~(C)~~(B) The FCI pathway application must be received on or before December 31, 2025.

~~(D)~~(C) The following FSE are not eligible for FCI crediting:

1. Any FSE that is permitted to operate prior to January 1, 2019; or

2. Any FSE receiving or spending funds pursuant to any settlement related to any California or Federal regulation enforcement; or

3. Any FSE built as a required mitigation measure pursuant to the California Environmental Quality Act.

~~(E)~~(D) Each FSE must have a minimum nameplate power rating of 150 kW.

~~(F)~~(E) Each FSE must be networked and capable of monitoring and reporting its availability for charging.

(2) *FCI Application Requirements.* The applicant must submit an application in the LRT-CBTS containing the following information:

(A) Name and address of the owner of the proposed FSE.

(B) Contact person for the owner entity.

1. Name

2. Title or position

3. Phone number

4. Mobile phone number

5. Email address

(C) Name, street address, latitude, longitude and a location description for each proposed FSE site.

(D) The number of FSEs.

(E) The nameplate power rating (kW), connector type(s), and model for each FSE.

1. The total nameplate power rating for all FSE at a single site claiming FCI credit under this provision cannot exceed 2,500 kW.

~~2. Notwithstanding 95486.2(b)(2)(E)1 above, upon request the Executive Officer may approve an application with total nameplate power rating for all FSE at a single site up to 6,000 kW. The total number of FSE at sites with total nameplate power rating greater than 2,500 kW cannot exceed 10 percent of total FSE approved under FCI pathways. The applicant must provide justification for requesting a total power rating greater than 2,500 kW at the given site.~~

(F) The effective simultaneous power rating (kW) for each FSE calculated using the equation below. The effective simultaneous power rating must be at least 50 percent of the nameplate power rating for each FSE.

$$P_{Sim}^{i} = P_{NP}^{i} \times \frac{P_{Sim}^{Tot}}{\sum_{i=1}^{n} P_{NP}^{i}}$$

where:

P_{Sim}^{i} is the simultaneous power rating (kW) for FSE i;

P_{NP}^{i} is the nameplate power rating (kW) for FSE i;

P_{Sim}^{Tot} is the maximum total power (kW) that can be delivered to all FSEs at a single site when they are operated simultaneously; and

n is the number of FSEs at a single site.

(G) The FCI charging capacity for each FSE calculated using the following equation:

$$Cap_{FCI}^{i} = 43 \times (P_{FCI}^{i})^{0.45}$$

where:

Cap_{FCI}^{i} is the FCI charging capacity (kWh/day) for the FSE i; and

P_{FCI}^{i} is the nameplate power rating for the FSE or 350 kW, whichever is less.

(H) Expected date that the FSE will be operational.

(I) Expected daily permitted hours of operation for the site. If the daily permitted hours are less than 24 hours, the applicant must provide documentation from a permitting authority demonstrating that daily permitted hours for the FSE are limited.

(J) A signed attestation letter from the applicant attesting to the veracity of the information in the application packet. The attestation letter must be submitted as an electronic copy, be on company letterhead, be signed by an officer of the applicant with authority to attest to the veracity of the information in the application and to sign on behalf of the applicant, be from the applicant and not from an entity representing the applicant (such as a consultant or legal counsel), and include the following attestation:

I, an authorized representative of _______________ (proposed FSE owner entity), attest to the veracity of the information submitted as part of the DC Fast Charging Infrastructure (FCI) application, attest that the proposed FSE is not receiving funds pursuant to any enforcement settlement related to any California or Federal regulation, and declare that the information submitted accurately represents the anticipated and intended design and operation of the charging infrastructure. Further, I understand and agree to each of the statements in the attached application. I am a duly authorized officer with authority to attest to the veracity of the information in the application and to sign on behalf of the respective applicant.

I understand that the following information in the FCI application will be made available on the LCFS ~~web site~~website: Name of the Applicant Entity, Site Name, Site Address, Number and Type of Charging Units, Nameplate and Effective Simultaneous Power Rating for Each Unit, and Effective Date Range for FCI Crediting

By submitting this application, ____(applicant entity) accepts responsibility for the information herein provided to CARB. I certify under penalty of perjury under the laws of the State of California that I have personally examined, and am familiar with, the statements and information submitted in this document. I certify that the statements and information submitted to CARB are true, accurate, and complete.

(K) CBI must be designated pursuant to the requirements described in section 95488.8(c).

(L) An application and supporting documents must be submitted electronically via the LRT-CBTS unless the Executive Officer has approved or requested in writing another format.

(3) *Application Approval Process.*

(A) The FCI application must be approved by the Executive Officer before the applicant may generate FCI credits. If estimated potential FCI credits from all approved FSEs exceed 2.5 percent of deficits in the prior quarter, the Executive Officer will not approve additional FCI pathways and will not accept additional applications until FCI credits are less than 2.5 percent of deficits. FCI applications will be evaluated for approval on a first come, first served basis.

Estimated potential FCI credits will be calculated using the following equation:

$$Credits_{FCI}^{Potential} = Credits_{FCI}^{Prior\ qtr} \times \frac{Cap_{FCI}^{Approved}}{Cap_{FCI}^{Operational}}$$

where:

$Credits_{FCI}^{Potential}$ means the estimated potential FCI credits from all approved FSEs;

$Credits_{FCI}^{Prior\ qtr}$ means the total FCI credits generated by operational FSEs in the prior quarter;

$Cap_{FCI}^{Operational}$ means the total FCI charging capacity of FSEs that were operational in the prior quarter; and

$Cap_{FCI}^{Approved}$ means the total FCI charging capacity of all approved FSEs, both operational and nonoperational.

(B) The estimated potential FCI credits for an individual applicant will be calculated using the same equation as in subsection (A) above, where:

$Credits_{FCI}^{Potential}$ means the estimated potential FCI credits from the applicant's approved FSEs;

$Credits_{FCI}^{Prior\ qtr}$ means the total FCI credits generated by the applicant for operational FSEs in the prior quarter;

$Cap_{FCI}^{Operational}$ means the total FCI charging capacity of the applicant's FSEs that were operational in the prior quarter; and

$Cap_{FCI}^{Approved}$ means the total FCI charging capacity of all of the applicant's approved FSEs, both operational and nonoperational.

(C) After receipt of an application designated by the applicant as ready for formal evaluation, the Executive Officer shall advise the applicant in writing either that:

1. The application is complete, or

2. The application is incomplete, in which case the Executive Officer will identify which requirements of section 95486.2(b)(2) have not been met.

   a. The applicant may submit additional information to correct deficiencies identified by the Executive Officer.

   b. If the applicant is unable to achieve a complete application ~~within 180 days~~during the quarter of the Executive Officer's receipt of the original application, the application will be denied on that basis, and the applicant will be informed in writing. The applicant may submit a new application for the station.

3. At any point during the application evaluation process, the Executive Officer may request in writing additional information or clarification from the applicant.

(D) The Executive Officer shall not approve an application if the Executive Officer determines, based upon the information submitted in the application and any other available information, that the application does not meet requirements in subsections 95486.2(b)(1) and (b)(2). If the Executive Officer does not approve the application, the applicant will be notified in writing and the basis for the disapproval shall be identified.

(E) If the Executive Officer determines the application has met all requirements for approval pursuant to subsections 95486.2(b)(1) and (b)(2), the Executive Officer will approve the application and provide an approval summary on the LCFS website including the site location and FSE ID, number and type of FSE, nameplate and effective simultaneous power rating for each FSE, and effective date range for FCI pathway crediting.

(F) *Crediting Period.* FCI crediting is limited to 5 years starting with the quarter following Executive Officer approval of the application.

(4) *Requirements to Generate FCI Credits.* To generate credits using FCI pathways the following conditions must be met. The applicant must maintain, and submit to CARB upon request, records demonstrating adherence to these conditions.

(A) The applicant must update the nameplate and effective simultaneous power rating of FSE if different from the power rating provided in the application. Any FSE design or operational information that deviates from the original application must be declared to the Executive Officer, and a new attestation must be submitted using the language in section 95486.2(b)(2).

(B) The FSE must be open to the public, meaning that no obstructions or obstacles exist to preclude vehicle operators from entering the FSE premises, no access cards or personal identification (PIN) codes are required for the FSE to dispense fuel, and no formal or registered equipment training shall be required for individuals to use the FSE.

(C) The FSE that charges a fee for service must be capable of supporting a public point-of-sale method that accepts all major credit or debit cards.

(D) The FSE passed final inspection by the appropriate authority having jurisdiction and has a permit to operate.

(E) The FSE owner has fully commissioned the FSE, and has declared it fit to service retail EV drivers.

(F) The FSE registration must be completed pursuant to section 95483.2(b)(8) and the quantity of dispensed electricity must be reported as required in section 95491.

(G) The FSE must be operational within 12 months of application approval. If the applicant fails to demonstrate the operability within 12 months of approval then the application will be canceled. The applicant can reapply for the same FSE site eligible only for 2 years of crediting.

(H) The estimated cumulative value of FCI credits generated for the FSE in the prior quarter must be less than the difference between the total capital expenditure reported pursuant to section 95486.2(b)(6)(B)1 and the total grant revenue or other funding reported pursuant to section 95486.2(b)(6)(B)5 in the prior quarter.

1. The estimated value of FCI credits, for the purpose of this determination, shall be calculated using the number of FCI credits generated for the FSE in the quarter and the average LCFS credit price for that quarter published on the LCFS website.

2. The cumulative credit value generated for each FSE will be tracked as the sum of all quarterly credit values in constant-dollar for the year in which the FCI application was approved using an annual discount rate of 10%.

3. The estimated value calculated under this provision will be made available only to the respective reporting entity in LRT-CBTS and will not be published on the LCFS website.

4. This will not affect the reporting entity's ability to generate non-FCI LCFS credits for the electricity dispensed at the FSE.

(5) *Calculation of FCI Credits.* FCI credits will be calculated using the following equation for each FSE approved under this provision:

$$Credits_{FCI}\ (MT) = (CI^{XD}_{standard} \times EER - CI_{FCI}) \times C_{Elec} \times \left(Cap^{i}_{FCI} \times N \times UT - Elec_{disp}\right) \times C$$

where:

$CI^{XD}_{standard}$ is the average carbon intensity requirement of gasoline (XD = "gasoline") for a given year as provided in section 95484(b);

EER is the dimensionless Energy Economy Ratio for Electricity/BEV or PHEV relative to gasoline as listed in Table 5;

CI_{FCI} is the California average grid electricity carbon intensity as listed in Table 7-1;

C_{Elec} is the conversion factor for electricity as listed in Table 4;

Cap^{i}_{FCI} is the FCI charging capacity (kWh/day) for the FSE;

N is the number of days during the quarter;

UT is the uptime multiplier which is the fraction of time that the FSE is available for charging during the quarter;

$Elec_{disp}$ is the quantity of electricity dispensed during the quarter (kWh);

C is a factor used to convert credits to units of metric tons from gCO_2e and has the value of:

$$C = 1.0x10^{-6} \frac{(MT)}{(gCO_2e)}$$

(6) *Reporting and Recordkeeping Requirements.* The following must be reported to the Executive Officer each quarter as set forth in section 95491 before credits will be issued to the LRT account associated with an approved FCI pathway.

(A) FSE availability. This is the percentage of hours the FSE is available for charging during the quarter relative to the permitted hours of operation for the site.

(B) Cost and revenue data. Provide a quarterly account of the following costs borne and revenues received by the FSE owner up through the most recent reporting quarter per site.

1. Total capital expenditures ($)

2. Total delivered cost ($) of electricity, including demand charges, and average delivered cost ($/kWh) for electricity

3. Total maintenance costs ($)

4. Total land rental cost ($)

5. Total grant revenue or other external funding received towards capital expenditures ($)

6. Total grant revenue or other external funding received towards operational and maintenance expenditures ($)

7. Total revenue ($) received from sale of electricity and average retail price ($/kWh) for electricity sold

8. Other operational expenditures ($)

(7) *~~Applications for Expanded~~ Transition to Light-Duty Fast Charging Infrastructure (LD-FCI ~~Capacity.~~* ~~Applicants who increase the~~*) Pathways.* Beginning January 1, 2026, an FSE owner or designee may submit an application to certify an LD-FCI pathway. The LD-FCI pathway retains the requirements of the FCI pathway, with the following amendments:

(A) Subsection 95486.2(b)(1)(A) is amended. The proposed LD-FCI station must be located in California in a low-income or disadvantaged community, or at least 10 miles from the nearest direct current fast charger open to the public with a nameplate capacity equal to or greater than 150 kW.

(B) Subsection 95486.2(b)(1)(C) is amended. The proposed LD-FCI pathway application must be received on or before December 31, 2030.

(C) Subsection 95486.2(b)(1)(E)1. is amended. The total nameplate power rating ~~of an~~for all FSE ~~or add an FSE to~~at a single site ~~that is already generating~~ claiming FCI credit under this provision cannot exceed 1,000 kW.

(D) Subsection 95486.2(b)(2)(D) is amended. The number of FSEs at an LD-FCI site cannot exceed 4.

(E) Subsection 95486.2(b)(2)(G) is amended. The FCI charging capacity for each FSE calculated using the following equation:

$$Cap^{i}_{MHD-FCI} = 0.2 \times P^{i}_{MHD-FCI} \times 24$$

where:

Cap^{i}_{FCI} is the FCI charging capacity (kWh/day) for the FSE i;

P^{i}_{FCI} is the nameplate power rating for the FSE or 350 kW, whichever is less; and

24 is the number of hours in a day (hr/day)

(F) Subsection 95486.2(b)(3)(A) is amended. If estimated potential LD-FCI credits ~~under the LCFS must submit an application to~~ from all approved stations exceed 0.5 percent of deficits in the most recent quarter data is available, the Executive Officer ~~to generate~~will not approve additional LD-FCI pathways and will not accept additional applications until estimated potential LD-FCI credits ~~based on the increased power or number of FSEs. Applications must be received before December 31, 2025 and do not extend the end date for the~~ are less than 0.5 percent of deficits. LD-FCI potential credits are calculated separately from FCI potential credits described in this section.

(G) Subsection 95486.2(b)(3)(F) is amended. LD-FCI crediting ~~specified upon~~is limited to 10 years starting with the quarter of Executive Officer approval of the application.

(H) Subsection 95486.2(b)(4)(G) is amended. If the applicant fails to demonstrate the operability within 12 months of approval and if the estimated potential LD-FCI credits exceed 0.5 percent of deficits in the most recent quarter deficit data is available, then the application will be canceled. The applicant can submit a new application for the same station the following quarter. The estimated value of LD-FCI credits, for the purpose of this determination, shall be calculated using the number of LD-FCI credits generated for the station in the quarter and the average LCFS credit price for that quarter published on the LCFS website.

(I) Subsection 95486.2(b)(4)(H) is amended. The estimated cumulative value of LD-FCI credits generated for the station in the prior quarter must be less than the difference between 1.5 times the initial ~~project approval in 95486.2(b)(3). The application must~~ capital expenditure, not including on-site generation, and the sum of total grant revenue or other external funding received towards capital, operational and maintenance expenditures in the prior quarter, reported pursuant to section 95486.2(b)(6)(B).

(J) Subsection 95486.2(b)(6)(B) is amended. Provide an annual account of the following costs borne and revenues received for the site. in the owner's annual report. The cost and revenue account must be included in the annual report submitted pursuant to section 95491.

~~(7)~~(K) Subsection 95486.2(b)(6)(B)1. is amended to include ~~the following elements~~a a breakdown of initial capital expenditure by equipment, labor, materials, fees and land ($). Costs for working capital and off-site facilities are not included.

~~(A) Updated number and type of FSE at the site.~~

~~(B) Updated FCI charging capacity, nameplate power rating and effective simultaneous power rating for each FSE at the site.~~

~~(C) The applicant must maintain records demonstrating that any new equipment added as a result of the expansion in capacity meet the requirements listed in 95486.2(b).~~

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95487. Credit Transactions.

(a) *General.* LCFS credits shall not constitute instruments, securities, or any other form of property.

(1) A regulated entity may:

(A) Retain LCFS credits without expiration for use within the LCFS market; and

(B) Acquire or transfer LCFS credits. A third-~~-~~ party, which is not a regulated entity or acting on behalf of a regulated entity, may not hold, purchase, sell, or trade LCFS credits, except as otherwise specified in section 95483.

(2) A regulated entity may not:

(A) Use credits in the LCFS program that are generated outside the LCFS program, including credits generated in other tradeable emission credit programs administered by the California Air Resources Board.

(B) Borrow or use credits from anticipated future carbon intensity reductions to demonstrate compliance pursuant to section 95485(a). This does not preclude contracting for future delivery of LCFS credits as described in section 95487(b)(1)(B), nor participation in the credit clearance market described in section 95485(c).

(C) Generate LCFS credits from fuels exempted from the LCFS under section 95482(d) or are otherwise not eligible pursuant to section 95482.

(D) Sell or transfer credits at a price that exceeds the Maximum Price set by the following formula:

1. \$200/credit ($MTCO_2e$) in 2016.

2. This per credit price shall be adjusted annually by the rate of inflation as measured by the most recently available twelve months of the Consumer Price Index for All Urban Consumers.

   “Consumer Price Index for All Urban Consumers” means a measure that examines the changes in the price of a basket of goods and services purchased by urban consumers, and is published by the U.S. Bureau of Labor Statistics.

3. The Maximum Price will be published on the first Monday of April and go into effect on June ~~1st~~1.

(b) *Credit Transfers between Parties.*

(1) A regulated entity that wishes to sell or transfer credits (“the Seller”) and a regulated entity that wishes to purchase or acquire a credit (“the Buyer”)

may enter into an agreement to transfer credits. Any such agreement must be fully documented in the LRT-CBTS pursuant to section 95487(b)(1)(B) through (F).

(A) *General Requirements for Credit Transfers.* The Seller may transfer credits provided the number of credits to be transferred by the Seller does not exceed the number of total credits in the Seller's credit account defined as follows:

$$Total\ Credits = Credits^{Gen} + Credits^{Aquired} - Sum\ of\,(Credits^{Retired} + Credits^{OnHold} + Credits^{Sold} + Credits^{Exported} + Credits^{CCMPledge})$$

where:

$Credits^{Gen}$, $Credits^{Aquired}$, $Credits^{Retired}$, $Credits^{OnHold}$, $Credits^{Sold}$, $Credits^{Exported}$, and $Credits^{CCMPledge}$ have the same meaning as those in section 95485(b).

(B) The credit transfer request must identify the type of transaction agreement for which the transfer request is being submitted, selecting one of the following types:

1. *Type 1 Transfer*: Over-the-counter agreement for the sale or transfer of LCFS credits for which delivery will take place no more than 10 days from the date the parties enter into the transaction agreement.

2. *Type 2 Transfer*: Over-the-counter agreement for the sale or transfer of LCFS credits for which delivery is to take place more than 10 days from the date the parties enter into the transaction agreement or that involve multiple transfers of LCFS credits over time.

3. *Type 3 Transfer*: Agreements for the sale of LCFS credits through any contract arranged through a clearing service provider.

(C) *For Type 1 Transfer.* Within 10 days from the date the parties enter into the credit transaction agreement, the Seller and the Buyer must initiate and complete the transfer request using the Credit Transfer Form (CTF) provided in the LRT-CBTS. The parties must provide:

1. *Date of Transaction Agreement.* The date on which the Buyer and Seller enter into the credit transaction agreement;

2. Names and the Federal Employer Identification Numbers (FEIN) of the Seller and the Buyer as registered in the LRT-CBTS;

3. First name, last name, and contact information of the Seller and Buyer representative;

4. The number of credits proposed to be transferred; and

5. The price or equivalent value of the consideration (in U.S. dollars) per credit proposed for transfer, excluding any fees.

(D) *For Type 2 Transfer.* Within 10 days from the date the parties enter into the credit transaction agreement, the Seller and the Buyer must report the following using the Credit Transfer Form (CTF) provided in the LRT-CBTS:

1. *Date of Transaction Agreement.* The date on which the Buyer and Seller enter into the credit transaction agreement;

2. Names and the Federal Employer Identification Numbers (FEIN) of the Seller and the Buyer as registered in the LRT-CBTS;

3. First name, last name, and contact information of the Seller and Buyer representative;

4. If the agreement requires a single delivery of credits or multiple deliveries of credits. The Executive Officer may assign reference numbers for reporting future credit transfers under agreements for multiple deliveries of credits;

5. The expected date of last credit delivery or the length of the agreement including the date by which all deliveries are to be completed;

6. The total number of credits anticipated to be transferred under the agreement;

7. The price per credit (in U.S. dollars) or the terms to determine the price for future credit transfer as per the agreement;

8. If the agreement is terminated or amended prior to its full execution as provided in subsection 5. above, the parties must notify the Executive Officer within 10 days; and

9. If the credit transfer is one of multiple deliveries under an agreement previously reported using a CTF, the parties must provide the reference number (if any) assigned by the Executive Officer.

(E) *For Type 3 Transfer.* A credit transfer request submitted for an agreement executed through a clearing service provider must provide the following information:

1. Identify the exchange through which the transaction is conducted;

2. Date of close of trading for the contract;

3. Identify the contract description code assigned by the exchange to the contract;

4. Price at close of trading for the contract;

5. The number of credits in the contract to be transferred; and

6. Date of delivery of LCFS credits covered by the contract.

(F) If the transaction agreement does not specify the price for LCFS credits, the Seller must provide a brief description of the pricing method for the full transaction inclusive of all products and value exchanged. The seller must also select one of the following options:

1. The proposed transfer is to reflect an adjustment in CI value of fuel transacted between Seller and Buyer;

2. The proposed transfer incorporates a credit trade along with the sale or purchase of other product, and does not specify a price or cost basis for the sale of the credits alone.

(G) *Recording a Credit Transfer.* Upon receiving a fully-completed CTF, the Executive Officer shall, either:

1. Process and approve the transfer request and update the account balances of the Seller and Buyer to reflect the credit transfer, provided the Executive Officer determines all required information was submitted, and it accurately reflects the parties' positions at the time of the proposed transfer; or

2. Notify the parties that the proposed credit transfer is infeasible and identify the reasons for rejecting the transfer.

(2) *Facilitation of Credit Transfer.* A Seller or Buyer may elect to use a third-party broker as defined in section 95481 to facilitate the transfer of credits. A broker cannot acquire credits. A broker who will document transfers in LRT-CBTS must register in the LRT CBTS, and the Buyer, Seller, or both must document, using the LRT CBTS, authorization for broker to act on their behalf. A broker may, with the consent of the parties, conduct a "blind transaction" where the Buyer of the credit does not know the identity of the Seller, and/or the Seller of the credit does not know the identity of the Buyer.

(3) *Correcting Credit Transfer Errors.* A regulated entity is responsible for the accuracy of information submitted to the Executive Officer. If a regulated entity discovers an error in the information reported to the Executive Officer or recorded by the Executive Officer, the regulated entity must inform the Executive Officer in writing within five (5) days of the discovery and request a correction. Each submitted request is subject to Executive Officer review and approval. If the Executive Officer determines that the error occurred during the recording of the credit by Board staff, the Executive Officer will make the correction and no additional re-submissions are required.

(c) *Public Disclosure of Credit and Deficit Balances and Credit Transfer Information*.

(1) The Executive Officer shall, no less frequently than quarterly, provide to the public reports containing a summary of credit generation and transfer information including, but not limited to:

(A) Total deficits and credits generated or incurred in the most recent quarter for which data are available, including information on the types and quantities of fuels used to generate credits.

(B) Total deficits and credits generated or incurred in all previous quarters of the most recent year for which data are available, including information on the types and quantities of fuels used to generate credits.

(C) Total credits in regulated entities' accounts and the total number of outstanding deficits carried over by regulated entities from a previous compliance year.

(D) Information on the credits transferred during the most recent quarter for which data is available including the total number of credits transferred, the number of transfers, the number of parties making transfers, and the monthly average credit price for transfers that reported a price.

(2) The Executive Officer shall provide reports, no less frequently than monthly, to regulated entities and the public containing information

necessary or helpful to the functioning of a credit market. Such reports may include recent information on credit transfer volumes, credit prices and price trends, and other information determined by the Executive Officer to be of value to market participants and the public. The Executive Officer shall establish, and may periodically modify, a schedule for the routine release of these reports.

(d) *Prohibited Transactions.* A trade involving, related to, or associated with any of the following is prohibited:

(1) Any manipulative or deceptive device;

(2) A corner or an attempt to corner the market for credits;

(3) Fraud, or an attempt to defraud any other entity;

(4) A false, misleading or inaccurate report concerning information or conditions that affects or tends to affect the price of a credit;

(5) An application, report, statement, or document required to be filed pursuant to this subarticle which is false or misleading with respect to a material fact, or which omits to state a material fact necessary to make the contents therein not misleading. A fact is material if it is reasonably likely to influence a decision by a counterparty, the Executive Officer, the Board, or the Board's staff; or

(6) Any trick, scheme, or artifice to falsify or conceal a material fact, including use of any false statements or representations, written or oral, or documents made by or provided to an entity through which transactions in credits are settled, or are cleared.

(7) Upon investigation pursuant to section 95495, the Executive Officer may cancel or reverse a credit transfer if a credit transfer is determined to be a prohibited transaction as per subsection (1) through (6) above. The Executive Officer shall notify the parties and identify the reasons for cancelling or reversing a credit transfer.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601, and 43018 Health and Safety Code; 42 U.S.C. section 7545, and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95488. Entities Eligible to Apply for Fuel Pathways.

(a) Any person may apply to the Executive Officer for fuel pathway carbon intensity certification for the purpose of credit or deficit generation.

(b) *Joint Applicants.* Multiple entities may contribute site-specific data to a single pathway application. In these cases, the parties involved may either designate a single entity as the pathway applicant, or designate multiple entities as joint applicants on a single pathway. Applying as joint applicants allows each entity to maintain control of confidential data for the portions of the pathway they submit.

(1) Each joint applicant is subject to all requirements for pathway application, attestations, validation and verification, recordkeeping, pursuant to this subarticle, for the portion of the pathway they control.

(2) A single entity designated to submit data on behalf of multiple entities within a pathway does not relieve any other entity in the pathway from responsibility for ensuring that the data submitted on its behalf is accurate.

(c) *Transition to CA-GREET~~3~~4.0.*

(1) *Existing certified pathways.* ~~In the first quarter of 2021~~Fuel pathway holders must use the CA-GREET4.0 model or associated Tier 1 CI Calculators for 2024 annual Fuel Pathway Reports. Upon receiving a positive or qualified positive verification statement for each 2024 annual Fuel Pathway Report, the Executive Officer will ~~deactivate all fuel pathway codes in~~update and adjust the ~~LRT-CBTS~~CIs for ~~fuel pathways that were~~each previously certified ~~pursuant to a prior version of this subarticle, which used the CA-GREET2.0 model to determine CI, for the purpose of~~pathway to be the verified operational CI with an added conservative margin of safety if requested by the pathway holder. The adjusted CIs will be effective and available for reporting for fuel transactions ~~that occurred~~occurring on and after ~~December 31, 2020. Fuel pathway holders seeking to generate credits from these pathways after that date must follow the pathway application and certification process outlined in this subarticle to receive a certified pathway.~~January 1, 2026..

(A) *Existing Lookup Table Pathways.* Fuel reporting entities using Lookup Table pathways that do not require an application pursuant to section 95488.1(b)(1) will be automatically updated in the LRT-CBTS to the values in Table 7-1 on the effective date of this subarticle.

(2) *New Pathway Applications.* ~~Beginning in 2019 or the effective date of this subarticle, new fuel pathway applications using CA-GREET2.0 will not be processed. The requirement to obtain a third-party validation statement is effective for all pathway applications pending or submitted on or after January 1, 2020. All new pathway applications certified in 2019 will be validated by the Executive Officer~~Fuel pathway applications certified with a CI effective date of January 1, 2025 or later must use the CA-GREET4.0 or associated Tier 1 CI Calculators.

NOTE: Authority cited: Sections 38510, 38560, 38560.5, 38571, 38580, 39600, 39601 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95488.1. Fuel Pathway Classifications.

(a) For purposes of fuel pathway carbon intensity determination, all new LCFS fuel pathways certified after January 1, 2019 (or the effective date of this regulation) shall be classified as either a:

(1) Lookup Table pathway;

(2) Tier 1 pathway; or

(3) Tier 2 pathway, as described below.

(b) *Lookup Table Classification.* Pathways falling under this classification are the simplest pathways to use. The Board's staff develops Lookup Table pathway CI values using the CA-GREET~~3~~4.0 model. Input variables and assumptions are provided in the ~~CA-GREET3.0 Lookup Table Pathways --~~ Technical Support Documentation ~~(August 13, 2018),~~for Lookup Table Pathways [Date of adoption], which is incorporated herein by reference.

(1) *Lookup Table Pathways That Do Not Require a Fuel Pathway Application.* The following pathways are developed using average values for inputs into the CA-GREET~~3~~4.0 model, which are not expected to vary significantly across providers of the fuel. Entities seeking to generate credits under the pathways listed in 95488.1(b)(1)(A) through (E) may report fuel transactions directly in the LRT-CBTS without taking any action in the AFP.

(A) California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB)

(B) California Ultra-low Sulfur Diesel (ULSD)

(C) Fossil Jet Fuel

~~(C)~~(D) Compressed Natural Gas

~~(D)~~(E) Fossil Propane

~~(E)~~(F) Electricity (California average grid)

(2) *Lookup Table Pathways That Require a Fuel Pathway Application.* Fuel pathway applicants for the following Lookup Table pathways must register

in the AFP and meet the application requirements of section 95488.5(b). Fuel pathway applicants may then report fuel transactions in the LRT-CBTS for the fuel pathways listed in 95488.1(b)(2)(A) through (~~F~~B).

(A) Electricity (100 percent zero-CI sources, which include: eligible renewable energy resources as defined in California Public Utilities Code sections 399.11-399.36, excluding biomass, biomethane, geothermal, and municipal solid waste)

(B) Electricity associated with smart charging pathway for EV charging and smart electrolysis pathway for hydrogen production through electrolysis

~~(C) Hydrogen (gaseous and liquefied) from central SMR of North American fossil-based natural gas~~

~~(D) Hydrogen (gaseous and liquefied) from central SMR of biomethane~~

~~(E) Hydrogen (gaseous) from electrolysis using California grid-average electricity~~

~~(F) Hydrogen (gaseous) from electrolysis using electricity from a zero-CI source as defined in (A) above~~

(c) *Tier 1 Classification.* The Tier 1 pathway classification applies to fuel pathway categories that the Board's staff has extensive experience evaluating. This classification includes fuel pathways for which the Executive Officer has identified a discrete set of site-specific inputs that can be modified to achieve CI changes. CI values for Tier 1 fuel pathways are determined using Board-approved ~~Simplified~~Tier 1 CI Calculators. The ~~Simplified~~Tier 1 CI Calculators provide a framework for applicants to enter monthly operational data inputs that are combined with emission factors and life cycle inventory data from the CA-GREET~~3~~4.0 model to calculate the pathway CI. The Tier 1 classification includes, but is not limited to, the following fuel pathways:

(1) Ethanol derived from starch or fiber in corn kernels or grain sorghum, and sugarcane;

(2) Biodiesel produced from feedstocks including but not limited to oilseed crop-derived oils; rendered animal fat, distiller's corn oil, distiller's sorghum oil, and used cooking oil;

~~(3)~~ Renewable ~~Diesel~~diesel, renewable naphtha, alternative jet fuel and renewable propane produced by hydrotreatment of feedstocks in a stand-alone reactor, including ~~but not limited to~~ oilseed crop-derived oils, rendered ~~tallow~~animal fat, distiller's corn oil, distiller's sorghum oil, and used cooking oil~~;~~

~~(4)~~(3) ~~LNG and L-CNG from North American fossil natural gas;~~, also known as Hydroprocessed Ester and Fatty Acid (HEFA) Fuels;

~~(5)~~(4) Biomethane from North American landfills, anaerobic digestion of wastewater sludge, dairy and swine manure, and food, urban landscaping waste, and other organic waste~~.~~; and

(5) Hydrogen produced from steam methane reforming of methane and electrolysis.

(d) *Tier 2 Classification.* The Tier 2 pathway classification shall apply to fuel pathways that the Board's staff has limited experience evaluating and certifying, including fuel pathways that are not currently in widespread commercial production. The Tier 2 classification includes all fuel pathways not included in Tier 1 or the Lookup Table pathways. The Tier 2 classification includes, but is not limited to the following fuel pathways:

(1) Cellulosic alcohols;

(2) Biomethane from sources other than those listed under the Tier 1 classification in (c)(5), above;

~~(3) Hydrogen pathways not found in the Lookup Table;~~

~~(4)~~(3) Electricity pathways not found in the Lookup Table;

~~(5)~~(4) Drop-in fuels (~~renewable~~biomass-derived hydrocarbons using processes such as gasification and pyrolysis and synthetic hydrocarbons) except for renewable ~~diesel~~hydrocarbon fuels produced from feedstocks described in section 95488.1(c)(3). This category includes fuels produced from low carbon feedstocks co-processed with fossil feedstocks in petroleum refineries;

~~(6)~~(5) Any fuel produced from unconventional feedstocks, such as algae oil;

~~(7)~~(6) Pathways classified as Tier 1 that are produced using innovative production methods. Innovative production methods include, but are not limited to:

(A) Use of one or more low-CI process energy sources.

(B) Use of carbon capture to produce an alternative fuel or carbon capture and sequestration where CO_2 capture occurs at the fuel production facilities. (Projects that utilize carbon capture and sequestration are subject to the provisions of section 95490).

(C) Pathways classified as Tier 1 that cannot be accurately modeled using the ~~Simplified~~Tier 1 CI Calculators.~~ Such pathways must meet the substantiality requirements of 95488.9(a).~~

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95488.2. Relationship Between Pathway Registration and Facility Registration.

After establishing an account in the Alternative Fuels Portal, per the requirements of section 95483.2(a), fuel pathway applicants must begin the application process by completing the facility and pathway registration through the AFP web portal. The provisions of 95488.2 do not apply to entities seeking to report fuel transactions for the fuel pathways listed in 95488.1(b)(1).

(a) *Production and Intermediate Facility Registration.* All production facilities and intermediate facilities from which site-specific operational data is relied upon in determining the CI score for a pathway must be registered in the AFP. All of the following fields that apply are required:

(1) Production company name and full mailing address.

(2) U.S. EPA Company ID for fuels covered by the federal RFS program. For fuels not covered by the RFS program, the AFP system will generate a Company ID.

(3) Company contact person's contact information.

(A) Name

(B) Title or position

(C) Phone number

(D) Mobile phone number

(E) Email address

(F) Company ~~web site~~website URL

(4) The fuel production facility name and address, for each proposed pathway.

(A) For biomethane to vehicle fuel pathways, the fuel production facility is the upgrading facility that purifies or otherwise produces biomethane that meets the applicable standards for pipeline or vehicle-quality natural gas.

(5) The names and addresses of any intermediate facilities, for each proposed pathway.

(A) For biomethane to vehicle fuel pathways, intermediate facilities that must be registered include the liquefaction facility, and the location where biogas or other biomethane feedstock is produced, if that location is not also the upgrading facility that is registered as the fuel production facility.

(B) For any feedstock whose supplier applies using site-specific CI data, the feedstock-processing facility must be registered as an intermediate facility for the fuel pathway in which the feedstock is utilized.

(6) U.S. EPA Facility ID for fuels covered by the federal RFS program. For fuels not covered by the RFS program, the Executive Officer will assign a Facility ID.

(7) Facility geographical coordinates (for each facility covered by the proposed pathways). Coordinates can be reported using either the latitude and longitude or the Universal Transverse Mercator coordinate systems.

(8) Facility contact person's contact information.

(A) Name

(B) Title or position

(C) Phone number

(D) Mobile phone number

(E) Email address

(9) Facility nameplate production capacity, or maximum expected throughput, in million gasoline gallon equivalents per year or other appropriate units. This information is required for each facility contributing site-specific data to the proposed pathways, including intermediate facilities in the supply chain.

(b) *Pathway Registration.* All of the following fields that apply are required.

(1) Consultant's contact information

(A) Name

(B) Title or position

(C) Legal company name

(D) Phone number

(E) Mobile phone number

(F) Email address

(G) ~~Web site~~Website URL

(2) Fuel type (renewable diesel, ethanol, etc.)

(3) Feedstock

(4) Brief pathway description (one to two sentences describing the technology, transport mode, and any non-standard co-products)

(5) Proposed pathway carbon intensity value

(6) Estimated annual fuel production quantity under the proposed pathway (estimated minimum, maximum, and average), in the applicable units specified for reporting in 95491(d)(1) through (5).

(7) *Classification.* The fuel pathway applicant must declare whether the proposed fuel pathway falls under the Lookup Table, Tier 1 or Tier 2 provisions of this regulation as specified in section 95488.1. The Executive Officer will evaluate the fuel pathway applicant's classification declaration and either approve or change it.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95488.3. Calculation of Fuel Pathway Carbon Intensities.

(a) *Calculating Carbon Intensities.* Fuel pathway applicants and the Executive Officer will evaluate all pathways based on life cycle greenhouse gas emissions per unit of fuel energy, or carbon intensity, expressed in gCO_2e/MJ. For this analysis, the fuel pathway applicant must use CA-GREET~~3~~4.0 model (including the ~~Simplified~~Tier 1 CI Calculators derived from that model) or another model determined by the Executive Officer to be equivalent or superior to CA-~~-~~-GREET~~3~~4.0~~.~~-.

(b) *CA-GREET~~3~~4.0.* The CA-GREET~~3~~4.0 model ~~(August 13, 2018)~~[Date of adoption] contains emission factors for calculating greenhouse gas emissions from site-specific inputs to fuel pathways and standard values for parts of the life cycle not included in applicant-specific data submission. The model is open source and publicly available at ~~http://www~~https://ww2.arb.ca.gov/~~fuels~~resources/documents/lcfs/~~lcfs.htm~~ life-cycle-analysis-models-and-documentation and is incorporated herein by reference. CA-GREET~~3~~4.0 includes contributions from the Oil Production Greenhouse Gas Estimator (~~OPGEE2.0~~OPGEE) model (for emissions from crude extraction) and Global Trade Analysis Project (GTAP-BIO) together with the Agro-Ecological Zone Emissions Factor (AEZ-EF) model for land use change (LUC).

Tier 1 ~~Simplified~~ CI Calculators, which incorporate emission factors and life cycle inventory data from the CA-GREET~~3~~4.0 model, are used to calculate carbon intensities for Tier 1 pathways. The ~~eight Simplified~~nine Tier 1 CI Calculators listed below are publicly available at ~~http://www~~https://ww2.arb.ca.gov/~~fuels~~resources/documents/lcfs/~~lcfs.htm~~ life-cycle-analysis-models-and-documentation and are incorporated herein by reference:

(1) Tier 1 ~~Simplified~~ CI Calculator for ~~Starch and Fiber*~~Corn or Sorghum Ethanol ~~(August 13, 2018)~~[Date of adoption]

(2) Tier 1 ~~Simplified~~ CI Calculator for Sugarcane~~-derived~~ Ethanol ~~(August 13, 2018)~~[Date of adoption]

(3) Tier 1 ~~Simplified~~ CI Calculator for Biodiesel ~~and Renewable Diesel (August 13, 2018)~~[Date of adoption]

(4) Tier 1 ~~Simplified~~ CI Calculator for ~~LNG and L-CNG from North American Natural Gas (August 13, 2018)~~Hydroprocessed Ester and Fatty Acid (HEFA) Fuels [date of adoption]

(5) Tier 1 ~~Simplified~~ CI Calculator for Landfill Biomethane ~~from North American Landfills (August 13, 2018)~~[Date of adoption]

(6) Tier 1 ~~Simplified~~ CI Calculator for ~~Biomethane from Anaerobic Digestion of~~ Wastewater Sludge ~~(August 13, 2018)~~Biomethane [Date of adoption]

(7) Tier 1 ~~Simplified CI Calculator~~CICalculator for ~~Biomethane from Anaerobic Digestion of~~ Dairy and Swine Manure ~~(August 13, 2018)~~Biomethane [Date of adoption]

(8) ~~Tier 1 Simplified~~Tier 1 CI Calculator for Organic Waste Biomethane [Date of adoption]

~~(8)~~(9) Tier 1 CI Calculator for ~~Biomethane from Anaerobic Digestion of Organic Waste (August 13, 2018)~~Hydrogen [Date of adoption]

(c) ~~*OPGEE2.0*~~*OPGEE*. The ~~OPGEE2.0~~OPGEE model is used to generate carbon intensities for crude oil used in the production of ultra-low sulfur diesel (ULSD) and California Reformulated Gasoline Blendstock for Oxygenate Blending (CARBOB).

(d) *Accounting for Land Use Change.* The Executive Officer calculates LUC effects for certain crop-based biofuels using the GTAP model (modified to include agricultural data and termed GTAP-BIO) and the AEZ-EF model. LUC values for six feedstock/finished biofuel combinations are provided in Table 6 below. The Executive Officer may use the same modeling framework to assess LUC values for other fuel or feedstock combinations, not currently found in Table 6, as part of processing a pathway application. Alternatively, the Executive Officer may require a fuel pathway applicant to use one of the values in Table 6, if the Executive Officer deems that value appropriate to use for a fuel or feedstock combination not currently listed in Table 6.

Table 6. Land Use Change Values for Use in CI Determination

Biofuel	***LUC (gCO_2/MJ)***
Corn Ethanol	19.8
Sugarcane Ethanol	11.8
Soy Biomass-Based Diesel	29.1
Canola Biomass-Based Diesel	14.5
Grain Sorghum Ethanol	19.4
Palm Biomass-Based Diesel	71.4

~~* Fiber in this case refers to corn and grain sorghum fiber exclusively.~~

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95488.4. Relationship of Pathway Carbon Intensities to Units of Fuel Sold in California.

(a) LCFS CIs represent the life cycle greenhouse gas emissions, expressed in a per-megajoule of finished-fuel energy basis, associated with long-term, steady-state fuel production operations. Actual CIs vary over time due to a variety of factors, including but not limited to seasonality, feedstock properties, plant maintenance, and unplanned interruptions and shutdowns. A fuel production operation will not be found to be in violation of its certified pathway based on CI unless a CI calculated from production data covering 24 months of operations is higher than the certified CI reported for that fuel in the LRT-CBTS system~~. A fuel pathway applicant~~ and the fuel pathway holder fails to satisfy an applicable deficit obligation for a verified CI exceedance specified in 95486.1(g). A fuel pathway holder may add a conservative margin of safety, of a magnitude determined by the applicant, to increase the certified CI above the operational CI calculated based on the data submitted in the initial fuel pathway application, to account for potential process variability and diminish the risk of non-compliance with the certified CI. Fuel producers labeling fuel sold in California with LCFS CIs (in product transfer or similar documents), and fuel reporting entities using those CIs to report the fuel in the LRT-CBTS system, must ensure that the fuel so labeled and so reported will be found to have a life cycle CI, as calculated from production data covering 24 months of operation, that is equal to or less than the CIs reported in the LRT-CBTS system and on product transfer documents. Fuel reporting entities shall not report fuel sales under any LCFS CI unless the actual CI of that fuel, calculated as described in this subarticle, is equal to or less than the LCFS CI under which sales of that fuel are reported in the LRT-CBTS system.

(b) *General Rule.* Except as provided in subdivision (c) below, fuel producers and fuel reporting entities covered by this regulation order must associate a CI with each unit of fuel sold in California. In general, fuel producers and fuel reporting entities shall assign all units of fuel produced while a given set of production parameters is in effect the same CI, regardless whether those units will be sold in California. For example, where a producer uses both biogas and natural gas as process fuel, the producer shall assign all units produced a single CI that reflects the mix of process fuels used to produce those units; the producer shall not assign the units destined for the California market a CI associated only with the use of biogas.

A producer or fuel reporting entity may assign a different certified CI only when one or more production parameters changes. Following that change, all units produced while the new set of production parameters is in effect have the new CI, regardless of whether those units will be sold in California.

(c) *Exceptions.* Under the following two sets of conditions, a producer or fuel reporting entity may assign different CIs to portions of the fuel produced while a given set of production parameters is in effect. Those conditions are:

(1) Two or more feedstocks are being simultaneously fed into the production process. For example, a renewable diesel production facility may feed a mixture of soy oil, ~~tallow~~animal fat, and used cooking oil into its production

process. Or a hydrogen production facility may use both natural gas and renewable natural gas as feedstock for steam methane reformation.

(2) Two or more co-products are being produced simultaneously. For example, a corn ethanol plant may dry only a portion of the distiller's grains it produces; a portion of the distiller's grains produced is sold dry, and the remainder is sold wet.

(d) *How to Use the Multiple Feedstock Exception.* When two or more feedstocks are being simultaneously fed into the production process, the producer or fuel reporting entity shall associate a portion of the fuel produced with each feedstock, using the production facility's average production yield and one of the methods provided in section 95491(d)(1)(C). The producer or fuel reporting entity must then label each feedstock-specific subdivision of the total fuel quantity produced with the certified CI associated with that feedstock.

(e) *How to use the Multiple Co-Product Exception.* When two or more co-products are being simultaneously produced, the producer or fuel reporting entity may label the fuel associated with those co-products one of two ways:

(1) If the production facility has available to it a single CI reflective of the current set of operational conditions (including the production of two or more co-products, in the proportions currently being produced), the producer or fuel reporting entity may label the facility's entire production run with that CI.

(2) If the production facility has available to it separate CIs associated with the production of each co-product, the producer or fuel reporting entity may label portions of the fuel produced with the certified CIs associated with each co-product, in proportion to the co-product stream fraction that each co-product comprises. The producer or fuel reporting entity shall calculate the co-product proportions on an appropriate basis to conform to the life cycle approach used for the fuel pathway.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95488.5. Lookup Table Fuel Pathway Application Requirements and Certification Process.

(a) *Applicability.* A fuel reporting entity may use a Lookup Table pathway if the Lookup Table (Table 7-1 in section 95488.5(e)) contains a fuel pathway that closely corresponds to the actual physical fuel production pathways used to produce the fuel in question. A fuel's actual physical fuel production pathway corresponds closely with a Lookup Table pathway when it is consistent with the Lookup Table pathway in all the areas listed in (1) through (6) below:

(1) Feedstocks used to produce the fuel;

(2) Fuel and feedstock production technology;

(3) Regions in which feedstocks and finished fuel are produced;

(4) The modes used to transport feedstocks and finished fuel and the transport distances involved;

(5) The types and amounts of thermal and electrical energy consumed in both feedstock and finished fuel production. This applies both to the energy consumed in the production process and to the upstream energy consumed (e.g., fuels used to generate electricity; energy consumed to produce natural gas, etc.); and

(6) The CI of the fuel pathway applicant's product must be lower than or equal to the Lookup Table pathway CI. If the Executive Officer determines the product has an actual CI that is likely to be higher than the Lookup Table CI value, the applicant may apply for a Tier 2 pathway.

(b) *Lookup Table Pathway Application Requirements.* Entities seeking approval to report fuel transactions using the fuel pathways listed in 95488.1(b)(2)(A) through (~~F~~B) (electricity generated from one of the zero-CI sources listed in 95488.1(b)(2)(A~~),~~) and smart charging or smart electrolysis~~, and all hydrogen Lookup Table pathways)~~ must submit the fuel pathway applicant attestation letter pursuant to the requirements of 95488.8(a) and meet the following requirements:

(1) The following information must be submitted with applications for the Lookup Table pathway for electricity generated from zero-CI sources and smart charging or smart electrolysis:

(A) For directly supplied zero-CI electricity, an applicant must indicate the locations of electricity generation equipment, meters, meter ID numbers, and identify any other users of the electricity.

(B) For zero-CI electricity supplied using book-and-claim accounting, contracts and invoices are required to demonstrate that the electricity meets the requirements of section 95488.8(i)(1).

(C) For smart charging or smart electrolysis electricity, records demonstrating the quantity of electricity dispensed during each hour for the latest quarter.

~~(2) The following information shall be submitted with applications for any hydrogen Lookup Table pathways:~~

~~(A) Submittal of the fuel pathway applicant attestation letter affirms that the applicant has reviewed and understood the pathway conditions described in the Lookup Table Pathways -- Technical Support Documentation specified in section 95488.5(e), and attests that their actual physical pathway is consistent with the Lookup Table pathway in the areas listed in 95488.5(a). Any exceptions, whether likely to result in a higher or lower CI, must be noted in the attestation letter.~~

~~(B) The completed NREL National Fuel Cell Technology Evaluation Center's Hydrogen Station Infrastructure Data Template covering three months of operation, if available, is required.~~

~~(3) The following information must be submitted with all Lookup Table pathway applications for renewable hydrogen:~~

~~(A) Contracts and invoices meeting the requirements of 95488.8(h), or 95488.8(i), are required to substantiate type and source of renewable input used to produce the fuel.~~

(c) *Completeness Check for Lookup Table Fuel Pathway Applications.* For the Lookup Table pathways listed in 95488.1(b)(2)(A) through (F), the Executive Officer will evaluate submitted information for completeness. The Executive Officer shall contact the applicant regarding any lack of required information or clarification of submitted information. If the fuel pathway applicant does not provide a satisfactory response to address the request within ~~15 business~~14 days, the Executive Officer will reject the pathway application. Applicants whose applications are rejected may submit a new application that addresses deficiencies highlighted during the earlier review.

(d) *Updates to Electricity Pathways.*

(1) *Annual Update to California Average Grid Electricity Pathway.* In order to reflect the rapidly evolving portfolio of electricity generating resources in California, the Executive Officer will update the "California Average Grid Electricity Used as a Transportation Fuel in California" Lookup Table pathway CI value on an annual basis. The Executive Officer will use the methodology described in the supporting document specified in section 95488.5(e) to determine the carbon intensity. The CA-GREET~~3~~4.0 model inputs and data sources used to calculate the CI will be posted for 45 days for public comment prior to certification. If these comments require significant revision of the originally published pathway, an updated pathway will be posted for public comment. The updated Lookup Table pathway CI value will be available for reporting in the quarter in which it is certified.

(2) *Update to Smart Charging Electricity Pathways.* In order to reflect the seasonal variation of electricity generating resources in California and to maintain accounting consistency with the CI of the California Average Grid Electricity pathway, the Executive Officer will use the methodology described in the supporting document specified in section 95488.5(e) and the public comment process described in 95488.5(d)(1) to update the smart charging or smart electrolysis pathway CIs in Table 7-2.

(e) ~~The following supporting document, which is incorporated herein by reference~~The Technical Support Documentation for Lookup Table Pathways, describes the methodology and data sources used to determine the carbon intensity values for the fuel pathways, shown below in Table 7-1, and the hourly windows for smart charging or smart electrolysis electricity pathways, shown below in Table 7-2:

~~Industrial Strategies Division, California Air Resources Board. August 13, 2018. CA-GREET3.0 Lookup Table Pathways Technical Support Documentation.~~

Table 7-1. Lookup Table for Gasoline and Diesel and Fuels that Substitute for Gasoline and Diesel[2]

Fuel	***Fuel Pathway Code***	***Fuel Pathway Description***	***Carbon Intensity Values (gCO_2e/MJ)***
CARBOB	CBOB	CARBOB -- based on the average crude oil supplied to California refineries and average California refinery efficiencies	100.~~82~~60
Diesel	ULSD	ULSD -- based on the average crude oil supplied to California refineries and average California refinery efficiencies	~~100.45~~105.76
Fossil Jet Fuel	FJF	Fossil Jet Fuel – based on the average crude oil supplied to California refineries and average California refinery efficiencies	89.43
Compressed Natural Gas	CNGF	Compressed Natural Gas from Pipeline Average North American Fossil Natural Gas	~~79.21~~81.18
Propane	PRPF	Fossil LPG from crude oil refining and natural gas processing used as a transport fuel	~~83.19~~81.43
	ELCG	California average grid electricity used as a transportation fuel in California	~~93.75~~81.00 (and subject to annual updates)

Fuel	***Fuel Pathway Code***	***Fuel Pathway Description***	***Carbon Intensity Values (gCO_2e/MJ)***
Electricity	ELCR	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	0.00
	ELCT	Electricity supplied under the smart charging or smart electrolysis provision	(See Table 7-2)
~~Hydrogen~~	~~HYF~~	~~Compressed H2 produced in California from central SMR of North American fossil-based NG~~	~~117.67~~
	~~HYFL~~	~~Liquefied H2 produced in California from central SMR of North American fossil-based NG~~	~~150.94~~
	~~HYB~~	~~Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills~~	~~99.48~~
	~~HYBL~~	~~Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills~~	~~129.09~~
	~~HYEG~~	~~Compressed H2 produced in California from electrolysis using California average grid electricity~~	~~164.46~~
	~~HYER~~	~~Compressed H2 produced in California from electrolysis using zero-CI electricity~~	~~10.51~~

[2] For comparison on an equivalent basis (gCO_2e per MJ of conventional fuel displaced), the CIs listed in Tables 7-1 and 7-2 must be divided by the EER in Table 5 for the appropriate fuel-vehicle combination. The EER-adjustment is made when fuel quantities are reported in the LRT-CBTS to calculate the correct number of credits or deficits, using the equations in 95486.1(a).

(f) *Smart Charging or Smart Electrolysis Lookup Table Pathways.* The Executive Officer will calculate the following carbon intensity lookup table that may be used for reporting electric vehicle charging and hydrogen produced via electrolysis in California. For hydrogen production through electrolysis outside of California, an applicant must provide, through the Tier 2 application process, a comparable method to determine smart electrolysis carbon intensity values for the grid electricity in the state or region where hydrogen is produced.

Updates to this table will be provided at least annually on the LCFS ~~web site~~website.

Table 7-2. Calculated Smart Charging or Smart Electrolysis Carbon Intensity Values for ~~2019~~[3]2023 (in $gCO2_e$/MJ)[3]

Hourly Window	~~*CI (gCO_2e/MJ)*~~*Q1*	*Q2*	*Q3*	*Q4*
	~~*Q1*~~	~~*Q2*~~	~~*Q3*~~	~~*Q4*~~
12:01 AM – 1:00 AM	87.~~06~~10	~~86~~87.91	~~86.87~~90.85	~~90.25~~96.66
1:01 AM – 2:00 AM	87.~~06~~07	~~85.91~~86.06	~~86~~87.80	~~88.55~~92.47
2:01 AM – 3:00 AM	87.~~06~~07	~~87.20~~86.01	~~86.77~~87.22	~~87.80~~90.37
3:01 AM – 4:00 AM	87.~~06~~07	~~87.03~~85.97	~~86.72~~87.00	~~87.91~~89.92
4:01 AM – 5:00 AM	87.~~63~~07	~~91.45~~87.23	~~87.17~~86.89	~~90.98~~91.86
5:01 AM – 6:00 AM	~~94.46~~92.55	~~105.76~~95.80	~~95.77~~88.86	~~105.08~~103.53
6:01 AM – 7:00 AM	~~110.98~~115.61	94.~~28~~41	~~92.09~~100.56	~~122.40~~126.80
7:01 AM – 8:00 AM	~~105.79~~114.77	~~2.48~~30.13	~~88.39~~96.61	~~109.22~~125.28
8:01 AM – 9:00 AM	~~86.35~~67.61	~~1.96~~2.44	~~89.39~~61.03	~~94.27~~103.11
9:01 AM – 10:00 AM	~~58.66~~2.20	~~2.92~~1.79	~~91.09~~7.52	~~90.26~~40.37
10:01 AM – 11:00 AM	~~57.80~~0.44	~~50.25~~3.20	~~93.23~~13.08	~~89.84~~44.00
11:01 AM – 12:00 PM	~~56.52~~0.00	~~53.31~~50.34	~~97.87~~21.99	~~91.17~~8.07
12:01 PM – 1:00 PM	~~55.97~~0.00	~~55.12~~53.57	~~104.23~~2.43	~~92.03~~9.63
1:01 PM – 2:00 PM	~~56.50~~0.00	~~58.67~~55.54	~~110.13~~45.52	~~93.36~~12.02
2:01 PM – 3:00 PM	~~56.53~~30.00	~~63.57~~59.30	~~115.76~~55.97	~~95.25~~42.69
3:01 PM – 4:00 PM	~~57.80~~30.37	~~26.45~~64.33	~~123.91~~105.71	~~104.30~~80.03
4:01 PM – 5:00 PM	~~92.45~~67.27	~~48.57~~27.72	~~131.52~~111.19	~~136.96~~131.76
5:01 PM – 6:00 PM	~~125.85~~110.22	~~120.79~~32.27	~~146.52~~137.65	~~156.40~~153.57
6:01 PM – 7:00 PM	~~144.90~~145.35	~~151.38~~80.02	~~155.70~~151.04	~~153.00~~156.76
7:01 PM – 8:00 PM	~~127.62~~140.29	~~150.96~~155.69	~~140.27~~158.23	~~141.37~~152.26
8:01 PM – 9:00 PM	~~114.50~~129.66	~~122.63~~156.76	~~118.35~~149.31	~~130.78~~144.86
9:01 PM – 10:00 PM	~~95.55~~108.04	~~93.62~~132.49	~~100.45~~127.34	~~115.22~~130.02
10:01 PM – 11:00 PM	~~88.25~~93.39	~~88.12~~100.05	~~91.21~~108.58	~~102.03~~115.45
11:01 PM – 12:00 AM	87.~~07~~53	89.87~~.12~~	~~88.57~~96.60	~~93.34~~100.98

[3] Based on 20~~19~~23 marginal emission rates determined using the Avoided Cost Calculator (May 2018)~~, which is incorporated herein by reference.~~).

(g) *Executive Officer Review of CI Selection.* A fuel reporting entity's choice of carbon intensity value from the Lookup Table is subject in all cases to Executive Officer review. The Executive Officer may request any documentation necessary to determine that the pathway conforms to the Lookup Table pathway.

(1) If the Executive Officer has reason to believe that a fuel reporting entity's Lookup Table choice is not the CI value that most closely corresponds to its actual pathway CI, the Executive Officer shall notify the entity through the LRT-CBTS to choose a different pathway from the Lookup Table; or

(2) If the Executive Officer has reason to believe that the Lookup Table does not contain a fuel pathway that closely corresponds with the actual fuel pathway, the Executive Officer will notify the entity accordingly and the fuel reporting entity will not be allowed to use the Lookup Table to

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generate credits or deficits. In that case, the entity may apply for a Tier 1 or Tier 2 pathway.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95488.6. Tier 1 Fuel Pathway Application Requirements and Certification Process.

(a) *Documentation Required for Tier 1 Pathways.* A fuel pathway applicant may apply for a Tier 1 pathway using the provisions set forth in this section. After satisfying all requirements for pathway and facility registration in 95488.2, the applicant must submit the following information to the Executive Officer for consideration of a Tier 1 pathway CI.

(1) *~~Simplified~~Tier 1 CI Calculator.* A fuel-specific ~~Simplified~~Tier 1 CI Calculator populated with all applicable site-specific operational data inputs is required. The period covered shall be the most recent 24~~-~~-month period of operation~~.~~ or at least three months of operation for provisional fuel pathway applications. Tier 1 applications must not have an interval of greater than 3 months between the end of the reported operational data month and the date of submission. Fields that require site-specific inputs are marked in the ~~Simplified~~Tier 1 CI Calculator. Site-specific inputs include, but are not limited to, the monthly quantity of all feedstocks consumed in the fuel production facility, the electricity generation mix of the subregion(s) where feedstock and fuel production occur, the types and monthly quantities of all energy used in the production of the fuel, and the monthly quantities of fuel produced.

(A) The ~~Simplified~~Tier 1 CI Calculators include appropriate LUC or other indirect carbon intensity modifiers from Table 6 when applicable.

(B) Applicants must follow the instructions for completing site-specific inputs in the ~~Simplified~~Tier 1 CI Calculators found in the Tier 1 ~~Simplified~~ CI Calculator Instruction Manuals. . The Tier 1 CI Calculator Instruction Manuals listed below are publicly available at https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation~~Manual (August 13, 2018),~~ and are herein incorporated ~~herein~~ by reference~~.~~:

1. ~~Industrial Strategies Division, California Air Resources Board. August 13, 2018.~~ Tier 1 ~~Simplified~~ CI Calculator for

Corn or Sorghum Ethanol - Instruction Manual~~.~~ [date of adoption]

2. Tier 1 CI Calculator for Sugarcane Ethanol - Instruction Manual [date of adoption]

3. Tier 1 CI Calculator for Biodiesel - Instruction Manual [date of adoption]

4. Tier 1 CI Calculator for Hydroprocessed Ester and Fatty Acid (HEFA) - Instruction Manual [date of adoption]

5. Tier 1 CI Calculator for Landfill Biomethane - Instruction Manual [date of adoption]

6. Tier 1 CI Calculator for Wastewater Sludge Biomethane - Instruction Manual [date of adoption]

7. Tier 1 CI Calculator for Dairy and Swine Manure Biomethane - Instruction Manual [date of adoption]

8. Tier 1 CI Calculator for Organic Waste Biomethane - Instruction Manual [date of adoption]

9. Tier 1 CI Calculator for Hydrogen - Instruction Manual [date of adoption]

(C) All applicants using grid electricity must choose electrical generation energy mixes from among the subregions in CA~~-~~-GREET~~3~~4.0 and the ~~Simplified~~Tier 1 CI Calculators, if applicable. The options include the 26 subregions defined in the U.S. EPA~~'~~'s Emissions and Generation Resource Integrated Database with year 20214 data (~~eGRID2014v2, released on February 27, 2017~~eGRID2021, January 30, 2023), and a national grid mix for Brazil and Canada.

1. *User-defined Process Energy Option.* Applicants whose fuel production facilities or feedstock source regions are located in an area for which there is no corresponding subregion included in the ~~Simplified~~Tier 1 CI Calculator may select the user-defined option, and shall consult with the Executive Officer for approval of the data prior to submitting an application.

(2) *Supplemental Information.* Supporting evidence for specified inputs to the CI calculator can be uploaded to the AFP as a supplemental information

document, as needed. Supplemental information is required under the following circumstances:

(A) If an alternative form of process energy supplied directly to the production facility are used, evidence must be provided to identify the source, to demonstrate that it is delivered directly to the production facility, and to determine the carbon intensity of the process energy input.

(B) If the fuel pathway applicant selects user-defined emission factors for regions not currently included in the ~~Simplified~~Tier 1 CI Calculator, to reflect the grid electricity resource mix, crude and natural gas for that region. Supporting evidence and data sources for these emission factors must be provided.

(C) If the fuel produced or any by-products or co-products receive additional processing after they leave site, such as additional distiller's grains drying or fuel distillation, supporting evidence of the energy consumed for those processes must also be submitted.

(D) If the fuel production facility is co-located with one or more unrelated facilities, and energy consumption data (or other data required in calculating CI) are not separately available for the fuel production facility, the applicant shall install automated metering equipment with electronic data archival to enable an Executive Officer accredited verification body to confirm energy consumption data for the 24 months of operation submitted in the application. The metering should be capable of recording daily total energy consumption data. The same requirements apply if a single facility includes multiple operations including fuel production.

(E) Other information to facilitate staff review may also be included as part of the supplemental information.

(b) *Certification Process for Tier 1 Pathway Applications*.

(1) *Validation.* The applicant must seek the services of an Executive Officer accredited verification body to complete a pathway validation as specified in section 95500. A positive or qualified positive validation statement must be received by the Executive Officer from the verification body in order for CARB's completeness review, evaluation, and certification of the pathway application to proceed. In cases where a single applicant or a joint applicant does not complete validation, the application will be denied without prejudice. In cases where ~~an applicant cannot complete~~ validation cannot be completed within six months of ~~submitting an~~the verification body receiving the application from CARB or an applicant receives an adverse validation statement, the application will be denied without

prejudice. Fuel pathway applicants whose applications are denied without prejudice may submit new applications with the most current operational data pursuant to section 95488.6(a)(1).

(2) *Completeness Review.* Upon receipt of a positive or qualified positive validation statement, the Executive Officer will conduct a completeness review of the Tier selection to ensure the pathway meets the requirements for Tier 1, and evaluate if the inputs to the ~~Simplified~~Tier 1 CI Calculator are complete.

(A) *Application Complete*. If the Executive Officer deems complete the applicant's ~~Simplified~~Tier 1 CI Calculator and supplemental information, the fuel pathway applicant shall be notified as such. The application deemed complete quarter is the quarter in which the application is returned by the verification body to the Executive Officer after the completion of validation with a positive or qualified positive statement.

(B) *Application Incomplete.* If the Executive Officer deems the ~~Simplified~~Tier 1 CI Calculator and supplemental information incomplete, the Executive Officer will reject the pathway application without prejudice and inform the fuel pathway applicant of the rationale for rejection. Applicants whose applications are rejected may submit a new application that addresses deficiencies highlighted during the earlier review.

(3) *Certification.* The Executive Officer may certify or reject a pathway application.

(A) The Executive Officer will evaluate the application to determine whether it has met all requirements necessary for certification. At any point during the evaluation process, the Executive Officer may request in writing additional information or clarification from the applicant.

(B) If the Executive Officer determines the application has met all requirements necessary for certification, the Executive Officer will complete a pathway summary of the inputs, the facility average fuel production yield, CI results, and any applicable limitations or conditions. Upon certification of a Tier 1 application, the pathway will be available for reporting for the quarter in which it was deemed complete.

(C) Upon certification, the fuel pathway applicant(s) becomes the fuel pathway holder(s) for the certified fuel pathway and is subject to the requirements of 95488.10, and any limitations or conditions identified by the Executive pursuant to (3)(B) above, in order for that pathway to remain eligible for reporting and credit generation purposes.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95488.7. Tier 2 Fuel Pathway Application Requirements and Certification Process.

(a) *Documentation Required for Tier 2 Pathways.* A fuel pathway applicant may apply for a Tier 2 pathway using the provisions set forth in this section. After satisfying all requirements for pathway and facility registration in 95488.2, the applicant must submit the following information to the Executive Officer for consideration of a Tier 2 pathway CI:

(1) *CA-GREET Model.* A copy of the CA-GREET~~3~~4.0 spreadsheet prepared for the life cycle analysis of the proposed fuel pathway. Tier 2 pathway carbon intensities must be calculated using the CA-~~GREET3.0 model, with the most current 24 months of operational data~~GREET4.0 model, unless the Executive Officer has approved the use of a method or model that the Executive Officer has determined is at least equivalent to the calculation methodology used by CA-~~GREET3.0. The CA-GREET3~~GREET4.0. The data period covered shall be the most current 24-month period of operation or at least three months of operation for provisional pathway applications. Tier 2 applications must not have an interval of greater than 3 months between the end of the operational data month and the date of submission. The CA-GREET4.0 model shall include appropriate LUC or other indirect carbon intensity modifier from Table 6 when applicable.

(2) *Life Cycle Analysis Report.* A life cycle analysis report that describes the full fuel life cycle, and describes in detail the calculation of the fuel pathway CI. The report shall contain sufficient detail to allow the Board's staff to replicate the CI calculated by the applicant. All inputs to, and outputs from, the fuel production process that contribute to the life cycle CI must be described in the life cycle analysis report. These inputs and outputs must then be fully accounted for in the calculation of the fuel pathway CI. The life cycle analysis report shall include the following information:

(A) A detailed description of the full fuel production process. The description shall include:

1. A description of the full well-to-wheels fuel life cycle, including the locations where each primary step in the fuel

life cycle occurs. This description shall identify where the system boundary was established for the purposes of performing the life cycle analysis on the proposed pathway. The discussion of the system boundary shall be accompanied by a schematic depicting the system boundary. That schematic shall show all feedstock and fuel production units that are included in the system boundary, as well as all material and energy flows across the system boundary. Any feedstock or fuel production units that have been excluded from the system must be shown on the schematic, and must be explicitly discussed in the narrative description of the full fuel life cycle.

2. A description of all fuel production feedstocks used, including all pre-processing to which feedstocks are subject. For fuels utilizing agricultural crops for feedstocks, the description shall include the agricultural practices used to produce those crops. This discussion shall cover energy and chemical use, typical crop yields, feedstock harvesting, transport modes and distances, storage, and pre-processing (such as drying or oil extraction).

3. A description of all material inputs to the production process not covered in 2, above. These include, but are not limited to enzymes, nutrients, chemicals, catalysts, and microorganisms.

4. A description of the transportation modes used throughout the fuel life cycle. This discussion must identify origins and destinations, cargo carrying capacities, fuel shares, and the distances traveled for each transport mode.

5. A description of all facilities and process units involved in the production of fuel under the proposed pathway.

6. A list of all combustion-powered equipment, along with their respective capacities, sizes, or rated power, and type and amount of fuel combusted, throughout all phases of the fuel life cycle over which the fuel pathway applicant exercises control.

7. A quantitative discussion of the thermal and electrical energy consumption that occurs throughout all phases of the fuel life cycle over which the applicant exercises control. All fuels used (natural gas, biogas, coal, biomass, etc.) must be identified and use rates quantified. The regional electrical energy generation fuel mix used in the CA~~-~~-GREET~~3~~4.0

analysis must be identified. Internally generated power such as cogeneration and combined heat and power must also be described. All fuel pathway applicants using grid electricity must choose electrical generation energy mixes from among the subregions in CA-~~-~~GREET~~3~~4.0, if applicable. The options include the 26 subregions defined in eGRID20~~14v~~21, and a national grid mix for Brazil and Canada. Applicants whose fuel production facilities or feedstock source regions are located in an area for which there is no corresponding subregion included in CA-GREET~~3~~4.0 must enter user-defined energy resources and submit the source of the data utilized to the Executive Officer for approval.

8. A description of all co-products, byproducts, and waste products associated with production of the fuel. That description shall extend to all processing, such as drying of distiller's grains, applied to these materials after they leave the fuel production process, including processing that occurs after ownership of the materials passes to other parties. Moreover, if a co-product credit is claimed for a co- or by-product, that credit must reflect all post-fuel-production processing steps covered by this section. If a co-product (e.g., electricity) is exported across the fence line, details of the quantity of energy transferred on a daily basis must be monitored using data systems with electronic archival.

(B) A detailed description of the calculation of the pathway CI. This description must provide clear, detailed, and quantitative information on process inputs and outputs, energy consumption, greenhouse gas emissions generation, and the final pathway carbon intensity, as calculated using CA-GREET~~3~~4.0. Important intermediate values in each of the primary life cycle stages shall be shown. Those stages include but are not limited to feedstock production and transport; fuel production, fuel transport, and dispensing; co-product production, transport and use; waste generation, treatment and disposal; and fuel use in a vehicle. This description shall include, at a minimum:

1. A table showing all CA-GREET~~3~~4.0 input values entered by the applicant. The worksheet, row, and column locations of the cells into which these inputs were entered shall be identified. In combination with the modifications identified in subsection (B)2. below, this table shall enable the Executive Officer to enter the reported inputs into a copy of CA-GREET~~3~~4.0 and to replicate the carbon intensity results reported in the application.

2. A detailed discussion of all modifications other than those covered by subsection (B)1. above, made to the CA-~~-~~GREET~~3~~4.0 spreadsheet. This discussion shall allow the Executive Officer to duplicate all such modifications and, in combination with the inputs identified in subsection (B)1. above, replicate the carbon intensity results reported in the application.

3. Documentation of all CA-GREET~~3~~4.0 values used in the carbon intensity calculation process.

4. A detailed description of all supporting calculations that were performed outside of the CA-GREET~~3~~4.0 spreadsheet.

(C) Descriptions of all co-located facilities, which in any way utilize outputs from, or provide inputs to, the fuel production facility. Such co-located facilities include but are not limited to cogeneration facilities, facilities that otherwise provide heat or electrical energy to the fuel production process, facilities that process or utilize co-products such as distillers grains with solubles, and facilities which provide or pre-process feedstocks or thermal energy fuels. If energy is supplied to the fuel production facility by a co-located cogeneration plant and that plant also supplies energy to other facilities, those other facilities must be identified and described. For facilities that are co-located with other production facilities or utilize multiple processing operations in addition to fuel production, demonstration of energy use should conform to section 95488.6(a)(2)(D).

(D) A list of references covering all information sources used in the preparation of the life cycle analysis. All reference citations in the application shall include standard in-text parenthetical citations stating the author's last name and date of publication. Each in-text citation shall correspond to complete publication information provided in the list of references. Complete publication information shall at a minimum, identify the author(s), title of the referenced document (and of the article within that document, if applicable), publisher, publication date, and pages cited. For internet citations, the reference shall include the universal resource locator (URL) address of the citation, as well as the date the ~~web site~~website was last accessed.

(E) One or more process flow diagrams that, singly or collectively, depict the complete fuel production process. Each piece of equipment or stream appearing on the process flow diagram shall include data on its energy and materials balance, along with any other critical information such as operating temperature, pH, rated capacity, etc.

(F) A copy of the federal Renewable Fuel Standard (RFS) Third Party Engineering Review Report required pursuant to 40 CFR part 80.1450, if available. If the RFS engineering report is not available, the Life Cycle Analysis Report shall explain why it is not available.

(G) A copy of the federal Renewable Fuel Standard (RFS) Fuel Producer Co-products Report as required pursuant to 40 CFR 80.1451(b)(1)(ii)(M)-(N), if available.

(3) *Tier 2 Pathways for EER-Adjusted Carbon Intensity.* Applicants supplying fuel for a transportation application that is not included in Table 5 may apply for an EER-adjusted carbon intensity for reporting and credit generation purposes.

(A) *Documentation Requirements.* To request an EER-adjusted carbon intensity, the applicant must provide the following in addition to subsections (1) and (2) above:

1. A letter of intent to request an EER-adjusted CI and why the EER values provided in Table 5 do not apply.

2. Supplemental information including a detailed description of the methodology used, all assumptions made, and all data and references used for calculation of the proposed EER-adjusted CI value. The methodology used must compare the useful output from the alternative fuel technology to that of comparable conventional fuel technology.

3. If the applicant plans to use a Lookup Table pathway to request an EER-adjusted CI then subsections (1) and (2) above do not apply.

(b) *Scientific Defensibility.* For a proposed Tier 2 pathway to be certifiable by the Executive Officer, the fuel pathway applicant must demonstrate that the life cycle analysis prepared in support of the pathway application is scientifically defensible in the Executive Officer's best engineering and scientific judgment.

For purposes of this regulation, “scientifically defensible” means the method for calculating the fuel's carbon intensity may rely on, but is not limited to, publication of the proposed pathway in a major, well-established and peer-reviewed scientific journal (e.g., the International Journal of Life Cycle Assessment; The Journal of Cleaner Production, Biomass and Bioenergy).

(c) *Documents for Public Review.* Section 95488.8(c) contains requirements for submittal of documents that contain confidential business information and redacted versions for posting to a public LCFS ~~web site~~website. Public information including emissions data, must not be redacted.

(d) *Certification Process for Tier 2 Pathway Applications*.

(1) *~~Completeness~~Pre-validation Review.* The Executive Officer will evaluate the LCA Report, CA-GREET~~3~~4.0 model, and all submitted documentation for completeness in order to conduct a comprehensive evaluation of the pathway application and confirm that the methods presented are appropriate from an LCA perspective and confirm that the fuel pathway application meets the requirements for the Tier 2 classification. The Executive Officer may contact the fuel pathway applicant for an explanation of any questionable inputs, methods or lack of information in the application. The applicant must respond and address the request within ~~15 business~~14 days, as provided in subsection (1)(B) below:

(A) *Application ~~Complete.~~Ready for Validation.* If the Executive Officer deems the Tier 2 application and LCA report ~~complete and appropriate~~ready for validation, the applicant will be notified accordingly and provided with a list of site-specific inputs required for validation. The fuel pathway applicant must ~~then~~ seek the services of an Executive Officer accredited verification body for validation as specified in section 95500 before the application can be accessed by the verification body in LRT-CBTS.

(B) *Application ~~Incomplete.~~not Ready for Validation.* If the Executive Officer deems the Tier 2 application ~~incomplete~~not ready for validation, and the applicant does not provide a satisfactory response to address the deficiencies within ~~15 business~~14 days, the Executive Officer will reject the pathway application without prejudice and inform the applicant of the rationale for rejection. Fuel pathway applicants whose applications are rejected may submit a new application with the most current operational data pursuant to section 95488.7(a)(1) that addresses deficiencies highlighted during the earlier review.

(2) *Site-specific Inputs.* Tier 2 pathways are expected to be unique with no predetermined life cycle analysis profile; therefore, such pathways do not include a defined set of predetermined site-specific inputs that are required to be provided in the annual Fuel Pathway Report and must be verified. The Executive Officer shall identify all site-specific inputs for a Tier 2 pathway and make this available for review by the fuel pathway applicant. This includes any non-numerical parameters or conditions which must be checked by the verifier. The applicant has ~~15 business~~14 days to review and accept the Executive Officer's proposed site-specific inputs. If there is disagreement, the applicant may suggest modified site-specific inputs within this period. The Executive Officer will review the

applicant's suggested inputs and present to the applicant a final list of site-specific inputs. The applicant then has 7~~ business~~ days to accept the updated site-specific inputs. If the applicant disagrees with the final list of site-specific inputs, the applicant may withdraw the pathway application; if not withdrawn, the application will be rejected by the Executive Officer. The Executive Officer~~'~~'s decision regarding the final list of site-specific inputs for Tier 2 pathways is binding.

(3) *Validation.* A positive or qualified positive validation statement must be received by the Executive Officer from the verification body in order for CARB~~'~~'s evaluation and certification of the pathway application to proceed. The application deemed complete quarter is the quarter in which the application is returned by the verification body to the Executive Officer after the completion of validation with a positive or qualified positive statement. In cases where a single applicant or a joint applicant does not complete validation, the application will be denied without prejudice. In cases where ~~an applicant cannot complete ~~validation cannot be completed within six months of ~~submitting an~~the verification body receiving the application~~,~~ from CARB or an applicant receives an adverse validation statement, the application will be denied without prejudice. Fuel pathway applicants whose applications are denied without prejudice may submit new applications with the most current operational data pursuant to section 95488.7(a)(1).

(4) *Engineering Review.* The Executive Officer has the authority to request any supporting documentation to investigate specific inputs in the fuel pathway applicant's submitted CA-GREET~~3~~4.0 model. The Executive Officer will evaluate all applications against the following criteria:

(A) The Executive Officer will attempt to replicate the applicant's carbon intensity calculations. Replication will proceed as follows:

1. Starting with a copy of CA-GREET~~3~~4.0 that has not previously been used for calculations associated with the proposed pathway, the Executive Officer will enter all the inputs reported by the applicant.

2. The Executive Officer will then apply all CA-GREET~~3~~4.0 modifications reported by the applicant.

3. If the Executive Officer is able to duplicate the applicant's results, the Executive Officer will proceed to subsection (B) below. If the Executive Officer is not able to duplicate the applicant's CA-GREET~~3~~4.0 results, the application shall be denied.

(B) The Executive Officer will evaluate the validity of all inputs and methods not directly related to energy consumption used to calculate the applicant's CI. If any of those inputs are found to be invalid, the application will be denied.

(C) The Executive Officer will complete a pathway summary containing the site-specific inputs, the facility average fuel production yield, CI results, and any applicable limitations or conditions. The pathway summary, with CBI redacted, will be posted to the LCFS ~~web site~~website for public review.

(5) *Public Comment Period.* The application package, containing the Executive Officer's pathway summary and the documents prepared by the applicant for public review, will be posted to the LCFS ~~web site~~website for public comment once the Executive Officer completes a final check of the pathway application to ensure it has met all requirements for certification.

(A) Comments will be accepted for ~~10 business~~14 days following the date on which the application was posted. Only comments related to potential factual or methodological errors will require responses from the fuel pathway applicant. The Executive Officer will forward to the applicant all comments identifying potential factual or methodological errors. In response, the applicant must either:

1. Make revisions to its application that respond to the comments received and submit those revisions to the Executive Officer. The revised application packet must include a detailed discussion of the revisions made. The discussion must clearly delineate how each comment is related to a responsive revision. The revisions submitted must be approved by the Executive Officer before the application can be certified;

2. Submit a detailed written response to the Executive Officer explaining why no revisions are necessary. The response submitted by the fuel pathway applicant must be approved by the Executive Officer before the application can be certified;

3. As specified in subsection 1, revise portions of the application in response to a subset of the comments received, and, as specified in subsection 2., submit a written response explaining why the remaining comments do not warrant revisions; or

4. Withdraw the application.

(B) The Executive Officer will evaluate the fuel pathway applicant's responses to the comments received, and determine whether they have adequately addressed the potential factual or methodological errors identified in those comments. If deemed adequate, those responses will be posted to the LCFS ~~web site~~website, and the pathway (revised as needed) will be certified and posted to the LCFS ~~web site~~website. If the applicant fails to submit responses or the responses are deemed inadequate, the application will be denied.

(C) If no public comments are received, the application will be certified and posted to the LCFS ~~web site~~website.

(6) *Certification.* The Executive Officer may certify or reject a pathway application. Upon certification of a Tier 2 application, the pathway will be available for reporting for the quarter in which it was deemed complete. Upon certification, the fuel pathway applicant(s) becomes the fuel pathway holder(s) for the certified fuel pathway and is subject to the requirements of 95488.10 in order for that pathway to remain eligible for reporting and credit generation purposes.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95488.8. Fuel Pathway Application Requirements Applying to All Classifications.

(a) *Requirements for Attestation Letter.* Each fuel pathway application must include a fuel pathway applicant attestation letter. The attestation letter must attest to the veracity of the information in the application packet and declare that the information submitted accurately represents the long-term, steady state operation of the fuel production process described in the application packet. The attestation letter must conform to the requirements of this subsection. The fuel pathway applicant attestation letter must make the following specific attestations:

(1) No products, co-products, by-products, or wastes undergo additional processing, such as drying, distillation, or clean-up, once they leave the production facility, except as explicitly included in the pathway life cycle analysis and pathway CI.

(2) All data and information supplied is true and accurate in all areas, including, but not limited to the following:

(A) Feedstocks used to produce the fuel;

(B) Fuel and feedstock production technology;

(C) Regions in which feedstocks and finished fuel are produced;

(D) Modes used to transport feedstocks and finished fuel and the transport distances involved;

(E) Types and amounts of thermal and electrical energy consumed in both feedstock and finished fuel production;

(F) Full life cycle carbon intensity, which must be no higher than the carbon intensity specified in the Lookup Table, or Tier 1 or Tier 2 application; and

(G) Fuel production operations.

(3) The signed LCFS fuel pathway applicant attestation letter must:

(A) Be submitted as an electronic copy;

(B) Be on company letterhead;

(C) Be signed by an officer of the applicant with the legal authority to attest to the veracity of the information in the application and to sign on behalf of the applicant;

(D) Be from the applicant and not from an entity representing the applicant (such as a consultant or legal counsel); and

(E) Include the following attestation:

I certify that the current fuel production process used to produce __________ (fuel) at the __________ facility is consistent in all of the following areas with all information submitted to CARB in connection with the pathway request: 1) feedstocks used in fuel production; 2) fuel and feedstock production technology; 3) geographic region in which feedstocks and finished fuel are produced; 4) transportation modes used to transport feedstocks and finished fuel and transport distances; 5) types and amounts of thermal and electrical energy consumed in both feedstock and finished fuel production; and 6) any other applicable fuel pathway standard or operating condition established by CARB. The carbon intensity (CI) of the fuel must be no higher than the CI for the certified FPC.

I understand that the following facility information will be posted on the LCFS ~~web site~~website: Facility Name, Facility Address, Company ID, Facility ID, Fuel Pathway Code(s), CI values, and Fuel Pathway Description(s).

By submitting this form, ____(Fuel Pathway Applicant) accepts responsibility for the information herein provided to CARB. I certify under penalty of perjury under the laws of the State of California that I have personally examined, and am familiar with, the statements and information submitted in this document. I certify that the statements and information submitted to CARB are true, accurate, and complete.

_____________________________ _____________________________ _________

Signature Print Name & Title Date

(b) If the Executive Officer at any time determines that a certified fuel pathway does not meet the requirements of this subarticle or the operational conditions specified in the pathway summary issued by the Executive Officer, the Executive Officer may revoke or modify the certification.

(c) *Designation of Confidential Business Information.* The definition of "confidential business information," for the purposes of this section, is the same as the definition of "trade secret" found in Government Code, section 6254.7. All documents (including spreadsheets and other items not in a standard document format) that are designated to contain confidential business information (CBI) must prominently display the phrase "Contains Confidential Business Information" above the main document title and in a running header. Additionally, a separate, redacted version of such documents must also be submitted. The redacted versions must be approved by the applicant for public posting on ~~LCFS web site. Specific redactions must be replaced with the phrase "Confidential business information has been redacted by the applicant." This phrase~~the LCFS website. The redaction must be displayed clearly wherever CBI has been redacted. If the applicant claims that information it submits is confidential, it must also provide contact information required by California Code of Regulations, title 17, section 91011.

(d) *Public Disclosure of Application Materials and Use of Application Materials in the LCFS Data Management System.*

(1) All information not identified as trade secrets are subject to public disclosure pursuant to California Code of Regulations, title 17, sections 91000 through 91022 and the California Public Records Act (Government Code §§ 6250 et seq.); and

(2) If the application is certified by the Executive Officer, the carbon intensity value(s) and its associated fuel pathway code(s) will be posted publicly on the LCFS ~~web site~~website and incorporated into the LCFS Data Management System for use by fuel reporting entities.

(e) *Submittal Formats.*

(1) An application, supporting documents, and all other relevant data or calculation or other documentation must be submitted electronically via the AFP unless the Executive Officer has approved or requested in writing another format.

(2) The fuel pathway applicant must not convert spreadsheets, including CA-GREET~~3~~4.0 spreadsheets, into other file formats or otherwise take steps to prevent the Executive Officer from examining all values and calculations in those spreadsheets.

(f) *Additional Demonstrations.* Upon request from the Executive Officer, a fuel pathway application must meet the following requirements:

(1) Demonstrate that the fuel that will be produced under the proposed pathway would comply with all applicable ASTM or other generally recognized national consensus standards; and

(2) Demonstrate that the fuel that will be produced under the proposed pathway is not exempt from the LCFS under section 95482(c).

(g) *Specified Source Feedstocks*.

(1) *Pathways Utilizing a Specified Source Feedstock.* In order to be eligible for a reduced CI that reflects the lower emissions or credit associated with the use of a waste, residue, by-product or similar material as feedstock in a fuel pathway, fuel pathway applicants must meet the following requirements.

(A) *Specified source feedstocks include:*

1. Used cooking oil, animal fats, fish oil, yellow grease, distiller's corn oil, distiller's sorghum oil, brown grease, and other fats/oils/greases that are the non-primary products of commercial or industrial processes~~ for food, fuel or other consumer products, which are used as feedstocks in pathways for biodiesel, renewable diesel, alternative jet fuel, and co-processed refinery products~~;

2. Biomethane supplied using book-and-claim accounting pursuant to section 95488.8(i)(2) and is claimed as feedstock in pathways for bio-CNG, bio-LNG, bio-L-CNG, and hydrogen via steam methane reformation;

3. Small-diameter, non-merchantable forestry residues removed for the purpose of forest fire fuel reduction or forest stand improvement and from a treatment where no-clear cutting occurred; Municipal solid waste that is diverted from landfill disposal;

~~3.~~4. Any feedstock whose supplier applies for separate CARB recognition using site-specific CI data; and

~~4.~~5. Other feedstocks designated as specified-source at the time of pathway review and prior to certification.

(B) *Chain-of-custody Evidence.* Fuel pathway applicants using specified source feedstocks must maintain either (1) delivery records that show shipments of feedstock type and quantity directly from the point of origin to the fuel production facility, or (2) information from material balance or energy balance systems that control and record the assignment of input characteristics to output quantities at relevant points along the feedstock supply chain between the point of origin and the fuel production facility. Chain-of-custody evidence is used to demonstrate proper characterization and accurate quantity. Chain-of-custody evidence must be provided to the verifier and to CARB upon request. Joint Applicants may assume responsibility for different portions of the chain-of-custody evidence but each such entity must meet the following requirements to be eligible for a pathway that utilizes a specified source feedstock:

1. Maintain records of the type and quantity of feedstock obtained from each supplier, including Feedstock transaction records, Feedstock Transfer Documents pursuant to section 95488.8(g)(1)(C), weighbridge tickets, bills of lading or other documentation for all incoming and outgoing feedstocks;

2. Maintain records used for material balance and energy balance calculations.

3. Ensure CARB staff and verifier access to audit feedstock suppliers to demonstrate proper accounting of attributes and conformance with certified CI data.

(C) *Feedstock Transfer Documents.* A feedstock transfer document must prominently state the information specified below.

1. Transferor Company name, address and contact information;

2. Recipient Company name, address and contact information;

3. Type and amount of feedstock, including units;

4. Transaction date.

(D) *Requirements for Feedstock Attestation Letter*. Each specified source feedstock supply chain entity must maintain a specified source feedstock supplier attestation letter. Supply chain entities supplying biogas or biomethane used as a feedstock must follow the requirements under section 95488.8(i)(2). The specified source feedstock supply chain entities include points of origin, collectors, aggregators, traders, distributors, and storage facilities that participate in the supply chain from point of origin to the fuel producer for specified source feedstocks. The attestation letter must attest to the veracity of the information supplied, declare that the information accurately represents the specified source feedstock(s), and conform to the requirements of this subsection. The specified source feedstock attestation letter must make the following specific attestations:

1. The specified source feedstocks have not undergone additional processing, such as drying or clean up except as explicitly included in the pathway life cycle analysis and pathway CI.

2. All data and information supplied are true and accurate in all areas, including, but not limited to the following:

    a. Specified source feedstocks meet the applicable definitions under 95481 or as a specified source feedstock approved by the Executive Officer during fuel pathway validation and certification;

    b. Deliveries of the specified source feedstock(s) consist entirely of what is documented on the feedstock transfer documents and are not mixed with any other materials that do not meet the definition of specified source feedstock;

    c. The specified source feedstocks were not intentionally produced, modified, or contaminated to meet the definition;

3. The signed specified source feedstock supplier attestation letter must:

    a. Be maintained by the specified source feedstock supplier, and submitted as an electronic copy upon request by a CARB accredited verifier or verification body or the Executive Officer;

    b. Be on company letterhead;

    c. Be maintained separately for each specified source feedstock;

    d. Be signed by an authorized representative employee of the specified source feedstock supplier;

    e. Include the following attestation:

I certify that the ____________ (specified source feedstock) supplied by ____________ (facility/company) meets all of the following requirements: 1) the specified source feedstock meets the definition under California Code of Regulations, title 17, section 95481, or as a specified source feedstock approved by the Executive Officer; 2) the specified source feedstock has not undergone additional processing, such as drying or clean-up except as explicitly included in the pathway life cycle analysis and pathway CI; 3) deliveries of the specified source feedstock consist entirely of what is documented on the feedstock transfer documents and are not mixed with any other materials that do not meet the definition of the specified source feedstock; and 4) The specified source feedstock was not intentionally modified or contaminated to meet the definition.

By signing this form, ___________ (specified source feedstock supplier) accepts responsibility for the information herein. I certify under penalty of perjury under the laws of the State of California that I have personally examined, and am familiar with, the statements and information in this document. I certify that the statements and information are true, accurate, and complete.

Signature Print Name & Title Date

(h) *Renewable or Low-CI Process Energy.* Unless expressly provided elsewhere in this subarticle, indirect accounting mechanisms for renewable or low-CI process energy, such as the use of renewable energy certificates, cannot be used to reduce CI. In order to qualify as a low-CI process energy source, energy from that source must be directly consumed in the production process as described in (1) and (2) below:

(1) Low-CI electricity must be supplied from generation equipment under the control of the pathway applicant. Such electricity must be able to demonstrate:

(A) Any renewable energy certificates or other environmental attributes associated with the energy are not ~~produced,~~issued credits or ~~are retired and not~~ claimed under any other voluntary or mandatory program with the exception of the federal RFS, and the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

(B) The generation equipment is directly connected through a dedicated line to a facility such that the generation and the load are both physically located on the customer side of the utility meter. The generation source may be grid-tied, but a dedicated connection must exist between the source and load.

(C) The facility's load is sufficient to match the amount of low-CI electricity claimed using a monthly balancing period.

(2) Biogas or biomethane must be physically supplied directly to the production facility. The applicant must submit the attestation set forth below in section 95488.8(i)(2)(C)2.

(3) Solar steam or heat generation must be physically supplied directly to the production facility, and any environmental attributes associated with the energy are not produced, or are retired and not claimed under any other program with the exception of the federal RFS, and the market-based

compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

(i) *Indirect Accounting for ~~Renewable or~~ Low-CI Electricity ~~and~~, Biomethane, and Low-CI Hydrogen*.

(1) *Book-and-Claim Accounting for ~~Renewable or~~ Low-CI Electricity Supplied as a Transportation Fuel, Direct Air Capture projects, ~~or~~ Used to Produce Hydrogen as a transportation fuel, or Used to Produce a Power-to-Liquid Fuel.* Reporting entities may use indirect accounting mechanisms for low-CI electricity supplied as a transportation fuel ~~or~~, for hydrogen production ~~through electrolysis~~and processing for ~~transportation purposes (including~~ hydrogen ~~that is~~ used ~~in the production of~~as a transportation fuel~~)~~, ~~or~~ for direct air capture projects, or for the production of a power-to-liquid fuel, provided the conditions set forth below are met:

(A) ~~Reporting entities may report low-CI~~ For electricity used as a transportation fuel ~~or as an input to hydrogen production delivered through~~ or as an input to power-to-liquid fuel production, the ~~grid without regard to physical traceability if it meets all requirements of this subarticle. The~~ low-CI electricity must be supplied to the grid within a California Balancing Authority (or local balancing authority for ~~hydrogen~~power-to-liquid fuel produced outside of California) or alternatively, meet the requirements of California Public Utilities Code section 399.16, subdivision (b)(1). Such book-and-claim accounting for low-CI electricity may span only three quarters. If a low-CI electricity quantity (and all associated environmental attributes, including a beneficial CI) is supplied to the grid in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to grid electricity used as a transportation fuel or for ~~hydrogen~~power-to-liquid fuel production no later than the end of the third calendar quarter. After that period is over, any unmatched low-CI electricity quantities expire for the purpose of LCFS reporting.

(B) Low-CI electricity used as a transportation fuel or as an input to power-to-liquid fuel production can be indirectly supplied through a green tariff program (including the Green Tariff Shared Renewables program described in California Public Utilities Code Section 2831-2833) or other contractual electricity supply relationship that meets the following requirements:

1. Electricity is generated by, or supplied under contract to, the pathway applicant for all environmental attributes of the claimed electricity. In order to substantiate low-CI electricity claims, the applicant must make contracts available to the Executive Officer, upon request, to demonstrate that the electricity meets the requirements of this subarticle.

Generation invoices or metering records are required to substantiate the quantity of low-CI electricity produced from the renewable assets. Monthly invoices must be unredacted copies of originals showing electricity sourced (in kWh) and contracted price;

2. All electricity procured by any LSE for the purpose of claiming a lower CI must be in addition to that required for compliance with the California Renewables Portfolio Standard (described in California Public Utilities Code sections 399.11-399.32~~) or, for hydrogen produced outside of California,~~) or, for power-to-liquid fuel produced outside California, in addition to local renewable portfolio requirements;

3. Renewable energy certificates or other environmental attributes associated with the electricity, if any, are ~~retired and~~ not issued credits or claimed under any other voluntary or mandatory program with the exception of the federal RFS, and the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800). Retirement of renewable energy credits for the purpose of demonstrating Green Tariff Shared Renewables procurement to the California Public Utilities Commission does not constitute a double claim.

(C) For direct air capture projects or for hydrogen used as a transportation fuel, low-CI electricity must meet the following criteria:

1. The low-CI electricity must be supplied to the grid within the local balancing authority where the electricity is consumed or delivered to that local balancing authority without substitution consistent with the requirements of California Public Utilities Code section 399.16, subdivision (b)(1).

2. The pathway holder or the project operator must be the first contracted entity for procuring the low-CI electricity.

3. Low-CI electricity must be supplied by new or expanded low-CI electricity that begins new or expanded production on or after January 1, 2022, or within three years of the start of the hydrogen production facility or direct air capture project, whichever is later.

4. Such book-and-claim accounting for low-CI electricity may span only one quarter. If a low-CI electricity quantity (and all associated environmental attributes, including a beneficial CI) is supplied to the grid in the first calendar quarter, the quantity claimed for LCFS reporting in the same calendar quarter. After that period is over, any unmatched low-CI electricity quantities expire for the purposes of LCFS reporting.

5. Any renewable energy certificates or other environmental attributes associated with the energy are not issued credits or claimed produced, or are retired and not claimed under any other voluntary or mandatory program with the exception of the federal RFS, incentives under the Infrastructure Investments and Jobs Act or the Inflation Reduction Act, and the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

(2) *Book-and-Claim Accounting for Pipeline-Injected Biomethane Used as a Transportation Fuel or to Produce Hydrogen.* Indirect accounting may be used for RNG used as a transportation fuel or to produce hydrogen for transportation purposes (including hydrogen that is used in the production of a transportation fuel), provided the conditions set forth below are met:

(A) RNG injected into the common carrier pipeline in North America (and thus comingled with fossil natural gas) can be reported as dispensed as bio-CNG, bio-LNG, or bio-L-CNG, or as an input to hydrogen production, without regards to physical traceability. Entities may report natural gas as RNG within only a three-quarter time span. If a quantity of RNG (and all associated environmental attributes, including a beneficial CI) is pipeline-injected in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to natural gas sold in California as RNG no later than the end of the third calendar quarter. After that period is over, any unmatched RNG quantities expire for the purpose of LCFS reporting.

(B) Biomethane reported under fuel pathways associated with projects that break ground after December 31, 2029, injected into the common carrier pipeline, and claimed indirectly under the LCFS program for use as bio-CNG, bio-LNG, or bio-L-CNG in CNG vehicles or as an input to hydrogen production must demonstrate compliance with the following requirements:

1. Starting January 1, 2041 for bio-CNG, bio-LNG and bio-L-CNG pathways, and January 1, 2046 for biomethane used as an input to hydrogen production, the entity reporting biomethane must demonstrate that the pipeline or pipelines along the delivery path physically flow from the initial injection point toward the fuel dispensing facility at least 50 percent of the time on an annual basis. Entities may report natural gas as RNG within only a three-quarter time span. If a quantity of RNG (and all associated environmental attributes, including a beneficial CI) is pipeline-injected in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to natural gas sold in California as RNG no later than the end of the third calendar quarter. After that period is over, any unmatched RNG quantities expire for the purpose of LCFS reporting.

(C) To substantiate RNG quantities injected into the pipeline for dispensing as bio-CNG, bio-LNG, or bio-L-CNG or as an input to hydrogen production, the pathway application and subsequent Annual Fuel Pathway Reports must include the following documents linking the environmental attributes of RNG (in MMBtu or Therms) with corresponding quantities of natural gas withdrawn: ~~u~~

~~(B)~~1. Unredacted monthly invoices showing the quantities of RNG (in MMBtu) sourced and the contracted price per unit;~~ and the unredacted contract by which the fuel pathway holder obtained the environmental attributes.~~

2. Unredacted contract by which the fuel pathway holder obtained the environmental attributes.

(D) Starting January 1, 2041 for bio-CNG, bio-LNG and bio-L-CNG pathways, and January 1, 2046 for biomethane used as an input to hydrogen production, to substantiate RNG quantities injected into the pipeline for dispensing as bio-CNG, bio-LNG, or bio-L-CNG under fuel pathways associated with projects that break ground after December 31, 2029, the pathway application and subsequent Annual Fuel Pathway Reports must include the documents required by section 95488.8(i)(2)(C) as well as the following documents.

1. Monthly pipeline nomination reports for each pipeline along the delivery path.

~~(C)~~(E) *Attestations Regarding Environmental Attributes*.

1. *Upstream Attestations.* An entity reporting any RNG as a transportation fuel in LRT-CBTS, and a fuel pathway holder using biogas or biomethane as feedstock or process energy, must obtain and keep attestations from each upstream party collectively demonstrating that (a) the entity claiming the environmental attributes has the exclusive right to claim environmental attributes associated with the sale or use of the biogas or biomethane, and (b) no entity has been issued credits based on the environmental attributes ~~have not been used or claimed~~ in any other voluntary or mandatory program ~~or jurisdictions~~ with the exception of the federal RFS, and the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800). ~~The~~The upstream parties must maintain the attestations. The reporting entities' and the upstream parties' attestations must be made available to the Executive Officer or a verifier upon request. The inability to promptly produce the attestations constitutes ground for credit invalidation pursuant to section 95495.

2. *Attestation to CARB.* An officer of any entity reporting biomethane in LRT-CBTS under the provisions of section 95488.8(i)(2), and an officer of any fuel pathway holder claiming use of biogas or biomethane as process energy under the provisions of section 95488.8(h)(2), must annually submit the following attestation to the Executive Officer:

I certify that to the extent that the gas used in the fuel pathway or supplied as transportation fuel is characterized as biomethane, __________ (entity name) owns the exclusive rights to the corresponding environmental attributes.

__________ (entity name) has not sold, transferred, or retired those environmental attributes in any program or jurisdiction other than the federal RFS.

Based on diligent inquiry and review of contracts and attestations from our business partners, I certify under penalty of perjury under the laws of the State of California that no other party has or will sell, transfer, or retire the environmental attributes corresponding to the biomethane for which _______(entity name) claims credit in the LCFS program.

______________________________	______________________________	__________
Signature	Print Name & Title	Date

~~(j) *Measurement Accuracy*.~~

~~(1) *Calibration Requirement.* All measurement devices that log or record data for use in fuel pathway applications must comply with the manufacturer-recommended calibration frequency and precision requirements. If~~

~~manufacturer-recommendations are not provided, the measurement devices must be calibrated every six years.~~

~~(2) *Requests to Postpone Calibration.* For units and processes that operate continuously with infrequent outages, it may not be possible to meet manufacturer-recommended calibration deadlines for measurement devices. In such cases, the owner or operator may submit a written request to the Executive Officer to postpone calibration or inspection until the next scheduled maintenance outage. Such postponements are subject to the procedures of subsections (A) through (B) below and must be documented in the monitoring plan.~~

~~(A) A written request for postponement must be submitted to the Executive Officer not less than 30 days before the required calibration, recalibration or inspection date. The Executive Officer may request additional documentation to validate the operator's claim that the device meets the accuracy requirements of this section. The operator shall provide any additional documentation to CARB within ten (10) business days of a request by CARB.~~

~~(B) The request must include:~~

~~1. The date of the required calibration, recalibration, or inspection;~~

~~2. The date of the last calibration or inspection;~~

~~3. The date of the most recent field accuracy assessment, if applicable;~~

~~4. The results of the most recent field accuracy assessment, if applicable, clearly indicating a pass/fail status;~~

~~5. The proposed date for the next field accuracy assessment, if applicable;~~

~~6. The proposed date for calibration, recalibration, or inspection which must be during the time period of the next scheduled shutdown. If the next shutdown will not occur within three years, this must be noted and a new request must be received every three years until the shutdown occurs and the calibration, recalibration or inspection is completed.~~

~~7. A description of the meter or other device, including at a minimum:~~

~~a. Make,~~

~~b. Model,~~

~~c. Install date,~~

~~d. Location,~~

~~e. Parameter measured by the meter or other device, including the data capture rate,~~

~~f. Description of how data from the meter or other device is used in a fuel pathway,~~

~~g. Calibration or inspection procedure,~~

~~h. Reason for delaying calibration or inspection,~~

~~i. Proposed method to ensure that the precision requirements listed by the manufacturer are upheld,~~

~~j. Name, title, phone number and e-mail of contact person capable of responding to questions regarding the device.~~

~~(k) *Missing Data Provisions*.~~

~~(1) *Meter Record, Accuracy, or Calibration Requirements Not Met.* If a measurement device is not functional, not calibrated within the time period recommended by the manufacturer, or fails a field accuracy assessment, the operator must otherwise demonstrate to the verifier that the reported data are accurate within +/-5 percent.~~

~~(A) If the operator can demonstrate to the verifier that reported data are accurate, the data are acceptable. The entity must then provide a detailed plan describing when the measurement device will be brought into calibration. This plan is subject to approval by the Executive Officer.~~

~~(B) If the operator cannot demonstrate to the verifier that reported data are accurate, the data is not acceptable and missing data provisions apply.~~

~~(2) *Missing Data Provisions.* If missing data exists, the entity must submit for Executive Officer approval an alternate method of reporting the missing data. Alternate methods shall be evaluated on a case-by-case basis.~~

~~(3) *Force Majeure Events.* In the event of a facility shutdown or disruption drastically affecting production attributable to a force majeure event, the fuel pathway applicant or holder must notify the Executive Officer.~~

(3) *Book-and-Claim Accounting for Pipeline-Injected low-CI Hydrogen Used in FCV and Alternative Fuel Production.* Indirect accounting may be used for low-CI hydrogen used in FCVs or to produce alternative fuel for transportation purposes provided the conditions set forth below are met:

(A) Low-CI hydrogen is injected into a dedicated hydrogen pipeline physically connected to California.

(B) The well-to-wheel carbon intensity of low-CI hydrogen does not exceed 55.00 gCO_2e/MJ of gaseous hydrogen or 95.00 gCO_2e/MJ if transported as liquid before pipeline injection. If hydrogen is produced from steam methane reforming of natural gas, book-and-claim accounting of biomethane may be used to meet the carbon intensity thresholds.

(C) Low-CI hydrogen is produced from production facilities that become operational or expand production after December 31, 2022.

(D) Low-CI hydrogen can be reported as dispensed to FCVs or as an input to transportation fuel production, without regards to physical traceability. Entities may report low-CI hydrogen using a monthly balancing period substantiated by contractual documents. After that period is over, any unmatched low-CI hydrogen quantities expire for the purpose of LCFS reporting. Any unmatched quantities of hydrogen must either use a default emission factor for hydrogen provided in the Tier 1 CI Calculator for renewable diesel if hydrogen is used as process input in biofuel production, or use the CI calculated from the Tier 1 CI calculator for hydrogen by considering natural gas as feedstock if hydrogen is used in fuel cell vehicles.

(E) To substantiate low-CI hydrogen quantities injected into the pipeline for dispensing in FCVs or as an input to alternative fuel production, the pathway application and subsequent Annual Fuel Pathway Reports must include the following documents linking the environmental attributes of low-CI hydrogen in kg with corresponding quantities of hydrogen in kg withdrawn from the pipeline: unredacted monthly invoices showing the quantities of low-CI hydrogen (in kg) sourced and the contracted price per kg; and the unredacted contract by which the fuel pathway holder obtained the environmental attributes.

(F) *Attestations Regarding Environmental Attributes.*

1. *Upstream Attestations.* An entity reporting any low-CI hydrogen as a transportation fuel in LRT-CBTS, or a fuel pathway holder using low-CI hydrogen as input to alternative fuel production, must obtain and keep attestations from each upstream party collectively demonstrating that (a) the entity claiming the environmental attributes has the exclusive right to claim environmental attributes associated with the sale or use of the low-CI hydrogen, and (b) no entity has been issued credits based on the environmental attributes in any other voluntary or mandatory program with the exception of the tax credits claimed under the Inflation Reduction Act. The inability to promptly produce attestations constitutes ground for credit invalidation pursuant to section 95495.

2. *Attestation to CARB.* An officer of any entity reporting low-CI hydrogen in LRT-CBTS and an officer of any fuel pathway holder claiming use of low-CI hydrogen as input to alternative fuel production under the provisions of section 95488.8(i)(3), must annually submit the following attestation to the Executive Officer:

I certify that to the extent that the hydrogen used in the fuel pathway or supplied as transportation fuel is characterized as low-CI hydrogen, ___________ (entity name) owns the exclusive rights to the corresponding environmental attributes.

___________ (entity name) has not sold, transferred, or retired those environmental attributes in any program or jurisdiction other than the federal RFS.

Based on diligent inquiry and review of contracts and attestations from our business partners, I certify under penalty of perjury under the laws of the State of California that no other party has or will sell, transfer, or retire the environmental attributes corresponding to the low-CI hydrogen for which ________ (entity name) claims credit in the LCFS program.

____

Signature Print Name & Title Date

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95488.9. Special Circumstances for Fuel Pathway Applications.

(a) *Substantiality Requirements*.

(1) The substantiality requirement applies in the two scenarios listed below. The substantiality requirement does not apply when re-applying for a

Provisional pathway with a new operational data period due to a process change, or pathways that qualify for Tier 2 due to the use of low-CI process energy sources, or use of carbon capture, as described in 95488.9(c), or when replacing a certified CI after annual verification using the process described in 95488.10(a)(6).

(A) ~~*Multiple applications*~~*Application(s) for multiple fuel pathways for the same feedstock-fuel combination.* When a fuel pathway applicant applies for two or more pathways ~~based on different inputs~~that are not differentiated by a process change, or applies again for the same feedstock-fuel combination ~~processed within an operational data period~~ at a single fuel production facility, the Executive Officer will consider separate pathways or an updated certification for a previously certified pathway only when the CI of one or more of the proposed pathways meet the substantiality requirement relative to the CI of the reference pathway. The "reference" pathway CI is the composite CI that results when the fuel is modeled using a single pathway that represents the average production of all quantities of the feedstock-fuel combination produced in the operational data period. In the case of an application for a previously certified pathway, the "reference" pathway CI is the verified CI from the most recent annual verification. For the purpose of CI comparison to the reference CI, the applicant must enter the operational data using the same calculator which was used for the most recent annual verification.

~~(B) *Tier 1 Pathways using Innovative Methods.* The Executive Officer will consider a Tier 2 application for a pathway that would otherwise be classified as Tier 1 if the Simplified CI Calculator for that fuel type cannot be used to accurately model the pathway due to process innovations and the proposed pathway meets the substantiality requirement relative to the CI of the reference pathway. The "reference" pathway is the CI of the proposed pathway as calculated by the applicable Simplified CI Calculator. The substantiality requirement does not apply to pathways that qualify for Tier 2 due to the use of low-CI process energy sources, or use of carbon capture, as described in 95488.1(d)(7).~~

(2) The applicant seeking to apply under one of the scenarios described in subsection (1), above, must demonstrate, to the Executive Officer's satisfaction, that the proposed pathway meets the following requirements:

(A) The source-to-tank carbon intensity of the fuel under the proposed pathway meets one of the following two criteria. "Source-to-tank" means all the steps involved in feedstock production and transport, finished fuel production and transport. A source-to-tank CI does not include the carbon intensity associated with the use of the fuel in a vehicle and does not include the LUC modifier.

1. For proposed pathway applications with source-to-tank carbon intensities greater than 20 gCO_2e/MJ (absolute value), that source-to-tank carbon intensity must be at least 5 percent lower than the source-to-tank carbon intensity of the reference pathway; or

2. For proposed pathway applications with source-to-tank carbon intensities of 20 gCO_2e/MJ (absolute value) or less, that source-to-tank carbon intensity must be at least 1 gCO_2e/MJ less than the source-to-tank carbon intensity of the reference pathway.

(b) *Temporary Fuel Pathways*.

(1) Fuel reporting entities may petition the Executive Officer to use a Temporary fuel pathway carbon intensity value for reporting quantities of fuel to generate credits or deficits.

(2) A Temporary pathway petition approved by the Executive Officer will allow the fuel reporting entity to use the pathway for LRT-CBTS reporting purposes for up to two quarters at a time. Reporting will be granted only for the quarter during which the Temporary pathway is approved for use and the subsequent full quarter. The Executive Officer may approve multiple subsequent petitions from the same fuel reporting entity, of up to two quarters each, but each approval will require a new petition.

(3) A petition to use a Temporary pathway must be submitted online in the AFP.

(4) *New Temporary Fuel Pathways.* An entity can apply for the use of a Temporary fuel pathway CI value if it appears in Table 8 in this subarticle or if the Executive Officer approves a new Temporary pathway (for a fuel or feedstock-fuel combination not found in Table 8) and publishes it on the LCFS ~~web site~~website. Any new Temporary pathway proposed by the Executive Officer will be posted for 45 days for public comment prior to certification. The posted information will include the rationale for assigning the CI to that particular Temporary pathway. If these comments require significant revision of the originally published pathway, a revised pathway will be posted for public comment. Upon certification of a new Temporary pathway created by the Executive Officer, the pathway will be available for reporting for the quarter in which it is certified.

Table 8. Temporary Pathways for Fuels with Indeterminate CIs

Fuel	***Feedstock***	***Process Energy***	***CI (gCO_2e/MJ)***
Ethanol	Corn	Grid electricity~~,~~/solar and wind electricity and natural gas~~, and/or renewables~~	90
Ethanol	Grain Sorghum	Grid electricity~~,~~/solar and wind electricity and natural gas~~, and/or renewables~~	95
Ethanol	Any Sugar Feedstock	Bagasse and straw only; no grid electricity	~~55~~60
Ethanol	~~Any Cellulosic Biomass~~ Grain fiber and bagasse	Grid electricity~~,~~/solar and wind electricity~~,~~ and natural gas~~, and/or renewables~~	50
Biomass-based Diesel (HEFA fuels and Biodiesel)	Fats/Oils/Grease Residues	Grid electricity~~,~~/solar and wind electricity and natural gas~~, and/or renewables~~	~~45~~50
Biomass-based Diesel (HEFA fuels and Biodiesel)	Any feedstock derived from plant oils~~,~~ (excluding palm oil and palm derivatives, as a sole feedstock or blended with other feedstocks, and distiller's corn oil)	Grid electricity~~,~~/solar and wind electricity and natural gas~~, and/or renewables~~	~~65~~70
Biomass-based Diesel (HEFA fuels and Biodiesel)	Distiller's Corn Oil	Grid electricity/solar and wind electricity and natural gas	60
Biomass-based Diesel (HEFA fuels and Biodiesel)	Any other feedstock	Grid electricity~~,~~/solar and wind electricity and natural gas~~, and/or renewables~~	Baseline (2010) CI value for ULSD
Renewable Propane	Fats/Oils/Grease Residues	Grid electricity/solar and wind electricity and natural gas	50
Renewable Propane	Any feedstock derived from plant oils (excluding palm oil and palm derivatives, as a sole feedstock or blended with other feedstocks, and distiller's corn oil)	Grid electricity/solar and wind electricity and natural gas	70
Renewable Propane	Distiller's Corn Oil	Grid electricity/solar and wind electricity and natural gas	60
Renewable Propane	Any other feedstock	Grid electricity/solar and wind electricity and natural gas	Baseline (2010) CI value for USLD
Renewable Naphtha and Renewable Gasoline Blendstock	Fats/Oils/Grease Residues	Grid electricity/solar and wind electricity and natural gas	50

Fuel	Feedstock	Process Energy	CI (gCO_2e/MJ)
Renewable Naphtha and Renewable Gasoline Blendstock	Any feedstock derived from plant oils (excluding palm oil and palm derivatives, as a sole feedstock or blended with other feedstocks, and distiller's corn oil)	Grid electricity/solar and wind electricity and natural gas	70
Renewable Naphtha and Renewable Gasoline Blendstock	Distiller's Corn Oil	Grid electricity/solar and wind electricity and natural gas	60
Renewable Naphtha and Renewable Gasoline Blendstock	Any other feedstock	Grid electricity/solar and wind electricity and natural gas	Baseline (2010) CI value for CaRFG
Alternative Jet Fuel	Fats/Oils/Grease Residues	Grid electricity/solar and wind electricity and natural gas	55
Alternative Jet Fuel	Any feedstock derived from plant oils (excluding palm oil and palm derivatives, as a sole feedstock or blended with other feedstocks, and distiller's corn oil)	Grid electricity/solar and wind electricity and natural gas	75
Alternative Jet Fuel	Distiller's Corn Oil	Grid electricity/solar and wind electricity and natural gas	65
Alternative Jet Fuel	Any other feedstock	Grid electricity/solar and wind electricity and natural gas	Baseline (2010) CI value for Fossil Jet Fuel
Fossil LNG	Petroleum Natural Gas	N/A	95
Fossil L-CNG	Petroleum Natural Gas	N/A	100
Biomethane CNG	Landfill gas or Municipal Wastewater Sludge	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	~~70~~65
Biomethane LNG	Landfill gas or Municipal Wastewater Sludge	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	~~85~~80
Biomethane ~~L-CNG~~LCNG	Landfill gas or Municipal Wastewater Sludge	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	~~90~~85
Biomethane CNG	~~Municipal Wastewater sludge,~~ Food Scraps, Urban Landscaping Waste, or Other Organic Waste	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	45

Fuel	*Feedstock*	*Process Energy*	*CI* (gCO_2e/MJ)
Biomethane LNG	~~Municipal Wastewater sludge,~~ Food Scraps, Urban Landscaping Waste, or Other Organic Waste	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	60
Biomethane ~~L-CNG~~LCNG	~~Municipal Wastewater sludge,~~ Food Scraps, Urban Landscaping Waste, or Other Organic Waste	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	65
Biomethane CNG, LNG or L-CNG	Dairy Manure and Swine Manure	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	-150
Hydrogen (compressed or liquefied)	~~Centralized SMR of fossil LNG~~Natural gas and Biomethane not derived from Dairy and Swine Manure	Grid electricity~~,~~/solar and wind electricity, and natural gas ~~and/~~with gaseous hydrogen transport distance of less than 500 miles or ~~renewables~~liquid hydrogen transport distance of less than 2,000 miles	1~~8~~95
Hydrogen (compressed or liquefied)	Biomethane from Dairy and Swine Manure	Grid electricity/solar and wind electricity and natural gas with gaseous hydrogen transport distance of less than 500 miles or liquid hydrogen transport distance of less than 2,000 miles	40
Hydrogen (compressed or liquefied)	Biomethane from Non-Dairy and Swine Manure Source	Grid electricity/solar and wind electricity and natural gas with gaseous hydrogen transport distance of less than 500 miles or liquid hydrogen transport distance of less than 2,000 miles	175
Hydrogen (compressed or liquefied)	Electrolysis of Water using zero-CI or Negative-CI electricity	Gaseous hydrogen transport distance of less than 500 miles or liquid hydrogen transport distance of less than 2,000 miles	55
Any gasoline substitute feedstock-fuel combination not identified above	Any	Any	Baseline (2010) CI value for CaRFG
Any diesel substitute feedstock-fuel combination not identified above	Any	Any	Baseline (2010) CI value for ULSD

(c) *Provisional Pathways.* As set forth in sections 95488.6(a) and 95488.7(a), LCFS fuel pathways are generally developed based on 24 months of operational data. The Executive Officer may consider Provisional pathway applications from 1) facilities that have been in operation for less than 24 months, or 2) existing facilities that can demonstrate a process change has been implemented, based on at least three months of operational data. Based on timely reports, the fuel reporting entity may generate credits or deficits using a provisionally-certified CI.

(1) *Application process.* Application requirements are the same as those for the applicable pathway classification, specified in sections 95488.6 and 95488.7 including validation of the data submitted in support of the provisional pathway application.

(2) *Verification schedule.* The certified pathway is subject to periodic verification as described in section 95500(b)(2) as applicable for the fuel pathway classification.

~~(3) *Adjusting CI and Credit Balance.* At any time during the 24 months following provisional certification, the Executive Officer may revise as appropriate the provisionally-certified CI. Until the Executive Officer has removed the provisional status pursuant to subsection (4) below, the Executive Officer may adjust the number of credits or reverse any credit in the fuel reporting entity's account using the provisional pathway without a hearing, notwithstanding the requirements of section 95495. At the end of the provisional period, the certified CI will be determined on the basis of 24 months of operational data.~~

~~(A) If the verified operational CI is higher than the provisionally-certified CI, the Executive Officer will replace the certified CI with the verified operational CI in the LRT-CBTS and will make any necessary credit adjustment in the fuel reporting entity's account using the provisional fuel pathway for reporting. Any credits generated using a provisionally-certified CI, across the entire period from original validation to completion of the periodic verification, are subject to adjustment.~~

~~(B) If the verified operational CI is lower than the provisionally-certified CI, the Executive Officer will certify the pathway with the lower CI, adding a conservative margin of safety per section 95488.4(a) if the applicant so desires. The fuel reporting entity will not be eligible for any retroactive credit generation for any quarter for which the reporting deadline has passed, but the revised CI will be valid for future reporting periods.~~

~~(4)~~(3) *Removal of provisional status.* Positive or qualified positive verification statements covering at least 24 months of operational data will result in the removal of the provisional status for the certified pathway.

(d) *Substitute Pathways for Reporting Exports and Other Transaction Types.* If a fuel reporting entity is unable to determine the pathway for reporting a fuel transaction type listed in subsection (1) below, a Substitute pathway corresponding to the fuel type must be used for reporting. Substitute pathways have CI values based on weighted average CIs of that fuel in the prior year, and are provided on the LCFS ~~web site~~website.

(1) The Substitute pathways are only available in the LRT-CBTS for reporting the following transaction types:

(A) Sold without obligation

(B) Purchased without obligation

(C) Export

(D) Loss of inventory

(E) Not used for transportation

(2) When using a Substitute pathway, the fuel reporting entity must use default Company ID and Facility ID values for reporting in the LRT-CBTS. These default values are provided on the LCFS ~~web site~~website.

(e) *Design-based Pathways.* As set forth in sections 95488.6(a) and 95488.7(a), LCFS fuel pathways are generally developed based on 24 months of operational data. However, in order to encourage the development of innovative fuel technologies, an applicant may submit a Design-based pathway application in the AFP for a fully engineered and designed facility with no operational data.

(1) Applications for Design-based pathways must include a detailed life cycle analysis of the anticipated pathway performed using the CA-GREET~~3~~4.0 model, and an LCA report as described in 95488.7(a)(2) detailing facility plans and specifications expected during commercial operation.

(2) The Executive Officer may, fully at his or her discretion, choose to conduct a detailed evaluation of the submitted information and evaluate whether the applicant provided a sufficient level of detail to warrant confidence in energy consumption and other key CI performance metrics. If the Executive Officer chooses to undertake such a review, and the Executive Officer agrees that the pathway warrants publication on the LCFS ~~web site~~website, a Design-based pathway summary will be posted for public comment as detailed in section 95488.7(d)(5) for Tier 2 pathways. Executive Officer approval of Design-based pathways will generally be

contingent upon meeting the requirements detailed in section 95488.7, exclusive of the requirement to obtain a validation statement.

(3) *Ineligibility for credit generation.* Design-based pathways are not eligible to report fuel volumes to the LRT-CBTS or generate credits. After a pathway has been in production for at least three months, in order to be eligible to report and generate credits, the applicant must complete a Provisional pathway application per section 95488.9(c).

(f) *Carbon Intensities that Reflect Avoided Methane Emissions from Dairy and Swine Manure or Organic Waste Diverted from Landfill Disposal*.

(1) A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that:

(A) A biogas control system, or digester, is used to capture biomethane from manure management on dairy cattle and swine farms that would otherwise be vented to the atmosphere as a result of livestock operations from those farms.

(B) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane.

(2) A fuel pathway that utilizes an organic material may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary diversion from decomposition in a landfill and the associated fugitive methane emissions, provided that:

(A) The organic material that is used as a feedstock would otherwise have been disposed of by landfilling, and the diversion is additional to any legal requirement for the diversion of organics from landfill disposal.

(B) Any degradable carbon that is not converted to fuel is subsequently treated in an aerobic system or otherwise is prevented from release as fugitive methane. Upon request, the applicant must demonstrate that emissions are not significant beyond the system boundary of the fuel pathway.

(C) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the avoidance or capture and destruction of biomethane.

(3) Carbon intensities that reflect avoided methane emissions from dairy and swine manure or organic waste projects are subject to the following requirements for credit generation:

(A) *Crediting Periods.* Avoided methane crediting for dairy and swine manure pathways as described in (f)(1) above, and for landfill-diversion pathways as described in (f)(2) above, is limited to three consecutive 10 years crediting periods, counting from the quarter following Executive Officer approval of the application. The pathway holder must formally request each subsequent crediting period for the project through the LRT-CBTS. The Executive Officer may renew crediting periods for fuel pathways certified before January 1, 2030, for up to three consecutive 10-year crediting periods. For pathways for bio-CNG, bio-LNG, and bio-L-CNG used in CNG vehicles associated with projects that break ground after December 31, 2029, the Executive Officer may only approve avoided methane crediting through December 31, 2040. For pathways for biomethane used to produce hydrogen that break ground after December 31, 2029, the Executive Officer may only approve avoided methane crediting through December 31, 2045.

(B) Notwithstanding (A) above, in the event that any law, regulation, or legally binding mandate requiring either greenhouse gas emission reductions from manure methane emissions from livestock and dairy projects or diversion of organic material from landfill disposal, comes into effect in California during a project's crediting period, then the project is only eligible to continue to receive LCFS credits for those greenhouse gas emission reductions for the remainder of the project's current crediting period. The project may not request any subsequent crediting periods.

(C) Notwithstanding (A) above, projects that have generated CARB Compliance Offset Credits under the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800) may apply to receive credits under the LCFS. However, the LCFS crediting period for such projects is aligned with the crediting period for Compliance Offset Credits, and does not reset when the project is certified under the LCFS.

(g) *Sustainability Requirements for Crop-Based and Forestry-Based Feedstocks.*

Crop-based and forestry-based feedstocks must not be sourced on land that was forested after January 1, 2008. A forest is as defined in section 95481 or where they are protected by international or national law or by the relevant competent authority for nature protection purposes.

All crop-based and forestry-based feedstocks used for LCFS fuel pathways must meet the following sustainability requirement:

(1) Maintain continuous third-party sustainability certification under an Executive Officer approved certification system.

(A) All feedstocks at the point-of-origin must be certified by January 1, 2028. Fuel quantities reported under fuel pathways utilizing feedstocks not certified by January 1, 2028 must be assigned the ULSD carbon intensity found in Table 7-1 of the LCFS regulation.

(B) The Executive Officer will review and may approve certification systems based on the following criteria:

1. The certification system has been recognized by an international, national, or state/provincial government for at least 24 months;

2. The certification system must consider environmental, social, and economic criteria;

3. The certification system must be consistent with consensus-based international standards and codes for assuring conformance and certification;

4. The certification system standard-setting process is participatory, and consensus driven:

a. Convenes representative groups of economic, environmental, and social stakeholders in both formal and informal manners; and

b. Creates a representative steering committee, technical working group(s), and advisory group(s);

5. The certification system must have clear, accessible, and transparent processes;

6. The certification system must publish procedures, guidance, certificates and audit report summaries on its website;

7. The certification system must be science based, provide clear targets to reach, and support demonstrable means of evaluation;

8. The certification system must demonstrate that requirements that are additional to the requirements of this subarticle are

vetted via a multi-stakeholder process to mitigate potential stakeholder bias;

9. The certification system must maintain an effective auditor training program to ensure auditor competency;

10. The certification system must maintain an effective oversight program over the participating auditing bodies and auditors to assure consistency and quality of verifications;

    a. The certification system must maintain conflict of interest policies and impartiality provisions to eliminate high potential for conflict of interest;

    b. The certification system must require auditing bodies to maintain professional liability insurance;

    c. The certification system must require auditing bodies to demonstrate that their procedures are consistent with the following international certification systems: ISO 14064-3. Part 3: Specification with guidance for the validation and verification of greenhouse gas assertions, 14065: Greenhouse gases – General principles and requirements for bodies validating and verifying environmental information, 17065: Conformity assessment – Requirements for bodies certifying products, processes and services, and 14066: Competence requirements for greenhouse gas validation teams and verification teams; and

    d. The certification system must require that auditing bodies must assume full responsibility for services performed by subcontractor auditor, and further subcontracting is not allowed;

11. The certification system must include an effective grievance mechanism to ensure that problems are resolved;

12. The certification system must include sanction mechanisms for participating feedstock suppliers and auditing bodies to ensure conformance with its system requirements; and

13. The certification system must demonstrate that policies and mechanisms are in place to monitor and prevent conflicts of interest between members of the system, audited entities, and members of the auditing bodies, consistent with ISO 17065: Conformity assessment -- Requirements for bodies certifying products, processes and services. The certification

system must have oversight mechanisms to assure knowledgeable and rigorous compliance of audit providers.

(C) Certification systems must be approved by the Executive Officer prior to the reporting deadline for the AFPR or QFTR the feedstock is being reported under.

(D) To apply for Executive Officer approval, the applicant must submit the following information to the Executive Officer:

1. General information on the certification system, including:

a. The name, address, telephone number, and e-mail address of the certification system;

b. A description of all services the certification system performs or intends to perform; and

c. A list of auditing bodies that are currently approved by the certification systems; and

2. A demonstration that the certification system has met the selection criteria specified in section 95488.9(g)(1)(B) and that the listed auditing bodies have met the requirements in 95488.9(g)(1)(B)(10).

(E) Certification system documents must be submitted to the Executive Officer at least 90 days prior to the reporting deadline for approval.

1. The submittal must include all documentation necessary for the Executive Officer to determine that the above identified criteria have been met.

2. The certification system documents may be submitted for Executive Officer review by a representative of the certification system, a feedstock supplier, a fuel producer, or any other participant in the LCFS.

3. The Executive Officer may request additional information from the submitter, and the submitter must provide the requested information within 14 days.

4. If a certification system is denied, the submitter may appeal to the Executive Officer within 30 days and provide any additional information that may be helpful in making a determination of acceptability.

5. The Executive Officer has 30 days from the date of appeal submittal to make a final determination.

(F) Approved certification systems will be published on the CARB LCFS website.

(G) Once a certification system is approved it is eligible for use by all relevant feedstock suppliers.

(H) Certification systems must be resubmitted for approval every three years to assure continuing adherence to the original approval standards.

(I) The Executive Officer may remove or suspend an approved certification system standard that no longer meets the requirements of section 95488.9(g)(1)(B).

(J) After the removal or suspension of an approved certification system standard, any feedstock relying on that standard must become certified under an approved standard within one year from the date of removal or suspension.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95488.10. Maintaining Fuel Pathways.

(a) *CI Data Reporting Requirement and Deadline.* Beginning in 2021, each fuel pathway holder must submit an annual Fuel Pathway Report to the AFP no later than March 31 of each calendar year.

(1) The annual Fuel Pathway Report must include the certified version of the ~~Simplified~~Tier 1 CI Calculator or the CA-GREET~~3~~4.0 model, if required in the initial certification, updated to include the most recent two calendar years of operational data. If less than 24 months of operational data is reported in an Annual Fuel Pathway Report, the operational data period must include the reported months established during initial pathway certification.

(2) The annual Fuel Pathway Report for Lookup Table pathways listed in 95488.1(b)(2), in lieu of the CI calculator, must include invoices or metering records substantiating the quantity of renewable or low-CI inputs procured from a qualifying source.

(3) Entities specified in section 95488.8(i)(2)(C) must provide the annual attestation regarding environmental attributes required by that provision.

(4) Any fuel pathway holder, including a joint applicant, who is not subject to site visits by a third~~-~~-party verifier, whose pathway involves the use of renewable or low-CI process energy, must submit invoices for that energy to the AFP. Additionally, for any electricity that is used to reduce carbon intensity of electricity used as a transportation fuel or hydrogen production via electrolysis, the pathway holder must upload records demonstrating that any renewable energy certificates generated were retired in WREGIS for the purpose of LCFS credit generation.

(5) The annual Fuel Pathway Report must include any temporally-variable information requested by the Executive Officer to be included in the initial application as supplementary information, or required data or documentation listed in the pathway summary operating conditions, must continue to be submitted annually as part of the annual Fuel Pathway Report.

~~(6) If the verified operational CI as calculated from production data covering the 24 months of operations is found to be lower than the certified CI, and a positive verification statement is issued for this period, the following options are available:~~

(6) Fuel pathway holders must submit 2024 annual Fuel Pathway Reports following the transition to CA-GREET4.0 procedure described in section 95488(c)(1). Upon receiving a positive or qualified positive verification statement for verification of a 2025 Annual Fuel Pathway Report and subsequent reporting years, the Executive Officer will replace the certified CI with the verified operational CI if this replacement is requested by the fuel pathway holder. The Executive Officer will add a conservative margin of safety to the verified operational CI per section 95488.4(a) upon request from the pathway holder.

(A) The fuel pathway holder may elect to keep the original certified CI.

(B) The fuel pathway holder may request to replace the certified CI with the verified operational CI based on the most recent 24 months of operational data, adding a conservative margin of safety per section 95488.4(a) if the applicant so desires. Fuel pathway holders requesting to replace the certified CI must submit an attestation that the new CI can be maintained through the next reporting period, and acknowledging that exceeding the newly certified CI in subsequent verifications will constitute non-compliance with the requirements of this subarticle.

(7) If the verified operational CI is found to be greater than the certified ~~CI,~~(including provisionally certified) CI:

(A) The Executive Officer will invalidate excess credits generated resulting from the CI exceedance for the applicable compliance year in the LRT-CBTS account of the associated fuel reporting entities.

(B) The fuel pathway holder is subject to the deficit obligation for a verified CI exceedance pursuant to 95486.1(g).

(C) Fuel pathway holders who demonstrate that the verified operational CI exceedances are solely due to calculator updates are exempt from the 95486.1(g) deficit obligation for the 2025 and 2026 compliance years. To make this demonstration, fuel pathway holders must submit both CA-GREET3.0 and CA-GREET4.0 modeling tools populated with the operational data for the same reporting period for annual verification in the AFP.

~~(7)~~(D) Unless the fuel pathway holder satisfies the 95486.1(g) deficit obligation or the exemption to that deficit obligation requirement specified in 95488.10(a)(7)(C) applies, the fuel pathway holder of a pathway with 24 months of operational data is out of compliance ~~with this subarticle~~per section 95488.4(a) and subject to investigation by the Executive Officer and possible enforcement action.

(b) *Credit True Up after Annual Verification.* Beginning with the 2025 annual Fuel Pathway Report data reporting year, the Executive Officer may perform credit true up for a fuel pathway that has a lower verified operational CI upon receiving a positive or qualified positive verification statement for the associated annual fuel pathway report and quarterly fuel transactions reports, notwithstanding the prohibition on retroactive credit generation in section 95486(a)(2). To implement this true up, the Executive Officer will calculate an equivalent number of credits representing the difference between the reported CI and the verified operational CI from annual Fuel Pathway Reports for each fuel pathway code reported with non-liquid transaction types and with the following liquid fuel transaction types "Production in California," "Production for Import," and "Import" during a compliance year, and place those credits in the account of each appropriate fuel reporting entity after August 31 for the prior compliance year. The credits will be calculated according to the following equation:

$$Credits^{FPC}_{CI\ difference}\ (MT)$$
$$= \left(Credits^{FPC}_{verified\ opertional\ CI}\ (MT) - Credits^{FPC}_{reported\ CI}\ (MT)\right)$$

If $Credits^{FPC}_{CI\ difference} > 0$

where:

$Credits^{FPC}_{CI\ difference}$ is the number of credits representing the difference between the reported CI and verified operational CI for each fuel pathway code;

$Credits^{FPC}_{verified\ operational\ CI}$ is the number of credits calculated using $CI^{XD}_{verified\ operational}$ instead of $CI^{XD}_{reported}$ in the equation in section 95486.1(a)(1). $CI^{XD}_{verified\ operational}$ is determined by the Executive Officer on the basis of the annual Fuel Pathway Report submitted pursuant to section 95488.10 for each fuel pathway code; and

$Credits^{FPC}_{reported\ CI}$ is the number of credits calculated using equation in section 95486.1(a)(1) for each fuel pathway code;

~~(b)~~(c) *Monitoring Plan for Entities Required to Obtain Validation or Verification Services under the LCFS*. Each entity responsible for obtaining validation or verification under this subarticle must complete and retain for review by a verifier, or the Executive Officer, a written Monitoring Plan. Specific requirements for Monitoring Plans are detailed in section 95491.1(c).

~~(c)~~(d) *Verification Requirement and Deadline.* Each fuel pathway holder, who is not exempt from obtaining verification in section 95500, must ensure that a positive or qualified positive verification statement covering the annual Fuel Pathway Report is received by the Executive Officer from the verification body pursuant to the schedule in 95500 in order to maintain a valid fuel pathway code for use in reporting fuel transactions. An adverse fuel pathway verification statement would result in investigation by the Executive Officer. It is the responsibility of the fuel pathway holder to ensure this deadline is met.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95489. Provisions for Petroleum-Based Fuels.

(a) *Deficit Calculation for CARBOB ~~or~~, Diesel Fuel~~.~~, or Fossil Jet Fuel.* A fuel reporting entity for CARBOB ~~or~~, diesel fuel, or fossil jet fuel must calculate separately the base deficit and incremental deficit for each fuel or blendstock derived from petroleum feedstock as specified in this provision.

Base Deficit Calculation

$$Deficits^{XD}_{Base}(MT) = (CI^{XD}_{Standard} - CI^{XD}_{BaselineAve}) \times E^{XD} \times C$$

Incremental Deficit Calculation to Mitigate Increases in the Carbon Intensity of Crude Oil

If $CI_{20XXCrudeAve} > CI_{BaselineCrudeAve} + 0.10$ *then:*

$$Deficits^{XD}_{Incremental20XX} = (CI_{BaselineCrudeAve} - CI_{20XXCrudeAve}) \times E^{XD} \times C$$

If $CI_{20XXCrudeAve} \leq CI_{BaselineCrudeAve} + 0.10$ *then:*

$$Deficits^{XD}_{Incremental20XX} = 0$$

where:

$Deficits^{XD}_{Base}(MT)$ and $Deficits^{XD}_{Incremental20XX}$ mean the amount of LCFS deficits incurred (a negative value), in metric tons, by the volume of CARBOB (XD = "CARBOB") and diesel fuel (XD = "diesel") that is derived from petroleum feedstock and is either produced in or imported into California during a specific calendar year, and by the volume of fossil jet fuel (XD = "fossil jet fuel") that is either produced or imported into California during a specific calendar year, starting in 2028;

$CI^{XD}_{Standard}$ has the same meaning as specified in section 95486.1(a);

$CI^{XD}_{BaselineAve}$ is the average carbon intensity value of CARBOB ~~or~~, diesel, or fossil jet fuel in gCO2e/MJ, that is derived from petroleum feedstock and is either produced in or imported into California during the baseline calendar year, 2010. For purposes of this provision, $CI^{XD}_{BaselineAve}$ for CARBOB (XD = "CARBOB~~")~~ ~~and~~"), diesel fuel (XD = "diesel"), and fossil jet fuel (XD = "fossil jet fuel") are the Baseline Average carbon intensity values for CARBOB ~~and~~, diesel (ULSD~~)~~), and fossil jet fuel set forth in Table 7-1. The Baseline Average carbon intensity values for CARBOB ~~and~~, diesel (ULSD~~)~~), and fossil jet fuel are calculated using data for crude oil supplied to California refineries during the baseline calendar year, 2010.

$CI_{BaselineCrudeAve}$ is the California Baseline Crude Average carbon intensity value, in gCO2e/MJ, attributed to the production and transport of the crude oil supplied as petroleum feedstock to California refineries during the baseline calendar year, 2010. For comparison to $CI_{20\cancel{18}23CrudeAve}$, the baseline is:

$$CI_{BaselineCrudeAve} = \cancel{\frac{[11.98 \times V_{2016} + 11.98 \times V_{2017} + 11.78 \times V_{2018}]}{[V_{2016} + V_{2017} + V_{2018}]}} \frac{[11.98 \times V_{2021} + 11.98 \times V_{2022} + 11.78 \times V_{2023}]}{[V_{2021} + V_{2022} + V_{2023}]}$$

For comparison to $CI_{2019CrudeAve}$, the baseline is:

$$CI_{BaselineCrudeAve} = \cancel{\frac{[11.98 \times V_{2017} + 11.78 \times V_{2018} + 11.78 \times V_{2019}]}{[V_{2017} + V_{2018} + V_{2019}]}} \frac{[11.98 \times V_{2022} + 11.78 \times V_{2023} + 11.78 \times V_{2024}]}{[V_{2022} + V_{2023} + V_{2024}]}$$

For comparison to $\cancel{CI_{2020CrudeAve}}CI_{2025CrudeAve}$ and subsequent years, the baseline is

$$CI_{BaselineCrudeAve} = 11.78$$

$CI_{20XXCrudeAve}$ is the Three-year California Crude Average carbon intensity value, in gCO_2e/MJ, attributed to the production and transport of the crude oil supplied as petroleum feedstock to California refineries during the most recent three calendar years. For example, the Three-year California Crude Average carbon intensity value for 20~~18~~23 is:

$$CI_{2018CrudeAve} = \cancel{\frac{[CI_{2016} \times V_{2016} + CI_{2017} \times V_{2017} + CI_{2018} \times V_{2018}]}{[V_{2016} + V_{2017} + V_{2018}]}} \frac{[CI_{2021} \times V_{2021} + CI_{2022} \times V_{2022} + CI_{2023} \times V_{2023}]}{[V_{2021} + V_{2022} + V_{2023}]}$$

V_{20XX} is the total volume of crude supplied to California refineries during the specified year 20XX.

CI_{20XX} is the Annual Crude Average carbon intensity value, calculated annually as described in section 95489(b). The Annual Crude Average carbon intensity value for 2021~~6~~ and 20~~17~~22 are specified in Table 9.

E^{XD} is the amount of fuel energy, in MJ, ~~from CARBOB (XD = "CARBOB") or diesel (XD = "diesel"),~~ determined from the energy density conversion factors in Table 4~~,~~. For CARBOB (XD = "CARBOB") or diesel (XD = "diesel"), E^{XD} is either produced in California or imported into California during a specific calendar year and sold, supplied, or offered for sale in California. For fossil jet fuel (XD = "fossil jet fuel"), E^{XD} is either produced in California or imported into California during a specific calendar year starting in 2028 and sold, supplied, or offered for sale in California.

$$C = 1.0 \times 10^{-6} \frac{MT}{gCO_2e}$$

(b) *Addition of Incremental Deficits that Result from Increases in the Carbon Intensity of Crude Oil to a Fuel Reporting Entity's Compliance Obligation*.

(1) Incremental deficits for CARBOB ~~or~~, diesel fuel, or fossil jet fuel that result from increases in the carbon intensity of crude oil will be calculated and added to each affected fuel reporting entity's compliance obligation for the compliance period in which the $Deficits^{XD}_{Incremental20XX}$ become effective, which will be the year following the year in which the $CI_{20XXCrudeAve}$ was established.

(2) Incremental deficits for CARBOB ~~or~~, diesel fuel, or fossil jet fuel for each fuel reporting entity will be based upon the amount of CARBOB ~~and~~, diesel fuel, and fossil jet fuel supplied by the fuel reporting entity in each compliance period for which the $Deficits^{XD}_{Incremental20XX}$ are effective.

(3) *Process for Calculating the Annual Crude Average Carbon Intensity Value*.

(A) An Annual Crude Average carbon intensity value will be calculated for each calendar year using a volume-weighted average of crude carbon intensity values. The volume for each imported crude will be the total volume of that crude reported by all fuel reporting entities in the Annual Compliance Reports for the calendar year. Volume contributions for California State fields will be based on oil production data from the California Department of Conservation and volume contributions for California Federal Offshore fields will be based on oil production data from the Bureau of Safety and Environmental Enforcement. Field production volumes for California-produced crude will be reduced, if necessary, to account for crude exports. Crude carbon intensity values are those listed in Table 9. For crude names not listed, the default carbon intensity value from Table 9 will be used until the crude name and carbon intensity value is added to Table 9 as described in section 95489(b)(3).

(B) ~~Within 15 days of receiving the Annual Compliance~~After receiving positive or qualified positive verification statements required by section 95500 for all annual MCON reports, the Executive Officer shall post the Annual Crude Average carbon intensity calculation at the LCFS ~~web site~~website for public comment. Written comments shall be accepted for ~~15~~14 days following the date on which the analysis was posted. Only comments related to potential factual or methodological errors in the posted Annual Crude Average carbon intensity value may be considered. The Executive Officer shall evaluate the comments received and, if the Executive Officer deems it necessary, may request in writing additional information or clarification from the commenters. Commenters shall be provided ~~10~~14 days to respond to these requests. ~~The~~After any comments necessary to be addressed have been addressed, the Executive Officer shall post the final Annual Crude Average carbon intensity value at the LCFS ~~web site within 15 days of receiving positive or qualified positive MCON verification reports per section 95500.~~website. An adverse verification statement would result in Executive Officer investigation and may result in delay of finalizing and posting the Annual Crude Average carbon intensity value.

(C) Revisions to the OPGEE model, addition of crudes to Table 9, and updates to all carbon intensity values listed in Table 9 will be considered ~~on a three-year cycle~~ through proposed amendments of the Low Carbon Fuel Standard regulation.

Table 9. Carbon Intensity Lookup Table for Crude Oil Production and Transport.

Country of Origin	***Crude Identifier***	***Carbon Intensity (gCO_2e/MJ)***
Baseline Crude Average*	California Baseline Crude Average applicable to crudes supplied during 20~~18~~23 and subsequent years	~~11.78~~12.61
	California Baseline Crude Average applicable to crudes supplied in 2021~~6~~ and 20~~17~~22	11.~~98~~78
Annual Crude Average	Volume-weighted California average CI for crudes supplied during 2021~~6~~	12.~~14~~80
Annual Crude Average	Volume-weighted California average CI for crudes supplied during 20~~17~~22	~~11.93~~12.71
Algeria	Saharan	~~14.77~~17.16
Angola	Cabinda	~~8.99~~12.24
	Clov	~~7.31~~9.11
	Dalia	~~8.90~~9.92
	Gimboa	~~8.86~~9.90
	Girassol	~~9.95~~11.87
	Greater Plutonio	~~8.72~~11.78
	Hungo	~~8.23~~10.01
	Kissanje	~~8.66~~11.75
	Mondo	~~8.98~~9.92
	Nemba	~~9.08~~12.21
	Pazflor	~~8.02~~9.84
	Sangos	~~7.06~~8.04
Argentina	Canadon Seco	~~10.16~~15.30
	Escalante	~~10.15~~13.81
	Hydra	~~7.77~~11.88
	Medanito	~~10.78~~15.44
Australia	Enfield	~~6.84~~10.15
	Pyrenees	~~8.24~~10.11
	Stybarrow	~~7.84~~10.46
	Van Gogh	~~8.46~~10.15
	Vincent	~~6.83~~10.24
Azerbaijan	Azeri	~~6.40~~11.09
Belize	Belize Light	~~9.70~~10.98
Brazil	Albacora Leste	~~5.99~~6.79
	Bijupira-Salema	7.~~18~~15
	Frade	~~5.63~~6.95

Country of Origin	***Crude Identifier***	***Carbon Intensity (gCO_2e/MJ)***
	Iracema	~~5.54~~6.88
	Jubarte	~~6.28~~8.11
	Lapa	7.99
	Lula	~~6.24~~7.55
	Marlim	~~6.76~~8.35
	Marlim Sul	~~7.78~~8.56
	Mero	7.89
	Ostra	~~5.65~~8.01
	Papa Terra	~~4.29~~5.86
	Peregrino	~~4.16~~7.60
	Polvo	~~4.31~~7.70
	Roncador	~~6.77~~7.19
	Roncador Heavy	~~6.45~~7.21
	Sapinhoa	~~6.00~~8.75
	Tubarao Azul	~~5.45~~8.16
	Tubarao Martelo	~~5.37~~9.60
Brunei	SLEB	9.88
Cameroon	Lokele	~~19.27~~25.56
Canada	Access Western Blend	15.~~15~~57
	Albian Heavy Synthetic (all grades)	~~23.68~~24.45
	BC Light	~~8.11~~10.68
	Bonnie Glen	~~8.11~~10.68
	Borealis Heavy Blend	~~15.41~~16.36
	Boundary Lake	~~8.11~~10.68
	Bow River	~~9.42~~10.37
	Cardium	~~8.11~~10.68
	Christina Dilbit Blend	~~12.71~~14.06
	Christina Synbit	18.~~66~~26
	Cold Lake	~~17.87~~19.92
	Conventional Heavy	~~9.42~~10.37
	CNRL Light Sweet Synthetic	~~25.27~~22.71
	Federated	~~8.11~~10.68
	Fosterton	~~9.42~~10.37
	Gibson Light Sweet	~~8.11~~10.68
	Halkirk	~~8.11~~10.68
	Hardisty Light	~~8.11~~10.68

Country of Origin	Crude Identifier	Carbon Intensity (gCO_2e/MJ)
	~~Hardisty Synthetic~~Herbon	~~36.39~~7.48
	~~Husky Synthetic~~Hibernia	~~32.66~~10.31
	Joarcam	~~8.11~~10.68
	Kearl Lake	12.~~89~~35
	Kerrobert Sweet	~~8.11~~10.68
	Koch Alberta	~~8.11~~10.68
	Leismer Dilbit	20.25
	Light Sour Blend	~~8.11~~10.68
	Light Sweet	~~8.11~~10.68
	Lloyd Blend	~~9.42~~10.37
	Lloyd Kerrobert	~~9.42~~10.37
	Lloydminster	~~9.42~~10.37
	Long Lake Heavy	~~30.54~~25.56
	Long Lake Light Synthetic	~~40.12~~34.16
	~~Mackay Heavy Blend~~	~~20.43~~
	Medium Gibson Sour	~~8.11~~10.68
	Medium Sour Blend	~~8.11~~10.68
	Midale	~~8.11~~10.68
	Mixed Sour Blend	~~8.11~~10.68
	Mixed Sweet	~~8.11~~10.68
	Moose Jaw Tops	~~8.11~~10.68
	Peace	~~8.11~~10.68
	Peace Pipe Sour	~~8.11~~10.68
	Peace River Heavy	~~19.21~~22.50
	Peace River Sour	~~8.11~~10.68
	Pembina	~~8.11~~10.68
	Pembina Light Sour	~~8.11~~10.68
	Premium Albian Synthetic	~~29.49~~26.12
	Premium Conventional Heavy	~~9.42~~10.37
	Premium Synthetic	~~27.38~~26.12
	Rainbow	~~8.11~~10.68
	Rangeland Sweet	~~8.11~~10.68
	Redwater	~~8.11~~10.68
	Seal Heavy	~~9.42~~10.37
	Shell Synthetic (all grades)	~~29.49~~26.12
	Smiley-Coleville	~~9.42~~10.37

Country of Origin	***Crude Identifier***	***Carbon Intensity (gCO_2e/MJ)***
	Sour High Edmonton	~~8.11~~10.68
	Sour Light Edmonton	~~8.11~~10.68
	~~Statoil Cheecham Dilbit~~	~~16.41~~
	~~Statoil Cheecham Synbit~~	~~21.08~~
	Suncor Synthetic (all grades)	~~27.09~~25.82
	Surmont Heavy Blend	22.~~48~~72
	~~Synbit Blend~~Surmont Heavy Dilbit	~~22.64~~17.45
	Syncrude Synthetic (all grades)	~~31.62~~28.74
	Synthetic Sweet Blend	~~29.36~~27.28
	Tundra Sweet	~~8.11~~10.68
	~~Wabasca~~	~~6.88~~
	Western Canadian Blend	~~9.42~~10.37
	Western Canadian Select	~~19.04~~21.01
	Default Dilbit	17.78
	Default Synthetic Crude Oil	26.33
	Default Synbit	22.52
Chad	Doba	~~11.42~~9.77
Colombia	Acordionero	~~6.96~~10.22
	Cano Limon	~~9.29~~10.68
	Chaza	10.00
	Castilla	~~10.55~~12.77
	Cusiana	~~9.99~~13.81
	Magdalena	~~22.28~~19.82
	Mares Blend	13.67
	Rubiales	~~9.79~~11.44
	South Blend	~~9.25~~10.80
	Vasconia	~~9.62~~11.16
Congo	Azurite	~~10.25~~13.76
	Djeno	~~10.73~~14.25
Ecuador	Napo	~~8.31~~11.06
	Oriente	~~10.07~~11.73
Equatorial Guinea	Ceiba	~~7.82~~8.03
	Zafiro	20.~~56~~20
Ghana	Ten Blend	~~8.08~~9.17
Iran	Dorood	~~12.65~~19.01
	Forozan	~~21.97~~23.67

Country of Origin	*Crude Identifier*	*Carbon Intensity (gCO_2e/MJ)*
	Iran Heavy	~~13.25~~17.07
	Iran Light	~~14.35~~18.03
	Lavan	~~11.11~~15.99
	Nowruz-Soroosh	~~10.53~~14.28
	Sirri	~~10.~~15.64
Iraq	Basra Light	~~13.45~~14.01
	Basra Medium	13.97
	Basra Heavy	~~10.69~~13.95
Kuwait	Kuwait	~~10.56~~12.93
Libya	Amna	15.~~82~~58
Malaysia	Tapis	~~12.73~~18.22
Mauritania	Chinquetti	~~13.74~~7.60
Mexico	Isthmus	~~11.31~~14.56
	Isthmus Topped	~~14.31~~17.56
	Maya	~~7.85~~10.50
Neutral Zone	Eocene	~~7.85~~9.36
	Khafji	~~7.84~~10.43
	Ratawi	~~9.42~~10.61
Nigeria	Agbami	~~12.04~~11.71
	Amenam	~~10.65~~11.71
	Antan	~~21.98~~11.71
	Bonga	~~5.06~~11.71
	Bonny	~~9.91~~11.71
	Brass	~~14.27~~11.71
	EA	~~6.66~~11.71
	Erha	~~10.91~~11.71
	Escravos	~~12.00~~11.71
	Forcados	~~8.97~~11.71
	Okono	~~8.67~~11.71
	OKWB	~~22.76~~11.71
	Pennington	11.~~18~~71
	Qua Iboe	11.~~45~~71
	Yoho	11.~~45~~71
Oman	Oman	~~13.32~~16.24
Peru	Bretana	8.63
~~Peru~~	Loreto	~~9.86~~12.40

Country of Origin	*Crude Identifier*	*Carbon Intensity (gCO_2e/MJ)*
	Mayna	~~11.07~~12.79
	Pirana	~~8.43~~11.30
Russia	ESPO	~~11.55~~14.93
	M100	~~17.35~~19.77
	Sokol	~~6.94~~8.78
	Vityaz	~~9.60~~12.50
Saudi Arabia	Arab Extra Light	~~9.41~~12.04
	Arab Light	~~9.23~~11.97
	Arab Medium	~~8.72~~11.48
	Arab Heavy	~~7.92~~10.50
Thailand	Bualuang	~~4.07~~5.75
Trinidad	Calypso	7.~~41~~31
	Molo	15.59
	Galeota	~~11.41~~13.31
UAE	Murban	~~10.01~~12.77
	Upper Zakum	~~7.96~~10.61
United Kingdom	North Sea Kraken	8.76
Venezuela	Bachaquero	~~28.75~~30.58
	Boscan	~~13.91~~20.64
	Hamaca	~~23.04~~34.28
	Hamaca DCO	~~10.02~~16.73
	Laguna	~~28.75~~30.58
	Mesa 30	~~12.49~~20.85
	Petrozuata (all synthetic grades)	~~23.09~~34.33
	Santa Barbara	~~17.32~~25.48
	Zuata (all synthetic grades)	~~23.04~~34.28
US Alaska	Alaska North Slope	~~15.91~~12.28
US Colorado	Niobrara	~~6.81~~9.08
~~US Gulf of Mexico~~	~~Mars~~	~~6.62~~
~~US Louisiana~~	~~GCA~~	~~8.72~~
US New Mexico	Four Corners	~~11.11~~10.03
	New Mexico Intermediate	~~11.11~~10.03
	New Mexico Sour	~~11.11~~10.03
	New Mexican Sweet	~~11.11~~10.03
US North Dakota	Bakken	~~9.73~~12.62
	North Dakota Sweet	~~9.73~~12.62

Country of Origin	Crude Identifier	Carbon Intensity (gCO_2e/MJ)
	Williston Basin Sweet	~~9.73~~12.62
US Oklahoma	Oklahoma Sour	~~11.93~~12.53
	Oklahoma Sweet	~~11.93~~12.53
US Texas	Eagle Ford Shale	~~11.93~~12.53
	East Texas	~~11.93~~12.53
	North Texas Sweet	~~11.93~~12.53
	South Texas Sweet	~~11.93~~12.53
	West Texas Intermediate	~~11.93~~12.53
	West Texas Sour	~~11.93~~12.53
US Utah	Covenant	~~4.43~~10.50
	Grand Cane	~~6.92~~10.50
	Utah Black Wax	~~5.85~~10.50
	Utah Sweet	~~6.92~~10.50
US Wyoming	Wyoming Sweet	~~10.98~~13.58
US California Fields	Aliso Canyon	~~4.94~~6.70
	Ant Hill	~~20.81~~10.68
	Antelope Hills	~~2.84~~3.14
	Antelope Hills, North	~~24.75~~19.96
	Arroyo Grande	~~31.11~~43.73
	Asphalto	~~8.01~~10.84
	Bandini	~~3.09~~1.96
	Bardsdale	~~3.47~~6.20
	Barham Ranch	~~4.15~~6.21
	Beer Nose	~~3.98~~4.35
	Belgian Anticline	~~5.01~~7.40
	Bellevue	5.~~95~~99
	Bellevue, West	~~6.60~~3.28
	Belmont, Offshore	5.~~12~~51
	Belridge, North	~~4.11~~6.20
	Belridge, South	~~17.09~~20.10
	Beverly Hills	~~5.41~~6.29
	Big Mountain	~~4.65~~7.38
	Blackwells Corner	~~3.07~~2.60
	Brea-Olinda	~~3.59~~4.40
	Buena Vista	~~7.44~~9.61
	Burrel	~~29.43~~13.37

Country of Origin	***Crude Identifier***	***Carbon Intensity (gCO_2e/MJ)***
	Cabrillo	~~4.14~~7.49
	Canal	~~4.40~~6.91
	Canfield Ranch	4.~~53~~99
	Carneros Creek	4.~~06~~63
	Cascade	~~3.00~~4.46
	Casmalia	~~10.26~~9.35
	Castaic Hills	2.~~68~~50
	Cat Canyon	~~7.83~~19.71
	Cheviot Hills	~~3.49~~4.68
	Chico-Martinez	~~48.13~~67.28
	Cienaga Canyon	~~5.78~~10.75
	Coalinga	~~25.81~~34.89
	Coles Levee, N	~~4.09~~5.36
	Coles Levee, S	~~5.87~~9.04
	Comanche Point	~~5.03~~4.63
	Coyote, East	~~5.96~~4.43
	Cuyama, South	~~14.70~~13.26
	Cymric	~~15.69~~18.78
	Deer Creek	~~11.51~~4.42
	Del Valle	5.~~78~~24
	Devils Den	~~7.51~~3.90
	Dominguez	~~3.57~~4.47
	Edison	~~14.53~~18.61
	El Segundo	~~4.38~~3.96
	Elk Hills	~~8.02~~12.06
	~~Elwood, S., Offshore~~	~~3.52~~
	Fruitvale	~~3.75~~4.81
	Greeley	~~7.91~~8.21
	Hasley Canyon	~~2.25~~3.40
	Helm	3.~~99~~00
	Holser	~~3.80~~6.10
	Honor Rancho	~~3.43~~2.72
	Huntington Beach	~~6.62~~5.63
	Hyperion	1.~~90~~62
	Inglewood	10.~~06~~58
	Jacalitos	~~2.72~~3.82

Country of Origin	Crude Identifier	Carbon Intensity (gCO_2e/MJ)
	Jasmin	~~16.59~~15.87
	Kern Bluff	~~12.54~~7.41
	Kern Front	~~35.68~~33.38
	Kern River	15.~~09~~17
	Kettleman Middle Dome	~~3.93~~5.77
	Kettleman North Dome	~~3.42~~7.48
	Landslide	~~12.53~~11.51
	Las Cienegas	~~4.96~~5.00
	Livermore	2.~~66~~84
	Lompoc	~~28.45~~20.61
	Long Beach	5.~~48~~27
	Long Beach Airport	4.~~92~~38
	Los Angeles Downtown	~~5.89~~4.99
	~~Los Angeles, East~~	~~14.71~~
	Lost Hills	~~12.99~~16.02
	Lost Hills, Northwest	~~5.36~~18.85
	Lynch Canyon	~~23.10~~34.75
	Mahala	~~4.99~~10.54
	McCool Ranch	~~9.59~~15.65
	McDonald Anticline	~~4.33~~2.80
	McKittrick	~~25.31~~28.52
	Midway-Sunset	~~29.33~~36.59
	Monroe Swell	1.47
	Montalvo, West	~~2.65~~4.18
	Montebello	~~17.03~~12.95
	Monument Junction	~~4.95~~6.86
	Mount Poso	3.~~71~~63
	Mountain View	~~3.97~~5.03
	Newhall-Potrero	~~3.66~~5.25
	Newport, West	~~5.21~~8.90
	Oak Canyon	~~4.04~~3.49
	Oak Park	~~3.01~~5.04
	Oakridge	~~3.46~~5.01
	Oat Mountain	~~3.17~~4.10
	Ojai	~~4.94~~7.95
	Olive	~~1.82~~2.35

Country of Origin	*Crude Identifier*	*Carbon Intensity (gCO_2e/MJ)*
	Orcutt	~~11.76~~23.32
	Oxnard	~~5.39~~8.99
	Paloma	~~4.88~~10.13
	Placerita	~~32.78~~58.44
	Playa Del Rey	~~6.87~~4.93
	Pleito	~~2.09~~3.50
	Poso Creek	~~21.96~~23.70
	Pyramid Hills	~~3.36~~6.28
	Railroad Gap	~~7.08~~9.22
	Raisin City	~~9.13~~28.32
	Ramona	~~4.47~~7.81
	Richfield	~~4.75~~3.55
	Rincon	~~4.88~~6.26
	Rio Bravo	~~6.98~~10.44
	Rio Viejo	2.~~74~~57
	Riverdale	~~3.80~~4.07
	Rose	~~2.91~~3.32
	Rosecrans	~~5.76~~7.66
	Rosecrans, South	~~3.54~~6.36
	Rosedale	~~2.35~~1.85
	Rosedale Ranch	~~8.32~~9.56
	Round Mountain	~~24.04~~25.21
	Russell Ranch	~~8.58~~9.86
	Salt Lake	~~3.18~~4.35
	Salt Lake, South	~~6.34~~5.12
	San Ardo	~~26.42~~23.72
	San Miguelito	~~5.25~~6.85
	San Vicente	~~3.22~~4.16
	Sansinena	~~3.21~~4.49
	Santa Clara Avenue	~~3.53~~4.26
	Santa Fe Springs	~~12.53~~7.75
	Santa Maria Valley	~~4.80~~8.39
	Santa Susana	~~5.29~~9.86
	Sargent	~~4.00~~6.83
	Saticoy	~~3.68~~5.45
	Sawtelle	~~2.56~~4.79

Country of Origin	*Crude Identifier*	*Carbon Intensity (gCO_2e/MJ)*
	Seal Beach	~~5.19~~6.06
	Semitropic	~~4.30~~6.43
	Sespe	~~3.98~~7.18
	Shafter, North	~~3.32~~4.14
	Shiells Canyon	~~5.07~~9.13
	South Mountain	~~3.58~~6.40
	Stockdale	2.~~18~~42
	Tapia	~~6.92~~3.76
	Tapo Canyon, South	~~3.08~~5.24
	Tejon	~~13.77~~9.59
	Tejon Hills	~~9.39~~7.90
	Tejon, North	~~5.63~~8.01
	Temescal	3.~~40~~43
	Ten Section	7.50
	Timber Canyon	~~4.74~~8.68
	Torrance	~~3.99~~4.02
	Torrey Canyon	~~3.52~~6.55
	Union Avenue	5.~~58~~55
	Vallecitos	~~4.53~~5.41
	Ventura	~~4.54~~7.72
	Wayside Canyon	~~2.36~~6.09
	West Mountain	~~3.53~~6.33
	Wheeler Ridge	~~2.80~~4.86
	White Wolf	~~1.92~~2.96
	Whittier	~~3.71~~4.90
	Wilmington	~~8.31~~16.17
	Yowlumne	~~13.90~~7.45
	Zaca	~~9.53~~6.43
US Federal OCS	Beta	~~1.59~~3.77
	Carpinteria	~~3.28~~6.78
	Dos Cuadras	~~4.57~~6.90
	~~Hondo~~	~~5.93~~
	Hueneme	~~4.67~~5.80
	~~Pescado~~	~~7.07~~
	~~Point Arguello~~	~~14.07~~
	Point Pedernales	~~8.26~~6.49

Country of Origin	*Crude Identifier*	*Carbon Intensity (gCO_2e/MJ)*
	~~Sacate~~	~~4.77~~
	Santa Clara	~~2.46~~5.15
	~~Sockey~~	~~13.09~~
Default		~~11.78~~12.61

* Based on production and transport of the crude oil supplied to the indicated California refinery(ies) during the baseline calendar year, 2010.

(c) *Credits for Producing and Transporting Crudes using Innovative Methods.* Credits may be generated for crude oil that has been produced or transported using innovative methods and delivered to California refineries for processing.

(1) *General Requirements*.

(A) For the purpose of this section, an innovative method means crude production or transport using one or more of the following technologies:

1. Solar steam generation (generated steam of 45 percent quality or greater). Steam must be used onsite at the crude oil production or transport facilities.

2. Carbon capture and sequestration (CCS). Carbon capture must take place onsite at the crude oil production or transport facilities from existing anthropogenic sources of CO_2.

3. Solar or wind electricity generation. To qualify for the credit, electricity must be produced and consumed onsite or be provided directly to the crude oil production or transport facilities from a third-party generator and not through a utility owned transmission or distribution network. Energy storage may be used to increase the quantity of electricity supplied to crude oil production or transport facilities from intermittent solar and wind electricity generation sources.

4. Solar heat generation including, but not limited to, boiler water preheating and solar steam generation with a steam quality of less than 45 percent. Heat must be used onsite at the crude oil production or transport facilities.

5. Renewable natural gas (RNG) or biogas energy. RNG or biogas must be physically supplied directly to the crude oil production or transport facilities.

(B) The innovative method must become operational no earlier than 2010 for solar steam and CCS projects or January 1, 2015, for any other innovative method above. Any project must be approved for use by the Executive Officer before generating credit under the LCFS regulation. Projects that utilize carbon capture and sequestration are subject to the provisions of section 95490.

No credits may be generated for any quarter preceding the quarter in which the application is approved.

(C) The project operator must initiate review of the opt-in project using the innovative method through a written application to the Executive Officer. If the innovative method involves steam, heat, RNG, biogas, or electricity produced by a third party and delivered to the crude oil producer or transporter, both the crude producer or transporter and the third party must apply and will be considered joint applicant project operator for approval of the innovative method. If more than one crude producer or transporter receives steam, heat, RNG, biogas, or electricity from a single third-party facility, each crude producer or transporter must submit an independent application with the third party as a joint applicant on each submittal. If the innovative method involves delivery of carbon captured by the crude oil producer or transporter to a third party to store the carbon, both the crude producer or transporter and the third party must apply and will be considered joint applicants for approval of the innovative method.

(D) A crude oil producer or transporter or designated third party join application must register under section 95483.1 as an opt-in project operator to receive credits for an approved innovative method. The crude oil producer or transporter, through a written agreement, may elect to transfer the right to opt in for credit generation to the joint applicant. If neither the crude oil producer or transporter nor the joint applicant using an approved innovative method registers as an opt-in project operator, credits generated by the producer's or transporter's use of the innovative method may be claimed by California refinery(ies) that purchase the crude produced or transported using the innovative method if CARB receives all information it needs to ensure compliance with limitations and reporting requirements applied to the method.

~~(E)~~ The innovative method must achieve ~~one of the following threshold criteria:~~

~~1. A carbon intensity reduction from the comparison baseline of at least 0.10~~ ~~gCO_2e/MJ~~~~, or~~

2. ~~An~~an emissions reduction of at least ~~5~~1,000 metric tons CO_2e per year.

(E) If the innovative method involves more than one crude producer or transporter using steam, heat, RNG, biogas, or electricity produced at a single third-party facility, the threshold criteria listed above may apply to the aggregated project total.

(F) Credits for producing crude oil with innovative methods must be calculated as specified below:

For crude oil produced using solar steam generation:

$$Credits_{Innov}(MT) = Avoided\ emissions \times \frac{V_{steam} \times f_{solar}}{V_{crudeproduced}} \times V_{Innov} \times C$$

Where avoided emissions, as calculated using the OPGEE model assuming displacement of steam produced using a natural gas fired once through steam generator, are correlated with the steam quality as tabulated below:

Steam quality	***Avoided emissions (gCO_2e/bbl solar steam)***
95% and above	~~34,875~~33,982
85% to <95%	~~30,443~~31,334
75% to <85%	~~28,188~~29,001
65% to <75%	~~25,932~~26,669
55% to <65%	~~23,677~~24,337
45% to <55%	~~21,421~~22,004

For crude oil produced or transported using solar or wind based electricity:

$$Credits_{Innov}(MT) = \cancel{511}314 \times \frac{E_{electricity} \times f_{renew}}{V_{crudeproduced}} \times V_{Innov} \times C$$

For crude oil produced or transported using any other innovative method listed in section 95489(c)(1)(A):

$$Credits_{Innov}(MT) = \Delta CI_{Innov} \times E_{Innov} \times V_{Innov} \times C$$

where:

$Credits_{Innov}(MT)$ means the amount of LCFS credits generated (a positive value), in metric tons, by the volume of a crude oil produced or transported using the innovative method and delivered to California refineries for processing;

V_{steam} means the overall volume, in barrels cold water equivalent, of steam injected;

f_{solar} means the fraction of injected steam that is produced using solar;

$V_{crudeproduced}$ means the volume, in barrels, of crude oil produced or transported using the innovative method;

V_{Innov} means the volume, in barrels, of crude oil produced or transported using the innovative method and delivered to California refineries for processing. If the crude produced or transported using the innovative method and delivered to California refineries is part of a blend, then V_{Innov} is the volume of blend delivered to California refineries times the volume fraction of the crude within the blend that was produced or transported using the innovative method.

$$C = 1.0 \times 10^{-6} \frac{MT}{gCO_2e}$$

$E_{electricity}$ means the overall electricity consumption to produce or transport the crude, in kW-hr;

f_{renew} means the fraction of consumed electricity that is produced using qualifying solar or wind power;

ΔCI_{Innov} means the reduction in carbon intensity (a positive value), in gCO_2e/MJ_{crude}, associated with crude oil production or transport with the innovative method as compared to crude oil production or transport by a baseline process without the method (hereafter referred to as the comparison baseline method); and

E_{Innov} means the energy density (lower heating value), in MJ/barrel, for the crude oil produced or transported with the innovative method.

(G) Renewable or low-CI energy sources listed in (A) that are used to generate LCFS credit for innovative crude may not also claim renewable energy certificates or other environmental attributes recognized or credited by any other jurisdiction or regulatory program, other than the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800). Any renewable energy certificates or other environmental attributes associated with the energy must be retired for the purpose of LCFS credit generation.

(2) *Application and Data Submittal.* Unless otherwise noted, an application for an innovative method shall comply with the requirements below:

(A) An applicant that submits any information or documentation in support of a proposed innovative method must include with the application a written statement clearly showing that the applicant understands and agrees to the following:

1. That all information in the application not identified as confidential business information is subject to public disclosure pursuant to California Code of Regulations, title 17, sections 91000 through 91022 and the California Public Records Act (Government Code §§ 6250 et seq.), and that information claimed by the applicant to be confidential might later be disclosed under section 91022 if the state board determines the information is subject to disclosure.

2. That the crude oil producer or transporter or third-party joint applicant must register under section 95483.1 as an opt-in project operator to receive LCFS credit for an innovative method, and that if the crude oil producer or transporter or third-party joint applicant does not register as an opt-in project operator, credits from an approved innovative method may be claimed by California refinery(ies) that purchase crude produced from the innovative method.

(B) An application must contain the following summary material:

1. A complete description of the innovative method and how emissions are reduced;

2. An engineering drawing(s) or process flow diagram(s) that illustrates the innovative method and clearly identifies the system boundaries, relevant process equipment, mass flows, and energy flows necessary to calculate the innovative method credits;

3. A map including global positioning system coordinates for the facilities described in section 95489(c)(2)(B)2.; and

4. A preliminary estimate of the potential innovative method credit, calculated as required in section 95489(c)(1)(F), including descriptions and copies of production and operational data or other technical documentation utilized in support of the calculation.

(C) An application, except for solar-generated steam for crude oil production (45 percent steam quality or greater), wind-based electricity, or solar-based electricity, shall include a detailed description of the innovative method and its comparison baseline method. The description of innovative and comparison baseline methods can be limited to those portions of the crude production or transport process affected by the innovative method. The description of the innovative method and its comparison baseline method must include each of the following, to the extent each is applicable to the innovative method:

1. Schematic flow charts that identify the system boundaries used for the purposes of performing the life cycle analyses on the proposed innovative method and the comparison baseline method. Each piece of equipment or stream appearing on the process flow diagrams shall be clearly identified and shall include data on its energy and materials balance. The system boundary shall be clearly shown in the schematic.

2. A description of all material and energy inputs entering the system boundaries, including their points of origination, modes of transportation, transportation distances, means of storage, and all processing to which material inputs are subject.

3. A description of all material and energy products, co-products, byproducts, and waste products leaving the system boundaries, including their respective destinations, transportation modes, and transportation distances.

4. A description of all facilities within the system boundaries involved in the production or transport of the crude oil and other byproducts, co-products, and waste products.

5. A description of all combustion and electricity-powered equipment within the system boundaries, including their respective capacities, sizes, or rated power, fuel utilization type, fuel shares, energy efficiency (lower heating value basis), and proposed use.

6. A description of the thermal and electrical energy production that occurs within the system boundaries, including the respective capacities, sizes, or rated power, fuel utilization type, fuel shares, energy efficiency (lower heating value basis), and proposed use.

7. A description of all sources of flared, vented, and fugitive emissions within the system boundaries, including the

compositions of the flared, vented, and fugitive emission streams leaving the system boundaries.

(D) An application, except for solar-generated steam for crude oil production (45 percent steam quality or greater), wind-based electricity, or solar-based electricity shall include descriptions of the life cycle assessments (LCAs) performed on the proposed innovative method and its comparison baseline method using the CARB OPGEE model or an alternative model or LCA methodology approved by the Executive Officer. Electronic copies of the models and calculations shall be provided with the application. The descriptions of the life cycle assessment results must include each of the following:

1. Detailed information on the energy consumed, the greenhouse gas emissions generated for the innovative method and the comparison baseline method;

2. Documentation of all non-default model input values used in the emissions calculation process. If values for any significant production parameters are unknown, the application shall so state and model default values shall be used for these parameters in the analysis;

3. Detailed description of all supporting calculations that were performed outside of the model; and

4. Documentation of all modifications other than those covered by subsection 2., above, made to the model. This discussion shall include sufficient specific detail to enable the Executive Officer to replicate all such modifications and, in combination with the inputs and supporting calculations identified in subsections 2. and 3., above, replicate the carbon intensity results reported in the application.

(E) An application shall include a list of references covering all information sources used in the preparation of the life cycle analysis and calculation of innovative method credit. The reference list must meet the requirements of section 95488.7(a)(2)(D).

(F) An application shall include a signed transmittal letter from the applicant attesting to the veracity of the information in the application packet and declaring that the information submitted accurately represents the actual and/or intended long-term, steady-state operation of the innovative method described in the application packet. The transmittal letter must meet the requirements of section 95488.8(a)(3)(A) through (D).

(G) CBI must be designated and a redacted version of any submitted documents designated to include CBI must be provided pursuant to the requirements described in section 95488.8(c).

(H) An application, supporting documents, and all other relevant data or calculation or other documentation must be submitted electronically via the ~~AFP~~LRT-CBTS unless the Executive Officer has approved or requested another format.

(3) *Application Approval Process.* The application must be approved by the Executive Officer before the crude oil producer or transporter, joint applicant, or purchasing refinery may generate credit for the innovative method.

(A) ~~Within 30 calendar days of~~Following receipt of an application designated by the applicant as ready for formal evaluation, the Executive Officer shall advise the applicant in writing either that:

1. The application is complete, or

2. The application is incomplete, in which case the Executive Officer will identify which requirements of section 95489(c) have not been met.

a. The applicant may submit additional information to correct deficiencies identified by the Executive Officer.

b. If the applicant is unable to achieve a complete application within 180 days of the Executive Officer's receipt of the original application, the application will be denied on that basis, and the applicant will be informed in writing.

(B) ~~After accepting an application as complete, the Executive Officer will post the application at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.~~ If the Executive Officer deems the application ready for validation, the applicant will be notified accordingly and provided with a list of eligibility requirements and comparison baseline inputs required for validation. The applicant must seek the services of an Executive Officer accredited verification body for validation as specified in section 95500 before the application can be accessed by the verification body. A positive or qualified positive validation statement must be received by the Executive Officer from the verification body in order for CARB's evaluation and certification of the project application to proceed. In cases where a single applicant or a joint applicant does not complete validation, the application will be denied without prejudice. In cases where an applicant cannot complete validation within six months of the verification body receiving the application from CARB, or receives an adverse validation statement, the application will be denied without prejudice.

~~(B)~~(C) After receiving a positive or qualified positive validation statement, the Executive Officer will post the application at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm. Public comments will be accepted for ~~10~~14 days following the date on which the application was posted. Only comments related to potential factual or methodological errors may be considered. The Executive Officer will forward to the applicant all comments identifying potential factual or methodological errors. Within 30 days, the applicant shall either submit revisions to its application to the Executive Officer, or submit a detailed written response to the Executive Officer explaining why no revisions are necessary.

~~(C)~~(D) The Executive Officer shall not approve an application if the Executive Officer determines, based upon the information submitted in the application and any other available information, that:

1. The proposed crude production or transport method is not an innovative method, as that term is defined in section 95489(c)(1).

2. Based upon the application information submitted pursuant to this section, the applicant's greenhouse gas emissions calculations cannot be replicated using the CARB OPGEE model or alternative model or LCA methodology approved by the Executive Officer.

~~(D)~~(E) As part of any action approving an application, the Executive Officer may prescribe conditions of the approval that contain special limitations, recordkeeping and reporting requirements, and operational conditions that the Executive Officer determines should apply to the innovative method. If the Executive Officer determines the application will not be approved, and the applicant will be notified in writing and the basis for the disapproval shall be identified.

(4) *Recordkeeping and Reporting.* Each applicant that receives approval for an innovative method must maintain records identifying each facility at which it produces crude oil for sale in California under the approved innovative method. For each such facility, the ~~applicant~~regulated entity must report quarterly or annually (through a Project Report~~) and maintain records~~); a regulated entity electing to report annually is required to submit its annual Project Report to CARB for the previous compliance year by

April 30 of each year. Records of each such facility must be maintained for at least ten years showing:

(A) The volume (barrels) of crude oil produced or transported using the approved innovative method and the crude name(s) under which it is marketed.

(B) If the crude oil produced or transported with an approved innovative method is marketed as part of a crude blend that is not wholly refined in California, the name of the blend and the volume fraction that the crude produced with the innovative method contributes to the blend.

(C) For crude oil imported into California, documentation showing that the innovative crude was supplied to one or more California refinery and the volume (barrels) of innovative crude supplied to each California refinery. For crude oil produced in California, documentation showing the innovative crude was supplied to one or more California refinery, the total volume (barrels) of innovative crude supplied to California refineries, and the total volume (barrels) of innovative crude exported from California.

(D) For solar or wind electricity projects, the following additional recordkeeping and reporting will be required:

1. Metered data on solar or wind electricity consumed at the crude oil production or transport facilities during the ~~quarter~~reporting period (kWh);

2. Metered data on total electricity consumed at the crude oil production or transport facilities during the ~~quarter~~reporting period (kWh); and

3. An attestation letter stating that all solar or wind electricity was supplied directly for crude oil production or transport and that the solar or wind electricity reported for generating LCFS credit did not produce renewable energy certificates or other environmental attributes recognized or credited by any other jurisdiction or regulatory program, other than the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

(E) For solar steam projects at crude oil production facilities, the following additional recordkeeping and reporting will be required:

1. Metered data on solar steam consumed for crude oil production at the oil field during the ~~quarter~~reporting period (barrels cold water equivalent);

2. Metered data on total steam consumed for crude oil production at the oil field during the ~~quarter~~reporting period (barrels cold water equivalent);

3. Volume-weighted average steam quality for solar steam consumed for crude oil production at the oil field during the ~~quarter~~reporting period; and

4. An attestation letter stating that all solar steam was supplied directly for crude oil production at the oil field and that the solar steam reported for generating LCFS credit did not produce renewable energy certificates or other environmental attributes recognized or credited by any other jurisdiction or regulatory program, other than the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

(F) Any additional records that the Executive Officer requires to be kept in pursuant to section 95489(c)(3)(D), and records that demonstrate compliance with all special limitations and operating conditions specified pursuant to section 95489(c)(3)(D).

These records shall be submitted to the Executive Officer during the quarterly or annual reporting period specified in section 95491(b).

(5) *Credits for Producing or Transporting Crude Oil Using Innovative Methods.* Credits for producing or transporting crude oil using innovative methods may be generated quarterly or annually, at the discretion of the credit generating party. ~~Within 30 days of~~After receiving reports from California refineries detailing crude names and volumes supplied to the refineries during the applicable crediting period, any records requested of the applicant under section 95489(c)(4), and a positive or qualified positive verification of the applicable Project Reports per section 95500, the Executive Officer will determine the number of credits to be issued to the crude oil producer or transporter, joint applicant, or purchasing refinery for the innovative method. An adverse verification statement would result in no credit issuance and Executive Officer investigation. Except for carbon capture and sequestration (CCS) projects, the crediting period for projects eligible for credit generation pursuant to section 95489(c) will end no later than December 31, 2040.

(d) *Low-Complexity/Low-Energy-Use Refinery Credit.* A refinery may receive credit for being a low-complexity and low-energy-use refinery.

(1) To be eligible for the credit calculation in section 95489(d)(3), a Low-Complexity/Low-Energy-Use Refinery must meet the criteria in the definition of “Low-Complexity/Low-Energy-Use Refinery” provided in section 95481(a) using the following equations:

(A) Modified Nelson Complexity Score

$$Modified\ Nelson\ Complexity\ Score = \sum_{i}^{n} (index_i)\left(\frac{Capacity_i}{Capacity_{dist}}\right)$$

where:

$index_i$ is the 2012 Nelson Complexity Index listed in Table 10;

$Capacity_i$ is the capacity of each unit listed in Table 10 in barrels per day unless otherwise indicated;

$Capacity_{dist}$ is the capacity of the distillation unit in barrels per day;

i is the process unit; and

n is the total number of process units.

Table 10. Nelson Complexity Indices.

Process Unit	***Index Value***
Atmospheric Distillation	1.00
Vacuum Distillation	1.30
Thermal Processes	2.75
Delayed and Fluid Coking	7.50
Catalytic Cracking	6.00
Catalytic Reforming	5.00
Catalytic Hydrocracking	8.00
Catalytic Hydrorefining/Hydrotreating	2.50
Alkylation	10.00
Polymerization	10.00

Process Unit	Index Value
Aromatics	20.00
Isomerization	3.00
Oxygenates	10.00
Hydrogen (MMcfd)	1.00
Sulfur Extraction (Metric Tons per day)	240.00

(B) Annual Energy Use

$$Annual\ Energy\ Use\ (in\ MMBtu) = fuel\ use + electricity + thermal$$

where:

$fuel\ use$ is the MMBtu of all fuel combusted during the compliance period;

$electricity$ is the imported electricity minus exported electricity per compliance period converted to MMBtu by using 3.142 MMBtu/MWh; and

$thermal$ is the imported thermal energy minus exported thermal energy per compliance period in MMBtu.

(2) In addition to other reporting requirements, a refinery operator that is claiming credits for a Low-Complexity/Low-Energy-Use Refinery must also report the following volumes produced during a specific calendar year and sold, supplied, or offered for sale in California for that refinery:

(A) The volume of CARBOB and volume of diesel produced from crude oil;

(B) The volume of CARBOB and volume of diesel produced from transmix;

(C) The volume of CARBOB and volume of diesel produced from Petroleum Intermediate feedstocks; and

(D) The volume of CARBOB and volume of diesel purchased for blending.

(E) If CARBOB or diesel is produced from feedstock other than crude oil (volumes in (2)(B) through (D), above), a separate annual report with third-party verification is required for produced volumes of CARBOB and diesel from crude oil. The annual report must be submitted by ~~March 31st~~April 30 and the verification statement is due August 31~~st~~.

(3) Credits for a low-complexity/low-energy-use refinery must be calculated using the following equations:

(A) *Carbon Intensity Adjustment.* For volumes reported in section 95489(d)(2)(A) a non-transferable credit of 5.0 gCO_2e/MJ will be generated.

(B) *Credit Calculation.* For CARBOB and diesel volumes reported in section 95489(d)(2)(A):

$$Credits^{XD}_{LC-LE} = 5\ gCO2e/MJ \times VF^{XD} \times E^{XD} \times C$$

where:

$Credits^{XD}_{LC-L}$ is the amount of LCFS credits generated (a zero or positive value), in metric tons, by a fuel or blendstock under the average carbon intensity requirement for gasoline (XD = “gasoline”) or diesel (XD = ”diesel”);

VF^{XD} means the volume fraction of CARBOB (XD = “CARBOB”) or diesel (XD = “diesel”) fuel that is derived from crude oil supplied to the Low-Complexity/Low-Energy-Use refinery. VF^{XD} is calculated by dividing the volume of CARBOB or diesel reported for section 95489(d)(2)(A) by the total volume of CARBOB or diesel reported for section 95489(d)(2)(A) through (D);

E^{XD} is the amount of fuel energy, in MJ, from CARBOB (XD = “CARBOB”) or diesel (XD = “diesel”), determined from the energy density conversion factors in Table 4, either produced in California or imported into California during a specific calendar year and sold, supplied, or offered for sale in California; and

$$C = 1.0 \times 10^{-6} \frac{MT}{gCO_2e}$$

(C) Credits created pursuant to section 95489(d) may not be sold or transferred to any other party.

(4) *Application Contents and Submittal.* An application for Low-Complexity/Low-Energy-Use Refinery Credits must comply with the following requirements:

(A) An application must contain the following summary material:

1. A complete description of the refinery including processing units and their capacity, and energy use;

2. An engineering drawing(s) or process flow diagram(s) that illustrates the project, relevant process equipment, and mass or volumetric flows necessary to calculate the Low-Complexity/Low-Energy-Use Refinery Credits; and

3. A preliminary estimate of the credit, calculated as required in section 95489(d)(3)(B), including descriptions and copies of production and operational data other technical documentation utilized in support of the calculation.

(B) An application must include a list of references covering all information sources used in the calculation of Low-Complexity/Low-Energy-Use Refinery Credits. The reference list must meet the requirements of section 95488.7(a)(2)(D).

(C) An application must include a signed transmittal letter from the applicant attesting to the veracity of the information in the application packet and declaring that the information submitted accurately represents the actual operation of the refinery. The transmittal letter must meet the requirements of section 95488.8(a)(3)(A) through (D).

(D) An applicant that submits any information or documentation in support of a proposed Low-Complexity/Low-Energy-Use Refinery Credit must include a written statement clearly showing that the applicant understands and agrees that all information in the application not identified as confidential business information is subject to public disclosure pursuant to California Code of Regulations, title 17, sections 91000 through 91022 and the California Public Records Act (Government Code, §§ .6250 et seq.), and that information claimed by the applicant to be confidential might later be disclosed under section 91022 if the Board determines the information is subject to disclosure.

(E) An application, supporting documents, and all other relevant data or calculation or other documentation must be submitted electronically via the ~~AFP~~LRT-CBTS unless the Executive Officer has approved or requested another format.

(F) If there is a change to an approved Low-Complexity/Low-Energy-Use Refinery which could impact the eligibility of the refinery, the refinery operator must notify the Executive Officer in writing within 30 ~~business~~ days after the material change has occurred, and the previously-approved application shall become invalid 30 ~~business~~ days after the material change has occurred.

(5) *Credit Issuance.* The Executive Officer will issue Low-Complexity/Low-Energy-Use Refinery Credits annually for the prior year upon the completion of the following:

(A) Confirmation of eligibility by the Executive Officer based on the refinery energy use verified under MRR annually.

(B) Receipt of a positive or qualified positive verification statement for the quarterly fuel transactions reported pursuant to section 95489(d)(2). An adverse verification statement would result in no credit issuance and Executive Officer investigation.

(C) The crediting period for projects eligible for credit generation pursuant to section 95489(d) will end no later than December 31, 2040.

(e) *Refinery Investment Credit Program.* A refinery, or a hydrogen production facility physically providing hydrogen to a refinery, may receive credit for reducing greenhouse gas emissions from its facility. For projects at hydrogen production facilities not owned by the refinery, the refinery and hydrogen production facility must apply as joint applicants. Any such credits must be based on fuel volumes sold, supplied, or offered for sale in California as set forth below.

(1) *General Requirements*.

(A) The application for a refinery investment credit must be submitted during or after the year 2016 and must be approved pursuant to this section before the refinery or hydrogen production facility can receive credit. A project is eligible if the project completion date is on January 1, 2016 or later.

(B) The refinery investment credit project must occur within the boundaries of the refinery~~, unless it involves carbon capture from~~ or hydrogen production facility. Sequestration sites for CCS do not need to be on-site at the refinery.

(C) The applicant must demonstrate that any net increases in criteria air pollutant or toxic air contaminant emissions from the refinery investment credit project are mitigated in accordance with all local, state, and national environmental and health and safety regulations.

(D) The following project types are eligible for the refinery investment project credits:

1. CO_2 capture from existing anthropogenic sources at refineries, or at hydrogen production facilities that supply hydrogen to refineries, and subsequent geologic sequestration;

2. Use of renewable or low-CI electricity supplied behind the meter ~~that meets the requirements of 95488.8(h)(1);~~at refineries or at hydrogen production facilities;

3. Use of lower-CI process energy such as biomethane, renewable propane, and renewable coke, to displace fossil fuel at refineries or hydrogen production facilities;

4. Electrification at refineries or hydrogen production facilities that involves substitution of high carbon fossil energy input with grid electricity.

5. Process improvement projects that deliver a reduction in baseline refinery-wide greenhouse gas emissions as outlined in 95489(e)(1)(~~G)2.~~J). Greenhouse gas emissions reductions due to curtailment, simple maintenance; and crude oil switching that results in greenhouse gas reductions in the project system boundary without improvements in the processing units or equipment involved are not eligible. For the purposes of this section, curtailment is defined as an intentional operational and/or physical change exclusively for the reduction or cessation of total gasoline and gasoline blendstocks and diesel production at the refinery~~.~~ or hydrogen production at the hydrogen production facility. Curtailment does not include the coincidental rate reduction or shutdown of associated emitting equipment as part of a process improvement project or projects aimed primarily at optimizing refinery or hydrogen production efficiency.

(E) Credits must be pro-rated for years where the units within the project system boundary were non-operational. This pro-rating will consider the ~~calendar~~ days of operation relative to non-operation.

(F) Credits must be pro-rated if the hydrogen production facility ~~that captures CO_2~~ does not supply all of its hydrogen to the applicant refinery.

(G) Credits generated pursuant to section 95489(e)(1)(D)5. are subject to the following limitations:

1. Credits may not be used to meet more than 10 percent of any entity's annual compliance obligation. The Executive

Officer will exclude incremental deficits incurred pursuant to section 95489(b) when assessing this 10 percent limitation.

~~2. Each project must generate at least 10,000 credits or one percent of the facility's annual pre-project emissions, whichever is less.~~

~~3.~~2. Crediting is limited to 15 years from the quarter in which the Executive Officer approves the project's application.

(H) Projects that utilize carbon capture and sequestration are subject to the provisions of section 95490.

(I) The project operator must provide a written application to the Executive Officer. If the project involves lower-CI process energy or renewable or low-CI electricity produced by a third party and delivered to the refinery or hydrogen production facility, both the refinery or hydrogen production facility and the third party must apply and will be considered joint applicant project operator for approval of the project. If more than one refinery or hydrogen production facility receives lower-CI process energy or renewable or low-CI electricity from a single third-party facility, each refinery or hydrogen production facility must submit an independent application with the third party as a joint applicant on each submittal. If the project involves delivery of carbon captured by the refinery or hydrogen production facility to a third party to store the carbon, both the refinery or hydrogen production facility and the third party must apply and will be considered joint applicants for approval of the project.

(J) Applications submitted pursuant to section 95489(e)(1)(D) must demonstrate an emissions reduction of at least 10,000 metric tons CO_2e per year or one percent of the facility's annual pre project emissions, whichever is less.

(K) Renewable or low-CI energy sources listed in 95489(e)(1)(D) that are used to generate LCFS credit may not also claim renewable energy certificates or other environmental attributes recognized or credited by any other jurisdiction or regulatory program, other than the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800). Any renewable energy certificates or other environmental attributes associated with the energy must be retired on behalf of the LCFS.

(2) *Calculation of Credits*.

(A) For carbon capture and sequestration projects, determine the credit in accordance with sections 95489(e)(2), 95490, and the CCS protocol.

(B) For other refinery investment credit projects, determine the credit as follows:

1. Establish a project system boundary. The project system boundary should include direct impacts and at least first order indirect impacts;

2. Determine the credit for the refinery investment credit project by calculating pre-project life cycle greenhouse gas emissions and project life cycle greenhouse gas emissions within the project system boundary;

$$Credit_{RIP} = (GHG_{pre-project} - GHG_{post-project}) \times \frac{Volume^{XD}}{Volume^{Total}}$$

where:

$Credit_{RIP}$ is the annual credit for the refinery investment credit project in metric tons per year;

$GHG_{pre-project}$ is the annual life cycle greenhouse gas emissions from the use of fuels, electricity, steam/heat and hydrogen in the project system boundary prior to project implementation in metric tons per year corrected for downtime;

$GHG_{post-project}$ is the annual life cycle greenhouse gas emissions from the use of fuels, electricity, steam/heat and hydrogen in the project system boundary due to project implementation in metric tons per year corrected for downtime;

$Volume^{XD}$ is the volume of gasoline, gasoline blendstocks, and diesel in gallons per quarter or per year produced at the refinery and sold, supplied, or offered for sale in California by the refinery involved in the Refinery Investment Credit Program; and

$Volume^{Total}$ is the total volume of gasoline, gasoline blendstocks, and diesel in gallons produced at the refinery per quarter or per year.

(3) *Application Contents and Submittal.* Unless otherwise noted, an application for refinery investment credits must comply with the following requirements:

(A) An application must contain the following summary material:

1. A complete description of the refinery investment credit project and how emissions are reduced;

2. An engineering drawing(s) or process flow diagram(s) that illustrates the project and clearly identifies the system boundaries, relevant process equipment, mass flows, and energy flows necessary to calculate the refinery investment credits, including any directly affected or indirectly affected processing units (at least first order indirect impacts) and a whole refinery diagram if requested; and

3. A preliminary estimate of the refinery investment credit, calculated as required in section 95489(e)(2), including descriptions and copies of any available production and operational data including energy use and other technical documentation utilized in support of the calculation. The application must contain process-specific data showing that the reductions are part of the transportation fuel pathway.

4. Supporting documents demonstrating that second or higher order indirect impacts are not significant beyond the identified project system boundary.

(B) An application must include a list of references covering all information sources used in the calculation of refinery investment credit. The reference list must meet the requirements of section 95488.7(a)(2)(D).

(C) An application must include a signed transmittal letter from the applicant attesting to the veracity of the information in the application packet and declaring that the information submitted accurately represents the actual and/or intended long-term, steady-state operation of the refinery investment credit project described in the application packet. The transmittal letter must meet the requirements of section 95488.8(a)(3)(A) through (D).

(D) CBI must be designated and a redacted version of any submitted documents designated to include CBI must be provided pursuant to the requirements described in section 95488.8(c).

(E) An application must include all relevant documentation identifying any changes, including decreases or increases, in criteria air pollutant or toxic air contaminant emissions based on local air permits and supporting permit documentation from the refinery investment credit project. An applicant must include a signed transmittal letter from the applicant attesting that any net increases in emissions from the refinery investment credit project are mitigated in accordance with all local, state, and national environmental and health and safety regulations.

(F) An applicant that submits any information or documentation in support of a proposed refinery investment credit must include a written statement clearly showing that the applicant understands and agrees that all information in the application not identified as confidential business information is subject to public disclosure pursuant to California Code of Regulations, title 17, sections 91000 through 91022 and the California Public Records Act (Government Code, §§ .6250 et seq.), and that information claimed by the applicant to be confidential might later be disclosed under section 91022 if the Board determines the information is subject to disclosure.

(G) An application, supporting documents, and all other relevant data or calculation or other documentation must be submitted electronically via the ~~AFP~~LRT-CBTS unless the Executive Officer has approved or requested another format.

(H) Applications for process improvement projects must be submitted on or before December 31, 2025.

(4) *Application Approval Process.* An application must be approved by the Executive Officer before the refinery investment credit project can generate credits under the LCFS regulation.

(A) After receipt of an application designated by the applicant as ready for formal evaluation, the Executive Officer will advise the applicant in writing either that:

1. The project system boundary is appropriate and the application is complete, or

2. The application is incomplete, in which case the Executive Officer will identify which requirements of section 95489(e) have not been met. The applicant may submit additional information to correct deficiencies identified by the Executive Officer. If the applicant is unable to achieve a complete application within 180 ~~calendar~~ days of the Executive Officer's receipt of the original application, the application will

be denied on that basis, and the applicant will be informed in writing.

(B) ~~After accepting an application as complete, the Executive Officer will post the application at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm.~~ If the Executive Officer deems the application ready for validation, the applicant will be notified accordingly and provided with a list of eligibility requirements and comparison baseline inputs required for validation. The applicant must seek the services of an Executive Officer accredited verification body for validation as specified in section 95500 before the application can be accessed by the verification body. A positive or qualified positive validation statement must be received by the Executive Officer from the verification body in order for CARB's evaluation and certification of the project application to proceed. In cases where a single applicant or a joint applicant does not complete validation, the application will be denied without prejudice. In cases where an applicant cannot complete validation within six months of the verification body receiving the application from CARB, or receives an adverse validation statement, the application will be denied without prejudice.

~~(B)~~(C) After receiving a positive or qualified positive validation statement, the Executive Officer will post the application at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm. Public comments will be accepted for ~~10 calendar~~14 days following the date on which the application was posted. Only comments related to potential factual or methodological errors may be considered. The Executive Officer will forward to the applicant all comments identifying potential factual or methodological errors. Within 30 ~~business~~ days, the applicant must either submit revisions to its application to the Executive Officer, or submit a detailed written response to the Executive Officer explaining why no revisions are necessary.

~~(C)~~(D) If the Executive Officer finds that an application meets the requirements set forth in section 95489(e), the Executive Officer will take final action to approve the refinery investment credit project. The Executive Officer may prescribe conditions of approval that contain special limitations, recordkeeping and reporting requirements, and operational conditions that the Executive Officer determines should apply to the project. If the Executive Officer finds that an application does not meet the requirements of section 95489(e), the application will not be approved, and the applicant will be notified in writing, and the basis for the disapproval will be identified.

(E) ~~*Credit Review and Issuance.*~~The Executive Officer shall not approve an application if the Executive Officer determines, based upon the information submitted in the application and any other available information, that:

1. The proposed project does not meet the requirements set forth in section 95489(e).

2. Based upon the application information submitted pursuant to this section, the applicant's greenhouse gas emissions calculations cannot be replicated.

(5) *Reporting, Credit Review, and Issuance.* For each approved refinery investment credit project, the regulated entity must report quarterly or annually through a Project Report. A regulated entity electing to report annually is required to submit its annual Project Report to CARB for the previous compliance year by April 30 of each year. Credits for refinery investment projects may be generated quarterly or annually, at the discretion of the credit generating party.

(A) Upon the completion of reporting period in which a positive or qualified positive verification statement for the applicable Project Reports per section 95500(e) is received, the Executive Officer will determine the number of credits to be issued to the applicants. An adverse verification statement would result in no credit issuance and Executive Officer investigation.

(B) Except for CCS projects, the crediting period for projects eligible for credit generation pursuant to section 95489(e) will end no later than December 31, 2040.

(6) *Recordkeeping.* For each approved refinery investment credit project, the ~~refinery~~regulated entity must compile and retain records pursuant to section 95491.1(a)(2) showing compliance with all limitation and recordkeeping requirements identified by the Executive Officer pursuant to section 95489(e)(4)(~~C~~E), above.

(f) *Renewable Hydrogen Refinery Credit Program.* A refinery, or a hydrogen production facility physically providing hydrogen to a refinery, may receive credit for greenhouse gas emission reductions from the production of CARBOB or diesel fuel that is partially or wholly derived from renewable hydrogen. For projects at hydrogen production facilities not owned by the refinery, the refinery and hydrogen production facility must apply as joint applicants. Any such credits must be based on fuel volumes sold, supplied, or offered for sale in California as set forth below.

(1) *General Requirements*.

(A) In order to receive a renewable hydrogen refinery credit, a refiner must produce CARBOB or diesel fuel that is partially or wholly derived from renewable hydrogen.

(B) The applicant must demonstrate that any net increases in criteria air pollutant or toxic air contaminant emissions from the renewable hydrogen refinery credit project are mitigated in accordance with all local, state, and national environmental and health and safety regulations.

(C) The project operator must submit a written application to the Executive Officer. If the project involves renewable natural gas or electricity produced by a third party and delivered to the refinery or hydrogen production facility, both the refinery or hydrogen production facility and the third party must apply and will be considered joint applicant project operator for approval of the project. If more than one refinery or hydrogen production facility receives renewable natural gas or electricity from a single third-party facility, each refinery or hydrogen production facility must submit an independent application with the third party as a joint applicant on each submittal.

(D) Applications submitted pursuant to section 95489(f) must demonstrate a generation of at least 10,000 credits or one percent of the facility's annual pre-project emissions, whichever is less.

(E) Renewable or low-CI energy sources that are used to produce renewable hydrogen and generate LCFS credit may not also claim renewable energy certificates or other environmental attributes recognized or credited by any other jurisdiction or regulatory program, other than the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800). Any renewable energy certificates or other environmental attributes associated with the energy used to produce renewable hydrogen must be retired on behalf of the LCFS.

(2) *Calculation of Credits*.

(A) For CARBOB or diesel fuel that is partially or wholly derived from renewable hydrogen produced from RNG that displaces fossil natural gas in a steam methane reforming unit, the calculation of credits generated quarterly or annually must be as follows:

$$Credits^{H}_{RIC} = (CI_{NG} - CI_{RNG}) \times E_{RNG} \times C \times \frac{Volume^{XD}}{Volume^{Total}}$$

where:

$Credits^{H}_{RIC}$ is the amount of LCFS credits generated (a zero or positive value), in metric tons, by renewable hydrogen;

CI_{NG} is the well-to-hydrogen production carbon intensity of North American pipeline natural gas in gCO_2e/MJ calculated using the same feedstock assumptions and pipeline distance as the Lookup Table pathway for Pipeline Average North American Fossil Natural Gas (CNGF);

CI_{RNG} is the well-to-hydrogen production carbon intensity of the RNG in gCO_2e/MJ and must be determined using the CA~~-GREET 3~~-GREET4.0- model unless the Executive Officer has approved the use of a method that is at least equivalent to the calculation methodology used by CA~~-~~-GREET~~3~~4.0 model. The process for obtaining CI_{RNG} will be identical to Tier 2 fuel pathway applications, and the life cycle steps evaluated will stop at hydrogen production at the refinery;

E_{RNG} is the amount of RNG in MJ ~~delivered~~that displaces fossil natural gas for hydrogen production at a refinery or a facility providing hydrogen to a refinery per quarter or per year;

$Volume^{XD}$ is the volume of gasoline, gasoline blendstocks, and diesel in gallons per quarter or per year produced at the refinery and sold, supplied, or offered for sale in California by the refinery;

$Volume^{Total}$ is the total volume of gasoline, gasoline blendstocks, and diesel in gallons produced at the refinery per quarter or per year; and

$$C = 1.0 \times 10^{-6} \frac{MT}{gCO2e}$$

(B) For CARBOB or diesel fuel that is partially or wholly derived from renewable hydrogen produced from other production processes, such as electrolysis using renewable electricity or syngas from biomass gasification, the calculation of credits generated quarterly or annually must be as follows:

$$Credits^{H}_{RIC} = (CI^{H}_{Fossil} - CI^{H}_{Renewable}) \times D^{H}_{Renewable} \times M^{H}_{Renewable} \times C \times \frac{Volume^{XD}}{Volume^{Total}}$$

where:

$Credits^{H}_{RIC}$ is the amount of LCFS credits generated (a zero or positive value), in metric tons, by renewable hydrogen;

CI^{H}_{Fossil} is the carbon intensity of fossil hydrogen in gCO_2e/MJ delivered or produced at the refinery, as determined using the CA~~-~~-

GREET~~3~~4.0 model or similar models approved by the Executive Officer. The process for obtaining CI^{H}_{Fossil} must comply with the requirements in sections 95488 to 95488.10;

$CI^{H}_{Renewable}$ is the carbon intensity of renewable hydrogen in gCO_2e/MJ delivered or produced at the refinery, as determined using the CA-GREET~~3~~4.0 model. The process for obtaining $CI^{H}_{Renewable}$ must comply with the requirements in sections 95488 to 95488.10;

$M^{H}_{Renewable}$ is the amount of renewable hydrogen in kg per quarter or per year;

$D^{H}_{Renewable}$ is the energy density of hydrogen in MJ/kg from Table 4;

$Volume^{XD}$ is the volume of gasoline, gasoline blendstocks, and diesel in gallons per quarter or per year sold, supplied, or offered for sale in California by the refinery involved in the Renewable Hydrogen Refinery Credit Program;

$Volume^{Total}$ is the total volume of gasoline, gasoline blendstocks, and diesel in gallons produced at the refinery per quarter or per year; and

$$C = 1.0 \times 10^{-6} \frac{MT}{gCO2e}$$

(3) *Application Contents and Submittal.* Unless otherwise noted, an application for renewable hydrogen credits must comply with the following requirements:

(A) An application must contain the following summary material:

1. A complete description of the production of CARBOB or diesel fuel with hydrogen and how renewable hydrogen is replacing fossil hydrogen in that process;

2. Purchase records identifying the renewable hydrogen and/or renewable feedstock used to produce the renewable hydrogen; and

3. A preliminary estimate of the renewable hydrogen refinery credit, calculated as required in section 95489(f)(2), including descriptions and copies of production and operational data, including energy use, and other technical documentation utilized in support of the calculation. The application must contain process-specific data showing that the reductions are part of the transportation fuel pathway.

(B) An application must include a list of references covering all information sources used in the calculation of renewable hydrogen refinery credit project. The reference list must meet the requirements of section 95488.7(a)(2)(D).

(C) An application must include a signed transmittal letter from the applicant attesting under penalty of perjury under California law, to the veracity of the information in the application packet and declaring that the information submitted accurately represents the actual and/or intended long-term, steady-state operation of renewable hydrogen refinery credit project described in the application packet. The transmittal letter must meet the requirements of section 95488.8(a)(3)(A) through (D).

(D) CBI must be designated and a redacted version of any submitted documents designated to include CBI must be provided pursuant to the requirements described in section 95488.8(c).

(E) An application must include all relevant documentation identifying any changes, including decreases or increases, in criteria air pollutant or toxic air contaminant emissions based on local air permits from the renewable hydrogen refinery credit project. An applicant must include a signed transmittal letter from the applicant attesting that any net increases in emissions from renewable hydrogen refinery credit project are mitigated in accordance with all local, state, and national environmental and health and safety regulations.

(F) An application, supporting documents, and all other relevant data or calculation or other documentation must be submitted electronically via the ~~AFP~~LRT-CBTS unless the Executive Officer has approved or requested another format.

(4) *Application Approval Process.* An application must be approved by the Executive Officer before the renewable hydrogen refinery credit project can generate credits under the LCFS regulation.

(A) ~~Within 30 calendar days of~~Following receipt of an application designated by the applicant as ready for formal evaluation, the Executive Officer will advise the applicant in writing either that:

1. The application is complete, or

2. The application is incomplete, in which case the Executive Officer will identify which requirements of section 95489(f) have not been met. The applicant may submit additional information to correct deficiencies identified by the Executive Officer. If the applicant is unable to achieve a complete

application within 180 days of the Executive Officer's receipt of the original application, the application will be denied on that basis, and the applicant will be informed in writing.

(B) If the Executive Officer deems the application ready for validation, the applicant will be notified accordingly and provided with a list of eligibility requirements and comparison baseline inputs required for validation. The applicant must seek the services of an Executive Officer accredited verification body for validation as specified in section 95500 before the application can be accessed by the verification body. A positive or qualified positive validation statement must be received by the Executive Officer from the verification body in order for CARB's evaluation and certification of the project application to proceed. In cases where a single applicant or a joint applicant does not complete validation, the application will be denied without prejudice. In cases where an applicant cannot complete validation within six months of the verification body receiving the application from CARB, or receives an adverse validation statement, the application will be denied without prejudice.

(C) After receiving a positive or qualified positive validation statement, the Executive Officer will post the application at http://www.arb.ca.gov/fuels/lcfs/lcfs.htm. Public comments will be accepted for 14 days following the date on which the application was posted. Only comments related to potential factual or methodological errors may be considered. The Executive Officer will forward to the applicant all comments identifying potential factual or methodological errors. Within 30 days, the applicant must either submit revisions to its application to the Executive Officer, or submit a detailed written response to the Executive Officer explaining why no revisions are necessary.

(D) The Executive Officer shall not approve an application if the Executive Officer determines, based upon the information submitted in the application and any other available information, that:

1. The proposed project does not meet the requirements set forth in section 95489(f).

2. Based upon the application information submitted pursuant to this section, the applicant's greenhouse gas emissions calculations cannot be replicated.

~~(B)~~(E) If the Executive Officer finds that an application meets the requirements set forth in section 95489(f), the Executive Officer will take final action to approve the renewable hydrogen refinery credit project. The Executive Officer may prescribe conditions of approval that contain special limitations, recordkeeping and reporting requirements, and operational conditions that the Executive Officer determines should apply to the project. If the Executive Officer finds that an application does not meet the requirements of section 95489(f), the application will not be approved, and the applicant will be notified in writing, and the basis for the disapproval will be identified.

(5) ~~*Credit Review and Issuance.*~~*Reporting, Credit Review, and Issuance.* For each approved renewable hydrogen refinery credit project, the regulated entity must report quarterly or annually through a Project Report. A regulated entity electing to report annually is required to submit its annual Project Report to CARB for the previous compliance year by April 30 of each year. Credits for renewable hydrogen refinery projects may be generated quarterly or annually, at the discretion of the credit generating party.

(A) Upon the completion of reporting period in which a positive or qualified positive verification statement for the applicable Project Reports per section 95500(e) is received, the Executive Officer will determine the number of credits to be issued to the applicants. An adverse verification statement would result in no credit issuance and Executive Officer investigation.

(B) The crediting period for projects eligible for credit generation pursuant to section 95489(f) will end no later than December 31, 2040.

(6) *Recordkeeping.* For each approved renewable hydrogen refinery credit project, the ~~refinery~~regulated entity must compile and retain records pursuant to section 95491.1(a)(2) showing compliance with all limitation and recordkeeping requirements identified by the Executive Officer pursuant to section 95489(f)(4)(~~B~~E), above.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95490. Provisions for Fuels Produced Using Carbon Capture and Sequestration.

(a) *Eligibility.* The following entities are eligible to submit ~~project~~ applications and, if approved, receive ~~CCS~~ credits associated with net GHG reductions from CCS projects, in accordance with following protocol which is incorporated herein by reference and is referred to as the “CCS Protocol” hereafter.

Industrial Strategies Division, California Air Resources Board. August 13, 2018. Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard.

(1) Alternative fuel producers, petroleum refineries, and oil ~~and gas~~ producers that capture CO_2 on-site, including at the location of the production of hydrogen used as an intermediate input, and geologically sequester CO_2 either on-site or off-site.

(2) An entity that employs direct air capture to remove CO_2 from the atmosphere using chemical and/or physical separation and geologically sequester the CO_2~~.~~

(A) Direct air capture and sequestration projects must be physically located in the United States.

~~(2)~~(B) If CO_2 derived from direct air capture is converted to fuels, it is not eligible for project-based CCS credits. However, applicants may apply for fuel pathway certification using the Tier 2 pathway application process as described in section 95488.7.

(b) *General Requirements*.

(1) Projects and fuel pathways claiming CCS credits must comply with the CCS Protocol. To be considered in compliance with the CCS protocol, a project must be issued executive orders and meet all the requirements throughout the project life in accordance with the permanence requirements of the CCS protocol.

(2) Credit determination for any project that utilizes CCS must be performed in accordance with the accounting requirements of the CCS protocol.

(3) Except for direct air capture and sequestration projects, credits must be prorated based on the volumes delivered to California.

(4) CCS credits generated by crude oil ~~and gas~~ producers must be claimed under the Innovative Crude Provision (section 95489(c)).

(5) CCS credits ~~generated~~ by refiners must be claimed under the Refinery Investment Credit Program (section 95489(e)).

(6) ~~The amount~~A Tier 2 pathway application must be submitted pursuant to section 95488.7 to capture the GHG reduction benefit of ~~net CO_2 sequestered by~~CCS associated with alternative fuel producers ~~can be~~

~~used to adjust the carbon intensities~~. The GHG reduction benefit of CCS is reflected in the ~~associated~~ CI score of the Tier 2 fuel pathway~~s~~.

(7) Projects utilizing CCS must undergo verification under section 95500 in order to receive credits.

(8) For direct air capture operations only, the greenhouse gas emissions for electricity used by the capture facility must be calculated as follows:

(A) For electricity generated onsite (i.e., behind the meter), the greenhouse gas emissions must be calculated using the CA-GREET4.0 emission factors for the specific electricity supply.

(B) Grid electricity used in direct air capture can be claimed as low-CI electricity as specified in section 95488.8(i)(1)(C).:

(C) If new or expanded purchased low-CI electricity cannot be demonstrated, the greenhouse gas emissions must be calculated using CA-GREET4.0 (e.g., eGRID U.S. subregion if applicable) emission factors.

(c) *Application Contents and Submittal.* Unless otherwise noted, an application for CCS credits must comply with the following requirements:

(1) An application must be filed jointly by an entity that captures CO_2, an entity that transports the CO_2, and an entity that sequesters the resultant CO_2, unless the same entity is responsible for CO_2 capture, transport, and sequestration.

(2) An application must contain the following materials:

(A) A complete description of the CCS project and how greenhouse gas emissions are reduced; to be eligible for LCFS credits, a CCS project sequestering CO_2 that is already being captured and used productively in industry must demonstrate a net reduction in greenhouse gas emissions by providing evidence that the marginal new source of CO_2 replacing the prior industrial use is newly installed or expanded capture from anthropogenic sources;

(B) An engineering drawing(s) or process flow diagram(s) that illustrates the project and clearly identifies the system boundaries, relevant process equipment, mass flows, including the quantity of CO_2 injected into pipeline or delivered by other modes of transport for CO_2 injection, and energy flows necessary to calculate the CCS credit;

(C) A description of all combustion and electricity-powered equipment within the system boundaries, including their respective capacities, sizes, or rated power, fuel utilization type, fuel shares, energy efficiency (lower heating value basis), and proposed use;

(D) A description of all sources of flared, vented, and fugitive emissions within the system boundaries, including the compositions and quantities of the flared, vented, and fugitive emission streams leaving the system boundaries;

(E) Receipts/invoices for energy use and chemicals;

(F) An estimate of the CCS credit, calculated in accordance with the accounting requirements of the CCS Protocol including descriptions and copies of production and operational data or other technical; and documentation utilized in support of the calculation. The application must contain process-specific data showing that the reductions are part of the CCS project, and

(G) Executive orders issued pursuant to the permanence requirements of the CCS protocol, certifying the sequestration site as capable of permanently storing CO_2 and authorizing operation and credit generation.

(3) An application must include a list of references covering all information sources used in the calculation of the CCS credit. The reference list must meet the requirements of section 95489(c)(2)(E).

(4) An application must include a signed transmittal letter from the applicant attesting to the veracity of the information in the application packet and declaring that the information submitted accurately represents the actual CCS project greenhouse gas emissions reductions. The transmittal letter must be the original copy, be on company letterhead, be signed by an officer of the applicant with authority to attest to the veracity of the information in the application and to sign on behalf of the applicant.

(5) CBI must be designated and a redacted version of any submitted documents designated to include CBI must be provided pursuant to the requirements described in section 95488.8(c).

(6) An applicant that submits any information or documentation in support of a proposed CCS project must include a written statement clearly showing that the applicant understands and agrees that all information in the application not identified as confidential business information is subject to public disclosure pursuant to California Code of Regulations, title 17, sections 91000 through 91022 and the California Public Records Act (Government Code, §§ 6250 et seq.), and that information claimed by the applicant to be confidential might later be disclosed under section 91022 if the Board determines the information is subject to disclosure.

(7) An application, supporting documents, and all other relevant data or calculation or other documentation must be submitted electronically via the AFP unless the Executive Officer has approved or requested another format.

(d) *Application Approval Process.* The Executive Officer must approve an application before the CCS project can generate credits under the LCFS regulation.

(1) After receipt of an application designated by the applicant as ready for formal evaluation, the Executive Officer will advise the applicant in writing either that:

(A) The application is complete, or

(B) The application is incomplete, in which case the Executive Officer will identify which requirements have not been met. The applicant may submit additional information within 30 days to correct deficiencies identified by the Executive Officer, otherwise, the application will be rejected.

(2) After accepting an application as complete, the Executive Officer will post the application on the LCFS ~~web site~~website. Public comments will be accepted for ~~10 calendar~~14 days following the date on which the application was posted. Only comments related to potential factual or methodological errors may be considered. The Executive Officer will forward to the applicant all comments identifying potential factual or methodological errors. Within 30~~ business~~ days, the applicant must either submit revisions to its application to the Executive Officer, or submit a detailed written response to the Executive Officer explaining why no revisions are necessary.

(3) If the Executive Officer finds that an application meets the requirements set forth in section 95490(b), the Executive Officer will take final action to approve the CCS project. The Executive Officer may prescribe conditions of approval that contain special limitations, recordkeeping and reporting requirements, and operational conditions that the Executive Officer determines should apply to the project. If the Executive Officer finds that an application does not meet the requirements of section 95490(b), the application will not be approved, the applicant will be notified in writing, and the basis for the disapproval will be identified.

(e) *Reporting.* Each CCS project operator must ~~submit~~report to the Executive Officer the net amount of annual sequestered CO_2 and meet ~~the~~all other applicable reporting requirements in accordance with the CCS Protocol~~.~~ and section 95490(d)(3).

(f) *Credit Review and Issuance.* ~~Credits for~~ A CCS project can receive LCFS credits either under the project-based provisions or through a Tier 2 fuel pathway.

~~(f)~~(1) For each approved CCS innovative crude project (section 95489(c)(1)(A)2.), refinery investment credit project (section 95489(e)(1)(D)1.), or direct air capture and sequestration project (section 95490(a)(2)), the regulated entity must report quarterly or annually through a Project Report. A regulated entity electing to report annually is required to submit its annual Project Report to CARB for the previous compliance year by April 30 of each year. Credits for these projects may be generated quarterly or annually, ~~at the discretion of the credit generating party.~~consistent with the reporting schedule.

~~(1)~~Upon the completion of reporting period in which a positive or qualified positive verification statement for the applicable Project R ports per section 95500(e) is received, the Executive Officer will determine the number of credits to be issued to the applicants. An adverse verification statement would result in no credit issuance and Executive Officer investigation.

(2) For a certified Tier 2 fuel pathway that incorporates a CCS project, credits for fuel transactions reported quarterly using the certified pathway CI will be generated for the given quarter, pursuant to section 95486.1. Fuel pathway holders must include the operational data from the fuel production and the CCS project in their Annual Fuel Pathway Reports, pursuant to section 95488.10. Entities required to obtain verification of their Annual Fuel Pathway Reports must comply with the requirements in section 95500(b).

(g) *Recordkeeping.* Pursuant to section 95491.1 and the CCS Protocol, each applicant that receives approval as a CCS credit generator must maintain records for the CCS project, including records necessary to verify permanent sequestration. At a minimum, the following records must be kept:

(1) The quarterly volume of alternative fuel, petroleum fuel, crude oil/natural gas produced and delivered to California;

(2) Energy use and chemical use data for the carbon capture facility and CO_2 injection facility;

(3) The Accounting Protocol and Permanence Protocol documents; and

(4) Any additional records that the Executive Officer requires to be kept in pursuant to section 95490(d)(3).

(h) *CO_2 Leakage and Credit Invalidation*.

(1) Credits for verified greenhouse gas emission reductions can be invalidated if the sequestered CO_2 associated with them is released or otherwise leaked to the atmosphere.

(2) The number of invalidated credits is equal to the quantity of CO_2 released or leaked from the sequestration zone ($CO_2^{leakage}$), which must be determined in accordance with the CCS Protocol.

(3) Prior to 50 years post-injection:

(A) The Executive Officer may retire credits from the buffer account, up to and including the project's total contribution, to count toward the number of invalidated credits.

(B) The project operator must retire credits for any balance after retiring credits pursuant to 95490(h)(3)(A).

(C) The Executive Officer may retire credits from the buffer account equivalent to remaining outstanding balance after retiring credits pursuant to 95490(h)(3)(A) and (B).

(4) After 50 years post-injection:

(A) The project operator is no longer responsible to make up any credits found to be invalid due to leakage.

(B) The Executive Officer may retire credits from the buffer account to cover any credits found to be invalid due to leakage.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95491. Fuel Transactions and Compliance Reporting.

A fuel reporting entity must submit to the Executive Officer Quarterly Fuel Transactions Reports and Annual Compliance Reports, as specified in this section.

(a) *Online Reporting.* The annual compliance and quarterly fuel transactions reports must be submitted using the LRT-CBTS. Prior to use, a fuel reporting entity must first register in the LRT-CBTS pursuant to section 95483.2.

The fuel reporting entity is solely responsible for ensuring that the Executive Officer receives its quarterly fuel transactions reports and annual compliance reports by the deadlines specified in this section. The Executive Officer shall not be responsible for failure of electronically submitted reports to be transmitted to the Executive Officer. The reports must contain a statement attesting to the report's accuracy and validity. The Executive Officer shall not deem an electronically submitted report to be valid unless the report is accompanied by a digital signature that meets the requirements of California Code of Regulations, title 2, sections 22000 et seq.

(b) *Reporting Frequency and Deadlines*.

(1) *Quarterly Fuel Transactions Data:* The data for the quarterly fuel transactions report for each fuel type must be uploaded in the LRT-CBTS within the first 45 days after the end of the quarter. During the subsequent 45 days, fuel reporting entities shall use the reconciliation tools provided in the LRT-CBTS and in conjunction with business partners to complete any necessary report corrections, if applicable.

(2) *Quarterly Fuel Transactions Reports.* Unless expressly provided elsewhere in this subarticle, quarterly fuel transactions reports must be submitted in LRT-CBTS by:

June 30~~th~~ - for the first calendar quarter covering January through March;

September 30~~th~~ - for the second calendar quarter covering April through June;

December 31~~st~~ - for the third calendar quarter covering July through September; and

March 31~~st~~ - for the fourth calendar quarter of the prior year covering October through December.

(3) *Annual Compliance Reports.* An annual compliance report for the prior calendar year must be submitted in LRT-CBTS by April 30~~th~~ of each year.

(c) *General Reporting Requirements for Quarterly Fuel Transactions Reports.* For each of its transportation fuels, a fuel reporting entity must submit a quarterly fuel transactions report that contains the information specified below and summarized in Table 11:

(1) All applicable transaction types listed for each fuel type in 95491 (d) below and defined in section 95481 must be included in each quarterly fuel transactions report.

(2) Information that must be reported are as follows: Organization FEIN, Reporting Period (year and quarter), FPC, Fuel Amount, Transaction Type, Transaction Date, Business Partner (if applicable), Aggregated Transaction Indicator, Fuel Application, Production Company ID and Facility ID (if applicable).

(d) *Specific Reporting Requirements for Quarterly Fuel Transactions Reports.* In addition to all requirements specified in section 95491(c), for each of its transportation fuels, a fuel reporting entity must submit a quarterly fuel transactions report that contains the information specified below and summarized in Table 11:

(1) *Specific Quarterly Reporting Parameters for Liquid Fuels including Gasoline, Diesel, Diesel Fuel Blends, Fossil Jet Fuel, and Alternative Fuels, and Alternative Jet Fuel*.

(A) The applicable transaction types, defined in section 95481, are as follows: Production in California, Production for Import, Import, Purchased with Obligation, Purchased without Obligation, Sold with Obligation, Sold without Obligation, Export, Loss of Inventory, Gain of Inventory, and Not Used for Transportation. The transaction type "Production for Import" is to be reported by out-of-state producers who choose to be the first fuel reporting entity for fuel imported into California. The transaction type "Import" is to be reported by non-producers who choose to be the first fuel reporting entity for out-of-state fuel imported into California. The following information are to be reported:

1. Production Company ID and Facility ID for each blendstock. CARBOB and diesel fuel are exempt from this requirement.

2. The certified fuel pathway code (FPC) of each blendstock.

3. The volume (in gal) of each blendstock per reporting period. For purposes of this provision only, except as provided in subsection 4. below, the fuel reporting entity may report the total volume of each blendstock aggregated for each distinct carbon intensity value (e.g., X gallons of blendstock with A gCO_2e/MJ, Y gallons of blendstock with B gCO_2e/MJ).

4. A producer of CARBOB, gasoline, or diesel fuel must report, for each of its refineries, the MCON or other crude oil name designation, volume (in gal), and Country (or State) of origin for each crude supplied to the refinery during the quarter.

(B) *Temperature Correction.* All liquid fuel volumes reported in the LRT-CBTS must be adjusted to standard temperature conditions of 60°F as follows:

1. For ethanol, the following formula must be used:

$$V_{s,e} = V_{a,e} \times (-0.0006301 \times T + 1.0378)$$

where:

$V_{s,e}$ is the standardized volume of ethanol at 60°F, in gallons;

$V_{a,e}$ is the actual volume of ethanol, in gallons; and

T is the actual temperature of the batch, in °F.

2. For biodiesel, one of the following two methodologies must be used:

   a. $V_{s,b} = V_{a,b} \times (-0.00045767 \times T + 1.02746025)$

      where:

      $V_{s,b}$ is the standardized volume of biodiesel at 60°F, in gallons;

      $V_{a,b}$ is the actual volume of biodiesel, in gallons; and

      T is the actual temperature of the batch, in °F.

   b. The standardized volume of biodiesel at 60°F, in gallons, as calculated from the use of the American Petroleum Institute Refined Products Table 6B, as referenced in ASTM D1250-08 (Reapproved 2013), which is incorporated herein by reference, or by comparable means that can be demonstrated to a verifier or the Executive Officer to be consistent with these standard methods.

3. For other liquid fuels, the volume correction to standard conditions must be calculated by the methods described in the American Petroleum Institute (API) Manual of Petroleum Measurement Standards Chapter 11 - Physical Properties Data (May 2004), the ASTM Standard Guide for Use of the Petroleum Measurement Tables, ASTM D1250-08 (Reapproved 2013), or the API Technical Data Book - Petroleum Refining Chapter 6 - Density (Sixth Edition, April 1997), all three of which are incorporated herein by reference, or by comparable means that can be demonstrated to a verifier or the Executive Officer to be consistent with these standard methods.

(C) *Fuel Pathway Allocation for Produced Fuel.* If a fuel production facility simultaneously processes multiple feedstocks, the producer or fuel reporting entity must associate each portion of the total fuel produced with processed feedstock during each reporting period (calendar quarter). Feedstock quantities must not be counted more than once for any fuel produced. The fuel reporting entity must use one of the following methods to allocate feedstock to the quantities of produced fuel reported under each certified FPC.

1. The quantity of fuel reported for a fuel pathway code must be determined using the following method:

   a. $Q^n_{Fuel\ i} = Y_{average\ yield} \times Q^n_{Feedstock\ i}$

      where:

      $Q^n_{Fuel\ i}$ is the quantity of produced fuel with a fuel pathway i at a production facility during reporting period n;

      $Y_{average\ yield}$ is the facility's average production yield for all feedstocks as determined during pathway certification; and

      $Q^n_{Feedstock\ i}$ is the quantity of feedstock counted as processed for a fuel pathway i at a production facility during reporting period n and the quantity of feedstock inventory associated with the fuel pathway i must be greater than or equal to zero at the end of each reporting period.

   b. If the actual quantity of fuel produced during a reporting period is greater than the quantity calculated using a. above, and all feedstocks in inventory and received by the production facility during the reporting period were included in the fuel pathway application, the excess fuel must be reported under a fuel pathway with the highest CI among all pathways certified for the fuel production facility.

2. Paragraph 1. above notwithstanding, a different allocation methodology may be used with the Executive Officer approval. The methodology must be submitted to the Executive Officer at the time of fuel pathway application and be included in the monitoring plan for verifier's review.

3. Facilities with multiple certified fuel pathways that do not use feedstock inventory accounting must include chemical analysis data supporting the calculated yield (i.e. the converted fraction of measured feedstock) in annual Fuel Pathway Reports. The producer or fuel reporting entity must use the yield calculated from the most recent prior analysis to determine the quantities of fuel to allocate to each FPC.

(D) *Exports.* If fuel reported in the LRT-CBTS is subsequently exported out of California, the export must be reported in the LRT-CBTS by the entity responsible for reporting export as described in subsection 95483(a).

1. *Reporting Fuel Blends.* When reporting export of fuel blends, the amount of each blendstock shall be reported in the LRT-CBTS. If the accurate blend percentage of each blendstock is not known then default blend percentage values provided on the LCFS ~~web site~~website shall be used for reporting the exports. Default blend percentage values are based on prior year average values.

2. *Substitute Pathways.* When an FPC is not available for reporting a fuel in the LRT-CBTS, a fuel reporting entity must use the Substitute pathway corresponding to its fuel type, pursuant to section 95488.9(d).

(2) *Specific Quarterly Reporting Parameters for Natural Gas (including CNG, LNG, and L-CNG).* For each fueling facility to which CNG, LNG, and L-CNG, is supplied as a transportation fuel:

(A) The quantity of fuel dispensed must be reported per FSE, as set forth in section 95483.2(b), with a certified FPC and with transaction type “NGV Fueling.” For CNG and L-CNG, the quantity of fuel dispensed (in Therms at Higher Heating Value (HHV)) per reporting period separately for all light/medium-duty vehicles (LDV & MDV), for heavy-duty vehicles with compression ignition engines (HDV-CIE), and for heavy-duty vehicles with spark ignition engines (HDV-SIE). For LNG, the volume of fuel dispensed (in gal) per reporting period separately for all LDV/MDV, for HDV-CIE, and for HDV-SIE.

(B) For Bio-CNG, Bio-LNG, and Bio-L-CNG: Biomethane production Company ID and Facility ID.

(C) The total quantity of fuel, summed across all FPCs, dispensed for transportation purpose through the FSE during the reporting period.

(D) When the vehicle application is unknown, for the purpose of reporting, a fueling event of less than 3,500 MJ (30 gasoline gallon equivalents) of fuel dispensed must be reported as NGV Fueling of LDV/MDV. A fueling event of 3,500 MJ or more must be reported as NGV Fueling of HDV.

(3) *Specific Quarterly Reporting Parameters for Electricity used as a Transportation Fuel*.

(A) *For Non-Metered Residential EV charging*.

1. Within the first 45 days after the end of the quarter, the EDU must provide the Executive Officer Daily Average EV Electricity Use data for the calculation of credits for non-metered charging from the prior quarter. The Executive Officer shall use the method set forth in subsection 95486.1(c)(1), to calculate any credits generated for the quarter and place them into the EDU's LRT-CBTS account; and

~~2. The LSE must use all credit proceeds to benefit current or future EV drivers in California;~~

~~3. The LSE must educate the public and customers on the benefits of EV transportation (including environmental benefits and costs of EV charging, or total cost of ownership, as compared to gasoline);~~

~~4. The LSE must provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid;~~

~~5. The LSE must include, in the Annual Compliance Report, the following supplemental information: an itemized summary of efforts to meet requirements 1. through 3. above and costs associated with meeting the requirements. Investor-owned utilities must also provide an unredacted copy of the annual implementation report required under Order 4 of Public Utilities Commission of California (PUC) Decision 14-12-083, or any successor PUC Decisions.~~

~~6. For claiming incremental credit for non-metered residential charging, the LSE must be able to provide, upon request of the Executive Officer: the VIN for each electric vehicle claimed and evidence of EV vehicle registration and low-carbon electricity supply at the same location.~~

~~7. A non-LSE credit generator must use credit proceeds to benefit EV drivers and their customers, and educate them about the benefits of EV transportation (including environmental benefits and costs of EV charging, or total cost of ownership, as compared to gasoline). The credit generator must include, in their Annual Compliance Report, an itemized summary of efforts and costs associated with meeting these requirements.~~

(B) *For Metered Residential EV charging*.

1. For generating base credits, the quantity of electricity (in kWh) used for residential EV charging must be reported per FSE, as set forth in section 95483.2(b), using the Lookup Table pathway for California Average Grid Electricity and with transaction type "EV Charging - Grid."

2. For generating incremental credit for low-CI electricity, the quantity of electricity (in kWh) used for residential EV charging must be reported per FSE, as set forth in section 95483.2(b), using a certified FPC and with transaction type "EV Charging - Non-Grid", and the following requirements must be met:

   a. The reporting entity must be able to provide to the Executive Officer records, upon request, demonstrating that the low-CI electricity is supplied (including through book-and-claim accounting) to the same residences where the EV charging is taking place and during the period for which incremental credits are generated, and that any renewable energy certificates associated with the low-CI electricity were retired in the WREGIS for the purpose of LCFS credit generation;

   b. Records must be provided to the Executive Officer, upon request, demonstrating an EV is owned or leased by an individual dwelling at the claimed residence; and

   c. Only a single entity can generate incremental credits using a low-CI pathway for the same FSE. If two or more entities report for the same FSE to generate incremental credits, no incremental credits will be issued for that FSE.

3. For generating incremental credit for smart charging, the quantity of electricity (in kWh) used for residential EV charging must be reported per FSE, as set forth in section 95483.2(b), using the smart charging pathway CI values and with transaction type "EV Charging - Smart Charging", and the following requirements must be met:

   a. The quantity of electricity used for each hourly window, as per Table 7-2 in section 95488.5(f), must be reported;

b. The reporting entity must be able to provide documentation showing the quantity of electricity used during a reporting period broken down by hourly windows upon request by the Executive Officer;

c. Only a single entity can generate incremental credits for smart charging for the same FSE; and

d. Records must be provided to the Executive Officer, upon request, demonstrating the FSE was enrolled in a Time-of-Use rate plan during the reporting period, if offered by the LSE.

(C) *For Non-Residential EV Charging*.

1. For generating credit using grid electricity, the quantity of electricity (in kWh) used for EV charging must be reported per FSE, as set forth in section 95483.2(b), using the Lookup Table pathway for California Average Grid Electricity and with transaction type "EV Charging - Grid."

2. For generating credit using any low-CI electricity, the quantity of electricity (in kWh) used for EV charging must be reported per FSE, as set forth in section 95483.2(b), using a certified FPC and with transaction type "EV Charging - Non-Grid", and the following requirements must be met:

a. The reporting entity must be able to provide to the Executive Officer records, upon request, demonstrating that the low-CI electricity is supplied (including through book-and-claim accounting) to the FSE during the period for which incremental credits are generated, and that any renewable energy certificates associated with the low-CI electricity were retired in the WREGIS for the purpose of LCFS credit generation.

3. For generating credit for smart charging, the quantity of electricity (in kWh) used for EV charging must be reported per FSE, as set forth in section 95483.2(b), using the smart charging pathway CI values and with transaction type "EV Charging - Smart Charging", and the following requirements must be met:

a. The quantity of electricity used for each hourly window, as per Table 7-2 in section 95488.5(f), must be reported;

b. The reporting entity must be able to provide documentation showing the quantity of electricity used during a reporting period broken down by hourly windows upon request by the Executive Officer; and

c. Records must be provided to the Executive Officer, upon request, demonstrating the FSE was enrolled in a Time-of-Use rate plan during the reporting period, if offered by the LSE.

(D) *For Fixed Guideway Systems.* The quantity of electricity used for transit propulsion (in kWh) must be reported per FSE with a certified FPC and with transaction type "Fixed Guideway Electricity Fueling." FSE ID is assigned by system during the registration as specified in section 95843.2(b)(8).

(E) *For Electric Forklifts.* The quantity of electricity used (in kWh) dispensed must be reported per FSE, as set forth in section 95483.2(b)(8), with a certified FPC and with transaction type "~~EV Forklifts~~Forklift Electricity Fueling." ~~The quantity of electricity used in electric forklifts may be determined as follows:~~

~~1. Quantity of electricity used during a reporting period, as measured per FSE, as set forth in section 95483.2(b), and with transaction type "Forklift Electricity Fueling", in the case of an electric forklift fleet owner or its designee generating credits; or~~

~~2. Quantity of electricity estimated using CARB approved methodology. The reporting entity must provide the number of electric forklifts in the fleet for generating credits; or~~

~~3. When electric forklift credits are claimed by an EDU, CARB staff will calculate the quantity of electricity supplied to electric forklifts in the EDUs service territory during a reporting period for the generation of credits. This reporting parameter is exempt from the quarterly reporting deadlines set forth in section 95491(b).~~

(F) *For Electric Transport Refrigeration Unit.* The quantity of electricity (in kWh) dispensed must be reported per FSE, as set forth in section 95483.2(b), with a certified FPC and with transaction type "eTRU Fueling."

(G) *Electric Cargo Handling Equipment.* The quantity of electricity (in kWh) dispensed must be reported per FSE, as set forth in section

95483.2(b), with a certified FPC and with transaction type "eCHE Fueling."

(H) *Electric Power for Ocean-going Vessel.* The quantity of electricity (in kWh) dispensed must be reported per FSE, as set forth in section 95483.2(b), with a certified FPC and with transaction type "eOGV Fueling."

(I) *Other Electric Transportation Applications.* The quantity of electricity (in kWh) dispensed must be reported per FSE with a certified FPC and with transaction type made available by Executive Officer pursuant to section 95488.7.

(4) *Specific Quarterly Reporting Parameters for Hydrogen Used as a Transportation Fuel*.

(A) The quantity (in kg) of hydrogen fuel dispensed per FSE, as set forth in section 95483.2(b), with a certified FPC and with transaction type "FCV Fueling" by vehicle weight category: LDV & MDV and HDV.

(B) For hydrogen fuel cell forklifts, the amount of hydrogen fuel dispensed (in kg) per FSE with a certified FPC and with transaction type "Forklift Hydrogen Fueling."

(C) Production Company ID and Facility ID.

(D) For hydrogen reported with a pathway that utilizes book-and-claim accounting for electricity as specified in section 95488.8(i)(1)(B) the reporting entity must be able to provide to the Executive Officer records, upon request, demonstrating that the low-CI electricity is supplied (including through book-and-claim accounting) to the FSE during the period, and that any renewable energy certificates associated with the low-CI electricity were transferred from the fuel pathway holder to the reporting entity and retired for the purpose of LCFS credit generation.

~~(D)~~(E) For hydrogen reported with a pathway that claims carbon intensity reductions for shifts in time of electricity use for electrolytic hydrogen production, the quantity of electricity (in kWh) used to produce hydrogen for each hourly window must be reported with transaction type "FCV Fueling--Smart Electrolysis" and the following requirements must be met:

a. The quantity of electricity used for each hourly window, as per Table 7-2 in section 95488.5(f), must be reported; and

b. The reporting entity must provide documentation showing the quantity of electricity used during a reporting period broken down by hourly windows, upon request by the Executive Officer.

(5) *Specific Quarterly Reporting Parameters for Propane*.

(A) The quantity (in gal) of propane dispensed per FSE, as set forth in section 95483.2(b), with a certified FPC and with transaction type "Propane Fueling."

(B) For renewable propane, the Production Company ID and Facility ID.

(e) *Reporting Requirements for Annual Compliance Reports.* A fuel reporting entity and project operators must submit an annual compliance report that aggregates the quarterly fuel transactions reports and provides the additional information set forth below:

(1) LRT-CBTS generates an annual summary, for each fuel reporting entity and project operator, that includes the following:

(A) The total credits and deficits generated by the fuel reporting entity and project operator in the compliance period, calculated in the LRT-CBTS as per sections 95486.1 and 95489;

(B) Any credits carried over from the previous compliance period;

(C) Any deficits carried over from the previous compliance period;

(D) The total credits acquired from another entity;

(E) The total credits sold or otherwise transferred;

(F) The total credits retired within the LCFS to meet compliance obligation per section 95485; and

(G) Total credits acquired from or pledged for sale into the CCM, if applicable;

(H) Total credits purchased as carryback credits; and

(I) Any credits on administrative hold.

(2) A producer of CARBOB, gasoline, or diesel fuel must report, for each of its refineries, the MCON or other crude oil name designation, amount (in gal), and Country (or State) of origin for each crude supplied to the refinery during the annual compliance period.

(3) All pending credit transfers initiated during a compliance period must be completed prior to submittal of the annual compliance report, if possible. If there is still a pending outgoing credit transfer, the credits will be taken from the account of the Seller that initiated the transfer and the annual compliance report will reflect the adjusted credit balance. If there is a pending incoming credit transfer, the Buyer's annual report will not reflect the balance until the transfer is completed. Upon completion, the annual compliance report must be reopened and resubmitted with the adjusted credit balance.

(4) *Attestations Regarding Environmental Attributes for Biomethane.* Entities reporting bio-CNG, bio-LNG, and bio-L-CNG must submit the environmental attribute attestation pursuant to section 95488.8(i)(2)(C) along with the annual compliance report in the LRT-CBTS.

(5) *Uses of Electricity Credit Proceeds*. Entities generating credits from electricity must use all credit proceeds to further transportation electrification efforts in California. The credit generator must include, in their Annual Compliance Report, an itemized summary of efforts and costs associated with meeting this requirement.

(A) Additional Reporting Requirements for Entities Generating Non-metered Base Credits.

1. *Reporting on Clean Fuel Reward Program Implementation*. By April 30 the administrator of the Clean Fuel Reward program funded by LCFS credit proceeds shall submit a report to the Executive Officer describing the disposition of LCFS Clean Fuel Reward program funds from the previous calendar year. This report must include:

a. The monetary value of LCFS credit proceeds received by the Clean Fuel Reward program; and

b. A summary, detailed list, and explanation of administrative costs, including start-up costs, utility overhead costs, and costs for program-related marketing, education, and outreach activities.

2. *Holdback Equity Reporting Requirements*. EDUs must include a discussion on how their portfolio of holdback credit equity projects is consistent with the findings and recommendations of the SB 350 Low-Income Barriers Study, Part B report prepared by CARB (rev. Feb. 2018), incorporated herein by reference. This discussion must include, as applicable, a description of how the projects: support increased access to clean transportation and

mobility options; consider, and to the extent feasible, either complement or build upon existing CARB, other State, or local incentive projects to diversify and maximize benefits from statewide investments; demonstrate partnership and support from local community-based organizations; and meet community-identified clean transportation needs.

3. Investor-owned utilities must also provide an unredacted copy of the annual implementation report required under Order 4 of Public Utilities Commission of California (PUC) Decision 1412-083, or any successor PUC Decisions.

(f) *Significant Figures.* A regulated entity must report the following quantities as specified below:

(1) Carbon intensity, expressed to the same number of significant figures as shown in Tables 7-1, and 9;

(2) Credits or deficits, expressed to the nearest whole metric ton CO_2 equivalent;

(3) Fuel amounts in units specified in sections 95491(d) and (e), expressed to the nearest whole unit applicable for that quantity; and

(4) Any other quantity must be expressed to the nearest whole unit applicable for that quantity.

(g) A fuel reporting entity must maintain a non-negative value for Total Obligated Amount and Total Amount, as defined in section 95481, for each FPC as summed across all quarterly data in the LRT-CBTS.

(h) *Correcting a Previously Submitted Report.* Upon discovery of an error, a fuel reporting entity may request to have previously submitted quarterly reports for the current compliance periods reopened for corrective edits and resubmittal by submitting a Correction Request Form online in the LRT-CBTS. The fuel reporting entity is required to provide justification for the report corrections and indicate the specific corrections to be made to the report. Pursuant to section 95486(a)(2), no credits may be claimed, and no deficits may be eliminated, retroactively for a quarter for which the quarterly reporting deadline has passed. Each submitted request is subject to Executive Officer review and approval. Permission to correct a report does not preclude enforcement based on misreporting.

Table 11. Summary Checklist of Quarterly and Annual Reporting Requirements.

Parameters to Report	***Gasoline ~~&~~, Diesel & Fossil Jet Fuel Blends***	***Natural Gas & Propane***	***Electricity***	***Hydrogen***	***Neat Ethanol, Biomass-Based Diesel Fuels, Alternative Jet Fuel & Other Alternative Fuels***
For Quarterly Reporting					
Organization FEIN	x	x	x	x	x
Reporting Period (year & quarter)	x	x	x	x	x
Fuel Pathway Code	x	x	x	x	x
Transaction Type	x	x	x	x	x
* Transaction Date	x	x	x	x	x
Business Partner (if applicable)	x	x			x
Production Company ID and Facility ID	x**	x**	n/a	x	x**
Fueling Supply Equipment ID	n/a	x	x	x	n/a
Vehicle Identifier (if applicable)	n/a	n/a	x	n/a	n/a
Aggregated Transaction Indicator (T/F)	x	x	n/a	x	x
Fuel Application	x	x	x	x	x
Amount of each gasoline and diesel blendstock	x	n/a	n/a	n/a	n/a
Amount of each fuel used as gasoline or diesel replacement	n/a	x	x	x	x

Parameters to Report	***Gasoline ~~&~~, Diesel & Fossil Jet Fuel Blends***	***Natural Gas & Propane***	***Electricity***	***Hydrogen***	***Neat Ethanol, Biomass-Based Diesel Fuels, Alternative Jet Fuel & Other Alternative Fuels***
Amount of each fuel used as a fossil jet fuel replacement	n/a	n/a	n/a	n/a	x
MCON or other crude oil name designation, volume (in gal), and country (or state) of origin for each crude supplied to the refinery	x	n/a	n/a	n/a	n/a
ZEV Fueling Infrastructure Pathway Costs and Revenues (if applicable)	n/a	n/a	x	x	n/a
For Annual Reporting (in addition to the items above)					
***Credits and Deficits generated per year (MT)	x	x	x	x	x
***Credits/deficits carried over from the previous year (MT), if any	x	x	x	x	x
***Credits acquired from another entity (MT), if any	x	x	x	x	x
***Credits sold to another entity (MT), if any	x	x	x	x	x
***Credits pledged for sale into CCM (MT), if any	x	x	x	x	x

Parameters to Report	***Gasoline ~~&~~, Diesel & Fossil Jet Fuel Blends***	***Natural Gas & Propane***	***Electricity***	***Hydrogen***	***Neat Ethanol, Biomass-Based Diesel Fuels, Alternative Jet Fuel & Other Alternative Fuels***
***Credits retired within LCFS (MT) to meet compliance obligation, if any	x	x	x	x	x
MCON or other crude oil name designation, volume (in gal), and country (or state) of origin for each crude supplied to the refinery	x	n/a	n/a	n/a	n/a

* Same as Title Transfer Date; For Aggregated Transactions enter the last day of the reporting period.
** Does not apply to CARBOB, Diesel Fuel, Fossil Propane, or Fossil NG.
*** Value will be calculated, stored and displayed in the LRT-CBTS.

Table 12. Annual Compliance Calendar.

February 14	Upload all Q4 fuel transactions data in the LRT-CBTS and begin any needed reconciliation with business partners; Electrical Distribution Utility (EDU) that has opted into LCFS provide the data relevant to the calculation of base credits for non-metered EV charging for the prior quarter
March 31	Submit final Q4 fuel transactions report; Submit Q4 Crude Oil Reports (MCON Reports)
March 31	Annual Fuel Pathway Reports and Annual Low-Complexity/Low-Energy-Use Refinery (LC/LEU) Reports are due to the Executive Officer
First Monday of April	Call for credits to be pledged into the Credit Clearance Market (CCM); the new maximum price for credits is published
April 30	Submit final Annual Compliance Report for preceding year; demonstrate compliance; voluntary pledge of credits for sale into CCM

April 30	Compliance Plan Implementation Report due if entity has an Approved Compliance Plan
April 30	Annual Crude Oil Reports (Annual MCON Reports~~)~~), Annual Low-Complexity/Low-Energy-Use Refinery (LC/LEU) Reports, and Project Reports electing annual verification are due to the Executive Officer
May 15	Upload all Q1 fuel transactions data in the LRT-CBTS and begin any needed reconciliation with business partners; EDU that has opted into LCFS provide the data relevant to the calculation of base credits for non-metered EV charging for the prior quarter
May 15	Executive Officer announces whether CCM will occur
June 1	Executive Officer posts list of CCM buyers and sellers
June 1	CCM for prior compliance year, if one occurs, opens and remains in effect until it closes on August 30~~th~~
June 1	New maximum credit price for all LCFS credit transactions goes into effect
June 30	Submit final Q1 fuel transactions report; Submit Q1 Crude Oil Reports (MCON Reports)
August 14	Upload all Q2 fuel transactions data in the LRT-CBTS and begin any needed reconciliation with business partners; EDU that has opted into LCFS provide the data relevant to the calculation of base credits for non-metered EV charging for the prior quarter
August 30	CCM for prior compliance year closes
August 31	Entities that bought and sold credits in the CCM submit amended Annual Compliance Report
August 31	Entities that participated in two consecutive CCMs submit a Compliance Plan
August 31	Verification Statements for Annual Fuel Pathway Reports, Quarterly Fuel Transactions Reports, Project Reports electing annual verification, Annual LC/LEU Reports, and ~~Quarterly and~~ Annual Crude Oil Reports (MCON Reports) are due to the Executive Officer
September 30	Submit final Q2 fuel transactions report; Submit Q2 Crude Oil Reports (MCON Reports)

November 14	Upload all Q3 fuel transactions data in the LRT-CBTS and begin any needed reconciliation with business partners; EDU that has opted into LCFS provide the data relevant to the calculation of base credits for non-metered EV charging for the prior quarter
December 31	Submit final Q3 fuel transactions report; Submit Q3 Crude Oil Reports (MCON Reports)

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95491.1. Recordkeeping and Auditing.

(a) *Record Retention.* Any record required to be maintained under this subarticle shall be retained for ten years. All data and calculations submitted by a regulated entity for demonstrating compliance, or generating credits or deficits are subject to inspection by the Executive Officer or a verification body accredited by the Executive Officer pursuant to section 95502, and must be made available within ~~20~~14 days upon request of the Executive Officer.

(1) *Record Retention for Fuel Reporting Entities.* Fuel reporting entities must maintain all records and calculations relied upon for data reported in the LRT-CBTS. These records include, but are not limited to:

(A) Product transfer documents;

(B) Copies of all data reports submitted to the Executive Officer;

(C) Records related to each fuel transaction;

(D) Records used for each credit transaction;

(E) Records related to FSE registration, including but not limited to copies of monthly utility bills, Bills of Lading, Division of Measurement Standards' certificates, and any other document used as a proof at the time of FSE registration pursuant to this subarticle;

(F) Chain of custody evidence for produced fuel imported into California;

(G) Attestations regarding environmental attributes associated with book-and-claim accounting for biomethane pursuant to 95488.8(i)(2)(~~C~~E); and

(H) Records used for compliance or credit and deficit calculations.

(2) *Record Retention for Fuel Pathway Holders and Applicants.* Fuel pathway holders and applicants must maintain all records relied upon in producing fuel pathway applications and annual Fuel Pathway Reports. The retained documents, including CI input source data and supplemental documentation, must be sufficient to allow for verification of each CI calculation. These records include but are not limited to:

(A) The quantity of fuel produced and subsequently sold in California under the certified fuel pathway. Sales invoices, contracts, and bills of lading for those fuel sales shall be retained.

(B) The quantity of feedstocks purchased to produce the fuel specified in subsection (A) above. Invoices from the sellers and purchase contracts shall be retained. Records to support material balance and energy balance calculations for facilities processing multiple feedstocks.

(C) The quantity of all forms of energy consumed to produce the fuel covered in subsection (A) above. All invoices for the purchase of process fuel, and all receipts for the sale of the fuel pathway applicant's finished fuel shall be maintained.

(D) Copies of the federal RFS Third Party Engineering Review Report, if required pursuant to 40 CFR 80.1450.

(E) The quantity of all products co-produced with the fuel covered by certified LCFS pathway. Copies of invoices, contracts, and bills of lading covering those sales shall be retained. In addition, copies of the federal RFS Fuel Producer Co-products Report shall be retained, if applicable. If the amount of co-product produced exceeds the amount sold by five percent or more, full documentation of the fate of the unsold fractions shall be maintained.

(F) Evidence demonstrating chain of custody from the point of origin along the supply chain to the fuel production facility is required for any feedstock defined as a specified source feedstock pursuant to section 95488.8(g). A copy of the federal RFS separated food waste plan required pursuant to 40 CFR 80.1450(b)(1)(vii)(B), if applicable.

(G) Any additional records that the Executive Officer requests during pathway certification, and records that demonstrate compliance with all special limitations and operating conditions issued at the time of certification.

(H) Attestations regarding environmental attributes associated with book-and-claim accounting for biomethane pursuant to 95488.8(i)(2)(~~C~~E).

(3) *Record Retention for Verification Bodies.* The verification body providing verification services pursuant to this subarticle must retain the following:

(A) The sampling plan in paper, electronic, or other format for a period of no less than ten years following the submission of each validation or verification statement. The sampling plan must be made available to the Executive Officer upon request.

(B) All material received, reviewed, or generated to render a validation or verification statement for an entity required to validate and verify under LCFS. The documentation must allow for a transparent review of how a verification reached its conclusion in the validation or verification statement, including independent review.

(b) *Documenting Fuel Transfers Reported in the LRT-CBTS.* A product transfer document provided by a fuel reporting entity pursuant to section 95483(a) must prominently state the information specified below.

(1) For transfers where an LCFS obligation to act as a credit or deficit generator is being passed to the recipient:

(A) Transferor Company Name, Address and Contact Information;

(B) Recipient Company Name, Address and Contact Information;

(C) Transaction Date: Date of Title Transfer for Fuel;

(D) Fuel Pathway Code (FPC) and Carbon Intensity (CI);

(E) Fuel Quantity and Units;

(F) A statement identifying whether the LCFS obligation to act as a credit or deficit generator is passed to the recipient; and

(G) Fuel Production Company ID and Facility ID as registered with RFS program or LCFS program. This does not apply to CARBOB, Diesel Fuel or Fossil NG.

(2) For transfers where the LCFS obligation to act as a credit or deficit generator was retained by the transferor, the following is to be provided to the recipient and passed along to any subsequent owner or supplier:

(A) All information identified in subsection 95491.1(b)(1). above as items (A) through (G);

(B) The following notice reading as follows:

"This transportation fuel has been reported to the CARB LCFS Program by <*Insert name of Fuel Reporting Entity holding LCFS obligation to act as a credit or deficit generator*> for intended use in California. If you export this fuel from California you must report to the CARB LCFS Program (www.arb.ca.gov/lcfsrt). Contact the CARB LCFS Administrator for assistance with reporting exported amounts (lrtadmin@arb.ca.gov)."

(c) *Monitoring Plan for Entities Required to Validate or Verify.* Each entity responsible for obtaining a validation or verification statement under this subarticle must complete and retain for review by a verifier, or the Executive Officer, a written Monitoring Plan. Entities also reporting pursuant to MRR may use a single monitoring plan for both programs, so long as all of the following elements are included and clearly identified:

(1) The monitoring plan must contain the following general items and associated references to more detailed information:

(A) Information to allow CARB and the verification team to develop a general understanding of boundaries and operations relevant to the entity, facility, or project, including participation in other markets and other third-party audit programs;

(B) Reference to management policies or practices applicable to reporting pursuant to this subarticle, including recordkeeping;

(C) Explanation of the processes and methods used to collect necessary data for reporting pursuant to this subarticle, including identification of changes made after January 1, 2019;

(D) Explanations and queries of source data to compile summary reports of intermediate and final data necessary for reporting pursuant to this subarticle;

(E) Reference to one or more simplified block diagrams that provide a clear visual representation of the relative locations and positions of measurement devices and sampling locations, as applicable, required for calculating reported data (e.g., temperature, total pressure, LHV or HHV, fuel consumption); the diagram(s) must include storage tanks for raw material, intermediate products, and finished products, fuel sources, combustion units, and production processes, as applicable;

(F) Clear identification of all measurement devices supplying data necessary for reporting pursuant to this subarticle, including identification of low flow cutoffs as applicable, with descriptions of how data from measurement devices are incorporated into the submitted report;

(G) Descriptions of measurement devices used to report LCFS data and how acceptable accuracy is demonstrated, e.g., installation, maintenance, and calibration method and frequency for internal meters or how the criteria in MRR section 95103(k)(7) are met to demonstrate meters are financial transaction meters such that the accuracy is acceptable; this provision does not apply to data reported in the LRT-CBTS for generating credits for EV charging;

(H) Description of the procedures and methods that are used for quality assurance, maintenance, and repair of all continuous monitoring systems, flow meters, and other instrumentation used to provide data for LCFS reports;

(I) Original equipment manufacturer (OEM) documentation or other documentation that identifies instrument accuracy and required maintenance and calibration requirements for all measurement devices used to collect necessary data for reporting pursuant to this subarticle;

(J) The dates of measurement device calibration or inspection, and the dates of the next required calibration or inspection;

(K) Requests for postponement of calibrations or inspections of internal meters and subsequent approvals by the Executive Officer. The entity must demonstrate that the accuracy of the measured data will be maintained pursuant to the measurement accuracy requirements of 95488.8(j);

(L) A listing of the equation(s) used to calculate flows in mass, volume, or energy units of measurement, and equations from which any non-measured parameters are obtained, including meter software, and a description of the calculation of weighted average transport distance;

(M) Identification of job titles and training practices for key personnel involved in LCFS data acquisition, monitoring, reporting, and report attestation, including reference to documented training procedures and training materials;

(N) Records of corrective and subsequent preventative actions taken to address verifier and CARB findings of past nonconformance and material misstatements;

(O) Log of modifications to fuel pathway report conducted after attestation in response to review by third-party verifier or CARB staff;

(P) Written description of an internal audit program that includes data report review and documents ongoing efforts to improve the entity's LCFS reporting practices and procedures, if such an internal audit program exists; and

(Q) Methodology used to allocate the produced fuel quantity to each certified FPC.

(2) The monitoring plan must also include the following elements specific to fuel pathway carbon intensity calculations and produced quantities of fuels per FPC, as applicable:

(A) Explanation of the processes and methods used to collect necessary data for fuel pathway application and Fuel Pathway Reports and all site-specific CA-GREET~~3~~4.0 inputs, as well as references to source data;

(B) Description of steps taken and calculations made to aggregate data into reporting categories, for example aggregation of quarterly fuel transactions per FPC;

(C) Methodology for assigning fuel volumes by FPC, if not using a method prescribed/suggested by CARB. If using a CARB suggested methodology, the methodology should be referenced;

(D) Methodologies for testing conformance to specifications for feedstocks and produced fuels, particularly describing physical testing standards and processes;

(E) Description of procedure taken to ensure measurement devices are performing in accordance with the measurement accuracy requirements of 95488.8(j);

(F) Methodology for monitoring and calculating weighted average feedstock transport distance and modes, including the specific documentation records that will be collected and retained on an ongoing basis;

(G) Methodology for monitoring and calculating fuel transport distance and modes, including the specific documentation records that will be collected and retained on an ongoing basis;

(H) References to contracts and accounting records that confirm fuel /quantities were delivered into California for transportation use in CI determination, and confirm feedstock and finished fuel transportation distance;

(I) All documentation required pursuant to 95488.8(g)(1)(B) for specified source feedstocks, defined in 95488.8(g)(1)(A);

(3) The monitoring plan must also include the following elements specific to quarterly fuel transactions reports for importers, exporters and producers of alternative fuels, gasoline and diesel, as well as quarterly reports of crude oil information, as applicable:

(A) Documentation that can be used to justify transaction types reported for fuel in the LRT-CBTS must be referenced in the monitoring plan. This can pertain to the production amount, sale/purchase agreements and final fuel dispensing records.

(d) *Verification Outcomes.* Each entity responsible for obtaining a validation or verification statement under this subarticle must obtain third-party verification services from a verification body that meets the requirements specified in section 95502. A positive or qualified positive verification statement for the previous calendar year must be submitted to the Executive Officer by the verification body by August 31 in order to maintain a valid fuel pathway code for use in reporting fuel transactions for credit generation. An adverse transactions verification statement would result in Executive Officer investigation and possible enforcement action.

(e) *Access to Records.* Pursuant to H&S section 41510, the Executive Officer has the right of entry to any premises used, leased, or controlled by a regulated entity in order to inspect and copy records relevant to the determination of compliance. Scheduling of access shall be arranged in advance where feasible and must not unreasonably disturb normal operations, provided, however that access shall not be unreasonably delayed.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95492. Enforcement Protocols.

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§ 95493. Jurisdiction.

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§ 95494. Violations.

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§ 95495. Authority to Suspend, Revoke, Modify, or Invalidate.

(a) If the Executive Officer determines that any basis for invalidation set forth in subsection (b)(1) below occurred, in addition to taking any enforcement action, he or she may: suspend, restrict, modify, or revoke an LRT-CBTS account; modify or delete a Certified CI; restrict, suspend, or invalidate credits; or recalculate the deficits in an LRT-CBTS account. For purposes of this section, “Certified CI” includes any determination relating to carbon intensity made pursuant to sections 95488 through 95488.10, or relating to a credit generating activity approved under section 95489.

(b) *Determination that a Credit, Deficit Calculation, or Certified CI is Invalid*.

(1) *Basis for Invalidating.* The Executive Officer may modify or delete a Certified CI and invalidate credits or recalculate deficits based on any of the following:

(A) Any of the information used to generate or support the Certified CI was incorrect for reasons including the omission of material information or changes to the process following submission;

(B) Any material information submitted in connection with any Certified CI or credit transaction was incorrect;

(C) Fuel reported under a given pathway was produced or transported in a manner that varies in any way from the methods set forth in any corresponding pathway application documents submitted pursuant to sections 95488 through 95488.10;

(D) Fuel transaction or other data reported into LRT-CBTS and used in calculating credits and deficits was incorrect or omitted material information;

(E) Credits or deficits were generated or transferred in violation of any provision of this subarticle or in violation of other laws, statutes or regulations;

(F) A person obligated to provide records under this subarticle refused to provide such records or failed to produce them within the required time; and

(G) The sequestered CO_2 associated with credits generated for verified greenhouse gas emission reductions by a CCS project was released or otherwise leaked to the atmosphere.

(H) Credits were generated in violation of section 95491.2(b)(2)(C).

~~(H)~~(I) For purposes of this section, "material information" means:

1. Information that would affect by any amount the Executive Officer's determination of a carbon intensity score, expressed on a gCO_2e/MJ basis to two decimal places, or

2. Information that would affect by any whole integer the number of credits or deficits generated under sections 95486, 95486.1, 95486.2, 95489, or resulting from any transaction or other activity reported in the LRT-CBTS.

(2) *Notice.* Upon making an initial determination that a credit (other than a provisional credit), deficit calculation, or Certified CI (other than a provisionally-certified CI) may be subject to modification, deletion, recalculation, or invalidation under subsection (b)(1), above, the Executive Officer will notify all potentially affected parties, including those who hold or generate credits or deficits based on a Certified CI that may be invalid, and may notify any linked program. The notice shall state the reason for the initial determination, and may be distributed using the LRT CBTS. Any party receiving such notice may submit, within ~~20~~14 days, any information that it wants the Executive Officer to consider. The Executive Officer may request information or documentation from any party likely to have information or records relevant to the validity of a credit, deficit calculation, or Certified CI. Within ~~20~~14 days of any such request, a regulated entity shall make records and personnel available to assist the Executive Officer in determining the validity of the credit, deficit calculation, or Certified CI.

(3) *Interim Account Suspension.* When the Executive Officer makes an initial determination pursuant to the preceding subsection, the Executive Officer may immediately take steps to suspend an account or a Certified CI as needed to prevent additional accrual of credits or deficits under the Certified CI and to prevent transfer of potentially invalid credits or deficits. Suspension of an account may include locking an account within the LRT-CBTS to prevent credit transfers or report alteration.

(4) *Final Determination.* Within ~~50~~30 days after making an initial determination under sections 95495(b)(1) and (2), above, the Executive Officer shall make a final determination based on available information whether, in his or her judgment, any of the bases listed in subsection (b)(1) exists, and notify affected parties and any linked program. If the final determination invalidates credits or deficit calculations, the corresponding credits and deficits will be added to or subtracted from the appropriate LRT-CBTS accounts. Where such action creates a deficit in a past compliance period, the deficit holder has 60 days from the date of the final determination to

purchase sufficient credits to eliminate the entire deficit. A return to compliance does not preclude further enforcement actions.

(5) *Adjustment of Invalidated Credits or Miscalculated Deficits.* The Executive Officer will seek the following options to address any invalid credits or miscalculated deficits in the program:

(A) First, the Executive Officer may remove the invalid credits from, or add miscalculated deficits to, the account of the credit or deficit generator, or other entity deemed responsible for the invalidation or miscalculation in the final determination pursuant to section 95486. The entity is responsible for returning its account to compliance.

(B) Next, the Executive Officer may choose to retire credits from the Buffer Account to address invalidated credits or uncovered deficits.

(C) After exercising options in subsection (A) and (B) above, the Executive Officer may remove remaining invalid credits from an entity's account that holds or previously held invalid credits. The entity is responsible for returning its account to compliance.

(D) The Executive Officer will not remove invalid credits from entities that purchased those credits in the Credit Clearance Market, pursuant to section 95485(c).

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511, and 43018 Health and Safety Code; 42 U.S.C. section 7545, and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95496. [Reserved].

§ 95497. Severability.

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§ 95500. Requirements for Validation of Fuel Pathway Applications; and Verification of Annual Fuel Pathway Reports, Quarterly Fuel Transactions Reports, Crude Oil Quarterly and Annual Volumes Reports, Project Reports, and Low -Complexity/Low-Energy-Use Refinery Reports.

(a) *Validation of Fuel Pathway Applications (CIs).*

(1) *Applicability.* The following entities must obtain the services of a verification body accredited by the Executive Officer for purposes of

conducting verification services, including required site visit(s), for each fuel pathway application submitted under this subarticle.

(A) Fuel pathway applicants supplying site-specific CI data for the fuel pathway application, as specified in sections 95488.5 through 95488.8.

(B) Specified source feedstock suppliers and other entities with site-specific CI data who apply for separate Executive Officer recognition as a joint applicant and elect to be responsible for separate validation and verification as specified in section 95488(b).

(b) *Verification of Annual Fuel Pathway Report (CIs)*.

(1) *Applicability.* The following entities must obtain the services of a verification body accredited by the Executive Officer for purposes of conducting verification services, including required site visit(s), for each Fuel Pathway Report submitted under this subarticle.

(A) Holders of certified fuel pathways who supplied site-specific CI data for pathway certification and are required to update site-specific CI data on an annual basis, as specified in this subarticle, are responsible for annual verification of their Fuel Pathway Report.

(B) Specified source feedstock suppliers and other entities with site-specific CI data who apply for separate Executive Officer recognition as a joint applicant and elect to be responsible for separate validation and verification as specified in section 95488(b).

(2) *Verification Schedule.* Entities required to contract for verification of Fuel Pathway Reports (CI) must ensure a fuel pathway verification statement for each Fuel Pathway Report is submitted to the Executive Officer according to the following schedule.

(A) *Annual Verification.* Verification statements are due to the Executive Officer by August 31 of the year the annual Fuel Pathway Report is submitted, beginning in 2021 for 2020 data, unless eligible to defer verification, as specified in section 95500(b)(2)(B).

(B) *Deferred Verification.* Fuel pathway holders producing alternative fuels may defer verification of their annual Fuel Pathway Reports for each production facility up to two years if the quantity of fuel produced at the production facility and reported by any entity does not result in 6,000 or more credits and also does not result in 6,000 or more deficits generated in LRT-CBTS during the prior calendar year and does not include a fuel pathway with biomethane or hydrogen supplied using book-and-claim accounting pursuant to section 95488.8(i)(2). Fuel pathway holders classified as joint applicants are not eligible to defer verification.

The verification body must submit fuel pathway verification statements to the Executive Officer for all prior unverified reports on or before August 31 of the year verification is required or conducted for the production facility.

(C) Verification services may not begin until the entity required to contract for verification services attests that the data submitted to the Executive Officer is true, complete, and accurate by certifying under penalty of perjury under the laws of the State of California.

"Quarterly review" for purposes of this subarticle means a review process conducted by the verification team after quarterly data is submitted and before annual data is submitted and verified.

Quarterly review does not supersede the requirements for the verification team to consider all quarterly data submitted during annual verification. Quarterly review is optional for annual Fuel Pathway Reports, Quarterly Fuel Transactions Reports, and Crude Oil Quarterly and Annual Volumes Reports. Quarterly review must conform to the requirements for verification services in section 95501. A verification statement and verification report are not submitted after quarterly review.

Quarterly review of operational CI data may only be included as part of annual verification services if the fuel pathway holder submits quarterly data to the Executive Officer. Quarterly review may only be conducted after the fuel pathway holder submits the report and attests that the statements and information submitted are true, accurate, and complete.

(c) *Verification of Quarterly Fuel Transactions Reports*.

(1) *Applicability.* Entities submitting Quarterly Fuel Transactions Reports under this subarticle that include the following transaction types must obtain the services of a verification body accredited by the Executive Officer for purposes of conducting verification services, including required site visit(s). The scope of verification services would be limited to the following transaction types, including associated corrections submitted in annual reports under this subarticle.

(A) For all liquid fuels:

1. Production in California;

2. Production for Import;

3. Import;

4. Export;

5. Gain of Inventory;

6. Loss of Inventory; and

7. Not Used for Transportation; and.

8. Fossil Jet Fuel used for Intrastate Flight.

(B) NGV Fueling;

(C) Propane Fueling;

(D) For the following hydrogen-based transaction types:

~~(C)~~1. Forklift Hydrogen Fueling; and

2. Fuel Cell Vehicle (FCV) Fueling

(E) For the following electricity-based transaction types:

1. EV Charging except as specified under 95491(d)(3)(A);

2. eTRU Fueling;

3. eCHE Fueling;

4. eOGV Fueling;

5. Fixed Guideway Electricity Fueling; and

6. Forklift Electricity Fueling.

~~(D)~~(F) FCV Fueling for hydrogen produced from biomethane supplied using book-and-claim accounting pursuant to section 95488.8(i)(2).

(2) *Verification Schedule.* Entities responsible for verification of Quarterly Fuel Transactions Reports must ensure a transactions data verification statement is submitted to the Executive Officer according to the following schedule.

(A) *Annual Verification.* The entity required to contract for verification of Quarterly Fuel Transactions Reports must ensure a transactions verification statement is submitted annually by August 31, beginning in 2021 for 2020 data, to the Executive Officer for the prior calendar year of data unless specified otherwise in sections 95500(c)(2)(B) or 95500(c)(2)(C).

Quarterly review of a Quarterly Fuel Transactions Report may only be included as part of annual verification services after the entity submits the report and attests that the statements and information submitted are true, accurate, and complete.

~~(B)~~ *Deferred Verification.* ~~Fuel pathway holders producing alternative fuels may defer annual verification of their Quarterly Fuel Transactions Reports for each production facility up to two years if the quantity of fuel produced at the production facility and reported by any entity does not result in 6,000 or more credits and 6,000 or more deficits generated in LRT-CBTS during the prior calendar year.~~

(B) Fuel reporting entities ~~only reporting alternative fuel quantities using Lookup Table Pathways~~ may defer annual verification of their Quarterly Fuel Transactions Reports up to two years if they do not generate 6,000 or more credits and 6,000 or more deficits in LRT-CBTS during the prior calendar year.

Any fuel quantity reported under a pathway with biomethane or hydrogen supplied using book-and-claim accounting pursuant to section 95488.8(i)(2) is not eligible for deferred verification.

The verification body must submit transactions verification statements to the Executive Officer for all prior unverified reports on or before August 31 of the year verification is required or conducted for the ~~production facility~~reporting entity.

(C) *Verification Exemption for Designated Liquid Fuel Transactions.* Entities reporting fuel transactions as Export, Gain of Inventory, Loss of Inventory, and Not Used for Transportation, which do not result in 6,000 or more credits and 6,000 or more deficits generated in LRT-CBTS in a calendar year are exempt from verification of the Quarterly Fuel Transactions Reports for that calendar year if all the following conditions are met:

1. The entity did not report any liquid fuel using the transaction types: Production in California, Production for Import, or Import; and

2. The entity did not report any transactions specified in section 95500(c)(1)(B) ~~or~~through 95500(c)(1)(~~C~~E).

(d) *Verification of Crude Oil Quarterly and Annual Volumes Reports*.

(1) *Applicability.* Entities submitting crude oil volume data must obtain the services of a verification body accredited by the Executive Officer for purposes of conducting verification services, including required site visit(s), for Crude Oil Quarterly and Annual Volumes Reports submitted under this subarticle.

(2) *Verification Schedule.* Entities required to contract for verification of Crude Oil Quarterly and Annual Volumes Reports must ensure a crude oil volume verification statement for the prior calendar year of data is submitted to the Executive Officer annually by August 31~~st~~, beginning in 2021 for 2020 data.

Quarterly review of a Crude Oil Quarterly Volumes Report may only be conducted as part of annual verification services after the entity submits the quarterly report and attests that the statements and information submitted are true, accurate, and complete.

(e) *Verification of Project Reports*.

(1) *Applicability.* The following entities must obtain the services of a verification body accredited by the Executive Officer for purposes of conducting verification services, including required site visit(s), for Project Reports submitted under this subarticle:

(A) Project operators and joint applicants for refinery investment project reports;

(B) Project operators and joint applicants for innovative crude project reports;

(C) Project operators and joint applicants for renewable hydrogen project reports; and

(D) Project operators and joint applicants for direct air capture project reports.

(2) *Verification Schedule.* Entities submitting Project Reports may elect to conduct quarterly or annual verification. Entities must determine before the initial verification of a Project Report whether to conduct quarterly or annual verification. If an entity elects to conduct quarterly verification, it may only switch to annual verification at the beginning of a calendar year.

Entities electing quarterly verification must ensure each quarterly project data verification statement is submitted to the Executive Officer within five months of the Quarterly Project Report deadline beginning with 2020 data.

Entities electing annual verification must ensure annual project data verification statements are submitted to the Executive Officer by August 31, 2021 for submittal of 2020 data, and annually thereafter.

(f) *Verification of Low-Complexity/Low-Energy-Use Refinery Reports*.

(1) *Applicability.* Entities submitting Low-Complexity/Low-Energy-Use refinery data must obtain the services of a verification body accredited by the Executive Officer for purposes of conducting verification services, including required site visit(s), for Low-Complexity/Low-Energy-Use Refinery Reports submitted under this subarticle.

(2) *Verification Schedule.* The verification body must submit an annual verification statement to the Executive Officer for the prior calendar year by August 31, beginning in 2021 for 2020 data.

(g) *Verification Body and Individual Verifier Rotation Requirements.* An entity that is required to contract for validation or verification must not use the same verification body or individual verifier(s) to perform validation and verification services under this subarticle for a period of more than six consecutive years, beginning January 1, 2020.

The six-year period begins on the execution date of the entity's first contract for any validation or verification under this subarticle and ends on the date the final verification statement is submitted. The six-year limit does not reset upon a change in ownership or operational control of the entity required to contract for validation or verification services.

If the entity is required or elects to contract with another verification body or verifier(s), the entity may re-engage the previous verification body or verifier(s) only after three years, except in the case of a set-aside of a validation or verification statement as specified in section 95501. An entity required to contract for validation or verification services must, in time for the next verification, replace a verification body that has a suspended or revoked Executive Order pursuant to MRR section 95132(d), and included by reference in section 95502(a).

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95501. Requirements for Validation and Verification Services.

Validation and verification services must be performed by verification bodies accredited by the Executive Officer; in addition, such services must meet the following requirements (the general term “verification services” includes validation services for fuel pathway applications unless otherwise provided):

(a) *Notice of Verification Services.* The verification body must submit a notice of validation or verification services to the Executive Officer.

For verification bodies, the notice must be submitted to the Executive Officer after the Executive Officer has provided a determination that the potential for a conflict of interest is acceptable, as specified in section 95503(e), and that verification services may proceed. The verification body may begin services for the entity required to contract for verification services after the notice is received by the Executive Officer, but the verification body must allow a minimum of 14 ~~calendar~~ days advance notice of the site visit unless an earlier date is approved by the Executive Officer in writing. In the event that the conflict of interest statement and the notice of verification services are submitted together, services cannot begin until ~~ten calendar~~10 days after the Executive Officer has deemed acceptable the potential for conflict of interest as specified in 95503(e).

The verifier's notice must include all the following information:

(1) A list of personnel who will be designated to provide verification services as a verification team, including the names of each designated employee, the lead verifier, and all subcontractors, and a description of the roles and responsibilities each team member will have. The independent reviewer must also be listed separately.

(2) Documentation that the verification team has the skills required to provide verification services for the entity required to contract for verification services and type of application or report. The notice must include a demonstration that the verification team includes at least one member with specified competency that is not also the independent reviewer, when required below:

(A) Specified competency as evidenced by experience in alternative fuel production technology and process engineering when providing validation services for fuel pathway applications or verification services for Fuel Pathway Reports;

(B) Specified competency as evidenced by accreditation by the Executive Officer as an oil and gas systems specialist pursuant to MRR when providing verification services for Quarterly Fuels Transactions Reports submitted by producers and importers of gasoline or diesel, Crude Oil Quarterly and Annual Volumes Reports, and Project Reports as listed in section 95500.

(3) General information on the entity required to contract for verifications, including:

(A) The entity's name and the facilities and other locations that will be subject to verification services, and the contact, address, telephone number and e-mail address for the entity required to contract for verification services;

(B) The LCFS ID(s) for the entity required to contract for verification services;

(C) The date(s) of the on-site visit, if required in section 95501(b)(3), with physical address and contact information;

(D) A brief description of expected verification services to be performed, including expected completion date, and whether quarterly review is planned in the context of an annual verification requirement.

(4) If any of the information under sections 95501(a)(1) or 95501(a)(2) changes after the notice is submitted to the Executive Officer, the verification body must notify the Executive Officer as soon as the change is made and submit an updated notice of verification services.

The verification body must also submit an updated conflict of interest self-evaluation form with an updated notice of verification services as soon as the change is made. The conflict of interest must be reevaluated pursuant to section 95503(e) and the Executive Officer must approve any changes in writing.

(b) Verification services must include, but are not limited to, the following:

(1) *Validation or Verification Plan.* The verification team must develop a validation or verification plan based on the following:

(A) Information from the fuel pathway applicant, pathway holder, or reporting entity. Such information must include all the following:

1. Information to allow the verification team to develop an understanding of facility or entity boundaries, operations, accounting practices, type of LCFS report(s) the entity is responsible for, LCFS regulatory sections they are subject to, other renewable or low carbon fuels markets they participate in, and other mandatory or voluntary auditing programs they are subject to, as applicable;

2. Organizational chart and list of key personnel involved in developing applications and reports submitted to the Executive Officer, as specified in section 95500, and their qualifications, including training;

3. Description of the specific methodologies used to quantify and report data, as required in this subarticle, which are needed to develop the validation or verification plan, including but not limited to calibration procedures and logs for measurement devices capturing site-specific data;

4. Information about the data management systems and accounting procedures used to capture and track data for fuel pathway application and each type of report as needed to develop the validation or verification plan;

5. Information about the entities in the supply chain upstream and downstream of the fuel producer that contribute to site-specific CI data, including a list of feedstock suppliers and contact names with physical addresses;

6. Evidence demonstrating that any joint applicants are being separately verified and thus are outside the scope of the instant verification services being provided by the verification body; and

7. Previous LCFS validation and verification reports, as applicable, and other audit reports including reports from production or management system certifications and internal audits.

(B) Timing of verification services. Such information must include:

1. Dates of proposed meetings and interviews with personnel of the entity required to contract for verification services;

2. Dates of proposed site visits;

3. Types of proposed document and data reviews and, if applicable, how quarterly review is planned in the context of an annual verification requirement;

4. Expected date for completing validation or verification services.

(2) *Planning Meetings with the Entity Required to contract for Verification Services.* The verification team must discuss with the entity contracting for verification services the scope of the verification services and request any information and documents needed for the verification services.

The verification team must create a draft sampling plan and verification plan prior to the site visit. The verification team must also review the documents provided, and plan and conduct a review of original documents and supporting data for the verification services specified in section 95501.

(3) *Site Visits.* At least one lead LCFS verifier accredited by the Executive Officer on the verification team must, in addition to one visit to validate an application, annually visit each facility; and, if different from the fuel production facility, the central records location for which the records supporting an application or report subject to verification are submitted. Site visits, included voluntarily as part of a quarterly review, may not substitute for the required site visit for annual verification services, which must occur after all LCFS data for the prior calendar year has been submitted to the Executive Officer and attested to.

(A) During site visits, the verification team member(s) must carry out tasks that, in the professional judgment of the team, are necessary, including the following:

1. Review supporting evidence used to develop reports listed in section 95500 submitted to the Executive Officer;

2. Interview key personnel, such as process engineers, metering experts, accounting personnel, and project operators, as well as staff involved in compiling data and preparing the LCFS reports;

3. Review and understand the data management systems and accounting practices used by the entity to acquire, process, track, and report LCFS data. The verification team member(s) must evaluate the uncertainty and effectiveness of these systems;

4. Directly observe production equipment, confirming diagrams for processes, piping, and instrumentation; measurement system equipment; and accounting systems for data types determined in the sampling plan to be high risk;

5. Assess conformance with measurement accuracy requirements specified in this subarticle for measurement devices that do not meet criteria for financial transactions meters, assess the reasonableness of temporary measurement methods, assess conformance with the monitoring plan, and assess conformance with data capture requirements specified in this subarticle, if applicable.

6. Review financial transactions to confirm complete and accurate reporting.

(4) *Sampling Plan.* As part of validating fuel pathway applications and verifying LCFS reports the verification team must develop a sampling plan that meets the following requirements:

(A) The verification team must develop a sampling plan based on a strategic analysis developed from document reviews and interviews to assess the likely nature, scale and complexity of the verification services for the entity required to contract for verification services and type of report. The analysis must include a review of: the inputs for the development of the submitted applications and reports specified in section 95500; the rigor and appropriateness of data management systems; and the coordination within the responsible entity's organization to manage the operation and maintenance of equipment and systems used to complete applications and reports.

(B) The sampling plan must include a ranking of data sources by relative contribution to the data type to be assessed for material misstatement and a ranking of data sources with the largest calculation uncertainty, including risk of incomplete reporting, based on type of report or application.

(C) The sampling plan must include a qualitative narrative of uncertainty risk assessment in the following areas as applicable in this subarticle:

1. Data acquisition equipment;

2. Data sampling and frequency;

3. Data processing and tracking;

4. Tracking of fuel transportation into California to include modes of transportation and distances traveled, as applicable;

5. CI calculations, as applicable;

6. Fuel pathway code (FPC) allocation methodology, as applicable;

7. Management policies or practices in developing LCFS reports.

(D) After completing the analysis required by sections 95501(b)(4)(A) through (C) above, the verification team must include in the sampling plan a list which includes the following:

1. Data sources that will be targeted for document reviews, data checks as specified in 95501(b)(5), and an explanation of why they were chosen;

2. Methods used to conduct data checks for each data type;

3. A summary of the information analyzed in the data checks and document reviews conducted for each data type.

The sampling plan list must be updated and finalized prior to the completion of verification services. The final sampling plan must describe in detail how the identified risks were addressed during the verification. When quarterly reviews are conducted as part of annual verification services, the final sampling plan must describe in detail how the risks and issues identified for the annual data set were addressed during each quarterly review and final annual verification.

(E) *Specified Source Feedstocks.* Specified source feedstocks included in fuel pathway applications and reports that require third-party verification must be included in the scope of verification services. When a fuel pathway does not require third-party validation or verification, e.g., Lookup Table pathways including hydrogen (gaseous and liquefied) from central SMR of biomethane, specified source feedstocks must be included in the scope of verification of the Quarterly Fuel Transactions Reports. The verification team must use professional judgment and include in its risk assessment and sampling plan its analysis of the need for a desk review or site visit for verification of any entity in the feedstock chain of custody. This analysis must include an evaluation of the need to trace feedstock through feedstock suppliers, including aggregators, storage or pretreatment facilities, and traders or brokers, to the point of origin as required in section 95488.8(g). If an error is detected during data checks of records maintained by the entity required to contract for verification services, the verification team must update its risk assessment and sampling plan to assure specified source feedstock characterization and quantities to the point of origin.

(F) The verification team must revise the sampling plan to describe tasks completed by the verification team as information becomes available and potential issues emerge with material misstatement or nonconformance with the requirements of this subarticle.

(G) The verification body must retain the sampling plan in paper or electronic format (which includes digital media) for a period of no less than ten years following the submission of each validation or verification statement. The sampling plan must be made available to the Executive Officer upon request.

(H) The verification body must retain all material received, reviewed, or generated to render a validation or verification statement for the entity required to contract for verification services for a period of no less than ten years. The documentation must allow for a transparent review of how a verification body reached its conclusion in the validation or verification statement, including independent review.

(5) *Data Checks.* To determine the reliability of the submitted data, the verification team must conduct data checks. Such data checks must focus on the most uncertain data and on data with the largest contributions to greenhouse gas emissions (including life cycle greenhouse gas emissions) and greenhouse gas emission reductions. The selection of data checks must meet all the following criteria:

(A) The verification team must use data checks to ensure that the appropriate methodologies have been applied for the data submitted in applications and reports required in this subarticle;

(B) The verification team must choose data checks to ensure the accuracy of the data submitted in applications and reports required in this subarticle;

(C) The verification team must choose data checks based on the relative contribution to greenhouse gas emissions or reductions and the associated risks of contributing to material misstatement or nonconformance, as indicated in the sampling plan;

(D) The verification team must use professional judgment in establishing the extent of data checks for each data type, as indicated in the sampling plan, which are needed for the team to conclude with reasonable assurance whether the data type specified for the application or report is free of material misstatement. At a minimum, the data checks selected by the verification team must include the following:

1. Tracing data in the application or report to its origin;

2. Reviewing the procedure for data compilation and collection;

3. Recalculating intermediate and final data to check original calculations;

4. Reviewing calculation methodologies used by the entity required to contract for verification services for conformance with this subarticle; and

5. Reviewing meter and analytical instrumentation measurement accuracy and calibration for consistency with the requirements of this subarticle.

(E) The verification team is responsible for determining via data checks whether there is reasonable assurance that the application or report conforms to the requirements of this subarticle.

(F) The verification team must compare its own calculated results with the submitted data in order to confirm the extent and impact of any omissions and errors. Any discrepancies must be investigated. The comparison of data checks must also include a narrative to indicate which data were checked, the quantity of data evaluated for each data type, the percentage of reported source data covered by the data checks, and any separate discrepancies that were identified in the application or report.

(6) *Application and Report Modifications.* As a result of data checks by the verification team and prior to completion of a validation or verification statement, the entity required to contract for verification services must fix all correctable errors that affect the data submitted in the application or reports specified in section 95500 and submit a revised application or report to the Executive Officer. Failure to do so before completion of verification services will result in an adverse verification statement. Failure to fix misreported data that do not affect credit or deficit calculations represents a nonconformance with this subarticle but does not, absent other errors, result in an adverse validation or verification statement.

The verification team must use professional judgment in identifying correctable errors as defined in section 95481(a), including determining whether differences are not errors but result from truncation or rounding or averaging.

The verification team must document the source of any difference identified, including whether the difference results in a correctable error or on the other hand, was the result of truncation, rounding, or averaging.

(7) *Findings.* To verify that the application or report is free of material misstatements, the verification team shall make its own calculation of the specified data types reported by substituting the checked data from 95501(b)(5). The verification team must determine whether there is reasonable assurance that the application or report does not contain a material misstatement, as defined for each application or report type in section 95481, and calculated pursuant to section 95501(b)(9) through

(11), using the units required by the applicable parts of this subarticle. To assess conformance with this subarticle, the verification team must review the methods and factors used to develop the application or report for adherence to the requirements of this subarticle and identify whether other requirements of this subarticle are met.

(8) *Log of Issues.* The verification team must keep a log that documents any issues identified in the course of verification services that may affect determinations of material misstatement and nonconformance, whether identified by the verifier, the entity required to contract for verification services, or the Executive Officer, regarding the original or subsequent application or report versions. The issues log must identify the regulatory section related to the nonconformance or potential nonconformance, if applicable, and indicate if the issues were corrected by the entity required to contract for verification services prior to completing the verification services. Any other concerns that the verification team has with the preparation of the application or report must be documented in the issues log and communicated to the entity required to contract for verification services during the course of the verification services. The log of issues must indicate whether each issue has a potential bearing on material misstatement, nonconformance, or both and whether an adverse verification statement may result if not addressed. If quarterly review is conducted before an annual verification, any issues identified must be formalized pursuant to this subsection in the log of issues during the quarterly review. The log of issues for the annual verification must include the cumulative record of issues from all quarterly reviews, as well as the annual verification.

(9) *Material Misstatement Assessments for Fuel Pathways and Quarterly Fuel Transactions.* Assessments of material misstatement are conducted separately on each calculated operational CI value and each quarterly fuel transaction quantity per FPC (expressed in units from the applicable sections of this subarticle). Material misstatement assessments are not conducted for quarterly review.

(A) *Operational CI.* In assessing whether a fuel pathway application or fuel pathway report contains a material misstatement, as defined in section 95481(a), the verification team must populate a controlled version of the ~~Simplified~~Tier 1 CI Calculator for Tier 1 pathways, or CARB-approved CA-GREET~~3~~4.0 for Tier 2 pathways, and determine whether any reported operational CI value contains a material misstatement using the following equations for relative error threshold and absolute error threshold.

The following calculations of relative error threshold, absolute error threshold, and percent error must be included in the final verification report pursuant to section 95501(c)(3)(A)8.

Each fuel pathway CI is subject to data checks in section 95501(b)(5) and must be assessed separately for material misstatement. One or more material misstatements results in a finding of material misstatement for the fuel pathway application or for the fuel pathway report.

$$Percent\ error\ (CI\ ) = \frac{\sum |\ Difference\ in\ CI\ |}{|\ Reported\ Operational\ CI\ |}\ x\ 100\%$$

$$Relative\ error\ threshold\ (CI)$$

$$\underline{= |\ Difference\ in\ CI\ |\ \ \geq 0.05\ x\ |\ Reported\ Operational\ CI\ Value\ |}$$

$$Absolute\ error\ threshold\ (CI)$$

$$\underline{= |\ Difference\ in\ CI\ |\ \ \geq 2.00\ gCO_2e/MJ}$$

where:

"$Difference\ in\ CI$" means the absolute value result of the reported operational CI minus the verifier's calculation of CI. The verifier's calculation of CI is based on site-specific data inputs modified to include discrepancies, omissions, and misreporting found during the course of verification services;

"$Discrepancies$" means any differences between the reported site-specific CI inputs and the verifier's calculated site-specific CI inputs subject to data checks in section 95501(b)(5);

"$Omissions$" means any site-specific CI inputs or associated source data the verifier concludes must be part of the fuel pathway application or fuel pathway report, but were not included;

"$Misreporting$" means duplicate, incomplete or other CI input data the verifier concludes should, or should not, be part of the fuel pathway application or fuel pathway report; and

"$|\ Reported\ Operational\ CI\ Value\ |$" means the absolute value of the operational CI submitted in the fuel pathway application or fuel pathway report.

(B) *Quarterly Fuel Transaction Quantities per FPC.* In assessing whether a quarterly fuel transaction report contains a material misstatement, as defined in section 95481(a), the verification team must determine whether any quarterly fuel transaction quantity per FPC specified in section 95500(c)(1) contains a material misstatement using the following equation. The reported quarterly fuel transaction quantity for an FPC contains a material misstatement if the 5.00 percent error threshold is exceeded. The following calculation of percent error must be included in the final verification report pursuant to section 95501(c)(3)(A)8.

Each aggregated quarterly fuel quantity per FPC is subject to data checks in section 95501(b)(5) and must be assessed separately for material misstatement. One or more material misstatements results in a finding of material misstatement for the verification period.

$$Percent\ error\ (fuel\ transaction\ quantity)$$

$$= \frac{\sum\ [Discrepancies, Omissions, Misreporting]}{Reported\ Quarterly\ Fuel\ Transaction\ Quantity\ for\ FPC}\ x\ 100\%$$

where:

"$Discrepancies$" means any differences between the fuel quantity for the FPC reported in the Quarterly Fuel Transactions Report and the verifier's calculation of fuel quantity subject to data checks in section 95501(b)(5);

"$Omissions$" means any fuel quantity the verifier concludes must be part of the Quarterly Fuel Transactions Report, but was not included;

"$Misreporting$" means duplicate, incomplete or other fuel quantity data the verifier concludes should, or should not, be part of the Quarterly Fuel Transactions Report; and

"$Reported\ Quarterly\ Fuel\ Transaction\ Quantity\ for\ FPC$" means the total of all reported fuel quantities for each FPC for each transaction type specified in section 95500(c)(1) for each quarter for which the verifier is conducting a material misstatement assessment.

(C) When evaluating material misstatement, verifiers must deem correctly substituted missing data to be accurate, regardless of the amount of missing data.

(10) *Material Misstatement Assessment for Project Reports (Project-based Crediting)*.

(A) Verification services, including assessment of material misstatement, are conducted separately for each Project Report. In assessing whether a Project Report contains a material misstatement, as defined in section 95481(a), the verification team must determine whether the greenhouse gas reductions quantified and reported in the Project Report contain a material misstatement using the following equation.

Any discrepancies, omissions, or misreporting found by the verification team must include the positive or negative impact on the total reported greenhouse gas emission reductions when entered in the material misstatement equation. The reported project data contain a material misstatement if the 5.00 percent error threshold is exceeded. The following calculation of percent error must be included in the final verification report pursuant to section 95501(c)(3)(A)8.

$$Percent\ error\ (project\ data\ ) = \frac{\sum\ [Discrepancies, Omissions, Misreporting]}{Reported\ GHG\ Emissions\ Reduction}\ x\ 100\%$$

where:

"$Discrepancies$" means any differences between the reported greenhouse gas emissions reductions in the Project Report and the verifier's calculated value based on data checks required in section 95501(b)(5);

"$Omissions$" means any greenhouse gas emissions, excluding any greenhouse gas reductions, the verifier concludes must be part of the Project Report, but were not included;

"$Misreporting$" means duplicate, incomplete or other greenhouse gas emissions or reductions data the verifier concludes should, or should not, be part of the Project Report;

"$Reported\ GHG\ emissions\ reduction$" means the total of all greenhouse gas emissions reductions reported in the Project Report for which the verifier is conducting a material misstatement assessment.

(B) When evaluating material misstatement, verifiers must deem correctly substituted missing data to be accurate, regardless of the amount of missing data.

(11) *Material Misstatement Assessment for Low-Complexity/Low-Energy-Use Refinery Reports*.

(A) Verifications and assessments of material misstatement are conducted separately for volumes of CARBOB produced from crude oil and for volumes of diesel produced from crude oil for the calendar year. In assessing whether a Low-Complexity/Low-

Energy-Use Refinery Report contains a material misstatement, as defined in section 95481(a), the verification team must determine whether the Low-Complexity/Low-Energy-Use refinery data specified in this subarticle contains a material misstatement using the following equation.

Any discrepancies, omissions, or misreporting found by the verification team must include the positive or negative impact on the total CARBOB or diesel volume produced from crude oil when entered in the material misstatement equation. The reported refinery data contain a material misstatement if the 5.00 percent error threshold is exceeded. The following calculation of percent error must be included in the final verification report pursuant to section 95501(c)(3)(A)8.

$$Percent\ error\ (low\ complexity\ low\ energy\ use\ refinery\ data\ )$$

$$= \frac{\sum\ [Discrepancies, Omissions, Misreporting]}{CARBOB\ or\ Diesel\ Volume\ Produced\ from\ Crude\ Oil}\ x\ 100\%$$

where:

"$Discrepancies$" means any differences between the sum of the quarterly volumes of CARBOB or diesel produced from crude oil reported in the Low-Complexity/Low-Energy-Use Refinery Report and the verifier's calculation based on data checks in section 95501(b)(5);

"$Omissions$" means any volume of CARBOB or diesel produced from crude oil or associated source data the verifier concludes must be part of the Low-Complexity/Low-Energy-Use Refinery Report, but was not included;

"$Misreporting$" means duplicate, incomplete or other refinery data the verifier concludes should, or should not, be part of the Low-Complexity/Low-Energy-Use Refinery Report;

"$CARBOB\ or\ Diesel\ Volume\ Produced\ from\ Crude\ Oil$" means the sum of the quarterly volumes of CARBOB or diesel produced from crude oil in a calendar year reported in the Low-Complexity/Low-Energy-Use Refinery Report for which the verifier is conducting a material misstatement assessment.

"$CARBOB\ Volume\ Produced\ from\ Crude\ Oil$" and "$Diesel\ Volume\ Produced\ from\ Crude\ Oil$" are separately subject to data checks in section 95501(b)(5) and must be assessed separately for material misstatement. One or more material misstatements results in a finding of material misstatement for the Low-Complexity/Low-Energy-Use Refinery Report.

(B) When evaluating material misstatement, verifiers must deem correctly substituted missing data to be accurate, regardless of the amount of missing data.

(12) *Crude Oil Quarterly and Annual Volumes Reports.* Material misstatement assessment does not apply to data submitted in crude oil quarterly and annual volumes reports, but the data must be assessed for reasonable assurance of conformance with this subarticle.

(13) *Review of Missing Data Substitution.* If a source selected for a data check was affected by a loss of data used for the reported data in the application or report, pursuant to this subarticle:

(A) The verification team must confirm that the reported data were calculated using:

1. the applicable missing data procedures, or

2. an Executive Officer approved alternate method

~~2.~~ a ~~reasonable~~ temporary method~~, or~~

3. as permitted under section 95491.2(b)(2)(A) and described in section 95481. A temporary method may be used for a source that was affected by a loss of data for a period not to exceed six months. Missing data covering a period of time longer than six months during a calendar year requires an Executive Officer approved alternate method.

(B) The verifier must note the date, time and source of any missing data substitutions discovered during the course of verification in the validation or verification report.

(c) Completion of verification services must include:

(1) *Validation or Verification Statement.* Upon completion of the verification services specified in section 95500, the verification body must complete a validation or verification statement, and provide its statement to the entity required to contract for verification services and Executive Officer by the applicable verification deadline specified in section 95500. Before the validation or verification statement is completed, the verification services and findings of the verification team must be independently reviewed by an employee of the verification body who is an accredited lead verifier not

involved in verification services for the entity required to contract for verification services during that application period or reporting period.

(2) *Independent Review*. The independent reviewer must serve as a final check on the verification team's work to identify any significant concerns, including:

(A) Errors in planning,

(B) Errors in data sampling, and

(C) Errors in judgment by the verification team that are related to the draft validation or verification statement.

The independent reviewer must maintain independence from the verification services by not making specific recommendations about how the verification services should be conducted. The independent reviewer will review documents applicable to the services provided, and identify any failure to comply with requirements of this subarticle or with the verification body's internal policies and procedures for providing verification services. The independent reviewer must concur with the verification findings before the validation or verification statement is issued.

(3) *Completion of Findings and Validation or Verification Report and Statement.* The verification body is required to provide each entity required to contract for verification services with the following:

(A) A detailed validation or verification report, which must at a minimum include:

1. A detailed description of the facility or entity including all data sources and boundaries;

2. A detailed description of the data management system and accounting procedures;

3. A detailed description of entities in the supply chain contributing CI parameters;

4. The validation or verification plan;

5. The detailed comparison of the data checks conducted during verification services;

6. The log of issues identified in the course of verification services and their resolution;

7. Any qualifying comments on findings during verification services;

8. Findings of omissions, discrepancies, and misreporting and the material misstatement calculations required in section 95501(b)(9) through (11).

(B) The validation or verification report must be submitted to the entity required to contract for verification services at the same time as or before the final validation or verification statement is submitted to the Executive Officer. The detailed validation or verification report must be made available to the Executive Officer upon request.

(C) The verification team must have a final discussion with the entity required to contract for verification services explaining its findings, and notify the entity required to contract for verification services of any unresolved issues noted in the issues log before the validation or verification statement is finalized.

(D) The verification body must provide the validation or verification statement to the entity required to contract for verification services and the Executive Officer, attesting whether the verification body has found the submitted application or report to be free of material misstatement, and whether the application or report is in conformance with the requirements of this subarticle. For every qualified positive validation or verification statement, the verification body must explain the nonconformances contained within the application or report, and must cite the section(s) in this subarticle that corresponds to the nonconformance and why the nonconformances do not result in a material misstatement. For every adverse validation or verification statement, the verification body must explain all nonconformances or material misstatements leading to the adverse validation or verification statement and must cite the sections in this subarticle that correspond to the nonconformance and material misstatements.

(E) The lead verifier on the verification team must attest that the verification team has carried out all verification services as required by this subarticle. The lead verifier who has conducted the independent review of verification services and findings must attest to his or her independent review on behalf of the verification body and his or her concurrence with the findings.

1. The lead verifier must attest in the validation or verification statement, in writing, to the Executive Officer as follows:

"I certify under penalty of perjury under the laws of the State of California that the verification team has carried out all validation or verification services as required by this subarticle."

2. The lead verifier who has conducted the independent review of verification services and findings must attest in the validation or verification statement, in writing, to the Executive Officer as follows:

"I certify under penalty of perjury under the laws of the State of California that I have conducted an independent review of the validation or verification services and findings on behalf of the verification body as required by this subarticle and that the findings are true, accurate, and complete."

(4) *Adverse validation or verification statement and petition process.* Prior to the verification body providing an adverse validation or verification statement for the application or report to the Executive Officer, the verification body must notify the entity required to contract for verification services and the entity required to contract for verification services must be provided at least 14 ~~calendar~~ days to modify the application or report(s) to correct any material misstatement or nonconformances found by the verification team. The verification body must provide notice to the Executive Officer of the potential for an adverse validation or verification statement at the same time it notifies the entity required to contract for verification services, and include a current issues log. The modified application or report and validation or verification statement must be submitted to the Executive Officer before the verification deadline, even if the entity required to contract for verification services makes a request to the Executive Officer as provided below in section 95501(c)(4)(A).

(A) If the entity required to contract for verification services and the verification body cannot reach agreement on modifications to the data that result in a positive validation or verification statement, the responsible entity may, before the validation or verification deadline and before the validation or verification statement is submitted, petition the Executive Officer to make a final decision as to the verifiability of the submitted application or report. At the same time that the entity required to contract for verification services petitions the Executive Officer, the entity required to contract for verification services must submit all information it believes is necessary for the Executive Officer to make a final decision.

(B) The Executive Officer shall make a final decision no later than October 31~~st~~ following the submission of a petition pursuant to section 95501(c)(4)(A). If at any point the Executive Officer requests information from the verification body, or the entity required to contract for verification services, the information must be submitted to the Executive Officer within ~~ten calendar~~10 days. The Executive Officer will notify the entity required to contract for verification services and the verification body of its determination.

(d) *Validated Applications and Verified Reports Considered Final by the Executive Officer.* Upon provision of a validation or verification statement to the Executive Officer, the reported data is deemed final by the Executive Officer. No changes may be made to the application or report as submitted to the Executive Officer, and all verification requirements of this subarticle shall be considered complete except in the circumstance specified in section 95501(e).

(e) *Set Aside of Validation or Verification Statement.* If the Executive Officer finds a high level of conflict of interest existed between a verification body and a reporting entity, an error is identified, or an application or report that received a positive or qualified positive verification statement fails an audit by the Executive Officer, the Executive Officer may set aside the positive or qualified positive verification statement issued by the verification body, and require the reporting entity to have the report re-verified by a different verification body within 90 ~~calendar~~ days. In instances where an error to a report is identified and determined by the Executive Officer to not affect the final value submitted in the application or report, the change may be made without a set aside of the positive or qualified positive verification statement.

(f) *Executive Officer Audits and Data Requests to the Entity Required to Contract for Verification Services.* Upon request by the Executive Officer, the entity required to contract for verification services must provide the data used to generate the application or report including all data available to a verifier in the conduct of validation or verification services, within 14 ~~calendar~~ days. Upon written notification by the Executive Officer, the entity required to contract for verification services must make available for an Executive Officer audit itself, its personnel, and other entities in its feedstock and finished fuel supply chain, as applicable.

(g) *Executive Officer Audits and Data Requests to the Verification Body.* Upon request by the Executive Officer, the verification body must provide the Executive Officer the validation or verification report given to the entity required to contract for verification services, as well as the sampling plan, contracts for verification services, and any other supporting documents and calculations, within 14 ~~calendar~~ days. Upon written notification by the Executive Officer, the verification body must make itself and its personnel available for an Executive Officer audit.

(h) *Eligibility for Less Intensive Verifications*. Upon receiving a positive verification statement under full verification requirements, fuel reporting entities required to obtain the services of a verification body under section 95500 and only reporting electricity transactions identified in section 95500(c)(1)(E) may choose to obtain less intensive verification services for the following two annual verifications of their Quarterly Fuel Transactions Reports. Otherwise eligible entities must obtain full verification services if any of the following conditions apply:

(1) There has been a change in the verification body;

(2) An adverse verification statement or qualified positive verification statement was issued for the previous annual report;

(3) A change of operational control of the entity required to obtain the services of a verification body under section 95500 occurred in the previous year;

(4) The verification body must provide information on the causes of a change and justification in the verification report if a full verification was not conducted in instances where the following differences from the previous annual report occur:

(A) The annual sum of the four Quarterly Fuel Transaction Quantities differs by more than 25%.

(5) Nothing in this paragraph shall be construed as preventing a verification body from performing a full verification if it is deemed necessary to reach reasonable assurance.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95502. Accreditation Requirements for Verification Bodies, Lead Verifiers, and Verifiers.

(a) Verification bodies, lead verifiers, and non-lead verifiers that will provide verification services (including validation services) under this subarticle must become accredited through fulfilling the accreditation requirements set forth in MRR sections 95132(b) through (e), with the exception of subsections 95132(b)(1)(G), 95132(b)(2), 95132(b)(3), 95132(b)(5), and 95132(e)(1).

MRR text is as referred to, except as otherwise specifically provided:

(1) Wherever “section 95102(a)” is referenced, “section 95481” must be substituted. Wherever “section 95132(b)(2) is referenced, “section 95502(c)” must be substituted. Wherever “section 95133” is referenced, “section 95503” must be substituted.

(2) Whenever “Performance Review” is referenced, the definition in 95481(a) of this subarticle must be substituted.

(b) The Executive Officer may issue accreditation to verification bodies, lead verifiers, and non-lead verifiers that meet the requirements specified in this section.

(1) *Verification Body Accreditation Application.* In addition to the requirements specified in MRR section 95132(b)(1), the applicant must submit the following to the Executive Officer:

(A) Documentation that the proposed verification body has procedures and policies to support staff technical training as it relates to validation or verification. This training must include CARB's verifier training curriculum and be provided by a verification body or verification body applicant to its employees and subcontractors that participate on verification teams. Participation of individual verifiers, including verifiers that are not acting as lead verifiers, must be documented.

(B) The verification body's templates for risk assessment, sampling, and log of issues for the entity types and report types the verification body intends to verify, as specified in section 95500.

(C) Verification body staffing changes are considered an amendment to the verification body accreditation application and therefore the Executive Officer must be notified of any such changes.

(2) *Verifier Accreditation Application.* To apply for accreditation as a lead verifier, the applicant must submit documentation to the Executive Officer that provides the evidence that the applicant meets the criteria in sections 95502(c)(1) though (6). To apply for accreditation as a non-lead verifier, the applicant must submit documentation to the Executive Officer that provides the evidence that the applicant meets the criteria in sections 95502(c)(1) through (2).

(c) *Verifier Competency Requirements.* To perform LCFS verifications, verifiers must be employed by, or contracted with, a verification body accredited by the Executive Officer and submit evidence to demonstrate that competency requirements are met.

(1) Verifiers must provide evidence demonstrating the minimum educational background required to act as a verifier for CARB. Minimum educational background means that the applicant has either:

(A) A bachelor's level college degree or equivalent in engineering, science, technology, business, statistics, mathematics, environmental policy, economics, or financial auditing; or

(B) Evidence demonstrating the completion of significant and relevant work experience or other personal development activities that have provided the applicant with the communication, technical, and analytical skills necessary to conduct verification.

(2) Verifiers must provide evidence demonstrating sufficient workplace experience to act as a verifier, including evidence that the applicant verifier has a minimum of two years of full-time work experience in a professional role involved in emissions data management, emissions technology, emissions inventories, environmental auditing, financial auditing, life cycle analysis, transportation fuel production, or other technical skills necessary to conduct verification.

(3) To act as a lead verifier, in addition to the qualifications in sections 95502(c)(1) and (2), one of the following qualifications must be met:

(A) The verifier must have participated within the previous two years as part of the verification team in at least three completed LCFS validations or verifications under the supervision of a lead verifier accredited under this subarticle by the Executive Officer;

(B) The verifier must be accredited as a lead verifier under MRR or the Cap-and-Trade Regulation by the Executive Officer;

(C) The verifier must have experience acting as the lead on an attestation engagement services team for the U.S. EPA Renewable Fuel Standard (RFS) program within the previous two years or currently be acting as a team lead;

(D) The verifier must have experience acting as the lead on a Quality Assurance Program (QAP) services team for the U.S. EPA RFS program within the previous two years or currently be acting as a team lead;

(E) The verifier must have experience acting as a ~~the~~ lead on a biofuels certification audit within the previous two years or currently be acting as a lead under one of the following international certification systems: International Sustainability and Carbon Certification (ISCC), Roundtable on Sustainable Biomaterials (RSB), or Bonsucro; or

(F) The verifier must have worked as a project manager or lead person for no less than four years, of which two may be graduate level work:

1. In the development of greenhouse gas or other air emissions inventories; or,

2. As a lead environmental data or financial auditor.

(G) Candidates meeting one of the lead verifier qualifications in sections 95502(c)(3)(A) through (E) must complete training specific to the LCFS program to become a lead verifier under this subarticle.

Candidates applying under section 95502(c)(3)(F) for accreditation as a lead verifier under this subarticle must take the CARB-approved comprehensive general verification training and examination in addition to the training specific to the LCFS program.

(4) To become accredited as a lead verifier for validation of fuel pathway applications (CI) or verification of Fuel Pathway Reports (CI) as specified in section 95500(a) and 95500(b), in addition to the qualifications in sections 95502(c)(1) through (3), the verifier must have experience in alternative fuel production technology and process engineering.

(5) To become and remain accredited as a lead verifier for verification of Quarterly Fuel Transactions Reports submitted by producers and importers of gasoline or diesel, Low-Complexity/Low-Energy-Use Refinery Report, Crude Oil Quarterly and Annual Volume Reports, and Project Reports as specified in section 95500, in addition to the qualifications in sections 95502(c)(1) through (3), the verifier must be accredited as an oil and gas systems specialist pursuant to MRR section 95131(a)(2).

(6) Nothing in this section shall be construed as preventing the Executive Officer from requesting additional information or documentation from a verifier or affiliated verification body to demonstrate that the verifier meets the competency requirements set forth here, or from seeking additional information from other persons or entities regarding the verifier's fitness for qualification.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

§ 95503. Conflict of Interest Requirements for Verification Bodies and Verifiers.

(a) *Applicability of Conflict of Interest Provisions.* The conflict of interest provisions of this section shall apply to verification bodies and lead verifiers, including independent reviewers, accredited by the Executive Officer to perform LCFS validation and verification services for responsible entities and must apply to all verification team members.

Any individual person or company that is hired by the entity required to contract with a verification body on behalf of the entity required to contract for verification services is also subject to the conflict of interest assessment in this subarticle. In such instances, the verification body must assess the potential conflict of interest between itself and the contracting entity as well as between itself and the responsible entity, and must also address the potential conflict of interest between the contracting entity and the responsible entity, including a written assessment provided and signed by the contracting entity.

(1) "Member" for the purposes of this section means any employee or subcontractor of the verification body or its related entities.

(2) "Related Entity" for the purposes of this section means any direct parent company, direct subsidiary, or sister company.

(3) "Lookback Period" for the purposes of this section means to disclose services provided and assess potential for conflicts of interest beginning five years preceding the start of verification services.

(4) Emerging conflicts of interest must also be monitored. The monitoring period for determining emerging conflicts of interest is during the period verification services are offered and one year after verification services are completed.

(b) *Disclosure of Services with High Potential for Conflict of Interest.* If any of the following occurred during the lookback period, the activity or activities must be disclosed to the Executive Officer with a description of actions the verification body has taken to avoid, neutralize, or mitigate any ongoing potential for conflict of interest.

The potential for a conflict of interest must be deemed high if any of the following occurred during the lookback period. If the Executive Officer determines the verification body or its related entities or any member of the verification team meets the criteria specified in section 95503(b), the Executive Officer shall find a high potential conflict of interest~~ with the following exceptions:~~.

~~Prior to August 31, 2023, the Executive Officer shall deem the following services to be medium potential for conflict of interest and allow verification services to proceed when the verification body or its related entities or a member of the verification team has provided the services listed in sections 95503(b)(2)(A), (B), (C), (E), (G), (H), (I), or (N) within the five year lookback period, provided that the potential conflict of interest is mitigated by meeting the minimum mitigation plan requirements in section 95503(d)(1). On and after August 31, 2023, if any of the situations or services listed in section 95503(b) occurred during the five year lookback period by a verification body and its related entities or a verification team member, verification services may not proceed and rotation is required.~~

(1) Organizational High Potential Conflict of Interest Conditions. The verification body and responsible entity share any management staff or board of directors membership, or any of the senior management staff of the responsible entity have been employed by the verification body, or vice versa; or

(2) Organizational and Individual High Potential Conflict of Interest Conditions. Any employee of the verification body, or any employee of a related entity, or a subcontractor who is a member of the verification team has provided to the responsible entity any of the following services:

(A) Designing, developing, implementing, reviewing, or maintaining an information or data management system for data submitted pursuant to this subarticle or MRR unless the review was part of providing independent quality assurance audit services, attestation engagement services, providing validation or verification services pursuant to the U.S. EPA RFS or the EU RED, or third-party engineering reports pursuant to the U.S. EPA RFS;

(B) Developing CI or fuel transaction data or other greenhouse gas-related engineering analysis that includes facility-specific information;

(C) Designing or providing consultative engineering or technical services in the development and construction of a fuel production facility; or energy efficiency, renewable power, or other projects which explicitly identify greenhouse gas reductions as a benefit;

(D) Designing, developing, implementing, conducting an internal audit, consulting, or maintaining a greenhouse gas emissions reduction or greenhouse gas removal offset project as defined in the Cap-and-Trade Regulation and reported to the Executive Officer, or a project to receive LCFS project-based credits;

(E) Preparing or producing LCFS fuel pathway application or LCFS reporting manuals, handbooks, or procedures specifically for the responsible entity;

(F) Directly managing any health, environment or safety functions for the responsible entity;

(G) Any service related to development of information systems, or consulting on the development of environmental management systems is considered high conflict of interest except for systems that will not be part of the validation or verification process and except for accounting software systems;

(H) Verification services that are not conducted in accordance with, or equivalent to, section 95503 requirements, unless the systems and data reviewed during those services, as well as the result of those services, will not be part of the verification process;

(I) Reporting pursuant to this subarticle, or uploading data for the Executive Officer, on behalf of the entity required to contract for verification services;

(J) Owning, buying, selling, trading, or retiring LCFS credits, RINs, or credits in any carbon market;

(K) Dealing in or being a promoter of credits on behalf of the responsible entity;

(L) Appraisal services of carbon or greenhouse gas liabilities or assets;

(M) Brokering in, advising on, or assisting in any way in carbon or greenhouse gas-related markets;

(N) Bookkeeping and other non-attest services related to accounting records or financial statements, excluding services and results of those services that will not be part of the validation or verification process;

(O) Appraisal and valuation services, both tangible and intangible;

(P) Any actuarially oriented advisory service involving the determination of amounts recorded in financial statements and related accounts;

(Q) Any internal audit service that has been outsourced by the entity required to contract for verification services that relates to the entity's internal accounting controls, financial systems or financial statements, unless the result of those services will not be part of the verification or validation process;

(R) Fairness opinions and contribution-in-kind reports in which the verification or validation body has provided its opinion on the adequacy of consideration in a transaction, unless the resulting services will not be part of the verification or validation process;

(S) Acting as a broker-dealer (registered or unregistered), promoter or underwriter on behalf of the responsible entity;

(T) Any legal services;

(U) Expert services to the entity required to contract for verification services, a trade or membership group to which the entity required to contract for verification services belongs, or a legal representative for the purpose of advocating the entity's interests in litigation or in a regulatory or administrative proceeding or investigation.

(3) *Prohibition on Monetary or Non-Monetary Incentives.* The potential for conflict of interest shall be disclosed and deemed to be high when any member of the verification body provides any type of monetary or non-monetary incentive to an entity required to contract for verification services to secure a validation or verification services contract.

The potential for conflict of interest shall be deemed to be high when any member of the entity required to contract for verification services provides any type of monetary or non-monetary incentive to a member of the verification body to influence validation or verification documentation or findings.

(4) Potential for High Conflict of Interest if Rotation Limit Exceeded. The potential for a conflict of interest shall also be disclosed and deemed to be high where any member of the verification body or verification team has provided verification services for the entity required to contract for verification services except within the time periods in which the entity required to contract for verification services is allowed to use the same verification body or team members as specified in section 95500(g).

(c) *Low Conflict of Interest.* The potential for a conflict of interest shall be deemed to be low where the following conditions are met:

(1) No potential for a high conflict of interest is found pursuant to section 95503(b); and

(2) Any services provided by any member of the verification body or verification team to the entity required to contract for verification, within the look-back period specified in section 95503(a)(3), are valued at less than 20 percent of the fee for the proposed verification services. Any verification conducted in accordance with, or substantially equivalent to, section 95503 provided by the verification body or verification team outside the jurisdiction of the Executive Officer is excluded from this financial assessment, but must be disclosed to the Executive Officer in accordance with section 95503(e).

(3) Non-CARB verification services are excluded from categories of risk if those services are conducted in accordance with, or substantially equivalent to, section 95503, including, but not limited to, auditing services provided under the U.S. EPA RFS (QAP services, attest engagement

services, third-party engineering reports), third-party certification of environmental management systems under ISO 14001, energy management systems under 50001 standards, or certification systems recognized by other governmental agencies, including the European Commission. Verification services provided under MRR or the Cap-and-Trade Regulation are also excluded from categories of risk for potential conflict of interest.

(d) *Medium Conflict of Interest.* The potential for a conflict of interest shall be deemed to be medium where the potential for a conflict of interest is not deemed to be either high or low as specified in sections 95503(b) and 95503(c). The potential for conflict of interest will also be deemed to be medium where there are any instances of personal or familial relationships between the members of the verification body and management or members of the entity required to contract for verification services.

(1) If a verification body identifies a medium potential for conflict of interest and intends to provide verification services for the entity required to contract for verification services, the verification body shall submit, in addition to the submittal requirements specified in section 95503(e), a plan to avoid, neutralize, or mitigate the potential conflict of interest situation. At a minimum, the conflict of interest mitigation plan shall include:

(A) A demonstration that any individuals with potential conflicts have been removed and insulated from the project.

(B) An explanation of any changes to the organizational structure or verification body to remove the potential conflict of interest. A demonstration that any unit with potential conflicts has been divested or moved into an independent entity or any subcontractor with potential conflicts has been removed.

(C) Any other circumstance that specifically addresses other sources for potential conflict of interest.

(2) The Executive Officer shall evaluate the conflict of interest mitigation plan and determine whether verification services may proceed pursuant to section 95503(e).

(e) *Conflict of Interest Submittal Requirements for Accredited Verification Bodies.* Verification bodies accredited by the Executive Officer to perform validation or verification services must adhere to the conflict of interest submittal, determinations, and monitoring requirements in MRR section 95133(e) through (g), except section 95133(f)(2) and (3). Except as otherwise specifically provided:

(1) Wherever the term “reporting entity” is used, the term “entity required to contract for validation or verification services” shall be substituted;

(2) Whenever the term “emissions data report” is used, the term “applications or reports specified in section 95500 of this subarticle” shall be substituted;

(3) Whenever the term “verification services” is used, the term “verification or validation services” shall be substituted;

(4) Wherever “section 95133(a)-(d)” referenced, “section 95503(a)-(d)” shall be substituted; and

(5) When potential for a conflict of interest is deemed to be low, as specified in section 95503(c), the verification body must submit its self-assessment to the Executive Officer, except the Executive Officer authorization to perform verification services as specified in MRR sections 95133(e)(1) and 95133(f)(3) is not required prior to performing LCFS verification services.

NOTE: Authority cited: Sections 38510, 38530, 38560, 38560.5, 38571, 38580, 39600, 39601, 41510, 41511 and 43018, Health and Safety Code; 42 U.S.C. section 7545; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975). Reference: Sections 38501, 38510, 39515, 39516, 38571, 38580, 39000, 39001, 39002, 39003, 39515, 39516, 41510, 41511 and 43000, Health and Safety Code; Section 25000.5, Public Resources Code; and *Western Oil and Gas Ass'n v. Orange County Air Pollution Control District*, 14 Cal.3d 411, 121 Cal.Rptr. 249 (1975).

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Comment 230 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Steve
Last Name	Compton
Email Address	steve@sevanabioenergy.com
Affiliation	Sevana Bioenergy
Subject	LCFS ISOR Comments
Comment	Please find our comments attached.
Attachment	www.arb.ca.gov/lists/com-attach/6889-lcfs2024-AXIGZVEmUmBROQNi.pdf
Original File Name	Sevana CARB_Comments 02_10_2024.pdf
Date and Time Comment Was Submitted	2024-02-20 13:23:09

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

SEVANA BIOENERGY

February 20, 2024

Matthew Botill
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Sevana Bioenergy Comments Regarding ISOR for the Low Carbon Fuel Standard

Dear Mr. Botill:

Thank you for the opportunity to submit comments in response to the Proposed Amendments (Proposed Rule) and associated Initial Statement of Reasons (ISOR) for the Low Carbon Fuel Standard (LCFS) released December 19, 2023. By way of background, Sevana Bioenergy develops RNG projects through design, construction, and operations, with strong partnerships and contributions to the local communities we serve. Our mission is to accelerate the production of RNG from anaerobic digestion facilities and contribute significantly to worldwide greenhouse gas reduction with net carbon-negative projects.

Sevana has staff based in California who have participated in the LCFS for nearly 15 years. We support the need for this rulemaking process to increase and extend LCFS targets that keep key successful elements intact, while enhancing the areas noted below. As you consider comments on this round of rulemaking, Sevana Bioenergy would like to offer the following feedback for your consideration.

Reduce the excess credit bank

Sevana Bioenergy applauds CARB's commitment to reducing carbon intensity and is pleased to see an initial proposed reduction target of at least 30% minimum and 18.75% step down for 2025. However, these targets remain lower than recommended in our letter from March 2023. In the meantime the credit bank has grown even faster than previously expected. The bank of over 20 million credits has depressed prices below the cost of production and return on capital needed to make ambitious investments in low carbon fuel sources and adopt lower emission vehicle technologies, stalling progress until these excess credits are absorbed and supply-demand balance reestablished.

We suggest the following three step solution to include in the final rulemaking:

Set the 2025 step down to 25%

216.1 We recommend a step down to 25% in 2025, or even by mid-2024. This magnitude of step down is essential to enable the LCFS to "catch up" and absorb the large supply of banked credits. This change could be implemented XXX.1 with minimal recycling of CARB's previous modelling as it would simply bring the targets in line with renewable diesel, electricity, and RNG utilization in California. This larger step down is also needed to mitigate the supply-demand balance impact from the new ULSD baseline (105.76). Without changing the 2030 target beyond the associated modelling, this near term step down demand signal is needed to sustain momentum to reach more ambitious targets proposed after 2030.

Strengthen the AAM's mechanics

216.2 We recommend three changes to the auto acceleration mechanism (AAM): First, allow it to take effect in 2027 (or 2026 if the 2025 step down remains less than 25%). Secondly, implement the triggering threshold when the
XXX.2 credit bank is more than 2.0 times greater than the quarterly deficits generated, based on analysis by AJW and others that 3.0 is excessive. Finally, the AAM should allow for the program to trigger continuously (no "freeze" needed between years as currently proposed). These adjustments to the AAM will ensure it is effective enough to avoid repeat regulatory revisions and give sufficient confidence to market participants to make informed investments and long term commitments.

Consider increasing the 2030 target

Based on our review and independent runs of the CATS model, we note generally high cost and limited availability assumptions may skew the results to predict too high prices with too few substitutes. In the future, implementing learning curves and Monte Carlo scenarios across ranges of assumptions could provide additional insights for
216.3 policy making. We respectfully propose CARB consider implementing at least a 35% target in 2030, especially if
XXX.3 the AAM and step down above is not fully implemented. This would also better align the pre-2030 and post-2030 annual targets (vs back-end loading post-2030).

True-up Temporary Pathway Codes

A true-up remains necessary to properly recognize the true environmental performance of all pathways for Temporary Pathway Code (TPC) time periods. Under industry-standard carbon intensity sliding scale contracts the TPC's worse-than-actual carbon intensity disproportionately shifts economics away from producers during the critical "valley of death" shortly after startup but before provisional pathway revenues are realized.

Extending the proposed ISOR true-up to also apply to TPCs is a simple fix to ensure correct accounting for actual GHG benefits delivered so that producers have adequate economics to bring new fuel sources online.

Furthermore, the penalty for inadvertently overstated carbon intensities during the true-up should be revised to 1.25x rather than 4.0x to penalize but not bankrupt producers that do not achieve carbon intensity modelled with best available information but fall short due to factors outside their control.

Streamline Tier 1 Pathway calculators

We support improvements to the Tier 1 calculators to improve processing timelines and streamline verification currently requiring Tier 2 pathways. We would recommend the Tier 1 DSW model enable entering 0, 1, or more lagoon cleanouts per year based on verified inputs. We also support recognizing the latest science finding higher methane emissions are otherwise generated from organic waste prior to processing in anaerobic digestors.

Maintain avoided methane and deliverability mechanics

Sevana is developing projects both inside and outside California, with both carbon negative electricity and RNG pathways, so we are familiar with and not biased toward any specific fuel type or geography. Furthermore, RNG can be used to generate hydrogen and other low carbon fuels. The science-based, technology-neutral and inter-state commerce compliant framework of the LCFS make it a strong and tested policy.

We recommend CARB maintain or extend the timeframes in the ISOR for eligibility of avoided methane deliverability. These mechanisms are supported by science and aligned with programs such as the RFS and other state LCFS. This will avoid tremendous risk of legal challenges, fuel shortages, higher emissions through workarounds such as trucking rather than pipeline deliveries, and perpetuating the sustained usage of fossil fuels by arbitrarily hindering low carbon fuels.

Methane is one of the most powerful greenhouse gases with a potency nearly 30 times that of carbon dioxide. RNG projects capture methane including from livestock and organic waste that would otherwise be released to the atmosphere and thus reduce greenhouse gas emissions and improve air quality. California should employ all options available to help mitigate methane emissions.

We hope these comments and suggestions are helpful to consider in the final rulemaking.

Sincerely,

Steve Compton
President & COO
Sevana Bioenergy

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Comment 226 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Brian
Last Name	McDonald
Email Address	bcmcdonald@marathonpetroleum.com
Affiliation	MPC
Subject	LCFS Regulation Comments
Comment	Please see attached.
Attachment	www.arb.ca.gov/lists/com-attach/6890-lcfs2024-B2RXMFwvWWgKU1c7.pdf
Original File Name	CARB LCFS Proposed Regulation Comments_45 day.pdf
Date and Time Comment Was Submitted	2024-02-20 13:36:46

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Marathon Petroleum Company LP

539 South Main Street
Findlay, OH 45840
Tel: 419.422.2121
Fax: 419.425.7040

SUBMITTED ELECTRONICALLY

February 20, 2024

Leanne Randolph
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Comments on the California Air Resources Board's Proposed Amendment Order to the Low Carbon Fuel Standard (LCFS)

Dear Chairwoman Randolph and Honorable Board Members:

Marathon Petroleum Company LP (MPC) appreciates the opportunity to provide comments to the California Air Resources Board's Proposed Amendment Order to the LCFS.

MPC is a wholly owned subsidiary of Marathon Petroleum Corporation, a leading, integrated, downstream energy company headquartered in Findlay, Ohio. MPC is a supplier of fuels in the State of California and MPC, both directly and through its subsidiaries, is investing in low-carbon solutions to meet the energy demands of today and into the future. MPC's commitment to low-carbon solutions is reflected in the successful conversions of its Dickinson, North Dakota and Martinez, California petroleum refineries into renewable fuel production facilities. Combined, these two operating facilities are expected to produce up to 2.5 million gallons per day of renewable transportation fuel from renewable feedstock sources with an aggregate life-cycle carbon intensity that is approximately 60 percent less than petroleum-based fuels.

The proposed amendments include several changes that MPC has provided comments to in previous workshops. MPC is supportive of several of the proposed amendments, and comments included here will focus on recommendations MPC believes are vital to enhancing the LCFS's ability to provide a strong stable signal and incentivize new low carbon technology use in the transportation fuel sector.

MPC's recommendations on the proposed amendment order are listed below. Additional discussion and support for these recommendations are provided in the subsequent sections.

- MPC recommends CARB recognize the carbon-reducing practices implemented by farmers in its Feedstock Sustainability requirement if it intends to implement a costly and complex Feedstock Sustainability program.
- MPC recommends CARB support the use of renewable natural gas as a feedstock for hydrogen production at a facility.

- MPC recommends CARB reconsider its proposal to add Attestation Letter requirements to the Specified Source Feedstock supply chain.
- MPC recommends CARB make the position holders of jet fuel in the tanks at an airport the First Fuel Reporting Entities.
- MPC recommends CARB not sunset the Refinery Investment Credit provision in 2040 and allow for additional process improvement projects after 2025.
- MPC recommends CARB address the issues MPC identified in CA GREET 4.0 and associated Tier 1 calculators.

The Feedstock Sustainability requirements stop short of recognizing emission reductions farmers are making today while adding costs and additional complexity to a complex feedstock supply chain.

217.1 MPC does not support a cap on crop-based feedstocks[1] and appreciates that the proposed amendments do not establish a cap. MPC has stated previously that a cap on feedstocks will slow progress of meaningful new farming practices. These practices, shown to enhance soil fertility, reduce fertilizer use, and increase soil organic carbon levels[2], can result in lower emissions within the transportation sector.

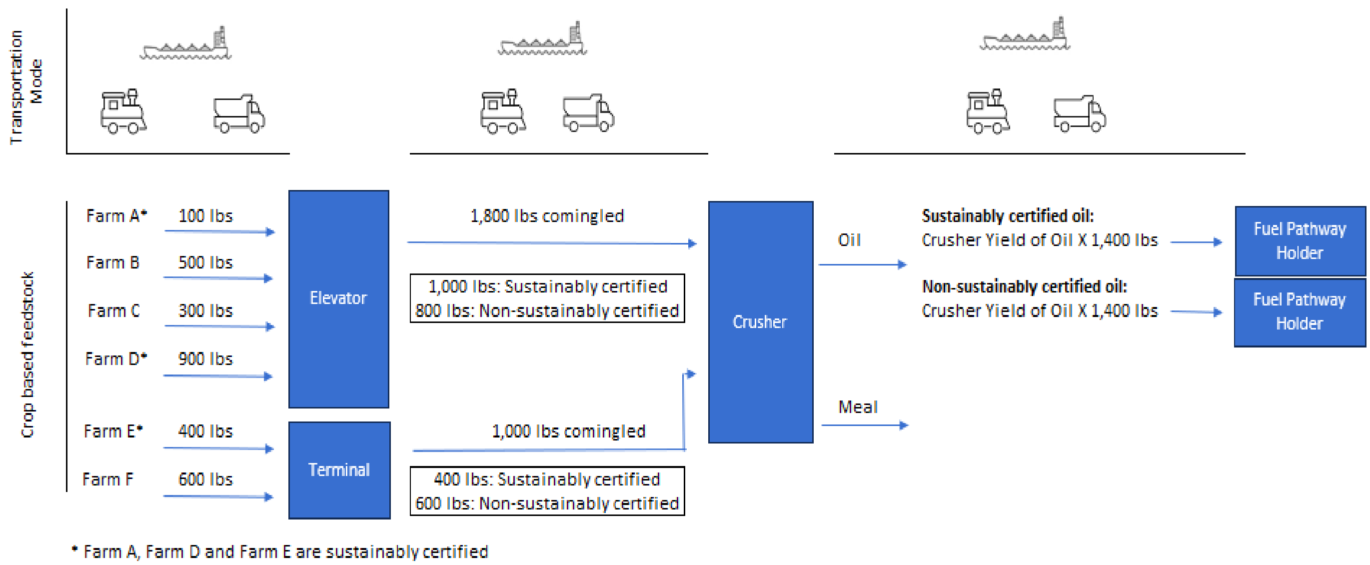
As an alternative to capping and restricting the use of crop-based feedstocks in the LCFS, CARB has proposed approving third-party programs to certify the sustainability of crop-based feedstocks used to produce transportation fuel that generates LCFS credits. This feedstock sustainability concept[3] includes smart agricultural practices that farmers are utilizing today but does not include a system for recognizing the carbon intensity reduction from such agricultural practices in the renewable fuels CI score. As discussed in the next paragraphs, a third-party certification program will add burden and costs, especially for farmers. Certifying 217.2 certain crop-based feedstocks as having a lower CI score can incentivize smart agricultural practices and help offset costs of the program.

As a producer of renewable diesel that relies on the crop-based feedstock supply chain within the U.S. and abroad, MPC is concerned about the proposal to add a certification process to the very complex U.S. crop-217.3 based feedstock supply chain as the process will increase costs to produce renewable diesel and potentially trigger feedstock supply disruptions, limiting renewable fuel production. The crop-based feedstock supply chain connects small family farms and corporate farms to grain elevators, transporters, and crushers to fuel producers and suppliers of renewable fuels. Most grain used to produce crop-based feedstocks are comingled several times throughout the supply chain. For example, after soybeans are harvested and dried, they are transported and comingled with other harvested soybeans, at grain terminals, elevators, and processing facilities for crushing[4]. Transportation methods will vary throughout the feedstock supply chain and includes rail, ship/barge, and trucks. Because the soybeans from multiple farms are commingled, any process developed to track the amount of sustainably certified soybeans used by a fuel pathway holder must 217.4 incorporate a material balance approach. Only a material balance approach will make it possible to track the amount and sustainability characteristics of such crops throughout the supply chain. Additionally, a material balance approach will prevent creating a system that requires segregation, leading to unnecessary

[1] MPC Comments: CARB 7.7.22 Workshop
[2] E.g., Koudahe et al. 2022. Critical review of the impact of cover crops on soil properties
[3] CARB Appendix E Purpose and Rationale: 2024 rulemaking p80
[4] U.S. Soy Export Council International Buyers Guide

transportation emissions and inefficiencies adding cost to the production of renewable diesel and causing feedstock supply disruptions.

Simplified depiction of a material balance approach applied to the crop-based feedstock supply chain



As noted, the sustainability certification system does not go far enough to distinguish the carbon-reducing practices implemented by some farmers. This system merely acknowledges whether the feedstock can be used in a LCFS fuel pathway. Rather, a sustainability program should acknowledge when a farmer has implemented techniques to reduce the carbon emissions from crop production, which in turn is used to lower the carbon intensity of the renewable fuel. If CARB implements the third-party certification program, MPC recommends
217.5 including provisions that would allow a renewable fuel producer to take carbon intensity reduction credit for crop-based feedstocks grown using smart agricultural practices.

Renewable natural gas is needed to decarbonize the industrial sector, any additional limitations will slow the use of renewable natural gas in the industrial sector.

CARB recognizes renewable natural gas as a low carbon intensity fuel in its use as a feedstock to hydrogen production. CARB allows the use of book-and-claim accounting to connect the environmental attributes of renewable natural gas produced at one location to the use of natural gas in hydrogen production at another location. Book-and-claim accounting is vital to renewable natural gas production and growth as many renewable natural gas facilities are not located in the same geographic regions where the hydrogen facilities are located. Because book-and-claim accounting has been available, renewable natural gas production facilities continue to be built throughout the country and have not been isolated to locations near hydrogen production facilities, California or adjacent states. If CARB were to limit the ability of renewable natural gas producers to use book-and-claim accounting, CARB would slow the growth of renewable natural gas and its
217.6 use in industrial facilities producing fuels supplied to the California market. Marathon thus supports the continued use of book-and-claim accounting.

Adding attestation requirements to Specified Source Feedstocks is unnecessary.

217.7 MPC opposes the attestation requirement for specified source feedstocks. The attestation requirement would add significant and unnecessary verification workload to the annual verification process, as the chain-of-custody evidence is already reviewed and verified under the current regulatory provisions.

The specified source feedstock supply chain includes multiple entities, such as points of origin, collectors, aggregators, storage terminals and at times pre-treatment facilities. Each of these entities must provide an attestation stating a feedstock has not been altered from the pathway application. This requirement is problematic. A downstream entity within the supply chain likely lacks the knowledge of how a previous entity handled the feedstock, including whether it has undergone additional processing.

xxx.7 If CARB retains the attestation requirement, then CARB must do two things. First, CARB must narrow the attestation to information about the feedstock while the feedstock was in that attesting entity's control. An entity representative should not be required to attest to information of which he has no knowledge. Second, CARB must explain the energy systems that are included in CARB's emission factors. The existing default emission factor documentation[5] does not explain to entities within the supply chain what is included in

217.8 CARB's default values for feedstock collection, processing, and handling. Any activities not included in the default emission factors would be considered "additional processing" and thus should be identified in the attestation. Unless each entity understands the activities considered to be "additional processing," entities may not submit accurate attestations.

The jet fuel importer or producer should not be the First Fuel Reporting Entity.

217.9 MPC opposes assigning the producer or importer of jet fuel as the First Fuel Reporting Entity and strongly recommends the position holder of the fuel in the tanks at an airport be the First Fuel Reporting Entity. This would allow those closest to the use of the fuel, the airports, airlines, and position holders, to work together and determine the most appropriate accounting and tracking method for reporting fuels with an obligation.

CARB's proposal identifies that fossil jet fuel after 2028 will no longer be exempted from a compliance obligation unless it is used for interstate or international flights. To distinguish exempt jet fuel from obligated jet fuel, the proposed amendments require the First Fuel Reporting Entity to designate the obligated volumes of jet fuel as "Fossil Jet Fuel used for Intrastate Flight." The jet fuel producer or importer, however, does not know whether its volume of jet fuel is used for intrastate flights or is used for interstate and international flights. Unlike gasoline or diesel, which can be tracked to determine whether it is sold in state or out of state, jet fuel is delivered to airports, commingled within storage tanks, and used to fuel all flights at the airport. The fuel producer cannot track its jet fuel into the airplane and determine whether the fuel was used for intrastate, interstate, or international flights.

As additional explanation, the jet fuel logistics within California includes the transportation of jet fuel through pipelines and trucks to airport storage facilities. Jet fuel traveling on the pipeline is often commingled in breakout tankage along the pipeline before reaching its final destination at airport storage facilities. These airport storage facilities may be owned by one or more airlines. The jet fuel delivered into the storage facilities

[5] CA GREET 4.0

is commingled and may be used by any one of the airlines, who loads the fuel onto any one of many aircraft departing from an airport. Once jet fuel is placed in these airport storage facilities, only the airlines will know if the fuel was used for intrastate, interstate, or international flight. Placing that burden on the producer, who has no knowledge of how the fuel is ultimately used, will make compliance with the proposed regulation impractical, leading to the potential for inaccurate reporting. The position holder in the airport storage tanks is the appropriate party to report obligated intrastate jet fuel because it is closest to the fuel and its use.

The Refinery Investment Credit Provision is critical to incentivize petroleum refineries to reduce emissions.

Refineries are comprised of many complex, large scale industrial pieces of equipment that are not easily retrofit or optimized to reduce emissions from the production of transportation fuels. Many times, energy efficiency and emission reduction projects within refineries require large amounts of capital. The LCFS incentive provides additional support to move these projects forward. These same projects may provide additional benefits to the State by reducing nitrogen oxide (NOx) and other combustion emissions in largely disadvantaged communities, maintaining Union jobs, and supporting the local economies surrounding the refineries.

217.10 The proposed amendments sunset the Refinery Investment Credit Protocol in 2040. MPC opposes setting a date for the provision to end as projects that qualify for crediting will continue to provide benefits to the state long past 2040. Additionally, MPC recommends CARB remove the requirement that applications for process improvement projects under §95489(e)(3)(H)[6] be submitted on or before December 31, 2025, as it does little to incentivize innovation and reduce emissions within a petroleum refinery.

Recommendations on the proposed CA-GREET 4.0 and associated Tier 1 calculators.

217.11

- The process energy natural gas emission factor for the Tier 1 Simplified Calculator Hydroprocessed Ester and Fatty Acid Fuels[7] found in Tab "CA-GREET 4.0", cell E23 of 75,496 gCO_2e/MMBtu NG, LHV is greater than the same value calculated in CA-GREET 4.0. Summing the emissions found in CA-GREET 4.0, Tab "NG" for NG Extraction, NG Processing, NG Transport 680 miles pipeline, and the average of emissions for a Large Boiler and Small Boiler results in a NG emission factor of 74,788 gCO_2e/MMBtu. MPC recommends CARB review the process energy natural gas emission factor value found in the Tier 1 Simplified Calculator to ensure it is correct, if the value is correct MPC requests CARB detail the method it used to derive the value as MPC cannot replicate it using CA GREET4.0.

217.12

- The emission factor in CARB's proposed Tier 1 Simplified Calculator for Hydroprocessed Ester and Fatty Acid Fuels for Standard Value, US/Canadian Feedstocks, Animal Fat found on Tab "CA-GREET 4.0" cell E14 of 286 gCO_2e/lb includes a Residual Oil share of process fuels of 28.6%[8]. A 2022 publication in ACS[9] identified that in the U.S., rendering facilities have "phased out residual oils and replaced them with natural gas" resulting in substantial emission reductions. MPC

[6] CARB LCFS Proposed Changes, 45-day package
[7] Tier 1 Simplified Calculator Hydroprocessed Ester and Fatty Acid Fuels
[8] CA GREET 4.0 Tab "Bio oil" cell C64
[9] XU et all. ACS Publications 2022

recommends CARB use this work and decrease the Standard Value for US/Canadian Feedstocks, Animal Fat to capture the transition of U.S. rendering facilities away from Residual Oil to natural gas.

217.13
- The emission factor in CARB's proposed Tier 1 Simplified Calculator for Hydroprocessed Ester and Fatty Acid Fuels for Land Transport, Barge found on Tab "CA-GREET 4.0" cell E17 of 0.0212 gCO2e/lb-mile has doubled in comparison to the same emission factor found in CA-GREET 3.0. It appears CARB has accounted for backhaul emissions from the use of barges to transport renewable feedstocks and products. Barges themselves do not generate a significant amount of emissions as they do not have main engines that propel them through the water. Barges are either tethered to a tugboat or pushed by a tugboat when transporting cargo[10]. The 2022 Commercial Harbor Craft Regulation (CHC) includes a requirement that both tugboats and barges utilize renewable diesel while operating in California waters, or approximately 24 nautical miles from the California coastline. MPC recommends CARB discount the barge emission factor for the biogenic portion of CO_2 that is produced from the use of renewable diesel in CHC transporting renewable feedstocks and products within California waters. If CARB is not able to account for this in the Tier 1 Simplified calculators, MPC recommends CARB allow pathway applicants provide documentation that identifies the barge and tug utilized to transport renewable feedstocks within California waters that utilized renewable diesel.

Thank you for the opportunity to comment on these subjects. If you have any questions about anything discussed here, feel free to reach out to me at bcmcdonald@marathonpetroleum.com.

Sincerely,

Brian McDonald
Marathon Petroleum Company LP | West Coast Regulatory Affairs Advisor

Cc: Rajinder Sahota, Deputy Executive Officer, Climate Change and Research
Matthew Botill, Division Chief, Industrial Strategies

[10] CARB Commercial Harbor Craft Regulation ISOR

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Comment 227 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Todd
Last Name	Trauman
Email Address	todd@usefuse.com
Affiliation	FuSE
Subject	FuSE Comments on 2024 Rulemaking Proposed LCFS Amendments
Comment	Please find attached comments to the 2024 Proposed LCFS amendment:
Attachment	www.arb.ca.gov/lists/com-attach/6891-lcfs2024-BmBSIQByWG5XDgJh.pdf
Original File Name	FuSE Comments CA LCFS Rulemaking February 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 13:40:19

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

FuSE

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: FuSE Comments on 2024 Rulemaking Proposed LCFS Amendments

Energy Mission Control, Inc. dba FuSE Carbon Technologies (FuSE) appreciates the opportunity to comment on the proposed Low Carbon Fuel Standard (LCFS) changes to the program. FuSE is a Sacramento-based technology company that helps facilitate participation in the LCFS, as well as in Oregon's Clean Fuels Program, Washington's Clean Fuel Standard, British Columbia's Low Carbon Fuel Standard, and the Canadian Clean Fuels Regulation for many hundreds of small, medium, and enterprise level businesses operating tens of thousands of electric vehicles and equipment in every qualified electricity reporting category. Building upon decades of clean-transportation industry and public funding experience, FuSE has developed a comprehensive and streamlined software platform that eliminates many of the administrative roadblocks that traditionally preclude small fleets from opting into clean fuel programs and allows them to take clear, affirmative, and immediate steps to reinvest in electrification efforts of their business operations.

We offer support, additional background on typical industry practice, information on the current state of affairs on electric off-road vehicle and equipment fleet participation, and a series of suggested alternatives or improvements on the current regulation language and amendment proposals:

218.1 **FuSE strongly supports the concept of the AAM, however, believes single-year or intra-year adjustments are technologically feasible and digestible to the market.** As currently proposed, and as the market has clearly identified via trading trends, the proposed updates to CI targets and infrequency of AAM triggering is not stringent enough.

218.2 **FuSE supports the amended text reflecting the transition of E_{XD} Displaced calculated values not applying to forklifts, and similarly should be expanded to fixed guideways.** Original intent and discussion of a model year threshold in both applications was tied to the implementation date of the LCFS program[1], the equipment's already deployed status, and not to the physical difference in equipment efficiencies across those model year threshold dates. The elimination of any model year association with technology deployments, especially as the LCFS program ages, makes less and less sense with newer technologies being deployed and streamlines the administrative work with submitting and reviewing applications greatly. There is no meaningful purpose for pre-2011 or post-2010 designations in these categories, or any others moving forward should new transportation equipment types be introduced in the future.

[1] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/12022016discussionpaper_electricity.pdf

FuSE

218.3 **e-Mission Control strongly opposes the EER reduction for forklifts under 12,000lb lift capacity, for three important reasons:**

1) This will **heavily undermine the success of the Zero-Emission Forklift Rule**, which uses the LCFS program funds, as currently calculated, to show a beneficial ROI. Reducing the EER by half increases the ROI by 50% or more, directly impacting small and medium-sized businesses that will be required to purchase new lifts and equipment to comply.

2) The **EER is not the place to account for market penetration effects of the LCFS program**. The purpose of the EER, the *Energy Economy Ratio*, is to define how much more energy efficient an alternative-fueled vehicle or equipment is relative to an internal combustion baseline. Making miscellaneous adjustments to the EER value implies that the same may happen to other vehicle or equipment categories as market penetration is increased, even if that is not the agency's current intent. **There already exists high market penetration of renewable diesel, electrified eOGVs/shore-power for container operations, and several other LCFS-qualified equipment segments. Cavalier EER adjustments set a bad precedent for future rulemaking, both in and outside of California.** If market penetration is a concern of LCFS staff, then a credit calculation variable should be introduced. Please be aware that **implementation of metering in the eMHE category will already reduce eMHE credit generation by 90%+ (most fleets will not see an ROI on submetering and Book-and-Claim ROI is not likely in the near term, meaning the reduced EER is impactful in the credit calculation equation twice).**

3) **Any tactic taken to reduce credit generation should only come from adjusting the compliance curve.** CARB has an unprecedented opportunity to move more and more capital from regulated entities to fleet electrification, with relatively very little argument from such regulated entities, and we believe any rollback of opportunity is simply a delaying of the overall GHG reduction opportunity in the transportation sector.

   As has long been established, the LCFS is meant to incentivize the adoption and use of low-, zero-, and negative-carbon fuels, and any policy within the program that facilitates this goal should be supported. FuSE currently represents many hundreds of small and medium-sized fleets, all of whom are operating some mix of equipment and vehicle types. For example, a small company may operate a few forklifts and a number of light-duty cars as part of their general operation. Simultaneously, a large company may operate hundreds of forklifts, thousands of refrigeration units, dozens of light and heavy-duty vehicles, several off-road pieces of equipment (i.e. yard trucks or rail car movers), and a host of other transportation technologies. In our experience, **none** are entirely zero-emission across their operation. The LCFS program should holistically support fleets of all types, mixes, and sizes, and, as there is no prohibition on spending funds generated from one technology (i.e. forklifts) on another (i.e. converting TRU's to hybrid eTRU's), CARB should continue incentivizing zero-emission technologies until **entire fleets, not specific technologies**, are entirely zero-emission.

Additionally, considering specific technologies for a reduced EER value simply based on the commercialization readiness or market penetration becomes an extremely slippery slope. In addition to forklifts, total cost of ownership analysis for light-duty vehicles[2], shore power[3], hybrid eTRUs[4], natural gas Class 8 trucks, and soon, heavy-duty vehicles[5], all regularly show a net benefit, even without incentive from the LCFS, and many will reach a significant market penetration well within the time bounds of the LCFS. The shore-power market penetration of container vessels subject to the At-Berth Regulation is over 90%, but eOGV is still an eligible category in the LCFS, as it should remain, so ports and port tenants can continue reinvesting in other technologies and other shore power verticals needing upgrades. This trend will continue as manufacturing becomes more effective, supplies become more readily available, and efficiencies and storage capacities increase substantially over the next five to ten years. We believe that the argument for reduced credit generation potential, if based on the concept of additionality (whereby a key decision maker would have made the decision to electrify a certain piece of equipment anyway, even without the LCFS), should be **fleet-focused**, and not equipment-focused. As mentioned above, being equipment-focused is a short-sighted perspective considering the volume and mix of equipment at any one company, and is entirely juxtaposed with the intention of the LCFS. For example, the question should not be, "Will a fleet operator purchase a forklift even without the LCFS value?" but instead should be, "Without the funds that an electric forklift would generate from the LCFS, would that fleet operator have upgraded vehicles or equipment on site that does not have a beneficial TCO?" If "No" is the response to the second question, then no equipment, regardless of commercialization, TCO, or market penetration should be excluded from the LCFS.

Also, while it is not in CARB's jurisdiction to consider other states or geographies developing clean fuel programs/standards, CARB should note that much of California's LCFS regulatory language is often heavily utilized in the deployment of other programs (i.e WA and OR both use much of the FSE definition, EER table values, and much more). In the same way that the localized emission reductions from out-of-state renewable fuels imported into the state are seen outside of California, CARB should consider the implications of regulatory change influencing other agencies considering the adoption or amendment of similar programs. Excluding technologies now will set a bad precedent, intentional or otherwise, for states that need to lean on the CARB LCFS regulatory language for success, and worse, heavily influence greenhouse gas emission reduction in areas that do not have wide adoption of electrified vehicles and equipment.

218.4 **Metering requirements for forklifts need to be phased in.** There is widespread agreement that metering for forklifts is a preferred method of reporting for credit generation, as it more closely aligns with other

[2] https://ww2.arb.ca.gov/sites/default/files/2020-06/190225tco_ADA.pdf
[3] https://theicct.org/sites/default/files/publications/ICCT-WCtr_ShorePower_201512a.pdf
[4] https://www.safeconnectsystems.com/the-ultimate-user-guide-to-etru/six-steps-to-convert-to-etru/ & https://www.mass.gov/doc/etru-grant-brochure/download
[5] https://ww2.arb.ca.gov/sites/default/files/2020-06/190225tco_ADA.pdf

reporting categories, is more accurate, and would eliminate an administrative burden related to registering and tracking equipment locations. However, as is also widely agreed, **the electric forklift technology evolution status is still very rudimentary,** with almost all deployed charging systems not having any integrated metering. To date, telematic deployments are still largely cost-prohibitive on a per-unit/battery level to be installed just for purposes of LCFS participation, have difficulty with data access and transfer within confined warehouse operations, and may not be appropriate across mixed OEM fleets. As "smarter" technologies are made more available by OEM's to give energy consumption insight to fleet operators, we believe a **phase-in schedule similar to the ZE Forklift Rule** is appropriate to accommodate for naturally-occurring turnover to new systems.

At only a 50% market adoption of electric forklifts, there is still a significant amount of equipment that needs to be transitioned to a zero-emission fuel source, especially considering that the overall electric market share has not changed in recent years. As mentioned in the paragraphs above, many of the companies we represent have mixed fleets and rely on the funds from their LCFS participation to expedite the continued conversion of their forklifts and to work towards full conversion of their on- and off-road fleets. FuSE supports the continued use of the Calculated Methodology used for forklift energy consumption, though technical revisions could be considered to ensure data accuracy and integrity.

218.5 **Regarding Third-Party Verification for the electricity provisions, FuSE supports extra visibility into data submissions as long as it avoids generating prohibitive burdens for small generators.** According to FSE-level registration data, aggregation service providers represent approximately 94% of electricity-provision-related FSEs participating in the LCFS, which we suspect is due largely to the burden of reporting and transaction activities. Specifically, the verification process should not be so burdensome as to prevent small generators from participating in the program, with or without an aggregator. FuSE encourages the ARB to further clarify the process of EV charging verification. In regards to site visits, program participants would benefit from understanding what information other than meter data would need to be verified. If the addition of verification increases participation costs, small fleets and/or aggregators may be prevented from helping small groups participate in the LCFS program. If verification
218.6 is expanded to include EV Charging transaction types (eTRU, eCHE, and eOGV Fueling, etc), FuSE would support an exemption for aggregators representing small volume generators, as there is no meaningful mechanical difference between an exempted small generator participating independently and a designator representing such a generator. The designator is simply facilitating the administration of the program and is likely to reduce the chance of reporting error.

218.7 **FuSE supports the inclusion of other equipment types, though we suggest CARB establish EER values for GSE and agriculture equipment.** During the July 7 workshop, CARB mentioned that staff is considering the inclusion or addition of zero-emission applications for rail, agricultural equipment, commercial harbor craft and airport GSE under the Tier 2 EER-adjusted CI pathway application process. We highlight that these application opportunities are already present under the current regulation and any pathway applicant may submit an EER-adjusted Tier 2 pathway application. Using other studies, such as the CAC's EER RFP[6], CARB should consider the additions of these equipment types to Table 5, significantly improving the likelihood of LCFS participation of these new technologies and would route badly needed funding toward fleets considering deployment.

218.8 **As proposed, modifications to the eMHE and eTRU credit ownership will NOT correct existing administrative issues.** Staff's intent is to award credit ownership to the fleet operator[7], however, as proposed, the credit ownership is awarded to the "FSE owner," with FSE defined as the "facility or location" and if, "there are multiple FSEs capable of measuring the electricity dispensed at the facility or location, then it is optional to provide serial number assigned to each equipment by the OEM and the name of OEM." This implies that if there are meters installed on site (which is regularly required in eMHE, eTRU, eOGV, and eCHE categories), then the ***meter*** owner becomes the credit generator. It is extremely common in leasing and renting arrangements that the charger ownership (and thereby the individualized meter, if available) be withheld by the lessor, and thereby the opportunity to assert ownership of credit generation remains, and worse, that double-counting occurs due to the lack of incentive of the meter owner to notify the FSE operator that credit generation is occurring. The electricity categories are fundamentally different from the liquid and gaseous fuel categories, and FuSE strongly suggests that CARB clarify that the FSE **operator** be the eligible credit generator in all electrification categories.

218.9 **"Private MHD-FCI charging site" is defined in the amendments, but no subsequent regulatory language is proposed.** The ISOR is clear that there is intent of supporting private MHD infrastructure, but no language is proposed. FuSE supports clarifying language identifying the opportunity for Private MHD-FCI crediting.

FuSE thanks CARB for the opportunity to comment and participate in the amendment process and looks forward to working with the LCFS team on future improvements that facilitate the transition of California's transportation fuel pool toward a more sustainable and decarbonized future.

Sincerely,

Energy Mission Control, Inc. dba FuSE Carbon Technologies

CC: Todd Trauman, CEO
Colby Green, Director of Business Development
Elaine O'Byrne, Director of Operations

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[6] https://www.oregon.gov/deq/rulemaking/Documents/CFP2022EWcacStudy.pdf
[7] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appe.pdf

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Comment 228 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Samantha
Last Name	Bourke
Email Address	samanthabourke@prairiefarms.com
Affiliation	Prairie Farms Dairy
Subject	Comments to CARB
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6892-lcfs2024-WmoCNlZmVzIGMlBk.pdf
Original File Name	021624 Comments on the Proposed Amendments to the LCFS.pdf
Date and Time Comment Was Submitted	2024-02-20 13:45:02

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 16, 2024

Chair Liane Randolph and Members of the Board California Air Resources Board
1001 I St.
Sacramento, CA 95814

RE: Prairie Farms Dairy Comments on the Proposed Amendments to the Low Carbon Fuel Standard

Dear Chair Randolph and Members of the Board,

Prairie Farms appreciates the opportunity to comment on the proposed amendments to the Low Carbon Fuel Standard (LCFS). Prairie Farms are a farmer-owned cooperative. This means we are owned and operated by over 600 farm families who are critical members of society. They have selflessly taken on the tremendous task of producing nutritious, high-quality milk for a growing population, which requires being on the job 24/7, 365 days a year. We have represented American agriculture since our founding in 1938. Many of our dairy farms are operated by several generations of family members with roots dating back to the 1800s. On average, each farm milks around 120 cows and everyone pitches in to keep them happy and healthy - which means around-the-clock care

Prairie Farms applauds the leadership the California Air Resources Board (CARB) is taking on climate change and appreciates being a part of this important dialogue surrounding potential changes to the Low Carbon Fuel Standard (LCFS). The dairy industry has answered the call to action and is embracing environmental responsibility - from family farms in California, to farms across America. By installing and utilizing biogas systems, farms are offering practical solutions to the challenges CARB seeks to address.

With our support of CARB and the LCFS in mind, Prairie Farms would like to offer the following suggestions for improving the proposed amendments to the Low Carbon Fuel Standard:

Strengthening Carbon Intensity (CI) Targets

219.1a
219.1b

Prairie Farms applauds CARB and is encouraged to see that the proposed amendments aim to set more ambitious carbon intensity targets. A strong CI reduction target is a critical component for driving down (GHG) emissions in the transportation sector, reducing reliance on petroleum fuels, and transitioning to electric vehicles where feasible. However, we believe that there is both room and a need to go further. Using the numbers from CARB's Quarterly Summary Report and averaging the rate of credit growth over the past five available quarters, it shows that the current scale-up in the production of clean fuels will continue to generate low carbon fuel standard credits with the cumulative bank likely eclipsing 25 million by the end of 2024.[1] The proposed increase in stringency falls short of what the market can deliver, and as a result, is missing an opportunity to deliver millions of additional tons of reductions in greenhouse gas emissions called for in statute and further underscored in the update to the state's Scoping Plan as approved by the Board in December 2022.

Prairie Farms believes that there are two key adjustments that CARB can make to the stringency as part of the 15-day change process that do not require new economic or environmental analysis as they fall within the scope of the work CARB has already included in the Initial Statement of Reasons (ISOR), specifically, by increasing the step-down as well as pulling forward the effective date for triggering the Auto Acceleration Mechanism (AAM) CARB can "recapture" reductions in GHG emissions that will otherwise be lost with the current proposal. Doing so will also send a clear, and supportive market signal to continue investments in clean fuels that would otherwise be constrained and subdued by the current proposal.

Avoided Emission Crediting

219.2

The proposed amendments seek to phase out avoided emission pathways for projects that break ground after December 31, 2029, for biomethane used as a transportation fuel through 2040 and for biomethane used to produce hydrogen through 2045. Prairie Farms believes that this is inconsistent with the incentive-based approach outlined in SB 1383 and currently being implemented in California. Moreover, eliminating or phasing out the avoided methane crediting in the dairy sector would lead to an inability to meet the state's targeted methane reduction goals and result in significant dairy methane emissions leakage. Avoided methane crediting is a key component of dairy methane reduction incentives that has achieved significant reductions

[1] California Air Resources Board, LCFS Data Dashboard Figure 3 – Quarterly Summary Report. https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard

to date and as stated previously, is one of the most effective tools to meet California's GHG goals.

According to a UC Davis analysis:

> . . . misguided efforts to change course by forced coercion to pasture-based operations, direct regulation of dairy farms, or limitation on dairy digesters incentives will not only fail to achieve the desired greenhouse gas emissions reductions but will exacerbate the problem by causing significant emissions leakage. Revenue streams that incentivize investment in biogas capture and beneficial use are critical. Phasing out of avoided methane crediting in the dairy sector would jeopardize existing projects, making them uneconomic in the long-term, and dry up investment capital for the additional digester projects sought by CARB to achieve the state's ambitious and aggressive targets.[2]

Avoided methane emissions are a critical part of science-based, life cycle assessments, and their inclusion in carbon intensity scores are consistent with internationally recognized standards of carbon accounting. The scientific evidence for this is robust and recognizes that the baseline includes methane emissions that would otherwise be released into the atmosphere. Recognizing methane and its role as a short-lived climate pollutant, while incentivizing its removal from the atmosphere, has proven highly successful in supporting the reduction of millions of metric tons of carbon dioxide equivalents. We strongly encourage CARB to continue its longstanding commitment to a science-driven framework that utilizes proven science including Argonne National Laboratory's GREET model.

Book-and-Claim and Deliverability Requirements

219.3

Book-and-Claim has allowed the LCFS to evolve by supporting investments in clean fuels that have helped the program remain one of the most influential and successful transportation decarbonization policies in the country. To date, CARB's approach to indirect accounting in the program has been pivotal to its success, including its principles of driving greenhouse gas emissions down, facilitating investments and production of clean fuels, and in supporting increased clean fuel options for consumers.

It remains to be seen if and how the proposed deliverability requirements can be harmonized with the California Public Utilities Commission SB 1440 program, as suggested. It has been clear over the past year that CARB was exploring potential deliverability requirements. However,

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[2] Kebreab, Ermias, Ph.D., Mitloehner, Frank, Ph.D., and Sumner, Daniel A., Ph.D., Meeting the Call: California is Pioneering a Pathway to Significant Dairy Methane Reduction (December 2022), available at: https://clear.ucdavis.edu/news/new-report-california-pioneering-pathway-significant-dairy-methane-reduction

throughout that process an actionable plan outlining the strategy and evidence necessary for imposing delivery requirements never emerged. Rather, stakeholders continued to raise concerns about the lack of a feasible plan which continues with the ambiguity of proposed amendments. Therefore, Prairie Farms recommends that the deliverability requirement language be removed from the current amendments to allow for further stakeholder engagement to support a clear and actionable plan for consideration in a subsequent rulemaking.

219.4 **True-up Provisions**

The proposal includes true-up provisions where verified operational CI's are drawn on to potentially adjust the credits based on certified CI's. The proposal indicates that a shortfall (i.e., a verified operational CI that is higher than the certified CI upon which project credits were generated) is subject to a "penalty" that is 4 times the spread for the applicable volume of fuel. The rationale for a 4X spread is unclear as a smaller spread (e.g., 2X) serves as a significant disincentive to producers for being overconfident in their analysis. Further, the language indicates that in the event the operationally verified CI is lower than the certified CI (i.e., it failed to generate as many credits as it could have) the Executive Offer (EO) "may" make the appropriate adjustment (true-up) by awarding additional credits to the applicable fuel reporting entity. The word "may" should be deleted. If the operationally verified CI, including an affirmative verification statement, is lower than the certified CI that was the basis for credit generation, the EO "must" award the supplemental credits supported by the underlying documentation.

The concept of adjustment to credits based on operationally verified CI's is sound. However, limiting the proposal to certified CI's is a significant oversight. The proposal must be carried over and applied to temporary and provisional CI's as fuel providers may rely on these CI's for months, or even years, as more refined pathways are evaluated and subsequently approved by CARB.

Temporary CI's have been an important option under the program, but applicants can be reluctant to use them given the heavy credit discount relative to facility-specific provisional CI's. Correcting for any under (or over) crediting while a temporary CI is used will help streamline and simplify the program as well as send a stronger signal to the market that investments in clean low-CI fuels will be rewarded. Further, including temporary CI's as part of the true-up process will reduce the pressure on CARB from developers to process LCFS applications quickly which has been an ongoing and growing challenge under the program. The concept of adjusting the awarding of credits based on operationally verified CI's is a key principle that supports innovation and must be reflected from project initiation, where a temporary CI is used, throughout the project's lifetime to properly account for and reward the associated reductions in greenhouse gas emissions. Credits should be awarded based on real-world operational experience and therefore adjusted accordingly when the temporary CI which is applied understates the benefits.

New Markets

219.5

As the technology in the transportation sector continues to evolve and advance towards lower carbon alternatives, Prairie Farms members and the rest of the dairy industry and are ready to serve these new markets, such as alternative jet fuel (AJF), low-CI hydrogen, as well as exploring opportunities where biomethane can be utilized outside of transportation. As these markets continue to grow, Prairie Farms asks CARB to remain mindful of the success of the historical framework of the program and to continue to apply it to these newer pathways and technologies, including the use of avoided emissions and book-and-claim.

Conclusion

Over the past year and a half, CARB staff have held numerous public workshops to gather feedback on potential changes to the program, and Prairie Farms is pleased to see that the rulemaking is nearing completion. Prairie Farms would like to underscore the importance of concluding this rulemaking as soon as possible. Any further delay to the rulemaking diminishes the necessary signal the market needs to facilitate and encourage continued investments in clean fuels. To continue the significant and unprecedented progress made by CARB and the dairy industry of California under the guidance and support of the CDFA, Prairie Farms urges CARB staff and the Board to finalize this rulemaking no later than the end of Q2 2024.

Thank you for the opportunity to comment on the proposed amendments, and we look forward to engaging with CARB staff on these topics.

Sincerely,

Samantha Bourke
Prairie Farms Dairy
Quality Program Coordinator
Producer Sustainability Coordinator

Comment Log Display

Here is the comment you selected to display.

Comment 229 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Matthew
Last Name	Rekeweg
Email Address	matt.rekeweg@corteva.com
Affiliation	Corteva Agriscience
Subject	Comments on Proposed Low Carbon Fuels Standard Amendments (lcfs2024)
Comment	Please see the uploaded attachment for comments on the Proposed Lo Carbon Fuels Standard Amendments from Corteva Agriscience.
Attachment	www.arb.ca.gov/lists/com-attach/6893-lcfs2024-AmFdOgBzUGEKUwVp.pdf
Original File Name	CARB LCFS Amendments comments - Corteva Agriscience.pdf
Date and Time Comment Was Submitted	2024-02-20 13:23:38

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Kendall Palmer
Sr. Director
Growth Leader Biofuels

Corteva Agriscience
Johnston Global Business Center
7100 NW 62nd Avenue
P.O. Box 1000
Johnston, IA 50131-1000

February 20, 2024

Carolyn Lozo
Chief, Transportation Fuels Branch
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Via electronic submission

Re: Proposed Low Carbon Fuel Standard Amendments

Transportation Fuels Branch Chief Lozo:

We appreciate the opportunity to comment on the California Air Resources Board's (CARB) Proposed Low Carbon Fuel Standard Amendments issued on December 19, 2023.

Corteva Agriscience is a U.S.-based global company entirely focused on agriculture. Founded on nearly a century of breeding and scientific expertise, we develop innovative seed and crop protection products and services with the goal of helping farmers maximize productivity, drive profitability, and enhance sustainability, while also equipping them to provide consumers with a wider range of safe, healthy and nutritious food options. These products are also critical components to a resilient agricultural system that enables food and energy security.

220.1 In the process of its review of proposed amendments to the Low Carbon Fuel Standard, we encourage CARB to consider two key points:

1) **Recognize existing and proven certification programs for sustainable biofuels production, rather than creating additional traceability requirements, which could create undue regulatory burdens on individual farmers.** U.S. farmers successfully participate in a variety of existing programs validating the use of biofuel production methods that meet international commercial and regulatory standards. Programs include the U.S. Soybean Export Council's Soy Sustainability Assurance Protocol, the National Cotton Council's Cotton Trust Protocol, and the U.S Grains Council's Corn Sustainability Assurance Protocol, among others. The certifications provided by these programs are increasingly sought by international buyers who wish to ensure sustainably sourced, deforestation-free inputs for their food, fiber, and fuel needs.

220.2

2) **Similarly, as CARB works to refine land-use and environmental models for biomass-based feedstock, ensure the use of the most up-to-date datasets that reflect the latest sustainable farming practices.** Farmers have made significant gains in yield and productivity over the years, resulting in consistently higher yields on the same or fewer acres, with less carbon intensive inputs. This progress should be reflected in current modeling.

We are committed to working side-by-side with farmers in the U.S. and around the world to deliver expertise and innovative products that support more sustainable and productive farming, whether the crops are used for feed, food, fiber, or fuel. We support farmers with training and tools to help them incorporate the latest advances and technology into their daily operations. Around the world and across all product portfolios, our experienced Corteva agronomy, product, sales, and R&D team members provide a variety of educational opportunities to farmers both in person and online. With a deep commitment to transparency, these efforts focus on sharing the latest information, technologies, best practices and product innovations to help farmers find ways to improve soil health, nutrient and water stewardship, and productivity that are right for their unique, local needs.

An example of a way we're providing the latest sustainable innovations to farmers is our proprietary winter canola seed adapted for the Southern U.S. environment. Together, with Bunge and Chevron Renewable Energy Group, we are working to develop the necessary seed and processing supply chain to support the production of renewable diesel and sustainable aviation fuel. The resulting fuel is compatible with existing combustion engines and will provide a more sustainable option for aviation and diesel fleets. Importantly, it will also support farmers as they work to address some of the world's most pressing challenges, including the energy transition, climate change and food security. Farmers can increase their income potential while prioritizing the sustainability of their operation by reducing greenhouse gas emissions and ensuring land coverage year-round.

Once again, we appreciate the opportunity to comment on the Proposed Low Carbon Fuel Standard Amendments and look forward to supporting your efforts to implement an effective LCFS program.

Sincerely,

Kendall Palmer
Senior Director and Growth Leader, Biofuels
Corteva Agriscience

Comment Log Display

Here is the comment you selected to display.

Comment 230 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jennifer
Last Name	LeRow
Email Address	jlerow@brayafuels.com
Affiliation	Braya Renewable Fuels (Newfoundland) LP
Subject	Braya Comments to CARB RE Proposed Changes to the LCFS
Comment	Dear CARB, Thank you very much for taking the time to consider our comments concerning the upcoming amendments proposed under the LCFS. Jennifer LeRow Braya Renewable Fuels (Newfoundland) LP
Attachment	www.arb.ca.gov/lists/com-attach/6894-lcfs2024-VzVcKFw8VX8FYghX.pdf
Original File Name	Braya Comments to CARB RE Proposed Changes to the LCFS 02.20.24.pdf
Date and Time Comment Was Submitted	2024-02-20 13:46:12

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed 2024 Low Carbon Fuel Standard (LCFS) Amendments

Dear California Air Resources Board,

Braya Renewable Fuels (Newfoundland) LP ("Braya") is the owner of the Come By Chance refinery in Newfoundland, Canada. Braya recently completed the conversion of the idled conventional oil refinery to renewable diesel and sustainable aviation fuel production. The refinery is strategically located to source a variety of low-carbon intensity feedstocks and deliver fuels to various end markets, including California, to help meet LCFS demand and California's broader greenhouse gas initiatives. Renewable diesel and sustainable aviation fuels help decarbonize sectors—heavy transport and aviation—that are key to economic activity and have few other near-term, executable decarbonization solutions.

CARB's successful LCFS program has attracted global attention and has inspired other states and nations with its market-based principles, scientific basis, and feedstock- and technology-neutral approach. The LCFS has exceeded expectations, is over-performing, and is becoming increasingly diverse in approaches that serve to reduce and replace fossil fuels as part of its decarbonization efforts. The LCFS has made meaningful investments in low-carbon fuels a reality - Braya's conversion of a conventional crude oil refinery to biofuels is a perfect example of achieving that goal.

We appreciate the opportunity to provide the feedback you requested in advance of the recently postponed Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments. We also have new evidence and data in support of the previous workshops conducted over the course of 2022 and 2023.

221.1 **Braya Opposes Artificial Cap on Vegetable Oil Feedstocks**

As presented in our previous comments in response to the November 9, 2022 and February 22, 2023 workshops, a number of studies have concluded that lipid-based feedstocks for biofuels do not impact food resources or cause deforestation and damaging land conversion. At present, crop-based feedstocks are needed to spur continued growth and investment in renewable diesel and sustainable aviation fuels, which are key solutions for decarbonizing the heavy transport and aviation sectors for the foreseeable future.

In our response submitted in December 2022, we provided evidence and a study conducted in November 2021 by LMC International and commissioned by the Advanced Biofuels Association (ABFA), identifying global lipid demand from all sources and all end-users and the fact that the current crop-based feedstock supply exceeds biofuels' forecast demand through 2030 while still meeting the demand for non-biofuel use. Further, the study assumed a maximum use of lipid-based feedstock for biofuels even though advances are being made regarding the use of wastes, starches, algae, and biomass, which will provide alternative feedstock supplies and naturally lower the demand for crop-based biofuels. The summary slides and 2030 conclusions can be found here: https://advancedbiofuelsassociation.com/study-shows-available-advanced-biofuels-feedstocks-can-pace-biofuel-demand-through-2030/ .

Following the February 2023 workshop, Braya submitted additional relevant data in our responses submitted in March 2023, utilizing the same scientific approach and presenting a Short-Term Outlook through 2025 developed by LMC in February 2023 (the "Report") in response to an updated request by the ABFA. The study identifies a number of events that have occurred globally and have positively impacted the amount of available crop-based and lipid feedstocks. To summarize, and as set forth in the Report, the supply of fats, oils, and greases (FOG), as well as soybean and canola have all increased and will continue to do so at no detriment to increased global demand or at the expense of the environment or society due to land use change. The Report is located in Appendix 1 on Page 11 of the ABFA's response to the EPA Set Rule on its website at the following location: https://advancedbiofuelsassociation.com/wp-content/uploads/2023/02/ABFA-2023-Set-Rule-Comments-Final.pdf

We re-emphasize that time and investment are still needed to continue growing the supply of second-
221.8 generation biofuels. The efforts are underway, but the continued support of the LCFS will help make this goal a reality. To date, the LCFS has maintained an unbiased, technology-neutral approach, allowing the program to evolve naturally, without picking winners and losers, which has been a key to CARB's success. CARB already has a stringent and ongoing review process in place to address indirect land use change ("iLUC") applicable to biofuel incentives. This mechanism significantly penalizes producers that utilize crop-based feedstocks by elevating CI scores well above those of non-crop-based feedstocks. A prohibition on crop-based feedstocks will increase costs across the board, including to end-use consumers, and stifle investment in the vital expansion of renewable diesel and sustainable aviation fuel supply that would otherwise continue as CARB continues to work toward its electrification goals.

Braya supports and appreciates CARB's efforts to support low-carbon fuel production and distribution. We commend CARB for understanding the impact of unnecessarily and prematurely eliminating a much-needed source of feedstocks that can readily meet the LCFS's objectives, specifically regarding medium to heavy transport and aviation biofuels, as there are currently no viable alternatives available on a scale to meet California's goals. We also note that the LCFS structure is effective in reducing the relative share of crop-based biofuels to the overall mix of biofuels to the extent such fuels do not represent significant carbon intensity reductions. Notably, crop-based biofuels represent about 60 percent (60%) of liquid biofuels (discounting natural gas, hydrogen, and electricity) in the years 2021 to 2023 according to the most recent LCFS Quarterly Data Spreadsheet available through the end of the third quarter of 2023. Indeed, these same crop-based fuels represented roughly 75 percent (75%) of the contribution to the success of the LCFS during the years of 2011 to 2021. Many other sources of feedstock are limited in quantity or can be difficult to trace back to the source and are, therefore, not used at large. Advances in technology and feedstocks are being realized as evidenced by the declining relative share of crop-based fuels, but it will take time to generate significant volumes of these feedstocks as electric initiatives come to fruition. In the meantime, crop-based biofuels are critical to meeting the near-term needs of the market and to continue reducing the carbon intensity of fuels in industries that are notoriously difficult to decarbonize.

221.2 **Braya Supports Emission Factor Updates**

The global agriculture industry has made significant investments in improved farming practices, feedstock processing and decreased emissions at the biofuels facility level over the past decade. Paradoxically, the current CA-GREET3.0 model does not account for or reward these substantial improvements. Additionally, the current CA-GREET3.0 model lacks key customization features such as not providing for specific vessel sizes (instead using wide ranges) and electricity mixes that are not representative of the various regions feeding into the LCFS. CARB has proposed to use an updated calculator CA-GREET4.0, in conjunction with the release of the new amendments, but much of the data is still woefully out of date. Specifically, the "Land Use Change" values for soy and canola oil remain unchanged at 29.1 and 14.5, respectively, as both calculators are based on a now decade-old GTAP-BIO model.

In June 2023, Floyd Vergara, former Chief and Assistant Chief in the Industrial Strategies Division and Research Division at CARB, overseeing the development of the LCFS, submitted public comments to CARB on behalf of Clean Fuels Alliance America (CFAA) and California Advanced Biofuels Alliance (CABA) in response to the May 31 and June 1, 2023, Low Carbon Fuel Standard Virtual Community Meetings: Clean Fuels CABA Comments CA LCFS EJ Community Meetings May-June 2023. The evidence provided by Mr. Vergara uses the most recent updates to the Argonne National Laboratory calculators and GTAP modeling by Purdue in 2023 and conclusively shows that the iLUC scores being used by CARB in both the CA-GREET3.0 and CA-GREET4.0 models are grossly inaccurate and unfairly punitive to crop-based biofuels. Notable findings include:

- 2023 Purdue estimates for soy iLUC are at 9.78 gCO_2e/MJ, compared to CARB's 29.1 gCO_2e/MJ.
- Purdue used 4x the shock volume of 3.22 billion gallons in 2023 to achieve the 9.78 gCO_2e/MJ.
- Accordingly, CARB's iLUC score of 29.1 for 800 million gallons is more than three times higher than the score that would result from using newer, more accurate evidence and methodologies.

We recommend updating the model used by CARB to reflect this more current and accurate data by reviewing Argonne and Purdue University's most recent releases. Such an update would also negate the age-old argument that a cap on crop-based biofuels is needed. Regenerative agriculture and superior agronomic practices are being adopted globally. Many countries, including Argentina, have been using these practices for decades on farmland that has been in place since at least the 1980s as shown by a number of studies, including the Organisation for Economic Co-operation and Development's (OECD) paper, Agricultural Policies in Argentina. Additionally, CARB benefits from the United States Renewable Fuel Standard (U.S. RFS) structure that requires evidence that crop-based feedstock must not be grown on land that was placed into production after December 19, 2007 as defined at 40CFR Part 80 §80.2 under "renewable biomass," exceeding the requirements under the LCFS.

Finally, we support Mr. Vergara's assertion that the use of biomass-based diesel is a significant positive factor in the health of citizens located in EJ communities given that drop-in biofuels reduce diesel particulate matter by up to 80% in older engines as shown in the CARB Assessment of the Emissions from the Use of Biodiesel as a Motor Vehicle Fuel in California "Biodiesel Characterization and NOx Mitigation Study." As additional support, the CFAA engaged Trinity Consultants to prepare a number of Health Effects Studies for CARB on the positive impacts of using drop-in biomass-based diesel in place of petroleum diesel. Of note are the "immediate community health improvements that can be measured in reduced medical costs and health care burdens" and estimates that switching to biomass-based diesel could result in the prevention of "over 900 premature deaths per year, hundreds of thousands of asthma cases reduced or avoided per year, and reducing over 100,000 work loss days per year, totaling $7 billion dollars per year in avoided health costs."

221.3 **Braya Supports Credit True-Ups for Temporary Pathways**

Braya applauds CARB for moving forward with the credit true-up for Tier 1 and Tier 2 pathways and is supportive of implementing a credit true-up for temporary pathways. Temporary pathways are inherently conservative CI scores; the longer a producer's facility-specific CIs are under review, the greater the expected loss of revenue that can be so vital at the start of operations. A true-up based on facility-specific production data will not only support new biofuel producers but will also provide more accurate data for CARB to measure the program's success in decreasing GHG emissions.

Similar to many other producers, Braya is constantly evaluating further capital projects to increase efficiencies and lower emissions. A true-up that would allow credit generators to be rewarded for reducing their CI scores over time would encourage these proactive and environmentally friendly projects.

221.8 Finally, we believe that CARB should synchronize efforts with other agencies to utilize data and precedents to streamline processes. Doing so would be of significant value, both to increase access to new pathways/new producers and reduce burdens on CARB's resources and staff. For example, the EPA has a number of approved pathways based on GREET modeling for national and global feedstocks. CARB should explore whether these pathways could be leveraged to establish a wider range of temporary pathways that could be used until facility-specific pathways (based on operational data) are fully available.

221.4 **Braya Supports CARB's Continued Advancement of the Standards**

Understanding that 30% under Alternative B is what CARB has identified as the basis on which to move forward with the current proposed rulemaking, Braya remains optimistic and in support of Alternative C, under CARB's Compliance Target Options, as discussed during the November 9, 2022 workshop. With standards based on achieving a 35% reduction in carbon intensity by 2030, Alternative C is the only option that truly advances CARB's efforts by making rational use of currently available and efficient
221.4a biofuels while incentivizing new technologies that are being developed. Further, under Alternative C there would be no cap on crop-based feedstocks, allowing the program to set more aggressive and beneficial targets. During the February 2023 workshop, CARB presented Alternative B as the base case for discussions, citing that a majority of stakeholders were in support of at least a 30% CI reduction based on comments received in December 2022. However, during the lengthy Q&A to follow, a majority of stakeholders providing input appeared to be in strong support of a 35% target, and Braya agrees. We hope that the supporting data we are providing as evidence, in addition to expanded support from other stakeholders will assist CARB in making the decision to move forward with a 35% target without artificially capping beneficial feedstock supply.

Also during the November workshop, CARB presented the possibility of devising a "Self-adjusting CI target mechanism" that would trigger an auto-adjustment in standards. We believe that this concept has merit, assuming that it would spur credit bank drawdown and stop plummeting prices when LCFS
221.4b credits are being over-generated. We were pleased to see this mechanism's adoption in the currently proposed rulemaking. However, we would like to see this much-needed mechanism implemented earlier than currently proposed. Without such a mechanism, producers who have made responsible investments in reliance on a functioning incentive-based LCFS program will face grave economic uncertainty. Braya also supports front-loading the new CI targets to further repair the currently significantly depressed credit prices. We look forward to CARB moving forward with both provisions.

221.5 **Braya Supports Streamlining and Updating the Application and Review Process for Pathway Approval**

By updating and improving the existing Lookup Table and Tier 1 calculators in addition to adding new and/or separate Tier 1 calculators, CARB will be able to focus attention on critical new feedstock sources, availability, and supply, as well as new technologies, thereby expediting approvals for new Tier 2 pathways. Braya truly appreciates all the effort the CARB staff have put into this daunting endeavor.

221.6 **Braya Supports an LCFS Verification Body Firm Rotation Alternative for CPA Firms**

Due to the increased federal and state regulatory oversight inherent in the nature of a licensed CPA firm, we suggest verification bodies that are also CPA firms not be subject to the audit firm rotation but would instead adhere to a Lead Verifier rotation every six (6) consecutive years. We have found it increasingly difficult to identify alternate qualified verification bodies under the current system.

221.7 **Braya Supports Less Intensive LCFS Verifications**

CARB staff's current proposal includes a provision allowing less intensive verifications solely for electricity used as transportation fuel by permitting verification bodies to skip site visits so long as they have visited the site within the last two (2) years and have issued a positive verification statement. CARB's rationale included:

- "[T]here is little change of operation from reporting period to reporting period thus reducing the benefit of annual site visits."
- "There is no or little risk to the integrity of the LCFS program to allow for less intensive verification services without a site visit in the annual verifications for the following two years."
- "This should reduce the cost of verification services which is often passed on to program participants."

We wholly agree with CARB's statements above and believe it should apply to all validations and annual verifications for any reporting entities. In CARB's MRR program (section 95130), less intensive verification is applied without prejudice to verification services by accredited verification bodies. We agree with staff that less intensive verification leads to little to no risk to the integrity of the LCFS program and that there is little change in operation from reporting period to reporting period, while also providing cost savings to verification providers that are then passed on to program participants. Finally, we acknowledge the importance of adhering to CARB's specified conditions that necessitate comprehensive verification services. These conditions already include the issuance of an adverse verification statement or a qualified positive verification statement in the preceding year and the occurrence of a change in operational control of the reporting entity in the previous year.

Thank you in advance for taking the time to review our comments and solutions concerning these very important issues. We look forward to working with CARB and welcome any opportunities to discuss further and provide any additional assistance and insight.

Respectfully,

Jennifer M. LeRow
Director of Regulatory Compliance
Braya Renewable Fuels (Newfoundland) LP

Comment Log Display

Here is the comment you selected to display.

Comment 231 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Victoria
Last Name	Bogdan Tejeda
Email Address	vbogdantejeda@biologicaldiversity.org
Affiliation	Center for Biological Diversity
Subject	Opposition to allowing fossil fuels + CCS to extend past 2040 phase-out
Comment	Please find a letter attached and signed by nearly 50 groups expressing their strong opposition to the proposed LCFS amendment that would allow petroleum projects using carbon capture and storage (CCS) to continue to generate credits beyond the phase-out date of December 31, 2040. This amendment creates a dangerous loophole that relies on a so-called climate solution that is anything but; the result will be California incentivizing and perpetuating the climate catastrophe and the health and environmental harms that come with it.
Attachment	www.arb.ca.gov/lists/com-attach/6896-lcfs2024-BjQGNFJ9VzRQZAUr.pdf
Original File Name	24.02.20 CCS LCFS Loophole Final Sign-on.pdf

222.1

Date and Time Comment Was Submitted	2024-02-20 13:52:49

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2023

Liane M. Randolph, Chair
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Submitted via CARB's online Comment Submittal Form

Re: Opposition to Proposed LCFS Amendment Loophole to Allow Petroleum Projects with Carbon Capture & Storage Past the 2040 Phase-out

222.1 (cont.)

The undersigned groups write to express their strong opposition to the proposed Low Carbon Fuel Standard (LCFS) amendment that would allow petroleum projects using carbon capture and storage (CCS) to continue to generate credits beyond the phase-out date of December 31, 2040.[1] This amendment creates a dangerous loophole that relies on a so-called climate solution that is anything but; the result will be California incentivizing and perpetuating the climate catastrophe and the health and environmental harms that come with it.

Evidence and real-world experience do not support CARB's apparent belief that CCS eliminates the problems of fossil fuel extraction, refining, processing, and use. Many of the signatories to this letter have submitted comments to CARB time and time again with information making this clear. Further, it is untrue that Intergovernmental Panel on Climate Change (IPCC) pathways require CCS to meet climate goals. What is needed is a just and rapid transition away from fossil fuel use;[2] CCS is a way to avoid that truth.

As recently said by Massachusetts Institute of Technology professor Dr. Charles Harvey (who himself once started a CCS company, before abandoning it upon realizing the technology simply fails): **every dollar spent on CCS is a waste** because it allows "for the continued production of oil and natural gas at a time when the world should be ending its dependence on fossil fuels." [3] As Dr. Harvey aptly notes: "Instead of spreading doubt about climate science, the industry now spreads false confidence about how we can continue to burn fossil fuels."[4] We see just that glaring problem in the proposed petroleum loophole.

Addressing the climate crisis requires resources, leadership, and courage. We have no time to waste. **CARB must act courageously and reject the proposed petroleum phase-out loophole.**

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[1] *See* LCFS Proposed Amendments, Appendix E at X.19 § 95488.10, proposed for §§ 95489(c)(5), 95489(d)(5)(C), 95489(e)(5)(B), and 95489(f)(5)(B).

[2] The IPCC-modeled pathway with the best chance of keeping warming at or below the target of 1.5°C makes no use of fossil fuels with CCS. IPCC, Summary for Policymakers in Global Warming of 1.5°C (2018) at 14, Section C.1.1., Figure SPM 3b (Pathway 1); *see also* IPCC SR1.5, at Ch. 2.3.3 and Table 2.SM.12.

[3] Dr. Charles Harvey, "Every Dollar Spent on This Climate Technology Is a Waste," New York Times (Aug. 16, 2022).

[4] *Id.*

Thank you,

1000 Grandmothers for Future Generations
350 Bay Area
350 Sacramento
350 San Diego
Asian Pacific Environmental Network
Biofuelwatch
Bold Alliance
California Nurses for Environmental Health and Justice
Center for Biological Diversity
Center on Race, Poverty & the Environment
Central California Environmental Justice Network
Climate Hawks Vote
CURE
East Yard Communities for Environmental Justice
EJCW (Environmental Coalition for Water Justice)
Elders Climate Action
Elders Climate Action, NorCal Chapter
Extinction Rebellion SF Bay
Food & Water Watch
Food Empowerment Project
Fossil Free California
Fresnans Againt Fracking
Friends of the Earth
Good Neighbor Steering Committee of Benicia
Indigenous Environmental Network
Interfaith Climate Action Network of Contra Costa County
Labor Rise Climate Jobs Acton
Oakland Teachers Advancing Climate Action
Oil and Gas Action Network
Physicians for Social Responsibility-Los Angeles
Physicians for Social Responsibility – San Francisco
Rodeo Citizens Association
Santa Cruz Climate Action Network
Science and Environmental Health Network
SF Baykeeper
SF Climate Reality Leaders
Stand.earth
Stop OAK Expansion Coalition
Sunflower Alliance
Sustainable Mill Valley
The Sacramento Environmental Justice Coalition
Tri-Valley CAREs
Valley Improvement Projects
West Berkeley Alliance for Clean Air and Safe Jobs

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Comment 232 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	David
Last Name	Edwards
Email Address	david.edwards@airliquide.com
Affiliation	Air Liquide
Subject	Air Liquide Comments on Proposed Low Carbon Fuel Standard Ammendments
Comment	Please see attached comment letter
Attachment	www.arb.ca.gov/lists/com-attach/6897-lcfs2024-AjBTZQc0VjFWfQU1.pdf
Original File Name	2024-02-19 LCFS Comments - Air Liquide.pdf
Date and Time Comment Was Submitted	2024-02-20 13:54:00

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Air Liquide

February 20, 2024

California Air Resources Board
1001 "I" Street, Sacramento, CA 95812

RE: Air Liquide Comments regarding the Proposed Low Carbon Fuel Standard Program

Dear CARB Staff:

On behalf of Air Liquide, thank you for the opportunity to submit our comments regarding the proposed changes to the Low Carbon Fuel Standard Program.

A world leader in gases, technologies and services for industry and health, Air Liquide has a presence in all 50 states, employing more than 20,000 people in the U.S. at more than 1,400 locations and plant facilities, offering industrial gases and related services to customers in a range of industries, including oil and gas, chemicals, steel, construction, food and beverage, research and analysis, electronics, and healthcare. Hydrogen has been, and continues to be a core growth area for our business in the U.S.

Air Liquide has more than 60 years of expertise across the entire hydrogen value chain. From production and storage to distribution and the development of applications for end users, Air Liquide is focused on hydrogen as a key molecule for investment, research, and technology development. Air Liquide is a global leader in clean hydrogen development and has made significant investments worldwide, exceeding more than $1 billion dollars invested in hydrogen in the U.S. and has a commitment to invest an additional $10 billion dollars globally in low-carbon hydrogen by 2035.

The LCFS regulations are among the most effective and influential regulations governing clean transportation fuels. In order to make the program as effective as possible and in order to ensure that the goals of the State of California with respect to implementation of zero emission vehicles and supporting infrastructure are met, we have the following recommendations:

223.1 **Carbon Intensity Benchmarks and Market Stabilization:** We believe the extension of the Carbon Intensity Benchmarks to 2045 and the "automatic acceleration mechanism" or "ratchet" that would advance the benchmark to the next year's target will prove to be an effective tool in managing the state's clean fuels targets. These benchmarks will help assure that by 2045 all fossil fuels, and also many alternative fuels, would generate deficits for almost all of the greenhouse gases that they create. The proposed mechanisms will also have the potential to strengthen the LCFS credit market. Low credit values have been a significant hindrance to investments, especially in the development of the much needed hydrogen refueling infrastructure. We are supportive of these and other actions needed to stabilize the credit market.

Hydrogen Refueling Infrastructure Credits. The LCFS currently provides credits for the unused capacity of hydrogen fueling stations that service light-duty vehicles and as proposed, its expansion to heavy duty vehicles.

> Heavy Duty Vehicle Program - The Heavy duty vehicle market represents both one of the largest emitters of carbon and particulates and one of the most difficult to abate sectors. Hydrogen fuel

cell vehicles now being made available to the market provide an ideal solution to address these challenges provided there is sufficient infrastructure and low carbon, low-cost, reliable hydrogen production and supply. The proposed expansion of the HRI credits to include Heavy Duty
223.2 stations will provide a mechanism to encourage this infrastructure investment and we are strongly supportive of the proposed program introduction.

Light Duty Vehicle Program - Expanding the light-duty (LD) Hydrogen Refueling Infrastructure (HRI) capacity is imperative. This is particularly crucial to accommodate the unique needs of medium-duty (MD) vehicles, given their co-mingling with LD fleets. The alignment of LCFS capacity credits with market behavior is paramount for station crediting. To support this,
223.3 maintaining the existing 1200kg credit is recommended, considering its success in driving private sector investment. This credit has proven effective in supporting the existing HRI, and its continuation is aligned with the ongoing success of the infrastructure.

Station Location Limitations To enhance the viability of hydrogen refueling stations, flexibility in
223.4 locations for both HD and LD is paramount. The current absence of a comprehensive station network argues against stringent geographic limitations. These limitations have the immediate consequence of limiting decarbonization and air quality impacts of transitioning from fossil fuels, especially in the overburdened communities along these statewide transportation corridors.

Inequity in Capacity Crediting Standards We suggest that the requirement of 80% renewable content requirement exclusively for HRI should be eliminated as it is unnecessary and counter to
223.5 the carbon intensity focus and technology-neutral principles that have driven innovation and investment in the LCFS program to date. The requirement will reduce available supply, increase the cost of H2 thereby hindering adoption and achievement of the state's zero carbon goals. The imposition of an 80% renewable content requirement exclusively for HRI raises concerns in comparison to Fast-Charging Infrastructure which will place hydrogen at a competitive disadvantage to other energy sources, electricity in particular, which benefit from substantial federal, state, and ratepayer subsidies not extended to hydrogen.

Biomethane. We are aligned with CARB's continued acknowledgment of the importance of methane reduction to address Global Climate Change and that the responsible use of RNG as a feedstock to hydrogen production can be a strong proponent of methane reductions regardless of the sourced location. We strongly support the changes in regulatory language which provide visibility to the eligibility
223.6 of RNG as a feedstock for extended years, a necessary step in our investment in these technology and energy sources. We make the following additional recommendations:

Deliverability Language The creation of barriers to prevent the importation of RNG into California markets or for use as a feedstock in both in-state and out-of-state production of fuels should not be adopted. RNG is physically interchangeable with fossil natural gas and can be distributed in the same natural gas pipeline networks across the US. This established distribution network provides a proven, national distribution network that should be leveraged, not restricted in the deployment of low carbon fuels. The 50% flow requirement is arbitrary and unjustified.

Landfill Methane Recognition of the methane avoidance of projects diverting organic material from Landfills should be revisited and expanded. The ability to increase methane capture rates through landfill RNG projects should be included.

RNG Power Sourcing Renewable natural gas facilities need flexibility to source renewable power as an input to RNG production in order to further incentivize the carbon reduction potential in its acquisition.

Book-and-Claim Accounting for Process Electricity. The expansion of the book-and-claim accounting for process energy will provide strong incentive to hydrogen producers to seek low-carbon alternatives in process energy to further reduce their process carbon intensities. To best take advantage of this proposed change we recommend the following:

223.7 Expansion to all process energy The opportunity to incentivize carbon reduction in process energy exists for all sources of energy. We recommend that the process energy allowance be expanded to include all energy sources used in production including such sources as the fuel used for thermochemical conversion energy.

Clarification on delivery The regulation reads as follows:

The low-CI electricity must be supplied to the grid within the local balancing authority where the electricity is consumed or delivered to that local balancing authority consistent with the requirements of California Public Utilities Code section 399.16, subdivision (b)(1).

CPUC Section 399.16(b)(1) requires delivery to ***California***, which makes this provision ambiguous. Presumably, the proposed amendment is intended to require delivery only to a "local balancing authority," even if outside of California, but it could be interpreted to require delivery to California. We recommend the wording be updated to ensure delivery to an end use such as hydrogen production, outside of California is included.

Sourcing from new production The proposal requires that Low-CI electricity must come from new or expanded electricity production (after January 1, 2022, or within three years of the start of the hydrogen production facility, whichever is later.) This is an overly restrictive requirement that burdens hydrogen production, disadvantages it to other electricity usage, and has not been shown to provide benefits in a regulated electricity market that includes significant grid renewables and a Renewable Portfolio Standard. We recommend the elimination of this requirement.

223.8 **Book-and-Claim Accounting for Low-CI Hydrogen.** The proposed amendments allow book-and-claim accounting for low-CI hydrogen injected into a pipeline. We recommend that this allowance include not only hydrogen used as a transportation fuel but also for hydrogen used as a feedstock to produce other low-CI fuels. Substituting low-CI hydrogen in these production processes can be one of the most effective mechanisms to improve the environmental footprint of traditional fossil fuel production, SAF, and renewable diesel. Including these uses in the eligible accounting for hydrogen provides a strong incentive for these producers to reduce their product CI.

We appreciate CARB staff's work on the development of the proposed rule and their commitment to improving the LCFS. Successful adoption of battery and fuel cell electric vehicle technologies requires changes in LCFS to reinforce market pricing, parity in policy, and encourage deployment of fueling and charging infrastructure for zero-emission fleets. Thank you for the opportunity to provide input to this critically important program. If you have any questions or comments, please contact me at any time.

Sincerely,

David P. Edwards, PhD
Director, Air Liquide Hydrogen Energy
david.edwards@airliquide.com
cel: 612 747 7636

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Here is the comment you selected to display.

Comment 233 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Evan
Last Name	Neyland
Email Address	evan.neyland@chargepoint.com
Affiliation	ChargePoint
Subject	ChargePoint comments on Dec 2023 LCFS amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6899-lcfs2024-VzQHaQFhV3YKawJn.pdf
Original File Name	ChargePoint Comments to Dec 23 LCFS Proposed Amendments.pdf
Date and Time Comment Was Submitted	2024-02-20 13:59:42

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

—chargepoin+

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: ChargePoint Comments on Proposed Low Carbon Fuel Standard Amendments

Thank you for the opportunity to submit comments on the proposed amendments to the Low Carbon Fuel Standard (LCFS) issued on December 19, 2023. ChargePoint has reviewed the Proposed Regulation Order and appreciates the work of the California Air Resources Board (CARB) Staff to implement changes to LCFS that will advance investment in low carbon fuels and infrastructure in California.

About ChargePoint

Since 2007, ChargePoint has been committed to making it easy for businesses and drivers to go electric with one of the largest electric vehicle (EV) charging networks and a comprehensive portfolio of charging solutions. ChargePoint's cloud subscription platform and software defined charging hardware is designed internally and includes options for every charging scenario from home and multifamily to workplace, parking, hospitality, retail, corridor, and fleets of all kinds.

Summary of comments

224.1
- Expand the scope of "less intensive verification" for on-road electricity crediting to allow for networked charging stations that meet certain requirements to be pre-approved. Entities that do not meet the requirements for less intensive verification could still undergo full verification.

224.2
- Remove the exemption for dedicated parking spaces under multifamily crediting and allow owner/operators to claim credits on all stations at multifamily locations.

224.3
- Regarding the MHD-FCI provision: (1) relax the siting requirement to within 5 mi of a FHAA corridor, (2) reduce the minimum kW nameplate capacity to 200, (3) consider shortening the FCI crediting window to 7 years, and (4) roll unutilized LD-FCI capacity into the MHD-FCI provision to increase deployments.

224.4
- Take greater action to stabilize the credit market, either through supply-side intervention or more stringent carbon intensity targets. Increase the step down to 10%.

224.5
- Modify the Automatic Acceleration Mechanism (AAM) formula to trigger once the credit bank exceeds three-fifths of the prior year's deficits, instead of three-fourths.

Requirements for less intensive verification

The inclusion of on-road electricity crediting in the verification program is not a small lift and needs to be done thoughtfully. Therefore, we suggest CARB consider putting off including electricity verification in this rulemaking given the many other issues being considered. However, if CARB believes that on-road electricity reports must undergo third-party verification under the amended regulation due to largescale risk of misreporting (which to our knowledge, there is currently no evidence of), CARB should lean on existing technology, standards and relevant regulations when designing verification. To that end, we appreciate CARB's inclusion of a "less intensive verification" pathway in the proposed rules but believe that this does not go far enough. The less intensive verification pathway should be expanded to consider the following:

The EV charging network is fundamentally different than the traditional point-source liquid fuel supply network: whereas liquid fuels originate from fewer and larger sources (refineries), EV charging stations are significantly more disaggregated, where each point (or charger) in the network represents a small amount of potential fuel supply which renders physical site visits across the whole network impractical and costly. For meter accuracy assurance, CARB should instead lean on accuracy thresholds that already exist in the industry, such as those within the California Type Evaluation Program (CTEP), which require that level 2 (L2) EV charging meters meet an accuracy threshold of ±1% upon manufacturing and calibration and ±2% over its useful life, while level 3 (L3) meters must meet a ±2.5% accuracy upon manufacturing and calibration and ±5% over its useful life. The CTEP standard is already being utilized by the California Division of Measurement Standards (DMS), the entity tasked with ensuring the accuracy of commercial devices, including EV charging stations. DMS sets standards to promote fair competition and ensure consumer protection and points to the CTEP as the metrological accuracy standard that chargers installed after a certain date must meet to be used for commercial purposes. County Weights & Measures offices, under the guidance of statewide rules established by DMS, serve to enforce the standards by conducting periodic site visits to verify the accuracy of fueling stations.

Recommendation: CARB should pre-approve charging stations that meet CTEP's meter accuracy standards for participation under the less intensive verification pathway.

Pre-approval would mean exempting eligible charging station models from site visits and third-party meter testing based on that model's meter accuracy substantiation. CARB could publish a list of exempt charging station models that meet CTEP's meter accuracy standards for credit generators' reference. This is similar to the approach taken under Canada's national Clean Fuels Regulation. Otherwise, the existence of the DMS framework for assessing and enforcing charger accuracy would render additional site visits and meter testing, even only in half of the years as currently proposed under the "less intensive verification" pathway, under the LCFS program duplicative and punitive on the industry, particularly for small owner/operators[1].

With assurances around charging station meter accuracy ensured by the accuracy standards embedded in CTEP, the final step to less intensive verification would be a "desktop" review of the data in the reports. The scope of the desktop review would be to ensure that the data in the quarterly reports submitted through the LRT matches the data that was output from the charging network. EV charging networks are underpinned by extremely accurate (down to the watt-hour), real-time data in a way that traditional liquid fuel networks are not[2]. Networked EV charging provides a near constant stream of data that can be verified against reported charging activity.

There are a number of standards, practices, technologies and processes charging network operators adhere to to ensure the accuracy of data. For example, ChargePoint complies with several standards to ensure that the data reported by the station maintains its accuracy as it is transferred from the station to the cloud, and that any data anomalies are detected and removed before being reported. Many network operators also maintain compliance with Payment Card Industry Data Security Standards (PCI DSS) to ensure an accurate and secure environment for network transaction data. CARB could pre-approve networks that meet certain standards for use under the less intensive verification pathway, similar to pre-approving charging station models based on meter accuracy. Standards and documents required for pre-approval could include SOC2 reports and/or PCI certification.

Our recommendations for the less intensive verification pathway are not necessarily meant to be prescriptive, but rather to point out how existing technologies, best practices, and standards already widely adopted in the industry should be incorporated into the pathway. This will greatly minimize administrative costs for an industry that is still scaling. This is also the general approach taken under Canada's national program. We urge CARB to not try and reinvent the wheel re: on-road electricity verification. Reporting entities that do not meet the requirements for less intensive verification would still be able to undergo full verification.

Credits for non-residential chargers at multi-family residential properties.

ChargePoint strongly supports the proposal to allow FSE owners to generate credits for stations installed at multifamily properties. This change will create more revenue opportunities for property owners that install chargers at multifamily locations, and

[1] The cost of a non-streamlined verification will be disproportionately significant to small owner/operators since LCFS revenues will be smaller. In multifamily residential settings, physical site visits will be particularly challenging due to privacy concerns.
[2] Some charging networks are more robust and secure than others and we recommend some level of minimum thresholds in order to qualify for the less intensive verification pathway, as we touch on below.

critically, incentivize more deployment of chargers for residents of multifamily homes, a market segment that has historically lacked investment.

Recommendation: remove the exemption for dedicated parking spaces and allow owner/operators to claim credits at all multifamily locations.

While we fully support the proposal to treat multifamily crediting the same as non-residential, we do not agree with the proposal to treat chargers in dedicated parking spaces differently. Not only will the exclusion of restricted parking spaces be extremely difficult to track, but it also arbitrarily distinguishes credit generation based on a residence's parking arrangement. Recent analysis by the CEC indicates that expanding the range of charging options available in the parking lots of multifamily housing will ensure charging is not a barrier to EV adoption.[3] Increasing home charger access for residents of multifamily homes must be a priority to equitably meet the routine charging needs of more EV drivers, and for this reason, we strongly support this change by CARB.

Residents of multifamily housing are generally not able to install conventional home charging without financial assistance from the building owner. This is because charger installation at multi-family properties often requires upgrades to shared electrical panels and running conduit across common parking areas. A single household of a multifamily residence is generally unable or unwilling to shoulder the high cost of charger installation themselves. In other words, there is a "split incentive" affecting multifamily properties in which a property owner must pay for and organize installation, while the chargers may only benefit the fraction of residents who drive EVs at the time of the upgrade.

In fact, there is a case to be made that chargers in dedicated multifamily residential parking places may have the most impact on those residents switching to electric and should therefore be supported by the LCFS through the ability to generate value from credit generation. This is especially true considering CARB's proposal to redirect funds from the Clean Fuel Reward (CFR) program towards MHD EVs (which we also strongly support). Whereas before, CFR value was generated by residential (including multifamily) charging so it made sense to return some of that value to individual EV drivers via LD EV rebates. If CFR value will now go towards MHD EV rebates, it only seems right to allow owner/operators of multifamily chargers to retain the value of the LCFS which can help finance or buy down the cost of the station.

<u>**Medium and heavy duty (MHD) Fast Charging Infrastructure (FCI) credits**</u>

ChargePoint strongly supports the addition of the MHD FCI provision. While the passage of the Advanced Clean Fleets and Advanced Clean Trucks regulations are expected to create greater demand for MHD EVs, infrastructure development to support these vehicles remains

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[3] California Energy Commission, Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment ("AB2127 Report") at 48.

economically challenging due to the lack of MHD vehicles on the road today and the expectation that it will take time for the market to grow. The expansion of FCI credits for both private and shared MHD FCI is a much-needed intervention to commercialize charging infrastructure and help stimulate investment for this segment. ChargePoint also appreciates the inclusion of shared private fleet chargers in this program. Nonetheless, a few revisions to the rules for MHD FCI credits will allow the program to support the nascent MHD refueling market more effectively.

Charging hubs for MHD vehicles are likely to require several megawatts of power for each site. These projects will in most cases require significant distribution grid upgrades by the utility. Due to the complex factors that inform site selection for MHD charging sites, including but not limited to access to travel corridors, proximity to vehicle routes, distribution grid capacity, and land acquisition, it remains unclear which locations will be the most efficient to locate private or shared MHD charging hubs. For this reason, overly narrow location requirements for MHD FCI sites may impede development by eliminating projects that would otherwise be ideal due to ample grid capacity. While we understand CARB's intent for the FCI program to focus charger deployment in alternative fuel corridors for the purposes of accessibility and equity, station owners and drivers would benefit from less stringent geographic limitation.

Recommendation: relax the geographic siting requirement to 5 mi from a FHAA fuel corridor to provide flexibility for site selection.

The amendment proposal establishes a minimum power level of 250 kW for chargers serving sites that receive MHD FCI credits. The minimum power level established for MHD-FCI sites should consider *today's* MHD fleet needs, as well as the anticipated needs of the future. For most MD vehicles on the road today, 200 kW is more than sufficient for the vehicle's needs and helps lower overall system costs (relative to 250 kW or greater). Therefore, ChargePoint recommends that CARB reduce the minimum power level for each charger serving MHD FCI to 200 kW, as this minimum is sufficient to meet the market where it is today, as well as accommodate the needs of coming MHD vehicles.

Recommendation: reduce the minimum kW eligibility requirement to 200 from 250.

Regarding the MHD-FCI crediting window, while some sites will need a 10-year window to recoup capital costs, a longer window could encourage overbuilding and disincentivize utilization in the short to mid-term, both of which are not ideal for the market. We believe a crediting window closer to 7 years will suffice for the majority of projects and encourage sites to build for utilization sooner rather than later. This should also free up more capacity under the MHD-FCI cap sooner which will open up capacity for more sites over time.

Recommendation: consider shortening the MHD-FCI crediting window to 7 years.

The CEC reports that as of 2023, California has over 9,000 DCFC ports in operation and is ahead of schedule to meet its port deployment target of 10,000 ports by 2025.[4] ChargePoint believes LD FCI revenue has successfully accelerated investment in the market for public DCFC and is partly responsible for the state's success in this segment. When paired with the continued growth of LD EV sales in California, it seems clear that continued investment in LD-FCI can sustain itself without greater support from FCI credits. By contrast, the MHD segment would benefit from greater FCI support because it is underdeveloped relative to the state's goals. The CEC estimates that by 2030, California's 155,000 MHD EVs will need about 114,500 public and shared chargers.[5]

To further accelerate the market for MHD electrification, **we recommend CARB rollover any unused LD-FCI credits into the MHD cap to allow for greater investment/deployments in this segment (more on this below)**.

Revised Clean Fuel Reward Program

ChargePoint supports the proposal to redirect funds from the CFR program to make MHD EVs more cost-effective. The current framework of allocating CFR funds towards LD EV rebates has long since lost efficacy as the rebate amount is not salient to prospective EV drivers to the point where it induces additional purchases. ChargePoint is pleased to see this change as the current state of the MHD EV market is more in need of funding than the LD segment.

Light duty FCI credits

The proposed regulation establishes a transition plan to reduce FCI crediting available for LD DCFC applicants. Among other changes, the proposal amends the cap for LD FCI credits to 0.5% of prior quarter deficits, a reduction from the previous cap of 2.5%. ChargePoint supports this change and agrees that LD-FCI credits should be capped to no more than 0.5% to focus infrastructure crediting on the more nascent MHD EV market. As discussed previously, ChargePoint believes MHD-FCI should be the priority and recommends CARB consider further reduction in the availability of LD-FCI credits in favor of a higher cap on MHD-FCI credits.

Should the LD-FCI pathway remain open beyond 2025, ChargePoint believes it would be premature to limit eligibility to stations with a nameplate capacity of 150 kW or more in light of the other proposed changes to the pathway. A station capacity minimum of 150 kW combined with the change to how FCI charging capacity is calculated as well as the extension of the crediting timeline to 10 years will together incentivize overbuilding sites without regard to utilization solely because of FCI credits.

[4] AB2127 Report at 3.
[5] AB2127 Report at 2.

New carbon intensity benchmarks

In the weeks following CARB's release of its amendment package in mid-December, the spot market for credit prices declined ~20% (falling from $70/credit to a low of $57/credit). In that time, the market incorporated CARB's proposal of a 30% carbon intensity (CI) target by 2030, along with the proposed changes to the supply side, and determined that this market will continue to be oversupplied. Without more ambitious CI targets and/or clearer steps to curb biofuel production with uncertain greenhouse gas benefits (Murphy & Wook, 2024)[6], it is apparent that this market will continue to be oversupplied and credit prices will remain low for the foreseeable future.

In prior conversations with CARB staff, we have come away with the understanding that CARB assumes the LCFS program, and the potential revenue it affords, does not factor into investment decisions for EV project operators (fleets, charging operators, etc.) and therefore investment in EVs and charging infrastructure is agnostic to LCFS credit prices. We do not agree with this assumption. Advanced Clean Cars, Advanced Clean Trucks, and Advanced Clean Fleets do not directly address or fund charging infrastructure. The LCFS program can, and often does, provide an important revenue stream for EV project operators and can be the difference between a project penciling or not. Project developers, operators, and investors in the EV space operate similarly as those in other spaces: they evaluate all available costs and revenues when assessing a potential project and often make decisions based on expected net cashflows. The difference between expected 5-year LCFS revenues on a L2 station with roughly average utilization in a world where credit prices hover in the ~$60/credit range vs ~$150/credit is significant. In the former, expected 5-yr LCFS revenues do not amount to enough to influence the business case, whereas in the latter, LCFS revenues offset a significant portion of the cost of the station and can even be leveraged for project financing.

As electrification has the most potential for long-term deep decarbonization of transportation, we urge CARB to account for the impact that sustained low credit prices may have on transportation electrification investments. Without clearer steps to limit crop-based biofuels – or specific carve outs for on-road electricity credits, like how some state Renewable Portfolio Standards set specific carve outs for solar – investments in charging infrastructure and electric fleets will be crowded out under the program by the continued surplus of biofuel credits in the market.

[6] Murphy, Colin & Ro, Jin Wook. Updated Fuel Portfolio Scenario Modeling to Inform 2024 Low Carbon Fuel Standard Rulemaking (Draft). University of California Davis Policy Institute for Energy, Environment, and Economy.

Recommendation: in lieu of some sort of cap on crop-based biofuels, we believe the 2030 CI target needs to be increased to 32.5% to 35% and the stepdown needs to be increased to 10% to raise price expectations to the level needed to usher in more investment.

Automatic Acceleration Mechanism (AAM)

ChargePoint supports the proposal to establish the AAM but recommends that CARB make the mechanism stronger. As proposed, the AAM would not have been triggered in any of the years after the 2018 amendments. These years include 2022, a year when the credit market price declined by ~50%.[7] The AAM should be designed specifically to counteract this type of negative price movement, so a mechanism that would not have reacted in 2022 is not strong enough.

To strengthen the mechanism, we recommend that ARB amend the first condition of the AAM to be reached when the cumulative credit bank is greater than three-fifths of the deficits generated over the same calendar year rather than the current condition set at three-fourths. With this update the AAM would have been triggered in 2022 but not any of the other years following the 2018 amendments. Since these other years saw price increases or modest declines, the new threshold suggests a balanced mechanism that reacts only to large price decreases.

Conclusion

ChargePoint appreciates the opportunity to submit comments to CARB on the Proposed Regulation. We stand ready to work with CARB Staff to implement the changes discussed in these comments, particularly to ensure that the process of verification is administratively efficient for the on-road charging market.

Respectfully,

Evan Neyland
Senior Manager, Carbon Markets

[7] LCFS data dashboard; https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard

Comment Log Display

Here is the comment you selected to display.

Comment 234 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Duncan
Last Name	Coneybeare
Email Address	d.coneybeare@hiiroc.com
Affiliation	HiiROC Ltd
Subject	Staff Report: Initial Statement of Reasons - response from HiiROC Ltd
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6900-lcfs2024-AHBUIFA+WXpROAJx.pdf
Original File Name	Proposed Low Carbon Fuel Standard Amendments (lcfs2024)_HiiROC Response_20220220.pdf
Date and Time Comment Was Submitted	2024-02-20 13:59:46

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

California Air Resources Board

Submitted electronically at:
[Submit Your Comments to the Board (ca.gov)]

HiiROC Limited
22 Mount Ephraim
Tunbridge Wells
United Kingdom
TN4 8AS

February 20, 2024

To whom it may concern:

HiiROC response to:
Staff Report: Initial Statement of Reasons, dated December 19, 2023,
'Proposed Amendments to the Low Carbon Fuel Standard'

Thank you for the opportunity to respond to this document and thereby provide comments in relation to the proposed revisions to California's Low Carbon Fuel Standard (LCFS). We welcome California's efforts to reduce greenhouse gas emissions to date and recognise the critical role that the LCFS is playing both in addressing climate change and improving air quality.

We fully support the objective of increasing the stringency of the LCFS program in reducing emissions and decarbonising the transportation fuel sector – in our view the proposals represent an effective means of doing so. We welcome the additional support the proposals create for the hydrogen sector, which will help it to play a full and meaningful role in achieving the aims of the Standard. However, we strongly urge that the proposals should take into account the fact that new pathways for the production of hydrogen at scale will soon be commercially available.

In particular, our own Thermal Plasma Electrolysis (TPE) process offers a route to hydrogen production at point of use which combines the low carbon dioxide footprint of water electrolysis with the low electricity input requirements of steam methane reforming. TPE does this by stripping the carbon from a wide range of hydrocarbon feedstocks, capturing the carbon as an inert solid, and producing low-carbon hydrogen fuel (with no CO_2 emissions created by the process itself).

1. About HiiROC (www.hiiroc.com)

HiiROC, a UK-based company, is developing its Thermal Plasma Electrolysis (TPE) process to produce low-cost, low-CO_2 hydrogen, at a comparable cost to steam methane reforming but without emissions from production and using only one-fifth of the electricity required by water electrolysis.

HiiROC's proprietary technology uses plasma torches to convert gaseous hydrocarbon feedstocks (such as biomethane/ renewable natural gas, flare and industrial waste gases, propane, and natural gas) into low carbon hydrogen and solid, high-quality carbon black. The latter co-product is stable and could simply be disposed of, but it also has existing and emerging end-use applications, ranging from tyres and inks to building materials and soil enhancement. Using our TPE process, hydrogen can be produced where it is needed, utilising existing energy infrastructure, and reducing hydrogen storage and transportation costs.

Our technology is rapidly approaching full commercial deployment, bringing with it the potential to unlock step-change growth in the hydrogen economy around the world.

2. Why are we responding to these proposals?

The California Air Resources Board (CARB) has been clear that hydrogen has a significant role to play in delivering the decarbonisation of transport in California and the LCFS is intended to provide economic incentives to produce hydrogen and thereby displace fossil transportation fuels. The proposals have also highlighted the need to incentivise greater production of clean fuels needed in the future, such as low-carbon hydrogen.

At HiiROC we are committed to delivering the potential for TPE to decarbonise economic activity, diversify production pathways for low-carbon hydrogen and enable the global energy transition that will be required to counter anthropogenic climate change.

Responding to these proposals represents a critical way for us to keep policymakers and regulators informed about the technological advances that we believe will enable delivery of low carbon hydrogen at greater scale and at lower cost than existing alternatives. In particular, we wish to highlight that low-carbon hydrogen can be produced without the generation of process CO_2 emissions, by splitting hydrocarbon feedstocks into hydrogen and solid carbon, and that outputting solid carbon in this way should be treated as equivalent to the storage and capture of gaseous CO_2.

We note that the UK's Low Carbon Hydrogen Standard (LCHS) has recently been amended to recognise this equivalency, with 'Gas splitting producing Solid Carbon' having been added as a production pathway falling within scope.[1]

We hope that our thoughts will be helpful and would welcome the opportunity to discuss them further.

3. Comments about: the key concepts underpinning the regulatory update proposal (page 4)

225.1
- *Increasing the stringency of the program to reduce emissions and decarbonize the transportation fuel sector, which will also aggressively reduce our dependence on fossil fuels*
  - We support the aim of increasing the stringency of the program, given the anticipated impacts of reducing emissions and decarbonizing the transportation fuel sector.
- *Strengthening the program's equity provisions to promote investment in disadvantaged, low income and rural communities*
  - In this context, we note that our TPE technology is modular, can be sized to meet local demand and can be deployed to produce hydrogen at point of use. This means that 225.2 there is significant flexibility in where investment in the technology is deployed, with the potential for 100% of any units installed in California to be sourced and manufactured in the United States.
  - TPE also draws on different supply chains from other low carbon hydrogen production technologies, minimising delivery risk for California's hydrogen economy and enabling a broader spread of investment.
- *Supporting electric and hydrogen truck refuelling*
  - 225.3 In this context, we note that our TPE technology is modular, can be sized to meet local demand and can be deployed to produce hydrogen at point of use. TPE is also capable of producing hydrogen on a flexible basis; this means it can deliver hydrogen volumes in

[1] https://www.gov.uk/government/publications/uk-low-carbon-hydrogen-standard-emissions-reporting-and-sustainability-criteria : UK Low Carbon Hydrogen Standard, version 3 – Appendix A, A.18 – A.26. The current treatment of Solid Carbon Sequestration is covered in the accompanying Data Annex, DA.53 – DA.55.

response to demand patterns. This makes it particularly suitable for the production of hydrogen at truck refuelling stations.

- *Incentivizing more production of clean fuels needed in the future, such as low-carbon hydrogen*
    - 225.4 We continue to view low-carbon hydrogen as a key enabler of an effective energy transition. What is important here is the carbon intensity of the hydrogen that is produced, not the production method itself. We strongly advocate for a regulatory framework that is technology-agnostic, providing a level playing field for the full range of production pathways which can satisfactorily deliver low-carbon hydrogen. This will best enable the emergence of price competition, which should in turn deliver a successful energy transition at least cost to consumers.
    - In particular, regulations need to recognise that producing solid carbon from hydrocarbons is an effective way of sequestering that carbon content. See Section 4 below for more specific discussion on this point.
- *Supporting methane emissions reductions and deploying biomethane for best uses across transportation*
    - We believe that deployment of our TPE technology at scale has a number of benefits from the perspective of methane emissions reduction.
        1. 225.5 Flare gas (i.e. natural gas associated with oil production which is combusted or simply vented to the atmosphere at the point of extraction, rather than being processed for onward use) can be used as a feedstock for the TPE process. Producing hydrogen on site from such flare gas, which would otherwise be flared or even vented directly to the atmosphere, has significant potential to reduce the methane and/or CO_2 emissions arising from the production of oil and gas.
        2. Conversion of methane into hydrogen at the site of oil and gas production also potentially reduces the need to transport methane, reducing the risk of methane emissions through leakage during transportation.
    - We would also argue that the best/most impactful use of biomethane is in the delivery of negative CO_2e emissions. When biomethane/renewable natural gas is used as the feedstock for the TPE process, this offers the capacity for negative emissions to be generated in the production of hydrogen, as the carbon content of the renewable feedstock is being fully captured. We believe that biomethane volumes should be prioritized for utilization in this way, delivering negative CO_2e emissions as well as hydrogen which can be used for transport applications.
- *Strengthening guardrails on crop-based fuels to prevent deforestation or other potential adverse impacts*
    - 225.6 We support the application of strong verification procedures for all low-carbon fuels, as we believe this is crucial to maintain public confidence in the robust credentials of those fuels.

4. **<u>Comments about: 'Allow Indirect Accounting for Low Carbon Intensity Injected into Hydrogen Pipelines physically connected to California and Expansion of Indirect Accounting for Low Carbon Intensity Electricity for Hydrogen Utilized as a Transportation Fuel'</u>** <u>(page 34)</u>

We note that the 2022 Scoping Plan Update calls for a significant increase in the production of low-carbon hydrogen, displacing fossil fuels for transportation.

HiiROC's TPE technology, by offering significantly lower electricity consumption compared to water electrolysis (approximately one-fifth), will allow far greater hydrogen production volumes from upstream energy infrastructure investment – including renewable electricity generation capacity. This opens the prospect of reaching California's decarbonization targets sooner and/or at a lower cost, with less major infrastructure investment required. For this reason, we believe (as highlighted earlier) that the regulatory framework needs to adopt a technology-agnostic approach which will allow all hydrogen production pathways to compete on a level playing field.

We fully support the adoption of "*book-and-claim of low-CI hydrogen to support the 2022 Scoping Plan update energy transition by overcoming bottlenecks in hydrogen production and supply*". We believe this will offer significant encouragement to what remains a nascent market today, by providing critical flexibility in matching supply and demand.

However, we are particularly concerned about the following proposal:

225.7 "*Staff is proposing to exclude hydrogen derived from fossil gas from book-and-claim eligibility unless low CI hydrogen is produced using book and claim of biomethane or with CCS and used as a transportation fuel.*"

We strongly urge that the output of solid carbon when producing hydrogen from hydrocarbons should be recognised as fully equivalent to CCS as a means of mitigating emissions of gaseous CO_2.

Carbon capture is inherently part of HiiROC's TPE process – the carbon content of the hydrocarbon feedstock is turned into solid, inert carbon. At no point in the process is CO_2 formed; for this reason, we wish to see the definition of CCS extended, such that it does not require CO_2 to be formed and then captured in order to qualify, and the outputting of solid carbon explicitly recognised as equivalent to CCS.

As we have noted above, biomethane can be used as a feedstock for the TPE process. Coupling this renewable feedstock with CCS, in the form of outputting solid carbon, presents the opportunity to deliver negative CO_2e emissions, which we contend will be an extremely valuable tool in countering anthropogenic climate change.

Once again, on behalf of HiiROC, I would like to thank you for the opportunity to comment on these important issues. Please do not hesitate to get in touch should any of the matters raised above require clarification.

Yours sincerely,

DJ Coneybeare

Duncan Coneybeare
Strategy, Policy and Markets Director
HiiROC Limited

Email: d.coneybeare@hiiroc.com

Comment Log Display

Here is the comment you selected to display.

Comment 235 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	John
Last Name	Steelman
Email Address	jsteelman@catf.us
Affiliation	Deputy Director, Transportation Decarbon
Subject	Comments on potential changes to LCFS
Comment	Submitting comments on behalf of the Clean Air Task Force and Pacific Environment on the proposed revisions to the LCFS. Please let us know if you have any questions. Thank you, John Steelman Deputy Director, Transportation Decarbonization Clean Air Task Force
Attachment	www.arb.ca.gov/lists/com-attach/6901-lcfs2024-AmEAZ1MmU2YEXVMy.docx
Original File Name	CATF and Pacific Environment Joint Comments_CARB LCFS Amendments.docx
Date and Time Comment Was Submitted	2024-02-20 13:56:45

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024
To: California Air Resources Board (CARB)

Re: Joint Comments on Proposed Low Carbon Fuel Standard Amendments
Submitted via CARB's online Comment Submittal Form

On behalf of Clean Air Task Force (CATF) and Pacific Environment, we are pleased to submit comments on CARB's proposed amendments to California's Low Carbon Fuel Standard (LCFS). We greatly appreciate the tremendous amount of work and transparency the CARB staff have invested in considering strengthening the LCFS 2030 targets, recommending new targets out to 2045, and proposing the important step of eliminating the current aviation fuel exemption for intrastate fossil jet fuel from the standard. However, as we and other have groups communicated with Chair Randolph[1] and as elaborated on by CARB staff at the February 22, 2023, workshop[2], without adequate safeguards, these measures pose significant and unacceptable risks of rapidly driving up demand for crop-based biofuels with several potential negative consequences. Such consequences include increased lifecycle greenhouse emissions from direct and indirect land use changes, as well as disruptions to food markets and natural ecosystems.

Pursuant to the California Global Warming Solutions Act of 2006, CARB must "adopt greenhouse gas ...emissions reduction measures by regulation to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions in furtherance of achieving the statewide greenhouse gas emissions limit."[3] The California Legislature strengthened this directive in the California Climate Crisis Act, which provides that it is the "policy of the state" to "[a]chieve net zero greenhouse gas emissions as soon as possible, but no later than 2045, and to achieve and maintain net negative greenhouse gas emissions thereafter."[4] CARB recognized in adopting the LCFS that the goal of the regulation is to "reduce the full fuel-cycle, carbon intensity of the transportation fuel pool used in California."[5] Without adequate safeguards limiting the rapid growth in demand for crop-oil based biofuels, the current LCFS proposal could result in an increase in lifecycle greenhouse emissions due to direct and indirect land use changes. This would not "effectuate the purpose of" the above statutes.[6]

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[1] Environmental Defense Fund, Clean Air Task Force and World Wildlife Fund-US letter to Chair Liane Randolph, May 5, 2023.
[2] Low Carbon Fuel Standard Public Workshop: Potential Regulation Amendment Concepts, February 22, 2023
[3] Cal Health & Saf. Code § 38562(a); see also id. § 38550 (directing CARB to establish a greenhouse gas emissions limit to be achieved by 2020).
[4] Cal Health & Saf. Code § 38562.2(c).
[5] 17 C.C.R. 95480.
[6] See Cal. Gov. Code § 11350(b)(1); see also id. (CARB's regulation must be supported by "substantial evidence" to demonstrate that it is "reasonably necessary to effectuate" the purpose of its enabling statutes).

Instead, such an outcome would go against the express goals of the LCFS and would frustrate California's mandate to reduce greenhouse gas emissions and effectively address climate change.[7]

While CATF is submitting separate comments on other aspects of the proposed amendments, these joint comments focus on the risks that the LCFS, if amended as proposed, will result in unsustainable consumption of vegetable oil-based biofuels and undermine the emission-reduction goals of the program.

In particular:

- Without adequate safeguards, strengthening and extending LCFS carbon intensity benchmarks will likely accelerate the rapid growth in demand for bio-oil based biofuels, directly and indirectly impacting food markets and increasing emissions from land use changes;
- 226.2 Including intrastate fossil jet fuel in the LCFS is an important policy signal for decarbonizing the aviation sector, but the current proposal will further increase demand for bio-oil based fuels, given that refining and hydrotreating bio-oils is currently the only commercially viable alternative to fossil jet fuel at scale; and
- 226.3 The only proposed sustainability requirement for crop-based biofuels is third-party certification that the feedstocks are derived from land that has not been forested since 2008, which is too narrowly scoped to serve as an effective constraint on climate-damaging land use change.

Given these risks, we make the following recommendations:

1. CARB should limit the volume of first-generation vegetable oil-based fuels that are eligible to generate credits under the LCFS program;
2. CARB should assess on an annual basis the direct and indirect market impacts from fuels obligated under the proposed sustainability requirements; and,
3. CARB should extend the sustainability requirements beyond crop oils to used cooking oil (UCO) and waste oils.

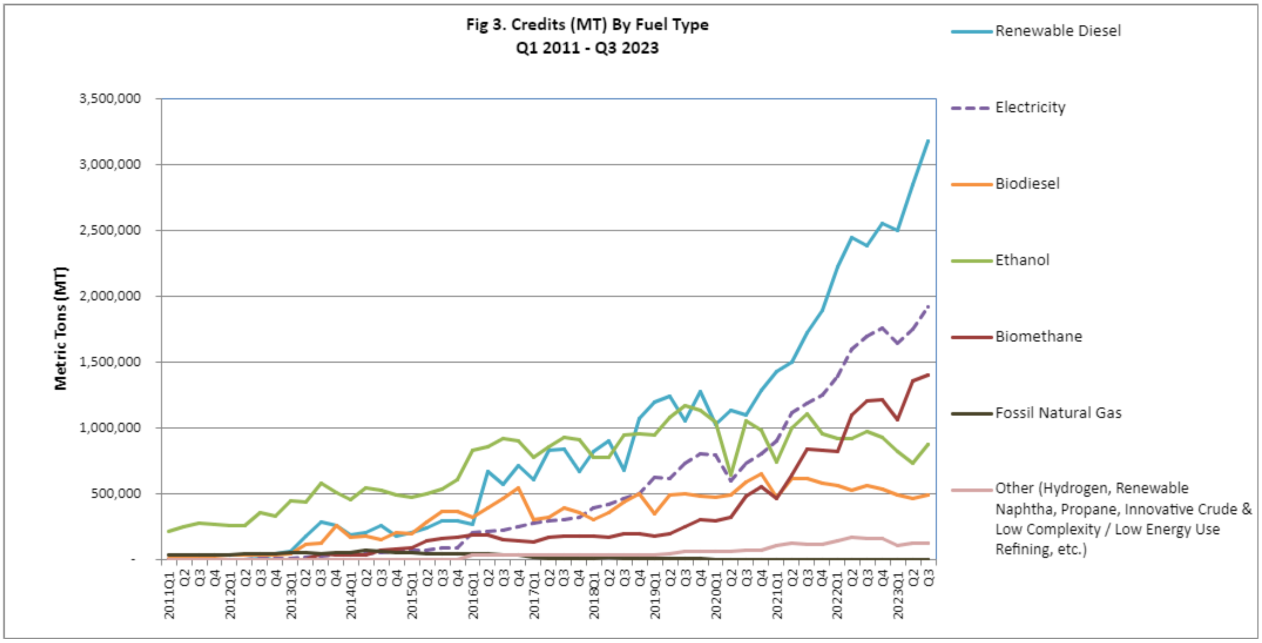
The Proposed Amendments to California's Low Carbon Fuel Standard Regulation[8] are likely to further accelerate the already growing demand for crop-oil based biofuels.

While our groups support CARB's intention to strengthen the LCFS' targets the lack of adequate safeguards or limitations on crop-oil feedstocks used in producing diesel and aviation fuel will further accelerate an already unsustainable growth in demand for crop-oil feedstocks. According to CARB's reporting data below, renewable diesel from bio-oils (mostly used cooking oil, tallow, and vegetable oils) are by far the largest and fastest growing source of credits in California's LCFS. [9]

[7] See Cal. Health & Saf Code § 38562.2; see also Rocky Mt. Farmers Union v. Corey, 913 F.3d 940, 945 (9th Cir. 2019).

[8] Proposed Amendments to the Low Carbon Fuel Standard Regulation, Appendix A-1, January 2, 2024

[9] Low Carbon Fuel Standard Reporting Tool Quarterly Summaries-Graphs, CARB, October 31, 2023



According to the most recently available data, bio-oil based diesel accounted for 60% of the California diesel fuel market as of the third quarter of 2023.[10] Since CARB has tracked feedstock data, beginning in 2021, quarterly use of crop-oil based fuels has grown by over 350% to 192 million gallons, accounting for 30% of the state's bio-oil diesel market.[11] California's use of crop-oil based fuels is now on track to exceed 700 million gallons in 2023.

In addition, in 2023 CARB certified 29 fuel pathways using soy, canola and corn oil feedstocks, compared with 8 such pathway certifications the year before. This further underscores the potential growth in crop-oil feedstock demand and attendant risks to food markets, climate, and the environment.[12]

While CARB projects that the use of renewable diesel will decline in the future as vehicle standard requirements tighten and the fuel begins generating deficits under the LCFS, CARB's regulatory impact assessment indicates that the *combined* in-state production of renewable diesel and alternative jet fuel alone will increase to more than 700 million gallons by 2028 and more than 800 million gallons by 2040.[13] Beyond in-state production of bio-oil fuel production, a recent study from U.C. Davis projects that strengthening California's LCFS reduction target to 30% by 2030 could result in 100% of the state's 3.5 billion gallons of diesel demand being met by bio-based diesel, most of which derived from vegetable oils.[14] Such a massive influx of vegetable-oil based diesel fuel would not only pose very large indirect land use impacts and potential GHG emissions, but could substantially erode carbon credit prices, which CARB is trying to address.

These recent trends and CARB's projections underscore the urgent need for careful safeguards in the LCFS amendments. Without adequate safeguards, the strengthening of the LCFS carbon intensity

[10] Calculated from Low Carbon Fuel Standard Reporting Tool Quarterly Summaries, CARB, October 31, 2023
[11] Calculated from Low Carbon Fuel Standard Reporting Tool Quarterly Summaries, CARB, October 31, 2023
[12] 2023 LCFS Pathways Requiring Public Comments and 2022 LCFS Pathways Requiring Public Comments, CARB
[13] Standardized Regulatory Impact Assessment (SRIA) of Proposed Amendments to the Low Carbon Fuel Standard Regulation, Table 47, CARB, September 9, 2023
[14] Forecasting Credit Supply Demand Balance for the Low-Carbon Fuel Standard Program, Bushnell et al, UC Davis, August 2023.

targets for diesel fuel and diesel substitutes to 74.03 gCO2e/MJ by 2030 and 10.57 gCO2e/MJ by 2045,[15] combined with the newly proposed Automatic Acceleration Mechanism (which increases the stringency of CI targets if triggered[16]) could greatly accelerate the unsustainable growth of crop-oil feedstocks used for making renewable diesel and alternative jet fuel. The resulting and potentially massive increase in demand for crop oil-based fuels markets can contribute to higher food and feed prices, which in turn can accelerate climate-damaging land clearing to accommodate new crop production.

While obligating intrastate jet fuel is an important step in achieving emissions reductions, it will further accelerate demand for crop-oil feedstocks without proper safeguards.

As with strengthening the LCFS targets, our groups have also supported CARB's consideration and intention to obligate fossil aviation fuels as a deficit generating fuel. CARB's proposal to eliminate the exemption for intrastate fossil jet fuel beginning in 2028[17] is an important (if limited) step toward reducing emissions from aviation fuel in California. Intrastate fuels account for approximately 10% of the roughly 3 billion gallons of jet fuel used in California each year.[18] Given the multiple certified fuel pathways for using crop oils as feedstocks for alternative jet fuel, obligating intrastate aviation fuel after 2028 could result in the consumption of several hundred million gallons of additional crop-based aviation fuel in addition to the rapidly increasing market for renewable diesel fuel. In addition, new federal tax credits for sustainable aviation fuels enacted in the Inflation Reduction Act[19] could drive further growth in crop-based alternative jet fuel, which will remain an opt-in fuel for interstate and international flights originating in California.

Rejecting a cap on vegetable oil-derived diesel fuel based on modeled health benefits is unjustified.

CARB's rejection of limits on credits from diesel fuel derived from vegetable oil feedstocks was based on modeled assumptions that particulate matter (PM) and smog-inducing nitrogen oxide (NOx) emissions would decline less than otherwise would occur under the proposed LCFS revisions that allow for continued growth of renewable diesel use. Research prepared for CARB, however, in which fuel blends were tested in diesel engines, concluded that there was no statistical difference in PM or NOx emissions between renewable diesel and fossil diesel used in new diesel engines with modern pollution controls.[20] Due to CARB's 2007 Truck and Bus regulation, all on-road diesels are required to be equipped with modern pollution controls; non-road diesel emission regulations require equivalent emission control regulation on an increasing share of vehicles in that sector as well. Air quality modeling studies by UC Davis have found minimal emission benefits from increasing blends of renewable diesel or biodiesel in 2030 and beyond due to the prevalence of these pollution controls. While biomass-based diesel played a real historical role in reducing emissions from diesel engines, significant evidence indicates that this will not be the case in the future.[21, 22]

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[15] *See* CARB, *Proposed Amendments to the Low Carbon Fuel Standard Regulation*, § 95484(e), Appendix 1 - table 2.

[16] *See* CARB, *Proposed Amendments to the Low Carbon Fuel Standard Regulation*, § 95484(b).

[17] *See* CARB, *Proposed Amendments to the Low Carbon Fuel Standard Regulation*, § 95482(c)(2).

[18] California State Energy Profile, U.S. Energy Information Administration, April 20, 2023

[19] *See* 26 U.S.C. 40B; *id.* 45Z. *See also* Internal Revenue Service, Notice 2023-06, Guidance on New Sustainable Aviation Fuel Credit (Dec. 19, 2022), https://www.irs.gov/pub/irs-drop/n-23-06.pdf.

[20] Low Emission Diesel (LED) Study Final Report, UC Berkeley for CARB, December 19, 2021.

[21] Modeling expected air quality impacts of Oregon's proposed expanded clean fuels program, UC Davis, March 1, 2023.

[22] Quality Impacts of Renewable Diesel and Sustainable Aviation Fuel (SAF) in California, UC Davis, presentation to the Joint Sustainable Aviation Fuels Subcommittee of the Transportation Research Board, January 8, 2024.

The proposed sustainability requirements for crop- and forest-based biofuels will not limit adverse environmental or food market impacts.

In considering the risks associated with crop-based biofuels, CARB concluded that "biofuel production must not come at the expense of food production or forests".[23] As CARB explained in its draft environmental impact analysis, "cultivation of biofuels on land currently used for food production could result in the conversion of additional existing forest, grassland, or other non-agricultural land to food-related agricultural uses."[24] Guardrails are necessary to avoid increased GHG emissions from land use change. CARB has stated it is considering such guardrails, including volume-based limits, credit limits, feedstock sustainability criteria, explicit bans on particular feedstocks, and bans of feedstocks from particular regions.[25]

The proposed sustainability certification requirement for crop- and forest-based biofuels,[26] however, will not guard against food production or forest impacts. By merely requiring third-party certification that the crop-based feedstocks were derived from land that was not forested as of 2008, without additional criteria to even evaluate secondary market impacts domestically or globally, the updated LCFS will continue to allow bio-oil feedstocks that negatively impact food markets and secondary impacts of expanded conversion of land for crop production, either within the country of the feedstock's origin or other crop-exporting countries. The likelihood of expanded land conversion could hinder the very GHG emissions reductions the LCFS seeks to achieve.

For example, this past December, a pathway application from Phillips 66 for importing soy oil from Argentina was approved by CARB.[27] As Argentina is the second largest exporter of soy meal and oil[28], any substantial diversion of exports from Argentina to California will likely create demand for expanded soy and/or palm oil production with impacts on food markets and/or forests that the proposed sustainability requirement would neither prevent nor track.

Recommendations

Given CARB's intention to strengthen and extend the carbon intensity benchmarks of the LCFS program and to obligate intrastate aviation fuels and considering the unexpected, highly risky, and rapid growth of bio-oil based fuels that will be accelerated by stronger targets and obligating aviation fuels, our organizations strongly recommend the following:

1. **CARB should limit the volume of first-generation vegetable oil-based fuels that are eligible to generate credits under its LCFS program.**

We propose the following mechanisms for limiting such fuels. First, CARB could establish a percentage-based system, based on the volume of diesel and aviation fuels sold in the state, such that only a certain percentage of credits may come from biolipid feedstocks. Alternatively, CARB could cap the total number of credits that may be generated from these fuels. In each of these two scenarios, the carbon intensity of the subsequent volumes of biolipid-based fuels would revert to the base fossil fuel CI score

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[23] California Low Carbon Fuel Standard, CARB presentation, September 28, 2023 (slides 36-37).
[24] [Draft EIA at 69]
[25] *Id*. (slide 37).
[26] *See* CARB, *Proposed Amendments to the Low Carbon Fuel Standard Regulation*, § 95488.9(g).
[27] Low Carbon Fuel Standard Tier 2 Pathway Application No. B0521, certified December 29, 2023
[28] Oilseeds: World Markets and Trade, USDA, January 2024

once the percentage or cap was surpassed. CARB should set these limits and add them to the updated LCFS, either in 17 C.C.R. § 95486, “Generating and Calculating Credits and Deficits” or 17 C.C.R. § 95486.1, “Generating and Calculating Credits and Deficits Using Fuel Pathways.”

2. **CARB should conduct annual assessments of the direct and indirect market impacts from fuels obligated under the proposed Sustainability Requirements.**

CARB should assess and report on an annual basis the market impacts on crop prices, acreage, and exports resulting from diverting bio-based feedstocks to biofuel production and imports that are obligated under the proposed Sustainability Requirements.

3. **CARB should extend the sustainability requirements beyond crop oils to used cooking oil (UCO) and waste oils.**

While UCO and waste oils are preferable and have lower carbon intensities than crop oils, there are existing markets for these oils that will otherwise turn to crop-based oils when UCO and waste oils are used to produced biofuels for use in California, which also results in land-use change impacts. Furthermore, instances of fraud of crop oils, such as palm oil, being passed off as waste oil have been reported and investigated.[29] Given the number of pathways that CARB has approved for imported waste oils, requiring 3rd party certification for these feedstocks and fuels is warranted.

With great appreciation for the tremendous effort CARB staff have invested in developing and proposing important revisions to California’s Low Carbon Fuel Standard, we thank you for your consideration of our recommendations and would be glad to elaborate or discuss these issues further.

Jonathan Lewis
Director, Transportation Decarbonization
Clean Air Task Force

Jayne Stevenson
Climate Policy Associate
Pacific Environment

[29] Calls for tighter rules on biofuels imports to root out palm oil fraud, The Guardian, December 14, 2023.

Comment Log Display

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Comment 236 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Joseph
Last Name	Boyd
Email Address	joseph.boyd@denaliwater.com
Affiliation	
Subject	IWP comments on proposed rule
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6903-lcfs2024-BTcGMAMwBGMBWFUn.pdf
Original File Name	2024 rule comments.pdf
Date and Time Comment Was Submitted	2024-02-20 13:59:25

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed LCFS Amendment Comments

Dear California Air Resources Board,

Imperial Western Products is a biodiesel producer and organics recycling company based in Coachella, California. We would like to provide our perspective on several aspects of the proposed amendments.

Benchmark CI reduction schedule

227.1a Current low LCFS credit values are driven in large part by oversupply due to a rapid acceleration in the amount of imported renewable diesel to CA starting in 2021. This trend does not show any signs of abating. To increase and stabilize credit values in the short and medium term, we support increasing the one-time step down in 2025 from 5 % to 8 %. We would also encourage CARB to explore ways to build more flexibility into
227.1b the AAM as to reduce lag time between the trigger criteria being met and the benchmark CI adjustment being implemented.

Less Intensive Verification

227.2 We echo the remarks of other producers and verification bodies to allow verification bodies to skip site visits to both production and intermediate facilities if they have visited the site in the last two years and issued a positive verification statement. Excessive site visit requirements add significantly to the cost of annual verification services, often require high CI air travel, and provide virtually no information which could not be provided by leveraging technology (photos, video calls, screen sharing).

Respectfully,

Joseph Boyd
Director of Engineering

Comment Log Display

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Comment 237 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Tom
Last Name	Van Heeke
Email Address	tvanheeke@rivian.com
Affiliation	Rivian Automotive
Subject	Comments on the ISOR for the Proposed Low Carbon Fuel Standard Amendments
Comment	Please see attached.
Attachment	www.arb.ca.gov/lists/com-attach/6904-lcfs2024-AXMAbwF2WGIHYANt.pdf
Original File Name	Rivian_CommentsISOR2024_FINAL.pdf
Date and Time Comment Was Submitted	2024-02-20 14:02:14

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

RIVIAN

February 20, 2024

Clerks' Office
California Air Resources Board
1001 I Street
Sacramento, CA 95814

SUBMITTED ELECTRONICALLY TO: www.arb.ca.gov/applications/public-comments

Re: Proposed Low Carbon Fuel Standard ("LCFS") Amendments, Initial Statement of Reasons ("ISOR")

Rivian Automotive, LLC, ("Rivian") appreciates the opportunity to submit comments on the ISOR for this critical rulemaking. The LCFS is a proven emissions reduction policy and a powerful enabler of transportation electrification. To date, it has served a key role in the state's portfolio of complementary climate policies. We believe it can and must continue to do so if the state wishes to achieve carbon neutrality.

228.1 Consistent with the direction provided through workshops and a Board update in 2023, the ISOR proposes to strengthen the LCFS targets and make valuable changes to the regulation's infrastructure crediting provisions. In general, Rivian supports these proposals—particularly a one-time 'stepdown' in the carbon intensity ("CI") target and implementation of an auto-acceleration mechanism ("AAM"). However, we find that even more stringent CI targets could be appropriate. The ISOR also introduces a novel concept for reforming the Clean Fuel Reward ("CFR"). Rivian has long advocated for a larger role for automakers in earning and investing a share of residential charging base credit revenue. CARB should still consider the benefits of such an approach even if it decides to move forward with the new CFR concept in parallel. That proposal is potentially promising, but the implementation details will matter a great deal. To maximize the impact of a new CFR for medium- and heavy-duty ("MHD") vehicles, medium-duty zero-emission vehicle ("ZEV") pickups must be eligible and the CFR's governance structure reformed to include MHD ZEV manufacturers.

Keep the World Adventurous Forever

Founded in 2009, Rivian is an independent U.S. company headquartered in California. With over 16,000 employees across the globe, Rivian's mission is to Keep the World Adventurous Forever. Rivian's focus is the design, development, manufacture, and distribution of all-electric adventure vehicles, specifically pickups, sport utility vehicles ("SUVs"), and commercial vans. Key to the success of our mission, these vehicles will displace some of the most polluting conventional vehicles on the road today.

Rivian brought the first modern electric pickup to market in 2021 when we launched the R1T from our manufacturing facility in Normal, Illinois, followed shortly thereafter by the R1S SUV and the EDV commercial van for Amazon. The R1T and R1S—both medium-duty passenger vehicles ("MDPVs")—provide all-electric options in segments where added utility is a necessity. The R1T has an EPA-certified range of up to 410 miles. The R1S is certified at up to 400 miles. The truck also features 11,000lbs of towing capacity, while the R1S is a seven-passenger full-sized SUV. Both are well-equipped for off-roading in a range of climates. Separately, our Class 2b and 3 commercial vans eliminate tailpipe emissions from last-mile delivery. Rivian is committed to producing 100,000 vans for our launch customer, Amazon, with more than 10,000 already in service in more than 800 U.S. cities. The van is now also available for purchase by other fleet customers in addition to Amazon. Beyond our vehicle lineup, Rivian is also building a network of public DC fast chargers across the country known as the Rivian Adventure Network ("RAN"). More than 14 RAN sites with 84 dispensers are already up and running in California alone.

Rivian Welcomes the 2024 Rulemaking to Amend and Extend the LCFS

The LCFS is a keystone regulation in California's portfolio of climate policies. As the 2022 Scoping Plan stated, the LCFS "is the primary mechanism for transforming California's transportation fuel pool" in service of the state's climate goals.[1] Indeed, as an electric vehicle manufacturer and charging provider, the LCFS is a priority for Rivian precisely because of the role it plays in speeding the transition toward renewable fuels in the transportation and electricity sector.

The transition toward renewable fuels is happening faster than the LCFS is currently designed for. Overcompliance with the policy's CI targets has resulted in an overabundance of compliance credits in the market, pushing down prices. Low credit prices jeopardize the very market investments the LCFS relies on to achieve its goals. Amending and extending the policy to keep pace is crucial.

Rivian strongly supports a rulemaking this calendar year and key elements of the staff's proposal, including the:

- **One-time stepdown.** Throughout the workshop process, Rivian called for a one-time stepdown in CI targets and we applaud the inclusion of just such a provision in the ISOR. We recommended an evaluation of several alternatives, including the 18.75 percent reduction in 2025 ultimately
228.1 proposed in the ISOR. We anticipate the proposed adjustment will force a draw on the credit bank that could help rebalance the program. **CARB should finalize a one-time stepdown no later than 2025 and at least as stringent as the one proposed.** (The proposed adjustment to the 2010 baseline CI for ultra-low sulfur diesel would blunt the effect of the stepdown on diesel and might justify a more substantial one-time adjustment.)[2]
- **AAM.** As we and many other stakeholders have noted previously, overcompliance in the LCFS strongly suggests the need for an AAM. In 2022, for example, regulated entities exceeded California's CI target by more than 2.6 percentage points.[3] We anticipate a similar level of
228.2 overcompliance in 2023. Even with a stepdown and more stringent targets in place, in short order the LCFS could very well find itself right back where it is today, with the market consistently and significantly outpacing the policy's CI targets resulting in a credit glut. Absent an automatic ratchet, a policy response would be years away due to regulatory development timelines. Therefore, the staff proposal for an AAM is encouraging. **CARB should approve an AAM as part of the LCFS amendments.**

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[1] CARB, *2022 Scoping Plan for Achieving Carbon Neutrality*, 190.
[2] CARB, *Appendix A-1: Proposed Regulation Order, Proposed Amendments to the Low Carbon Fuel Standard Regulation*, Table 2, Footnote (a).
[3] CARB, *LCFS Data Dashboard*, available at www.arb.ca.gov/resources/documents/lcfs-data-dashboard.

Nonetheless, we believe the proposal would benefit from a reconsideration of more stringent CI targets. We offer comments on this and several other aspects of the ISOR below.

Consider Greater Stringency

228.3 CARB should bring the LCFS up to date, reflecting conditions in the transportation sector and clean fuels industries that have changed substantially since even 2018 when the Board promulgated the last round of regulatory amendments. This includes exponential growth in the sale of electric vehicles. Increasing the ambition of the regulation's CI targets should be a central pillar of the updates made in the current rulemaking.

Rivian views the staff's proposal for a 30 percent reduction in CI by 2030 as a big step in the right direction. However, we find that **a 30 percent target in 2030 is the minimum level of stringency the Board should consider. The Board should take a closer look at targets greater than 30 percent.**

We recognize that CARB must balance many concerns in this rulemaking, but a reconsideration of the costs and benefits of a more stringent schedule of CI reductions is warranted for several reasons.

1. **Evidence from the credit market suggests deeper CI reductions are possible.** Following the ISOR's publication, type 1 credit prices have fallen over 15 percent. According to CARB data, weekly average credit prices dropped week-over-week throughout the month following the ISOR's release. While not conclusive, this is strongly suggestive of a market conviction that the currently proposed targets can be comfortably achieved.

Chart 1. *Average weekly credit prices fell following the ISOR's publication.*[4]

228.9 2. **The ISOR's analysis shows that the more stringent Alternative 2 would deliver cost-effective additional emissions and public health benefits.** Relative to the baseline, Alternative 2 reduces more greenhouse gas ("GHG") emissions on an accelerated timeline and abates more NOx and PM2.5. In turn, the air quality improvements lead to a variety of public health benefits 11 percent more valuable, in dollar terms, than those delivered under the baseline proposal. Crucially, while

[4] Neste, *California Low Carbon Fuel Standard Credit Price*, available at www.neste.com/investors/market-data/lcfs-fuel-standard-credit-price.

regulated entities incur greater costs under Alternative 2, its GHG abatement cost—$58/ton—compares favorably with the baseline proposal's $57/ton.[5]

Staff cite higher credit prices under Alternative 2 as a reason to reject it. Rivian acknowledges that higher credit prices necessarily raise compliance costs and could introduce greater pass-through costs to some extent for day-to-day consumers of fossil fuels. However, the ISOR itself estimates that the alternative delivers a valuable and cost-effective trade-off in terms of environmental and public health benefits. The LCFS is fundamentally an emissions reduction policy aimed at addressing climate change and air pollution. Cognizant of the rapidly worsening consequences of climate change and a persistent air quality crisis in the state, we believe CARB should take seriously the alternative that cost-effectively accelerates GHG reductions and maximizes air quality improvements in the shortest possible time.

Moreover, CARB should consider how the higher credit prices modeled under Alternative 2 would play in the full arc of the LCFS regulation and against the backdrop of California's broader goals. By 2045, the ISOR proposes a CI reduction target of 90 percent, supporting the 2022 Scoping Plan objective of carbon neutrality and an 85 percent reduction in GHG emissions by the same year. Higher credit prices in the near term will call further investment in to the market today to support compliance with much more ambitious CI targets in the outyears. We believe this is a compelling reason to consider additional stringency in the pre-2030 timeframe.

3. **It is unclear whether the modeling baseline accurately accounts for EV market growth.** In Rivian's
228.10 analysis of the ISOR and supporting documentation, we found it challenging to identify and validate with certainty the assumptions regarding future EV volumes—and therefore future consumption of electricity as a transportation fuel—that underpin the agency's modeling. Underestimating future EV volumes would result in a conservative policy recommendation.

Rivian consulted the ISOR, the Standardized Regulatory Impact Assessment ("SRIA"), and the California Transportation Supply ("CATS") Model technical documentation cited by the SRIA.[6] We did not find a downloadable data file plainly documenting the EV stock and electricity consumption estimates underpinning the modeling conducted to support the ISOR. We respectfully request that CARB furnish this information, providing stakeholders with an unambiguous understanding of the EV population and energy demand figures relied upon by the staff.

What the SRIA and CATS documentation do provide, however, are narrative descriptions of the key assumptions. Specifically, we understand that annual light-duty EV stocks follow the Scoping Plan's

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[5] CARB, *Staff Report: Initial Statement of Reasons* (December 19, 2023), available at www.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf.

[6] CARB, *Appendix C-1: Standardized Regulatory Impact Assessment (SRIA), Proposed Amendments to the Low Carbon Fuel Standard Regulation* (September 9, 2023), available at www.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appc-1.pdf; CARB, *California Transportation Supply Model—Technical Documentation v0.2* (March 2023), available at www.arb.ca.gov/sites/default/files/2023-03/CATS%20Technical%20v0.2.pdf.

Proposed Scenario while heavy-duty EV stock numbers reflect those in EMFAC2021 v.1.02.[7] However, this raises at least two issues for clarification by staff.

- EV stock estimates in the Scoping Plan's Proposed Scenario do not reflect those found in other sources, including the dashboard maintained by the California Energy Commission ("CEC"). According to the CEC, EVs numbered approximately 1.1 million in California at the end of 2022, the last year for which CEC data are available.[8] Yet the Scoping Plan's Proposed Scenario estimates just 738,428 EVs on the road that year.[9] Similar discrepancies exist between the CEC and the Scoping Plan's Proposed Scenario for EV sales. To the extent that the Scoping Plan's assumptions consistently understate or are behind the curve of the true pace of vehicle electrification in the California market, it will affect the modeling of CI reduction targets.
- To the best of our knowledge, EMFAC2021 does not incorporate expected compliance with the Advanced Clean Fleets ("ACF") rule.[10] CARB promulgated ACF after finalization of EMFAC2021. Yet the SRIA states clearly that ACF is "represented in the baseline."[11] The CATS documentation states that heavy-duty stock numbers, specifically, flow from EMFAC2021 but that the BEV-FCEV split mirrors the adjustment factors used in the ACF's development.[12] Ultimately, we find the combined descriptions opaque and remain unsure of the MHD EV stock assumptions used in the ISOR. If staff modified EMFAC2021 or took other steps to account for ACF, the ISOR and supporting documentation should explicitly say so.

To clarify these issues, Rivian recommends that CARB publish its EV stock assumptions in a clear and digestible format for stakeholder review. At a minimum, publishing a clear database of model inputs aids transparency and would avoid confusion. An accurate, verifiable, and up-to-date picture of the on-road EV population in California is vital for developing an LCFS regulation that maximizes its potential.

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[7] *Id.*, 6; CARB, *Appendix C-1: Standardized Regulatory Impact Assessment (SRIA), Proposed Amendments to the Low Carbon Fuel Standard Regulation* (September 9, 2023), SRIA-11.
[8] California Energy Commission, *Light-Duty Vehicle Population in California*, available at www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics/light-duty-vehicle.
[9] Energy and Environmental Economics, California PATHWAYS Model Outputs (May 2, 2022), spreadsheet available at www.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents. In the Scoping Plan documentation, California reaches 1.1 million EVs on-road a year later in 2023.
[10] Other stakeholders appear to share this understanding, including consultancy ICF, per ICF Resources, *Analyzing Future Low Carbon Fuel Targets in California: Accelerated Decarbonization in California's Transportation Fuels Sector* (September 2023), available at www.static1.squarespace.com/static/5b57ab49f407b4a7ffa44ffa/t/65170a31c95f5b288d3074d0/1696008770133/230928+LCFC+re.+ICF+Analysis.pdf.
[11] CARB, *Appendix C-1: Standardized Regulatory Impact Assessment (SRIA), Proposed Amendments to the Low Carbon Fuel Standard Regulation* (September 9, 2023), SRIA-11.
[12] ICF Resources, *Analyzing Future Low Carbon Fuel Targets in California: Accelerated Decarbonization in California's Transportation Fuels Sector* (September 2023), 6.

Expand and Extend Fast-Charging Infrastructure ("FCI") Pathway Credits

228.4 Rivian welcomes the qualified extension of light-duty ("LD") FCI crediting in low-income, rural, or disadvantaged communities as well as the expansion of the FCI pathway to include medium- and heavy-duty ("MHD") FCI at both public and private sites.

Public LD FCI projects merit continued regulatory support through the FCI pathway. Building public confidence in the availability of charging infrastructure remains a top priority, especially in low-income, rural, or disadvantaged communities. Rivian's RAN product is intended to support EV adventure and exploration in every corner of the country. Coupled with our highly capable pickup and SUV offerings, serving rural communities with relatively lower utilization is aligned with the company's mission and the purpose of our vehicles and charging product. We look forward to leveraging the FCI pathway to expand the footprint of RAN into high-need regions across California. We appreciate that the proposed regulation defines rural, low-income, and disadvantaged locations in an easily understood and implementable manner consistent with existing definitions found elsewhere in California law. This is crucial for smooth implementation by charging providers.

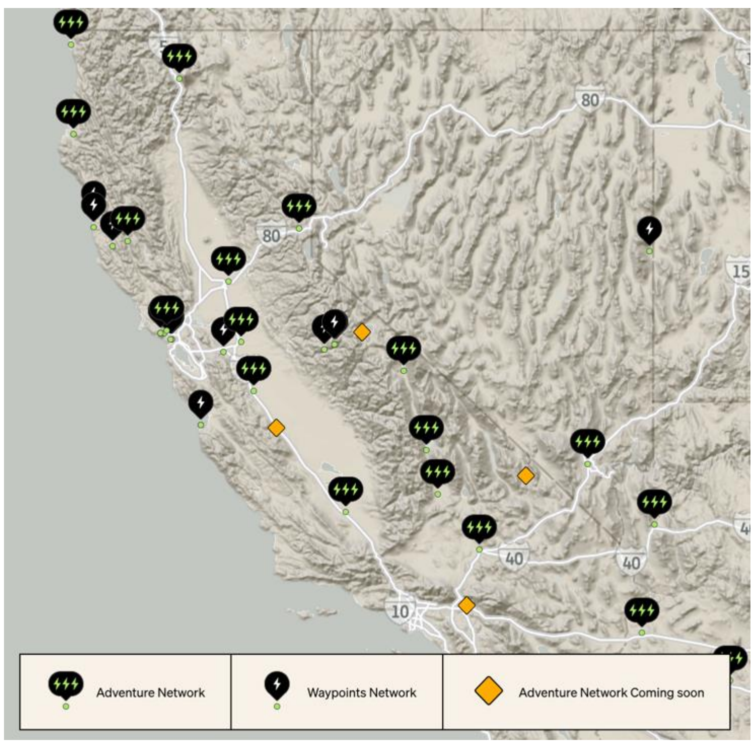

Figure 1. *Rivian's charging network is growing across California.*

We urge CARB to reconsider the cap on credits in this pathway, currently proposed at 0.5 percent of deficits from the prior quarter. Deploying public chargers remains as important today as it is financially challenging—all the truer in high-need regions of the state. As the lack of charging infrastructure is often cited as the number 1 concern for prospective EV owners, this is not the time to cut back on regulatory support for vital infrastructure.[13] **Rivian strongly recommends preserving the existing limit of 2.5 percent of deficits from the prior quarter.**

The expansion of the FCI pathway to MHD infrastructure is a welcome development that Rivian supported conceptually throughout the workshop process. Capacity-based crediting will bolster the business case for early deployment of MHD FCI investments, which in turn will build confidence in the viability of MHD EV products and drive their sale and use. Additionally, allowing private-facing fleet chargers to qualify is a crucial addition to the pathway, coming at a moment of accelerating efforts to electrify MHD fleets in compliance with ACF mandates. As the staff rightly acknowledge, installing private FCI for MHD EVs can be a challenging financial proposition and the possibility of earning credits via the MHD FCI pathway could complete the capital stack for important projects across the state.

Establish a Pragmatic Approach to Third-Party Verification

The ISOR proposes to introduce third-party verification requirement for an expanded list of electricity credit pathways. This includes a proposed requirement that verifiers "annually visit each facility; and, if
228.5 different from the fuel production facility, the central records location for which the records supporting an
application or report subject to verification are submitted."[14] Notably, the proposed regulations only exempt unmetered residential EV charging implying that third-party verifiers must conduct site visits for metered residential charging.

We urge CARB to reconsider the proposals and establish pragmatic requirements that account for real-world implementation concerns. In this regard, we align ourselves with the recommendations of other stakeholders including 3Degrees and Bridge to Renewables.

- **Reduce the site visit burden for non-residential charging.** In the case of designated reporting entities or entities exceeding a reasonable registered FSE count threshold, require that verifiers need only visit the designated reporting entity's central location for recordkeeping and a reasonable sample of facilities. California is home to thousands of pieces of FSE. It is simply not feasible nor cost-effective to require regular visits to each. CARB could also consider alternative approaches, such as attestations for registered FSE like those required under Oregon's regulation.
- **Exempt metered residential charging from site visit requirements.** Site visits to residential locations would be impractical, raise privacy concerns, and incur costs—estimated by the staff at $6/MWh—that would significantly erode the economics of the incremental credit pathway. The implications of potentially disincentivizing automaker generation of incremental credits include relatively more carbon-intense EV charging, diminished market pressure to accelerate the development of renewable electricity generation, and the potential loss of the best available data on residential EV charging, which CARB now uses to establish base credit volumes. We also note a fairness concern in that non-metered charging, used to generate far more lucrative base credits for utilities, are not subject to verification requirements. CARB should direct staff to revise the final

[13] Rob Schmitz and Camila Domonoske, *NPR*, "Major Sticking Point to Buying an Electric Vehicle is the Lack of Public Chargers," July 6, 2023, available at www.npr.org/2023/07/06/1186154285/major-sticking-point-to-buying-an-electric-vehicle-is-the-lack-of-public-charger.

[14] 17 CCR §95501(b)(3)). Rivian acknowledges that the proposed regulation order includes a provision for "less intensive verifications" in certain circumstances. But even if utilized this does not eliminate the costly and infeasible burden of a site visit to each facility at least once every three years.

regulatory language in §95500(c)(1)(E)(1) to state, "EV Charging except as specified under 95491(d)(3)(A) *and 95491(d)(3)(B)*" (new text in italics). This would exempt both metered and non-metered residential charging from third-party verification.

Align Low-CI Electricity Requirements with Other Clean Fuels Programs

228.6 CARB should make renewable energy certificates ("RECs") supplied by generation assets in the entire Western Electricity Coordinating Council (WECC) footprint, and not just directly transmitted into the state, eligible to meet the requirements for low-CI electricity pathways. Broadening REC generation eligibility would incentivize the buildout of renewables where they can have a greater avoided emissions impact and harmonize with the rules governing similar pathways in the Oregon and Washington clean fuels regulations. Increasing the REC supply would also protect against the potentially unintended upward cost pressure we have already seen from limiting eligibility to only resources in-state or directly transmitted into the state. Inflated REC prices, coupled with a depressed LCFS credit price, could undermine participation in the low-CI electricity pathway. We believe a reconsideration of REC eligibility would strike a balance between supporting the development of impactful projects while protecting against the unintended consequences under the existing rules.

Maximize the Impact of Residential Charging Base Credits

228.7 In previous comments, workshop input, and engagement with CARB, Rivian advocated consistently for a fresh approach to the use of revenue earned from residential EV charging base credits. We welcome staff and Board consideration of alternative structures and uses for base credit revenue.

Rivian previously recommended regulatory amendments that allow for EV manufacturers to share in base credit generation. Clean fuels policies are intended to be market-based systems that create incentive structures for private sector investments by the providers and users of clean transportation fuels. In the light-duty vehicle sector, the two most important market participants are vehicle manufacturers and their customers. Consistent with the core principles of the LCFS, the policy should encourage the participation of these market actors and reward them for making investments in EVs.

Rivian's preferred approach would incentivize automakers to empirically substantiate its vehicles' residential charging activity with telematics data by allowing manufacturers to earn base credits in return. **With a sufficiently large allocation of base credits, manufacturers whose vehicles generate credits (light-duty and medium-duty) could operate the Clean Fuel Reward ("CFR") more efficiently and sustainably than under the utility-led framework.**[15] We were disappointed that the ISOR did not consider such a concept. With CARB's decision to sunset the Clean Vehicle Rebate Project, the CFR would be the last universally available EV purchase incentive in the state—a key tool for sustaining the EV market's growth into the mainstream of the consumer market.

The staff has instead proposed a significant revision to the allocation of base credits. The majority are now proposed to go to the 'holdback' pool, with the remaining credits supporting a reformulated CFR for MHD EVs (more on this below). If CARB finalizes this overall funding structure, **Rivian recommends that the**

[15] Rivian has previously submitted comments along these lines both individually and in partnership with shared-vision partners. See for example comments submitted by Rivian and in coalition with Audi, Tesla, and Bridge to Renewables.

Board award a durable and significant share of holdback credits to automakers on the condition that the
228.7a revenues fund investments to advance transportation electrification and lower the total cost of EV ownership. These investments could include all or some of the following, with an appropriate carveout for administrative costs:

- Annual dividend checks returned to customers, paying out the value of charging credits.
- Rebates on home EVSE purchases.
- Public charging infrastructure deployment.
- Vehicle-grid integration ("VGI") technology development and implementation.[16]

CARB could establish a 'menu' of investment options for automakers including several of the above categories, or others, to provide flexibility for participants. The regulation could prescribe additional detail. Automakers would report to the Board annually on their expenditures.

228.7b **In parallel, allocating remaining base credits to funding a CFR for qualified MHD EVs is potentially promising.** As a general proposition, Rivian strongly supports targeting additional incentive dollars at fleet buyers of MHD EVs. If the proposal to establish an MHD CFR can create a reliable and sustainable purchase incentive in place of the existing light-duty CFR, with its many challenges, it will be a welcome achievement.[17]

In recent years, CARB has rightly focused on abating emissions from the MHD sector, developing cutting-edge regulations including the Advanced Clean Trucks ("ACT") and ACF rules that will help push the pace of electrification in the MHD fleet. Rivian strongly supported both ACT and ACF. However, ACF's exemption for small fleets, coupled with their resource constraints and reduced appetite for risk, mean that regulators need to consider additional policy measures to spur the purchase of MHD EVs by those operators. Redirecting the CFR to incentivize small fleet purchases of MHD EVs is a potentially impactful change—albeit one that departs from the LCFS' first principles by using LCFS credit revenue earned by one set of market participants to incentivize behavior by another.

An additional benefit of an MHD CFR is that it could steer some LCFS benefits to take-home fleets. The regulation's current structure and flow of credits makes it impossible for owners of take-home fleet vehicles, such as medium-duty pickups and vans, to receive incentives under the policy. This is a major 'blind spot' of the LCFS and one that Rivian has highlighted in previous comments and engagement with CARB. Rivian continues to believe that allocating base credits to vehicle manufacturers would create the conditions for a more direct and efficient solution to this problem. However, to the extent that take-home fleet vehicles are disproportionately represented among the small fleets targeted by the MHD CFR, this proposal would use LCFS credit proceeds to benefit a population of vehicle owners and users that otherwise fall through the gaps of the policy.

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[16] VGI enables customers to fully extract the value of their vehicle as a load management tool and grid asset and help reduce costs for all ratepayers.

[17] The existing light-duty CFR proved volatile and unreliable, with administrators cutting the rebate's value and ultimately suspending the program entirely. Even if it were still active, the rebate as currently formulated excludes a growing lineup of EVs technically classified as medium-duty passenger vehicles that create significant credit value under the LCFS but exceed the light-duty vehicle definition used to define rebate-eligible vehicles.

If the Board elects to finalize the MHD CFR, Rivian stands ready to support implementation, beginning with careful consideration of the following key issues and concerns.

228.7c
- **Clearly make medium-duty ("MD") EV pickups eligible for the CFR.** MD pickups comprise approximately 60 percent of the MD truck and van market and those in turn account for the majority of all MHD vehicle sales.[18] Moreover, MD pickups are the workhorse of many fleets. A variety of EV pickup models now exist in the marketplace and can serve fleet needs. However, the state's main MHD EV incentive program, HVIP, categorically excludes pickups from incentive support. To achieve the state's targets for MHD electrification, EV pickups must receive the same policy support as other categories of MHD vehicles. CARB should direct that the full range of MHD EVs, including pickups when purchased by ACF-exempt fleets for fleet use, be eligible for the reformed CFR.

228.7d
- **Tier rebates by vehicle class.** CARB should direct that the CFR provide rebates tiered by vehicle class—making the most of the available resources and reflecting the often-substantial difference in the purchase price of MHD vehicles.

228.7e
- **Allow fleets to combine the CFR with other incentives, including HVIP vouchers.** To maximize the benefits and simplicity of the reformed CFR, it should be offered on the hood and by right to qualified fleet purchasers and made 'stackable' with other incentives, including HVIP vouchers. 'Stack-ability' is not just a matter of maximizing incentives for fleets, though that is a worthy objective in and of itself. It also provides certainty for fleets when budgeting for vehicle procurements, while streamlining program implementation for administrators who would not need to verify whether applicants have already applied for or received other incentives.

228.7f
- **Invite MHD ZEV manufacturers to participate in the governance of the CFR in partnership with the utilities.** As Rivian understands the proposal, the new CFR would be administered by the utilities much like the existing light-duty CFR. Light-duty manufacturers have historically been included in the CFR's governance structure in an advisory capacity. We recommend that the new CFR be guided by a collaboration between the utilities and MHD manufacturers. CARB should direct that a steering committee be formed comprising utilities and all major MHD ZEV manufacturers to collaborate on the details of the program's design and implementation.

The Board should clearly signal its intent that the CFR operate in accordance with the above recommendations.

Conclusion

Rivian welcomes the current rulemaking to revise and extend the LCFS. The LCFS is a powerful policy that, with the right reforms, can contribute even more to the state's efforts to address climate change and electrify transportation. Moreover, urgent action is needed to match the policy's CI reduction requirements with the real-world performance of the clean fuels market. Rivian recommends that CARB consider even greater stringency than proposed, implement an AAM, and finalize the FCI pathway amendments without a lower cap on credits in the LD FCI pathway. In addition, CARB should take a more pragmatic approach to third-party verification requirements for electricity crediting in both non-residential

[18] U.S. Environmental Protection Agency, *Multi-Pollutant Emissions Standards for Model Years 2027 and Later Light-Duty and Medium-Duty Vehicles: Draft Regulatory Impact Analysis* (April 2023), 3-10.

and metered residential contexts. Finally, Rivian reiterates the benefits of awarding automakers a share of residential base credits, whether in sufficient quantity to restore the existing CFR or to fund other investments in transportation electrification. If CARB decides to move forward with the reformed CFR for MHD EVs, we respectfully urge that MD pickups be eligible and MHD manufacturers be included in the program's advisory committee. As a manufacturer of MHD EVs, Rivian stands ready to support the design and implementation of an MHD CFR.

Rivian values this opportunity to provide feedback and is excited about the prospect of strengthening the LCFS. Thank you to the staff for all the hard work that goes into a rulemaking of this magnitude.

Please contact me with any questions about our comments. Rivian looks forward to the upcoming workshop and future Board hearing.

Sincerely,

Tom Van Heeke
Senior Policy Advisor
Rivian Automotive, LLC
641-888-0035 | tvanheeke@rivian.com

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Comment 238 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Greg
Last Name	Kester
Email Address	gkester@casaweb.org
Affiliation	California Assoc of Sanitation Agencies
Subject	Comments on LCFS Program
Comment	Please find attached comments from the California Association of Sanitation Agencies on the proposed revisions to the LCFS program
Attachment	www.arb.ca.gov/lists/com-attach/6905-lcfs2024-BzVWfVFiUzBVfgAy.pdf
Original File Name	2-20-24 CASA LCFS Comment Letter.pdf
Date and Time Comment Was Submitted	2024-02-20 14:02:05

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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CALIFORNIA ASSOCIATION of SANITATION AGENCIES

925 L Street, Suite 200 • Sacramento, CA 95814 • TEL: (916) 446-0388 • www.CASAweb.org

February 20, 2024

Matt Botill, Division Chief
Industrial Strategies Division

Cheryl Laskowski, Branch Chief
Transportation Fuels Branch

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Submitted electronically to:

Re: California Association of Sanitation Agencies Comments on the Low Carbon Fuel Standard Proposed Regulatory Revisions

Dear Mr. Botill and Ms. Laskowski:

The California Association of Sanitation Agencies (CASA) appreciates this opportunity to provide comments on the proposed revisions to the Low Carbon Fuel Standard (LCFS) as published January 5, 2024. For the reasons articulated below, CASA urges CARB to carve out the wastewater sector to
229.1 preserve use of our non-fossil renewable wastewater-derived biomethane (biogas) in the LCFS program indefinitely. We will continue to produce and capture the biogas, as well as strive to beneficially use (not waste) it for as long as we are performing the essential public service of wastewater and solids treatment with anaerobic digesters. We have made similar arguments during the Scoping Plan Update and the more recent development of the Advanced Clean Fleet (ACF) regulations. The CARB Board included language in the last paragraph of the adopted Resolution 23-13 (included at the end of this letter) accompanying the adoption of the ACF Regulations directing staff to work with sister regulatory agencies and CASA to ensure multiple long-term uses of our biogas.

CASA is an association of local California wastewater agencies, known as Water Resource Recovery Facilities (WRRFs), engaged in advancing the recycling of wastewater into usable water, as well as the generation and beneficial use of renewable energy, biosolids, fuel, and other valuable resources. Through these efforts we help create a clean and sustainable environment for Californians. Our members are focused on helping the State achieve its climate change mitigation mandates and goals, which include:

- Reducing short-lived climate pollutant (SLCP) emissions by accepting and co-digesting diverted organic (food) waste from landfills pursuant to SB 1383
- Reducing carbon intensity of transportation fuel by using the biogas we generate
- Providing 100 percent of the state's energy needs from clean and renewable sources
- Increasing soil carbon and carbon sequestration by land applying biosolids and supporting the Healthy Soils Initiative, Climate Smart Strategy, and Wildfire and Forest Resilience Action Plan

As we have noted in previous discussions and comment letters for both the ACF and LCFS regulations, the wastewater sector represents an important in-state partner for development of low-carbon fuels as well as for meeting SB 1383 organic waste diversion requirements. As documented in the report released in August 2020 assessing co-digestion capacity at WRRFs, the California State Water Resources Control Board (SWRCB) estimated total existing available wastewater digester capacity may be able to receive all food waste required to be diverted from landfills in California for co-digestion. This will exponentially increase the biogas produced and captured at WRRFs.

The wastewater sector is aligned with LCFS program goals, notably to diversify transportation fuels away from fossil fuel-based sources and achieve carbon neutrality. As noted by the SWRCB, WRRFs across California have the ability to increase co-digestion in support of SB 1383 implementation but can only do so if it is cost-effective. The economic analysis performed as part of the SB 1383 process identified use of the biogas (resulting from digesting the diverted organic waste) as a low carbon transportation fuel supporting the program's feasibility.

The LCFS program should continue to provide a viable incentive for co-digestion of diverted organic waste and the conversion of WRRF renewable biogas to biomethane transportation fuel. In addition to the ACF Regulations, we are concerned CARB's proposal to phase out the use of WRRF biomethane in the LCFS program by 2040 will further inhibit SB 1383 implementation. Implementation of SB 1383 is in its very early stages – however, 75% diversion of organics away from landfills is required by January 1, 2025. With implementation at WRRFs, co-digestion will increase significantly to meet the mandate, in turn, so will diversified uses of WRRF biogas. However, CARB is proposing to phase out the avoided landfill methane credit, which disincentivizes the production and use of non-fossil renewable organic waste-derived biomethane in the LCFS program. At the same time, CalRecycle incentivizes co-digestion in their regulations to implement SB 1383 by requiring jurisdictions that must divert organic waste to procure a corollary product of that diversion, including the use of biogas as a low carbon transportation fuel. While the LCFS program has not been widely utilized at WRRFs to date, we expect that to shift as co-digestion becomes more common. The success of SB 1383 hinges on the public wastewater sector accepting diverted food waste for co-digestion but that will only occur if it is cost-effective and we are assured of the ability to beneficially use all our biogas.

229.1 cont

We strongly urge CARB to preserve the use of our biogas as a viable low carbon fuel in perpetuity since it will always be produced and SB 1383 implementation hinges on its beneficial use. Similarly, the proposed ACF Regulations will also inhibit SB 1383 implementation by limiting the use of medium- and heavy-duty trucks using WRRF biogas-derived compressed natural gas to only those in our fleets as of January 1, 2024 – we have proposed that be extended to follow the implementation of SB 1383 and provide WRRFs a pathway for use of the increased biogas. As CASA noted in our comments on the proposed ACF Regulations (and CARB staff acknowledged this in their December 12, 2022 presentation), medium- and heavy-duty electric trucks and vehicles unique to the needs of our sector are not commercially available and we do not expect them to be for many years. Likewise, biogas-to-hydrogen as a transportation fuel for these vehicles is not yet commercially available or demonstrated, both research and demonstrations are necessary to advance that technology and we have offered to work with CARB on those efforts. In the meantime, state regulations and policy should promote biogas deployment using proven technology that most efficiently reduces GHGs to mitigate climate change while also complying with the Omnibus regulations.

CASA has previously had productive discussions with CARB where it seemed understood that multiple benefits are realized through co-digestion and that credit should be awarded for the GHG emission reductions achieved. This requires immediate further action by either developing new simplified calculators or integrating existing ones for sewage sludge digestion and diverted food waste digestion as a Tier 1 option. Rather than phasing out the use of WRRF-derived biogas from the program, prioritizing a diverted food waste pathway within a co-digestion system at WRRFs would encourage SB 1383 organic waste diversion as well as accelerate development of low-carbon fuel production from these systems. Certification of a fuel pathway for each individual co-digestion feedstock would be onerous and we suggest that the food waste contribution to biogas production be prioritized and prorated. We strongly recommend a simplified approach assuming a baseline biogas production from sewage sludge digestion operating within defined parameters (mean cell residence time, temperature, volatile solids destruction, etc.) and assume all additional biogas is the result of the additional organic waste feedstock, eliminating the unnecessary burden of excessive testing. A similar approach has been adopted by the USEPA as part of their Renewable Fuel Standard regulatory revisions in June 2023.

In order for the receipt of diverted food waste for co-digestion to be viable, it must be cleaned of contaminants so as not to have adverse impacts on equipment, the microbial community in the anaerobic system, nor on the biosolids which are another product of digestion. LCFS credits, particularly those with a negative carbon intensity (CI) value, could be a strong economic incentive to invest in the needed equipment and the ability to accept more food waste. To achieve the state's organic waste diversion and GHG emission reduction goals, it is critical that the appropriate pathways are established in an expeditious manner to provide this incentive. We strongly urge CARB staff to work with CASA and our members to extend and expand these pathways that can serve as a model for others.

Specific comments are as follow:

229.2

1. We support the increased reductions in carbon intensity as proposed. This includes a 25% reduction by 2025; a 30% reduction by 2030; and a 90% reduction by 2040.

229.1 cont

2. Section 95482(g): we disagree with the proposed phase out of the use of biomethane as a transportation fuel as articulated above.
3. Section 95488.9(f)(3): we disagree with the proposed phase out of avoided methane crediting for both biomethane and hydrogen from biomethane sources. The rationale is provided above.

We appreciate this opportunity to comment and your willingness to consider our recommendations. We look forward to continued collaboration to develop pragmatic solutions to these issues. Please let me know if we can set a time to meet for discussion of our recommendations. I can be contacted at gkester@casaweb.org or at 916-844-5262.

Sincerely,

Greg Kester

Greg Kester
Director of Renewable Resource Programs

cc: Adam Link, Executive Director, CASA
Sarah Deslauriers, Climate Change Program Manager, CASA
Rajinder Sahota, CARB
Anil Prabhu, CARB
Charlotte Ely, SWRCB
Chris Hyun, SWRCB
Mark de Bie, CalRecycle

Cara Morgan, CalRecycle

Last Paragraph of Resolution 23-13:
Be it further resolved that, consistent with the latest Scoping Plan, the Board recognizes that the successful implementation of the food waste diversion requirements and methane emissions reductions mandated by SB 1383 are critical to the State's climate goals. The Board further recognizes that multiple reliable uses for non-fossil biomethane will be needed for successful implementation. The Board recognizes the need for coordination meetings with other state agencies such as CEC, CPUC, State Water Resources Control Board, CalRecycle, CDFA, CNRA, California Division of Occupational Safety and Health, and other relevant stakeholders such as the California Association of Sanitation Agencies and the California Air Pollution Control Officers Association, to implement SB 1383 and SB 1440. As such, the Board directs staff to prioritize policy discussions related to SB 1383 and SB 1440 implementation and discussions on how to transition biomethane into hard to decarbonize sectors, or as a feedstock to produce hydrogen for FCEV fuel and to produce electricity to charge BEVs to achieve the SB 1383 target. The Board further directs staff to report to the Board by the end of 2025 on progress for alternative uses of biomethane, including identifying any appropriate regulatory actions as needed.

Comment Log Display

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Comment 239 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Chirag
Last Name	Bhakta
Email Address	cbhakta@fwwatch.org
Affiliation	Food & Water Watch
Subject	LCFS Rulemaking
Comment	Please find attached a letter from more than 160 groups from 25 states and the District of Columbia calling on Governor Newsom and the California Air Resources Board (CARB) to reconsider proposed rulemaking that doubles down on polluting factory farm biogas as the most lavishly incentivized transportation fuel under the state's Low Carbon Fuel Standard (LCFS). Thank you,
Attachment	www.arb.ca.gov/lists/com-attach/6906-lcfs2024-VTlWMwZhBSUAKwlm.pdf
Original File Name	LCFS-Org-Sign-On-Letter-_Formatted-2.pdf
Date and Time Comment Was Submitted	2024-02-20 14:09:20

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

FOOD & WATER WATCH
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LEADERSHIP COUNSEL FOR JUSTICE & ACCOUNTABILITY

February 15, 2024

Dear Governor Newsom and Members of the California Air Resources Board:

We write to express our collective concerns regarding the Air Resources Board's (CARB) proposed rulemaking that doubles down on polluting factory farm biogas as the most lavishly incentivized transportation fuel under the state's Low Carbon Fuel Standard (LCFS). Factory farm biogas is not clean energy, and CARB staff's embrace of this false solution for the next two decades throws Californians already subjected to some of the worst environmental pollution in the nation under the bus. The proposed amendments to the LCFS fly in the face of years of advocacy by environmental justice and climate advocates and blatantly ignore California's commitment to a just climate transition.

We call for immediate and meaningful action to fix the environmental injustices and abuses that have become inherent in the program and that the proposed amendments lock in place for over 20 more years.

California's LCFS, originally conceived as a tool to combat climate pollution in the transportation sector, has been exploited and manipulated by powerful corporations, particularly Big Ag and Big Oil. Rather than serving its intended purpose, the LCFS has become the nation's largest and most lucrative pollution trading scheme for factory farm biogas across the country.

In its current form, the LCFS rewards and entrenches some of the worst factory farming practices, both in California and across the country, providing lavish subsidies to operations that are getting paid to pollute. The program's flawed accounting practices assign factory farm biogas a lower "carbon intensity" than even solar and wind energy, creating a smokescreen for the continued pollution of the fossil fuel industry.

Polluters such as Chevron can offset their emissions by paying industrial factory farms to extract methane gas from on-farm waste. This so-called "biogas" is then traded in California's credit system, providing a misleading cover for continued pollution from fossil fuel operations.

Factory farm biogas' extremely negative carbon intensity scores are based on several fundamental flaws. First, CARB is ignoring greenhouse gas emissions from the underlying factory farming operations as well as the increased greenhouse gas emissions when operators use and dispose of the digester waste. Second, CARB refuses to acknowledge that methane emissions from livestock manure cesspools is a choice and can be avoided with more sustainable practices like dry manure handling. For years, the LCFS operated under a rational framework that did not assume perpetual free-venting of methane pollution from livestock operations. CARB staff made the change to today's perverse "avoided methane crediting" policy in 2019, kicking off a nationwide expansion of factory farm biogas operations—a concerning trend dubbed the "manure gold rush."

The existing LCFS rules perpetuate environmental injustice by disproportionately harming low-income communities and communities of color. Factory farms, predominantly located in these marginalized areas, cause severe harm to air, water, public health, rural economies, and overall quality of life. The extraction of methane from factory farm cesspools does nothing to alleviate the massive harm inflicted by mega-dairies and large factory farms on these communities.

This rulemaking package put forward by CARB staff claims to “Uplift Environmental Justice,” but entirely ignores the central environmental injustice that has been the focus of advocates' calls for LCFS reforms for over two years. Staff’s willful ignorance of how the LCFS is harming Californians is egregious and is the latest example of a rogue agency unwilling to hear the voices and lived experiences of those living near large dairies in the state.

This disregard is all the more stunning considering the Environmental Justice Advisory Committee's (EJAC) raised concerns with factory farm biogas in its resolution to reform the LCFS in this rulemaking to address the injustices embedded in the current program.

Governor Newsom's California Air Resources Board (CARB) has a pivotal opportunity this year to adopt a new rule that aligns the LCFS with California's environmental justice commitments. The Environmental Justice Advisory Committee has presented a clear and effective alternative to the current policies that reward polluters.

We demand the following reforms to the LCFS aimed at stopping incentives for factory farms and factory farm gas:

230.1 1. Eliminate "avoided methane crediting" in 2024.

230.2 2. Fix the inaccurate Life Cycle Assessment that ignores upstream and downstream GHG emissions associated with factory farm gas production.

230.3 3. Eliminate the 10-year "grace period" for factory farm gas producers.

230.4 4. Eliminate credit generation from factory farm gas projects that would have happened anyway due to other programs or investments

FOOD & WATER WATCH
Fight like you live here.

LEADERSHIP COUNSEL FOR JUSTICE & ACCOUNTABILITY

We demand a future free from the clutches of Big Oil and Big Ag, and we urge Governor Newsom and CARB to prioritize the well-being of Californians over the profits of corporations looking to exploit the climate crisis.

Governor Newsom, CARB has the power to shift California towards truly clean energy solutions and remove the incentives for factory farms to produce and sell dirty credits that enable the continued reliance on Big Oil and combustion fuels. You have spoken eloquently about the need to take bold climate action rooted in justice, but this is one major area where California not only falls short, but has a policy that is making the climate and pollution crisis worse. You can change this. We appreciate your attention to this critical matter and look forward to seeing decisive action taken to reform the LCFS and protect the communities most affected by its current flaws.

Sincerely,

Chirag Bhakta
Food & Water Watch

Emily Brandt
San Joaquin Valley Democratic Club

Matthew Baker
Planning and Conservation League

Jan Dietrick
350 Ventura County Climate Hub

Jennifer Hauge
Animal Legal Defense Fund

Ellie Cohen
The Climate Center

Nicholas John Ratto
350 Bay Area Action

Jean Mendoza
Friends of Toppenish Creek

Phoebe Seaton
Leadership Council for Justice and Accountability

Antonio Tovar
Farmworker Association of Florida

Barbara Sattler
California Nurses for Environmental Health and Justice

David Muraskin
FarmSTAND

Jack Eidt
SoCal 350 Climate Action

Nancy Utesch Kewaunee
CARES

Lisa Whelan
Iowa Citizens for Community Improvement

Marti Olesen
Buffalo River Watershed Alliance

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LEADERSHIP COUNSEL FOR JUSTICE & ACCOUNTABILITY

Shoshana Wechsler
Sunflower Alliance

Susan Penner
1000 Grandmothers for Future Generations

Bob Musil
Rachel Carson Council

Cari Gardner
NYPAN Greene

Andrea Pierce
Anishinaabek Caucus of the Michigan Democratic Party

Joanie Steinhaus
Turtle Island Restoration Network

Sarah Stewart
Animals Are Sentient Beings, Inc.

Peggy Ann Berry
Between the Waters

Haley Ehlers
Climate First: Replacing Oil & Gas (CFROG)

Paddy McClelland
Wall of Women

Alan Weiner
350 Conejo / San Fernando Valley

Matt Leonard
Oil and Gas Action Network

Stephen Brittle
Don't Waste Arizona

Jerry Rivers
North American Climate, Conservation and Environment (NACCE)

Jean Ross
Vote Climate

Tara Thornton
Endangered Species Coalition

Liz Ndoye
MoveOn.org Hoboken RESIST

Lewis GrassRope
Wiconi un tipi

Jodi Lasseter
NC Climate Justice Collective

Paul Norland
ICRA Worth County

Lynn Saxton
The Climate Reality Project, Western New York Chapter

Barbara W Brandom, MD
Concerned Health Professionals of Pennsylvania

Timothy Edward Duda
Terra Advocati

Brian Eden
Campaign for Renewable Energy

Harry Rhodes
Food Animal Concerns Trust (FACT, INC)

Liz Kirkwood
For Love of Water (FLOW)

Nathan Taft
Stand.earth

Sandra NA Kissam
Orange RAPP

John E. Peck
Family Farm Defenders

Matt Nelson
Presente.org

Ken Dolsky
Don't Gas the Meadowlands Coalition

Ryan Madden
Long Island Progressive Coalition

Dineen O'Rourke
350PDX

Sally Jane Gellert
Occupy Bergen County

Carter Dillard
Fair Start Movement Advisor

Dashel Murawski
Center for Food Safety

Mary Smith
Church Women United in New York State

Sonia Demiray
Climate Communications Coalition

Diana Bohn
Nicaragua Center for Community Action

Dave Swanson
Grant County Rural Stewardship

Mary Gutierrez
Earth Ethics, Inc.

John Farais
Indigenous Edibles

Nora Nash
Sisters of St . Francis of Philadelphia

Melissa Vatterott
Missouri Coalition for the Environment

Manny Rutinel
Climate Refarm

Yvonne Taylor
Seneca Lake Guardian

Ethan Duke
Missouri River Bird Observatory

Trevor McCarty
Farm Forward

Danielle M. Wirth
Environmental Horizons, Partners

Fran
Unite North Metro Denver

Christine Reid
Friends Of the Forestville Dam, Inc.

Steven
Door County Environmental Council Inc

Alex Cerussi
Mercy For Animals

Janice Brown
CASE Citizens Alliance for a Sustainable Englewood

Terry Lowman
Unitarian Universalists for a Just Economic Community

David Meyer
Food System Innovations

Susan Williams
MONITEAU County Neighbors Alliance

Gail Eisnitz
Humane Farming Association

Maddie Kempner
Northeast Organic Farming Association of Vermont (NOFA-VT)

Annette Manusevich
World Animal Protection

Molly Armus
Friends of the Earth

Gary J. Lessard
Schenectady Neighbors for Peace

Rudy Arredondo
Latino Farmers & Ranchers International, Inc.

Beth Brunton
South Seattle Climate Action Network

RL Miller
Climate Hawks Vote

Andrea O'Ferrall
Extinction Rebellion Seattle

Riddhi S. Patel
Center on Race, Poverty & the Environment

Miranda Eisen
Farm Sanctuary

Barbara Chicherio
St. Louis Green Party

Patty Hine
350 Eugene

Melody Torrey
Missouri Stream Team 714

Edith Kantrowitz
United for Action

Frank James
Dakota Rural Action

William Brieger
350 Sacramento

Matthew Sheets
Land Stewardship Project

Ben Lilliston
Institute for Agriculture and Trade Policy

Sherri Dugger
Socially Responsible Agriculture Project

Megan Betz
Mother Hubbard's Cupboard

Lora Fraracci
On Behalf Of Future Generations

Edith Haenel
ICRA - Iowa Citizens for Responsible Agriculture Worth County

Valerie Vetter
Poweshiek CARES

Marven Norman
Center for Community Action and Environmental Justice

Kim Dupre
St. Croix County Defending Our Water

Patty Lovera
Campaign for Family Farms and the Environment

Igor Tregub
CADEM Environmental Caucus

Pauline Seales
Santa Cruz climate action network

Jennifer Scarlott
Bronx Climate Justice North

Sandra Adams
350 Pensacola

Jennifer Scarlott
North Bronx Racial Justice

Mary Shesgreen
Fox Valley Citizens for Peace & Justice

Beth Brunton
350 Seattle

Cheryl Frank
ColorBrightonGreen
Eco Justice Collaborative
GBC Sustainability Team

John alder
Pjals

Katie Ruth
Pennsylvania Interfaith Power & Light

Mariel Nanasi
New Energy Economy

Martha Dina Argüello
Physicians for Social Responsibility - Los Angeles

Roberta Stern
Therapists for Peace & Justice

Georgina Shanley
Citizens United for Renewable Energy (CURE)

Kimi Wei
The Wei LLC

Laura Neish
350 Bay Area Executive Director

Kyle Ferrar
FracTracker Alliance

Meghan Sahli-Wells
Elected Officials to Protect America

Amelia Keyes
Communities for a Better Environment

Chelsea Davis
Animal Rights Collective Portland (ARCPDX)

Haleemah Atobiloye
Breast Cancer Action

Carlos Orbe, Jr.
Maryland Latinos Unidos

Leah Redwood
Extinction Rebellion San Francisco Bay Area

Diane Rosenberg
Jefferson County Farmers & Neighbors, Inc.

Jason Pfeifle
Center for Biological Diversity

Lee McNair
Cedar Lane Environmental Justice Ministry

Liza Tucker
Consumer Watchdog

Kristin Ostrom
Oregon Rural Action

Joyce Lane
SanDiego350

Dave Arndt
Maryland Legislative Coalition Climate Justice Wing

Kate Baildon
Northeast Organic Farming Association of New York (NOFA-NY)

Andrew Hinz
Beyond Extreme Energy

Tina Weishaus
DivestNJ

Mark Lesko
Highland Park Ecology and Environmental Group

Karen Feridun Berks
Gas Truth

Ted Glick
350 NJ - Rockland

Diane Wexler
Northjersey Pipeline Walkers

Rachel Dawn Davis
Waterspirit

Karen Elias
No False Solutions PA

Marci Henzi
Green Party of US

Paula Rogovin
Coalition to Ban Unsafe OIl Trains

Jay Notartomaso
NEPA Green Coalition

JANE POPKO
LPA

Guy Jacob
Nassau Hiking & Outdoor Club

Joseph Bouvier
South Jersey Progressive Democrats

Michael Stocker
Ocean Conservation Research

Karen Feridun
Better Path Coalition

Collin Rees
Oil Change International

Hannah Tremblay
Farm Aid

Alan Minsky
Progressive Democrats of America

Rebecca Roter
Breathe Easy Susquehanna County

Jean Ross
Vote Climate

Charles Loflin
Unitarian Universalist Faith Action NJ

Sherry Pollack
350 Hawaii

Sharon Furlong
Bucks Environmental Action

Keith E. Iding
Northwest VEG.org

Teryn Yazdani
Beyond Toxics

Carol E Gay
NJ State Industrial Union Council

Mary Gutierrez
Earth Ethics, Inc.

Ruth Kastner
The Quantum Institute

Peggy Ann Berry
Between the Waters

Veronica Wilson
Labor Network for Sustainability

Barbara W Brandom, MD
TIAA-Divest!

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Comment 240 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Evan
Last Name	Neyland
Email Address	evan.neyland@chargepoint.com
Affiliation	ChargePoint
Subject	ChargePoint comments on Dec 2023 LCFS amendments

Comment

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: ChargePoint Comments on Proposed Low Carbon Fuel Standard Amendments

Thank you for the opportunity to submit comments on the proposed amendments to the Low Carbon Fuel Standard (LCFS) issued on December 19, 2023. ChargePoint has reviewed the Proposed Regulatio Order and appreciates the work of the California Air Resources Board (CARB) Staff to implement changes to LCFS that will advance investment in low carbon fuels and infrastructure in California.

About ChargePoint

Since 2007, ChargePoint has been committed to making it easy for businesses and drivers to go electric with one of the largest electric vehicle (EV) charging networks and a comprehensive portfolio of charging solutions. ChargePoint's cloud subscription platform and software defined charging hardware is designed internally and includes options for every charging scenario from home and multifamily to workplace, parking, hospitality, retail, corridor, and fleets of all kinds.

Summary of comments

•Expand the scope of "less intensive verification" for on-road electricity crediting to allow for networked charging stations tha meet certain requirements to be pre-approved. Entities that do not meet the requirements for less intensive verification could still undergo full verification.
•Remove the exemption for dedicated parking spaces under multifamily crediting and allow owner/operators to claim credits o all stations at multifamily locations.
•Regarding the MHD-FCI provision: (1) relax the siting requirement to within 5 mi of a FHAA corridor, (2) reduce the minimum kW nameplate capacity to 200, (3) consider shortening the FCI crediting window to 7 years, and (4) roll unutilized LD-FCI

capacity into the MHD-FCI provision to increase deployments.
•Take greater action to stabilize the credit market, either throug
supply-side intervention or more stringent carbon intensity targets. Increase the step down to 10%.
•Modify the Automatic Acceleration Mechanism (AAM) formula to trigger once the credit bank exceeds three-fifths of the prior year's deficits, instead of three-fourths.

Requirements for less intensive verification

The inclusion of on-road electricity crediting in the verificatio program is not a small lift and needs to be done thoughtfully. Therefore, we suggest CARB consider putting off including electricity verification in this rulemaking given the many other issues being considered. However, if CARB believes that on-road electricity reports must undergo third-party verification under th amended regulation due to largescale risk of misreporting (which t our knowledge, there is currently no evidence of), CARB should lea on existing technology, standards and relevant regulations when designing verification. To that end, we appreciate CARB's inclusio of a "less intensive verification" pathway in the proposed rules but believe that this does not go far enough. The less intensive verification pathway should be expanded to consider the following

The EV charging network is fundamentally different than the traditional point-source liquid fuel supply network: whereas liqu fuels originate from fewer and larger sources (refineries), EV charging stations are significantly more disaggregated, where each point (or charger) in the network represents a small amount of potential fuel supply which renders physical site visits across th whole network impractical and costly. For meter accuracy assuranc CARB should instead lean on accuracy thresholds that already exis in the industry, such as those within the California Type Evaluation Program (CTEP), which require that level 2 (L2) EV charging meters meet an accuracy threshold of ±1% upon manufacturing and calibration and ±2% over its useful life, while level 3 (L3) meters must meet a ±2.5% accuracy upon manufacturing and calibration and ±5% over its useful life. The CTEP standard is already being utilized by the California Division of Measurement Standards (DMS), the entity tasked with ensuring the accuracy of commercial devices, including EV charging stations. DMS sets standards to promote fair competition and ensure consumer protection and points to the CTEP as the metrological accuracy standard that chargers installed after a certain date must meet to be used for commercial purposes. County Weights & Measures offices under the guidance of statewide rules established by DMS, serve to enforce the standards by conducting periodic site visits to verify the accuracy of fueling stations.

Recommendation: CARB should pre-approve charging stations that meet CTEP's meter accuracy standards for participation under the less intensive verification pathway.

Pre-approval would mean exempting eligible charging station models from site visits and third-party meter testing based on that model's meter accuracy substantiation. CARB could publish a list of exempt charging station models that meet CTEP's meter accuracy standards for credit generators' reference. This is similar to the approach taken under Canada's national Clean Fuels Regulation. Otherwise, the existence of the DMS framework for assessing and enforcing charger accuracy would render additional site visits and meter testing, even only in half of the years as currently proposed under the "less intensive verification" pathway, under the LCFS program duplicative and punitive on the industry, particularly for small owner/operators .

With assurances around charging station meter accuracy ensured by the accuracy standards embedded in CTEP, the final step to less intensive verification would be a "desktop" review of the data in the reports. The scope of the desktop review would be to ensure that the data in the quarterly reports submitted through the LRT matches the data that was output from the charging network. EV charging networks are underpinned by extremely accurate (down to the watt-hour), real-time data in a way that traditional liquid fuel networks are not . Networked EV charging provides a near constant stream of data that can be verified against reported charging activity.
There are a number of standards, practices, technologies and processes charging network operators adhere to to ensure the accuracy of data. For example, ChargePoint complies with several

standards to ensure that the data reported by the station maintai
its accuracy as it is transferred from the station to the cloud, and that any data anomalies are detected and removed before being reported. Many network operators also maintain compliance with Payment Card Industry Data Security Standards (PCI DSS) to ensure an accurate and secure environment for network transaction data. CARB could pre-approve networks that meet certain standards for u
under the less intensive verification pathway, similar to pre-approving charging station models based on meter accuracy. Standards and documents required for pre-approval could include SOC2 reports and/or PCI certification.

Our recommendations for the less intensive verification pathway a
not necessarily meant to be prescriptive, but rather to point out how existing technologies, best practices, and standards already widely adopted in the industry should be incorporated into the pathway. This will greatly minimize administrative costs for an industry that is still scaling. This is also the general approach taken under Canada's national program. We urge CARB to not try an
reinvent the wheel re: on-road electricity verification. Reportin
entities that do not meet the requirements for less intensive verification would still be able to undergo full verification.

Credits for non-residential chargers at multi-family residential properties.

ChargePoint strongly supports the proposal to allow FSE owners to generate credits for stations installed at multifamily properties This change will create more revenue opportunities for property owners that install chargers at multifamily locations, and critically, incentivize more deployment of chargers for residents of multifamily homes, a market segment that has historically lack
investment.

Recommendation: remove the exemption for dedicated parking spaces and allow owner/operators to claim credits at all multifamily locations.

While we fully support the proposal to treat multifamily creditin
the same as non-residential, we do not agree with the proposal to treat chargers in dedicated parking spaces differently. Not only will the exclusion of restricted parking spaces be extremely

difficult to track, but it also arbitrarily distinguishes credit generation based on a residence's parking arrangement. Recent analysis by the CEC indicates that expanding the range of charging options available in the parking lots of multifamily housing will ensure charging is not a barrier to EV adoption. Increasing home charger access for residents of multifamily homes must be a priority to equitably meet the routine charging needs of more EV drivers, and for this reason, we strongly support this change by CARB.

Residents of multifamily housing are generally not able to install conventional home charging without financial assistance from the building owner. This is because charger installation at multi-family properties often requires upgrades to shared electrical panels and running conduit across common parking areas A single household of a multifamily residence is generally unable or unwilling to shoulder the high cost of charger installation themselves. In other words, there is a "split incentive" affecting multifamily properties in which a property owner must pay for and organize installation, while the chargers may only benefit the fraction of residents who drive EVs at the time of the upgrade.

In fact, there is a case to be made that chargers in dedicated multifamily residential parking places may have the most impact on those residents switching to electric and should therefore be supported by the LCFS through the ability to generate value from credit generation. This is especially true considering CARB's proposal to redirect funds from the Clean Fuel Reward (CFR) progra towards MHD EVs (which we also strongly support). Whereas before, CFR value was generated by residential (including multifamily) charging so it made sense to return some of that value to individual EV drivers via LD EV rebates. If CFR value will now go towards MHD EV rebates, it only seems right to allow owner/operators of multifamily chargers to retain the value of the LCFS which can help finance or buy down the cost of the station.

Medium and heavy duty (MHD) Fast Charging Infrastructure (FCI) credits

ChargePoint strongly supports the addition of the MHD FCI provision. While the passage of the Advanced Clean Fleets and Advanced Clean Trucks regulations are expected to create greater demand for MHD EVs, infrastructure development to support these vehicles remains economically challenging due to the lack of MHD vehicles on the road today and the expectation that it will take time for the market to grow. The expansion of FCI credits for both private and shared MHD FCI is a much-needed intervention to commercialize charging infrastructure and help stimulate investment for this segment. ChargePoint also appreciates the inclusion of shared private fleet chargers in this program. Nonetheless, a few revisions to the rules for MHD FCI credits will allow the program to support the nascent MHD refueling market more effectively.

Charging hubs for MHD vehicles are likely to require several megawatts of power for each site. These projects will in most case require significant distribution grid upgrades by the utility. Due to the complex factors that inform site selection for MHD charging sites, including but not limited to access to travel corridors, proximity to vehicle routes, distribution grid capacity, and land acquisition, it remains unclear which locations will be the most efficient to locate private or shared MHD charging hubs. For this reason, overly narrow location requirements for MHD FCI sites may impede development by eliminating projects that would otherwise be ideal due to ample grid capacity. While we understand CARB's inter for the FCI program to focus charger deployment in alternative fue corridors for the purposes of accessibility and equity, station owners and drivers would benefit from less stringent geographic limitation.

Recommendation: relax the geographic siting requirement to 5 mi from a FHAA fuel corridor to provide flexibility for site selection.

The amendment proposal establishes a minimum power level of 250 kW for chargers serving sites that receive MHD FCI credits. The minimum power level established for MHD-FCI sites should consider today's MHD fleet needs, as well as the anticipated needs of the future. For most MD vehicles on the road today, 200 kW is more tha sufficient for the vehicle's needs and helps lower overall system costs (relative to 250 kW or greater). Therefore, ChargePoint recommends that CARB reduce the minimum power level for each charger serving MHD FCI to 200 kW, as this minimum is sufficient t meet the market where it is today, as well as accommodate the need of coming MHD vehicles.

Recommendation: reduce the minimum kW eligibility requirement to 200 from 250.

Regarding the MHD-FCI crediting window, while some sites will neec a 10-year window to recoup capital costs, a longer window could encourage overbuilding and disincentivize utilization in the shor to mid-term, both of which are not ideal for the market. We belie a crediting window closer to 7 years will suffice for the majorit of projects and encourage sites to build for utilization sooner rather than later. This should also free up more capacity under tl MHD-FCI cap sooner which will open up capacity for more sites ove time.

Recommendation: consider shortening the MHD-FCI crediting window 1 7 years.

The CEC reports that as of 2023, California has over 9,000 DCFC ports in operation and is ahead of schedule to meet its port deployment target of 10,000 ports by 2025. ChargePoint believes I FCI revenue has successfully accelerated investment in the market for public DCFC and is partly responsible for the state's success in this segment. When paired with the continued growth of LD EV sales in California, it seems clear that continued investment in LD-FCI can sustain itself without greater support from FCI credit By contrast, the MHD segment would benefit from greater FCI suppo because it is underdeveloped relative to the state's goals. The C estimates that by 2030, California's 155,000 MHD EVs will need about 114,500 public and shared chargers.

To further accelerate the market for MHD electrification, we recommend CARB rollover any unused LD-FCI credits into the MHD ca to allow for greater investment/deployments in this segment (more on this below).

Revised Clean Fuel Reward Program

ChargePoint supports the proposal to redirect funds from the CFR program to make MHD EVs more cost-effective. The current framewor of allocating CFR funds towards LD EV rebates has long since lost efficacy as the rebate amount is not salient to prospective EV drivers to the point where it induces additional purchases.

ChargePoint is pleased to see this change as the current state of the MHD EV market is more in need of funding than the LD segment.

Light duty FCI credits

The proposed regulation establishes a transition plan to reduce F(crediting available for LD DCFC applicants. Among other changes, the proposal amends the cap for LD FCI credits to 0.5% of prior quarter deficits, a reduction from the previous cap of 2.5%. ChargePoint supports this change and agrees that LD-FCI credits should be capped to no more than 0.5% to focus infrastructure crediting on the more nascent MHD EV market. As discussed previously, ChargePoint believes MHD-FCI should be the priority ar recommends CARB consider further reduction in the availability of LD-FCI credits in favor of a higher cap on MHD-FCI credits.

Should the LD-FCI pathway remain open beyond 2025, ChargePoint believes it would be premature to limit eligibility to stations with a nameplate capacity of 150 kW or more in light of the other proposed changes to the pathway. A station capacity minimum of 15(kW combined with the change to how FCI charging capacity is calculated as well as the extension of the crediting timeline to 1 years will together incentivize overbuilding sites without regard to utilization solely because of FCI credits.

New carbon intensity benchmarks

In the weeks following CARB's release of its amendment package in mid-December, the spot market for credit prices declined ~20% (falling from $70/credit to a low of $57/credit). In that time, th market incorporated CARB's proposal of a 30% carbon intensity (CI) target by 2030, along with the proposed changes to the supply side and determined that this market will continue to be oversupplied. Without more ambitious CI targets and/or clearer steps to curb biofuel production with uncertain greenhouse gas benefits (Murphy Wook, 2024) , it is apparent that this market will continue to be oversupplied and credit prices will remain low for the foreseeable future.

In prior conversations with CARB staff, we have come away with the understanding that CARB assumes the LCFS program, and the potentia revenue it affords, does not factor into investment decisions for

EV project operators (fleets, charging operators, etc.) and therefore investment in EVs and charging infrastructure is agnost: to LCFS credit prices. We do not agree with this assumption. Advanced Clean Cars, Advanced Clean Trucks, and Advanced Clean Fleets do not directly address or fund charging infrastructure. Tl LCFS program can, and often does, provide an important revenue stream for EV project operators and can be the difference between project penciling or not. Project developers, operators, and investors in the EV space operate similarly as those in other spaces: they evaluate all available costs and revenues when assessing a potential project and often make decisions based on expected net cashflows. The difference between expected 5-year LCI revenues on a L2 station with roughly average utilization in a world where credit prices hover in the ~$60/credit range vs ~$150/credit is significant. In the former, expected 5-yr LCFS revenues do not amount to enough to influence the business case, whereas in the latter, LCFS revenues offset a significant portion of the cost of the station and can even be leveraged for project financing.

As electrification has the most potential for long-term deep decarbonization of transportation, we urge CARB to account for the impact that sustained low credit prices may have on transportatio electrification investments. Without clearer steps to limit crop-based biofuels - or specific carve outs for on-road electricity credits, like how some state Renewable Portfolio Standards set specific carve outs for solar - investments in charging infrastructure and electric fleets will be crowded out under the program by the continued surplus of biofuel credits in the market.

Recommendation: in lieu of some sort of cap on crop-based biofuel: we believe the 2030 CI target needs to be increased to 32.5% to 3! and the stepdown needs to be increased to 10% to raise price expectations to the level needed to usher in more investment.

Automatic Acceleration Mechanism (AAM)

ChargePoint supports the proposal to establish the AAM but recommends that CARB make the mechanism stronger. As proposed, the AAM would not have been triggered in any of the years after the 2018 amendments. These years include 2022, a year when the credit market price declined by ~50%. The AAM should be designed specifically to counteract this type of negative price movement, s a mechanism that would not have reacted in 2022 is not strong enough.

To strengthen the mechanism, we recommend that ARB amend the first condition of the AAM to be reached when the cumulative credit bank is greater than three-fifths of the deficits generated over the same calendar year rather than the current condition set at three-fourths. With this update the AAM would have been triggered in 2022 but not any of the other years following the 2018 amendments. Since these other years saw price increases or modest declines, the new threshold suggests a balanced mechanism that reacts only to large price decreases.

Conclusion

ChargePoint appreciates the opportunity to submit comments to CARB on the Proposed Regulation. We stand ready to work with CARB Staff to implement the changes discussed in these comments, particularly to ensure that the process of verification is administratively efficient for the on-road charging market.

Respectfully,

Evan Neyland
Senior Manager, Carbon Markets

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-20 14:08:06

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Comment 241 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Richard
Last Name	DeRose
Email Address	RDeRose@sjindustries.com
Affiliation	SJI Renewable Energy Ventures
Subject	Response Comments to Proposed LCFS Amendments
Comment	Please accept the attached comments on behalf of Kyle Nolan, COO, SJI Renewable Energy Ventures. We look forward to continued dialogue.
Attachment	www.arb.ca.gov/lists/com-attach/6908-lcfs2024-VCYBbgRmAzgHYAZ0.pdf
Original File Name	Richard DeRose - SJI Renewable Energy Ventures Response Letter 2.20.2024.pdf
Date and Time Comment Was Submitted	2024-02-20 14:10:33

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SJI
Renewable Energy
Ventures

February 20, 2024

VIA ELECTRONIC FILING

Matthew Botill
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: SJI Renewable Energy Venture's Comments on the Low Carbon Fuel Standard (LCFS) Proposed Amendments

Dear Mr. Botill:

SJI Renewable Energy Ventures focuses on clean energy development and decarbonization via renewable energy production and energy management activities. Through these activities, we are committed to the nations transition to a carbon-free economy and, accordingly, has developed a comprehensive clean energy plan that includes being a leader in the development of dairy digestor projects in the United States. SJI works closely with the Environmental Protection Agency (EPA, California Air Resources Board (CARB), local dairy farmers, utilities, and surrounding communities to directly reduce greenhouse gas (GHG) emissions.

SJI Renewable Energy Ventures thanks CARB for the opportunity to take part in the many workshops and conversations during the development of the Proposed Amendments (Proposed Rule) and the Initial Statement of Reasons (ISOR). We respectfully submit the following comments on the Proposed Rule and ISOR. Through the enhancement of the program's goals, CARB will be best suited to address GHG reductions from transportation fuels. The following comments will focus on avoided methane crediting, increased program ambition, credit true-up, and deliverability. Additionally, SJI Renewable Energy Ventures supports the technical comments submitted by the RNG Coalition and additional comments from the American Biogas Council.

Avoided Methane Crediting

SJI Renewable Energy Ventures has invested in projects that will cost-effectively achieve immediate fugitive methane emission reductions from agricultural operations. The lifecycle GHG emissions

accounting that underpins the LCFS program recognizes the benefit of these avoided methane emissions that would have otherwise occurred absent investments like those made by SJI Renewable Energy Ventures. The RNG projects that we are developing will likely be certified at deeply negative carbon intensity values because of this explicit and immediate benefit to methane emission reductions at

SJI Renewable Energy Ventures

agricultural operations. The Proposed Rule seeks to utilize a fixed year phase-out of avoided methane crediting. Avoided methane emissions is a vital, fact-based, part of the life cycle assessment and its' inclusion in carbon intensity scores is consistent with internationally recognized carbon accounting. The LCFS program has been extremely successful in reducing overall methane emissions. SJI Renewable Energy Ventures strongly encourages CARB to
232.1 continue to utilize the current method of acknowledging avoided methane emissions and the
use of Argonne National Laboratory's GREET model.

Increased Program Ambition

SJI Renewable Energy Ventures is encouraged to see that the Proposed Rule sets forth more ambitious carbon intensity targets. As mentioned in previous comments, stronger CI reduction targets is an essential element to driving down GHG emissions. Given the current LCFS credit surplus, seen over the last few years, a larger step-down in the carbon intensity benchmark is critical to signal market support and increase investments. We support the ABC's comments on
232.2 this topic. Specifically, (1)"by increasing the step-down as well as pulling forward the effective
232.3 date for triggering the Auto Acceleration Mechanism (AAM) CARB can "recapture" reductions in
GHG emissions that will otherwise be lost with the current proposal. Doing so will also send a clear, and supportive market signal to continue investments in clean fuels that would otherwise be constrained and subdued by the current proposal." Additionally, we support the RNGC on this policy topic through their comments. (2) "Increasing the program's benchmarks to set a 25% CI reduction below the 2010 Baseline in 2025 would be sufficient to begin to draw down the credit bank, reestablish a demand for additional expansion in low carbon fuel supply, and therefore drive additional greenhouse gas abetment. Further, starting the step-down as soon as
232.4 possible and avoiding unnecessary bank build is crucial. We recommend that CARB target the
step-down to occur on 7/1/2024 to a level of 25% below the 2010 baseline and maintain that level through 12/31/2025 (assuming CARB elects to retain the updated 2010 diesel baseline value and that the necessary administrative steps can be accomplished on this timeline)." Finally, we
232.5 strongly encourage CARB to continue to target *at least* a 30% CI reduction by 20230.

Deliverability Requirements/Book-and-Claim

Book-and-Claim has allowed the LCFS to become one of the most successful decarbonization programs in the country. California has benefitted from the use of indirect accounting through national investments and participation in the LCFS. In return, the program has been highly successful at reducing GHGs, a goal we all support. SJI Renewable Energy Ventures respectfully requests CARB continues to allow for this type of accounting to ensure GHG reductions
232.6 continue at a successful rate. Although the policy concept of new deliverability requirements
has been mentioned throughout the stakeholder process, specifics never emerged. We strongly request that deliverability language, in the Proposed Rule, be removed to allow for greater stakeholder engagement on the specific topic.

(1) American Biogas Council Comments on the Proposed Amendments to the Low Carbon Fuel Standard
(2) RNG Coalition's Comments on Low Carbon Fuel Standard Initialt Statemen of Reasons

SJI Renewable Energy Ventures

Credit True-Up

232.7 We support the inclusion of a credit true-up after Annual Verification. An appropriately implemented true-up policy will ensure that that all GHG benefits are accounted for. However, as drafted in the Proposed Rule, we believe there needs to be a correction. As drafted, it appears the Proposed Rule will NOT allow true-ups during the temporary pathway period. During the August 2022 LCFS Workshop, CARB Staff proposed providing a credit true up to correct for under crediting to pathway holders *only* during the period where a project is using temporary CI scores at the outset of their credit generation. The material used during the Workshop provided that such a limited true up would help reduce the pressure on CARB from developers to process LCFS applications quickly.

Due to factors such as weather and herd size changes, dairy manure digestors can experience drastic changes in gas production throughout a given year. With the carbon intensity of the gas being calculated against the quantity of avoided methane emissions, the variations in biogas production results in changes in a digestor's CI score every year. We believe, if digestors were allowed to fully true-up the LCFS credit generation to the actual CI score (based on actual GHG performance data), any issues the Proposed Rule is trying to address, would be resolved.

Conclusion

SJI Renewable Energy Ventures appreciates the opportunity for continued participation throughout this rulemaking process. A process that is critical to achieve the decarbonization goals that we both share. We remain committed to providing RNG to the California LCFS market and helping to reduce methane emissions, improve animal manure management in agricultural communities and decarbonize California's transportation sector. We thank CARB for your continued work toward this end and look forward to a robust and effective LCFS update.

Sincerely,

Kyle Nolan

Kyle Nolan
Chief Operating Officer
SJI Renewable Energy Ventures

(1) American Biogas Council Comments on the Proposed Amendments to the Low Carbon Fuel Standard
(2) RNG Coalition's Comments on Low Carbon Fuel Standard Initial Statemen of Reasons

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Comment 242 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Dan
Last Name	Bowerson
Email Address	dbowerson@autosinnovate.org
Affiliation	
Subject	Auto Innovators Comments on Proposed LCFS Amendments
Comment	Please find the attached comments from the Alliance for Automotive Innovation on proposed LCFS amendments.
Attachment	www.arb.ca.gov/lists/com-attach/6909-lcfs2024-AWBRIlInBztSC1I7.pdf
Original File Name	Auto Innovators Comments_CARB LCFS Amendments (February 20 2024).pc
Date and Time Comment Was Submitted	2024-02-20 14:20:21

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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February 20, 2024

SUBMITTED ELECTRONICALLY https://ww2.arb.ca.gov/applications/public-comments

Clerks' Office
California Air Resources Board
1001 I Street
Sacramento, California 95814

Subject: Low Carbon Fuel Standard – Light-Duty Vehicle Residential Base Credits

The Alliance for Automotive Innovation (Auto Innovators) and our members appreciate the opportunity to comment on the proposed changes to the Low Carbon Fuel Standard (LCFS).[1] Automakers and this association have long supported reductions in the carbon content of liquid fuels. Low carbon liquid fuels are an additional pathway for reducing transportation GHG as they are (1) technically feasible today, (2) the only viable decarbonization solution for the legacy vehicle fleet, (3) an important complement to vehicle electrification over a long transition, and (4) affordable for consumers whose needs or budgets require different solutions. Since the vast majority of the 280 million vehicles on U.S. roads today have an internal combustion engine, decarbonizing liquid fuels on a well-to-wheel basis would yield immediate benefits for lowering the carbon intensity of transportation energy.

233.1 While we support the LCFS, we do not support the changes that would take revenue generated by light-duty (LD) electric vehicle (EV) residential charging and use it to subsidize utilities and businesses operating medium- and heavy-duty vehicles. Instead, this funding should be used exclusively to develop the light-duty and residential EV market through infrastructure, vehicle incentives, and public education.

[1] California Air Resources Board. (2024). Notice of Public Hearing to Consider Approving for Adoption the Proposed Low Carbon Fuel Standard Amendments. Retrieved January 26, 2024, from https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_notice.pdf

1. Light-duty EV market

The transition to zero emission vehicles (ZEVs)[2] for light-duty vehicles (LDVs) is far from complete. Despite a 25% market share for LD EVs in 2023, substantial progress is needed to meet the Advanced Clean Cars (ACC) II requirements of 51% ZEV in 2028, 68% ZEV in 2030, and 100% ZEV in 2035. Without vastly improved LD residential and public infrastructure, there is a high probability the LD EV market growth will stall long before these levels are met.

Current new EV buyers are far more likely to be affluent single-family homeowners who can both afford the higher cost of EVs and have ready access to reliable, low-cost, and convenient home charging. While most new car buyers might be affluent single-family homeowners, the transition to 100% ZEVs in ACC II requires not just "most new car buyers" but "all new car buyers."

Moreover, meeting the ACC II ZEV sales mandate also requires used car buyers (including the third, fourth, and fifth vehicle owners, who are less likely to have access to home charging) to embrace ZEVs. Access to home charging that most current ZEV buyers enjoy dramatically lowers the need for public charging. As the ZEV requirements increase under ACC II in the next few years, the portion of drivers that do not have home charging increases and these drivers will be forced to rely on public charging, which is currently inadequate, unreliable, inconvenient, and expensive compared to home charging.

Thus, to ensure the successful full transition to EVs outlined and required under ACC II, funding generated by residential EV charging should be used exclusively to develop the LDV EV market through infrastructure, vehicle incentives, and public education.

2. Reestablish California Clean Fuel Rewards administered by automakers for LD EVs

233.1

Auto Innovators recommends reestablishing the California Clean Fuels Reward (CCFR) program as a point of purchase incentive. Less than four years ago, this program was established with unanimous support from automakers, utilities, and CARB to provide a point of purchase reward of up to $1,500 for new EVs. The CCFR was reduced to $750 and then eliminated altogether on September 1, 2022. This program incentivized residential customers – *the very customers who generate the LCFS credits that fund this program* – to choose electricity rather than gasoline to fuel their vehicles. Moreover, the CCFR was provided at the time of purchase, avoiding the weeks- or months-long wait associated with other rebate programs. It also provided an ongoing

[2] ZEVs include battery, plug-in hybrid, and fuel cell electric vehicles (BEV, PHEV, and FCEV, respectively).

233.1 revenue stream, rather than dependency on the annual state budget allocation. Lastly, it was one of the last remaining financial incentives in California for LDVs. Its demise came at a time when ZEV sales were becoming more dependent on purchases by mainstream consumers. These consumers need more encouragement to purchase an electric vehicle than early adopters.

233.2 Auto Innovators continues to support CCFR directed to LD EVs. However, rather than providing the LCFS credits to utilities, participating EV automakers and a third-party administrator selected by CARB (CFR Program Administrator) should administer the program and provide the EV Purchase reward. Automakers have decades of experience administering vehicle rebates and can do so far more efficiently than utilities.

To provide a stable and predictable EV incentive, CARB and automakers should set the CCFR EV purchase reward annually based on estimated revenue from LCFS credit generation from residential EV charging. Unlike utilities that require minimum cash reserves (around $10 million) and thus needed to quickly change the CCFR program, participating automakers could continue the CCFR throughout the year and then adjust the CCFR reward in subsequent years.

3. Equity programs should receive 45% of residential EV charging revenue

233.3 Automakers recognize the transition to an all-electric future will not happen without the full participation of equity communities. In fact, equity communities represent the most difficult segment in the transition to all LD EVs due to historically lower incomes, lack of reliable, low-cost, convenient residential charging, need for reliable transportation, and potentially longer commutes. Ironically, these communities stand to benefit the most from LD EVs, with the proper support in place. CARB should revise the regulation to ensure that at least 45% of residential EV charging LCFS credit revenue is directed to equity community LD EV projects, including:

- LD EV multi-family residential and public infrastructure.
- Workforce development related to LD EV market development, including LD EV residential and public infrastructure installation, operation, maintenance, and repair and LD EV sales, maintenance, and repair.
- Additional rebates for new and used LD EVs in equity communities.
- Rebates for residential charger installation in equity communities.

233.3
- Vouchers for public charging to equity community members.

4. Automakers Producing EVs Should Receive Base Residential Charging Credits

No industry is investing more than automakers to develop the EV market. By 2030, the auto industry will invest more than $500 billion globally in everything from critical minerals and critical mineral processing, to battery cell and pack production, to vehicle development, certification, and production, to charging stations and consumer education. Moreover, automakers are developing telematics, vehicle-to-home (V2H), and vehicle-to-grid (V2G) technologies that benefit the electric grid. Nonetheless, automakers are excluded from receiving any of the base residential charging credits generated by their investment.

CARB regulations should provide automakers "pre-approved" uses for the credit proceeds like those provided to the utilities. For example, the following pre-approved projects parallel those provided for non-equity utility holdback credits (c)(1)(A)5.b.:

233.2 cont

i. Investments to improve EV efficiency, charging time, and EV charging convenience.
ii. Investments in V2H and V2G technology development including
    1. Encouraging the optimization of EV charging through education and technology to improve the ability of customers to charge at times of lowest cost.
    2. Providing incentives to encourage drivers to participate in managed charging, demand response, V2H, or V2G programs.
    3. Supporting the development and use of vehicle bidirectional charging.
    4. Other innovative approaches to promote and manage EV charging and discharging to benefit customers and the grid, including methods to reduce battery degradation from V2H, V2G, and fast charging events.

iii. Hardware and software that reduces the cost of EVs.

5. Revenue FROM light-duty EV owners TO light-duty EVs

233.4

As noted above, rather than subsidizing electric utilities or businesses operating medium- and heavy-duty vehicles, revenue generated from LD EV residential charging should be used to grow the LD EV market. Thus, we recommend eliminating "pre-approved projects" in the proposed regulations that provide funding for changes not related to the LD EV market. Specifically, we recommend eliminating the following pre-approved projects recognizing that utilities could still propose and seek approval of these projects.

233.4 cont

- Electrification of drayage trucks and other M/HD EVs or off-road vehicles, including school and transit buses.
- Incentives for using public transit, including car and ride share, public transit and school bus (including battery swap programs).
- Micro-mobility solutions (eBikes, eScooters, eMotorcycles, etc.).
- Investments in grid-side distribution infrastructure for M/HD EVs.
- VGI projects (EV charging education, incentives to encourage drivers to participate in managed charging, deployment of bi-directional charging equipment, or other innovative approaches to promote managed charging).
- Hardware and software that reduces the costs or avoids updates to infrastructure.

6. Conclusion

Again, we sincerely appreciate the opportunity to work with CARB on proposed changes to the LCFS regulations. Please don't hesitate to contact me if you have any questions or need additional information.

Sincerely,

Dan Bowerson
Vice President, Energy & Environment
dbowerson@autosinnovate.org

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Comment 243 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Bruno
Last Name	Maier
Email Address	bruno.maier@raizen.com
Affiliation	
Subject	Raízen´s Contribution to LCFS Amendments 2024
Comment	Dear Chair Randolph, We appreciate the opportunity to comment on the Proposed Low Carb Fuel Standard (LCFS) Amendments. Respectfully, Raízen Team
Attachment	www.arb.ca.gov/lists/com-attach/6910-lcfs2024-WzgCZVMgVWRQCQFz.pdf
Original File Name	CARB_Rulemaking_Raízens Comments_20240220.pdf
Date and Time Comment Was Submitted	2024-02-20 13:42:14

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Raízen Energia S.A.
Av. Brig. Faria Lima, 4100 - Itaim Bibi,
São Paulo - SP, 04538-132

February 20, 2024

The Honorable Liane Randolph
Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814
(Comments submitted electronically)

Dear Chair Randolph,

We appreciate the opportunity to comment on the Proposed Low Carbon Fuel Standard (LCFS) Amendments.

Raízen is a company created from an independent Joint Venture with shared control between Shell and Cosan, which operates in the production and sale of sugar, bioenergy and bioeletricity. We have a fully integrated process that involves everything from the cultivation of the sugarcane to the production of sugar and ethanol and the logistics of distribution and marketing of these products. We are currently the largest sugarcane-ethanol producer globally, and a unique holder of second-generation ethanol technology operating in a commercial scale.

We would like to start our comments by recognizing CARB's technical staff's diligent work and willingness to engage with stakeholders in the process of updating the LCFS regulations through this rulemaking.

We continuously seek to manage and improve the carbon footprint of our products by diversifying our renewable energy portfolio, with the objective of delivering decarbonization solutions to the market. We increasingly invest to support the mitigation of climate change and the global energy transition. Markets that aim to decarbonize the transportation sector and have a premium policy related to biofuels, such as LCFS / CARB (Low Carbon Fuel Standard / California Air Resources Board), are naturally of interest to Raízen for the commercialization of our biofuels. We pride ourselves for being a committed stakeholder to CARB's LCFS program for a long time and for always offering reliable and trustworthy data on the ethanol sector in Brazil. Raízen has also supplied a significant amount of ethanol to California in recent years.

While acknowledging the advancements that the draft proposal brings, we would like to highlight some points we believe may improve the proposed amendments to the LCFS program.

1. **Comments on Sustainability Requirements for Crop-Based Feedstocks (Section 95488.9 (g), Appendix A-1.1)**

We understand the pivotal role sustainability certifications play in assuring a fair-trade system combined with sustainable development. Raízen, for instance, has its plants certified by certification schemes, such as Bonsucro and ISCC. Recently, we were the first ethanol producer in the world to be certified with the ISCC CORSIA Plus certification.

In addition to certifications, geographic traceability is maintained for the sugarcane we process, whether sourced from our own operations or from third-party suppliers. This entails the possession of shapefiles delineating the locations of the farms and plots from which we procure or cultivate sugarcane. Our differentiated management of the supply chain enables us to ensure the geographic traceability of our raw materials under the highest sustainability standards in production.

234.1 Based on our experience complying with and promoting sustainable practices, we regard such certifications (RSB, ISCC and Bonsucro) as internationally recognized in this field. Not to mention Renovabio, in Brazil. We would therefore encourage CARB to carefully consider these established certification schemes and taking steps to recognize and align with these respected approaches thus avoiding duplication of efforts and placing additional burdens on companies that intend to have trade flows with the state of California and would need to abide by LCFS' sustainability criteria.

Finally, for tracking crop-based feedstock in the supply chain, Raízen strongly recommends the mass-balance approach, a system widely recognized by sustainability certification schemes. The mass balance approach is widely utilized due to its simplicity, particularly within value chains that involve multiple suppliers. In the mass balance tracking model, materials, or products with a set of specified characteristics are mixed according to defined criteria with materials or products without that set of characteristics. Acknowledging the relevance of international reliable certification schemes, the mass balance approach would require fewer resources for biofuel producers, CARB staff and certification bodies. It also ensures transparency through clear documentation. This approach provides feedstock buyers with greater certainty about the sustainability criteria.

2. **Comments on Tier 1 for Second-Generation Ethanol (E2G)**

234.2

Raízen is the unique holder of second-generation ethanol technology operating at a commercial scale. We have one E2G plant operating since 2018 (Costa Pinto) producing at full capacity (~7,925.161,6 gallons/year), as well one recently delivered new plant under construction and 8 more to be constructed soon. It is important to highlight that the E2G production is entirely bagasse-based, tackling climate change with a less carbon intense fuel compared to conventional biofuels, and bringing disruptive technology, as well providing good local jobs and economic growth.

234.2

Looking at this expansion plan and benefits of the second-generation ethanol, Raízen's E2G production will significantly increase during the coming years. **Therefore, we strongly advocate for CARB staff to incorporate the second-generation ethanol pathway into Tier 1.** Recognizing the hurdles in integrating new pathways, we stand ready to support CARB staff by providing valuable operational data.

3. Comments on Backhaul Energy Intensity (Section II-C, Appendix B)

234.3

Raízen echoes Shell's assertion that **the addition of backhaul energy intensity to ocean tankers for Brazilian sugarcane is not a universally applicable condition**. This situation does not apply to ethanol transported from Brazil to the US. Raízen can provide evidence of its trading logistics, as it has done in the past, and is pleased to collaborate with CARB staff again to offer further information.

4. Comments on Tier 1 CI Calculator

Firstly, we want to acknowledge CARB's technical staff for their continued efforts and willingness to collaborate with us in the ongoing process of updating the calculator for sugarcane ethanol. However, CARB is faced with a significant responsibility, one that will influence transportation policy for years to come, not only in the US but also in other jurisdictions across the United States and internationally. We are eager to continue contributing to this endeavor.
As we discussed last year during the amendment process of the Draft Tier 1 Calculator, we would like to reiterate some of our comments regarding the assumptions incorporated in the Tier 1 CI Calculator. **Recognizing the potential challenges faced by CARB staff in reviewing Tier 2 applications, we respectfully propose the integration of the following requests into the Tier 1 calculator**. This strategic enhancement aims to optimize efficiency and mitigate administrative burdens associated with Tier 2 evaluations, aligning with our commitment to facilitating smoother processes within regulatory frameworks.

a. N_2O emissions from applied N

The emission factor for direct N_2O emissions from nitrogen inputs, as previously outlined in CA-GREET 3.0, stood at 0.01 kg-N_2O-N/kg N-fert applied to soils, as sourced from the IPCC (2006). In the current version of the CA-GREET 4.0, this figure has been revised to 0.00895 kg-N_2O-N/kg N-fert based on Wang et. al (2012). But no updated was included in the Tier 1 CI Calculator. Raízen acknowledges the efforts of CARB staff in updating this value in CA-GREET 4.0.

Despite this updated science evidence, it is worth noting that this adjustment may still not accurately reflect the Brazilian reality, and **the IPCC generally recommends prioritizing regional data whenever available.**

Carvalho et al. (2021)[1], in a recent publication, conducted a comprehensive study based on 14 relevant publications reflecting current nitrogen fertilization practices in South-Central Brazil's sugarcane industry. Their research is grounded in data gathered from field studies conducted across 17 experimental sites. Importantly, they meticulously accounted for background emissions of N_2O EF, incorporating over 86 reported values. Notably, the study encompasses N_2O EFs derived from sugarcane cultivated under green mechanized harvesting, which dominates over 95% of the sugarcane cultivation area in the South-Central region of Brazil.

Carvalho et al. (2021) found the average N_2O–N EF of 0.006 kg N2O-N/kg N applied, considering all N fertilizer sources, for the sugarcane ratoon, which receives most of the N application of the sugarcane areas, and represents 80% of the sugarcane cycle and 89% of the total amount of N fertilizer consumed considering the entire sugarcane mill. **The EF value recommended by Carvalho is 33% lower than the value proposed by Wang et at. (2012).** The value identified by Carvalho is justified by good drainage properties of the deep Oxisols soils, where sugarcane is commonly cultivated in Brazil.

Hence, the review of in situ N_2O–N EF measurements from sugarcane in Brazil indicates values below the default currently proposed in the CA-GREET 4.0, and notably lower than those observed in many sugarcane areas in other regions worldwide. IPCC (2019) values, used in the current Tier 1 CI Calculator, were
234.4 primarily derived from studies in Europe (34%), North America (28%), and Asia (19%), with Central-South America contributing with only 6−7% to the dataset. Therefore, does not represent the sugarcane reality in the region.

Raízen strongly recommends that CARB staff consider using the value of 0.006 kg-N_2O-N/kg N-fert for both CA-GREET 4.0 and Tier 1 CI Calculator, reflecting the specific conditions in South-Central Brazil's sugarcane production areas.

b. Unburned Mechanized Harvesting

Mechanized harvesting, which involves unburned methods, dominates the sugarcane harvesting landscape in Brazil's Center-South region, representing more than 95% of the total yield. This assertion is substantiated by both official governmental data[2] and primary data meticulously collected and

[1] *Carvalho, J. L. N.; Oliveira, B. G.; Cantarella, H.; Chagas, M. F.; Gonzaga, L. C.; Lourenço, K. S.; Bordonal, R. O.; Bonomi, A. Implications of regional N2O–N emission factors on sugarcane ethanol emissions and granted decarbonization certificates. Renewable and Sustainable Energy Reviews, 149 (2021), 111423. https://doi.org/10.1016/j.rser.2021.111423*

[2] Safra cana-de-açúcar, Center-South region: https://unicadata.com.br/listagem.php?idMn=4

audited by Renovabio in 2018 and 2019. Renovabio's findings further affirm the correlation between mechanized harvesting practices and the adoption of unburned methods. However, despite this evidence, the default values in the Tier 1 CI Calculator for sugarcane ethanol indicate a mechanization rate of just 80% in São Paulo state and 65% in other states, including the Center-South region.

As per CARB's request, an analysis utilizing remote sensing data was conducted employing the Mapbiomas-Fire[3] and UNICA's sugarcane area vectors. Data were processed in the Qgis software. For each sugarcane polygon, the percentage of intersection with the polygon of burned area from Mapbiomas-Fire was estimated. After the geospatial statistics calculations, the results were added to the attribute table of the vector, and state-level statistics were computed. Consequently, the total sugarcane area for 2020 was assessed at 10,280,528.7 hectares, of which 82,847.10 hectares were subjected to burning practices, accounting for less than 1% of the sugarcane area (**Figure 1**).

234.5

Considering the significant influence of this input on the calculator and the industry's substantial efforts to reduce emissions through modern harvesting techniques**, Raízen asks CARB staff to carefully review this information**. The implications of CARB's policies extend beyond California, impacting the wider country and the world. It's crucial that CARB's assumptions regarding mechanized harvesting accurately reflect Brazil's sugarcane production patterns, translating into improved carbon intensity for Brazilian ethanol.

We respectfully urge CARB to consider implementing an option for individual mechanization percentage, supported by evidence, within the Tier 1 CI calculator. If, for any reason, this is not feasible, we kindly request that the staff adjust the default mechanization values for Center-South Brazil to a value no lower than 95%. By doing so, CARB will align input more closely with actual practices.

[3] MapBiomas. MapBiomas Project - Mapbiomas-Fire Collection 1. 2022. Available at: https://mapbiomas.org/en/colecoes- mapbiomas-1?cama_set_language=en. *The Mapbiomas-Fire product was elaborated from mosaics of Landsat Satellite images, with 30 meters of spatial resolution, covering the years from 1985 to 2020, providing monthly and annual data of the burned areas in Brazil. The burned area estimation was carried out using artificial intelligence from machine learning algorithms in the Google Earth Engine platform. The algorithm was trained with samples of burned and non-burned areas, in addition with the burned area product of MODIS sensors (MCD64A1) and hot spots data from INPE.*

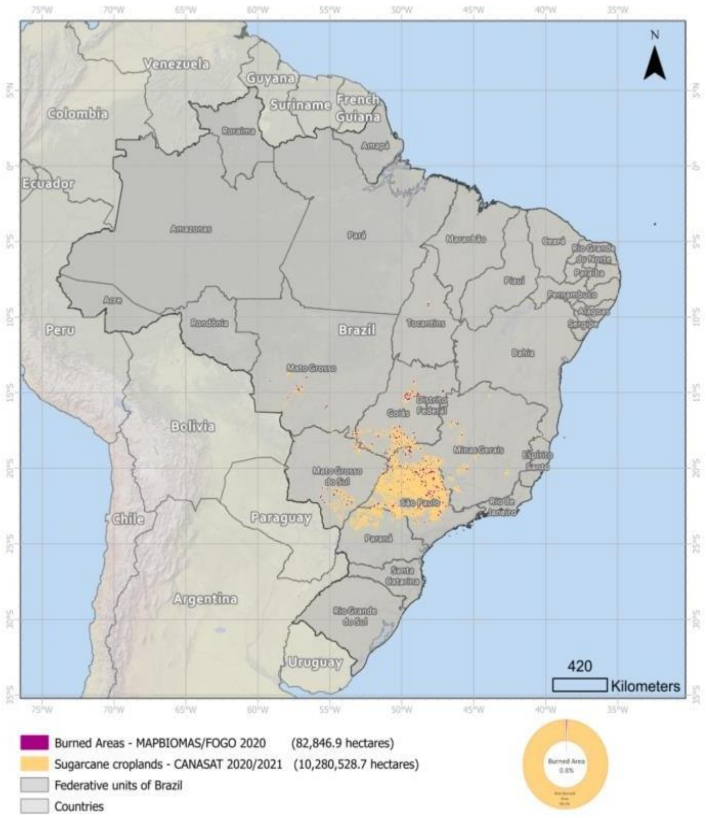


Figure 1. Intersection from the sugarcane area with the burned areas polygons from the MapBiomas-Fire for the center-south region of Brazil. Sources: Mapbiomas-Fire, Canasat.

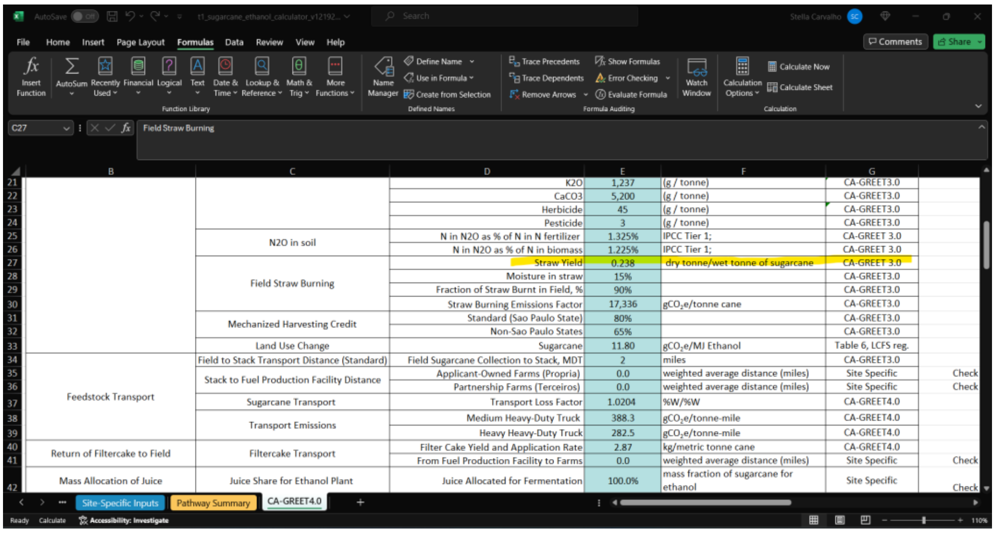
c. Electricity Exported Credits

Sugarcane-based electricity in Brazil serves as a valuable supplement to hydroelectric generation, particularly during the dry season when water resources may be limited. Its contribution helps mitigate the need for natural gas- and coal-based electricity generation, thus promoting a more sustainable energy mix. **Raízen strongly recommends that CARB staff consider electricity export credits by acknowledging the displacement of the margin of the Brazilian electricity grid.** This should be based on sugarcane electricity's contribution to total thermoelectric generation during the dry
234.6 season in Brazil. This approach allows for the reallocation of energy dispatching primarily during this period, reducing the risk of deficit without worsening water reservoir conditions. Raízen disagrees with CARB's approach, which excludes energy exported in the off-season and fails to consider energy produced by cogeneration from third-party biomass. This can create a "double standard" where the rainy season is used to calculate the national electricity grid average but ignored when CARB excludes export electricity credits generated in the off-season months. Both approaches significantly impact the carbon intensity (CI) value of ethanol mills in Brazil.

For a more detailed exploration of electricity production and dispatch in Brazil, please refer to **Annex A.**

d. Straw Yield

Raízen greatly appreciates CARB staff's consideration in updating the sugarcane straw yield in the CA-GREET 4.0, reducing it from 0.24 t/t cane (dry basis) to 0.14 t/t cane (dry basis). However, **Raízen identified the need to CARB staff also**
234.7 **implement this change in the Tier 1 CI Calculator.** As previously explained, this revised value is widely accepted by the academic community and is being utilized in numerous studies, including the latest versions of the Argonne GREET Model. **We therefore strongly ask CARB to reconsider this value in the Tier 1 CI Calculator.**



	B	C	D	E	F	G	
21			K2O	1,237	(g / tonne)	CA-GREET3.0	
22			CaCO3	5,200	(g / tonne)	CA-GREET3.0	
23			Herbicide	45	(g / tonne)	CA-GREET3.0	
24			Pesticide	3	(g / tonne)	CA-GREET3.0	
25		N2O in soil	N in N2O as % of N in N fertilizer	1.325%	IPCC Tier 1;	CA-GREET 3.0	
26			N in N2O as % of N in biomass	1.225%	IPCC Tier 1;	CA-GREET 3.0	
27		Field Straw Burning	Straw Yield	0.238	dry tonne/wet tonne of sugarcane	CA-GREET 3.0	
28			Moisture in straw	15%		CA-GREET3.0	
29			Fraction of Straw Burnt in Field, %	90%		CA-GREET3.0	
30			Straw Burning Emissions Factor	17,336	gCO_2e/tonne cane	CA-GREET3.0	
31		Mechanized Harvesting Credit	Standard (Sao Paulo State)	80%		CA-GREET3.0	
32			Non-Sao Paulo States	65%		CA-GREET3.0	
33		Land Use Change	Sugarcane	11.80	gCO_2e/MJ Ethanol	Table 6, LCFS reg.	
34	Feedstock Transport	Field to Stack Transport Distance (Standard)	Field Sugarcane Collection to Stack, MDT	2	miles	CA-GREET3.0	
35		Stack to Fuel Production Facility Distance	Applicant-Owned Farms (Propria)	0.0	weighted average distance (miles)	Site Specific	Check
36			Partnership Farms (Terceiros)	0.0	weighted average distance (miles)	Site Specific	Check
37		Sugarcane Transport	Transport Loss Factor	1.0204	%W/%W	CA-GREET4.0	
38		Transport Emissions	Medium Heavy-Duty Truck	388.3	gCO_2e/tonne-mile	CA-GREET4.0	
39			Heavy Heavy-Duty Truck	282.5	gCO_2e/tonne-mile	CA-GREET4.0	
40	Return of Filtercake to Field	Filtercake Transport	Filter Cake Yield and Application Rate	2.87	kg/metric tonne cane	CA-GREET4.0	
41			From Fuel Production Facility to Farms	0.0	weighted average distance (miles)	Site Specific	Check
42	Mass Allocation of Juice	Juice Share for Ethanol Plant	Juice Allocated for Fermentation	100.0%	mass fraction of sugarcane for ethanol	Site Specific	Check

Figure 2. Current assumption for straw yield in the Tier 1 CI Calculator for sugarcane ethanol.

In conclusion, Raízen appreciates the opportunity to contribute with the LCFS rulemaking process and with CARB staff. Once again, we would like to put ourselves available for technical discussions with the high qualified CARB staff. We look forward to continuing the ongoing dialogue and collaboration staff to move forward with these discussions that we are certain will contribute to lowering emissions in the California transport sector.

Sincerely,

Raízen

Annex A. The Brazilian Electrical System

The Brazilian Electrical System (National Interconnected System - SIN) is 99% interlinked[4], so virtually all the production and transmission of electricity in Brazil happens in one main grid closely monitored by the National Electric System Operator (ONS), a federal agency responsible for coordinating and controlling operation of the electricity generation and transmission facilities in the SIN under the supervision and regulation of the National Electric Energy Agency (ANEEL). This unique system adopted by the country creates certainty as to what sources contribute to the marginal generation of power. Sugarcane biomass-based electricity in Brazil receives a fixed income to deliver a "package" of energy per year to the grid. Sugarcane biomass receives this fixed income for the energy it produces and declares its Unit Variable Cost (UVC) equal to zero, since cogeneration of sugarcane biomass electricity occurs in order to meet the demand of the sugar and ethanol industry. Wind and solar sources also have a UVC equal to zero. In this way, all the electrical energy these sources produce is made available to the national grid (since the government already paid a fixed income for it).

The procedure varies for thermo-gas sources. In addition to the fixed income they receive for standby readiness, their UVC exceeds zero. This implies that whenever the ONS deploys them, they are compensated for both their fuel expenses and operational costs. In fact, since sugarcane biomass is classified with a unit variable cost equal to zero, the ONS adopts the so-called merit order,where thermal plants from lower to higher operating costs are dispatched in order to meet demand. The ones with lower UVC are the first to be called to meet domestic demand. Since biomass plants have unit variable cost equal to zero, when available (during the sugarcane harvest season), they are the first to be dispatched to the system, without the need for an order from the ONS. Differently from sources like coal, diesel, and natural gas, the generation of energy from sugarcane biomass sources is controlled and dictated by the industrial process itself instead of by order of the national operator.

[4] https://www.ons.org.br/paginas/sobre-o-sin/sistemas-isolados

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Comment 244 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	lucas
Last Name	Grimes
Email Address	lucas.grimes@resource-solutions.org
Affiliation	Center for Resource Solutions
Subject	Center for Resource Solutions comments on LCFS
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6911-lcfs2024-UzBWIlMhWFQHYgZp.pdf
Original File Name	CRS Comments to CARB on LCFS updated 2.20.24.pdf
Date and Time Comment Was Submitted	2024-02-20 14:25:31

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

CRS

February 20, 2024

California Air Resources Board (CARB)
1001 I Street, Sacramento, CA 95814
Submitted Electronically

RE: CALIFORNIA AIR RESOURCES BOARD PUBLIC HEARING TO CONSIDER PROPOSED LOW CARBON FUEL STANDARD AMENDMENTS

Dear California Air Resources Board Staff,

Center for Resource Solutions (CRS) appreciates this opportunity to submit comments in response to the March 21, 2024 Public Hearing to Discuss Potential Changes to the Low Carbon Fuel Standard (LCFS) and Proposed Amendments to the Low Carbon Fuel Standard Regulation (hereafter "Draft"). We support the LCFS Program and the Assembly Bill (AB) 32 Scoping Plan. Our comments pertain to a utility-specific carbon intensity (CI) value of electricity, the definitions of environmental attributes and book-and-claim accounting, and book-and-claim accounting best practices for biomethane and hydrogen.

BACKGROUND ON CRS AND GREEN-E®

CRS is a 501(c)(3) nonprofit organization that creates policy and market solutions to advance sustainable energy and has been providing renewable energy and carbon policy analysis and technical assistance to policymakers and other stakeholders in California for over 20 years. CRS also administers the Green-e® programs. For over 20 years, the Green-e® program has been the leading independent certification for voluntary renewable electricity products in North America. In 2021, the Green-e® Energy program certified retail sales of over 110 million megawatt-hours (MWh), serving over 1.3 million retail purchasers of Green-e® certified renewable energy, including over 309,000 businesses.[1] The Green-e® Renewable Fuels program was launched in 2021, initially as a standard and certification for biomethane products and associated environmental attributes. This program is in the process of expanding to certify green hydrogen transactions and programs and can serve as a guide for CARB as it helps accelerate the adoption of biomethane and clean hydrogen, while ensuring that they are from sustainable renewable resources and meet the highest environmental standards, and that customers are protected in their purchase and ability to make verified usage claims.

[1] See the 2022 (2021 Data) Green-e® Verification Report (soon to be published) here for more information: https://www.green-e.org/verification-reports

Center for Resource Solutions
1012 Torney Ave, 2nd Floor
San Francisco, CA 94129

w : www.resource-solutions.org
p : 415.561.2100

COMMENTS ON THE DRAFT

Utility-Specific Carbon Intensity Value of Electricity

1. We recommend that the Lookup Table CI value for electricity be utility-specific CIs that represent retail electricity delivery.

235.1 The Lookup Table CI value for electricity should allow for entities to claim a utility-specific CI that reflects retail transactions instead of the California grid mix. This enables a more accurate reflection of the emissions associated with electricity use and is already part of the Oregon Clean Fuels Program.[2] To further improve the accuracy of this value, it should be updated to reflect electricity delivery to retail sales. The Lookup Table CI value for California grid electricity currently reflects the statewide grid average of electricity generation and does not reflect the sale of Renewable Energy Certificates (RECs) or voluntary electricity products. Since the LCFS allows for adjustments of CI scores based on contractual mechanisms like RECs and other contracts for specified power, the default CI should also reflect retail deliveries, not simply generation.

The California Energy Commission's (CECs) Power Source Disclosure (PSD) program would be the best place to start in determining this value. PSD calculates provider portfolio-specific emissions intensities that are intended to represent the emission intensity of electricity delivered to retail load. The PSD program requires that RECs must be owned and not sold.[3] The program also backs out voluntary renewable electricity product sales from provider's default emission intensity.[4] Using these emissions intensities could avoid double counting where voluntary green power programs and RECs are used to generate additional and incremental LCFS credits (i.e., the same renewable energy is included in the statewide grid average).

Environmental Attribute Definition

235.2 2. We recommend that CARB update the environmental attribute definition at § 95481 Definitions and Acronyms to: "*Environmental Attributes: Any and all impacts and benefits attributable to the generation from the Generating Unit, including but not limited to the fuel or resource type,*

[2] Oregon Clean Fuels Program Updated Electricity Carbon Intensity Values for 2021. Available at: https://www.oregon.gov/deq/ghgp/Documents/cfpUpdated2021CIs.pdf

[3] See Section 1393(c)(1)(B) of Power Source Disclosure Regulation in Title 20, CCR Available at: https://www.energy.ca.gov/programs-and-topics/programs/power-source-disclosure/power-source-disclosure-resources-retail

[4] See Section 1394.1 (a) of Power Source Disclosure Regulation in Title 20, CCR Available at: https://www.energy.ca.gov/programs-and-topics/programs/power-source-disclosure/power-source-disclosure-resources-retail

location, greenhouse gas emissions, greenhouse gas emissions avoided or displaced on the grid."

235.2 The definition in the Draft refers to all attributes as "emissions reductions,"[5] which is misleading as not all attributes of generation are reductions. For example, RECs reflect attributes of generation, including both the direct emissions and any avoided grid emissions associated with generation. But RECs are not carbon offsets and do not represent a quantity of emissions reductions.[6] We suggest using the above definition, which is consistent with the Western Renewable Energy Generation Information System (WREGIS)[7] and represents a more encompassing and accurate definition of environmental attributes.

<u>Book-and-claim Accounting Definition</u>

235.3

3. We recommend that CARB update the book-and-claim accounting definition at § 95481 Definitions and Acronyms to: "*Book-and-Claim Accounting is chain of custody model in which the administrative record flow is not necessarily connected to the physical flow of material or product throughout the supply chain. For example, the environmental attributes of low-CI electricity, biomethane or low-CI hydrogen may be separated from or matched with the use of grid electricity, fossil natural gas or hydrogen respectively.*"

The definition in the Draft describes book-and-claim accounting as "an indirect accounting system where a physical product and its environmental attributes can be separately traded."[8] The reference to "indirect accounting" may be misinterpreted as a reference to indirect emissions accounting. Indirect emissions, sometimes called avoided emissions, are the net changes in emissions on the grid due to the generation, while direct emissions are the emissions associated with the generation.[9] Since the emissions being tracked for LCFS are the direct emissions associated with electricity generation, this may be confusing. We recommend the above definition, which is based on the International Organization for Standardization (ISO)[10] 22095 Standard and reflects the broader use of the term in other sustainability accounting practices.

<u>Book-and-claim for Biomethane</u>

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[5] <u>Appendix A-1: Proposed Regulation Order (Proposed Sections for Amendments)</u>. § 95481 Definitions and Acronyms

[6] For more information on the difference between attribute certificates such as RECs and emissions reductions/offsets, see the U.S. Environmental Protection Agency Guide to RECs and Offsets. Available atL https://www.epa.gov/sites/default/files/2018-03/documents/gpp_guide_recs_offsets.pdf

[7]Western Renewable Energy Generation Information System (WREGIS) Operating Rules. Available at: https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/WREGIS%20Operating%20Rules%20October%202022%20Final.pdf&action=default&DefaultItemOpen=1

[8] <u>Appendix A-1: Proposed Regulation Order (Proposed Sections for Amendments)</u>. § 95481 Definitions and Acronyms

[9] See Corporate and Voluntary Renewable Energy in State Greenhouse Gas Policy An Air Regulator's Guide. (pg.8). Available at: https://resource-solutions.org/learn/policy-solutions/

[10] ISO 22095:2020 Standard Chain of custody — General terminology and models. Available at: https://www.iso.org/obp/ui/#iso:std:iso:22095:ed-1:v1:en

4. We recommend that CARB remove the requirement that eligible pipelines must flow towards California at least 50% of the time.

CRS supports the LCFS program rules that biomethane use may be demonstrated via book-and-claim accounting. But we are concerned by the requirement that eligible pipelines must flow towards California at least 50% of the time. We request more information regarding the overall the purpose or need for this restriction, the rationale behind the 50% number, and how it will be verified and how often.

235.4

The use of book-and-claim accounting, without the pipeline flow restriction, is an appropriate and successful use of book-and-claim accounting as it recognizes the realities of common carrier pipelines—in which fossil methane and biomethane are blended and indistinguishable—and values incentivizing biomethane production without undue restrictions regarding physical traceability. Limiting book-and-claim accounting based on the physical flow of pipelines is inconsistent with its premise and the contractual basis for credible claims of biomethane use from common carrier pipelines that CARB has established. The direction of physical flow on the pipeline does not affect the biomethane use claim of the entity holding the attestation of environmental attributes.

Please refer to CRS's December 14, 2022, comments to the California Energy Commission[11] for suggestions regarding additional requirements for verification of credible use claims for book-and-claim accounting for biomethane using both Renewable Fuels Certificates and the Green-e® Renewable Fuels program.

<u>Book-and-claim for Hydrogen</u>

5. CRS supports allowing the purchase and retirement of attributes and use of contracts to demonstrate use of renewable energy for hydrogen production from both electrolysis and steam methane reforming (SMR).

235.5

Book-and-claim accounting practices for both renewable electricity and renewable natural gas (i.e., biomethane) rely on energy attribute certificates[12] (e.g., RECs and Renewable Thermal Certificates, RTCs, respectively) to demonstrate clean energy use. The sections below describe the importance of energy

[11] Comments on the California Energy Commission Clean Hydrogen Program under AB209 (Docket 22-ERDD-03). Section: "Hydrogen Produced by Steam Methane Reforming" Pg. 3-4.
Available at: https://resource-solutions.org/document/121422/

[12] Delivery of energy attributes may also be verified in contracts and attestations which specify which party retains the right to make environmental claims on the attribute, and that no other party may make claims on the attributes. Using established certificates (e.g., RECs and RTCs) and tracking systems facilitates verification of attribute ownership.

attributes for clean hydrogen produced by electrolysis or SMR. Allowing hydrogen production facilities to purchase attributes and use contracts to demonstrate use of renewable energy for hydrogen production (book-and-claim) is essential to the feasible implementation of a clean hydrogen pathway. Requiring the retirement of these attributes or verifying their contractual delivery for use in renewable energy for hydrogen production avoids double counting. Relying on existing market mechanisms and established best practices facilitates the growth of clean hydrogen.

Hydrogen Produced by Electrolysis

235.5

CRS supports CARB's requirement that "any renewable energy certificates or other environmental attributes associated with the energy are not issued credits or claimed under any other voluntary or mandatory program."[13] Verifying the use of renewable electricity for the production of hydrogen requires RECs. RECs are defined very clearly in California by the California Public Utilities Commission (CPUC) as including "all renewable and environmental attributes."[14] As such, RECs are required to substantiate delivery and use of renewable electricity and the specified CI of a renewable generation unit. Whether renewable electricity is procured for hydrogen production using onsite generation, a power purchase agreement (PPA), or a utility program, for example, the associated RECs should be retired to substantiate exclusive use of renewable electricity at that hydrogen production facility and prevent double counting. RECs may be retired in WREGIS by or on behalf of hydrogen production for registered generators. In the case that the renewable generator used is not registered with WREGIS, RECs or generation attributes should be transferred and retired contractually on behalf of hydrogen production.

Hydrogen Produced by Steam methane reforming (SMR)

In the United States, 95% of hydrogen is produced by SMR, a reaction between a methane source, such as natural gas, and high-temperature steam[15]. Biomethane, also known as renewable natural gas (RNG), is increasingly recognized for its lower lifecycle greenhouse gas emissions and presents an opportunity to lower the carbon intensity of Hydrogen produced by SMR. CRS support CARB's requirement for hydrogen produced from biomethane that "the entity claiming the environmental attributes has the exclusive right to claim environmental attributes associated with the sale or use of the biogas or biomethane."[16]

There are multiple pathways for producing RNG, each with their own environmental and social considerations. Many of the same factors that are relevant to producing high quality renewable energy,

[13] Appendix A-1: Proposed Regulation Order (Proposed Sections for Amendments). 95488.8. (i)(1)(C)5
[14] See CAL. PUB. UTIL. CODE § 399.12(h)(2).
[15] For further discussion see U.S. IRS (2020). HYDROGEN STRATEGY Enabling A Low-Carbon Economy. Available at: https://www.energy.gov/sites/prod/files/2020/07/f76/USIRS_FE_Hydrogen_Strategy_July2020.pdf
[16] Appendix A-1: Proposed Regulation Order (Proposed Sections for Amendments). 95488.8. (i)(1)(E)1

such as accounting for fuel delivery, using sustainable resources, credit vintage requirements, and facility age have bearing on RNG production as well. The Green-e® Renewable Fuels program can serve as a guide for the eligibility rules for the LCFS to ensure that RNG used in hydrogen production meets the highest standards and has positive impacts.

Please refer to CRS's December 14, 2022 comments to the California Energy Commission[17] regarding the use of both Renewable Fuels Certificates and the Green-e® Renewable Fuels program for additional information related to fuels certificates, time-matching, facility age, vintage requirements, and impact considerations for hydrogen.

We thank you for this opportunity to provide comments on the LCFS Program. Please feel free to reach out with any questions or comments.

Sincerely,
Lucas Grimes
Manager, Policy

[17] Comments on the CEC's Clean Hydrogen Program under AB209 (Docket 22-ERDD-03). Pg. 4-6. Available at: https://resource-solutions.org/document/121422/

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Comment 245 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jacqueline
Last Name	Moore
Email Address	jmmoore@pmsaship.com
Affiliation	PMSA
Subject	PMSA comments on LCFS Amendments
Comment	Please find attached Pacific Merchant Shipping Association's (PMSA comments on the proposed Low Carbon Fuel Standard (LCFS) Program amendments.
Attachment	www.arb.ca.gov/lists/com-attach/6912-lcfs2024-UyNVPlYkWWsFXFMw.pdf
Original File Name	PMSA Comments on LCFS Amendments 02.20.2024 Final.pdf
Date and Time Comment Was Submitted	2024-02-20 13:50:22

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

PMSA
PACIFIC MERCHANT SHIPPING ASSOCIATION

February 20, 2024

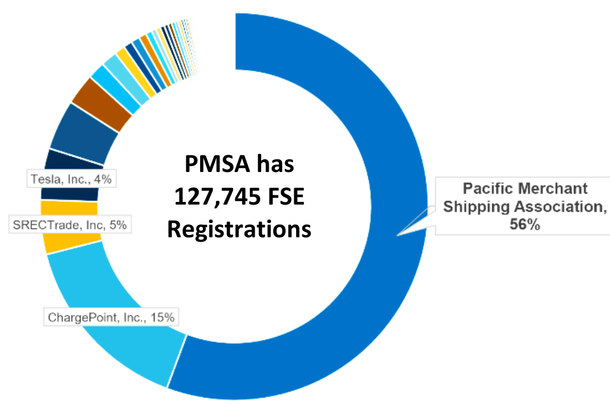
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Submitted electronically to: https://ww2.arb.ca.gov/lispub/comm/bclist.php

Comments Re: Proposed Low Carbon Fuel Standard Amendments (December 19, 2023)

On behalf of the members of the Pacific Merchant Shipping Association (PMSA), thank you for the opportunity to provide comments on the proposed Low Carbon Fuel Standard (LCFS) Program amendments. PMSA represents ocean carriers and marine terminal operators at California's public ports. In this capacity, PMSA also directly participates in the LCFS program on behalf of its member companies, facilitating the implementation of credit generation resulting in the broad and comprehensive participation by the maritime industry.

PMSA registers the largest number of Fuel Supplying Equipment (FSE) in the LCFS program statewide, with over 127,000 individual registrations today. As the largest program participant, PMSA submits these comments in support of the LCFS program overall, and to facilitate the successful continued participation by the maritime sector moving forward.



PMSA holds the most FSE registrations in California, at approximately 56%. As this graphic is based on Q1 2022 data, being the latest publicly available FSE registration data, PMSAs percentage has very likely grown due to continual eTRU registrations. PMSA may register 3,000 – 5,000 new FSEs *every quarter*.

236.1 As the single largest program FSE registerer, PMSA supports and welcomes raising the carbon intensity (CI)
targets and benchmark proposed, and we further support "auto-acceleration" to stabilize the credit market in
236.2 the event of rapid decarbonization. However, we are gravely concerned with the wholly unnecessary, wasteful,
and counter-productive proposed third-party verification for eCHE, eOGV, and eTRU transactions. These
unnecessary additions to the overhead cost of LCFS program participation will unduly impact the maritime
sector, reduce the monetary benefit of participation in the LCFS program and undermine the intent of the LCFS
236.3 program itself. PMSA does notsupport this proposal and urges CARB not to place new overhead and
administrative costs on its own successful program participants where no current program deficiencies have
been identified.

<u>Third-party Verification for eCHE, eOGV and eTRUs is Unnecessary and Diminishes Monetary Benefits</u>
PMSA strongly urges deletion of the additional proposed third-party verification requirements for eTRU, eCHE, and eOGV activities at items 2 through 4 of Section 95500(c)(1)(E). No clear and compelling justification exists for expanding third-party verification requirements to certain categories, including eCHE, eOGV, and eTRU, for Quarterly Fuel Transactions Reports (QFTR) (Section 95500(c)(1)(E)). To the contrary, the proposed expansion of third-party verification requirements will increase the costs of participating in the LCFS program, thereby diminishing the benefits of such a program, without meaningfully improving the quality of the data gathered. The eTRU, eCHE, and eOGV category third-party verification proposal specifically impacts the maritime sector, unjustly targeting the one sector that generates the single greatest source of credits, and which has an unblemished multi-year track record, as PMSA has complied and successfully participated in the program since its inception.

In most instances, PMSA utilizes reliable meter readings for equipment on dedicated circuits provided by the utility. In the few instances where utility meter data is not available, PMSA collects power consumption data directly from on-board telematic systems. All data collected over the course of the program is always available, and always has been available for CARB audit review upon request, at PMSA's expense. Third-party verification of these data sources upfront would not improve the existing high level of data quality or unparalleled availability of original data CARB staff on demand. As PMSA already utilizes the most accurate and reliable data
236.3 sources for reporting electrical usage available, *third-party verification is simply unnecessary for eCHE, eOGV, and eTRU transactions.*

Further, unlike eCHE and eOGV, eTRU equipment are not based at only one specific facility and must be individually registered for each usage every quarter. The LCFS regulation requires a new registration with a unique identifier based on the location. *PMSA can register 3,000 – 5,000 new FSE every quarter*. Due to this mobile nature and the immense quantity of eTRU activity and ongoing FSE registrations, third-party verification is not even possible for eTRU equipment, especially for third-party verification site visits.

As relayed previously, we are unaware of any specific data reliability or audit issues that exist with the current program. CARB staff have not identified any deficiencies which require changes to the program in order to be remedied. PMSA welcomes a discussion of those issues should they arise. In such an instance, we would expect CARB to facilitate a conversation about any existing concerns and how to effectively remedy those problems with our participating member companies and our consulting team and to specifically iron out those issues ahead of any significant programmatic changes. PMSA is also always ready to pro-actively organize a specific tour or demonstration at any time for CARB staff at a marine terminal in order to demonstrate the industry's reliable data collection methods should CARB staff find a theoretical weakness that should be explored, but which is currently unidentified.

As the single largest LCFS program FSE, the maritime industry remains transparent in its desire and eagerness to grow and expand its participation in the LCFS program. Unfortunately, the third-party verification proposal does nothing beyond only increasing the administrative burden and costs of participants. As far as we can ascertain, this proposal would only benefit the accredited verifiers who would be exercising the verification effort.

No real rationale is offered as justification in Appendix E ("Purpose and Rationale of Proposed Amendments for the Low Carbon Fuel Standard Requirements"). As no real deficiency is identified with respect to existing eTRU, eCHE, and eOGV activities, which are not currently subject to third-party verification, no justification is asserted for the claim that CARB must ensure "…electricity and hydrogen associated transaction types are held to the same standard of data quality through third-party verification." (Appendix E, page 117).

Electricity as a whole only accounted for approximately one quarter of the total 2022 annual credits. While it is claimed that "data assurance needs" for these sources cannot be met with the staffing capacity of CARB (Appendix E, page 117), as noted, there is no current program defect compelling third-party verification for all transaction types. Moreover, any additional burden estimated by CARB staff based on future potential data needs are counter-intuitive; in fact, if electricity and hydrogen transactions do continue to grow, the administrative burden would actually *decrease* for CARB. Any increased burden would only exist by CARB's own making: by amending Section 95500(c)(1) to include the fuel transaction types in question. And, as a result, both the state and regulated, participating community would find their administrative costs increased.

No Clear Estimate of Total Third-Party Verification Expenses for Aggregated Participants is Provided, Whilst the Outstanding New Liabilities Might Be Extraordinary

236.3 Given the lack of specifics, CARB cannot reliably calculate the total cost and expense of third-party verification, but all parties acknowledge that it is certainly significant. Even though it is currently impossible to calculate third-party verification service expenses because of the many questions which remain as to what CARB would actually require for electrical transactional verifications, the costs to an FSE aggregator such as PMSA could be staggeringly high relative to the value of the credits generated.

As PMSA works on behalf of its member companies to administer and aggregate credit generation at multiple facilities and locations in California, these many unknown variations in site visits could significantly alter expenses incurred. For example, is a physical site visit to every location where a charger is installed to be required? Or, is a site visit to the company or administrator headquarters sufficient? Given the number of participating PMSA members and locations, the total cost per annual visit has been estimated at $100,000 - $150,000, not including plan preparation, review and other administration services required for verification. A $150,000 expense per year and/or per visit, is not insignificant and may render the LCFS program impractical for PMSA or specific members, undermining the LCFS program's effectiveness. These funds, which would otherwise be utilized for expanding electrical capacity and purchasing zero-emissions equipment and infrastructure, would now either be eaten up as overhead costs, or result in foregone participation altogether. In practical terms, this $150,000 could instead fund approximately six heavy-duty eCHE chargers at the ports, directly championing the state's, port's, and maritime industry's goal of 100% zero-emission cargo handling operations.

236.3 Eligibility for less intensive verifications for the electrical transactions in question is proposed per Section 95500(h); however, questions remain on what the "less intensive verification services" entail for the following two annual verifications. If site visits are still to be required, the expenses would not be reduced, regardless of "intensity." While in some instances it might be reasonable to require one initial site visit to the company or administrator headquarters for the first annual electrical transaction verification, even in such a scenario no subsequent site visits should be necessary. FSE data will remain always available as needed, based on operations and the data collection mechanism utilized. Site visits should not be required for any data collected via the utility meter or directly from on-board telematic systems.

Electrical Transaction Third-party Verifications Would be Challenging Timing Wise and May Result in a Barrier to Credit Generation Altogether

236.3 PMSA also has concerns regarding the timing and the frequency of reviews, as they may restrict access to credit generation. In many instances, utility data is made available with very limited time remaining prior to required submittal timelines to CARB. If third-party additional reviews are to be required, there may very well be insufficient time for a third-party to complete their review and verification to meet the deadlines for LCFS credit generation in a specific quarter. Third-party verification for eCHE, eOGV, and eTRU transactions may cause Annual and Fuel Transaction Reporting delays, thereby threatening credit generation and associated proceeds, further undermining the intent of the LCFS program.

While we understand the CARB intends these changes to increase accountability and transparency in these transactions, they must be balanced against the overall health and effectiveness of the LCFS credit market. The participants in the current program have demonstrated exceptional transparency and high participation rates, even during periods of very low prices for credit generation. These changes which threaten that stability, high levels of participation, and access to the credit market should be studiously avoided.

We appreciate the opportunity to provide comments regarding the LCFS amendments. PMSA strongly urges CARB to reject the proposed third-party verification requirements for eTRU, eCHE, and eOGV transactions. We welcome facilitating an ongoing conversation on how to effectively remedy any perceived issues as it relates to electric equipment activity by our members. Please feel free to reach out to us by email (jmmoore@pmsaship.com) should you have any questions.

Sincerely,

Jacqueline M. Moore

Jacqueline M. Moore
Vice President

Cc:
Steve Cliff, Executive Officer
Heather Arias, Division Chief

Comment Log Display

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Comment 246 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Bang
Last Name	Phung
Email Address	bang.phung@ladwp.com
Affiliation	LADWP
Subject	Los Angeles Department of Water and Power (LADWP) LCFS Comments
Comment	Please see attached for LADWP's comments on the LCFS proposal.
Attachment	www.arb.ca.gov/lists/com-attach/6914-lcfs2024-UT1dOlcyByMDdQJd.pdf
Original File Name	LADWP Comments on 2024 LCFS Proposed Amendments 2.20.2024 signed.pdf
Date and Time Comment Was Submitted	2024-02-20 14:31:35

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

Honorable Chair Liane Randolph and Honorable Board Members
California Air Resources Board
1001 I Street
Sacramento, CA 95814
Submitted Electronically

Subject: Los Angeles Department of Water and Power's Comments on California Air Resources Board's Proposed Amendments to the Low Carbon Fuel Standard Regulation

Dear Chair Randolph and Honorable Board Members,

The Los Angeles Department of Water and Power (LADWP) appreciates the opportunity to provide comments on the California Air Resources Board's (CARB) Proposed amendments to the Low Carbon Fuel Standard (LCFS) Regulation (Proposal) posted on December 19, 2023, and updated on January 1, 2024. LADWP reaffirms its strong support of the LCFS program and its role in achieving the substantial greenhouse gas (GHG) emissions reductions goals of AB 32, SB 32, and AB 1279.

As an electrical distribution utility (EDU), LADWP is the largest municipal electric utility in the nation, serving approximately 1.4 million residential and business customers. As a large publicly owned utility, LADWP is in the most optimal position to promote transportation electrification and reduce financial impacts to our customers by investing in programs that benefit everyone. LADWP offers the following comments on the proposed amendments for your consideration.

I. <u>§ 95484. Annual Carbon Intensity Benchmarks and Automatic Acceleration Mechanism</u>

The LCFS regulation is vital to decarbonizing the transportation fuel sector. LADWP supports CARB's proposed 30% reduction in fuel carbon intensity (CI) by 2030 and 90% reduction in fuel CI by 2045. To comply with long-term zero-emission vehicle adoption targets of regulations such as Advanced Clean Cars II, Advanced Clean Fleets, Advanced Clean Trucks, and others, which have deadlines in 2045, extending the LCFS program will continue providing essential support for the transition. LADWP agrees with CARB staff that long-term deployment of low carbon technologies is necessary to achieve long-term transportation decarbonization goals.

237.1 Additionally, LADWP supports the proposed near-term step-down and Automatic
Acceleration Mechanism. LADWP agrees that there needs to be a mechanism in place
237.2 to enhance the stringency of the standard if and when transportation decarbonization
advances more rapidly than staff initially anticipated.

II. § 95483(c)(1). Updates to Residential EV Charging

a. *Base Credits*

LADWP has been a long-time advocate of electrifying the transportation sector. From
light-duty electric vehicle charger rebates first offered in 2013 to medium- and heavy-
duty vehicle charger rebates in 2018 and previously owned electric vehicle rebates
expanded in 2023, LADWP continues to develop various programs that promote electric
vehicles and increase benefits to disadvantaged communities and low-income
customers. LADWP relies on the LCFS program to continue funding these equity-
focused efforts while reducing the financial impacts to our customers. LADWP supports
237.3 the proposed reduction in the Publicly Owned Utilities' (POUs') minimum base credit
contribution required to fund the Clean Fuel Reward and the corresponding increase in
237.4 the holdback credit which will help fund LADWP's transportation electrification
programs.

b. *Restrictions on Use of Holdback Credits*

LADWP supports the Proposal to keep the holdback equity requirement for POUs at
237.4 50% as stated in Appendix E (page 15) of the Proposed Amendment. However, this is
not reflected in the language of the proposed regulation in section 95483(c)(1)(A)5.a.
LADWP recommends that CARB staff amend the language of the proposed regulation
to explicitly state the holdback equity requirements for POUs for clarification.

LADWP also agrees that the projects listed under section 95483(c)(1)(A)5.a. (Holdback
Credit Equity Projects) unconditionally support the equity community and applaud
237.5 CARB's efforts to include them. Under this section, a list of preapproved projects follow
the statement, "These projects may include:", which casts uncertainty on whether all
listed projects qualify as supporting equity. LADWP asks that CARB amend the text to
clarify CARB's intent that the list of preapproved projects unconditionally supports equity
(i.e. regardless of location of the project).

Section 95483(c)(1)(A)5.b. (Other Holdback Projects) of the Proposed Amendment
states that, "Holdback projects that are not specified in subsection 95483(c)(1)(A)6.a.
237.5 must follow the requirements…". LADWP asks CARB to verify whether subsection
95483(c)(1)(A)6.a. was incorrectly cited and instead was intended to refer to
95483(c)(1)(A)5.a.

Depending on which activities qualify towards the definition of administrative cost, the
proposed reduction in allowable administrative costs for holdback credit equity projects

237.6 to 5 percent of total spending on holdback credit equity projects may be too low, as proposed in section 95483(c)(1)(A)5.c. There is a misalignment on what is considered administrative cost between CARB's programs (i.e. LCFS guidance and Cap-and-Trade guidance), and other regulators (i.e. CPUC's Energy Efficiency Policy Manual). LADWP recommends that CARB staff clearly define and list examples of activities that are considered administrative and consider keeping the allowable administrative cost at 10 percent for holdback credit equity projects.

III. § 95483(c)(2), 95491(d)(3)(A), and 95491(e)(5) Uses of Electricity Credit Proceeds for Non-Residential Electrical Vehicle Charging

The reclassification of non-limited chargers located at multi-family residences as non-residential EV charging, and subsequent changes to sections 95483(c)(2)(C), 95491(d)(3)(A), and 95491(e)(5), raise questions on the requirements for non-Load Serving Entity (non-LSE) owners of EV chargers at multi-family residences. In the Proposed Amendment, section 95483(c)(2)(C) includes a revision that replaces the requirements set forth in paragraphs 2. through 7. in section 95491(d)(3)(A) with requirements in section 95491(e)(5). The original language in paragraph 7 of section 95491(d)(3)(A), which is copied below, clearly cites the specific requirements for non-LSE owners making it clear how the cost of charging is applied:

> "A non-LSE credit generator must use credit proceeds to benefit EV drivers and their customers and educate them about the benefits of EV transportation (including environmental benefits and costs of EV charging, or total cost of ownership, as compared to gasoline). The credit generator must include, in their Annual Compliance Report, an itemized summary of efforts and costs associated with meeting these requirements."

The new proposed language under Section 95491(e)(5), as cited below, on the other hand, is more general and lacks the pertinent information that the previous language specified:

> "Entities generating credits from electricity must use all credit proceeds to further transportation electrification efforts in California. The credit generator must include, in their Annual Compliance Report, an itemized summary of efforts and costs associated with meeting this requirement."

237.7 LADWP is concerned with the new language's shift of allowable use of credit proceeds from benefitting EV drivers and customers to a more general "further transportation electrification efforts." From LADWP's experience, even with the current customer-focused requirements, credit proceeds are not being passed down to customers via affordable rates or incentives at multi-family residences. After charger installation, single-family residents pay little more than the cost of electricity to fuel their EVs. By contrast, multifamily residents can be subjected to additional fees, benefiting operators or landlords, eliminating the driver's cost savings versus fueling with gasoline. The cost of charging may be a barrier for EV adoption for residents of multifamily buildings. LADWP recommends that CARB consider amending the proposed language to include provisions to protect the customers, such as requiring non-LSE credit generators with

237.7 EV chargers located next to a multi-family residence to provide affordable rate options to those multifamily residents.

IV. § 95486.2(b) and 95486.3(b). Generating and Calculating Credits for ZEV Fueling Infrastructure Pathways

237.8 LADWP supports the proposed amendments that expand the current ZEV infrastructure crediting provisions beyond light-duty (LD) infrastructure to medium- and heavy-duty (MHD) infrastructure and extending the light-duty crediting. LADWP believes that infrastructure crediting will help reduce the risk of under-utilized chargers and will drive the buildout of necessary infrastructure.

V. § 95501. Requirements for Validation and Verification Services

Staff's proposal to add third-party verification requirements for EV charging except for section 95491(d)(3)(A) (non-metered residential) means that metered residential transactions, for base credits or incremental credits, will be subject to verification. Verification of residential EV charging may be challenging because of the required site visits.

Section 95501(b)(3) states that, "*Site Visits*. At least one lead LCFS verifier accredited by the Executive Officer on the verification team must, in addition to one visit to validate an application, annually visit each facility; and, if different from the fuel production facility, the central records location for which the records supporting an application or report subject to verification are submitted."

237.9 Annual site visits to *each* facility for verification of Quarterly Fuel Transactions Reports can be time consuming and burdensome. Fuel transactions that are low risk can easily be verified using the Lookup Table CIs, site visits, especially for the verification of residential EV charging data. LADWP recommends that CARB staff amend or add language that allows for site visits at a central records location for these types of verifications or exempt these transactions from the site visit requirement. Additionally, for small credit generators, it may not be financially feasible (even with deferred verification) to hire third-party verifiers. LADWP recommends verification exemption, through the Executive Officer approval process, for when the cost of verification exceeds the value of the LCFS credits generated.

In closing, LADWP appreciates the opportunity to provide comments and feedback on these important topics. If you have any questions about LADWP's comments, please contact Ms. Andrea Villarin at (213) 367-0409 or Mr. Bang Phung at (213) 367-8689.

Sincerely,

Katherine Rubin
Director of Corporate Environmental Affairs

BP:
c: Ms. Rajinder Sahota, CARB
Mr. Matthew Botill, CARB
Mr. Jacob Englander, CARB
Mr. Jordan Ramalingam, CARB
Ms. Andrea Villarin
Mr. Bang Phung

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Comment 247 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Michael
Last Name	Daley
Email Address	mdaley@carbonsolutionsgroup.com
Affiliation	Carbon Solutions Group
Subject	CSG Comments on the Proposed LCFS Amendments
Comment	Please find attached comments from Carbon Solutions Group on the proposed LCFS amendments. Thank you for your time and attention.
Attachment	www.arb.ca.gov/lists/com-attach/6916-lcfs2024-UDNWMV0uBDUGb1U7.pdf
Original File Name	Carbon Solutions Group_Comments on the Proposed LCFS Amendments.pdf
Date and Time Comment Was Submitted	2024-02-20 14:29:57

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20th, 2024

To the California Air Resources Board:

Thank you for your innovation and dedication to making California the standard by which all other environmental policy is judged. As a developer of electric vehicle charging infrastructure and member of CalETC, Carbon Solutions Group strongly supports California's LCFS program. We consider this program to be the main lever in statewide EV adoption, as well as the model for so many emerging fuel standards across the country.

Today, CARB's progressive policies remain as crucial as ever for driving zero emissions economic development. Notably, EV sales have recently seen a significant, and surprising, slowdown. Various other recent indicators of industry trouble include Hertz announcing that it will jettison 20,000 EVs from its fleet (to which the market responded favorably) as well as media commentators warning of consumer "range anxiety" cooling interest in pure EVs. Over the last several years, low utilization rates and macro-economic factors have also resulted in EV industry burnouts and below market acquisitions by oil and gas majors.

Thus, this next round of LCFS amendments may be decisive when it comes to pushing EV adoption into the mainstream. This is especially the case regarding LD EV adoption amongst historically disenfranchised communities, which maintain the lowest utilization rates and the least financial incentive to abandon gasoline. Presently, as CARB no doubt already knows, LD EVs appear to be most utilized in higher-income homes, and often as secondary vehicles. And while we agree with CARB that EV sales will increase in the years to come, we are not confident that an increase in vehicles will, *de facto*, be evenly distributed across income types, nor that EV sales will necessarily increase linearly with throughput. EV sales and EVSE development remain on two separate, but linked, trajectories.

For the disenfranchised, several fundamental obstacles are presently at play. DCFC economics in low-income/low utilization areas often result in a high price-per-kWh of throughput, which can end up with a "pump price" greater than gasoline. This high price-per-kWh is caused by the low utilization (thus expenses are spread across fewer kWhs) as well as the fact that wear-and-tear costs are more prevalent in public charging stations (as opposed to MHDV stations which are frequented by professionally trained drivers). Perhaps most important, access to home charging is a critical factor when prospective combustion engine drivers consider EV adoption. It appears that most low-income drivers do not currently have access to L2 home charging.

In short, to reach an inflection point in which EVs become the primary mode of transport in California, we believe EVs will need to become the primary mode of transport for middle- and low-income drivers. While EV adoption amongst the upper classes has been largely ideological in nature, EV adoption amongst those struggling paycheck-to-paycheck needs to be a purely economic decision. That decision will be based on whether sound EVSE businesses can offer price competitive charging optionality. Thus, California's stated climate goals will continue to require policy-driven economics that aggressively incentivize the installation and operation of charging infrastructure.

To that end, we are supporters of CalETC's recommendations for the present round of proposed LCFS amendments, in both LDV and MHDV categories. In addition to the group's formal recommendations, we also propose the following items for your consideration. In some cases (e.g., base credit qualification), we offer an appeal outside the scope of CalETC's position. In other cases (e.g., deficit cap and geographic restrictions), we echo CalETC's formal recommendations.

Residential: Base Credit Qualification

As per Section 95483(c)(1)(A), EDUs presently retain base credits for metered and non-metered residential charging infrastructure. We see this statute potentially undermining the larger goal of majority EV adoption.

From an economic perspective, the inability for an EVSE owner to claim a base credit eliminates a key incentive for that owner to implement charging infrastructure. Considering single-family homeownership has become cost-prohibitive for many Californians, multi-unit dwellings and rentals are particularly important. By awarding residential EVSE owners with base credits + incremental credits (whether single-family or multi-unit), we believe middle- and low-income EV adoption will significantly increase.

While we recognize that EDUs do in fact use base credit earnings to distribute zero emission rebates to disadvantaged/low-income communities, we believe that this indirect allocation does not efficiently incentivize the primary risk takers in California's LCFS—the producers of low-carbon fuel solutions. Directly incentivizing these builds is paramount when it comes to establishing a landscape in which low-income EV adoption is possible. In other words, if the charging infrastructure is not readily available, indirect rebates to drivers/homeowners may be irrelevant.

Additionally, by providing the option for aggregators to also participate in base + incremental credits (along with the EVSE owners), CARB could establish an incentive to create an efficient framework that limits the potential for individual account creation overload, while still rewarding individual residential accounts.

238.1 At minimum, awarding base + incremental credits to EVSE owners for L2 communal parking in multi-unit dwellings would make the most substantial impact in any single property category, as a communal charging option in multi-unit/rental residences can open up the opportunity for low-to-middle income drivers to adopt EVs with greater ease. Growth in communal L2 charging in multi-unit dwellings can also help support CARB's broader goal of achieving a greater volume of distributed charging points rather than fewer, congested charging points.

238.1 Yet, from the regulator's perspective, it is important to drive advances in innovative, clean infrastructure and not to merely spur adoption of existing supply chains. To that end, another element that could further justify awarding EVSE/network owners with base + incremental credits could be that the award is premised on the installation of bi-directional chargers for multi-unit and/or single-family residences. Bi-directionality is a value-add that would further both grid resilience and California's climate goals.

Residential: Metered Base Credit Qualification

As is known, in metered residential scenarios, EDUs have no access to specific charge point metering, unless the EDU operates the charge point itself or the charge point is on its own sub-meter. Therefore, EDU-qualified non-metered base credits are necessarily premised on assumptions. Because these factors are based on averages, rather than actual utilization (which can vary widely), these base credits do not rely on the best available data that accurately reflects real world utilization dynamics.

On the other hand, designated aggregators, EVSE owners, and telematics-enabled vehicle owners have access to real utilization data specific to each charge point/vehicle. This data is exact and not based on averages.

238.2 We respectfully appeal to CARB to consider awarding base + incremental credits to qualified EVSE owners/aggregators that are able to report actual, metered utilization data. This base + incremental credit qualification would prioritize best available data whenever it is available. In turn, this would likely lead to more stringent credit generation, as the metered credits would be based on *actual* utilization rather than *estimated* utilization. In this way, the aggregator/EVSE owner can be rewarded for providing CARB with the best available data.

Public-Private: Verification Requirements

238.3 By allowing designated aggregators and EVSE owners to participate in base + incremental credits, the verification process can also be optimized at a lower cost and faster speed.

CARB's proposed verification requirements (i.e., that site hosts must pay for 3rd party in-person verification) will incur significant costs and operational friction that fall outside of current industry models, in turn, severely damaging overall industry momentum. However, we believe that, by providing CARB with real utilization data, designated aggregators and EVSE owners can easily enable a purely desktop verification methodology that will 1) achieve equitable if not greater integrity at a lower economic cost than in-person site visits; and 2) efficiently eliminate potential redundancies in the process.

Regardless of the above, we also respectfully suggest a change regarding the proposed verification deferment option for entities generating less than 6,000 credits/year. Instead, we recommend that entities that generate less than 2,001 credits/year be exempted from all verification, and that those applicants with 2,001 to 6,000 credits/year be eligible for deferment of 3rd party in-person verification.

238.4 Likewise, we respectfully ask CARB to further clarify that only credits subject to verification count towards the credit cap for deferment or exemption. Overall, we believe

238.4 cont deferment and exemption can potentially have a sizable impact in incentivizing residences to come online with charging infrastructure.

Public-Private: DCFC for Multi-Unit Dwellings

Certain L2 installations for multi-unit dwellings face logistical challenges, particularly for retrofits of existing properties. In some cases, common parking spaces are limited, leading to an undersupply of L2 charging points within the dwelling's parking lot (if such a lot even exists). In other cases, structural complexities may pose too great an obstacle for L2 installation on site.

238.5

In addition to allowing EVSE owners to retain both the base + incremental credits, one remedy to this challenge would be to incentivize DCFC infrastructure on-site, adjacent, or proximally located within five miles of a multi-unit dwelling. Proximal fast charging can compensate for cases where there is an insufficient number of L2 chargers, and still address an underserved population that is central to the broader goals of the EV industry and the State of California. FCI credits allotted to multi-unit-based/adjacent DCFC, even if not publicly accessible to non-tenants, could provide the proper incentive in this regard.

Public: FCI Parity with Hydrogen (HRI)

238.6 We believe there is a lack of equity between the proposed LD FCI program and the LD HRI program. Specifically, we strongly appeal to CARB to reconsider the allowance of REC matching to achieve 0 CI electricity in the FCI formula. Doing so, would create equal conditions for FCI and HRI, as currently only H_2 can claim 0 CI as per the proposed regulation.

Carbon Intensity Step-Down

238.7 We believe that an immediate CI step-down of at least 7% (instead of 5%) would help push the market to more significant levels of emissions reduction. Again, we believe that the next few years are a time in which to push forward ever more aggressively in meeting California's climate goals.

Public: LDV FCI—Deficit Cap

Considering the precarious economic landscape laid out above, we recommend that CARB retain the 2026-2030 deficit cap at today's 2.5% (rather than the proposed 0.5%).

238.8

To reach California's goals, as set out by ACC II, more than an 8x increase in DCFC will be required, as today's ~10,000 DCFC must reach 83,000 in the next eleven years. Likewise, ACC II calls for a dramatic increase in EV sales—with today's 20% market share needing to reach 100% in the next eleven years. However, even if this ambitious increase in EV sales is achieved, a correlating increase in DCFC is unlikely to be supported by market-driven consumer demand alone for some of the reasons laid out previously in this letter. And, conversely, if extensive charging infrastructure does not materialize, an exponential growth in EV sales may be hard to manifest on its own. Therefore, policy-driven DCFC economics will remain a necessity to reach ACC II objectives. Without strong policy-based incentives, low utilization areas (e.g., low-income, rural, etc.) will suffer the worst from a lack of DCFC infrastructure.

238.8 cont Within this context then, we do not believe a 0.5% cap will sufficiently incentivize DCFC to ACC II levels. Instead, a 0.5% cap would likely spur a major slowdown in DCFC development.

Public: LDV FCI—Geographic Restrictions

238.9 For similar reasons laid out above (re: maintaining a 2.5% cap), we also contend that geographic restrictions on public FCI would likely impinge on greater EV adoption, particularly among the low-income and middle-income communities that are the most important to incentivize. Geographic restrictions will likely cause investor confusion and conservatism (whether deserved or not) at a time when more capital needs to be deployed for infrastructure in low utilization locales.

In both cases (re: 2.5% and no geographic constraints), we do not project an oversupply of credits due to the self-limiting nature of FCI—in that as kWh consumption increases, the FCI credits decrease. More so, CARB's novel acceleration mechanism should successfully buffer against significant credit devaluation.

Public: FCI Timing for LDV

238.10 As per the amendment of Subsection 95486.2(b)(4)(H): While we fully support this helpful capex multiple, we respectfully appeal to you, to qualify it for immediate application upon passage of the regulation (ca. 2024), as opposed to its stated 2026 start date. As noted above, a variety of pressing economic challenges currently face public charging infrastructure. The ability to utilize this amendment sooner than 2026 would be most efficacious in bridging and rapidly scaling up LD charging infrastructure, particularly in those low-income areas that could most benefit.

We appreciate the time and attention you have given to considering the details of this letter. We commend you on your leadership and look forward to implementing another phase of a world-changing program.

Best Regards,

Michael Daley
Carbon Solutions Group
mdaley@carbonsolutionsgroup.com

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Comment 248 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Dan
Last Name	Ress
Email Address	dress@crpe-ej.org
Affiliation	Center on Race, Poverty & the Environmen
Subject	Coalition Comment on Direct Air Capture and Enhanced Oil Recovery in the LCFS

Comment

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Hello,

I'm submitting a letter from environmental justice, environmental,
public health, and labor groups requesting that CARB remove direct
air capture and enhanced oil recovery using captured carbon from
the Low Carbon Fuel Standard.

Please feel free to reach out with any questions.

Wishing you well,

Dan Ress
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Attachment	www.arb.ca.gov/lists/com-attach/6917-lcfs2024-VDgAZVA3BCQKU1Q3.pdf
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If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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CCAC Central California Asthma Collaborative
STAND.earth
Leadership Counsel for Justice & Accountability

February 20, 2023

Liane M. Randolph, Chair
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Submitted via CARB's online Comment Submittal Form

Re: Opposition to the Proposed LCFS Provision to Allow Direct Air Capture Crediting Nationwide and to the Continued Crediting of Enhanced Oil Recovery Using Captured Carbon

Dear Chair Randolph and members of the CARB Board,

The undersigned groups write to express their strong opposition to the California Air Resources
239.1 Board (CARB) staff proposal regarding the Low Carbon Fuel Standard (LCFS), specifically provisions
regarding nationwide direct air capture (DAC) crediting and carbon capture and storage (CCS) crediting
239.2 for projects that use captured carbon for enhanced oil recovery (EOR). These two programs risk
undermining any climate benefits from the LCFS while exacerbating environmental injustice. As such, we
urge CARB to revise the staff proposal to eliminate crediting for DAC and EOR using captured carbon.

DAC does not belong in the LCFS because it is not a transportation fuel.

The LCFS is a market mechanism intended to reduce the carbon intensity of California's transportation fuels. DAC is a new, speculative technology—so far never deployed at scale—that aims to reduce atmospheric carbon dioxide (CO2) by capturing it from the ambient air. The main product of DAC is CO2, a waste product from excessive combustion that must be buried deep underground.[1] While there are proposals to use CO2 to create new transportation fuels, in almost all cases CO2 from DAC will not be

239.1 cont used to create fuels, let alone transportation fuels in California. Since it has no apparent relationship to California's transportation fuels, DAC does not belong in a program intended to address the carbon intensity of California's transportation fuels, and it should be omitted from the LCFS.

Including DAC in the LCFS would delay necessary direct emissions reductions and the phase out of fossil fuels.

The combustion of fossil fuels is the primary driver of the climate crisis, and the scientific consensus is that they must be phased out quickly to prevent global catastrophe and the collapse of human civilization. At the same time, the combustion of fossil fuels causes severe air pollution across the world, the nation, and the state, including in the San Joaquin Valley, the nation's worst air basin. Moreover, that air pollution burden is not just concentrated geographically but also socioeconomically and racially such that low-income communities of color are much more likely to live with far worse air pollution. As such, both public health and environmental justice require the swift phaseout of fossil fuels.

Over-reliance on CDR would present the grave moral hazard of delaying direct emissions reductions and the phaseout of fossil fuels. If we delay this needed action, we risk exacerbating the environmental justice, public health, and climate crises, and ultimately the collapse of our civilization.

239.1 cont Because the LCFS is a market mechanism that relies on tradable credits, any projects that generate credits allow the continuation and development of projects that need to purchase credits, such as fossil oil and gas refining. DAC crediting will thus directly facilitate the combustion of fossil fuels that would otherwise not be burned (or would need to be offset by other low-carbon-intensity fuels in California's market). The net impact is to decrease our ambition to reduce combustion of fossil fuels.

DAC must be reserved for truly hard-to-decarbonize sectors because it is so energy intensive and expensive.

The transportation sector can be decarbonized without relying on offsets from CDR such as DAC. CARB's own Advanced Clean Cars and Advanced Clean Fleets rules and accompanying analyses show that ambitious transition to zero emission vehicles (ZEVs) is possible in this sector. While transoceanic shipping and aviation are more difficult to decarbonize, those subsectors, too, include realistic decarbonization pathways in the relevant time frame.

[1] Captured CO2 can also be used. The only use for CO2 proven at scale is for EOR, discussed further below.

Because carbon is just 0.0421% of the atmosphere, capturing it from the ambient air is exceptionally expensive and energy intensive.[2] Considering the challenges of quickly deploying renewable energy with storage and transmission as we electrify our economy, we should be cautious about embarking on projects that require gross expansion of renewable energy capacity to power them. In the face of this reality, insofar as the state decides to include DAC in its climate plans, we must reserve DAC to offset emissions from truly hard-to-decarbonize sectors.

239.1 cont DAC, insofar as the state relies on it despite its cost, energy burden, and lack of proven track record at scale, must not be used to offset transportation emissions—where other solutions exist—but instead must be reserved for other sectors without viable decarbonization options.

DAC only makes sense if it is carbon negative, yet crediting DAC in the LCFS ensures that it can be carbon neutral at best.

Given the moral hazard and extreme expense and energy burden of DAC, it only makes sense to employ DAC when it is carbon negative. However, when a DAC project generates LCFS credits, those credits will be acquired by fossil oil refiners, offsetting any possible reduction in atmospheric carbon and at best resulting in the DAC project being carbon neutral. DAC projects that are not carbon negative offer no benefit, but rather waste precious climate funding on fossil fuel greenwashing.

The staff proposal allows double- and triple-counting DAC credits, potentially resulting in significant increases in carbon emissions.

In other provisions of the proposed LCFS amendments (e.g., book-and-claim electricity, book-and-claim RNG, book-and-claim hydrogen, renewable or low-CI process energy), the regulation text prohibits generating LCFS credits if the Renewable Energy Certificates (RECs) or environmental attributes are "being claimed in any other voluntary or mandatory program" with certain exceptions. Conspicuously absent from this provision are both DAC and CCS projects.[3] As such, DAC projects credited under the LCFS are likely to generate credits in multiple programs, and thus to offset carbon emissions in multiple markets. Anywhere DAC generates credits, it allows further emissions, so where credits are stacked, it effectively allows double or even triple counting. In other words, under the staff proposal, credited DAC projects could effectively cause emissions to increase by a factor of two or three relative to a scenario in which DAC does not occur—an outcome that would be simply unacceptable.

And that analysis only considers literal crediting programs, leaving out other incentive programs. If a project collects a grant from the U.S. Department of Energy, for example, the federal government will likely claim its negative carbon emissions in its own accounting while the project also generates offsets in the LCFS and other markets, allowing further over-counting. The above also leaves out opportunity costs, such as of the foregone transition from fossil fuels to renewables, with the renewable capacity that could

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[2] See, e.g., Sekera, J., Lichtenberger, A., Biophys Econ Sust., *Assessing Carbon Capture: Public Policy, Science, and Societal Need* (Oct. 2020), https://doi.org/10.1007/s41247-020-00080-5.
[3] E.g., Section 95488.8(i)(1)(B)(3).

have been used for the transition instead going to DAC. The implications from employing such flawed accounting in our climate programs is very alarming.

To be effective and safe, nationwide DAC projects need better oversight than CARB can provide through the LCFS.

Outside of California, CARB has a limited presence and jurisdiction. While CARB can certainly review documents from out of state, it is unlikely to conduct frequent onsite inspections for DAC projects in, say, Louisiana, but rather will count on oil majors to honestly conduct their operations, despite the well-documented history of oil companies lying for decades about climate science.[4] Without careful oversight, projects likely will not provide any climate benefits at all and may instead cause net increases of greenhouse gases. Further, poor oversight and weak regulations in other states may result in significant local harms.[5]

DAC's extreme energy demands can be met by any energy source, but CARB must ensure that, where it allows or incentivizes deployment, DAC only employs clean renewable energy with storage. However, some DAC projects plan to use fossil fuels for energy, such as one of the Carbon TerraVault projects that intends to use methane fuel cells , which will paradoxically yield greenhouse gas emissions while trying to capture CO2. Meeting DAC power demands with fossil fuels, whether onsite or through the grid, could cause projects to generate more greenhouse gases than they capture. In addition, they will cause local harms along the lifecycle of those fossil fuels, from extraction to refining to transportation to storage to combustion.

239.1 cont

Insofar as DAC projects plan to rely on the electrical grid as a primary or secondary energy source, the projects will only be clean if the grid is clean, which will not be the case until it is fully supplied by renewables with storage. Further, renewable supply consumed by DAC is renewable supply that cannot meet other energy demands, so the proper baseline for assessment is against the grid with the same capacity but without DAC.

Given the impossible task of ensuring broad compliance with such tight parameters nationwide, CARB staff cannot responsibly manage such a program and call it CDR. As such, CARB must remove nationwide DAC crediting from the LCFS.

DAC must be deployed sparingly because of local harms.

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[4] See, e.g., Louis Sahagún, Los Angeles Times, California sues five major oil companies for 'decades-long campaign of deception' about climate change (Sept. 2023), https://www.latimes.com/california/story/2023-09-16/california-sues-five-major-oil-companies-for-lying-about-climate-change.

[5] California also lacks strong community protections for DAC and CCS. We look forward to the SB 905 rulemaking to produce strong protections for our communities soon, before these projects beat regulators to the punch.

Apart from the climate harms discussed above, and even assuming that DAC relies exclusively on onsite, behind-the-meter renewables rather than fossil fuels, DAC is dangerous and must be carefully regulated and limited in deployment.

239.1 cont Most DAC projects rely on toxic materials like ammonia to filter carbon from ambient air, and thus they risk leaking toxic pollution into the air and water.[6] Moreover, DAC's intended purpose is to gather and concentrate CO2, which is a toxic waste.[7] An accident at a DAC facility would present grave risks for workers and surrounding communities for miles around. DAC can be done anywhere, so it is feasible to construct DAC facilities away from communities and right above storage formations to avoid the need for carbon pipelines, but unfortunately, California, along with most other states, does not have a requirement that DAC only occur well away from where people live.

Storing carbon is also a significant concern. Underground geologic storage is not well studied for climate purposes.[8] Perhaps the best studied projects are Norway's Sleipner and Snøhvit projects, often held up by industry as shining examples of the promise of CCUS technology. However, as the Institute for Energy Economics and Financial Analysis found in a 2023 report, these projects are better understood as cautionary tales, demonstrating that "carbon capture and storage is not without material ongoing risks that may ultimately negate some or all the benefits it seeks to create"; that "[e]very project site has unique geology, so field operators must expect the unexpected, make detailed plans, update the plans and prepare for contingencies"; and that "[e]nsuring storage is securely maintained implies a high level of proactive regulatory oversight, activities for which governments may not be adequately equipped". The report also finds that the facilities "cast doubt on whether the world has the technical prowess, strength of regulatory oversight, and unwavering multi-decade commitment of capital and resources needed to keep carbon dioxide sequestered below the sea – as the Earth needs – permanently."[9]

Leakage pathways for geologically stored carbon include the ~100,000 oil and gas wells just in Kern County, California's many tectonic faults, and other natural and manmade perforations or cracks in storage formations. Also, upon interacting with water, CO2 forms carbonic acid. While carbonic acid is safe to drink, it harms irrigation supplies. In California, that could have serious implications because our storage formations are right below the nation's most productive agricultural lands in the Central Valley.

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[6] Hambdy L. B. et al., *The application of amine-based materials for carbon capture and utilisation: an overarching view*, in Material Advances, 2021, 2 5843-5880; EEA Technical report no. 14/2011, *Air pollution impacts from carbon capture and storage (CCS)*, (2011), https://www.eea.europa.eu/publications/carbon-capture-and-storage, at p. 10; Report of the Special Rapporteur, Okechukwu Ibeanu, *Adverse effects of the illicit movement and dumping of toxic and dangerous products and wastes on the enjoyment of human rights*, report no. A/HRC/5/5 (2007), https://undocs.org/Home/Mobile?FinalSymbol=A%2FHRC%2F5%2F5&Language=E&DeviceType=Desktop&LangRequested=False at p. 8.

[7] When concentrated, CO2 is indeed toxic, and, because it is a waste product from combustion and most plans involve burying it deep underground to keep it out of the atmosphere, toxic waste is an apt description.

[8] The oil and gas industry has studied EOR using captured carbon extensively, but as a climate tool geological carbon storage remains in its infancy.

[9] Institute for Energy Economics and Financial Analysis, *Norway's Sleipner and Snøhvit CCS: Industry Models or Cautionary Tales?* (June 2023), https://ieefa.org/resources/norways-sleipner-and-snohvit-ccs-industry-models-or-cautionary-tales.

Further, carbonic acid tends to carry heavy metals such as arsenic, which *can* spoil drinking water supplies.[10]

The LCFS is effectively a gas tax, and forcing low-income communities of color to pay at the pump for DAC is unjust.

As CARB notes in its Standardized Regulatory Impact Assessment (SRIA) for the LCFS, the proposed amendments are expected to increase gas prices by as much as $1.83 per gallon, especially in the late 2030s and 2040s. In the same document, CARB acknowledges that these price increases are likely to impact disadvantaged communities more than others "because individuals living in these communities traditionally spend a larger share of their income on transportation fuels" and because "individuals in these communities may lack the means to effectively make use of ZEV technology as quickly as wealthier individuals, and therefore would rely on more expensive fossil fuels for longer."[11] CARB neglected to mention that people of color and people with lower incomes also tend to have longer commutes. These problems are even more acute in rural areas, where public transit tends to be minimal or nonexistent, and where needed services and retail like schools, doctor's offices, and grocery stores tend to be much farther from where people live. Moreover, charging infrastructure tends to be much scarcer in rural areas; some communities in the Central Valley and elsewhere lack access to the electric grid altogether because of disinvestment and environmental racism. Thus, low-income people of color living in disadvantaged rural communities are likely to be among the last to adopt expensive electric vehicles (EVs), will pay the most through increased gas prices, and can least afford to pay higher gas prices. While the LCFS is not technically a gas tax, its impacts are effectively the same, and gas taxes are inherently a regressive form of revenue generation for the reasons stated above.

The SRIA also notes that disadvantaged communities tend to benefit the most from the reduced emissions of heavy duty vehicles, which is both true and another way of saying that communities of color face the greatest harms from pollution in this sector (among others) in the status quo. However, offsetting emissions with DAC does nothing to reduce emissions and in fact brings new harms and risks to frontline communities, as discussed above, with projects likely to be located near rural, disadvantaged communities. So, under the current proposed amendments to the LCFS, rural disadvantaged
239.1 cont communities will pay the most through increased gas prices while being the least able to afford them, get no local benefits, and face local harms and risks from DAC, all to subsidize a speculative climate technology that, at least in the LCFS context, is more likely to harm our climate efforts than advance them. In short, low-income communities of color—especially in rural areas—would be forced to pay for their own degradation. That outcome is unjust.

This injustice flies in the face of AB 32, which requires that CARB, "to the extent feasible and in furtherance of achieving the statewide greenhouse gas emissions limit,… [e]nsure that activities undertaken to comply with the regulations do not disproportionately impact low-income communities."

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[10] Catherine M. Cooney, Inside Climate News, *Study Charts How Underground CO2 Can Leach Metals into Water*, https://insideclimatenews.org/news/07122010/study-charts-how-underground-co2-can-leach-metals-water/.

[11] California Air Resources Board, *Standardized Regulatory Impact Assessment (SRIA): Proposed Amendments to the Low Carbon Fuel Standard Regulation* (Sept. 9, 2023).

The staff proposal would do the opposite: disproportionately harm low-income communities. CARB must chart a different course and remove DAC from the LCFS.

CARB must immediately cease crediting CCS projects that use captured carbon for enhanced oil recovery in harmony with the statewide prohibitions in SB 1314 (Limón 2022) and SB 905 (Caballero 2022).

239.2 cont In 2022, California prohibited the use of captured carbon for enhanced oil recovery in recognition of the local and climate harms of the practice, and it is incoherent for CARB to continue subsidizing the practice in other states. Apart from the hypocrisy of subsidizing outside of our state what is illegal inside it, the same reasons that we outlawed enhanced oil recovery in California demand that we immediately stop issuing LCFS credits for EOR using captured carbon outside the state.

Using captured carbon for EOR results in serious climate harms under the guise of climate action. When captured carbon is used for EOR, four times more carbon is emitted than is captured.[1] This is deeply troubling given that an estimated 80% of global captured carbon is being used to increase oil production.[2] Expanding EOR in the United States could result in an additional 400,000 barrels per day oil production by 2035, which would directly lead to as much as 50.7 million metric tons of net CO2 emissions annually.[3] Funded largely by taxpayers and—through the LCFS—car drivers, that is not a
239.2 cont climate solution but rather a fossil fuel subsidy. We should not use the LCFS as a fossil fuel subsidy, so we should discontinue this crediting practice immediately.

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[1] Jaramillo, Paulina et al., *Life Cycle Inventory of CO2 in Enhanced Oil Recovery System. Environmental Science & Technology* (2009), https://pubs.acs.org/doi/10.1021/es902006h.

[2] Garcia Freites, S. & Jones, C., *A Review of the Role of Fossil Fuel-Based Carbon Capture and Storage in the Energy System,* (2021), https://www.research.manchester.ac.uk/portal/files/184755890/CCS_REPORT_FINAL_v2_UPLOAD.pdf.

[3] Oil Change International, *Expanding Subsidies for CO2-Enhanced Oil Recovery: A Net Loss for Communities, Taxpayers, and the Climate (2017),* http://priceofoil.org/content/uploads/2017/10/45q-analysis-oct2017-final.pdf.

239.2 cont Further, the local impacts of EOR using captured carbon are significant. EOR is a threat to local and regional air and water quality, and using captured carbon only exacerbates those harms. Pressurizing oil and gas wells with CO2 leads to serious risks of leaks of not just carbon dioxide but also methane, hydrogen sulfide, and various air toxics and volatile organic compounds (VOCs), in addition to oil and toxic produced water. Further, CO2 can leak catastrophically from pressurized wells, leading potentially to serious harm and death because concentrated CO2 is a toxic asphyxiant that is heavier than air. This problem is not without history; although carbon capture has so far seen limited deployment, we've already seen a major leak. In 2016, a Wyoming school was forced to shut down for almost a year because old, plugged oil and gas wells leaked dangerous levels of CO_2 that had been injected for EOR.[12]

239.2 cont

Given the clear climate and local harms and utter lack of benefits beyond oil industry profits, as well as the illegality of the practice within the state, CARB must not delay in ending LCFS credits for enhanced oil recovery. While we recognize that the SB 905 rulemaking is gearing up and could also address this problem, that rulemaking is moving slowly at CARB, with little visible activity in the year and half since SB 905 was passed. Further, we see other changes to CCS crediting in the proposed amendments, and CARB would advance no public benefit by continuing crediting and subsidizing EOR while that rulemaking progresses, even as CARB makes other changes to the LCFS CCS protocol. Thus, CARB must end its fossil fuel subsidy for EOR under the LCFS in the current rulemaking.

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This rulemaking provides CARB the opportunity to improve the LCFS, bring it into closer alignment with principles of climate justice, and strengthen it as a climate tool. Or, CARB can double down on the extractive past. We urge CARB to revise the staff proposal to eliminate crediting for DAC and EOR using captured carbon because of the negative consequences for climate and for disadvantaged communities both in-state and across the nation.

Sincerely,

Dan Ress
Center on Race, Poverty & the Environment

Catherine Garoupa
Central Valley Air Quality Coalition

Shoshana Wechsler
Sunflower Alliance

Bianca Lopez
Valley Improvement Projects

Robert M. Gould, MD
San Francisco Bay Physicians for Social Responsibility

Valerie Ventre-Hutton
350 Bay Area Action

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[12] Inside Climate News, *Exxon Touts Carbon Capture as a Climate Fix, but Uses It to Maximize Profit and Keep Oil Flowing* (Sept. 27, 2020), https://insideclimatenews.org/news/27092020/exxon-carbon-capture/.

Sara Zimmerman, JD
Climate Equity Policy Center

Gracyna Mohabir
California Environmental Voters

Victoria Bogdan Tejeda
Center for Biological Diversity

Amelia Keyes
Communities for a Better Environment

Nathan Taft
Stand.earth

Kevin D Hamilton
Central California Asthma Collaborative

Veronica Wilson
Labor Network for Sustainability

Olivia Seideman
Leadership Counsel for Justice and Accountability

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Comment 249 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Sam
Last Name	Wade
Email Address	sam@rngcoalition.com
Affiliation	Coalition for Renewable Natural Gas
Subject	RNG Coalition 2024 LCFS ISOR Comments
Comment	Please see our attached comment letter.
Attachment	www.arb.ca.gov/lists/com-attach/6918-lcfs2024-UiBSOgNlWVVWMwBv.pdf
Original File Name	RNG Coalition Comments on LCFS ISOR.pdf
Date and Time Comment Was Submitted	2024-02-20 14:41:40

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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1017 L Street #513
Sacramento, CA 95814
(916) 588-3033
sam@rngcoalition.com

VIA ELECTRONIC FILING

February 20, 2024

Matthew Botill
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: RNG Coalition's Comments on Low Carbon Fuel Standard Initial Statement of Reasons

Dear Mr. Botill:

The Coalition for Renewable Natural Gas (RNG Coalition) is a California-based nonprofit organization representing and providing public policy advocacy and education for the Renewable Natural Gas (RNG) industry.[1] RNG Coalition respectfully submits these comments to the California Air Resources Board (CARB) in response to the Proposed Amendments (Proposed Rule) to the Low Carbon Fuel Standard (LCFS) and associated Initial Statement of Reasons (ISOR).

We thank CARB staff for acknowledging the importance of continued RNG growth and share CARB's goal of supporting "methane emissions reductions and deploying biomethane for best uses across transportation." The biggest barrier to continued LCFS-driven methane reduction is the Proposed Rule's lack of overall ambition. We recommend that CARB focus on swiftly enhancing the program's goals to achieve the maximum technologically feasible and cost-effective greenhouse gas reductions from transportation fuels.

240.1 CARB should adopt an LCFS program target of at least 25% for the remainder of 2024 (and through
240.2 2025) to immediately reduce the program's credit bank to an appropriate level. CARB should also set
midterm targets in the range of a 30-44% reduction by 2030. The Automatic Accelerator Mechanism
240.3 should be allowed to trigger as early as possible, to guard against the case where the near-term target
step down in not sufficient to address the current oversupply.

Additionally, the specifics of the Proposed Rule do not fully alleviate stakeholder uncertainty about RNG's future role in the program. Our comments below explain the importance of continued expansion of the robust national framework for RNG accounting, further adjustments to the credit true up concept, and avoiding the dangers of phasing out avoided methane crediting without a replacement strategy to ensure methane emissions reductions from various organic waste streams.

Sincerely,

/S/
Sam Wade
Director of Public Policy
Coalition for Renewable Natural Gas

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[1] For more information see: http://www.rngcoalition.com/

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1 Increased Program Ambition is Critical for Continued Methane Reduction and Growth in All Low Carbon Fuels

Given the LCFS credit surpluses over the last two years, a significant step-down in the Annual Carbon Intensity (CI) Benchmarks is critical at this time. Based on all recent market information to date, 2024 will have many more credits produced than deficits. This will cause the bank to continue to build rapidly, prices to fall, and low carbon fuel investment to stall.

CARB's goal should be to reduce this troubling trend and take advantage of the opportunity to promote greater use of low carbon fuel. The key to accomplishing this goal is setting the appropriate stringency trajectory for the CI Benchmarks and to avoid unnecessary price volatility as we go from large quarterly surpluses to quarterly deficits. Therefore, improved target setting has always been, and remains, the most critical topic in this rulemaking.

1.1 We Support the Target-Setting Analytical Work Conducted by the Consulting Firm ICF

Throughout this rulemaking, a diverse group of Clean Fuel voices has contracted with the consulting firm ICF to independently prepare and submit an analysis of what program targets are feasible. ICF has extensive experience modeling supply and demand in analogous clean fuel programs, both for governments and non-governmental organizations—including the Colorado Energy Office, Great Plains Institute, Oregon Department of Environmental Quality, Puget Sound Clean Air Agency, and for private clients. We encourage CARB to rely upon the results of the ICF analytical work as it represents the most comprehensive and realistic analysis of supply and economics of RNG available to the LCFS system, as well as for other low carbon fuels.

Key findings of the ICF work include the following:

- ICF recommends a "step down" of 10.5% to 11.5% in 2025 to achieve a target credit bank equivalent of 2-3 quarters worth of deficits. This is equivalent to a 2025 target of 24.25-25.25%.
- ICF recommends that the Automatic Acceleration Mechanism be considered for implementation as soon as 2026, rather than waiting until 2028. ICF also recommends that the first criteria for the Automatic Acceleration Mechanism be modified such that the mechanism is enacted when the credit bank is more than 2.5 times greater than the quarterly deficits generated in a given year.
- ICF recommends that Staff increase transparency in credit price modeling so that stakeholders can better understand what is driving the magnitude of credit pricing and the patterns emerging from the data.
- ICF's analysis shows that the proposed changes to the fossil diesel baseline significantly change the relative stringency of the program's targets, when expressed as a percentage of baseline levels.

1.2 A 2025 Target of ≥25% is Needed to Address Current Oversupply Issues. This Level of Ambition Should also be Implemented in Q3 or Q4 of 2024, if Administratively Possible.

240.1a Based on the ICF work, we believe that it is appropriate to increase the program's benchmarks to set at least a 25% CI reduction below the 2010 Baseline in 2025. This should be sufficient to begin to draw down the credit bank, reestablish a demand for additional expansion in low carbon fuel supply, and therefore drive the necessary long-run amount of additional greenhouse gas abatement to reach the state's overall transportation decarbonization goals.

240.1b Further, starting this step down as soon as possible and avoiding unnecessary bank build is crucial. We recommend that CARB target the step down to occur on 7/1/2024 to a level of 25% below the 2010 baseline and maintain that level through 12/31/2025 (assuming CARB elects to retain the updated 2010 diesel baseline value and that the necessary administrative steps can be accomplished on this timeline).

1.3 A 2030 Target of 30% can be Achieved with a Lower Credit Price Trajectory than Predicted in CARB's Modeling of the Primary ISOR Scenario

240.2 ICF's work shows significantly different LCFS credit price outcomes than CARB's ISOR analysis of the primary scenario. We believe that ICF's outlook is better informed by the true near-term supply outlook across all low carbon fuels, deeper analysis of production costs, and a better understanding of the potential other areas of public policy support (e.g., federal biofuel and clean vehicle policy). Given that this deeper understanding demonstrates that it is possible to achieve greater mid-term reductions, we recommend that CARB continue to target at least a 30% CI reduction by 2030 and adjust their credit price forecasting to reflect ICF's input.

1.4 2030 Targets in the Range of 41-44% are Achievable. Additional Enhancement of the Program to Support all Low Carbon Fuels is In Line with Statewide Goals.

The ICF work also demonstrates that greater ambition is achievable in the 2030 timeframe—if additional adjustments are made to maximize opportunities for greenhouse gas reductions across RNG and all other types of the low carbon fuel. We note that CARB's primary Scoping Plan scenario targeted a 48% economy-wide reduction in greenhouse gases by 2030[2] and at least a 40% reduction is required by law.[3]

Since transportation remains the largest sector of greenhouse gas (GHG) emissions in California, and clearly additional low carbon fuel supply is feasible, we believe CARB should continue to try to expand the ambition of LCFS program targets and match the LCFS more closely to economy-wide goals.

1.5 Changes to Fossil Diesel Baseline Significantly Change the Relative Stringency of Program Targets

Per ICF's analysis, the Proposed Rule's decision to increase the CI of Ultra Low Sulfur Diesel from 100.45 g CO_2e/MJ to 105.76 g CO_2e/MJ has major unarticulated consequences. This change—especially without at least some analogous change for the N_2O performance of Renewable Diesel pathways—has a material impact on the program's ambition, when expressed as a percentage of that baseline.

240.4 ICF analysis suggests that this will yield substantially more credit generation than previously forecast. CARB should better justify this change in diesel fuel baseline—with respect to alignment between tailpipe emissions performance of vehicles using both conventional and renewable diesel—or be sure to correct for this factor more transparently during final target setting.

[2] https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf
[3] California Code, Health and Safety Code § 38566.

2 Additional RNG-Related Changes Are Needed to Improve Investor Confidence and Increase the Pace of Methane Emissions Abatement

Despite CARB staff's stated support for RNG throughout the informal workshop process (and in the ISOR) investors remain concerned about how the Proposed Rule shifts the LCFS's RNG crediting framework. The simple fact is that many anaerobic digestion (AD) RNG projects in planning and construction across North America currently rely on LCFS revenues to be built and operated. Without clear rational for RNG programmatic changes—and consistency in concepts between draft regulatory text, material presented in workshop slides, modeling tools, and statements by all levels of CARB staff—investors do not fully know how to respond to regulatory signals sent by CARB's Proposed Rule.

It took an almost decade-long history of LCFS credit being awarded to RNG projects, clear recognition of the methane reduction benefits across a variety of feedstocks, and consistent positive statements from CARB leaders before investors begin to seriously rely on this program to construct RNG projects. If CARB truly wants methane abatement from sources such as agricultural wastes to continue, and for new sources of RNG activity such as organic waste diversion from the municipal waste stream to develop they must reconvince the clean fuel investment community that RNG will remain a viable and important contributor to the LCFS framework.

2.1 CARB Correctly Continues to Acknowledge the Importance of Methane Reduction to Addressing Global Climate Change and the Benefits of RNG in Promoting Methane Reductions, Regardless of Location or End Use

Methane is a highly potent greenhouse gas with impacts greater than 80 times that of carbon dioxide over a 20-year period. The critical need to address methane as a potent short lived climate pollutant was well stated in CARB's 2017 Short Lived Climate Pollutant (SLCP) Reduction Strategy and echoed by many other leading authorities.[4]

The concentration of methane in the atmosphere is increasing at an alarming rate.[5] It is the second most important GHG, behind carbon dioxide, and it can and must be addressed quickly. There is no more effective and immediate step we can be taking as a planet to address climate change now than to aggressively and rapidly reverse emissions of fugitive methane from all sectors, including society's organic waste streams.

The Intergovernmental Panel on Climate Change (IPCC) continues to emphasize the importance of methane capture stating that, "reducing non-CO_2 emissions such as methane more rapidly would limit peak warming levels and reduce the requirement for net negative CO_2 emissions" and that, "strong,

[4] See our December 9, 2022, workshop comments for a more comprehensive list of expert bodies calling for near-term action on methane.

[5] See "Increase in atmospheric methane set another record during 2021", National Oceanic and Atmospheric Administration, Press Release, April 7, 2022. http://noaa.gov/news-release/increase-in-atmospheric-methane-set-another-record-during-2021.

rapid and sustained reductions in methane emissions can limit near-term warming and improve air quality by reducing global surface ozone."[6]

As shown in Figure 1, the IPCC lists at least four key GHG mitigation options that relate directly to RNG production and use, including reducing methane and N_2O in agriculture, reduce methane from waste/wastewater, bioelectricty (including bioenergy with carbon capture and sequestration) and—most importantly for LCFS discussions—biofuels for transport.

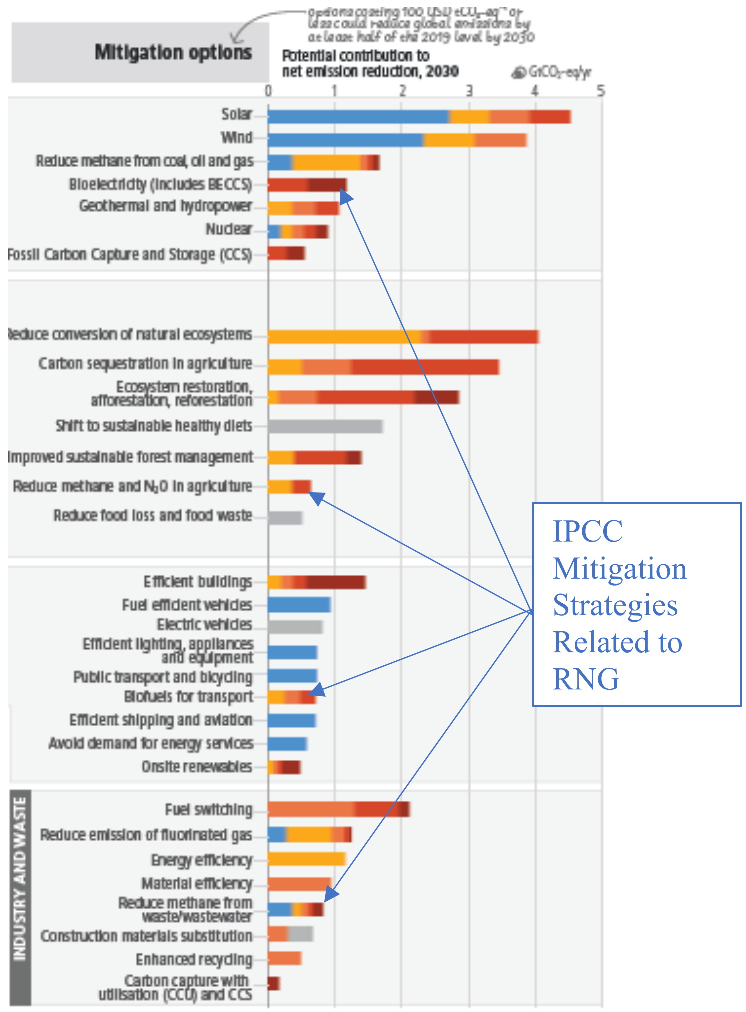

Figure 1. The IPCC Recommends Many Mitigation Options Related to RNG[7]

Further, last year—for the first time—the International Energy Agency (IEA) included a special section on Biogas and Biomethane in their *Renewables 2023 Analysis and Forecast to 2028* report.[8] Renewables

[6] IPCC, 2023: *Summary for Policymakers. In: Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* https://www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_SPM.pdf

[7] Ibid. See Figure SPM.7: Multiple Opportunities for Scaling Up Climate Action.

[8] International Energy Agency, *Renewables 2023: Analysis and Forecasts to 2028* https://iea.blob.core.windows.net/assets/96d66a8b-d502-476b-ba94-54ffda84cf72/Renewables_2023.pdf

2023 is the IEA's primary analysis on the Renewables sector, based on current policies and market developments. It forecasts the deployment of renewable energy technologies in electricity, transport, and heat to 2028 while also exploring key challenges to the industry and identifying barriers to faster growth.

In the special section[9] on biogas and biomethane, IEA states that, "in view of the urgent need to limit global temperature rise to 1.5°C, countries have begun to view biogas as a ready-to-use technology that can help accelerate decarbonisation in the short term, and they are therefore developing specific policies that include biogas as a key component in their energy transition strategies." The IEA also finds that, "using biogas and biomethane helps build a circular economy around residue and waste valorisation, contributes to rural economic development and creates employment. Plus, producing natural fertilisers as a co-product of biogas and biomethane production can augment farmers' income and help reestablish soil health by eliminating certain environmental impacts related to untreated manure use." The report also finds that:

> "In the United States, biomethane development has historically been driven by the transport sector and support schemes such as the Renewable Fuel Standard (RFS) and California's Low Carbon Fuels Standard (LCFS) applicable to fuels sold in California."

These findings are not new, but if CARB wants to build on this global recognition for smart LCFS policy design and expand influence in clean fuel conversations, they must continue to follow fact-based analysis from a science- and data-driven perspective. RNG remains a well-recognized global strategy to reduce emissions from organic waste sectors that can work in conjunction with other strategies—like waste reduction.

The United States Environmental Protection Agency (US EPA) has been tracking and attempting to incentivize anaerobic digesters with productive energy use since the inception of the AgStar program in 1994.[10] California efforts to install dairy digesters dates back (at least) to 2002 and the first round of funding for the California Energy Commission's Dairy Power Production Program.[11] Twenty to thirty years since the initial serious US exploration of this approach, while biogas recovery systems are technically feasible for over 8,000 *existing*[12] large dairy and hog operations across the US, AgSTAR estimates that still only 343 manure-based anaerobic digestion systems are installed and reducing methane emissions.[13] The LCFS needs to remain a key tool to help accelerate the critically needed action to reduce methane from these sources.

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[9] https://www.iea.org/reports/renewables-2023/special-section-biogas-and-biomethane

[10] https://www.epa.gov/agstar

[11] https://calepa.ca.gov/history/

[12] We emphasize EPA's assessment of the number of existing farms that can support digesters to avoid triggering concerns that avoided methane crediting somehow leads to expansion or consolidation of farms. As discussed in more detail below, incentivizing anaerobic digestion as a clean fuel and manure management method does not incentivize manure production by dairy farmers or increases in herd size.

[13] https://www.epa.gov/agstar/agstar-data-and-trends

2.1.1 Avoided Methane Crediting Makes Agricultural RNG Projects Possible, Incentivizes Maximum Greenhouse Gas Capture During RNG Production

240.5 A fixed-year phase-out of avoided methane crediting—as included in the Proposed Rule—is simply not smart policy. Agricultural and organic waste diversion projects are heavily dependent on LCFS revenue for profitability, driven by the avoided methane components of their CI scores. During the informal workshop period of this rulemaking, many of our members have, on a confidential basis, individually supplied CARB with detailed economics for the development of dairy RNG facilities that clearly demonstrate that avoided methane crediting is critical to meet capital repayment requirements for new projects.

At current LCFS credit prices, a framework without avoided methane crediting does not even cover operating costs for existing agricultural projects in some instances. For projects where that is true—absent some new market that covers the cost of operations—existing digesters will not continue operating after their avoided methane crediting periods expire, potentially reversing progress made by the program.

2.1.2 Recognition of Avoided Methane is the Industry Standard in Europe

Opponents of recognizing RNG for avoided methane benefits often portray the CA LCFS's lifecycle analysis framework for methane from organic waste as if it is outside of the norm, or out of step with clean fuel policy in other leading jurisdictions. However, this is not the case. In fact, similar accounting was first pioneered in the European Union's Renewable Energy Directive (RED).

The Renewable Energy Directive is the legal framework for the development of clean energy across all sectors of the EU economy. The EU has found[14] that there is a clear need to scale-up RNG (biomethane) by 2030, as outlined in the *REPowerEU Plan* published in May of 2022.[15] Under that plan, the EU's biomethane production, either as biogas or its upgraded version as RNG, is targeted to reach 35 billion cubic meters per year by 2030.

Within the RED framework,[16] Annex VI provides Default GHG emission values and calculation rules for gaseous biomass fuels and their fossil fuel comparators.[17] As can be seen in Table 1, reproduced from that RED Annex, RNG from dairy manure for use as a transport fuel has carbon negative performance (e.g., achieves emission reductions greater than 100% relative to the emissions of the fossil fuel displaced).

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[14] https://energy.ec.europa.eu/topics/renewable-energy/bioenergy/biomethane_en#:~:text=EU's%20biomethane%20production%20needs%20to,amounts%20to%20%E2%82%AC37%20billion.&text=This%20is%20a%20modal%20window.&text=Beginning%20of%20dialog%20window.,cancel%20and%20close%20the%20window.

[15] https://eur-lex.europa.eu/resource.html?uri=cellar:fc930f14-d7ae-11ec-a95f-01aa75ed71a1.0001.02/DOC_1&format=PDF

[16] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:02018L2001-20231120

[17] https://joint-research-centre.ec.europa.eu/welcome-jec-website/reference-regulatory-framework/renewable-energy-recast-2030-red-ii_en

Table 1. The EU RED Framework Continues to Recognize the Carbon-Negative Performance of Manure to RNG Transportation Pathways

BIOMETHANE FOR TRANSPORT (*)			
Biomethane production system	Technological options	Greenhouse gas emissions savings – typical value	Greenhouse gas emissions savings – default value
Wet manure	Open digestate, no off-gas combustion	117 %	72 %
	Open digestate, off-gas combustion	133 %	94 %
	Close digestate, no off-gas combustion	190 %	179 %
	Close digestate, off-gas combustion	206 %	202 %

Despite ongoing analogous scrutiny in Europe of anaerobic digestion of animal wastes—from similar voices as those active in California—the EU has found it is appropriate to continue this framework in the amending Directive EU/2023/2413, entered into force on November of 2023.[18] Embracing the true GHG
240.5 performance of RNG projects has been a recipe for successful RNG project buildout in both the CA LCFS and EU cases. CARB should continue to coordinate with European leaders on this important topic.

2.1.3 Avoided Methane Crediting Should Continue in LCFS Unless and Until a Realistic and Proven Replacement Policy is Implemented

Given the importance of the LCFS crediting in project viability, is unwise and irresponsible to propose an
240.5 arbitrary (tied to a fixed year) phase-out of avoided methane crediting without a detailed plan for developing a supporting replacement policy. Because of this fact, although better than prior proposals discussed during the workshop period, the Proposed Rule's treatment of avoided methane would still lead to significant project uncertainty and increases the potential for stranded assets—an issue correctly cited by CARB during the workshops as a key signal to be avoided.[19]

A California-only mandate for dairy manure methane control would likely drive "economic leakage" (unless LCFS support continued as well). Economic leakage in the environmental context occurs when a regulatory environment in one jurisdiction drives the migration of a key business sector to another region without similar regulations. This can lead to simply shifting the pollution location without any global reduction in GHGs. This is particularly likely to occur in markets with the demand for the product is steadily increasing, such as the market for milk products.[20]

[18] https://energy.ec.europa.eu/topics/renewable-energy/renewable-energy-directive-targets-and-rules/renewable-energy-directive_en#the-revised-directive

[19] See CARB's Presentation at the February 22, 2023, LCFS Workshop, slide 31. https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/LCFSpresentation_02222023.pdf

[20] Office of Environmental Farming and Innovation, California Department of Food and Agriculture, March 29th 2022 Workshop Presentation, Slide 3, Dr. Amrith Gunasekara, Manager. https://ww2.arb.ca.gov/sites/default/files/2022-04/dairy-ws-session-2-CDFA.pdf

Although demand for liquid beverage milk is declining, and milk substitutes have emerged, US supply and demand for total milk products (both per capita and in aggregate) continues to grow.[21,22] These facts make it challenging for individual states, even a large dairy state such as California, to require control of manure methane unilaterally. However, it is possible that a federal requirement, or a mandate developed by a coalition of like-minded dairy states could be effective. We advise proponents of such a shift from "carrots" to "sticks" that, for such a transition to be effective it will require the cooperation of both the California dairy and RNG industries.

The current LCFS rule already contemplates an appropriate phase-out of avoided methane crediting once mandatory control requirements are in place. Section § 95488.9(f)(3)(B) of the Current Rule states that:

> "…in the event that any law, regulation, or legally binding mandate requiring either greenhouse gas emission reductions from manure methane emissions from livestock and dairy projects or diversion of organic material from landfill disposal, comes into effect in California during a project's crediting period, then the project is only eligible to continue to receive LCFS credits for those greenhouse gas emission reductions for the remainder of the project's current crediting period. The project may not request any subsequent crediting periods."

It is possible that a federal mandate to control manure methane could be developed, promulgated, and in effect in the 2040 timeframe. RNG Coalition would consider supporting such federal action if it treated anerobic digestion with productive energy use as best available control technology. However, we currently see no signs that such a federal effort is on the horizon.[23] We continue to support CARB requiring phase-out of avoided methane crediting once replacement policies are in place. However, we do not support the Proposed Rule's required phase-out of avoided methane crediting *without* a suitable replacement policy.

If CARB staff continues to treat RNG as a temporary solution that might be arbitrarily phased out—without regard to scientific analysis of ongoing emission benefits or development of a replacement strategy—investors will view RNG as a permanently "at risk" fuel, less favored by regulators and therefore not worthy of investment.

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[21] USDA, *Dairy Products: Per Capita Consumption, United States (Annual)*, last updated 9/30/22. https://www.ers.usda.gov/webdocs/DataFiles/48685/pcconsp_1_.xlsx?v=4825
[22] USDA, *US Milk Production and Related Data*, last updated 8/15/22. https://www.ers.usda.gov/webdocs/DataFiles/48685/quarterlymilkfactors_1_.xlsx?v=4825
[23] Multiple states are moving to adopt LCFS policies that could provide a regional framework for addressing these emissions. Beyond expansion of LCFS-style policy no other serious state-level collaboration on manure management methane emissions has yet been proposed.

2.1.4 The Underlying Facts that Justify Avoided Methane Crediting to Ag RNG Projects Have Not Changed, CARB Should Rely on Extensive Prior Public Process and Leave the Current Framework in Place

While we always support additional stakeholder dialog around AD and RNG issues, we note that the facts on these issues have not changed and CARB has held extensive stakeholder outreach on these topics over the last decade, as required by Senate Bills (SB) 605 (Lara, 2014)[24] and SB 1383 (Lara, 2016).[25]

Senate Bill 605 required that CARB complete a comprehensive strategy to reduce emissions of short-lived climate pollutants (SLCP) in the state and hold at least one public workshop during the development of the strategy. CARB did so, developing the *Short Lived Climate Pollutant Reduction Strategy*[26] (SLCP Strategy) in March of 2017 with input from, "state and local agencies, academic experts, a working group of agricultural experts and farmers convened by the California Department of Food and Agriculture (CDFA), businesses, and other interested stakeholders in an open and public process".[27] Throughout this process, CARB "sought advice from academic, industry, and environmental justice representatives".[28] The SLCP Strategy contained extensive economic analysis of agricultural RNG projects[29] and found that:

> "The LCFS and the federal Renewable Fuel Standard (RFS) incentivize the use of renewable natural gas as a transportation fuel, creating large revenue potential within the dairy manure and organic diversion measures. These programs in particular can help support cost-effective projects to reduce methane from the dairy and waste sectors. Without the LCFS or RFS programs, additional sources for financial incentives and funding may be needed."[30]

SB 1383 further required that CARB provide a forum for public engagement on these issues by holding at least three public meetings in geographically diverse locations throughout the state where dairy operations and livestock operations are present. CARB went above and beyond this requirement and conducted almost two years of stakeholder engagement on these topics through a Dairy and Livestock Greenhouse Gas Reduction Working Group (Working Group).[31]

The three subgroups of the Working Group held 28 meetings that were open to the public for in-person and remote attendance and participation. The subgroup meetings typically included "information presented by subject matter experts and representatives from academia, industry, and non-governmental organizations, including environmental justice advocates" and environmental justice experts served on the subgroups.[32] The full Working Group—composed of the principals at CARB, the California Department of Food and Agriculture (CDFA), the California Energy Commission (CEC), and the

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[24] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB605
[25] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383
[26] https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf
[27] CARB SLCP Strategy, p. 25.
[28] Ibid.
[29] CARB SLCP Strategy, *Appendix F: Supporting Documentation for the Economic Assessment of Measures in the SLCP Strategy*. https://ww2.arb.ca.gov/sites/default/files/2021-01/appendixF-SLCP-Final-2017.pdf
[30] CARB SLCP Strategy, p. 107.
[31] *Recommendations to the State of California's Dairy and Livestock Greenhouse Gas Reduction Working Group* https://ww2.arb.ca.gov/sites/default/files/2020-11/dairy-subgroup-recs-112618.pdf
[32] Ibid., p. 3.

California Public Utilities Commission (CPUC)—held three public meetings. This led to a set of recommendations that helped inform the Current Rule.[33]

In March of 2022 CARB held another extensive public discussion of these topics, conducting an all-day workshop on *Methane, Dairies and Livestock, and Renewable Natural Gas in California*.[34] This workshop contained an in-depth presentation from CARB on LCFS mechanics.[35] In the same month CARB released an *Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target*[36] after taking extensive public input[37] on a draft of that analysis. In the *Analysis of Progress* document CARB provided further analysis of LCFS and RFS environmental credit prices on ag AD project economics and continued to support AD as a primary means to reduce dairy manure methane emissions.

2.1.5 External Academic Analysis Shows that CARB's Strategy is Working

Realistically, if California wants to continue to lead globally on critical reductions in this SLCP from dairy and swine operations they cannot consider significantly upending their approach every few years, especially if the existing framework continues to demonstrate success. Recent UC Davis analysis shows continued implementation of California's incentive-based dairy methane reduction efforts will, by 2030, achieve the full SB 1383 40% reduction goal.[38]

This is a powerful and important finding. California's dairy industry, with support from the LCFS and other key programs (e.g., CDFA grants and the federal Renewable Fuel Standard), is on a course to meet the methane reduction challenge required by California law. In terms of both emission reduction and cost effectiveness, these are some of the state's most successful climate protection activities.[39]

Any further changes to the treatment of avoided methane crediting for agricultural AD in the LCFS
would likely directly contradict the state's prior existing emissions reduction strategy for dairy manure
240.5 methane, ignore the extensive stakeholder engagement work conducted by state agencies on these
topics detailed above, discourage a new RNG industry that has been coalesced primarily to reduce
greenhouse gas emissions, and most importantly disincentivize investment in one of the most effective
methods of methane abatement that the state fundamentally needs to use to reach its statutory goals.

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[33] Including a recommendation to stabilize LCFS price support to ag RNG projects through a pilot financial mechanism that was never acted upon. Had such a provision been added projects would not be facing the current negative impacts of low prices.

[34] https://ww2.arb.ca.gov/our-work/programs/slcp/meetings

[35] https://ww2.arb.ca.gov/sites/default/files/2022-04/dairy-ws-session-9-CARB.pdf

[36] California Air Resources Board, *Analysis of Progress Toward Achieving the 230 Dairy and Livestock Sector Methane Emissions Target,* p. 22, March 2022, https://ww2.arb.ca.gov/sites/default/files/2022-03/final-dairy-livestock-SB1383-analysis.pdf.

[37] https://www.arb.ca.gov/lispub/comm2/bccommlog.php?listname=draft-dl-analysis-ws

[38] Kebreab, Mitloehner and Sumner, *Meeting the Call: How California is Pioneering a Pathway to Significant Dairy Sector Methane Reduction*, December 2022, https://clear.ucdavis.edu/news/new-report-california-pioneering-pathway-significant-dairy-methane-reduction

[39] CARB, *Analysis of Progress Toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target*, p. 17, Table 3.

2.1.6 There is No Evidence of a Perverse Incentive to Increase Farm Size from LCFS

LCFS credits from biomethane production does *not* incentivize manure production by increasing herd size. Even skeptical academic experts studying this issue[40] have found no empirical evidence to support the "perverse incentive" claims that underly some of the comments that continue to be made by uninformed anti-dairy voices.

Dairy RNG, at current transportation GHG market prices, generates only a small fraction of the gross revenue that is created by milk-sales. What is more, only a small share of that revenue goes to the farmer—the majority will be distributed to cover the costs of the digester developers, the gas marketer, the credit broker, end users (e.g., fleets adopting clean vehicles), the investors, and the banks. Meaning that the farmer does not make enough additional revenue from RNG to justify increasing herd size. However, the additional LCFS revenue from RNG production *is* critical to help defray the cost of an anaerobic digestor and encourage the transition toward a model of sustainable agriculture.

Even at higher prices, the LCFS incentive is unlikely to shift farm behavior. Dairy farmers are in the business of milk production and not RNG production. Agricultural voices that run dairy farms provided oral comment to this effect at the informal workshops and public meetings in direct response to questions from CARB Staff. RNG production at farms is usually handled by third-party project developers who constitute a large share of RNG Coalition's membership. These firms take substantial financial risk on these projects, historically because of explicit direction to do so from CARB and other California leaders.

Agricultural RNG projects are also a clear example that tests the thesis that investments based primarily on LCFS revenue—and GHG emission reduction benefits in general—is a feasible business model. Agricultural RNG development is one of the first major low carbon fuel industry built primarily around the LCFS program and it has only been successful because it was stood up by CARB based on the extensive public process described above. Major changes to this framework—without substantive new information—would undermine prior efforts to convince investors to make long-term capital deployment decisions based on LCFS credit value specifically, and California's climate strategies more
240.5 generally.[41] Therefore, CARB should leave the current avoided methane crediting framework in place.

2.2 A Full Credit True-up Remains Necessary to Properly Recognize the True Environmental Performance of RNG Pathways

We support the Proposed Amendment's inclusion of a "Credit True Up" after Annual Verification. When implemented properly, such a concept can ensure that the LCFS program correctly accounts for the full GHG benefits all fuel pathways produce. However, we believe the Proposed Amendment's true up language may be mis-drafted as it appears to *not* allow true ups during the temporary pathway period.

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[40] Smith, Aaron, *"Are Manure subsidies Causing Farmers to Milk More Cows?"* April 8, 2023. https://agdatanews.substack.com/p/are-manure-subsidies-causing-farmers?r=i2qe&utm_campaign=post&utm_medium=web

[41] For the initial years of the LCFS, prospective low carbon fuel producers included anticipated credit revenue in financial models and the investors would ignore or heavily discount the LCFS line item, due to perceived change in law risk (colloquially called "stroke of the pen" risk).

This is confusing because, at both October 2020 and August 2022 LCFS Workshops, CARB Staff proposed providing a credit true up to correct for under crediting to pathway holders *only* during the period where a project is using temporary CI scores at the outset of their credit generation. At the time, CARB workshop material stated that such a limited true up would help reduce the pressure on CARB from developers to process LCFS applications quickly.

We continue to support a full true up to verified actual CI performance for all pathways (temporary, provisional, and fully certified).[42] Dairy Manure Digesters (and other biological systems) experience substantial increases and decreases in gas production due to weather, livestock herd changes, and other factors that are not present in other fuel pathways. Because the carbon intensity of the gas from these systems is calculated against a quantity of avoided methane emissions, these variations in biogas production necessarily result in outsized changes in the digesters' carbon intensity (CI) scores every year. Under the current structure of the LCFS (prior to the changes proposed in this rulemaking), all dairy digesters pathways experience the following negative impacts:

1. Substantial underestimation of greenhouse gas benefit (and associated lost revenue) during the temporary CI period.
2. Substantial risk of underestimation of greenhouse gas benefit (and lost revenue) each year during annual verification.
3. Substantial risk of LCFS enforcement, including risks of fines or potential pathway cancellation, due to no fault of the pathway holder.

These consequences are an unavoidable outcome of CARB's overly conservative approach under the Current Rule to dairy digester pathways (and some other pathways with biological feedstocks). As we will describe below, no amount of careful management, conservative pathway assumptions, or other actions can fully protect a digester under the Current Rule—and the Proposed Rule's changes alleviate some, but not all, of these concerns.

All three of the current negative impacts can be substantially mitigated or even eliminated with one simple policy change. Namely, if pathways were allowed to fully "true up" their LCFS credit generation to their actual CI score, once that score was knowable based on actual greenhouse gas performance data, all the problems are resolved.

The current LCFS regulation requires an annual verification to determine the true CI score, relative to the certified CI score. But the result of that annual verification is that pathway holders can only give up
240.6 credits if their actual CI score goes up—they cannot also gain credits if their verified CI score goes down. We believe that, absent some manipulation or misrepresentation, the exchange should go both ways. With proper safeguards around the timing of the true up and potentially some requirement to hold credits in reserve, this policy can serve to encourage very low carbon pathways whereas the current policy discourages very low carbon fuels in favor of less variable fuels. We describe in detail the justification for correctly addressing each of these impacts below.

[42] See our comment letters dated January 7, 2022, August 8, 2022, and September 18, 2022, submitted during the informal workshop period.

2.2.1 Analysis of Impact #1: Additional Changes to the Proposed Rule are Needed to Address Understatement of GHG Reductions During the Temporary CI Period

New dairy digesters in California must apply to CARB staff for pathways to generate LCFS credits. Assuming no major problems with the application, it currently takes a new digester startup 24-27 months to receive from CARB a provisionally certified LCFS pathway due, primarily, to CARB pathway processing timelines.

Most dairy digester provisionally certified Carbon Intensity (CI) scores are between -250 and -425 grams CO_2 equivalent per MJ. During the period where the applicant is waiting to receive its site-specific, provisionally certified score, CARB will usually allow the project to generate credits under a Temporary Fuel Pathway Code (TFPC) at a score of -150. That TFPC code allows a digester project to generate .219 LCFS credits per MMBTU of injected biomethane, which is substantially less than the 0.401 credits that a typical California -350 CI dairy pathway would create.

A digester must usually share the first block of credits generated (regardless of CI) with the dispensing natural gas vehicle fueling station that creates the vehicle fuel. So, the net credits per MMBTU of gas that a digester can create with a TFPC is severely discounted as compared to a provisionally certified pathway. As shown in the Table 2 below, a digester operating under a TFPC makes only 46% as much LCFS revenue as compared to one operating under a provisionally certified pathway. In effect, the two-year delay in processing the application forces the digester to receive 54% less credit (and thus less revenue) than the actual value of greenhouse gas reductions that the project has generated, according to the CA GREET model.

The reductions are real, and calculated according to CARB's requirements, but the delay in processing the application means that the project is not recognized for the reductions it generates. Even once the site-specific score (e.g., -350) is known based on actual data, the LCFS regulation does not allow the project to go back and create credits at the score for the period where it used the -150 TFPC. During the startup period for a typical 3,000-cow California digester, this undercounting incorrectly misses over 16 thousand metric tons CO_2e of emissions benefits driven by the LCFS. This also translates to lost revenues equal to approximately $1,310,400 for the project, assuming an LCFS credit price of $80/credit.

Table 2. Dairy Digester Pathways Lose Significant Value When Using a Temporary Pathway

	CI Score	Credits/MMBTU	Dispensing Cost	Credits to Digester	MMBTU/ quarter	Net Credits/quarter	$/Credit	$/quarter	Quarters awaiting Pathway	
Temporary Pathway	-150	0.219	-0.063	0.156	11,250	1,755	$80	$ 140,400	8	$ 1,123,200
Certified Pathay	-350	0.401	-0.063	0.338	11,250	3,803	$80	$ 304,200	8	$ 2,433,600
									Lost Revenue	**$ 1,310,400**

In some cases, it is possible to store the RNG by not dispensing it as CNG while awaiting LCFS pathway certification. But RNG may only be stored for three quarters under the LCFS, while pathway certification takes 8-9 quarters. So even with perfect foresight, a digester can only store a minor fraction of its gas pending certification. Furthermore, storage is expensive, and it prevents the digester from realizing any revenue, which is needed in the early stages of a project lifespan for operations, maintenance, and debt service.

<u>True Up Solution</u>: CARB's existing policy is to allow the project to generate credits at a -150 TFPC, followed by eventual provisional certification of a project-specific CI score. This initially conservative

policy is sound. However, after 24-27 months, the CI analysis nearly always reveals that the project has generated substantially more greenhouse gas reductions than the -150 score at which the project generated temporary credits. An easy fix would be for CARB to allow the project to "true up", at the time of provisional pathway certification, and generate additional credits for all prior reporting periods where it used the -150 TFPC.

As described above, CARB staff previously workshopped the option of making such a limited true up to address the temporary period. However, the ISOR proposal is unclear on how and when a true up
240.6 would occur during this period. We recommend that this uncertainty be corrected, or that CARB otherwise justify—in response to this comment in the Final Statement of Reasons—why dairy derived RNG and other clean fuels are not being recognized for their true greenhouse gas performance in the program during the temporary period.

2.2.2 Analysis of Impact #2: The Proposed Rule Correctly Addresses Substantial Lost Revenue by Allowing for a True Up Each Year During Annual Verification.

Once a new dairy digester has secured a provisionally certified LCFS pathway, the project can generate credits each quarter using that CI score. At the end of every year, the project must perform an annual verification to see whether its actual CI score over the prior 24 months was higher or lower than the provisionally certified CI score.

The need for annual verification is a proven tool to ensure accuracy of GHG performance in the LCFS (and similar programs), but the policy implementation of verified actual values under the current rule is lopsided (especially in the case of highly variable CI feedstocks such as manure used in anaerobic digesters). These projects cannot control the weather, which greatly impacts the CI modeling of baseline methane emissions via the Methane Conversion Factor. As shown on Table A.5 from the *Proposed Tier 1 Simplified Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure (Proposed Dairy Tier 1 Calculator)*,[43] methane conversion factors can vary by as much as 10x across the temperature range.

Nor can the project control the number and type of livestock present at the host site, which greatly impacts both the baseline calculation and the amount of biogas produced by the project. Table 3 below (labeled A.1 and A.2 in the *Proposed Dairy Tier 1 Calculator*) shows the variability of volatile solids production and biogas production potential, among animal types.

[43] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/ca-greet/t1_biomethane_ad_dairy_swine_manure_simplified_calculator_v12192023.xlsm

Table 3. Various Animal Types Have Different Volatile Solids and Biogas Production Potential

Table A.1 and A.2: Typical Average Mass ($Mass_L$), Volatile Solids, and Maximum Methane Potential of all Livestock Category			
Livestock Category (L)	**Livestock Typical Average Mass (TAM) in kg**	**VS_L (kg/day per 1,000 kg mass)**	**$B_{o,L}$ (m^3 CH_4/kg VS added)**
Dairy cows (on feed)	680	11.41	0.24
Non-milking dairy cows (on feed)	684	5.56	0.24
Heifers (on feed)	407	8.44	0.17
Bulls (grazing)	874	6.04	0.17
Calves (grazing)	118	7.70	0.17
Heifers (grazing)	351.5	13.96	0.17
Cows (grazing)	582.5	8.89	0.17
Nursery swine	12.5	8.89	0.48
Grow/finish swine	70	5.36	0.48
Breeding swine	198	2.71	0.35

Most other LCFS fuel pathways have much more control over their CI inputs. Liquid fuel production CIs are not as impacted from weather and seasonal feedstock animal population. Even leaving aside all other operational variables that might apply to digesters, these two components are sufficient to cause the CI of a manure digester project to vary by over 100 points from year to year.

If the annual verification reveals that the actual CI score was lower (more negative) than the provisionally certified score, the project should be eligible to claim credits for the difference, but is not eligible to do so under the Current Rule. Just like during the temporary CI period described above, the project will have created more greenhouse gas reductions than it will receive revenue for.

On the other hand, if the annual verification reveals that the actual CI score was higher (less negative) than the provisionally certified CI score, the project already has to pay back credits to CARB under the current rule (and would have to pay back 4 credits for every one credit exceeded under the Proposed Rule). The CI of a dairy digester changes every year. Thus, each year the project will either under or over perform the CI that was verified the previous year. So, digesters essentially pay a “variability penalty”. Table 4 below shows a digester where the actual score—as determined by CA-GREET and verified by a third party—averages out to -350 over 10 years. However, the CI score available to the project over the first ten years (either certified or TFPC) averages to a -306. But since the project is in each year forced to generate credits at its worst performance level, the project is actually paid at a -285 CI under the Current Rule.

Table 4. Under the Current Rule Ag Digesters are Subject to a "Variability Penalty"

Year	TFPC or Certified Score	Actual (Verified) Score	Monetized Score*
1	-150	-350	-150
2	-150	-365	-150
3	-350	-260	-260
4	-260	-310	-260
5	-310	-405	-310
6	-405	-295	-295
7	-295	-375	-295
8	-375	-385	-375
9	-385	-380	-380
10	-380	-375	-375
AVG	**-306**	**-350**	**-285**

The net result of this policy is that highly negative CI pathways receive substantially fewer LCFS credits than the greenhouse gas benefits they actually create. Thus, project developers are incentivized to develop less carbon negative pathways that are more stable, because more negative pathways must pay a "variability penalty" under the Current Rule.

240.6 We Support Components of the ISOR Proposed True Up Solution, We Don't Support 4-to-1 Penalty: We support the provisions in the proposed rule where, if the verified CI is lower than the certified pathway, the project will generate additional credits based on the incrementally lower verified score using backward-looking actual performance.

This true up process should be automated by CARB in the LRT-CBTS system for all fuels. In this situation, because of the true up, the total credits awarded would be equal to the true value of greenhouse gas emissions reductions, which is historically the stated intention of the LCFS program. Consequently, highly variable CI scores would not pay a variability penalty (assuming they adopt an appropriate margin of safety), and project developers would be encouraged to seek lower CI scores rather than methods of ensuring steady/less-variable CI scores.

However, we do not support the Proposed Rule's approach to the case where a verified CI is higher than the certified CI. The Proposed Rule requires that the quantity of deficits generated by CI exceedance be assessed as four times the difference between the verified operational fuel pathway CI and the reported CI (multiplied by the quantity of fuel reported using that fuel pathway during the applicable year).[44] Therefore, if over crediting occurs by one ton the pathway holder must "pay back" four credits. This is overly punitive and unsymmetrical. We recommend that, instead, if the verified CI is higher than

240.7 the certified CI, the project should simply repay CARB for any excess credits claimed, and not be subject to any further enforcement liability (see next section) unless there is malfeasance or other such cause.

[44] See proposed text in § 95486.1(g).

2.2.3 Analysis of Impact #3: The Proposed Rule Addresses Risk of Unwarranted LCFS Enforcement Resulting in Fines or Pathway Cancellation, but 4-to-1 Penalties are Unnecessary and Arbitrary

As we've described above—and highlighted since at least 2020 for CARB in informal workshop feedback—a dairy digester pathway's CI will go up or down every year. So, each year during annual pathway verification when the actual CI performance from the previous 24 months is determined, if a project selects it's true initial CI based on historical data, there is a 50% chance that the next year will be higher than that mark, and a 50% chance that it will be lower. Thus 50% of the years, under the Current Rule a given CI pathway will be vulnerable to potential CARB enforcement action—including penalties and possible loss of pathway—due to no fault or malfeasance by the pathway holder. This situation presents a risk that no digester developer can quantify, and that gives pause to investors who are funding the expansion of dairy digesters and the resulting reduction of methane emissions.

But what tools exists to mitigate this risk? The only tool available in the Current Rule is to input a "margin of safety" in the CI score. So, for example, if the digester owner shown in Table 2 above expects that over the course of 10 years it's verified CI will fluctuate between -405 and -260, then the digester owner should set the margin of safety input (available in the CI calculator tool) each year so that they claim credits at a -250. Assuming the owner has calculated properly, and assuming no surprises occur, this digester can make it through 10 years without exceeding that CI. However, this digester was truly achieving -350 average verified reductions, and only being paid for an average score of -285 (due to TFPC effects). With this added "margin of safety" the average CI score the digester will achieve over 10 years is now -230. See Table 5 below.

Table 5. Dairy Pathway Holders Must be Overly Conservative to Avoid Enforcement Risks Under the Current Rule

Year	TFPC or Certified Score	Actual (Verified) Score	Monetized Score*	Monetized Score to Avoid NOV
1	-150	-350	-150	-150
2	-150	-365	-150	-150
3	-350	-260	-260	-250
4	-260	-310	-260	-250
5	-310	-405	-310	-250
6	-405	-295	-295	-250
7	-295	-375	-295	-250
8	-375	-385	-375	-250
9	-385	-380	-380	-250
10	-380	-375	-375	-250
AVG	**-306**	**-350**	**-285**	**-230**

So, enforcement risk is avoided by accepting an even larger "variability penalty" The project is receiving credits at an average score of -230 when it's GREET verified score is -350. Under these circumstances, it makes less economic sense for business to attempt to create ultra-low carbon fuel pathways, if a third of that benefit can never be monetized.

240.18 We Support the Proposed Rule True Up Solution to Address Unwarranted Enforcement Risk: We support how the Proposed Rule helps address this issue as it retains the margin of safety framework but allows for a true up to verified CI performance.

We note that CARB still retains all its enforcement tools to intervene if a pathway holder is engaging in misrepresentation, delayed or incorrect reporting, or does not meet strict verification obligations. But in cases where the pathway holder has done nothing other than fully comply with CARB's requirements, and operated using best practices, yet later finds the CIs have naturally changed, enforcement action (and underreporting of environmental benefit) is not beneficial.

2.3 Deliverability Language Creates a Barrier to Imports, Should Not be Adopted in the LCFS

The Proposed Rule's deliverability requirements are still problematic for RNG development. The ISOR suggests that CARB staff is patterning these changes on concepts from California's Renewable Portfolio Standard (RPS) requirements. Stating that:[45]

> "For projects that break ground after Dec 31, 2029, staff is proposing to require deliverability starting January 1, 2041 for pathways that include biomethane used in CNG vehicles or starting January 1, 2046 for biomethane used as an input to hydrogen production. In particular, staff proposes to align with the deliverability policy for biomethane in the California Energy Commission's Renewables Portfolio Standard (RPS) program (Public Utilities Code section 399.12.6) and the California Public Utilities Commission 1440 program. Specifically, the concept is to require demonstration that eligible biomethane is carried through common carrier pipelines that physically flow within California or toward end use in California. Such pipelines must flow toward California 50% of the time on an annual basis, as defined by the current RPS eligibility guidebook."

240.8 This language is not an improvement in reporting that would somehow provide greater accuracy, or certainty that imported RNG molecules can be traced to California Natural Gas Vehicle (NGV) fuel tanks. As described in more detail below, it is simply an arbitrary requirement—with no additional environmental benefit or grounding in the physical gas system.

Such a requirement might, in practice, prohibit *all* imported RNG from being used in California for LCFS, due to cost and administrative complexity. The existing RPS approach includes a set of complex tests that essentially serve to ensure that no imports can meet the requirements. The factual record from the RPS clearly demonstrates that this language creates a barrier to imports in practice. As shown in Figure 2,[46] no new importing facilities were built to serve the CA RPS, after the deliverability language was imposed through Assembly Bill 2196 (Chesbro) in 2012, despite in-state project development continuing.

[45] See ISOR page 31.

[46] Figure derived from California Energy Commission RPS data available here: https://rps.energy.ca.gov/Pages/Search/SearchApplications.aspx

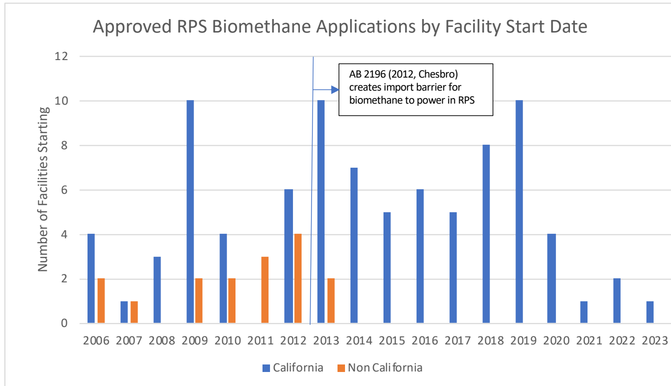

Figure 2. No New Importing Facilities Have Been Built to Serve the California RPS Since AB 2196 Deliverability Language was Established

Protectionist language in portions of the RPS program design—including the de-facto ban on imported RNG—have not succeeded in creating a well-functioning California-only electric grid, able to function entirely using only in-state renewable energy and without imports and exports. Instead, the California Independent System Operator is *currently trying to expand electricity markets regionally* to make it easier to adopt more renewables.[47] We encourage CARB to learn from this example, continue current LCFS practice, and not to close our boarders to imported RNG supply. Harmonizing RNG markets rules with other US states—just as California is now attempting to do to maximize the use of renewable electricity—is a better outcome both for the climate and for California fuel consumers.

Unlike the RPS, the LCFS has been a strong driver of both in-state and out-of-state RNG project development. Because in-state projects have also historically been receiving support through grant programs,[48] the amount of in-state RNG production has been increasing rapidly in California over the past few years and now enjoys a greater proportionate domestic (in-California) market share than many other types of energy. For example, we believe we import more than 90% of our conventional gas in California but only ~77% of our RNG.[49]

Given that California clearly benefits from broad North American and global energy markets for other types of energy—and the recent trend toward significant increases of the in-state supply of RNG—we question why CARB would propose eliminating imported RNG eligibility from any portion of the North American gas system. In the next section we describe how the gas system functions and how the Current Rule's "book and claim" provisions for RNG fit well with the realities of the gas system.

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[47] The California Independent System Operator is "continually pursuing strategies to manage higher amounts of renewable energy into the electricity system. Studies by the ISO show that expanding the energy market across the western US region would accelerate California's efforts to meet the state's ambitious clean energy goals, while saving costs, lowering emissions, and promoting economic growth." See: http://www.caiso.com/informed/Pages/RegionalSolutions.aspx

[48] For example, see: https://www.cdfa.ca.gov/oefi/ddrdp/ and https://calrecycle.ca.gov/climate/grantsloans/organics/

[49] See our December 9, 2022, comments for more details on how this estimate was derived. We encourage CARB to publish import share of RNG using the LCFS data as they do for liquid biofuels in the LCFS Data Dashboard.

2.3.1 Because it is Physically Interchangeable with Fossil Natural Gas, Renewable Natural Gas can be Distributed in the Same, Longstanding Natural Gas Pipeline System that has Served California for Decades

Natural gas currently flows throughout the United States depending on shifts in production, demand, weather, export pricing, and natural gas balancing. All major North American gas pipelines are interconnected, sharing gas flow and balancing, which can be contrasted with the power sector that is currently a more balkanized system, with some limits on wheeling between regions—despite the efforts mentioned above to increase interconnection of the power grid.

When RPS limitations were developed, gas was just beginning to come from all over the country to California. The map in Figure 3 below shows cross-country flows, dating back to 2011, illustrating the interconnectedness of the natural gas pipeline system in the United States at that time.[50]

Natural gas has long been distributed through these pipeline systems tracking volumes being injected and withdrawn throughout the entire system. These volumes are carefully tracked, as the pipeline system has state and federal regulatory oversight and third-party pipelines have metering throughout the system. Not only does this create a robust and liquid market for physical gas delivery across North America, that market already optimizes moving gas from supply to demand in a least cost (and lowest GHG)[51] fashion.

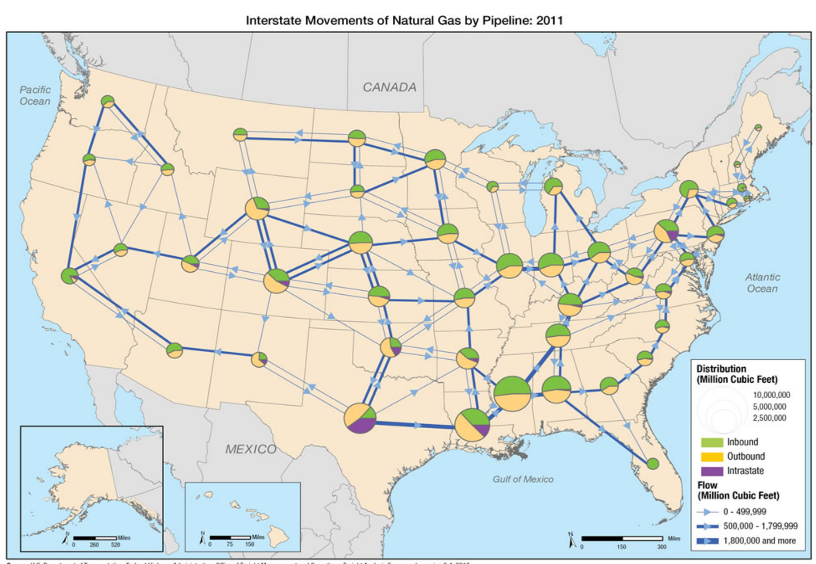

Figure 3. The Natural Gas System Has Interconnected Flows Across North America

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[50] U.S. Department of Transportation Federal Highway Administration, *Interstate Movements of Natural Gas by Pipeline: 2011 Map*, https://ops.fhwa.dot.gov/freight/freight_analysis/nat_freight_stats/interstatenatgas2011.htm (last modified Mar. 23, 2020).

[51] Moving gas requires additional energy and emissions from compression stations and potential methane leakage. These factors are already correctly accounted for in the LCFS CI modeling, which assumes physical gas flow from source to sink, regardless of the ability to trace actual molecule path. This provides a fair and appropriate disincentive that recognizes GHG disbenefits of moving gas from projects located farther from California, all else equal.

The conventional gas market did away with point-to-point service long ago and created trading hubs and flexible receipt and delivery points to give suppliers a variety of options for getting gas to market. Generally, price signals are sent, and liquid trading occurs where the gas is produced, traded, and consumed without having to track individual gas sources throughout the value chain.

2.3.2 This System Can Move Gas Bidirectionally Across North America, therefore, a 50% Flow Requirement is Arbitrary and Unjustified.

Since the RPS provisions were developed, North American pipelines have evolved even further toward one unified system. For example, natural gas can now flow from the Northeast region to all areas of the United States, from Texas to California, and from the Rockies to California. The entire pipeline system in the United States is interconnected and in many cases is now bidirectionally flowing. Examples are provided below.

According to EIA,[52] the Appalachian Basin's large shale formations—which were developed after the RPS proposal was implemented—have dramatically changed gas flows. The Appalachian Marcellus and Utica formations:

- Accounted for 34% of all U.S. dry natural gas production in 2021. On its own, the Appalachian Basin would have been the third-largest natural gas producer in the world in the first half of 2021, behind only Russia and the rest of the United States.
- Since the development of these formations (which cover parts of Kentucky, Maryland, New York, Ohio, Pennsylvania, Virginia and West Virginia) there has been an increase in natural gas flows and pipeline infrastructure from the Mid-Atlantic and Ohio regions to the West and other regions.
- From 2008 to 2020, total pipeline takeaway capacity from the Northeast increased from 4.5 Bcf/d to 24.5 Bcf/d. Most of the increase in takeaway capacity happened between 2014 and 2020, when pipeline capacity increased by 16.5 Bcf/d.

In January 2022, for the first time in its history, the Rocky Mountain Express (REX) natural gas pipeline—which moves bidirectionally from Ohio to Wyoming—had larger gas flows westward than eastward, indicating growth in supply in the eastern U.S. and use to serve demand in the western U.S.[53] Ruby Pipeline interconnects with the Rockies Express Pipeline to bring Appalachian natural gas to the West Coast.[54]

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[52] EIA, *Natural Gas Weekly Update* (for the week ending Sept. 1, 2021), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/09_02/#itn-tabs-1.
[53] Jon Bowman, *Rex Flows Into the Rockies in January – a Fluke or a Sign of Things to Come?* FACTSET, Feb. 23, 2022, https://insight.factset.com/rex-flows-into-the-rockies-in-january-a-fluke-or-a-sign-of-things-to-come.
[54] Sheetal Nasta, *Ruby, Ruby, When Will You be Mine-Tallgrass Bid Breathes New Purpose into Languishing Ruby Pipeline*, Jan. 8, 2023, https://rbnenergy.com/ruby-ruby-will-you-be-mine-tallgrass-bid-breathes-new-purpose-into-languishing-ruby-pipeline.

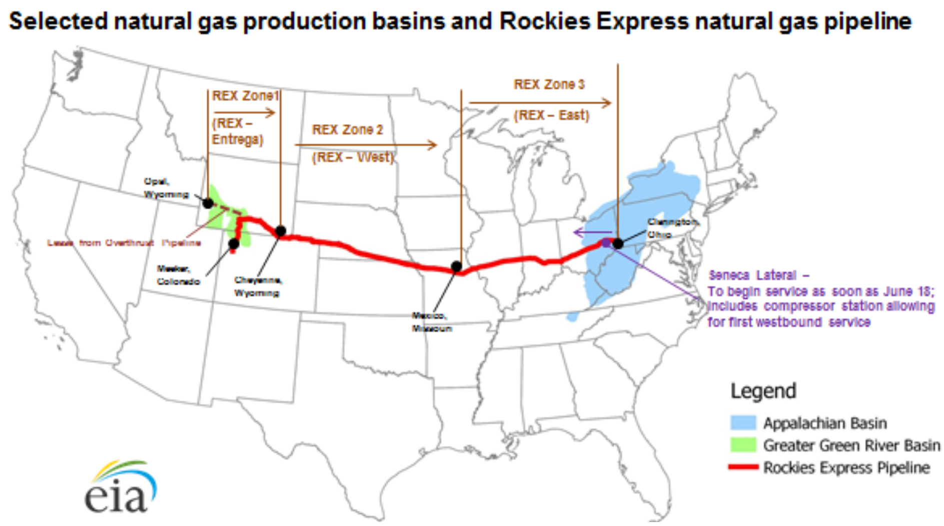

Figure 4. Rocky Mountain Express Pipeline Flows Bidirectionally and Can Bring Gas from East to West[55]

Any successful framework for RNG must build off existing gas system realities, but it does not need to assume that the gas system is static or that RNG supply should be limited to regions that currently supply most of the conventional gas to California. Repurposing existing natural gas infrastructure to rapidly deliver a blend of low-carbon fuels, including RNG, across North America will complement initiatives to cut demand for gas through expanding energy efficiency and electrification.

As demonstrated above, gas system flow can shift over time. Fossil gas demand reduction and RNG supply growth will surely also create large changes in the gas system and the map of the system today is unlikely to match the map of the system in 2040. However, RNG is still a nascent market and cannot be expected to dramatically impact gas flows immediately, unless and until fossil gas use also declines. Therefore, pipes that currently supply less than 50% flow toward California may eventually be adjusted to be capable of supplying more than this percentage. Conversely, prevailing flows may shift over time
240.8 and pipes that currently serve California with more than 50% of their flow may not do so in perpetuity. Given this uncertainty, RNG developers could not invest in a long-lived (e.g., 20-year) asset, based on the LCFS value, if the program has such a 50% flow test. The prevailing flows in gas pipelines are completely outside of the control of any one developer and thus represents an unacceptable risk unless the facility is sited in California.

Finally, the 50% flow concept is not applied to limit delivery of any other fuels in either the Current or Proposed Rule. Analogous non-sensical requirements could certainly be conceived for other fuels. For example, the majority of rail traffic on a given line could be required to move in the direction for California (perhaps even when not specifically carrying ethanol, to create a full analogy).

Alternatively, will California stop accepting fossil gas deliveries through pipelines that do not flow toward California 50% of the time? Imagine how catastrophic such a limit would be when supply crunches occur, such as the one that occurred in Southern California in late 2022.[56]

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[55] Figure Source: EIA, *Today in Energy: First westbound natural gas flows begin on Rockies Express Pipeline*, June 18, 2014, https://www.eia.gov/todayinenergy/detail.php?id=16751

[56] U.S. Energy Information Administration, *Daily Natural Gas Spot Prices in Western United States Exceed $50.00/MMBtu in December*, January 24, 2023. https://www.eia.gov/todayinenergy/detail.php?id=55279

While RNG opponents may desire to create administrative complexities to artificially increase costs or impose barriers to RNG use, CARB should not be swayed by such arguments. The existing CA RPS language is simply a canard to disincentivize out-of-state RNG development, distract from the legitimacy of RNG's environmental benefits, and turn a key advantage of RNG (it's compatibility with the existing gas system) into a perceived weakness. We strongly recommend that CARB avoid implementing
240.8 arbitrary RNG deliverability requirements—and treating fossil gas preferentially to RNG—simply because RNG must currently share the gas system with fossil gas.

2.3.3 Guarantee of Origin Systems (Book-and-Claim) are the Industry Standard in Europe

As described above, because it is not possible to physically segregate delivery of renewable gas once it is intermingled with fossil gas in the pipeline system, other chain of custody methods must be utilized. "Book and claim" is a guarantee of origin concept that was pioneered in the European Union's renewable fuel policies. A key advantage is that such accounting lowers administrative barriers and facilitates matching sources of renewable fuel production to demand centers.

Given the physics of how gases quickly intermix in pipeline systems, no feasible alternative exists to book and claim accounting for RNG. Requiring redundant RNG-only pipeline infrastructure and/or physically segregated trucking/rail of gas would clearly increase GHG emissions and the non-climate environmental impact of RNG delivery. Requiring an RNG developer to hold long-term firm pipeline capacity from production source to end use does not ensure that the renewable molecules flow in that path. Instead, it only adds an extra layer of cost because it does not allow market participants to take advantage of liquid supply trading hubs and pipeline displacement, which can bring transportation costs down significantly.

The renewable gas strategies of leading European countries, such as Denmark[57] which currently have around 40% RNG in their gas system (and expect to reach 100% by 2034), should be more closely studied by CARB as it relates to these issues. Denmark's Green Gas Strategy[58] prioritizes free trade of green gases across borders and states that:

> "When a biogas plant feeds biogas into the gas system, it is mixed with other gas. In the gas system, both biogas and natural gas are mixed to form a uniform gas. In order for the gas supplier to prove the origin of the gas supplied to the final customer, guarantees of origin are used. Energinet issues guarantees of origin, thereby ensuring that it can be documented that a consumed volume of gas is matched by an equivalent production of green gas. This system prevents double counting of renewable energy, allowing companies and other consumers to pay for green gas."

There are now ongoing efforts to move from national RNG registries to a European-wide registry to track RNG volumes using the book-and-claim concept. The European Renewable Gas Registry (ERGaR) was established as an independent documentation scheme for tracking RNG and other renewable gases distributed along the European gas network.[59] Recently there was also a €3 million EU-funded project

57 https://ens.dk/sites/ens.dk/files/Naturgas/groen_gasstrategi_en.pdf

58 Ibid.

59 https://www.ergar.org/abous-us/

known as REGATRACE[60] to develop an efficient trading system based on the issuance and trading of Guarantees of Origin (GO) for RNG.[61] The final report[62] from this process contains the following statements:

> "The European Renewable Gas Registry (ERGaR) was started by and continues to be composed of long-established registries and stakeholders of the biomethane and renewable gas industry. A growing imbalance between biomethane production and consumption in several countries necessitated crossborder transfers. Individual bilateral solutions were established, but in most cases member states refused to grant any benefits to imported biomethane. As such, it has been in its best interest to create a system in which the cross-border transfer of gas certificates could be both technically facilitated and recognised in the target country.
>
> GOs serve only for consumer disclosure, which means that the "green gas" attribute is separated from the gas physical volume. This model is called "book and claim" and is useful for setting the path to the European biomethane market because the GOs help document the volumes being produced, distributed and consumed."

2.3.4 CARB Should Promote a Unified North American RNG Registry System

Given that Europe is expanding RNG trade, built on a clear guarantee of origin system (book and claim), one centralized registry, and the same conceptual principles that CA LCFS currently uses, we think North America can achieve the same objective if leading jurisdictions, such as California, continue to support such a framework.

It is a better outcome for the climate if we start by setting up one well-functioning North American system for RNG, rather than create unnecessary delays with balkanized programs (that likely must be consolidated at some point in the future, in line with the European experience).

The RNG Coalition continues to support development of one North American registry for tracking RNG production and end use to ensure no double counting of RNG volumes. The leading registry system tracking RNG and other forms of renewable thermal energy is the Midwest Renewable Energy Tracking System (M-RETS).[63] The use of M-RETS to supplement LCFS reporting would reduce administrative
240.9 burden on CARB staff and offer California a chance to harmonize the design of such systems with other jurisdictions who are now undertaking similar RNG-supportive policies. Use of M-RETS aligns well with the existing RNG accounting methods in the LCFS.

[60] https://www.regatrace.eu/

[61] Given the recent gas crisis in Europe, the EU now plans to increase biomethane deployment to displace 17 bcm of gas imports in the short-term (approximately equivalent to all natural gas demand for power production in California). https://ec.europa.eu/info/strategy/priorities-2019-2024/european-green-deal/repowereu-affordable-secure-and-sustainable-energy-europe_en

[62] https://www.europeanbiogas.eu/wp-content/uploads/2022/11/EN_Renewable-GAs-TRAde-Center-in-Europe_WEB.pdf

[63] https://www.mrets.org/m-rets-renewable-thermal-tracking-system/

2.3.5 The Current LCFS RNG Framework Aligns with Fuel Use Reporting in the US Renewable Fuels Standard and with State-level Partners. This Alignment Should be Enhanced, not Dismantled.

A key market reality today is that most RNG projects need both LCFS and RIN credits to be viable. Currently only NGV end uses offer full alignment between both programs, which is why that end use has been so popular for RNG thus far. Unlike California's RPS, the US EPA's Renewable Fuel Standard has consistently created a strong framework for RNG growth and is a much better model for CARB's LCFS to continue to align with.

Deliverability rules in the RFS program have long recognized that once RNG and fossil gas is co-mingled there is no way to ensure deliverability of just the subset of renewable molecules. For a recent example of EPA's analysis of this issue, the preamble[64] for the RFS "Set" rulemaking explicitly stated that:

> "When RNG moves through a pipeline system for distribution, the RNG is mixed with a much larger proportion of fossil natural gas using the same system. The two natural gases—one derived from renewable sources, the other from fossil sources—are fungible at that point. Consequently, by the time the natural gas is used to fuel a vehicle, there is no meaningful way to identify which molecules of methane were originally sourced from biogas and which came from fossil sources. As discussed above, and in light of this dynamic, when EPA introduced RNG as a transportation fuel in the RFS program in the Pathways II rule, we set up a system whereby the demonstration that RNG was used as transportation fuel relied on accounting protocols, recordkeeping requirements, and requirements for contracts and affidavits attesting that a specific volume of RNG was used as transportation fuel, and for no other purpose."

EPA correctly recognized that efforts to trace deliverability (e.g., based on securing gas transmission rights or tracing prevailing pipeline physical flows) still cannot guarantee that the RNG molecules flow along preferred paths (or separate paths from fossil molecules). Therefore, any attempts to impose such tests simply increases compliance costs for parties creating and using RNG without achieving any additional environmental benefit.

The current LCFS's book-and-claim rules allow for consistent claims in RNG volume across the RFS and the LCFS. Deviating from this approach for imports will inherently create misalignment in claims, administrative confusion at both reporting entities and CARB, and fewer financially viable projects. The US EPA may also eventually enhance the incentive for the biogas/RNG resource to be sent toward electricity generation for electric vehicle use (eRINs), use in hydrogen production, and as a bio-intermediate to producing liquid fuels. We recommend that CARB consider even further alignment
240.19 between the LCFS and RFS, especially with respect to matching biogas/RNG electricity pathways to EV fleets and hydrogen pathways, if they wish to see these end uses for RNG grow.

Following US EPA and California's currently positive example, book-and-claim accounting has emerged as the preferred method to track RNG in all analogous North American Clean Fuel programs. For example, the Canadian Clean Fuel Standard, the Oregon Clean Fuel Standard, and the Washington Clean

[64] US EPA, Federal Register, Vol. 87, No. 250, Friday, December 30, 2022, Proposed Rules. See page 80637. https://www.govinfo.gov/content/pkg/FR-2022-12-30/pdf/2022-26499.pdf

Fuel Standard all use book and claim for RNG projects as well as for electricity and hydrogen. Gas utility procurement programs for RNG use similar concepts.

Given that the California LCFS pioneered such reporting in North America, it should not abandon it now. The fact that analogous programs are close to being established in other states reduces the likelihood of California being overly reliant on imported RNG in the long term. Each new state that adopts an LCFS-style policy creates a new demand center, which regional supply will likely consider serving first before California (assuming similar credit pricing).

Finally, in summary, many fuels in the LCFS have a relatively high import market share and all fuel categories credited by the LCFS involve lifecycle emissions (and emission reductions) that occur outside of California. For example, a significant share of California's grid mix of electricity (~44%)[65] is produced from conventional natural gas, over 90% of which is imported.[66] Reducing *all* GHG emissions (including the upstream emissions performance) of *all* fuels (including imports) continues to be a critical advantage of the lifecycle approach taken by the LCFS. RNG imports should not be singled out from other fuels for
240.19 different treatment, especially considering the critical importance of reducing methane to mitigate the effects of near-term warming.

3 The Auto Acceleration Mechanism Should Be Able to Trigger Earlier, if Needed to Address Current Oversupply

CARB should adopt an Automatic Accelerator Mechanism (AAM) feature that dynamically responds in the event of future sustained and significant CI reductions by tightening programmatic stringency. The RNG Coalition supports the creation of credit-price-band mechanisms in tradeable environmental credit markets—both generally and as conceptually discussed in the Proposed Rule. Such features can increase investor certainty in credit markets.

CARB's proposed timeline for implementing the AAM is currently that 2028 will be the first year for which the AAM can amend CI reduction targets. We recommend that 2025's performance should be able to trigger the AAM. As we understand the AAM proposal, a 2025 data-year triggering would be able to impact CI targets in 2027, or one year prior to when the ISOR currently proposes. We recommend adjusting the implementation timeline accordingly. Essentially, the AAM should be allowed to trigger as
240.3 early as possible, to guard against the case where the step down in not sufficient to address the current oversupply.

4 Improvements in Pathway Processing and Updates to Tier 1 Calculators and CA-GREET

4.1 We Support the Revised Tier 1 Calculators and Focusing on Improving Pathway Processing Times

We were pleased to see CARB staff's efforts to improve Tier 1 calculators for this rulemaking. We support the majority of RNG pathways being Tier 1 in the future and we remain committed to working

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[65] See Table 1-2 of CARB's 2023 *Carbon Intensity Values for California Average Grid Electricity Used as a Transportation Fuel in California and Electricity Supplied Under the Smart Charging or Smart Electrolysis Provision* *https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/2023_elec_update.pdf?_ga=2.5711222.418438686.1678413739-188703561.1626734718*

[66] https://www.energy.ca.gov/data-reports/energy-almanac/californias-natural-gas-market/supply-and-demand-natural-gas-california

with CARB to help improve processing times and reduce administrative complexity for RNG pathways. We also note that simplification of pathway processing is critical for other jurisdictions to adopt LCFS analogs.

4.2 Recognition of Methane Benefits of RNG Projects Diverting Organic Material from Landfills Should be Revisited and Expanded

Both CARB and US EPA have mandatory emission control requirements for landfills that help reduce methane emissions, yet research literature suggests that many landfills still contribute methane emissions at rates that are much higher than previously estimated.[67] A 2019 study by NASA JPL estimates that landfills' contribution to the state's methane emissions is double current estimates – approximately 41% of all methane point source emissions in California.[68] RNG Coalition and a wide swath of other stakeholders have been raising these issues with CARB for more than three years.[69]

LCFS can help address methane from organic waste handling through better recognition of the benefits of RNG projects that divert organics from landfills and into dedicated digesters. Better quantification of the methane benefits of avoided landfilling and incenting such reductions in the LCFS should be a key focus for CARB, rather than considering arbitrary dates for eventual sunsetting of avoided methane crediting.

We support and appreciate the change for years 1-3 in the *Tier 1 Calculator Biomethane from Anaerobic Digestion of Organic Waste* acknowledging the fact that significant methane emissions occur from the open face of the landfill. However, maintaining the average 75% assumed capture rate for the remaining years is inaccurate and does not align with current science, most notably EPA's October 2023 EPA findings that 61% of methane from landfilled food waste escapes to atmosphere (39% capture rate).[70]

Given that EPA was the source for prior capture rate assumptions (with the 75% capture coming from a 1997 EPA study), EPA's much more robust and up-to-date results should be immediately adopted and the 2023 EPA findings of 39% capture rate incorporated into the Tier 1 calculator.

4.3 The Ability to Increase Methane Capture Rates and Reduce Flaring Through Landfill RNG Projects Should be Recognized

[67] This fact should be noted by those that believe a mandate to control is the sole solution that should be employed for other sources of fugitive methane, such as agricultural manure methane emissions.

[68] Duren, R.M., Thorpe, A.K., Foster, K.T. et al. California's methane super-emitters. Nature 575, 180–184 (2019). https://doi.org/10.1038/s41586-019-1720-3

[69] See our LCFS Workshop comment letter dated November 5, 2020 and Anaergia's LCFS Workshop comments dated September 19, 2022 for examples.

[70] United States Environmental Protection Agency, Office of Research and Development, October 2023, *Food Waste Management: Quantifying Methane Emissions from Landfilled Food Waste* https://www.epa.gov/system/files/documents/2023-10/food-waste-landfill-methane-10-8-23-final_508-compliant.pdf

LCFS recognition of projects that improve methane capture efficiency at landfills beyond regulatory requirements could help improve capture efficiencies of the methane that results from the waste in place at existing landfills.[71,72]

As CARB has workshopped preliminary concepts for potential improvements to the Landfill Methane Regulations CARB staff analysis found that approximately two-thirds of landfill gas collected statewide is currently flared and identified an additional 30 to 50 Californian landfills that could capture sufficient methane each year to cost-effectively utilize gas for energy generation.[73] We are disappointed to see
240.6 that no effort has been made, thus far, to better incentivize productive use of landfill gas under the LCFS framework in this rulemaking.

4.4 Assuming One Annual Lagoon Cleanout for Dairy and Swine Manure Pathways is an Understandable Simplification, however it Will Significantly Harm Many RNG Pathway CIs

We note that the Draft Rule's changes to the *Proposed Tier 1 CI Calculator for Dairy and Swine Manure Biomethane* includes a simplifying default assumption related to lagoon cleanouts (a factor that impacts baseline methane emissions). Under this change, it appears that all projects would be required to assume at least one cleanout would have occurred annually in September, even if this does not match the actual historical practice of the farm in question.

Many dairies have a series of lagoons large enough that annual clean outs of accumulated solids are not necessary. This can take several forms, for example, when one or more lagoons are full the farm stops filling them and begin filling others, leaving the full one(s) to dry out (via evaporation in hot weather) which often takes 1-4 years after the lagoons have ceased receiving fresh manure. During this time one or more other lagoons may be in use. When the unused lagoon(s) are sufficiently dry the remaining solids would be hauled out with loaders and/or excavators. Such practices should not be modeled as a cleanout since the volatile solids have all degraded by the time the dried solids are removed. This baseline practice of no lagoon cleanouts is most likely to occur in regions with warmer and more arid conditions primarily storing manure in thin, liquid forms, including California and other parts of the Southwestern US.

Assuming one lagoon cleanout annually in the base case will reduce methane avoidance and thus
240.10 increase the CI for these projects. This will, in turn, reduce the credits issued to many dairy and swine RNG projects—in some cases significantly.

We understand CARB staff is proposing this change primarily to respond to calls from anti-dairy voices to be more conservative in CI scoring, and to improve administrative simplicity of evaluating baseline

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[71] Page 234 of the 2022 CARB Scoping Plan States that, "While reducing organic waste disposal is the most effective means of achieving reductions in waste sector methane, strategies to reduce emissions from waste already in place in landfills also will play a role in achieving near-term reductions." https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

[72] For an example protocol evaluating the installation of an automated collection system that can increases landfill gas collection efficiency above that obtained with standard collection methods see: https://americancarbonregistry.org/carbon-accounting/standards-methodologies/landfill-gas-destruction-and-beneficial-use-projects

[73] CARB, *Preliminary Concepts for Potential Improvements to Landfill Methane Regulation Public Workshop Slides*, May 18, 2023, https://ww2.arb.ca.gov/sites/default/files/2023-05/LMR-workshop_05-18-2023.pdf

conditions for these projects. We support the goals of improved administrative simplicity, especially if it can lead to increased pathway processing times. However, modeling lagoon cleanouts where they do not truly occur will lead to an underestimation of avoided methane emissions benefits and, therefore, cause a barrier to investment in livestock-manure-to-RNG projects. On the other hand, ignoring lagoon cleanout could result in overestimating the baseline methane emissions, which we understand that CARB staff feels they must avoid at all costs.

In summary, this simplifying assumption on lagoon cleanout practices will make a material impact on CI scores for many RNG projects to the detriment of their total crediting. While we accept this change for the sake of simplicity, we urge CARB to avoid any further pushes to be overly conservative. We also believe that this example of enhanced conservativeness in the avoided methane calculations of the Tier 1 calculator makes it even more critical that the true up concepts discussed above are also implemented in this rulemaking to correct another source of under crediting. RNG pathways simply will not remain economically viable if subjected to additional arbitrary and unjustified "haircuts" that fail to recognize the true GHG benefits of this fuel.

4.5 Fix the Default Electricity Emissions Regional Refactoring Issue in the Tier 1 Models Identified by U.S. Venture

We support addressing the issue raised in U.S. Venture Inc.'s February 12, 2024, comment letter. U.S. Venture points out that default electricity emission factors within CARB's Tier 1 calculators, which are derived from the CA-GREET model, may be off by a significant amount. As CARB adjusts the National
240.11 GREET calculator, which uses a NERC region map (11 regions) to determine electricity emission profiles, to one that uses the eGRID subregions (27 regions), there appears to be an error in this refactoring that needs to be corrected.

4.6 Renewable Natural Gas Facilities Need Flexibility to Source Renewable Power as an Input to RNG Production

The Proposed Rule should continue to introduce flexibility to experiment and find the optimal mix of inputs and outputs in all forms of low carbon fuel production. A significant share of energy demand at many RNG facilities is electricity used to power gas cleanup equipment. It is not always possible to have low-CI electricity sources that are directly connected to the RNG production facility "behind the meter", as required in Section 95488.8(h)(1)(B) of the current rule.

The challenge of generating one's own renewable power is heightened by the cost and risk multipliers that are triggered when one must simultaneously develop both an RNG production facility and a renewable power project capable of matching the load of the RNG plant. We recommend that flexibility
240.12 be added to allow RNG to source low-CI electricity—either under specific Power Purchase Agreements (PPAs) or Book-and-Claim renewable energy certificates (REC) purchases.

4.7 All Biomethane Pathways Should Include the Option to Model Power Generation Matched with Electric Vehicle Use as a Finished Fuel

We continue to recommend that all Tier 1 calculators allow electricity generation as a finished fuel to
240.12 facilitate matching with electric vehicle (EV) use. Alternatively, CARB could develop a Tier 1 calculator that takes a RNG pathway as an input and converts it to electricity for use in EVs. This would create a strong analog with the approach taken for hydrogen. CARB has expressed a desire to see the

biogas/RNG resource utilized outside of natural gas vehicle applications (including into fuel cells and other power generation equipment), creating appropriate Tier 1 calculators would help to facilitate this.

4.8 Liquid Fuel Production and Electricity Production Needs Flexibility to Be Able to Source RNG as an Input

Under existing LCFS provisions, Low-CI electricity supplied as a transportation fuel, e.g., used to power EVs, can be sourced flexibly using RECs or via a qualifying Green Tariff program. Similarly, we recommend that an accounting system be developed to allow both liquid fuel production facilities and pipeline-connected gas-fired electric generation (matched to EV use) to source RNG as a method to reduce CI scores for these fuels.

As CARB explores the implementation of more stringent carbon reduction targets, the use of book-and-claim accounting for inputs like RNG and electricity will likely prove invaluable for its success. This is particularly true if opportunities for renewable gases as an input for transportation fuels like sustainable aviation fuel (SAF) and renewable diesel (RD) are expanded.

With CARB's proposal to obligate fossil jet fuel to generate deficits within the LCFS, the demand for low carbon fuels across different feedstocks and end uses will inevitably increase, with SAF as an end use being a priority for certain airlines. Currently, there are no provisions in the regulation allowing book-and-claim accounting for offsite biomethane used as feedstock for SAF and RD production. We believe that allowing the book-and-claim of RNG to SAF/RD will not only accelerate reaching these targets, but it
240.13 will also help to reach the roughly 800 million gallons of SAF required to meet Governor Newsom's 20% clean fuels adoption target, 1.5 billion gallons in 2030 to meet the AB 1322 (Rivas) goal, and 3.2 billion gallons by 2045 to meet the 2022 Scoping Plan target.

5 Other Minor Suggested Edits and Clean Up

§ 95501(h) – Less Intensive Verification - The Proposed rule allows for less intensive verification for electricity Quarterly Fuel Transaction Reports (QFTR) only, which we support. However, site visits for *all* QRTF are generally unnecessary. Verification site visits for a QFTR are primarily comprised of a visit to an entity's headquarters or other location of central data management and comprises reviewing electronic records. The site visit can easily be done virtually—as was approved, observed by CARB LCFS Staff, and successfully completed during COVID. Alternatively, CARB could rely upon the discretion on the third-party verification body to determine if a visit is required, if they deem a less intensive verification will not suffice. By allowing less intensive verifications for QFTRs, there will be a reduction in required travel and the associated GHG
240.14 emissions from them. Therefore, LCFS should allow for less intensive verifications for all QFTR reports.

240.15
- § 95488.9(b) – Table 8. The temporary fuel pathway codes for hydrogen derived from RNG seem unnecessarily high. For example, compressed or liquified hydrogen derived from dairy or swine manure has a temporary CI of 40, yet registered pathways under the Current Rule producing hydrogen from such RNG are often highly carbon negative. We request that CARB clarify this discrepancy in the Final Statement of Reasons, and we note the connection between this issue and the need for the full true up described above.

240.16
- § 95491.2(b)(2)(C) – Force Majeure Events. If a site has a force majeure event and shuts down for months, the CI score will be heavily impacted, and at that point it will be too late to add an

240.16 cont additional margin of safety to the score. We ask CARB to clarify how such situations will be addressed in the Final Statement of Reasons. The types of events CARB are implying might occur in this section may already be captured in shutdown logs provided to the verification body along with the data captured during the events (typically null or zero values). Thus, it seems unnecessary and unduly burdensome to require special reporting for such events within 90 days, given the remote nature and geographic location of many alternative fuel facilities and especially given that production during these events is minimal to zero, which is readily captured in the reported dataset(s).

- § 95501(13)(A) - Review of Missing Data Substitution. CARB, like many regulatory bodies, has previously recognized the use of "reasonable temporary methods" to address data gaps, noting operational realities result in varying gaps that can be reliably filled in reasonable ways that consider the context of each situation. RNG Coalition urges CARB to continue to allow those participating in the LCFS to be able to use "a reasonable temporary method," rather than prescribing the limited data substitution tactics specified under 95491.2(b)(2)(B)'s Table 13 unless such additional flexibility is already allowed under the use of an "Executive Office approved alternate method".

240.17

6 Conclusion

RNG Coalition appreciates the opportunity for continued engagement on these topics. CARB has an opportunity to provide clarity and investment certainty through additional changes to the Proposed Rule, leveraging renewable gas production to help reduce methane emissions, improve organic waste management, and decarbonize California's transportation sector—or any other sector that CARB deems appropriate. We thank CARB for your continued work toward this end and look forward to the conclusion of a robust and effective LCFS rulemaking.

Comment Log Display

Here is the comment you selected to display.

Comment 250 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Tanya
Last Name	DeRivi
Email Address	tderivi@wspa.org
Affiliation	WSPA
Subject	WSPA Comments on Proposed 45-day LCFS Amendments
Comment	Please see attached.
Attachment	www.arb.ca.gov/lists/com-attach/6919-lcfs2024-AnVVIAFwVWdQCQNv.pdf
Original File Name	WSPA LCFS 45-Day Comment Letter 2-20-2024.pdf
Date and Time Comment Was Submitted	2024-02-20 14:44:46

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

WSPA

Tanya M. DeRivi
Senior Director, California Climate and Fuels

February 20, 2024

Ms. Rajinder Sahota
Deputy Executive Officer – Climate Change and Research
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Uploaded at:
https://www.arb.ca.gov/lispub/comm/iframe_bcsubform.php?listname=lcfs2024

Re: WSPA Comments on Proposed 2024 Low Carbon Fuel Standard Amendments

Dear Ms. Sahota,

The Western States Petroleum Association (WSPA) appreciates the opportunity to comment on the California Air Resources Board's (CARB) proposed amendments and related 45-day rulemaking documents for the Low Carbon Fuel Standard (LCFS) program. WSPA is a non-profit trade association that represents companies that import and export, produce, refine, transport and market petroleum, petroleum products, natural gas and other energy supplies in California and four other western states, and has been an active participant in air quality planning issues for over 30 years.

WSPA has engaged with CARB throughout the LCFS rulemaking process, and previously submitted comments in response to CARB's 2022 and 2023 LCFS workshops. Those comments are incorporated into this letter by reference and are also attached.[1,2,3,4,5,6]

GENERAL COMMENTS

Fiscal Impact of Proposed Amendments

CARB's proposed amendments are projected to significantly increase the cost of California gasoline, despite ongoing and serious supply constraints related to transportation fuels in California. CARB's Standardized Regulatory Impact Analysis (SRIA) estimates that the proposed amendments to the LCFS program will potentially increase the price of gasoline by an average of $0.37 per gallon between 2024 and 2030, and further increase the price of gasoline by $1.15 per gallon between 2031 and 2046.[7] While CARB's Initial Statement of Reasons (ISOR) describes its cost estimates as "conservative,"[8] CARB's analysis underestimates revenue impacts to the State's gas tax revenues. CARB estimates that tax revenues will decrease by $29.2 million[9] due to "increase[s] in volume of
241.1 renewable gasoline, ethanol, and renewable diesel fuel sold in the State,"[10] but this estimate does not capture the significant revenue impacts associated with a 90% reduction in gasoline demand,

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[1] Western States Petroleum Association. "WSPA Comments on CARB Workshop to Discuss Potential Changes to the LCFS," August 8, 2022.
[2] Western States Petroleum Association. "WSPA Comments on the August 18th CARB Workshop to Discuss Potential Changes to the LCFS," September 19, 2022.
[3] Western States Petroleum Association. "WSPA Comments on the November 9th CARB Workshop regarding Potential Changes to LCFS," December 21, 2022.
[4] Western States Petroleum Association, "WSPA Comments on CARB Preliminary Discussion Draft of Potential Low Carbon Fuel Standard Regulation Amendments and February 22, 2023 LCFS Workshop," March 15, 2023.
[5] Western States Petroleum Association, "WSPA Comments on CARB's Proposed Low Carbon Fuel Standard Auto-Acceleration Mechanism and May 23, 2023 Workshop," June 6, 2023.
[6] Western States Petroleum Association, "WSPA Comments on the Low Carbon Fuel Standard Modeling Updates Workshop," September 12, 2023.
[7] *See* SRIA at 58, https://dof.ca.gov/wp-content/uploads/sites/352/2023/09/LCFS-SRIA-to-DOF-ADA-Compliant.pdf.
[8] CARB LCFS ISOR at page 83 https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf
[9] https://oal.ca.gov/wp-content/uploads/sites/166/2024/01/2024-Notice-Register-No.-1-Z-January-5-2024.pdf
[10] CARB, Low Carbon Fuel Standard 2023 Amendments, Standardized Regulatory Impact Assessment, September 8, 2023, at https://dof.ca.gov/wp-content/uploads/sites/352/2023/09/LCFS-SRIA-to-DOF-ADA-Compliant.pdf

which is the forecasted impact of the proposed amendments. The gas tax provides substantial funding for California's infrastructure projects, which will be needed to meet California's electrification goals and address associated increases in electricity demand. CARB has also adopted several rules designed to reduce gasoline demand (e.g., Advanced Clean Cars II, Advanced Clean Trucks, Advanced Clean Fleets), but has neither assessed the full impacts of this change nor has it addressed how to replace this funding, which leaves the State in a vulnerable position.

These significant cost increases conflict with ongoing efforts by the California legislature to ease cost burdens associated with California fuels. Senate Bill (SB) X1-2 (2023) directs State agencies to evaluate measures to ensure that petroleum and alternative transportation fuels are adequate, affordable, reliable, and equitable. The California Energy Commission (CEC) estimates that the LCFS Regulation already adds 11 cents per gallon to the cost of California gasoline.[11] The impacts of these price increases are significant for California consumers – California continues to face serious supply constraints for transportation fuels, leading energy affordability to be a pressing priority for many Californians. The legislature recognized the importance of these impacts in enacting SB X1-2. CARB must therefore ensure that its revised LCFS program does not further compromise the supply reliability of critical transportation fuels, a consequence of which could increase energy costs and further burden California drivers, conflicting with clear legislative priorities in SB X1-2.

CARB's proposed LCFS Amendments may exacerbate these cost issues by constraining the credit generation for fuels, such as crop-based biofuels and hydrogen, while simultaneously and significantly increasing and potentially accelerating program stringency. Credit prices are also approaching a maximum – CARB estimates that credit prices will reach the program ceiling in 2025 and 2026. As CARB emphasized in 2020, prices beyond this point would create "potential adverse impacts to California consumers."[12] CARB's proposed program amendments would add new limits to credit generating opportunities just as LCFS credit prices approach the price ceiling, exacerbating cost impacts. These combined measures undermine the program's cost-effectiveness, in violation of Health and Safety Code (HSC) § 38560, which requires CARB to ensure that its program amendments are cost-effective. Similarly, HSC § 43018 requires CARB to adopt only necessary, cost-effective, and technologically feasible regulations. California Government Code § 11346.2(b)(4) also requires CARB to consider "reasonable alternatives to the regulation that would lessen any adverse impact on small business," and reasonable alternatives that are "less burdensome." As part of these alternatives, CARB must consider "overall societal benefits, including reductions in other air pollutants, *diversification of energy sources*, and other benefits to the economy, environment, and public health."[13] To comply with these provisions, WSPA urges CARB to revise its proposed program amendments to create a more cost-effective, less burdensome regulatory program that protects a diverse energy portfolio.

As part of preserving a diverse energy portfolio, CARB must ensure that the proposed amendments
241.2 do not burden ethanol development. As drafted, proposed § 95488.9(g)(1)(A) states: *"All feedstocks at the point-of-origin must be certified by January 1, 2028. Fuel quantities reported under fuel pathways utilizing feedstocks not certified by January 1, 2028, must be assigned the ULSD carbon intensity [(CI)] found in Table 7-1 of the LCFS regulation."* This requirement is overly broad and may require ethanol feedstocks to meet certification and tracking requirements, which would significantly increase the cost and burden of ethanol and disincentivize ethanol development. This would conflict with HSC § 38560's mandate that CARB adopt measures "to achieve the maximum technologically

[11] Based on CEC SB X1-2 data at https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/california-oil-refinery-cost-disclosure
[12] 2020 CARB ISOR pII-2. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2019/lcfs2019/isor.pdf
[13] HSC § 38562.

feasible and cost-effective greenhouse gas emission reductions from sources." Ethanol is critical for achieving lower-CI for gasoline with limited to no substitutes for ethanol to achieve today's CI reductions. CARB should therefore clarify that these requirements *do not* apply to ethanol, and
241.2 account for costs related to ethanol production and importation in assessing the program amendments.

Additionally, CARB should ensure that the program amendments preserve a *technology-neutral* approach in order to maximize cost-effectiveness. CARB's proposal to phase out avoided methane crediting and project-based crediting treats different low-CI technologies inconsistently, disincentivizing certain investments and foregoing important emissions benefits. For example, in Book-and-Claim accounting, low-CI process energy would need a direct connection, while low-CI
241.3 electricity and hydrogen used in transportation would not require this additional step. Removing existing crediting mechanisms risks stranding assets while discouraging investments in other zero-emission and low-emission technologies, which will lead to increased program costs and will decrease emissions benefits associated with methane reductions. This approach also runs counter to existing programs incentivizing the development of projects to address Short-Lived Climate Pollutants. We encourage CARB to instead study the potential impacts of imposing deliverability requirements before adding untested regulatory restrictions.

The LCFS program centers around a market-based approach to emissions reductions from all transportation fuels. Preserving flexibility in how credits are spent enhances the trading program and protects investments made by private companies to help make the program both successful and replicable. By contrast, imposing spending requirements, like those on electric vehicles, impedes private sector investment in alternative fuel technologies and infrastructure, such as hydrogen refueling and alternative uses for biomethane, which are essential for achieving California's greenhouse gas (GHG) reduction goals.[14,15]

Unsubstantiated Need for Crop-based Feedstock "Guardrails"

241.4 WSPA supports CARB's decision not to include arbitrary caps on crop-based feedstocks or fuels. As WSPA noted in prior comment letters, these caps would limit proven GHG reductions strategies that are delivering significant GHG reductions today. Any concept of a cap on a specific fuel type conflicts with Health and Safety Code § 38560's mandate that CARB adopt measures "to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions from sources."[16] For the same reasons, any such cap would also likely run afoul of Health and Safety Code § 38562's requirement to consider "diversification of energy sources, and other benefits to the economy, environment, and public." Staff has also confirmed that CARB "received limited data, analysis and supporting documents" and that there was no majority of stakeholders presenting a compelling argument in favor of such a significant programmatic change.

While CARB has declined to include a "cap" on crop-based feedstocks, CARB is now proposing to impose "sustainability guard rails" that may limit the supply of crop-based feedstocks used in the production of biofuels. As part of these guardrails, the feedstock supply chain would be required to comply with a resource-intensive, duplicative third-party process to ensure that crop-based and
241.5 forestry-based feedstocks are not sourced on land that was forested after January 1, 2008. This process would increase costs associated with biofuel production. CARB explains that these guardrails are intended to "reduce the risk that rapid expansion of biofuel production and biofuel feedstock demand could result in deforestation or adverse land use change."[17] However, CARB has

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[14] California Transportation Commission's Clean Freight Corridor Efficiency Assessment (SB 671), November 22, 2023, at https://catc.ca.gov/-/media/ctc-media/documents/ctc-meetings/2023/2023-12/14-4-4.pdf
[15] Joint Agency Staff Report on Assembly Bill 8: 2023 Annual Assessment of the Hydrogen Refueling Network in California, December 22, 2023 at https://www.energy.ca.gov/publications/2023/joint-agency-staff-report-assembly-bill-8-2023-annual-assessment-hydrogen
[16] *See also* HSC § 43018.
[17] ISOR at 32.

not provided data demonstrating that there is a sustainability issue that needs to be addressed. The details of this concept were introduced late in the rulemaking process based on general concerns raised by commenters, and CARB has not received sufficient public input from key stakeholders – including California's transportation fuel producers who rely on crop-based feedstocks to support the delivery of alternative transportation fuels for Californians.

Existing LCFS program measures and related federal programs provide sufficient guardrails to address potential land use changes associated with crop-based feedstocks. The LCFS program "uses land use change emissions estimates…[to] make fuel pathways from crop-based feedstocks more carbon intensive," thereby discouraging the use of crop-based fuels and incentivizing "waste-and-residue-based" feedstocks.[18] In addition, the federal Renewable Fuel Standard (RFS) program[19] imposes mapping and tracking requirements for foreign sourced crops, as well as specific forest-based feedstock requirements. This program mandates that crop-based feedstocks be sourced from existing agricultural land cleared or cultivated prior to December 19, 2007. For feedstocks grown outside of the United States or Canada, entities must map and track the point of origin to ensure that this restriction is met.[20] For feedstock grown in the United States or Canada, EPA verifies compliance when it issues a Renewable Volume Obligation.[21] Regulated entities are also prevented from obtaining federal Renewable Identification Number (RIN) compliance credits for converting land not already in use as of 2007.[22] Further, all feedstock used to produce compliance renewable fuels must meet the definition of "renewable biomass." Given these existing requirements, CARB's proposed tracking and certification requirements would be duplicative.

241.5 The additional measures proposed by CARB will create an unnecessary burden for transportation fuel producers and may impact the availability of alternative transportation fuels. Requiring farmers to obtain third-party certification may increase feedstock prices, impacting biofuel production costs and increasing overall fuel prices in California. Requiring farmers to provide documentation that dates to January 1, 2008, would likely also impose an undue burden. This information will be 20 years old by the time these program revisions go into effect. By comparison, Canada's Clean Fuel Regulation only requires documentation to July 1, 2020.

Moreover, as written, if a feedstock supplier for ethanol production cannot obtain the required certification and that ethanol is transported into California, the default CI score of that ethanol is that of ultra-low sulfur diesel (ULSD). This would penalize the ethanol supplier by increasing the CI 6.61 points from the gasoline value, which would otherwise be the appropriate CI score for fuel ethanol acting as a gasoline substitute. Suppliers would therefore be disincentivized from transporting ethanol into California, and ethanol supply may decrease. Inclusion of ethanol into this provision may significantly limit ethanol supply and, thus, gasoline supply (as diesel does not have this requirement), because there are limited oxygenates on the market that meet CARB's requirements. Therefore, lowering ethanol supply by imposing burdensome new requirements may also constrain the supply of gasoline substitutes and may significantly limit gasoline supply.

If CARB retains these "guardrail" provisions, WSPA recommends the following revisions:

- **Definitions and Scope.** The proposed regulation fails to include important definitions – as identified later in the technical section of this letter – that will be necessary for implementation. 241.6 CARB should clearly define the feedstocks covered by the feedstock sustainability criteria to ensure that certification requirements are narrowly tailored to address soybean oil and canola-based biodiesel and renewable diesel. The proposed amendments do not define crop- and

[18] CARB, Low Carbon Fuel Standard 2023 Amendments, Initial Statement of Reasons, December 19, 2023, at 32.
[19] See RFS Section 80.1454(c) and (g).
[20] See 80.1454(c).
[21] See 80.1454(g).
[22] Energy Independence and Security Act, Public Law 110-140 enacted December 19, 2007.

forest-based feedstocks. Without a definition, CARB's proposed tracking and certification requirements may apply to ethanol, which would likely impose significant burdens on alternative fuels that are critically important for achieving California's stringent gasoline formulation requirements.

241.7
- **Certification Process.** CARB should clarify procedures for entities to submit certifications under the proposed requirements. Section 95488.9(g) focuses on requirements for entities seeking to become approved certification systems, but gives little direction to entities complying with the sustainability standards. WSPA requests clarification on the following issues:
  - How and when will certifications be submitted?
  - Which party is responsible for submitting the certification – the feedstock supplier, the fuel pathway holder, or the fuel reporting entity?
  - Can this obligation transfer? The proposed regulation states that fuel quantities reported under fuel pathways utilizing feedstocks not certified by the deadline will be assigned the ULSD CI. However, this does not account for co-processed feedstocks, some of which may have certification and others that do not.

241.8
- **Certification System Approval.** CARB should define clearer criteria for certification scheme approval. Proposed § 95488.9(g)(1)(B)(2) states that the certification system "must consider environmental, social, and economic criteria." However, these criteria are overly vague and leaves too much discretion to the Executive Officer. Instead, CARB should ensure that the approval process includes a mechanism for incorporating input from the public and the regulated industry. This public review process would be more consistent with existing LCFS procedures for pathway applications.

WSPA believes that creating a new crop-based biofuel certification regime by 2028 will be daunting, unjustified, and will only further add to the administrative burden for CARB staff and regulated entities. The proposed LCFS Amendments should provide sufficient time to implement any substantive provisions that directly impact the production and certification of lower CI technologies – including sustainability certifications for crop-based biofuels – as obligated parties must be able to plan accordingly for technology investments and deployment. As such, CARB should defer adding these requirements until a future rulemaking when they can be more thoroughly vetted with stakeholders and address incorporating "climate smart" agricultural practices. If CARB decides to include these certification regimes, WSPA urges CARB to align requirements with programs in other
241.8 jurisdictions, such as Canada's Clean Fuel Regulation, to ensure consistency and to preserve market stability.

Concerns Regarding Proposed Specified Source Feedstock Attestation Requirements
241.9 CARB's proposed attestation requirement is unnecessary. The specified source feedstock attestation requirements would unduly burden fuel producers with no significant benefit as existing regulatory provisions already require review and verification related to the chain of custody. Fuel pathway holders must submit to third party verification evidence of chain of custody for specified source feedstocks as well as provide a RFS separated food waste plan. Imposing additional attestation requirements on top of these existing provisions would significantly add to process workloads.

If these provisions are retained, WSPA requests that CARB clarify procedural obligations associated
241.9 with attestations. *First*, CARB must clearly specify which default emission factors supply chain entities are required to attest against. It is not possible to attest that a step within the supply chain does not meet a pathway CI unless the default emission factors CARB requires pathway holders to utilize are clearly understood by each entity within the supply chain. For example, using the terms "additional processing" is a broad category that fuel producers may interpret differently than CARB. WSPA does not view water removal and basic filtration at the point of collection as additional

processing. But separating out solids, removing soluble impurities, drying the feedstock and filtration using bleaching clay, diatomaceous earth and/or other filter agents may be considered additional processing.

241.9 *Second*, without some limiting factor, every entity within a supply chain could be pulled into attestation requirements. For example, for a used cooking oil supply chain, current provisions could be read to require that each individual restaurant maintain attestations, all the way back to the first collection point. WSPA recommends that CARB specify that attestation requirements begin at the physical feedstock aggregator where feedstocks are collected before any processing occurs upstream of the fuel producer to limit burdens associated with this requirement. This approach would be consistent with the limited attestation language provided in § 95488.8(g)(1)(D)(3), which contains information that only later entities in the supply chain would be able to attest to (specifically, that "the specified source feedstock has not undergone additional processing, such as drying or clean-up except as explicitly included in the pathway life cycle analysis and pathway CI").

241.9 *Third*, CARB should clarify that attestations will not be required to be passed down the supply chain from entity to entity, and that fuel pathway holders will not be liable for failure of supply chain entities to meet the attestation letter requirement. Such a requirement is unnecessary given the existing feedstock supplier auditing requirements, which ensure that both third-party verifiers and CARB have sufficient information to verify compliance. To address these procedural issues, WSPA recommends that CARB provide guidance documents, including examples, for regulated entities, supported by clear regulatory language. CARB already has third-party requirements on specified source feedstocks; however, as indicated above, the verification (or attestation) requirement belongs with the feedstock producer, not with the renewable fuel producer that purchases the feedstock.

Reporting Requirements for Newly Obligated Intrastate Fossil Jet Fuel

The proposed LCFS Amendments would eliminate the existing exemption for intrastate fossil jet fuel and make fuel importers and producers the First Fuel Reporting Entity beginning in 2028. 241.10 WSPA strongly urges CARB to retain the exemption, or make aircraft operators (which include passenger airlines, aircraft cargo companies, and small aircraft owners) the First Fuel Reporting Entity instead, consistent with CARB's earlier proposal in considering program updates.

Fuel importers and producers lack sufficient information to meet these additional reporting requirements. Under the newly proposed reporting requirements, these entities would be required to report information on how fossil jet fuel is *used*, based on whether aircraft operators use fossil jet fuel <u>only</u> for intrastate flights (defined as flights that take off and land in California). Under other existing regulatory provisions, fuel importers and producers generate deficits at the time of importation or production – but CARB would now be imposing the point of deficit generation at end-use, past even the point of sale. It seems unlikely that a fuel importer or producer could manage this obligation. Airport storage facilities are typically jointly owned by the airlines, and the fuel in these storage facilities is not segregated out by airline. After delivery of the fuel into an airport storage facility, fuel importers and producers have no visibility into how individual airlines use the jet fuel. Requiring fuel importers and producers to report on usage would be extremely challenging, if not impossible.

Aircraft operators are far better positioned to report on fuel usage, and can better ensure that the reported information is accurate. Operators possess relevant information to support reporting, including:

- How each individual operators use the fuel supplied to the airport storage facility;
- Which plane the fuel is uploaded into; and

- The flight path of each plane (including those scheduled to take off and land within the State of California).

Some of this information may be considered confidential business information, which WSPA believes should not be shared with fuel producers and importers. The proposed amendments do not specify what information airlines must provide to fuel producers and importers or how information-sharing would work. Without access to this information, fuel suppliers cannot verify end use and cannot meet the proposed reporting obligations.

This information/reporting mismatch creates substantial challenges that extend well beyond logistical concerns:

241.10
- ***Overreporting.*** To account for lack of information on flight paths, fuel importers and producers may need to assume that any fuel delivered to an airport storage facility will be used in-State unless an aircraft operator explicitly states otherwise. Reporting would therefore unwittingly include interstate and international jet fuel, which the program is not intended to regulate. Further, it is unclear if the existing compliance reporting reconciliation timeline fits within any existing data collection process an aircraft operator utilizes to ensure deficits are not accrued for non-obligated uses.

241.10
- ***Increased Prices***. Without information on the intended use of the fuel at the time a transaction takes place, *all* fossil jet fuel may carry an obligation which may increase the price of jet fuels within the State.

241.10 The ripple effect of adding the intrastate jet fuel obligation may include aircraft operators re-optimizing flights to flight paths to include additional fueling outside of California, reducing intrastate jet fuel consumption; this would contribute to emissions leakage. Under Assembly Bill (AB) 32 (2006), CARB has an obligation to minimize leakage resulting from its regulatory activities.

As described above, fuel importers and producers have no ability to differentiate between intrastate, interstate, and international fuel usage in meeting proposed reporting obligations.[23] CARB also has not proposed a definition for intrastate jet fuel consumption, including an appropriate method for calculating the quantity of jet fuel consumed. Airlines have varying approaches to fueling operations, including visiting multiple stops between fueling (e.g., out-of-State, visiting multiple California airports without refueling). As written, CARB's proposal will sweep in a broad range of fueling operations outside intrastate jet fuel consumption and impose significant reporting burdens on entities that have minimal connections to California. CARB's proposal may therefore impermissibly burden *inter*state commerce in violation of the Dormant Commerce Clause doctrine. States cannot
241.11 place burdens on interstate commerce that are "clearly excessive in relation to the putative local benefits."[24] By regulating aviation fuels, CARB's proposal impacts the instrumentalities of interstate transportation and impedes the flow of interstate commerce.

In sum, WSPA believes that the addition of intrastate fossil jet fuel deficits creates unique challenges and may not address the goal of encouraging alternative jet fuel use. If CARB proceeds with this addition, WSPA strongly encourages CARB to reconsider this proposed amendment and return to the proper reporting parties that *do* possess the knowledge required to accurately comply: the aircraft operators. CARB must also incorporate better definitions and clear compliance methodology, including the following:

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[23] Interestingly, there is no consideration that some fossil jet fuel imported or produced in California may also be used in military applications. There is no evaluation of whether this is a legally permissible scope for LCFS or whether fuel producers and importers could reasonably expect to be provided with information about the end use of such fuel, given the classified nature of such information.
[24] *Pike v. Bruce Church, Inc.*, 397 U.S. 137, 142 (1970).

- The First Fuel Reporting Entity for intrastate fossil jet fuel use would be the aircraft operators (or Fixed Base Operator for general aviation use).

241.10
- A simplified reporting approach that does not rely on aircraft operators to track and report actual consumption. CARB should work with aircraft operators to determine a mileage-based multiplier or similar methodology.
- Clear verification parameters specific to intrastate jet fuel reporting.

LCFS Program Stringency

CARB is proposing several updates to increase the LCFS program stringency. *First*, the amendments would set more stringent CI reduction targets, increasing the 2025 CI target by 5%, increasing the 2030 CI reduction target from 20% to 30%, and adding a 2045 CI target of 90%. *Second*, the proposed amendments would add a triggering mechanism – the Automatic Acceleration Mechanism (AAM) – which would advance the CI standard in a given year to a future year if specified market conditions are met, in order to bridge periods of credit surplus and maintain a steadier program signal.

The proposed amendments increase program stringency while removing certain compliance tools and key flexibilities for fuel producers that mitigate program costs. Based on this confluence of factors, without certain protections in place, the AAM may compromise necessary market signals that incentivize the production of lower-CI fuels while preserving consumer choice and providing a
241.12 level playing field for all technologies. To better understand potential market impacts, WSPA requests that CARB release information on how often the AAM could be triggered, using the modeling scenarios CARB developed with the CATS Model. In addition, we recommend that CARB incorporates a robust yearly review as a standard program feature to evaluate the impacts of these
241.12 structural changes, including the annual status of the credit bank, and the effects on California energy prices. Energy pricing data is readily available, since LCFS-associated costs embedded into all wholesale gasoline sales are required to be reported on a monthly basis pursuant to SB 1322 and SB X1-2.[25] CARB should also incorporate a robust consultation process with relevant stakeholders (such as fuel providers and distributors) to better understand potential issues and
241.12 consider possible unintended consequences during this annual review and before triggering the AAM.

In order to address any credits-to-deficit imbalance resulting from overly aggressive CI benchmarks
241.13 or the AAM, CARB should also incorporate a reset mechanism. This mechanism would strengthen the credit trading market by providing greater regulatory certainty and strike an appropriate balance between achieving meaningful reductions offering sufficient business, technology, and financial support to industry, which would ensure these accelerated targets are durable and achievable. Such a mechanism should be available in several circumstances tied to market activity signals and statutory factors, including: a recession or an accelerated growth period in California, a significant unforeseen event (e.g., a global pandemic), and growing affordability and supply reliability issues. Incorporating a reset mechanism would better effectuate SB X1-2's directive for State agencies to evaluate measures to ensure that petroleum and alternative transportation fuels are adequate, affordable, reliable, and equitable, and would better fulfill CARB's duty under HSC § 38560 to ensure that its regulations are cost-effective. Consistent with SB X1-2, CARB must consider impacts to gasoline costs resulting from its regulations, including the LCFS program and other programs such as the Cap-and-Trade program. As the SRIA indicates that LCFS pass-through costs on gasoline will be well over $1.00 per gallon beginning in 2037,[26] CARB must mitigate additional costs in adopting LCFS program updates.

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[25] Senate Bill 1322 (2022) and Senate Bill X1-2 (2023); data posted at: https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/california-oil-refinery-cost-disclosure

[26] CARB LCFS 2023 Amendments SRIA, September 8, 2023, Table 22 at https://dof.ca.gov/wp-content/uploads/sites/352/2023/09/LCFS-SRIA-to-DOF-ADA-Compliant.pdf

Program Streamlining Recommendations

WSPA appreciates CARB's ongoing efforts to streamline program implementation by updating existing Tier 1 calculators and creating a new Tier 1 calculator for hydrogen. WSPA encourages CARB to build on these efforts and address additional inefficiencies associated with the current
241.14 pathway application review and approval process (for registration and renewals). The current system includes duplicative steps that increase workloads for both CARB staff and pathway applicants. To address these redundancies, CARB should work directly with regulated entities, who have significant experience navigating the application process and can readily identify improvement opportunities.

There are currently informal policies and processes in place that would benefit from formal direction via regulation. For example, for both Tier 1 and Tier 2 fuel pathway applications, CARB should
241.14 streamline the fuel pathway application process when an applicant submits a fuel pathway that adds a new feedstock for an existing renewable fuel facility. In such case, CARB should allow the submission under the same fuel pathway application number as the original fuel pathway application, possibly with the original application number with a revision number (e.g., B0123-02). The review process by both CARB and the third-party should also be expedited and focus on the new feedstock. No site visit by the third-party verifier should be required. The Annual Fuel Pathway Report (AFPR) process would also be simplified by submitting a single AFPR for a renewable fuel facility that processes multiple feedstocks, rather than submitting a duplicated AFPR as is currently required.

WSPA urges CARB to adopt the following administrative improvements to streamline the program:

- ***Pathway Holder Deficit Obligation.*** CARB should lessen deficit obligations for pathway holders
241.15 that exceed their CI in a 24-month period. Under the proposed amendments, pathway holders would incur a deficit four times the amount of the annual excess CI generated, *and* have excess credits invalidated, which effectively creates a penalty of five times the amount of the annual excess CI generated. This penalty is disproportionate to the severity of the violation and will likely have an outsized impact on pathway holders, particularly since any true up benefit in a CI is provided to the *importer*, not the pathway holder. Both the benefit *and the obligation* should be with the same party. CARB should lessen the severity of this obligation and either (1) impose the deficit on the importer, or (2) provide true up benefits to the pathway holder as well. Imposing deficit obligations on pathway holders who do not produce fuel in the State, import fuel into the State, or sell fuel into the State, may also unduly burden interstate commerce in violation of the Commerce Clause, by requiring out-of-State pathway holders to suddenly participate in the credit/deficit market, which creates significant new obligations compared to being a pathway holder participant. WSPA also requests clarity on when fuel pathway holders would need to register in the LCFS Reporting Tool and Credit Bank & Transfer System (LRT/CBTS) and when they would become subject to the reporting requirements in § 95491.
- ***Expiring Fuel Pathways.*** Consistent with WSPA's prior comment letters, WSPA urges CARB
241.16 to keep pathway codes active for two quarters after their expiration date. Under the current LCFS Regulation, regulated entities can sell volumes up to two quarters after purchasing them. CARB should keep these pathway codes active for two quarters after their expiration date, to allow for follow-on downstream activity to be reported. Any new production would not be allowed to be reported during those two quarters. This would eliminate a substantial amount of ongoing rework when downstream parties report a legitimate resale of a pathway purchased, only to find later that CARB has deactivated it.
- ***Accelerate Approvals Where Feasible.*** CARB should accelerate temporary pathway approvals or provisional pathway approvals by creating a 30-day deadline to review a temporary
241.17 fuel pathway request application and provide initial feedback. CARB is proposing to change the "deemed complete date" for Tier 2 applications; however, this date does little to streamline the

pathway application process or resolve the issues with fuel pathway processing, given that application reviews and validations are taking several months to complete. This means that credit generation is delayed while these reviews are ongoing. Ultimately, availability of the certified pathway often occurs multiple quarters, if not years, after the deemed complete date. Rather than merely deeming an application complete, the application should be automatically deemed complete *and approved* if CARB staff has not reviewed the application within 30 calendar days. CARB should also consider automatically extending temporary pathways for pathway applicants who have a Tier 1 or Tier 2 pathway application pending. Finally, WSPA notes that it is critically important that CARB ensure there are adequate resources to support the development and implementation of an efficient fuel pathway review process.

241.18
- ***Credit True Ups***. CARB should revise the proposed regulatory language to specify that CARB "shall" perform a credit true up for a fuel pathway. As drafted, the current language states only that CARB "may" perform a credit true up for a fuel pathway, which creates uncertainty. WSPA also urges CARB to include credit true ups back to a facility's startup date and the approval of both temporary and provisional pathways from startup of renewable fuel production.[27]

241.19
- ***Verifications***. WSPA encourages CARB to extend the proposed provisions allowing for "less intensive" verifications for entities that receive a positive verification result to other fuel suppliers and projects in order to reduce administrative burdens. In addition, WSPA urges CARB to limit site visit requirements for third-party verification. CARB should allow third-party verification site visits to be done remotely. Video conferencing and screen sharing are well-established technologies and should be sufficient for other types of verification, especially the verification of LCFS quarterly reports. CARB should also limit site visit requirements to an initial LCFS fuel pathway validation, and once every three years thereafter for LCFS fuel pathway verification. Lastly, CARB should work to incorporate a thorough evaluation process for new or converted facilities, followed by a more streamlined process for such sites for future reviews as part of one application process.

241.20
- ***Incremental Deficits***. CARB should streamline crude CI determinations by eliminating the annual update requirement. Under the current program, CARB updates the Oil Production Greenhouse Gas Emission Estimator (OPGEE) Model and determines the average crude CI on an annual basis, which requires reporting entities to expend significant time and resources generating MCON reports and having the MCON reports verified by third parties. Compared to this significant effort, annual adjustments to the CARBOB and ULSD CI score have been very minor. Instead, reducing benchmarks has a comparatively outsized impact on deficit generation. WSPA recommends that CARB address any significant impacts on the crude CI to CARBOB and ULSD during the LCFS rulemaking process instead of requiring annual updates.

241.21
- ***MCON (Crude) Reporting***. CARB should eliminate the requirement for refineries to report California crudes by field name in the MCON report. This reporting requirement is unnecessary, because CARB is using data from the California Department of Conservation instead. CARB should also eliminate verification requirements for California crudes.

241.22
- ***Information Technology (IT) Updates***. WSPA recommends including an IT portal system that allows many separate entities to input their own CI data to generate a "create your own pathway score" tool. For example, if an entity wants to process feedstock through crushers and refiners (that are already in the system), the entity would be able to just allocate volumes across a refinery/crusher using the database.

[27] See Section 95488.10(a)(1).

241.23
- ***Enhanced Communication.*** CARB should provide regular status updates on temporary pathway applications that can be shared with counterparties. CARB should post a list of approved temporary pathways by company and by date of applicability.

241.24
- ***Reporting Deadlines.*** CARB should change the third quarter reporting deadline from December 31st to January 15th, to allow flexibility over the winter holidays.

241.25
- ***Crediting for Corrected Reporting Errors.*** CARB should allow credits to be generated for reporting errors that have been corrected. Corrections for commercial transactions and accounting adjustments are a routine part of business and regulated parties should not be penalized for improving the accuracy of reporting under the LCFS program.

241.26
- ***Abnormalities.*** WSPA recommends that CARB provide guidelines to account for transient operations and abnormal conditions given the 24-month data requirement.

241.27
- ***Implementation of GREET 4.0.*** To maintain consistency in the program and minimize disruption, current pathways should remain open during the transition from GREET 3.0 to GREET 4.0. Please see further comments below regarding specific GREET 4.0-related issues and concerns.

Limiting Hydrogen Unnecessarily Constrains Investment and Deployment Opportunities
Incentivizing growth and investment in the hydrogen sector is critical for California's efforts to reduce GHG emissions while also providing affordable, reliable, and cleaner energy for all Californians. According to CARB's 2022 Scoping Plan Update[28] the State will need to add approximately 1,700 times the amount of the current hydrogen supply by 2045. Scaling up hydrogen production for California's energy systems requires development of a broad range of technologies, including steam methane reforming (SMR), autothermal reforming (ATR), and electrolysis using renewable electricity, as well as biogas, biomethane, and thermochemical conversion of biomass and waste feedstocks.[29]

241.28
Yet CARB's proposed program updates would inhibit hydrogen development by imposing new constraints on hydrogen eligibility within the LCFS program. Specifically, CARB should not propose to limit end-uses of program-incentivized hydrogen based on a "color" system, limit Book-and-Claim accounting for hydrogen, and impose a new 50% capacity cap. CARB should reconsider these proposals.

241.28
- ***Hydrogen End-Uses.*** Limiting end-uses of program-incentivized hydrogen will inhibit the development of additional hydrogen production. Instead, the LCFS program should continue to preserve consumer choice and provide a level playing field for all technologies, embracing fuel- and technology-neutral principles that focus on the meaningful and timely reduction of GHG emissions. WSPA urges CARB to adopt a technology-neutral approach that uses a CI score as the main driver to reduce emissions, rather than a "color" system that constrains uses. The color system creates regulatory uncertainty by facilitating subjective, changing definitions and interpretations of permissible uses, which stifles long-term investment and innovation.

  CARB assumes that limiting end-uses of hydrogen will funnel new capital investments to certain preferred hydrogen technologies such as electrolysis using renewables, a technology that is, by most estimates,[30] at least triple the cost of hydrogen currently produced by SMR.

[28] 2022 Scoping Plan Update https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents

[29] *See* CEC, "Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California," June 2020. https://www.energy.ca.gov/publications/2020/roadmap-deployment-and-buildout-renewable-hydrogen-production-plants-california

[30] Justin Bracci, Adam Brandt, Sally M. Benson, Gireesh Shrimali and Sarah D. Saltzer, "Pathways to Carbon Neutrality in California: The

However, rapid growth across a broad range of hydrogen technologies must be incentivized to successfully scale up hydrogen production. Large-scale innovation and new investment in various industrial sectors relies on a diverse portfolio of resources. Arbitrarily restricting end-uses will stifle investments and innovation, and conflict with federal funding incentives.

By constraining end uses, CARB is failing to achieve the "maximum technologically feasible and cost-effective greenhouse gas emission reductions" in accordance with Health and Safety Code § 38560. A technology-neutral approach would better align with CARB's rulemaking obligations under Government Code § 11346.2(b)(4)(A), which requires CARB to consider performance standards as an alternative to mandating the use of specific technologies or equipment, or prescribing specific actions or procedures.

- ***Book-and-Claim Accounting***. The proposed regulatory updates would unnecessarily limit Book-and-Claim Accounting for hydrogen, which would likely constrain growth in hydrogen production and deployment. This conflicts with emission reduction measures in the 2022 Scoping Plan Update, which requires significant expansion of hydrogen production. As noted in WSPA's prior comment letters, the goal of the LCFS program is to incentivize the production of low carbon intensity fuels and energy sources for transportation, rather than fuel/energy dispensing infrastructure. All hydrogen production pathways should be considered based on
241.28 their CI reduction potential. CI benchmarks should be used as the singular determining factor to drive CI reductions and credit values.

- ***Capacity Cap.*** CARB is proposing a new 50% capacity cap to incentivize more market participation without inflating the overall credit supply. However, this approach may instead nullify investor incentives and constrain future hydrogen development. A capacity cap is
241.29 unnecessary – the LCFS program already includes a 2.5% limit on credits, and this segment has not yet come close to reaching the limit.

- ***Tax Credits***. CARB is proposing to model LCFS program updates on pending federal updates to tax credits under Internal Revenue Code Sections 45V and 48(a)(15). Imposing well-to-wheel CI limits of ≤55 grams per megajoule (gCO2e/MJ) for gaseous hydrogen and ≤95 gCO2e/MJ for liquid hydrogen for pipeline transfers to "align" with the US Treasury/IRS proposed rule on Section 45V "Clean Hydrogen Production Tax Credit" of the Inflation Reduction Act, is unnecessary and confusing. The Treasury/Internal Revenue Service (IRS) proposal was published on December 26, 2023, and will likely be finalized well after CARB finalizes these LCFS amendments. These regulations may significantly change before they
241.30 become final. However, if CARB seeks to align these programs, then it should, at minimum, retain the IRS's technology-neutral approach.

SPECIFIC COMMENTS

Section 95481. Definitions and Acronyms

The proposed regulation is missing critical definitions that will make implementation challenging for CARB and regulated entities. This includes a definition for crop- and forest-based feedstocks as
241.31 well as palm derivatives. For example, CARB is proposing to prohibit transportation fuels produced from palm oil or palm derivatives, based on deforestation concerns identified by the European Commission.[31] However, without a clear definition of "palm derivatives," this action may exclude

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Hydrogen Opportunity," Stanford Center for Carbon Storage and Stanford Carbon Removal Initiative.https://sccs.stanford.edu/california-projects/pathways-carbon-neutrality-california.

[31] European Commission, Report from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions on the status of production expansion of relevant food and feed crops worldwide. Brussels. March 13, 2019. https://eur-lex.europa.eu/legalcontent/EN/TXT/?uri=CELEX:52019DC0142 European Commission, Annexes to the Report from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee

fuels that can contribute to the objectives of the LCFS program, such as fuels derived from palm oil mill effluent (POME) oil, waste oil extracted from spent bleaching earth from palm oil refining (SBEO) or empty palm fruit bunches oil. These fuels are different from palm oil and are not considered high-risk feedstock. The European Union's REDII Annex IX Part A[32] considers waste generated by palm oil mills, such as POME oil, SBEO[33] and empty palm fruit bunches oil, as "advanced" raw materials. The European Union has also distinguished between the *types* of palm derivatives, including POME oil, SBEO, empty palm fruit bunches oil, and palm fatty acid distillates (PFAD). PFAD are excluded from the residue definition in European jurisdictions (e.g., Germany, Sweden, Norway), while POME oil and empty palm fruit bunches oil are included in the REDII as waste streams within either energy intensity or GHG reductions. These alternative fuels can significantly reduce GHG emissions – the International Council on Clean Transportation (ICCT) has indicated that renewable diesel derived from POME oil has a net GHG emission reduction of 71%.[34] CARB should narrowly define any restrictions for "palm derivatives" to facilitate feedstocks such as POME oil, SBEO and empty palm fruit bunches that can contribute to the stringent carbon intensity reductions contemplated in the proposed rule. CARB should also ensure that the scope of the certification requirements are clearly defined – the proposed amendments do not define "point-of-origin," which creates significant uncertainty on the point of certification requirement.

Other considerations in proposed definitions and acronyms include:

241.32
- *"Alternative Jet Fuel" means a drop-in fuel made from ~~petroleum or~~ non-petroleum sources, which can be blended ~~and used with~~ <u>into</u> conventional ~~petroleum~~ jet fuels without the need to modify aircraft engines and existing fuel distribution infrastructure."*
  - This amendment, to eliminate petroleum sources, would eliminate coprocessing and other means to produce Sustainable Aviation Fuel. CARB should remove the proposed strikeouts and restore the original wording.

241.33
- *"Break ground" means earthmoving and site preparation necessary for construction of the digestor system and supporting infrastructure that starts following approval of all necessary entitlements/permits for the project."*
  - This definition should be expanded to other projects. It should not singularly apply to digestor systems.

241.44
- *"Byproduct" means a secondary product with marginal economic value outside its use in a biofuel pathway.*
  - WSPA seeks clarification from CARB that a "byproduct" cannot be designated as a co-product.

241.45
- *"Clean Fuel Reward" is a statewide program established by EDUs to provide a reduction in price ~~on new light duty EV~~ purchases or leases for new medium- or heavy-duty electric vehicles that are not subject to the High Priority and Federal Fleets requirements as specified in, title 13, California code of Regulations, section 2015(a)(1) in California. The Clean Fuel Reward is funded exclusively through LCFS proceeds generated by EDUs from electricity fuel.*
  - WSPA requests that CARB confirms that the intent of this definitional change is to no longer generate Clean Fuel Rewards for light duty vehicles.

241.46
- *"Conservative" means reducing the estimated GHG reduction benefits of an operation or utilizing methods and factors that over-estimate energy usage or carbon intensity (90th*

of the Regions on the status of production expansion of relevant food and feed crops worldwide. Annexes 1 to 2. Brussels. March 13, 2019. Searle, S., Defining Low and High Indirect Land-Use Change Biofuels in European Union Policy. The International Council on Clean Transportation. November 2018.

[32] Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources. Source: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=uriserv:OJ.L_.2018.328.01.0082.01.ENG&toc=OJ:L:2018:328:TOC

[33] See Annex 9A under part (g), Commission Implementing Regulation (EU) 2022/996, June 14, 2022, on rules to verify sustainability and greenhouse gas emissions saving criteria and low indirect land-use change-risk criteria.

[34] "Potential greenhouse gas savings from a 2030 greenhouse gas reduction target with indirect emissions accounting for the European Union.

241.46 *percentile or highest value) or under-estimate produced fuel volumes (10th percentile or lowest value).*

- WSPA requests that CARB clarify this definition because under-estimating produced fuel volumes of CARBOB or ULSD is *not* a "conservative" estimate.

241.47
- *"Organic Waste" is material that meets both the LCFS definitions of "biomass" and "waste."*
  - WPSA requests that CARB provides some examples of what qualifies for organic waste and what does not.

241.48
- *"Renewable Naphtha" means naphtha that is produced from hydrotreated lipids and biocrudes, or from gasified biomass that is converted to liquids using the Fischer-Tropsch process. This includes the renewable portion of a naphtha fuel derived from co-processing biomass with a petroleum feedstock.*
  - CARB should extend the definition of renewable naphtha to any type of renewable feedstocks.

<u>Section 95482. Fuels Subject to Regulation</u>

241.49
- In (a)(11) CARB should remove fossil jet fuel. Otherwise, CARB should specify "intrastate" fossil jet fuel.
- In (c)(2) CARB should clarify by stating: Fossil jet fuel. Otherwise, CARB should specify "Fossil jet fuel produced or imported before 2028 or used for interstate or international flights <u>in any year</u>."

241.50
- In (f), CARB should confirm that this section does not apply to fuels such as used cooking oil from palm oil, and therefore used cooking oil from palm oil is eligible for LCFS credits. Please refer to comments above on palm derivatives definitions.

<u>Section 95483. Fuel Reporting Entities – Jet Fuel</u>

241.10
- In (a), the reference to "fossil jet" should be removed from this section. In (a)(C), the reference to "fossil jet" should be removed from this section as well.

<u>Section 95484. Annual Compliance Benchmark</u>

241.51
- <u>In (b), Auto-acceleration Mechanism,</u> (2) CARB needs to clarify the definition of $Credits_{20xx}$ and $Deficits_{20xx}$: does $Credits_{20xx}$ represent the cumulative total number of credits generated since 2011 ("the program") or does it represent the number of credits generated in a single year? Does $Deficits_{20xx}$ represent the cumulative total number of deficits generated since 2011 ("the program") or does it represent the number of deficits generated in a single year? WSPA requests that CARB explain the basis for the equation under 95484(2)(A). WSPA recommends that CARB conducts a formal annual program review which would consider not only historical data, such as the credit bank and the deficits and credits generated, but also a forecast of the fuel demand and production in the various category of fuels. This information would be used to assess how the benchmark would be set (higher, flat, lower) for the next compliance period(s). This would be more practical that borrowing credits from the future as described in section 95485 (c)(3)(C) (Advanced Credits).

241.52
- WSPA requests that CARB justify why the USLD baseline values increase by more than 5 gCO2e/MJ starting in year 2025 at 105.76 gCO2e/MJ from 100.45 gCO2e/MJ in the current regulation.

<u>Section 95485. Demonstrating Compliance</u>

241.53
- In subsection (c)(3)(c) Advanced Credits, WSPA appreciates that CARB is proposing to increase the limit of Advanced Credits from 10 to 30 million. However, as described in our other comments regarding benchmarks, it would be more effective if CARB "froze" the benchmarks instead of advancing credits from the future as described in this section.

Section 95486.1. Generating and Calculating Credits and Deficits Using Fuel Pathways

241.54
- In Section 95486.1, under deficit obligation for verified CI exceedance, the nature of a facility's operations will result in variation of CI with time, which could result in unintended situations where the certified CI is exceeded. To account for these operational variations, similar to the provision for the incremental deficit calculation associated with crude, CARB should consider only accounting for true ups (deficits or credits) when the difference exceeds a certain threshold.

241.55
- In (a)(1), CARB should remove the reference to fossil jet fuel.

241.56
- In (g) and (g)(1), Calculation of Deficit Obligation for Verified CI Exceedance, CARB should not apply a penalty of four to five times (when including the penalty for the pathway holder as a first reporter) the deficits if the fuel pathway CI is higher. This is excessive. CARB should apply one times the deficit and reset the CI score to the verified value and allow for rebalancing and readjustments by affected parties.

Section 95488.5. Lookup Table 7-1

241.57
- CARB should justify the significantly higher CI score for ULSD compared to the current rulemaking (105.76 vs. 100.45 gCO2e/MJ).

Section 95488.6. Tier 1 Fuel Pathway Application Requirements and Certification Process

241.14
- In section (b)(2)(A), the deemed completed date should remain when CARB approved the submission, *before* the fuel pathway application is routed to the third-party verifier. Otherwise, the fuel pathway applicant will likely need to report for an extra quarter with the temporary CI score.

Section 95488.7. Tier 2 Fuel Pathway Application Requirements and Certification Process

241.58
- In section (d)(3): The deemed completed date should remain when CARB approved the submission, *before* the fuel pathway application is routed to the third-party verifier. Otherwise, the fuel pathway applicant will likely need to report for an extra quarter with the temporary CI score.

Section 95488.8. Fuel Pathway Application Requirements Applying to All Classifications

241.9
- In section (g)(1)(D), WSPA requests more detail on how the feedstock producers should be responsible for the attestation letter, if CARB maintains this new requirement, and what at what frequency the attestation letter needs to be renewed.

241.28
- In section (i), CARB should allow book-and-claim accounting for low-CI electricity, biomethane, and low-CI hydrogen for the production of renewable fuels as well, such as the production of renewable diesel.

Section 95488.9(b). Special Circumstances for Fuel Pathway Applications

241.59 For Temporary CI Scores (Table 8), CARB should explain and justify why it proposes to increase the CI scores of the temporary pathways by 5 gCO2e/MJ for biodiesel and renewable diesel.

Section 95489. Provisions for Petroleum-Based Fuels

241.60
- In section (a), incremental deficit calculation for crude oil, WSPA notes that the equations for the baseline crude averages appear to be incorrect. Appendix E of the ISOR states that the equations for the three-year California Crude Average CI and California Baseline Crude Average CI contained in this section are being revised "*to be consistent with the updated Oil Production Greenhouse Gas Emission Estimator (OPGEE) model version, the updated Carbon Intensity Lookup Table for Crude Oil Production and Transport, and the implementation timeline of the amended regulation*." However, it appears that the existing CI factors continued to be used in the $CI_{BaselineCrudeaAve}$ calculations. These CI factors should be updated to reflect the revised factors derived using OPGEE 3.0b (which are assumed to be the updated factors

listed in the updated Table 9).

- In section (a), fossil jet fuel and deficit calculation, CARB also proposes to add the following language to the E^{xd} parameter: "*For fossil jet fuel (XD = "fossil jet fuel"), E^{XD} is either produced in California or imported into California during a specific calendar year starting in 2028 and sold, supplied, or offered for sale in California*." As drafted, this language would capture both intrastate and *inter*state jet fuel, which is expressly beyond the scope of CARB's proposal. The
241.61 added language should be revised to clearly state that the parameter should only include intrastate fossil jet fuel.
- 241.62 In section (e)(1)(G), CARB should maintain the eligibility criteria for a project that generates at least 10,000 credits not to discourage GHG reduction projects.
- 241.63 In section (e)(5)(B), CARB should not arbitrarily disallow refinery investment credits after 2040. The LCFS standards will be very stringent then and will need many crediting sources.
- 241.64 In section (f)(5)(B), CARB should not arbitrarily disallow renewable hydrogen refinery credits after 2040. The LCFS standards will be very stringent then and will need many crediting sources.

Section 95491. Fuel Transactions and Compliance Reporting

- 241.24 In section (b)(2) and table 12, CARB should change the third quarter reporting deadline as January 15, as the current deadline of December 31 is conflicting with holiday vacations.

GREET 4.0 Update Issues and Concerns

- **Modifications Incorporated in CA-GREET 4.0.**
  - A backhaul energy intensity was added to ocean tanker transport for Brazilian sugarcane. Though Appendix B indicates that this is based on data provided by fuel suppliers, this does not apply to all fuel suppliers. WSPA requests that pathways should determine whether a backhaul is included and verify it as part of the verification process. Additionally, barges and tugboats that move them within California waters since the passage of the 2022 Commercial
241.65 Harbor Craft (CHC) Regulation are utilizing renewable diesel. The CO2 potion of the emissions from the CHC should not be counted as part of the emission factor for the use of barges in GREET. Like backhaul, pathway holders should be able to petition CARB to reduce emissions from the use of barges within California water as part of the verification process.
  - **Density and Carbon Content Inputs.** From CA-GREET3.0 to CA-GREET4.0, the density and percent carbon content in fuels changed with updates from GREET2016 to GREET2022. The fuel low heating value (LHV) has also been updated separately in CA-GREET4.0 to match the LRT-CBTS reporting system. These data points are then used to determine the tailpipe CO2 emissions of various fuels. For California diesel, the changes result in a ~2 g/MJ increase of the baselines default values. We are uncertain of whether the combination of LHV and density/percent carbon content reported in CA-GREET4.0 are
241.65 accurate as they are obtained from different sources. The LHV is dependent on the density and percent carbon content of the fuel and therefore, CARB should be using a consistent basis when updating the values.
  - **Tailpipe Emission Factors.** It appears that CARB updated GREET2022 transportation and tailpipe emission factors with data from the EMFAC2021 (v1.0.2) model, which reflects significant changes in ULSD tailpipe nitrous oxide (N2O) emissions, from 0.724 g/MJ in CA-CA-GREET3.0 to 3.49 g/MJ in CA-GREET4.0. However, it seems tailpipe N2O emissions for lower emission fuel pathways, such as biodiesel and renewable diesel, are based on a different data source and consistent with the CA-GREET3.0 data. We request that CARB
241.65 explain this choice as CARB should treat all fuels under a consistent framework for model input and output accuracy.

  - **Natural Gas.** CARB should update the methane fugitive factors by using GREET 2022, not the obsolete factors from GREET 2014.
  - **Tallow energy use.** CARB should update the tallow energy use with the data from GREET 2022, not the obsolete value from GREET 2016.

- **Expirations.** WSPA is concerned with any potential of pathways that were developed under CA-GREET 3.0 expiring as CARB transitions to CA-GREET 4.0. To maintain consistency in the
241.66 program and minimize disruptions, current pathways should remain open during the transition from GREET 3.0 to GREET 4.0.

241.67 - **Data Assumptions.** WSPA requests that CARB provide data sources used to update electricity transmission and distribution losses in the model.

WSPA appreciates the opportunity to provide comments. If you have any questions regarding this submittal, please contact me via email at tderivi@wspa.org.

Sincerely,

Tanya DeRivi

Tanya DeRivi
Senior Director, California Climate and Fuels

Jim Verburg
Director, Fuels

August 8, 2022

Sent via e-mail and upload to: https://www.arb.ca.gov/lispub/comm/iframe_bcsubform.php?listname=lcfs-wkshp-jul22-ws&comm_period=1&_ga=2.85577753.167319428.1658172472-237475923.1631295388

Dr. Cheryl Laskowski
Branch Chief – Low Carbon Fuel Standard
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: WSPA Comments on CARB Workshop to Discuss Potential Changes to the LCFS

Dear Dr. Laskowski,

Western States Petroleum Association (WSPA) appreciates the opportunity to comment on the staff presentation at California Air Resources Board (CARB) Workshop to discuss potential changes to the Low Carbon Fuel Standard (LCFS) held on July 7, 2022. WSPA is a trade association that represents companies that provide diverse sources of transportation energy throughout the west, including California. This includes the transport and marketing of petroleum, petroleum products, natural gas, renewable fuels, and other energy supplies.

Provided below is WSPA's initial feedback on CARB's proposed changes in the LCFS Program as presented to stakeholders by CARB staff on July 7, 2022:

LCFS is a Critical Part of California's Climate Portfolio - The last bullet point on Slide 9 of the CARB staff presentation states: *"Providing long-term price signals needed to support transition to ZEVs and decarbonizing remaining liquid fuel demand."* The LCFS program should remain fuel/energy carrier neutral and not privilege ZEV technology to the detriment of liquid or gaseous fuels. The carbon intensity (CI) is the referee in the LCFS program, so if a liquid or gaseous fuel with low CI values can compete with ZEV technology, CARB should ensure these technologies remain available in the program and are treated fairly, as enablers of carbon reductions.

Accelerating 2030 Target to 25% or 30% - The CARB staff presentation (Slide 12) introduced a proposal to potentially accelerate the LCFS (CI) reduction targets to 25% or 30% by 2030. WSPA is concerned that this proposal has been presented to stakeholders without the illustrative compliance scenarios necessary to demonstrate potential pathways to achieving these targets. WSPA encourages CARB to hold a series of workshops focused on this topic and direct engagement with stakeholders as soon as possible. The illustrative compliance scenarios should, at minimum, include an assessment of the demand for low CI fuels among the western states and Canada as multiple low carbon fuel programs drive competition.

Post-2030 CI Targets - While setting aspirational long-term targets can be a signal to encourage investment in low-carbon alternatives, these targets would be arbitrary and established without sufficient underlying analysis and thus are unlikely to be effective. It is also important to note that the Scoping Plan already serves to provide direction for programs like the LCFS. As one of the key elements for a successful Scoping Plan, the LCFS should be focused on nearer-term goals that are supported by peer-reviewed analysis and proven technologies.

WSPA recommends that CARB set LCFS targets no further out than 2030 and consider setting targets for years that are currently more than 10 years out with the next rulemaking.

Market Signals versus Market Disruptions - CARB has built the LCFS program with an intent to provide a market signal for investment. WSPA member companies are working to support California's policy goals and reduce emissions in the transportation sector. WSPA is concerned about the broader impact of CARB's proposal to remove forklifts as a credit generator. This proposal tells regulated entities CARB is reviewing and determining which technologies are in or out of the program based on the metric of "maturity" without discussing the criteria it used to make this assessment. In 2015 when CARB brought into the LCFS the forklift crediting provision it did so with no expiration, subsequent credit provisions bolted onto the program have included expirations and limits that signal CARB's intent to monitor the adoption rates and perceived maturity of a technology. By introducing the concept that a credit provision can simply be stripped from the program creates a disruption. A logical follow up question is "what comes next?" WSPA opposes the concept of using an arbitrary term like "maturation" in the LCFS program, without any discussion on the criteria used to determine if a technology is mature.

MHD HRI/FCI Crediting - For both hydrogen refueling infrastructure (HRI) and fast charging infrastructure (FCI) crediting, WSPA encourages CARB to pursue a practical approach to calculating refueling facility capacities. It was suggested by CARB staff during the workshop that infrastructure credits would be assessed separately for light duty (LD) vehicles and medium/heavy duty (MHD) vehicles. CARB staff's current methodology for applying this distinction is to require separate infrastructure at each fueling location, meaning separate storage, piping, and dispensers for each vehicle type. This is an impractical, inefficient use of resources that will discourage facility expansion. If infrastructure credits are to be a part of the LCFS, they should be applied equitably and efficiently. WSPA urges CARB to work with stakeholders to find a practical solution for assessing the capacity of facilities serving both LD and MHD vehicles.

Arbitrary Pathway Caps - WSPA opposes arbitrary caps on fuel pathways. An example is crop-based biofuel. While we share CARB's concern for food security and any unintended consequences from low carbon fuel programs, a compelling case has not been presented for this proposal. Setting such limits requires a thorough, independent analysis that demonstrates a measurable impact to land use due to crop-based feedstocks used for fuel production. WSPA encourages CARB to continue prioritizing sustainability as part of the LCFS, but objects to any further limitations. CARB already establishes indirect land use change (ILUC) values for crop-based biofuels which is in addition to the production and transportation emissions that together makes up the CI value of the renewable fuel produced from crop-based feedstocks. Therefore, CARB should not create an additional penalty or set an arbitrary limit on the volume of crop-based feedstocks in the program. CARB should work to incentivize the production and use of feedstocks produced sustainably, not limit one of the most important and effective tools CARB has to reduce emissions from the transportation sector.

Pathway Approvals - WSPA believes that the current pathway application review process has inefficiencies that are cumbersome in workload burden to both CARB staff and pathway applicants. A significant restructuring of the process is recommended with input from regulated parties. At minimum, enhancements may include credit true-ups back to a facility's startup date and the approval of provisional pathways from startup of the renewable fuel production. WSPA requests that CARB adds in the LCFS regulatory language a deadline for CARB staff to review a pathway application. If CARB has not reviewed the pathway application within 60 days, the pathway application shall be deemed complete and opened for third-party verification.

Renewable Hydrogen Definition - WSPA believes that all renewable light hydrocarbons, not only biomethane and renewable natural gas (RNG), should have the same consideration as RNG in the LCFS regulation, including for the production of hydrogen. Renewable feedstocks should not be limited to pipeline quality biomethane and RNG in the production of renewable hydrogen. As such, facilities that produce both renewable fuels and hydrogen will utilize internally produced fuels like renewable ethane, renewable propane, renewable butanes, renewable pentanes, and renewable C6+ as feedstocks to produce hydrogen and should qualify for the production of renewable hydrogen. WSPA requests that the definition of renewable hydrogen be expanded to include the use of renewable light hydrocarbons for the production of renewable hydrogen. In addition, renewable hydrogen produced from renewable light hydrocarbons should qualify under the Hydrogen Refueling Infrastructure provision of the regulation for lower emission factors than hydrogen produced from fossil natural gas. The provisions above should apply regardless of whether the renewable feedstocks used to produce renewable light hydrocarbons are waste oils, fats, used cooking oil, distiller's corn oil or "fresh" vegetable oils, such as soybean or canola oils.

Verification - With verifications nearing completion for the second year under the LCFS, CARB should engage regulated parties and verifiers to seek feedback on the process and identify opportunities for improvement.

Aviation Fuel - WSPA would appreciate seeing more details regarding the proposal to obligate intrastate fossil jet fuel (i.e., where the point of obligation would be and how it would be executed). In general, WSPA believes that CARB cannot obligate jet fuel used for intrastate flights.

Much of the aviation industry is inherently interstate and international, making this sector particularly appropriate for the federal government to regulate. As such, 42 U.S.C. § 7573 preempts states from adopting or enforcing *"any standard respecting emissions of any air pollutant from any aircraft or engine thereof unless such standard is identical"* to USEPA's standards. On January 11, 2021, USEPA adopted new greenhouse gas (GHG) emission standards that apply to apply to civil subsonic jet airplanes and larger civil subsonic propeller-driven airplanes.[1] Notably, the standards are equivalent to the airplane carbon dioxide standards adopted by the International Civil Aviation Organization in 2017.[2] In the preamble to the final rule, USEPA notes, *"These standards will ensure control of GHG emissions, maintain international uniformity of airplane standards, and allow U.S. manufacturers of covered airplanes to remain competitive in the global marketplace."*[3] Thus, CARB should account for emission reductions in the aviation industry due to compliance with the new federal GHG emissions standards for airplanes, but should not presume that it can impose more restrictive emission standards than exist at the federal level.

In addition, intrastate fossil jet fuel represents a small fraction of jet fuel supplied in California and jet fuel suppliers do not know how much of the fuel is consumed intrastate versus interstate or out of the country. This makes compliance with the proposed obligation extremely complicated.

[1] Control of Air Pollution From Airplanes and Airplane Engines: GHG Emission Standards and Test Procedures, 86 Fed. Reg. 2136 (Jan. 11, 2021).
[2] *Id.* at 2137.
[3] *Id.* at 2138.

WSPA appreciates the opportunity to provide comments on this important regulatory process. If you have any questions regarding this submittal, please contact me at (360) 296-0692 or via email at jverburg@wspa.org.

Sincerely,

James Verburg
Director, Fuels
WSPA

Jim Verburg
Director, Fuels

September 19, 2022

Sent via e-mail and upload to: https://www.arb.ca.gov/lispub/comm/iframe_bcsubform.php?listname=lcfs-wkshp-jul22-ws&comm_period=1&_ga=2.85577753.167319428.1658172472-237475923.1631295388

Dr. Cheryl Laskowski
Branch Chief – Low Carbon Fuel Standard
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: WSPA Comments on August 18th CARB Workshop to Discuss Potential Changes to LCFS

Dear Dr. Laskowski,

Western States Petroleum Association (WSPA) appreciates the opportunity to comment on the staff presentation at California Air Resources Board (CARB) Workshop to discuss potential changes to the Low Carbon Fuel Standard (LCFS), held on August 18, 2022. WSPA is a trade association that represents companies that provide diverse sources of transportation energy throughout the West, including California. This includes the transport and marketing of petroleum, petroleum products, natural gas, renewable fuels, and other energy supplies. Provided below is WSPA's initial feedback with references to the staff presentation slides[1] on CARB's proposed changes in the LCFS Program as presented to stakeholders by CARB staff on August 18, 2022:

Pathway Streamlining – Deemed Complete Date (Slides 9-13) – WSPA appreciates CARB's efforts to streamline LCFS program implementation. Although the alignment of deemed complete status reduces some confusion, changing the "*deemed complete date"* for Tier 2 pathway applications does little to streamline the pathway application process or resolve the issues with fuel pathway processing. Currently, for Tier 2 applications, the deemed complete date has little effect on credit generation, given that application reviews and validations are taking several months to complete. Ultimately, availability of the certified pathway often occurs multiple quarters after the deemed complete date. To achieve substantive changes in application processing, WSPA recommends that CARB incorporate into the regulation a deadline of 30 calendar days for CARB to review fuel pathway applications. If the applications are not reviewed within 30 days, the pathway application process should move on to the next step, such as the third-party validation step or the fuel pathway certification step. WSPA also recommends that CARB set staffing levels such that smooth and effective fuel pathway review processes can be achieved.

Temporary Pathway Credit True-Up (Slides 14-18) – WSPA supports the CARB staff proposal to true-up temporary fuel pathways with provisional and operational CI values. As CARB staff develops the draft regulatory language to implement this true-up element, we offer several factors to consider:

- The true-up should cover all volumes reported back to the first quarter during which the temporary pathway was used. Slide 16 suggests that it would be the first "full" quarter. This is an unnecessary limitation.

[1] https://ww2.arb.ca.gov/sites/default/files/2022-08/August%202022%20Workshop%20Slide%20Deck%20Presentations.v16.pdf – Accessed 9-12-2022

- True-ups should be automatic. Once CARB has certified a provisional or permanent pathway, credits should be added to the applicant's LRT-CBTS account without any administrative approval step.

- It is possible that a pathway holder may not be the fuel reporting entity for their pathway. In that case, they should have the option to designate another party to receive the true-up credits as part of their pathway application.

- True-ups should be applicable to pathways under review at the time that the regulatory changes take effect, including pathways still under provisional status.

WSPA also supports the proposal made during the public comment period to extend true-ups to the annual fuel pathway reporting process as well. Following verification, fuel pathway holders should be rewarded for incremental improvement in their operational carbon intensity. Doing so on an annual basis would reduce the need for pathway holders to reapply for their pathways to capture the value of operational improvements.

Hydrogen Tier 1 Calculator (Slides 19-23) - WSPA supports the establishment of a Tier 1 calculator for hydrogen. For a rapidly growing segment of the California LCFS program, this proposal may serve to streamline hydrogen applications so that focus can be placed properly on other complex Tier 2 pathways. For hydrogen pathways produced by steam hydrocarbon reforming, WSPA requests that CARB incorporate into the Tier 1 calculator all renewable hydrocarbons, (other than biomethane or renewable natural gas) as acceptable components to produce renewable hydrogen. An illustrative example is a renewable fuel facility that produces renewable propane as a co-product resulting from the conversion of renewable feeds to produce renewable diesel and/or alternative jet fuel. The renewable propane can be sent to the hydrogen plant as feedstock or used as thermal energy in the process heater for the hydrogen plant. Thus, the hydrogen derived from that portion of the renewable propane should be recognized as renewable hydrogen and should qualify for the hydrogen refueling infrastructure crediting program.

EMFAC Model Estimation (Slide 45) – WSPA does not support the use of EMFAC as a source of data for generating base credits for residential EV charging. EMFAC's primary purpose is to estimate the emissions inventories of on road mobile sources in California in the aggregate. CARB staff Slide 45 states: "*EMFAC is not designed to estimate residential PEV charging - estimates are not intended to reflect charging behavior" and "modifications would need to be made to transform model outputs into an estimate of residential PEV charging"*. As such, EMFAC may not be the best tool for accurately calculating credits for residential EV charging.

WSPA appreciates the opportunity to provide comments on this important regulatory process. If you have any questions regarding this submittal, please contact me at (360) 296-0692 or via email at jverburg@wspa.org.

Sincerely,

James Verburg
Director, Fuels
WSPA

Tanya M. DeRivi
Vice President, Climate Policy

December 21, 2022

Sent via upload to:
https://www.arb.ca.gov/lispub/comm2/bcsubform.php?listname=lcfs-wkshp-nov22-ws&comm_period=1

Dr. Cheryl Laskowski
Branch Chief – Low Carbon Fuel Standard
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: WSPA Comments on November 9 CARB Workshop regarding Potential Changes to LCFS

Dear Dr. Laskowski,

The Western States Petroleum Association (WSPA) appreciates the opportunity to comment on the staff presentation at the California Air Resources Board (CARB) workshop to discuss potential changes to the Low Carbon Fuel Standard (LCFS), held on November 9, 2022. WSPA is a trade association that represents companies that provide diverse sources of transportation energy throughout the west, including California. This includes the transport and marketing of petroleum, petroleum products, natural gas, renewable fuels, and other energy supplies.

Provided below is WSPA's feedback regarding the CARB staff presentation[1] on proposed changes in the LCFS Program as provided to stakeholders on November 9. WSPA has previously submitted comments to CARB staff pursuant to the CARB's July 7 and August 18 LCFS workshops. Those comments are incorporated into this letter by reference.[2,3]

CATS Model Overview (Slides 12-21)

The California Transportation Supply (CATS) Model is intended to develop optimized scenarios based on the user input. CARB needs to assess that the basis for its inputs to CATS are technically sound, in particular for emerging technologies. WSPA recommends that CARB develop sensitivity analysis for different input variables, including (but not an exhaustive list):

- Various gasoline demand scenarios, including flat gasoline demand or gasoline demand not dropping as fast as expected in the original scenario.
- Different electricity prices, as the cost of electricity seems to be too low if set at 80 $/MWh as stated in Slide 16. The United States Energy Information Administration (EIA) recently reported that in September 2022, the "average price of electricity to ultimate customers" for the transportation sector in California was 15.63 cents/KWh (equates to 156.30 $/MWh).[4] In addition, modeled scenarios for future years should take into account upward pressures on electricity rates such as those presented by the California Energy Commission in their

[1] https://ww2.arb.ca.gov/sites/default/files/2022-11/LCFSPresentations.pdf
[2] Western States Petroleum Association. "WSPA Comments on CARB Workshop to Discuss Potential Changes to the LCFS", August 8, 2022.
[3] Western States Petroleum Association. "WSPA Comments on the August 18th CARB Workshop to Discuss Potential Changes to the LCFS", September 19, 2022.
[4] https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.

September 21, 2021, Demand Analysis Working Group which shows forecasted statewide commercial and residential rates greater than 20 cents/KWh in 2030 and beyond.[5]

- A range of crude oil price ranges, rather than a single 90 $/barrel proposed on Slide 16 and Table 4 of the CATS documentation.

CATS should also model the additional cost of electricity for building up the electric vehicle (EV) charging infrastructure and the construction of additional power generation.

Table 8 of the "Draft California Transportation Supply Model – Technical Documentation" (hyperlink to document provided on Slide 21) shows a significant difference between the fixed cost of CARBOB production and the fixed cost of ultra-low sulfur diesel (ULSD) production. WSPA requests that CARB provide more information on how these fixed costs are established as ULSD and CARBOB are co-produced at oil refineries. CARB should also confirm whether the biodiesel equivalence value under the United States Environmental Protection Agency's Renewable Fuel Standard (RFS) program should be 1.5 rather than 1.4 as stated on Page 20 of the "Draft California Transportation Supply Model – Technical Documentation."

CATS Summary Input Spreadsheet – Fuel Production Tab – Exogenous Subsidy (Slide 21)

In reviewing the "core model inputs" (hyperlink to spreadsheet provided on Slide 21), WSPA requests that CARB staff confirm if the 0.369 $/MJ value of compressed natural gas (CNG) is correct, or if it should instead be 0.0369 $/MJ. The 0.369 $/MJ corresponds to nearly $390 million per BTU – which seems very high. It is also requested that CARB provide the basis for the renewable gasoline 0.019 $/MJ exogenous subsidy.

Scenario Design: Carbon Intensity (Slides 25-26)

WSPA is concerned about the current pace of the LCFS rulemaking. CARB proposes to significantly accelerate near-term LCFS targets and potentially extend targets as far out as 2045. However, CARB staff is just beginning to assess potential compliance scenarios. The presentation during the November 9 workshop described high-level compliance curves, with little transparency into the methodology and no discussion of feasibility. To meet a January 2024 implementation date, these scenarios need to be presented in a more comprehensive manner, with transparency and significant stakeholder input. Without that, it is difficult to comment on the three compliance curves presented. Consequently, we can only comment on the modeling inputs described by CARB staff.

For example, Slide 6 shows that the program only slightly "overperformed" – by 0.61% carbon intensity (CI) reduction in 2021 (9.36% CI reduction vs. 8.75% CI target) – which is only about half of the current annual increase in the CI benchmark. If the pace of adopting Zero Emission Vehicles does not occur as planned into 2030, the number of deficits will far exceed any credits being generated. Yet this scenario is not being evaluated as part of the scenarios. As a result, CARB should be careful in setting more stringent CI standards and ensure that the new CI standards do not quickly exhaust the credit bank.

In addition, CARB should include in the proposed regulatory language a provision that stipulates a formal annual program review with an option to reset the benchmarks in the event that credit generation falls short or/and deficit generation is higher than expected.

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[5] CEC Demand Analysis Working Group (https://www.energy.ca.gov/sites/default/files/2021-09/1%20Electricity%20Rate%20Forecast%20Updates_ADA.pdf) – Accessed 12-15-2022

Crop-Based Biofuel (Slides 28-29)

As WSPA stated in our August 8 comment letter, no arbitrary limit should be set on crop-based feedstock. Any concerns around land use impacts are handled in feedstock carbon intensity calculations. Indirect Land Use Change (ILUC) values already increase the CI score of renewable fuel produced from crop-based feedstocks, resulting in lower emission reductions attributable to the fuels. An artificial limit on supply is not the appropriate method of accounting for these impacts.

Food supply concerns are similarly addressed by ILUC inputs to carbon intensity scores. It is noteworthy that the 2018 LCFS readoption evaluated several different fuel supply scenarios[6] with varying amounts of biodiesel and renewable diesel available to support the LCFS's goal of reducing the CI of fuels in California 20% by 2030. The scenario chosen to illustrate a feasible program estimated the growth of biodiesel and renewable diesel would be on the order of 146% (and evaluated growth up to a 215% increase) from 2018 levels through to 2030. Much of the anticipated growth in these fuels has already been considered by CARB, including potential land use impacts and other factors[7]. Today, feedstock availability is aligning with expectations from the 2018 LCFS readoption. As shown in the 2018 illustrative compliance calculator,[8] CARB forecasted the CIs for biodiesel and renewable diesel to be 34 gCO2e/MJ for biodiesel and 30 gCO2e/MJ for renewable diesel into 2030. As of Q2 2022, CARB has reported[9] average CI values of 27.51 gCO2e/MJ for biodiesel and 35.96 gCO2e/MJ for renewable diesel. Given investments taking place, additional restrictions should not be created as anticipated growth of these fuels and impact to land use has already been considered.

Additionally, no data has been presented by CARB or other stakeholders suggesting that any threat to food supply has been created by growing biofuel demand. It is noteworthy that while CARB is proposing limits on crop-based feedstock, the proposed regulation encourages the increased development of renewable electricity sources (specifically solar) which will undoubtedly result in the conversion of agricultural lands. WSPA believes that this duplicity in policy is concerning and sends a mixed message to stakeholders.

Rather than establish artificial limits on crediting for specific fuels, WSPA encourages CARB to continue analyzing land use change factors and focus on CI score accuracy. WSPA also requests that CARB define the term "virgin crop-based oil." Specifically, the definition should not include cover crops. Cover crops are used to slow erosion, improve soil fertility and quality, and help control pests and diseases.

Biomethane Crediting (Slides 30-32)

CARB staff presented potential scenarios for limiting crediting for biomethane, including arbitrary geographical limits and a phase-down of avoided methane crediting without providing a clear approach as to how CARB would implement these changes. For example, it is not clear whether or not the gas to a hydrogen production facility (a legacy pathway not tied to a landfill renewable natural gas (RNG) facility book-and-claim) would be removed from crediting as of 2030. Clarity around considerations such as this is important for stakeholders to understand and to provide meaningful feedback. Because biomethane crediting has been a major contributor to the success of the LCFS program, to arbitrarily limit those credits threatens the continued success of the program. It is also contrary to the technology neutral, market-based nature of the LCFS program.

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[6] CARB 2018 rulemaking. Illustrative Compliance Calculator.
[7] CARB 2018 Environmental Analysis.
[8] *Supra*, tab "Calculations" Row's 57 and 58.
[9] CARB LCFS Quarterly Data Spreadsheet.

CARB cited a desire to focus biomethane use in hydrogen production and non-transportation use. The proper way to do so is to establish incentives that encourage use in those applications, rather than simply removing incentives elsewhere. As producers discussed during the November 9 workshop, such an approach is more likely to slow or even reverse investments in methane capture. Rather than limit crediting for biomethane under the LCFS, CARB should be looking for ways to establish credit, such as removing the limit on book-and-claim treatment for biomethane used for process energy in refineries and crude production facilities.

Further, WSPA believes that CARB should not attempt to harmonize RNG with electricity (see Slide 32) as the natural gas pipeline is vastly different from the electricity grid. For example, there is more flexibility to move gas longer distances than the electric grid is capable of. If Alternative A or B is adopted, then CARB should grandfather in all current pathways that have RNG facilities located outside of the "Western NG network" as project investment was based upon dispensing in California.

Other Modeling Assumptions Under Consideration (Slide 35)

CARB included a phase out of petroleum project-related crediting in two of the scenarios presented without describing the rationale behind such a change. Given that all scenarios involve continued use of petroleum products in the coming decades, it is contrary to the goals of the LCFS program to discourage carbon reduction projects at crude production and refining facilities.

Rather than arbitrarily constrain these credits without science-based drivers, CARB should be removing current barriers to qualification. Innovative Crude credits are currently restricted to a discrete set of technologies and should be expanded to enable emerging technologies and efficiency investments that reduce carbon emissions. Similarly, the use of biomethane in both crude production and refining facilities should be allowed book-and-claim treatment.

WSPA continues to object to the addition of deficits for intrastate fossil jet use. This is a needlessly complicated addition to the program for a very small portion of jet fuel demand in the State. It would have little impact on alternative jet fuel demand and create considerable work for aviation stakeholders, CARB staff, and verifiers (i.e., fuel producers and importers do not know who controls how much of the jet fuel that is consumed in intrastate flights – nor do they have access to this information). However, if CARB decides to implement such a LCFS obligation on intrastate jet fuel, the obligation should not be borne by fuel producers or importers.

WSPA appreciates the opportunity to provide comments on this important regulatory process. If you have any questions regarding this submittal, please contact me at via email at tderivi@wspa.org.

Sincerely,

Tanya DeRivi

Tanya DeRivi
Vice President, Climate Policy

Tanya M. DeRivi
Senior Director, Climate Policy

March 15, 2023

Sent via upload to:
https://www.arb.ca.gov/lispub/comm2/bcsubform.php?listname=lcfs-wkshp-feb23-ws&comm_period=1

Dr. Cheryl Laskowski
Branch Chief – Low Carbon Fuel Standard
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: WSPA Comments on CARB Preliminary Discussion Draft of Potential Low Carbon Fuel Standard Regulation Amendments and February 22, 2023 LCFS Workshop

Dear Dr. Laskowski,

The Western States Petroleum Association (WSPA) appreciates the opportunity to comment on the Preliminary Discussion Draft of Potential Low Carbon Fuel Standard (LCFS) Regulation Amendments and the associated staff presentation at the California Air Resources Board (CARB) workshop, held on February 22, 2023. WSPA is a trade association that represents companies that provide diverse sources of transportation energy throughout the west, including California. This includes the transport and marketing of petroleum, petroleum products, natural gas, renewable fuels, and other energy supplies.

In considering potential amendments to the LCFS Regulation, it is essential to recognize that LCFS adds approximately 11 cents per gallon to the cost of California gasoline according to the California Energy Commission.[1] While California continues to face serious supply constraints as it relates to transportation fuels and the California legislature considers how to provide relief at the pump for California drivers, CARB should ensure that its proposed LCFS regulation amendments do not increase costs uniquely impacting California fuels. Proposed amendments including arbitrary caps on alternative fuel pathways, hydrogen production and a self-ratcheting mechanism, among other amendments, will likely increase costs of California fuels. WSPA is generally concerned with proposed amendments to the LCFS regulation that could further compromise the supply reliability of critical transportation fuels, a consequence of which could be increasing energy costs at a time when energy affordability is a pressing priority for many Californians.

The LCFS program is primarily a liquid fuels program, for which WSPA members have made significant investments to help make the program both successful and replicable. WSPA supports LCFS and believes that the program should continue to provide an appropriate market signal that incentivizes the production of low-carbon intensity (CI) fuels. The LCFS should continue to preserve consumer choice and provide a level playing field for all technologies. The market-based program should embrace fuel- and technology-neutral principles that focus on the meaningful and timely reduction of GHG emissions. Because step changes on CI stringency would be required upon adoption of final regulatory language starting as early as 2024, LCFS should provide a clear and durable market signal for investments in the production of lower CI technologies with sufficient time from adoption to implementation for obligated parties to plan for investments and deployment plans for technologies.

[1] Based on OPIS data; CEC staff presentations at https://www.energy.ca.gov/event/workshop/2022-11/commissioner-hearing-california-gasoline-price-spikes-refinery-operations

Provided below is WSPA's feedback regarding the Preliminary Discussion Draft of Potential LCFS Regulation Amendments and CARB staff presentation[2] from the February 22nd workshop. WSPA previously submitted comments pursuant to CARB's July 7th, August 18th, and November 9th LCFS workshops. Those comments are incorporated into this letter by reference.[3,4,5]

General Comments

Arbitrary Caps on Alternative Fuels Pathways

CARB continues to discuss the concept of placing an arbitrary cap on crop-based fuels but has not yet presented data to demonstrate what problem the cap would address. CARB staff even mentions on Slide 37 that they have *"received limited data, analysis and supporting documents."* Since there is no majority of stakeholders presenting a compelling argument in favor of such a significant programmatic change, this concept should be set aside unless a verifiable issue arises. In fact, an arbitrary cap on crop-based fuels would go against Health and Safety Code Section 38560, the statutory basis for CARB's proposed set of actions, which requires CARB "to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions from sources."[6] When all options must be on the table, CARB's concept would be *limiting* proven GHG reductions strategies that are technologically feasible and cost effective, and have garnered significant GHG reductions in the past.

We would also like to once again point out that CARB has already included a control mechanism for potential land use change concerns. This is precisely what the ILUC factors in CI modeling are meant to do, so additional limits are not needed nor appropriate. WSPA believes that adding an arbitrary cap would unnecessarily respond to an issue that was addressed long ago in the LCFS program.

Hydrogen Production

All hydrogen production pathways should be considered based on their CI reduction potential. Similar to what has been discussed above, a more robust hydrogen infrastructure has shown to be a technologically feasible, cost-effective way to reduce GHG emissions, which is what Health and Safety Code Section 38560 requires CARB to accomplish. WSPA does not support either the exclusion of hydrogen derived from fossil fuels from book-and-claim eligibility or the exclusion of hydrogen production by steam methane reforming in Medium- and Heavy-Duty Hydrogen Refueling Infrastructure (MHD-HRI) crediting. There is already a severe shortage of hydrogen refueling options across California (especially in relation to electric charging options) – just as CARB prepares to adopt the proposed Advanced Clean Fleets regulation that will demand the immediate and exponential growth of hydrogen refueling options for MHD vehicles.

We urge CARB to avoid proposed amendments that would arbitrarily constrain hydrogen production at a time when California consumers need more affordable fuel options – not less.

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[2] https://ww2.arb.ca.gov/sites/default/files/2022-11/LCFSPresentations.pdf
[3] Western States Petroleum Association. "WSPA Comments on CARB Workshop to Discuss Potential Changes to the LCFS", August 8, 2022.
[4] Western States Petroleum Association. "WSPA Comments on the August 18th CARB Workshop to Discuss Potential Changes to the LCFS", September 19, 2022.
[5] Western States Petroleum Association. "WSPA Comments on the November 9th CARB Workshop regarding Potential Changes to LCFS", December 21, 2022.
[6] Cal. Health & Safety Code § 38560.

CATS Model

CARB staff stated at the February 22nd LCFS workshop that the California Transportation Supply (CATS) Model would be released within a week for stakeholders to evaluate and use. According to CARB's document, the CATS Model *"can be used to explore how different assumptions relating to the cost, supply, demand, and carbon intensities of various fuel may impact the transportation market, and how Low Carbon Fuel Standard credit prices may respond to changes in market conditions and program stringency."*[7] WSPA subsequently inquired with CARB staff on the status and timing to comment when that week-long timeframe had passed. As the CATS modeling has yet to be released, we along with other stakeholders are unable to offer robust comments at this time.

Providing the CATS modeling with adequate review time would have helped stakeholders raise issues for CARB staff or to seek clarification from CARB staff regarding important input assumptions being used to inform CARB's modeling of future LCFS requirements. Even without the CATS modeling release, WSPA does have questions about various modeling assumptions, including cost of compliance, how feedstock pricing was established, inclusion of fixed cost regression for some fuel components, interim pricing for intrastate Sustainable Aviation Fuels, inflationary assumptions, costs associated with fossil fuel sales, and other important variables.

Specific Comments – CARB Staff Presentation

Slide 11 – Alternative Fuel Diversification

CARB staff rightfully noted in their introductory comments that *"LCFS drives investment and fuel diversification"* and that further investment is needed to meet accelerated targets. It is concerning, however, that CARB staff then proposed a number of changes that would scale back existing investments and discourage future growth. This includes dramatic increases in biogas carbon intensity, artificial caps on crop-based fuels, halving credits for ZEV forklifts, and phasing out crediting for GHG reduction at upstream and refining facilities. Further constraining fuel options just as CARB seeks to increase the program's stringency is the wrong approach for Californians. Such proposals would also go against Health and Safety Code Section 38560 which requires CARB to seek out technologically feasible, cost-effective GHG reduction mechanisms.

Slide 15 - Self-Ratcheting Mechanism

The second bullet on Slide 15 identifies as an element of the rulemaking scope: "*Mechanisms to auto-adjust CI targets to accelerate investment if program is over-performing."* WSPA recommends against a self-ratcheting mechanism that would auto-adjust the CI targets. We believe that rulemaking is the appropriate process to update the CI targets, because it is what is expected under basic principles of California administrative law,[8] and because a self-ratcheting mechanism would defeat the spirit of the LCFS regulation, which is to allow banking of LCFS credits for future use as the program becomes more stringent over time. It would also not appear to account for exceptional circumstances, such as the COVID pandemic nor recessionary-driven slowdown, that have demonstrably significant impacts on the fuels market as well. A self-ratcheting mechanism may lead to an excessive use of LCFS credits in the short term to the detriment of long-term compliance

[7] https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/lcfs-meetings-and-workshops.
[8] *See* Cal. Gov't Code § 11346.2 (discussing the notice-and-comment process); *POET, LLC v. State Air Res. Bd.*, 218 Cal. App. 4th 681, 744 (2013), *as modified on denial of reh'g* (Aug. 8, 2013) ("agencies must . . . (1) give the public notice of the proposed regulatory action; (2) issue a complete text of the proposed regulation with a statement of reasons for it; (3) give interested parties an opportunity to comment on the proposed regulation; (4) respond in writing to public comments; and (5) maintain a file as the record for the rulemaking proceeding").

options. Further, such mechanism fails to provide market certainty.

Slide 16 - Rulemaking Process

CARB staff lays out a very general rulemaking process on Slide 16 without discussing timing. Given the progress to date on this rulemaking, WSPA urges CARB staff to identify an achievable implementation date for any regulatory changes made and to publish a detailed rulemaking calendar.

Slide 25 (and Slide 52) - Compliance Target Step Down and Acceleration Mechanism

This is the first workshop during which CARB officially discussed the concept of an "acceleration mechanism." We find this concept concerning as it shortcuts the deliberative, public process of a formal rulemaking (i.e., an "acceleration mechanism" could remove credits from the bank too quickly and risk rendering the program infeasible in the later years when the CI standards become ever more stringent) which the public is entitled to under basic administrative law principles in California.[9] The credit bank should be looked to as a long-term compliance option. We also believe that any market indicators identified could result in serious unintended consequences such as credit shortages or market volatility. With the concept under consideration, such consequences could only be addressed through emergency actions by CARB, followed by an immediate rulemaking.

Regarding the potential triggers CARB listed, a credit price trigger is the least appropriate. While the LCFS is intended to spur investment, CARB should not seek to fix prices. The price cap in the Credit Clearance Market is there as a relief valve to avoid harmful spikes. Setting an effective price floor would represent market manipulation. Furthermore, markets are volatile. Establishing a price trigger could lead to frequent, disruptive alterations to compliance targets. Adding such volatility to California's fuel market would be highly inadvisable.

However, of the triggers CARB identified, the total credit bank size would be the most appropriate. If the credit bank size were used as a trigger, it would obviously behoove CARB to include automatic "deceleration" of targets should the credit bank become very low or negative. It is unclear what "credit to deficit ratio" means as a trigger for changing targets.

Finally, the LCFS credits modeled by CARB is above the maximum allowed credit price, which indicates a shortage of credits. Therefore, no step-change should be considered in the program. Rather CARB should establish CI standards that can be met while maintaining the LCFS credit price below the maximum allowed price.

Slide 29 - ZEV Refueling Infrastructure

While the replication of the light-duty ZEV refueling infrastructure language for medium- and heavy-duty vehicles is appreciated, it is critical that CARB staff identify a reasonable mechanism for modeling "hybrid" stations to avoid creating a requirement for the duplication of storage-to-dispensing infrastructure.

Slide 32 - Methane Crediting

CARB staff cited a desire to focus biomethane use in hydrogen production and non-transportation use. The proper way to do so is to establish incentives that encourage use in those applications, rather than simply removing incentives elsewhere. As stakeholders discussed this issue during

[9] Please see discussion in Footnote 7.

previous LCFS workshops, such an approach is more likely to slow or even reverse investments in methane capture. Rather than limit crediting for biomethane under the LCFS, CARB should be looking for ways to *establish* credit, such as removing the limit on book-and-claim treatment for biomethane used for process energy in refineries and crude production facilities.

WSPA also believes that Avoided Methane Crediting is needed to support current and future investment and project development. These credits for methane – that was previously emitted or flared – are key components of dairy renewable natural gas (RNG) investments and should be preserved to ensure the maximum production of clean fuels and emission reductions.

Further, WSPA recommends that CARB not attempt to harmonize RNG with electricity as the natural gas pipeline is vastly different from the electricity grid. For example, there is more flexibility to move gas longer distances than the electric grid is currently capable of.

Slide 35 - Intrastate Jet Fuel

WSPA continues to object to the addition of deficits for intrastate fossil jet use. This is a needlessly complicated addition to the program for a very small portion of jet fuel demand in the state. It would have little impact on alternative jet fuel demand and create considerable work for aviation stakeholders, CARB staff, and verifiers. Crediting for alternative jet fuel is based on delivery to airport storage, while the proposed deficits would be based on consumption during intrastate flights. Given that, blending more alternative jet fuel would not reduce the deficits generated by airlines for intrastate flights. This means that these added deficits would simply make the airlines credit purchasers in the program and would not incentivize increased blending of alternative jet fuel.

If CARB decides to implement a LCFS obligation on intrastate jet fuel, WSPA agrees that the obligation should not be borne by fuel producers or importers (but rather the airlines that will use the jet fuel) as fuel producers and importers do not control the volume of jet fuel that is used for intrastate travel. This would enable more direct tracking of intrastate jet consumption.

Slides 36-41 - Crop-Based Fuels

As a follow-up to the General Comment above and consistent with past WSPA comment letters, no arbitrary limit should be set on crop-based feedstock. A free-market CI based policy should drive technology choices and there should not be additional prohibition mechanisms in favor/or against certain technologies. ILUC values already increase the CI score of renewable fuel produced from crop-based feedstocks, resulting in a lower economic value for these fuels compared to fuels produced from waste-based feedstocks. CARB should let the market optimize the fuel slate based on market economics and feedstock availability and not set arbitrary constraints.

WSPA further suggests that Best Farming Practices be included in, and accounted for, within the program CI calculation methodology to properly credit “climate smart” agricultural practices. Doing so would recognize the projected GHG mitigation and carbon sequestration benefits associated with ongoing or new and innovative farming practices associated with the intentional production of climate-smart commodities (e.g., reduced use of fertilizer, targeted fertilizer nutrients, soil carbon sequestration, etc.).

Slide 43 - Project-Based Crediting – Phase Out

WSPA objects to an artificial phase out of project-based crediting and limiting the duration of the crediting period of these projects, as project-based crediting incentivizes incremental GHG emission reductions. Such an approach is arbitrary and discourages investment in real GHG reduction investment at refineries and oil producing facilities. Rather than arbitrarily constrain these credits without science-based drivers, CARB should be removing current barriers to qualification. Innovative Crude credits are currently restricted to a discrete set of technologies and should be expanded to enable emerging technologies and efficiency investments that reduce carbon emissions – especially given the strong and long-term demand for these fuels identified in the 2022 Scoping Plan Update.

Similarly, the use of biomethane in both crude production and refining facilities should be allowed book-and-claim treatment. Restricting book-and-claim for RNG to CNG transport outlets but not for hydrogen feedstock dispositions again seems to be attempting to pick "winners and losers" based upon long-term speculative market forecasts. We continue to support a free market-based policy and level playing field for various RNG pathways. To that end, we support maintaining the robust tracking, traceability, and documentation requirements and continuing to allow book-and-claim from all existing geographies for all RNG pathways, as this represents the best path forward to achieve more stringent LCFS targets.

Slide 48 - LCFS Modeling Framework

WSPA requests detailed clarification of the CATS Model assumptions. Areas of concern identified from information available to date include but are not limited to the following:

- The model does not appear to be tracking any possible increase in the cost of fossil fuel sales in the model (or are not explaining how it is included), which may incorrectly increase the cost of compliance.
- Inflation does not seem to be factored into the model; more clarification is needed on assumptions and methodology.
- The Sustainable Aviation Fuel (SAF) model appears to reflect only the interim SAF pricing in years 2023-24 versus 2025-27. It is not clear if an entity can carry this forward beyond the years approved. The model is showing soybean oil SAF with a $1.25/gallon subsidy at 50% CI reduction, or 42 CI. This indicates the assumptions used citing the federal Inflation Reduction Act are based on 40B New SAF credits rather than 45Z New Clean Fuel Production credits, which would make better sense.
- More clarity is needed as to how feedstock pricing was established.
- More clarity is needed as to whether the model is assuming an infinite amount of virgin oil feedstock available, driven only by increasing price.
- More clarity is needed on how the model estimates higher fossil and agriculture benchmark costs, relative to historic values.
- The fixed cost regression for FAME and Renewable Diesel is confusing (as well as the one for CARBOB and ULSD) – additional clarification is needed.
- While the model has a fixed price of $1.45/RIN for D4s and FAME RIN equivalence of 1.4 (vs 1.5) and D6s are modeled at $1.13/RIN, a reference for D3s cannot be found.

Slides 49-51 - LCFS Modeling Outputs

Slides 49 and 50 show a significant destruction of gasoline demand over time, yet the diesel pool continues to have a sizable proportion of petroleum diesel. WSPA suggests that CARB evaluate an alternative scenario where the entire pool of petroleum diesel is replaced with renewable diesel and biodiesel blends over the next few years. As alternative fuels saturate the market to near-completion, there should be a step change in credit generation that slows credit generation; it is more difficult to substitute petroleum CARBOB with renewable fuels, due to several constraints, including ethanol blending limits. In particular, if the growth of electric vehicles does not materialize as fast of CARB's current prediction, the deficit generation from CARBOB may be challenging to balance with credits. This uncertainty should also be modeled.

Slide 51 shows the LCFS credit price going over the maximum credit price which suggests a shortage of credits to balance the deficits. Therefore, WSPA requests that CARB also model a CI standard curve where the LCFS credits remain below the LCFS maximum credit price throughout the duration of the modeled period. Another modeling scenario CARB should consider is incorporating the bank of credits held by firms today, by including the credit bank in any forward forecast; including the credits will allow stakeholders to assess how CARB's potential updates will impact the current market.

Slides 62-64 - Updates to Tier 1 Calculators

WSPA supports the development of a new hydrogen calculator. CARB should also include options for renewable hydrocarbon feedstocks, such as renewable propane and other renewable hydrocarbon and hydrocarbon mixtures (such as ethane, propane, butane, etc.) in the steam reforming hydrogen calculator.

In addition, WSPA requests that CARB update the definition of renewable hydrogen to allow infrastructure crediting for hydrogen fuel produced from renewable hydrocarbons other than biomethane/renewable natural gas, by including renewable ethane, renewable propane, renewable butane and other renewable hydrocarbons and a mixture thereof.

Slide 69 - OPGEE

WSPA requests that CARB eliminate the incremental deficit provision from imported petroleum CARBOB and petroleum ULSD (CARB diesel). CARBOB and ULSD produced at refineries outside California do not process the same crude slate as the crude slate processed in California, and therefore, the incremental deficit calculations are not relevant for imported products.

WSPA also requests that CARB release the latest dataset from 2019 used to establish crude baselines in OPGEE. This is an important step to maintain the model's transparency.

Side 70 - Verification Updates

MCON (Crude) Reporting - Refineries should not need to report California crudes by field name in the MCON report as CARB is not using this information. CARB is using the data from the Department of Conservation. Therefore, no verification of California crudes should be required.

Site Visits - No site visit should be required other than for fuel pathway verification. Video conferencing and screen sharing are sufficient for other types of verification.

Quarter 3 LCFS Reporting Deadline - WSPA requests that CARB change the Q3 reporting date from December 31st to January 15th to allow time for the winter holidays.

<u>Specific Comments – Proposed Regulatory Text</u>

§95486.3(a)(1)(B): This section would require proposed MHD-HRI stations to be located in California within one mile of a Federal Highway Administration Alternative Fuel Corridor. WSPA requests that CARB provide the rationale for placing limits on designated corridors and locations rather than leaving the market to define those locations based upon real world demands.

§95486.3(a)(1)(C): This section would allow application on MHD-HRI pathway application through December 31, 2029. WSPA requests that application submissions for light-duty HRI be extended to the same date as well in section §95486.2(a)(1)(B) and §95486.2(a)(7).

§95486.3(a)(2)(E): This proposed section references the HySCapE model. WSPA requests that CARB clarify if there will be a different version of the HySCapE model – one for heavy-duty and one for light-duty hydrogen fuel cell vehicles – or if the same HySCapE model will be used in any case.

§95486.3(a)(3)(A): This section includes an equation for estimating potential MHD-HRI credits. WSPA suggests that CARB consider additional language for exemptions and waivers considerations and provide clarity on credit equation for extreme cases where an approved station is not operational for an extended period after approval (extreme case).

§95486.3(a)(4)(B): This section requires that the station must be open to at least two different trucking companies. WSPA suggests eliminating this restriction on station owners.

§95486.3(a)(4)(D): This section requires that at least three Original Equipment Manufacturers have confirmed that the station meets protocol expectations, and their customers can fuel at the station. WSPA requests that CARB provide the reasoning behind this rigorous requirement.

§95486.3(a)(5): In the equation for the calculation of MHD-HRI credits, it appears that the CI_{HR} factor is not the same CI_{HR} factor delivered to the actual station *("… is the carbon intensity used for HRI crediting. Company-wide weighted average CI for dispensed hydrogen during the quarter or 0 g/MJ, whichever is greater")*. WSPA requests further information on this CI input.

§95486.3(a)(6): In this section, certain requirements appear to include information that is competitively sensitive, business confidential information. WSPA requests that CARB identify how this information will be protected against disclosure. In addition, CARB needs to clarify what entities will have access to this information and why that access is necessary.

WSPA appreciates the opportunity to provide comments on this important regulatory process. If you have any questions regarding this submittal, please contact me at via email at tderivi@wspa.org.

Sincerely,

Tanya DeRivi

Tanya M. DeRivi

Tanya DeRivi
Senior Director, California Climate and Fuels

June 6, 2023

Dr. Cheryl Laskowski
Branch Chief – Low Carbon Fuel Standard
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Sent via upload to:
https://ww2.arb.ca.gov/public-comments/public-comments-regarding-auto-acceleration-mechanisms-low-carbon-fuel-standard

Re: WSPA Comments on CARB's Proposed Low Carbon Fuel Standard Auto-Acceleration Mechanism and May 23, 2023 Workshop

Dear Dr. Laskowski,

The Western States Petroleum Association (WSPA) appreciates the opportunity to comment on potential changes to the Low Carbon Fuel Standard (LCFS), to add a mechanism that would accelerate the carbon intensity benchmarks if certain conditions are met, and the associated staff presentation at the California Air Resources Board (CARB) workshop held on May 23, 2023. WSPA is a trade association that represents companies that provide diverse transportation energy resources throughout the west, including California. These include the transport and marketing of petroleum, petroleum products, natural gas, renewable fuels, and other energy supplies.

General Comments

In considering potential LCFS regulation amendments, it is essential to recognize that the LCFS adds approximately 11 cents per gallon to the cost of California gasoline according to the California Energy Commission (CEC).[1] As California continues to face serious transportation fuels supply constraints, the California legislature and the Governor recently approved legislation[2] attempting to address this fuel supply concern. This new statute requires CARB and CEC to prepare a Transportation Fuels Transition Plan "in consultation with the state's fuel producers and refiners" that "shall include, at a minimum, a discussion of how to ensure that the supply of petroleum and alternative transportation fuels is affordable, reliable, equitable, and adequate." WSPA looks forward to working closely with CARB and CEC to inform the Transition Plan's development – where fuel affordability and equity must be central considerations to help inform policies under the baseline assumption that internal combustion engine vehicles (including hybrid vehicles) will be used and needed by Californians for decades to come.

While the LCFS program has a maximum credit sale or transfer price of $200 (2016$) it is important that CARB ensure the potential LCFS amendments recognize the impacts of a change to costs uniquely impacting California fuels. WSPA is extremely concerned with proposed amendments that could further compromise the supply reliability of critical transportation fuels and destabilize the program – a consequence of which could be increasing energy costs at a time when energy affordability is a pressing priority for many Californians. Proposed amendments like a one-way auto-

[1] Based on OPIS data; CEC staff presentations at https://www.energy.ca.gov/event/workshop/2022-11/commissioner-hearing-california-gasoline-price-spikes-refinery-operations.
[2] Senate Bill SB X1-2 (Skinner, 2023) https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202320241SB2.

acceleration mechanism, among other potential changes, will likely increase California fuels costs. Newly inserting an automatic mechanism would be wholly inappropriate and set a bad precedent for a program that was developed through and has been amended multiple times since by formal rulemaking processes.

WSPA members have made significant investments to help make the LCFS program both successful and replicable. WSPA supports the LCFS and believes the program should continue to provide an appropriate market signal that incentivizes the production of low-carbon intensity (CI) fuels. This market-based program should focus on providing clear, meaningful, durable, and timely market signals for the reduction of greenhouse gas emissions through investments in the production of lower CI technologies, with sufficient time from adoption to implementation for obligated parties to plan for investments and deploy technologies.

Specific Comments – CARB Staff Presentation

Provided below is WSPA's feedback regarding the auto-acceleration mechanism under consideration for potential LCFS amendments and the CARB staff presentation[3] from the May 23rd Workshop. WSPA previously submitted comments pursuant to CARB's July 7, 2022, August 18, 2022, November 9, 2022, and February 22, 2023 LCFS Workshops. Those comments are incorporated into this letter by reference.[4,5,6,7]

Slide 7 – Scope of Rulemaking. The second bullet point on Slide 7 identifies mechanisms to auto-adjust CI targets to accelerate investment if the LCFS program is overperforming. WSPA recommends against including a (one-way) auto-adjustment of the CI targets. We believe that rulemaking is the appropriate process to update the CI targets, because it is what is expected under the basic principles of California administrative law,[8] and because such a mechanism would defeat the spirit of the LCFS regulation, which is to allow banking of LCFS credits for future use as the program becomes increasingly more stringent over time.

Instead of an auto-adjustment of the CI targets, WSPA suggests that CARB consider utilizing annual fuels forecasting to determine the need to adjust CI targets. For example, the Oregon Department of Administrative Services (DAS) annually completes a fuels forecast (pursuant to Oregon Administrative Rule 340-253-2100) to inform the Oregon Department of Environmental Quality (DEQ) as to the performance of the DEQ's Clean Fuels Program. A similar independent approach by CARB is encouraged for transparency and consistency.

An auto-adjustment of the CI targets would also appear to <u>not</u> account for exceptional circumstances – such as the COVID pandemic nor a recessionary-driven slowdown – that have demonstrably significant impacts on the fuels market. Instead, such an auto-acceleration mechanism may lead to

[3] https://ww2.arb.ca.gov/sites/default/files/2023-05/LCFSPresentation_052223_0.pdf
[4] Western States Petroleum Association. "WSPA Comments on CARB Workshop to Discuss Potential Changes to the LCFS", August 8, 2022.
[5] Western States Petroleum Association. "WSPA Comments on the August 18th CARB Workshop to Discuss Potential Changes to the LCFS", September 19, 2022.
[6] Western States Petroleum Association. "WSPA Comments on the November 9th CARB Workshop regarding Potential Changes to LCFS", December 21, 2022.
[7] Western States Petroleum Association. "WSPA Comments on the February 22nd CARB Workshop regarding Potential Changes to LCFS", March 15, 2023.
[8] *See* Cal. Gov't Code § 11346.2 (discussing the notice-and-comment process); *POET, LLC v. State Air Res. Bd.*, 218 Cal. App. 4th 681, 744 (2013), *as modified on denial of reh'g* (Aug. 8, 2013) ("agencies must . . . (1) give the public notice of the proposed regulatory action; (2) issue a complete text of the proposed regulation with a statement of reasons for it; (3) give interested parties an opportunity to comment on the proposed regulation; (4) respond in writing to public comments; and (5) maintain a file as the record for the rulemaking proceeding").

an excessive use of LCFS credits in the short-term to the detriment of long-term compliance options. Further, such a mechanism fails to provide the market certainty necessary to ensure petroleum and alternative transportation fuel supplies are affordable, reliable, equitable, and adequate as California's leaders seek to achieve.

Slides 11-12 – Compliance Target Step Down and Acceleration Mechanism Concepts. This was the first workshop where CARB officially discussed details of an "acceleration mechanism." Previously, there was only one workshop where a broad concept was presented. WSPA finds the concept (and the late introduction of details) that introduces a complex structural change to the LCFS program at the very end of the informal rulemaking process concerning. Because such a mechanism could remove credits from the bank too quickly, it risks rendering the LCFS program infeasible in the later years when the CI standards become ever more stringent for regulated entities to comply with. Yet CARB provides no mechanism to *reverse* any unintended consequence of this action as the only options presented to date (including by third party stakeholders without compliance obligations) operate only to *increase* CI benchmarks.

WSPA believes this would be a significant enough structural change that further stakeholder discussion, analysis, and modeling is required. We strongly encourage CARB not to include the concept in the upcoming 45-day package to be released within the next several weeks and to instead separate it from the forthcoming rulemaking to allow for further discussion and evaluation.

Slides 15-25 – Different Ways to Implement the Auto-Acceleration Mechanism. WSPA believes incorporating an auto-acceleration mechanism into the LCFS program now would be premature. Compromising the health of the program without sufficient analysis, in an effort to artificially inflate LCFS credit prices, would be inappropriate and highly problematic by unnecessarily increasing programmatic and market complexities at a time when the transportation sector is already working through dramatic transformation. It also presumes that fuel supply and demand scenarios will perform as envisioned to meet the ambitious 2022 Scoping Plan Update goals – that supply will phasedown in line with demand – despite known uncertainties in the energy market itself rather than seeking to ensure supply and demand for liquid fuels remains harmonious.

The credit bank is and should continue to be looked to as real emission reductions that regulated entities may use as a long-term compliance option. We also believe that any market indicators identified could result in serious unintended consequences such as credit shortages or market volatility. With the concept under consideration, such consequences could only be addressed through emergency actions by CARB, followed by an immediate rulemaking.

Should CARB proceed with incorporating this concept into the program through the upcoming formal rulemaking process, WSPA believes that additional work and stakeholder engagement is necessary. This should also include incorporating a means to reverse or "release" an auto-accelerator mechanism to avoid cementing overly ambitious forward CI benchmarks in place if the market would struggle to comply and compromise the integrity of the program. As the CARB Governing Board has exercised with multiple regulations before, we would encourage the Governing Board direct CARB's Executive Officer to work with stakeholders and perform additional analysis and then return later for formal approval.

We encourage CARB to provide regular periodic review of the program's performance to assess what additional changes would be required and discussed through a formal rulemaking process where all stakeholders can participate.

WSPA appreciates the opportunity to provide comments on this important regulatory process. If you have any questions regarding this submittal, please contact me at via email at tderivi@wspa.org.

Sincerely,

Tanya DeRivi

Senior Director, California Climate and Fuels

WSPA

Tanya M. DeRivi
Senior Director, California Climate and Fuels

September 12, 2023

Dr. Cheryl Laskowski
Branch Chief – Low Carbon Fuel Standard
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: WSPA Comments on the Low Carbon Fuel Standard Modeling Updates Workshop

Dear Dr. Laskowski,

The Western States Petroleum Association (WSPA) appreciates the opportunity to provide these written comments on the California Air Resources Board's (CARB) August 16, 2023 public workshop regarding updates to the California Transportation Supply (CATS) Model used for the Low Carbon Fuel Standard (LCFS) program. WSPA is a trade association that represents companies that provide diverse sources of transportation energy throughout the west, including California. This includes the transport and marketing of petroleum, petroleum products, natural gas, renewable fuels, and other energy supplies.

Diesel Fuel Demand and Heavy-Duty Vehicle Zero Emission Vehicle (ZEV) Assumptions

While CARB has sought to update the CATS Model to account for the recent adoption of the Advanced Clean Fleets (ACF) regulation, WSPA appreciates the known transportation electrification-related uncertainties as identified in the 2022 Scoping Plan Update's "Uncertainty Analysis"[1] and the ACF regulation itself. These were recently discussed during CARB's new ACF "Truck Regulations Advisory Committee" on August 22, 2023 – where infrastructure challenges and vehicle readiness were amongst the priority issues identified by affected stakeholders that could affect compliance. We further note that the ACF regulation was only recently finalized and re-filed with the Office of Administrative Law for a final determination, so CARB has not yet submitted it to the U.S. Environmental Protection Agency for the required Clean Air Act waiver request that would make the regulation enforceable (if granted). Furthermore, we note that the North American Electric Reliability Corporation – the entity responsible for the reliable operation of our bulk power system – recently identified energy policy as the top risk – with grid transformation, resilience to extreme events, security risks, and critical infrastructure interdependencies falling behind – to the reliable operation of the Bulk Power System in their 2023 ERO Reliability Risk Priorities Report.[2] We again urge CARB to more closely evaluate what impact the large-scale shift of heavy-duty trucks would have on the energy demand of California's electric grid.

We would recommend that CARB not set LCFS benchmarks based on the presumed and wholly successful implementation of ACF given the significant known challenges identified to date and without also having an alternative pathway to ensure the reliable provision of necessary services to all Californians. Although CARB shows a 37% reduction of diesel fuel demand from 2022 to 2045 in the CATS Model updates, if medium- and heavy-duty ZEVs do not saturate the market as quickly as CARB assumes in staff's presentation (slides 17 and 18), likely resulting in prolonged and heightened demand for liquid fuels, transportation fuel companies will need a continuing means to comply with the LCFS regulation. We encourage CARB to conduct periodic reviews of

[1] Appendix J, https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-appendix-j-uncertainty-analysis.pdf
[2] https://www.nerc.com/comm/RISC/Related%20Files%20DL/RISC_ERO_Priorities_Report_2023_Board_Approved_Aug_17_2023.pdf

the program, accounting for the real world implementation status of ACF, Advanced Clean Trucks, the Omnibus regulation, and include a flexible compliance mechanism to make adjustments accordingly.

CATS Technical Documentation – CI Factor Assumptions

Table 11[3] shows a significant reduction of the carbon intensity (CI) of the electric grid from 2044 to 2045 – from 48.3 (in 2044) to 16.5 (in 2045). WSPA seeks clarification from staff regarding the CI curve for the electricity grid, and confirmation that such a substantial CI reduction could take place in a single year.

WSPA appreciates the opportunity to provide comments on the CATS modeling updates. If you have any questions regarding this submittal, please contact me via email at tderivi@wspa.org.

Sincerely,

Tanya DeRivi

Tanya M. DeRivi
Senior Director, California Climate and Fuels

[3] California Transportation Supply (CATS) Model v0.2 – Technical Documentation for August 2023 Example Scenario, Last Modified: August 2023 https://ww2.arb.ca.gov/sites/default/files/2023-08/CATS%20Technical_1.pdf

Comment Log Display

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Comment 251 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Madison
Last Name	Vander Klay
Email Address	mvanderklay@svlg.org
Affiliation	Silicon Valley Leadership Group
Subject	SVLG Comments on Low Carbon Fuel Standard
Comment	Please find attached Silicon Valley Leadership Group's comments or the Low Carbon Fuel Standard.
Attachment	www.arb.ca.gov/lists/com-attach/6920-lcfs2024-WzdUMVI1U3NWDwRn.pdf
Original File Name	LCFS Comments, Feb 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 14:51:17

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 19, 2024

Clerk of the Board
California Air Resources Board (CARB)
1001 I Street
Sacramento, CA 95814

RE: Staff Draft Proposal on the Low Carbon Fuel Standard: Silicon Valley Leadership Group Comments

Dear Chair Randolph,

Thank you for the opportunity to comment on the staff draft proposal for the Low Carbon Fuel Standard (LCFS) rulemaking process.

Silicon Valley Leadership Group (SVLG), founded in 1978 by David Packard of Hewlett-Packard, represents hundreds of Silicon Valley's most respected employers on issues that affect the economic health and quality of life in Silicon Valley. Our membership includes many key players in this arena—from companies transitioning to electric vehicle (EV) fleets, to those producing zero-emission vehicles (ZEVs) and developing innovative new zero-emission technologies. At a high level, our organization believes CARB should employ flexible, market-based and technology-neutral policies that achieve maximum greenhouse gas (GHG) emissions reductions at the lowest cost.

We appreciate the Board and staff's diligence in drafting a thoughtful staff proposal for the Low Carbon Fuel Standard. However, we would urge a timely resolution to the rulemaking process to revitalize the LCFS credit market as soon as possible. Imbalances to the market caused by an overabundance of credits have tanked credit value, jeopardizing financing for clean energy projects and significantly diminishing the ability of the state to deploy zero-emission vehicles and charging infrastructure. This is no small problem for the state as regulators, advocates, and industry alike work to meet California's ambitious climate and air quality goals.

Our following comments reflect the changes SVLG would like to see made to the LCFS program.

Adopting an Acceleration Mechanism

SVLG thanks the Board and Staff for including an auto-acceleration mechanism to automatically increase carbon-intensity benchmarks when credit values fall too far and credits outnumber

242.1 deficits. However, SVLG requests that the auto-acceleration mechanism and its triggers be implemented as soon as possible without delay. An implementation date of 2026 would sooner protect the health of the market and provide much-needed assurance to industry stakeholders on credit value.

Infrastructure Capacity Credits:

SVLG appreciates the extension of infrastructure capacity crediting for light-duty vehicles (LDV). However, the reduction in available capacity credits for LDV fast charging infrastructure (FCI) from 2.5% to half a percent of deficits will significantly constrain the market opportunities for
242.2 deploying LDV FCI. SVLG would encourage the Board to maintain the capacity crediting cap for LDV FCI at 2.5%, which reflects increasing demand for light-duty zero-emission vehicles (ZEVs) and the need for refueling capacity across the state.

242.3 Additionally, SVLG supports the inclusion of capacity credits for medium- and heavy-duty zero emission vehicle fueling within LCFS. This new incentive program will be groundbreaking for encouraging the deployment of infrastructure needed to serve clean trucking fleets throughout the state as companies comply with the Advanced Clean Fleets rulemaking.

Third Party Verification Requirements:

242.4 SVLG is concerned that requiring site visits for third party verification of Fueling Supply Equipment for electricity pathways will pose an excessive and unnecessary burden on owners of both commercial and residential EV credit generators. EV charging infrastructure is both highly distributed by nature and subject to many state and federal standards ensuring accuracy. Quality data can already be provided remotely by EV service providers and through vehicle telematics. As California continues to develop a well-distributed and geographically diverse charging network, the challenge of conducting site visits will only grow. SVLG requests that the Board consider exempting electricity pathways from Fueling Supply Equipment site visits

Book-and-Claim Accounting for EV Charging: Parity between Energy Types

SVLG appreciates the flexibility created by allowing the quantity of EV charging provided by low carbon intensity (CI) electricity to be reported through book-and-claim accounting. To achieve parity between energy types and further encourage EV charging in a wider variety of geographic
242.5 areas, SVLG requests that the Board extend the ability to use book-and-claim accounting to

242.5 allow biomethane and renewable natural gas to be used by offsite systems generating electricity for EV charging services as well.

Obligating Jet Fuel

SVLG appreciates the Board's goal of reducing GHG emissions associated with air travel, and is supportive of increasing the production and use of sustainable aviation fuel (SAF). SAF is by far the most efficient alternative to jet fuel currently available, presenting an 80% reduction in lifecycle emissions in comparison. However, current in-state SAF production is insufficient to meet market need.

242.6 SVLG is concerned that obligating jet fuel under an LCFS pathway at this time would present enormous and excessive cost implications for all airlines and airports that operate in-state, without effectively supporting production of the tools and fuels needed to reduce emissions. In turn, these cost impacts would be felt by all consumers and businesses that rely on airline services for travel and commerce. SVLG encourages CARB to continue working with industry to instead develop an incentive-based framework to ramp up both production and use of SAF. This approach would be the most time-efficient and cost-effective way to support California's emission reduction goals without creating excessive costs impacts on consumers in and beyond California.

Summarizing Thoughts

California leads the nation in light-duty ZEV adoption, surpassing our goals of selling 1.5 million electric vehicles and installing 10,000 fast chargers ahead of schedule. Thanks to the Advanced Clean Fleets regulation, zero-emission medium- and heavy-duty trucks are not far behind. While SVLG has been proud to support the state and our diverse membership in achieving these goals, much more progress needs to be made to further reduce the GHG emissions and air pollution associated with transportation.

A robust LCFS program is essential for building the infrastructure necessary to support ZEV deployment, and is critical for meeting the targets outlined in the Board's 2022 Scoping Plan. SVLG welcomes the opportunity to partner with CARB to support a thriving Low Carbon Fuel Standard. We look forward to working with you further.

Sincerely,

Tim McRae

SVP Sustainable Growth

Comment Log Display

Here is the comment you selected to display.

Comment 252 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Dallas
Last Name	Gerber
Email Address	dgerber@growthenergy.org
Affiliation	Growth Energy
Subject	Growth Energy Comments on 2024 Proposed LCFS Amendments
Comment	Please see the attached comments from Growth Energy's Senior Vice President of Regulatory Affairs, Chris Bliley, on CARB's proposed amendments to the Low Carbon Fuel Standard.
Attachment	www.arb.ca.gov/lists/com-attach/6921-lcfs2024-VmQCNFVmWT5XfwY2.pdf
Original File Name	2024.02.20 - Growth Energy Comments on Proposed LCFS Amendments Final.pdf
Date and Time Comment Was Submitted	2024-02-20 14:47:31

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Growth Energy™
Expanding America's Bioeconomy

February 20, 2024

Liane Randolph
Chair
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
Via electronic submission

RE: Growth Energy Comments on Proposed LCFS Amendments

Chair Randolph:

Growth Energy appreciates the opportunity to provide comments to CARB regarding potential amendments to the Low Carbon Fuel Standard (LCFS) ("Proposed Amendments" or "Proposal"). Growth Energy is the world's largest association of biofuel producers, representing 97 U.S. plants that each year produce 9.5 billion gallons of renewable fuel; 115 businesses associated with the production process; and tens of thousands of biofuel supporters around the country. Together, we are working to bring better and more affordable choices at the fuel pump to consumers, improve air quality, and protect the environment for future generations. We remain committed to helping our country diversify its energy portfolio to grow more green energy jobs, decarbonize the nation's energy mix, sustain family farms, and drive down the costs of transportation fuels for consumers.

Growth Energy has previously submitted extensive comments demonstrating the vital role low carbon biofuels and higher biofuel blends can play in meeting California's ambitious climate goals. As we have previously noted, biofuels have been among the largest contributors to the success of the LCFS program to date and are poised to continue to do so with appropriate updates to the program.[1]

Unfortunately, the Proposal could impose new, costly, and unnecessary compliance burdens on bioethanol producers in the form of as-yet unknown and undefined "sustainability requirements"[2] that risk reducing the availability of credit-generating biofuels within the LCFS Program. Of most significant concern, contrary to the California Administrative Procedure Act (APA) and the California Environmental
243.1 Quality Act (CEQA), CARB is not providing the public and regulated community notice

[1] *Decarbonizing Combustion Vehicles,* Transportation Energy Institute (July 2023) https://www.transportationenergy.org/wp-content/uploads/2023/07/Decarbonizing-Combustion-Vehicles_FINAL.pdf
[2] Proposed 17 C.C.R § 95488.9(g).

243.1 and the opportunity to comment on the substance of these requirements. Rather, CARB intends to outsource development of these vague sustainability "certification systems" covering a host of undefined "environmental, social, and economic criteria" to third parties. The Proposal specifies that CARB alone will determine which certification systems suffice, removed from the California regulatory process intended to protect the public and regulated community and without consideration of potential adverse environmental impacts consistent with CEQA. Without any clear indication in the Proposal or voluminous rulemaking materials as to what such "certification systems" may entail, it is difficult to determine whether they may in practice, unintentionally or otherwise, exclude as much as 60% of the current credit-generating fuels from the
243.1 LCFS program. Such a reduction would create increased demand for fossil fuels, resulting in higher emissions of GHGs as well as toxic air pollutants.

If such "certification systems" did function in that manner, whether due to economic, social, or environmental criteria, the regulations could not comport with AB32's requirement for cost-effective, technology-neutral greenhouse gas (GHG) emissions reductions. For example, removal of even a portion of currently credit-generating biofuels could substantially increase compliance costs on obligated parties and passed-down costs to consumers at the pump, disproportionately harming low-income communities that are most impacted by fuel costs. None of these potential impacts have been adequately identified or evaluated in CARB's rulemaking materials accompanying the Proposal.

The proposed sustainability requirements are also legally flawed because they
243.2 are not reasonably necessary to effectuate AB32, or to address any regulatory purpose provided in CARB's rulemaking materials. Put simply, CARB has failed to identify any credible evidence of direct land use conversion that could be mitigated by some form of feedstock tracking based on social, economic, and environmental criteria of an unknown form and substance. As many decades of data has demonstrated, increases in bioethanol demand have consistently been met with increased yield per acre, not with increased corn acreage. Further, other regulatory mechanisms — including oversight from the U.S. Environmental Protection Agency (EPA) under the Renewable Fuel Standard (RFS) Program — adequately ensure that U.S. feedstocks are sustainably sourced and do not contribute to land use conversion. CARB itself also already imposes a highly conservative and overestimated penalty to the carbon intensity of bioethanol in the LCFS program that greatly disincentivizes bioethanol as compared to other fuel types. And CARB lacks authority under AB32 to, through a third-party certification system, impose wide-ranging socio-economic criteria that are unrelated to the cost-effective reduction of GHG emissions.

We understand that CARB is postponing the public hearing on the Proposed Amendments in order to undertake "more consideration of the proposed sustainability

guardrails, among other topics."[3] Growth Energy agrees such additional consideration is
necessary. Indeed, consistent with the California APA, if the Proposed Amendments
intend to encompass some form of feedstock tracking requirements tailored to address
243.3 a specific environmental need, we urge CARB to allow regulated parties to comment on
a subsequent proposal that includes consideration of potential environmental and
economic consequences.

In addition to these issues, the Proposed Amendments fail to include several key
updates and as a result, fall far short of unlocking the LCFS Program's full
243.4 decarbonizing potential. These omissions include declining to recognize and incentivize
low-carbon agricultural practices, failing to update emissions factors and lifecycle
modeling to reflect the best available science, and continuing to prohibit the use of E15
in the state.

We encourage CARB to reconsider these aspects of the Proposal to ensure the real and significant GHG emissions reductions benefits of biofuels are realized under the LCFS. We look forward to engaging collaboratively with the agency to support its efforts.

I. Bioethanol Has Been and Must Continue to Be a Key Driver of Transportation-Sector Emissions Reductions in California

The transportation sector is responsible for 39% of California GHG emissions — far larger than any other sector.[4] Light-duty vehicles (LDVs) alone emit more than any other entire sector, with over 27% of the state's total emissions.[5] Critically, over 97% of LDVs on the road in California today rely on liquid fuels.[6] On-the-road fleet turnover is a lengthy process, meaning impacts from California's 2035 zero-emission vehicle (ZEV) new vehicle sales requirements are still many years away.[7] To decarbonize the transportation sector today, California will need to decarbonize the liquid fuels being used by the vast majority of its vehicles by displacing fossil fuel consumption with low-carbon, renewable biofuels, including bioethanol.

Beyond LDVs, low-carbon biofuels will also play a substantial role in reducing emissions from harder-to-abate subsectors including medium- and heavy-duty vehicles, maritime fuels, and aviation. With lower ZEV adoption to date and longer fleet turnover

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[3] Email from CARB to stakeholders, "Postponed: [LCFS] Public Hearing" (Feb. 14, 2024).
[4] Based on 2021 data available at *Current California GHG Emission Inventory Data*, https://ww2.arb.ca.gov/ghg-inventory-data.
[5] *Id.*
[6] *See* 2022 Light-Duty Vehicle Registration Counts by State and Fuel Type, U.S. DOE Alternative Fuels Data Center, https://afdc.energy.gov/vehicle-registration.
[7] *See* 13 C.C.R. § 1962.4.

lead times, these subsectors are even more reliant on biofuels to achieve California's decarbonization goals.

Already, we've seen biofuels provide the foundation for the LCFS. In fact, biofuels like bioethanol have generated more than 75% of LCFS credits.[8] In 2022, domestically produced bioethanol made up ~50% of credit-generating biofuels by volume.[9] This group of fuels has been among the largest contributors to the success of
243.5 the LCFS Program to date, and will need to continue to be a central component of California's transportation sector decarbonization strategy if the LCFS is to continue its success into the future. Indeed, according to recent data from Environmental Health and Engineering, today's bioethanol reduces GHG emissions by nearly 50% compared to gasoline and can provide even further GHG reductions with additional readily available technologies.[10] For example, over a decade ago, CARB reported the average carbon intensity (CI) for bioethanol at 88 g/MJ. Through the third quarter of 2022, the average recorded CI for bioethanol decreased to 59.39 g/MJ, a 33% reduction in CI, even including overstatements in modeled indirect land use change emissions.[11]

The world is in a decisive decade to address GHG emissions while critical climate goals remain in reach, and biofuels have the greatest potential to reduce GHG emissions across the transportation sector this decade — while also achieving benefits for air quality through reductions in harmful particulates and air toxics, as discussed further below.

II. The Proposed Sustainability Certification Requirements for Biofuels are Legally Flawed

243.3

A. CARB Cannot Outsource Development of a Sustainability Certification System to Third Parties with No Meaningful Public Participation from the Regulated Community and No Notice as to What the Sustainability Criteria Will Be.

The California APA was designed both to "advance meaningful public participation in the rulemaking process" and "create an administrative record assuring effective judicial review."[12] Central to these goals is the principle of fair notice so the regulated community can understand, anticipate, and participate in the development of the legal requirements they will be subject to. As the California Supreme Court has

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[8] Based on 2022 gasoline-gallon-equivalent data available at LCFS Data Dashboard, Figure 2, https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard.
[9] Based on 2022 gasoline-gallon-equivalent data available at LCFS Data Dashboard, Figure 10(a), https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard.
[10] Scully, et. al. *Carbon intensity of corn ethanol in the United States: state of the science*, 16 Environ. Res. Lett. 4 (2021).
[11] Based on data available at LCFS Pathway Certified Carbon Intensities, https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities.
[12] Voss v. Superior Ct., 46 Cal. App. 4th 900, 908, 54 Cal. Rptr. 2d 225, 229 (1996).

explained, the APA works "to ensure that those persons or entities whom a regulation will affect have a voice in its creation, as well as notice of the law's requirements so that they can conform their conduct accordingly."[13] To support fair notice, the APA mandates regulations be presented with sufficient clarity so as to be "easily understood by those persons directly affected by them."[14] A regulation is not presumed to comply with the clarity standard if it "can, on its face, be reasonably and logically interpreted to have more than one meaning" or "uses terms which do not have meanings generally familiar to those directly affected by the regulation, and those terms are defined neither in the regulation nor in the governing statute."[15]

The APA's collaborative public rulemaking process not only benefits the public and regulated community but CARB as well, since "the party subject to regulation is often in the best position, and has the greatest incentive, to inform the agency about possible unintended consequences of a proposed regulation."[16] The process also "directs the attention of agency policymakers to the public they serve, thus providing some security against bureaucratic tyranny."[17]

243.1 Here, the Proposed Amendments would remove all meaningful public participation by assigning to a third-party development of sweeping "certification systems" intended to determine which fuels are eligible and ineligible to generate credits under the program. The Proposal does not provide biofuels producers with any notice of what "environmental, social and economic criteria" will be included, how the producer might accomplish "demonstrable means of evaluation," or what "sanction mechanisms" could be levied for non-compliance. Each of these vague and open-ended terms is susceptible to many differing meanings and is not defined in either the regulation or the governing statute, therefore lacking the clarity required by the APA. Indeed, Appendix E, which purports to explain the purpose and rationale for specific regulatory provisions, suggests the certification standards will ensure biofuels are "sustainably produced," but nowhere does CARB define what that means or how a complex certification system encompassing wide-ranging social, economic, and environmental considerations would accomplish that end.[18]

Not only is the certification system still undefined today, CARB proposes that the system — which will have the power to potentially exclude the majority of the fuels currently generating credits in the LCFS — will be developed not through a CARB public rulemaking process, but rather by a third-party entity requiring only the sign-off of the

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[13] Morning Star Co. v. State Bd. of Equalization, 38 Cal. 4th 324, 333 (Cal. 2006).
[14] Cal. Gov. Code § 11349(c); *see also* Sims v. Dep't of Corr. & Rehab., 216 Cal. App. 4th 1059, 1076 (Cal. App. 2013).
[15] 1 C.C.R. § 16.
[16] Tidewater Marine W., Inc. v. Bradshaw, 14 Cal. 4th 557, 569 (1996).
[17] *Id.*
[18] Appendix E at 80.

CARB Executive Officer. This extremely broad delegation of authority to third parties outside the regulatory process is highly concerning.

More fundamentally, as detailed below, the overwhelming evidence does not support a need to institute a feedstock tracking system for U.S. bioethanol producers. However, to the extent CARB does intend to proceed with the development of feedstock tracking requirements tailored to ensuring land conversion is not occurring, it must develop those requirements itself, through public engagement and the APA rulemaking process. The agency cannot simply outsource a complex rulemaking process to third

243.1 parties, guided by only vague statements of "environmental, social, and economic criteria" without notice and opportunity for the regulated community to comment on the scope, form, or stringency of the future standards.[19] Absent an informed decision-making process, the "sustainability" certification systems may function to erroneously exclude low carbon fuels from the LCFS Program with dire consequences both for the Program and the environment. Because such requirements are yet unknown, CARB itself has not yet adequately analyzed the potentially complex environmental impacts of the Proposed Amendments, as explained further below.

B. CARB Has Not Identified a Reasonable Need to Impose Sustainability Requirements on U.S. Bioethanol Producers

As a threshold matter, under California law, "no regulation adopted is valid or effective unless consistent and not in conflict with the statute and reasonably necessary to effectuate the purpose of the statute."[20] California agencies must provide "[a]n initial statement of reasons for proposing the adoption, amendment, or repeal of a regulation," that must include, *inter alia*, (i) the specific purpose of the proposed rule, amendment, or repeal, (ii) the "rationale for the determination by the agency that each [rule] adoption, amendment, or repeal is reasonably necessary to carry out the purpose and address the problem for which it is proposed" and (iii) the benefits of the proposed rulemaking.[21]

243.2 Here, CARB has failed to adequately articulate a reasonable need for the proposed sustainability requirements.[22] These requirements risk undercutting the broader purpose of the 2024 Amendments to implement the 2022 Scoping Plan by reducing GHG emissions, do not serve any function not already addressed through other regulatory measures, and extend far beyond the scope of what is necessary to effectuate AB32.

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[19] *See, e.g.* Morning Star Co. v. State Bd. of Equalization, 38 Cal. 4th 324, 328, (2006) (setting aside hazardous waste fee schedule developed without APA procedures); Vasquez v. Dep't of Pesticide Regul., 68 Cal. App. 5th 672, 684, (2021) (setting aside township pesticide cap program developed without APA procedures).

[20] Cal. Gov. Code § 11342.2.

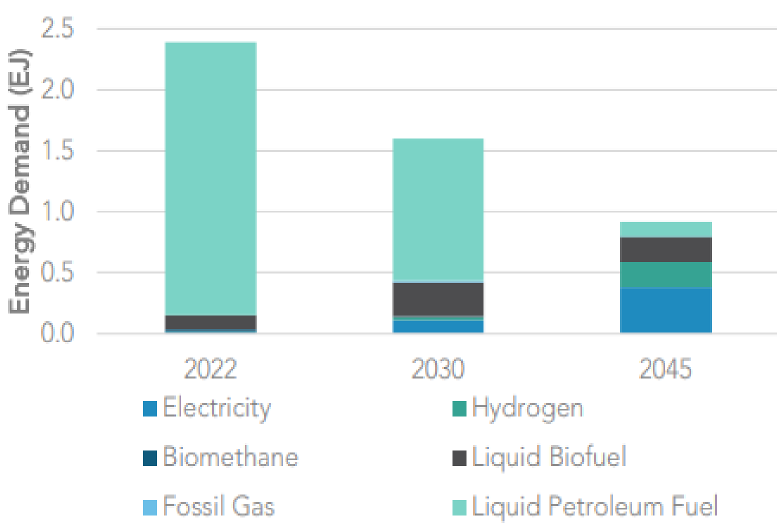
[21] Cal. Gov. Code § 11346.2(b).

[22] *See* Light v. State Water Res. Control Bd., 226 Cal. App. 4th 1463, 1495 (2014) (noting that regulations may be declared invalid if the agency's determination of reasonable necessity is not supported by "substantial evidence").

243.6 1. The sustainability requirements risk undermining the overarching purpose of the 2024 Amendments and 2022 Scoping Plan

CARB's initial statement of reasons (ISOR) states that the Proposed Amendments are intended "to implement the 2022 Scoping Plan Update" by "reduc[ing] emissions by driving down fossil fuel demand in transportation, transitioning to zero-emission technology wherever feasible, and increasing the supply of low-carbon alternative fuels as quickly as possible."[23] The 2022 Scoping Plan calls for substantial ***increases*** in liquid biofuels between 2022 and 2030, with demand in 2045 still remaining higher than current levels. Bioethanol, which currently makes up half of the biofuel used in California, will need to remain a major fuel source if the increases called for in the Scoping Plan are to be achieved.[24]

Figure 4-2: Transportation fuel mix in 2022, 2030, and 2045 in the Scoping Plan Scenario[332]



The 2022 Scoping Plan calls for substantial increases to liquid biofuel demand. See 2022 Scoping Plan at 190.

The proposed sustainability requirements, however, could undermine this stated purpose by levying unnecessary and substantial compliance costs on certain biofuels, and risk excluding certain low carbon fuels altogether. The effect of which would be to reduce the volume of credit-generating biofuel available to displace fossil fuels in the California market. Indeed, CARB's own analysis in this rulemaking is clear that

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[23] Proposed Low Carbon Fuel Standard Amendments, Staff Report: Initial Statement of Reasons (Dec. 19, 2023) at 22 [hereinafter "ISOR"].
[24] Based on 2022 gasoline-gallon-equivalent data available at LCFS Data Dashboard, Figure 10(a), https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard

limitations on biofuels like bioethanol can result in increased fossil fuel consumption and increased GHG emissions.[25] Although the sustainability requirements are not an established cap on crop-based biofuels volumes, the potential for increased costs and decreased availability of qualifying fuels would limit the LCFS Program's ability to meet its carbon-intensity reduction targets by arbitrarily excluding certain low carbon intensity fuels for unknown "social and economic" reasons.

The Scoping Plan does caution that a "dramatic increase in alternative fuel production must not come at the expense of global deforestation, unsustainable land conversion, or adverse food supply impacts."[26] Growth Energy agrees. But CARB has failed to identify any credible evidence that U.S. bioethanol production is contributing to global deforestation, unsustainable land conversion, or adverse food supply impacts and no such evidence exists. Nor has CARB adequately described how the certification systems oriented towards a range of economic, social, and environmental considerations would protect against such impacts if they were a valid concern. Moreover, this single precautionary sentence is not an authorization to disregard the Scoping Plan's central purpose of achieving GHG emissions reductions, driven in part by increasing biofuel consumption in the transportation fuel mix.

243.6 2. CARB has not identified any credible evidence that domestically produced bioethanol contributes to direct land use change

The proposed sustainability certification requirements are introduced as a method to address *direct* land use change (dLUC).[27] As the feedstock tracking requirements presumably would follow only those crops used to produce biofuels eventually used in the California market, they would not and could not address *indirect* land use change (iLUC), which is a modeled estimate of price-mediated global land use impacts attributable to demand increases, regardless of whether a particular crop makes its way to the California market or is used in biofuel production at all. As such, CARB's analysis of whether new regulations are "reasonably necessary" must address whether the sustainability requirements are reasonably necessary to protect against *direct* land use change. For U.S. corn starch bioethanol that answer is unequivocally no, as there is no evidence that U.S. bioethanol production contributes to direct land use change. CARB suggests that "the growing demand for crop- and forest-based feedstocks for use in the LCFS program produce an increasing risk of deforestation and use of land with a high biodiversity value to meet this demand."[28] But there simply is no factual support for that statement as applied to U.S. bioethanol.

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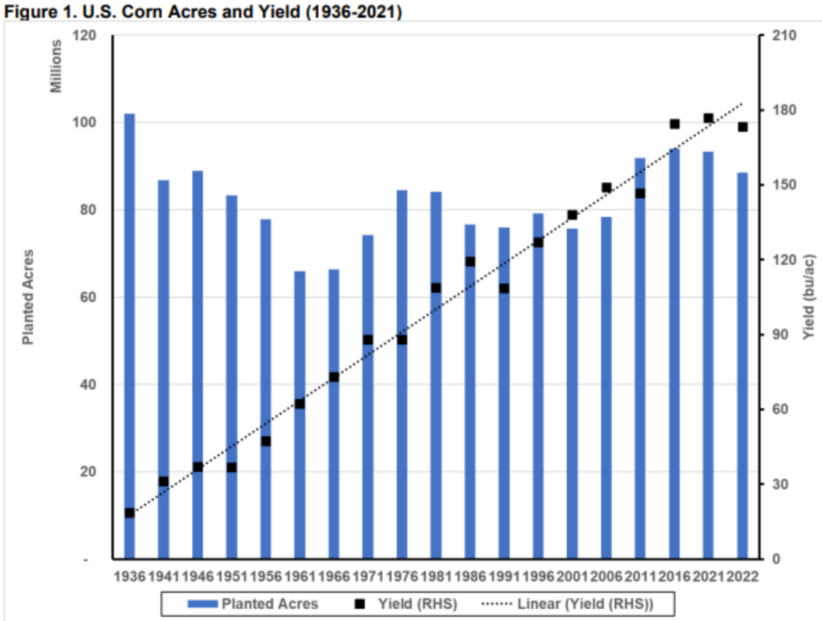
[25] ISOR at 116 (analyzing the impacts of an alternative proposal which would place a specific cap on crop-based biofuels).
[26] *2022 Scoping Plan for Achieving Carbon Neutrality*, CARB, (Dec. 2022) at 191 [hereinafter "2022 Scoping Plan"].
[27] ISOR at 32.
[28] Proposed Low Carbon Fuel Standard Amendments, Appendix E: Purpose and Rationale at 79-80.

Indeed, decades of empirical data from the U.S. Department of Agriculture (USDA) that EPA closely monitors as part of the federal RFS demonstrates that the amount of corn acres planted has remained stable over time even as bioethanol production has expanded by billions of gallons over the past 15 years. U.S. farmers have consistently met increased demand through increases to the amount of corn yielded per acre, rather than through expanding the acreage in production:

Figure 1. U.S. Corn Acres and Yield (1936-2021)



***Source**: USDA, Stillwater analysis*

Demand increases have been consistently met with increases in corn yield and the demand-offsetting effects of dry distillers grain solubles (DDGS), without any need for land extensification.[29]

Moreover, the RFS Program adds an additional layer of protection against cropland expansion by limiting eligible renewable fuels to those sourced from agricultural land that was cleared prior to 2007 in order to be eligible to generate credits under the program. To enforce this provision, U.S. EPA closely monitors aggregate cropland data in the United States to ensure that increases in biofuels demand do not result in increased cropland acreage. EPA may in the future determine that a feedstock tracking requirement is necessary if data shows that U.S. corn acreage begins to increase, but to date that agency has determined that it is unnecessary to do so given clear data indicating increased production absent land conversion. CARB's proposal to apply sustainability requirements to domestically produced bioethanol is therefore an unnecessary "solution" in search of a not-yet-existent problem. Further, the Proposed

[29] Stillwater Assoc., LLC, *Assessment of Production and Consumption Capacity of Conventional Ethanol in 2023-2025* (Feb. 9, 2023).

Amendment's scope strays widely from what would be necessary to address land use change, if there were in fact a problem to address.

With no evidence that corn acreage is increasing, the potentially substantial compliance costs of the proposed sustainability requirements are not reasonably necessary to address CARB's stated purpose. At a minimum, U.S. corn bioethanol producers should be excluded from the requirements due to the decades of evidence showing stable domestic corn acreage, as well as the existing oversight from U.S. EPA as part of the RFS Program. Socio-economic sustainability requirements are not reasonably necessary to effectuate cost-effective GHG reductions or address direct land use change.

AB32 designated CARB as the state agency charged with "monitoring and regulating the sources of emissions of greenhouse gasses" to further the statute's goal to "achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions."[30] While the agency may "consider overall societal benefits" when crafting its regulations,[31] AB32 does not endow CARB with broad authority to enact economic and social regulations that are untethered from cost-effective GHG emissions reductions. The Executive Order establishing the LCFS has a similarly discrete focus: "to reduce the carbon intensity of California's transportation fuels."[32]

CARB does not specify the certification requirements that will eventually be adopted, but the Proposed Amendments include a vague, far-reaching list of topics with no clear nexus to whether a feedstock originates on land placed into agricultural production prior to a certain date. For example, the contemplated feedstock certification program must address "social and economic criteria" and include "economic . . . and social stakeholders," but nowhere does CARB explain why a certification system must encompass such wide-ranging concepts to address the purported issue of land use change.[33] While CARB's proposal provides no detail as to what will actually be required of biofuel producers, it is difficult to conceive how these socio-economic standards could be crafted in a manner that would be reasonably necessary to reducing GHG reductions in a cost-effective manner. Moreover, it is unclear why CARB selected January 1, 2008 as the date by which agricultural land must have been put to such uses or how regulated parties will retroactively prove out feedstock eligibility when the certification systems eventually take effect in 2028. More fundamentally, it should not be left to regulated parties, the public, or the courts to guess as to how these requirements will be crafted — CARB must clearly state the rationale for its reasonably necessary determination in its statement of reasons.[34]

[30] Cal. Health and Safety Code § 38510; *Id*. at § 36569.
[31] *Id.* § 38562(b).
[32] Cal. Exec. Order S-01-07 (January 18, 2007).
[33] Proposed 17 C.C.R § 95488.9(g).
[34] Cal. Gov. Code § 11346.2(b).

243.6 3. Inconsistent with best available science, CARB's lifecycle emissions modeling tool already substantially over-penalizes bioethanol for modeled land use change impacts

The proposed sustainability requirements are also not reasonably necessary because CARB *already* "disincentivizes sourcing biofuel feedstocks from crops with higher land-use change risks" through application of an outdated and overly conservative estimated land use change penalty to bioethanol's carbon intensity.[35] CARB's analysis for this rulemaking acknowledges that "the likelihood of [direct and indirect land use change] is at least partially (**and potentially fully**) accounted for by the LUC scores added to crop-derived pathways."[36]

Specifically, CARB currently applies a LUC penalty of 19.8 gCO2e/MJ to U.S. corn starch bioethanol, derived from modeled estimates of iLUC.[37] However, through a multitude of refinements to model design and model inputs since CARB last updated its analysis in 2015, iLUC estimates for bioethanol have converged around a relatively narrow range that is substantially lower than CARB's estimate, even when differing models and differing model inputs are considered.[38] This cross-model convergence is observed in both American and European analyses, and is particularly highlighted by comparing studies which have published updates to their initial analysis using otherwise similar methodology. The most recent credible iLUC models have continued to adjust, refine, update, and calibrate their methodologies, resulting in a downward trend of estimates and convergence around -1.0 to 8.7 gCO2e/MJ.[39]

As discussed, CARB's proposed sustainability requirements would be ineffective at addressing iLUC, since the requirements apply only to crops physically used for biofuel feedstocks without consideration of global economic and land use patterns. However, to the extent that CARB's proposal is intended to disfavor crop-based biofuels within the LCFS program, CARB's inflated iLUC penalty already places a heavy finger on the scale to disincentivize such fuels.

C. The Proposal Will Lead to Increased Fossil Fuel Consumption Resulting in Increased Emissions of Toxic Air Pollutants in Violation of AB32

CARB may not undertake regulatory activities to reduce GHG emissions that interfere with federal or state efforts to reduce toxic air contaminant emissions in the

[35] ISOR at 32.
[36] EIA at 44 (emphasis added).
[37] 17 CCR § 95488.3 at Table 6.
[38] *See* Environmental Health and Engineering, *Response to Proposed Renewable Fuel Standard (RFS) Program Standards for 2023–2025*, Exhibit 2 of EPA-HQ-OAR-2021-0427-0796 (Feb. 10, 2023).
[39] *Id.*; Scully, et. al. *Carbon intensity of corn ethanol in the United States: state of the science*, 16 Environ. Res. Lett. 4 (2021).

state.[40] The proposed sustainability requirements may reduce the amount of renewable biofuel consumed in California by placing significant compliance costs on producers of bioethanol and decreasing the availability of credit-generating biofuels. As a direct result of reducing the available volumes of biofuel, fossil fuel consumption will increase. This boost in fossil fuel consumption would increase not only GHG emissions, but also emissions of several toxic air pollutants.

As CARB acknowledges in the ISOR, higher amounts of renewable fuel consumption lead to significant reductions of both NOx and $PM_{2.5}$ emissions.[41] A recent study conducted by the University of California, Riverside also found that greater use of bioethanol-blended fuels can reduce carbon monoxide, ozone, and primary PM levels relative to the use of gasoline-only fuels.[42]

In addition, bioethanol boosts octane in fuel without the harmful impacts of alternative octane-boosting fuel additives, including methyl tert-butyl ether (MTBE), lead, and aromatics (including benzene, toluene, ethylbenzene, and xylene). Indeed, the level of aromatics in fuel decreases by about 7% for every 10% by volume increase in bioethanol content.[43] Decreasing aromatics in fuel has direct impacts on tailpipe emissions, with higher-ethanol fuels resulting in lower emissions of particulate matter (PM), black carbon (BC), particle number (PN), benzene, toluene, ethylbenzene, m/p-xylene and o-xylene (BTEX), and 1-3 butadiene as compared to higher aromatic fuels. Bioethanol blends are particularly effective at reducing cold-start PM and VOC emissions, with a 15-18% decrease in PM emissions for each 10% increase in bioethanol content by volume.[44] Primary $PM_{2.5}$ emissions have substantial human health impacts and have been shown to disproportionately impact racial and ethnic minorities, which are often located in urban areas where cold-start conditions are most common.[45]

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[40] Cal. Health & Safety Code § 38562(b)(4) (CARB must "[e]nsure that activities undertaken pursuant to the regulations complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions.").

[41] ISOR at 127 (noting that NOx and PM2.5 reductions in the accelerated decarbonization alternative as compared to the proposal were "primarily due to higher amounts of renewable fuels used."); *see also* ISOR at 66.

[42] Yang, et al. *Emissions from a flex fuel GDI vehicle operating on ethanol fuels show marked contrasts in chemical, physical and toxicological characteristics as a function of ethanol content*, 683 Sci. of the Total Env't 749 (Sep. 2019), https://doi.org/10.1016/j.scitotenv.2019.05.279.

[43] *See* Environmental Health and Engineering, *Response to Proposed Renewable Fuel Standard (RFS) Program Standards for 2023–2025*, Exhibit 2 of EPA-HQ-OAR-2021-0427-0796 at Part III (Feb. 10, 2023).

[44] *Id.*

[45] Tessum, et al., *PM2.5 polluters disproportionately and systemically affect people of color in the United States*, Sci. Advances (2021) at 7, https://doi.org/10.1126/sciadv.abf4491; Colmer, et al., *Disparities in PM2.5 air pollution in the United States*, 369 Science 6503 (2020) at 575, https://doi.org/10.1126/science.aaz9353.

In short, the Proposal is legally deficient in failing to grapple with the fundamental issue that the sustainability certification requirements may be inconsistent with CARB's mandate to protect air quality while achieving cost-effective GHG emissions reductions. In addition to providing adequate notice to the regulated community of what the sustainability criteria will entail, CARB must disclose and carefully evaluate the air quality impacts of any such new requirements consistent with Health & Safety Code § 38562(b)(4).

D. The Proposed Rulemaking Package Fails to Identify and Consider Potential Economic and Environmental Justice Costs of the Sustainability Requirements

Throughout the rulemaking materials accompanying the Proposed Amendments, CARB's analysis systematically omits any evaluation of the potential impacts imposed by the applicability of new sustainability requirements in conjunction with tightening carbon intensity standards through 2045. Indeed, the sustainability requirements are so undefined that it is unlikely that CARB could estimate such potential impacts with any level of confidence. But that does not relieve CARB of its obligations under California law. If CARB is unable to properly identify and evaluate the impacts of the sustainability requirements, it cannot finalize those requirements as proposed.

243.7 1. CARB Fails to Adequately Identify Potential Economic Costs

For major regulations, the APA requires agencies to publish a standardized regulatory impact analysis that includes "all costs" of the regulation on businesses in California.[46] The scope of this analysis must encompass "each type of business subject to the relevant proposals"[47] and is intended to provide to the agency and the public the "tools to determine whether the regulatory proposal is an efficient and effective means of implementing the policy decisions enacted in statute or by other provisions of law in the least burdensome manner."[48] Further, AB32 requires that CARB consider costs to employ technology-neutral and cost-effective GHG emissions reductions approaches.[49]

Nowhere in CARB's economic analysis does the agency address the potential costs of the proposed sustainability requirements. These requirements create plainly foreseeable potential impacts in at least two ways. First, the requirements are very likely to impose direct compliance costs on biofuels producers. CARB clearly overlooks the entire set of compliance costs imposed on low-carbon biofuels producers by asserting

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[46] Cal. Gov. Code § 11346.2(b)(2)(B); *Id.* at § 113463.3; 1 C.C.R. § 2000(e).
[47] *John R. Lawson Rock & Oil, Inc. v. State Air Resources Bd*., 20 Cal. App. 5th 77, 114 (Cal. App. 2018) (finding CARB's economic analysis violated the APA for failing to consider impacts on intrastate trucking).
[48] Cal. Gov. Code § 11346.3(e).
[49] Cal. Health & Safety Code § 38562

that the Proposal's cost increases will "fall exclusively on producers of high-carbon intensity fuels," and consumer costs passed through by high-carbon fuels producers.[50]

Second, depending on how the sustainability requirements are eventually developed, there is potential for substantial costs on fuel producers as well as consumers if a large volume of credit-generating biofuels is unable to meet the sustainability requirements due to social, economic, or other considerations. The magnitude of this potential cost is unknown because the stringency and practicality of the sustainability requirements remain entirely undefined. But with bioethanol and other crop-based biofuels accounting for the majority of fuel in the program, poorly crafted sustainability requirements could create enormous disruption to the LCFS market if all or most of these fuels shift from credit-generating to deficit-generating volumes. CARB's fundamental failure to acknowledge and evaluate this potential risk in its economic analyses is highly concerning and contrary to law. As such, CARB must address in its record for this rulemaking a wide variety of economic cost impacts it ignores in this Proposal.

We encourage CARB to fully identify and evaluate the economic costs of the Proposal once any "sustainability" requirements are clarified prior to finalizing this rule.

243.8 2. CARB Fails to Adequately Identify Potential Adverse Environmental Justice Impacts

CARB's environmental justice analysis suffers from similar and overlapping flaws as its economic analyses by failing to consider the potential impacts of the sustainability requirements. As discussed above, unworkable or overly stringent sustainability requirements would likely lead to a decrease in available credit-generating biofuels in the LCFS Program. This would increase compliance costs on deficit-generating fuels producers, who would then pass through those costs to consumers in the form of higher fuel costs. This risks disproportionately burdening lower-income communities which spend a higher relative portion of their income on fuel expenses and for whom new electric vehicles may remain out of reach.

In addition, if the sustainability requirements displace volumes of biofuels, these volumes will likely shift to increased fossil fuel consumption, with resulting adverse air quality impacts as discussed above in Section II (C). This increase in toxic air pollution risks disproportionately burdening frontline communities located near major transportation corridors and around airports and ports.

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[50] Proposed Low Carbon Fuel Standard Amendments, Appendix C-1: Standardized Regulatory Impact Analysis at 57.

We encourage CARB to fully identify and evaluate the potential environmental justice impacts of the Proposal once any "sustainability" requirements are clarified prior to finalizing this rule.

III. The Draft Environmental Impact Analysis Fails to Comport with CEQA's Requirements

243.9

At its core, CEQA requires California agencies to inform decision makers and the public about the potential environmental impacts of proposed projects (including rulemakings), and to reduce adverse environmental impacts to the extent feasible. For the myriad reasons discussed above, the Proposed Amendments and the accompanying Draft Environmental Impact Analysis (EIA) fail to satisfy this requirement. Informed decision-making is infeasible where CARB has failed to elucidate the details of a critical component of the LCFS that may materially impact volumes and types of fuels within the California transportation fuel mix. In so doing, it impermissibly "deprive[s] decision makers and the public of substantial relevant information about the project's likely impacts."[51]

In particular, CEQA regulations require that a draft EIA include "[a] discussion and consideration of environmental impacts, adverse or beneficial."[52] Nowhere does the Draft EIA grapple with the complex potential GHG and air quality implications of the poorly circumscribed "sustainability criteria." Indeed, the Draft EIA misapprehends the Proposed Amendments' scope entirely. It conceptualizes the sustainability requirement as tied exclusively to environmental considerations, i.e., confirmation of feedstock point-of-origin and potential conversion of land for use as feedstock.[53] It fails to recognize the "social and economic" considerations relevant to obtaining a certification and, in turn, fails to evaluate whether those criteria may drive low carbon and environmentally beneficial fuels like bioethanol out of the program.

Moreover, the Draft EIA summarily rejects an alternative option that eliminates the crop-based fuels sustainability criteria on unrelated grounds.[54] Specifically, the Draft EIA establishes a strawman: an alternative that it asserts does not meet the objectives of the Proposed Amendments and therefore need not be explored consisting of, among other things, a very aggressive 40% carbon intensity reduction requirement by 2030 coupled with no sustainability criteria. Without explanation, the Draft EIA claims this scenario "increases the risk of greater environmental impacts" without elaborating how specifically the sustainability criteria would function to abate impacts of concern, and why there may be environmental *benefits* to exclusion of such criteria.

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[51] *Ctr. for Biological Diversity v. Dep't of Fish & Wildlife*, 62 Cal. 4th 204, 228, 361 P.3d 342, 356 (2015), as modified on denial of reh'g (Feb. 17, 2016).
[52] 17 C.C.R. § 60004.2.
[53] Draft EIA at 20 (emphasis added).
[54] *Id.* at 179.

Nor does the Draft EIA address why exclusion of the sustainability requirements is a relevant alternative scenario in only one of the multiple options evaluated. In accordance with California regulation, "[t]he range of feasible alternatives [must] be selected and discussed in a manner to foster meaningful public participation and informed decision making."[55] Prior to finalizing the Proposed Amendments and EIA, CARB must further define the sustainability criteria, allow regulated parties and the public to comment on the requirements' potential details and potential implications, and address any such comments regarding adverse environmental impacts that may follow from finalization of the requirements.

IV. CARB Should Use the 2024 Amendments to Accelerate Decarbonization

Despite the urgent need to address climate change and reduce GHG emissions from California's highest-emitting sector, CARB declined to adopt an "Accelerated Decarbonization" scenario that could have maximized the GHG-benefits of the LCFS Program. We urge CARB to reconsider several specific components of that proposal for inclusion in its final rule, as well as to update its lifecycle analysis for corn starch bioethanol to incorporate the best available science.

243.4 ### *A. CARB Should Recognize and Incentivize Low-Carbon Agricultural Practices*

Growth Energy strongly supports the appropriate crediting of on-the-farm low-carbon agricultural practices in the LCFS. As the Scoping Plan recognizes, climate-smart practices have "significant potential" to increase soil carbon storage and reduce GHG emissions, with important social and environmental co-benefits including in public health, water quality, water availability, and biodiversity.[56]

The ISOR states that consideration of low-carbon agricultural practices was rejected because "there is not yet a mechanism within the LCFS for quantifying, verifying, and including greenhouse gas emissions reductions or soil-carbon sequestration from changes in individual farm-level management practices in LCFS fuel pathways."[57] But there are more than enough tools and systems available to CARB to create such a mechanism, including the GREET FD-CIC model from U.S. Department of Energy's (DOE's) Argonne Laboratory, as well as USDA national standards for climate-smart agriculture. Specifically:

- *Use of cover crops*. Use of cover crops improves soil health and enhances soil organic carbon (SOC) sequestration. By sequestering atmospheric carbon dioxide in the soil, such use of cover crops offsets other carbon dioxide emissions from feedstock production, and lowers the lifecycle GHG emissions of

[55] 14 C.C.R. § 15126.6(f).
[56] 2022 Scoping Plan at 254.
[57] ISOR at 125.

bioethanol produced from corn feedstock grown using this method. USDA currently offers cover crop initiatives as part of its climate smart agriculture programs and has issued national conservation practice standards to define the practice.[58]

- *Effect of tillage*. Another method to enhance SOC sequestration is switching to no-till or reduced-till practices. Reduced disturbance of the soil supports greater sequestration of atmospheric carbon dioxide. USDA has also issued national conservation practice standards for both no-till and reduced-till agriculture.[59]

- *Manure application.* Application of agricultural byproducts and waste products such as manure can materially increase SOC sequestration. GREET's FD-CIC model can calculate changes in SOC emissions resulting from the use of swine, dairy cow, beef cattle, or chicken manure.

- *Improved fertilizer practices.* Precision application of fertilizer through "4R" techniques (right time, right place, right form, right rate) can significantly reduce emissions attributable to fertilizer usage. Similarly, applying bio-based fertilizers to corn, such as nitrogen-fixing biological products, legumes, or manure can significantly reduce the need for conventional fertilizer, providing a lower carbon-intensive source of fertilizer for the corn. In addition, nitrogen stabilizers can reduce the loss of nitrogen into the environment. This often leads to a reduced application rate of fertilizer, further reducing its environmental impact.[60]

- *Green or low-carbon ammonia.* Ammonia used to make fertilizer can be produced using renewable energy (where hydrogen from electrolysis of water reacts with atmospheric nitrogen) or with carbon-reducing technologies, reducing lifecycle GHG for producing corn feedstock to bioethanol production.[61]

There has been a wealth of data on the substantial benefits of these and other low-carbon agricultural practices, including a recent study by Argonne National Laboratory showing the possibility of a 35% reduction in carbon intensity through

[58] USDA Press Release No. 0005.22, *USDA Offers Expanded Conservation Program Opportunities to Support Climate Smart Agriculture in 2022* (Jan. 10, 2022); USDA Conservation Practice Standard # 340, Cover Crop (Ac.) (Sep. 2014).
[59] USDA Conservation Practice Standard # 329, *Residue and Tillage Management, No Till (Ac.)* (Sep. 2016); USDA Conservation Practice Standard # 345, *Residue and Tillage Management, No Till* (Ac.) (Sep. 2016).
[60] GHG reductions from precision application of fertilizer and use of nitrogen stabilizers are available from standard values in GREET's FD-CIC module. GHG reductions from bio-based fertilizer can be calculated based on farming inputs.
[61] GHG reductions from green ammonia are available from standard values in GREET's FD-CIC module. GHG reductions for low carbon ammonia can be calculated based on the ammonia production process.

adoption of current best on-farm practices.[62] With the LCFS' verification requirements, capturing these on-the-farm benefits for biofuel pathways is now more realistic and scalable. To the extent that CARB decides to implement additional verification requirements in the form of the proposed sustainability requirements, it would be especially arbitrary to simultaneously disallow credit-generation of verifiable low-carbon agricultural practices. Appropriately crediting climate smart ag will help biofuels producers continue to further innovate and lower their carbon intensity, while providing key incentives for farmers to adopt these effective conservation practices.

243.10 *B. CARB Should Update Its Lifecycle Analysis for Bioethanol to Incorporate the Best Available Science*

As discussed above in Section II(A)(3), CARB's current lifecycle analysis for U.S. corn starch bioethanol is outdated and a substantial overestimate as compared to the best available science. This overestimate is driven by an inflated iLUC penalty, which CARB has not updated since 2013-2015. Unlike CARB's iLUC estimate, the science of lifecycle emissions modeling has not remained stagnant over the past decade. Instead, through various improvements to both models themselves and the data models rely on, iLUC modeling has improved significantly in recent years with a clear downward trend converging around iLUC values that are less than half of CARB's current estimate.

This trend is made most obvious by comparing studies from the same authors that have updated their work. For example, EPA initially estimated in 2009 iLUC associated with ethanol that was more than double the value it ultimately incorporated into its final rule establishing the 2010 Renewable Fuel Standard.[63] More recently, studies from Taheripour, et al. demonstrated that using an updated land use module in GTAP-BIO resulted in iLUC estimates one-third to one-half of the magnitude of estimates using an outdated land use module within the same model.[64]

One key input in iLUC modeling where CARB's current methodology is particularly outdated is CARB's choice of emissions factors. Estimates of iLUC are the result of multiplying the acres of land that a model projects will be converted from various existing land uses to crop production (in order to meet a perceived increase in biofuel demand) by the additional GHG emissions that are attributable to that land conversion. The second input in this equation, estimating the GHG emissions attributable to each acre of land conversion, is referred to as the "emissions factor." Emissions factors vary based on the type of land converted. For example, converting forestland to cropland has greater GHG emissions than converting pastureland to cropland. Emissions factors are built on a multitude of assumptions relating to carbon

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[62] Liu, et. al., *Shifting agricultural practices to produce sustainable, low carbon intensity feedstocks for biofuel production*, 15 Environ. Res. Lett. 8 (2020).
[63] *See* Environmental Health and Engineering, *Response to Proposed Renewable Fuel Standard (RFS) Program Standards for 2023–2025*, Exhibit 2 of EPA-HQ-OAR-2021-0427-0796 (Feb. 10, 2023).
[64] *Id.*

stocks of particular land types, including both above ground carbon (i.e., in trees or vegetation) and below ground carbon (including soil organic carbon). The choice of emissions factor that a model applies can have a significant impact on iLUC estimates.[65]

CARB's current iLUC modeling is based on the AEZ-EF emissions factors. Argonne National Laboratory — the authors of the GREET model that CARB incorporates for non-iLUC aspects of lifecycle emissions modeling — instead utilizes the CENTURY and Winrock emissions factors as part of the Carbon Calculator for Land Use Change from Biofuels (CCLUB). The CCLUB emissions factors are more scientifically defensible than AEZ-EF for multiple reasons. For one, CCLUB is updated by Argonne regularly to improve its estimates as the best available science develops.[66] In contrast, AEZ-EF was created for a particular modeling exercise completed to develop CARB's iLUC estimate in 2014, and has not been updated in the decade since, notwithstanding significant refinements in understandings regarding critical inputs like SOC estimates.[67] By its authors' own admission, AEZ-EF "relies heavily on IPCC greenhouse gas inventory methods and default values" from **2006**.[68] CCLUB also incorporates U.S. soil organic carbon estimates rather than relying on outdated international defaults,[69] and CCLUB's treatment of cropland pasture — one type of land that could potentially be converted for cropland — is informed by empirical data from USDA. This makes CCLUB more evidence-based than AEZ-EF, which simply assumes that converting cropland pasture to cropland releases 50% of the emissions associated with converting pasture to cropland. In addition, CCLUB accounts for a broad range of soil, climate, and management conditions, which "is consistent with the technique of the Intergovernmental Panel on Climate Change of continuously updating carbon stock change factors based on such factors as management activities and various yield scenarios."[70]

Further, empirical data show that iLUC is far lower than the range predicted by agro-economic models from more than a decade ago and is substantially overstated in those models. A recent International Energy Agency report, for example, evaluated real-world data from 2005-2015 and found "no link" between increased U.S. biofuel

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[65] Taheripour, et al., *Biofuels induced land use change emissions: The role of implemented emissions factors in assessing terrestrial carbon fluxes (2022)* at Table 2.
[66] *See, e.g.* Kwon, et al. *Carbon Calculator for Land Use and Land Management Change from Biofuels Production (CCLUB) Users' Manual and Technical Documentation*, Argonne National Laboratory (Oct. 2021).
[67] Plevin, et. al, *Agro-ecological Zone Emission Factor Model v52*, (Jan. 2014).
[68] Plevin, et. al, *Agro-ecological Zone Emission Factor Model* (Sep. 2011).
[69] *Cf.* Kwon, et al. (2021) at 8 (describing CCLUB approach to modeling soil organic carbon changes in the U.S.; Plevin, et. al. (2014) at Table 20 (citing IPCC defaults).
[70] Taheripour et al. *Response to "how robust are reductions in modeled estimates from GTAP-BIO of the indirect land use change induced by conventional biofuels?"* 310 Journal of Cleaner Production 127,431 (2021).

production and corn production or deforestation in Brazil.[71] Instead, the report casts doubt on any causal relationship between biofuel production and corn prices or animal production.[72]

Ample scientific evidence currently exists for CARB to promulgate an updated LUC value for bioethanol that is consistent with the reduced range of iLUC values observed across the recent scientific literature. Growth Energy has submitted an abundance of evidence in both state and federal rulemakings to demonstrate the current state of the science, and we would be happy to work with CARB to address any outstanding concerns that may be delaying a much-needed update to CARB's lifecycle analysis.

243.11 *C. CARB Should Take Concrete Steps to Allow the Use of E15 Fuel in California*

We continue to urge CARB to expedite its approval of E15 fuel. E15, a blend consisting of 15% bioethanol, has been approved for use by the EPA in all passenger vehicles model year 2001 and newer — more than 96% of the vehicles on the road today — and is now for sale at more than 3,400 locations in 31 states. It is striking that in the state with the most aggressive climate policy in the country, the lowest carbon intensity gasoline product on the market (E15), remains unavailable to consumers and as a compliance tool for parties obligated to reduce the greenhouse gas emissions of California transportation fuel under the LCFS. In addition to its climate benefits through displacing more fossil fuel, E15 also provides substantial public health benefits through the reduction of criteria air pollutants, particularly $PM_{2.5}$ as discussed above. And E15 provides substantial cost benefits as well, selling for 15 cents less per gallon on average this summer where it was available. In certain states, these cost savings reached as high 60 cents per gallon. Many of these benefits are especially impactful to communities that are disproportionately overburdened by pollution, including urban communities in close proximity to highways and vehicular traffic, and low-income communities for which fuel costs make up a higher proportion of household expenditures.

We appreciate the Multimedia Working Group's continued work on the multi-media evaluation of E15, and we strongly encourage CARB to make material commitments towards expediting the approval of E15 for California consumers and to help drive immediate GHG reductions.

243.12 *D. CARB Should Allow Biofuel Producers to Access Crediting for Low-CI Power*

[71] *Towards an improved assessment of indirect land-use change*, IEA Bioenergy (Oct. 2022), https://task43.ieabioenergy.com/wp-content/uploads/sites/11/2022/10/IEA-Bioenergy-iLUCreport_Final.pdf.

[72] *Id.*

The Proposal also fails to recognize the carbon-reduction potential in crediting low-CI power sourcing in the production of biofuels, reserving this crediting mechanism solely for hydrogen used as a transportation fuel. This narrow provision provides no satisfactory justification, instead citing faulty arguments about resource shuffling and restricting low-CI power for other sources if the provision is expanded. Firstly, the Proposal fails the LCFS' fundamental policy goal of reducing carbon intensity in transportation fuels used in California. Allowing bioethanol producers to source *new* contracted low-CI power that is not included in a utility resource plan via a power purchase agreement does not impact electricity demand. Secondly, biofuels production occurs largely outside of California, in other electricity markets. Not only does this render the resource shuffling argument moot, but it also denies California the opportunity to lead other jurisdictions towards low-CI power capability.

243.13 *E. Accelerating the Use of Sustainable Aviation Fuel (SAF)*

As producers of one of the most scalable feedstocks for SAF production, we appreciate the Board's attention to development of this key market through its proposal to remove the exemption for intrastate jet fuel. We encourage CARB to continue to work with SAF producers, biofuel feedstock producers, and airlines to continue to seek ways to accelerate use of these important fuels to help decarbonize the aviation sector.

V. Conclusion

Thank you for the opportunity to provide input on the 2024 LCFS Amendments. The LCFS Program is a critical tool to addressing climate change, and we look forward to working with CARB to ensure the role of biofuels in making California's fuel mix more sustainable and help the state achieve its progressive climate goals through the expanded use of bioethanol.

Sincerely,

Christopher P. Bliley
Senior Vice President of Regulatory Affairs
Growth Energy

Comment Log Display

Here is the comment you selected to display.

Comment 253 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Tim
Last Name	Gibbons
Email Address	timgibbons@morural.org
Affiliation	Missouri Rural Crisis Center
Subject	Comments for Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments LCFS
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6923-lcfs2024-AG0AdABiAzMFXANg.pdf
Original File Name	MRCC Comment--Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments (lcfs2024) 2.20.24.pdf
Date and Time Comment Was Submitted	2024-02-20 15:00:50

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

MISSOURI
RURAL CRISIS
CENTER
1906 Monroe St. ◊ Columbia, MO 65201 ◊ (573) 449-1336 ◊ Fax (573) 442-5716

February 20, 2024

California Air Resources Board (CARB)
1001 I Street
Sacramento, CA 95814

Re: Comments for Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments (lcfs2024)

Missouri Rural Crisis Center appreciates the opportunity to offer these comments to the California Air Resources Board (CARB) for the "Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments (lcfs2024)".

Missouri Rural Crisis Center is a nearly 40-year old statewide farm and rural membership organization representing thousands of farm families in hundreds of rural communities. Our mission is *to preserve family farms, promote stewardship of the land and environmental integrity and strive for economic and social justice by building unity and mutual understanding among diverse groups, both rural and urban*.

We previously submitted comments in January 2022, following a December 2021 workshop regarding the Low Carbon Fuel Standard and urged CARB to grant the "Petition for Rulemaking to Exclude All Fuels Derived from Biomethane from Dairy and Swine Manure from the Low Carbon Fuel Standard" and initiate an immediate rulemaking to restore integrity to the LCFS.

We also submitted comments in April 2022 for the March 29, 2022 "Workshop on Methane, Dairies and Livestock, and Renewable Natural Gas in California".

Because it's illogical, counterintuitive and harmful, we continue to oppose corporate factory farm gas as a
244.1 solution to climate change, and we vehemently support LCFS amendments to exclude all fuels derived from dairy and swine factory farm gas from the Low Carbon Fuel Standard.

CARB should not continue to implement a bad and misguided proposal that would allow corporate factory farm dairy and hog operations (anywhere in the country) to sell the methane created in their operations into this system. Specifically, including factory farm gas as a "solution" toward your Low Carbon Fuel Standard Goals would:

- Incentivize more corporate factory farms, harming family farmers, rural communities, and our environment, including increased water and air pollution.
- Create more corporate consolidation in the U.S. livestock industry.
- Commoditize methane production, which would fuel more methane producing practices, creating more destructive greenhouse gases.
- Create additional overproduction of commodities, pork and milk, increasing supply and further pushing down market prices paid to independent family farms.
- Pay foreign multinational meatpackers, like Chinese-owned Smithfield and Brazilian-owned JBS, for their pollution.

- Create incentives for the public (taxpayer dollars through government subsidies) to fund anaerobic digesters to capture factory farm gas.

On behalf of our 5,000+ members, we ask that you reform this pollution trading scheme that inflicts harm on our communities. We urge you to reform the LCFS to exclude all fuels derived from factory farm gas.

Thank you for your time and please let me know if you have any questions.

Sincerely.

Tim Gibbons
Missouri Rural Crisis Center
1906 Monroe St.
Columbia, MO 65201
timgibbons@morural.org
(573) 449-1336

Comment Log Display

Here is the comment you selected to display.

Comment 254 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Michael
Last Name	Boccadoro
Email Address	mboccadoro@westcoastadvisors.com
Affiliation	Dairy Cares
Subject	Dairy Cares Technical Comments on LCFS Proposed Amendments

Comment

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Dear CARB,

Please find attached the technical comments submitted on behalf of
Dairy Cares in response to the proposed amendments to the Low
Carbon Fuel Standard proposed amendments.

Sincerely,
Michael Boccadoro
Dairy Cares
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Attachment	www.arb.ca.gov/lists/com-attach/6924-lcfs2024-ADJUZldmBWQLPwEx.pdf
Original File Name	240220_Dairy Cares Comments on Proposed LCFS Amendments (00627554xBA8E1).pdf

Date and Time Comment Was Submitted	2024-02-20 14:56:39

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Dairy Cares Technical Comments on the Proposed
Low Carbon Fuel Standard Amendments

February 20, 2024

Dairy Cares[1] appreciates the opportunity to provide these comments on the California Air Resources Board's ("CARB") proposed Low Carbon Fuel Standard ("LCFS") amendments ("Amendments"). Dairy Cares represents the California dairy sector, including dairy producer organizations, leading cooperatives, and major dairy processors. We appreciate CARB's efforts to lead a robust stakeholder process and its efforts to prepare a voluminous record in support of the proposed revisions to the LCFS. These comments focus on the biomethane crediting provisions. Our comments are summarized as follows:

245.1
1. Dairy Cares is broadly supportive of the proposed amendments, including updates to the environmental targets and alignment with Short Lived Climate Pollutant ("SLCP") reduction laws.

245.2
2. The Amendments impose an overly-broad phase-out timeline for biomethane crediting. CARB should revise these requirements and retain discretion to align implementation of crediting pathways under the LCFS with its statutory obligations under SB 1383.

DISCUSSION

1. Ongoing Crediting for Anaerobic Digester Projects Is Necessary to Meet the Statutory Requirements of SB 1383.

Greenhouse gas ("GHG") emissions are global pollutants, and it is important for CARB to demonstrate that its programs can harmonize environmental goals and protect the state's economy, consistent with the statutory requirements for the LCFS. Section 38560 of the California Health and Safety Code directs CARB to adopt regulations that achieve the "maximum technologically feasible and cost-effective" greenhouse emission reductions. Consistent with these requirements and the regulatory programs adopted to date, California's dairy farming families clearly recognize the importance of reducing GHG emissions and are

[1] For more information about Dairy Cares, please visit www.dairycares.com.

striving to advance many new in-state projects that reduce potent SLCP emissions. These projects are attributable to the signals provided by the LCFS. As a result of this important program, dairy farmers are able to reduce emissions and enhance the environment and economic stability of their farms. The LCFS plays a key role in justifying the investments needed to achieve SLCP reductions. In the face of anti-dairy activism, we greatly appreciate CARB's ongoing efforts to analyze factual evidence and understand the importance of voluntary programs like the LCFS to achieving the statutory mandates under SB 1383.

The LCFS is part of a comprehensive strategy for all types of GHG reductions, and the proposed Amendments follow through on CARB's previously stated intention to create a comprehensive plan to reduce SLCP emissions. We applaud CARB for its leadership and understanding the potential for California's bold action to have far-reaching impacts on a global scale:

> By developing a comprehensive plan to achieve necessary SLCP emission reductions in an effective and beneficial way, California can foster broader action beyond its borders and demonstrate effective processes and strategies to address climate change.[2]

The agency's 2022 Scoping Plan Update correctly recognized that, given the urgency of climate change and avoiding climate tipping points as identified in the recent Intergovernmental Panel on Climate Change assessment, efforts to reduce SLCPs are especially important right now.[3] The 2022 Scoping Plan Update accounted for the full 40% reduction in SLCPs by 2030, to achieve the overall reductions in GHGs by 2030 sought by the Plan. The 2022 Scoping Plan Update identified that "[i]nstall[ing] state of the art anaerobic digesters that maximize air and water quality protection, maximize biomethane capture, and direct biomethane to sectors that are hard to decarbonize or as a feedstock for energy" as a key strategy for successfully achieving reductions in dairy and livestock methane.[4]

Since then, it has become increasingly clear that global demand for dairy and meat is expected to increase significantly in the coming years. According to an analysis recently published by the Food and Agriculture Organization of the United Nations, by 2050, the growing and more affluent global population is anticipated to drive a 20 percent increase in animal

[2] CARB's Short-Lived Climate Pollutant Reduction Strategy (March 2017), p. 106, available at: https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.

[3] IPCC, 2022: Summary for Policymakers [P.R. Shukla, J. Skea, A. Reisinger, R. Slade, R. Fradera, M. Pathak, A. Al Khourdajie, M. Belkacemi, R. van Diemen, A. Hasija, G. Lisboa, S. Luz, J. Malley, D. McCollum, S. Some, P. Vyas, (eds.)]. In: *Climate Change 2022: Mitigation of Climate Change. Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change* [P.R. Shukla, J. Skea, R. Slade, A. Al Khourdajie, R. van Diemen, D. McCollum, M. Pathak, S. Some, P. Vyas, R. Fradera, M. Belkacemi, A. Hasija, G. Lisboa, S. Luz, J. Malley, (eds.)]. Cambridge University Press, Cambridge, UK and New York, NY, USA. doi: 10.1017/9781009157926.001.

[4] CARB's 2022 Scoping Plan for Achieving Carbon Neutrality, p. 232, available at: https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

product demand for animal products [sic] compared to 2020 levels. Without intervention, this upward trend could result in increased emissions from livestock systems, potentially undermining efforts to reduce GHG emissions and exacerbating global temperature rises.[5]

CARB has extensively evaluated the role the LCFS plays in California's ability to achieve the SLCP reductions called for in Senate Bill ("SB") 1383, and the findings have consistently supported CARB's own conclusion that "the LCFS facilitates significant private investment in technologies that provide the methane reductions from dairy, livestock manure, organic waste, and landfill management operations called for by SB 1383."[6] The productive use of dairy biomethane is the primary strategy that is reducing SLCP emissions, as required by SB 1383..

Arguments that the LCFS will directly lead to larger dairy herd populations should be
245.3 rejected. Allegations of incentives to increase herds solely due to the LCFS are unsupported. In fact, reductions in total herd size continue to occur. This is especially apparent in Tulare County, which is the largest dairy producing county in the nation and location of many of the dairy digester projects that have already contributed to considerable methane reductions in California. A March 2023 report produced by Tulare County shows that milk cow populations in Tulare County decreased by nearly 15% during the same period that 39 digester projects began operations and another 13 were in planning and development.[7] Tulare County reported significant emission reductions during this same timeframe, making clear that, in Tulare County, the presence of LCFS incentives clearly did not increase total herd populations or otherwise alter the ongoing trend of herd reductions and consolidation in California's dairy industry.

Unfortunately, anti-dairy activists continue their misguided efforts to call for a complete change of course on the State's SLCP Reduction goals. Some have called for forced conversion to pasture-based operations, direct regulation of dairy farms, and immediate phase outs of dairy
245.4 digester incentives. These proposals will not only fail to achieve the desired greenhouse gas emission reductions but will also exacerbate the problem by causing significant emissions "leakage." Command and control measures for SLCP reductions in the dairy industry will accelerate dairies leaving California for states with less costly regulations and less commitment to climate protection. This outcome would be in direct conflict with CARB's mandates to minimize emission leakage in the design of its GHG programs. CARB has wisely rejected calls for immediate phase out of dairy biomethane pathways. We applaud CARB for developing a robust record on the importance of the LCFS to the achievement of SLCP emission reductions.

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[5] FAO. 2023. Pathways towards lower emissions – A global assessment of the greenhouse gas emissions and mitigation options from livestock agrifood systems. Rome https://doi.org/10.4060/cc9029en, p. x.

[6] Staff Report: Initial Statement of Reasons (December 19, 2023), p. 8, available at: https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf

[7] Tulare County Annual Report of Dairy and Feedlot GHG Emissions in 2021 (March 2023) p. 8, available at: https://tularecounty.ca.gov/rma/permits/dairy/bos-agenda-item-2022-annual-report-of-total-ghg-emissions-from-dairies-feedlots-for-2021/.

245.2 **2. <u>CARB Should Not Create A Blanket 2040 Phaseout for In-state Dairy Fuel Pathways.</u>**

The Initial Statement of Reason ("ISOR") discusses the role of pipeline biomethane and that in the longer term, the State plans to shift away from biomethane as a transportation fuel source.[8] According to the ISOR, "this resource should be transitioned to other sectors. … in the long term, the existing market signals will need to transition accordingly to avoid stranded assets and the closure of methane capture projects."[9] The Amendments would phase out CNG pathways after December 31, 2040 and biomethane - hydrogen-based pathways would be phased out after December 31, 2045.

The ISOR does not identify what exactly the long-term tool will be once these phase-out dates take effect. Similarly, the ISOR does not address how, if at all, the Amendments would continue to support SLCP reductions after the phase out. We are concerned that in the absence of an ongoing financial signal, there could be project failure, which would risk increasing SLCP emissions. Smaller projects that naturally have longer pay-back periods (i.e., due to economies of scale in digester development), may not be undertaken at all. This is possible, particularly in light of the fact that in the period of 2025-30, out-of-state dairy projects will enjoy a permanent exemption from the new deliverability requirements, so long as the developer breaks ground before 2030. We are concerned that project developers will focus their efforts on locking in incentives for out-of-state projects, while smaller in-state projects are overlooked and face relatively short financial pay-back periods. There is important hydrogen-related fuel development occurring in the dairy sector that we are hopeful will qualify these concerns, but based on what we know now, more must be done to support SLCP reductions at smaller in-state dairies.

For this rulemaking, CARB should supplement the record and address how it will ensure that in-state dairies have access to financial capital needed to make long-term investments. CARB should qualify the uniform application of the proposed phase-out dates for biomethane pathways. The Tier 2 pathway application process should provide an opportunity to address unique circumstances, particularly those of smaller dairies that may require longer crediting periods to attract financing. Dairy Cares urges CARB to take a more nuanced approach and allow projects that will reduce emissions sources covered by SB 1383 to request an extension to the phaseout timelines through the tier 2 pathway application process.

CONCLUSION

Dairy Cares appreciates the opportunity to comment on this rulemaking and looks forward to continuing to partner with CARB and other stakeholders on the implementation of the Amendments and the successful achievement of the State's climate goals.

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[8] *Id.*, p. 30.

[9] Id.

CARB and other leading climate researchers have concluded that dairy digester development is a necessity if the State has any hope of fulfilling its role as a world leader in the climate community. The need is acute for CARB to demonstrate to California dairy farmers that there are viable tools and long-term financial markets available for them to justify investing in long-term emission reduction solutions at their farms. This is particularly true now that LCFS prices have declined in recent years. The 2022 Scoping Plan Update provides guidance to CARB and other responsible agencies on how individual regulatory programs, such as the LCFS, are needed to ensure that the State's programs, such as the SLCP Plan, collectively achieve the emission reduction targets. Market mechanisms such as the LCFS are incredibly important to successfully protect SLCP project financing. The bottom line is that without markets for beneficial use of captured biomethane, projects will not be financed and built.

Dairy Cares encourages CARB to continue setting an example for the rest of the country by following the SLCP reduction guidelines established in SB 1383. The statute is clear in its direction to minimize leakage, and other states certainly will not follow California's lead if heavy-handed direct regulatory action is taken that causes dairy farmers to lose confidence in the program. Concern for direct regulation could lead to businesses leaving the state, increasing emissions elsewhere. This result is not only at odds with California's requirements for minimizing leakage pursuant to Assembly Bill 32, but also with the achievement of the SB 1383 targets and the state's overall climate goals.

Comment Log Display

Here is the comment you selected to display.

Comment 255 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Julia
Last Name	Levin
Email Address	jlevin@bioenergyca.org
Affiliation	Bioenergy Association of California
Subject	LCFS2024
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6925-lcfs2024-VDZUM1MxU18GY1M8.pdf
Original File Name	BAC Comments on LCFS Amendments (Feb2024).pdf
Date and Time Comment Was Submitted	2024-02-20 14:58:32

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Bioenergy Association of California

February 20, 2024

The Honorable Steven S. Cliff
Executive Officer
California Air Resources Board
Sacramento, CA 95814

Re: <u>Proposed Amendments to the Low Carbon Fuel Standard Regulation</u>

Dear Executive Officer Cliff:

I am writing on behalf of the Bioenergy Association of California (BAC) to comment on the 45-day language to amend the Low Carbon Fuel Standard regulations, which was released in early January. BAC strongly supports the increased stringency of the proposed regulation, but is very concerned about the continued use of Book and Claim for undelivered biomethane and the phase-out of avoided methane credits. Failing to require delivery of biomethane means that California will continue to use fossil gas on
246.1 the road and it will hurt instate projects that are converting organic waste to energy to meet the state's Short-Lived Climate Pollutant reduction, landfill diversion, wildfire reduction, and other important state policies. Phasing out credit for avoided methane emissions, even when they are not required by law, will also undermine efforts to meet the SLCP reduction requirements of SB 1383. BAC urges the Air Board, therefore, to revise the amendments to require biomethane delivery consistent with RPS and SB 1440, and to only phase out avoided methane emissions to the extent that they are required by law.

BAC represents more than 100 public agencies, private companies, and non-profit organizations working to convert organic waste to energy. BAC's public sector members include cities and counties, Tribes, local air districts, environmental and solid waste agencies, wastewater treatment facilities, public research institutions, community and environmental groups, and a publicly owned utility. BAC's private sector members include bioenergy project developers, technology providers, investors, an investor owned utility, waste haulers, food processing and agricultural companies, and more.

BAC members are currently producing the lowest carbon fuels in the LCFS program, including biomethane, electricity and hydrogen generated from dairy manure, diverted organic waste, landfill and wastewater biogas. Other BAC members are developing projects to convert forest and agricultural waste to low carbon and carbon negative fuels.

BAC's comments focus on the 45-day language regarding Book and Claim for undelivered biomethane and the phaseout of avoided methane emissions even where they are not required by law or higher emitting alternatives are allowed.

A. BOOK AND CLAIM SHOULD BE PHASED OUT CONSISTENT WITH THE RPS AND SB 1440.

BAC urges the Air Board to go back to the staff recommendations in 2022 and 2023 that would have phased out undelivered biomethane consistent with the RPS and SB 1440. This is critical for several reasons, described below. At the same time, BAC urges the Air Board to allow Book and Claim for biomethane used to produce low-CI electricity, provided both the biomethane and the electricity are produced and delivered consistent with the RPS and SB 1440.

1. Undelivered Biomethane Does Not Help California Reduce SLCP Emissions.

SB 1383 requires significant reductions in methane and black carbon emissions by 2030, and diversion of 75 percent of organic landfill waste by 2025. Biomethane generated in other states that is never delivered to California does not help to meet these critical climate and public health goals. This is why the Legislature, in SB 1440 (Hueso, 2018) requires that eligible biomethane must help achieve the goals of SB 1383.[1] SB 1440 further requires that the capture or production of eligible biomethane must directly result in at least one of the following environmental benefits to California: reduction of air pollutants or greenhouse gas emissions, reduction of water pollution, or reduction of odors in California.[2]

Only instate biomethane or biomethane that is actually delivered to California helps to meet the methane and black carbon reduction requirements of SB 1383 or to provide benefits to California's environment, as outlined in SB 1440.

The Air Board should phase out undelivered biomethane, as the 2023 staff proposals lay out, to help meet the requirements of SB 1383, reduce open burning and mitigate wildfire. Only instate or delivered biomethane provides these critical benefits.

2. Undelivered Biomethane Means that California Vehicles Will Continue to Use Fossil Gas.

From its inception, the Low Carbon Fuel Standard has had two goals, reducing carbon emissions and reducing fossil fuel use in motor vehicles. Continuing to allow credit for undelivered biomethane means that natural gas vehicles on the road in California will in fact be using fossil fuel gas. This is not a desirable result since fossil fuel production, refining and transport have adverse impacts on the environment and public health. It

[1] Public Utilities Code section 651(a)(1).

[2] Public Utilities Code section 651(a)(3)(B)(ii).

will also undermine support for the LCFS program since California drivers will continue to pay a premium for low carbon fuels that aren't even being delivered to California – in other words, Californians are being asked to buy something that they never in fact receive.

Phasing out the use of fossil fuels on the road in California requires that low carbon and renewable fuels actually be delivered and used to displace fossil fuels.

3. **Allowing Undelivered Biomethane Puts Instate Projects at a Severe Disadvantage.**

Allowing undelivered biomethane to participate in the LCFS reduces demand for instate biomethane, since instate production is significantly more expensive than out-of-state and undelivered fuels. California has stronger environmental, public health, labor, permitting, and other requirements. As an example, interconnection costs in California can be 2 to 10 times higher than in other states. California also has the most stringent pipeline biomethane standards in the country and the Air Board has recently proposed making pipeline biomethane standards even more stringent. Out of state biomethane projects do not have to meet California's standards to protect public health and pipeline integrity, which puts instate projects at a competitive disadvantage.

Continuing to make instate projects compete with undelivered biomethane will only slow the state's efforts to reduce SLCP emissions, landfilling, and wildfire as it makes it harder for instate projects to compete, both economically and in terms of the time needed to develop projects.

4. **The LCFS Should be Consistent with the Legislatively Mandated RPS and SB 1440 Programs.**

For all the reasons above, BAC urges the Air Board to go back to the staff proposals on the LCFS, which would have phased out undelivered biomethane consistent with the RPS and SB 1440. The 45-day language does not do this in any meaningful way. Projects built before 2030 will never be required to deliver their biomethane to California. And projects built after 2030 do not have to show delivery until 2040 or later and, even then, only have to inject the biomethane into a pipeline that flows in the general direction of California. This is not a clear standard and definitely does not ensure that the biomethane will help reduce SLCP emissions or provide other environmental benefits in California, as both SB 1440 and the RPS require.

5. **The LCFS Regulation Should Allow Book and Claim for Biomethane that is Delivered for Use in California, Including for Low-CI Electricity, Consistent with the RPS.**

BAC supports the use of Book and Claim for biomethane that is both generated and used in California or the western United States, whether it is used offsite as biomethane, for low-CI electricity generation or for hydrogen production. BAC urges the

Air Board to clarify in the amendments to the LCFS regulation that book and claim for biomethane converted to low-CI electricity is allowed, provided that both the biomethane and low-CI electricity production are consistent with the RPS. This could be done by adding conversion of biomethane to low-CI electricity in Sections 95488.8(i)(2) and 95488.8(g)(1)(A)(2).

246.2

B. CARB SHOULD NOT PHASE OUT CREDIT FOR AVOIDED METHANE EMISSIONS UNLESS THEY ARE REQUIRED BY LAW AND HIGHER EMITTING ALTERNATIVES ARE NOT ALLOWED.

BAC also urges the Air Board to continue to give credit for avoided methane emissions that are not required by law. This includes avoided methane emissions from livestock manure, which is not currently regulated, as well as avoided emissions from diverted organic waste projects where bioenergy can provide far greater carbon reductions than alternative products procured pursuant to CalRecycle's SB 1383 regulations. BAC appreciates that lifecycle analyses should not include emissions reductions that are required by law, but in both of these cases, the specific reductions are not required by law and should be credited in a lifecycle analysis.

1. Dairy and Other Livestock Waste

SB 1383 requires a 40 percent reduction in methane by 2030, but it does not include requirements for dairy methane reductions. On the contrary, the law requires a number of findings before the state can regulate dairy methane emissions[3] and those findings are difficult to impossible to achieve, so the State cannot currently regulate dairy methane emissions unless it changes the law. Therefore, dairy biogas producers should receive full credit for avoided methane emissions from dairy manure that is used to produce biofuels participating in the LCFS program.

2. Diverted Organic Waste

Diverted organic waste is a more complex category since SB 1383 does require 75 percent of organic landfill waste to be diverted from landfill by 2025. At the same time, neither SB 1383 nor CalRecycle's regulations require that diverted organic waste be converted to bioenergy. CalRecycle's SB 1383 regulations explicitly allow alternatives to bioenergy that emit far more carbon. Those alternatives include compost production and mulch, which are less expensive to produce than bioenergy, but also have greater carbon emissions.

CalRecycle affirmed this recently when it determined that a diverted organic waste to hydrogen project will have lower emissions than if that same waste were converted to compost (the finding required under Article 2 of CalRecycle's SB 1383 regulations). The State of Oregon's Department of Environmental Quality has also conducted a literature of 148 separate studies and found that bioenergy plus composting the

[3] Health and Safety Code section 39730.7(b)(4).

remainder (digestate) provide 3.5 times greater carbon reductions than compost alone.[4] More recent methane monitoring by NASA's Jet Propulsion Lab also found that compost production facilities emit substantial amounts of methane and yet this is an allowed alternative under CalRecycle's regulations.[5] None of this is to dismiss the value of compost, but where low carbon fuel can be generated instead, the difference in emissions should still be valued under the LCFS.

As long as CalRecycle's SB 1383 regulations allow higher emission alternatives to biofuels (biomethane, hydrogen or electricity generated from that waste), then the LCFS should continue to provide credit for the difference between bioenergy and other, higher emitting compliance products.

Thank you for your consideration of these comments.

Sincerely,

Julia A. Levin
Executive Director

[4] Morris, et al, *Evaluation of Climate, Energy, and Soils Benefits of Selected Food Discards Management,* Prepared for the State of Oregon Department of Environmental Quality, October 2014, Table ES-2 at page iii.
[5] See, **http://methane.jpl.nasa.gov/**

Comment Log Display

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Comment 256 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Frank
Last Name	Miller
Email Address	fmiller@bur.org
Affiliation	Hollywood Burbank Airport
Subject	California Air Resource Board Proposal to Regulate Jet Fuel
Comment	See attached letter.
Attachment	www.arb.ca.gov/lists/com-attach/6926-lcfs2024-Uj9UO1U4UW4DYFMh.pdf
Original File Name	Miller BUR Comment Letter CARB.pdf
Date and Time Comment Was Submitted	2024-02-20 15:04:22

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

California Air Resources Board
P.O. 2815
Sacramento, CA 95812
Email: arbboard@arb.ca.gov

VIA EMAIL

Re: California Air Resources Board Proposal to Regulate Jet Fuel

Dear ARB Members:

I write on behalf of the Burbank-Glendale-Pasadena Airport Authority ("Authority") regarding the recent California Air Resources Board ("CARB") proposal to regulate jet fuel under its Low Carb Fuel Standard ("LCFS") program. As the owner and operator of Hollywood Burbank Airport ("BUR"), the Authority is supportive of feasible measures that fight climate change. The Authority is doing its part by striving for a LEEDS Gold certification for the Replacement Passenger Terminal project that is underway. Unfortunately, the LCFS proposal being considered by CARB will set a standard that is infeasible at this time.

The U.S. airline industry plays a vital role in California's economy. Furthermore, the industry is committed to reducing its climate impact and achieving "net zero" carbon emissions by 2050. Transitioning to Sustainable Aviation Fuels ("SAF") is core to this commitment, and the industry has pledged to work with governments and other stakeholders to make three billion gallons of SAF available in the United States by 2030. Achieving these goals requires new and additional policy incentives, streamlined permitting processes, and close collaboration among airlines, fuel companies, manufacturers, environmental organizations and governments, among others.

With respect to SAF, California has established itself as an early leader in attracting investment, production, and use of SAF through the existing LCFS Program, which provides an opt-in credit for SAF that helps reduce the price difference between SAF and conventional jet fuel. This voluntary regulatory structure has been successful in enabling the growth of the SAF market in California and across the country. California has the most viable market for SAF today in the United States and, as airlines increase their demand, the market continues to grow.

Aviation accounts for only 2.6% of United States' greenhouse gas emissions. In contrast, aviation's impact on the country's and the state's gross domestic product is significant, respectively amounting to 5% and 4.1%. There are 380,000 employees of United States commercial aviation firms based in California, with an overall economic impact of $194 billion[1]. Aviation is critical to driving California's economy and its rank as the 5th largest economy in the world. Aviation enables $114 billion in annual trade flows and underpins many of the rest of state's biggest economic drivers such as agriculture, tourism, manufacturing, banking, technology and small business. Ensuring a healthy and vibrant aviation industry is essential to California's future, and leveraging CARB's early leadership on SAF can enable California leadership in the emerging SAF production industry, creating new jobs and economic development opportunities.

[1] The Economic Impact of Civil Aviation on the U.S. Economy, State Supplement, US Department of Transportation, November 2020

2627 N. Hollywood Way • Burbank, California 91505 • (818) 840-8840 • Fax: (818) 848-1173

247.1 With this context, the Authority respectfully asks CARB to reconsider the proposal to regulate jet fuel as an obligated fuel under the LCFS Program. It our understanding that CARB's proposed changes to the LCFS Program include elimination of the existing exemption for conventional jet fuel use for flights within California. This proposed change is unlikely to result in increased SAF production, availability, or use in the state, but would lead to higher jet fuel prices. The International Air Transportation Association estimates that SAF production reached 158 million gallons in 2023, yet the U.S. Government Accountability Office estimates that 35 billion gallons of SAF will be needed by 2050 to satisfy 100% of demand. The primary impediment to increased SAF production and availability in California remains the higher cost of SAF for producers and buyers relative to conventional jet fuel and renewable diesel. CARB's proposal would not meaningfully address this fundamental challenge and therefore is unlikely to meaningfully increase SAF supply or use.

247.2 It bears emphasis that federal law preempts state agencies from regulating jet fuel to reduce emissions from aviation. CARB recognized this fact when it exempted jet fuel in 2018.[2] Aviation has unique circumstances, which go beyond considerations of interstate commerce, for the safe operation and maintenance of aircraft. Federal law, including the Clean Air Act, fully occupies this field and gives exclusive regulatory jurisdiction to federal agencies like the Environmental Protection Agency and the Federal Aviation Administration.

Moving forward with eliminating the fossil jet fuel exemption and implementation of a new obligation inevitably will result in lengthy and costly litigation that does nothing to advance the mission of increasing SAF production. Such litigation will divert resources from the state and the aviation industry that would be better spent enabling greater SAF production. Our mutual interest is to increase SAF production, availability, and use. The most effective way to accomplish this is to continue the positive, collaborative approach represented by the existing "opt-in" mechanism developed by CARB and the aviation community.

Based on these considerations, the Authority urges CARB to work with the aviation industry on another win-win solution. CARB should preserve the existing opt-in approach for SAF and partner with the aviation sector and stakeholders across the emerging SAF ecosystem on new policies and approaches to speed the availability of SAF in California.

Sincerely,

Frank R Miller

Frank Miller
Executive Director, Hollywood Burbank Airport

cc: Commissioners, Burbank-Glendale-Pasadena Airport Authority

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[2] CARB stated that "[s]ubjecting aircraft fuels to annual carbon intensity standards would raise federal preemption issues" *available at* https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/isor.pdf?_ga=2.259407882.1202437490.1641231788-253234234.1573227006

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Comment 257 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Cinda
Last Name	Lohmann
Email Address	cindalohmann@turnermason.com
Affiliation	Turner, Mason & Company
Subject	Comments on Proposed Amendments
Comment	Attached is our comment letter.
Attachment	www.arb.ca.gov/lists/com-attach/6927-lcfs2024-BXFWPQBiAAwFYAlo.pdf
Original File Name	TMC_CALCFS2024Amendments_Comments.pdf
Date and Time Comment Was Submitted	2024-02-20 15:04:55

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Turner, Mason & Company
energy consulting & advisory

February 19, 2024

California Air Resources Board
1001 I Street, 23rd Floor
Sacramento, CA 95814

Subject: Comments on Proposed Amendments Regarding Intrastate Jet Fuel Obligations and Less Intensive Verification

Dear Members of the California Air Resources Board,

Turner, Mason & Company (TM&C) appreciates the opportunity to provide comments on the 2024 proposed Low Carbon Fuel Standard (LCFS) amendments.

TM&C is an accredited verification body under the California LCFS, boasting a rich legacy of over 30 years working with petroleum and renewable fuel producers. With a team comprising seasoned consultants, each equipped with decades of first hand industry experience operating within Federal and State regulatory frameworks, TM&C stands as a trusted partner for clients navigating the intricate landscape of fuel compliance and verification. Through our extensive industry tenure and unwavering commitment to excellence, TM&C has consistently delivered invaluable insights to ensure regulatory compliance and operational efficiency for our clients.

I am writing on behalf of TM&C's verification body to provide comprehensive feedback on three critical aspects of the proposed amendments: 1) the inclusion of intrastate jet fuel as an obligated fuel, 2) the concept of less intensive verification, and 3) the current requirements for verification body rotation after six years.

Regarding the addition of intrastate jet fuel as an obligated fuel, we echo previous
248.1 concerns raised about the complexities and challenges associated with this proposal. The verification process for transactions involving this type of fuel would undoubtedly pose significant challenges, particularly given the intricate nature of traceability requirements.

It is crucial for CARB to engage not only with fuel producers but also with verification bodies to better understand the barriers and challenges inherent in the verification process. This collaborative effort will inform the development of effective verification methodologies and ensure that any regulatory measures implemented are grounded in feasibility and practicality.

Furthermore, CARB must ensure that there are clearly established methods for demonstrating and verifying the intended use of jet fuel for intrastate transport versus interstate or international transport. Without such clarity, reporting entities and verification bodies will face difficulties in meeting the requirements outlined in Section 95500(c) for fossil jet fuel used in intrastate flights.

Turning to the concept of less intensive verification, while we commend CARB for considering this approach to streamline the verification process, we believe there are opportunities for refinement to ensure effectiveness and equity. Specifically, we recommend extending the provision for less intensive verification services to encompass all transaction types listed in Section 95500(c)(1)(A through F), as well as the verification
248.2 of Crude Oil Quarterly and Annual Volumes Reports outlined in Section 95500(d). Additionally, eligibility for less intensive verification for Annual Fuel Pathway Reports (AFPR) should be extended to entities operating in manufacturing jurisdictions with established process safety regulations, as these jurisdictions demonstrate a higher level of internal control and compliance.

An assessment process for specific supporting information could be incorporated into the Notice of Verification to facilitate the application of less intensive verification. This would provide an opportunity for the Verification Body and CARB to determine whether there is sufficient supporting information to approve a less intensive verification process.

In addition to “less intensive verification”, CARB should consider eliminating the restriction of using the same verification body or individual verifier(s) to perform validation and
248.3 verification services for a period more than six consecutive years (see Section 95500(g)). This change would enable verification bodies to develop and maintain organizational competency and capability for the long-term thereby providing for increased sustainability of the LCFS validation / verification program.

With the experience gained from almost four years of validation / verification reporting, CARB should consider the performance history of the verification body or individual verifiers and not simply require a default change without a fundamental reason (i.e. cause). CARB has the authority to accredit and discredit verification bodies, lead verifiers, and verifiers based upon the competency requirements within section 95502(c).

In conclusion, TM&C believes that refining the proposed amendments to include these recommendations will enhance the effectiveness and fairness of the verification process while still achieving the intended goal of the program.

We appreciate the opportunity to provide feedback on this matter and look forward to the continued improvement of the regulatory framework.

Thank you for your consideration on these matters. If you have any questions, please reach out to us.

Regards,

Cinda J Lohmann

Cinda J Lohmann
Executive Vice-President,
Fuels Regulatory Practice
Turner, Mason & Company

Comment Log Display

Here is the comment you selected to display.

Comment 258 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Myles
Last Name	Culhane
Email Address	myles_culhane@oxy.com
Affiliation	
Subject	1PointFive Comments to Proposed Low Carbon Fuel Standard Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6928-lcfs2024-VmcFc1c5WGIGbgF1.pdf
Original File Name	1PointFive_comments_on_2024LCFSAmendments.pdf
Date and Time Comment Was Submitted	2024-02-20 15:08:56

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed 2024 Low Carbon Fuel Standard Amendments

Dear Chair Liane Randolph,

On behalf of 1PointFive, I extend our gratitude for the opportunity to provide comments on the California Air Resources Board's (CARB) 2024 Proposed Amendments to the Low Carbon Fuel Standard (LCFS). 1PointFive is a Carbon Capture, Utilization and Sequestration company that is working to help curb global temperature rise to 1.5°C by 2050 through the deployment of decarbonization solutions, including Carbon Engineering's Direct Air Capture (DAC) and AIR TO FUELS™ solutions alongside geologic sequestration hubs.

We commend the state's unwavering commitment to climate action and leadership in incentivizing the deployment of carbon capture and sequestration (CCS) and DAC technologies. As a pioneer in sustainable practices, California has demonstrated the feasibility and efficacy of ambitious low carbon fuel standards, significantly influencing other jurisdictions in shaping their climate policies. California's leadership continues to catalyze a broader, collective commitment to fostering cleaner, more sustainable energy practices on a global scale.

California's dedication to reducing greenhouse gas (GHG) emissions sets a laudable example, and we appreciate the chance to contribute to the ongoing dialogue. Our comments are focused on the proposed amendments related to DAC and CCS. As identified by California's Scoping Plan, these technologies play a critical role in achieving the state's climate goals. We look forward to engaging in a constructive discussion to further enhance California's LCFS regulation.

Indirect Accounting of Low-CI Electricity in Direct Air Capture Projects

249.1 1PointFive strongly supports CARB's proposal to permit indirect accounting for low-CI electricity, biomethane and low-CI hydrogen.[1] Pursuant to CARB's proposed LCFS amendments, reporting entities may use indirect accounting mechanisms for low-CI electricity supplied as a transportation fuel, for hydrogen used as a transportation fuel, or *for direct air capture projects*, provided certain conditions are met. In conjunction with the amendment providing for indirect accounting for DAC, we also support CARB's proposed definition for "Book-and-Claim Accounting".[2]

1PointFive is currently constructing the first commercial scale DAC project which, once complete, will have a design capacity to capture 500,000 tons of CO_2 per year from the atmosphere. To maximize net removal of CO_2, DAC technologies require a continuous, reliable, and economic electricity supply. CARB's proposed amendments including indirect accounting methods for DAC, i.e., book-and-claim, are critical to ensuring the technical and commercial

[1] Proposed Amendments to the Low Carbon Fuel Standard Regulation, 17 CCR §95488.8(i)(1) ("Book-and-Claim Accounting for Low-CI Electricity Supplied as a Fuel, Direct Air Capture projects, or Used to Produce Hydrogen as a transportation fuel").
[2] Defined as "an indirect accounting system where a physical product and its environmental attributes can be separately traded...separated environmental attributes of low-CI electricity...may be matched under certain conditions to the use of grid electricity...." Proposed Amendments to the Low Carbon Fuel Standard Regulation, 17 CCR §95488.

feasibility of this nascent technology. And, as CARB noted in its Initial Statement of Reasons (ISOR), DAC is a key scoping plan component to meeting California's 2045 carbon neutrality goals.[3]

1PointFive's position is that book-and-claim accounting will also be a key contributor to the broader deployment of DAC at a climate-relevant scale. While small pilot-scale DAC projects may be able to rely upon "behind the meter" connections to provide needed energy, larger commercial-scale projects need multiple commercial-scale energy sources to ensure a continuous supply of energy. CARB's inclusion of book-and-claim accounting recognizes the challenges of optimally siting renewable and low-CI electricity projects, enables projects to enter into commercially competitive power purchase agreements with multiple energy sources, and serves as a powerful incentive for the development of new and expanded renewable and low-CI energy electricity generation.

Risk of Resource Shuffling and CARB's Proposed Criterion in 95488.8(i)(1)(C):

1PointFive is cognizant that any use of indirect or book-and-claim accounting must avoid creating or elevating the risk of "resource shuffling." To address this risk, CARB proposes that in order for reporting entities to use indirect accounting mechanisms for low-CI electricity supplied as a transportation fuel, for hydrogen used as a transportation fuel, or for direct air capture projects, five requirements or criterion must be met.[4] CARB explains that "[t]hese requirements will help ensure against resource shuffling where existing renewable electricity is potentially redirected to hydrogen production and backfilled with non-zero electricity."[5] Although not expressed in the ISOR, we understand that this reasoning applies equally to hydrogen and DAC.

1PointFive supports including amendments to the LCFS that will mitigate the risk of resource shuffling but recommends revisions to reflect the technical feasibility and commercial implications of imposing these criteria on DAC projects. **As part of its DAC development program, 1PointFive has carefully examined low-CI electricity sourcing and has determined that a book-and-claim accounting period shorter than 12 months is currently**
249.2 **infeasible and will severely constrain the deployment of this important climate mitigation technology.** Such a requirement should wait until such time when robust long-duration storage capacity is available, the necessary market and regulatory frameworks are in place, and sufficient dispatchable low-CI electricity is available, which we anticipate will not occur in this decade. Otherwise, the outcome of including this constraint would be harmful to the imperative to facilitate successive and rapid deployment of the initial generations of DAC technologies to progress along the technology learning curve and reduce costs to enable future deployment at a scale meaningful for climate mitigation.

CARB Should Require Low-CI Electricity to be Supplied to the Grid Within the Local Balancing Authority Where the DAC is Located

249.3 1PointFive supports CARB's recommendation that the low-CI electricity must be supplied to the grid within the local balancing authority where the DAC project is consuming the electricity. Furthermore, 1PointFive proposes that if the new low-CI electricity source from which the DAC

[3] California Air Resources Board, Staff Report: Initial Statement of Reasons. 32, 80, 124. Dec. 19, 2023; California Air Resources Board, 2022 Scoping Plan for Achieving Carbon Neutrality. 91-97. Nov. 16, 2022 ("increased deployment of DAC can help achieve net negative emissions…help[ing] avoid the most damaging impacts of climate change.").
[4] See, § 95488.8(i)(1)(C).
[5] California Air Resources Board, Staff Report: Initial Statement of Reasons. 34. Dec. 19, 2023.

249.4 project procures its electricity is not located in the same balancing authority as the DAC project, the DAC project must demonstrate that it can contractually and physically be able to supply the electricity to the grid within the local balancing authority where the DAC project is located. This will help mitigate the risk of resource shuffling or the double-counting of benefits.

CARB has already found that this approach, combined with the requirement that low-CI electricity be new or expanded (as required by criterion 3) did not lead to resource shuffling in the cap-and-trade program. The cap-and-trade program and the LCFS are two of the four credit trading programs California implements. Although the program frameworks differ in some respects, there are several similarities. Each establishes a declining target (for cap-and-trade, the total amount of permissible emissions, calculated on an annual basis, for LCFS, a carbon intensity applicable to transportation fuels that may be calculated on an annual or quarterly basis) and each allows for the creation and trading of credits (referred to as allowances under cap-and-trade) to meet annual compliance obligations.

The cap-and-trade program regulations expressly prohibit resource shuffling and in its analysis of the potential for resource shuffling within the cap-and-trade program, CARB found that California and Western Electricity Coordinating Council (WECC)-wide GHG emissions from electricity production decreased after 2013.[6] CARB analysis concludes that these decreases in emissions and the corresponding increases in zero-GHG and natural gas generation are key indicators the California Cap-and-Trade Program has not resulted in resource shuffling. Further, CARB found that declining costs of natural gas and renewable generation were driving year-over-year decreases in California electricity GHG emissions from both imports and in-State generation as in-State renewables more than doubled since 2013 and renewable generation in the WECC increased year over-year. We are confident that this analysis applies equally for the LCFS and should be used to inform CARB's consideration of the LCFS's approach to permitting annual balancing for DAC projects. We also encourage CARB to periodically update its review of the potential for resource shuffling for both the cap-and-trade and LCFS programs.

<u>CARB Should Focus on Ensuring that the Low-CI Power can be Accurately Tracked Rather than the First Contracting Entity</u>

1PointFive supports CARB's efforts to ensure that the low-CI electricity and associated environmental attributes are accurately tracked and accounted to mitigate the risk of double counting renewable energy certificate (RECs) or other environmental attributes. We understand that CARB's proposal that "The pathway holder must be the first contracted entity for procuring the low-CI power" is designed to mitigate this risk. However, 1PointFive recommends that rather than requiring DAC projects to be the first contracted entity, CARB should focus on requiring the pathway holder or project operator to prove that it can and has tracked the RECs and, in
249.5 accordance with CARB's proposed amendments, that credits are retired and not claimed under any other program, other than those expressly listed.[7]

In addition, CARB's proposed requirement is inconsistent with certain practical commercial approaches taken by companies to execute and manage power procurement contracts. In many cases, parent companies will establish an affiliate to manage their power purchase agreements, track, account and retire RECs and ensure electricity usage is managed on a daily basis across multiple decarbonization projects or business units. 1PointFive understands that CARB may be intending to prevent the double-counting of low-CI power procured and, if so, we recommend

[6] California Air Resources Board, Review of Potential for Resource Shuffling in the Electricity Sector. Feb. 2020.
[7] Proposed Amendments to the Low Carbon Fuel Standard Regulation, 17 CCR 95488.8(i)(5)(C)5.

that the criteria be changed to require the pathway holder (not necessarily the contracting entity)
249.5 to be the only entity that can claim the electricity and associated environmental attributes from the low-CI project, and such claim must be auditable and verifiable by CARB. In the alternative, CARB could revise this criterion to recognize commercial realities as follows:

> "The pathway holder, ~~or the~~ project operator or any of its affiliates must be the first contracted entity for procuring the low-CI electricity."

CARB Should Confirm that New or Expanded Low-CI Electricity Includes Repowered Sources

1PointFive fully supports the requirement that any low-CI electricity must be supplied by new or expanded low-CI electricity that begins new or expanded production on or after January 1, 2022, or within three years of the start of the DAC project. This is the key requirement to achieve CARB's goal to prevent resource shuffling. However, 1PointFive respectfully requests
249.6 that CARB confirms that a full repower of a renewable resource will qualify as a new low-CI source so long as it meets the criteria established by the Internal Revenue Service's "80/20" rule.[8]

CARB Should Permit Indirect Accounting on an Annual Basis

Requiring book and claim accounting to span a single quarter is neither technically feasible nor commercially viable. For direct air capture projects, we recommend that CARB revise its
249.7 proposed amendments to permit book and claim accounting for low-CI electricity on no less than an annual basis.

Allowing low-CI electricity matching to span a minimum of four quarters is necessary for a number of reasons. First, solar and wind energy capacity is subject to significant seasonal variability, regardless of the geographic location of the solar or wind energy generation. In the case of solar energy generation, seasonal variation is well documented across the United States and becomes more pronounced as latitudes increase. Consequently, any new and additional solar energy sources will provide significantly more electricity than a DAC project will need during summer months, particularly during the later days of a second calendar quarter and early days of a third calendar quarter but significantly less than a DAC project will need during the fourth and first calendar quarters. Seasonal variabilities in wind energy capacity are also well documented, although more dependent on geographic location. While seasonal variation in wind capacity is more localized, it is particularly pronounced on the west coast. Consequently, renewable power capacity, regardless of location, experiences significant seasonal variations, independent of and across multiple calendar quarters. Therefore, the use of book-and-claim accounting must be allowed to span at least four quarters to encompass a full seasonal cycle.

Some may suggest that renewable power generation combined with battery storage can address variabilities in the available renewable energy capacity. This is currently not a technically feasible or viable solution. Generally, large scale battery storage capacity is currently limited to less than four hours and suffers from pronounced energy degradation.[9] Battery storage can be configured for longer durations but not such durations sufficient to support a quarterly balancing period. Long duration energy storage (LDES) beyond 4 hours is a

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[8] Definition of Energy Property and Rules Applicable to the Energy Credit, 88 Fed. Reg. 82188, 82211, 82218 (Nov. 22, 2023).
[9] Denholm, Paul, Wesley Cole, and Nate Blair. 2023. Moving Beyond 4-Hour Li-Ion Batteries: Challenges and Opportunities for Long(er)-Duration Energy Storage. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-85878. https://www.nrel.gov/docs/fy23osti/85878.pdf.

recognized challenge. The challenge is perhaps most clearly exemplified by the Department of Energy's (DOE) "Long Duration Storage Energy Earthshot" announced in 2022 that establishes a target to reduce the cost of grid-scale energy storage by 90% for systems that deliver 10+ hours of duration within the decade. In September 2023, the DOE's Office of Clean Energy Demonstrations announced funding of $325 million for nine proposals for LDES test projects. While these first projects (which have been selected but are yet to be awarded) appear promising, they also provide a clear indication that broader deployment of LDES, on both a technical and economic basis, is unlikely before 2035. DAC deployment cannot wait on these technologies to reach suitable duration, cost and deployment.

<u>Resource Shuffling is not Dependent on Whether the Use of Low-CI Electricity Spans Multiple Quarters</u>

We understand that CARB proposes a quarterly balancing period as a mitigating factor against resource shuffling. As CARB explains in its ISOR:

> "[L]ow CI electricity must be new or expanded capacity, must be delivered to the local balancing authority... and must be matched on a quarterly basis. These requirements will help ensure against resource shuffling where existing renewable electricity is potentially redirected... and backfilled with non-zero electricity."[10]

We agree that requiring new or expanded capacity low-CI electricity and delivery to the local balancing authority will help ensure against resource shuffling. However, as we discuss, *supra*,[11] we urge CARB to permit the use of low-CI electricity to span multiple quarters because we are confident that it will have no effect on, much less enable, resource shuffling. DAC projects seeking to maximize net CO_2 capture and sequestration will necessarily enter power purchase agreements with low-CI electricity suppliers. CARB's requirement that these sources be new or expanded will result in additional low-CI sources being developed and brought on-line to primarily provide energy to DAC projects, with excess energy provided to the grid. Delivery to the local balancing authority will help ensure that additional low-CI electricity projects will not permit high-CI energy to be sent to other balancing authorities. The additional criteria that RECs and other environmental attributes associated with the electricity are not issued credits or claimed produced or are retired and not claimed (except as permitted by the proposed amendment language) will require DAC projects to establish robust tracking, accounting and verification processes that meet or exceed CARB requirements. If these criteria are met, we are aware of no analysis suggesting that permitting the use of low-CI to span multiple quarters will somehow lead to resource shuffling.

<u>There is no Correlation Between Calendar Quarters and Renewable Electricity Generation</u>

The use of at least an annual balancing period should also be permitted because there is simply no correlation between calendar quarters and renewable electricity generation. In addition, to seasonal and year-over-year variations, renewable electricity generation varies significantly within quarters. This is not surprising because the calendar quarters in the United States do not align with seasonal electricity generation. The seasonal and year-over-year variability of renewable electricity generation is effectively illustrated by the California Energy Commission's (CEC) Visualization of Seasonal Variation in California Wind Generation website.[12] Users

[10] California Air Resources Board, Staff Report: Initial Statement of Reasons. 34. Dec. 19, 2023.
[11] CARB, Review of Potential for Resource Shuffling in the Electricity Sector.
[12] https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/visualization-seasonal-variation-0, last accessed February 17, 2024.

accessing the CEC's website can enter the month and year and generate a graphical representation of wind energy production The resultant graphs clearly show that wind energy generation varies significantly even within calendar quarters.

Global Deployment of Direct Air Capture is Critical for Achieving Cost Reductions and Climate Goals

California's leadership in addressing climate change is evident through its innovative approach to incentivizing DAC technology. By incorporating DAC into its LCFS regulation and allowing projects to be located anywhere in the world, California recognizes the shared nature of the atmosphere and the collective benefit of CO_2 emissions reduction and removal wherever it occurs on Earth. DAC technology has an important role in climate mitigation, but its widespread deployment is contingent upon achieving cost reductions through repeated deployment as rapidly as possible. California's precedent to allow for global deployment of DAC in its LCFS market helps facilitate accelerated deployment by enabling DAC projects to be located where they can be most effective and economical. Each DAC technology is most efficient in certain climatic conditions and requires access to low-CI power and secure geologic sequestration resources, which every jurisdiction cannot offer equally. DAC deployment at climate-relevant scale will therefore be greatly facilitated by market systems that enable deployment in the geographical regions they are best suited to.

As noted in its ISOR, CARB's LCFS program influences the development of similar programs in other jurisdictions, including Japan, the European Union, and Australia, with this list likely to grow in the future. Limiting DAC's geographic deployment to the United States, as proposed in § 95490(a)(2)(A), may encourage other jurisdictions to adopt similar deployment restrictions. Such restrictions will reduce the markets each DAC facility can access, making financing and deployment more difficult, and therefore hinder the ability to achieve rapid cost reductions to enable large-scale deployment. Global cooperation in emissions reductions and removals trading will be essential for optimizing the path to net-zero emissions. We encourage CARB to continue to allow for globally deployed DAC projects to generate LCFS credits.

Jointly Filed Application for CCS Credits

1Pointfive appreciates CARB's initiative to track the movement of CO_2 throughout the supply chain, from point of capture to secure storage. However, adding the entity responsible for transporting captured CO_2, as proposed by § 95490(c)(1), may obstruct development of CCS
249.8 projects because parties providing transport, are reluctant if not entirely opposed to taking on the responsibility of understanding subsurface geology and geophysics. Further, there is simply no reason for such parties to take on such tasks because carbon capture and sequestration projects may only generate LCFS credits once the CO_2 is stored in a CCS Project that has met the requirements of the CCS Protocol. In the unlikely event that captured CO_2 is lost by the party owning or operating the transportation infrastructure, those lost masses of CO_2 will never be included in a calculation of CO_2 for purposes of generating credits because the CO_2 never reaches the sequestration site. Accordingly, the responsibility for understanding subsurface geology and geophysics and the other requirements of the U.S. Environmental Protection Agency's Underground Injection Control Class VI regulation and the CCS Protocol are best imposed on the sequestration site owner/operator (even if there is a contractual allocation of risk, this is a matter between the parties in privity with the sequestration site operator).

However, we do recognize that where parties agree to submit a fuel pathway that maximizes LCFS credit generation through the use of a CARB approved sequestration project, it is appropriate that the fuel pathway be a joint application to ensure that the fuel pathway, which will receive the generated LCFS credits, can be held responsible for any credit invalidation.

Crediting Period for Carbon Capture and Sequestration Projects

California's Scoping Plan underscores the importance of point source carbon capture technologies, particularly in industries such as petroleum refining, cement production, and electricity generation from gas plants, to achieve its long-term climate target. 1PointFive
249.9 supports CARB's proposed amendment to allow the crediting period for CCS projects in the Refinery Investment Credit Program to extend beyond 2040 as proposed in § 95489(e)(5)(B). This proposal acknowledges the critical role of CCS in helping California achieve its ambitious climate goals and will enable ongoing investment and innovation in CCS technology, ensuring its long-term viability as a climate mitigation solution.

Conclusion

In closing, we fully support CARB's proposal to allow indirect accounting for low-CI electricity used by DAC projects. However, we believe there are significant challenges to requiring that low-CI electricity use by DAC span a single calendar quarter, including.

- Technological: As discussed, *supra*, pairing seasonal and intermittent low-carbon electricity generation (e.g., renewables) with long term energy storage technology is simply not achievable today at the scale needed to support DAC projects currently being deployed. Existing battery energy storage systems that have been deployed in the US generally have less than a 4 hours duration, and only represent a small portion of the available capacity of the grids where they are installed, making it infeasible to firm-up intermittent resources for sustainable periods. Furthermore, in order to maximize the amount of carbon sequestered, DAC technologies should not be cycled in response to the seasonality of renewable resources, and instead should operate at maximum capacity year-round. Annual matching, in conjunction with the additionality requirements, accomplishes CARB's goal of ensuring that enough new low-CI generation is installed in the grid where the project will operate, while allowing DACs to operate at full capacity year-round without the burden of having to over-build or over-procure.

- Logistics: The tracking, trading, and usage systems supporting energy attributes (e.g., RECs) currently only allow for annual time resolution; systems capable of handling shorter time resolution are projected to take years to put into place (with a few very limited exceptions like PJM and M-RETS). Moreover, the mere availability of tracking systems to handle shorter time resolution is not sufficient; robust liquid markets for shorter time resolution energy attributes will be needed to achieve acceptable supply and pricing risk for project finance. These markets will take years to develop. In the interim, there is no ability for a project to be able to cover this risk other than significantly over contracting/installing low-carbon intensity generation, putting undue financial stress on projects.

- Economics: The additional economic burden required to comply with the first two challenges is significant and risks stifling this nascent industry. We are concerned about the increased low-carbon power supplies required to cover for intermittent generation under a balancing period of one quarter. For example, we have estimated that on a quarterly reconciliation basis an additional 25% more power could be required to be over-contracted and not consumed by the DAC project, at substantial market price risk, compared with annual matching even in the most favorable locations for renewable resources.

Given the current technological, market systems, and economic landscape for continuous low-CI electricity supply, annual book-and-claim matching period is necessary and appropriate for DAC technology today. Annual matching, in conjunction with the additionality requirements, accomplishes CARB's goal of ensuring that enough new low-CI generation is installed in the grid where the project will operate to prevent resource shuffling, while allowing DAC projects to operate at full capacity year-round without the additional cost and risks associated with quarterly matching. Requiring additional low-CI energy production in the local balancing authority is the key to avoiding resource shuffling and not balancing periods shorter than 12 months.

We would like to express our sincere appreciation for the opportunity to offer our insights on CARB's proposed LCFS amendments. We value the dialogue surrounding these significant matters and look forward to further discussions. Should any inquiries arise, we are prepared to provide thorough responses. We look forward to continuing our collaboration and working together to deploy CCS and DAC technologies.

Sincerely,

Michael Avery

Michael Avery
President and General Manager
1PointFive

Comment Log Display

Here is the comment you selected to display.

Comment 259 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jordan
Last Name	Kearns
Email Address	jordan.kearns@antora.energy
Affiliation	Antora Energy
Subject	Antora Energy Comments Re: Proposed Amendments to the Low Carbon Fuel Standard Regulation
Comment	See attached file.
Attachment	www.arb.ca.gov/lists/com-attach/6929-lcfs2024-UTABaVwpUW0Hc1Ax.pdf
Original File Name	Antora Energy Comments Re_ Proposed Amendments to the Low Carbon Fuel Standard Regulation.pdf
Date and Time Comment Was Submitted	2024-02-20 15:04:16

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

ANTORA

1244 Reamwood Ave
Sunnyvale, CA 94089
www.antoraenergy.com

February 20, 2024

Air Resources Board
1001 I Street
Sacramento, CA 95812

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments

We appreciate the opportunity to comment on the Proposed Amendments to the Low Carbon Fuel Standard Regulation.

Based in Sunnyvale, CA, Antora is a thermal energy storage company that converts low-cost, intermittent renewable electricity into reliable, on-demand, zero-emissions industrial heat and power. Specifically, we are working to decarbonize industrial process heating for facilities that produce fuels for sale in California.

250.1 Antora strongly supports the use of clean energy in renewable fuel production, as detailed in the accounting framework for *Renewable or Low-CI Process Energy* in Section 95488.8(h) of the existing and proposed regulations. Section 95488.8(h) is designed to ensure the integrity of renewable and low-CI process energy used in fuel production, including by ensuring that renewable energy certificates (RECs) and other environmental attributes are not double-counted, as detailed in Section 95488.8(h)(1)(A).

Such a safeguard against double-counting of RECs and similar attributes is important to the integrity of the LCFS's decarbonization impact, as it ensures that any unit of renewable energy that is used to produce low-CI fuel sold in the LCFS market is not also claimed in another marketplace or program. However, the proposed amendments include a wording change (highlighted below) that could inadvertently provide *less* clarity to developers and potentially disqualify renewable energy inputs that align with the intent of the regulations:

> Any renewable energy certificates or other environmental attributes associated with the energy are not ~~produced,~~issued credits or ~~are retired and not~~ claimed under any other voluntary or mandatory program with the exception of the federal RFS [95488.8(h)(1)(A)]

250.1 This language inserts additional ambiguity for project developers due to the nuances of REC issuance, making it unclear whether certain issuance structures qualify. Under the proposed language of the provision, it remains unclear whether "are not issued credits or claimed" is equivalent to (i) "are neither issued credits nor claimed" or (ii) "either are not issued credits or are not claimed." That is, it is unclear whether both criteria must be met or either criteria alone is sufficient. In the former interpretation, a credit issued but not claimed (as described below)

ANTORA

1244 Reamwood Ave
Sunnyvale, CA 94089
www.antoraenergy.com

would be ineligible, despite no double-counting occuring—slowing the deployment of renewable fuel production and invalidating currently-eligible projects.

Under the structures of certain renewable energy and renewable fuel projects, a credit may be *issued* but not *claimed*, *used*, or *sold* except by the load associated with the renewable generation and claimed for the sole purpose of reducing emissions under the LCFS program. The issuance and separate use of the credit is useful in scenarios where separate, affiliated entities may be generating and consuming the electricity and the issue and sale of the REC is useful for accounting purposes between affiliates. In this scenario, the credit is not used to account for emissions reductions under other programs and thus would not represent double-counting when claimed under the LCFS. This scenario is likely to arise for renewable energy assets that provide some energy to low-CI fuel producers and some energy to the grid.

250.1 It is therefore critical that Section 95488.8(h)(1)(A) accounts for electricity where a credit is issued but not claimed under any other program. Reverting the language or making an amendment such as the following (bold and underlined) would maintain the integrity of the regulation without inadvertently restricting renewable energy production used and claimed solely for low-CI fuel production:

> Any renewable energy certificates or other environmental attributes associated with the energy **<u>either</u>** are not issued credits or **<u>are not</u>** claimed under any other voluntary or mandatory program with the exception of the federal RFS.

Thank you for the opportunity to comment. We look forward to working with CARB to further decarbonize the production of low-carbon fuels.

Sincerely,

Jordan Kearns

Jordan Kearns
VP of Project Development
Antora Energy

Comment Log Display

Here is the comment you selected to display.

Comment 260 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Zach
Last Name	Franklin
Email Address	zfranklin@gridalternatives.org
Affiliation	
Subject	Joint Comments on Proposed Amendments to the LCFS Expenditure Regulations
Comment	Attached please find joint comments on the proposed amendments to the LCFS expenditure regulations from Coalition for Clean Air, The Greenlining Institute, GRID Alternatives, GreenLatinos, Center for Biological Diversity, Central California Asthma Collaborative, ClimatePlan, Regional Asthma Management & Prevention (RAMP), SanDiego350, and Move LA.
Attachment	www.arb.ca.gov/lists/com-attach/6930-lcfs2024-BW8BaARsVWgBcwZZ.pdf
Original File Name	Joint Comments to CARB on LCFS Revised Expenditure Regulations 2.20.24.pdf
Date and Time Comment Was Submitted	2024-02-20 15:07:44

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, California 95814
Via electronic submittal

Re: Proposed Amendments to the Low Carbon Fuel Standard Expenditure Regulations

Dear Chair Randolph and Board Members:

As mission-aligned organizations focusing on economic and environmental justice in the clean energy transition, we appreciate the opportunity to provide comments on the proposed Low Carbon Fuel Standard amendments. Specifically, we would like to provide comments on the proposed changes to the expenditure regulations, related to the "allocation and uses of LCFS credits representing
251.1 non-metered residential EV charging". We applaud CARB's significantly increased focus on equity investments in the proposed revisions, and also want to share a specific concern and specific recommendations for some of the details, to ensure these changes have the desired impacts to meet our collective transportation electrification goals.

251.2 First and foremost, we want to express our strong support for the major LCFS expenditure changes being proposed by CARB, specifically:

251.2
- **Changing the scope of the statewide Clean Fuel Reward from a light-duty rebate to a medium and heavy-duty rebate.** A recent study in Nature Sustainability has quantified what our communities have known for decades - that pollution and health impacts from medium and heavy duty transportation are primarily and disproportionately borne by low-income communities and communities of color.[1] Catalyzing medium and heavy-duty electrification will begin to reduce
251.2 contd these harms, in addition to helping California meet its climate goals. The transition to zero-emission medium and heavy-duty transportation is essential to meeting air quality and climate standards; this transition is well behind the pace of the light-duty sector, so the proposed re-prioritizing of the CFR is appropriate.

251.3
- **Altering the minimum base credit contribution required to fund the Clean Fuel Reward from 60% of total base credits to 40% with a corresponding increase in holdback credits, and expanding the proportion of holdback credit proceeds required to be invested in disadvantaged, low-income, rural, and tribal communities.** Together these provisions

[1] https://www.nature.com/articles/s41893-023-01219-0 "*Air quality, health and equity implications of electrifying heavy-duty vehicles*"

251.3contd represent a significant increase in the overall percentage of LCFS credit proceeds invested towards transportation equity investments for low-income households. This smart strategy will both help CARB meet its equity goals and its transportation electrification goals, by focusing investments on the light duty market segments that are least able to transition to EVs without additional assistance. Both the light-duty equity and medium-heavy-duty investments take on even more importance due to the Governor's proposed cuts in budgetary support for ZEV incentives.

251.4

- **Adding workforce development programming to the pre-approved projects eligible for funding of holdback equity credits.** We specifically want to express our support for the addition of "re-skilling and workforce development for transportation electrification and electric vehicle infrastructure applications" as a pre-approved project category. However we are also concerned about a proposed elimination of a critical pre-approved project category, as 251.5 discussed below.

251.6 Secondly, we recommend rescinding and/or modifying some smaller proposed changes that propose to remove equity-focused outreach activities from the program regulations. Specifically:

- **CARB should retain and enhance the existing category of "Multilingual marketing, education, and outreach" within the list of pre-approved projects eligible for funding of holdback equity programs.** The Initial Statement of Reasons (ISOR) does not provide an explanation for why CARB is proposing to remove this category, and the proposed removal goes
251.6contd counter to the ISOR's stated goal of "***enhancing*** the pre-approved projects eligible for funding of holdback equity credits" (emphasis added).[2] Equity-focused community groups and stakeholders participating in CARB's Low Carbon Transportation Investments public work groups and convenings consistently are asking for ***greater*** investment in this area, and specifically investments that directly fund local community-based organizations who are trusted in priority communities and are best able to support Californians who have the most barriers to transitioning to EVs. We recommend that this category be retained in the revised regulations, and amended to explicitly pre-approve investments in outreach through funding provided to community-based organizations. ISOR doesn't explain why this is proposed to be removed, but if the concern relates to having electric utilities use holdback credit proceeds to fund their own internal work in this area, the language could be made specific to funding outreach via community based organizations that are based in and serve disadvantaged, low-income, rural, and tribal communities.

251.7

- **CARB should enhance the regulation's existing language regarding aligning holdback credit equity investments with the recommendations of CARB's SB 350 Low-Income Barriers Study.** CARB has been a leader in terms of operationalizing the recommendations of its SB 350 Low-Income Barriers Study[3], which represents the collective input and needs of a broad cross-section of equity stakeholders from EJ communities across the state around the barriers they see to adopting EVs and related technologies. These stakeholders invested

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[2] ISOR, p. 36.
[3] https://ww2.arb.ca.gov/resources/documents/carb-barriers-report-final-guidance-document "*CARB Barriers Report: Final Guidance Document - Low-Income Barriers Study, Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents*"

substantial time, resources and wisdom to help CARB understand how to best ensure that all of
our communities can access the benefits of EVs. We recommend that this language[4] be
amended to ***explicitly*** state that EDUs must align their portfolios of holdback credit equity
251.7contd projects with the findings and six priority recommendations[5] of CARB's SB 350 Low-Income
Barriers Study. CARB's proposed addition of workforce development as a pre-approved project 251.8
category aligns well with recommendation #5, and retaining and enhancing the pre-approved
251.9 outreach project category as recommended above aligns well with recommendations #2 and #3.

These smaller proposed changes, which mostly consist of retaining and refining existing regulatory
language, will provide critical support to ensure that CARB's proposed broader shift towards equity
investments is successful. As upper and middle income households increasingly have robust access to
affordable EVs in a maturing market, we are now faced with the much greater challenge of supporting
this transition for Californians with the lowest incomes and the most barriers to EV adoption. While
CARB's proposed increased financial investment in equity programs here will help, these barriers are
not just simply economic - they include cultural barriers, linguistic barriers, trust barriers, barriers related
251.10 to peer validation, and more. By authorizing investments in multilingual outreach programs through
trusted community-based organizations, and by ensuring that these broader investments are aligned
with the findings and recommendations of CARB's SB 350 Low-Income Barriers Study, CARB can help
ensure that we bring to bear the capacity and wisdom of our communities to ensure that every
Californian has the support they need to transition to zero-emission mobility.

Thank you for your consideration.

Sincerely,

Bill Magavern
Coalition for Clean Air

Román Partida-Lopez
The Greenlining Institute

Zach Franklin
GRID Alternatives

Andrea Marpillero-Colomina, PhD.
GreenLatinos

Scott Hochberg
Center for Biological Diversity

Kevin D Hamilton
Central California Asthma Collaborative

Nailah Pope Harden
ClimatePlan

Joel Ervice
Regional Asthma Management & Prevention (RAMP)

Rita Clement
SanDiego350

Eli Lipmen
Move LA

[4] Proposed Regulation Order Appendix A-1, previously on p. 44 and now moved to p. 233.
[5] https://ww2.arb.ca.gov/sites/default/files/2018-08/sb350_final_guidance_document_022118.pdf, the six priority recommendations are on p. 15-17.

Comment Log Display

Here is the comment you selected to display.

Comment 261 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Martin
Last Name	Ryan
Email Address	laurenl@berQrng.com
Affiliation	BerQ RNG
Subject	LCFS updates ISOR response letter
Comment	Please see the attached comment letter.
Attachment	www.arb.ca.gov/lists/com-attach/6931-lcfs2024-B2RROFA8Az0FZlA+.pdf
Original File Name	Comment Letter -LCFS Initial Statement of Reasons (BerQ RNG 2.20.24).pdf
Date and Time Comment Was Submitted	2024-02-20 15:13:22

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

BerQ RNG
2400 Ansys Drive, Suite 102
Canonsburg, PA, 15317 USA
+1 (412) 656 8863

VIA ELECTRONIC FILING

February 20, 2024

Matthew Botill
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: BerQ RNG's Comments on Low Carbon Fuel Standard Initial Statement of Reasons

Dear Mr. Botill:

BERQ RNG ("BERQ") is a renewable natural gas company who develops, own and operates a portfolio of fourteen (14) projects in the US processing and upgrading biogas from dairy manure digesters, swine manure digesters and landfill gas into pipeline quality renewable natural gas ("RNG") representing an investment in this industry in excess of $450 million. BERQ currently has three (3) dairy digester projects participating in the CA LCFS by producing RNG dispensed as CNG in the California transportation market and has an additional eleven (11) projects in construction or late stage development undertaken in reliance on participation in the LCFS program.

BERQ appreciates the opportunity to submit comments to CARB on the proposed scoping plan Initial Statement of Reasons. ***We strongly support the proposed amendment allowing projects***
252.1 ***that break ground by December 31, 2029 to preserve the current approach of book and claim and the full three, 10 year avoided methane crediting periods to continue to incentivize the growth of the biogas to RNG industry as an integral component of achieving CARB's goals.***

We agree with CARB's goal of reducing methane emissions but believe the proposed rule lacks ambition to support this goal in the near term and thus ***we urge CARB to set more ambitious***
252.2 ***CI reduction targets of at least 25% in 2025 and at least 35% in 2030.*** Adopting these targets would greatly assist in reestablishing adequate demand for credits by depleting the credit bank and creating a more competitive market for the sale of credits.

CARB has proposed that all digester projects would be required to model one (1) lagoon cleanout a year in September even if this does not match the actual practice of the farm. Implementing this assumption would result in the Carbon Intensity scores of most biogas
252.3 digester projects becoming more positive by a range of 40-70 CI points causing a significant adverse impact on the economics of such biogas digester to RNG projects and may either cause planned projects to be cancelled or cause current or soon to be commercial biogas digester RNG projects to divert supply to alternative markets. While we understand CARB is proposing this change primarily to improve administrative simplicity of evaluating baseline conditions, we strongly urge CARB to reevaluate this position as modeling lagoon cleanouts

BerQ RNG
2400 Ansys Drive, Suite 102
Canonsburg, PA, 15317 USA
+1 (412) 656 8863

252.3 cont where they do not occur will lead to a gross underestimation of avoided methane emissions and cause investments in manure RNG projects to be greatly reduced.

Thank you in advance for your consideration.

Kind regards,

Martin L. Ryan

Marty Ryan
President
BERQ US Investment LLC

Comment Log Display

Here is the comment you selected to display.

Comment 262 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Chris
Last Name	Vervaet
Email Address	chris.vervaet@copacanada.com
Affiliation	chris.vervaet@copacanada.com
Subject	Canadian canola industry submission
Comment	Comments enclosed
Attachment	www.arb.ca.gov/lists/com-attach/6932-lcfs2024-UTJRPwNwWGIAdQVa.pdf
Original File Name	Chris Vervaet - LCFS Comment - CANADIAN OILSEED PROCESSORS ASSOCIATION (COPA).pdf
Date and Time Comment Was Submitted	2024-02-20 15:15:01

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Attention:
Matthew Botill
Division Chief, Industrial Strategies Division
California Air Resources Board
1001 I Street
Sacramento, California 95814

Submitted electronically.

RE: Proposed Low Carbon Fuel Standard Amendments

Dear Mr. Botill,

On behalf of the Canola Council of Canada (CCC) and Canadian Oilseed Processors Association (COPA) we welcome the opportunity to provide feedback on the *Proposed Low Carbon Fuel Standard Amendments (the proposed Amendments)*.

The CCC and COPA are non-profit industry associations that work collaboratively to help address issues impacting the value chain and oilseed processing sector in Canada.

California is among Canada's largest and most important customers for canola, with exports of oil and meal valued at $900 million in 2022. Canola oil has long been regarded as one of the healthiest cooking oils available and is also increasingly recognized as a low-carbon feedstock for renewable fuel production. Canola meal is also contributing to GHG emission reductions through its inclusion in dairy feed rations. Recent research shows that feeding dairy cows canola meal reduces enteric methane emissions while at the same time improving milk productivity[1].

Our industry is growing[2] and is committed to helping contribute to California's climate change objectives through increased utilization of low carbon fuels from sustainably produced canola. Since early 2021, more than $3 billion of processing capacity has been announced in Canada, equating to nearly 1 billion gallons of additional canola oil supplies for food and fuel markets. Owing to canola's natural ability to sequester carbon from the air and store this carbon in the soil via sustainable production practices such as reduced tillage, renewable fuels derived from canola are also recognized for significantly reducing GHG lifecycle emissions when compared to fossil diesel.

Given the growth of our sector and the proven GHG emission benefits of using canola as a low carbon and sustainable feedstock in renewable fuel production, changes to California's Low Carbon Fuel Standard (LCFS) are an important priority. We are pleased to provide the following feedback on *the proposed Amendments.*

---

[1] https://www.canolacouncil.org/news/new-research-demonstrates-increased-milk-production-and-reduced-greenhouse-gas-emissions-when-dairy-cows-are-fed-canola-meal/
[2] https://www.canolacouncil.org/about-canola/processing-industry/

1. **Treatment of Crop-Based Biofuels**

253.1 The canola industry in Canada appreciates CARB's analysis and recognition that its previous consideration of a cap or limitation on crop-based oil feedstocks is unwarranted and would increase fossil diesel use resulting in higher costs for consumers and greater GHG, PM2.5 and NOx emissions.

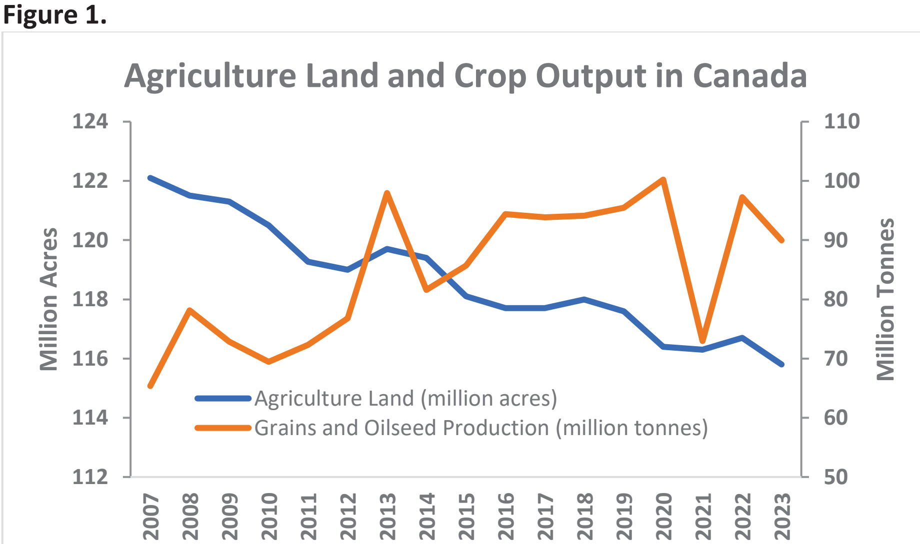
253.2 The proposed amendments that would subject crop-based feedstocks to sustainability certification and require tracking to their point of origin was not previously consulted by CARB. While we respect the importance of sustainability criteria in the development of low carbon fuel markets, it is important to work closely with stakeholders to understand its impact and develop practical solutions that limit unnecessary burden. Accordingly, we were encouraged to see a notice provided by CARB on February 14, 2024, informing stakeholders that staff plans to host a workshop in mid-April 2024 to discuss potential refinements to the proposed regulatory amendments, including the sustainability requirements.

253.3 To help inform this upcoming workshop and potential refinements to the sustainability requirements, our industry recommends CARB consider an option whereby feedstock can comply to sustainability requirements on aggregate in lieu of third-party certification. For example, provisions in the U.S. Renewable Fuel Standard (RFS) or Canadian Clean Fuel Regulation (CFR) provide options for jurisdictions to demonstrate that crop production does not contribute to negative land use changes or compromise biodiversity.

Due to advanced agricultural production practices, rigorous regulatory environments, and robust data sets validated by government, Canadian and U.S. crop-based feedstock already comply on aggregate with sustainability requirements in both the RFS and CFR respectively. A key metric to demonstrate compliance on aggregate is providing data/evidence that agricultural land is not expanding.

The Canadian government has been tracking agricultural land area for many years and official data shows land used for agricultural purposes has been in consistent decline (refer to Figure 1). While agricultural land area is shrinking, crop output continues to grow. This clearly indicates that crops grown and harvested in Canada do not contribute to deforestation or any associated adverse land use impacts. Furthermore, it is a testament to the innovation of crop production in Canada, with farmers deploying enhanced plant genetics and applying sustainable growing practices to grow more on less land.

Figure 1.



Source: Statistics Canada

253.3 contd An ‘aggregate’ approach to demonstrate compliance with sustainability requirements carries clear advantages for both CARB and market participants including:

1. It opens the door to a wider compliance option for CARB and allows for recognition of similar efforts taken in partner jurisdictions (i.e. U.S. and Canadian governments).

2. It encourages jurisdictions (not just individual entities) to demonstrate that their supply chains can and do meet sustainability criteria on key issues such as land clearance and deforestation.

3. Where sustainability equivalency can be demonstrated on aggregate across a jurisdiction, it will reduce the administrative burden and costs of feedstock supplies from those jurisdictions that are already fully meeting sustainability requirements under the rule.

Given the above advantages, we recommend the following regulatory text be added to section *(g) Sustainability Requirements for Crop-Based and Forestry-Based Feedstocks* in the *proposed Amendments*. This is not meant to prescriptive but instead offer a potential solution for CARB’s consideration.

> *“In lieu of subsection (g)(1), the Executive Officer may recognize legislation or regulation which has been enacted by a government authority in another jurisdiction where the effects of such legislation or regulation in that jurisdiction are assessed and deemed to be equivalent to the sustainability requirements under this rule”.*

253.4 We’d also like to take this opportunity to remind CARB that it has already accounted for land use impacts in the development of the LCFS through the incorporation of indirect land use change penalties (iLUC) – values which continue to be significantly overestimated. Accounting for iLUC and requiring sustainability guardrails to address concerns around land use impacts is unnecessarily duplicative in our view.

253.5 2. **Carbon Intensity Targets**

We continue to support the trajectory of increasingly stringent carbon intensity targets. Moving to a 30 % CI reduction from the baseline by 2030 is both appropriate and achievable. Increasing the stringency beyond 30 % is equally achievable, but to support these more aggressive targets, CARB should consider
253.6 the role of low carbon farming practices in the calculation of CIs for crop-based fuels. Incorporating carbon savings farm practices such as zero/min till or application of enhanced efficiency fertilizers are proven to significantly reduce emissions and contribute to lowering the CI of fuels in the marketplace.

253.7 We also applaud CARB for including a CI target for jet fuel in the amendments. Sustainable Aviation Fuel (SAF) is a growing opportunity to support the decarbonisation of air travel. Mandating a CI reduction for intrastate jet fuel is an important first step to encourage more production and consumption of SAF.

On behalf of the CCC and COPA, we appreciate this opportunity to comment, and look forward to an ongoing dialogue with CARB and other relevant stakeholders to enact changes to the LCFS that will address climate change while creating economic opportunities for those in the low carbon fuel value chain.

Sincerely,

Chris Davison
President and CEO
CCC

Chris Vervaet
Executive Director
COPA

Comment Log Display

Here is the comment you selected to display.

Comment 263 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Hossein
Last Name	Tabatabaie
Email Address	htabatabaie@iwatani.com
Affiliation	Iwatani Corporation of America
Subject	Iwatani Comments on the LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6933-lcfs2024-BWxVJARkV3AHYFA+.pdf
Original File Name	Iwatani Corporation of America_final version.pdf
Date and Time Comment Was Submitted	2024-02-20 15:28:45

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Iwatani
Iwatani Corporation of America

February 20, 2024

Ms. Liane M. Randolph
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: California Air Resources Board's Potential Changes to the Low Carbon Fuel Standard

Dear Chair Randolph,

Iwatani Corporation of America (ICA) would like to thank the California Air Resources Board (CARB) for the opportunity to comment on the potential changes to the Low Carbon Fuel Standard (LCFS) program. ICA owns and operates several hydrogen refueling stations across California and is rapidly expanding to serve the fast-growing hydrogen market in California and the U.S. ICA expects to have more than 15 light-duty stations in operation at the end of 2026[1]. Although the plans are not public yet, we are working on some very large heavy-duty projects that are expected to be shared in the near future. Since 1941, Iwatani has regarded hydrogen as the ultimate clean energy source and have consistently engaged in initiatives to encourage its widespread use. ICA is committed to support the zero emissions vehicle (ZEV) market by expanding the fueling infrastructure and supplying hydrogen to both light-duty and heavy-duty vehicles. Under the corporate slogan "A world where all enjoy true comfort – this is Iwatani's desire," we strive to solve environmental concerns with the aim of achieving a carbon free society through the use of hydrogen.

254.1 We want to congratulate CARB for developing and implementing the LCFS program which has saved more than 140 MMT of greenhouse gas (GHG) emission and surpassed expectations for renewable fuel growth production and reducing the carbon intensity (CI) of the transportation sector. Secondly, we support CARB in proposing potential changes to the LCFS program as we believe that the proposed changes make the program more efficient,
254.2 resilient, and can potentially accelerate investment into many projects contributing further to the decarbonization of the transportation sector. Please find ICA's comments on certain proposed changes to the LCFS program.

[1] This letter contains forward-looking statements that reflect management's views and assumptions in the light of information currently available with respect to certain future events, including expected financial position, operating results and business strategies. These statements can be identified by the use of terms such as "will," "believes," "should," "projects," "plans," "expects," and similar terms and expressions that identify future events or expectations. Actual results may differ materially from those projected, and the events and results of such forward-looking assumptions cannot be assured. Any forward-looking statements speak only as of the date of this letter, and no duty is assumed to update such statements. Factors that may cause actual results to differ materially from those predicted by such forward-looking statements include, but are not limited to: unanticipated changes in demand for the company's principal products, owing to changes in the economic conditions in the company's principal markets; changes in exchange rates or the impact of increased competition; unanticipated costs or delays encountered in achieving the company's objectives with respect to globalized product sourcing and new information technology tools; uncertainties as to the results of the company's research and development efforts and its ability to access and protect certain intellectual property rights; the impact of regulatory changes and accounting principles and practices; and the introduction, success and timing of business initiatives and strategies.

Increasing the CI reduction target pre-2030

254.3 As discussed during the workshops, the LCFS program has been successful in reducing and replacing fossil fuels, accelerating investment in low-carbon fuel production, ZEV infrastructure buildout, and facilitating the transition to 100% ZEV sales by 2035. According to the LCFS quarterly reports[2] published by CARB, not only has the volume and diversity of low-carbon fuels increased significantly within the past few years, but the CI of fuels has decreased leading to more LCFS credit generation and GHG savings. Moreover, substituting fossil fuels (gasoline and diesel) with low-carbon fuels and growth in ZEV sales have reduced the consumption of fossil fuels in the transportation sector. While this clearly shows that the LCFS program is overperforming, the demand for LCFS credits should be strengthened to balance the market and achieve the decarbonization goals. Nowadays, the LCFS credit bank balance is at a historic high and subsequently, the LCFS credit price, which is the main driver of investments in the clean fuels industry, is very low. To strengthen the demand for LCFS credits and restore the credit prices, CARB staff proposed increasing the stringency of CI reduction targets through 2030, however, ICA believes that the proposed CI reduction target (i.e., 30%) will not be enough to restore and stabilize the LCFS credit price and urges CARB to consider a greater CI reduction target, at least 40%, and implements the CI step down (5%) and auto acceleration mechanism (AAM) sooner than the proposed dates to restore the LCFS credit price faster and jumpstart the investment in production of clean fuels.

Infrastructure Crediting

254.4 Since CARB has established the infrastructure crediting program including HRI (hydrogen refueling infrastructure), and FCI (fast charging infrastructure) for light-duty vehicles, the number of fueling stations has grown significantly which is necessary for expansion of ZEV market and achieving ZEV mandate goals. The infrastructure crediting program has proven to be an efficient way to encourage ZEV infrastructure and support the state goals. ICA believes that a similar infrastructure crediting program for medium- and heavy-duty vehicles will help achieving the MHD ZEV Mandate targets. MHD ZEV is a necessary strategy for decarbonization of transportation sector and a more efficient way of using fuels (EER of 1.9 for MDH fuel cell). Hence ICA strongly supports CARB's proposal to extend the infrastructure crediting program to medium- and heavy-duty-(MHD) vehicles. Below are our comments regarding the current proposal:

- 254.5 ICA highly recommends considering 15 years instead of 10 years as the crediting period and extending the deadline for HRI application submission from December 31, 2030, to December 31, 2035. MHD ZEV infrastructure requires more capital investment compared to Ligh-Duty (LD) ZEV infrastructure and to make the investment economically feasible, the crediting period of MHD HRI should be at least equal to LD HRI which is 15 years. Additionally, extending the deadline for MHD HRI application submission is more aligned with the state's MHD ZEV mandate goals and creates more opportunity for MHD ZEV infrastructure development throughout California State.
- 254.6 ICA also believes that the 80% renewable content requirement can be costly and creates a burden for hydrogen refueling infrastructure and urges CARB to focus on CI and preserve the 40% renewable content requirement for the entire HRI crediting period.

Sincerely,

Hossein Tabatabaie

Director of Product Management

[2] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

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Comment 264 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Greg
Last Name	Staiti
Email Address	greg.staiti@calumetspecialty.com
Affiliation	Montana Renewables, LLC
Subject	Public Comments of Montana Renewables, LLC on Proposed LCFS Amendments
Comment	Please see our attached comments on CARB's proposed amendments to the Low Carbon Fuel Standard program. Thank you for your consideration.
Attachment	www.arb.ca.gov/lists/com-attach/6934-lcfs2024-WjcHbgBvV3ADZFI8.pdf
Original File Name	Montana Renewables, LLC - Public Comments on Proposed LCFS Amendments (2.20.2024).pdf
Date and Time Comment Was Submitted	2024-02-20 15:28:25

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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MONTANA RENEWABLES™

Montana Renewables, LLC
1807 3rd St NW, Great Falls, MT 59404
https://montana-renewables.com/

February 20, 2024

Via electronic submission to: https://ww2.arb.ca.gov/lispub/comm/bclist.php

Dr. Steven Cliff
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed Low Carbon Fuel Standard Amendments

Dear Dr. Cliff,

Montana Renewables, LLC ("MRL" or "the Company") appreciates the opportunity to comment on proposed amendments to the California Low Carbon Fuel Standard ("LCFS"). Since beginning commercial production little more than a year ago, MRL has established itself as a significant contributor of renewable diesel to California markets. Moreover, with sustainable aviation fuel ("SAF") production capacity amongst the largest in the nation, MRL is positioned to be a leading producer of this emerging and critically important low carbon fuel.

MRL is one of the true success stories of the LCFS program. Our parent corporation, Calumet Specialty Products Partners, L.P., ("Calumet") has operated a conventional oil refinery in Great Falls, Montana, for over a decade and in that time has provided high quality fuels and other products within its predominantly Montana/Upper Rockies service area. Thanks in large part to the incentives offered and demand created by the LCFS program and others like it, Calumet embarked on a bold plan to convert part of the Great Falls refinery to produce fuels from 100% renewable biomass, announcing the formation of MRL in November 2021. The result is a 15,000 bpd capacity renewable plant producing fuels from a wide range feedstocks (including animal fats, distiller's corn oil and canola) whose products are now sold by our offtakers in California, Oregon, Washington and British Columbia. The Company is not content to have merely joined the growing contingent of refiners that have announced plans to convert assets to produce renewable fuels; we have put our plans into action in near-record development time and have innovated along the way, including:

- steam methane reformer upgrades completed in March 2023 that have allowed MRL to become fully self-sufficient in its hydrogen needs;
- the installation of SAF assets in April 2023, allowing co-production of SAF with renewable diesel;
- the addition of on-site feedstock pretreatment capabilities in May 2023 using first-of-its-kind technology that should reduce energy consumption compared to traditional pretreatment processes; and,
- the first receipt of camelina oil in September 2023, which has great future promise to produce low carbon fuels from a sustainable feedstock that does not compete with traditional food crops.

We appreciate the efforts of the California Air Resources Board ("CARB") staff in engaging in a thorough stakeholder outreach program last year and recognize the significant commitment of time and resources that have gone into preparing the proposed amendments. The thrust of our comments today focus on expanding opportunities for SAF, as well as several other targeted regulatory measures to enhance incentives, increase transparency, and lower compliance burdens.

<u>Expanding Opportunities for Sustainable Aviation Fuel</u>

CARB's amendments propose to eliminate a long-standing exemption for conventional jet fuel, beginning in 2028, used for intrastate flights (meaning flights taking off and landing in California). We recognize that jurisdictional constraints may limit CARB's authority to impose new obligations on conventional fuels used in other flights. However, even within these limits, we respectfully believe that CARB could go further and faster to improve the incentive structure for SAF.

255.1

To start, we believe it is unnecessary to delay obligations for three years after the expected effective date of the amendments (January 1, 2025). For comparison, the original LCFS regulations – imposing entirely new and unfamiliar requirements throughout the fuel supply chain and for renewable fuel producers outside of California – were originally adopted in 2010 and obligations became effective January 1st of the following year. Against this backdrop, a three-year lead-in for jet fuel only if used in intrastate flights, within the context of a well-established program, seems unnecessary. We request that CARB reconsider whether a two- or even a one-year delay in implementation would better serve the state of California's overarching objective of reducing the carbon emissions from the aviation sector while still providing sufficient time for new and existing regulated parties to adjust to their obligations.

255.2

Besides the timing for implementation, we believe there are more targeted measures that CARB could take to support the rapid development and deployment of SAF. The proposed changes would, at best, only create indirect demand for SAF. Regulated parties for non-exempt conventional jet fuel would be under no compulsion to actually buy or blend SAF; they could simply purchase LCFS credits generated for wholly unrelated fuels to satisfy their newly created annual deficit obligations. Spurring investment and making a market for an emergent fuel requires policies with concrete obligations. The European Union and British Columbia have both recognized this in their respective renewable and low carbon fuel programs, each recently adopting a form of direct blending mandate for SAF. Consequently, we have over the last few months begun seeing a tremendous push from our offtakers and other market participants to ensure that SAF will be eligible in each jurisdiction. If California is to compete on even terms with these programs over the long term, CARB must keep the LCFS incentives structure on par. Even if CARB is unable to directly adopt a blending mandate within its current legal framework, it could achieve similar results by requiring regulated parties for conventional jet fuel to satisfy a percentage of their annual deficits via LCFS credits generated for SAF.

255.3

Beyond new incentives for blending SAF into the California aviation pool, CARB should review and align aspects of the LCFS regulatory framework to better allow producers to optimize the production of SAF (and therefore help defray its higher production cost on average compared to renewable diesel). To this end, we believe that CARB's final rule should address the allocation of commingled feedstocks to multiple product outputs from a production facility. The existing LCFS regulations begin to tackle this issue in Sections 95488.4(d) (setting forth the general rules for commingled feedstock allocation) and 95491(d)(1)(C) (providing an allocation formula to be applied each calendar quarter). These rules are a reasonable accommodation to the reality that fuel producers rarely can segregate and batch-run individual feedstocks. The rules and CARB's related interpretive guidance (see LCFS Guidance 19-08) further allow producers to optimize the feedstock-to-fuel allocations for shipments to California, as long as a quarterly material balance is maintained. However, neither the existing rules nor guidance directly address situations like MRL's and many other renewable distillate producers, where more than one fuel product is produced in a quarter.

Two types of feedstock allocation methodologies addressing multiple product outputs have emerged under other programs. The “proportional allocation” methodology requires allocation of each feedstock used in the same proportions as products produced in a given quarter; Table 1 below provides an illustrative example for a generic producer of renewable diesel (RD), SAF and renewable naphtha (RN)[1]:

Table 1: Proportional Allocation Methodology Example

Feedstock Type	Feedstock Qty (gal)	RD Volume (80% Yield)	SAF Volume (15% Yield)	RN Volume (5% Yield)
Soy	35,000	28,000	5,250	1,750
Canola	40,000	32,000	6,000	2,000
Tallow	25,000	20,000	3,750	1,250

255.3 contd

In the above scenario, the producer would be limited to allocating only 3,750 gallons out of 25,000 gallons worth of tallow – the best performing feedstock from a carbon intensity perspective – to SAF production. Compare this outcome with a “free allocation” methodology, which still requires a producer to fully account for all feedstocks used in a quarter but gives the producer greater flexibility to assign those feedstocks to product output, as depicted in Table 2 below:

Table 2: Free Allocation Methodology Example

Feedstock Type	Feedstock Qty (gal)	RD Volume (80% Yield)	SAF Volume (15% Yield)	RN Volume (5% Yield)
Soy	35,000	35,000	0	
Canola	40,000	35,000	0	5,000
Tallow	25,000	10,000	**15,000**	0

The benefits to the producer under free allocation should be obvious. But so, too, should the benefits to California if the state truly wishes to incentivize more SAF production and consumption. By allowing the allocation of the lowest-carbon feedstocks to SAF, producers will be better able to cover the higher average cost of production and would be better incentivized to expand SAF production capacity. Neither allocation methodology would alter a producer’s overall feedstock mix nor impact calculation of CI in the GREET model; the methodologies are simply about how to assign feedstocks from the mix to different product outputs. Feedstock usage still would remain subject to annual verification to ensure quarterly material balances are maintained. And in many ways, adopting a free allocation methodology would harmonize California’s approach with other jurisdictions and programs (such as the ISCC CORSIA and PLUS protocols and the emerging Canadian Clean Fuels Regulation) that in meaningful ways are competitors for nascent SAF supply. We urge CARB to take the opportunity afforded by this amendment process to build on the existing LCFS regulatory framework and adopt the free allocation methodology described above for producers of multiple transportation fuels.

[1] For the sake of simplicity, the examples in Tables 1 and 2 above assume 100% conversion of feedstocks to the three listed products. In reality, a small percentage of feedstock yield loss and/or use in producing other co-products (such as renewable LPGs) would be expected and must be accounted for by producers.

Comments on Other Proposed Changes and LCFS Policy

We address below several other issues raised by or otherwise germane to CARB's proposed LCFS amendments.

Credit True Up After Annual Verification

255.4 MRL strongly supports the proposed amendment to 17 CCR 95488.10(b), which would authorize the Executive Officer to perform a credit true-up for a fuel pathway that has a lower verified operational CI, as evidenced in its annual fuel pathway report, than the CI for which the fuel pathway was previously approved. We believe this amendment properly rewards producers that invest in emission reduction improvements or are otherwise able to "overcomply" with their registered pathways. In addition, the proposed amendment should encourage producers to conservatively calculate and assign margins of safety to their CI scores during the pathway registration process, since the benefits of overcomplying would be returned to the producer in the credit true-up rather than being lost to the LCFS buffer account (as is the case in the current regulations). We request that CARB make the credit true up provisions effective immediately, meaning that the first opportunity for such true up would occur after the submission of Annual Fuel Pathway reports in March 2025 (for calendar year 2023/2024 data).

Deficit Calculation for Verified CI Exceedance

255.5 CARB has proposed amendments to 17 CCR 95486.1(g) that would subject non-provisional pathway holders to a calculated obligation of four times the number of deficits in the event of a verified CI exceedance. MRL agrees with the importance of maintaining compliance with fuel pathways; however, we believe that the proposed amendment as written could be unnecessarily punitive. There are reasonable, no-fault circumstances that may trigger a CI exceedance in a given fuel pathway reporting year (e.g., an unexpected asset or facility outage; feedstock supply disruptions leading to sourcing from more distant locations; undetected meter reading errors; etc.). We recognize that the proposed credit true-up language described above should incentivize conservative calculations and margins of safety, but the possibility of CI exceedance still exists even with these safeguards. If the "four times penalty" is included in the final amendments, we request that CARB adopt an additional condition that the penalty would not apply if, in the year following the exceedance, the fuel pathway holder is able to both fully comply with its registered CI *and* make up the difference in the exceedance based on the reported CI score in its annual fuel pathway report. This approach would be very similar to the "deficit carryover" concept that exists under the current U.S. Renewable Fuel Standard program, wherein an obligated party would not be penalized for falling short of its renewable volume obligations in year 1 as long as such shortfall and all other obligations are met in year 2. We believe this would be a reasonable compromise to help avoid triggering a punishment for what may be an atypical (and in many cases unpreventable) CI exceedance in a given year.

Sustainability Requirements for Crop-Based Feedstocks

255.6 CARB has proposed amendments at 17 CCR 95488.9(g) that would impose new sustainability obligations for crop-based feedstocks. MRL is supportive of sustainable production. We ask that CARB provide specific examples of existing third party certification systems, if any, that would satisfy the prescribed criteria proposed in Section 95488.9(g)(1)(B).

255.7 We also believe that CARB should engage in a collaborative process with all stakeholders in the development and approval of consensus-based sustainability certification systems, and should tie the effective date of these new requirements to the adoption of these consensus standards.

255.8 To facilitate a smooth transition to the new sustainability obligations, we urge CARB to consider nation-level exemptions or to at least temporarily delay the effective date of these requirements for crop-based feedstocks originating in the U.S. and Canada. Such nation-level exemptions are common concepts that have been embraced under the U.S. Renewable Fuel Standard and Canadian Clean Fuels Regulation. U.S. and Canadian crops do not raise the same degree of sustainability concerns that undoubtedly have motivated the proposed new requirements. For these reasons, we believe nation-level exemption or implementation delays for U.S. and Canadian crops would be a reasonable addition to the sustainability amendments if finalized.

Changes to Annual Standards, Near-Term Step Down, and Automatic Acceleration Mechanism

CARB has proposed a variety of changes aimed at increasing the stringency of the program and, correspondingly, the demand for LCFS credits. These changes are a reflection of the overwhelming success of the program in incentivizing low carbon fuel production and consumption in California to-date. We note, however, that the proposed 5% reduction in the CI benchmarks in 2025 (referred to as the "near-term step down") could have unintended consequences for existing renewable fuel producers. Each of the aforementioned measures attempt to head off a growing credit surplus that could stifle prices and deter

255.9 future investments. If credit prices do not rise at the speed or to the degree CARB forecasts in its rulemaking analysis, the near-term step down could end up doing more harm than good for existing producers; credit generation would be curtailed by the sharp decline in the 2025 benchmark without a corresponding rise in prices to help offset these losses. We ask CARB to carefully consider the credit availability and pricing analyses of other stakeholders in their comments in evaluating the necessity of the near-term step down versus a more gradual approach to achieving the proposed 30% CI reduction target by 2030. CARB should also consider whether de-coupling the proposed CI benchmarks for diesel substitutes and fossil jet fuel substitutes, allowing the latter to progress at a slower pace, would more

255.10 appropriately reflect the current state of the industry and afford greater credit generation potential (and incentivizes) for SAF produced from existing feedstocks and production technologies.

Streamlining Verification Requirements

MRL is currently or expects to soon be subject to annual verification or audit obligations under LCFS or LCFS-like programs in the states/provinces of California, Oregon, Washington, British Columbia, and

255.11 Alberta, as well as the U.S. Renewable Fuel Standard, the Canadian Clean Fuels Regulation and the ISCC. We recognize and support the need for independent review to facilitate regulatory oversight and market confidence in the validity of emission reductions represented by credits. We ask CARB simply to consider where there may be opportunities to reduce redundancies and streamline verification obligations for consistency with equivalent programs, and to remain open to alignment on these requirements in the future.

* * *

Thank you for considering these comments. We look forward to working collaboratively with CARB throughout this rulemaking process. Please do not hesitate to contact us with any questions.

Regards,

Greg Staiti

Greg Staiti
Compliance Director, MRL

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Comment 265 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Russell
Last Name	Dyk
Email Address	russ.dyk@btr.energy
Affiliation	Bridge To Renewables, Inc.

Subject	RE: Preliminary Staff Report Proposed Low Carbon Fuel Standard (“LCFS”) Amendments
Comment	On behalf of Bridge To Renewables and General Motors, we are pleased to provide comments on potential changes to California's Low Carbon Fuel Standard ("LCFS") program. We appreciate the opportunity to engage with Air Resources Board ("ARB") staff durir this process.
Attachment	www.arb.ca.gov/lists/com-attach/6935-lcfs2024-UTIBZlQnWGkGX1c0.pdf
Original File Name	CARB Comment Letter_02.20.2024_BTR_General Motors.pdf
Date and Time Comment Was Submitted	2024-02-20 15:34:00

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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February 20, 2024

VIA ELECTRONIC FILING

The Honorable Liane M. Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Preliminary Staff Report Proposed Low Carbon Fuel Standard ("LCFS") Amendments

Dear Chair Randolph and California Air Resources Board's Transportation Fuels Branch Staff,

On behalf of the undersigned companies, we are pleased to provide comments on potential changes to California's Low Carbon Fuel Standard ("LCFS") program. We appreciate the opportunity to engage with Air Resources Board ("ARB") staff during this process.

Under ARB's leadership, California's LCFS program has been an important driver of the State's greenhouse gas emissions ("GHG") emissions reductions. It has not only provided a model for similar programs in other states, but also proved just how successful such programs can be. As of the most recent data, from Q3 2023[1], California has reduced transportation emissions by over 15% below 2010 levels, an achievement consistent with the program's current 2026 target. That is extraordinary progress!

However, ARB's LCFS amendments proposed in the Initial Statement of Reasons (ISOR), released on December 19th, 2023[2], jeopardize the program's progress in the years to come.
256.1 ARB's proposed amendments to the program's carbon intensity ("CI") targets fail to bring the
program's ambitions in line with its performance, thus presenting broad challenges to every producer of low-carbon fuels and risking a sharp drop in clean fuels and technologies investment.

Additionally, the ISOR's sharp adjustment of the treatment of LCFS base credit generation for residential charging of light-duty electric vehicles ("LD EVs") is extremely problematic. Accelerating LD EV adoption is crucial for the state to achieve its GHG emissions reduction
256.2 goal; but at a time when LD EV adoption may be slowing, ARB has proposed to terminate the
California Clean Fuel Rewards ("CCFR") program for LD EVs. As is, the proposal would effectively eliminate LD EV automakers ("OEMs") from the program, because under the proposal there would be no economically viable way for OEMs to participate.

256.3 We believe the most effective changes ARB could make to its proposal are to adjust the
magnitude of the Step-Down to set the program's CI targets ahead of its performance in the
256.4 256.5 short-term; to adjust the timing of the Auto Acceleration Mechanism; and to revive and rework

[1] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries
[2] https://ww2.arb.ca.gov/rulemaking/2024/lcfs2024?utm_medium=email&utm_source=govdelivery

256.5 cont. the CCFR for LD EV purchases. If ARB does not revive the CCFR, it should at least allocate a significant portion of base credits for residential EV charging to OEMs, which play the lead role
256.6 in enabling and accelerating EV adoption and are best positioned to support ARB's objectives.

I. Carbon Intensity Targets

We commend ARB for proposing to implement a 5% carbon intensity ("CI") reduction target Step-Down, to 18.75% in 2025. ARB has also proposed to increase the 2030 CI reduction target to 30% from its current 20%.

As noted above, both ARB and the market are well aware of the program's current success: as of Q3 2023, the achieved CI reduction of transportation fuels in California was ~ 15.5% below 2010 levels, 4.25% more than the 2023 target of 11.25%.[3] At this rate it is quite likely that by the end of 2024 the achieved CI could be 18.75%.

Given that, finalizing both a near-term Step Down and a higher 2030 target are both sensible and defensible actions. However, the timing and magnitude of ARB's proposals in the ISOR are insufficiently ambitious.

256.7 Since the ISOR's release, LCFS prices have dropped over 20% to levels not seen since 2015.[4] The market is sending a clear signal to ARB that it believes performance is likely to continue outpacing targets - including the updated targets in the ISOR - and that the LCFS program could be a victim of its own success.

We believe the fundamental issue with the Step-Down as proposed is that it is too little to fulfill its fundamental purpose: to reset the ambitions of the program ahead of its performance.

This is particularly true since ARB has proposed adjusting the 2010 baseline CI for ultra-low sulfur diesel ("ULSD") upwards by 5.3%, from 100.45 gCO2/MJ to 105.76 gCO2/MJ. This adjustment effectively negates any impact of the Step-Down on ULSD, since the new "stepped-down" 2025 target of 85.93 gCO2/MJ is less than 1% below the current target[5]. The impact of this is to increase the supply of credits from renewable diesel, which already generates the most credits in the program.

Climate research suggests that it's imperative to reduce emissions sooner rather than later. ARB can build on the program's extraordinary progress by setting more ambitious targets between now and 2030, such as those proposed by the Low Carbon Fuels Coalition.

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[3] BTR estimate.
[4] OPIS Carbon Market Report, January 24, 2024
[5] Proposed Low Carbon Fuel Standard Amendments, Appendix A-1, Proposed Regulation Order, Table 2, Footnote (a), pg. 66.

Recommendations:

256.8
- Adjust the magnitude of the Step-Down from the proposed 5% below the current 2025 level to at least 10%.
    - This implies a new 2025 CI reduction target of at least 23.75% below the 2010 baseline.

256.9
- Set a 2030 CI reduction target greater than 30%.

II. Automatic Acceleration Mechanism

While an appropriate Step-Down and 2030 target are the most effective means to build on the program's success and provide an incentive for continued investment in response to the visible near-term oversupply of credits, the Automatic Acceleration Mechanism ("AAM") is an important tool to allow the program to adjust for unforeseen imbalances more flexibly in the future.

256.10 ARB proposes to delay the first trigger of the AAM until 2027, which would not impact CI reduction targets until 2028 - three years after ARB's proposed Step-Down in 2025.

We believe that timing is too late and encourage ARB to consider an earlier, modified trigger, in line with that proposed by the Low Carbon Fuels Coalition.

Recommendations:

256.11
- Allow the AAM to trigger in 2026, one year after the effective date of the Step-Down in 2025.

256.12
- Adjust the bank-to-deficit ratio to 2.5 from 3.0.

III. Residential LD EV Charging Credits

Background

Since ARB's last amendments in 2018, the LCFS program has provided crediting pathways for residential LD EV charging credits to both electric utilities and OEMs. The utilities are awarded "base" credits in a volume proportional to the reduction in emissions from an internal combustion engine vehicle fueled by gasoline relative to a "non-metered" LD EV charged with grid-average electricity. OEMs can generate "incremental" credits by purchasing low-CI electricity, typically through purchase of a Renewable Energy Certificate ("REC"), to pair with "metered" EV charging, evidenced using data from vehicle telematics.

There are five important factors to bear in mind about base and incremental credits under the current program:

1. Utilities receive base credits for no cost but must agree to spend the associated credit revenue for specific purposes, as directed by ARB.

2. OEMs may generate incremental credits but must agree to spend the associated credit revenue for specific purposes and must also bear the REC cost and any associated costs of collecting vehicle telematics data including, as ARB has proposed, third-party verification.
3. The current magnitude of the incremental credit relative to the base credit, in terms of transportation emissions reductions per MWh, is approximately 2.7 times lower.
4. The magnitude of the incremental credit value relative to the base credit value, in terms of dollars per MWh, is over 19 times lower, based on current 2024 LCFS and REC prices estimates, as shown in Table 1 below.
5. Beginning in 2023, CARB has relied on “metered” vehicle telematics data provided by the OEMs for incremental credit generation as the “best available data” to establish the volume of “non-metered” base credits awarded to utilities.

Table 1: Base and Incremental Credit Generation Revenue Comparison[6]

Utility Base Credit Value Calculation	***EV OEM Incremental Credit Value Calculation***
Base Credits/MWh EV Charging: 0.775	Incremental Credits/MWh EV Charging: 0.29
2024 LCFS Price: $64.18/MT	2024 LCFS Price: $64.18/MT
Gross Revenue/MWh: $49.74	Gross Revenue/MWh: $18.61
2024 REC Cost: N/A	2024 REC Cost: $16.00
Net Revenue/MWh: $49.74	Net Revenue/MWh: $2.61

While the existing crediting pathways provide most of the volume and value of the emissions reductions generated by LD EV adoption to the utilities, OEMs nevertheless have been incentivized to participate in and generally support the LCFS program for two primary reasons.

First, until recently, there had been a sufficient LCFS price incentive coupled with a sufficient amount of eligible low-CI electricity to generate positive economics for incremental credit generation.

Second, and most importantly, ARB required utilities to spend 60% of LCFS base credit revenue to fund on-the-hood incentives for LD EV purchases through the CCFR.

256.13 ARB’s proposals in the ISOR upset and diminish those incentives by transforming the CCFR from a light-duty to a medium- and heavy-duty (“MH EV”) incentive program and introducing third-party verification requirements and costs on the OEMs that cannot be covered by the now marginal value of incremental credits.

[6] ICE End of Day Market Report, LFS-California Low Carbon Fuel Standard Credit ($/MT) Future, 2/16/24; BTR estimates.

Transformation of the California Clean Fuel Rewards Program

ARB proposes to transform the CCFR program from a universal new LD EV rebate to a rebate focused available for new and used MH EVs that are exempted from the Advanced Clean Fleets regulation.

ARB's rationale for its proposal to redirect the program away from LD EVs and towards MH EVs is to "jumpstart the transition for a harder to transition segment of the truck sector that is not otherwise covered by other CARB regulations."[7]

However, we believe that removing incentives funded by base credits for LD EV adoption is both short-sighted and problematic for three reasons.

256.14 First, multiple studies show that purchase incentives remain critical to ensure the transition of EV ownership from only early adopters to a wider group of buyers. Incentives under the Inflation Reduction Act (IRA) are not available for many LD EV models, which makes programs like the CCFR that much more important to support continued adoption. Unlike other programs, the CCFR is not dependent on a California state budget allocation, and, before it was paused, it was one of the last remaining financial incentives in California for LD EVs.

Second, LD EV adoption is critical to the success of the LCFS program and to achieving California's GHG emissions reductions goals generally. We forecast that electricity credits will account for 50% of total credits by 2030 and 65% by 2035, with LD EVs accounting for between 75-80% of that volume if LD EV adoption continues to grow.[8]

Third, LD EV adoption continuing to grow and ultimately reaching California's ambitious targets is not a foregone conclusion. Recent market indicators paint a troubling picture of LD EV adoption. Inventories of LD EVs hit a record high in December 2023, reaching two times the level of the prior year.[9] Annual sales growth for LD EVs this year has been forecast to be only a quarter of 2023's level.[10] LD EVs remain more costly than comparable internal combustion engine (ICE) models, and a high interest rate environment increases the cost of financing the purchase.[11]

Despite the importance of LD EV adoption, ARB proposes to remove direct consumer adoption incentives at a moment when there is little to no value from residential incremental crediting, no alternate crediting pathway or base credit value available for OEMs, no value available from the federal Renewable Fuel Standard for electricity used as a transportation fuel, and an uneven availability of federal incentives for LD EV adoption.

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[7] Proposed Low Carbon Fuel Standard Amendments, Appendix E: Purpose and Rationale for the Proposed Amendments for the Low Carbon Fuel Standard Requirements, pg. 14.
[8] BTR estimates.
[9] Bloomberg Hyperdrive, "America's EV Rethink," January 4th, 2024.
[10] Ibid.
[11] Ibid.

Third-Party Verification Requirements

ARB also proposes to introduce third-party verification requirements on incremental credit generators. This is problematic for four reasons.

256.15

- In its Standardized Regulatory Impact Assessment (SRIA), ARB assumed a $6/MWh verification cost.[12] Even assuming a cost one-third that level, third-party verification costs significantly diminish the economic incentive for OEMs to generate incremental credits under the current LCFS and REC price environment, as shown in Table 1(a) below.
- These additional costs are imposed on OEMs for reporting the "best available" vehicle telematics data that establishes the volume of base credits awarded to the utilities.
- ARB's proposal specifically exempts the utilities from any third-party verification requirements for base credits.
- In its current form, third-party verification requires site visits which may conflict with requirements imposed on incremental credit generators by the 2018 California Consumer Privacy Act, particularly for residential EV charging, not to mention be unfeasible given the hundreds of thousands of vehicles reporting.

Table 1(a): Base and Incremental Credit Generation Revenue Comparison

Utility Base Credit Value Calculation	***EV OEM Incremental Credit Value Calculation***
Base Credits/MWh EV Charging: 0.775	Incremental Credits/MWh EV Charging: 0.29
2024 LCFS Price: $64.18/MT	2024 LCFS Price: $64.18/MT
Gross Revenue/MWh: $49.74	Gross Revenue/MWh: $18.61
2024 REC Cost: N/A	2024 REC Cost: $16.00
Net Revenue/MWh: $49.74	Net Revenue/MWh: $2.61
Third Party Verification Cost: N/A	Third Party Verification Cost: [$2.00]
Net Revenue/MWh: $49.21	Net Revenue/MWh: $0.61

ARB's own quarterly data shows that over the past four reporting quarters, residential incremental credit volume has dropped 75%, from 15% of overall residential credits to just under 4%.[13] Additional verification costs as proposed by ARB will significantly diminish the economic
256.16 viability of incremental credit generation and, in turn, the incentive for OEMs to provide vehicle telematics data.

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[12] Standardized Regulatory Impact Assessment, 9/8/2023, Appendix A: Methodology for Estimating Costs, pg. A-1

[13] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries; BTR estimates.

256.16 cont. This would have the perverse result of forcing ARB to once again estimate non-metered utility base credit volumes at the exact time that ARB is specifically phasing out estimation in other electricity crediting pathways.

Recommendations:

256.17 OEMs play a core role in enabling and accelerating the transition to LD EVs. OEMs enjoy comparatively strong relationships with consumers and act as primary distributors of information regarding the consumer and environmental benefits of LD EVs. OEMs also guide consumer preferences by providing compelling LD EV products (e.g., rate plans and managed charging programs) to help maximize the emissions reductions and grid incentives associated with LD EV adoption.

Without the CCFR or some other form of programmatic support for LD EVs, the two market participants <u>most directly responsible</u> for light-duty vehicle electrification and resulting emissions reductions – the OEMs who produce and sell the LD EVs and the drivers who purchase and use them – could be eliminated from the value chain of LCFS entirely, a departure from the first principles of the LCFS program.

256.18 As such, we believe ARB should revive and rework the LD EV CCFR. If ARB does not maintain the LD EV CCFR, it should establish a structure that provides OEMs a durable share of base credit generation for residential EV charging, creating a more inclusive program in which the roles of different stakeholders are more appropriately balanced and ensuring programmatic targets are met.

256.19

- ARB should maintain the existing LD EV rebate from the CCFR but make OEMs and a third-party administrator – rather than the utilities – responsible for administering it.
    - Over the past three years under its existing administration, the CCFR incentive was first halved and then indefinitely paused, creating confusion for customers.
    - OEMs have decades of experience administering vehicle rebates and are better positioned than utilities to administer an LD EV CCFR, since they are customer-facing at the important "point-of-decision" and could better communicate directly with customers.
    - To provide a stable and predictable incentive, ARB and OEMs should set the CCFR LD EV purchase reward annually based on estimated revenue from LCFS credit generation from residential LD EV charging.

256.20

- If ARB instead is determined to finalize its proposed MH EV-focused CCFR program, then ARB should award to the OEMs a portion of the base credits which are not dedicated to the new CCFR fund. OEMs could use the base credit revenue to fund specific projects that benefit EV customers, as directed by ARB, as well as administrative costs related to those projects and to the collection of LD EV vehicle telematics data and the costs of ARB's proposed third-party verification requirements.

256.20 cont. OEMs are by far best positioned to support certain projects already identified by ARB in the ISOR to be valid uses of base credit revenue. For example, ARB has identified various vehicle-grid integration projects such as encouraging the optimization of LD EV charging, providing incentives for managed charging and demand response, supporting the installation and deployment of bidirectional charging capabilities, and developing innovative approaches that benefit both drivers and the grid.[14] All of these projects require significant investment and could be better facilitated by OEMs. Awarding a portion of base credits to fund these investments would provide three key advantages for ARB and the LCFS program.

- First, it would accelerate the managed charging, vehicle-to-home (V2H), and vehicle-to-grid (V2G) technologies that OEMs are already developing.
- Second, it would underpin an incentive that OEMs could offer drivers at purchase, on an ongoing operational basis, or both.
- Third, if implemented in parallel to the changes in the Smart Charging Lookup Table Pathway detailed in Section IV below, it would reinforce the incentive for OEMs to encourage drivers to optimize their charging to hours with the lowest grid emissions and to provide information on utility rate pricing, etc. at the point of sale.

256.21
- If ARB does not award to OEMs a portion of the based credits, we would encourage ARB to consider revising § 95500(c)(1)(E)(1) to state, "EV Charging except as specified under 95491(d)(3)(A) *and 95491(d)(3)(B)*" (new text in italic). This would exempt both metered and non-metered residential charging from third-party verification.

IV. Adjustments to the Smart Charging Lookup Table Pathway

256.22 As noted above, because incremental credit generation requires the purchase of RECs to pair with the LD EV telematics data, the associated LCFS credit revenue must be sufficient to cover REC costs plus the cost of aggregating, filtering, and reporting the telematics data and any cost of capital associated with the REC costs.

One targeted yet limited change ARB can make that would provide a floor for incremental credit generation economics would be to remove the current requirement in the Smart Charging Lookup Table Pathway that reporting entities must demonstrate that "the FSE was enrolled in a Time-of-Use rate plan during the reporting period."[15] This would enable participation in the

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[14] Proposed Low Carbon Fuel Standard Amendments, Appendix A-1, Proposed Regulation Order, §95483(c)(1)(A)(5)(b)(ii)(I-IV), specifically "Support for vehicle-grid integration with projects such as: I. Encouraging the optimization of EV charging through education in the following areas: peak demand, rate pricing, grid emergencies, potential power shutoffs, infrastructure deferral, renewable integration, and/or other signals and grid needs to provide grid and customer benefits. II. Providing program incentives to encourage driver participation in monitored/managed charging, demand response, or vehicle-to-load / vehicle-to- grid applications. III. Supporting the deployment and installation of bidirectional charging equipment. IV. Other innovative approaches to promoting and managing EV charging and discharging that provide benefits to customers and the grid.

[15] Proposed Low Carbon Fuel Standard Amendments, Appendix A-1, Proposed Regulation Order, § 95483(c)(1)(B)(1)(b)

Smart Charging Lookup Table Pathway when other incremental credit pathways are not economically viable.

256.22 cont.

This change would require only two minor adjustments to existing regulatory language and would have little impact on any existing credit generation since few if any fuel reporting entities have ever utilized the Smart Charging Lookup Table Pathway for either metered residential or non-residential charging.

Recommendations:

We encourage ARB to revise § 95483 and § 95491 as follows:

- § 95483(c)(1)(B)(1)(b): Smart charging. ~~In the case of an entity claiming smart charging incremental credits, the credit generator must demonstrate the residence is enrolled in a Time-of-Use rate plan, if offered by the LSE serving the residence.~~
- § 95491(d)(3)(B)(3)(d): ~~Records must be provided to the Executive Officer, upon request, demonstrating the FSE was enrolled in a Time-of-Use rate plan during the reporting period, if offered by the LSE.~~
- We further recommend that CARB update the Application and Reporting Instructions for the Smart Charging Lookup Table Pathway to reflect these changes.

V. Adjustments to the Requirements for Low-CI Electricity

256.23

The supply of RECs eligible for demonstrating low-carbon intensity (low-CI) electricity generation for incremental book-and-claim crediting under the LCFS program is limited relative to other state clean fuel standard programs in the WECC due to ARB's deliverability restrictions on low-CI electricity.

This supply limitation jeopardizes the economic viability of incremental credit generation, particularly at a moment when LCFS prices are historically low and there is no alternate crediting pathway or base credit value available for OEMs.

Recommendations:

- Amend the deliverability requirement such that low-CI electricity from generating units registered in WREGIS and located in *any* state in the WECC may be used for incremental crediting, even if such low-CI electricity is not scheduled into a California balancing authority.
- Exercise ARB's authority as a "Program Administrator" under the WREGIS Operating Rules to introduce flexibility specifically for LCFS-eligible RECs into the generating unit registration requirements imposed by WREGIS.

256.24

V. Other Programmatic Changes and Clarifications

Geofencing Radius for Residential EV Charging

256.25 ARB should consider reducing the current "conservative" Geofencing Radius (GFR) of 220 meters to a smaller and more precise GFR, as described in LCFS Guidance 19-03, Appendix A "Rationale for Minimum and Maximum Geofencing Radius." The GFR is used to "disaggregate the quantity of electricity used for residential and non-residential EV charging" and should be as precise as possible.

We are concerned that as charging station network operators and utility companies install more charging stations, an increasing amount of residential EV charging will be erroneously categorized as non-residential and therefore ineligible to generate credits. This will be particularly acute in densely populated urban areas of a mixed-use commercial/residential nature.

We believe that geolocation data (latitude, longitude) provided by non-residential reporting entities, as well as the precision of on-vehicle telematic systems, supports a higher precision GFR. We note that the Washington State Department of Ecology proposed a "conservative estimate of 110 meters or less for the maximum GFR to geofence a residential charging location."[16]

Hierarchy of Incremental Credit Generation for Residential EV Charging and Non-Metered Incremental Credit Generation

256.26 OEMs are currently second in a "hierarchy" of stakeholders eligible to generate incremental LCFS credits for residential EV charging. This hierarchy provides little value to the efficacy of the LCFS and unnecessarily complicates the registration process. OEMs generate the vast majority of all incremental LCFS credits generated for residential LD EV charging; furthermore, the "best available data" from their metered vehicle telematics establishes the volume of non-metered residential base credits.

We recommend ARB consider either eliminating the hierarchy and establishing OEMs as the sole stakeholder eligible to generate incremental LCFS credits for residential LD EV charging or reorganizing the hierarchy such that OEMs are the first- priority credit generator.

256.27 ARB should also clarify in the regulation that OEMs may designate a third-party to act as a first-priority credit generator on their behalf.

256.28 Finally, ARB should also allow OEMs that report metered vehicle telematics data to generate incremental credits for non-metered residential charging. Using the same metered vehicle

[16] https://apps.ecology.wa.gov/publications/SummaryPages/2314029.html

256.28 cont. telematics data and vehicle registration data, ARB could establish the volume of non-metered residential charging for which OEMs may generate incremental credits by purchasing a REC.

VI. Conclusion

256.29 We encourage ARB to continue to pursue aggressive policies that support California's climate goals. As the transportation sector is the largest sector contributing to greenhouse gas emissions, reducing those emissions is critical to achieving carbon neutrality. The LCFS has been an important and effective tool, but it will only continue to perform if ARB makes changes like those described above.

We thank you again for the opportunity to provide these comments, and we look forward to continued engagement with ARB staff. If we can provide additional information or further support your efforts, please contact any of the undersigned.

Sincerely,

Michael Maten
Director, EV Policy and Regulatory Affairs
General Motors

John (Jack) Barrow
Chief Executive Officer
Bridge to Renewables

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Comment 266 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Neal
Last Name	Reardon
Email Address	nreardon@sonomacleanpower.org
Affiliation	

Subject Sonoma Clean Power Comments on Proposed LCFS Amendments

Comment

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Dear CARB,

Please find attached Sonoma Clean Power's comments on the proposed
Low Carbon Fuel Standards amendments.

Sincerely,
Neal Reardon
Director of Regulatory Affairs
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Attachment www.arb.ca.gov/lists/com-attach/6936-lcfs2024-BzUHNVxtUDEBNVBg.pdf

Original File Name 240220_SCP Comments on Proposed LCFS Amendments (00627562xBA8E1).pdf

Date and Time Comment Was Submitted	2024-02-20 15:38:03

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Sonoma Clean Power

February 20, 2024

Chair Lianne Randolph
Hon. Steven S. Cliff
Executive Officer
California Air Resources Board
1001 Street
Sacramento, CA 95812

Filed Electronically

RE: Sonoma Clean Power Authority Comments on Low Carbon Fuel Standard Proposed Amendments

Dear Chair Randolph and Executive Officer Cliff,

Sonoma Clean Power Authority ("SCP") offers the following comments on the Proposed Amendments to the Low Carbon Fuel Standard ("LCFS"). SCP's comments focus on Amendments that will affect electric vehicle charging. SCP is a community choice energy provider and is committed serving EV charging load with low-CI power. SCP's comments are summarized as follows:

1. SCP Supports the proposal to classify Multi-family Residences as non-
residential EV Charging for purposes of LCFS credit generation. This
257.1 proposal will provide much-needed revenue to facilitate EV charging in
this important customer segment and should be further expanded to
apply to all multi-family residences, not just those with shared parking.

2. CARB should amend the Regulation to provide that all 100% RPS or
zero-CI electricity tariffs are be able to generate LCFS credits without
257.2 proving that Renewable Energy Credits ("RECs") were not retired for
the RPS.

257.3 3. CARB should clarify that amendments to the REC language in Section
95488.8(i) would not preclude the use of RECs to generate LCFS
credits.

DISCUSSION

1. Community Choice Aggregators ("CCAs"), like SCP, Are Committed to Providing Carbon Free Energy to Supply EV Charging in Their Territories, Including Multi-Family Residences.

SCP is the community choice energy provider for Sonoma and Mendocino counties, apart from Ukiah and Healdsburg which have existing municipal utilities in their service territories. SCP's service territory includes a population of about a half-million, with our energy demand split roughly in half between residential and non-residential customers. In downtown Santa Rosa, SCP operates the only Advanced Energy Center[1] in the United States dedicated to helping customers transition to 100% renewable energy for their homes, businesses, and cars. SCP is also the only power provider in California offering 100% renewable energy generated within our service territory twenty-four hours per day, every day of the year.

In addition to developing renewable and low-GHG resources, SCP offers an evolving suite of programs to help educate customers and unlock the benefits of a clean energy economy. Some of these programs include:

- Free residential electric vehicle chargers: SCP provides customers with an up-front discount of 50% on the cost of a Level 2 EV charger and an additional $250 incentive if the customer activates and enrolls their charger in SCP's demand response program, GridSavvy Rewards.[2] Since 2016, this program has supported the installation of 4,908 additional Electric Vehicle Supply Equipment ("EVSEs") in our territory. In addition, through our participation in the California Electric Vehicle Infrastructure Project ("CALeVIP"),[3] we have built another 103 publicly-available, Level 2 chargers, and 10 DC fast chargers. In 2024, SCP will consider revisions to the program to reach more low-income customers and underserved communities.

- Non-profit electric vehicle incentives: SCP offers reimbursement to non-profits to help them transition from gas-powered vehicles to clean EVs. SCP offers a $15,000 incentive for EV passenger vehicles and a $22,500 incentive for vehicles with payloads over 1,500 pounds (e.g., vans and trucks). To date, this program has supported the purchase of 19 electric vehicles by local non-profit organizations.

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[1] Advanced Energy Center: https://scpadvancedenergycenter.org/.

[2] GridSavvy Rewards program: https://sonomacleanpower.org/programs/gridsavvyrewards.

[3] CALeVIP provides funding for installing publicly available EV charging stations to support the rapid adoption of electric vehicles across California: https://calevip.org/about-calevip.

- Drive EV: From 2016 to 2019, SCP's Drive EV Program enabled 1,258 customers to purchase electric vehicles at a collective discount of over $14 million. By providing financial incentives and exchanging free marketing for participating EV dealers in exchange for dealer and manufacturer discounts, the program reduced the average EV sales price by over $10,000 (from $38,523 to $27,759) *in addition* to any state or federal incentives.

- Bike Electric: Launched in 2021, SCP has supported its Bike Electric[4] program to incentivize electric bike ("E-bike") ridership by offering income-qualified customers a $1,000 incentive toward the purchase of an E-bike to promote their use instead of car ridership for short trips. Since its inception, the program has provided incentives for 423 E-bike purchases. One of the lessons learned from our Bike Electric program is that many of the E-bikes purchased were being used for recreation (78% of respondents) or exercise (65%). Only 22% said they used their new E-bikes for commuting. SCP has set a goal to improve on those metrics by targeting local employers and providing grants for organizations that want to make electric bike commuting more accessible to their employees.

These programs have been designed to encourage EV usage throughout our diverse customer base. In particular, we have developed a suite of EV strategies that provide benefits to customers, but we have been limited in our ability reach customers that don't own their residence. Multi-family residences represent a unique challenge because the residents are typically renters and do not make decisions about whether the residence will have EV charging capability. The Proposed Amendments would help facilitate access to EV charging in these situations by amending Section 95843(c). The Proposed Amendments would clarify that multi-family residences will be considered non-residential EV charging to the extent that charging equipment is not limited to serving dedicated or reserved parking spaces. SCP supports this clarification in the LCFS and if adopted by CARB, SCP will evaluate how it can use these incentives to continue to grow EV penetration in the SCP service territory. To better effectuate access by multi-family residents, this amendment should be expanded to include all multi-family residential charging and not limited to EVSEs installed in shared parking spaces.

2. **CARB Should Broaden the Application of Green Tariff Programs and Clarify that that 100% RPS or Zero-CI electricity Tariffs are Eligible Even if Renewable Energy Credits ("RECs") Are Not Retired.**

Currently, the LCFS Regulation only allows a certain class of Green Tariff Shared Renewables Programs to be eligible for low-CI charging. The Regulation states that Green Tariff Shared Renewables include programs are described in Public Utilities Code Section 2831-2833. For all other sources of energy supplied to EV charging, the fuel provider must demonstrate that it retired RECs associated with the power and that the RECs were not used for the RPS or other programs. The narrow class of GTSR programs included in the aforementioned

[4] Bike Electric Rider's Guide: https://sonomacleanpower.org/bike-electric.

PUC code unfairly limits other voluntary renewable programs that may be similar in nature, but have not been expressly authorized by the CPUC. This limitation is arbitrary because it effectively precludes non-EDUs from qualifying for the GTSR provisions for no other reason than the fact that the entity is not an EDU subject to CPUC jurisdiction.

Since the adoption of the last amendments to the LCFS Regulation, there has been considerable growth of CCAs and 100% RPS or Zero-CI electricity retail offerings. RECs are used under these programs for RPS compliance, but that does not change the fact that the low-CI energy is still additional to low-CI energy, the offering has a CI that is lower than the grid-average, and often includes low-CI energy in excess of what is already required by the RPS. Forcing CCAs participating in the LCFS to choose whether to use their RECs for RPS or low-CI energy places an unfair burden on CCAs that does not further the fundamental objectives of the LCFS (i.e., achieving the maximum technologically feasible and cost-effective emission reductions). Moreover, this requirement is unnecessary in light of the fact that retail offerings by load serving entities are now subject to extensive, GHG-based reporting under the California Energy Commission's Power Source Disclosure program. Limiting GTSR programs to those governed by the CPUC unnecessarily restricts feasible emission reductions and arbitrarily discriminates against non-EDU LSEs. To address this issue, SCP recommends amending Section 95488.8(i) to remove the reference to Sections 2831-2833 of the Public Utilities Code.

3. CARB Should Clarify that Amendments to the REC Language in Section 95488.8(i) Would Not Preclude RPS Eligible Projects that Generate RECs.

The Proposed Amendments include changes to REC requirements in Section 95488.8(i)(1)(B)(3). The Proposed Amendments would remove the current language stating that RECs cannot be retired under any other program. The Proposed Amendments would provide that electricity cannot be "issued credits." Currently, entities claiming incremental EV charging rely on power generated by facilities that generate RECs for the entirety of the electricity delivered to the grid. Under existing LCFS rules, the Fuel Supplying Entity will use RECs and prove that the RECs were not used for the RPS by retiring the RECs to a WREGIS retirement account that is used solely for LCFS compliance. RECs can only be retired once and by retiring RECs to an LCFS-specific retirement account, this action proves that the RECs were not also used for the RPS.

Under the Proposed Amendments, electricity from a project that is "issued credits" would not be eligible. The introduction of the word "or" in this Section suggests that either generating RECs or retiring them in another program precludes RECs from being used in the LCFS. This reading would effectively preclude any RPS-eligible power plant from being used to supply incremental energy. RPS eligible resources generate RECs for all generation delivered to the grid. It is then up to the LSE to decide how to use the RECs (e.g., use them for the RPS or the LCFS). Limiting the generation of RECs in the first instance would preclude LSEs from participating in incremental EV charging. We do not believe this is CARB's intent, and would recommend retaining the existing language in Section 95488.8(i).

CONCLUSION

SCP appreciates the opportunity to submit written comments on the proposed amendments to the LCFS Program. We look forward to continuing to work with CARB to incentivize EV charging and low-CI power in SCP's territory and throughout the state.

Respectfully submitted,

Neal M. Reardon

Neal Reardon
Director of Regulatory Affairs
Sonoma Clean Power Authority

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Comment 267 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Chaitanya
Last Name	Khare
Email Address	ckhare@sgh2energy.com
Affiliation	
Subject	Comments for LCFS amendments CARB from SGH2 Energy Global Corporati

Comment

Currently, SGH2 Energy is in the process of developing and
building
a green hydrogen plant from biomass/waste non-recyclable paper.
1. The facility will be requiring power to run the plant. We
need about 6 -8 MW of power for the plant operation, which is
standard processing equipment like pumps, compressors, sensors,
258.1 and
electronics. And this power is not used for electrolytic H2
production. We request that we use book and claim of renewable
energy credits to cover for this power consumption. For
comparison,
an electrolytic hydrogen production plant to produce similar
hydrogen as our plant (4,000,000 Kg), would require a 100 MW of
solar panels.
2. Methane - global warming potential (GWP) should be calcula
based on 20 years. Methane being a potent greenhouse gas which
traps heat in the atmosphere and contributes to climate change.
Over a 20-year period, methane's GWP is between 84 and 87, meaning
258.2 that one ton of methane emitted today has the same GWP as 84 to 87
tons of carbon dioxide over the next 20 years. And methane also
has
a short half-life, and its impact is only in the first 20 years.
Therefore, there is no reason to calculate its GWP over 100 years
3. According to EPA, landfill gas when captured is not more t
50%. Not all California Landfills are capped for gas. Therefore,
258.3 we
recommend CARB use EPA statistic and only 50% of landfill gas can
be captured.

Attachment www.arb.ca.gov/lists/com-attach/6937-lcfs2024-UzBQPVcJUy1WDwlq.pdf

Original File Name CK - combined files.pdf

Date and Time Comment Was Submitted	2024-02-20 15:24:45

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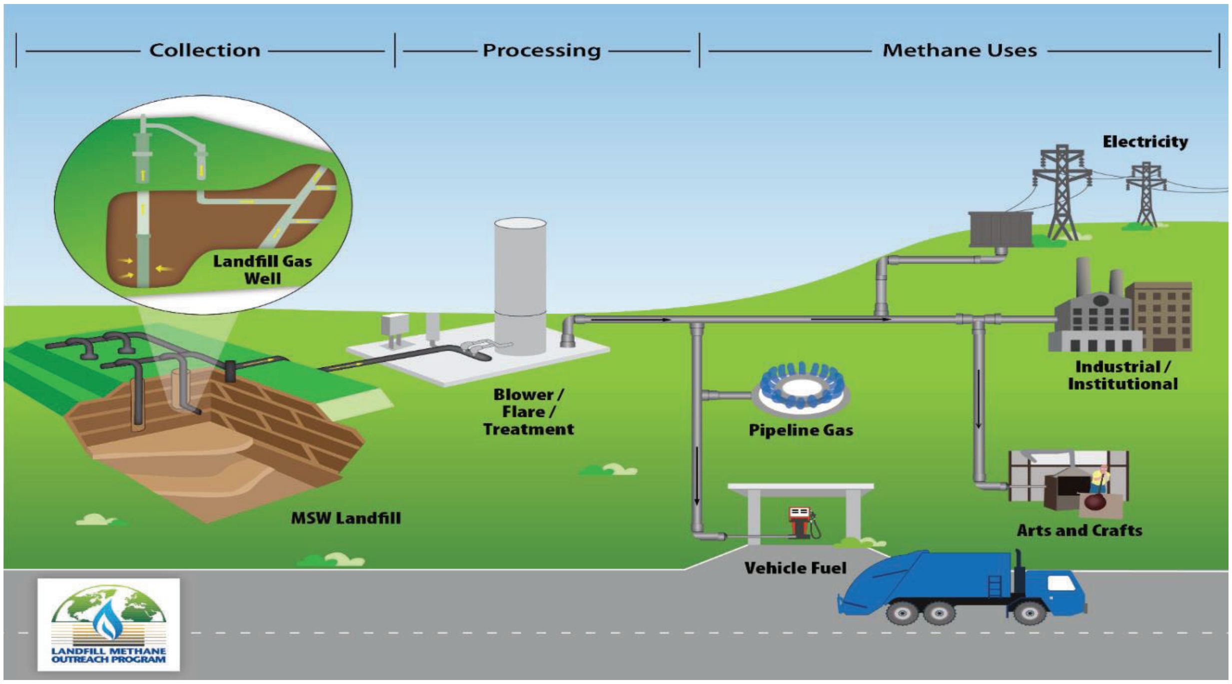
Landfill Gas Methane Capture Information

Landfill gas (LFG) is a natural byproduct of the decomposition of organic material in landfills. LFG is composed of roughly 50 percent methane (the primary component of natural gas), 50 percent carbon dioxide (CO_2) and a small amount of non-methane organic compounds. Methane is at least 28 times more effective than CO_2 at trapping heat in the atmosphere over a 100-year period. Landfills are the third largest source of anthropogenic methane in the United States. According to the EPA, landfill gas (LFG) comprises 17.7 percent of all U.S. methane emissions

Instead of escaping into the air, LFG can be captured, converted, and used as a renewable energy resource. Using LFG helps to reduce odors and other hazards associated with LFG emissions, and prevents methane from migrating into the atmosphere and contributing to local smog and global climate change.

LFG is extracted from landfills using a series of wells and a blower/flare (or vacuum) system. This system directs the collected gas to a central point where it can be processed and treated depending upon the ultimate use for the gas. From this point, the gas can be flared or beneficially used in an LFG energy project.
LFG collection efficiency capture can achieve 85 percent efficiency or more in closed and engineered landfills; it is least effective in open dumps, where the collection efficiency is approximately 10 percent and capture is typically not seen as economically favorable.

Available options to convert LFG into energy include categories such as – Electricity Generation, Direct Use of Medium-Btu Gas, and Renewable Natural Gas.



The cost of an LFG project depends on a number of factors, including the size, location, and layout of the landfill. Typically, one million tons of landfill waste emit approximately 432,000 cubic feet of LFG per day, enough to produce either 0.78 MW of electricity or 216 MMBtu of heat.

Approximately 70 percent of LFG projects generate electricity, primarily via internal combustion engines, gas turbines, and microturbines. Costs vary, but internal combustion engines (ICEs) smaller than 1 MW typically cost $2,300/kW to install, with annual operation and maintenance costs of $210/kW, and ICEs larger than 800 kW typically cost $1,700/kW, with annual operation and maintenance costs of $180/kW. Revenue depends on electricity buy-back rates that are specific to local electric utilities, but typically range between 2.5 and 7 cents/kWh.

<u>Example of current usage of LFG capture for energy:</u>

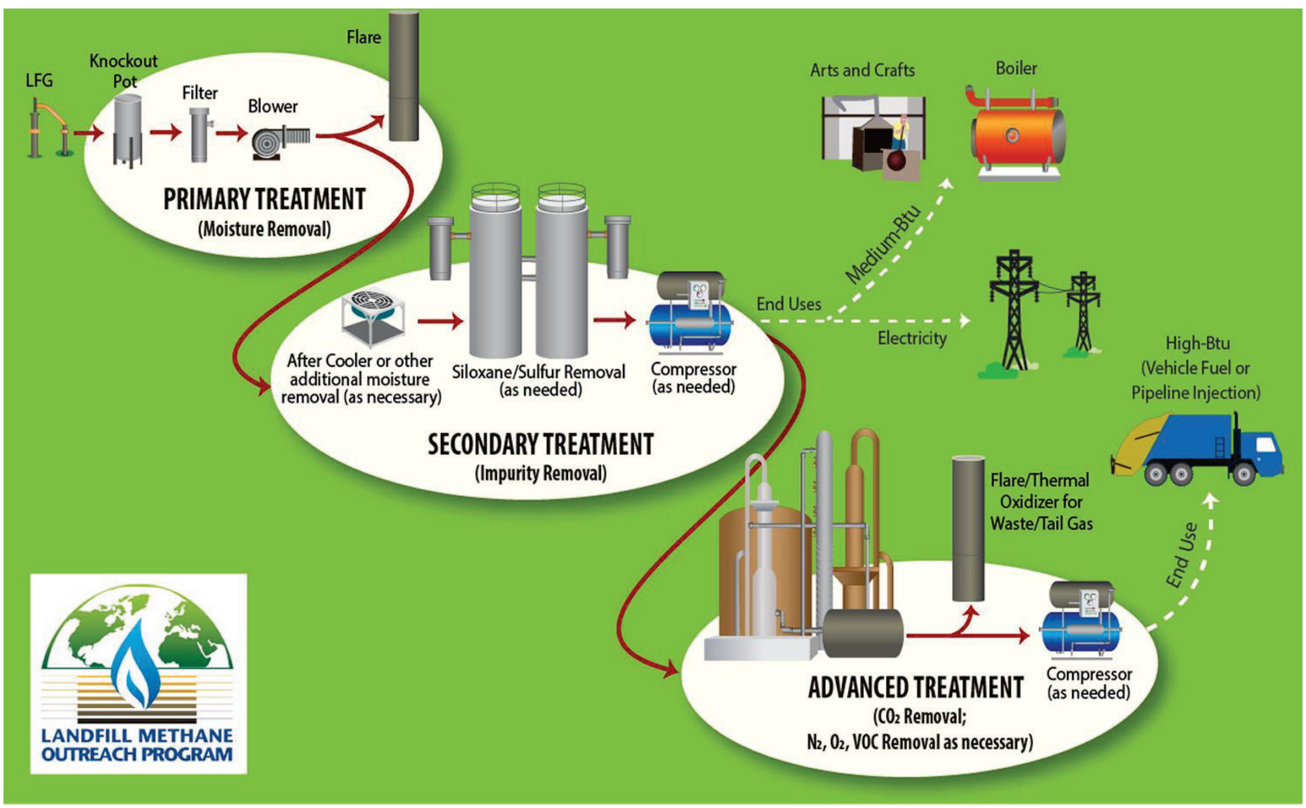
BMW Manufacturing Landfill Gas Energy Project:

Location:	Greer, South Carolina
End User(s):	BMW Manufacturing Co.
Sector(s):	Auto manufacturing

Landfill(s):	Palmetto Landfill
Landfill Size:	22.9 million tons waste-in-place (2015) [closed]
Project Type:	Combined Heat and Power (cogeneration – two gas turbines)
Project Size:	6.5 megawatts (MW) generation [11 MW rated capacity]
Savings:	$1 million/year
LMOP Partners Involved:	Ameresco, BMW Manufacturing Co., Durr Systems, South Carolina Energy Office, Waste Management

At its South Carolina assembly plant, BMW began using landfill gas (LFG) from Waste Management's Palmetto Landfill in 2003 to fuel four gas turbine cogeneration units (4.8 MW rated capacity) and recover 72 MMBtu per hour of hot water. The turbines fulfilled about 25 percent of the plant's electrical needs and nearly all of its thermal needs.

Three stages of LFG Treatment



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https://www.sciencedirect.com/topics/earth-and-planetary-sciences/landfill-gas

Environmental Science Processes & Impacts

CRITICAL REVIEW

Cite this: *Environ. Sci.: Processes Impacts*, 2018, **20**, 1323

Methane emissions: choosing the right climate metric and time horizon

Paul Balcombe,*[ab] Jamie F. Speirs,[bc] Nigel P. Brandon[bc] and Adam D. Hawkes[ab]

Methane is a more potent greenhouse gas (GHG) than CO_2, but it has a shorter atmospheric lifespan, thus its relative climate impact reduces significantly over time. Different GHGs are often conflated into a single metric to compare technologies and supply chains, such as the global warming potential (GWP). However, the use of GWP is criticised, regarding: (1) the need to select a timeframe; (2) its physical basis on radiative forcing; and (3) the fact that it measures the average forcing of a pulse over time rather than a sustained emission at a specific end-point in time. Many alternative metrics have been proposed which tackle different aspects of these limitations and this paper assesses them by their key attributes and limitations, with respect to methane emissions. A case study application of various metrics is produced and recommendations are made for the use of climate metrics for different categories of applications. Across metrics, CO_2 equivalences for methane range from 4–199 $gCO_{2eq.}/gCH_4$, although most estimates fall between 20 and 80 $gCO_{2eq.}/gCH_4$. Therefore the selection of metric and time horizon for technology evaluations is likely to change the rank order of preference, as demonstrated herein with the use of natural gas as a shipping fuel *versus* alternatives. It is not advisable or conservative to use only a short time horizon, *e.g.* 20 years, which disregards the long-term impacts of CO_2 emissions and is thus detrimental to achieving eventual climate stabilisation. Recommendations are made for the use of metrics in 3 categories of applications. Short-term emissions estimates of facilities or regions should be transparent and use a single metric and include the separated contribution from each GHG. Multi-year technology assessments should use both short and long term static metrics (*e.g.* GWP) to test robustness of results. Longer term energy assessments or decarbonisation pathways must use both short and long-term metrics and where this has a large impact on results, climate models should be incorporated. Dynamic metrics offer insight into the timing of emissions, but may be of only marginal benefit given uncertainties in methodological assumptions.

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Environmental significance

Methane emissions are a key contributor to climate change but have a substantially different impact on global warming than carbon dioxide: methane has a much high radiative efficiency but is relatively short-lived. Consequently, the use of Global Warming Potentials over a single 100 year time frame has been frequently called into question as it hides the substantial variation in impact over time. This study compares a comprehensive range of different climate metrics and their key qualities to provide an insight on which metric and time horizon is most appropriate for use in different applications.

1. Introduction

Methane emissions are the second largest contributor to climate change next to carbon dioxide, with its direct impact representing around 20% of additional climate forcing since 1750 according to the Saunois *et al.*[1] Further, the estimated direct and indirect forcing effects of methane (including oxidation to CO_2 and impact on ozone creation) is estimated to be 58% of the value of CO_2 (0.97 W m^{-2} for methane compared to 1.68 W m^{-2} for CO_2).[2] Annual emissions are only 3% w/w of those associated with CO_2 (0.56 $GtCH_4$/year *vs.* 14.5 $GtCO_2$/year for methane and CO_2 respectively),[1,3] but methane has a radiative forcing approximately 120 times more than CO_2 immediately after it is emitted. On the other hand, methane has a perturbation life of only 12.4 years,[2] whereas CO_2 lasts in the atmosphere for much longer: 50% of an emission is removed from the atmosphere within 37 years, whilst 22% of the emission effectively remains indefinitely.[4] Consequently, the relative impact of methane compared to CO_2 changes over time.

[a]Department of Chemical Engineering, Imperial College London, UK, SW7 2AZ. E-mail: p.balcombe@imperial.ac.uk
[b]Sustainable Gas Institute, Imperial College London, UK, SW7 1NA
[c]Department of Earth Sciences and Engineering, Imperial College London, UK, SW7 2BP

Global warming potentials (GWP) are used to compare the relative impact of different greenhouse gases (GHGs) on climate forcing, by converting emissions into 'CO_2 equivalents'. It is defined as the average (time-integrated) radiative forcing of a pulse emission over a defined time horizon, compared to CO_2. GWP is used widely across industrial, regulatory and academic applications to compare the effect of a change in product or process. The 100 year time horizon is most common, giving a CO_2 equivalent value of 28–36 for methane (depending on whether various indirect climate effects are included).[2] However, there is much criticism about the use of GWP, because:

- The selected time horizon has a large impact on the value of the metric;
- Despite its name, it does not compare gases against their effect on global temperature;
- Measures an average climate forcing effect of a single pulse emission over time but gives no indication of the climate impact at an end-point in time, or that of a sustained emission.

Increasingly there are calls for the use of different time horizons (*e.g.* 20 years) or even different metrics that better reflect climate change or align with climate targets (*e.g.* the global temperature change potential as described in the IPPC AR5 [2]). But which metric is most appropriate for different applications and over what time horizon?

Previous studies have assessed the impacts of a small selection of alternative metrics on natural gas *versus* coal for electricity[5] and the climate impacts of transportation.[6] Deuber *et al.*[7] and Johansson[8] examine the physical basis and relationship between some metrics, whilst others assess the cost of emissions mitigation using different metrics.[9,10] Mallapragada and Mignone[11] classify a selection of metrics based on some key characteristics and apply metrics to a case study of natural gas *versus* gasoline-fuelled vehicles.

This paper goes further by assessing a large suite of climate metrics regarding their key differentiating characteristics and applies a case study technology assessment to demonstrate the impact of metric selection on technology preference. The study makes recommendations for which metrics and time horizons are most appropriate for different applications, including short term regional emissions estimates, life cycle technology assessments and energy systems pathways.

The contribution this paper makes is to provide insight for industry, policy makers and academics to ensure the appropriate use of metrics. A range of metric values and methods are presented and synthesised, and clear guidelines are given for the use of metrics across different applications.

First, the report describes the procedure for assessment for the climate metrics. Section 3 gives a summary of the climate impact of GHGs and methane in the atmosphere. Section 4 describes the global warming potential metric, including its history and limitations. Alternative metrics are defined in the following Section 5 and key differences and factors that affect the choice of metrics are outlined in Section 6. Evidence around the impact of using the various metrics are described in Section 7, before recommendations and conclusions are made.

2. Assessment methods

Given the purpose of this study is to assess the impact of using different climate metrics and to make recommendations for their use in different applications, the following stages of assessment are undertaken:

- Contextualising the climate cause–effect chain.
- Assessing climate metrics and key characterising factors.
- Applying a case study.

To place the analysis of different climate metrics in context, the study first describes the climate cause–effect chain, against which metrics will be categorised and assessed. Methane is the focus of this study and is explained in this context, but it should be noted that the assessment is applicable for the study of other emissions and environmental impacts.

A review of a full suite of proposed climate change metrics is then carried out. Firstly, the standard GWP metric is defined and characterised relating to its physical basis, methodological construction and associated uncertainty. Alternative metrics are synthesised from a wide body of literature and compared against GWP and each other, relating to their 'CO_2 equivalent' quantities as well as their basis for construction, intuitiveness and associated uncertainty. Key characteristics are developed and analysed against typical applications of each metric. Characteristics considered are:

- The time horizon or associated discount rates;
- The physical/economic basis of the metric;
- Static *versus* dynamic metrics;
- The level of uncertainty *versus* tangibility; and
- The suitability of metrics for different applications.

To demonstrate the impact of the broad range of metrics and CO_2 equivalent values, a case study is given: a climate assessment of the use of LNG as a shipping fuel, against alternative fuels. The case study is based on the outputs of a full environmental assessment, but focuses on the change in rank preference of fuel based on different CO_2 equivalents, as well as the use of dynamic *versus* static metrics.

Different applications of metrics from industry, policy and academic are characterised in terms of factors such as their required simplicity and their time-frames of consideration. From this, a series of recommendations for the use of metrics are made, which may serve as guidelines for further discussion.

3. Greenhouse gases and the climate cause–effect chain

The link between GHG emissions, climate change and damage to human health and ecosystems is multifaceted. Fig. 1 illustrates a simplified cause–effect chain linking emissions with climate change-related damage, and later in this report the metrics will be placed in this context. Firstly, a GHG is emitted, which increases the concentration of this GHG in the atmosphere. Each GHG has a radiative efficiency, which is the capacity of an atmospheric concentration of gas to trap and re-radiate heat downwards, measured in W m^{-2} ppb^{-1}.[2] When multiplied by the atmospheric concentration, this gives the

Fig. 1 The cause–effect chain linking greenhouse gas emissions to climate change-related damage.

total radiative forcing attributed to the GHG. Thus, radiative forcing is the total change in heat balance in the atmosphere from the increase in concentration of a greenhouse gas,[5] measured in W m^{-1}.[12]

An increase in radiative forcing results in a temperature increase, where the degree of temperature rise is governed by the magnitude of emission and radiative efficiency, as well as the existing atmospheric concentration of the GHG and the concentrations of other gases in the atmosphere. The increase in global average temperature causes damage *via* increased extreme weather events, sea level rise, oceanic circulation changes, species extinction and more. This damage is likely to increase faster than the rate of change in global temperature.[13]

Two important points require emphasis. First, increased radiative forcing is not the same as temperature increase. Temperature change is a result of increased forcing, but the value of temperature change is governed by other factors as well. There is also a lag between radiative forcing and temperature change of approximately 15–20 years,[14] as shown in Fig. 2. Second, global average temperature change is not the only indicator that may describe climate change. Other important factors describe climate change, including the rate of temperature rise and the cumulative temperature rise. Each of these climate change attributes are interrelated but cause damage to health and ecosystems in different ways, examples of which are described in Table 1. The global average temperature rise increases the variation and volatility of temperatures and results in more extreme weather events. The rate of temperature increase governs how much time species may take to adapt to new conditions and so a fast rate will cause more species extinction. The cumulative temperature rise (*i.e.* prolonged increases) strongly affects longer term changes such as glacial melt and seal level rise. Emissions of GHGs affect each of these climate attributes differently, depending on: emission quantity; existing concentration of pollutant in the atmosphere; residence time of emission in the atmosphere; and the concentration of other molecules in atmosphere (*e.g.* OH^- and O_3).

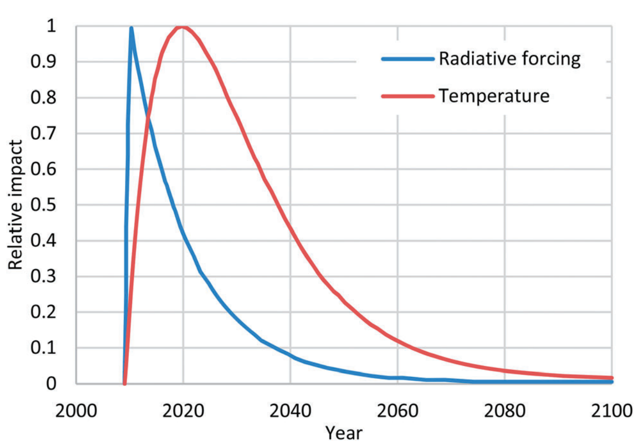

Fig. 2 The relative impact of a pulse emission of methane on radiative forcing and subsequent impact on temperature change. Source: ref. 14.

For methane, an emission has a much larger radiative forcing effect than CO_2 given the difference in radiative efficiency and indirect impacts.[4] However, methane is a short-lived climate pollutant (SLCP) and has an atmospheric lifetime of 8.4 years, defined as the atmospheric burden divided by the sink strength.[15]

Methane comes out of the atmosphere and troposphere by typically reacting with hydroxyl radicals, oxidising to form CO_2 and water (which are also both greenhouse gases). 88% of the methane reacts this way, meaning that one gram of methane will form 2.4 grams of CO_2.[13] The other 12% of the methane forms molecules such as methanal (formaldehyde) and methyl hydroperoxide. The increasing concentration of methane in the atmosphere reduces the availability of the hydroxyl radicals for further reactions which in turn would increase the lifespan of methane. Thus, the perturbation lifetime of methane, which allows for the gases influence on other atmospheric species during its life, is 12.4 years.[2]

In comparison, the lifespan of CO_2 is more complicated due to the different mechanisms that take CO_2 out of the atmosphere, but 50% of a pulse emission is removed from the atmosphere within 37 years, whilst 22% of the emission effectively remains indefinitely.[4] Thus, whilst the initial radiative forcing is low compared to methane, the lasting and cumulative effects are large. The change in radiative forcing over time is shown in Fig. 3 for methane and CO_2.

The effect of GHG emissions on the climate is multifaceted and detailed climate models are required to understand the effects of changing emissions and the environment over time. Such models as MAGICC6 [17] are used in integrated assessment projects to estimate the impacts. However, these are detailed

Table 1 Climate change attributes and resultant damage. Sources: ref. 5 and 14

Climate change measure	Damage
Temperature increase	Extreme weather events
	Heat waves
	Coral bleaching
Rate of temperature rise	Species extinction
Cumulative temperature rise	Sea level rise
	Glacial melt
	Ocean circulation change

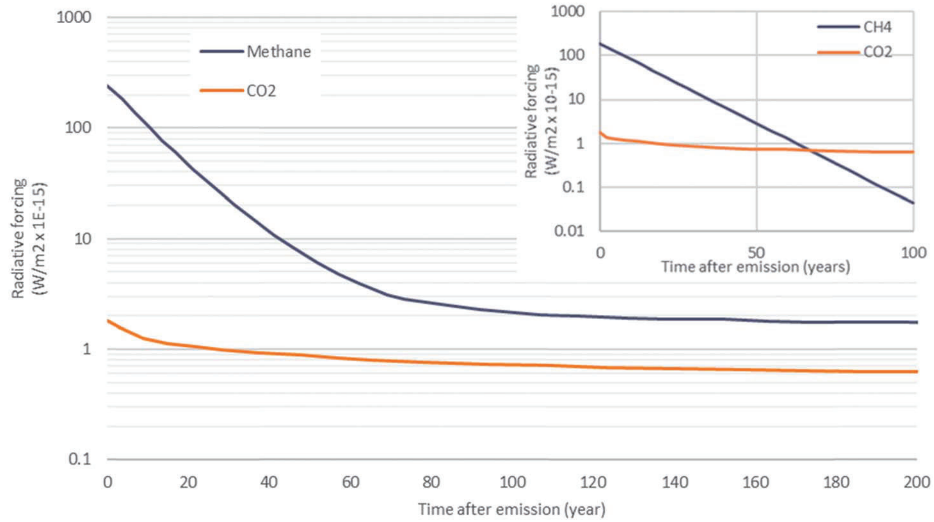

Fig. 3 Radiative forcing of a 1 kg pulse emission of methane and carbon dioxide over time, including the eventual oxidation of methane into CO_2. Graph inset is the radiative forcing of methane without the inclusion of methane oxidation into CO_2. Source: ref. 4 and 16.

global models that require many environment-related assumptions. Simpler, faster approaches are often required to compare the effect of changing processes or technologies in studies such as industrial emissions measurements, policy-related emissions strategies and environmental life cycle assessments. This is the role of climate metrics, to compare technologies, products and policy pathways simply and effectively.

4. Global warming potential

Global warming potential (GWP) is the standard metric used to compare GHGs emitted from different products and services. The metric was developed for use following the Kyoto Protocol and adapted by the Intergovernmental Panel on Climate Change[18] to help in the design of emissions strategies, accounting for the trade-offs between different types of GHG.[19] It is defined as the time-integrated radiative forcing of an emission pulse of a gas, relative to that of CO_2, over a defined time horizon.

For a 100 year time horizon, methane GWP is 36 $gCO_{2eq.}$/gCH_4, meaning that the average radiative forcing of a methane emission over 100 years after the emission is 36 times that of an equivalent mass of CO_2. The IPCC have typically given estimates of GWP for time horizons of 20, 100 and 500 years (although the most recent 5th assessment report excluded 500 years) and the 100 year GWP (GWP100) remains the most common metric used.

With a high radiative efficiency and short lifetime compared to CO_2, methane has a much higher GWP over short timescales: GWP20 is 87 $gCO_{2eq.}$/gCH_4. Fig. 4 shows the GWP of methane over different timescales, but not including the effect of climate-carbon feedback (CCFB), resulting in slightly lower numbers than those expressed within this paragraph (*e.g.* a GWP100 of 30 rather than 36).

The values of GWP for each GHG have been developed over each IPCC assessment report, to account for better understanding of radiative forcing and the various indirect radiative forcing effects, such as cloud albedo and CCFB.[2,21] CCFB is a broad term that encompasses both negative and positive feedback effects associated with increased forcing or temperature. For example, a positive feedback is an increase in temperature causing greater concentrations of water vapour, which itself results in further radiative forcing. The cloud albedo effect is the impact of clouds reflecting radiation and contributing to climate cooling. The concentration of GHGs in the atmosphere and troposphere has an impact on cloud formation and consequently the cloud albedo effect. Additionally, most atmospheric methane eventually oxidises into CO_2, which raises the total GWP values by 1 and 2 for 20 and 100 year time horizons, respectively. This is summarised in Table 2, presenting the change in GWP for methane across IPCC publications.

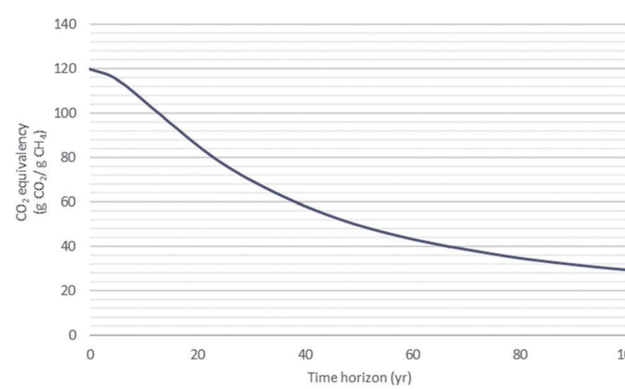

Fig. 4 Illustration of the changing GWP of methane over time. Sources: ref. 20 and 12, using GWP factors without climate-carbon feedback effects.

Table 2 Changes to GWP and perturbation lifetime of methane in IPCC assessment reports. Source: ref. 2, 18, 19, 22 and 23

					Effect included[c]		
Publication	Year	Lifetime (years)	GWP (20 year)	GWP (100 year)	T-O_3	S-H_2O	CCFB
1st AR	1990	10	63	21	✗	✗	
2nd AR	1995	12.2 ± 3	56	21	✗	✗	
3rd AR[a]	2001	12	62	23	✗	✗	
4th AR[b]	2007	12	72	25	✗	✗	
5th AR without CCFB	2013	12.4	84	28	✗	✗	
5th AR with CCFB	2013	12.4	86	34	✗	✗	✗
5th AR with CCFB and oxidation	2013	12.4	87	36	✗	✗	✗

[a] CO_2 AGWP revised down in AR3 leading to relative increase in GWP for other gasses including methane. [b] CCFB included for calculation of CO_2 AGWP. [c] T-O_3 – tropospheric ozone. S-H_2O – stratospheric water vapour. CCFB – climate-carbon feedbacks.

Additionally, indirect effects have been inconsistently included in historical IPCC publications. In the second and third assessment reports calculations of GWP did not include CCFB. In the fourth assessment report, CCFB were included in the calculation of CO_2 absolute global warming potential (AGWP), the baseline against which the GWP for other gases is based. However, while CCFB also impacts on the radiative forcing of other gasses, these impacts were not included in the GWP calculations until AR5, which results in a large increase, especially for the 100 year horizon GWP, as shown in Table 2.

4.1 Criticism of GWP

There are a number of criticisms levelled at the use of GWPs relating to the three key aspects of this metric: a time horizon must be set; it is modelled on a single pulse emission; and it measures time-integrated radiative forcing.

First, the need to select a time horizon requires the metric user to decide a timeframe that is important. This is a particular issue for methane given that the GWP values change so significantly over time. The selection of a single time horizon is arbitrary and means that other timeframes are disregarded: selection of a short timeframe for methane will ignore the long-term impacts of CO_2, whereas selection of a long timeframe for methane will largely ignore the short term forcing of methane. Indeed, the fact that any time horizon is set means that longer term impacts are systematically underrepresented.

Second, the GWP was designed to equate pulse emissions, *i.e.* one-off emissions, rather than sustained or developing emissions, such as those modelled using life cycle assessment methods. This does not generally reflect the consequences of real-world investment or policy decisions.[12]

Last, the physical basis of the GWP is the integrated radiative forcing and does not represent the temperature (or other climate) impact. As described in Section 3, radiative forcing is a precursor to temperature change, but they are not synonymous. Additionally, the fact that GWP is based on an integrated measure means that the GWP indicates the average impact over a time horizon rather than the impact at the end-point of the time horizon (both are useful in estimating the impacts of climate change).

The limitations associated with GWP have given rise to the creation of alternative climate metrics over the last 20 years. These metrics are defined in the following section, after which their key differentiating factors are discussed in Section 6, including time horizons and physical basis.

5. Alternative metrics

The many climate metrics that have been proposed in the last few decades can be categorised in a number of ways, which are summarised in Table 3. Table 3 lists the most cited metrics and categorises them based on key factors: CO_2 equivalency value, their physical basis, whether they are static or dynamic metrics, cumulative or end-point estimates, and their level of uncertainty. The following section firstly describes the most used alternative, GTP, before outlining the characteristics of each other metric in order that they appear in the table.

5.1 GTP – global temperature change potential

Global temperature change potential (GTP) is the most popular and most researched alternative climate metric to GWP.[2] It was developed by Shine *et al.*[24,32] and is included in the IPCC Assessment Reports. It is defined as the change in mean surface temperature after a specified time due to a pulse emission, relative to the effect from an equivalent pulse emission of CO_2. The key differences compared to the GWP are:

• It is an end-point metric,[11] measuring the impact at the end of a time period, rather than a cumulative effect within a time period; and

• It estimates the effect on temperature, rather than radiative forcing (which gives rise to temperature but the relationship is not linear).

Values of GTP for methane are currently estimated as 13 $gCO_{2eq.}/gCH_4$ (GTP100) and 71 (GTP20) including an allowance for CCFB and the eventual oxidation of methane into CO_2. Whilst the GTP20 is around 20% lower than the equivalent GWP20 (87), the 100 year time horizon differs greatly, over 60% lower than GWP, as shown in Fig. 5. This is because the GTP figure measures at the end-point and does not account for the strong forcing prior to this time. At 100 years the proportion of the pulse emission remaining in the atmosphere is

Table 3 Climate metrics relating to methane and their key attributes. Source: ref. 2, 4, 12, 14, 16 and 24–30

Metric	Full name	Source	Time horizon/end-point value 20	100	500	Indicator type	Static/dynamic	Emission type	Time frame	Uncertainty
GWP	Global warming potential[a]	IPCC 2014 (ref. 31)	84–87	28–36	8–11[b]	Radiative forcing	Static	Pulse	Cumulative	Lowest
SGWP	Sustained-flux global warming potential	Neubauer 2015 (ref. 4)	96	45	14	Radiative forcing	Static	Sustained	Cumulative	Lowest
ICI	Instantaneous climate impact	Edwards 2014 (ref. 16)	43	0.1	—	Radiative forcing	Dynamic	Sustained	End-point	Low
CCI	Cumulative climate impact	Edwards 2014 (ref. 16)	86	34	—	Radiative forcing	Dynamic	Sustained	Cumulative	Low
TWP	Technology warming potential	Alvarez 2012 (ref. 12)	—	—	—	Radiative forcing	Dynamic	Sustained	Cumulative	Low
GTP	Global temperature change potential	Myhre 2013 (ref. 2)	71	13	—	Temperature change	Static	Pulse	End-point	Low
IGTP	Integrated global temperature change potential[c]	Peters 2011 (ref. 6)	96	38	12	Temperature change	Static	Pulse	Cumulative	Low
TEMP	Temperature proxy index	Tanaka 2009 (ref. 29)	—	39	—	Temperature change	Static	Pulse	Cumulative	Low
CCIP	Climate change impact potential	Kirschbaum 2014 (ref. 14)	—	32	—	Temperature change; rate of change; cumulative change	Static			Medium
GSP	Global sea level rise potential	Sterner 2014 (ref. 28)	78	18	3.8	Sea level rise	Static	Pulse	End-point	High
IGSP	Integrated global seal level rise potential	Sterner 2014 (ref. 28)	95	39	11	Sea level rise	Static	Pulse	Cumulative	High
GPP	Global precipitation change potential	Shine 2015 (ref. 30)	120	8.1	—	Precipitation	Static	Pulse	End-point	High
GDP	Global damage potential	Kandlikar 1995 (ref. 25)	—	—	—	Economic	Static	Pulse	Cumulative	Highest
GCP	Global cost potential	Manne 2001 (ref. 27)	—	—	—	Economic	Static	Pulse	End-point	Highest
SCM	Social cost of methane	Shindell 2017 (ref. 13)	—	—	—	Economic	Static	Pulse	Cumulative	Highest

[a] Range of values for GWP represents various additional inclusions for carbon climate feedback and oxidation of methane into CO_2. [b] The 500 year value is not given in the most recent IPCC assessment report, so the figure presented is from the 4th assessment report. [c] The IGTP metric values are estimated to be 12% higher than equivalence GWP values and are thus calculated. The original estimation was based on the 4th assessment report values of the GWP.

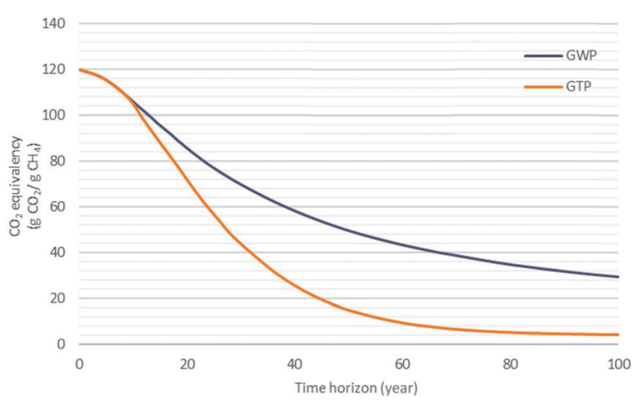

Fig. 5 The global temperature change potential of methane compared to the global warming potential, CO_2 equivalencies across different time horizons. Note, indirect carbon climate feedback and methane oxidation effects are not included within these estimates. Source: ref. 33.

relatively small. Indeed, at this time after the emission, the dominant force is from only the indirect effects such as CCFB and methane oxidation (without which the GTP100 would be only 4).

The GTP goes one step further down the cause–effect chain (see Fig. 8) than GWP by estimating the relative temperature change resulting from the increased radiative forcing. This brings more clarity when using the metric for temperature-based analyses (*e.g.* keeping global temperatures below 2 °C). However, the estimation of GTP incorporates additional assumptions about physical processes, such as climate sensitivity and the exchange of heat between the atmosphere and the ocean.[2,24] This consequently brings more uncertainty compared to GWP.[4] The IPCC estimate an uncertainty of GTP100 of ±75% (with a 90% confidence), compared to ±30% and ±40% for GWP20 and GWP100, respectively.[2]

5.2 SGWP – sustained-flux global warming potential

The sustained-flux global warming potential (SGWP) has been previously called the step-change global warming potential[4,34] and is designed to eliminate the dependence of the GWP metric on the single 'pulse' emission. This metric measures the relative radiative forcing of a sustained emission of a GHG relative to that of CO_2. This metric is otherwise the same as GWP, but the sustained emission measurement results in a larger CO_2 equivalence and is 40% higher than GWP for the 100 year horizon.[4]

5.3 ICI and CCI – instantaneous and cumulative climate impact

Edwards and Trancik[16] developed a new set of metrics in 2014, intended to be a simplified dynamic method to account for changing emissions profiles over time, in order to assist with development of effective emissions pathways. Instantaneous climate impact (ICI) measures the radiative forcing associated with emissions at a specific time point, similar to an instantaneous version of GWP. It is dynamic in that the time horizon end-point is fixed, rather than the time period after an emission (further explained in Section 6). Consequently, in a multi-year emissions assessment (*e.g.* a life cycle assessment), as the year of emission increases, the time period decreases until the end time point is reached. The result is that any methane emissions incurred at the start of the time frame contributes relatively little, but the values increase significantly as the emissions approach the end-point.

The second of the set of impacts developed by Edwards and Trancik[16] is a cumulative version of the ICI, the CCI. As such, it measures the cumulative radiative forcing of an emission or emission profile. It is similar to the GWP in that it measures cumulative radiative forcing, but whereas the time horizon is fixed with GWP (*e.g.* 100 years), the end point is fixed with CCI (*e.g.* 2080). In other words, the CCI is a dynamic version of GWP.[11]

5.4 TWP – technology warming potential

Technology warming potential (TWP) is designed specifically for comparing technologies or products over variable time and is classed as a dynamic metric.[12] TWP does not produce a CO_2 equivalency metric as such, but produces a 'technology equivalency', as it gives relative improvements (or otherwise) associated with technology switching over a time frame. It is defined as the relative proportional change in cumulative radiative forcing over different timescales and may be as a result of a pulse or sustained emission.[5] The effect is broadly similar to the ratio of GWPs associated with two different technologies, but the initial set-up of TWP did not allow for climate carbon feedbacks, suggesting that the methane impact may be underestimated in this metric.[5]

5.5 IGTP – integrated global temperature change potential

The integrated global temperature change potential (IGTP) is a cumulative version of the GTP. Unlike the GTP which estimates the temperature impact of a pulse emission at a specific time, the IGTP estimates the cumulative temperature impact from the time of a pulse emission to a specific time horizon, relative to CO_2.[6] In this respect, it is a temperature equivalent of the global warming potential. This means that IGTP values are higher than GTP, as the initial high radiative (and temperature) forcing is effectively 'remembered' in the cumulative time horizon estimates.[26,28] Values are approximately 12% higher than the GWP for the 20, 50, 100 and 500 year time horizons.

5.6 TEMP – temperature proxy index

The temperature proxy index (TEMP) was developed by Tanaka *et al.*[29] in 2009 to provide a temperature based equivalency metric similar to the GTP but integrated over a specific time horizon (similar to the IGTP). Instead of a projected impact metric derivation such as the GWP, TEMP values are numerically estimated based on the historical contribution of different GHGs over the post-industrial time period.[30] The TEMP metrics and analysis suggest that GWP100 underestimates the contribution from methane and that a value of 39 would be most appropriate (which is not dissimilar to the current GWP100 value of 36 including carbon climate feedbacks and oxidation to CO_2).

5.7 CCIP – climate change impact potential

The climate change impact potential (CCIP) metric was created by Kirschbaum[14] in 2014 and is the only mid-point type metric that combines the effects of temperature rise with cumulative warming as well as rate of warming. Key assumptions associated with this metric are that each impact (temperature, cumulative temperature and rate of rise) are weighted equally in importance and the values are only available for 100 year time horizon, which is similar to the GWP100 at 32 $gCO_{2eq.}/gCH_4$.

This is a unique metric in its attempt to incorporate the different types of climate impact. If there were a specific calculator that allowed the selection of weighting and time horizon to generate the appropriate CO_2 equivalence, this would be a useful bridge between simple static metrics and more complicated climate models.

5.8 GSP and IGSP – global sea level rise potential

The global sea level rise potential was developed in 2014 and goes a step further than the temperature impacts of emission by estimating the specific impact on sea level rise.[28] It is a static metric based on a set time horizon, estimating the relative change in sea level at the end of the time horizon. The values for 20, 100 and 500 year time horizons lie between those associated with GWP and GTP for methane, at 78, 18, 3.8 $gCO_{2eq.}/gCH_4$ respectively.[28] The relative uncertainty associated with GSP is likely to be higher than GWP or GTP as it is further in the line of damage estimation (see Fig. 8). However, this is still a physical metric with no required socio-economic evaluation, unlike the GDP and GCP.

The IGSP is a cumulative version of the GSP, similar to the GWP but estimating average sea level impacts. The metric values for IGSP are slightly higher than those of GWP at 95, 39 and 11 $gCO_{2eq.}/gCH_4$ for 20, 100 and 500 year horizons respectively.

5.9 GPP – global precipitation change potential

Global precipitation change potential is a static equivalency metric created in 2015 that compares GHGs against their effect on global average change in precipitation, due to a pulse or a sustained emission.[30] The precipitation estimate over time uses both a radiative forcing element (GWP) and a temperature change element (GTP) and their relative impact changes over time.[26] Similar to the sea level rise metric, this metric goes further along the cause and effect chain, whilst still being physically based (rather than socio-economic). The metric values are higher than GWP and GTP values for the 20 year horizon (120) and slightly lower for the 100 year (8.1). This indicates that the effect of methane on global precipitation change is large in the short term, much larger than the temperature change impact.

5.10 GDP – global damage potential

Global damage potential (GDP) goes beyond mid-point physical impacts to estimate the end-point damages caused by climate change, relating to human health, increased rates of mortality and ecosystem losses, which are aggregated using an economic value.[7] It is still an equivalency metric in that it estimates the relative damage impact of an emission compared to CO_2 and is based on the cumulative impact over time. The end-point economics-based metric removes the requirement to specify a timeframe by setting an infinite horizon and setting a discount rate at which future emissions are discounted against near term emissions. Recently estimated GDP equivalences for methane are between 19 and 100 with a base case of 50 (with an additional outlier of 420, associated with high discount rate).[35] The estimation of an economic value on damage represents significantly higher uncertainty than other mid-point metrics, owing to the additional assumptions that must be made to estimate:

- The damage caused by an increase in concentration (*e.g.* number of extreme weather events, sea level rise, extinction events); and
- The economic value placed on such damage.

The GDP is an intuitively useful method to determine the least-cost mitigation strategy.[25] However, the move from a physical to economic basis and the high uncertainty reduces the transparency and useability of such a metric for many applications and it is typically utilised within an integrated climate-cost model framework.[2]

5.11 GCP – global cost potential

Global cost potential (GCP) is also an end-point economic metric and defines price ratios between GHGs and CO_2 that deliver the least-cost mitigation solutions to meet a specific climate target at a specific time.[2,27] Similar to the GDP, this metric is typically an output from a climate-economic model generating price ratios for different GHG mitigation options using an optimisation model[36] and are not normally used in carbon equivalency-related studies due to their complexity and dependence on system assumptions. Tanaka *et al.*[36] recently estimated GCP values that fit with a 2 °C climate target, resulting in a range of values from 5 to 65 $gCO_{2eq.}/gCH_4$, with a peak at the time of stabilisation around 2060.

5.12 SCM – social cost of methane

The social cost of methane (SCM) is another estimator of the economic costs of damage associated with methane. As indicated by the name, the damages focus on methane rather than the climate effect, as it includes damages associated with air quality and tropospheric ozone creation which has a large impact on crop yield and premature deaths.[13] Impacts are monetised and levelized per tonne of emission, and subsequently compared to the social cost of carbon. Instead of using specific time horizons, the time horizon is infinite and a discount rate is set. Thus, instead of varying values over time horizons, they vary significantly over discount rate: 10% discount rate equates to a CO_2 equivalency of 199; 5–102%; 4–76%; 2.5–42%; 1.4–26%. These values are higher than most other equivalency metrics, partly due to the incorporation of the damage effect of ozone creation.

6. The key factors that differentiate climate metrics

There are many important differentiating factors associated with the climate metrics, which are analysed below to inform recommendations for metric selection. The following section assesses metric in relation to: selecting the timeframe; static *vs.* dynamic metrics; the physical basis; level of uncertainty; simplicity *vs.* tangibility; and suitability for the application.

6.1 Selecting the timeframe

The need to select an appropriate timeframe is the most common criticism of the GWP and has the largest impact on metric value. This variation is shown in Fig. 6, giving equivalencies for different metrics for methane over different time horizons.

There is no single correct time horizon to use: it depends on the perspective and reason for which the estimation is being carried out.[11,26,37–39] The IPCC typically uses a 100 year time horizon (GWP100), being commensurate with the scenario timescales used in its modelling work. However, 20 year time horizons are increasingly used, which can significantly alter results, often leading to disagreement and conflicting conclusions in the literature.[12,40] Using a short-term metric inherently ignores the impact of long term, long-lived forcers (CO_2) and on a systems scale this means prolonging the point at which the globe reaches climate stabilisation. Conversely, a long-term metric inherently ignores the large impact of short-lived forcers (methane), which may cause more rapid temperature increases require more drastic emission reduction measures earlier to meet temperature targets.

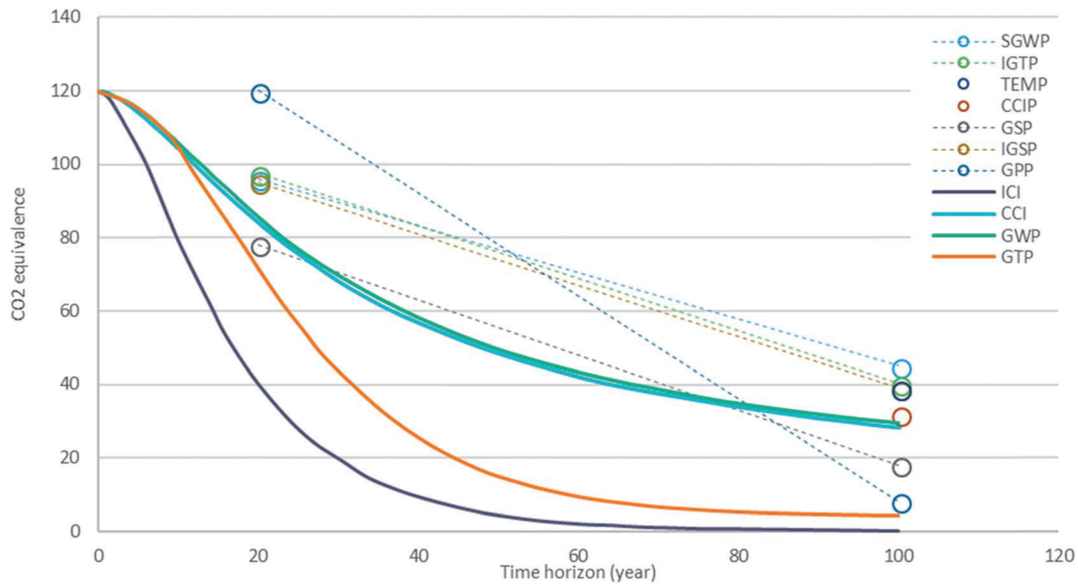

Fig. 6 The CO_2 equivalence of methane using different climate metrics, against the time horizon. Dotted lines are placed between paired values of the same metric where only two points are known. Note, for static metrics the *x* axis denotes the time since the emission and for dynamic metrics CCI and ICI, the *x* axis represents the time away from the end-point stabilisation year (*e.g.* 40 years on the *x* axis means this value is associated with a time horizon of 40 years before the stabilisation period).

Using a GWP100 gives the average radiative forcing occurring over the 100 years after an emission. But why is the average effect over the next 100 years important and are there other important time horizons? The selection of time horizon is a policy decision: are there concerns about short-term or long-term global temperatures? Many countries have committed to reducing GHG emissions by 2030 or 2050, but these are interim targets with the aim of long term decarbonisation. There is an argument to suggest that an appropriate time horizon should be in accordance with 1.5 or 2 °C decarbonisation pathways that require stabilisation of GHG concentrations by 2050–2100 : 30–80 years.[41–43] However, the GWP metric does not measure the impact at a specific time, but the average effect over a period. When concerned with a specific time for stabilisation, an instantaneous metric (such as GTP) may be more appropriate.

As the time of required climate stabilisation grows closer, the importance of methane mitigation grows stronger. Conversely, in 2100, an emission of methane from 2015 will be seen as relatively unimportant. The timeframe after a stabilisation year will also be extremely important in maintaining a stabilised climate, whilst the application of a short time horizon effectively reduces the importance of longer term emissions to zero, which may be inappropriate.

Alvarez *et al.*[12] suggest that for technological environmental analyses, it is most appropriate and transparent to plot estimated GHG emissions over different time horizons. Other studies suggest that a comparison should span a flexible range of time horizons, *e.g.*[12,16] Ocko *et al.*[65] suggest simply presenting GWP from both a 20 and 100 year time horizon. For larger-scale integrated assessment models which project emissions up-to, and beyond, climate stabilisation periods, the use of a single GWP value such as the GWP100 would significantly undervalue the impact of methane emissions. Thus the inclusion of both short and long-term metrics is imperative to assess the robustness of any projections, especially where the contribution of methane emissions is significant.

From the development of metrics that analyse impacts on sea level and precipitation,[28,30] it is clear that potent short lived pollutants like methane may play a strong role in climate change in both the shorter (20 years) and longer (100+ years) time horizons. Both the short term and longer term effects of emissions must be understood and thus the inclusion of multiple time horizons help to prevent any unintended consequences associated with a technology or product switch.

As described in Section 5, there are three metrics described here that do not require the setting of a time horizon, but instead use a discount rate to estimate impacts over an infinite time: the GDP, GCP and SCM metrics. Whilst the avoidance of a time horizon is beneficial, the need to apply a discount rate represents a similar arbitrary weighting of preference for shorter (or longer) time horizons and so there is little advantage from this perspective. The numerical values are even more wide ranging as shown in Fig. 7, perhaps due to the compounding of assumptions relating to discount rates and the cost of damages.

6.2 Physical basis of the metric

The various metrics differ with respect to their physical or socio-economic basis, and are primarily categorised as: radiative forcing; temperature; economic; or a mix of the aforementioned. They can also be categorised in relation to their position along the climate cause–effect chain as shown in Fig. 8. Metrics sitting closer to the end-point effects are more intuitively useful and understandable. As described, GWP is based on radiative forcing, but there is suggestion that a switch from GWP to

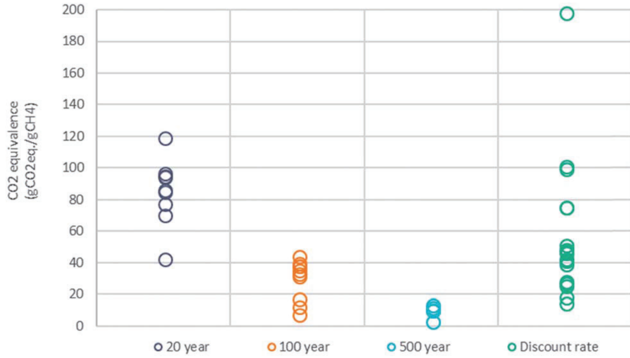

Fig. 7 CO_2 equivalence of methane for different time horizons and compared to metrics which use discount rates instead of time horizons.

a temperature-based metric such as GTP is more appropriate given that our climate targets revolve around global mean temperature changes.[2]

However, at the point in the cause–effect chain where metrics estimate end-point damage, they convert from a physical basis to socio-economic and this carries additional uncertainty. These damage indicators may be extremely useful for broader studies into decarbonisation pathways, but typically require energy/climate/economic system models and are a step away from a simple metric design. The use of simpler physical metrics is preferable for such uses as annual emission inventories from a company or national perspective, or for simpler technological evaluations.

More recent metrics estimating contribution to sea level rise, the GSP, and to precipitation change, GPP, are very useful in improving our understanding of the physical effects of emissions across different timeframes and will help to inform the appropriate CO_2 equivalencies. It is notable that these metrics are broadly within ranges bounded by the GWP and GTP for equivalent time horizons.

6.3 Static *vs.* dynamic metrics

The way that GWP (and GTP) is used in most abatement studies does not take into account the timing of emissions. Typically, one metric (*e.g.* GWP100) is used to estimate emissions, for example from a natural gas well, over the lifetime of the well. However, as a well may be active and emitting for 30 years or more, this means that the end-point of the time horizon is not fixed. For example, if a well emits within the first year of operation, say 2015, the GWP100 would consider the impact up to 2115. If the well still operates and emits at 2045, the GWP100 estimation would consider the impact up to 2145.

Static metrics like the GWP and the GTP use fixed time horizons. This means that the time horizon (*e.g.* 100 years) stays the same length, even when emissions studies may span multiple years (*e.g.* life cycle assessments). However, these metrics may also be used dynamically instead, using a fixed end-point in time rather than a fixed time horizon. This means that for multiple year studies, the end-point (*e.g.* the year 2100) stays the same and the horizon reduces as the year of emission advances. For example, a GWP100 may be used with an emission in 2015, a GWP99 in 2016 and GWP98 in 2017 *etc.*[44] Fig. 9 shows the difference between static (GWP and GTP) and dynamic (ICI and CCI) metrics by defining the CO_2 equivalency value over time.

To use a dynamic approach in a technology assessment, first an end-point must be selected (*e.g.* 100 years from the start of the assessment time). Estimations of emissions must be made for each year of the assessment period (*e.g.* over a 30 year lifetime of a technology). Additionally, a different metric value for each year must be estimated. For example, emissions at year zero will be multiplied by the 100 year metric value, whilst emissions at year one will be multiplied by the 99 year metric value, and so on until the end of the assessment period (*e.g.* emissions at year 30 multiplied by the 70 year metric value). Thus, the use of dynamic metrics adds significant complexity to

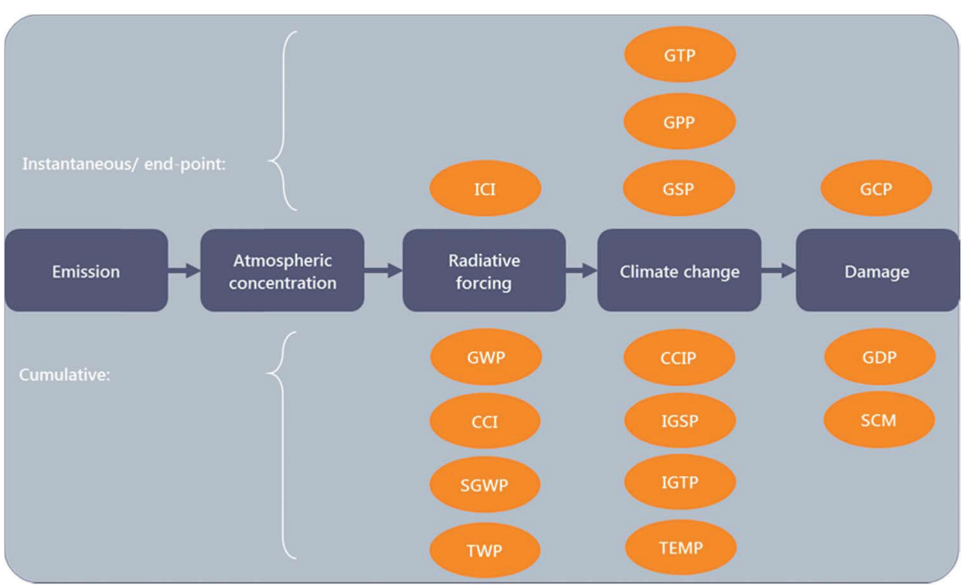

Fig. 8 Climate metrics categorised by: stage in cause–effect chain; whether they indicate instantaneous or cumulative impacts.

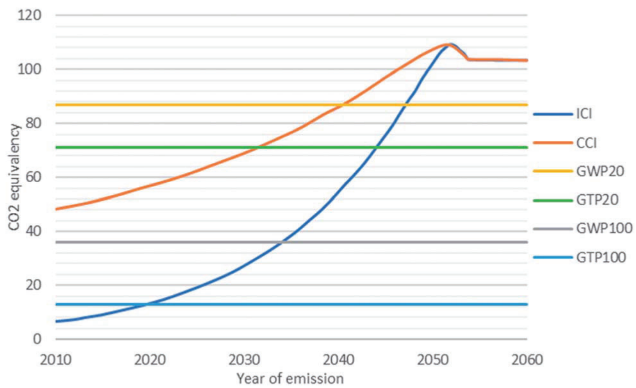

Fig. 9 Comparing GWP, GTP, ICI and CCI metric values over time. ICI and CCI values are dynamic and are set to an end-point of 2059, as per Edwards and Trancik,[16] giving an equivalent initial time horizon of 49 years.

the calculation relative to static metrics. Applications of the use of dynamic metrics in environmental studies include Levasseur *et al.*[44] and Edwards and Trancik.[16]

The use of static metrics must be carried out with care for emissions scenarios over long timeframes, for example with life cycle assessments. When doing so, the definition of the metric changes from its original meaning, for instance with GWP, which is intended to measure the average effect of a single pulse emission over a specific time horizon. Both the pulse and specific time horizon aspects are no longer applicable as there may be sustained emissions over many years.

The use of a dynamic metric may result in significantly different results compared to the use of static metrics.[16] Using the example above, the methane emissions during the first year would have a significantly lower impact on global warming than equivalent methane emissions during the 30th year. Such metrics are the ICI[16] or a dynamic version of the GTP.[2]

Whilst the use of dynamic metrics may be preferable when comparing technologies over long timescales, static metrics are most appropriate for emissions estimates based on shorter timescales, for example annual emissions estimates. Additionally, the projection of a specific stabilisation year for use with a dynamic metric is an assumption, with atmospheric GHG concentration stabilisation years spanning 40 years or more across different emission pathways, as mentioned in Section 6.1. Thus, the use of a simpler static GWP for an LCA that spans 30 years would fall within this uncertainty range. Thus, there may be only marginal benefit in applying a dynamic metric methodology, which may be outweighed by the relative increase in complexity of calculation.

6.4 Simplicity *vs.* tangibility

As metrics move along the cause–effect chain, they become more policy relevant[2] and relatable as an output. For example, temperature change may be a more tangible measure than radiative forcing, whereas damage estimates as a result of climate change are even more so. However, with greater tangibility comes more assumptions, uncertainty and complexity. For example, moving from a physical temperature change to estimating the socio-economic damage caused by that temperature change requires the modelling of climate impacts, population and demand projections, as well as technological resilience and innovation. Thus, there is a trade-off between simplicity, uncertainty and tangibility.

Myhre *et al.*[2] show that uncertainty is higher for GTP than for GWP for example: ±40% for GWP100 compared to ±75% for GTP100 (with a 90% confidence interval). However, the impact of different time horizons gives even more variation in results than this uncertainty. Further, the uncertainty in estimates of methane emissions in the first place have relatively high uncertainties in some cases *e.g.*,[51] which are likely to be of similar order of magnitude to those from GWP or GTP. Some uncertainty is to be expected, which is why sensitivity analyses should be carried out wherever an investment or policy decision is marginal or at risk. It is the authors' opinion that for technology assessments and annual emission inventory estimates, physical climate metrics that enable CO_2 equivalency over a broad range of values best serve the purpose of understanding the range of potential climate impacts.

6.5 Suitability for application

Perhaps most importantly, the chosen metric must be appropriate for the application. Different applications require different levels of complexity and span different time scales as shown in Table 4. Typical uses of climate metrics are:

- Emissions inventories from industry operations.
- National/regional emissions contributions.
- Technology assessments *e.g.* LCA for policy planning.
- Energy system mitigation pathways.

When the result will inform a long-term investment decision or policy, it is imperative that the impacts of using different metrics and time horizons on the result are explored.

Broadly, estimates of emissions over a short timeframe, *e.g.* annual emissions estimated from a company or national perspective, are likely to require a simple and static metric, given the lack of time variation and the requirement for fast and repeated estimation. For a technology assessment or a life cycle assessment that spans multiple years, a suitable metric may be:

Table 4 Categories of applications for the use of climate metrics, with associated qualities and requirements

Application	Timeframe	Calculation complexity	Static/dynamic	Suitable metrics
Annual estimate: facility/region	~1 year	Low	Static	GWP/GTP/similar
Technology assessments	~20 years	Medium	Static or dynamic	GWP/ICI/CCI/GSLP *etc.*
Decarbonisation pathways	~100 years	High	Dynamic	End-point metrics

a dynamic metric which accounts for the longer time frame considered; and a simple metric, given that the scope boundary is small and does not consider wider global implications. Estimates of emissions pathways to meet climate targets over longer time scales and multiple technologies may require metrics that: estimate the effects of climate change, either physical or economic damage; and may utilise more complex approaches such as climate models or end-point metrics.

7. The impact of different metrics on emissions results

As seen in the summary Table 3, the CO_2 equivalency values of methane range from 4 to 120 across metrics and time horizons. Additionally, the end-point metrics SCM and GDP have even higher values associated with the highest discount rates (for example the SCM estimates an equivalency of 199 at 10% discount rate[13]). It is clear that the time horizon (or discount rate) has the largest impact on variation, more so than the metric type. Given that these are static multipliers in emission estimates, the impact of using different static values is large and linear.

To determine the impact of using different static and dynamic metrics and time horizons, this study applies the various metrics and equivalency values to an emissions case study: an estimate of greenhouse gas emissions associated with the production and consumption of various shipping fuels, including liquefied natural gas (LNG), heavy fuel oil (HFO) and methanol. Multi-year technology or fuel assessments typically use a single metric (*e.g.* the GWP100), but this assessment shows that the use of a singly metric inappropriately ignores the importance of timing of emissions and of the differences between short-term and long-term climate impact.

LNG exhibits 25–30% lower CO_2 emissions than liquid fossil fuels such as HFO upon combustion on an energy output basis, but typically has greater methane emissions.[45–48] Total methane emissions are governed by both the upstream supply chain and the engine type: this study investigates the use of a lean-burn spark ignition (LBSI) and a high-pressure dual fuel (HPDF) engine.[45] HFO and methanol are both used within diesel engines, where methanol also has lower CO_2 emissions due to its relatively higher H–C ratio.[48–50] A full environmental assessment has been conducted and is presented in a parallel paper to this, but a summary of the life cycle CO_2 and methane emissions are given in Fig. 10.

For the natural gas supply chain, upstream methane emissions arise from extraction, gathering and processing, liquefaction, storage and bunkering. Median estimates from Balcombe *et al.*[51] were used for production, gathering and processing. Liquefaction figures were estimated based on mean values derived from 6 studies[52–57] and synthesised in Balcombe *et al.*[58] For LNG storage the study uses assumptions made in Lowell *et al.*,[53] whereas for bunkering, it is assumed that 0.22% of LNG is boiled off or displaced as vapour during fuelling, with a 50% capture resulting in 0.11% emission.[53,59]

For methanol, the production and processing of natural gas is the same as included for the LNG supply chain. The inventory for gas reforming and methanol synthesis is derived from the NREL database,[60] using the Ecoinvent 3.3 database for the ancillary impacts.[61] The upstream allocated impacts to heavy fuel oil and marine diesel oil are taken from the Ecoinvent 3.3 database. For HFO, bunker oil with an average sulphur content of 3.5% w/w is assumed. For diesel, the production of low sulphur light fuel oil is used, with a sulphur content of 0.005% w/w. For upstream carbon dioxide emissions, 440 gCO_2/kg HFO and 524 gCO_2/kg diesel is associated with the production up to point of use.[61]

Engine efficiencies, total methane emissions and total CO_2 emissions are given for each fuel/engine option in Table 5. For engine efficiencies, average values from various sources: ref. 45–48, 53, 62 and 63 were taken and emissions are expressed per kWh of power output considering the average efficiency.

As can be seen in Fig. 10, large differences exist across the options in methane emissions both upstream and at end-use, as

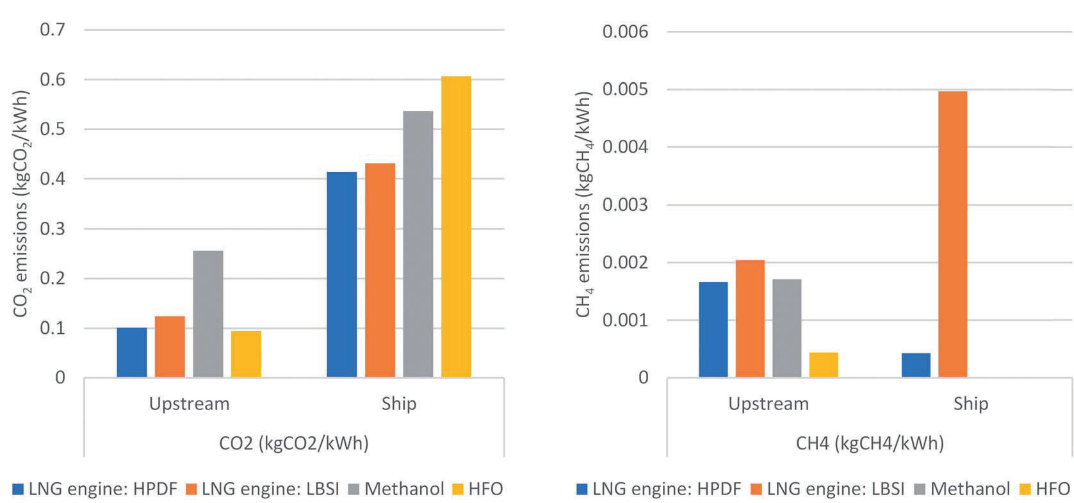

Fig. 10 CO_2 and methane emissions associated with the supply and use of 4 different fuels and engines for ships. Emissions are divided into upstream supply chain and ship usage. Source: ref. 51–61.

Table 5 Summary of inventory of engine efficiencies, methane and CO_2 emissions. Data averages from various sources: ref. 45–48, 53, 62 and 63

	LBSI	HPDF 2-stroke	HFO	MDO	Methanol
Efficiency (% LHV)	45%	51%	45%	45%	45%
Methane (gCH_4/kW h)	4.8	0.3	0.011	0.01	0
CO_2 (gCO_2/kW h)	462.3	427	593.0	524	536.4

well as some moderate variation in CO_2 emissions. Combined life cycle GHG emissions are represented in Fig. 11 for different CO_2 equivalency values assumed. Given the different emission profiles, there exist some crossover points where the rank order of fuels change. Under low equivalency values of less than 20 $gCO_{2eq.}/gCH_4$, both LNG fuelled engines exhibit the lowest GHG emissions. Putting this in context, CO_2 equivalence values of less than 20 are those associated with longer time horizons and end-point metrics which do not account for the high initial forcing impacts. Such metrics with less than 20 $gCO_{2eq.}/gCH_4$ are the GTP at timeframes greater than 45 years, the ICI at timeframes greater than 30 years and the global sea-level rise potential (GSP) and global precipitation change potential (GPP) at 100 year time horizon.

As CO_2 equivalency value increases, the higher methane emissions associated with LBSI LNG engine result in this fuel/engine option exhibiting the highest GHG emissions. Conversely, the LNG fuelled HPDF engine exhibits the lowest impacts across all equivalency values beside the highest at 120 $gCO_{2eq.}/gCH_4$, due to its significantly lower methane slip rates. It should be noted that methanol fuelled engines exhibit higher GHG emissions than HFO across all time horizons due to the high CO_2 emissions associated with methanol production from natural gas, as well as the moderate upstream methane emissions.

To understand the time dependence of emissions, we employ dynamic versions of the GTP and GWP for the above case study. The climate impact of the different fuels varies over time significantly, as shown in Fig. 12. When long time horizons are considered, LNG engines perform favourably, especially in the case of GTP. For GTP and time horizons greater than 40 years, LNG presents a reduced climate impact by 10–20%. However, the LBSI engine with high levels of methane slip performs very poorly with respect to short term climate forcing. With respect to GWP, the integrated nature of the metric means that the initial high climate forcing of LNG engines maintains its impact for the LBSI engine across all timeframes considered, resulting in a higher climate impact than HFO. The HPDF with lower methane slip and low CO_2 emissions has the lowest climate impact across all time horizons.

Two implications arise from this assessment. Firstly, short-term impacts are substantially different to long-term impacts across different technologies and the selection of timeframe may change the rank order of preference. It is imperative that both short and long-term climate impacts are accounted for when considering industrial investment or policy decisions. Secondly, for LNG fuelled engines to reduce GHG emissions compared to HFO, both upstream and end-use methane emissions must be constrained. Engines which inherently exhibit high methane slip are inappropriate for reduction of climate impacts. It should be noted however that LNG offers other benefits than just climate impact, including reduced NO_x, SO_x, particulates as well as cost improvements.

The effect of changing equivalency value on the climate impact of other technology groups is also noticeable. For example, Edwards and Trancik[16] compare the operation of a CNG passenger vehicle *versus* one fuelled with petrol. Using a GWP100 results in the CNG vehicle improving GHG emissions by 10–15%, but with a GWP20 the CNG vehicle exhibits 20% higher emissions than for petrol. Producing a dynamic assessment using ICI and CCI

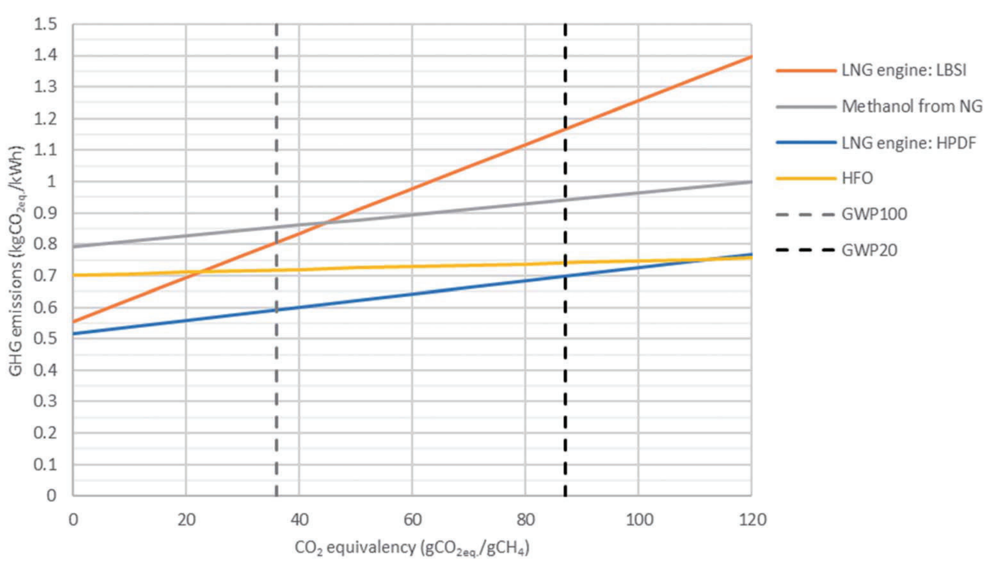

Fig. 11 Estimates of total CO_2 equivalent GHG emissions for different shipping fuels and engines.

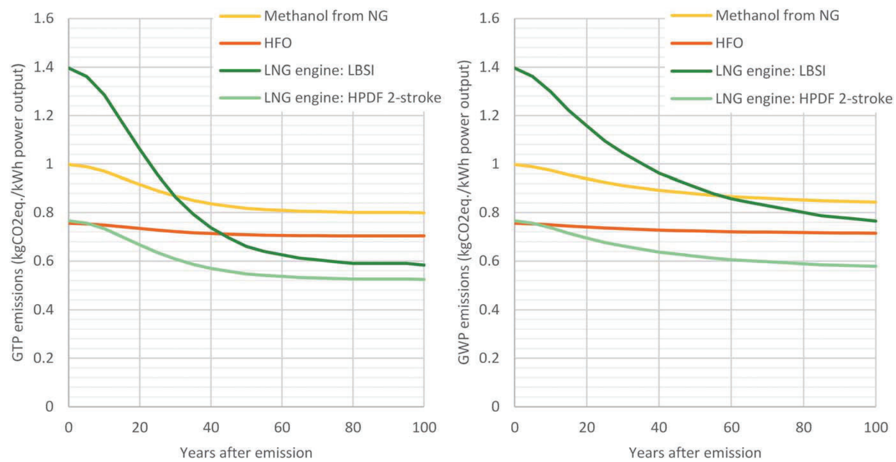

Fig. 12 Life cycle GHG emissions associated with a selection of fuels and marine engine types, expressed for each year after emissions using GTP (left) and GWP (right) metrics.

metrics shows that CNG passenger vehicles offer a climate benefit only over timeframes longer than 20 years.

The comparison of natural gas against coal for power generation is robust in favour of natural gas and shows preference in all but the most conservative of assumptions about GWP values and methane emissions.[64] However, for estimates where carbon capture and storage is used to reduce combustion emissions by up to 90%, the impact of methane emissions proportionally increases. In this case, the choice of metric and time horizon is likely to have a large impact on the relative benefit.

Thus, the selection of metric, and more importantly, time horizon, has a large impact on the ranking of these fuels and technologies, as well as the magnitude of estimates. Investment or policy decisions that trade-off different greenhouse gases like above must ensure that both short-term and long-term climate impacts are taken into consideration.

8. Conclusions and recommendations

This report has investigated the use of various climate metrics and analysed their key attributes and limitations, with respect to methane emissions. There is no single metric or time horizon that is appropriate for all applications and situations. One key point is that methane emissions for the most part are transitory,[33] whereas CO_2 emissions are persistent. Consequently, when considering time horizons the emphasis must not be lost on eliminating CO_2 emissions as, if they are not largely eliminated, the climate will not stabilise. Therefore, any adoption of a shorter time horizon should be tempered with a comparatively longer one.

Given the requirement to stabilise GHG concentrations and to ensure there is no long-term climate change beyond a 2 °C limit, it is inadvisable to use only a 20 year time horizon. A 20 year horizon effectively disregards the impact of emissions after this point, which in the context of comparing methane to CO_2 emissions, dangerously undervalues the long term impact of CO_2. A two-value approach, which indicates the effect over two different time horizons, is suggested by a number of studies.[65]

In selecting an appropriate metric, there is a trade-off between simplicity and transparency.[66] The most appropriate metric depends on the application and which aspect of climate change is most pertinent to the study.[2] Using a single value equivalency such as the GWP100 or GTP100, is the simplest option but hides much information which may be needed to make an investment decision or a policy recommendation. For example, a GHG with a short life but strong radiative forcing may have the same GWP value over a set time horizon as a GHG with a long life but weak forcing effect: the impact of each GHG on climate change may be significantly different but this is lost with such a simplification.[32]

A temperature-based metric such as GTP fits well with a temperature based climate target, but it is suggested that the damage caused by climate change will increase faster than the temperature increase.[13] Consequently, reducing our CO_2 equivalencies from GWP values to GTP values may cause an underestimation of the impact of methane. Even the use of GWP100 may cause an underestimation of the contribution of methane,[16] for example to impacts relating to sea level rise.[28]

The overarching recommendation from this study is to present emissions results with transparency. It is prudent to report methane and CO_2 emissions separately and where climate metrics are used, a summary of the magnitude and type of metric should be given. If the equivalency value has a large impact on results, both low and high values should be used to assess the impact.

Broadly, metric applications can be placed into three categories: short-term (*e.g.* annual) emissions estimates of processes, facilities or regions; multi-year technology assessments or life cycle assessments; and long-term modelling of energy systems and decarbonisation pathways. Recommendations are made for each category.

Estimates of emissions on a short timescale in the order of 1 year typically involve aggregating estimates for a facility or region and require simple static metrics such as GWP or GTP.

Two recommendation options are to: present emissions using a single GWP or GTP metric (50 or 100 year), and include the separated contribution from both methane and CO_2; present two time horizons, a short term (*e.g.* 20 or 50) and a longer term (*e.g.* 100 or more), such that any comparative arguments for technology change holds in both the short term or the long term, or at least that a detriment to either short or long term has been considered.

For technology assessments or life cycle assessments that span 20 or 30 years, suitable metrics could be static (GWP or GTP) or dynamic (*e.g.* ICI or TWP) to account for the emissions timing. However, given the uncertainty associated with a projected stabilisation year, this report considers dynamic metrics to be of only marginal benefit. Additionally, given the increase in complexity associated with using a dynamic metric, the selection of a static metric and incorporating two (or more) time horizons would be appropriate.

For longer term analyses of multiple energy systems over long timeframes, higher levels of complexity are acceptable and application of climate models is most suitable. Where this is not feasible, the application of dynamic metrics or the assessment of both short and long-term time horizons is imperative, especially under scenarios where methane emissions are significant.

In summary, the use of climate metrics in GHG estimation must be carried out with great care and the standard usage of a single global warming potential is not acceptable as it may hide key trade-offs between short and long-term climate impacts. To counter this, transparent reporting of methane and CO_2 emissions is required. It is vital to test any GHG estimates with high and low equivalency values to ensure that we are not simply replacing long-term climate forcing with short-term, or *vice versa*.

Conflicts of interest

There are no conflicts to declare.

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European Commission

Energy, Climate change, Environment

Energy

Methane emissions

The EU methane strategy aims to reduce methane emissions, improve air quality and reinforce the EU’s global leadership in the fight against climate change.

Methane is the second most important greenhouse gas contributor to climate change following carbon dioxide. In fact, methane’s ability to trap heat in the atmosphere is even stronger than that of carbon dioxide.

On a 100-year timescale, methane has 28 times greater global warming potential than carbon dioxide and is 84 times more potent on a 20-year timescale.

According to the International Energy Agency, the annual increase in methane concentration from 2020 to 2021 was the highest on record and real-time data shows that levels continued to increase in 2022. When using fossil gas for electricity generation, lifecycle methane emissions must not exceed 3% of delivered volumes, because in climate terms, it would then be better to use coal for electricity generation. Abating methane emissions is therefore highly relevant to achieving the 2050 climate objectives. Moreover, methane is a potent local air pollutant and contributor to ozone formation, which causes serious health problems.

Key figures on methane

2nd

most important GHG contributor to climate change

60%

of the global methane emissions result from human activity

1/3

of this comes from the energy sector

According to the Climate and Clean Air Coalition (CCAC) Scientific Advisory Panel, reducing methane emissions associated with human activity by 50% over the next 30 years would mitigate against global temperature change by 0.2°C, a significant step towards keeping the overall temperature increase below 2°C.

The International Energy Agency estimates that more than 260 bcm of gas was wasted worldwide in 2021 (https://www.iea.org/reports/global-methane-tracker-2023/overview) due to flaring, venting and leaking and that 47% of those emissions can be mitigated with existing technology through measures, such as leak detection and repair. That gas could contribute to the EU security of supply, greater liquidity and help lower prices. It could also mean that new reserves would not be needed to take us to 2050. Given the market value of the additional gas captured through such measures, 40% of these mitigations would have no net-cost.

EU methane strategy

©European Union

Tackling greenhouse gas emissions is a priority of the European Green Deal.

The EU's methane strategy (COM2020/663), published in October 2020, sets Europe's ambition and aims to curb temperature increases, improve air quality and reinforce the EU's global leadership in the fight against climate change.

It focuses on reducing methane emissions in the energy, agriculture and waste sectors, which account for almost all human-related methane emissions.

This cross-sectoral approach takes targeted action in each area while also promoting synergies across sectors, for example through the production of biomethane.

Regulation on methane emissions reduction in the energy sector

As announced in the EU methane strategy, the Commission adopted on 15 December 2021 a proposal for a regulation aimed at reducing methane emissions in the energy sector.

The provisional agreement was reached *(https://ec.europa.eu/commission/presscorner/detail/en/IP_23_5776)* between the European Parliament and the Council on 15 November 2023. After its formal adoption, it will be published in the EU Official Journal and enter into force 20 days later.

The new legal act will provide for reducing energy sector methane emissions in Europe and in our global supply chains. It aims to stop the avoidable release of methane into the atmosphere and to minimise leaks of methane by fossil energy companies operating in the EU. The new regulation covers

- improved measurement, reporting and verification of energy sector methane emissions
- an immediate reduction in emissions through mandatory leak detection and repair and a ban on venting and flaring practices, which involve the release of methane directly into the atmosphere
- a methane transparency requirement on imports, collecting information on whether and how exporter countries/companies are measuring, reporting and abating methane emissions, with a view to establish a methane intensity profile of those entities

The Commission proposals on measurement and reporting of methane emissions, which build on the Oil and Gas Methane Partnership 2.0 (OGMP 2.0) framework, will help understand the exact locations and volumes of methane emitted, allowing a shift from estimates to direct measurements of methane emissions, checked by independent verifiers. The urgency to tackle methane emissions is reflected in the proposals on mitigation that aim to deliver reductions soon after the legislation will enter into force.

For **oil and gas**, companies would need to frequently survey their equipment to detect leaks. If found, they would need to be repaired immediately, mostly within 5 or 15 working days and monitored to ensure that repairs were successful. The proposal also bans venting and routine flaring, allowing venting only in exceptional or unavoidable circumstances for safety reasons. It allows flaring only if re-injection, utilisation on-site or transport of the methane to a market are not technically feasible, with more restrictive rules for how it can be carried out.

For **coal**, the proposal envisages a phase out of venting and flaring of methane, ensuring that safety aspects in coal mines are accounted for. The proposal also obligates EU countries to establish mitigation plans in the case of abandoned coal mines and inactive oil and fossil gas wells.

Partners and initiatives

As methane emissions transcend national borders, the European Green Deal stresses the need for international collaboration.

Global Methane Pledge

President von der Leyen and President Biden launched the Global Methane Pledge (GMP) at COP26 in Glasgow 2021 to slash methane emissions by 30% by 2030. Since its launch, the GMP has generated unprecedented momentum for methane action. Country endorsements have grown from just over 100 in 2021 to over 150 representing 80% of the global economy, and more than 50 countries have developed national methane action plans or are in the process of doing so.

At the COP28 Global Methane Pledge Summit in December 2023, President von der Leyen presented the first ever EU methane regulation for the energy sector and announced €175 million in funding to methane actions *(https://ec.europa.eu/commission/presscorner/detail/en/ip_23_6057)*. Moreover, she committed to developing a roadmap for COP29 for the global rollout of the "You Collect, We Buy" scheme, whereby the EU incentivises companies to commercialise gas that would otherwise go to waste, announcing that the EU and Algeria would be the first to pilot the scheme.

This video is also available on the EC AV portal. It was produced for COP28 December 2023, and explains the objectives of the Global Methane Pledge.

At the Major Economies Forum in April 2023, the EU joined the **Methane Finance Sprint**, launched by President Biden asking governments to contribute to the goal of mobilising at least $200 million in new methane finance for projects by COP28.

In September 2023, at the occasion of the UN General Assembly in New York, Canada, the Federated States of Micronesia, Germany, Japan, and Nigeria joined the EU and the US as Champions of the Global Methane Pledge.

In June 2022, a **GMP Energy Pathway** was launched at the Major Economies Forum on Energy and Climate to accelerate methane emissions reductions in the fossil energy sector. A **GMP Food and Agriculture Pathway** and **GMP Waste Pathway** were launched in the margins of COP27, where the EU and the US convened a Methane Ministerial to highlight the progress and discuss further implementation steps, including enhanced efforts leading up to COP28.

Joint declaration on reducing GHG emissions from fossil fuels

At COP27 in 2022, the EU also confirmed its commitment on methane emission reduction by endorsing a 'Joint declaration on reducing greenhouse gas emissions from fossil fuels *(https://ec.europa.eu/commission/presscorner/detail/en/statement_22_6827)*', together with the United States, Japan, Canada, Norway, Singapore, and the United Kingdom.

Together they represent 50% of global gas import volumes and over 30% of global gas production. And they aim to take steps to reduce the methane emissions associated with their energy consumption, which can spur emissions reductions across the value chain.

MMRV Working Group

The new International Working Group on measurement, monitoring, reporting and verification (MMRV) was publicly announced on 15 November 2023. It's a follow up action to the Joint Declaration on reducing greenhouse gas emissions from fossil fuels adopted at COP27, where the importance of adopting robust measurement, monitoring, reporting, and verification frameworks at international level was highighted.

The Working Group members include 12 countries, the European Commission and the East Mediterranean Gas Forum (as observer): Australia, Brazil, Canada, Colombia, France, Germany, Italy, Japan, Norway, Republic of Korea, United Kingdom and the United States of America.

It aims to develop a consensus-based approach for the MMRV of greenhouse gas (GHG) emissions across the international supply chain of natural gas, from pre-production through final delivery, to enable the provision of comparable and reliable information as well as to better equip companies with tools to rapidly reduce their GHG emissions.

The Working Group will also advance data accuracy and comparability by building upon well-established and globally recognised frameworks, particularly OGMP 2.0, which today includes over 115 companies with assets in more than 60 countries, representing over 35% of the world's oil and gas production and over 70% of LNG flows.

International Methane Emission Observatory

To help take the issue forward, the Commission supported in 2021 the establishment of the International Methane Emission Observatory (IMEO) together with the UNEP, the Climate and Clean Air Coalition and the International Energy Agency.

Funding from EU Horizon 2020 kick-started the development of the observatory, followed by further contributions from the EU through the Neighbourhood, Development and International Cooperation Instrument (NDICI) and from other partners, such as the Global Methane Hub and Bezos Earth Fund.

The IMEO collects and verifies methane emissions data to provide the international community with an improved understanding of global emissions and where abatement action should be focused. It provides a sound scientific basis for the implementation of the Global Methane Pledge. Its collected data help to prioritize actions and monitor results against commitments made by state actors as well as oil and gas companies.

The IMEO also coordinates the Oil and Gas Methane Partnership 2.0 (OGMP 2.0), the flagship oil and gas reporting and mitigation programme of UNEP. It is the only comprehensive, measurement-based international reporting framework for the sector, which today covers 35% of oil and gas producers and 70% of LNG flows.

In November 2022, at the COP27 in Sharm El-Sheikh, IMEO announced the Methane Alert and Response System (MARS), a satellite-based system to detect methane emissions. It has started through pilots to detect major emissions from the energy sector, and in the future, it will expand to cover other methane emitting sectors, such as waste and livestock.

Climate and Clean Air Coalition

The EU is actively involved in several international initiatives on reducing methane emissions, including through the Climate and Clean Air Coalition (CCAC), established under the United Nations Environment Programme (UNEP). The CCAC works to tackle short-lived climate pollutants such as methane and black carbon in an effort to combat climate change and improve local air quality. In this context, the Commission submitted an EU methane action plan in November 2022 to appear alongside other national plans.

Documents

- Factsheet: Global Methane Pledge: From Moment to Momentum (November 2022)
- EU Methane Action Plan (November 2022)
- Report: An Eye on Methane: International Methane Emissions Observatory 2023 Report (https://www.unep.org/resources/report/eye-methane-international-methane-emissions-observatory-2023-report) (December, 2023)
- Report: Climate change 2013: The physical science basis (Intergovernmental Panel on Climate Change, 2013)

Related links

Press material and news

- EU announces €175m financial support to reduce methane emissions at COP28 (https://ec.europa.eu/commission/presscorner/detail/en/ip_23_6057) (02/12/2023)
- Commission steps up ambition to agree on a global framework for the measurement, monitoring, reporting and verification of greenhouse gas emissions (/news/commission-steps-ambition-agree-global-framework-measurement-monitoring-reporting-and-verification-2023-11-15_en) (15/11/2023)
- Deal on first-ever EU law to curb methane emissions (15/11/2023)
- Proposal of a new EU framework to decarbonise gas markets, promote hydrogen and reduce methane emissions (15/12/2021)

- Methane tracker 2023, International Energy Agency
- Proposal for a Regulation on methane emissions reduction in the energy sector (COM (2021)805)
- Impact assessment report (SWD/2021/459)
- Executive summary of the impact assessment report (SWD/2021/460)
- Study: Assistance to assessing options improving market conditions for bio-methane and gas market rules (December 2021)
- An EU strategy to reduce methane emissions (COM(2020)663 final)
- Workshop: Strategic plan to reduce methane emissions in the energy sector (20/03/2020)
- International Methane Emissions Observatory (https://www.unep.org/explore-topics/energy/what-we-do/methane/imeo)
- Global Methane Pledge
- Climate and Clean Air Coalition (CCAC)

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ARTICLE

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Delaying methane mitigation increases the risk of breaching the 2 °C warming limit

Claude-Michel Nzotungicimpaye [1,2,3✉], Alexander J. MacIsaac[1] & Kirsten Zickfeld [1]

Atmospheric methane levels are growing rapidly, raising concerns that sustained methane growth could constitute a challenge for limiting global warming to 2 °C above pre-industrial levels, even under stringent CO_2 mitigation. Here we use an Earth system model to investigate the importance of immediate versus delayed methane mitigation to comply with the 2 °C limit under a future scenario of low CO_2 emissions. Our results suggest that methane mitigation initiated before 2030, alongside stringent CO_2 mitigation, could enable to limit global warming to well below 2 °C over the next three centuries. However, delaying methane mitigation to 2040 or beyond increases the risk of breaching the 2 °C limit, with every 10-year delay resulting in an additional peak warming of ~0.1 °C. The peak warming is amplified by the carbon-climate feedback whose strength increases with delayed methane mitigation. We conclude that urgent methane mitigation is needed to increase the likelihood of achieving the 2 °C goal.

[1] Department of Geography, Simon Fraser University, Burnaby, BC, Canada. [2] Department of Geography, Planning and Environment, Concordia University, Montréal, QC, Canada. [3] Climate and Environment, St. Francis Xavier University, Antigonish, NS, Canada. ✉email: cnzotung@stfx.ca

Methane (CH_4) is a potent greenhouse gas, second only to CO_2 in the contribution to global temperature increase relative to pre-industrial levels[1]. Atmospheric CH_4 levels have grown rapidly since the year 2007[2,3]. The mean atmospheric CH_4 concentration ([CH_4]) currently exceeds 1900 parts per billion (ppb), which is >2.5 times larger than the pre-industrial average[4]. Recent trends of observed CH_4 levels are tracking future scenarios of unmitigated emissions[5,6]. For more than three decades, global CH_4 emissions have been dominated by anthropogenic sources mostly related to fossil fuel exploitation, livestock production, waste and agriculture[2,3,7]. Several studies have highlighted the importance of CH_4 mitigation for tackling climate change in the current century, in parallel with efforts to decarbonize the world economy[8–10].

A salient outcome of the 2015 Paris Agreement is the international commitment to keep global warming to well below 2 °C above pre-industrial levels, and pursue efforts to limit the mean global temperature increase to 1.5 °C above pre-industrial levels[11]. Achieving these temperate goals will require reaching net-zero CO_2 emissions alongside deep reductions in CH_4 and other non-CO_2 emissions by or around mid-century[12]. While the need for urgent CH_4 mitigation is now recognized (e.g. the Global Methane Pledge following COP26[13]), it is necessary to assess the importance of immediate versus delayed CH_4 mitigation to comply with the temperature goals in the Paris Agreement—particularly taking into account potential Earth system feedbacks. There is still limited knowledge about (i) the importance of biogeochemical feedbacks[14,15] in the context of CH_4 mitigation for achieving the Paris temperature goals[16,17], and (ii) long-term (i.e. multi-century) climate impacts of delaying or failing to mitigate CH_4 in the current century[18,19].

In this study, we use an Earth system model with an interactive CH_4 cycle to investigate the importance of immediate versus delayed CH_4 mitigation to comply with stringent warming limits in the Paris Agreement. It is important to note that: (i) currently, there are very few Earth system models driven by CH_4 emissions in their representation of the global CH_4 cycle[17,20]; and (ii) previous research applying an Earth system modeling approach to investigate CH_4 mitigation and its implication for meeting stringent temperature goals have relied on scenarios of prescribed [CH_4] without considering explicit changes in anthropogenic CH_4 emissions, potential climate-CH_4 feedbacks, and climate impacts of CH_4 mitigation beyond the 21st century[16]. We use version 2.10 of the University of Victoria Earth System Climate Model (UVic ESCM)[21], into which we implemented a simplified representation of the global CH_4 cycle—featuring simulated wetland CH_4 emissions (including CH_4 emissions from previously frozen soil carbon upon permafrost thaw)[22] and atmospheric CH_4 decay (See Methods). We validate the model against historical [CH_4] data and estimations of the global CH_4 budget in recent decades (See Supplementary Notes 1 & 2).

To assess the importance of timing for CH_4 mitigation to achieve the 2 °C temperature goal, we prescribe anthropogenic CH_4 emissions according to two Shared Socioeconomic Pathways (SSPs)[23,24]: (i) SSP1-2.6, a scenario featuring immediate CH_4 mitigation; and (ii) SSP3-7.0, a scenario without CH_4 mitigation throughout the 21st century. We design four additional scenarios of anthropogenic CH_4 emissions by assuming different initiation of CH_4 mitigation over the next few decades. These scenarios follow the SSP3-7.0 trajectory up to a specific year (2020, 2030, 2040 and 2050) and decline linearly to reach the same amount of CH_4 emissions as SSP1-2.6 in 2100, and then evolve according to the SSP1-2.6 extension beyond the 21st century (Fig. 1). These mitigation scenarios assume deep reductions in anthropogenic CH_4 emissions, corresponding to 69–78% of emission reductions between the year of peak emissions and the year 2100

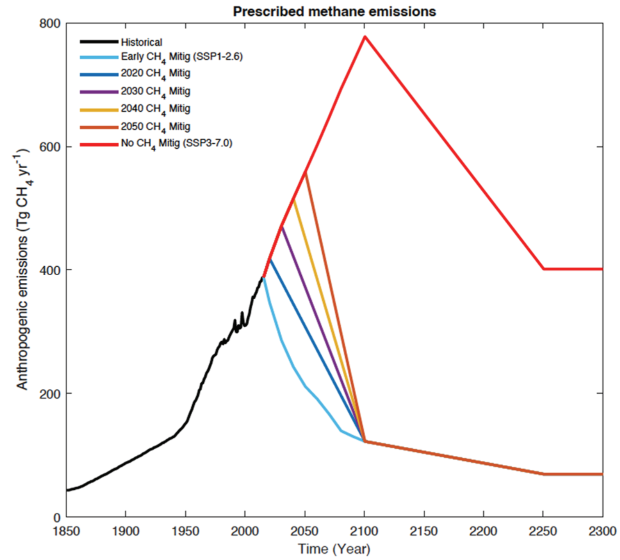

Fig. 1 Anthropogenic CH_4 emissions prescribed to the UVic ESCM in this study. Emissions in the early mitigation scenario ("Early Mitig") correspond to SSP1-2.6, whereas emissions without mitigation ("No Mitig") correspond to SSP3-7.0. Immediate and delayed mitigation scenarios follow the SSP3-7.0 CH_4 emission trajectory to the specified point in time and decline linearly to reach the same amount of CH_4 emissions as SSP1-2.6 in 2100, and evolve according to the SSP1-2.6 extension beyond the 21st century.

(Supplementary Table 1). CH_4 mitigation approaches that are currently achievable with existing strategies and technologies (i.e. technically feasible solutions) could– once deployed– lead to the elimination of >50% of global anthropogenic CH_4 emissions by the year 2050, with large contributions from cutting fossil fuel and solid waste emissions[25]. By design, our idealized mitigation scenarios allow us to compare the effect of immediate versus delayed CH_4 mitigation on the global climate at the end of the 21st century and beyond. We further assume that all other future anthropogenic forcings (including CO_2 emissions) evolve according to SSP1-2.6, which is a scenario aimed at limiting global warming to below 2 °C throughout the 21st century[26].

Results

Delaying CH_4 mitigation results in higher peak warming. The timing of CH_4 mitigation affects peak levels of [CH_4], [CO_2], and surface air temperature (SAT) in the future. According to our model, every 10-year delay in CH_4 mitigation increases the [CH_4] peak by 150-180 ppb (Fig. 2b). As such, delaying CH_4 mitigation to the 2040-2050 decade will increase the [CH_4] peak by 450–540 ppb relative to CH_4 mitigation initiated at or around 2020. The [CH_4] increase has a direct effect on global mean surface air temperature (SAT). For every 10-year delay in CH_4 mitigation, our model simulates an additional peak warming of ~0.1 °C (Fig. 2d). Delaying CH_4 mitigation to or around mid-century will increase the peak warming by 0.2–0.3 °C relative to a CH_4 mitigation initiated at present-day. Through feedback mechanisms operating in the Earth system (discussed below), one indirect effect of delaying CH_4 mitigation manifests with atmospheric CO_2 concentration ([CO_2]). Our model suggests that every 10-year delay in CH_4 mitigation implies an increase in the [CO_2] peak by 2-3 ppm (Fig. 2c). Consequently, delaying CH_4 mitigation to the 2040-2050 decade will increase the [CO_2] peak by 6-9 ppm relative to CH_4 mitigation at present-day. Relative to the early mitigation scenario (SSP1-2.6), delaying CH_4 mitigation to the 2040-2050 decade implies more [CH_4]

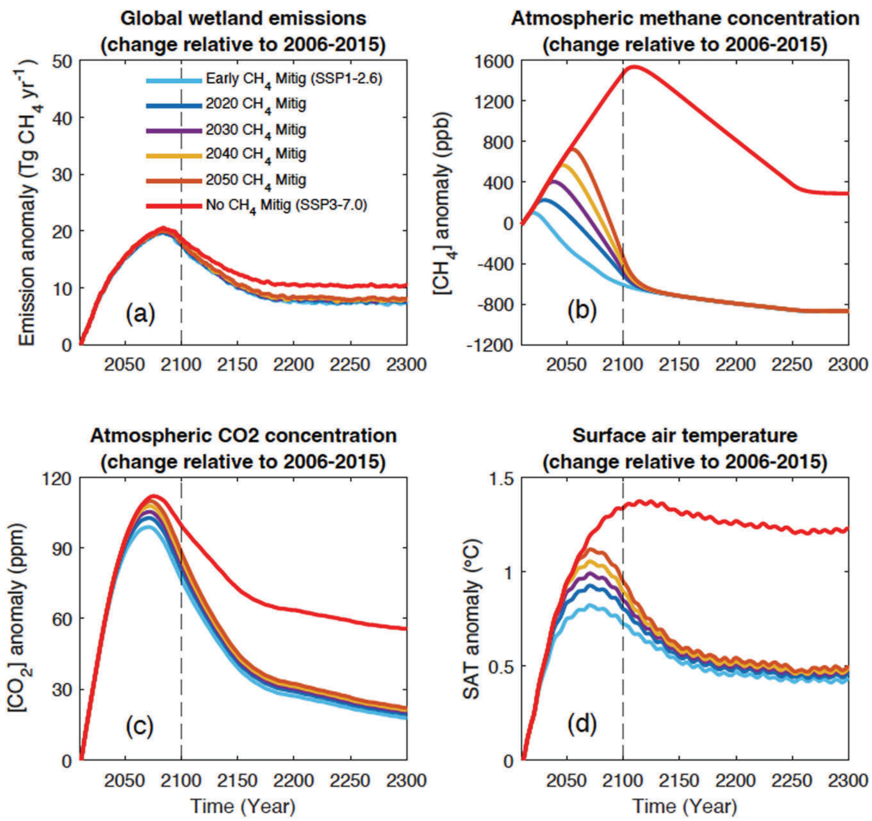

Fig. 2 Projected changes in atmospheric composition and temperature relative to present-day conditions under the mitigation scenarios explored in this study. Changes are shown for (**a**) global wetland CH_4 emissions, (**b**) atmospheric CH_4 concentration, (**c**) atmospheric CO_2 concentration, and (**d**) surface air temperature (SAT) relative to 2006-2015 for different initiation of CH_4 mitigation under the assumption that all non-CH_4 forcing agents (including CO_2) from anthropogenic sources evolve according to SSP1-2.6. The variability in the SAT curves is associated with the solar cycle.

(~200 ppb) and warming (~0.2 °C) at the year 2100 (Fig. 2b, d and Supplementary Note 3).

The decline in [CH_4] in response to CH_4 mitigation depends on the balance between CH_4 sources and sinks (Supplementary Fig. 1). CH_4 sources are dominated by anthropogenic CH_4 emissions (Fig. 1 and S1a), whereas CH_4 sinks in our model are proportional to the atmospheric CH_4 burden (Methods and Supplementary Fig. 1b, c). A delayed CH_4 mitigation results in a higher atmospheric CH_4 burden and [CH_4] than for an early mitigation, which implies a lag in the decline of CH_4 sinks and [CH_4] for the delayed mitigation in comparison to the early mitigation. Implications of this lag are most noticeable towards the end of the 21st century: while total CH_4 emissions converge in 2100 for all mitigation scenarios, the atmospheric CH_4 burden around the year 2100 remains high for delayed CH_4 mitigation relative to early CH_4 mitigation owing to a lag in CH_4 sinks (Supplementary Fig. 2). Overall, relative to the early CH_4 mitigation (SSP1-2.6), simulated CH_4 sinks in 2100 are ~65 Tg CH_4 yr^{-1} higher for CH_4 mitigation delayed to 2040-2050 (See Supplementary Note 4).

The peak warming is amplified by biogeochemical feedbacks. In our model simulations, SAT changes are influenced by biogeochemical feedbacks in addition to the timing of CH_4 mitigation. In particular, we find that the feedback of SAT changes on the atmospheric CO_2 concentration (referred to as the carbon-climate feedback) contributes to increasing peak SAT differences between early and delayed CH_4 mitigation. While we prescribe the same anthropogenic CO_2 emissions in all our model simulations (See Methods), atmospheric CO_2 levels are projected to be higher for delayed CH_4 mitigation scenarios than for early CH_4 mitigation scenarios (Fig. 2c). In comparison to early CH_4 mitigation, delayed CH_4 mitigation results in high [CH_4] levels that lead to high SAT levels. Enhanced global warming results in high [CO_2] levels, which in turn contribute to increase the SAT differences between early and delayed CH_4 mitigation scenarios. Such feedbacks between SAT and [CO_2] involve the response of natural CO_2 sinks to global warming and climate change. For instance, increased SAT enhances the release of CO_2 through soil respiration and weakens the uptake of atmospheric CO_2 by oceans through the solubility pump, resulting in enhanced [CO_2] and an amplification of global warming[14]. Overall, we deduce that the carbon-climate feedback amplifies the SAT response in late versus early CH_4 mitigation scenarios (Fig. 2d and Fig. 3). To quantify the contribution of the carbon-climate feedback to additional peak warming from delayed CH_4 mitigation, we performed additional model simulations with prescribed CO_2 concentration from the early mitigation scenario (i.e. Early CH_4 Mitig SSP1-2.6). These model simulations suppress the warming signal from delayed CH_4 mitigation that is due to the carbon-climate feedback, and their difference with our standard model simulations allows to quantify the magnitude of the feedback. According to our results, the contribution of the carbon-climate feedback to the peak warming increases for every 10-year delay in CH_4 mitigation (Fig. 3). The peak warming attributable to the feedback ranges from ~0.03 °C for CH_4 mitigation initiated in 2020 to ~0.06 °C for CH_4 mitigation initiated in 2050 (Fig. 3).

In contrast, we do not detect a strong feedback between global warming and wetland CH_4 emissions in our model simulations– despite changes in precipitation patterns and wetland areal extents between the different mitigation scenarios explored in this study (Supplementary Fig. 3). Differences in projected wetland CH_4

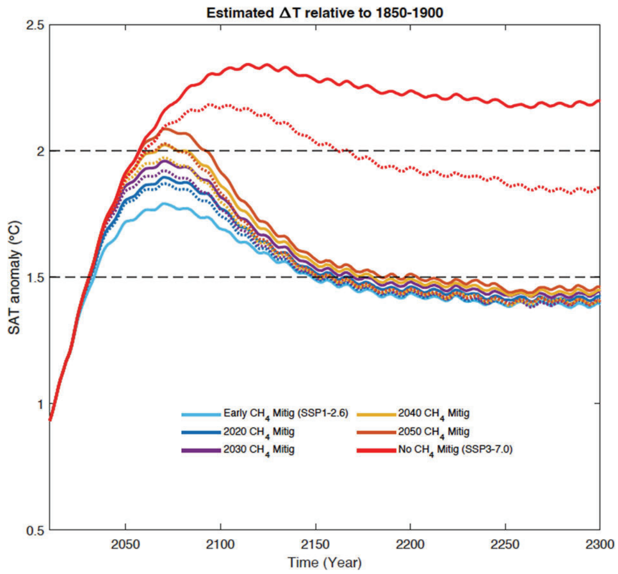

Fig. 3 Projected changes in air temperature relative to the pre-industrial era under the mitigation scenarios explored in this study. Changes are shown for global mean surface air temperature (SAT) relative to 1850–1900 for different initiation of CH_4 mitigation under the assumption that non-CH_4 forcing agents evolve according to SSP1-2.6. An estimate of 0.97 °C is considered for the global warming level in the 2006-2015 decade relative to the 1850–1900 period[29]. The variability in the SAT curves is associated with the solar cycle. Given that the observed historical warming level for the 2006-2015 decade relative to the 1850–1900 period is associated with an uncertainty of ±0.12 °C[29], we provide a version of this figure with the uncertainty range in the supplementary information (Supplementary Fig. 5). The dashed lines correspond to model simulations with prescribed CO_2 concentration from the Early CH_4 Mitig (SSP1-2.6) scenario, which imply climate projections without the carbon-climate feedback. The difference between dashed and continuous lines of the same color illustrates the magnitude of the carbon-climate feedback.

emissions between early and delayed CH_4 mitigation scenarios do not exceed 1 Tg CH_4 yr^{-1} for more than two centuries (Fig. 2a), which translates into a negligible fraction of [CH_4] and SAT differences between these mitigation scenarios. We conclude that the importance of the feedback between wetland CH_4 emissions and climate change is small under the low CO_2 emission scenarios explored in this study.

Timing of CH_4 mitigation and stringent warming limits. Determining the historical warming level is a critical aspect for assessing the implications of future climate projections on global warming limits in the Paris Agreement[27,28]. Our model simulates a global warming level of 1.1 °C for the 2006-2015 decade relative to the 1850–1900 period, whereas the recent Sixth Assessment Report (AR6) by the IPCC provides an estimate of 0.97 °C for the global warming level over the same decade relative to the same baseline period[29]. Hence, for this study, we adopt the above IPCC estimate to project future global warming levels associated with different scenarios of CH_4 mitigation (Fig. 3).

According to our model simulations, the 2 °C temperature goal can be achieved through rapid and deep cuts in anthropogenic CH_4 emissions along with stringent CO_2 mitigation. Our results suggest that global warming relative to the pre-industrial period (1850–1900) could be limited to well below 2 °C throughout the 21st century if global-scale CH_4 mitigation is initiated before 2030 while all other anthropogenic emissions evolve according to SSP1-2.6 (Fig. 3). However, if CH_4 mitigation is delayed to 2040, our results suggest that the 2 °C warming target will be overshot for at least two decades in the 21st century (Fig. 3), with longer mitigation delays implying longer overshoot periods of the 2 °C threshold. As expected with SSP1-2.6, all our considered CH_4 mitigation scenarios imply a breaching of the 1.5 °C limit relative to the 1850–1900 levels (Fig. 3).

Timing of CH_4 mitigation and its implications beyond the 21st century. The timing of CH_4 mitigation over the next three decades has implications beyond the 21st century. While anthropogenic CH_4 emissions prescribed to our model converge by the year 2100 for all considered scenarios other than SSP3-7.0 (Fig. 1), atmospheric [CH_4] levels for delayed and early CH_4 mitigation scenarios converge in the first half of the 22nd century (Fig. 2b). However, SAT differences between our mitigation scenarios persist for more than two centuries in the future (Fig. 2d), owing partly to the carbon-climate feedback (Fig. 2c and Fig. 3) as well as inertia in the climate system. These results suggest that, although CH_4 stays in the atmosphere for only about a decade, delaying CH_4 mitigation by 10–30 years will have an impact on global warming over many centuries.

The timing of CH_4 mitigation has long-term implications for achieving the temperature goals in the Paris Agreement. When implemented alongside CO_2 mitigation, rapid and deep reductions in CH_4 emissions will provide long-term benefits with regards to lowering global warming levels. According to our model simulations, initiating CH_4 mitigation before 2050 will increase the likelihood of limiting global warming to 1.5 °C in the long run—from the second half of the 22nd century onwards, after an overshoot in the first half of the 21st century (Fig. 3). However, even under the assumption of net-zero CO_2 emissions by mid-century, an eventual failure to mitigate CH_4 in the current century will raise global warming to >2 °C above pre-industrial levels throughout the 21st century and beyond (Fig. 3). We conclude that rapid CH_4 mitigation efforts will provide a long-term safeguard for the temperature goals in the Paris Agreement, whereas a failure to mitigate CH_4 within the next few decades will constitute a serious challenge for achieving the 2 °C warming limit.

Discussion

Previous studies have demonstrated that deep reductions in CH_4 emissions alongside stringent CO_2 mitigation by mid-century are needed to limit global warming to below 2 °C above pre-industrial levels, in agreement with our results[18,19,30,31]. Our study presents two additional findings: (i) the importance of biogeochemical feedbacks in the context of CH_4 mitigation to achieve stringent temperature limits, and (ii) long-term climate impacts of a delay or failure to mitigate CH_4 in the current century. Our study shows that the carbon-climate feedback amplifies the SAT response for delayed versus early CH_4 mitigation. In particular, our results suggest that the strength of the carbon-climate feedback increases for every 10-year delay in CH_4 mitigation (Fig. 3). The simulated contribution from the carbon-climate feedback to the peak warming ranges from ~0.03 °C to ~0.06 °C for CH_4 mitigation initiated in 2020 and 2050, respectively. Given that the UVic ESCM has a relatively high carbon-climate feedback parameter compared to most other ESMs[32] and a TCRE (transient climate response to cumulative emissions) value close to the CMIP6 ensemble mean[14,21], we infer that our estimated warming from the carbon-climate feedback lies in the upper 50-percentile of what the CMIP6 ESM ensemble would simulate in the context of this study. With regards to climate-CH_4 feedbacks, our model simulations suggest a negligible contribution from wetland CH_4 emissions to temperature change for every 10-year delay CH_4

mitigation in a low CO_2 emission scenario. However, we do not rule out the potential for a strong climate-CH_4 feedback involving wetlands, wildfires, and atmospheric CH_4 oxidation[15]—which would imply a potential underestimation of the contribution from the climate-CH_4 feedback to the additional peak warming under delayed CH_4 mitigation.

Despite that CH_4 stays in the atmosphere for only about 10 years, delaying CH_4 mitigation by 2-3 decades will have an impact on global warming over many centuries (Fig. 2d and Fig. 3). Such a delayed CH_4 mitigation may result in other long-term impacts such as a persistent sea-level rise over many centuries[33]. On the contrary, early CH_4 mitigation reduces the risk of losing the summer sea-ice across the Arctic Ocean[34]. A failure to mitigate CH_4 in the current century implies a high risk for global warming to exceed the 2 °C warming limit for more than two centuries even under net-zero CO_2 emissions by 2050 (Fig. 3). Such an overshoot of the 2 °C threshold has the potential to increase the risk for record-breaking climate extremes[35] and tipping elements in the Earth's climate system such as the dieback of the Amazon rainforest as well as the melting of the Greenland and West Antarctic Ice Sheets[36].

While mitigation research and efforts generally focus on achieving net-zero CO_2 emissions by 2050[12,19], it is becoming more clear that rapid reductions of both CO_2 and CH_4 emissions are crucial for holding global warming to well below 2 °C above pre-industrial levels[37]. To pave the way for CH_4 mitigation in the context of meeting the temperature goals in the Paris Agreement, there is a growing number of studies on: (i) understanding processes and reasons behind changes in [CH_4] trends in recent decades[2,5], (ii) constraining the global CH_4 budget[2,38], and (iii) developing strategies for reducing anthropogenic CH_4 emissions[39] as well as technologies for atmospheric CH_4 removal[40]. Research suggests that many anthropogenic sources of CH_4 can be reduced cost-efficiently[19,25,39,41], and that the priority for deep emission cuts should be in the energy, industry and transport sectors without neglecting the high potential from the waste and agricultural sectors[6,7,19,30,31,39]. If deployed rapidly, readily available measures for large-scale CH_4 mitigation by sector can contribute to slowdown global warming[18]. In addition to the Global Methane Pledge by >100 countries representing 70% of the global economy[13], multilateral partnerships already exist to support large-scale CH_4 mitigation (e.g. the Climate and Clean Air Coalition as well as the Global Methane Initiative[42–45]). Given that atmospheric CH_4 is a precursor to ground-level ozone (O_3)—an air pollutant with negative impacts on human health and crop yields, CH_4 mitigation offers the opportunity of simultaneously tackling climate change and improving air quality, global health, as well as food security[17,46,47].

Limitations of this study include uncertainties in the areal extent and dynamics of natural wetlands, as well as in the wide array of physical, biological, and chemical controls on CH_4 production and oxidation which determine the response of wetland CH_4 emissions to climate change[48]. Despite its simplicity, our wetland CH_4 model is capable of reproducing present-day wetland CH_4 emissions based on soil moisture, carbon, and temperature simulated by the UVic ESCM[22] (Supplementary Table 2). Additional limitations of this study are associated with: (i) static CH_4 emissions from non-wetland natural sources, and (ii) a constant lifetime for atmospheric CH_4 as part of the parameterization for atmospheric CH_4 decay. Natural CH_4 emissions from non-wetland sources (such as termites, lakes, wildfires, geologic seeps, marine hydrates) are not represented in the UVic ESCM and are held fixed in our model simulations (See Methods). Processes governing the future evolution of these natural CH_4 sources are poorly understood[2,49].

The consideration of a constant lifetime for atmospheric CH_4 is a simplified assumption made in this study as part of initial steps to represent the atmospheric CH_4 decay and the global CH_4 cycle in the UVic ESCM (See Methods and Supplementary Note 5). In reality, the atmospheric CH_4 lifetime varies by a few months to a few years mostly due to changes in atmospheric chemistry associated with CH_4 sinks[50], and this variation in the CH_4 lifetime has been invoked to explain past changes in the growth rates of atmospheric CH_4 levels[3,50]. Variations in the atmospheric CH_4 lifetime are mainly regulated by a chemical feedback involving the oxidation of CH_4 by the OH radical[3,50], a process not simulated by our model. This feedback mechanism is such that increasing [CH_4] (e.g. under delayed CH_4 mitigation) reduces the abundance of the OH radical, which further increases [CH_4] and raises the global warming level. Therefore, one consequence of our assumption of a constant lifetime for atmospheric CH_4 is a potential underestimation of the [CH_4] peak in delayed mitigation scenarios. However, our main result that delaying CH_4 mitigation increases the risk of breaching the 2 °C warming limit is not considerably affected by the use of different values for the atmospheric CH_4 lifetime in the range of published estimates (i.e. 7–11 years)[2] (Supplementary Fig. 4).

By design, this study makes a fundamental assumption with regards to future emission scenarios: effective mitigation of CO_2, other non-CH_4 greenhouse gases (GHGs), as well as aerosols, except for CH_4. This assumption is such that future emissions of non-CH_4 GHGs (including CO_2) and aerosols decline by mid-century according to a scenario consistent with limiting global warming to 2 °C by 2100 (i.e. SSP1-2.6), while anthropogenic CH_4 emissions continue to increase throughout the next three decades and beyond (i.e. SSP3-7.0). While we acknowledge the importance of aerosols and other non-CO_2 forcing agents in the context of climate mitigation to achieve the temperature goals in the Paris Agreement[16,51], our future scenarios focus on CH_4 mitigation to investigate recent concerns raised about sustained [CH_4] growth since 2007 and the associated potential challenge for achieving the 2 °C warming limit even under stringent CO_2 mitigation by mid-century[5,38].

Our study suggests that aggressive reductions of anthropogenic CO_2 emissions without CH_4 mitigation could push the Earth system beyond the 2 °C warming limit above pre-industrial levels for more than two centuries in the future. Initiating large-scale CH_4 mitigation in the current decade, along with stringent CO_2 mitigation, can allow to achieve the temperature goals in the Paris Agreement. However, delaying CH_4 mitigation to the next decade or beyond will increase the risk of breaching the 2 °C warming limit. According to our model simulations, every 10-year delay in CH_4 mitigation will result in an additional peak warming of about 0.1 °C. Consequences of such an increased peak warming over time and breaching the 2 °C warming limit are widespread, including an increased risk for an Arctic Ocean without sea ice in the summer[34], record-breaking climate extremes[35], the dieback of the Amazon rainforest[36], the disintegration of major ice sheets[36], persistent sea-level rise over multiple centuries[33], and several other global and regional impacts of increasing global warming levels on natural and socio-economic systems[52,53]. Considering that [CH_4] has been rising steadily since 2007 in line with unmitigated emission scenarios[5,6], we highlight the importance of immediate cuts in anthropogenic CH_4 emissions globally, along with stringent CO_2 mitigation, in order to increase the likelihood of keeping global warming to well below 2 °C above pre-industrial levels. Actions associated with the Global Methane Pledge[13] launched at COP26 in November 2021 should not be delayed, because every year of delayed CH_4 mitigation implies additional global warming.

Methods

Model description. We use the University of Victoria Earth System Climate (UVic ESCM) for our simulations. The UVic ESCM consists of a 2-D (vertically-integrated) energy-moisture balance model for the atmosphere coupled to a comprehensive 3-D ocean general circulation model (OGCM) with marine biogeochemistry, a thermodynamic sea ice model, and a land surface model with dynamic vegetation as well terrestrial carbon fluxes (in the form of CO_2)[54,55]. In this study, we use a version of the EMIC based on UVic ESCM 2.10[21] which features a multi-layer ground structure (i.e. 14 ground layers of unequal thicknesses extending down to a depth of 250 m) that is capable of simulating permafrost freeze-thaw processes as well as permafrost CO_2 fluxes (i.e. CO_2 release and uptake)[56]. Furthermore, the version of the UVic ESCM used in this study simulates the spatial and temporal dynamics of wetlands[57]. In particular, sub-grid scale wetlands are identified in the EMIC following a TOPMODEL approach for global models[58]. The areal extent of wetlands varies in response to changes in soil hydrology (soil moisture content, runoff, surface inundation, etc.), which is affected by changes in precipitation, evapo-transpiration, temperature, vegetation—among many other atmospheric and terrestrial processes. In this study, we use a modified version of UVic ESCM 2.10 into which we incorporated a simplified representation of the global CH_4 cycle (See next sections).

Wetland CH_4 emissions. Wetland CH_4 emissions are simulated in the UVic ESCM following a recent model development[22]. Wetland CH_4 emissions are calculated as the balance between microbial production and oxidation of CH_4 in the soil column. CH_4 production is calculated in each soil layer as a function of moisture content, carbon content, temperature, and the relative depth from the soil surface. In this approach, soil moisture (i.e. water saturation) represents potential anoxic conditions. Soil carbon represents organic matter that may be accessed by methanogens. Soil temperature allows to estimate potential changes in methanogenic activity, whereas the relative depth from the soil surface allows to represent the net effect of depth-dependent controls on CH_4 production that are unresolved by the UVic ESCM (e.g. the quality of organic matter and the distribution of methanogens in the soil). CH_4 production is assumed to not take place in dry soil layers (i.e soil layers unsaturated with water) as well as in frozen soil layers. CH_4 oxidation is calculated for the entire soil column as a fraction of the amount of CH_4 produced in the soil column. The oxidized CH_4 fraction is determined based on an estimated oxic zone depth, which represents the prevalence of methanotrophs in the soil. This fraction increases as the oxic zone deepens. By design, our model simulates wetland CH_4 emissions associated with CH_4 production across the globe (including CH_4 emissions from previously frozen soil carbon upon permafrost thaw)[22].

Atmospheric CH_4 and associated radiative forcing. A simple one-box model is used to simulate the evolution of the atmospheric CH_4 burden (B) with time as the balance between total CH_4 emissions (E) and total CH_4 sinks (S). The box model is defined as $\frac{dB}{dt} = (E - S)$, where $E = E_a + E_w + E_n$ represents the sum of prescribed anthropogenic CH_4 emissions (E_a), simulated wetland CH_4 emissions (E_w), as well as natural CH_4 emissions from non-wetland sources (E_n) such as termites, wild ruminants, wildfires, lakes, rivers, geologic seeps, and marine hydrates. Given that the UVic ESCM does not incorporate these non-wetland natural sources and in the absence of dataset for CH_4 emissions from these sources, we assume that non-wetland natural CH_4 emissions remain constant in time at 45 Tg C yr^{-1} (equivalent to 60 Tg CH_4 yr^{-1}). This value is in the range of estimated total CH_4 emissions from non-wetland natural sources over the last four decades[2,3] as well as pre-industrial periods[59]. Sinks of atmospheric CH_4 are aggregated into a single term (S) calculated as $S = B\,(1 - \exp(-\frac{1}{\tau_{CH4}}))$, where τ_{CH4} is the atmospheric CH_4 lifetime assumed to be 9.3 years[2]. Similar estimates for the atmospheric CH_4 lifetime have been reported for the pre-industrial era (9.5 ± 1.3 years) and present-day (9.1 ± 0.9 years)[60]. At each time step, $[CH_4]$ is determined based on the atmospheric CH_4 burden (B) by using a factor equivalent to ~2.8 Tg CH_4/ppb. Radiative forcing associated with changes in $[CH_4]$ is calculated using the formulation in ref. [61] and is accounted separately from the aggregated forcing of other non-CO_2 GHGs that is prescribed to the UVic ESCM in its standard configuration[21].

Non-CH_4 radiative forcing agents. To drive the UVic ESCM over the 1850–2300 period (1850–2014 for the historical simulation and 2015-2300 for future projections), we use CMIP6 data for non-CH_4 natural and anthropogenic radiative forcing agents[23,62–64]. For natural forcing agents (volcanic and solar), we use volcanic radiative forcing anomalies spanning the historical period (1850–2014)[64] and solar constant data prescribed to 2300[63]. For anthropogenic forcing agents, we (i) use CMIP6 data for the historical simulation, and (ii) assume that all non-CH_4 GHGs (including CO_2) as well as aerosols evolve according to a scenario consistent with limiting global warming to 2 °C throughout the future (i.e. SSP1-2.6). Specifically, we prescribe CO_2 emissions from fossil fuels as defined in the SSP1-2.6 scenario and their long-term extension[23,24]. The SSP1-2.6 scenario features strong reductions in CO_2 emissions as well as negative CO_2 emissions (i.e. artificial removal of atmospheric CO_2) in the second half of the 21st century[65]. Furthermore, we prescribe gridded land-use change (LUC) data according to SSP1-2.6[66] and the UVic ESCM internally calculates corresponding LUC CO_2 emissions. The radiative forcing of CO_2 is calculated within the UVic ESCM following the formulation from ref. [61]. Radiative forcing values of other non-CH_4 GHGs are calculated externally using concentration data and their extension[23], which are then summed up into an aggregated forcing that is prescribed to the UVic ESCM. For anthropogenic sulfate aerosols, we prescribe SSP1-2.6 gridded aerosol optical depth (AOD) data to the UVic ESCM[67,68] and the model uses this data to internally calculate the associated radiative forcing. While forcing data for CO_2 and other non-CH_4 GHGs extend to 2300[23], forcing data for LUC and sulfate aerosols are prescribed to 2100 and their radiative forcing are held fixed at their 2100 values in our climate simulations.

Reporting summary. Further information on research design is available in the Nature Portfolio Reporting Summary linked to this article.

Data availability

The model outputs analyzed in this study are archived at https://doi.org/10.20383/102.0748[69].

Code availability

The code for the University of Victoria Earth System Climate Model (UVic ESCM) used in this study is available at https://doi.org/10.5281/zenodo.7999745[70].

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Acknowledgements

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Author contributions

C.-M.N. conceived the study and designed the model experiments, with contributions from K.Z.. C.-M.N. implemented the representation of the global CH_4 cycle in the UVic ESCM, with contributions from AJM on the atmospheric CH_4 module. C.-M.N. performed the model simulations, model validation, as well as the analysis and interpretation of results. K.Z. contributed to the interpretation of results. C.-M.N. wrote the manuscript and all authors provided critical feedback that helped shape its final version.

Competing interests

The authors declare no competing interests.

Additional information

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Correspondence and requests for materials should be addressed to Claude-Michel Nzotungicimpaye.

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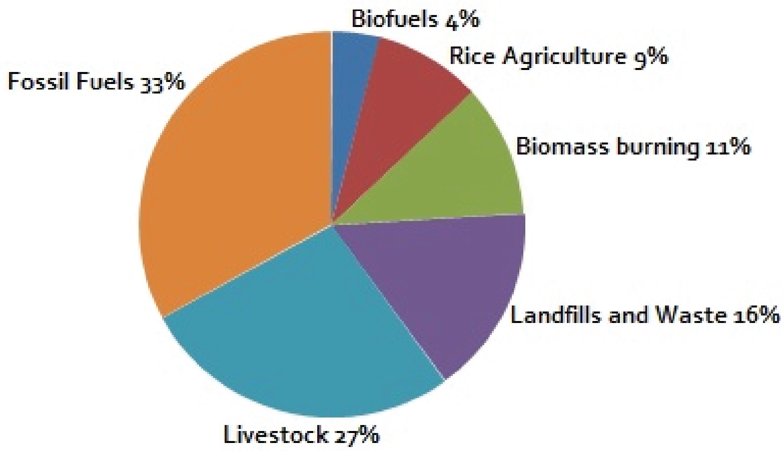
The Challenge

Methane is a powerful greenhouses gas with a 100-year global warming potential 28-34 times that of CO2. Measured over a 20-year period, that ratio grows to 84-86 times.

About 60% of global methane emissions are due to human activities. The main sources of anthropogenic methane emissions are the oil and gas industries, agriculture (including fermentation, manure management, and rice cultivation), landfills, wastewater treatment, and emissions from coal mines. Fossil fuel production, distribution and use are estimated to emit 110 million tonnes of methane annually.



Methane is the primary component of natural gas, with some emitted to the atmosphere during its production, processing, storage, transmission, distribution, and use. It is estimated that around 3% of total worldwide natural gas production is lost annually to venting, leakage, and flaring, resulting in substantial economic and environmental costs.

Coal is another important source of methane emissions (/node/33). Coal mining related activities (extraction, crushing, distribution, etc.) release some of the methane trapped around and within the rock. Methane is emitted from active underground and surface mines as well as from abandoned mines and undeveloped coal seams.

The geological formation of oil can also create large methane deposits that get released during drilling and extraction. The production, refinement, transportation and storage of oil are all sources of methane emissions, as is incomplete combustion of fossil fuels. No combustion process is perfectly efficient, so when fossil fuels are used to generate electricity, heat, or power vehicles these all contribute as sources of methane emissions.

On a global scale, methane emissions from oil and natural gas systems account for 1,680 MtCO2e. The estimates are considered to be uncertain and are thought to be low.

Based on the best currently available data, around 3.6 trillion cubic feet (Tcf) (or 102 billion cubic meters (bcm)) of natural gas escaped into the atmosphere in 2012 from global oil and gas operations. This wasted gas translates into roughly U.S. $30 billion of lost revenue at average 2012 delivered prices, and representes about 3% of global natural gas production.

Emissions are expected to grow under a central growth scenario by 23% between 2012 and 2030.

Regarding the global reduction potential by 2030, it is estimated that emissions could be reduced by 26% using existing technology (equal to 1,219 MtCO2e).

Despite methane's short residence time, the fact that it has a much higher warming potential than CO2 and that its atmospheric volumes are continuously replenished make effective methane management a potentially important element in countries' climate change mitigation strategies. As of today, however, there is neither a common technological approach to monitoring and recording methane emissions, nor a standard method for reporting them.

Comment Log Display

Here is the comment you selected to display.

Comment 268 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Paul
Last Name	Sousa
Email Address	paul@wudairies.com
Affiliation	Western United Dairies
Subject	LCFS Comments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6938-lcfs2024-VztRNFcwBCQKUwBj.pdf
Original File Name	LCFS comments 2.20.24.pdf
Date and Time Comment Was Submitted	2024-02-20 15:41:59

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

WESTERN**UNITED**DAIRIES

February 20, 2024

The Honorable Steven S. Cliff
Executive Officer
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Regarding: **Proposed Amendments to the LCFS Program**

Dear Mr. Cliff:

Western United Dairies is the largest dairy farmer trade organization in California representing dairy farms from throughout the state of all sizes. Our members are committed to meeting the goals of SB 1383 and reducing livestock manure methane emissions. As a result of that commitment, many of our members have installed anaerobic digesters to capture manure methane emissions and produce Renewable Natural Gas (RNG), which displaces fossil fuels. In both capturing fugitive methane and displacing fossil fuels these projects significantly reduce greenhouse gas (GHG) emissions. Likewise, these projects also improve air quality by helping to transition away from diesel fueled vehicles to cleaner RNG.

259.1 WUD urges the Air Board to continue to provide credits for avoided methane emissions from livestock manure, which are the most cost effective GHG emissions reductions funded by the State. When asked by the State, dairy farmers stood up and achieved what was asked of them, it is important that the State now uphold its support of these projects through the LCFS program as promised. Therefore, dairy biogas producers should receive full credit for avoided methane emissions from livestock manure that is used to produce biofuels participating in the LCFS program.

The success of the LCFS program cannot be overstated in bringing down the carbon intensity of transportation fuels, which is one of the more difficult sectors to decarbonize. By linking the carbon intensity of fuels to voluntary projects like digesters on dairy farms, the program has also spurred a significant reduction in methane emissions. This has driven change and innovation on farms to be part of the solution. It is important that ARB maintain the course that has gotten us here and not abandon those that have stepped up to be part of the solution. To accomplish this the value of the avoided methane emissions must continue to be included in the carbon intensity score of fuels produced from dairy biomethane. The projects developed by our members to help ARB achieve its goals are not inexpensive to operate and maintain. The LCFS is the most important revenue source for these projects and keeps these projects viable. It also continues to

WESTERN**UNITED**DAIRIES

reward innovation and maintains the pace of emissions reductions, which has been unprecedented.

California dairy farms are very sensitive to leakage with the California dairy herd continuing to migrate to other states as shown in recent ARB reports on dairy and livestock populations, including the ARB GHG inventory. Removing the avoided methane emissions value from the LCFS will add pressure on California dairies to leave California to other states without GHG reductions targets for dairies. This will increase global GHG emissions counter to ARB goals. The most effective way to achieve ARB's GHG goals is to support California's dairy farmers in their reduction of methane emissions thereby providing an example to other states and countries on how to achieve emissions reductions and maintain a healthy farm sector that provides jobs in much needed areas of the state and supports fresh local food production. This is how California can achieve meaningful global GHG emissions reductions by being a successful laboratory of innovation while at the same time supporting our economy.

Consolidation is not unique to California dairies. Many businesses in California have experienced consolidation to survive increasing costs and regulatory pressures, including environmental pressures. Consolidation has been happening in dairies across the United States for over 50 years, and California is no exception. The LCFS program is not driving this, but other business pressures to become more efficient and productive. Scale allows dairies to implement practices that reduce GHG emissions and improve air quality. California dairies also provide important year-round jobs, many to disadvantaged communities, that would disappear without our dairy farms.

Ending credits for avoided methane emissions would be counter to SB 1383. It also sends a message that investments in these projects are risky as the state is not willing to support these projects long term. These projects provide some of the most cost-effective investments the state is making in carbon reductions and should be strengthened, not abandoned. For all these reasons, WUD urges ARB to maintain a lifecycle analysis approach to carbon emissions, including avoided methane emissions. Western United Dairies (WUD) appreciates the opportunity to provide comments regarding the proposed amendments to the Low Carbon Fuel Standard (LCFS).

Sincerely,

Paul Sousa

Paul Sousa, Director of Regulatory and Environmental Affairs
Western United Dairies

Comment Log Display

Here is the comment you selected to display.

Comment 269 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Tony
Last Name	Marlow
Email Address	tmarlow@castlecooke.com
Affiliation	Castle & Cooke Aviation

Subject	Low Carbon Fuel Standard

Comment

As President of Castle & Cooke Aviation Services, Inc. headquartered at the Van Nuys Airport in Los Angeles, with 36
260.1 employees in Southern California, I am opposed to the CARB proposal to eliminate the LCFS's current exemption of jet fuel due to the following concerns:

1. The new amendment would increase the current price of jet fuel, negatively impacting the aviation industry's economic impact.

2. Jet fuel was originally recognized by CARB as exempted. This change would increase company demerits if jet fuel were used, negatively impacting overall company goals.

3. SAF production does not match current fuel uptake rates, and this proposal would do nothing to increase SAF availability.

4. Reduction in aviation activity due to the above items could negatively impact my employment numbers reducing payroll and tax contribution to the state.

We appreciate the CARB's consideration of my comments and concerns and look forward to moving ahead to find plausible, economically viable, and mutually beneficial solutions to sustainable aviation through the state.

Attachment

Original File Name

Date and Time Comment Was Submitted 2024-02-20 15:37:01

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

Here is the comment you selected to display.

Comment 270 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	John
Last Name	Peck
Email Address	familyfarmdefenders@yahoo.com
Affiliation	Family Farm Defenders
Subject	LCFS methane offsetting through biogas digesters needs to stop

Comment

Dear Governor Newsom and California Air Resources Board (CARB) members,

On behalf of Family Farm Defenders, a national grassroots organization based in Madison, WI with over 3000 members in all fifty states, including CA, I am writing to you to express our concern about CAFO biogas digesters being used to offset pollution generated in your state through the Low Carbon Fuel Standard (LCFS)

Pollution trading is fundamentally flawed in that it does not actually require pollution reduction, but allows polluters to instead shift their pollution impact to other communities. Worse
261.1 yet, many of these supposed offsets have been shown to be bogus, meaning that the over all climate change pollution impact is actually worse.

This is certainly true in the case of CAFO biogas digesters, supposedly offsetting carbon dioxide emissions by reducing methane emissions, but in reality many of these biogas digesters are doing neither. In the case of WI there are over a dozen CAFO mega dairy farms who have long been claiming methane offset credits under the LCFS carbon market trading scheme. Thanks to the diligent oversight of many local citizen activists, we know that many of these WI CAFO biogas digesters are not actually functional as claimed and that methane is not being actually being reduced.

When this corruption was exposed in the media, CA authorities had to work hard to claw back the bogus offset credits from the WI CA biogas digesters, but that should not be the belated response if there was proper vetting and accountability mechanisms in place. Concerned private citizens should not have to be the watchdog for taxpayer-subsidized government-created carbon/methane trading offset markets. To be honest, such false offset claims in a pollution trading market is tantamount to wire fraud and should lead to federal prosecution.

Many of the mega dairy WI CAFO biogas digesters implicated in this fraud have a long sordid record of breaking other state and federa laws, including violations of labor laws (some farmworkers have died at these facilities trying to work on the biogas digesters) a

well as numerous environmental regulations related to the Clean
Water and Clean Air Acts. Some of our WI CAFO biogas digesters
have even blown up and been implicated in massive manure leaks
contaminating public water supplies, raising potential liability
concerns for anyone who may be financially connected - such as
those engaged in the CA LCFS carbon trading market.

As a national family farm organization, we would urge you to no
longer allow methane offsets in the LCFS market - these are dubiou
(at best) and the mega dairy CAFOs claiming such credits are
causing serious harm to Midwest rural communities. At minimum,
there should be no "grace period" allowed for such CAFO biogas
offset claims - their lousy track record hardly warrants such. Th
261.2 "life cycle" analysis of supposed methane emissions as a possible
offset for carbon dioxide emission needs to be seriously
reevaluated - especially if the credit claims are egregiously
overstated or even totally bogus.

The best offset would be giving LCFS credits to rotational grazin
dairy operations (which are actually the most economically viable
and climate friendly here in the Midwest according to many studie
from the UW-Madison Center for Dairy Profitability), but that is
261.3 sadly not acceptable under the current LCFS carbon trading system
Apparently, if a family farmer does NOT create a methane problem i
the first place (by not confining their animals in a building and
then putting their manure into anaerobic lagoons) then they can n
get any taxpayer subsidized carbon credit for solving the climate
crisis.

If the State of California is serious about reducing GHG emission
through a pollution trading system, then they should not allow
corrupt CAFO operators across the country to take advantage of
261.1 cont. shoddy oversight and lackadaisical accountability to bilk taxpaye
through bogus offsets.   We ask that you no longer shift your
pollution responsibility onto Midwest rural communities (or
anywhere else for that matter) and terminate the methane biogas
digester offsets in the LCFS program.

Attachment

Original File Name	
Date and Time Comment Was Submitted	2024-02-20 14:50:46

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Comment Log Display

Here is the comment you selected to display.

Comment 271 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Heather
Last Name	Breyne
Email Address	hbreyne1@gmail.com
Affiliation	
Subject	Jet fuel regulatory proposal
Comment 262.1	I do not agree with this change. If jet fuel is not being omitted then it will raise the prices and jet fuel is already a huge part of a budget for the airline industry thus this will raise ticket prices for customers and this will negatively impact sales.
Attachment	
Original File Name	
Date and Time Comment Was Submitted	2024-02-20 15:45:15

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Board Comments Home

Comment Log Display

Here is the comment you selected to display.

Comment 272 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Yoshiko
Last Name	Tsuwaki
Email Address	jetrola@jh2f.org
Affiliation	Japan Hydrogen Forum (JH2F)
Subject	JH2F Comments on the Proposed LCFS Amendments
Comment	Please see attached for JH2F's comments on the proposed LCFS amendments.
Attachment	www.arb.ca.gov/lists/com-attach/6942-lcfs2024-AWtRP1xvBTBSC1Bi.pdf
Original File Name	JH2F_2024LCFSamendments_1204PMFinal.pdf
Date and Time Comment Was Submitted	2024-02-20 15:37:49

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Ms. Liane Randolph
Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95864

Re: CARB Proposed Low Carbon Fuel Standard Amendments

In response to California Air Resources Board (CARB)'s proposed updates to the Low Carbon Fuel Standard (LCFS) [1], Japan Hydrogen Forum (JH2F) is pleased to submit the following comments for consideration. JH2F is an organization formed in 2021 to contribute to the goal of decarbonization in the United States, consisting of 31 Japan-affiliated companies with hydrogen related technologies from production, carrier conversion, transportation, storage to utilization, including hydrogen fuel cell providers for heavy-duty (HD) truck and cargo handling equipment OEMs and retail hydrogen refueling station (HRS) providers in California. We would like to express our sincere gratitude for your staff's work on the development of the proposed rule and their commitment to improving the LCFS to achieve carbon neutrality by 2045 and reduce greenhouse gas emissions 85% below 1990 levels by 2045.

While acknowledging the continued improvements to the program, we would propose some critical refinements to ensure the success of hydrogen, and its necessary role in meeting California's 2045 carbon neutrality goal.

Increasing CI Targets and Market Stability

263.1 We strongly support staff's recommendation of the 30% reduction in fuel carbon intensity (CI) by 2030
and a 90% reduction in fuel CI by 2045 from a 2010 baseline. However, we are concerned that the
historically low credit prices [2] will continue through 2025, which has a chilling effect on providers'
263.2 financing further stations and is increasingly discouraging OEMs from committing capital to Hydrogen
fuel cell light-duty (LD) and HD vehicles. Unlimited biodiesel and renewable diesel supply has been one
of the leading causes of the LCFS credit market's inability to effectively support other pathways.

We therefore urge starting with tighter targets and policies that can result in the immediate recovery of credit prices. We request the Board implement the one-time 5% CI step down and the auto acceleration mechanism (AAM) sooner than the proposed date.

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[1] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf

[2] https://r.search.yahoo.com/_ylt=AwrgzbOD88tlcAQAl.ZXNyoA;_ylu=Y29sbwNncTEEcG9zAzIEdnRpZAMEc2VjA3Ny/RV=2/RE=1709074564/RO=10/RU=https%3a%2f%2fww2.arb.ca.gov%2fresources%2fdocuments%2fmonthly-lcfs-credit-transfer-activity-reports/RK=2/RS=yu36..J0ANG2sS86H065qyHr788-

777 S. Figueroa St., Suite 3750 | Los Angeles, CA 90017 | Japan Hydrogen Forum (JH2F) | USA - JETRO

Infrastructure Crediting

Crediting Period

263.3 The shift from a 15-year to a 10-year timeframe for HRI crediting has a significant impact on station financing and economics. Notably, this change introduces a new challenge for HD stations, which are both larger and more capital-intensive. The shorter 10-year timeframe contrasts with the previously longer capacity crediting period, creating a misalignment with the capital costs associated with hydrogen station infrastructure. Reevaluating the timeframe in consideration of the unique characteristics and financial requirements of hydrogen station infrastructure is crucial for fostering a conducive environment for hydrogen development in this sector.

LD HRI program

263.4 In addition to the crediting period of 10-year timeframe, limiting capacity to 600 kg/d, hinders the growth of the HRS network. This is especially true for the 600 kg/d capacity cap given that medium-duty (MD) trucks typically fill at neighborhood fueling stations, not HD stations along freeways (i.e., truck stops). We urge the Board to simply extend the LD HRI program "as is" and revisit in a few years to ensure the program is operating as intended and serving disadvantaged communities.

Inequity in Capacity Crediting Standards

263.5 We agree that renewable hydrogen production is the ultimate pathway for transportation, however, the imposition of an 80% renewable content requirement exclusively for HRI may be premature and overly restrictive, particularly in comparison to Fast-Charging Infrastructure (FCI). This requirement places hydrogen at a competitive disadvantage against other energy sources, which benefit from substantial federal, state, and ratepayer subsidies not extended to hydrogen, and could significantly increase relative costs. We believe that the exclusive application of this requirement to hydrogen tilts the scale heavily against fuel cell pathways. We suggest that this additional requirement should be eliminated as it is unnecessary and counter to the carbon intensity focus and technology neutral principles that have driven innovation and investment in the LCFS program to date.

We appreciate your consideration and thoughtful feedback to address our concerns. We look forward to contributing to California's goal of zero-emissions transportation.

Sincerely,

Takehito Yokoo
Chairperson,
Japan Hydrogen Forum

777 S. Figueroa St., Suite 3750 | Los Angeles, CA 90017 | Japan Hydrogen Forum (JH2F) | USA - JETRO

Comment Log Display

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Comment 273 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Anna Bella
Last Name	Korbatov
Email Address	annabella@fermataenergy.com
Affiliation	Fermata Energy
Subject	Fermata Energy Comments on Proposed 2024 LCFS Amendments
Comment	Please see attached comments on behalf of Fermata Energy.
Attachment	www.arb.ca.gov/lists/com-attach/6943-lcfs2024-BWMGZVUmWWcEYwZy.pdf
Original File Name	Fermata Energy Comments to CARB_LCFS_2024 Amendments_2.20.24.docx.pdf
Date and Time Comment Was Submitted	2024-02-20 15:04:58

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Fermata Energy

February 20, 2024

Honorable Chair Liane M. Randolph and
Honorable Board Members California Air Resources Board
1001 I Street
P.O. Box 2815
Sacramento, CA 95812

Submitted electronically via public Comment Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments (https://ww2.arb.ca.gov/applications/public-comments?utm_medium=email&utm_source=govdelivery)

RE: Notice of Public Hearing to Consider Proposed 2024 Low Carbon Fuel Standard Amendments (LCFS)

Dear Chair Randolph and Honorable Board Members:

Fermata Energy is pleased to provide comments in response to the Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments.[1] In June 2023, Fermata Energy staff members had the opportunity to meet CARB representatives Joshua Cunningham, Analisa Bevan, and Leslie Goodbody at the California-UK Vehicle-to-Everything ("V2X") Global Expert Mission. The discussion in this meeting included the proposal to extend the LCFS program scope to value V2X benefits, which was supported by Fermata Energy, ev.energy, and others. Our first three proposals are not addressed in the proposed LCFS Amendments, and as such, we raise new issues for CARB's consideration. Our fourth recommendation supports the revisions to Section 5.b of the "Proposed Regulation Order: *Proposed Amendments to the Low Carbon Fuel Standard Regulation*," on the use of LCFS Holdback Funds for V2X Programs.[2]

Background: Founded in 2010, Fermata Energy is a leading Vehicle-to-Everything ("V2X") bidirectional charging services provider. Fermata Energy designs, supplies, and operates the technologies required to integrate electric vehicles ("EVs") into homes, buildings, and the electric grid. Fermata Energy's V2X platform incorporates CHAdeMO and CCS connectors in a

[1] See California Air Resources Board Notice Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments available at https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_notice.pdf,

[2] See Section § 95483. Fuel Reporting Entities. < (c) For Electricity Used as a Transportation Fuel. (1) Residential EV Charging. (A) Base Credits. < 5b, at page 45,https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appa1.pdf

bidirectional charger and management software platform that connects the EV and electricity user to the grid. Fermata Energy's V2X platform extends the value of an EV and allows the vehicle to act as a dispatchable energy storage resource when the vehicle is not in use.

Fermata Energy's customers today are earning thousands of dollars per EV and EVSE pair through Vehicle-to-Grid ("V2G") and Vehicle-to-Building ("V2B") programs nationwide. The company's bidirectional EV charging system is the first to be certified by UL Solutions in North America to UL 9741, the Standard for Bidirectional EV Charging System Equipment and is the first to earn approval in the U.S. from a major OEM for battery warranty.

In addition to developing the hardware and software required to perform V2X activities, Fermata Energy has spent over 10 years studying how V2X can unlock additional value streams from EVs, including those that are commercially viable today without regulatory intervention and how to best monetize these value streams. Fermata Energy has extensive experience with analyzing use cases, monetization mechanisms, and business models to maximize the benefits of V2X technologies. Vehicle Grid integration ("VGI") encompasses both V1G (smart and managed charging solutions) and V2X (bidirectional power transfer to the grid, building, home, microgrid, or any other external load source). While V1G enables EVs to participate in off-peak charging programs and provide automated load management, V2X unlocks additional value streams and benefits for ratepayers and the grid by enabling the discharge of power stored onboard an EV. V2X that Fermata Energy provides unlocks the value of EVs to provide all of the services that that V1G does, in addition to backup power/resilience, demand charge management, demand response, system-wide peak shaving, and ancillary services, among others.

The interest in V2X commercialization is widespread and accelerating. In addition to the launch of the Ford Lightning (EV F150 pickup truck) V2H offering, 2023 saw several EV manufacturers announce plans to make their EVs bidirectional.[3] Furthermore, several electric vehicle supply equipment ("EVSE") manufacturers announced plans to bring bidirectional chargers to market, expanding the limited number of bidirectional chargers that are available today.[4] The ACC II amendments are timely and offer an opportunity for CARB to ensure that manufacturers' bidirectional EVs meet basic interoperability standards for bidirectional charging and demonstrate these capabilities through assurance testing.

Fermata Energy Recommendations

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[3] See Automotive News, GM to offer bidirectional charging on all EVs by 2026 available at https://www.autonews.com/mobility-report/gm-evs-have-bidirectional-charging-technology-2026 and CleanTechnica, Tesla Plans To Adopt Bi-Directional Charging By 2025 available at https://cleantechnica.com/2023/08/19/tesla-plans-to-adopt-bi-directional-charging-by-2025/.

[4] See electrek, Wallbox and Kia team up to try and bring bidirectional charging capabilities to EV9 owners available at https://electrek.co/2023/08/25/wallbox-kia-bidirectional-charging-capabilities-ev9-owners-home/ and

1. **Proposed Methodology for Accounting for Energy for Transportation for V2X Customers:** We would like to propose the following formula to account for energy for
264.1 transportation for V2X customers that wish to generate LCFS credits. Electricity dispensed from electric vehicle supply equipment ("EVSE") for transportation can be netted out from the overall electricity dispensed for a V2X system that includes a bidirectional charger that has an approved interconnection agreement with the electric distribution company ("EDC") according to the following:

Electricity charged for driving (kWh) = Total electricity charged (kWh) - Electricity discharged (kWh)

Note: Where charged and discharged electricity are the energy flows measured at the charger meter.

$$Electricity\ charged\ for\ driving\ (kWh)\ =\ [Total\ electricity\ charged\ (kWh)\ -\ Electricity\ discharged(kWh)]$$

The two energy uses of a V2X charger are 1) driving (transportation) and 2) exports to buildings or the grid, so the total energy charged at any charger will be equal to the energy required to refill the battery for those uses. This means that for V2X services, energy discharged (kWh) = energy charged (kWh). The remainder of charging at a V2X charger is to refill from driving uses. We understand and appreciate that this proposed methodology above can be adopted with a technical note (e.g., Guidance Document or similar) and therefore does not require an amendment to the LCFS program amendment. However, we take this opportunity to share our above proposed methodology to be included in the public record as CARB considers LCFS program amendments and would prefer the greater certainty that a regulatory amendment provides.

2. **Consideration for Account for V2X Discharge in LCFS Methodology**

The stated aims of the LCFS program are: "[...] to decrease the carbon intensity of California's transportation fuel pool and provide an increasing range of low-carbon and
264.2 renewable alternatives, which reduce petroleum dependency and achieve air quality benefits."[5]
Fermata Energy understands the scope and purpose of the program, and that LCFS is a fuels regulation aimed at decarbonizing the transportation sector. However, below, we expand upon how accounting for V2X discharge in the LCFS methodology will help CARB achieve the stated

[5] https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard/about#:~:text=The%20LCFS%20is%20designed%20to,and%20achieve%20air%20quality%20benefits

goals of the LCFS program and further its mission.[6] CARB may have to expand the scope of LCFS to fully incentivize the potential of bidirectionally-enabled EVs to support transportation decarbonization and provide the associated air quality benefits.

Decreasing the Carbon Intensity of CA's Transportation Fuel Pool

Bidirectionally-enabled EVs decrease the carbon intensity of California's transportation fuel pool in the same way as other EVs: by displacing the emissions from mobility (driving) from a conventional fuel to an alternative fuel (electricity). This is included in the methodology proposed in (1) above. The formula is attractively simple, however it does not take into account the potential benefits of V2X for further lowering CO2 from transportation assets.

V2X Discharge Enables EVs to Generate Revenue for Grid Services, Lowering EV TCO, and Helping Accelerate EV Adoption and Renewables Integration in CA

EVs are the primary mechanism to achieve transportation decarbonization. V2X accelerates the transition to electric vehicles, by providing new value streams that increase
264.2 consumer adoption of EVs by lowering EV total cost of ownership (TCO). This also increases the range of consumer options in selecting an EV, which is aligned with the goals of the LCFS program.

In addition to lower EV TCO, V2X supports renewables integration. By fully unlocking the ability of EVs to respond as grid-supporting, flexible load resources, V2X can help California achieve a cleaner generation profile. Bidirectional EVs can discharge to the grid during the CA system-wide peak and be aggregated into Virtual Power Plants (VPPs) to displace fossil-fuel powered peaker plants. Bidirectional charging can also charge when there is excess solar and wind power generation, thereby reducing renewable energy curtailment.

Achieving further air quality benefits from the transportation sector, beyond the transportation sector, by reducing both grid and transportation emissions

What an EV does when it is parked is just as important as what an EV does when it is driving. Recognizing V2X in LCFS can turn transportation assets into carbon sinks; bidirectional charging, when optimized for carbon-signals, can lead to a net displacement of CO2 emissions. By following a carbon signal and discharging at high Carbon Intensity (CI) times and charging at low CI times, V2X EVs create a net environmental benefit, turning EVs into potential carbon sinks. The LCFS market design may need to change to create the incentives for EVs to provide these additional environmental benefits. While this may necessitate an expansion of LCFS's

[6] "CARB's mission is to promote and protect public health, welfare, and ecological resources through effective reduction of air pollutants while recognizing and considering effects on the economy. CARB is the lead agency for climate change programs and oversees all air pollution control efforts in California to attain and maintain health-based air quality standards." https://ww2.arb.ca.gov/about

official scope, these goals do align with CARB's broader mission as an organization and the spirit of the LCFS program.

Proposed formula for CARB to include V2X discharged energy in LCFS accounting

Fermata Energy proposes that CARB make the total energy cycled through the vehicle battery in the course of V2X operations eligible for LCFS credits. The formula would account for the hourly energy charge and discharge flows and the associated hourly carbon emissions, which could lead to either adding or subtracting LCFS credits from a participants' credits earned depending on performance.

The proposed formula for V2X is then:

$$\sum_{h=0}^{h=H} Net\ Electricity(h) \times CI(h) = [Electricity\ charged(h) - Electricity\ discharged(h)] \times CI(h)]$$

Where H is the total number of hours in the year, h is the hour, Electricity charged and Electricity discharged are the hourly energy measurements at the charger, and CI is the carbon intensity recorded for hour h.

Worked example of V2X as net carbon sink

Here, we propose the example use case of a delivery truck at a warehouse with V2G charging infrastructure on-site. This medium-heavy duty vehicle has a usable battery capacity of 120 kWh, and is parked at its designated parking space and charger. At 7 am, as instructed by Fermata Energy's algorithms, the truck starts discharging electricity for 2 hours until 9 am,
264.2 discharging a total of 40 kWh of electricity. During this time, the carbon intensity of the CA grid is 450 gCO2/kWh on average. Fermata Energy's V2X software ensures that the vehicle is left with enough state of charge to complete its morning duty cycle. At 9 am, the vehicle leaves the warehouse and drives 50 miles, for which it uses 15 kWh of electricity. When the vehicle returns to the warehouse, Fermata Energy charges it from about mid-day to 2:30 pm, recharging 15 + 40 kWh = 55 kWh, when the CI of the grid is 0 gCO2/kWh. This creates a carbon footprint for the vehicle of (55 x 0) - (40 x 450) = -18,000 gCO2/kWh, i.e. a net CO2 reduction of 18 kg.

Conclusion on including V2X discharge

In summary, supporting V2X EVs are still primarily transportation assets that are purchased for mobility as a primary use; but their full potential should be addressed via the LCFS program. CARB has an opportunity to incentivize EVs to generate far greater emissions reductions by making V2X eligible for carbon credits in the LCFS program. Standard EV charging, in comparison, can only minimize emissions from mobility, i.e. offset its own carbon footprint. V2X EVs can generate far greater emissions reductions, beyond the vehicle use itself by enabling discharge to the grid during peak CI times. Fermata Energy recommends that the program fully incentivize these benefits for the state at large by making all V2X discharged and charged energy accountable for LCFS credits. This change would help achieve the program's goal of lowering emissions in the state.

264.3 **3. Consideration of WattTime Data for More Accurate Carbon Intensities (CI) Values**

Fermata Energy recommends that CARB consider using WattTime Data or a similar provider for LCFS CI values. More accurate, granular data on marginal carbon intensities of charging from grid electricity in California is widely available today, from data providers such as WattTime or electricitymaps.

WattTime provides average and marginal operating emissions rates (AOER and MOER) for California grid areas, at 5-min intervals. WattTime data is used in the Self-Generation Incentive Program (SGIO), which is another CA program that aims to reduce carbon emissions from subsidized assets (battery energy storage systems), for which the data is made available to registered users for free (via CEC's MIDAS open access portal).

Fermata Energy has assessed the difference in the CI assumptions required by the LCFS program vs. the marginal operating emissions rates (MOER) calculated by WattTime. We have compared the two data sets and their impact on emissions calculations for two representative vehicle profiles: a residential and a fleet use case over a year. We found that the LCFS CI assumptions significantly underestimate the emissions relative to using the WattTime MOER (see Appendix Table on page 8). This means that EV market participants optimizing against the LCFS CIs are not achieving as many emissions reductions as they could, even for standard charging technologies.

While Fermata Energy cannot comment on the differences in these underlying models, the extent of the difference between the two data sources (CARB vs. WattTime) warrants investigating the accuracy and reliability of the LCFS assumptions. Fermata Energy recommends that CARB consider re-evaluating the current CI methodology and updating the CI assumptions for the smart charging pathway calculations.

If WattTime data is correct, the current assumptions favor LCFS market participants (including Fermata Energy) by underestimating their CO_2 emissions, and therefore giving them access to more credits than they would otherwise be able to obtain using more granular real-time CI values. This leads to potential over compensation of market participants, and unnecessary costs to the program and the state. Improving the data accuracy will therefore improve the actual environmental impact of EV charging (including V2X), incentivize market players to develop better charge management strategies, and lead to lower LCFS program costs by ensuring participants are not overcompensated.

Lastly, Fermata Energy recognizes that optimization for CI's and V2X monetization
opportunities may sometimes conflict. The formula proposed on hourly CI accounting of V2X
264.4 net energy flows is not necessarily aligned with our economic interest nor that of our
commercial and residential customers. To avoid this misalignment, CARB should ensure that
sufficient financial incentives are available through the LCFS program so that participants are
incentivized to reduce the carbon emissions.

4. Support for Use of LCFS Holdback Funds for Grid-Supported V2X Programs

Fermata Energy supports CARB's proposal to use LCFS Holdback Funds on VGI and V2G
264.5 programs.[7] However, we urge CARB to ensure that funding for V2G programs be limited to only
those that use grid-supported or "grid-tied" technologies and use cases. Non-grid-tied forms of V2G, such as islanded backup power, do not provide the same decarbonization benefits to the grid. Fermata Energy agrees with the pre-approved uses for these other holdback projects. In addition, we proposed that the list of holdback projects be amended so that it is clearer that grid-tied V2G projects can qualify as both equity and non-equity holdback projects. The proposed regulation is unclear and it looks like V2G projects only qualify as non-equity holdback. This should be fixed as V2G projects can benefit the communities and individuals defined as equity in Section 95483 (c)(1)(A) 5.

Fermata Energy appreciates the opportunity to provide these comments in response to CARB's Proposed LCFS Amendments. We look forward to collaborating with CARB as they finalize the proposed amendments to LCFS.

Respectfully submitted,

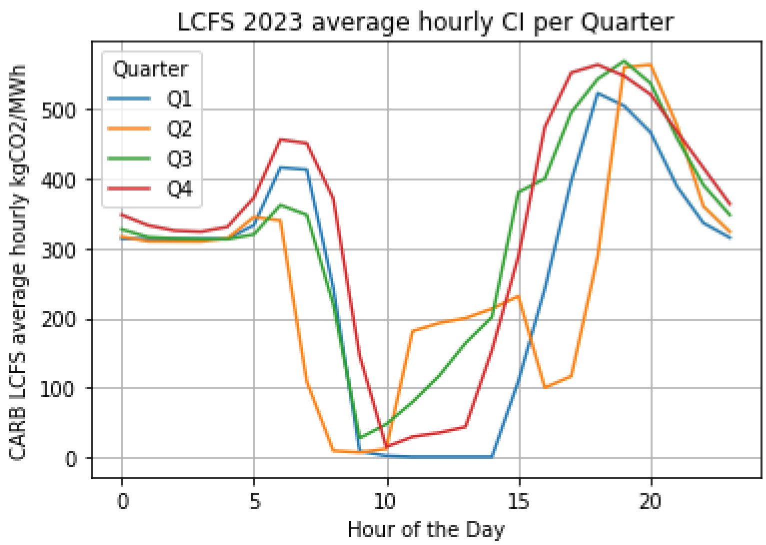
/s/ Anna Bella Korbatov
Director of Regulatory Affairs
Fermata Energy
annabella@fermataenergy.com
310-666-8010

/s/ Claire Weiller
Director of European Strategic
Partnerships & Product Product Management
Fermata Energy
claire.weiller@fermataenergy.com
+44 7980 206166

[7] See Section § 95483. Fuel Reporting Entities. < (c) For Electricity Used as a Transportation Fuel. (1) Residential EV Charging. (A) Base Credits. < 5b, at page 45,https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appa1.pdf

Appendix

Fig A Comparison of quarterly average hourly carbon intensity data



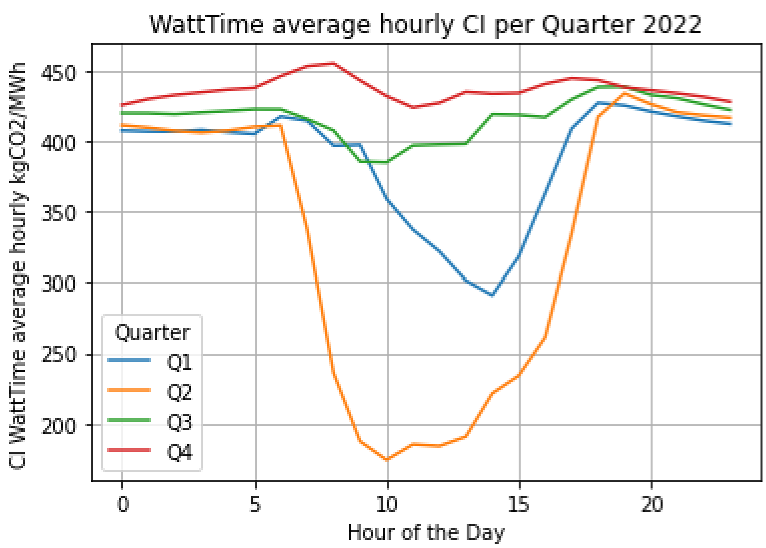


Table A - V2X emissions calculations for different user profiles and CI data sources

This table presents the environmental impact of two example V2X profiles in CA: one for a residential user and one for a V2G fleet vehicle, calculated using each of the two CI data sources for 2022

The charging and discharging profiles were obtained from Fermata Energy's optimization forecast. They represent the behavior of an EV owner aiming to maximize their economic revenue from V2X (detailed assumptions available upon request).

Units: kg CO2/year (for year 2022)	**LCFS Smart Charging CIs**	**WattTime MOER**
Residential	-716	-5,676
Fleet	6,559	-23,695

Note: A positive number reflects a net benefit in CO_2 reduction i.e. carbon removal due to V2X discharge offsetting V2X charging. CARB's CI assumptions would lead to an estimation of a net carbon benefit of a fleet V2X EV.

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Comment 274 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Gene
Last Name	Harrington
Email Address	gharrington@bio.org
Affiliation	Biotechnology Innovation Organization
Subject	2024 Proposed Low Carbon Fuel Standard Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6944-lcfs2024-UDZWNVY1BCUHdAFg.pdf
Original File Name	February2024BIOCALCFSProposedChangesComments.pdf
Date and Time Comment Was Submitted	2024-02-20 15:47:08

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

Liane Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: 2024 Proposed Low Carbon Fuel Standard Amendments

Dear Chair Randolph:

I write on behalf of the Biotechnology Innovation Organization (BIO) - the world's largest biotechnology focused trade group with members that produce agricultural, environmental, industrial, and health care products – to comment on the California Air Resources Board (CARB) 2024 proposed amendments to the Low Carbon Fuel Standard (LCFS).

Specific to the pending rulemaking, BIO members produce both the feedstock and biofuels from which California's LCFS – along with the state's environment and economy - has benefitted so greatly the last 14 years.

Effective since 2011, California's LCFS has, by any standard, been wildly successful. In 2022 alone, the LCFS program helped to replace nearly two billion gallons of regular diesel fuels with a combination of renewable diesel, biodiesel, electricity, and hydrogen. Since compliance began, the program has helped replace more than 8.6 million gallons of diesel. In 2023, California hit an important milestone in its shift away from polluting fuel sources, with clean fuels replacing over 50% of the diesel used in the state in the first quarter of the year.

Thanks to the LCFS' technology neutral, market driven approach, California also receives significant volumes of other low carbon fuels, including ethanol, biomass-based diesel, and biomethane. To that end, since the inception of the LCFS, California has increased consumer choice by considerably diversifying the fuel mix and, in doing so, the state has doubled the volume of low-carbon fuel consumption. Collectively, alternative fuels supported by the LCFS displaced over 3.9 billion gallons of petroleum fuel in 2022 in California.

265.1 It is therefore puzzling then that CARB is proposing unworkable certification requirements instead of relying on existing and proven certification programs. Moreover, CARB's multiple references about "deforestation" in the documents accompanying the rulemaking seem to bely a general unawareness of the significant gains farmers have made in productivity over the years, leading to higher yields on the same or fewer acres, with less carbon intensive inputs. It also telling that the primary references for the "deforestation" claims come from European and not U.S. sources, leading one to wonder about the applicability and relevance of such information. Furthermore, the timber sector is in dire need of additional markets for low grade timber, so the idea that large swaths of land in the U.S. land is being deforested either in the agriculture or forestry sectors to benefit from California's LCFS appears unsubstantiated and misplaced.

265.2 Not only is proposed Section 95488.9(g): "Sustainability Requirements for Crop-Based and Forestry Based Feedstocks" not technology neutral, it appears aimed at eliminating the low carbon fuels that have been largely responsible for the program's overall success.

Frankly, it isn't clear why crop and forestry-based fuels are being singled out for meeting social and economic criteria, which have implications for any fuel pathway participating in the LCFS program, including electric vehicles. These additional criteria have the potential to add substantial administrative burden to both farmers and fuel producers, potentially creating barriers to participation in the LCFS. As such, this requirement should be dropped altogether.

265.3 BIO also wishes to take this opportunity to urge CARB push for the use of E!5 in California in whatever way possible. Although E!5 is technically not related to this rulemaking, it should be noted that California is one of only two states that does not permit the sale of E15.

Allowing E15 will help reduce the carbon intensity of the state's gasoline supply and cut emissions of criteria pollutants. In fact, the University of California-Riverside's Center for Environmental Research and Technology found that replacing E10 with E15 in California will significantly improve air quality. Additionally, E15 is EPA-approved for nearly all vehicles on the road and offers meaningful cost savings, but Californians are currently paying more at the pump because CARB has not yet approved E15.

Again, BIO appreciates the opportunity to comment on CARB's proposed amendments to the LCFS. Please feel free to contact me at gharrington@bio.org or (202) 365-6436 if you have any questions regarding BIO's comments.

Sincerely,

Gene Harrington
Senior Director, State Government Affairs, Agriculture & Environment

Comment Log Display

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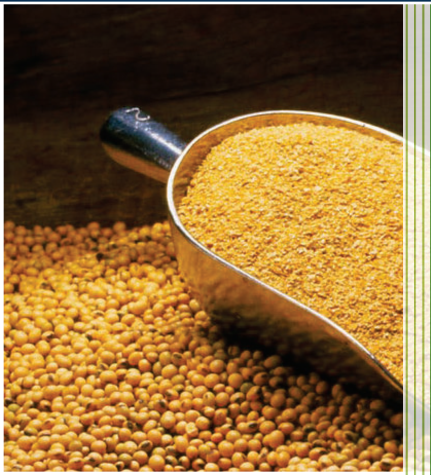
Comment 275 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	David
Last Name	Hovermale
Email Address	dhovermale@nopa.org
Affiliation	National Oilseed Processors Association
Subject	Comments on Proposed LCFS Program
Comment	Attaching National Oilseed Processors Comments (NOPA) on LCFS Program and submitting NOPA and United Soybean Board (USB) LCA Study in a zip file.
Attachment	www.arb.ca.gov/lists/com-attach/6945-lcfs2024-VzNWMVMkU2kLaQBf.pdf
Original File Name	David Hovermale - combined files.pdf
Date and Time Comment Was Submitted	2024-02-20 15:55:57

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Life Cycle Assessment of U.S. Soybeans, Soybean Meal, and Soy Oil



Prepared For:
United Soybean Board
and the
National Oilseed Processors Association

January 2024

SustainableSolutions CORPORATION
155 Railroad Plaza, Suite 203
Royersford, PA 19468 USA
T: 610 569 1047
F: 610 569 1040
www.SustainableSolutionsCorporation.com

Life Cycle Assessment of

U.S. Soybeans, Soybean Meal, and Soy Oil

January 2024

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DO NOT DISTRIBUTE

Commissioned by the United Soybean Board and the National Oilseed Processors Association

LCA Practitioner: Sustainable Solutions Corporation

Prepared for:

United Soybean Board	National Oilseed Processors Association
16305 Swingley Ridge Rd	1310 L Street, NW
Suite 150	Suite 375
Chesterfield, MO 63017	Washington, DC 20005

Conducted according to ISO 14040 and ISO 14044 International Standards

Life Cycle Assessment of U.S. Soybeans, Soybean Meal, and Soy Oil

Executive Summary

Life cycle assessment (LCA) is a rigorous study of the inputs and outputs of a particular product or product system which provides a scientific basis for evaluating the environmental impacts through each phase of the life cycle. LCA is an alternative to the single-criterion decision-making that currently guides many environmental choices.

This LCA is designed to be used by the United Soybean Board (USB) and the National Oilseed Processors Association (NOPA) to better understand the current state and environmental impact of the U.S. soybean industry's farming, processing, and oil refining operations. This report documents the methodology, data, details, and results of the LCA on the impacts of one kilogram (kg) of soybeans, one kilogram (kg) of soybean meal, one kilogram (kg) of crude soy oil, and one kilogram (kg) of refined soy oil produced in the United States. Primary data were obtained from direct information sources electronically collected from farmers and processors, with the assistance of USB and NOPA staff. Secondary data were obtained from the U.S. Department of Agriculture (USDA), U.S. Lifecycle Inventory (USLCI), and Ecoinvent databases.

Findings in this study provide a snapshot of industry performance based on acquired primary data from USB and NOPA members in support of this assessment:

- **Soybean cultivation data reflect 454 farms across 16 states.**
- **Soybean meal, crude soy oil, and refined soy oil data reflect 52 U.S. soybean processing plants and 27 co-located soy oil refineries operating across 18 states.**

Key Findings

Based on 2020 - 2021 harvesting yields reported by U.S. soybean farmers and 2021 operations and production data for U.S. soybean processing plants and co-located soy oil refiners as reported by NOPA members, **the global warming potential (GWP) profile decreased considerably for all evaluated U.S. soy commodities** compared to previously reported findings published in 2015 and 2010.

U.S. Soybeans, Soybean Meal & Soy Oil GWP Profile Reductions Since 2015

- 19% per kg U.S. soybeans
- 6% per kg U.S. soybean meal
- 22% per kg U.S. crude soy oil
  - 8% per kg U.S refined soy oil (produded at co-located processing/refining cites)

Previous life cycle assessments were commissioned by USB in collaboration with NOPA, each prepared and evaluated by different LCA practitioners. Data for oilseed processing operations was not formally collected as part of the 2015 assessment.*

Findings presented in this LCA show that herbicides, field operations, and fertilizer are the main drivers of most environmental impact categories assessed for soybean cultivation. **This analysis assumes an average production yield of 51 bushels per acre harvested, based on USDA estimates.** The percentages that each soybean agriculture component contributes to each impact category are shown in Table 0.1.

Table 0.1 – Agriculture Component Contributors by Impact Category

Impact Category	Field Operations	Fertilizer	Fungicide	Herbicide	Insecticide
Global Warming Potential	38.58%	24.37%	1.30%	31.92%	3.83%
Fossil Fuel Depletion	30.25%	27.82%	1.38%	36.61%	3.94%
Eutrophication	0.93%	90.69%	0.06%	8.08%	0.24%
Smog	51.00%	26.41%	0.58%	20.13%	1.87%
Acidification	28.81%	28.95%	1.09%	37.83%	3.32%
Ozone Depletion	5.92%	29.88%	2.22%	55.19%	6.80%
Carcinogenics	10.52%	51.12%	0.25%	37.06%	1.05%
Non-Carcinogenics	2.95%	22.71%	0.10%	7.68%	66.55%
Respiratory Effects	13.94%	42.22%	0.83%	40.51%	2.51%
Ecotoxicity	0.58%	4.73%	0.17%	36.48%	58.03%
Land Use	98.87%	0.57%	0.03%	0.42%	0.10%
Water Consumption	90.85%	5.99%	0.02%	2.92%	0.21%
Cumulative Energy Demand	25.44%	23.73%	1.78%	43.72%	5.33%

Soybean cultivation and harvesting, followed by energy usage in processing, are the main drivers of all impacts from soybean meal and soybean oil production. During processing, soybeans are

* The 2015 LCA study relied on NOPA member data for 50 processing plants based on previously reported data used for the 2010 study. In preparing the processing operations data used for the 2015 study, NOPA members reviewed the 2010 dataset and elected to revise only the electricity use input value. As such, the 2015 dataset reported the weighted average value instead of the upper bound value which was used for the 2010 study. This change was made so that the input value better reflected typical operating conditions at a soybean processing plant.

responsible for approximately 65% of the crude soy oil and soybean meal cradle-to-gate impacts, while energy usage is responsible for approximately 32%, depending on the impact category.

To account for the high amount of variability in agricultural practices, a range of sensitivity studies were conducted to evaluate the validity of the results and their dependence on the assumptions made throughout the LCA. The specific studies focused on:

- *Harvest yields* – testing the extent to which lower (41 bushels per acre, past yields) or higher (61 bushels per acre, average high yields) harvest yield assumptions affect impacts. Impact results at the lower and upper bound of the soybean yields show a 20% change over the baseline case (51 bushels per acre, average yield used in this study).

- *Diesel* – testing the sensitivity of results to the amount of diesel used during soybean farming. The baseline of 1.4 gallons of diesel per acre was compared to 2.5 gallons per acre, 5 gallons per acre, and 6 gallons per acre. Most categories remained constant or showed a small (1% - 5%) to moderate (5% - 21%) increase in impacts. Smog, however, showed significant increase in impacts (20% - 90% increase for soybeans, 17% - 70% for crude soy oil and soybean meal, and 12% - 52% increase for refined soy oil) due to the chemical reactions that occur when diesel is combusted.

- *Allocation method* – testing how utilizing economic allocation or energy content allocation instead of mass allocation affects environmental impacts attributed to each product. Since four times more meal is produced than oil, meal will always have a higher percentage of the impacts. However, results show that the gap between their respective shares of impacts decreases with economic and energy content allocations: 20% oil / 80% meal for mass allocation, 33% oil / 67% meal for allocation by energy content, and 41% oil / 59% meal for economic allocation.

Sensitivity analysis is a tool used in LCA to identify whether the model and results are dependent upon assumptions made. Assumptions and uncertainties are inherent within LCA and cannot be avoided; however, sensitivity analyses allow the practitioner to validate the strength of the assumptions used in a study. The results of the various sensitivity analyses show that for certain impact categories, there can be significant deviation in the results based on the assumptions made.

The sensitivity analyses conducted focused on the assumptions that would have the largest impact on the LCI (i.e., method of allocation and yield per acre). Both assumptions are integrally intertwined with all the LCI calculations, therefore, variation in these assumptions is expected to cause significant deviations. These assumptions were developed through primary data collection, expert validation, and research into industry common practices. As such, these assumptions have been determined to be the most accurate way to represent the soy industry in the United States.

Acknowledgements

Sustainable Solutions Corporation (SSC) gratefully acknowledges John Jansen and Jack Cornell from USB, Lauren Maul from Smith Bucklin, and Katie Vassalli from NOPA for their significant support and contributions throughout this project. They provided domain expertise on soybean agriculture and soybean processing, led surveys, and provided accurate primary data.

Additionally, SSC, along with USB and NOPA, would like to thank all the U.S. soybean growers and soybean crushers who provided valuable facility operations data and shared their institutional

knowledge about soybean farming, processing, and oil refining operations to ensure the high quality of this study.

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1.0 Introduction

Life cycle assessment (LCA) is a powerful tool used to quantify the environmental impacts associated with the various stages of a product's life. This section provides a background and overview of LCA methodology and benefits.

1.1 Background

Soybean is a major commodity crop. Global production went from less than 50 million tons in the year 1970 to 161 million tons in the year 2000 and over 350 million tons in the year 2020. The U.S. and Brazil alone account for two-thirds of this production, with the U.S. being the largest producer and second largest exporter of soybeans. Soybeans comprise about 90% of U.S. oilseed production in the agricultural sector.

The use of LCA is growing rapidly in many industries including agriculture, food, chemical, and fuel. To support this growth and the increased demand for environmental profiles like carbon footprints, the United Soybean Board (USB) and the National Oilseed Processors Association (NOPA) commissioned an update to their life cycle assessment. This report is designed to benchmark the global warming potential of U.S. soybeans, soybean meal, and soy oil to help U.S. producers better assess and understand their contribution to the environmental impacts of U.S. soy lifecycle from farm gate (soybeans) to factory gate (soybean meal and soy oil). Findings of this study may also be used to evaluate what changes in industry practices may have contributed to the observed reductions between the data collection years (e.g. 2021, 2015 and 2010).

These datasets provided by USB and NOPA members will further be used to update public life cycle inventory database (e.g. U.S. GREET Model, Federal LCA Commons) for these commodities. These data may also be used to update LCA profiles of downstream products such as human foods, animal feeds, biofuels, and other industrial applications. This LCA is valuable to USB as a tool for competitive positioning.

1.2 Overview of Life Cycle Assessment

Life Cycle Assessment (LCA)[2] is an analytical tool used to comprehensively quantify and interpret the environmental flows to and from the environment (including emissions to air, water, and land, as well as the consumption of energy and other material resources) over the entire life cycle of a product (or process or service). By including the impacts throughout the product life cycle, LCA provides a comprehensive view of the environmental aspects of the product and an accurate picture of the true environmental tradeoffs in product selection.

The standards in the ISO 14040-series set out a four-phase methodology framework for completing an LCA, as shown in Figure 1.1: (1) goal and scope definition; (2) life cycle inventory

[2] This introduction is based on international standards in the ISO-14040 series, *Environmental Management – Life Cycle Assessment.*

(LCI); (3) life cycle impact assessment; and (4) interpretation. An LCA starts with an explicit statement of the goal and scope of the study; the functional unit; the system boundaries; the assumptions, limitations and allocation methods used; and the impact categories chosen. In the inventory analysis, a flow model of the technical system is constructed using data on inputs and outputs. The input and output data needed for the construction of the model are collected (including resources, energy requirements, emissions to air and water, and waste generation for all activities within the system boundaries). Then, the environmental loads of the system are calculated and related to the functional unit, to finalize the flow model. Inventory analysis is followed by impact assessment, where the LCI data are characterized in terms of their potential environmental impact (e.g., acidification, eutrophication, and global warming potential effects). The impact assessment phase of LCA is used to evaluate the significance of potential environmental impacts based on the LCI results. The impact assessment data are interpreted and validated by sensitivity analysis performed by the LCA practitioner to provide useful data to the company that commissioned the LCA.

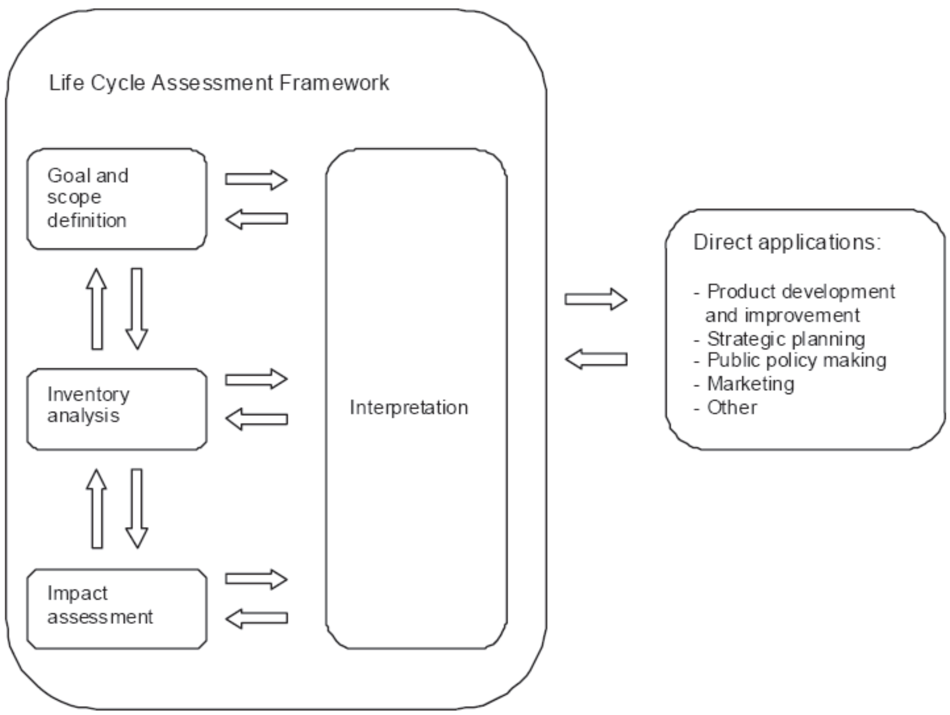


Figure 1.1 – The Four Stages of Life Cycle Assessment

The working procedure of LCA is iterative, as illustrated with the back-and-forth arrows in Figure 1.1. The iteration means that information gathered in a later stage can cause effects in a former stage. When this occurs, the former stage and the following stages must be reworked, taking into account the new information. Therefore, it is common for an LCA practitioner to work at several stages at the same time.

This LCA study is characterized as a "cradle-to-gate" study examining soybean cultivation and processing from raw material extraction through the processing facility gate. For this life cycle assessment, Sustainable Solutions Corporation (SSC) collected specific data on energy and material inputs, wastes, water use, emissions, and transportation impacts for the cultivation and processing of soybeans in the United States for the calendar year 2021. This LCA was conducted using SimaPro software with the National Renewable Energy Lab (NREL) USLCI database serving as the primary source of life cycle inventory data for secondary raw materials and processes. Where data were not available in the USLCI database, data from the Ecoinvent LCI database, private SSC LCI databases, and published reports were used. Data from any European databases were adapted using U.S. electricity impacts. The TRACI 2.1 impact assessment methodology was used to calculate the environmental impacts in this LCA. TRACI was developed by the U.S. Environmental Protection Agency (EPA) as a tool to assist in impact analysis in Life Cycle Assessments, process design, and pollution prevention. Impact categories include:

1. Global Warming Potential
2. Acidification
3. Carcinogens
4. Non-Carcinogens
5. Respiratory Effects
6. Eutrophication
7. Ozone Depletion
8. Ecotoxicity
9. Smog
10. Fossil Fuel Depletion
11. Water Consumption
12. Land Use
13. Cumulative Energy Demand

2.0 Goal and Scope Definition

The nature of life cycle assessment is to include a wide range of inputs associated with the product analyzed. Constraining the LCA scope is an essential part of the study. The following section defines the goal, scope, and boundaries of this LCA study.

This LCA went through a formal critical review by Marty Heller, AgResilience Consulting, LLC in January of 2024, as is required by ISO 14040 Standards for external release. The study was conducted following appropriate ISO standards and best practices and is intended to assist USB and NOPA with understanding the life cycle impacts of their products.

2.1 Goal of the Study

The goal of this analysis is to identify and quantify the environmental impacts associated with each stage in the cradle-to-gate life cycle of soybeans, soybean meal, crude soy oil, and refined soy oil, including soybean cultivation and harvesting, transportation, and processing.

USB and NOPA partnered together initially in 2010 to complete a similar analysis to ascertain the environmental impacts of soybeans, soybean meal, crude soy oil, and refined soy oil. In 2015, a second analysis was performed. For this study, NOPA members reviewed the 2010 LCA dataset and updated certain values to reflect a weighted average value. NOPA members concluded that this revision to the dataset was required in order to better represent the actual operating conditions required for soybean processing. See Appendix A for a detailed historical comparison of the results.

Intended Uses

LCA is a tool that can effectively be applied for process improvements, education and market support, environmental management, and sustainable reporting. USB and NOPA, who are the primary audience of the study, intend to use the study results for the following purposes:

- To understand and evaluate the impacts of soybeans, soybean meal, crude soy oil, and refined soy oil across the products' life cycle.
- To prepare for sustainable supply chain requirements, carbon taxes, and other potential policy requirements.
- For competitive analysis and positioning to analyze and evaluate claims or LCA information published in the future by competing industries.
- As a basis for future publication of a soybean, soybean meal, crude soy oil, and refined soy oil LCA if required by the market or if desired by USB and NOPA for marketing or competitive purposes.
- As a tool to illustrate the reduced environmental impacts to regulatory agencies (such as state/local environmental agencies or U.S. EPA) of agricultural practice, process, facility, or raw material improvements.
- To meet future requirements for green purchasing programs for the U.S. government, corporations, or other businesses.

2.2 Functional Unit

All flows to and from the environment within the system boundary (see Section 2.3 below) are normalized to a unit summarizing the function of the system. The functions of soybeans, soybean meal, crude soy oil, and refined soy oil are to be used in food manufacturing, biodiesel production, and industrial production.

Once the primary functions of the systems are defined, a functional unit is selected in order to provide a similar basis, consistent with the above-mentioned goals, for summarizing the LCA. The functional units utilized for this study are one kilogram (kg) of each product. This functional unit is consistent with the goal and scope of the study. Table 2.1 list specific details of soybeans, soy oil, and soybean meal.

Table 2.1 – Soybeans, Soybean Meal, Crude Soy Oil, and Refined Soy Oil Product Details

	Soybeans	Soybean Meal	Crude Soy Oil	Refined Soy Oil
Processing Location	United States	United States	United States	United States
Functional Unit	1 kg of soybeans	1 kg of soybean meal	1 kg of crude soy oil	1 kg of refined soy oil
Weight	1 kg	1 kg	1 kg	1 kg

The functional unit is the basis for reporting in an LCA. It provides a unit of analysis and comparison for all environmental impacts. Both crude soy oil and soybean meal are produced simultaneously. This required the allocation of impacts between the meal and the oil. Mass allocation was selected in order to remain consistent with previous studies.

2.3 System Boundary

This project considers the life cycle activities from resource extraction through processing facility gate. Figure 2.1 defines the system boundary for soybeans and soybean products included in this study. The study system boundary includes the transportation of major inputs to (and within) each activity, based on logistics data provided by USB and NOPA by common modes. Any site-generated energy and purchased electricity is included in the system boundary. The extraction, processing and delivery of purchased primary fuels, e.g., natural gas and primary fuels used to generate purchased electricity, are also included within the boundaries of the system. Purchased electricity consumed at the various site locations is modeled based on U.S. grid averages, using the models published in the USLCI and Ecoinvent cut-off databases.

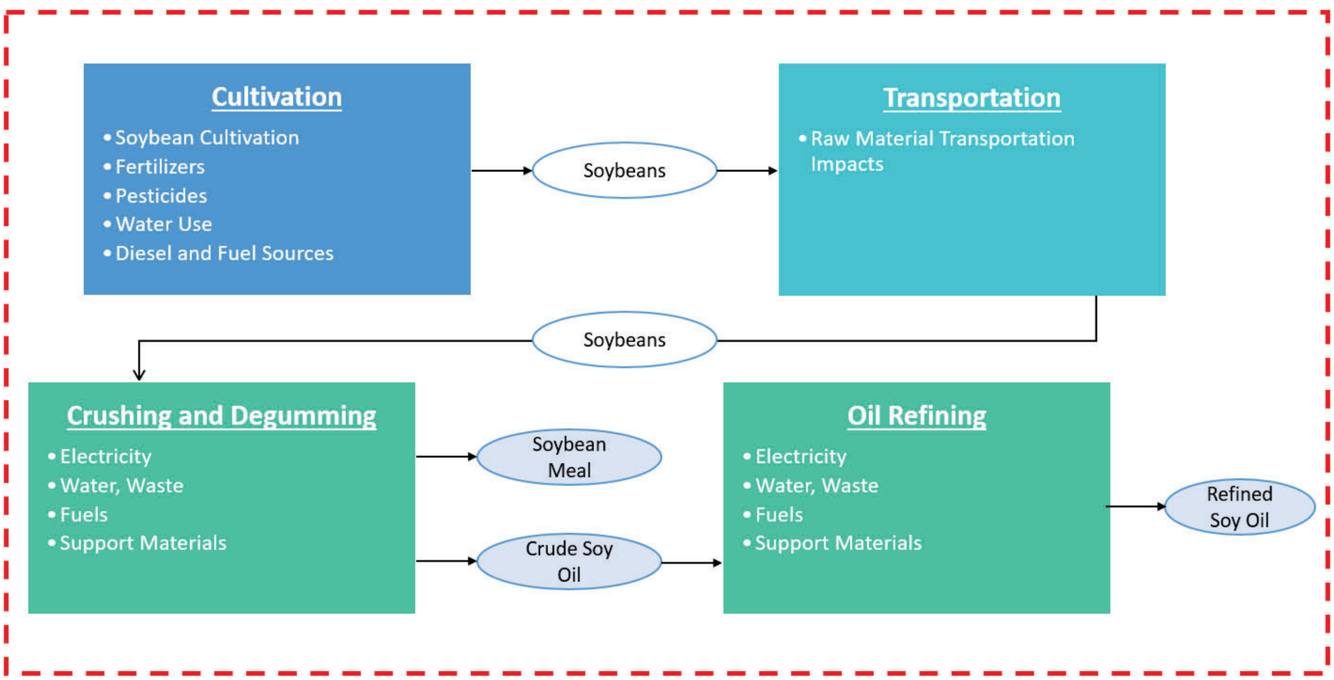


Figure 2.1 – System Boundary for Soybeans, Soybean Meal, Crude Soy Oil, and Refined Soy Oil

Both human activity and capital equipment were excluded from the system boundary. The environmental effects of manufacturing and installing capital equipment and buildings have generally been shown to be minor relative to the throughput of materials and components over the useful lives of the buildings and equipment. Human activity involved in the cultivation and processing of soybean products and their component materials no doubt has a burden on the environment; however, the data collection required to properly quantify human involvement is particularly complicated and allocating such flows to the production of the soybean products, as opposed to other societal activities, was not feasible for a study of this nature. Typically, human activity is only considered within the system boundary when value-added judgments or substituting capital for labor decisions are considered to be within the scope of the study; however, these types of decisions are outside this study's goal and scope. The details of the data excluded from the system boundary can be found in the subsequent inventory sections.

Table 2.2 – System Boundary Description

Included	Excluded
• Soybean cultivation, harvesting, and agricultural waste • Soybean transportation to processing facilities • Energy and inputs for soybean processing (the crushing and degumming process) • Energy and inputs in oil refining process	• Construction of capital equipment • Transportation of chemicals applied in fields • Maintenance of operation and support equipment • Human labor and employee commute

2.3.1 Cut-off Criteria

Processes whose total contribution to the final result, with respect to their mass and in relation to all considered impact categories, is less than 1% can be neglected. The sum of the neglected processes may not exceed 5% by mass and by 5% of the considered impact categories. For that a documented assumption is admissible.

For Hazardous Substances, as defined by the U.S. Occupational Health and Safety Act, the following requirements apply:

- The Life Cycle Inventory (LCI) of hazardous substances will be included if the inventory is available.
- If the LCI for a hazardous substance is not available, the substance will appear as an input in the LCI of the product if its mass represents more than 0.1% of the product composition.
- If the LCI of a hazardous substance is approximated by modeling another substance, documentation will be provided.

This LCA complies with the cut-off criteria since no known processes were neglected or excluded from this analysis outside of the specific items listed under "Excluded" in Table 2.2.

3.0 Data Sources and Modeling Software

The quality of the results of an LCA study are directly dependent on the quality of input data used in the model. This section describes the data quality guidelines used in this study, the sources from which the data were selected, the software used to model the environmental impacts, and any data excluded from the scope of the study.

3.1 Data Quality

3.1.1 Primary Data

Primary data were obtained from direct information sources electronically collected from farmers and processors with the assistance of USB and NOPA staff.

Soybean Cultivation Data

An online survey performed by USB in partnership with OBP, a marketing firm for agriculture, tourism, and food provided soybean cultivation primary data. Farmers were asked about soybean yield and moisture content, how much was spent on electricity and natural gas, fuel usage, waste produced, soil health, water quality related practices, and conversion of acres. 454 U.S. soybean farmers across 16 states completed the survey providing data for 2020 and 2021.

Soybean Processing and Soy Oil Refining Data

Primary data for soybean processing were based on NOPA member company responses to an electronic data collection survey performed by NOPA in partnership with SSC and Clean Fuels Alliance America. NOPA member-owned companies were asked to provide facility data about the transportation of inputs, processing and refining inputs/outputs, energy usage, and related sources.

For this study, NOPA provided SSC with aggregated data based on survey responses for 11 NOPA member companies, representing a total of 52 soybean processing plants and 27 co-located soy oil refineries operating across 18 states.

NOPA member facility data were submitted for calendar year 2021 NOPA Member Soybean Processing Operations based on analysis of aggregated NOPA member facility data. Individual facility data was anonymized and aggregated, then validated by NOPA's Certified Public Accountant. Analysis of the aggregated data was conducted by NOPA's Environmental Advisory Group prior to submission to SSC.

3.1.2 Secondary Data

Secondary data were obtained from USDA, USLCI and Ecoinvent databases. Where used, this study adopts critically reviewed data for consistency, precision, and reproducibility to limit uncertainty. Secondary data sources used are complete and representative of the U.S. in terms of the geographic and technological coverage and are a recent vintage (i.e., less than ten years old). Datasets that utilized data that were more than ten years old were updated with more recent data when possible. Secondary datasets used from the USLCI database utilize mass or energy allocation (process dependent) and datasets from the Ecoinvent database utilize economic or energy allocation. The allocation methodology implemented in secondary datasets is not always consistent with the allocation methodology used in this LCA study; however, those datasets represent the most appropriate options for the inventory.

Deviations from these initial data quality requirements for secondary data are documented in the report, found in Appendix B.

3.1.3 Data Quality Factors

The results of an LCA are only as good as the quality of input data used. Important data quality factors include precision (measured, calculated, or estimated), completeness (e.g., unreported emissions or excluded flows), consistency (uniformity of the applied methodology throughout the study), and reproducibility (ability for another researcher reproduce the results based on the methodological information provided). The primary data collected from USB and NOPA members were from the latest data available. Secondary datasets were taken from SimaPro databases, either USLCI or Ecoinvent. These databases are widely distributed and referenced within the LCA community and are either partially or fully critically reviewed.

Precision

There is a wide variability of farming, and this study attempts to capture this breadth of farming practices. The precision for primary data for processors is considered high; however, the uncertainty of the primary data has not been quantified. While the uncertainty of the primary data was not directly quantified, steps were taken to ensure the datasets were appropriate for use in the study. These steps included data validation with USB and NOPA personnel, data comparison to the previous U.S. Soybean LCAs, and evaluation against data published by credible sources, most notably the USDA survey database. More information on these steps can be found in the *Consistency* section.

Secondary data sets were used for raw materials extraction and processing, end of life, transportation, and energy production flows. The Ecoinvent database was used for most of the raw material data sets, such as chemical applications and fuels. Since the inventory flows for Ecoinvent processes are very often accompanied by a series of data quality ratings, a general indication of precision can be inferred. Using these ratings, the data sets used generally have medium-to-high precision. Precision for the datasets used from the USLCI database was not formally quantified. However, many data sets from the USLCI were developed based on well-documented industry averages with data quality indicators provided for each flow.

Completeness

The processes modeled represent the specific situations in the soybeans' cradle-to-gate life cycle. Data were evaluated for completeness to ensure that all relevant inventory items that were above the required reporting threshold, per the cut-off criteria, were included. System boundaries and exclusions are clearly defined in the sections above, and no other data gaps were identified.

Consistency

Farming survey data represented soy production for 2020 and 2021. Primary soybean cultivation data were obtained through a survey that was filled out by 454 soybean farmers across 16 states in the U.S. Soybean farms below 300 acres were excluded along with three outliers, establishing a sample size of 377 farms. Operations below 300 acres were determined to not be representative of the common U.S. cultivation practices based on discussions with industry experts. These smaller scale operations have much lower production volumes than larger ones and tend to utilize more unconventional cultivation methods due to the flexibility of managing lower volumes. These unconventional methods were excluded as they were expected to cause inaccurate reductions of environmental impacts, based on efficiencies of managing lower volumes, that do not correctly represent the U.S. soybean industry's common cultivation practices.

Individual farming survey responses were summed at the state level, for each inventory input and output, and benchmarked using the sum of total production at the state level, to calculate a state average LCI based on the interests of USB. A weighted average based on total production of individual states, relative to the total U.S. production calculated from the farm surveys, was used to develop the U.S. average LCI. Non-responses and zero values were included in the average when the majority of questions were answered by the respondent but were otherwise excluded. A statistical analysis of key energy inputs is presented in Table 3.1. The mean depicts the average of all survey respondents, while the weighted mean (i.e., state-level production-weighted average) captures the LCI values found in Table 5.1 on a per acre basis.

In the NOPA data, four outliers were examined to ensure that their exclusion would not alter or distort the results of the study and removed from the data as appropriate. Two outliers were found in the crushing and degumming process and two were found in the oil refining stage. Since the data represented a reasonable sample size over a 12-month period under normal operating conditions, the consistency is considered high. Secondary data were modeled using either USLCI or Ecoinvent databases as available. Proxies were only identified and used if secondary data were not available in these or other databases. This methodology provided consistency throughout the model.

Table 3.1 – Statistical Analysis of Survey Energy Data

Input	Unit	Weighted Mean	Mean	Minimum	Maximum	Standard Deviation	Coefficient of Variation
Electricity	MJ/acre	8.47E+01	6.38E+01	2.12E-02	9.00E+02	1.01E+02	119%
Natural Gas	MJ/acre	1.78E+02	2.66E+02	1.75E-01	8.68E+03	7.53E+02	423%
Diesel	gal/acre	5.15E-01	7.79E-01	1.00E-05	2.56E+01	2.44E+00	474%
Gasoline	gal/acre	8.12E-02	1.22E-01	1.18E-05	4.26E+00	4.56E-01	562%

Methodological consistencies between the previous studies were intentionally kept similar where relevant and appropriate to ensure a level of comparability exists between studies. This was done so that USB and NOPA could use this study internally to evaluate the effect of operational changes that have been implemented geared towards regulatory compliance in environmental impacts, increasing reliability, lowering costs, and improving sustainability.

Reproducibility

Most datasets are from nationally accepted and publicly available databases, ensuring reproducibility by an average practitioner. Confidential data from the plant would inhibit reproducing these results without access to the data.

Representativeness

The representativeness of the datasets is chosen to be for the United States, capturing average technologies of the major producers and distributors. Soybean processing and refining has data for a significant and highly representative fraction of producers. The average soybean acreage harvested in 2020 and 2021 was 84,457,500 acres. The total soybean acreage of the 377 farms that met the inclusion criteria was 378,592 acres, meaning the survey responses utilized in this study accounted for 0.45% of the total soybean acreage harvested in the U.S. between 2020 and 2021. However, soybean agriculture data are deemed to be representative of the average farming conditions stemming from the key U.S. geographies. Of the farming survey respondents, 39% are from the "I" states (Iowa, Illinois and Indiana), which correlates strongly with the states regarded as most relevant to soybean production.

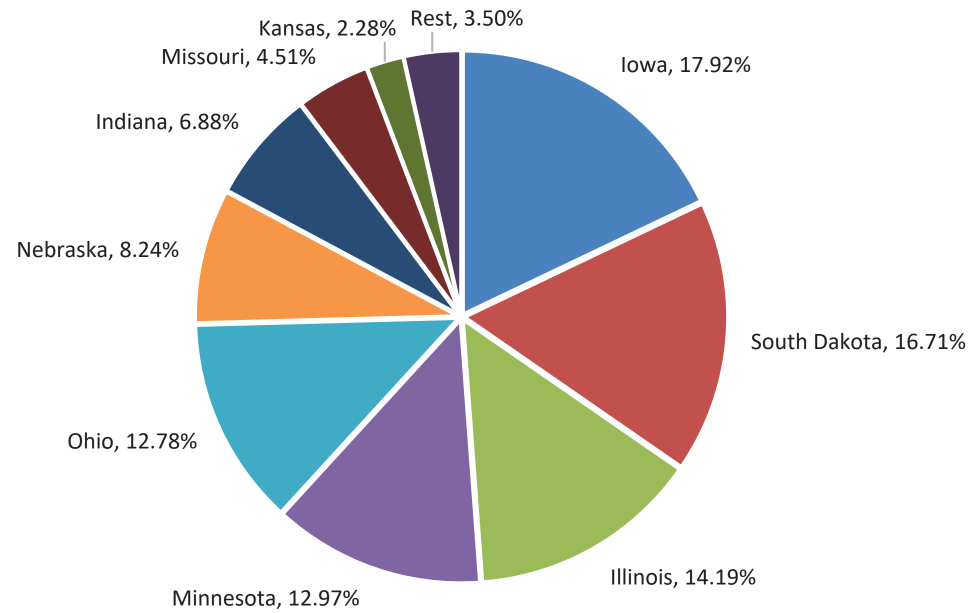


Figure 3.1 – Location of Farming Survey Respondents

Uncertainty

Uncertainty for primary energy data collected through the farming survey were quantified through statistical analysis. The collected data and allocation methodologies were determined to be accurate by USB and NOPA personnel based on the common industry practices, however, individual farming practices can vary widely due to a number of variables, so the range of input variables can vary significantly as shown in Table 3.1. Most of the secondary data sets in USLCI and Ecoinvent databases have some uncertainty information documented and varies per model.

The primary data from the manufacturer were from the latest data available, incorporating the most recent updates to the process into the model. Each dataset used was taken from SimaPro databases, either USLCI or Ecoinvent. These databases are widely distributed and referenced within the LCA community. The datasets use relevant yearly averages of primary industry data or primary information sources of the manufacturers and technologies. The uncertainty of each dataset is not formally quantitatively known. Each dataset is from publicly available databases, ensuring reproducibility. The datasets chosen are representative of the United States average technologies of the major producers and distributors and of recent and modern vintage. Below is a more detailed description of the datasets used in the model of raw materials extraction and processing for the major components of soybean cultivation and processing and refining of soy oil and soybean meal.

3.2 Data Sources

The United States is considered as the geographic boundary of this study. The reference year is 2021 since the primary soybean cultivation and processing data were gathered for that calendar year. Both primary and secondary LCI and metadata are used throughout the study.

3.2.1 Soybean Cultivation

Primary soybean cultivation data were obtained through a survey conducted by an independent third party in March of 2022. The third-party survey was focused on obtaining primary data from U.S. soybean farmers in order to accurately capture the practices used in U.S. soybean cultivation. Approximately 60,000 soybean farmers across the US were invited to participate in the survey by sharing data related to their growing metrics during the 2020 and 2021 growing seasons. The metrics of interest included yield; moisture content; spend on electricity, natural gas, and fuel; and volume of different types of waste produced. Of the participants invited, 454 soybean farmers spanning 16 different US states completed the survey. SSC determined that the states that responded to the survey represent an average approximation of U.S. soybean cultivation based on discussions with industry experts. Ranges in acreage, average yield per acre, and average moisture content were used to validate the discussions with industry experts. Data collected in the survey included the harvest acreage of alternate and cover crops. Soybeans are commonly grown in rotation with crops such as corn, wheat, and other crops in order to capture some of the operational benefits that exist utilizing this method. As such, the field operation inventory was allocated to soybean cultivation based on total harvest acreage.

During the data analytics process, SSC removed outliers from the utilized survey data by excluding data that could be deemed erroneous or irrelevant. An example of an erroneous data point is a response that indicated a yield of more than 100 bushels of soybeans per acre. An example of an irrelevant data point is a response from an operation with less than the minimum size which could accurately be classified as an "average" U.S. soybean operation. This number was determined to be 300 total acres. Operations below 300 acres were determined to not be representative of the common U.S. cultivation practices based on discussions with industry experts; and as such, these operations were excluded to focus the study on larger production practices.

Once outliers were removed from the dataset, the individual farming survey responses were summed at the state level, for each inventory input and output, and benchmarked using the sum of total production at the state level, to calculate a state average LCI based on the interests of USB. A weighted average based on total production of individual states, relative to the total U.S. production calculated from the farm surveys, was used to develop the U.S. average LCI on a 1 kg of soybean basis.

3.2.2 Soybean Processing

Data on primary soybean processing of soybean meal, crude soy oil, and refined soy oil were provided by NOPA, based on data gathered from 52 (crushing and degumming) facilities and 27 (oil refining) co-located facilities. All secondary data are taken from literature, previous LCI studies, and USDA and life cycle databases. The USLCI database (www.nrel.gov/lci) is frequently used in this analysis. Much of the LCI data residing in the USLCI database pertain to common fuels – their combustion in utility, stationary and mobile equipment inclusive of upstream or pre-combustion effects (i.e., raw material extraction). Generally, these modular data are of a recent vintage (less than ten years old). This study draws on these data for combustion processes, electricity generation, and transportation on a regional United States basis. These data are free and publicly available, and thus, offer both a high degree of transparency and an ability to replicate the results of the study; however, there are limitations, as some processes are missing for some of the products available in this LCI database, creating an issue with respect to completeness.

When United States data were not available for a product or process, North American or European Ecoinvent LCI database was utilized. This database contains over 3,500 LCI modules for processes and products, all of which have undergone peer review. The basic assumption when using these data is that North American and European production processes are generally similar to the United States, but that these data need to be adapted for United States circumstances (e.g., electricity grids, fuels and transportation modes and distances need to be modified to better reflect the United States operations). Such adaptation was conducted whenever necessary.

3.3 Modeling Software

SimaPro v9.2.0.2 software was utilized for modeling the complete cradle-to-gate LCIs for soybean agriculture, soybean meal, crude soy oil, and refined oil. All process data including inputs (raw materials, energy, and water) and outputs (emissions, wastewater, solid waste, and final products) are evaluated and modeled to represent each process that contributes to the life cycle of soybean products. The study's geographical and technological coverage has been limited to the United States. SimaPro was used to generate life cycle impact assessment (LCIA) results utilizing the TRACI impact assessment methodologies as well as single impact assessments (Global Warming Potential and Cumulative Energy Demand). See Section 4.1 for a description of the selected LCIA categories and characterization measures used in this study.

4.0 Life Cycle Impact Assessment (LCIA)

The environmental impacts of a product can be categorized and presented in many ways. This section briefly describes the methodology used to develop the impact assessment and defines the selected impact categories used to present the results. This section also lists assumptions of the study and describes the inherent limitations and uncertainty of the LCA results.

4.1 Impact Categories/Impact Assessment

As defined in ISO 14040:2006, "the impact assessment phase of an LCA is aimed at evaluating the significance of potential impacts using the results of the LCI analysis." In the LCIA phase, SSC modeled a set of selected environmental issues referred to as impact categories and used category indicators to evaluate the magnitude and significance of the potential environmental impacts. These category indicators are intended to "characterize" the relevant environmental flows for each environmental issue category to represent the potential or possible environmental impacts of a product system. The LCIA results are relative expressions and do not predict impacts on category endpoints, the exceeding of thresholds, safety margins, or risk.

ISO 14044 does not specify any specific methodology or support the underlying value choices used to group the impact categories. The value-choices and judgments within the grouping procedures are the sole responsibilities of the commissioner of the study.

The framework surrounding LCIA includes three steps that convert LCI results to category indicator results. These include the following:

1. Selection of impact categories, category indicators, and models.
2. Assignment of the LCI results to the impact categories (classification) – the identification of individual inventory flow results contributing to each selected impact indictor.

3. Calculation of category indicator results (characterization) – the actual calculation of the potential or possible impact of a set of inventory flows identified in the previous classification step.

To maximize the reliability and flexibility of the results, SSC used an established impact methodology for assigning and calculating impacts. The Tools for Reduction and Assessment of Chemical and other environmental Impacts (TRACI) methodology was used for all calculations of environmental impact. TRACI was developed by the U.S. EPA to assist in impact analysis in Life Cycle Assessments, process design, and pollution prevention.

4.2 Selected Impact Categories

While LCI practice holds to a consistent methodology, the LCIA phase is an evolving science and there is no overall generally accepted methodology for calculating all of the impact categories that might be included in an LCIA. Typically, the LCIA is completed in isolation of the LCI. The LCI involves the collection of a complete mass and energy balance for each unit process under consideration. Once completed, the LCI flows are sifted through various possible LCIA indicator methods and categories to determine possible impacts. Due to the United States focus of this LCA study, SSC used the TRACI LCIA methodology to characterize the study's LCI flows. Impact categories include:

1. *Ozone Depletion* (kg CFC-11 eq) – Certain chemicals, when released into the atmosphere, can cause depletion of the stratospheric ozone layer, which protects the Earth and its inhabitants from ultraviolet radiation. This radiation can have a negative impact on crops, materials, and marine life, as well as contributing to cancer and cataracts. This impact measures the release of those chemicals.
2. *Global Warming* (kg CO_2 eq) [IPCC AR5] – The methodology and science behind the Global Warming Potential calculation can be considered one of the most accepted LCIA categories. Because this study also tracks an overall life cycle carbon balance, the carbon dioxide emissions associated with biomass combustion are included in the Global Warming Potential calculation per the Intergovernmental Panel on Climate Change (IPCC) methodology. Carbon dioxide and other greenhouse gases are emitted at every stage in the life cycle. These gases can trap heat close to the Earth, and the global warming potential attempts to express the radiative forces of these different gasses and their contribution to global warming relative to the effect of carbon dioxide.
3. *Smog* (kg O_3 eq) – Under certain climatic conditions, air emissions from industry and transportation can be trapped at ground level where, in the presence of sunlight, they produce photochemical smog, a symptom of photochemical ozone creation. While ozone is not emitted directly, it is a product of interactions of volatile organic compounds (VOCs) and nitrogen oxides (NOx). The Smog indicator is expressed as a mass of equivalent ozone (O_3).

4. *Acidification* (moles SO_2 eq) – Acidification is a more regional rather than global impact affecting fresh water and forests as well as human health when high concentrations of SO_2 (and other chemical compounds) are attained. Acidification is a result of processes that contribute to increased acidity of water and soil systems, frequently through air emissions that contribute to acid rain. The largest contributors to acid rain are sulfur dioxide and nitrogen oxide. The acidification potential of an air emission is calculated relative to the acidification produced by SO_2 molecules; and therefore is expressed as potential SO_2 equivalents on a mass basis.

5. *Eutrophication* (kg N eq) – Eutrophication is the fertilization of surface waters by nutrients that were previously scarce. When a previously scarce or limiting nutrient is added to a water body, it leads to the proliferation of aquatic photosynthetic plant life. This may lead to the water body becoming hypoxic, eventually causing the death of fish and other aquatic life. Contributions from both nitrogen and phosphorus nutrient emissions are included in this indicator. This impact is expressed on an equivalent mass of nitrogen (N) basis.

6. *Human Health: Carcinogens* (CTU_h) – This impact assesses the potential health impacts of more than 200 chemicals. These are average general health impacts, based on emissions from the various life cycle stages, and do not take into account increased exposure that may take place in manufacturing facilities or on farms. These impacts are expressed in terms of Comparative Toxic Units (CTU_h). For human health this represents the estimated increase in morbidity in the total human population per kg of chemical emitted.

7. *Human Health: Non-Carcinogens* (CTU_h) – This impact assesses the potential health impacts of more than 200 chemicals. These health impacts are general, based on emissions from the various life cycle stages, and do not take into account increased exposure that may take place in manufacturing facilities. These impacts are expressed in terms of Comparative Toxic Units (CTU_h). For human health this represents the estimated increase in morbidity in the total human population per kg of chemical emitted.

8. *Respiratory Effects* (kg $PM_{2.5}$ eq) – This impact methodology assesses the potential impact of increasing concentrations of particulates on human health, as well as emissions that may contribute to particulate matter formation. Most industrial and transportation processes create emissions of very small particles which can damage lungs and lead to disease and shortened lifespans. This impact is expressed in terms of $PM_{2.5}$ (particulates that are 2.5 microns or less in diameter).

9. *Ecotoxicity* (CTU_e) – Many chemicals, when released into the environment, can cause damage to individual species and to the overall health of an ecosystem. Ecotoxicity measures the potential damage to the ecosystem that would result from releasing that chemical into the environment. This impact is measured in terms of Comparative Toxic Units (CTUe) and provides an estimate of the potentially affected fraction of species (PAF) integrated over time and volume per unit mass of chemical emitted.

10. *Fossil Fuel Depletion (MJ surplus)* – Maintaining fossil fuel resources for future generations is an essential part of sustainable development. This impact category measures the depletion of those resources in terms of megajoules (MJ). Fossil fuels are used as energy sources as well as raw materials for chemical production.
11. *Land Use* (m^2a crop eq) [ReCiPe] – Development of uninhabited land has been a major focus in the sustainable development industry, especially in the agricultural sector, where developing for socio-economic gain often results in long-lasting changes to the soil. This impact category primarily measures the impact of the occupation of land on terrestrial species by change of land cover and actual use of new land. The impact assessment also accounts for some transformation of land from pre-existing ecosystems. Land use characterizes intensities in terms of the equivalent square meters of annual cropland land use. There are various characterization factors for different land use types; including transformation, occupation, and relaxation.
12. *Water Consumption* (m^3) [ReCiPe] – Freshwater consumption is a growing concern in the global sustainability community because the freshwater resource available on the planet has been rapidly depleted over the past century. This indicator quantifies the removal of water from the watershed such that it is not available for use by other users. This impact category reports the inventory of water consumption that the process requires, in terms of cubic meters.
13. *Cumulative Energy Demand* (MJ) – This impact methodology assesses the total energy consumed throughout the life cycle. Cumulative energy demand is the sum of all energy sources drawn directly from the earth, such as natural gas, oil, coal, biomass, hydropower energy, and more. It takes into account all upstream and downstream processes and calculates the energy demand during different stages in the life cycle. This is an important impact category as higher energy demand translates to higher environmental impact. This impact category can help identify areas for improving and optimizing energy efficiency.

While the TRACI methodology supports fossil fuel depletion (on a global scale), it does not readily report primary energy use as an impact category. Primary energy use on a cumulative energy demand basis is tabulated and summarized as an impact category based on the LCI flows. Energy use is a key impact indicator over which soybean farmers and soybean meal and oil producers are likely to assert a considerable level of control and, therefore, is a good internal target for resource conservation. Cumulative energy demand is the sum of all energy sources drawn directly from the earth, such as natural gas, oil, coal, biomass, or hydropower energy. The total primary energy contains further categories, namely non-renewable, renewable, and feedstock energy. Yield is another key indicator where soybean farmers have some control, and it plays a significant role in determining the average environmental impacts of each functional unit. Additionally, farmers can focus their efforts on optimizing other agricultural inputs, such as fertilizers and herbicides, to maximize their impact reduction while reducing costs.

5.0 Soybean Production

5.1 Important Assumptions

Life cycle analysis requires that assumptions are made to constrain the project boundary or model processes when little to no data are available. In this study of soybeans, the following assumptions were made:

- Data from the survey are complete and representative of the U.S. average farming practice based on the methodology outlined in Section 3.2.
- Data collected in the survey included the harvest acreage of alternate and cover crops. Soybeans are commonly grown in rotation with crops such as corn, wheat, and other crops in order to capture some of the operational benefits that exist utilizing this method. As such, the field operation inventory was allocated to soybean cultivation based on total harvest acreage.
- USDA data were used for fertilizers & pesticides. Survey data were collected for yield but then it was decided to use USDA data for yield to maintain a conservative value for yield and remain in alignment with the USDA data used for field applications.
- Nitrate and phosphorus emissions were modeled following existing soybean models, which obtained their information from the USDA digital commons project. Emissions rates were calculated in alignment with the IPCC methodology for managed soils.[3] Dinitrogen monoxide emissions from anthropogenic nitrogen conversion were calculated as 1.11 kilograms per hectare, using the IPCC methodology for managed soils.
    - The calculation methodology included accounting for tier 1 direct and indirect emissions from synthetic fertilizer, manure, crop resides, and nitrogen fixation.
- When a material is not available in the available LCI databases, another chemical which has similar manufacturing and environmental impacts may be used as a proxy to represent the actual chemical. The Proxy Chemical List used in this analysis includes:
    - Alachlor as a proxy for acetochlor.
    - Pesticides without Ecoinvent background data and representing a minority fraction of material inputs were aggregated and proxied as generic pesticides.

5.2 Life Cycle Inventory

A thorough analysis of the material inputs and the product recipe was completed for the inventory of this study. The soybean cultivation inputs are listed in Table 5.1 below.

[3] IPCC N_2O Emissions from Managed Soils, and CO_2 Emissions from Lime and Urea Application

This section describes the cradle-to-gate life cycle inventory of soybeans.

Primary data on field operations for 2020 and 2021 were collected from surveys completed by U.S. soybean farmers. Secondary data on fertilizer use were obtained from the USDA 2020 census. A detailed analysis of the cultivation process was completed by SSC to understand soybean farming practices.

The process starts when soybean seeds are planted in the spring once soil temperature reaches sufficiently warm temperatures, typically in early spring. The type of seed depends on the location, as different soybean types are better suited to different climates and growing conditions. Water, fertilizers, and pesticides are used in custom quantities to help maximize yields without wasting resources. As soybean plants grow throughout the year, eventually their flowers turn into pods containing 1 - 4 seeds each. The soybeans are ready to harvest in the fall. In some countries, like Brazil, the warm climate allows for a second harvest in a year, but the U.S. is limited due to its cold winters. However, double cropping is practiced in some states in the South and southern Midwest, where winter wheat is planted in the fall and harvested in the spring. A variety of technologies are used by farmers throughout the process for everything from planting, irrigation, and fertilizing to harvesting.

Field operations data on electricity, fuel, and waste are based on survey responses from U.S. farmers. Of the respondents, 377 had soybean operations exceeding 300 acres and were included in the dataset. Production-weighted averages based on state-level production share were used to calculate the lifecycle inventory. The lifecycle inventory is based on an average yield of 51 bushels of soybeans per acre.

Soybean cultivation is modeled within LCA by considering energy, water, and materials which go into the field and waste and emissions that are outputs from the agricultural process.

Table 5.1 – U.S. Average Soybean Cultivation Inputs

Category	Product Recipe	Unit	Quantity per kg of Soybeans
Field Operations	Electricity	MJ	6.10E-02
	Natural Gas	MJ	1.28E-01
	Diesel	MJ	1.69E-01
	Gasoline	MJ	9.60E-02
	Propane	MJ	2.60E-02
	Water	m^3	4.18E-02
Fungicides	Picoxystrobin	kg	4.51E-05
	Pyraclostrobin	kg	3.95E-05
	Azoxystrobin	kg	3.69E-05

Category	Product Recipe	Unit	Quantity per kg of Soybeans
	Propiconazole	kg	3.43E-05
	Mefentrifluconazole	kg	3.33E-05
	All Other Fungicides	kg	1.70E-04
Herbicides	Glyphosate	kg	1.75E-03
	Dicamba	kg	1.06E-03
	Metolachlor	kg	1.04E-03
	Atrazine	kg	8.70E-04
	Acetochlor	kg	3.58E-04
	All Other Herbicides	kg	2.72E-03
Insecticides	Acephate	kg	3.55E-04
	Chlorpyrifos	kg	3.23E-04
	Methoxyfenozide	kg	4.77E-05
	Bifentrhin	kg	4.77E-05
	Chloratraniprole	kg	4.44E-05
	All Other Insecticides	kg	1.86E-04
Fertilizer	Potash	kg	2.91E-02
	Phosphate	kg	1.80E-02
	Nitrogen	kg	5.56E-03
	Sulfur	kg	4.25E-03

5.3 Soybean Production Results

This section presents the results of the LCA study. It includes energy, global warming, and other quantified impacts for each of the TRACI impact categories.

The impacts for one kg of soybeans were estimated based on the inputs detailed in Table 5.1, utilizing a modified TRACI v2.1 methodology that includes water consumption and land use (see

Section 4.2 for methodology explanation). Figure 5.1, found below, shows the graphical analysis of the driving factors in each impact category. Absolute values can be found in Table 5.2.

Table 5.2 – U.S. Soybean Analysis per 1 kg of Soybeans

Impact Category	Unit	Field Operations	Fertilizer	Fungicide	Herbicide	Insecticide	Total
Global Warming Potential	kg CO_2 eq	1.31E-01	8.30E-02	4.42E-03	1.09E-01	1.30E-02	**3.41E-01**
Fossil Fuel Depletion	MJ surplus	1.26E-01	1.16E-01	5.74E-03	1.53E-01	1.64E-02	**4.17E-01**
Eutrophication	kg N eq	3.52E-05	3.43E-03	2.36E-06	3.06E-04	9.05E-06	**3.79E-03**
Smog	kg O_3 eq	1.05E-02	5.44E-03	1.20E-04	4.14E-03	3.86E-04	**2.06E-02**
Acidification	kg SO_2 eq	5.75E-04	5.78E-04	2.17E-05	7.55E-04	6.62E-05	**2.00E-03**
Ozone Depletion	kg CFC-11 eq	1.84E-09	9.28E-09	6.89E-10	1.71E-08	2.11E-09	**3.11E-08**
Carcinogenics	CTUh	1.23E-09	5.95E-09	2.88E-11	4.32E-09	1.22E-10	**1.16E-08**
Non-Carcinogenics	CTUh	6.02E-09	4.63E-08	2.09E-10	1.57E-08	1.36E-07	**2.04E-07**
Respiratory Effects	kg $PM_{2.5}$ eq	2.62E-05	7.94E-05	1.56E-06	7.62E-05	4.71E-06	**1.88E-04**
Ecotoxicity	CTUe	3.48E-01	2.83E+00	9.99E-02	2.18E+01	3.47E+01	**5.97E+01**
Land Use	m^2a crop eq	1.75E+00	1.02E-02	4.58E-04	7.44E-03	1.83E-03	**1.77E+00**
Water Consumption	m^3	4.18E-02	2.76E-03	8.83E-06	1.35E-03	9.87E-05	**4.60E-02**
Cumulative Energy Demand	MJ	1.13E+00	1.06E+00	7.92E-02	1.95E+00	2.37E-01	**4.46E+00**

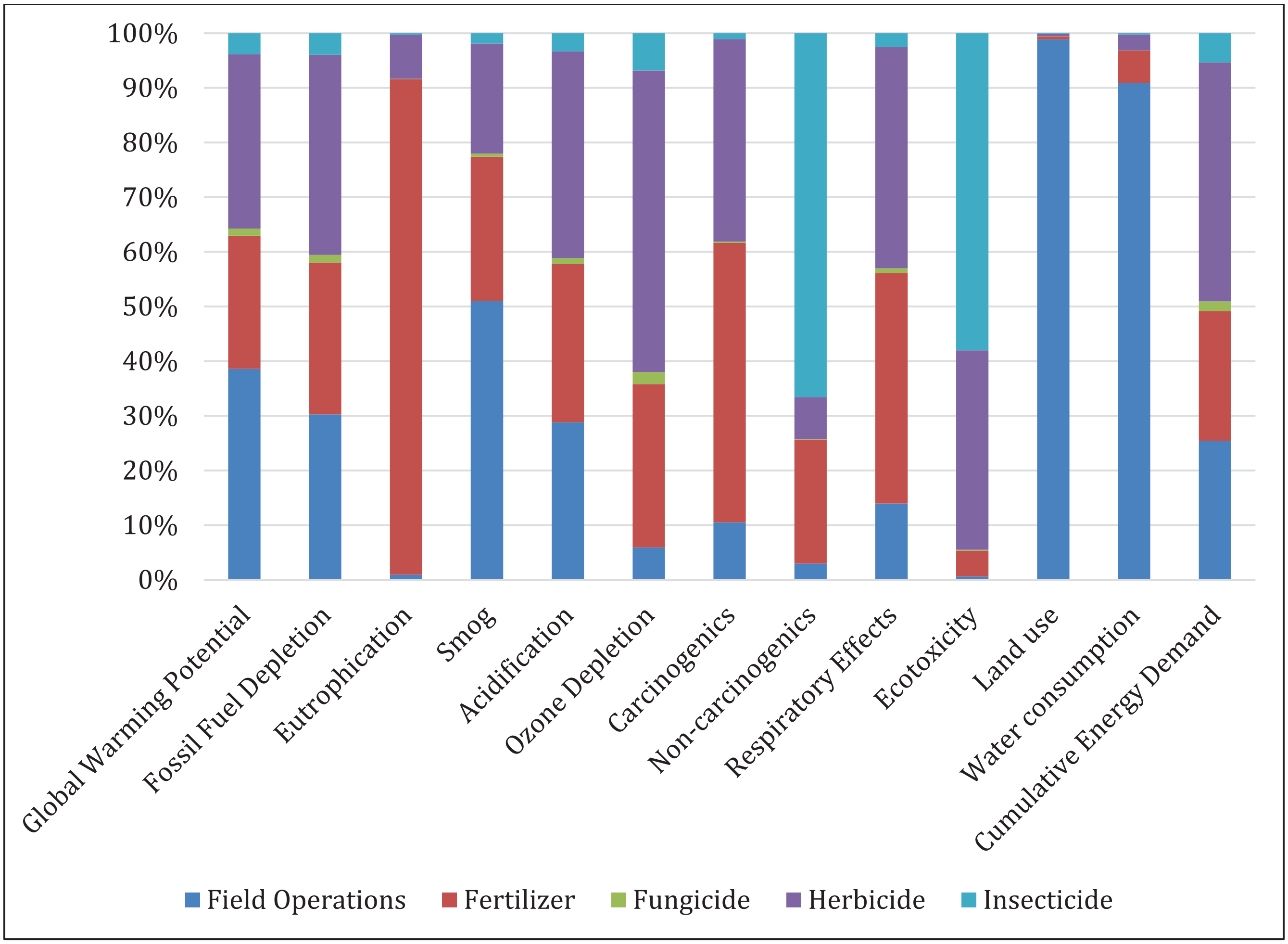


Figure 5.1 – U.S. Soybean Analysis per 1 kg of Soybeans

Figure 5.1 illustrates how each component is driving impacts in each of the 13 impact categories. Overall, field operations, fertilizer, and herbicides are significant contributors to impacts in most categories. Field operations are particularly substantial when it comes to land use and water consumption. Field operations include the measurement of the use of land, as well as energy and water inputs. Land use impacts are driven by operations, as agriculture requires vast quantities of land, and soybeans are an agricultural product. Similarly, while producing fertilizers and pesticides requires some energy, agriculture is much more energy-intensive due to the quantity of fuel needed to operate the equipment required to plant and harvest the soybeans.

Field operations, fertilizer, and herbicide are further analyzed next. Figure 5.2 and Table 5.3 show the breakdown of the different components that make up field operations.

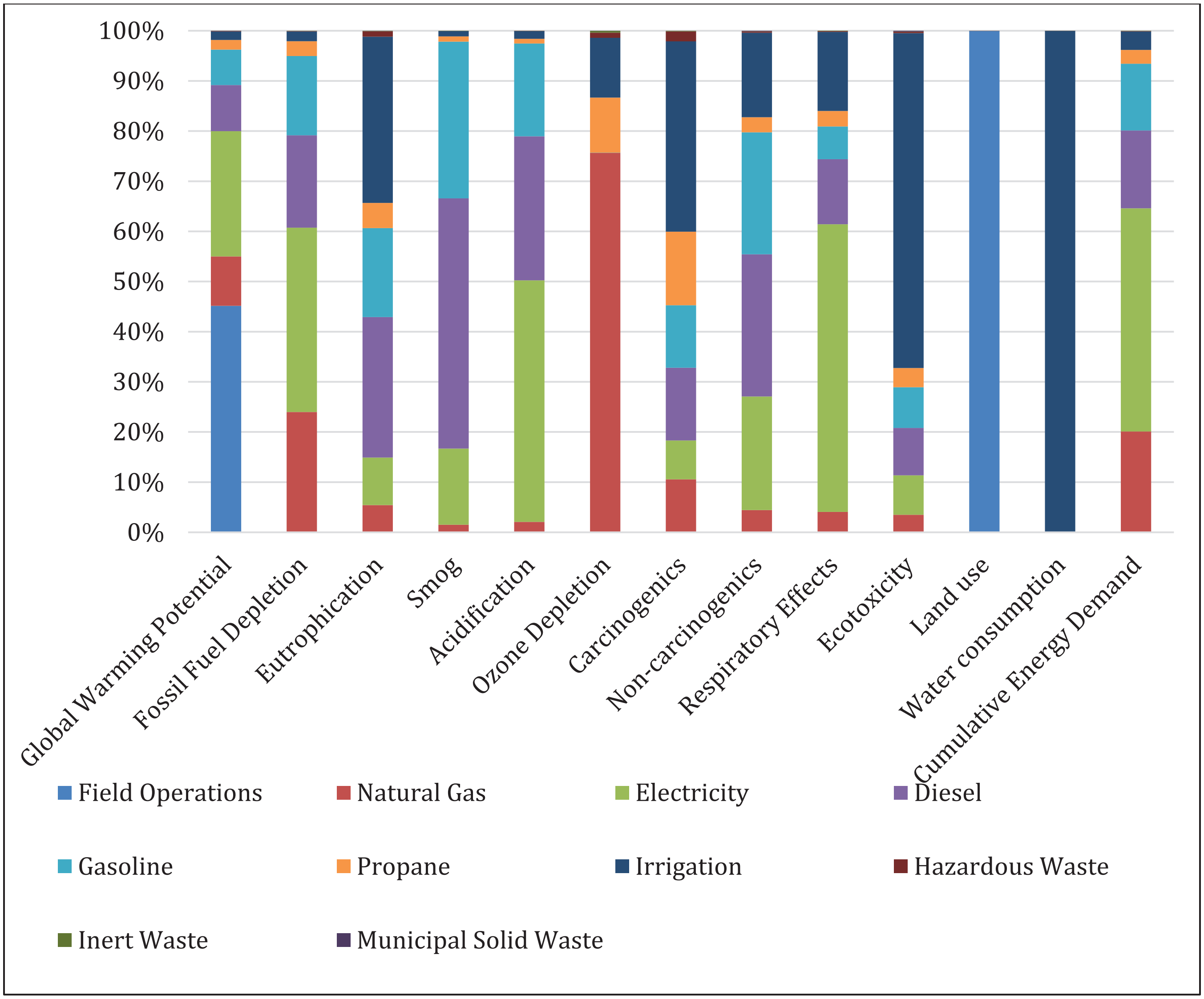


Figure 5.2 – Impacts of Field Operations per kg of Soybeans

Note: Field Operations includes impacts from land occupation and direct emissions to air from N_2O.

Table 5.3 – Impact of Field Operations per kg of Soybeans

Impact Category	Unit	Field Operations	Natural Gas	Electricity	Diesel	Gasoline	Propane	Irrigation	Hazardous Waste	Inert Waste	Municipal Solid Waste	Total
Global Warming Potential	kg CO_2 eq	5.94E-02	1.29E-02	3.28E-02	1.21E-02	9.27E-03	2.55E-03	2.24E-03	1.54E-04	1.63E-05	3.90E-06	**1.31E-01**
Fossil Fuel Depletion	MJ surplus	0.00E+00	3.03E-02	4.64E-02	2.32E-02	1.99E-02	3.73E-03	2.49E-03	8.53E-05	6.31E-05	2.57E-07	**1.26E-01**
Eutrophication	kg N eq	0.00E+00	1.91E-06	3.34E-06	9.87E-06	6.26E-06	1.77E-06	1.17E-05	3.82E-07	2.70E-08	5.19E-09	**3.52E-05**
Smog	kg O_3 eq	0.00E+00	1.59E-04	1.59E-03	5.24E-03	3.28E-03	1.10E-04	1.10E-04	3.07E-06	3.43E-06	6.03E-08	**1.05E-02**
Acidification	kg SO_2 eq	0.00E+00	1.19E-05	2.77E-04	1.65E-04	1.07E-04	5.38E-06	8.81E-06	2.10E-07	1.38E-07	2.20E-09	**5.75E-04**
Ozone Depletion	kg CFC-11 eq	0.00E+00	1.39E-09	3.51E-13	4.92E-13	4.22E-13	2.02E-10	2.19E-10	1.88E-11	7.07E-12	2.77E-14	**1.84E-09**
Carcinogenics	CTUh	0.00E+00	1.29E-10	9.48E-11	1.78E-10	1.52E-10	1.80E-10	4.65E-10	2.44E-11	1.11E-12	3.55E-13	**1.23E-09**
Non-Carcinogenics	CTUh	0.00E+00	2.67E-10	1.36E-09	1.71E-09	1.46E-09	1.81E-10	1.01E-09	1.58E-11	1.65E-12	6.20E-12	**6.02E-09**
Respiratory Effects	kg $PM_{2.5}$ eq	0.00E+00	1.07E-06	1.50E-05	3.40E-06	1.71E-06	8.07E-07	4.14E-06	3.66E-08	1.83E-08	1.71E-10	**2.62E-05**
Ecotoxicity	CTUe	0.00E+00	1.22E-02	2.74E-02	3.29E-02	2.82E-02	1.33E-02	2.33E-01	9.57E-04	8.23E-05	5.50E-04	**3.48E-01**
Land Use	m^2a crop eq	1.75E+00	9.04E-06	0.00E+00	0.00E+00	0.00E+00	1.50E-05	4.37E-05	8.20E-07	2.63E-06	8.65E-09	**1.75E+00**
Water Consumption	m^3	0.00E+00	2.10E-06	0.00E+00	0.00E+00	0.00E+00	2.61E-06	4.18E-02	5.15E-07	4.93E-07	8.55E-09	**4.18E-02**
Cumulative Energy Demand	MJ	0.00E+00	2.28E-01	5.04E-01	1.76E-01	1.51E-01	3.13E-02	4.19E-02	8.26E-04	4.96E-04	2.57E-06	**1.13E+00**

Field operations, which accounts for land occupations and direct air emissions, are the main drivers of eutrophication and land use. Soybeans are a nitrogen fixing crop, meaning that they naturally release nitrogen, in the form of nitrate, into the ground. This can be carried by rain and irrigation into nearby bodies of water, such as lakes and rivers, resulting in higher levels of eutrophication. Figure 5.3 and Table 5.4 show the results of impacts from fertilizer.

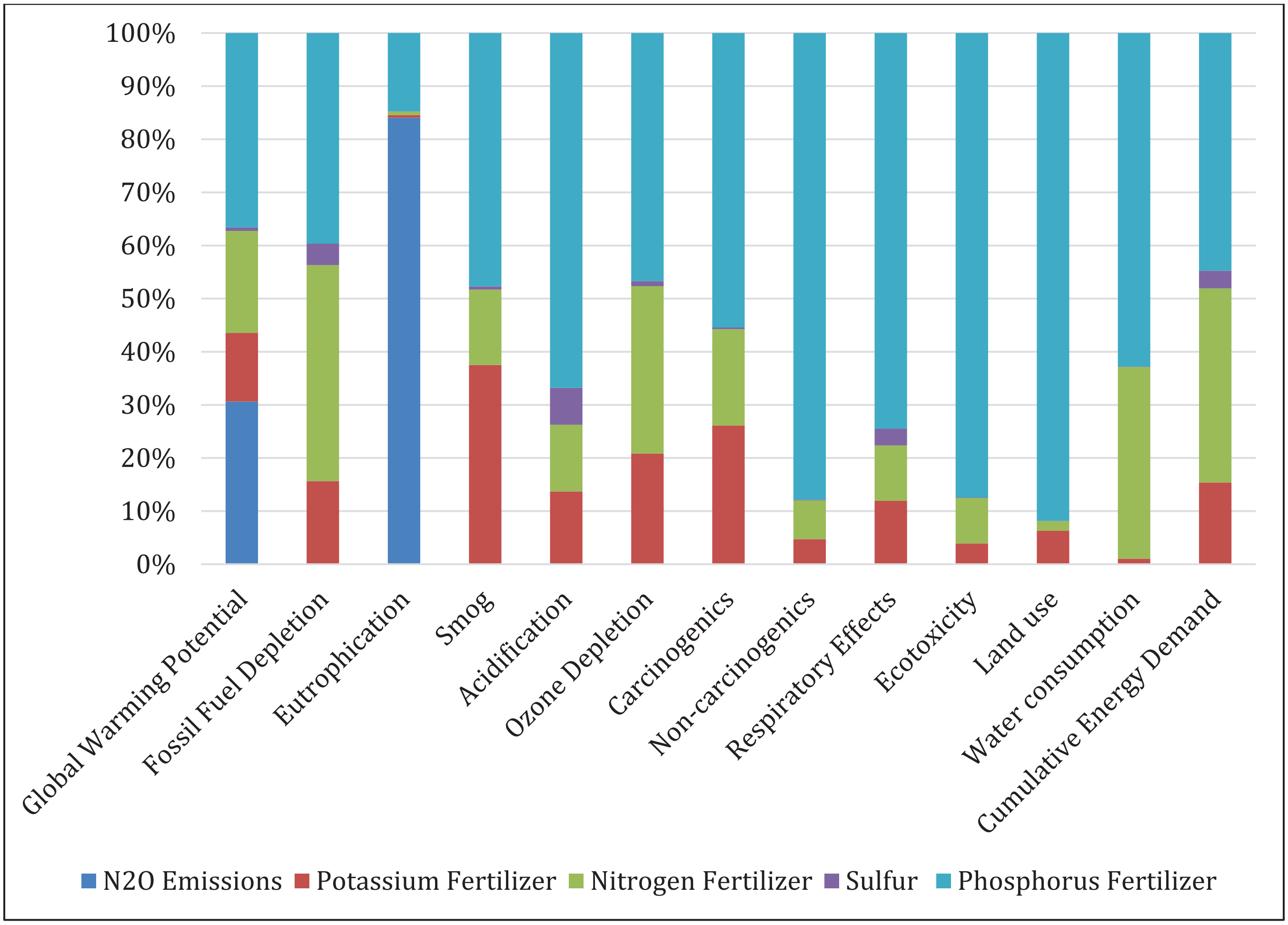


Figure 5.3 – Impacts of Fertilizer per kg of Soybeans

Table 5.4 – Impacts of Fertilizer per kg of Soybeans

Impact Category	Unit	N_2O Emissions	Potassium Fertilizer	Nitrogen Fertilizer	Sulfur	Phosphorus Fertilizer	Total
Global Warming Potential	kg CO_2 eq	2.54E-02	1.07E-02	1.59E-02	5.57E-04	3.04E-02	**8.30E-02**
Fossil Fuel Depletion	MJ surplus	0.00E+00	1.82E-02	4.72E-02	4.66E-03	4.61E-02	**1.16E-01**
Eutrophication	kg N eq	2.89E-03	1.77E-05	2.30E-05	4.42E-07	5.07E-04	**3.43E-03**
Smog	kg O_3 eq	0.00E+00	2.04E-03	7.72E-04	3.23E-05	2.59E-03	**5.44E-03**
Acidification	kg SO_2 eq	0.00E+00	7.92E-05	7.25E-05	4.01E-05	3.86E-04	**5.78E-04**
Ozone Depletion	kg CFC-11 eq	0.00E+00	1.94E-09	2.93E-09	8.63E-11	4.33E-09	**9.28E-09**
Carcinogenics	CTUh	0.00E+00	1.55E-09	1.08E-09	1.73E-11	3.30E-09	**5.95E-09**
Non-Carcinogenics	CTUh	0.00E+00	2.19E-09	3.38E-09	6.32E-11	4.07E-08	**4.63E-08**
Respiratory Effects	kg $PM_{2.5}$ eq	0.00E+00	9.49E-06	8.26E-06	2.52E-06	5.91E-05	**7.94E-05**
Ecotoxicity	CTUe	0.00E+00	1.11E-01	2.42E-01	2.12E-03	2.47E+00	**2.83E+00**
Land Use	m^2a crop eq	0.00E+00	6.40E-04	1.87E-04	2.98E-06	9.32E-03	**1.02E-02**
Water Consumption	m^3	0.00E+00	2.90E-05	9.95E-04	1.52E-06	1.73E-03	**2.76E-03**
Cumulative Energy Demand	MJ	0.00E+00	1.63E-01	3.86E-01	3.50E-02	4.73E-01	**1.06E+00**

The main driver of environmental impacts in most categories is phosphorus fertilizer. This is because phosphates represent the second most used fertilizer for farming soybeans and energy intensive materials in their upstream manufacturing (e.g., sulfuric acid). The one exception is eutrophication, which is dominated by fertilizer emissions to water. Fertilizer runoff, due to rain or irrigation, can reach nearby bodies of water, leading to algae blooms. The results shown above account for the soybean nutrient uptake from applied fertilizers, thus the impacts are attributed to excess fertilizer application.

There were also multiple types of herbicides, as illustrated in Figure 5.4. below.

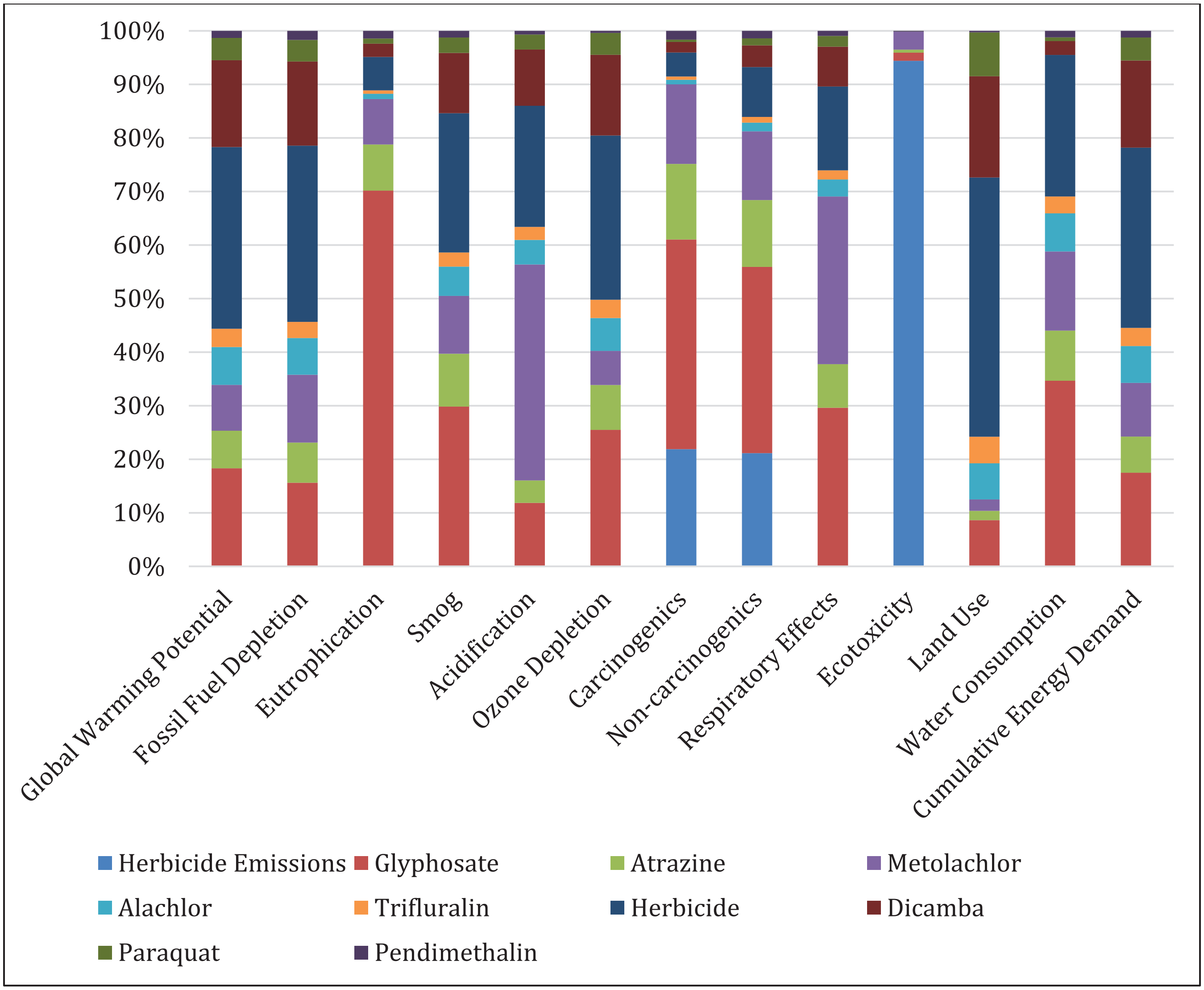


Figure 5.4 – Impacts of Herbicides per kg of Soybeans

Table 5.5 – Impacts of Herbicides per kg of Soybeans

Impact Category	Unit	Herbicide Emissions	Glyphosate	Atrazine	Metolachlor	Alachlor	Trifluralin	Herbicide	Dicamba	Paraquat	Pendimethalin	Total
Global Warming Potential	kg CO_2 eq	0.00E+00	1.99E-02	7.63E-03	9.32E-03	7.69E-03	3.71E-03	3.69E-02	1.76E-02	4.54E-03	1.42E-03	**1.09E-01**
Fossil Fuel Depletion	MJ surplus	0.00E+00	2.39E-02	1.15E-02	1.94E-02	1.05E-02	4.57E-03	5.03E-02	2.40E-02	6.15E-03	2.60E-03	**1.53E-01**
Eutrophication	kg N eq	0.00E+00	2.15E-04	2.64E-05	2.60E-05	2.98E-06	2.00E-06	1.91E-05	7.62E-06	2.91E-06	4.37E-06	**3.06E-04**
Smog	kg O_3 eq	0.00E+00	1.24E-03	4.08E-04	4.48E-04	2.26E-04	1.10E-04	1.08E-03	4.66E-04	1.20E-04	5.17E-05	**4.14E-03**
Acidification	kg SO_2 eq	0.00E+00	8.95E-05	3.17E-05	3.04E-04	3.47E-05	1.84E-05	1.71E-04	7.94E-05	2.12E-05	5.16E-06	**7.55E-04**
Ozone Depletion	kg CFC-11 eq	0.00E+00	4.37E-09	1.44E-09	1.09E-09	1.05E-09	5.84E-10	5.26E-09	2.58E-09	7.00E-10	6.79E-11	**1.71E-08**
Carcinogenics	CTUh	9.44E-10	1.69E-09	6.09E-10	6.41E-10	3.77E-11	2.65E-11	1.93E-10	8.55E-11	1.85E-11	7.06E-11	**4.32E-09**
Non-Carcinogenics	CTUh	3.31E-09	5.44E-09	1.96E-09	2.01E-09	2.56E-10	1.64E-10	1.46E-09	6.37E-10	2.03E-10	2.19E-10	**1.57E-08**
Respiratory Effects	kg $PM_{2.5}$ eq	0.00E+00	2.26E-05	6.19E-06	2.39E-05	2.41E-06	1.30E-06	1.19E-05	5.68E-06	1.52E-06	7.14E-07	**7.62E-05**
Ecotoxicity	CTUe	2.06E+01	3.29E-01	1.23E-01	7.31E-01	1.91E-03	1.34E-03	1.05E-02	4.40E-03	1.17E-03	1.40E-02	**2.18E+01**
Land Use	m^2a crop eq	0.00E+00	6.43E-04	1.28E-04	1.58E-04	5.03E-04	3.70E-04	3.60E-03	1.41E-03	6.10E-04	2.04E-05	**7.44E-03**
Water Consumption	m^3	0.00E+00	4.66E-04	1.26E-04	1.99E-04	9.56E-05	4.25E-05	3.56E-04	3.47E-05	9.37E-06	1.65E-05	**1.35E-03**
Cumulative Energy Demand	MJ	0.00E+00	3.41E-01	1.31E-01	1.96E-01	1.34E-01	6.60E-02	6.55E-01	3.17E-01	8.35E-02	2.42E-02	**1.95E+00**

Glyphosate and herbicide are the most prominent drivers of several impact categories. This is because of higher impact materials and energy needs in the synthesis of glyphosate and other herbicides.

Results were compared to those found in the previous LCA study performed by Quantis in 2015. This comparison can be found in Appendix A.

6.0 Crude Soybean Oil and Soybean Meal Production

6.1 Important Assumptions

In this study of soybean meal and crude soy oil, SSC made the following assumptions:

- Data provided are complete and representative of U.S soybean processing operations.
- Allocation by mass of co-products was used to distribute impacts to crude soy oil and soybean meal.
    - Allocation was determined to be 20.17% to crude soy oil and 79.83% to soybean meal, based on the mass output of the co-products when processing a single soybean. Consequently, the impacts associated (on a per kg basis) with soybean meal and soybean oil production are identical.
    - Soybean hull allocation was conducted by mass and included with soybean meal as it doesn't go through further processing after crushing phase.
- Hexane inputs are directly related to solvent loss, which typically occurs during extraction in the form of emissions. Actual hexane data were not collected for the purposes of this study. Instead, the total hexane emissions value used in the model is based on a solvent loss factor of 0.2 gallons/ton of conventional soybeans crushed as specified under the National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production [40 CFR 63.2840].
    - Using this value provides a conservative estimate of total hexane emissions as it represents the maximum hexane loss threshold allowed under U.S. regulations. This approach is consistent with the previous 2015 and 2010 LCA studies where hexane emissions from soybean processing facilities were estimated using the same loss factor as designated under 40 CFR 63.2840.
- Soybeans are the primary material input and used in their entirety to produce soybean hulls, soybean meal, and crude soy oil. Soybean hulls are not discarded, rather they are either cycled back into the process to be added to soybean meal or sold as is to downstream manufacturers for further use.
    - Hull output values have been combined and reported as part of the meal hull output value. Soy hulls are not the primary outputs resulting from soybean processing, and thus were not called out as a specific product for analysis as part of this study.
- Actual total pounds of soybean inputs were reported as an aggregated average, while other input/output values were reported per 1,000 bushels with an assigned weight of

60 lbs. bu. Consequently, the aggregated data used in the analysis of soybean processing operations did not reflect a 1:1 mass balance for soybean inputs and product output values reported in Table 6.1.

- Other factors that may further contribute to the mass balance misalignment that resulted in the 1.03 kg soybean input value reported in Table 6.1:
    - USB reports an average bushel weight of 58.6 pounds,[4] whereas NOPA assumed an average bushel weight of 60 pounds in aggregating individual facility data for oilseed processing and co-located refining operations. This was done in order to align with data as reported in previous studies, and to maintain consistency with assumptions for hexane use based on the maximum threshold as allowed by EPA under 40 CFR 63.2840, identified above.
        - Actual bushel weight may vary due to a variety of product quality factors including amount of moisture within the soybean, amount of residual crop-waste and size of individual beans. Soybeans are sold as a commodity by bushel based on an average weight that is adjusted to account for product quality impacts.
    - There is a recognized material loss that occurs during processing due to dust generation and soybean hull spillage during the crushing and degumming process. Dust generation that is not captured by filter systems can be aggregated and incorporated back into the process for soybean meal production. Due to the variation in the number of cycles through the process, the output material is difficult to trace to a final system output. As such, the loss is captured as additional input material.
- All soybean products are transported by bulk via barge, railcar, tank truck, and/or pipeline.
- When a material is not available in the available LCI databases, another chemical which has similar manufacturing and environmental impacts may be used as a proxy, representing the actual chemical. The Proxy Chemical List used in this analysis includes:
    - Heat, onsite boiler, softwood mill average, NE-NC/MJ/RNA as proxy for "Biomass."
    - Heat, from steam, in chemical industry {RoW}| steam production, as energy carrier, in chemical industry | Cut-off, U" as proxy for "Purchased Steam."
    - Diesel as proxy for "Other Fuels."

[4] See Appendix D for crude soy oil and soybean meal inventory adjusted for USB bushel weight of 58.6 pounds.

6.2 Life Cycle Inventory

This section describes the cradle-to-gate life cycle inventory of soybean meal and crude soybean oil. Data on the soybean crushing and degumming process were collected from members of the National Oilseed Processors Association (NOPA) processing facilities located in the U.S. for the 2021 calendar production year. The participating processing plants provided resource transportation mode and distance data to support the calculation of raw material transportation flows. The transportation LCI data from the USLCI database (kg-km basis) were used to develop the resource transportation LCI profile.

Over 50 percent of NOPA member companies that participated in this study reported data for crushing and degumming as well as co-located refining processes. SSC completed a detailed analysis of the manufacturing process steps involved in the production of soybean meal, crude soybean oil, refined soybean oil, and specialty products following the solvent extraction stage to understand these production processes, as illustrated in Appendix C.

NOPA member soybean facilities operate seven days a week, 24 hours a day, 365 days a year and modifying its production schedule as needed to perform routine maintenance inspections, replace/repair equipment, address facility permitting requirements, advance facility modification/construction projects, etc. Transportation data was provided by NOPA to account for the delivery of soybeans at the processing facility. Soybeans are received at the processing facility by truck (84% of soybeans delivered); rail (13% of soybeans delivered); or barge (3% of soybeans delivered). Upon delivery, the first step is to grade the beans for moisture, damage, foreign materials, and color.

In the U.S. up to 13% moisture is allowed, though a moisture level within the range of 8-9% is typically observed. Some facilities may use non-invasive Near Infrared (NIR) to measure oil content as well. Following inspection, soybeans are sent to a temporary storage container.

From the storage bin. the soybeans are first dehulled, dried and cracked, either through a conventional or hot dehulling process. The hulls are ground and pelletized while the "crack" is rolled into thin flakes to expose the oil cells.

The flakes are then sent through an extractor where hexane is used to separate the oil from the flake. The flakes are then removed from the oil and hexane mixture, desolventized to remove residual solvent from the flakes, then toasted, dried and cooled before being ground into soybean meal. Concurrently, hexane is separated from the oil which can then be placed in a centrifuge to remove gums from the oil to produce degummed crude soybean oil.

Soybean hulls, meal and crude soy oil are co-products of NOPA member oilseed processing operations, and as globally traded commodities, all products must meet federal, state and industry standards in accordance with U.S. laws and regulations. Consequently, because these commodities are produced simultaneously, this study allocates the impacts between meal and oil as equal. Mass allocation was selected in order to remain consistent with previous studies.

To produce soybean meal and crude soy oil, energy, water, and materials go into the process and wastewater and emissions are outputs from the manufacturing process. SSC conducted an inventory based on the allocation described above. Table 6.1 details the process inputs and outputs.

Table 6.1 – Soybean Processing Inventory

Energy Inputs	Unit	Quantity per kg of Soybean Meal or Crude Soy Oil
Electricity	kWh	3.90E-02
Natural Gas	mmbtu	6.71E-04
Coal	mmbtu	5.55E-05
Biomass	mmbtu	5.18E-06
Other Fuels	mmbtu	8.13E-06
Purchased Steam	mmbtu	5.20E-04
Material Inputs	**Unit**	**Quantity per kg of Soybean Meal or Crude Soy Oil**
Soybeans	kg	1.03E+00
Hexane	kg	5.52E-04
Water	**Unit**	**Quantity per kg of Soybean Meal or Crude Soy Oil**
Inflow	L	3.54E-01
Wastewater	L	1.41E-01
Evaporated Water	L	2.13E-01
Transportation	**Unit**	**Quantity per kg of Soybean Meal or Crude Soy Oil**
Truck	kgkm	7.20E+01
Rail	kgkm	4.82E+01
Barge	kgkm	2.21E+01
Emissions	**Unit**	**Quantity per kg of Soybean Meal or Crude Soy Oil**
Hexane	kg	5.52E-04
Note: Soybean meal and crude oil are co-products resulting from crushing operations. Consequently, inventory data was unable to be allocated to product specific processes and the product values are the same.		

6.3 Crude Soy Oil and Soybean Meal Production Results

Processors purchase the raw materials and control operational processes used to produce meal and oil; however, their ability to directly influence the production of raw materials, and thus environmental impact, is typically outside their control. Environmental impacts that occur in soybeans shipping, processing, and final product shipping are directly under NOPA members' purview. This puts much of the environmental impact of the final product out of the control of soybean processors unless material substitutions can be made. However, since this is a cradle-to-gate study that ends at the factory gate, final product shipping is not be included in this paper.

6.3.1 Crude Soy Oil and Soybean Meal Processing Impacts ONLY

Energy is the main component of the crushing and degumming process to manufacture soybean meal and crude soybean oil. It is also required to grow or extract, process, and ship raw materials to the plant.

Table 6.2 below lists the amount of cumulative energy consumed during the manufacturing process for crude soy oil and soybean meal most directly under the control of NOPA member processing facilities. All the energy consumption was calculated in megajoules (MJ), using the cumulative energy demand impact category defined in Section 4.2, to allow for comparison of energy consumption across all uses. Cumulative energy demand is the sum of all energy sources drawn directly from the earth, and accounts for all upstream and downstream processes. This energy consumption is based on the original manufacturing inventory in Section 6.2 where allocation and fuels and energy sources are discussed.

Table 6.2 – Energy Use During Soybean Processing

Manufacturing Energy Consumption	Energy Use per kg of Crude Soy Oil or Soybean Meal (MJ/kg)
Electricity	1.40E-01
Natural Gas	7.08E-01
Coal	5.85E-02
Biomass	5.46E-03
Other Fuels	8.58E-03
Purchased Steam – Natural Gas	2.94E-01
Purchased Steam – Coal	7.18E-02
Purchased Steam – Biomass	1.78E-01
Purchased Steam – Liquid Petroleum Gas	4.39E-03
Total	**1.47E+00**
Note: Soybean meal and crude oil are co-products resulting from crushing operations. Consequently, the energy use data was unable to be allocated to product specific processes and the product values are the same.	

Figure 6.1 shows the same energy breakdown in a pie chart. This further illustrates the overwhelming contribution that natural gas (and purchased steam from natural gas) contributes to energy used to produce crude soy oil and soybean meal in the U.S.

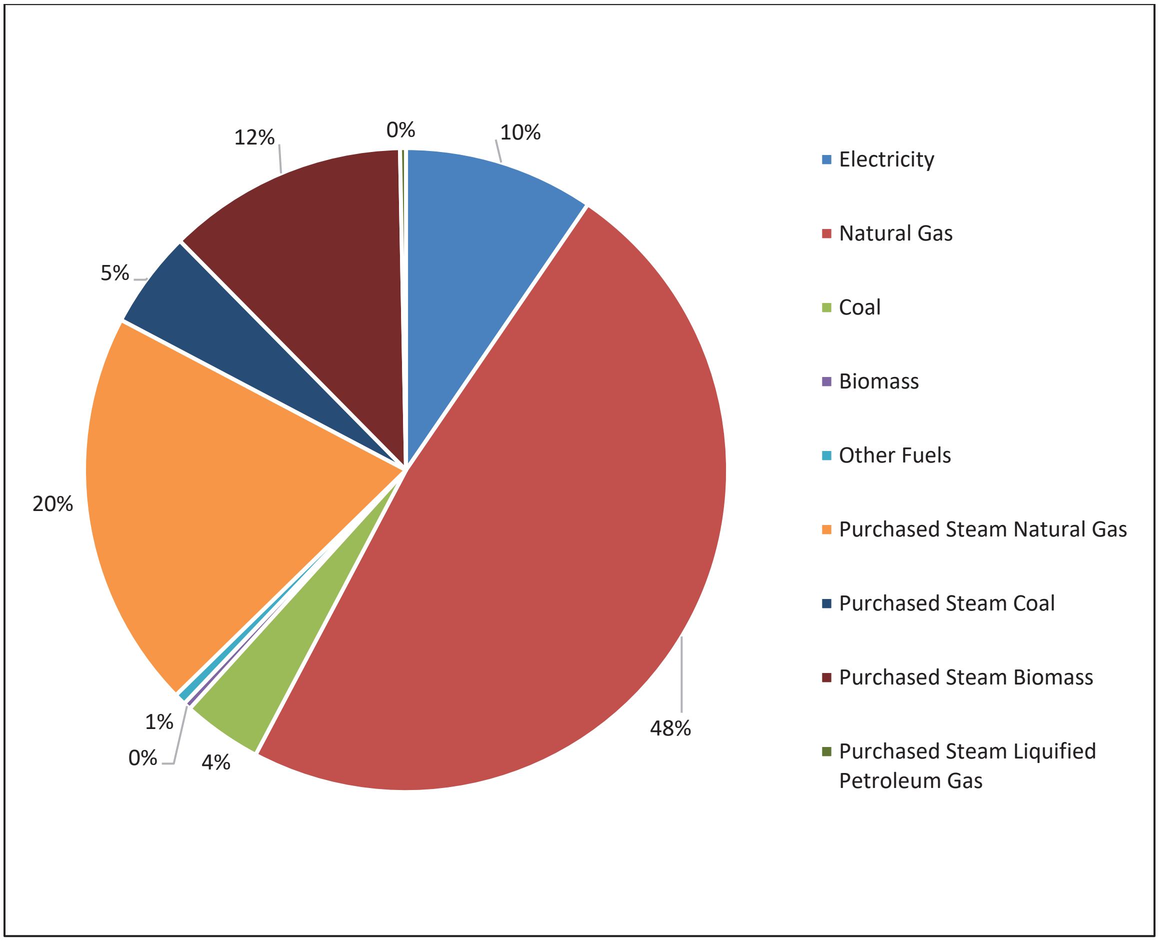


Figure 6.1 – Energy Breakdown for Crude Soy Oil and Soybean Meal Production

The impacts of processing of one kilogram of soybean meal or one kilogram of crude soybean oil from the inputs included in Table 6.1 were estimated utilizing the modified TRACI v2.1 methodology. The results are displayed in Figure 6.2 and quantified in Table 6.3.

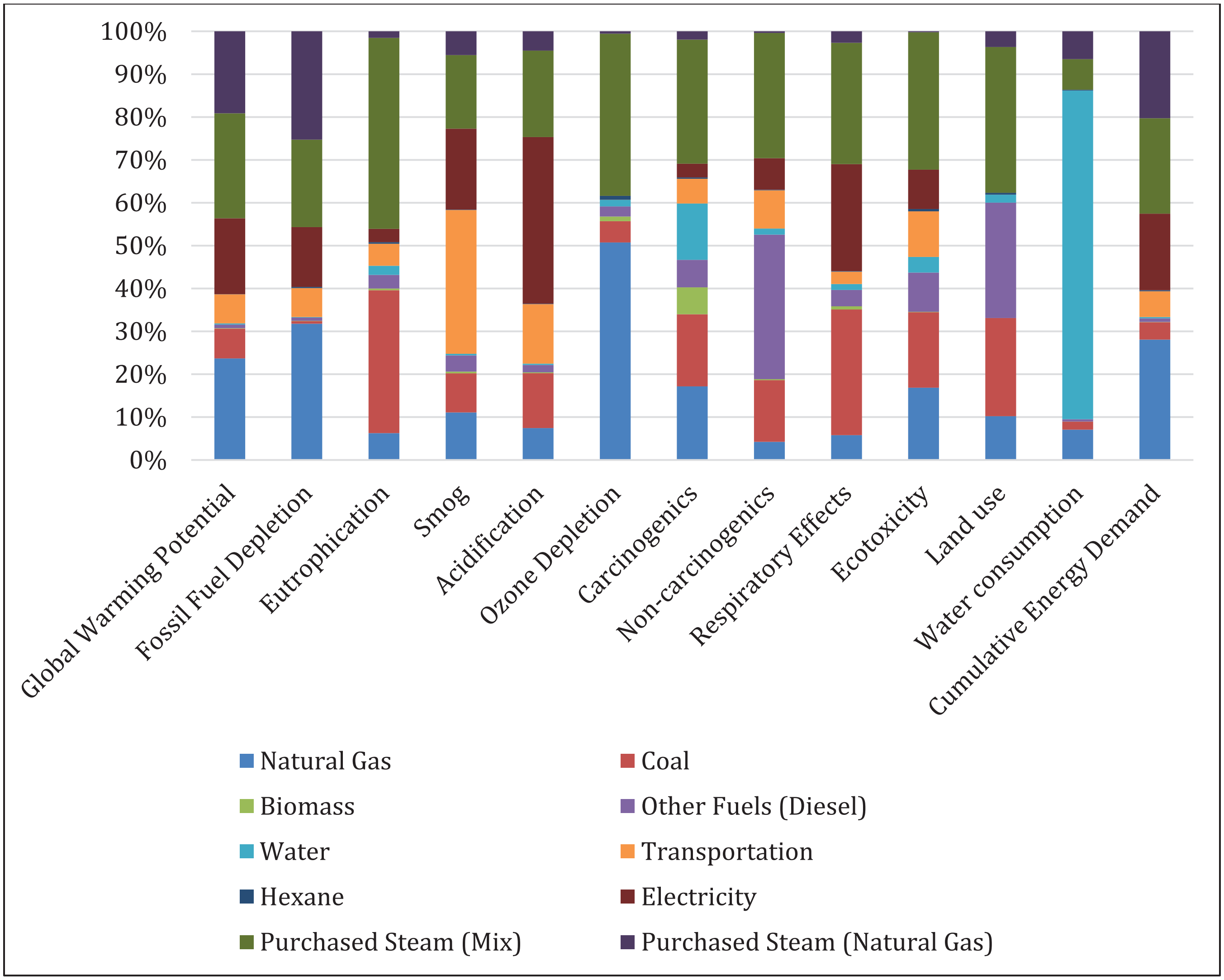


Figure 6.2 – Impacts of Soybean Processing for 1 kg of Soybean Meal or 1 kg Crude Soy Oil

As expected, natural gas and purchased steam are significant components of most impact categories, followed by electricity. Natural gas is typically used for heating and steam generation which is used during drying and oil/solvent recovery process steps.

Table 6.3 – Impacts of Soybean Processing for 1 kg of Soybean Meal or 1 kg Crude Soy Oil

Impact Category	Unit	Natural Gas	Coal	Biomass	Other Fuels (Diesel)	Water	Transportation	Hexane	Electricity	Purchased Steam (Mix)	Purchased Steam (Natural Gas)	Total
Global Warming Potential	kg CO_2 eq	2.98E-02	8.75E-03	9.75E-05	1.07E-03	3.65E-04	8.50E-03	6.07E-05	2.22E-02	3.08E-02	2.40E-02	**1.26E-01**
Fossil Fuel Depletion	MJ surplus	7.16E-02	1.35E-03	1.81E-04	1.66E-03	3.21E-04	1.52E-02	5.92E-04	3.14E-02	4.60E-02	5.70E-02	**2.25E-01**
Eutrophication	kg N eq	4.60E-06	2.45E-05	2.93E-07	2.34E-06	1.56E-06	3.76E-06	2.86E-07	2.26E-06	3.28E-05	1.12E-06	**7.35E-05**
Smog	kg O_3 eq	6.32E-04	5.21E-04	2.34E-05	2.16E-04	2.01E-05	1.91E-03	5.51E-06	1.08E-03	9.78E-04	3.18E-04	**5.71E-03**
Acidification	kg SO_2 eq	3.59E-05	6.19E-05	9.38E-07	8.22E-06	1.58E-06	6.70E-05	4.79E-07	1.87E-04	9.74E-05	2.17E-05	**4.83E-04**
Ozone Depletion	kg CFC-11 eq	3.99E-09	3.91E-10	8.39E-11	1.88E-10	1.22E-10	3.22E-13	7.03E-11	2.37E-13	2.97E-09	4.32E-11	**7.86E-09**
Carcinogenics	CTUh	3.42E-10	3.35E-10	1.25E-10	1.28E-10	2.62E-10	1.16E-10	5.62E-12	6.41E-11	5.77E-10	3.85E-11	**1.99E-09**
Non-Carcinogenics	CTUh	5.27E-10	1.80E-09	3.12E-11	4.20E-09	1.74E-10	1.11E-09	1.64E-11	9.21E-10	3.64E-09	4.94E-11	**1.25E-08**
Respiratory Effects	kg $PM_{2.5}$ eq	2.36E-06	1.19E-05	3.06E-07	1.55E-06	5.63E-07	1.17E-06	5.05E-08	1.02E-05	1.15E-05	1.10E-06	**4.07E-05**
Ecotoxicity	CTUe	3.41E-02	3.55E-02	2.42E-04	1.85E-02	7.34E-03	2.15E-02	1.07E-03	1.85E-02	6.48E-02	4.79E-04	**2.02E-01**
Land Use	m^2a crop eq	3.66E-05	8.19E-05	0.00E+00	9.62E-05	6.60E-06	0.00E+00	1.64E-06	0.00E+00	1.22E-04	1.31E-05	**3.58E-04**
Water Consumption	m^3	3.27E-05	8.48E-06	1.51E-07	2.58E-06	3.54E-04	0.00E+00	9.36E-07	0.00E+00	3.28E-05	3.00E-05	**4.61E-04**
Cumulative Energy Demand	MJ	5.37E-01	7.77E-02	1.47E-03	1.61E-02	5.87E-03	1.15E-01	4.57E-03	3.41E-01	4.26E-01	3.88E-01	**1.91E+00**

Table 6.4 displays the breakdown of Global Warming Potential (GWP) from the manufacturing of crude soy oil and soybean meal in the U.S. Similar to energy use, the majority of GWP in the manufacturing process is from purchased steam and natural gas consumption, as well as electricity.

Table 6.4 – GWP from the Manufacture of Crude Soy Oil and Soybean Meal in the U.S.

Processing Component	Crude Soy Oil or Soybean Meal GWP (kg CO_2 eq/kg)
Natural Gas	2.98E-02
Coal	8.75E-03
Biomass	9.75E-05
Other Fuels (Diesel)	1.07E-03
Water	3.65E-04
Transportation	8.50E-03
Hexane	6.07E-05
Electricity	2.22E-02
Purchased Steam (Mix)	3.08E-02
Purchased Steam (Natural Gas)	2.40E-02
Total	**1.26E-01**

Note: Soybean meal and crude oil are co-products resulting from crushing operations. Consequently, the GWP data was unable to be allocated to product specific processes and the product values are the same.

Figure 6.3 shows the same GWP breakdown in a pie chart. This further illustrates the contribution that purchased steam, natural gas, and electricity contribute to GWP from the production of crude soy oil and soybean meal in the U.S.

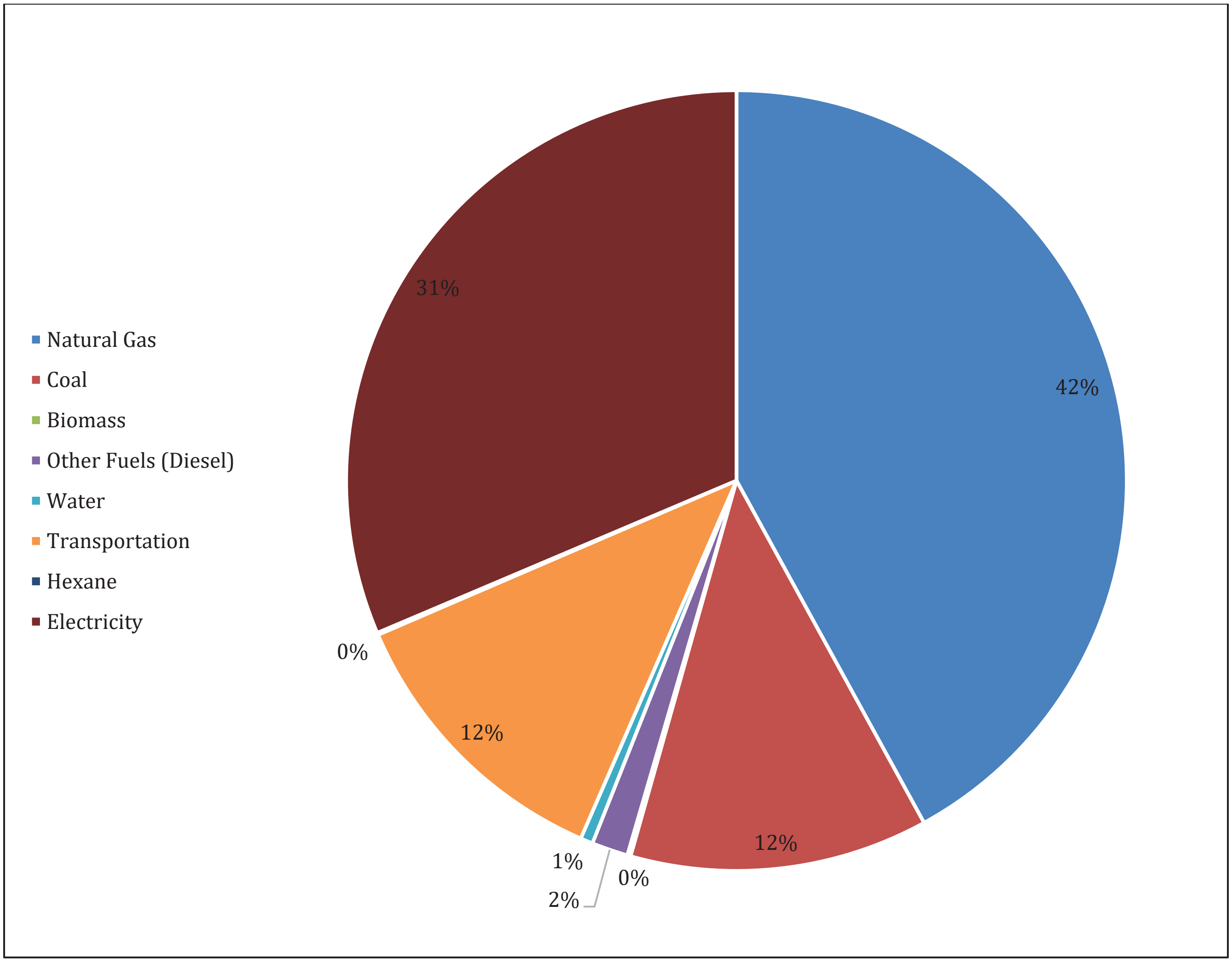


Figure 6.3 – GWP of 1 kg of Crude Soy Oil or 1 kg of Soybean Meal

6.3.2 Overall Impacts

Besides energy demand and carbon emissions during processing, the soybeans also have embodied impacts. SSC ran a modified TRACI analysis to include the soybeans needed for making 1 kg or crude soy oil or 1 kg of soybean meal, as presented in Table 6.1. Results are displayed in Figure 6.4, and specific numbers are included in Table 6.5 and Table 6.6.

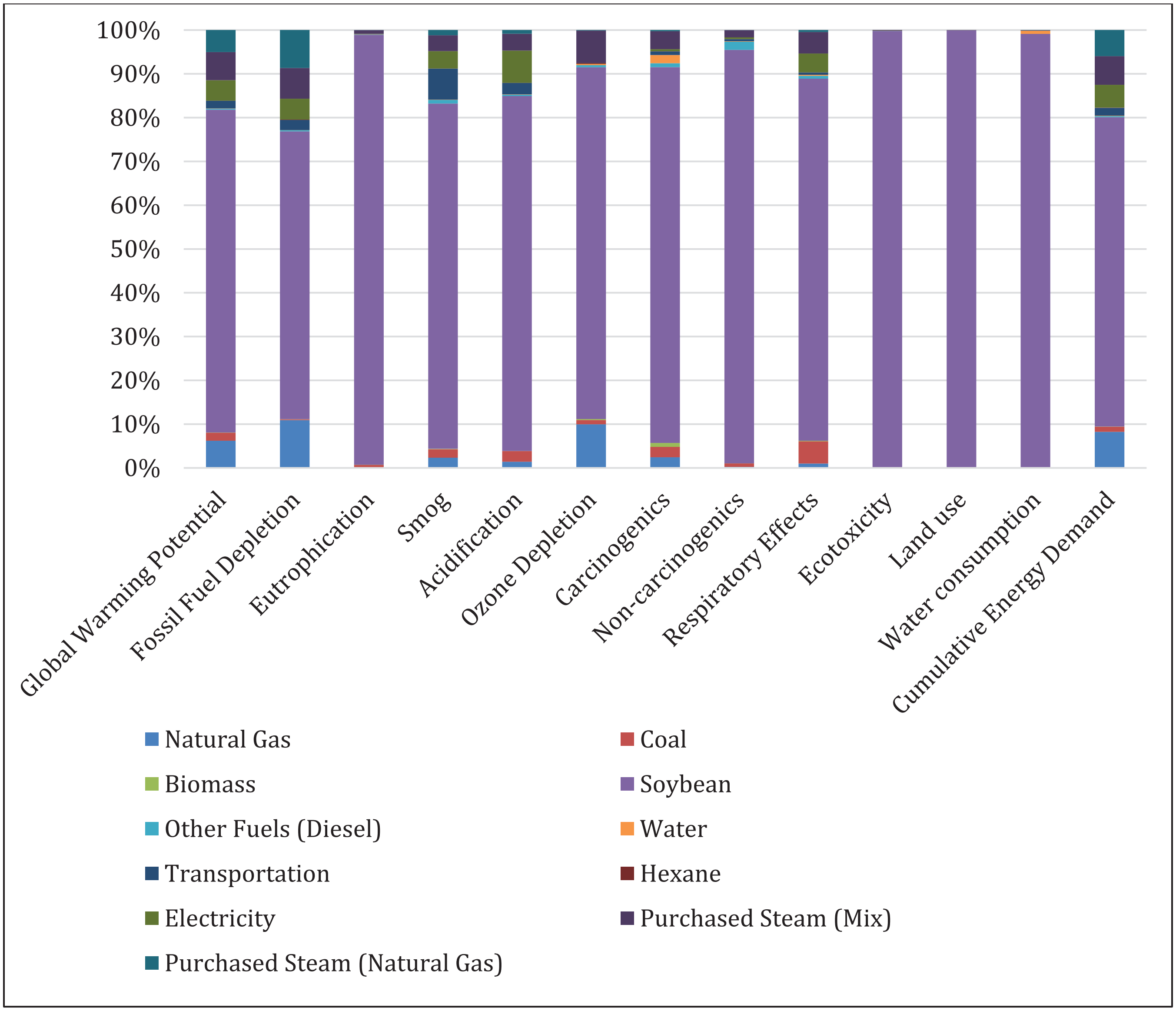


Figure 6.4 – Overall Impacts of the Crushing and Degumming Process for 1 kg of Crude Soy Oil or 1 kg of Soybean Meal

Table 6.5 – Environmental Impacts from Producing 1 kg of Crude Soy Oil

Impact Category	Unit	Natural Gas	Coal	Biomass	Soybean	Other Fuels (Diesel)	Water	Transpor tation	Hexane	Electricity	Purchased Steam (Mix)	Purchased Steam (Natural Gas)	Total
Global Warming Potential	kg CO_2 eq	2.98E-02	8.75E-03	9.75E-05	3.52E-01	1.07E-03	3.65E-04	8.50E-03	6.07E-05	2.22E-02	3.08E-02	2.40E-02	**4.78E-01**
Fossil Fuel Depletion	MJ surplus	7.16E-02	1.35E-03	1.81E-04	4.32E-01	1.66E-03	3.21E-04	1.52E-02	5.92E-04	3.14E-02	4.60E-02	5.70E-02	**6.57E-01**
Eutrophication	kg N eq	4.60E-06	2.45E-05	2.93E-07	3.92E-03	2.34E-06	1.56E-06	3.76E-06	2.86E-07	2.26E-06	3.28E-05	1.12E-06	**3.99E-03**
Smog	kg O_3 eq	6.32E-04	5.21E-04	2.34E-05	2.13E-02	2.16E-04	2.01E-05	1.91E-03	5.51E-06	1.08E-03	9.78E-04	3.18E-04	**2.70E-02**
Acidification	kg SO_2 eq	3.59E-05	6.19E-05	9.38E-07	2.06E-03	8.22E-06	1.58E-06	6.70E-05	4.79E-07	1.87E-04	9.74E-05	2.17E-05	**2.55E-03**
Ozone Depletion	kg CFC-11 eq	3.99E-09	3.91E-10	8.39E-11	3.21E-08	1.88E-10	1.22E-10	3.22E-13	7.03E-11	2.37E-13	2.97E-09	4.32E-11	**4.00E-08**
Carcinogenics	CTUh	3.42E-10	3.35E-10	1.25E-10	1.20E-08	1.28E-10	2.62E-10	1.16E-10	5.62E-12	6.41E-11	5.77E-10	3.85E-11	**1.40E-08**
Non-Carcinogenics	CTUh	5.27E-10	1.80E-09	3.12E-11	2.11E-07	4.20E-09	1.74E-10	1.11E-09	1.64E-11	9.21E-10	3.64E-09	4.94E-11	**2.23E-07**
Respiratory Effects	kg $PM_{2.5}$ eq	2.36E-06	1.19E-05	3.06E-07	1.94E-04	1.55E-06	5.63E-07	1.17E-06	5.05E-08	1.02E-05	1.15E-05	1.10E-06	**2.35E-04**
Ecotoxicity	CTUe	3.41E-02	3.55E-02	2.42E-04	6.18E+01	1.85E-02	7.34E-03	2.15E-02	1.07E-03	1.85E-02	6.48E-02	4.79E-04	**6.20E+01**
Land Use	m^2a crop eq	3.66E-05	8.19E-05	0.00E+00	1.83E+00	9.62E-05	6.60E-06	0.00E+00	1.64E-06	0.00E+00	1.22E-04	1.31E-05	**1.83E+00**
Water Consumption	m^3	3.27E-05	8.48E-06	1.51E-07	4.76E-02	2.58E-06	3.54E-04	0.00E+00	9.36E-07	0.00E+00	3.28E-05	3.00E-05	**4.81E-02**
Cumulative Energy Demand	MJ	5.37E-01	7.77E-02	1.47E-03	4.61E+00	1.61E-02	5.87E-03	1.15E-01	4.57E-03	3.41E-01	4.26E-01	3.88E-01	**6.52E+00**

Table 6.6 – Environmental Impacts from Producing 1 kg of Soybean Meal

Impact Category	Unit	Natural Gas	Coal	Biomass	Soybean	Other Fuels (Diesel)	Water	Transportation	Hexane	Electricity	Purchased Steam (Mix)	Purchased Steam (Natural Gas)	Total
Global Warming Potential	kg CO_2 eq	2.98E-02	8.75E-03	9.75E-05	3.52E-01	1.07E-03	3.65E-04	8.50E-03	6.07E-05	2.22E-02	3.08E-02	2.40E-02	**4.78E-01**
Fossil Fuel Depletion	MJ surplus	7.16E-02	1.35E-03	1.81E-04	4.32E-01	1.66E-03	3.21E-04	1.52E-02	5.92E-04	3.14E-02	4.60E-02	5.70E-02	**6.57E-01**
Eutrophication	kg N eq	4.60E-06	2.45E-05	2.93E-07	3.92E-03	2.34E-06	1.56E-06	3.76E-06	2.86E-07	2.26E-06	3.28E-05	1.12E-06	**3.99E-03**
Smog	kg O_3 eq	6.32E-04	5.21E-04	2.34E-05	2.13E-02	2.16E-04	2.01E-05	1.91E-03	5.51E-06	1.08E-03	9.78E-04	3.18E-04	**2.70E-02**
Acidification	kg SO_2 eq	3.59E-05	6.19E-05	9.38E-07	2.06E-03	8.22E-06	1.58E-06	6.70E-05	4.79E-07	1.87E-04	9.74E-05	2.17E-05	**2.55E-03**
Ozone Depletion	kg CFC-11 eq	3.99E-09	3.91E-10	8.39E-11	3.21E-08	1.88E-10	1.22E-10	3.22E-13	7.03E-11	2.37E-13	2.97E-09	4.32E-11	**4.00E-08**
Carcinogenics	CTUh	3.42E-10	3.35E-10	1.25E-10	1.20E-08	1.28E-10	2.62E-10	1.16E-10	5.62E-12	6.41E-11	5.77E-10	3.85E-11	**1.40E-08**
Non-Carcinogenics	CTUh	5.27E-10	1.80E-09	3.12E-11	2.11E-07	4.20E-09	1.74E-10	1.11E-09	1.64E-11	9.21E-10	3.64E-09	4.94E-11	**2.23E-07**
Respiratory Effects	kg $PM_{2.5}$ eq	2.36E-06	1.19E-05	3.06E-07	1.94E-04	1.55E-06	5.63E-07	1.17E-06	5.05E-08	1.02E-05	1.15E-05	1.10E-06	**2.35E-04**
Ecotoxicity	CTUe	3.41E-02	3.55E-02	2.42E-04	6.18E+01	1.85E-02	7.34E-03	2.15E-02	1.07E-03	1.85E-02	6.48E-02	4.79E-04	**6.20E+01**
Land Use	m^2a crop eq	3.66E-05	8.19E-05	0.00E+00	1.83E+00	9.62E-05	6.60E-06	0.00E+00	1.64E-06	0.00E+00	1.22E-04	1.31E-05	**1.83E+00**
Water Consumption	m^3	3.27E-05	8.48E-06	1.51E-07	4.76E-02	2.58E-06	3.54E-04	0.00E+00	9.36E-07	0.00E+00	3.28E-05	3.00E-05	**4.81E-02**
Cumulative Energy Demand	MJ	5.37E-01	7.77E-02	1.47E-03	4.61E+00	1.61E-02	5.87E-03	1.15E-01	4.57E-03	3.41E-01	4.26E-01	3.88E-01	**6.52E+00**

As shown in the figure above, the manufacturing impacts are dominated by the soybeans. This is because soybeans are the only ingredient in making crude soybean oil and soybean meal. Furthermore, growing soybeans is a process that takes several months before a harvest. This is more energy and resource-intensive than processing after harvesting. These results were also compared to the 2015 study, which can be found in Section A.2 of Appendix A.

7.0 Refined Soy Oil Production

7.1 Important Assumptions

In this study of refined soy oil, SSC made the following assumptions:

- Data provided are representative of U.S soy oil refining operations. NOPA member companies provided soy oil refinery data for 27 refineries co-located with soybean processing plants that produce crude soy oil and soybean meal.
- Crude soy oil is the primary material input used in the production of refined oil. Depending on plant design and co-location of processing and refining operations, crude soy oil may be delivered as degummed or not degummed oil.
    - Crude soy oil inputs were determined based on total percentage of degummed (39%) and not degummed (61%) crude soy oil reported by NOPA member companies.
- Actual total pounds of crude oil inputs were reported as an aggregated average, while all other input/output values were reported based on unit per short tons refined. Consequently, the aggregated data used in the analysis of soy oil refining operations did not reflect a 1:1 mass balance for crude soy oil inputs and refined oil output values reported in Table 7.1.
- Assumptions outlined in Section 6.1 also contributed to mass balance misalignment that resulted in the 1.02 kg crude soy oil equivalent value.
- This study assumes crude oil was delivered to the refinery from the processing plant via intra-facility piping, due to the co-located nature of the facilities represented in data provided. However, some facilities may also receive crude oil inputs from other transportation modes (e.g., truck, barge, rail). Refineries which are not co-located with a processing plant will typically receive crude soy oil by truck, rail or barge. For this reason, secondary transportation data were used for analysis.
- When a material is not available in the available LCI databases, another chemical which has similar manufacturing and environmental impacts may be used as a proxy, representing the actual chemical. The Proxy Chemical List used in this analysis includes:
    - Diesel as proxy for "Other Fuels."

7.2 Life Cycle Inventory

This section describes the life cycle inventory of refined soy oil. Data were collected from NOPA members for 27 soy oil refineries that are co-located with crushing operations. Once the solvent has been separated from the oil (discussed under Section 6.2 above and illustrated within Appendix C), crude oil is placed in a centrifuge to remove gums and soap stocks from the oil. Soy oil may be sold at this stage as “crude, degummed soy oil,” primarily as a feedstock for vegetable oil refining.

After degumming is completed, the oil is run through diatomaceous earth to take out impurities. Soy oil may be sold at this stage as “once refined soy oil”, primarily as a feedstock for the production of biodiesel.[5] The next step is to modify color and clarify the oil using bleaching clays. Soy oil may be sold at this stage as “once refined and bleached soy oil”, primarily as a feedstock for the production of renewable diesel and sustainable aviation fuel.[6] Finally, the soy oil may undergo a final deodorization step to meet U.S. Department of Agriculture and U.S. Food and Drug Administration product quality standards. Soy oil sold following this stage are typically used in the manufacturer and production of animal feed and human food applications.[7]

An inventory detailing the process steps for soy oil refining are shown in Table 7.1. The term inventory is used in LCA to refer to the list of inputs and outputs that are required to achieve the product function unit (e.g., 1.0 kg for purposes of this LCA).

Table 7.1 – Soy Oil Refining Inventory

Energy Inputs	Unit	Quantity per kg of Refined Soy Oil
Electricity	kWh	6.09E-02
Natural Gas	mmbtu	5.57E-04
Coal	mmbtu	4.33E-05
Other Fuels	mmbtu	3.99E-06
Material Inputs	**Unit**	**Quantity per kg of Refined Soy Oil**
Crude Soy Oil	kg	1.02E+00
Sodium Hydroxide	kg	1.14E-03
Bleaching Earth	kg	2.74E-03
Water	**Unit**	**Quantity per kg of Refined Soy Oil**
Inflow	L	7.90E-01
Wastewater	L	7.39E-01
Evaporated Water	L	5.10E-02
NOTE: Inventory data based on weighted average values as reported by NOPA member companies for 27 soy oil refineries which are co-located on the same site with a soybean processing facility.		

[5] Marketed as "Once Refined Soybean Oil” under the *NOPA Trading Rules for the Purchase and Sale of Soybean Oil*.

[6] Marketed as "Once Refined & Bleached" under the *NOPA Trading Rules for the Purchase and Sale of Soybean Oil*.

[7] Marketed as "Refined, Bleached, and Deodorized (RBD)" under the *NOPA Trading Rules for the Purchase and Sale of Soybean Oil*.

7.3 Refined Soy Oil Environmental Impacts

7.3.1 Oil Refining Impacts ONLY

Crude soy oil can be further processed to become refined soy oil. The refining process consists of eliminating any impurities from the crude soy oil. SSC estimated the impacts of this process with the modified TRACI methodology based on the inputs included in Table 7.1 and are displayed in Figure 7.1 and quantified in Table 7.2.

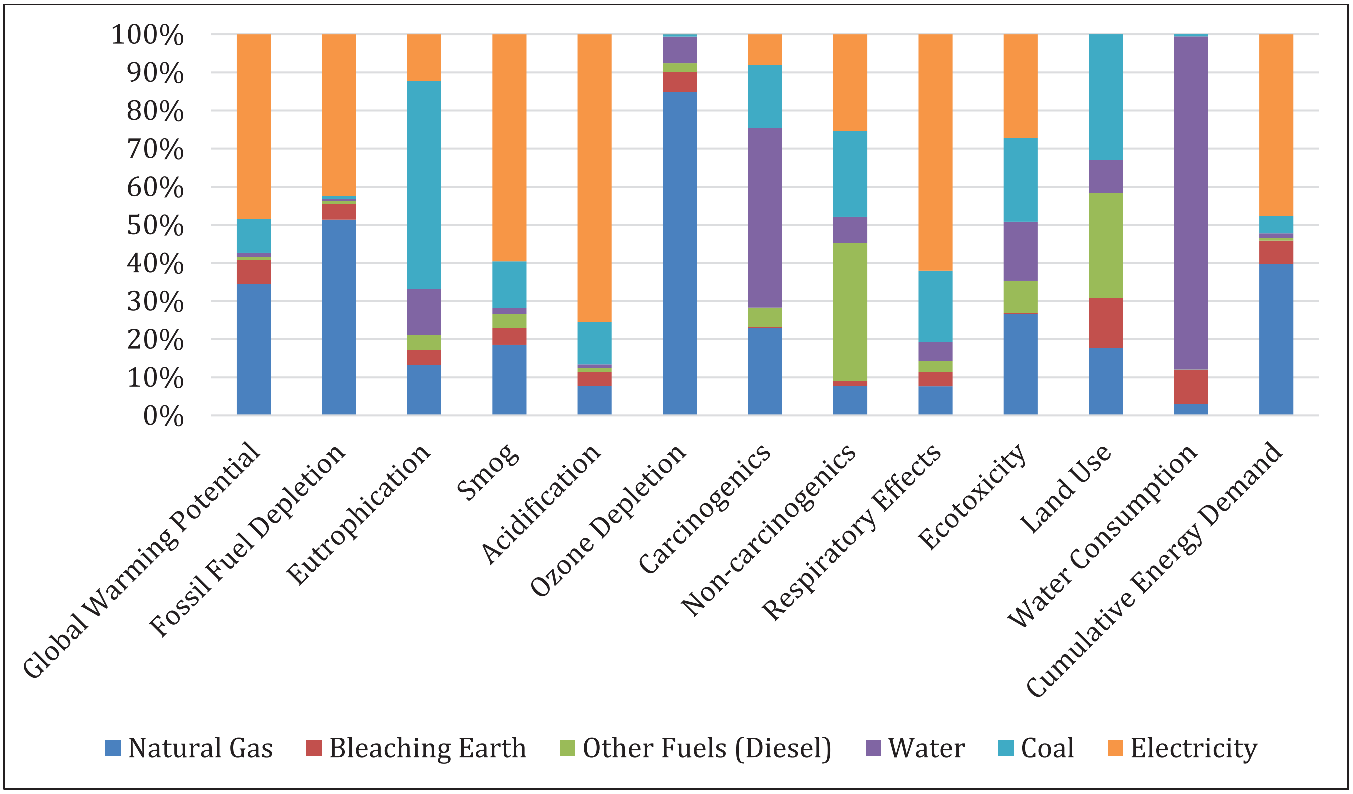


Figure 7.1 – Soy Oil Refining Impacts

Here, natural gas and electricity are the main drivers of most impacts. This is because most of the inputs for refining oil are energy, and natural gas and electricity are the main two sources of energy used for soybean oil refining.

Table 7.2 – Soy Oil Refining Impacts

Impact Category	Unit	Natural Gas	Bleaching Earth	Other Fuels (Diesel)	Water	Coal	Electricity	Total
Global Warming Potential	kg CO_2 eq	2.46E-02	4.56E-03	5.22E-04	8.16E-04	6.30E-03	3.47E-02	**7.16E-02**
Fossil Fuel Depletion	MJ surplus	5.93E-02	4.77E-03	8.14E-04	7.17E-04	7.78E-04	4.91E-02	**1.15E-01**
Eutrophication	kg N eq	3.81E-06	1.15E-06	1.15E-06	3.48E-06	1.57E-05	3.53E-06	**2.89E-05**
Smog	kg O_3 eq	5.24E-04	1.24E-04	1.06E-04	4.50E-05	3.44E-04	1.68E-03	**2.82E-03**
Acidification	kg SO_2 eq	2.97E-05	1.46E-05	4.03E-06	3.53E-06	4.31E-05	2.93E-04	**3.88E-04**
Ozone Depletion	kg CFC-11 eq	3.30E-09	2.01E-10	9.21E-11	2.72E-10	2.37E-11	3.71E-13	**3.89E-09**
Carcinogenics	CTUh	2.83E-10	4.74E-12	6.26E-11	5.84E-10	2.04E-10	1.00E-10	**1.24E-09**
Non-Carcinogenics	CTUh	4.36E-10	7.22E-11	2.06E-09	3.88E-10	1.28E-09	1.44E-09	**5.67E-09**
Respiratory Effects	kg $PM_{2.5}$ eq	1.95E-06	9.55E-07	7.57E-07	1.26E-06	4.81E-06	1.59E-05	**2.56E-05**
Ecotoxicity	CTUe	2.82E-02	2.00E-04	9.07E-03	1.64E-02	2.32E-02	2.89E-02	**1.06E-01**
Land Use	m^2a crop eq	3.03E-05	2.24E-05	4.72E-05	1.48E-05	5.66E-05	0.00E+00	**1.71E-04**
Water Consumption	m^3	2.71E-05	8.06E-05	1.26E-06	7.90E-04	5.04E-06	0.00E+00	**9.04E-04**
Cumulative Energy Demand	MJ	4.45E-01	6.88E-02	7.91E-03	1.31E-02	5.19E-02	5.33E-01	**1.12E+00**

7.3.2 Overall

The graphs in this section are designed to communicate the overall cradle-to-facility-gate environmental impacts of refined soybean oil. These include soybean agriculture, transportation to oil processing facility, the crushing and degumming process, and soybean oil refining.

Table 7.3 and Figure 7.2 demonstrate the overall environmental impact (using the modified TRACI methodology) of manufacturing one kilogram of refined soybean oil. The figure illustrates the relative impact contribution from each of the life cycle stages (soybean cultivation and harvesting, soybean transportation, the crushing and degumming process, and soy oil refining) to each of the environmental impacts. In this analysis, soybean transportation impacts are separated from the "soybean cultivation and harvesting" stage.

Table 7.3 – Refined Soybean Oil Environmental Impacts using the TRACI Impact Methodology

Impact Category	Unit	Crushing and Degumming	Soybeans	Natural Gas	Bleaching Earth	Other Fuels (Diesel)	Water	Coal	Electricity	Transport	Total
Global Warming Potential	kg CO_2 eq	1.28E-01	2.71E-01	2.46E-02	4.56E-03	5.22E-04	8.16E-04	6.30E-03	3.47E-02	2.87E-02	**4.99E-01**
Fossil Fuel Depletion	MJ surplus	2.30E-01	4.41E-01	5.93E-02	4.77E-03	8.14E-04	7.17E-04	7.78E-04	4.91E-02	5.14E-02	**8.39E-01**
Eutrophication	kg N eq	7.51E-05	4.01E-03	3.81E-06	1.15E-06	1.15E-06	3.48E-06	1.57E-05	3.53E-06	1.27E-05	**4.12E-03**
Smog	kg O_3 eq	5.84E-03	2.18E-02	5.24E-04	1.24E-04	1.06E-04	4.50E-05	3.44E-04	1.68E-03	6.46E-03	**3.69E-02**
Acidification	kg SO_2 eq	4.94E-04	2.11E-03	2.97E-05	1.46E-05	4.03E-06	3.53E-06	4.31E-05	2.93E-04	2.26E-04	**3.22E-03**
Ozone Depletion	kg CFC-11 eq	8.04E-09	3.29E-08	3.30E-09	2.01E-10	9.21E-11	2.72E-10	2.37E-11	3.71E-13	1.09E-12	**4.48E-08**
Carcinogenics	CTUh	2.04E-09	1.23E-08	2.83E-10	4.74E-12	6.26E-11	5.84E-10	2.04E-10	1.00E-10	3.91E-10	**1.60E-08**
Non-Carcinogenics	CTUh	1.28E-08	2.16E-07	4.36E-10	7.22E-11	2.06E-09	3.88E-10	1.28E-09	1.44E-09	3.76E-09	**2.38E-07**
Respiratory Effects	kg $PM_{2.5}$ eq	4.16E-05	1.99E-04	1.95E-06	9.55E-07	7.57E-07	1.26E-06	4.81E-06	1.59E-05	3.96E-06	**2.70E-04**
Ecotoxicity	CTUe	2.07E-01	6.32E+01	2.82E-02	2.00E-04	9.07E-03	1.64E-02	2.32E-02	2.89E-02	7.28E-02	**6.36E+01**
Land Use	m^2a crop eq	3.66E-04	1.87E+00	3.03E-05	2.24E-05	4.72E-05	1.48E-05	5.66E-05	0.00E+00	0.00E+00	**1.87E+00**
Water Consumption	m^3	4.72E-04	4.87E-02	2.71E-05	8.06E-05	1.26E-06	7.90E-04	5.04E-06	0.00E+00	0.00E+00	**5.01E-02**
Cumulative Energy Demand	MJ	1.96E+00	4.71E+00	4.45E-01	6.88E-02	7.91E-03	1.31E-02	5.19E-02	5.33E-01	3.89E-01	**8.18E+00**

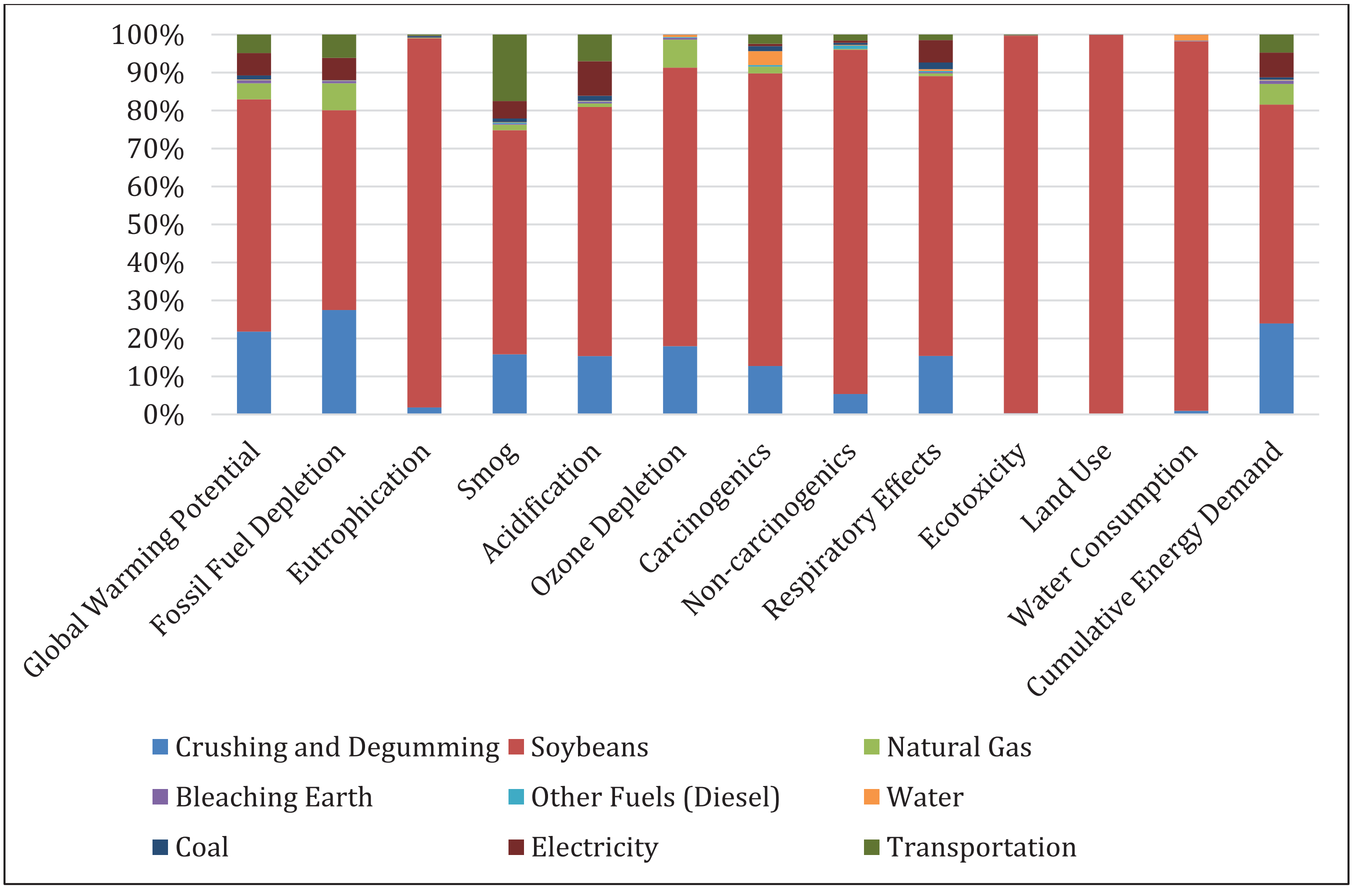


Figure 7.2 – Environmental Impacts of Refined Soybean Oil (TRACI Impact Assessment Methodology)

Overall, soybean cultivation and harvesting is the main driver of environmental impacts, with its contribution ranging from approximately 54% for GWP to almost 100% for land use.

Figure 7.2 shows that, similarly, to results for the crushing and degumming process to produce crude soybean oil, soybeans contribute a majority of the impact in most categories for refined soybean oil. The crushing and degumming process also has a slightly higher impact than oil refining. For eutrophication, human toxicity and ecotoxicity, the majority of the impacts occur also in the soybean agriculture stage, mostly due to the use of fertilizers and crop residue of nitrogen. Overall, environmental impacts of refined soybean oil have also declined overtime when compared to the results from the 2015 study, as shown in Figure A.4 in Appendix A.

8.0 Additional Analysis – Biofuels

Soybeans are 18-20% oil by mass and have fewer nutrient requirements than any other oilseed crop. Consequently, one of the primary uses for soy oil is as a renewable, plant-based feedstock in the production of biodiesel, renewable diesel and sustainable aviation fuel. In fact, U.S. Energy Information Agency data indicate that over 60 percent of U.S. biodiesel today is produced from soy oil.

Biofuels are vital in meeting U.S. transportation needs and climate policy objectives. For example, soy-based biodiesel offers a more sustainable energy source than fossil fuels, and has replaced billions of volumes of petroleum-based diesel under the U.S. Environmental Protection Agency's Renewable Fuels Program. According to the Clean Fuels Alliance America:

- For every unit of fossil energy it takes to produce biodiesel, as much as 3.5 units of renewable energy is returned, the best of any U.S. fuel.
- Compared to petroleum-based diesel, biodiesel lowers particulate matter pollution by 47%.
- Biodiesel combustion emits less greenhouse gases that can contribute toward GWP, compared to petroleum-based diesel, biodiesel can reduce hydrocarbon emissions by nearly 70%.

Increased production to meet market demands may impact water and air quality if facilities are not operated in accordance with environmental permitting requirements, agricultural development for oilseed cultivation in the U.S. may impact biodiversity in certain regions and can result in direct or indirect land use changes.

The effects of utilizing biodiesel, which is largely produced using soy oil feedstocks generated by the soybean processing companies that participated in this study, in different concentrations to replace diesel, gasoline, propane, and natural gas during soybean cultivation are illustrated in Figure 8.1 and detailed in Table 8.1. This sensitivity does not account for energy efficiency differences between the current fuels and biofuels, or practical limitations associated with the complete replacement of traditional petroleum-based fuels with biodiesel.

Table 8.1 – Environmental Impacts of Replacing Fossil Fuels with Biodiesel for Soybean Cultivation/Harvesting

Impact Category	Unit	0% Biodiesel	50% Biodiesel	100% Biodiesel
Global Warming Potential	kg CO_2 eq	3.41E-01	3.26E-01	3.11E-01
Fossil Fuel Depletion	MJ surplus	4.17E-01	3.86E-01	3.54E-01
Eutrophication	kg N eq	3.79E-03	3.81E-03	3.84E-03
Smog	kg O_3 eq	2.06E-02	2.55E-02	3.05E-02
Acidification	kg SO_2 eq	2.00E-03	2.13E-03	2.27E-03
Ozone Depletion	kg CFC-11 eq	3.11E-08	3.05E-08	2.99E-08
Carcinogenics	CTUh	1.16E-08	1.14E-08	1.12E-08
Non-Carcinogenics	CTUh	2.04E-07	2.03E-07	2.03E-07
Respiratory Effects	kg $PM_{2.5}$ eq	1.88E-04	1.91E-04	1.95E-04
Ecotoxicity	CTUe	5.97E+01	6.00E+01	6.03E+01
Land Use	m^2a crop eq	1.77E+00	1.78E+00	1.79E+00
Water Consumption	m^3	4.60E-02	4.63E-02	4.65E-02
Cumulative Energy Demand	MJ	4.46E+00	4.22E+00	3.99E+00

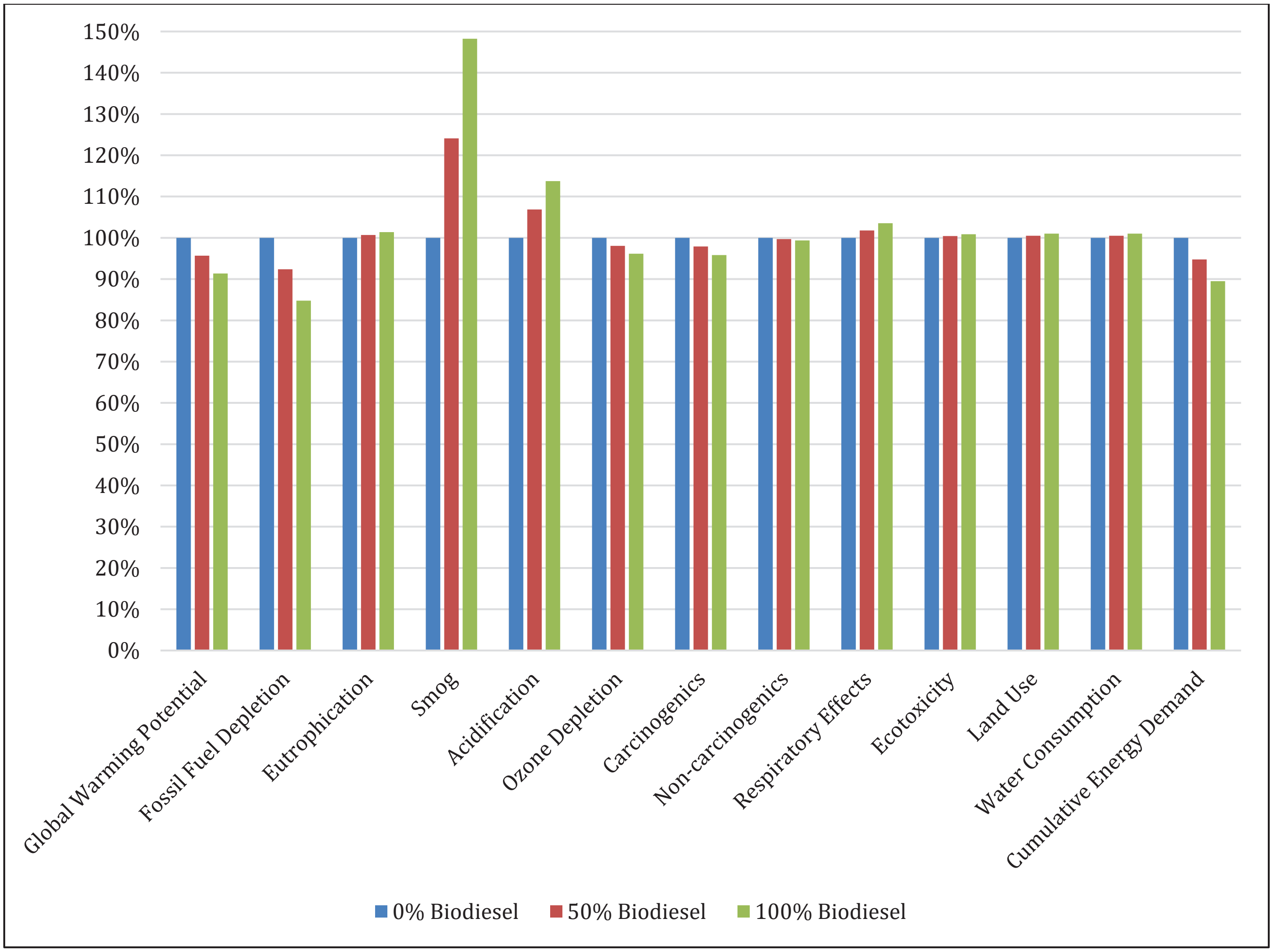


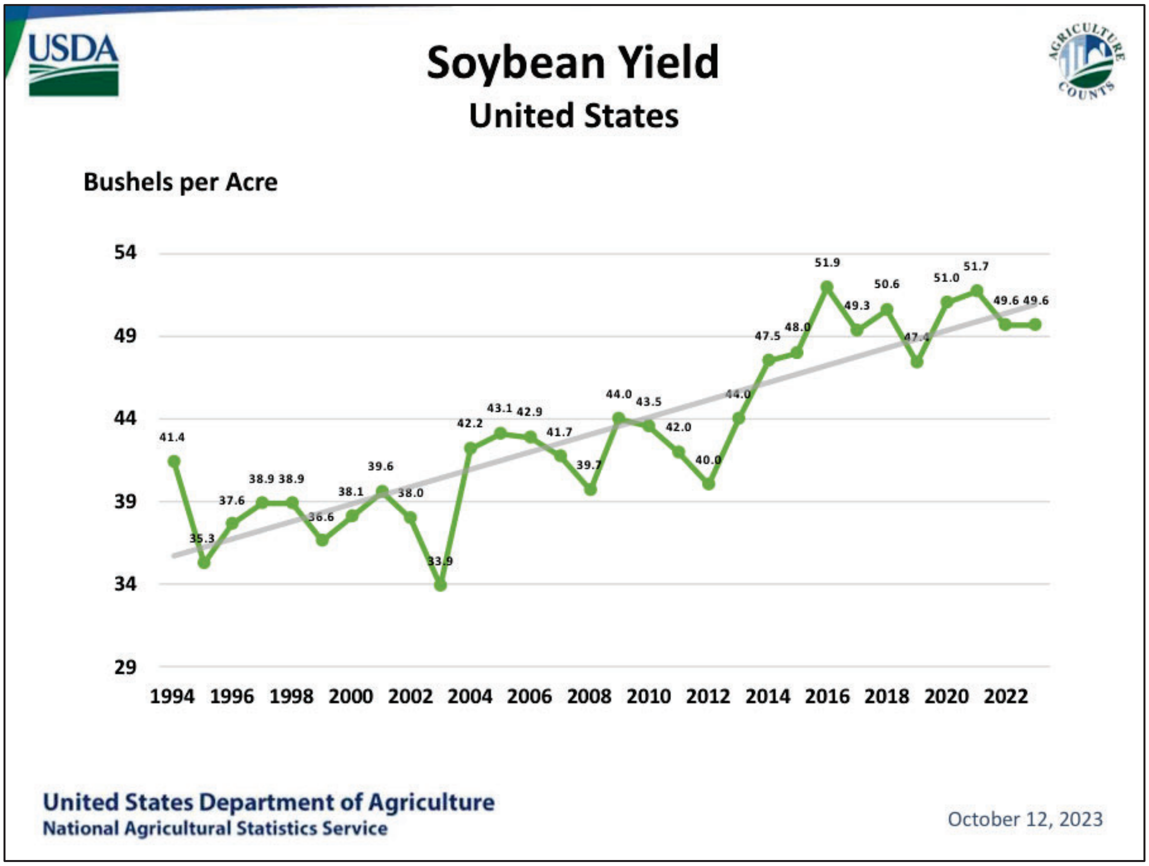
Figure 8.1 – Environmental Impacts of Replacing Fossil Fuels with Biodiesel for Soybean Cultivation/Harvesting

The most significant change is smog, which increases significantly because biodiesel combustion generates more smog than other fuel alternatives. Acidification also shows a visible increase when switching to biodiesel, but on a smaller scale than smog. While biodiesel has higher impact in those two categories, it also remains relatively the same in eutrophication, land use, and water consumption. Switching to biodiesels also shows considerable improvements in global warming potential, fossil fuel depletion, and to a lesser extent, ozone depletion.

9.0 Sensitivity Analysis

9.1 Harvest Yield

The most influential variable in the soybean farming operation was determined to be the harvest yield, characterized as bushels of soybeans per acre of farmed land. Soybean yields (bushels per acres) continue to improve as indicated by the USDA figure below. Improvements in seed quality and farmer practices drive more bushels per acre, as demonstrated by numerous reporting agencies. This is being done while reducing chemicals, passes through the fields, and increasing practices such as no till and cover crop expansion.



The average yield for all soybean farming in the United States is 51 bushels/acre (USDA 2020) which is the value applied to calculate the baseline results of the study. Soybean yields have been reported in the range of 40-70 bushels/acre (USDA 2020, farming survey). Lower yields of around 40 bushels per acre result from the use of organic farming techniques (USDA 2020). Lower yields can also occur under sub-optimal growing conditions (e.g., when crops don't receive sufficient water in drought conditions).

A value of 41 bushels/acre was selected as the low bound for sensitivity analysis. This value is consistent with the yield from the previous LCA carried out by Quantis and is near the lower limit for reported yields as described in the scenarios above. A value of 61 bushels/acre was selected for the upper bound. This value represents the average yield reported in the farming survey and is near the high average of 64 bushels/acre reported for fully irrigated soybean cultivation (USDA 2020). Impact results at the lower and upper bound of the soybean yields show approximately a 25% change over the baseline case. Figure 9.1 and Table 9.1 illustrate the result differences.

Note: This analysis only represents changes in yield data for the 2020-2021 years and not any other parameters that may influence yield, such as fertilizer application.

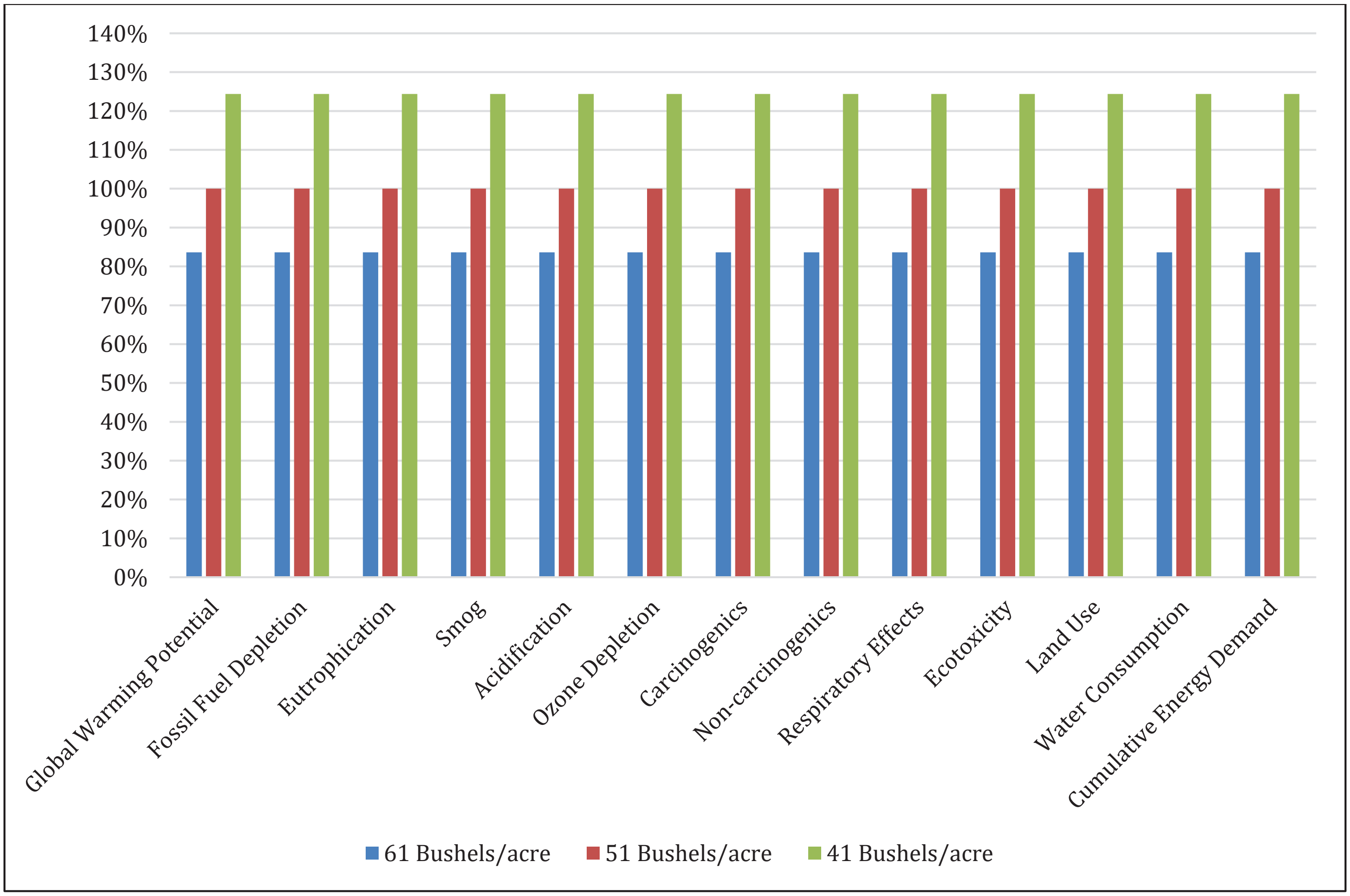


Figure 9.1 – Soybean Yield Sensitivity Analysis

Table 9.1 – Environmental Impacts of 1 kg of Soybeans with Different Harvest Yields

Impact Category	Unit	61 Bushels/acre	51 Bushels/acre	41 Bushels/acre
Global Warming Potential	kg CO_2 eq	2.85E-01	3.41E-01	4.24E-01
Fossil Fuel Depletion	MJ surplus	3.49E-01	4.17E-01	5.19E-01
Eutrophication	kg N eq	3.17E-03	3.79E-03	4.71E-03
Smog	kg O_3 eq	1.72E-02	2.06E-02	2.56E-02
Acidification	kg SO_2 eq	1.67E-03	2.00E-03	2.48E-03
Ozone Depletion	kg CFC-11 eq	2.60E-08	3.11E-08	3.86E-08
Carcinogenics	CTUh	9.73E-09	1.16E-08	1.45E-08
Non-Carcinogenics	CTUh	1.70E-07	2.04E-07	2.54E-07
Respiratory Effects	kg $PM_{2.5}$ eq	1.57E-04	1.88E-04	2.34E-04
Ecotoxicity	CTUe	4.99E+01	5.97E+01	7.43E+01
Land Use	m^2a crop eq	1.48E+00	1.77E+00	2.20E+00
Water Consumption	m^3	3.85E-02	4.60E-02	5.73E-02
Cumulative Energy Demand	MJ	3.72E+00	4.46E+00	5.54E+00

9.2 Diesel

Survey results suggest that farming practices require approximately 1.4 gallons of diesel per acre, which under the current yield assumptions results in approximately 0.001 gallons of diesel per kg of soybeans. However, previous studies had worked under the assumption that soybean farming requires approximately 5 to 6 gallons per acre, which under current yield assumptions corresponds to 0.0036 and 0.0043 gallons per kg, respectively. A sensitivity analysis tests the effects of higher diesel concentrations, comparing baseline survey results to 2.5 gallons per acre, 5 gallons per acre, and 6 gallons per acre. Results are shown Figure 9.2.

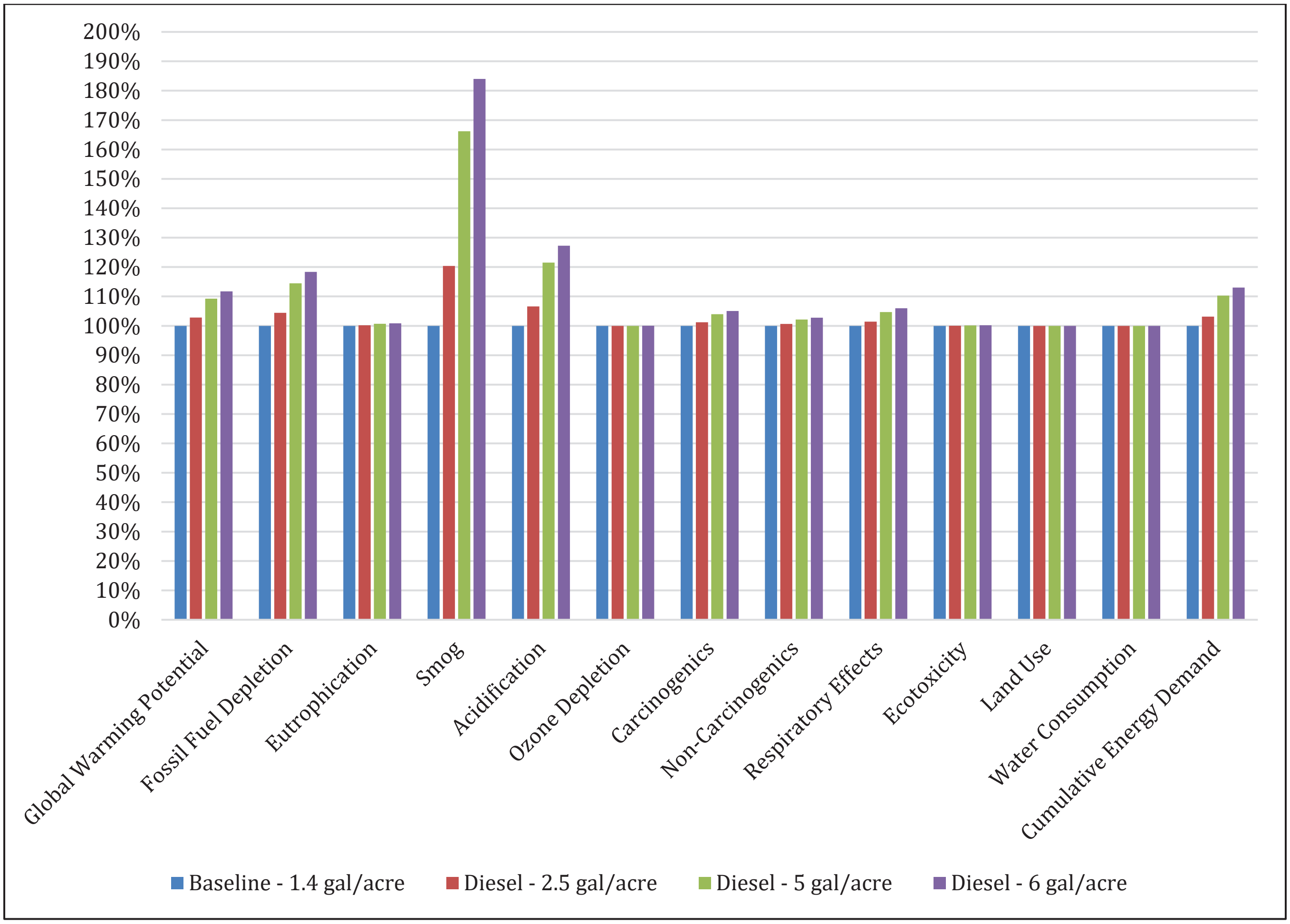


Figure 9.2 – Diesel Sensitivity Analysis, 1 kg of Soybeans

The effects of higher diesel concentrations remain relatively low in most impact categories except smog. This is due to the chemical reactions that take place when diesel is combusted. Overall impacts resulting from each of the different diesel quantities considered in this sensitivity analysis are included in Table 9.1 below.

Table 9.2 – Environmental Impacts of 1 kg of Soybeans with Different Diesel Concentrations

Impact Category	Unit	Baseline	2.5 gal/acre	5 gal/acre	6 gal/acre
Global Warming Potential	kg CO_2 eq	3.41E-01	3.50E-01	3.72E-01	3.81E-01
Fossil Fuel Depletion	MJ surplus	4.17E-01	4.36E-01	4.78E-01	4.94E-01
Eutrophication	kg N eq	3.79E-03	3.80E-03	3.81E-03	3.82E-03
Smog	kg O_3 eq	2.06E-02	2.48E-02	3.42E-02	3.79E-02
Acidification	kg SO_2 eq	2.00E-03	2.13E-03	2.42E-03	2.54E-03
Ozone Depletion	kg CFC-11 eq	3.11E-08	3.11E-08	3.11E-08	3.11E-08
Carcinogenics	CTUh	1.16E-08	1.18E-08	1.21E-08	1.22E-08
Non-Carcinogenics	CTUh	2.04E-07	2.05E-07	2.08E-07	2.09E-07
Respiratory Effects	kg $PM_{2.5}$ eq	1.88E-04	1.91E-04	1.97E-04	1.99E-04
Ecotoxicity	CTUe	5.97E+01	5.98E+01	5.98E+01	5.99E+01
Land Use	m^2a crop eq	1.77E+00	1.77E+00	1.77E+00	1.77E+00
Water Consumption	m^3	4.60E-02	4.60E-02	4.60E-02	4.60E-02
Cumulative Energy Demand	MJ	4.46E+00	4.60E+00	4.91E+00	5.04E+00

Since soybeans are the main drivers of impacts for soybean oil and meal, Figure 9.3 and Figure 9.4 show the impacts that result from these higher diesel concentrations. Table 9.3 and Table 9.4 detail the impact assessment results.

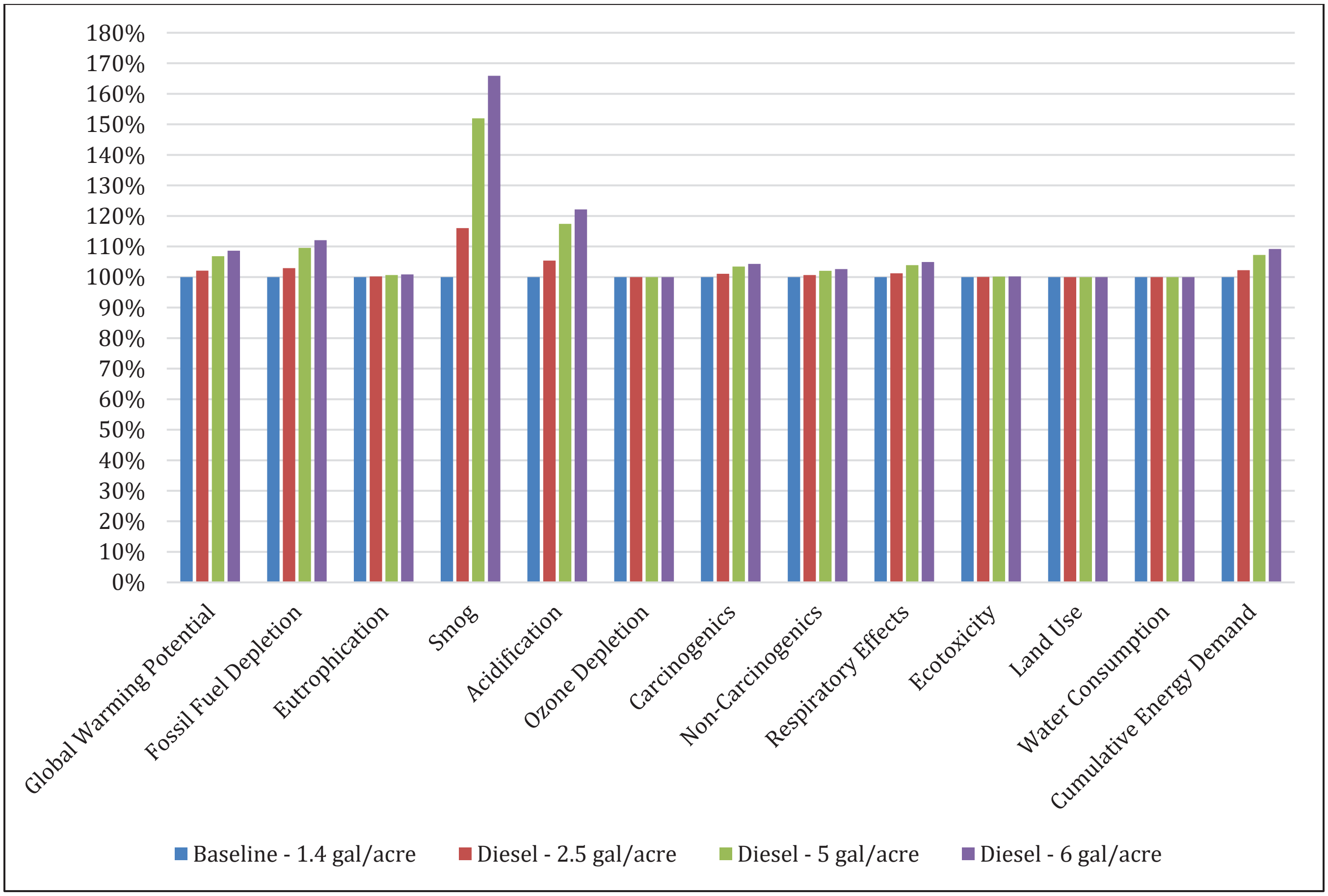


Figure 9.3 – Diesel Sensitivity Analysis, 1 kg of Crude Soy Oil or 1 kg of Soybean Meal

Table 9.3 – Environmental Impacts of 1 kg of Crude Soy Oil or Soybean Meal with Different Diesel Concentrations

Impact Category	Unit	Baseline	2.5 gal/acre	5 gal/acre	6 gal/acre
Global Warming Potential	kg CO_2 eq	4.78E-01	4.88E-01	5.11E-01	5.19E-01
Fossil Fuel Depletion	MJ surplus	6.57E-01	6.76E-01	7.19E-01	7.36E-01
Eutrophication	kg N eq	3.99E-03	4.00E-03	4.02E-03	4.02E-03
Smog	kg O_3 eq	2.71E-02	3.15E-02	4.12E-02	4.50E-02
Acidification	kg SO_2 eq	2.55E-03	2.68E-03	2.99E-03	3.11E-03
Ozone Depletion	kg CFC-11 eq	4.00E-08	4.00E-08	4.00E-08	4.00E-08
Carcinogenics	CTUh	1.40E-08	1.42E-08	1.45E-08	1.46E-08
Non-Carcinogenics	CTUh	2.23E-07	2.25E-07	2.28E-07	2.29E-07
Respiratory Effects	kg $PM_{2.5}$ eq	2.35E-04	2.38E-04	2.44E-04	2.47E-04
Ecotoxicity	CTUe	6.20E+01	6.20E+01	6.21E+01	6.21E+01
Land Use	m^2a crop eq	1.83E+00	1.83E+00	1.83E+00	1.83E+00
Water Consumption	m^3	4.81E-02	4.81E-02	4.81E-02	4.81E-02
Cumulative Energy Demand	MJ	6.52E+00	6.67E+00	6.99E+00	7.12E+00

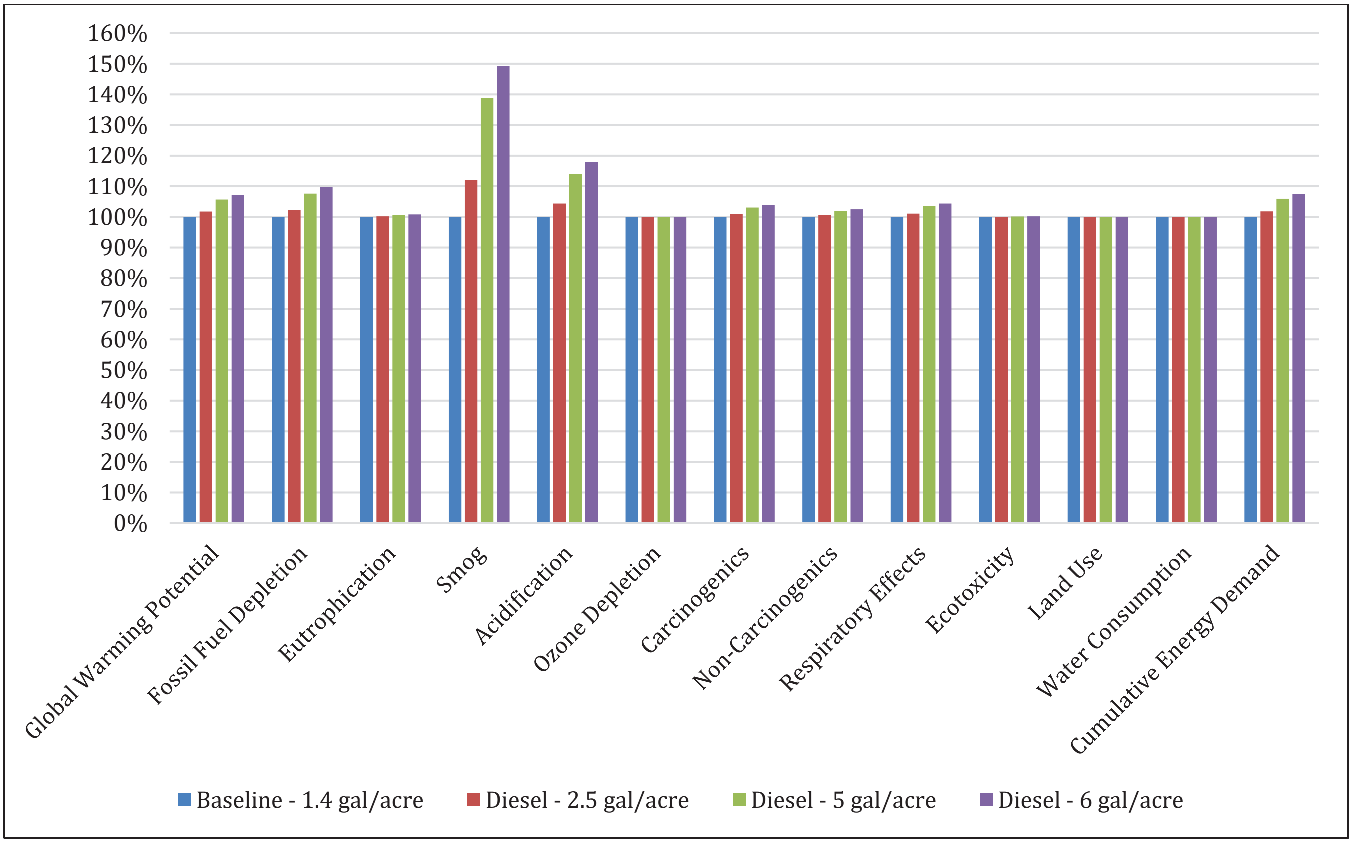


Figure 9.4 – Diesel Sensitivity Analysis, 1 kg of Refined Soy Oil

Table 9.4 – Environmental Impacts of 1 kg of Refined Soy Oil with Different Diesel Concentrations

Impact Category	Unit	Baseline	2.5 gal/acre	5 gal/acre	6 gal/acre
Global Warming Potential	kg CO_2 eq	5.88E-01	5.98E-01	6.21E-01	6.30E-01
Fossil Fuel Depletion	MJ surplus	8.37E-01	8.57E-01	9.01E-01	9.18E-01
Eutrophication	kg N eq	4.11E-03	4.12E-03	4.14E-03	4.15E-03
Smog	kg O_3 eq	3.70E-02	4.14E-02	5.13E-02	5.52E-02
Acidification	kg SO_2 eq	3.21E-03	3.35E-03	3.66E-03	3.79E-03
Ozone Depletion	kg CFC-11 eq	4.47E-08	4.47E-08	4.47E-08	4.47E-08
Carcinogenics	CTUh	1.59E-08	1.61E-08	1.64E-08	1.66E-08
Non-Carcinogenics	CTUh	2.37E-07	2.39E-07	2.42E-07	2.43E-07
Respiratory Effects	kg $PM_{2.5}$ eq	2.69E-04	2.72E-04	2.79E-04	2.81E-04
Ecotoxicity	CTUe	6.34E+01	6.34E+01	6.35E+01	6.35E+01
Land Use	m^2a crop eq	1.87E+00	1.87E+00	1.87E+00	1.87E+00
Water Consumption	m^3	4.99E-02	4.99E-02	4.99E-02	4.99E-02
Cumulative Energy Demand	MJ	8.16E+00	8.31E+00	8.64E+00	8.77E+00

The results are very similar to those for soybeans, with little to no significant change for most impact categories outside of diesel. However, as processing the soybeans or further processing the oil increases processing impacts, this results in lower overall changes when increasing the quantities of diesel used in farming.

9.3 Allocation Methods

Soybean meal and crude soybean oil are co-products during the soybean crushing and degumming stage. Energy and raw materials for this process were allocated to each product based on mass. This is consistent with the allocation method used in the 2015 Quantis LCA study, but other allocation methods, such as economic and by energy content, were also considered. Economic allocation consists of allocating energy and resources to each product based on their economic value in the market. This is a good alternative for allocation when products that would normally be considered waste streams are sold to other markets. This is also the allocation method recommended by EU Product Environmental Footprint Category Rules for Feed for Food Producing Animals. Allocation by energy content allocates materials and resources to each co-product based on their caloric content. This can be helpful when allocating for co-products that will be used to generate energy, such as oil. Figure 9.5 shows what percentage of the environmental impacts of each kg of processed soybeans are allocated to crude soy oil and to soybean meal according to each of the different allocation methods.

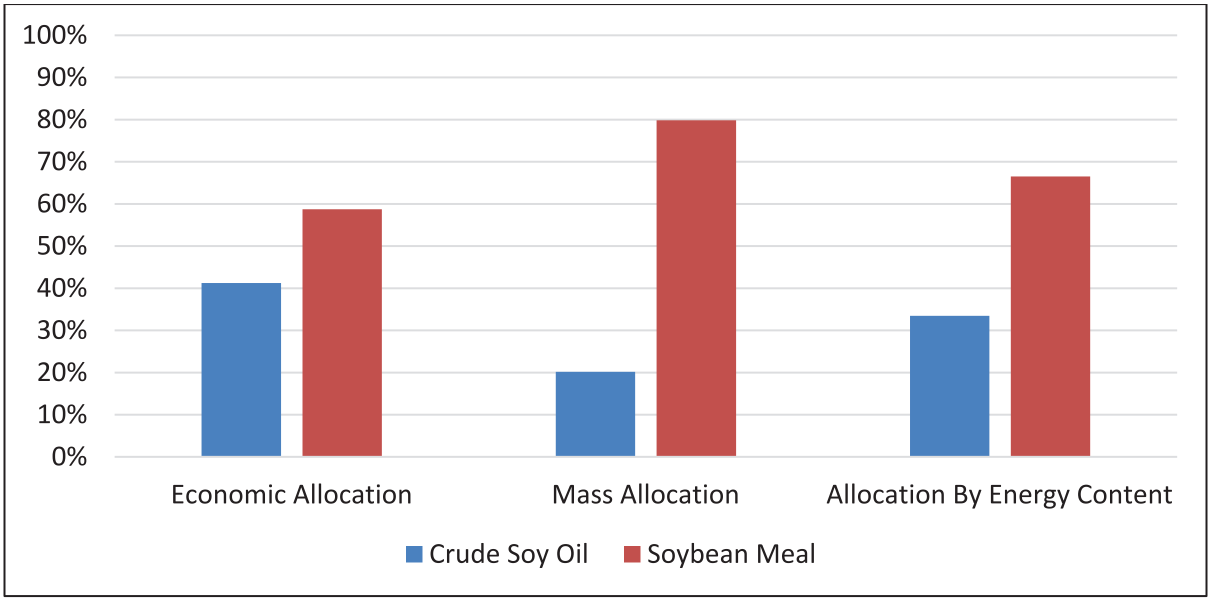


Figure 9.5 – Soybean Allocation Sensitivity Analysis – per kg of Soybeans

Soybeans are approximately 20% oil by mass, and the rest is turned into soymeal. Since soymeal is about 80% of the product, it has a higher allocation of impacts regardless of which method is used. Overall, the gap between their respective shares of impacts decreases with economic and energy content allocations: 20% oil/80% meal for mass allocation, 33% oil/67% meal for allocation by energy content, and 41% oil /59% meal for economic allocation. This happens because crude soy oil has a higher energy content than soybean meal, and it is significantly more expensive. Figure 9.6 portrays what percentage of impacts are allocated to soybean meal in proportion to those allocated to crude soy oil on a per-kilogram of each product basis.

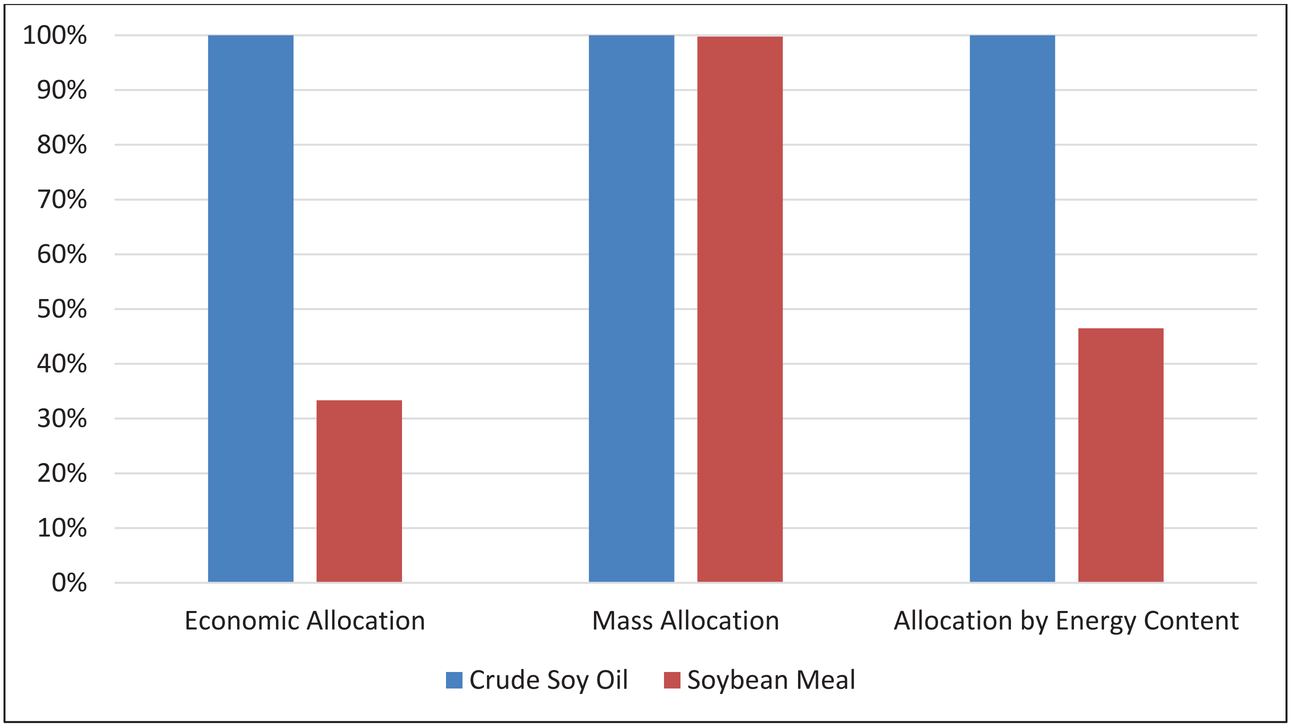


Figure 9.6 – Soybean Allocation Sensitivity Analysis – per kg of Product

10.0 Limitations

All energy and waste data for the soybean cultivation and harvesting were obtained directly from U.S. soybean farmers through collaboration with a third-party survey organization. The data for water usage and soil management practices were obtained from publicly available USDA surveys. Transportation distances and modes were collected directly from publicly available data published by the Soy Transportation Coalition. All processing and transportation data were collected and provided directly from NOPA. Fertilizer data were obtained from USDA. Efforts were made to check the data for internal consistency and to verify data with organization personnel.

The findings in this research are limited by the inherent uncertainty of creating a representative model through LCA. Many assumptions were made in modeling the product system with representative processes and datasets. The authors addressed the uncertainty in modeling decisions by conducting a mass balance and sensitivity analysis as the LCI model was being constructed (data verification/validation relative to cut-off criteria and study goals).

Geography, soil, and rainfall are just some of the key variables that influence soybean cultivation. This study attempts to capture the average case for soybean cultivation in the United States. The results for individual farming practices will differ based on their unique operations. Approaches such as organic farming result in different emissions profiles but may have lower yields, resulting in different impact profiles per unit produced. During the period of this study, organic soybeans represented 0.3% of the entire U.S. soybean production, thus, organic soybeans were excluded from the scope of this study. Additionally, crop rotation is a method commonly used in soybean cultivation to utilize the benefits of soil nutrients leftover from crop cultivation. This study allocated the field operation inventory based on harvest acreage; however, there are more nuances and complexities behind this system that makes this an oversimplified allocation. This was the most feasible way to account for the crop rotations but should be noted as a limitation of the study. While the farming survey is believed to be representative of the average soybean cultivation and harvesting practices, any additional data collection on soybean agricultural activity would strengthen the study. Similarly, yield and field applications are known to have a direct correlation on the environmental impact of agricultural products. A sensitivity analysis was conducted to evaluate how yield would affect the results presented; however, field application rates were not adjusted accordingly due to the complexity of soil nutrient maintenance. This is an opportunity for improvement of the study.

There exists limitation within the secondary data used for the material processes. One of these limitations is the reliance on assumptions, as established in Section 5.1, Section 6.1, and Section 7.1. Another limitation is from the methodology for obtaining primary data. The methodology relied on responses from many different farmers who were not instructed on how to specifically measure the data points. This approach can inherently carry some uncertainty based on the method of measurement. Due to the volume of responses collected, it was not feasible to host individual sessions on how to measure data; however, SSC conducted a thorough screening of the survey responses to eliminate any data points that were inconsistent with traditionally expected ranges. The ideal solution to this limitation would be to employ a single team to go to each survey site and measure the data points of interest using a pre-established methodology. This solution would require a multi-year planning and implementation procedure to collect all the necessary data for a production year, and thus would risk the temporal relevance of the study data. Due to this limitation, the data collection survey was not capable of including fertilizer application rates which have a direct correlation to the yield of production.

Additionally, primary data for this study were based on survey responses from 454 U.S. farmers across 16 states, which might not fully represent the entire soybean industry in the U.S. Attempts were made to expand the field of the survey by inviting 60,000 farmers across all soybean growing states; although, the third-party was unable to obtain responses from the larger sample set in the required timeline. This represents an opportunity for improvement in the study; however, given the temporal and geographic relevance of the data utilized, the study data are still deemed relevant. Similarly, these survey data represent two years of farm practices, but farm practices vary significantly based on numerous factors such as climate, crop rotations, and more. An opportunity for improvement of this study is to utilize three to five years' worth of data in future studies to strengthen the background datasets and mitigate these effects.

The method of data aggregation detailed in Section 6.1 and Section 7.1 present opportunities for improvement of the study in future iterations. Data aggregation based on weight of soybeans processed will eliminate misalignments in the processing mass balance that will improve the results of the study.

An additional opportunity for improvement for this study is the inclusion of soil carbon sequestration in the inventory. This study does not account for soil carbon sequestration due to the complexities of accounting for the carbon mass balance; however, accounting for soil sequestration that results from no-till and cover crop practices, as well as additional agricultural techniques, represents an opportunity to reduce the environmental footprint of the U.S. soybean farming practices.

The EU Product Environmental Footprint Category Rule (PEFCR) and the Global Feed LCI Institute recommend using economic allocation, rather than a mass-based allocation which was used in this study. This is acknowledged as a limitation to the study's applicability to European markets, however, this study is intended for North American markets, so a mass allocation was used to remain consistent with previous studies. Evaluating an economic allocation approach is recommended as an opportunity for improvement in future studies.

A quantitative uncertainty analysis was not conducted as it is only required for statements of comparative assertion per ISO 14044. Only the data quality assessment described in Section 3.0 to evaluate the uncertainty in use of inventory data has been carried out. The characterization models used to calculate midpoint and endpoint results also introduce uncertainty; however, there is currently no way to quantify this uncertainty in the software tools being used. Therefore, the overall uncertainties will be necessarily underestimated due to this uncharacterized uncertainty in the characterization models.

11.0 Conclusions

Soybean yields have trended upwards since 2010, from around an average return of 41 bushels per acre planted to 51 bushels per acre. This 24% increase is the result of improved farming practices that allow for more efficient use of land. As yields continue to increase, the environmental impacts for soybeans and soybean products will look more favorable on a per mass basis.

Based on the analysis and findings presented above, the soybean meal, crude soy oil, and refined soy oil life cycle impacts are strongly driven by the cultivation and harvesting of soybeans. More specifically, field operations, fertilizer, and herbicides. Further increasing yields, decreasing chemical applications, and reducing energy consumption would be the best way to reduce overall environmental impacts.

Higher soybean yields resulted in increased soybean meal and soy oil production during the same period from around 41 bushels/acre in 2010 to 51 bushels/acre in 2021. This 24% increase in production is also tied to increased global demand for U.S. soy-based feedstocks used in the manufacturing of food, feed, biofuels, and industrial products. Despite experiencing increased production, NOPA member companies have implemented numerous improvements to plant operations based on the latest technology available, plant design and U.S. regulatory requirements, which have resulted in overall process improvements between 2010 and present day.

As discussed in Section 3.0 the data used in this LCA was deemed to be as accurate as possible for quantifying a national average; however, there was high uncertainty in primary data as it pertains to the range of variation in survey responses. USB survey responses accounted for 0.45% of the total U.S. soybean production in 2020 and 2021 but were deemed to be a good representation of the U.S. soybean process as the majority of respondents were from the highest producing geographical regions. NOPA data were gathered from 52 (crushing and degumming) facilities and 27 (oil refining) co-located facilities, representing the vast majority of the U.S. soybean processing industry. SSC recommends utilizing three to five years of data in future iterations of this study in order to improve the quality of the data and reduce the uncertainty of primary data.

Based on the analysis and findings presented above, the life cycle impacts are strongly driven by energy inputs (e.g., electricity), transportation (e.g., rail, truck, barge), and raw material inputs (e.g., soybeans). Any opportunity to reduce energy consumption during the manufacturing process, as well as impacts resulting from the transportation of raw materials and final goods, would have a direct reduction in environmental impacts. Implementation costs and permitting restrictions may impact operational costs and consumers.

12.0 Recommendations

This information can prepare USB and NOPA for future sustainable supply chain requirements and can form the basis of marketing literature focused on environmental benefits. This LCA can also assist USB and NOPA members with greenhouse gas modeling and evaluating their own green product claims.

Opportunities to improve the relative impacts of U.S. soybeans, soybean meal, and soy oil production include:

- Enhancing seed quality to improve soybean yields and protein content to maximize value of U.S. soybean products.
- Guiding farmers to adopt sustainable growing practices through implementation of climate-smart technologies.
- Reducing consumption of high-carbon fuels (e.g., coal, petroleum-based diesel, kerosene).
- Modifying equipment and revising operating procedures, where practicable, to improve energy efficiency at processing facilities and refineries.

At this time, SSC recommends the publication of this study and corresponding data for U.S. soybean, soybean meal and soy oil; and for future use by USB and NOPA as the basis for sharing LCA data if market conditions, government requirements, or customers require public release of the data.

13.0 References

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Appendix A: Comparison to Previous Study[8]

The analysis presented in this appendix is focused on evaluating the environmental impact differences between the two studies. Impact categories for comparison were limited to what was reported in the 2015 study, so the only impact categories evaluated in this section were TRACI impacts. Data collection and allocation the two studies were similar in respect to methodology. The methodological consistencies between the recent studies were intentionally kept similar where relevant and appropriate to ensure a level of comparability exists between studies. USB and NOPA intend to use this study internally to evaluate the effect of organizational changes that have been implemented geared toward reductions in environmental impacts. The comparison of the results cannot be entirely attributed to the organizational improvements that USB and NOPA have implemented, due to the improvements in LCA datasets and methodologies, as well as the differences in the LCA methods employed by the LCA practitioners; however, the impact of these changes should not be understated and are considered to have a considerable contribution to the comparison.

The main driving factors for each study stayed consistent. In both studies:

- Field operations and chemical application were the main impact drivers for soybean production.
- Soybean cultivation was the main impact driver for the production of soybean meal, crude soy oil, and refined soy oil.

A.1 Soybean Comparison: 2015 and 2021

A comparison of TRACI environmental impacts of soybean agriculture from 2015 and 2021 is illustrated in Figure A.1 below.

[8] The processing data in the 2015 study were collected in 2010 and reevaluated in 2015 with no changes. The 2015 dataset for refined soybean oil leveraged existing databases and publicly available information; including, the Ecoinvent v3 dataset for soybean oil and meal, and the Omnitech 2010 study for soybean processing.

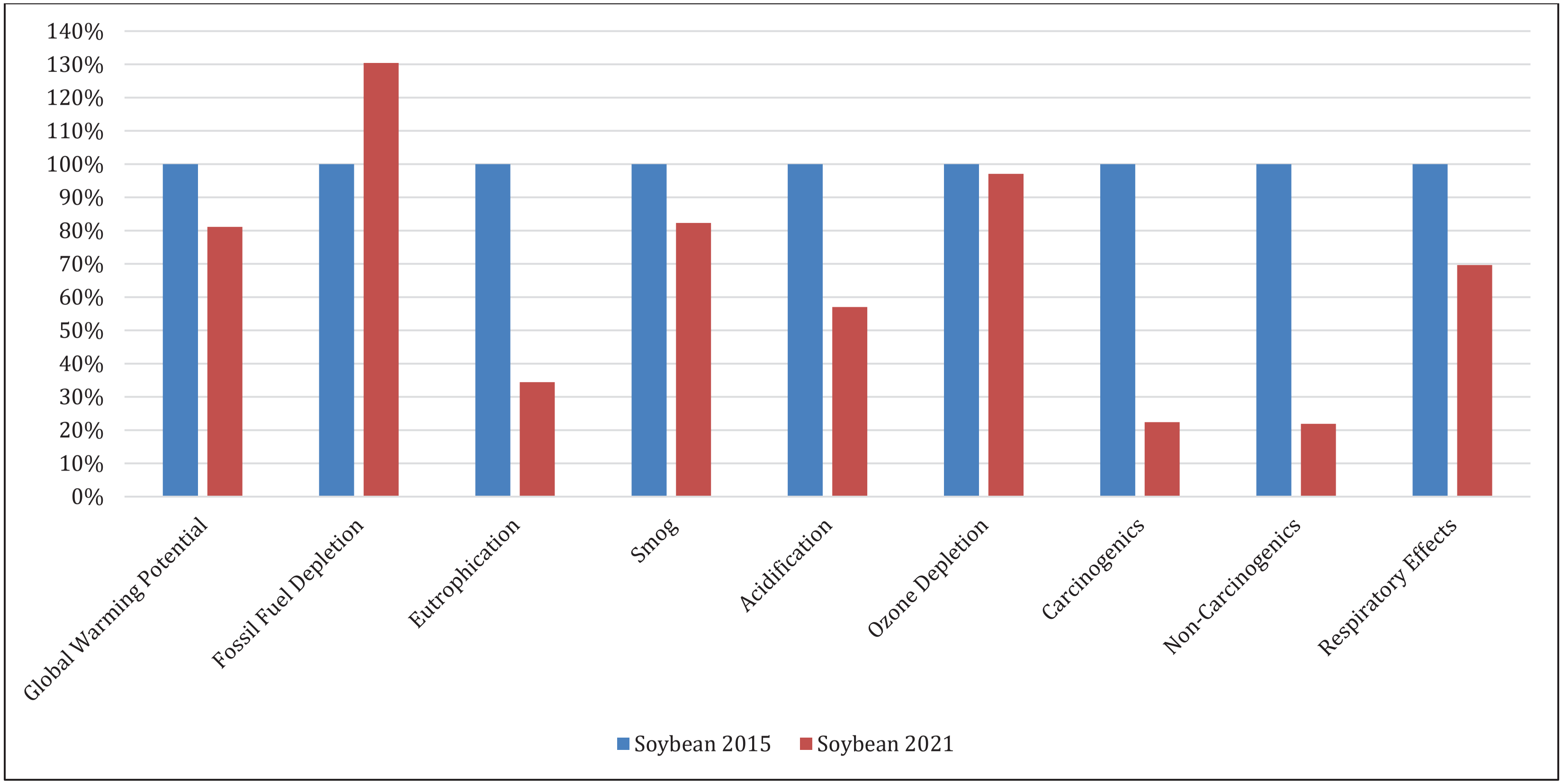


Figure A. 1 – 2021 Values Compared to 2015 Values

The figure above demonstrates that, in general, impacts of soybean production have decreased over the last 5 years. This is due to more efficient farming equipment and farming practices, as well as increasing yields. Yields went from 41 bushels per acre in 2015 to 51 bushels per acre in 2021, which significantly contributed towards impact reduction. Changes in farming practice to use lower impact fuels, such as natural gas, and reduction in pesticide use reduced impacts when compared with the previous study. Overall energy consumption decreased by around 10% per acre, further contributing to the reductions observed. The one exception to this trend is Fossil Fuel Depletion (FFD), in which the impact increased slightly. This is because the use of natural gas for the soybean drying process increased to replace other fossil fuels, such as propane. There are fewer natural gas reserves, which drives FFD up, but since natural gas is a cleaner fossil fuel, it is still better for the environment and reduces overall emissions.

A.2 Soybean Meal and Crude Soy Oil Comparison: 2015 and 2021

The impacts of soybean processing for crude soy oil and soybean meal are illustrated in Figure A.2 and Figure A.3 respectively.

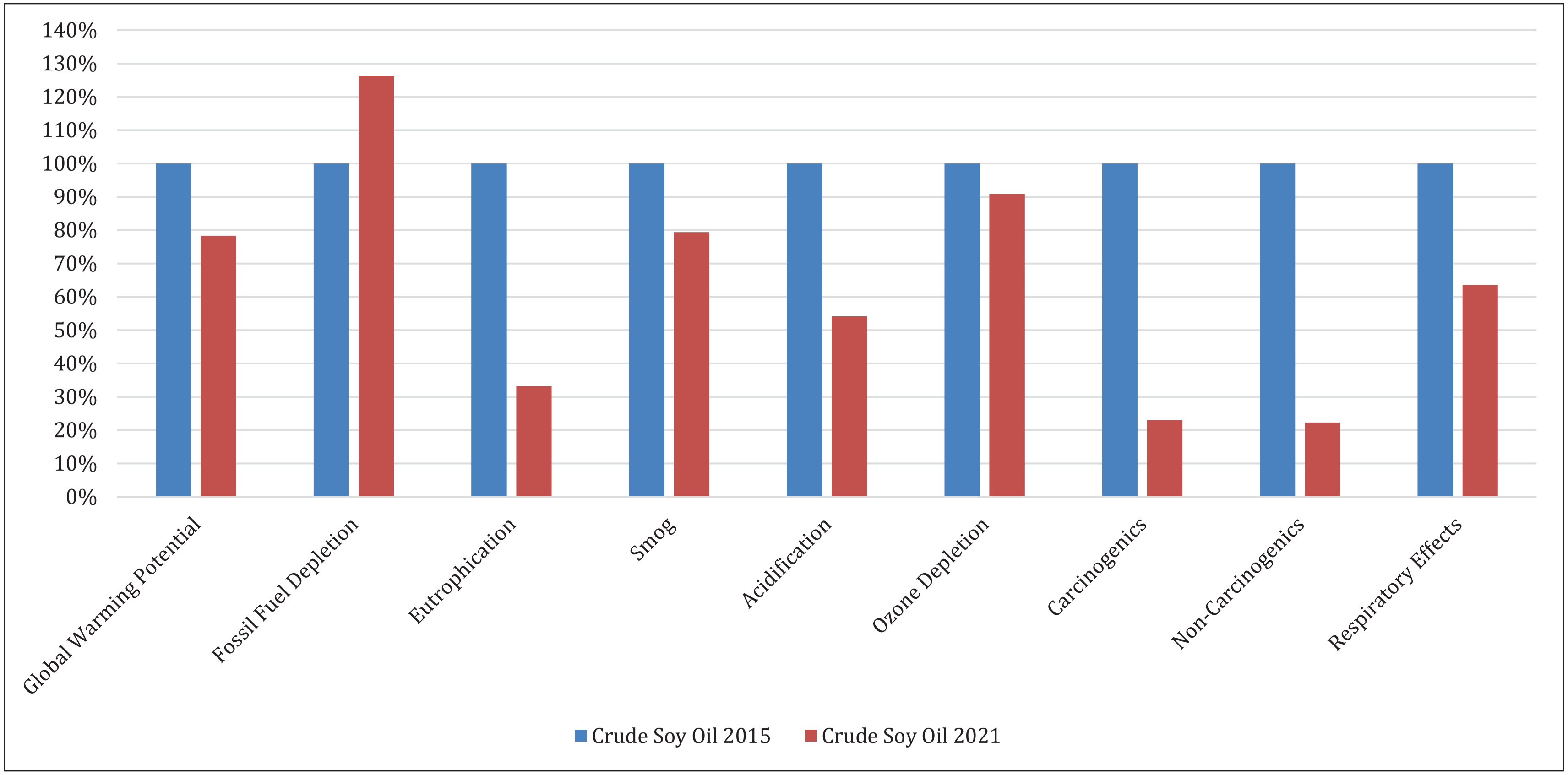


Figure A. 2 – Crude Soy Oil in 2015 vs 2021

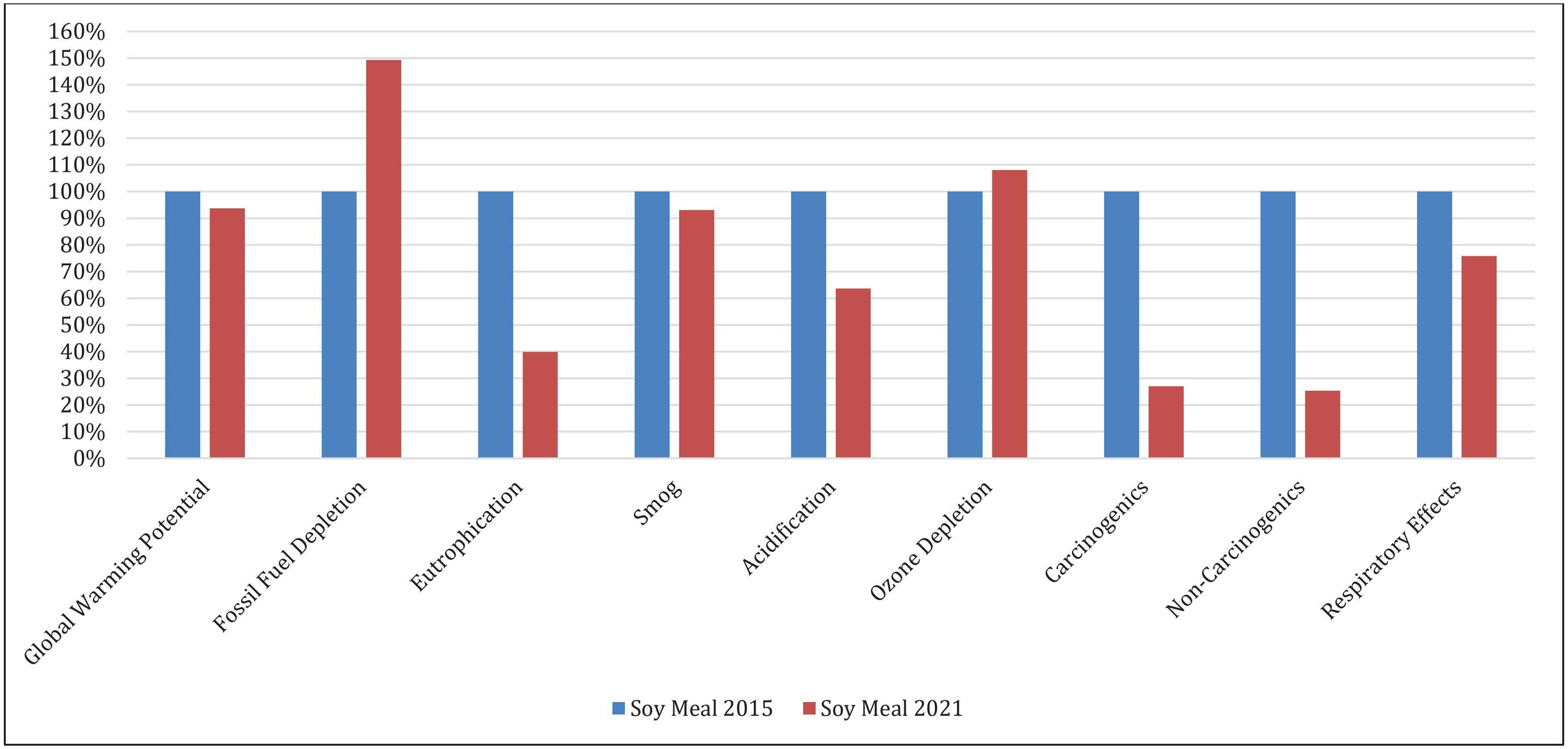


Figure A. 3 – Soybean Meal in 2015 vs 2021

Overall, impacts have decreased throughout most categories, closely following the results from comparing 2015 soybean agriculture to 2021 soybean agriculture. This is partially due to the embodied impacts of the soybeans that have declined over the last several years, and partially because soybean processing technologies have been improving and becoming more efficient. The one exception is fossil fuel depletion, which is a result of the shift to natural gas as a fuel source in farming practices.

A.3 Soy Oil Refining Comparison: 2015 and 2021

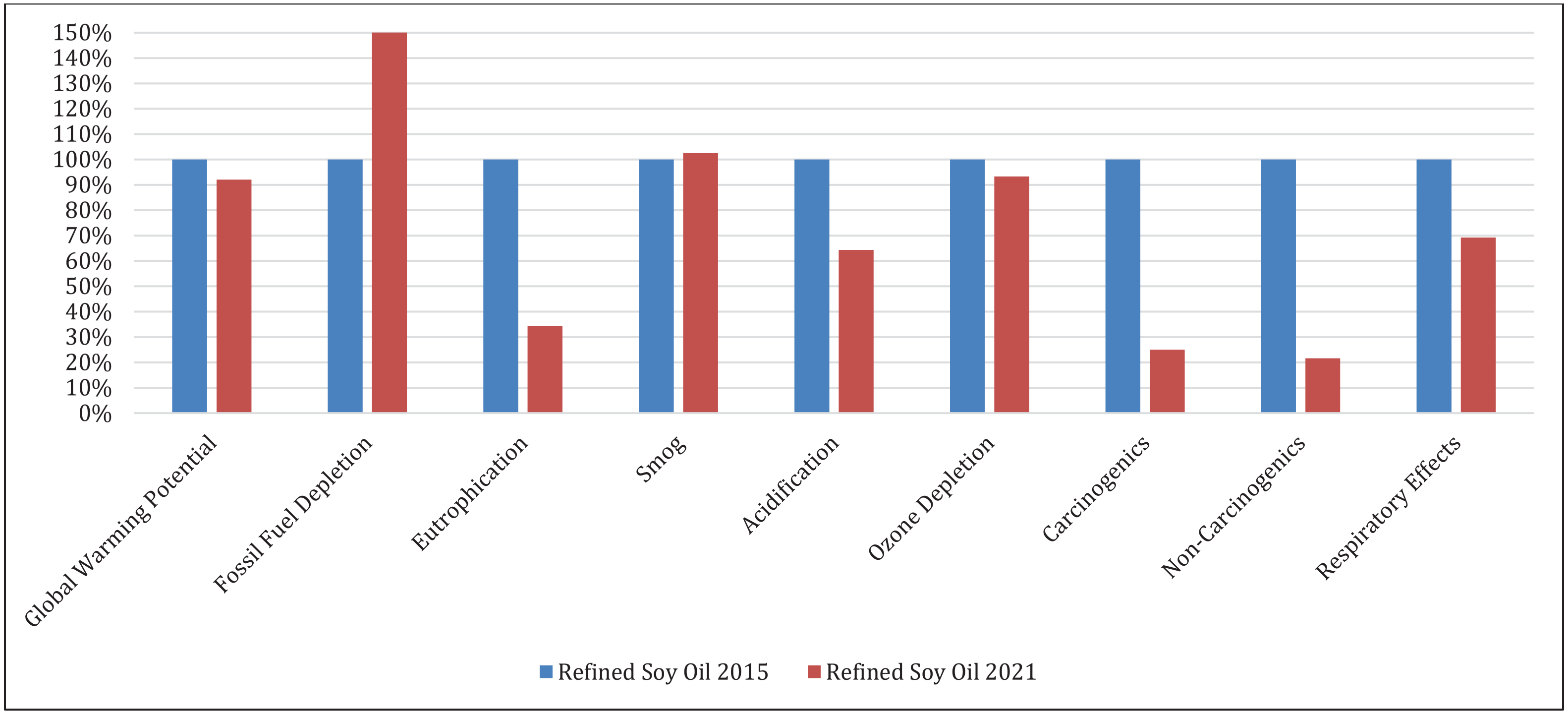


Figure A. 4 – Refined Soy Oil in 2015 vs 2021

Following suit with the soybean product trends described previously, there is a reduction of impacts across the spectrum of impact categories, again with the exception of fossil fuel depletion. The explanation for the previous trends holds true for refined soy oil, since it is downstream of the process flow. In addition, improvements in the refining process contribute to more significant reductions observed in Figure A. 4.

Note: 2015 LCA data was not exclusive to co-located refineries.

Quantified comparative values can be found in Table A. 1.

A.3 Soybean Products Comparison Table: 2015 and 2021

Table A. 1 – Comparison to Previous Study

		Soybeans		Crude Soy Oil		Soy Meal		Refined Soy Oil	
Impact Category	**Unit**	**2015**	**2021**	**2015**	**2021**	**2015**	**2021**	**2015**	**2021**
Global Warming Potential	kg CO_2 eq	4.20E-01	3.41E-01	6.10E-01	4.78E-01	5.10E-01	4.78E-01	6.40E-01	5.89E-01
Fossil Fuel Depletion	MJ surplus	3.20E-01	4.17E-01	5.20E-01	6.57E-01	4.40E-01	6.57E-01	5.50E-01	8.39E-01
Eutrophication	kg N eq	1.10E-02	3.79E-03	1.20E-02	3.99E-03	1.00E-02	3.99E-03	1.20E-02	4.12E-03
Smog	kg O_3 eq	2.50E-02	2.06E-02	3.40E-02	2.70E-02	2.90E-02	2.70E-02	3.60E-02	3.69E-02
Acidification	kg SO_2 eq	3.50E-03	2.00E-03	4.70E-03	2.55E-03	4.00E-03	2.55E-03	5.00E-03	3.22E-03
Ozone Depletion	kg CFC-11 eq	3.20E-08	3.11E-08	4.40E-08	4.00E-08	3.70E-08	4.00E-08	4.80E-08	4.48E-08
Carcinogenics	CTUh	5.20E-08	1.16E-08	6.10E-08	1.40E-08	5.20E-08	1.40E-08	6.40E-08	1.60E-08
Non-Carcinogenics	CTUh	9.30E-07	2.04E-07	1.00E-06	2.23E-07	8.80E-07	2.23E-07	1.10E-06	2.38E-07
Respiratory Effects	kg $PM_{2.5}$ eq	2.70E-04	1.88E-04	3.70E-04	2.35E-04	3.10E-04	2.35E-04	3.90E-04	2.70E-04

Appendix B: Data Quality Tables

Table B. 1 – Data Quality Table for Soybean Cultivation

<table>
<tr><th>Component</th><th>Input</th><th>Database(s) and Source</th><th>Temporal Information</th><th>Regional Coverage</th><th>Technology Coverage</th><th>Data Type</th></tr>
<tr><td rowspan="4">Fertilizer</td><td>inorganic potassium fertiliser, as K2O {RoW}| nutrient supply from potash salt | Cut-off, U</td><td>Ecoinvent 3</td><td>2020</td><td>Rest of World</td><td>Supply of nutrients from ''potash salt'' for fertiliser use</td><td>Secondary</td></tr>
<tr><td>inorganic nitrogen fertiliser, as N {RNA}| nutrient supply from urea | Cut-off, U</td><td>Ecoinvent 3</td><td>2020</td><td>North America</td><td>Supply of nutrients from ''urea'' for fertiliser use.</td><td>Secondary</td></tr>
<tr><td>Sulfur {GLO}| market for | Cut-off, U</td><td>Ecoinvent 3</td><td>2020</td><td>Global</td><td>This activity starts at the gate of the activities that produce sulfur within the geography of this dataset, with the product ready for transportation. This activity ends with the supply of 1 kg of sulfur to the consumers of this product.</td><td>Secondary</td></tr>
<tr><td>inorganic phosphorus fertiliser, as P2O5 {RoW}| nutrient supply from triple superphosphate | Cut-off, U</td><td>Ecoinvent 3</td><td>2020</td><td>Rest of World</td><td>Supply of nutrients from ''triple superphosphate'' for fertiliser use.</td><td>Secondary</td></tr>
<tr><td rowspan="2">Field</td><td>Occupation, annual crop, conventional tillage</td><td>Inputs from Nature</td><td>N/A</td><td>N/A</td><td>N/A</td><td>Secondary</td></tr>
<tr><td>Heat, district or industrial, natural gas {GLO}| market group for | Cut-off, U</td><td>Ecoinvent 3</td><td>2020</td><td>Global</td><td>The module includes fuel input from high pressure (RER) network, infrastructure (boiler), emissions to air and water, and electricity needed for operation.</td><td>Secondary</td></tr>
</table>

<table>
<tr><th>Component</th><th>Input</th><th>Database(s) and Source</th><th>Temporal Information</th><th>Regional Coverage</th><th>Technology Coverage</th><th>Data Type</th></tr>
<tr><td></td><td>Electricity, at grid, US/US 2020</td><td>USLCI</td><td>2020</td><td>United States, excluding Alaska and Hawaii</td><td>Representative of year 2000 mix of fuels used for utility electricity generation in the U.S. Fuels include coals, fuel oil, nuclear, hydroelectric, and unconventional energy sources. Data are weighted according to percent share of consumption. Includes line loss factor of 9.91%, which represents the difference between electricity generated and electricity sold.
SSC modified to represent the average US grid mix in 2020 based on EPA data</td><td>Secondary</td></tr>
<tr><td></td><td>Diesel, combusted in industrial equipment/US</td><td>USLCI</td><td>2015</td><td>United States</td><td>Diesel combustion in industrial applications such as mobile refrigeration units, generators, pumps, and portable well-drilling equipment</td><td>Secondary</td></tr>
<tr><td></td><td>Gasoline, combusted in equipment/US</td><td>Sustainable Solutions</td><td>2019</td><td>United States</td><td>Gasoline combustion in equipment such as mobile refrigeration units, generators, pumps, and portable well-drilling equipment.</td><td>Secondary</td></tr>
<tr><td></td><td>Propane, burned in building machine {GLO}| market for | Cut-off, U</td><td>Ecoinvent 3</td><td>2020</td><td>Global</td><td>The module describes the use of liquid propane fuel extracted for natural gas to provide the service of burning 1 MJ in a building machine.</td><td>Secondary</td></tr>
</table>

Component	Input	Database(s) and Source	Temporal Information	Regional Coverage	Technology Coverage	Data Type
	irrigation {US}| irrigation, surface | Cut-off, U	Ecoinvent 3	2020	United States	Surface irrigation is the application of water by gravity flow to the surface of the field.	Secondary
Fungicide	Fungicide, at plant/RER Mass	Agri-footprint 5	1987	N/A	Fungicide production. Dataset was the only available option.	Secondary
Herbicide	Glyphosate {RoW}| production | Cut-off, U	Ecoinvent 3	2020	Rest of World	Production of glyphosate including materials, energy uses, infrastructure and emissions.	Secondary
	Atrazine {RoW}| production | Cut-off, U	Ecoinvent 3	2020	Rest of World	Production of atrazine	Secondary
	Metolachlor {RoW}| production | Cut-off, U	Ecoinvent 3	2020	Rest of World	Production of metolachlor including materials, energy uses, infrastructure and emissions.	Secondary
	Alachlor, at plant/RER Mass	Agri-footprint	2017	RER	Pesticide Production	Secondary
	Trifluralin, at plant/RER Mass	Agri-footprint	2017	RER	Pesticide Production	Secondary
	Herbicide, at plant/RER Mass	Agri-footprint	2017	RER	Pesticide Production	Secondary
	Dicamba, at plant/RER Mass	Agri-footprint 5	2017	RER	Pesticide Production	Secondary
	Paraquat, at plant/RER Mass	Agri-footprint 5	2017	RER	Pesticide Production	Secondary

Component	Input	Database(s) and Source	Temporal Information	Regional Coverage	Technology Coverage	Data Type
	Pendimethalin {RoW}| production | Cut-off, U	Ecoinvent 3	2020	Rest of World	Production of pendimethalin including materials, energy uses, infrastructure and emissions.	Secondary
Insecticide	Insecticide, at plant/RER Mass	Agri-footprint		RER	Pesticide Production	Secondary

Component	Input	Database(s) and Source	Temporal Information	Regional Coverage	Technology Coverage	Data Type
Rail	Transport, train, diesel powered/US	USLCI	2015	United States	Combustion of diesel in a locomotive.	Secondary
Truck	Transport, combination truck, average fuel mix /US	USLCI	2015	United States	Mixing process for combination truck, assuming 100% diesel and 0% gasoline	Secondary
Barge	Transport, barge, average fuel mix/US	USLCI	2015	United States	Mixing process for barge transport (78% residual and 22% diesel)	Secondary

Table B. 2 - Data Quality Table for Soybean Meal and Crude Soy Oil Manufacturing

Component	Input	Database(s) and Source	Temporal Information	Regional Coverage	Technology Coverage	Data Type
Natural Gas	Heat, district or industrial, natural gas {GLO}| market group for | Cut-off, U	Ecoinvent 3	2020	Global	The module includes fuel input from high pressure (RER) network, infrastructure (boiler), emissions to air and water, and electricity needed for operation.	Secondary
Coal	Heat, district or industrial, other than natural gas {RoW}| heat production, at coal coke industrial furnace 1-10MW | Cut-off, U	Ecoinvent 3	2020	Rest of World	Combustion of coke coal in an industrial furnace is modeled based on an combustion of hard coal in an industrial boiler in early 1990s. Stoker boiler used as reference technology.	Secondary
Biomass	Heat, onsite boiler, softwood mill average, NE-NC/MJ/RNA	USLCI	2006	United States	Steam and Air-Conditioning Supply. Average technology.	Secondary
Other Fuels	Diesel, burned in agricultural machinery {GLO}| diesel, burned in agricultural machinery | Cut-off, U	Ecoinvent 3	2020	Global	1 MJ (0.0222 kg) diesel burned for running a tractor with a trailer. The inventory represents heavy road transport with tractor and 2 tyre-trailers of max. 8 t loading capacity each. Mean velocity when loaded = 15 km/h. Mean velocity when empty = 25 km/h. Empty return over the same distance included.	Secondary
Water	Tap water {RoW}| market for | Cut-off, U	Ecoinvent 3	2020	Rest of World	This activity starts from tap water, under pressure, at tap water treatment plant and fed into the tap water distribution network. This activity ends	Secondary

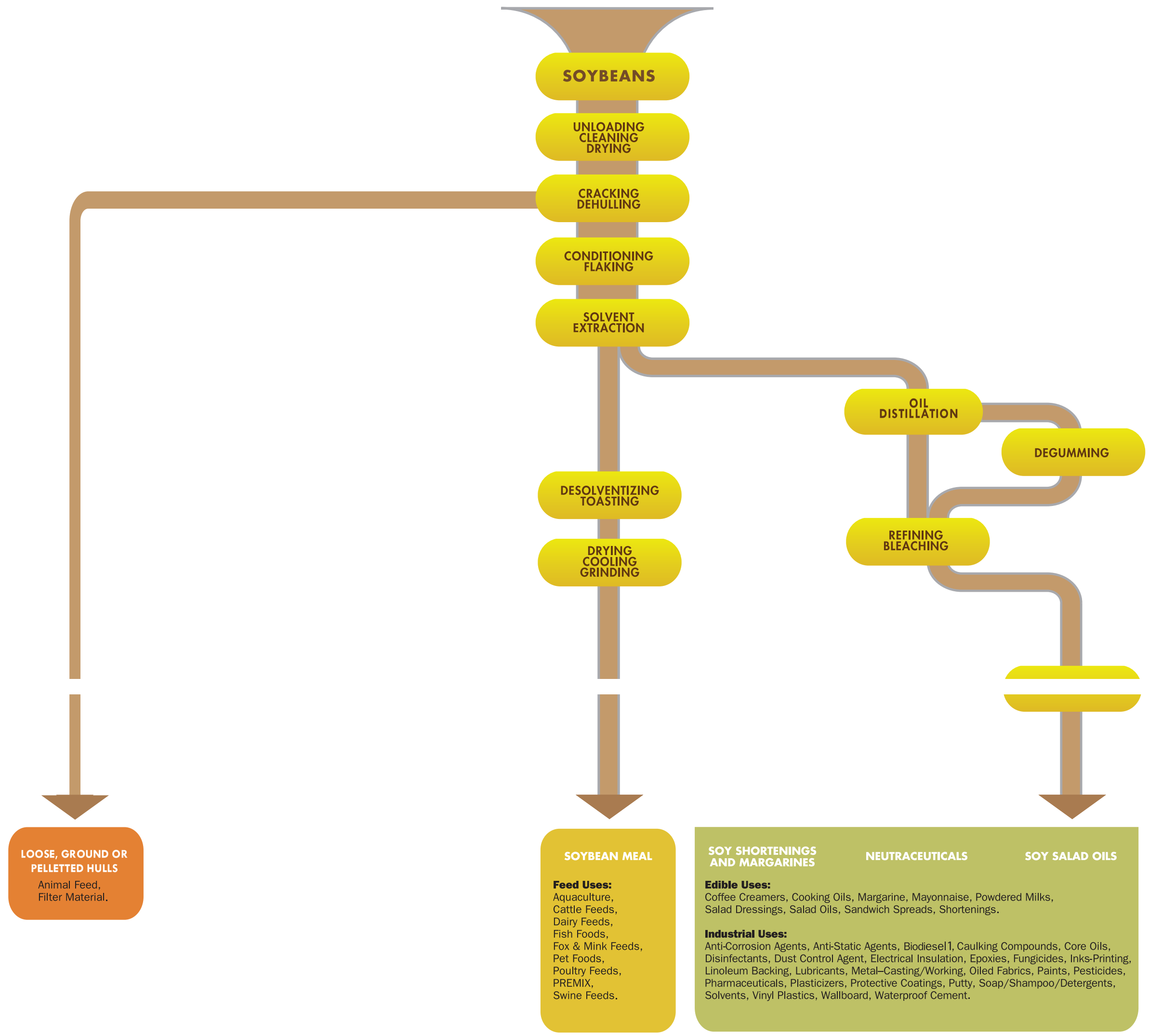
Component	Input	Database(s) and Source	Temporal Information	Regional Coverage	Technology Coverage	Data Type
					with 1 kg of water at consumer (industrial or household).	
Electricity	Electricity, at grid, US/US 2020	USLCI	2020	United States, excluding Alaska and Hawaii	Representative of year 2000 mix of fuels used for utility electricity generation in the U.S. Fuels include coals, fuel oil, nuclear, hydroelectric, and unconventional energy sources. Data are weighted according to percent share of consumption. Includes line loss factor of 9.91%, which represents the difference between electricity generated and electricity sold. SSC modified to represent the average US grid mix in 2020 based on EPA data	Secondary
Purchased Steam	Heat, from steam, in chemical industry {RoW}| steam production, as energy carrier, in chemical industry | Cut-off, U	Ecoinvent 3	2020	Rest of World	Production of 1 MJ of steam used for heating in the chemical and petrochemical industry. The inventory represents the average fuel mix used for steam production in the chemical and petrochemical industry.	Secondary
Purchased Steam from Natural Gas	Process steam from natural gas, heat plant, consumption mix, at plant, MJ, EU-27 S System - Copied from ELCD	Agri-footprint 5	2015	EU-27	The process steam is produced in a natural gas specific heat plant. Provision of 1 MJ of process steam at heat plant for final consumers.	Secondary

Table B. 3 - Data Quality Table for Refined Soy Oil

Component	Input	Database(s) and Source	Temporal Information	Regional Coverage	Technology Coverage	Data Type
Sodium Hydroxyde	Sodium hydroxide	Inputs from nature	N/A	N/A	N/A	Secondary
Bleaching Earth	Bleaching earth, at plant/RER Mass	Agri-footprint 5	2009	N/A	Bleaching earth production. Dataset was the only available option.	Secondary
Electricity	Electricity, at grid, US/US 2020	USLCI	2020	United States, excluding Alaska and Hawaii	Representative of year 2000 mix of fuels used for utility electricity generation in the U.S. Fuels include coals, fuel oil, nuclear, hydroelectric, and unconventional energy sources. Data are weighted according to percent share of consumption. Includes line loss factor of 9.91%, which represents the difference between electricity generated and electricity sold. SSC modified to represent the average US grid mix in 2020 based on EPA data	Secondary
Natural Gas	Heat, district or industrial, natural gas {GLO}| market group for | Cut-off, U	Ecoinvent 3	2020	Global	The module includes fuel input from high pressure (RER) network, infrastructure (boiler), emissions to air and water, and electricity needed for operation.	Secondary

Component	Input	Database(s) and Source	Temporal Information	Regional Coverage	Technology Coverage	Data Type
Coal	Heat, district or industrial, other than natural gas {RoW}| heat production, at coal coke industrial furnace 1-10MW | Cut-off, U	Ecoinvent 3	2020	Rest of World	Combustion of coke coal in an industrial furnace is modeled based on an combustion of hard coal in an industrial boiler in early 1990s. Stoker boiler used as reference technology.	Secondary
Other Fuels	Diesel, burned in agricultural machinery {GLO}| diesel, burned in agricultural machinery | Cut-off, U	Ecoinvent 3	2020	Global	1 MJ (0.0222 kg) diesel burned for running a tractor with a trailer. The inventory represents heavy road transport with tractor and 2 tyre-trailers of max. 8 t loading capacity each. Mean velocity when loaded = 15 km/h. Mean velocity when empty = 25 km/h. Empty return over the same distance included.	Secondary
Water	Tap water {RoW}| market for | Cut-off, U	Ecoinvent 3	2020	Rest of World	This activity starts from tap water, under pressure, at tap water treatment plant and fed into the tap water distribution network. This activity ends with 1 kg of water at consumer (industrial or household).	Secondary

Appendix C: Soybean Meal and Soybean Oil Process Flow Diagram



NOTE: The National Oilseed Processors Association (NOPA) represents the U.S. soybean, canola, flaxseed, sunflower seed and safflower seed crushing industries. This flowchart is an illustrative diagram of standardized steps employed in the processing of soybeans. The steps employed may vary from plant to plant and from oilseed to oilseed.

Figure C. 1 – Process Flow Diagram for Soybean Processing

Appendix D: Adjusted Crude Soy Oil and Soybean Meal LCI

Table D. 1 - Crude Soy Oil and Soybean Meal LCI Adjusted for 58.6 lbs./bushel

Energy Inputs	Unit	Quantity per kg of Soybean Meal or Crude Soy Oil
Electricity	kWh	3.90E-02
Natural Gas	mmbtu	6.71E-04
Coal	mmbtu	5.55E-05
Biomass	mmbtu	5.18E-06
Other Fuels	mmbtu	8.13E-06
Purchased Steam	mmbtu	5.20E-04
Material Inputs	**Unit**	**Quantity per kg of Soybean Meal or Crude Soy Oil**
Soybeans	kg	1.00E+00
Hexane	kg	5.52E-04
Water	**Unit**	**Quantity per kg of Soybean Meal or Crude Soy Oil**
Inflow	L	3.54E-01
Wastewater	L	1.41E-01
Evaporated Water	L	2.13E-01
Transportation	**Unit**	**Quantity per kg of Soybean Meal or Crude Soy Oil**
Truck	kgkm	7.01E+01
Rail	kgkm	4.69E+01
Barge	kgkm	2.15E+01
Emissions	**Unit**	**Quantity per kg of Soybean Meal or Crude Soy Oil**
Hexane	kg	5.52E-04
Note: Soybean meal and crude oil are co-products resulting from crushing operations. Consequently, inventory data was unable to be allocated to product specific processes and the product values are the same.		

Marty Heller
AgResilience Consulting, LLC
Traverse City, MI 49686

agresilienceconsulting@
gmail.com

January 21, 2024

Marquis Miller
Sustainable Solutions Corporation
155 Railroad Plaza, Suite 203
Royersford, PA 19468 USA

Enclosure: Review Table

Critical Review Statement: "Life Cycle Assessment of U.S. Soybeans, Soybean Meal, and Soy Oil"

This memo serves as a Review Statement for the critical review of the study performed by Sustainable Solutions Corporation for United Soybean Board and the national Oilseed Processors Association.

The Scope of the Critical Review

As the LCA does not involve a product comparison and will not be used to support a comparative assertion, based on ISO 14044 recommendations, a review by a single external expert was deemed sufficient. The reviewer had the task to assess whether:

- the methods used to carry out the LCA are consistent with ISO 14044:2006 and ISO/TS 14071: 2014
- the methods used to carry out the LCA are scientifically and technically valid,
- the data used are appropriate and reasonable in relation to the goal of the study,
- the interpretations reflect the limitations identified and the goal of the study, and
- the study report is transparent and consistent.

The review of the study was performed to demonstrate conformance with the following standards:

- International Organization for Standardization. (2006). *Environmental management -- Life cycle assessment – Principles and framework* (ISO 14040:2006).
- International Organization for Standardization. (2006). *Environmental management -- Life cycle assessment -- Requirements and guidelines* (ISO 14044:2006).
- International Organization for Standardization. (2014). *Environmental management -- Life cycle assessment -- Critical review processes and reviewer competencies: Additional requirements and guidelines to ISO 14044:2006*. (ISO/TS 14071:2014).

The independent third-party critical review was conducted by Marty Heller, PhD, AgResilience Consulting, LLC

REVIEW SCOPE

The intent of this review was to provide an independent third-party external critical review of a LCA study report in conformance with the aforementioned ISO standards. This review did not include an assessment of the Life Cycle Inventory (LCI) model; however, it did include a critical review of the general approach to complete the study and consideration of the individual datasets applied.

REVIEW PROCESS

The critical review process of the LCA study was conducted to ensure conformance to the International Organization for Standardization (ISO) 14040/44 LCA standards following the review processes and procedures per ISO 14071. The primary task of the review process per ISO 14044 review requirements is to ensure the general requirements for conducting LCA studies are met:

- *Are methods used to carry out the LCA consistent with ISO 14040/14044 standards?*
- *Are methods used to carry out the LCA scientifically and technically valid?*
- *Are data used appropriate and reasonable in relation to the goal of the study?*
- *Do interpretations reflect limitations identified and the goal of the study?*
- *Was the study report transparent and consistent?*

The review process involved the review of all requirements set forth by the applicable ISO standards, cataloged in a comprehensive review table along with editorial comments. There were two rounds of comments by the reviewer submitted to the LCA practitioner. Responses by the LCA practitioner to each issue raised were resolved and acknowledged by the reviewer to have been satisfactorily addressed.
The following summarizes the key comment topics raised by the reviewers that were deemed important for appreciating the nuances and complexities of the study:

- Early rounds of review identified incomplete accounting of nitrous oxide emissions associated with anthropogenic additions of nitrogen to soil. These were sufficiently addressed and updated by the practitioner.
- Primary data used in the LCA were based on a survey of US growers with limited response rate and based on only two years of farm practices. In addition, the survey covered only a portion of the data necessary for the LCA, with the remainder supplemented by USDA statistics, introducing a potential disconnect between the survey population responses and dependent data such as yield. These limitations have been acknowledged in the report.
- The mass allocation method chosen to allocate impacts between co-products of crushing (soybean meal and soybean oil) are not aligned with recommendations from the EU Product Environmental Footprint Category Rule for Feed from Food Producing Animals and the Global Feed LCI Institute. Therefore, care must be taken in making comparisons with results aligned with these international standards. This limitation has been acknowledged in the study.

CRITICAL REVIEW STATEMENT

Based on the independent critical review objectives, the final report, LIFE CYCLE ASSESSMENT OF U.S. SOYBEANS, SOYBEAN MEAL, AND SOYBEAN OIL, dated January 12, 2024, was determined to be in conformance with the applicable ISO standards. The plausibility, quality, and accuracy of the LCA-based data and supporting information are confirmed.

I confirm that I have sufficient scientific knowledge and experience of agricultural processes and the applicable ISO standards to carry out this critical review.

Sincerely,

Marty Heller

Managing Director
AgResilience Consulting, LLC

NATIONAL OILSEED PROCESSORS ASSOCIATION

1310 L Street NW Suite 375 • Washington DC 20005
phone 202.864-4365 • fax 202.842.9126
nopa@nopa.org • www.nopa.org

February 20, 2024

Carolyn Lozo
Chief, Transportation Fuels Branch
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Via electronic submission

Re: Proposed Low Carbon Fuel Standard Amendments

Transportation Fuels Branch Chief Lozo:

Thank you for the opportunity to comment in response to the California Air Resources Board's (CARB) "Proposed Low Carbon Fuel Standard Amendments." The National Oilseed Processors Association (NOPA) appreciates being able to share our observations. NOPA members have a vital interest in these issues.

266.1 **NOPA appreciates CARB's analysis and recognition that consideration of a cap or limitation on crop-based oil feedstocks is unwarranted and would increase fossil diesel use resulting in higher costs for consumers and greater greenhouse gas (GHG), PM2.5 and NOx emissions. CARB should simultaneously promote sustainability and maintain the cost and health benefits afforded by Biomass-Based Diesel (BBD) by**
266.2 **recognizing that fuels certified under the federal Renewable Fuel Standard (RFS) meet CARB's newly proposed sustainability criteria.**

Background

Organized in 1930, NOPA represents the U.S. soybean, canola, flaxseed, safflower seed, and sunflower seed-crushing industries. NOPA's membership includes 15 members that are engaged in the processing of oilseeds for meal and oil that are utilized in the manufacturing of food, feed, renewable fuels, and industrial products. NOPA member companies operate a total of five softseed and 62 solvent extraction plants across 21 states. Collectively, NOPA members process 95 percent of all soybeans in the U.S. which accounts for approximately 2 billion bushels annually.

NOPA members' oilseed processing operations yield protein-rich meal for human and animal nutrition, as well as vegetable oil that is used as an ingredient in food manufacturing and as a feedstock for renewable fuels such as biodiesel, renewable diesel and sustainable aviation fuel (SAF). These sustainably produced biofuels help reduce carbon dioxide equivalent (CO_2e) greenhouse gas emissions and the carbon intensity of transportation fuels in use today. NOPA is uniquely qualified to respond to CARB's proposed sustainability criteria for crop-based biofuels given the number of markets that NOPA members serve, including the food, feed, fuel, and industrial markets.

266.3 NOPA supports California's Low Carbon Fuel Standard (LCFS) which drives demand for biodiesel, renewable diesel and SAF, and encourages investment in low carbon feedstocks and value-added agricultural opportunities. BBD is the largest domestically produced and commercially available fuel to meet the U.S. EPA's definition of an advanced biofuel under the RFS and provides one of the best carbon-reduction strategies for diesel engines available with today's vehicle technologies.

Sustainable Oilseed Processing Feedstocks and Investments

NOPA members are committed to producing sustainable feedstocks. Many of our members have made sustainability commitments and net-zero deforestation pledges. NOPA and the United Soybean Board (USB) published a study which demonstrates the following carbon reductions since 2015:

- 19% decrease for U.S. Soybean cultivation
- 6% decrease for U.S. Soybean Meal production
- 22% decrease for U.S. Crude Soy Oil production
- 8% decreased for U.S. refined soy oil production

NOPA members are also making significant investments to produce sustainable vegetable oil supplies to meet all the demands of biofuel, feed, and food customers. As critical feedstock suppliers to the renewable fuels industry, our industry has announced well over $6 billion in soybean crushing capacity investments since 2021 encompassing some 20 or more expansions or new facilities. These projects are currently on track to increase soybean crush capacity by over 30% between 2023-2026. Collectively, these projects will provide enough additional feedstock to support a 1-billion-gallon increase in BBD capacity over the next several years, **without impacting food or land use**.

This increased capacity will be largely supported by improving the yields from existing acreage already farmed with oilseed crops, increasing the amount of oil produced by such crops and regenerative farming practices, such as cover crops, which reduce the carbon intensity of agricultural practices.

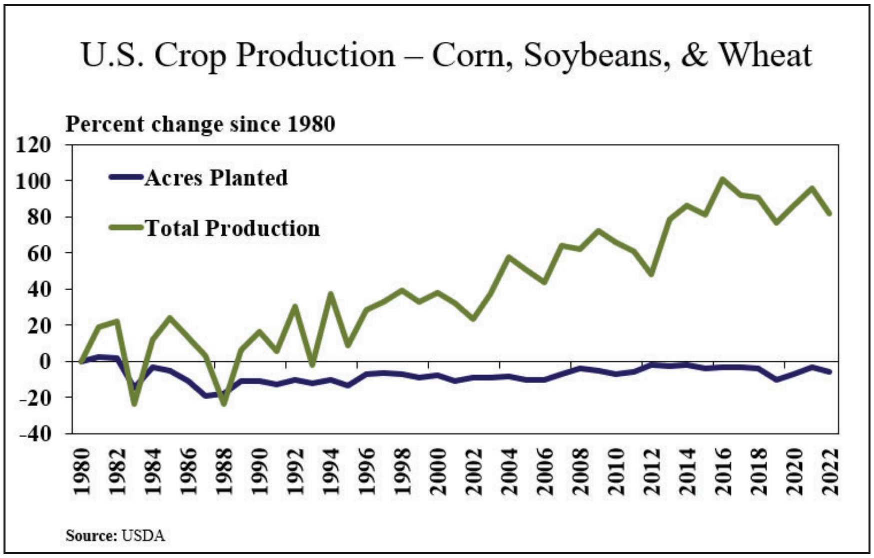
CARB's Proposed Crop-Based Biofuels Sustainability Criteria

266.4 As previously mentioned, NOPA appreciates CARB's analysis and recognition that its previous consideration of a cap or limitation on crop-based oil feedstocks is unwarranted and would increase fossil diesel use resulting in higher costs for consumers and greater GHG, PM2.5 and NOx emissions.

266.5 While CARB's newly proposed sustainability criteria does afford time for market participants to comply, NOPA would urge CARB to adopt a more risk-based approach to addressing deforestation by recognizing the sustainability requirements already provided for under the RFS. By not recognizing that the RFS already requires certification of all the sustainability criteria proposed by CARB, it would have the unintended consequence of disadvantaging regions of crop-based feedstock production with low-risk of deforestation (U.S. and Canada) at the expense of feedstocks produced in regions with a significantly higher risk of deforestation where segregated supply chains are more prevalent due to those risks.

As noted in Figure 1, total U.S. agricultural land use today is lower than it was in 1980; lower than it was when the RFS was created; and lower than it was when the LCFS was created. And total crop production has increased on roughly the same amount of land by over 80%.

Figure 1



266.5 cont. Not only is U.S. agriculture producing more with less and on fewer acres, it continues to do so at the lowest costs due to its comparative advantage in the world through our efficient bulk commodity, aggregation and transportation system. Layering additional cost and segregation on U.S. producers could have the effect of increasing demand for feedstocks from regions with the highest risk of deforestation.

266.6 NOPA also continues to remind CARB staff that it has already overly accounted for land use impacts in the development of the LCFS through the incorporation of indirect land use change penalties (iLUC) – values which continue to be significantly overestimated, and by default provide additional guardrails which CARB staff identified as motivation for additional sustainability criteria.

RFS Compliance with Proposed Sustainability Criteria

266.7 NOPA urges CARB to recognize that fuels produced and certified under the RFS meet CARB's newly proposed sustainability criteria. As demonstrated below, the RFS already meets the sustainability requirements proposed under the LCFS amendments:

Proposed Feedstock Sustainability Requirements	**RFS Feedstock Sustainability Requirements**
Must not be sourced on land forested after Jan. 1, 2008	Must not be sourced from agricultural land cleared or forested after December 19, 2007
Maintain continuous certification	Maintain continuous certification
Certification system must be recognized by an international, national, or state/provincial government for at least 24 months.	The RFS was approved by the U.S. Congress on, and has been in effect since, December 19, 2007
Certification system must consider environmental, social and economic criteria	Factors addressed by U.S. EPA during annual rulemakings to establish Renewable Volume Obligations (RVOs) under the RFS include: • Impact on the environment • Impact on cost to consumers and cost to transport goods, and job creation

266.7 cont.

	• Soil Quality • Environmental Justice
Certification system standard-setting process is participatory, and consensus driven – convening groups of economic, environmental and social stakeholders in both formal and informal manners; and creates a representative steering committee technical working group(s) and advisory group(s)	The passage of the RFS through Congress was by definition consensus driven, which allowed for the input by all stakeholders as afforded during the legislative process. EPA's annual rulemakings to establish RVOs allow for public comment by all stakeholders, both formal and informal. This process includes input from EPA's Clean Air Scientific Advisory Committee (CASAC) – an independent advisory group of non-EPA scientists, engineers, economists and social scientists.
The certification system must have clear, accessible, and transparent processes;	The development of the implementing regulations for the RFS and each subsequent rulemaking to establish RVOs went through a transparent and public comment process before finalization.
The certification system must publish procedures, guidance, certificates and audit report summaries on its website;	All RFS regulations, certificates, and compliance reports are available at https://www.epa.gov/renewable-fuel-standard-program
The certification system must be science based, provide clear targets to reach, and support demonstrable means of evaluation;	The development of the implementing regulations for the RFS and each subsequent rulemaking to establish RVOs by U.S. EPA go through a transparent and public comment process before finalization, based on specific scientific criteria and evaluation.
The certification system must demonstrate that requirements that are additional to the requirements of this sub article are vetted via a multi-stakeholder process to mitigate potential stakeholder bias;	The passage of the RFS through Congress was by definition consensus driven, which allowed for the input by all stakeholders as afforded during the legislative process. EPA's annual rulemakings to establish RVOs also allow for public comment by all stakeholders, both formal and informal. This process includes input from EPA's Clean Air Scientific Advisory Committee (CASAC) – an independent advisory group of non-EPA scientists, engineers, economists and social scientists.
The certification system must maintain an effective auditor training program to ensure auditor competency;	The RFS compliance and audit program is maintained by U.S. EPA and can be found at https://www.epa.gov/renewable-fuel-standard-program/compliance-overview-renewable-fuel-standard-program
The certification system must include an effective grievance mechanism to ensure that problems are resolved;	EPA's annual rulemakings to establish RVOs also allow for public comment by all stakeholders, both formal and informal. A petition process is also afforded under the RFS, which has been utilized by stakeholders. https://www.epa.gov/renewable-fuel-

	standard-program/other-requests-under-renewable-fuel-standard
266.7 cont. The certification system must include sanction mechanisms for participating feedstock suppliers and auditing bodies to ensure conformance with its system requirements; and	The RFS compliance and audit program is maintained by U.S. EPA and can be found at https://www.epa.gov/renewable-fuel-standard-program/compliance-overview-renewable-fuel-standard-program. The RFS and Clean Air Act also establish penalties for non-compliance.

As demonstrated, the RFS already complies with CARB's proposed sustainability criteria and should be explicitly recognized as a compliant certification system under the LCFS amendments.

Ensuring Integrity of Imported Feedstocks

266.8 NOPA notes that imports of Used Cooking Oil (UCO) and other low carbon feedstocks have significantly increased since 2022 for LCFS compliance. While we recognize and support the need for low carbon and waste-based feedstocks, NOPA encourages CARB to undergo additional scrutiny and monitoring of imported feedstocks. Such actions will ensure continued program confidence and compliance.

266.9 **Acknowledgement and Appreciation for Additional CARB Steps on Sustainability Requirements:** NOPA notes that in the amendments to the LCFS, the proposed Sustainability Requirements released on December 19 was the first time stakeholders had any opportunity to review these provisions or its concept. Given the precedent-setting nature of this program in the U.S., and the potential for significant cost and compliance burden to stakeholders, NOPA was pleased to see CARB indicate on February 14 that it will take additional time to allow stakeholders to properly vet the intent, impact, and implications of the proposed sustainability requirements.

Conclusion

266.10 The body of CARB analysis, and market and scientific data collectively demonstrate that consideration of a cap or limitation on crop-based oil feedstocks is unwarranted. Further, doing so at this point would undercut the investments that are being made and are needed for low carbon feedstocks from the industry expansion.

A vibrant U.S. oilseed sector, and the advanced biofuels produced from oilseeds, are critically important to lowering the GHG emissions in the U.S. and California's fuel supply. Efforts to undercut current policies regarding eligible feedstocks will significantly and negatively impact investments being made in lower carbon feedstocks and fuels.

NOPA is eager to continue working with CARB to support the role of agriculture in diversifying the fuel supply through more sustainable feedstocks and thereby supporting cleaner fuel options in California and beyond. On behalf of America's soybean processors, we appreciate this opportunity to comment, and look forward to collaborating with CARB and other relevant stakeholders to enact policies that will address climate change while expanding the use of soy-based biofuels and market opportunities for soybean farmers.

Sincerely,

Kailee Tkacz Buller

Kailee Tkacz Buller
President & CEO
NOPA

Comment Log Display

Here is the comment you selected to display.

Comment 276 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Amanda
Last Name	Myers Wisser
Email Address	amanda.myers.wisser@weavegrid.com
Affiliation	WeaveGrid
Subject	WeaveGrid Comments on Proposed LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6946-lcfs2024-VSIBYlU1VnNVNlUy.pdf
Original File Name	WeaveGrid_Proposed LCFS Amendments_final.pdf
Date and Time Comment Was Submitted	2024-02-20 15:54:28

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

375 Alabama Street
Suite 325
San Francisco, CA 94110

Amanda Myers Wisser
Senior Manager, Policy and Regulatory Affairs
amanda.myers.wisser@weavegrid.com

February 20, 2024

California Air Resources Board
1000 I Street
Sacramento, CA 95814
Submitted Electronically

Re: Weave Grid, Inc. Comments in Response to Proposed Low Carbon Fuel Standard Amendments

Dear Chair Randolph, Honorable Board Members, and California Air Resources Board Staff,

Weave Grid, Inc. (WeaveGrid) respectfully submits these comments in response to the California Air Resources Board (CARB) Proposed Low Carbon Fuel Standard (LCFS) Amendments.

I. Introduction

WeaveGrid is a California-based software company that helps load-serving entities support increased adoption of electric vehicles (EVs) through greater understanding of customer charging behaviors, managed charging programs, and distribution-level optimization. WeaveGrid's technology leverages utility and charging data, including the embedded vehicle telematics—data, controls, and communication systems—and the charging equipment to transform unpredictable and disaggregated EV charging loads into a cohesive network of controllable grid resources. We also support load-serving entities in engaging their EV customers with personalized messages, insights, and notifications via the web, email, and text. Our approach enables broad participation in EV load management programs, while helping reduce the costs to serve EV loads. WeaveGrid is a market leader in providing these solutions.

II. Comments

WeaveGrid appreciates Staff's thoughtfulness with the proposed changes to the LCFS regulation. LCFS plays an essential role in supporting California's ambitious transportation electrification goals. WeaveGrid's comments focus on our support for proposed changes to the regulation specific to holdback credits. We also recommend updated guidance for reporting incremental credits for residential EV charging. Overall, WeaveGrid is highly supportive of the efforts to increase the stringency of the program.

A. Strong support for broader use of holdback credits

267.1 WeaveGrid urges flexibility with the use of holdback credits. The transportation electrification sector is rapidly changing, which is encouraging. LCFS serves as an important source of funding in California to advance electric mobility. As needs evolve with the changing sector, a flexible use of LCFS holdback funds can maximize impact.

WeaveGrid particularly supports the proposed additions within Section 95483(c)(1)(A)5.b.[1] As EV adoption in California increases, we need to adapt the grid accordingly. We appreciate that the focus of these proposed additional allowable holdback projects supports greater grid investment to accommodate a growing number of EVs on California's roads. We support the additions in this section, including investments in distribution infrastructure for EV charging, support for vehicle-grid integration (VGI) projects, and technology, such as EV load management software, that can avoid or reduce grid upgrades. Distribution grid investments ensure that charging infrastructure needs are met, especially in underserved communities and for medium- and heavy-duty electric vehicles. VGI projects help EV drivers charge when and where it is most beneficial for the grid and for customers generally.[2] VGI enables cleaner charging by increasing renewables integration and providing a signal for drivers when it is cleanest to charge. Technology helps enable VGI and makes it more driver-friendly by being more automated. VGI projects that use automated technology can benefit from greater participation and, therefore, better outcomes.

B. Recommend updated guidance for reporting incremental credits for residential EV charging

We understand that after LCFS rulemaking updates, there can be updates to associated guidance documents. As such, we are using this comment opportunity to suggest an update
267.2 to LCFS Guidance 19-03. Specifically, for Method 2, Option 1, we recommend that the minimum Geofencing Radius (GFR) be reduced from 220 meters.[3] On-vehicle telemetry has advanced in recent years and particularly the component of telematics specific to identifying geographical location can be very accurate. The current GFR can be very

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[1] Appendix A-1 Proposed Regulation Order, Section 95483(c)(1)(A)5.b., p. 45, https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appa1.pdf.
[2] LBNL, Quantifying the Financial Impacts of Electric Vehicles on Utility Ratepayers and Shareholders, February 2023, https://emp.lbl.gov/publications/quantifying-financial-impacts.
[3] LCFS Guidance 19-03: Reporting for Incremental Credits for Residential EV Charging, p. 3, https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/guidance/lcfsguidance_19-03.pdf.

limiting for measuring incremental credits in densely populated areas where non-residential charging is prevalent, for example, in San Francisco. This update to the guidance can help various entities be further incentivized to provide and use cleaner charging.

III. Conclusion

WeaveGrid appreciates the opportunity to submit these comments. We thank CARB for consideration of these comments and look forward to continued engagement.

Respectfully submitted,

/s/ Amanda Myers Wisser
Amanda Myers Wisser
Senior Manager, Policy and Regulatory Affairs
WeaveGrid
Phone: 650-590-9021
Email: amanda.myers.wisser@weavegrid.com

Comment Log Display

Here is the comment you selected to display.

Comment 277 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Randy
Last Name	Hoyle
Email Address	rwhoyle@aeraenergy.com
Affiliation	Aera Energy LLC
Subject	Aera Energy LLC Comment Letter
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6947-lcfs2024-WzpQMwNwAjALUgFk.pdf
Original File Name	Aera Energy LCFS Comment Letter 2_20_24.pdf
Date and Time Comment Was Submitted	2024-02-20 15:50:13

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Ms. Rajinder Sahota
Deputy Executive Officer – Climate Change and Research
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Aera Energy Comments on Proposed 2024 Low Carbon Fuel Standard Amendments

Dear Ms. Sahota,

Aera Energy LLC (Aera) appreciates the opportunity to provide the comments below regarding the California Air Resources Board's (CARB) proposed amendments and related 45-day rulemaking documents for the Low Carbon Fuel Standard (LCFS) program. Aera is one of California's largest oil producers, with assets across the State. As a California-based company, Aera understands the need to reduce GHG emissions to work towards the 2045 carbon neutrality target, which is why we are helping lead the State in developing low carbon projects, including carbon capture and sequestration (CCS), direct air capture (DAC), and renewable energy.

268.1 **Section 95489(c)(1)(F). Updates to the Emission Factor for Calculating Credits for Producing Crude Oil with Innovative Methods using Solar or Wind-Based Electricity**

In Section 95489(c)(1)(F), CARB staff propose updating the emission factor for producing crude oil with solar or wind electricity from 511 gCO2e/kWh (current emission factor) to 314 gCO2e/kWh (proposed emission factor), which would result in a 39% reduction in credits generated by these projects. In *Appendix E: Purpose and Rationale for Low Carbon Fuel Standards Amendments*, the rationale for this update is that the solar projects approved by CARB under this pathway to date have been supplemented by grid electricity. Therefore, the avoided emissions from solar projects should be based on the carbon intensity of grid electricity (the proposed emission factor) rather than the carbon intensity of electricity from a natural gas fired combined cycle plant (the current emission factor).

However, this change presumes that future innovative crude solar or wind project applications will all be supplemented by grid electricity, similar to previous project applications. In fact, Aera has contracted with a solar developer to install 37 MW DC (27 MW AC) of solar PV at its Belridge oilfield, with an estimated completion date of 2025. This would be one of the largest innovative crude solar projects to date, and unlike previous projects, the solar electricity would be supplemented with electricity from natural gas fired cogeneration units that currently supply almost all of the electricity to the Belridge oilfield. Therefore, the emissions avoided from this project would be similar to the emission factor in the current LCFS regulation, rather than the proposed reduced emission factor. Lowering the emission factor and credits generated by a project such as the one at Belridge would incorrectly calculate avoided emissions and discourage investment in oilfield solar electricity and energy storage, as companies such as Aera consider installation of much larger solar projects. Aera recommends that innovative crude solar or wind electricity projects that displace natural gas electricity generation utilize the current emission factor when calculating LCFS credits generated.

Section 95489(c)(5). Phaseout Provisions for Petroleum Projects.

268.2 In Section 95489(c)(5), CARB staff proposes to phase out crediting of innovative crude projects no later than December 31, 2040, excluding CCS projects. In *Appendix E: Purpose and Rationale for Low Carbon Fuel Standards Amendments*, the rationale for this phase out was the 2022 Scoping Plan, where the "*State has identified the need to phase down fossil fuel production as fossil fuel demand drops, and the need for all viable tools such as CCS and direct air capture to address the existential threat that climate change presents.*"

While fossil fuel demand in California will decline over time, it is not expected to be eliminated in 2040. Given this need past 2040, as well as the goals of reducing GHG emissions, Aera is evaluating solar electricity and solar steam projects that would be some of the largest in the world, to achieve near-zero emissions crude oil production, including after 2040. This would allow fossil fuel production in California to be much less carbon intensive than fossil fuel imported from elsewhere. Given the size of these projects, they would require years of permitting and construction and hundreds of millions of dollars in investment, with long payouts. Eliminating LCFS credit generation "no later than December 31, 2040" would hurt the investment case for these projects, as well as send a signal to developers of all types of projects that LCFS credit generation could be prematurely eliminated in future rulemaking. Such a phase out, and uncertainty over future potential LCFS regulatory changes, would discourage investment, incentivizing higher emissions from the crude oil producers and imports in the coming years.

In *Appendix E: Purpose and Rationale for Low Carbon Fuel Standards Amendments*, CARB staff also recognize the need for tools such as CCS and direct air capture to address climate change, which is presumably the rationale for allowing these credit generation pathways to continue post 2040. Similar to CCS and DAC, other innovative crude projects such as solar electricity and solar steam are tools needed to address climate change long-term, with the potential to provide zero-carbon energy long after the cessation of oil production. Aera recommends removing the post-2040 phase of innovative crude crediting, supporting investments that not only result in near-term emissions reductions, but also long-term low-carbon energy generation that would benefit the State for decades to come.

Aera looks forward to working with CARB and other stakeholders to craft policies that will facilitate the projects and technologies needed for California's energy transition. If you have any questions regarding this submittal, please contact me via email at rwhoyle@aeraenergy.com.

Sincerely,

Randy Hoyle
Chief Carbon Solutions Officer
Aera Energy LLC

Comment Log Display

Here is the comment you selected to display.

Comment 278 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Alexa
Last Name	Combelic
Email Address	acombelic@soy.org
Affiliation	American Soybean Association
Subject	American Soybean Association Comments
Comment	Please see attached comments from the American Soybean Associatior
Attachment	www.arb.ca.gov/lists/com-attach/6948-lcfs2024-UTABdFU1U19QewBf.pdf
Original File Name	ASA - CARB LCFS Comments - Final.pdf
Date and Time Comment Was Submitted	2024-02-20 15:54:15

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Via electronic submission

Re: Comments on Proposed Changes to LCFS, Initial Statement of Reasons

The American Soybean Association (ASA) appreciates the opportunity to provide comments on the proposed changes to the Low Carbon Fuel Standard (LCFS) presented in the Initial Statement of Reasons on December 19, 2023. ASA has welcomed the opportunity to engage with the California Air Resources Board (CARB) throughout the LCFS workshop and rulemaking process.

ASA represents approximately 500,000 U.S. soybean farmers on domestic and international policy issues important to the soybean industry and has 26 affiliated state associations representing 30 soybean-producing states. U.S. soybean growers have long been committed to producing the world's food, feed, fuel, and thousands of bioproducts in a sustainable and climate-smart way.

The growth in the biomass-based diesel industry has been spurred by strong federal and state-level policies that promote cleaner, lower-carbon energy sources. Increased utilization of biomass-based diesel over the past several years has had a marked impact on the rural economy. Further, according to CARB's Initial Statement of Reasons, biodiesel and renewable diesel are the largest renewable fuel source and have served as the greatest source of greenhouse gas (GHG) reductions in the LCFS to-date.

U.S. soybean growers have been long supporters and partners in the development of cleaner, lower-carbon fuels. A vibrant soybean sector, and the biofuels produced from soybeans, is critically important to lowering GHG emissions in the U.S. and supporting California's future carbon intensity reduction targets. Importantly, ASA appreciates that CARB has acknowledged the important role of agriculture in the LCFS and has not moved forward with a proposal to cap crop-based feedstocks in this update.

Carbon Intensity Reduction Targets and Modeling Considerations

269.1 ASA is largely supportive of CARB's proposed carbon intensity (CI) reduction targets through 2030 and the auto-acceleration mechanism. However, ASA is concerned that without a comprehensive update to the Global Trade Analysis Project model for biofuels (GTAP-BIO) that CARB utilizes, soy-based feedstocks will be phased out of the LCFS, even though current data indicates a much lower CI score. Without
269.2 updated methodology, soy-based biofuels will only generate credits until approximately 2035, and even sooner if the auto-acceleration mechanism triggers. Updated methodology indicates credit generation for years beyond that timeframe.

During this rulemaking, CARB is updating all major models used for lifecycle emissions calculations <u>except</u> for GTAP-BIO. Rather, CARB continues to rely on a 2014 model that uses data from 2004. As ASA has highlighted in previous comments to CARB, outdated indirect land use change (ILUC) modeling puts soy at a significant disadvantage even though the industry has made vast improvements in sustainability and efficiency over the past two decades. The ILUC score accounts for half or more of the CI score for soy-based biofuels. CARB's current modeling assigns soy biomass-based diesel with an ILUC impact of 29.1g CO2e/MJ whereas updated results from the model used to calculate ILUC scores indicate a value of between 9 and 10 gCO2e/MJ for soybeans[1]. The LCFS is intended to be a science-based program, so using data from 2004 that is no longer relevant undercuts the science and thereby does not incentivize the optimal allocation of feedstocks to decrease carbon emissions.

ASA strongly urges CARB to use the time afforded by a postponement in the March Board public hearing to appropriately update its GTAP model to align with other modeling changes being made. It is incongruous to update more recent models while leaving the older, more impactful model unchanged. The benefits of an LCFS are only achieved if CI values are accurately captured.

Alternative Jet Fuel

269.3 ASA applauds CARB's desire to add intrastate flights to the LCFS program. Leaving some forms of transportation out of the program while leaving others in has financially incentivized switching to the unobligated modes. The proposal would help put air travel and ground travel on the same playing field. We also believe that it could help spur the adoption of new technologies to reduce air emissions such as sustainable aviation fuel.

Sustainability Guardrails for Crop-Based Biofuels

269.4 ASA has significant concerns with the introduction of the sustainability guardrail concept in this proposed rule. While ASA engaged with CARB throughout the informal rulemaking and workshop process, this concept was never discussed publicly as a potential addition to the LCFS program. Any new requirements to develop traceability and certification mechanisms for crop-based feedstocks should be carefully considered with appropriate stakeholder input to avoid potential financial burdens and duplication of current procedures. We find the desire to include the sustainability guardrails especially puzzling given that CARB is not proposing to update the portion of the modeling work that deals with this issue (GTAP-BIO).

If CARB pursues this concept, it is important to consider current sustainability measures that may align with CARB's goals. The U.S. does not have a deforestation issue as noted below. However, our crop supply chains are the bulk movement of commodities. As such, soybeans from multiple sources are commingled. While small shipments can be separated to preserve their identity, this process is limited in scale and is expensive. Our concern is that the Sustainability Guardrails has no problem to fix with U.S. supplies but will require a very expensive compliance process that only benefits certifiers, not the environment. In fact, if identity-preserved shipments are required the lack of supply-chain efficiency could increase emissions for U.S. sourced feedstocks. CARB should convene a working group that includes agricultural representatives if it moves forward with this concept.

Sustainability Measures to Consider

269.5 When Congress updated the Renewable Fuel Standard in 2007, a provision was included requiring all eligible feedstock to be grown on lands cleared or cultivated by the date of enactment (December 19,

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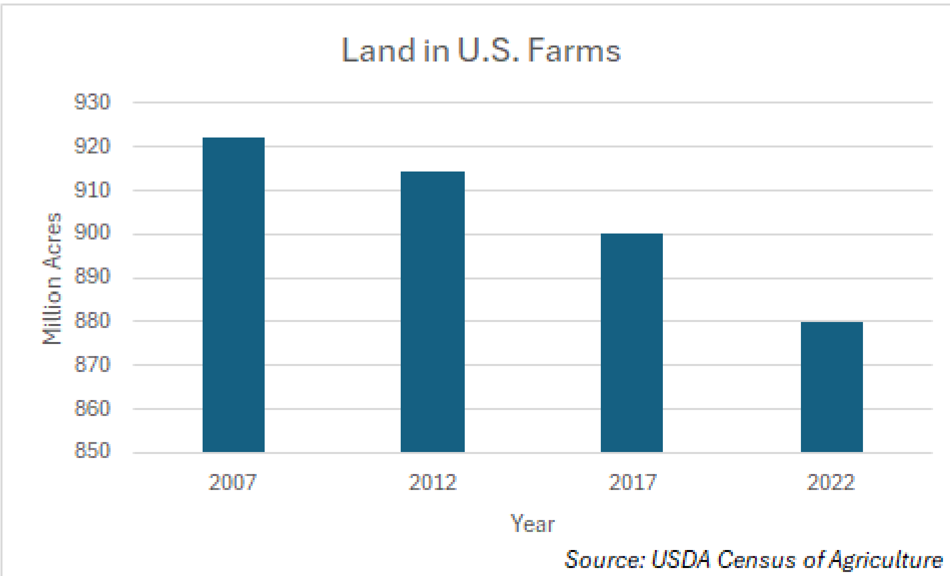
[1] Taheripour, F., Karmai, O., and Sajedinia, E. (2023). *Biodiesel Induced Land Use Changes: An Assessment Using GTAP-BIO 2014 Data Base*. Purdue University

2007) and non-forested. Much like the concept proposed by CARB, the intent of this provision is to prevent any deforestation or land use change that could otherwise occur due to renewable fuel incentives. Using a 2007 baseline cropland acreage of 402 million acres, EPA tracks eligible acres using annual data. To-date, U.S. cropland acreage has not exceeded the baseline, illustrating that increased crop production is based on efficiency rather than land use change. The provision helps protect against imported feedstocks that come from more environmentally sensitive areas. We support the National Oilseed Processors Association's comment letter with specific focus on how the RFS standards satisfy the desires of CARB's Feedstock Guardrails.



While EPA uses acreage in crop production, the USDA Census of Agriculture also illustrates a consistent decline in overall land in U.S. farming, as noted in the chart above. (Source: USDA Census of Agriculture)

Stakeholder Engagement

269.4 contd In addition to considering other sustainability measures which already apply to soybean farmers, ASA urges CARB to convene a working group or workshop process before finalizing any new sustainability guardrail concept. CARB will need to carefully consider limitations and financial impacts of chain of custody tracing of crop-based feedstocks, and the unintended impacts that could result from such a concept.

ASA welcomes the ability to continue engaging with CARB on this proposal and share more information on sustainability, traceability, and valuation. For such a complex proposal, it is imperative that CARB engage with key stakeholders throughout the crop-based feedstock value chain. For soy, this proposal will impact entities from the farm to the biofuel processor.

Imported Feedstocks

269.6 ASA was encouraged to see CARB propose a prohibition on palm-derived feedstocks. For clarification, ASA is interested in whether this prohibition is strictly for virgin palm oil, or all palm-derived feedstocks, including palm-based used cooking oil (UCO).

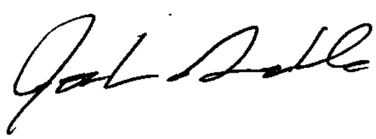
Looking more broadly at UCO, U.S. imports have become substantial and continually sets new records. While ASA sees UCO as an important component of the biomass-based diesel feedstock portfolio, concerns throughout our value chain have been rising about the integrity of UCO imports. These increased imports are coming from palm-producing parts of the world. ASA encourages CARB to look at the exporting countries' ability to generate the UCO being exported from them. Furthermore, if collection rates in foreign countries are utilizing nearly all available used cooking oil for purposes of exports, CARB should consider whether UCO from these sources is incentivizing cooking oil consumption and thereby palm oil production. Additionally, we encourage CARB to verify the integrity of UCO used in the LCFS program and will be engaging at a federal level to explore this issue in more detail.

Conclusion

ASA is encouraged by the continued successes of programs that support the development of cleaner, low-carbon fuels. We appreciate the goals of the proposed update, including CARB moving away from a proposal to cap crop-based feedstocks. Moving forward, ASA encourages CARB to utilize sound, current data in CI valuations, specifically through a long-needed update to GTAP. Further, ASA looks forward to working with CARB in finalizing an LCFS update that is not overly burdensome for agricultural producers.

ASA is eager to continue working with CARB to support the role of agriculture in diversifying the fuel supply and supporting cleaner fuel options in California and beyond. On behalf of U.S. soybean farmers, we appreciate the opportunity to comment and look forward to collaborating with CARB and other relevant stakeholders on implementation of policies that expand the use of soy-based biofuels and market opportunities for soybean farmers.

Sincerely,



Josh Gackle, President
American Soybean Association

Comment Log Display

Here is the comment you selected to display.

Comment 279 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Alexandra
Last Name	Frumar
Email Address	monika@remoracarbon.com
Affiliation	Mobile Carbon Capture Coalition
Subject	Mobile Carbon Capture Coalition Comments on Proposed LCFS Amendments
Comment	Please see attached the comments of Carbon Ridge, Remora, Seabound, Stax Engineering, and Wärtsilä, jointly as the Mobile Carbon Capture Coalition.
Attachment	www.arb.ca.gov/lists/com-attach/6949-lcfs2024-ATMHMVJhBGNWfgEx.pdf
Original File Name	2024.02.20 MCCS Coalition LCFS Amendment Comments.pdf
Date and Time Comment Was Submitted	2024-02-20 15:56:55

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
[submitted electronically]

RE: Comments On Proposed Low Carbon Fuel Standard Amendments

Carbon Ridge, Remora, Seabound, Stax Engineering, and Wärtsilä, jointly as the Mobile Carbon Capture Coalition, appreciate the opportunity to provide comments on the California Air Resources Board's (CARB) Proposed Amendments to the Low Carbon Fuel Standard Regulation (LCFS). The Mobile Carbon Capture Coalition is committed to working with CARB, other state agency partners, and all stakeholders to deliver innovative climate solutions that will provide benefits in California and beyond.

About Mobile Carbon Capture Technology

Carbon capture technologies are an important part of California's toolkit for deep decarbonization. Mobile carbon capture technologies use carbon capture directly on hard-to-decarbonize mobile sources, including Class 8 heavy-duty vehicles (semi-trucks) and marine shipping vessels.

These transportation methods are essential to our economy, but are also difficult to decarbonize. The nation's two million semi-trucks and the global shipping industry emit approximately 340 and 700 million metric tonnes of CO_2 respectively each year.[1] In addition, these high-emitting vehicles and ships will be in operation for decades to come, given the capital investments made and the need to support supply chains across the nation and world. Importantly, mobile carbon capture technology already works, with Mobile Carbon Capture Coalition members having robust partnerships with Fortune 500 companies and initial deployments.

Mobile carbon capture can also provide air quality benefits, as many mobile carbon capture technologies act as a filter on engine exhaust. Along with capturing CO_2, it demonstrates the potential to drastically improve air quality by reducing toxic air pollutants and other greenhouse gasses (GHGs) like nitrogen oxides.

Mobile carbon capture technologies can *quickly* address the most difficult sectors to decarbonize, including heavy-duty trucking, vessel shipping, and rail. Mobile carbon capture technology is a critical near-term solution that can deliver significant climate benefits and support and complement efforts toward achieving zero-emission transportation in California. When paired with renewable fuels, this innovative technology can **make transportation carbon negative** (in what is known as a bioenergy with carbon capture and storage or "BECCS" carbon removal pathway).

California is also not the only place considering the role of carbon capture, particularly mobile carbon capture, in decarbonization plans. The European Union and International Maritime Organization (IMO), the United Nations specialized agency responsible for regulating shipping, are already evaluating and implementing programs to account for reductions in emissions from mobile carbon capture. The European Union has even gone as far as integrating mobile carbon capture into its Emission Trading Scheme (ETS).

LCFS Proposed Amendment Comments

270.1 The Mobile Carbon Capture Coalition supports actions to decarbonize the transportation sector as soon as possible. California's transportation sector is the State's largest source of both GHG emissions and air pollution, accounting for more than half of statewide emissions.[2] Rapidly driving down these emissions is a critical element of California's strategy to achieve carbon neutrality. As the Governor rightly recognized in his July 22,

[1] https://www.iea.org/energy-system/transport/international-shipping
[2] See Draft 2022 Scoping Plan Update, pg. 147.

2022, letter to CARB Chair Randolph on the 2022 Climate Change Scoping Plan Update, innovative carbon capture and sequestration technologies will be necessary for California to reach its climate goals, including carbon neutrality by 2045. Additionally, SB 905 (Caballero & Skinner, 2022) further underscores the role that carbon capture technologies will need to play as part of these efforts. Solutions that can significantly reduce—and even fully eliminate—greenhouse gas emissions from California's transportation sector will be key. CARB should ensure that, as new carbon capture and removal technologies emerge, they can be quickly incorporated into the LCFS to decarbonize the transportation sector.

270.2 For these reasons, the Mobile Carbon Capture Coalition supports CARB's proposal to establish a strong carbon intensity reduction target of 30 percent by 2030 with increasing stringency in subsequent years, as the emission reductions driven by the LCFS program will be critical to ensure California remains on track to meet its climate goals. LCFS CI targets can be made more ambitious by the inclusion of a suite of transportation decarbonization technologies, including mobile carbon capture technologies that can be rapidly scaled to deliver significant climate, air quality, and public health benefits in California.

270.3 Additionally, the Mobile Carbon Capture Coalition supports the incorporation of a compliance target acceleration mechanism that can automatically adjust based on clear criteria to increase programmatic stringency. This type of mechanism will help provide critically needed emissions reductions and provide market certainty for ongoing investment in low- and zero-carbon technologies.

The Mobile Carbon Capture Coalition appreciates the opportunity to submit comments, and we look forward to continuing to work with you and all stakeholders in California on this critically important effort.

Sincerely,

/s/ Alexandra Frumar
Alexandra Frumar
Chief Legal and Policy Officer
Remora

/s/ Chase Dwyer
Chase Dwyer
CEO
Carbon Ridge

/s/ Alisha Fredriksson
Alisha Fredriksson
CEO and Co-Founder
Seabound

/s/ Mike Walker
Mike Walker
CEO
Stax Engineering

/s/ Stian Aakre
Stian Aakre
General Manager, Technical and R&D
Wärtsilä

Comment Log Display

Here is the comment you selected to display.

Comment 280 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	George
Last Name	Gentry
Email Address	georgeg@calforests.org
Affiliation	Calforests
Subject	Low Carbon Fuel standard Regulation
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6950-lcfs2024-WjkCZQZrV2IFbAV3.pdf
Original File Name	Calforests LCFS letter.pdf
Date and Time Comment Was Submitted	2024-02-20 16:00:44

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

500 Capitol Mall, Suite 2360
Sacramento, CA 95814

February 20, 2024

The Honorable Steven S. Cliff
Executive Officer
California Air Resources Board
Sacramento, CA 95814

Re: Proposed Amendments to the Low Carbon Fuel Standard Regulation

Dear Executive Officer Cliff:

The following comments from the California Forestry Association (Calforests) focus on the 45-day language to amend the Low Carbon Fuel Standard (LCFS) regulations released in early January. Calforests members manage over 3.5 million acres of timberland in California to the highest professional standards, with many of these acres under a combination of Habitat Conservation Plans and third party certifications.

271.1 Our concern is that the 45-day language restricts use of forest biomass resulting from sustainable forest management within California. We believe the Air Board, therefore, should revise the amendments to promote use of forest fiber from all forest management consistent with **California's Forest Practice Act**.

We are concerned with the language in the proposed LCFS amendments that makes biomass derived from legal and silviculturally justified clearcuts ineligible. Even aged management is an important tool, particularly where shade intolerant species are being restored. The language proposed would result in the elimination of an important potential source of feedstock from private landowners that would be a credible long-term feedstock supply.

The practice of clearcutting is tightly restricted by State regulations, which are set forth in the California Forest Practice Rules in Title 14 of the California Code of Regulations (CCR) at Chapters 4, 4.5 & 10. Specifically, 14 CCR Section 921.3(c) establishes circumstances under which clearcutting may be employed, as well as detailed rules regarding the extent and way it may be used. Once proposed, it is reviewed by state agencies and found in conformance with the Forest Practice Act by the Director. It is also reviewed in the context of the California Environmental Quality Act (CEQA) which further means that any adverse effect is less than significant.

Given the tightly regulated usage of clearcutting, allowing the forest residual materials that remain after a clearcut to be utilized as biomass feedstock does not encourage further clearcutting or forest degradation.

271.2 We suggest that the language in § 95488.8. Fuel Pathway Application Requirements Applying to All Classifications. section (g) Specified Source Feedstocks (1) (A) subsection 3 be amended to read as follows:

> "Small-diameter, non-merchantable forestry residues removed for the purpose of forest fire fuel reduction or forest stand improvement and from a treatment where no-clear cutting occurred, *unless from forest lands where timber operations comply with California's Forest Practice Act*; Municipal solid waste that is diverted from landfill disposal;".

California's Forest Practice Act regulations are the most stringent in the United States and set a standard for sustainability, long-term increases in forest carbon storage, and retention of forest lands.

As such, we respectfully submit that the focus should be on landscape-scale improvements to forestlands and that compliant clear-cutting practices on individual small stands of pre-existing plantations should be seen within that larger context. We recommend that the Board revise 45-day language to promote use of forest fiber from all forest management consistent with California's Forest Practice Rules.

Thank you for your consideration of these comments.

Sincerely,

George D. Gentry

Senior Vice President
California Forestry Association

Comment Log Display

Here is the comment you selected to display.

Comment 281 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Claire
Last Name	Broome
Email Address	cvbroome@gmail.com
Affiliation	350 Bay Area
Subject	Reform LCFS staff proposal to address distorted promotion of combustion fuels
Comment	see attached
Attachment	www.arb.ca.gov/lists/com-attach/6951-lcfs2024-ATJTYFZnAw9SNlU0.pdf
Original File Name	350 Bay Area-LCFS comment.pdf
Date and Time Comment Was Submitted	2024-02-20 15:59:20

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

350 Contra Costa
350 East Bay
350 San Francisco
350 Marin
350 Silicon Valley
350 Sonoma
Napa Climate NOW!

February 20, 2024

California Air Resources Board
Sacramento, CA

Dear Colleagues,

350 Bay Area is a non-profit organization focused on ensuring a sustainable climate and associated environmental and economic justice for all, with a reach of over twenty-two thousand people, primarily concentrated in the nine Bay Area counties. At this critical stage in the transition to renewable clean energy, California should be a national and international leader supporting real solutions based on a full life cycle analysis, rather than entrenching policies which incent counterproductive and polluting false solutions such as manure biogas and corn ethanol.

Specifically this revision of the Low Carbon Fuel Standard (LCFS) must correct the distorted economic incentives that reward some of the worst factory farming practices, both in California and across the country, providing lavish subsidies to operations that are getting paid to pollute. The program's flawed accounting practices assign factory farm biogas a lower "carbon intensity" than even solar and wind energy, creating a smokescreen for continued pollution.

Furthermore, a study found that corn ethanol, promoted through the LCFS, is 24% more carbon-intensive than traditional fuel. The enormous rise in nitrogen fertilizer to raise corn for ethanol has increased emissions of nitrous oxide, a potent greenhouse gas that is 289 times as powerful as CO2. Fertilizers used in corn production, including for ethanol, also cause vast water pollution extending from drinking water in Iowa to the Dead Zone in the Gulf of Mexico. Building ethanol infrastructure locks in ethanol and gasoline for decades, reducing incentives for investors or policymakers to shift towards more sustainable transportation.

[1]

[1] Environmental outcomes of the US Renewable Fuel Standard PNAS 2022
119 (9) e2101084119
https://doi.org/10.1073/pnas.2101084119

We urge that CARB revise the staff proposal to:

272.1 - Eliminate avoided methane crediting for fuel derived from livestock manure.

272.2 - Oppose proposed LCFS amendment loophole to allow petroleum projects with carbon capture & storage past the 2040 phase-out.

272.3 - Conduct and incorporate a full life cycle assessment of all air pollution and greenhouse gas (GHG) emissions for all pathways, and their implications for environmental justice communities.

272.4 - Create ZEV multipliers to boost electric school bus and electric public transit bus and rail system deployments.

272.5 - Eliminate credit generation from factory farm gas projects that would have happened anyway due to other programs or investments.

CARB has the power to shift California towards truly clean energy solutions and remove the incentives that enable the continued reliance on combustion fuels, especially those which artefactually increase dairy biogas and corn ethanol production. The staff proposal includes policies noted above that make the climate and pollution crisis worse. CARB must take decisive action to reform the LCFS and protect the communities most affected by its current flaws.

Sincerely,

____/sig/____

Claire Broome
Clean Energy Team Lead
350 Bay Area

Comment Log Display

Here is the comment you selected to display.

Comment 282 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Erin
Last Name	Cooke
Email Address	erin.cooke@flysfo.com
Affiliation	
Subject	LCFS Missing Key Programs to Drive SAF Uplift
Comment	SFO Letter Re: Low Carbon Fuel Standard Missing Key Programs to Drive SAF Uplift as Key Components to Reach California's Climate and Regional Air Quality Goals
Attachment	www.arb.ca.gov/lists/com-attach/6952-lcfs2024-UiFXNwFvVlpXPVIm.pdf
Original File Name	SFO Ltr - LCFS Missing Key Programs to Drive SAF 2-20-24.pdf
Date and Time Comment Was Submitted	2024-02-20 15:56:54

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

SFO

San Francisco International Airport

February 20, 2024

The Honorable Liane M. Randolph
Chair, California Air Resources Board (CARB)
1001 I Street
Sacramento, CA 95814

TRANSMITTED VIA EMAIL
https://ww2.arb.ca.gov/lispub/comm/bclist.php

RE: Low Carbon Fuel Standard Missing Key Programs to Drive SAF Uplift as Key Components to Reach California's Climate and Regional Air Quality Goals

Dear Chair Randolph,

273.1 As you know San Francisco International Airport (SFO) is a global leader of sustainable aviation fuel (SAF) uplift, using ten million gallons of neat SAF delivered last year. Receipt of this fuel was exclusively enabled by CARB's 2018 Low Carbon Fuel Standard Rulemaking that incentivized SAF beyond any other state or country. Since this adoption, SFO and the Sustainable Aviation Fuel (SAF) Coalition we launched that is comprised of airlines, airports, conventional and alternative aviation fuel producers, and other nonprofit and government partners, has met with CARB staff and leadership to compel additional programs to sustain the state's SAF leadership. Further, the SAF Coalition teamed with the Speaker of the Assembly, Robert Rivas, to author the widely supported AB1322, which passed unanimously through the California Legislature, to gap analyze SAF programs that could ensure California's continued SAF competitiveness. While SFO respects the bold decarbonization vision that CARB outlined in its 2022 Scoping Plan Update, we write today to humbly request that CARB team with key members of our aviation industry, as AB1322 requested, to develop a far broader playbook than that proposed in this 2024 Low Carbon Fuel Standard (LCFS) Rulemaking to ensure the state meets Governor Newsom's 20% clean fuels adoption for the aviation sector, estimated at 1.5 billion gallons of SAF by 2030.

California and CARB must model a complete program that addresses the greenhouse gas and criteria air emissions across all sectors. Aviation efforts are falling short of our European counterparts. SFO aligns with our industry peers to urge CARB to align LCFS policy across both hydrogen and SAF to allow for book and claim accounting for low-CI electricity and RNG inputs via the use of Power Purchase Agreements (PPAs). SAF and hydrogen are both nascent industries and the state should equally allow the indirect accounting for both technologies.

SFO continues to encourage CARB to consider LCFS and other levers that can materialize new markets to recognize SAF's non-CO2 benefits, as outlined in previous communications with CARB, the California Natural Resources Agency (CNRA), the Bay Area Air Quality Management District, and GoBiz. These positive externalities include improvements to air quality, economic development through green jobs, and wildfire risk reduction, and are detailed in industry studies and should be represented in the LCFS, Scoping Plan, further CARB

Rulemaking, GoBiz programs and/or CNRA incentive structures. A recent Airport Cooperative Research Program (ACRP), administered by the Transport Research Board of the U.S. National Academies of Sciences, found that a 50% SAF blend could reduce by nearly 40% oxides of sulfur and PM reductions of up to 65%. A more recent measurement campaign found that SAF produced via the alcohol-to-jet pathway could reduce non-volatile PM by up to 97%.

The California aviation sector utilizes four billion gallons of conventional jet fuel annually. By creating new programs that enable airlines to switch to SAF, California can reduce aviation GHG emissions by 50-80% on a lifecycle basis. If aircraft in California uplifted just 5% SAF by 2025, greenhouse gas emissions avoided from those flights would total up to 2 million metric tons of CO2. Without growing AJF use, aviation sector emissions are expected to grow to over 25% of California's emissions by 2040, as other sectors (e.g., buildings, road transport) have full decarbonization pathways.

SFO has set a goal of expanding SAF use by its airlines to 5% by 2025. And while we are on our way, hitting 1% last year, achieving this goal will require 200 million gallons of SAF per year (MGY) by 2025, or 16 new SAF plants. As this goal of 200 MGY represents only about one-third of California's 2019 renewable diesel supply, it requires a rapid scaling of SAF production to be achieved.

SAF is being commercialized and is scalable, but volumes are currently small, with roughly 15 million gallons used exclusively in California last year, compared to 2.5 billion gallons of biodiesel and renewable diesel consumption. The key factor limiting SAF growth is the total monetary value that SAF producers receive when compared to that available to producers of alternative fuels to serve the on-road market. This has been quantified and detailed in a 2020 submittal by Graham Noyes ("Cap and Rack Cost" + LCFS cost) and is recognized by the industry to be approximately $0.40 per gallon. To that end, we request that CARB further review LCFS through its Public Workshops and consider revising the regulations to overcome the disparity in policies between the production of renewable diesel and SAF. Doing so will send the price signal producers need to secure investment capital to expand their facilities and increase supply to airlines uplifting SAF in California. It also offers a lifeline to renewable diesel fuel producers that exclusively serve the on-road sector, which is now obligated to increasingly electrify through State Executive Order and regulation to retrofit and retool plants for a future of aviation fueled by SAF.

With quotas and targeted SAF incentives announced and growing in Canada, the United Kingdom, Sweden, Norway, and the European Union, we hope that CARB will consider expanding the LCFS credit for SAF. Doing so will help power aviation's contribution to California's continued post-COVID and wildfire recovery in a way that keeps our state climate-competitive and fuels our industry's energy transition. While other states are starting to develop more robust SAF tax credits and incentive programs, CARB must grow SAF's LCFS credit value, or pursue other programs that can scale (not hinder) SAF as a key waypoint in California's climate emergency response planning and create a lasting legacy for our state.

We stand ready to support CARB's leadership, side by side with our airline and SAF producer peers, through the development of a mutual and robust SAF campaign that we hope you'll take on through this LCFS Rulemaking.

Very truly yours,

Ivar C. Satero
Airport Director

Comment Log Display

Here is the comment you selected to display.

Comment 283 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nora
Last Name	Cohen Brown
Email Address	nora@charmindustrial.com
Affiliation	Charm Industrial
Subject	Charm's Comments on 2024 Proposed LCFS Amendments
Comment	Please find Charm's comments attached.
Attachment	www.arb.ca.gov/lists/com-attach/6953-lcfs2024-ADAHMwEuB2YANgkn.pdf
Original File Name	02.20.20224 _ Proposed LCFS Amendments Comments.docx (2).pdf
Date and Time Comment Was Submitted	2024-02-20 15:16:53

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
[submitted electronically]

RE: Charm Comments on the Proposed Amendments to the Low Carbon Fuel Standard Regulation

Charm Industrial (Charm) appreciates the opportunity to submit comments to the California Air Resources Board (CARB) on the Proposed Amendments to the Low Carbon Fuel Standard (LCFS) Regulation. Charm is a California-based company working in support of State efforts to rapidly drive down greenhouse gas emissions (GHGs) on the path to carbon neutrality. Our innovative negative emissions technology can play a key role in these efforts. We look forward to continuing to work with CARB, its state agency partners, and all stakeholders to deliver innovative climate solutions that will provide benefits in California and beyond.

About Our Technology
Charm has developed a proven carbon dioxide removal technology that has already removed thousands of tons of carbon from the atmosphere. Our innovative approach converts waste biomass into carbon-rich liquid that is safely and permanently stored underground. Agricultural waste and highly combustible forest residue that would otherwise burn or be left to rot spewing GHGs into the atmosphere is instead transformed into a carbon benefit. In addition to the vital climate benefits that negative emissions technologies like bio-oil sequestration provide, our approach delivers critically needed air quality, wildfire resilience, and economic benefits in parts of California that most need them like the Sierras and the Central Valley.

Charm Supports Strong Carbon Intensity (CI) Targets and a Well Designed Auto-Acceleration Mechanism
California must build on and accelerate actions to rapidly cut GHGs. These actions must include a robust policy and regulatory framework that will take advantage of the

significant benefits that innovative carbon removal and sequestration technologies can deliver, while still prioritizing direct emissions reductions.

274.1 Charm supports the LCFS proposed amendments to increase both the pre- and post-2030 stringency of the LCFS CI benchmarks to incorporate a more stringent CI reduction target of at least 30 percent by 2030 and a 90 percent reduction in fuel CI by 2045 from a 2010 baseline, as well as an initial step-down of at least 5% in 2025. The emission reductions driven by the LCFS program will be critical to ensure California remains on track to meet its climate goals. 274.2 Additionally, a well-designed compliance target acceleration mechanism that functions to increase stringency based on program performance will support critically needed emissions reductions and provide market certainty for ongoing investment in low and zero-carbon technologies.

CARB Should Ensure that Additional Technologies are Rapidly Incorporated into the Existing Regulatory Framework for Carbon Removal within the LCFS

Charm can help support the success of an ambitious LCFS program through its proven carbon dioxide removal technology as one part of a suite of innovative technologies that California will need to meet our climate goals. The kinds of solutions that Charm has developed can also play a key role in supporting California's biomass and forest waste management goals, wildfire and forest resilience actions, and air quality goals. As a California-based company, we are invested in helping the state continue to be a climate leader by putting in place policies that pave the way for innovative technologies and solutions to support climate action. Policies that support emerging carbon-negative technologies will ensure continued investment, job creation, and economic growth for California.

274.3 Consistent with the necessary and ambitious goals for carbon removal technology detailed in the 2022 Scoping Plan, CARB should ensure that as new carbon dioxide removal and sequestration technologies emerge, they can be quickly incorporated into the existing regulatory framework for carbon removal technologies within the LCFS.

Conclusion

Charm is fully committed to helping California meet its climate goals. California is going to need a host of strategies to decarbonize virtually every economic sector in the state to achieve carbon neutrality. While we support ongoing efforts to secure direct emission reductions wherever possible, it is clear that innovative carbon removal and sequestration technologies are also going to be needed for California to reach its climate goals, including carbon neutrality by 2045.

Our company was founded to develop and bring technological solutions to the collective effort needed to turn the tide against climate change rapidly. We look forward to continuing to work with CARB on this challenge.

Sincerely,

Nora Cohen Brown
Head of Market Development and Policy

Comment Log Display

Here is the comment you selected to display.

Comment 284 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Sean
Last Name	Lock
Email Address	Sean@monarchbio.com
Affiliation	
Subject	Comments from Monarch Bioenergy LLC
Comment	See attachment
Attachment	www.arb.ca.gov/lists/com-attach/6954-lcfs2024-AWwAaQZpWGpVIQdk.pdf
Original File Name	Monarch Bioenergy Comments on CARB LCFS Amendments - 20 Feb 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 16:03:43

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

MONARCH

20 February 2024

VIA ELECTRONIC FILING

Matthew Botill
Branch Chief, Industrial Strategies Division
California Air Resources Board 1001 I Street
Sacramento, California 95814

RE: Proposed 2024 Low Carbon Fuel Standard Amendments

Dear Mr. Botill,

Monarch Bioenergy LLC (Monarch) develops, owns, and operates several of the most significant Renewable Natural Gas (RNG) facilities in CARB's LCFS program. As a long-term participant in the LCFS program, Monarch applauds CARB for continuing to develop and enhance the LCFS program, which supports innovative Renewable Natural Gas projects in California and across the United States.

CARB continues to identify RNG's critical role in reducing methane emissions as a potent short-lived climate pollutant, as stated in CARB's 2017 Short-Lived Climate Pollutant (SLCP) Reduction Strategy. The concentration of methane in the atmosphere is increasing at an alarming rate, and there is no more effective and immediate step we can take than to aggressively and rapidly reverse emissions of fugitive methane from all sectors, including society's organic waste streams. Accordingly, Monarch respectfully submits these comments to the California Air Resources Board in response to the Proposed Amendments to the Low Carbon Fuel Standard posted on 19 December 2023.

1. Increase the 2030 Annual Carbon Intensity Benchmark from 30% to 40%

Increased program ambition is critical for continued methane reduction and growth in all low-carbon fuels. Due to the observed surplus of LCFS credits over the last two years, it is crucial to implement a significant reduction in the Annual Carbon Intensity (CI) Benchmarks. The forecast for 2030 indicates an abundance of credits compared to deficits, leading to a rapid build-up in the bank, a decline in prices, and a potential stall in low-carbon fuel investment. To address this issue and to maintain a healthy market, CARB should ideally focus on mitigating the current trend and carefully transitioning from large quarterly surpluses to modest deficits. Setting an appropriate trajectory for the CI Benchmarks and making improved target setting a pivotal aspect of the rulemaking process are excellent ways to achieve this result.

275.1 Monarch supports a more aggressive CI reduction from CARBs proposed 30% target to 40% by 2030. Throughout the rulemaking process, consulting firm ICF, with experience modeling supply and demand for clean fuel programs, has independently analyzed feasible program targets and revealed significant disparities in LCFS credit price outcomes compared to CARB's analysis[1]. The ICF analysis indicates that a 2030 target exceeding 30% CI reduction is achievable with a lower credit price trajectory than anticipated in CARB's LCFS planning scenarios.

[1] *Analyzing Future Low Carbon Fuel Targets in California*, February 2024, https://static1.squarespace.com/static/5b57ab49f407b4a7ffa44ffa/t/65cd3c74d1a72f445cdc7a7e/1707949173143/ICFReport2024.pdf

2. Continue to support and enhance RNG projects based on methane reductions.

275.2 CARB appropriately recognizes the crucial role of reducing methane emissions in the Proposed Amendments in combating global climate change and the positive impact of RNG in facilitating methane reductions, regardless of the project's location or ultimate end-use. To address climate change, we must aggressively and rapidly reverse fugitive methane emissions from all sectors, including organic waste streams. Thus, we encourage CARB to advocate for keeping and even increasing RNG-related opportunities to boost investor confidence, accelerate methane emission reductions, and highlight the urgency of addressing methane as a potent climate pollutant on a global scale.

Leading authorities have echoed the need to reduce methane emissions. In 2023, the International Energy Agency's (IEA) report featured a dedicated section on Biogas and Biomethane[2], underscoring global acknowledgment of biogas in decarbonization. The report forecasts the deployment of renewable energy technologies in electricity, transport, and heat until 2028, addressing fundamental challenges and identifying barriers to industry growth. The IEA highlights the role of biogas and biomethane in fostering a circular economy through residue and waste valorization, contributing to rural economic development, and generating rural employment. Additionally, the US EPA has endeavored to promote anaerobic digester installation for productive energy use for the last 30 years since the inception of the AgStar program in 1994. Both reports support CARB continuing to utilize a fact-based analysis for LCFS updates.

275.3 Until there is a more effective replacement for avoiding methane emissions, CARB should continue to allow avoided methane credits as a pivotal tool to reduce methane emissions. A fixed-year phase-out of avoided methane crediting may jeopardize the viability of future agricultural RNG projects. These projects rely heavily on LCFS revenue for profitability, with avoided methane components essential for meeting capital repayment requirements. Without methane crediting, existing agricultural projects may struggle to cover operating costs, leading to potential closures and the risk of losing the opportunity to abate significant methane release. CARB should not arbitrarily embrace an avoided methane reduction phase-out without a detailed replacement policy for those emissions. This policy is essential to reduce significant LCFS project risks, avoid potentially stranding assets, and ensure continued investment and buildout of projects that can reduce organic methane release wherever possible.

3. Amend Proposed Amendments Deliverability Language

275.4 Request to amend or delete the proposed deliverability amendment language. CARB's requirements, influenced by concepts from California's Renewable Portfolio Standard (RPS), propose mandates for deliverability starting in 2041 for specific biomethane pathways. However, the 50% standard lacks environmental benefit or justification in the current physical gas system. Due to administrative complexity, this requirement could drastically reduce RNG use in California from sources outside of the state under the LCFS. Past experiences, such as RPS deliverability language, have historically created a barrier to imports, hindered facility development, increased costs, and were, ultimately, unsuccessful in creating a well-functioning California-only electric grid. We encourage CARB to revisit the state's learnings from the RPS example and remove the Proposed Amendments deliverability language.

Furthermore, a successful RNG framework should leverage existing gas system realities, avoiding assumptions of a static nature or limiting supply to specific regions. The U.S. natural gas pipeline system is interconnected and bidirectionally flowing, carefully tracking volumes throughout the system with state and federal oversight and third-party pipeline metering. Repurposing the established natural gas infrastructure for efficient delivery of a low-carbon fuel blend, including RNG, aligns with efforts to reduce gas demand through enhanced energy

[2] https://www.iea.org/reports/renewables-2023/special-section-biogas-and-biomethane

efficiency and electrification. Given RNG's physical interchangeability with fossil natural gas, distributing it within the longstanding pipeline system that has efficiently served California for decades is feasible. Therefore, a 50% flow requirement is arbitrary and unjustified, as the gas system's bidirectional nature allows for effective RNG movement across North America.

We encourage building an RNG framework based on the realities of existing gas systems without assuming static conditions and urge CARB to avoid implementing RNG deliverability requirements that favor fossil gas in the interest of fairness and practicality within the gas system.

4. Triggering the Auto Acceleration Mechanism

275.5 Monarch supports adopting an Automatic Accelerator Mechanism (AAM) and amending the proposed language to trigger the AAM earlier. The AAM is a complementary refinement to the step-down in program stringency within the LCFS. This mechanism will dynamically respond to sustained and significant CI reductions by tightening programmatic stringency, increasing investor certainty in credit markets.

Acknowledging the challenges in predicting technological innovation and feedstock availability, the AAM aims to adjust the program's stringency when the market significantly surpasses the set requirements. This feature automatically responds to significant and sustained credit generation beyond program targets while enhancing overall LCFS certainty. By doing so, it encourages ongoing investments and innovation in clean fuels. The credit bank expands when the program experiences substantial overperformance, slowing innovation and investment in low- and zero-carbon fuels. The AAM addresses this by giving the market greater certainty that the program's stringency will automatically adjust based on publicly available data, ensuring a transparent and predictable response to surplus credit accumulation over an extended period.

While CARB's current timeline suggests the AAM's implementation in 2028, Monarch recommends allowing 2025's performance to trigger the AAM. By doing so, CI reduction targets for 2027 will commence one year earlier than in the Proposed Amendments. This clarifies and improves Monarch's ability to make significant additional capital investments in decarbonization projects.

Monarch Bioenergy appreciates this opportunity to contribute to the ongoing dialogue on these central decarbonization topics. We greatly appreciate CARB's continued efforts to find the best solution for the industry and your constituents. Your commitment to addressing these issues is vital for our industry and highly appreciated. We trust that the outcome will reflect a robust and practical framework for the benefit of all stakeholders. Thank you.

Sincerely,

Sean M. Lock

Sean Lock
President and Chief Investment Officer
Monarch Bioenergy LLC

Comment Log Display

Here is the comment you selected to display.

Comment 285 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jeremy
Last Name	Martin
Email Address	jmartin@ucsusa.org
Affiliation	Union of Concerned Scientists
Subject	UCS Comments on 2024 LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6955-lcfs2024-Wi8CZ1MhUFwHYgFu.pdf
Original File Name	UCS Comments on LCFS Amendments .pdf
Date and Time Comment Was Submitted	2024-02-20 16:08:04

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Union of Concerned Scientists

To: California Air Resources Board

From: Jeremy Martin, Daniel Barad, Samuel Wilson, David Reichmuth and Don Anair

Date: February 20, 2024

Subject: LCFS Amendments

The Union of Concerned Scientists (UCS) is a long-standing supporter of the Low Carbon Fuel Standard (LCFS) and has been actively involved in its implementation for more than 15 years. We urge the California Air Resources Board (CARB) to modernize the LCFS to ensure it equitably meets the needs of Californians and supports the attainment of air quality standards. Beyond California's borders, the LCFS is an important policy model for other states and the federal government, which could help address the many deficiencies of the Renewable Fuel Standard. But to meet these needs the LCFS must be modernized, to rebalance credit markets, provide reliable support for non-combustion pathways, strengthen safeguards against deforestation and the diversion of food to fuel use and phase out counterproductive methane digester subsidies that are contributing to dairy and meat industry consolidation.

Rebalance supply and demand for credits by reducing credits that are misaligned with California's goals rather than focusing entirely on increasing stringency.

The low credit prices and growing bank of credits do not simply reflect success and signal a need ramp
stringency faster but are instead sign of disfunction, as a huge share of credits are awarded to vegetable
276.1 oil-based renewable diesel and manure biomethane pathways that do little or nothing to benefit California
and create major problems elsewhere. A durable solution must address the root cause of the problem by
limiting the supply of these counterproductive credits. Limiting supply will stabilize credit prices without such dramatic increases in overall stringency, which will reduce regressive passthrough costs to California drivers of gasoline powered vehicles. While passthrough costs have been very modest to date, CARB should carefully consider the impact of the LCFS on costs to drivers from increasing stringency. Support for transportation electrification has clear returns to California drivers (and people breathing the air) but the same is not true for bidding up the global price of vegetable oil or subsidizing manure digesters in other states.

Update transportation electrification provisions to support a fast and equitable transition.

The LCFS provides vital support for transportation electrification, and as such it underpins other critical regulations that help cars and heavy-duty trucks transition to zero emission vehicles. The Total Cost of Ownership analysis used for the Advanced Clean Fleets Rule was based on an LCFS credit prices of $200
through 2030, while recent prices have been below $80 which creates problems for these policies. CARB
should ensure the LCFS continues to support the transition to electrification by retaining a 2.5% credit
cap for light duty vehicle fast charging infrastructure credits, increase the flexibility and overall credit cap
for the proposed medium and heavy-duty infrastructure credits, facilitate electrification of other modes
276.2 and applications by establishing default energy economy ratios, and support a combination of
electrification and vehicle mile traveled reduction by updating LCFS eligibility for fixed guideway
systems and establishing credit multipliers for mass transit vehicles. Specific recommendations for
improvements to transportation electrification provisions are below.

Cap compliance from vegetable oil-based biofuels to ensure the LCFS doesn't exacerbate global hunger and deforestation.
We published extensive analyses earlier this year on the implications of the boom in renewable diesel consumption in California for global food markets and deforestation (Attachment 1) and why a cap on the use of vegetable oil-based fuels for LCFS compliance is essential to avoid this harm and stabilize the LCFS (Attachment 2). The reasons given in the Initial Statement of Reasons (ISOR) to reject a cap on virgin oil-based fuels in Alternative 1 are based on inaccurate claims of climate and air quality benefits
276.3 and associated health outcomes, which double count climate benefits already required by federal law and ignore CARB's own research on air quality benefits from new technology diesel engines running on renewable diesel. A corrected analysis would show that there are few if any real climate or air quality benefits associated with unlimited use of vegetable oil-based fuels and there are enormous harms. The proposed sustainability guardrails are inadequate because they do not address vegetable oil diverted from
276.4 food to fuel use. Alternative 1 discussed in the ISOR is a useful step forward, but a better solution would
276.5 be to limit the use of all lipid-based fuels at a reasonable share, certainly less than half, of the feedstock available for fuel production in the United States, or about 1.5 billion gallons. While chain of custody
276.6 tracking is an inadequate safeguard against deforestation, it should be implemented for used cooking oil to reduce the risk of fraud.

276.7 **Phase out credits for "avoided methane emissions" and limit LCFS carbon intensity scores to no less than zero to wind down what has become in effect a poorly run offset program.**
We recently published an analysis of the problems caused by crediting manure digesters with avoided methane emissions, substituting an energy subsidy for a much-needed pollution regulation, and creating what is in effect a poorly run offset program (Attachment 3). Negative carbon intensity scores have no place in the LCFS. The LCFS should support the transition away from fossil fuels and hold all fuel producers accountable for pollution in their own supply chains. The California Legislature gave CARB the authority to start regulating dairy pollution in 2024, and CARB should start developing these regulations. However, instead of winding down the subsidies, the ISOR is doubling down, suggesting credit for avoided methane pollution could remain in place for decades after the legislature granted CARB
276.8 the authority to regulate and extending the problems into the power and hydrogen sectors. Using negative carbon intensity (CI) biomethane to generate negative CI electricity or hydrogen is greenwashing, which will subsidize digesters in other states in place of supporting investment to reduce emissions in California.

Carbon sequestration associated with enhanced oil recovery or any fossil fuel extraction should not be credited under the LCFS.
276.9 SB 1314 and SB 905 make it clear the legislature does not support carbon dioxide captured for use in enhanced oil recovery and therefore CARB should exclude this use of sequestered carbon from credit generation within the LCFS whether it occurs within California's borders or outside. Expanded federal support already provides generous support for the use of captured carbon dioxide, and adding LCFS compliance value to federal tax credit effectively subsidizes oil-extraction at the expense of California drivers.

Transportation electrification

To address climate change and reach California's goals of net zero emissions by 2045, the rapid electrification of mobile emissions sources is needed. The LCFS provides a vital source of investment in transportation electrification which complements other state, federal, local, utility, and private investment. Hence the proposed changes to the transportation electrification elements of the LCFS program are particularly important for keeping California's transition on track. UCS urges the following modifications to the proposed electrification components to increase the effectiveness in LCFS support for transportation electrification.

Light-Duty

The fast-charging infrastructure credits for light-duty vehicles have supported the further development and expansion of charging infrastructure in CA and can be a continued catalyst for investment through 2035 as the transition towards 100 percent zero emission vehicle sales continues. UCS urges CARB to
276.10 maintain a program cap of 2.5% credits through 2035, rather than reducing the cap to 0.5% as proposed and to maintain the current power and charging port limits of the current program.

CARB should update the Energy Economy Ratio (EER) for light duty plug-in electric vehicles to reflect the current efficiency of vehicles sold. Based on sales over the prior 5 years, the sales-weighted and utility
276.11 factor-weighted average efficiency of plug-in light duty EVs was 0.305 kWh/mi.[1] When compared to the most recent average fuel economy for the light duty fleet (26.0 mpg), an EER of 4.2 is justified.[2] At a minimum, CARB should increase the EER to 4.0 from the current value of 3.4 approved for light duty electric vehicles.

Heavy-duty

Medium- and heavy-duty vehicles (MHDVs) are responsible for the most significant contributions of lung-damaging and ozone-forming pollutants from vehicles on California's roads and highways. As such, CARB has adopted several transformative regulations, including the Advanced Clean Trucks and Advanced Clean Fleets rules, to accelerate the economy-wide transition to zero-emission trucks and buses. While these rules are necessary to increase vehicle availability and adoption, the LCFS also plays a vital role in this transition, particularly given the large amount of fuel consumed by commercial vehicles and the potential for the program to generate support for early adopters of clean trucks and buses and companies providing charging infrastructure.

We appreciate the recognition of the unique electrification needs of MHDVs compared to LDVs in the draft. However, the current draft could be significantly improved upon by better accounting for the diverse duty cycles and charging needs of currently deployed and forthcoming battery-electric MHDVs, particularly in the language regarding charging infrastructure credits. Where the current draft does not
276.12 maximize potential near-term investments and deployment of zero-emission MHDVs, several tweaks could accelerate and embolden the much-needed transition to electric delivery, short-haul, vocational, and drayage trucks. At the highest level, the LCFS should better balance vastly different electrification barriers and opportunities within MHDV classes and duty cycles.

Increase flexibility of funding for critical electrification catalysts

Staff's current proposal includes a cap on credits for Fast-Charging Infrastructure (FCI) of 2.5 percent of deficits. While we understand the need for LCFS revenue to support a wide range of projects, funding priorities within the program should reflect both the dire need to reduce emissions from the MHDV sector

[1] New electric vehicle sales data for 2019-2023 as reported by the California Energy Commission "ZEV and Infrastructure Stats Data", online at https://www.energy.ca.gov/files/zev-and-infrastructure-stats-data. Model vehicle fuel economy values and plug-in hybrid range data was sourced from US EPA and Department of Energy's fueleconomy.gov website.
[2] "The 2023 EPA Automotive Trends Report: Greenhouse Gas Emissions, Fuel Economy, and Technology since 1975", EPA-420-R-23-033, December 2023.

and the financial barriers facing early adopters and developers of charging infrastructure. FCI is most likely to serve Class 7 and 8 tractor trucks, which consume the largest amount of fuel and contribute the highest amount of pollution among the state's MHDV fleet, despite being a small fraction of total trucks and buses. Additionally, where most commercial electric vehicles are likely to charge at depots, long-haul tractor trucks are far more likely to rely on publicly available FCI as a primary fueling source.

276.13 Given this, it becomes apparent that the development of high-power FCI is a primary barrier to an accelerated shift to zero-emission long-haul freight. Increasing the cap on FCI credits, or developing a dynamic cap based on real-world data including vehicle registrations and ZEV deployment goals, is necessary to address the often-cited barrier of FCI deployment and the very real problem of climate-warming and toxic air pollution from long-haul trucks.

276.14 A successful LCFS can and should facilitate accelerating the electrification of both "low-hanging fruit" and "harder-to-electrify" MHDVs. While FCI development is a primary barrier for long-haul electrification, the vast majority of commercial vehicles in operation – straight trucks, delivery vans, and the like – are unlikely to use public charging regularly or require FCI access due to lower daily mileage and tendency to return to depots each night. According to the US Census Bureau's 2021 Vehicle Inventory and Use Survey data, *78 percent of non-tractor MHDVs travel less than 50 miles on a typical day*.[3] Because of this duty cycle, model availability, and total-cost of ownership upsides, these vehicle types are ripe for early electrification. However, the current draft's prohibition of credit generation at lower power charging depots removes economic incentives for these fleets to electrify sooner. Additionally, high power charging requirements for credit generation may lead to fleets pursuing charging capabilities greater than their needs, which may lead to interconnection delays. It is important that the LCFS include flexibilities that promote the "right-sizing" of charging infrastructure for different types of vehicles and duty cycles.

Geographic and station size restrictions may hinder near-term MHDV electrification

276.15 Current draft language in Section 95486.3 limits the eligibility of MHDV FCI to areas including Federal Highway Administration Alternative Fuel Corridors and areas currently used for MHDVs parking. We assume that staff's inclusion of geographic and charging station power restrictions were meant in some way to focus LCFS support to charging infrastructure development in the most appropriate areas. However, the proposed restrictions are excessive and premature given the current state of the zero-emission MHDV market and infrastructure deployment.

While we appreciate that the current proposed language may be intended to prioritize some of the hardest to electrify MHDVs, the program should include flexibilities to respond to both current and future market trends and align with the ACT and ACF's influences on the market. The proposed geographic restrictions may reduce opportunities for developing zero-emission fueling stations geared towards regional haul and last-mile delivery vehicles in the near term. As mentioned above, these vehicles are far more likely to return to a home base depot each night and are currently well-suited for electrification given their duty cycles and model availability. These vehicles are also on an accelerated electrification timeline in both the ACT and ACF. The LCFS would be in better alignment with these market trends and regulations by allowing for increased geographic flexibility.

Increasing geographic flexibility may help to address common barriers to charging station development including grid capacity, land availability, and zoning. By restricting eligibility to sites currently used as

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[3] United States Census Bureau. "Vehicle Inventory and Use Survey Public Use File." Accessed January 2024. https://www.census.gov/data/datasets/2021/econ/vius/2021-vius-puf.html

vehicle parking or depots, the program fails to consider that these sites may not have existing grid capacity to support fleet electrification. As such, opportunities to accelerate near-term freight electrification may be stifled. A more strategic approach may be to consider phased-in restrictions that consider factors such as market trends, vehicle availability, and grid readiness and aligns with existing regulatory requirements for fleets and vehicles manufacturers.

276.16 While we support increasing geographic flexibilities for zero-emission fueling stations, the program should include restrictions to avoid increasing traffic and noise burdens in communities adjacent to freight and industrial operations. We encourage CARB to work directly with these communities and consult pollution and traffic data when designing credits and incentives for ZEV fueling stations.

276.17 The program should also allow for additional station size and power flexibilities over the near term to influence accelerated zero-emission MHDV deployment. The proposed restriction of 10 FSEs or 10 MW for MHD-FCI sites within one-quarter mile may reduce appetite for early investments in station development. We understand the need for balanced credit generation to maintain sustainable credit prices, however, such restrictions should not be placed on electrified commercial transportation given its emerging natural and clear environmental upsides over combustion fuels.

276.18 Finally, we recommend that rule language regarding restrictions be placed with corresponding eligibility language (such as that in Section 95486.2 (b)(1)), rather than with application requirements, to improve readability.

Facilitate support for electrification of other applications

276.19 There are many electrification opportunities beyond cars and trucks that can contribute to lowering carbon and other tailpipe emissions from the use of combustion fuels. However, they lack a readily accessible pathway to participate in the LCFS. CARB should establish default EERs for equipment, vehicles, and vessels in emerging electrification applications such as agriculture and forest management, mining, marine, aviation, and other off-road to facilitate market participation and encourage greater electrification. Establishing default, conservative EERs would provide support for these emerging opportunities and minimizing complexity and barriers to participation.

Prioritize support for zero emissions transit to support communities and reduce car dependence

276.20 To ensure the LCFS is aligned with the vehicle mile reduction targets of the scoping plan, CARB should remove the penalty on credit generation for fixed guideway systems installed prior to 2011. This penalty is inconsistent with the treatment of other fuels and should be corrected to ensure the LCFS appropriately supports one of the most vital strategies to support CARB's Policy Framework to Advance Sustainable and Equitable Communities. If older fixed guideway transit system were treated the same as newer systems, they would generate 3.1 to 4.6 times as many LCFS credits, depending on the type of vehicles that use the system. This would help cash-strapped systems maintain and improve service, reduce car dependence and ease the associated burdens that are inequitably borne by California's low-income communities and communities of color.

276.21 CARB should also implement a credit multiplier for zero-emissions mass transportation vehicles to account for the outsized impact of vehicles that reduce vehicle miles travelled on the carbon-intensity of California's transportation fuels. For example, a 2x multiplier would be appropriate in support of the Scoping Plan objective to double transit capacity and service frequency by 2030.

Attachment 1. Everything You Wanted to Know About Biodiesel and Renewable Diesel. Charts and Graphs Included

January 10, 2024. Available online at https://blog.ucsusa.org/jeremy-martin/all-about-biodiesel-and-renewable-diesel/

Back in 2016 I wrote a long post about biodiesel, explaining what it is made from (mostly vegetable oil) and arguing that EPA should show restraint in setting targets for biodiesel because of the limited availability oils and fats and the harmful consequences of drawing too heavily from these limited sources. The world has changed in many ways since 2016, but the large-scale diversion of vegetable oil from food to fuel remains a bad idea. Now it is California policymakers' turn to establish sensible guardrails on fuel policies to avoid creating problems in California, and around the world.

Since 2016, EPA has generally shown restraint in setting targets for biodiesel and related fuels, insofar as the law allows, and biodiesel consumption has actually fallen. But in its place renewable diesel is booming, produced in large oil refineries retrofitted for the purpose and consumed primarily in California. Biodiesel and renewable diesel are closely related fuels made from the same oils and fats, which remain scarce, expensive, and linked to deforestation and food price spikes.

For this reason, it is important that policy makers, not only at EPA but also in California, are realistic about the sustainably available supply of oils, and implement fuel policies to avoid excessive diversion of vegetable oil into transportation fuel production. The idea that a large number of oil refineries can keep humming along by replacing petroleum diesel with vegetable oil or used cooking oil is a dangerous illusion. Biofuels can play a productive role when used at a sustainable level. But we need to be realistic about where they come from, and limit feedstocks to sustainable resources used at a reasonable scale to avoid turning a helpful tool into a harmful dead end.

This article draws heavily from a series of articles on the Renewable Diesel Boom by Maria Gerveni, Scott Irwin and Todd Hubbs at farmdoc daily that I heartily recommend for more quantitative economic analysis. The conclusions and policy recommendations are purely my own.

Biodiesel and renewable diesel are mostly made from vegetable oil

Biodiesel and renewable diesel are made from the same starting materials, are both blended into diesel fuel, and are supported by the same regulations. Collectively biodiesel and renewable are referred to as bio-based diesel, which is especially relevant when considering the availability of oils and fats.

More than 80 percent of bio-based diesel is made from vegetable oil (the rest is mostly animal fats). The soybean and canola oil that make up the majority of biodiesel is basically the same as the cooking oil you buy at the grocery store, while the corn oil is mostly an inedible byproduct of ethanol production that is generally used for animal feed and other purposes. Yellow grease is a catch all term that includes used cooking oil as well as lower quality tallow from rendering facilities.

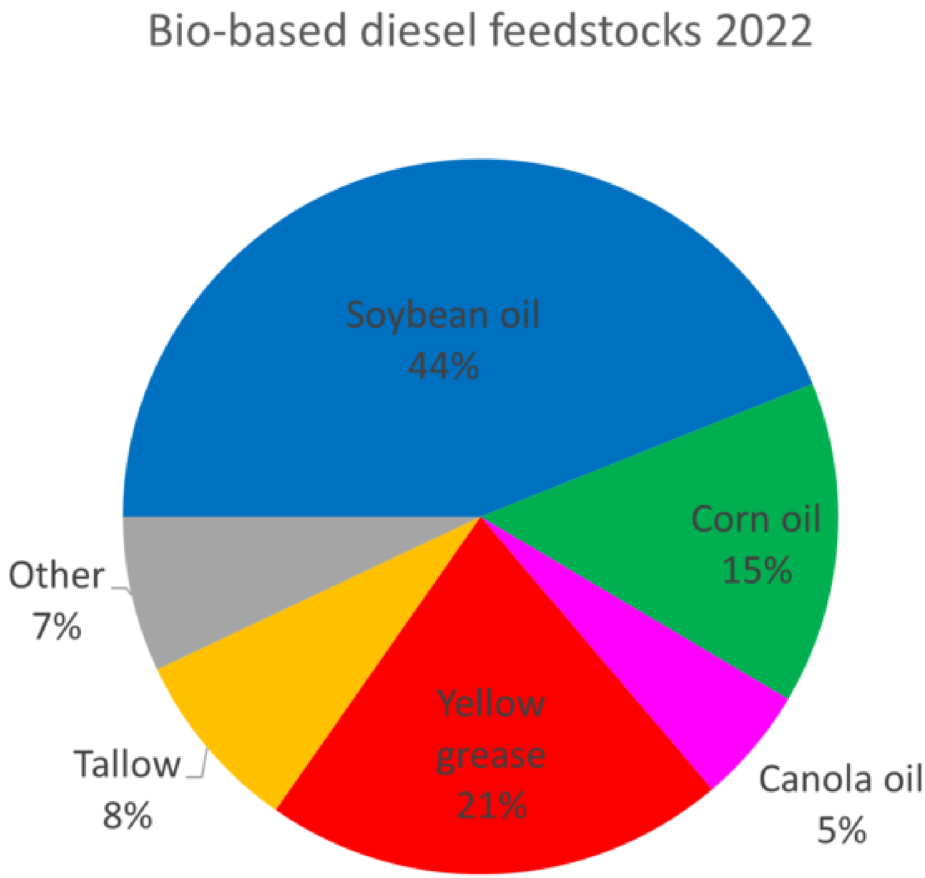


Figure 1. Most bio-based diesel fuels are made from vegetable oil. The chart above shows the oils and fats used to make biodiesel and renewable diesel in 2022. (Source EIA Monthly Biofuels Capacity and Feedstocks Update)

Using more oils and fats for fuel instead of food and animal feed has consequences for competing users of these products and for the global agricultural system. Of particular importance from a climate perspective is the relationship between rising use of oils and fats for fuel in the United States and soybean expansion in South America and palm oil expansion in Southeast Asia, both of which are major drivers of deforestation and global warming pollution. Figure 1 above shows that palm oil itself is not a significant direct source of US biofuel production. However, there are important indirect links between how much soybean oil bio-based diesel we use in the US and how quickly palm oil plantations expand in Indonesia or Malaysia. I'll get to these connections shortly, but first, let's consider the relationship between biodiesel and renewable diesel.

Renewable diesel is the fastest growing part of the US biofuel market

Biofuels overall account for a small but growing share of US transportation energy. Figure 2 shows that petroleum supplies 94 percent of US transportation energy while biofuels are 6 percent. Of the biofuels, ethanol, biodiesel and renewable diesel make up 70, 13 and 14 percent respectively. Ethanol consumption grew rapidly between 2000 and 2010 but after 2010 biodiesel took over as the major source of biofuel growth before being eclipsed by renewable diesel after 2016.

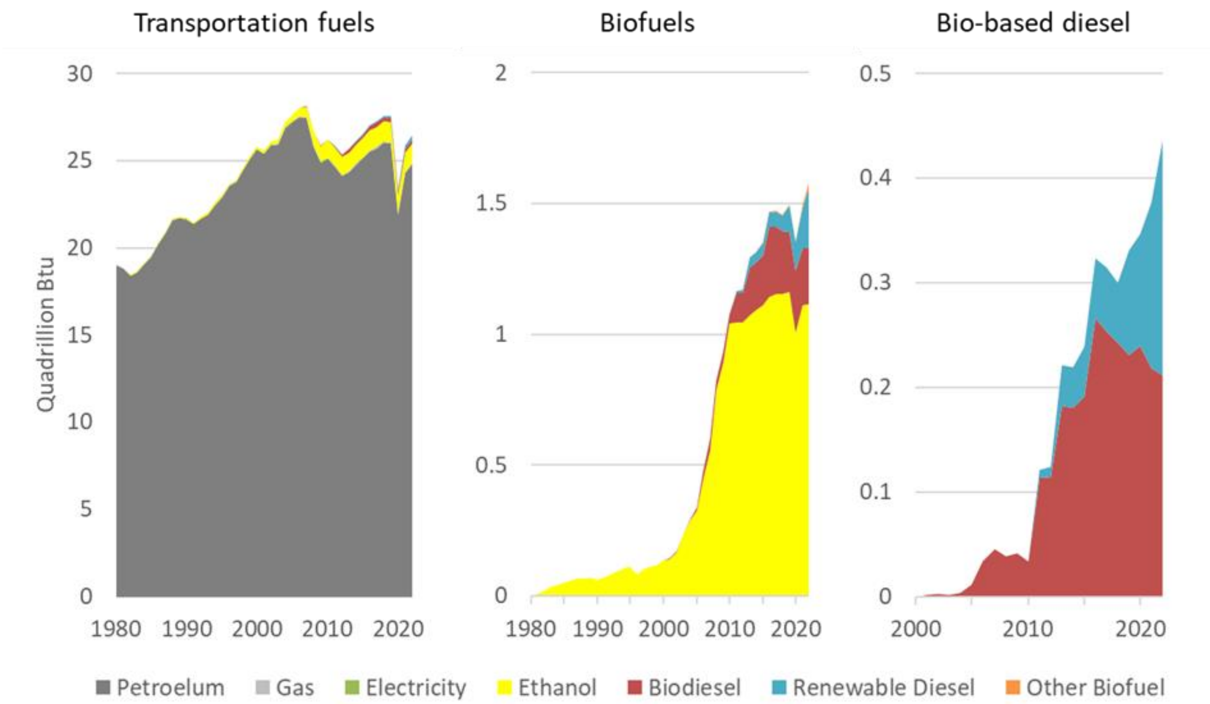


Figure 2. While ethanol remains the largest US source of biofuel, biodiesel and more recently renewable diesel have accounted for most of the growth since 2010. Source US Energy Information Administration.

Biodiesel versus renewable diesel

Biodiesel and renewable diesel have several similarities and a few key differences. Both fuels are made from vegetable oils and fats and are blended into diesel fuel. Both fuels satisfy the requirements of the Federal Renewable Fuel Standard (RFS), which requires oil companies to blend biofuels into the gasoline and diesel they sell. So, in that sense biodiesel and renewable diesel compete for both feedstock and customers.

Biodiesel = an additive blended into diesel
Renewable diesel = a replacement for diesel fuel
Bio-based diesel = biodiesel + renewable diesel

Although biodiesel and renewable diesel are derived from the same feedstocks, the processes used to make them are different. Renewable diesel production uses a hydrogen treatment to remove oxygen from the fats and oils, while biodiesel is produced by a less complex process and retains some oxygen.

Renewable diesel, like fossil diesel, is a pure hydrocarbon and is so similar to fossil diesel that they can be used interchangeably. That is why renewable diesel is often described as a “drop in” fuel. By contrast, biodiesel is limited to specific maximum blends (usually 5 or 20 percent) and higher blends must be specially labeled and their use is limited to compatible vehicles.

The hydrogen treatment used to remove oxygen from the fats and oils increases the costs of renewable diesel production, but adds flexibility, so the latter may be produced from animal fats that are less readily made into biodiesel.

These differences also connect to historical and geographical differences. The growth of the biodiesel industry was promoted by soybean producers as a way to expand the market for soybean oil. As such it is not surprising that the Midwest has 70% of U.S biodiesel capacity, which is primarily in Iowa, Missouri, Illinois, and Indiana.

The renewable diesel industry is less centralized, but the largest share of production capacity, 60 percent, is in the Gulf Coast states, primarily Louisiana and Texas. US renewable diesel production was initially linked to animal fat. Tyson Foods helped launch a Renewable Diesel facility in Geismar, Louisiana that started up in 2010 as the first large US producer of renewable diesel made from animal fat.

More recently, much of the growth in renewable diesel has been from converted oil refineries, which already have the facilities for hydrogen treatment as well the logistics to receive trains or tanker ships of incoming oil (fossil or vegetable) and ship out finished diesel fuel. The oil industry increasingly controls bio-based diesel fuel production. Among other links, in 2022 Chevron purchased the largest biodiesel producer in the US, the Renewable Energy Group, and Marathon Petroleum and Phillips 66 are converting oil refineries to produce renewable diesel.

Perhaps the most notable difference between biodiesel and renewable diesel is that since 2016 renewable diesel consumption has been booming while biodiesel consumption has been declining. Biodiesel consumption in the US peaked in 2016, and by 2022 had declined 24 percent, while renewable diesel use has risen rapidly, growing almost 4-fold between 2016 and 2022. In 2022 renewable diesel surpassed biodiesel for the first time and combined the two sources of bio-based diesel now account for 7.3 percent of US diesel fuel consumption by volume.

Renewable diesel is (mostly) a California story

Most of the renewable diesel consumed in the United States is consumed in California (Figure 3). The concentration of renewable diesel in California is partly the result of California's Low Carbon Fuel Standard policy, discussed later in this post. In 2022 California consumed half of US bio-based diesel. Rising California consumption has come partly at the expense of biodiesel consumption elsewhere in the US, which fell 28% percent in 2022 compared to its peak in 2016.

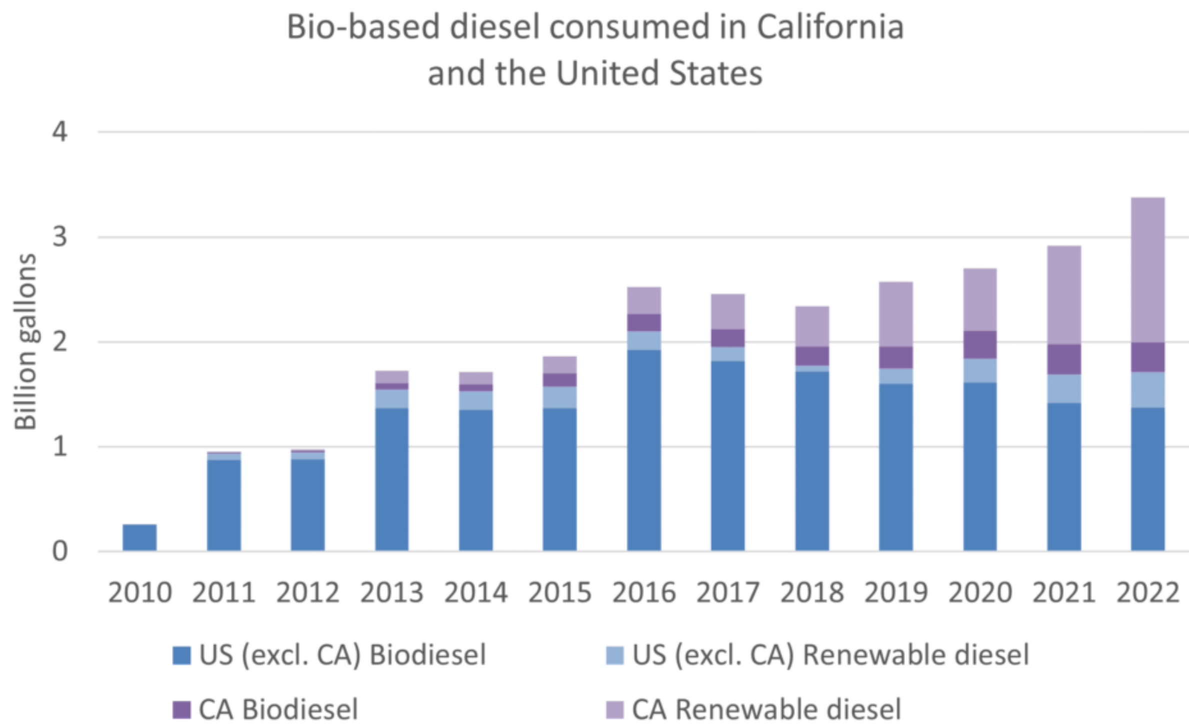


Figure 3. Since 2016 California has dramatically increased consumption of renewable diesel, partly at the expense of biodiesel used elsewhere in the US. California Air Resources Board, US Energy Information Administration.

The blend rate of bio-based diesel in California is rising rapidly. In the first half of 2023, the combined share of renewable diesel and biodiesel rose to 59 percent of total diesel fuel use in California. Outside of California the share of bio-based diesel has fallen from 5 percent in 2016 to only 3.8 percent in 2022. A recent analysis from researchers at the University of California Davis found a 50 percent chance that petroleum diesel would disappear from California by 2028.

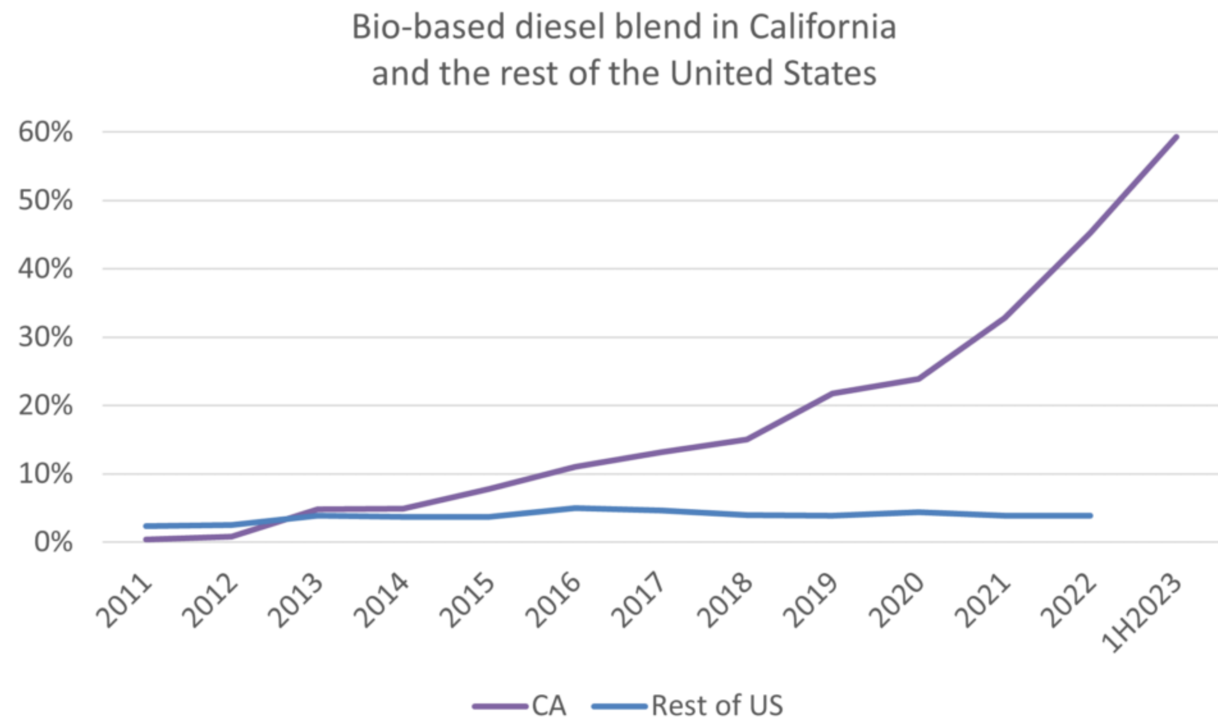


Figure 4. The share of renewable diesel and biodiesel blending into diesel fuel sold in California has grown rapidly and in the first half of 2023 it reached 59 percent. Outside of California the blend rate fell, from a peak of 5 percent in 2016 to 3.8 percent in 2022. Source California Air Resources Board, US Energy Information Administration.

Renewable diesel production capacity is poised to grow rapidly

Renewable diesel production capacity in the United States is in the middle of a massive expansion. Production capacity grew by 400 percent between 2019 and 2022 and based on announced and planned projects, it could double again by the end of 2024. The figure below from a recent analysis of *farmdoc daily*, March 29, 2023 illustrates the massive, planned capacity buildout for renewable diesel. Whether all these facilities get built and operate at their full capacity depends a lot on policy decisions in California, DC and elsewhere.

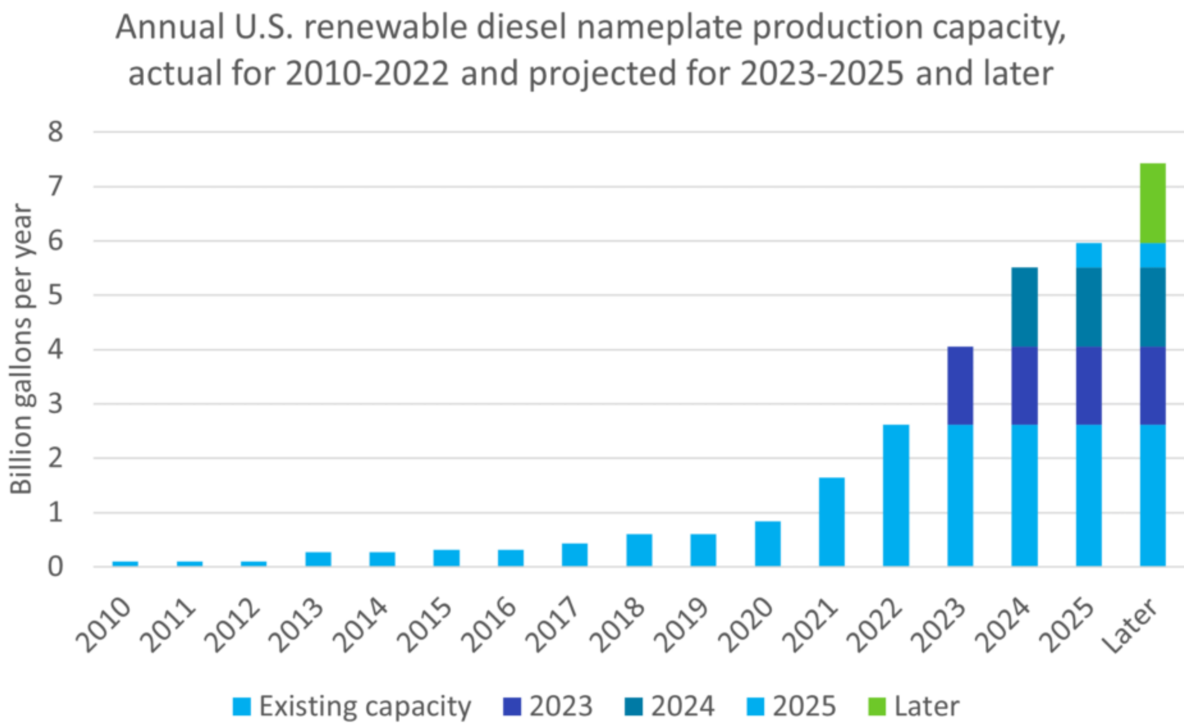


Figure 5: Renewable diesel production capacity has expanded dramatically and is poised to grow much further. farmdoc daily, [March 29, 2023](#).

California is at the eye of the storm, both as the main driver of demand and soon as a major producer as well. Two thirds of the capacity planned for 2023 and 2024 is in California, especially two projects in the San Francisco Bay area, the Marathon Martinez and Phillips 66 Rodeo refineries. These two facilities plan to bring on-line capacity of more than 1.4 billion gallons by the end of 2024.

Converted oil refineries

An important caveat to keep in mind when looking at renewable diesel capacity growth announcements, both recent and planned, is that the renewable diesel production facilities are generally not new facilities being built from the ground up for renewable diesel production. Many are oil refineries being converted from fossil fuel production to renewable fuel production. Petroleum refineries are massive compared to biofuel facilities. The difference in scale reflects both the larger scale of the demand for petroleum fuel and the economies of scale associated with the required facilities and infrastructure, including pipelines and ports to offload crude from tankers. Biofuel production facilities have generally been built on a smaller scale, reflecting the economic advantage of producing the fuel closer to where the vegetable oil or animal fat is produced.

Because oil companies are converting facilities they already have, the decision on capacity is based in part on the scale of the facilities they are converting. If these were new construction projects, the massive capacity expansions might be interpreted as reflecting a strong belief by investors that demand is likely to expand a commensurate amount, otherwise it would be foolish to invest their money. But for an oil company with an excess refining capacity, the decision to convert to renewable diesel may have a much lower threshold, and the capacity may be a function of the capacity of the existing infrastructure as much as a bet of new money on the scale of a new opportunity.

Another motivation for renewable diesel conversions is to help oil companies more cost effectively meet their obligations under the federal RFS and state fuel policies. The RFS requires companies selling gasoline and diesel to purchase biofuels to blend into the fuels they sell or else purchase credits from others who sell biofuels. The decision to convert an unneeded oil refinery to renewable diesel production facility reflects a decision that it is more cost effective to buy the feedstock and directly produce the fuel required for compliance compared to buying the fuel or associated credits from someone else. Selling renewable diesel in California also helps refiners satisfy the requirements of the California LCFS.

Finally, the conversion of a petroleum refinery to renewable diesel is attractive in part because it forestalls the need to begin a costly and complicated process of decommissioning an old refinery. UCS commissioned a recent report about lessons learned from the closure of a Philadelphia Oil refinery, which highlights how reluctant refiners are to close their refineries. A conversion to renewable diesel postpones the day of reckoning and gives the refinery owner more time to develop the most advantageous exit strategy.

The bottom line is that oil companies have a clear motivation to overstate the potential to convert oil refineries to biofuel production. The realistic potential for biofuel conversions is quite small because of the limited availability of suitable feedstocks. Exaggerated hype about potential for refinery conversions to biofuel production amounts to greenwashing that distracts from more scalable solutions.

Fuel markets are much bigger than feedstock markets

Securing adequate feedstock is a very different challenge than finding excess petroleum refining capacity. It is clearly not feasible for many states or the whole country match the rapid scaleup of bio-based diesel underway in California because the feedstocks are just not available. To produce 100 percent of 2022 US diesel fuel consumption in the transportation sector would require more than 160 million metric tons (MMT) of feedstock, which is 10 times US production of vegetable oils in 2022 or 80 percent of global vegetable oil production in 2022 (Source US Energy Information Administration, USDA Foreign Agricultural Service)[4]. To get a handle on the realistic potential for bio-based diesel, and the consequences of rapidly ramping up production, we need to explore the current and potential future supply of feedstock.

Where does the feedstock come from?

Figure 6, produced using data from *farmdoc daily* December 11, 2023, December 20, 2023, illustrates the feedstock used to produce the bio-based diesel fuels produced in the United States. Total feedstock consumption more than doubled in the last decade, exceeding 11 MMT in 2022. Imported bio-based diesel fuel consumed another 1.0 MMT of feedstock for fuel production abroad, so total US bio-based diesel consumption in 2022 required 12 MMT of feedstock, half of it to supply fuel to California.

[4] In the discussion of feedstock requirements I make a few simplifying assumptions about conversion rates and report everything in millions of metric tons (MMT). My estimates are based fuel consumption data from EIA reported in gallons and assuming 7.55 pounds of feedstock per gallon for biodiesel and 8.125 pounds per gallon for renewable diesel, consistent with *farmdoc daily*, May 1, 2023. Actual values will vary by feedstock, conversion process and facility, but this should be a reasonable and consistent approximation.

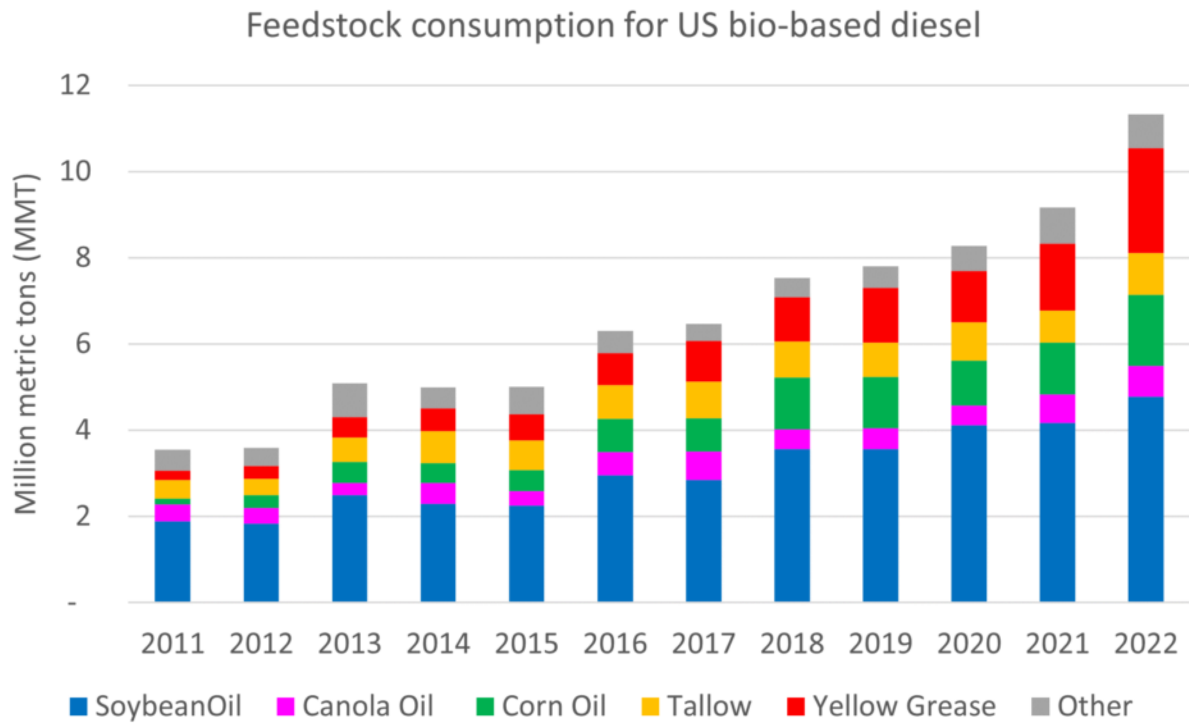


Figure 6. Feedstock consumption for bio-based diesel fuel produced in the US has more than doubled since 2012 and exceeded 11 MMT in 2022. Source *farmdoc daily* December 11, 2023, December 20, 2023.

Soybean oil is by far the most important source of bio-based diesel feedstock, accounting for almost half of the total. Combined with corn and canola oil, vegetable oils make up more than two thirds of feedstock. Yellow grease and tallow make up most of the remaining oil. Yellow grease includes used cooking oil and some other animal fats.

The US Department of Agriculture tracks the share of US vegetable oil production devoted to bio-based diesel, which has risen steadily and exceeded 40 percent in 2022.

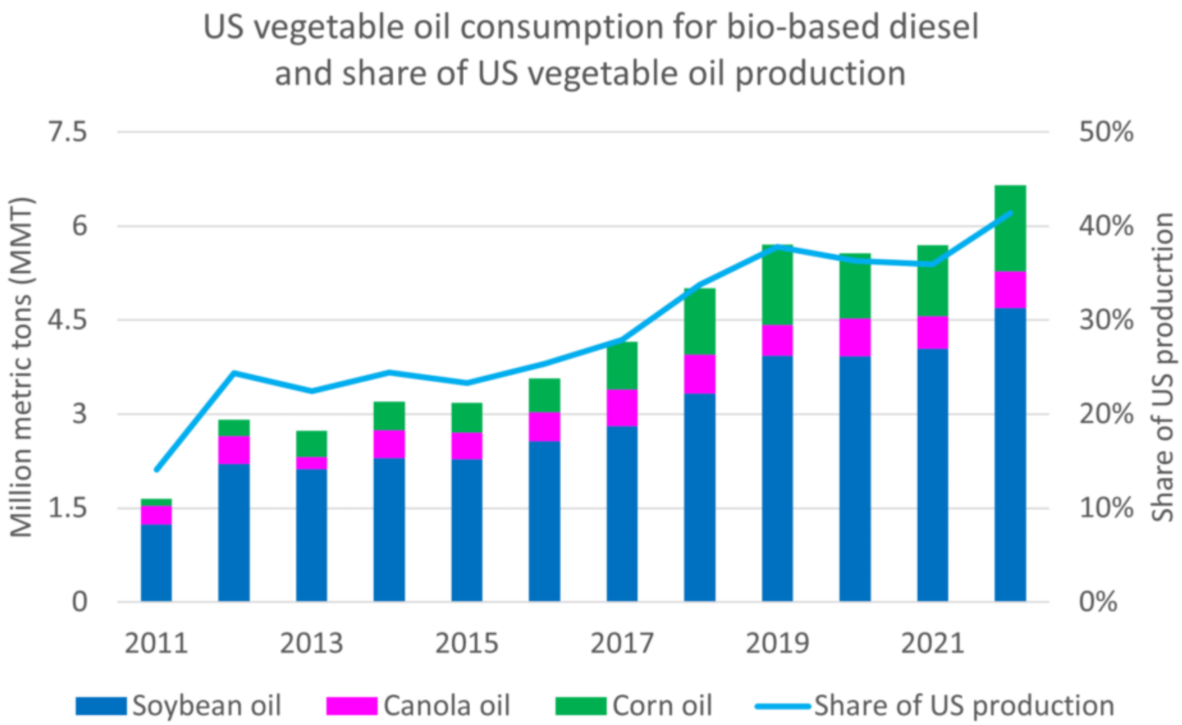


Figure 7: Use of vegetable oil to produce bio-based diesel increased more than 4 fold between 2011 and 2022 and the share of US vegetable oil production used for biofuels exceeded 40 percent in 2022. Source USDA Oil crops yearbook.

Statistics for yellow grease, tallow and other feedstocks are less well documented, so it is hard to assign a precise share, but experts agree that a large share of the available resources are now being used to produce the bio-based diesel.

The growing share of US vegetable oil used for bio-based diesel production is reflected in the balance of US trade in vegetable oil. Net vegetable oil imports grew by about 4 MMT between 2006 and 2022, especially canola oil and palm oil, which have replaced soybean oil in food uses. This has been a gradual process that reflects both changing consumer preferences and diversion of soybean oil to fuel production. More recently the US has effectively exited the export market for vegetable oil entirely and is now the 4th largest importer of vegetable oil after India, China and the European Union (USDA Foreign Agricultural Service).

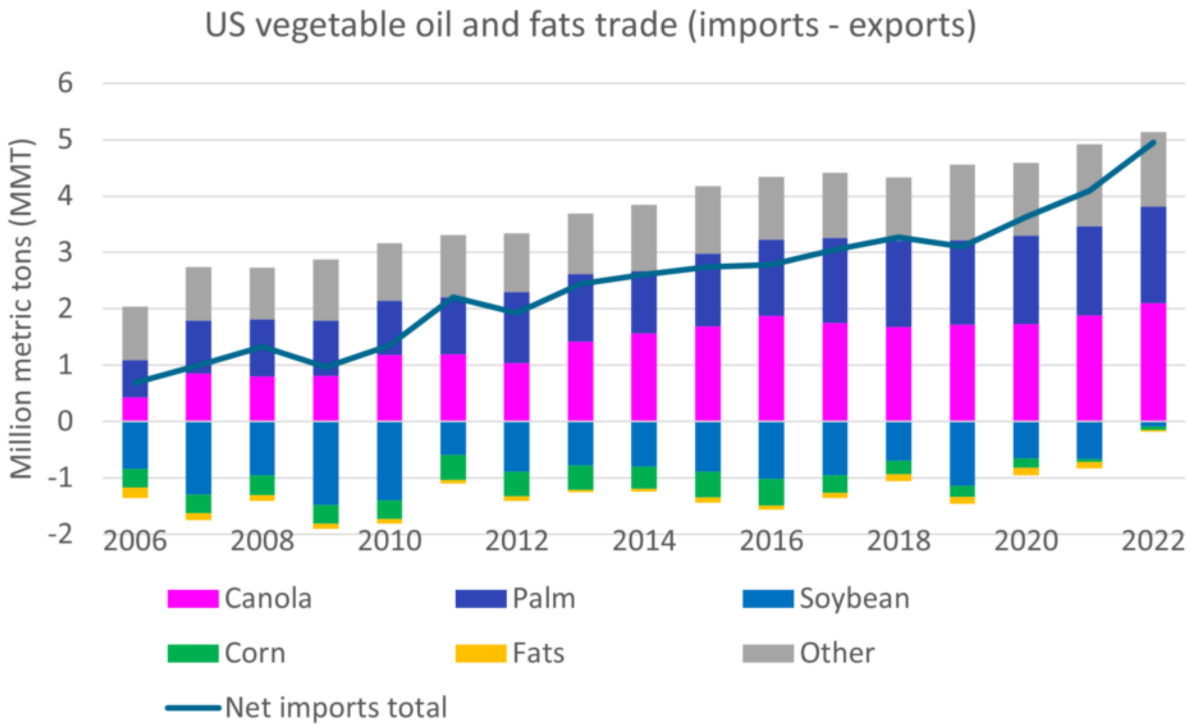


Figure 8. US vegetable oil imports have steadily risen, and exports have fallen as bio-based diesel production has climbed. Source USDA Oil Crops Yearbook.

How much feedstock is needed for future bio-based diesel production?

Scaling up bio-based diesel production requires more than production capacity; it also requires feedstock and demand. Figure 9 summarizes the quantity of feedstock that would be consumed if the planned renewable diesel facilities are built and operate at full capacity and the biodiesel industry continues to operate at its capacity as of the end of 2022. Capacity for feedstock consumption could rise by 10 to 20 MMT a year, or even more, a massive increase compared to the 11 MMT of actual US consumption in 2022. Declining production of biodiesel could potentially free up some feedstock for renewable diesel production, but since only 6 MMT of feedstock was used for biodiesel in 2022, even completely shutting down biodiesel production would free up just half of the feedstock required by renewable diesel capacity expansion announced for 2023 and 2024.

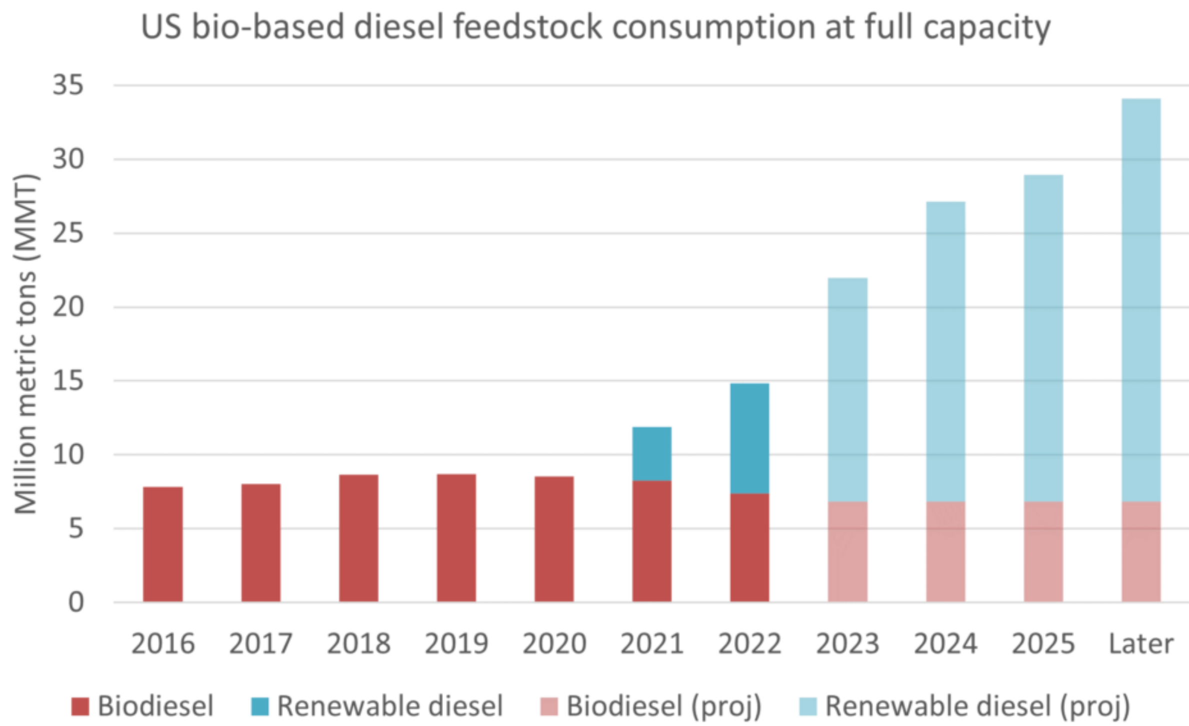


Figure 9: Combining current and announced renewable diesel production capacity and existing biodiesel production capacity, total feedstock consumption at full capacity could reach 34 MMT in the next few years. Source Energy Information Administration and farmdoc daily, March 29, 2023.

Where could an additional 10-20 MMT of feedstock come from?

The scale of demand for vegetable oil required to operate planned renewable diesel capacity is so large that meeting it would require dramatic changes to global markets for oils and fats with major implications for food consumers around the world and tropical deforestation. The bottom line is that palm oil is the only source of vegetable oil that could plausibly scale up to provide 10-20 MMT of additional vegetable oil in the next few years. Since palm oil is not an eligible feedstock for US biofuel production, other sources of oil, especially soybean oil, would most likely be diverted from food to fuel, while palm oil backfilled the soybean oil. It may seem absurd to even discuss increases this large, but analysis commissioned by a trade association for the renewal diesel industry argued recently that US feedstock for bio-based diesel could rise to 32 MMT in 2030, primarily from soybean oil.

A detailed explanation is provided in the appendix, but the main points are summarized below. Figure 10 shows global vegetable oil production in 2022.

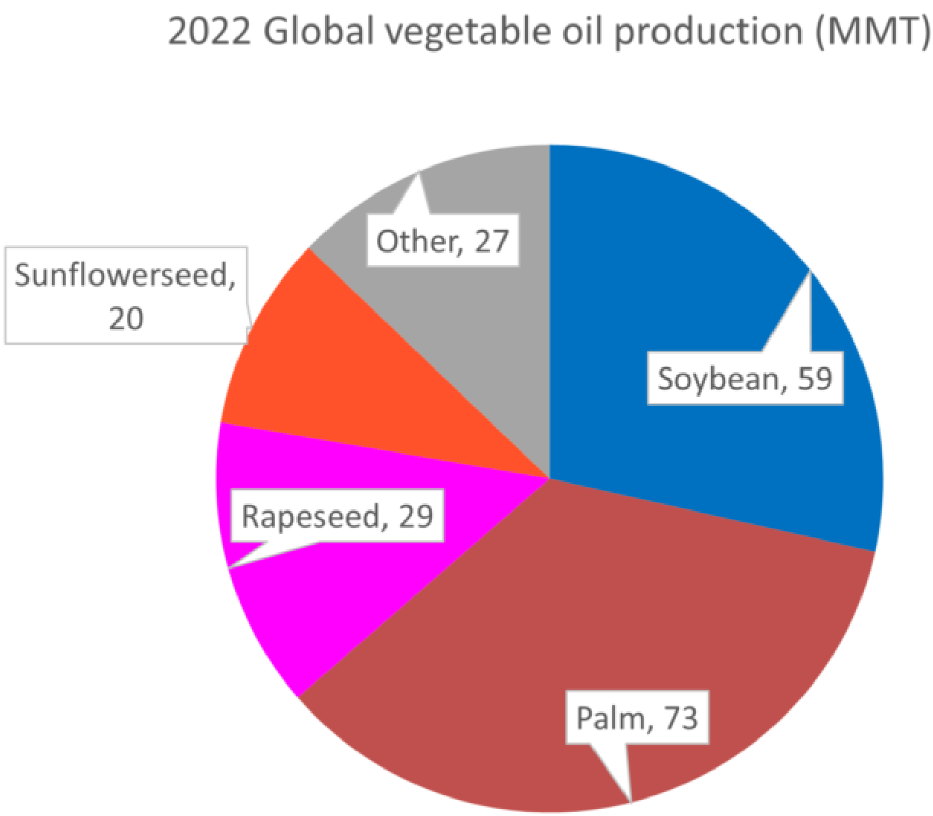


Figure 10: Global vegetable oil production in 2022 totaled 208 MMT of which palm oil accounted for 35 percent and soybean oil 29 percent. Source USDA Foreign Agricultural Service Oilseeds: World Markets and Trade.

Soybean oil accounts for three quarters of US vegetable oil production, and 29% of global production. and is the most plausible sources of supply for large increases in domestic production. To secure millions of metric tons of additional soybean oil, the US would need to reduce exports of whole soybeans and start importing soybean oil from Argentina and Brazil. If US oil companies are willing to outbid all other consumers, they could theoretically secure 10-20 MMT of additional RFS eligible feedstock. The bidding war would pit US oil companies against people's food consumption. Over the longer term, oil crop cultivation would catch up with demand and stabilize prices. But because soybean oil is a joint product with soybean meal, it is not economic to expand soybean production faster than demand for soy meal as animal feed. Thus, the additional vegetable oil required to replace the soybean oil used for fuel will mostly come from palm oil, which together with soybean oil made up 64 percent of global vegetable oil production in 2022. Domestic production and imports of other oil crops like canola/rapeseed and increased imports of used cooking oil from around the globe can contribute a small amount. But at the scale of the biodiesel boom there is no plausible source of feedstock other than soybean oil backfilled in cost sensitive food markets by palm oil.

Advice to policymakers

The idea that oil refineries can keep humming along by replacing petroleum diesel with vegetable oil or used cooking oil is a dangerous illusion. Having US oil companies backed up by billions of dollars in direct and indirect subsidies compete on the global market for vegetable oil to make into fuel is an expensive dead-end that does not support investment in scalable low carbon technology but drives up food prices and ultimately serves mostly to expand the cultivation of palm oil to replace the soybean and other oils made into fuel.

When policymakers subsidize new technologies, the justification is often the potential that scaling up a new technology will lead to cost reductions over time. But producing soybean oil and refining it at existing oil refineries is not catalyzing any fundamentally novel technology, so there is no reason to expect breakthroughs in cost to result. Policymakers need to pay attention to where the vegetable oil and feedstocks for bio-based diesel fuels come from. And when policies are placing an unsustainable draw on scarce resources, they need to act decisively to limit feedstock utilization at a sustainable level.

Today the renewable diesel boom in California is at risk of becoming a crisis, and policymakers at the Air Resource Board must act now to stop the massive expansion of soybean oil-based renewable diesel. California officials should ensure that California does not use more than half the US supply of feedstocks for bio-based diesel and related fuels.

A comparison with electric vehicles in instructive. In 2016, California accounted for 50 percent of the registrations of passenger car EVs in the US. Since that time, EV registrations in California have grown 540 percent, but registrations in the rest of the US have grown even faster, so the share of EV registrations in California has fallen to 37 percent (Source: Alternative Fuels Data Center). Over the same timeframe, consumption of renewable diesel in California has grown almost as fast as EV registrations, up 440 percent between 2016 and 2022. But where early action by California policymakers led to reduced cost and increased availability of EVs elsewhere, California's appetite for bio-based diesel feedstocks led to a decline of bio-based diesel consumption in the rest of the United States, with US consumption of bio-based diesel outside of California falling 19 percent between 2016 and 2022. The biodiesel boom is increasing costs and decreasing availability of renewable diesel and biodiesel in the rest of the United States and if the boom in California is not contained, it will lead to disruptions of global vegetable oil markets and accelerate tropical deforestation. More details on UCS's proposals to reform the Low Carbon Fuel Standard can be found here.

Ultimately, excessive utilization of any source of biofuel can become a problem if exploited at an unsustainable level. Biofuels can play a productive role if the crops used to produce them are grown without displacing food production or expanding the footprint of agriculture onto sensitive ecosystems. Policymakers need to be realistic about where biofuels come from, and limit feedstocks to a sustainable scale to avoid sending our fuel policies down a damaging dead-end road.

Appendix: Where could an additional 10-20 million metric tons of vegetable oil to produce bio-based diesel come from?

Soybean oil

Soybean oil is the natural place to start a search for additional US bio-based feedstock, since it accounts for 70 percent of US vegetable oil production and is the only domestic feedstock that could plausibly scale up by several MMT in a few years' time. As shown in Figure 1 below, the US produced almost 12 MMT of soybean oil in 2022, or which 4.7 MMT was used for bio-based diesel production.

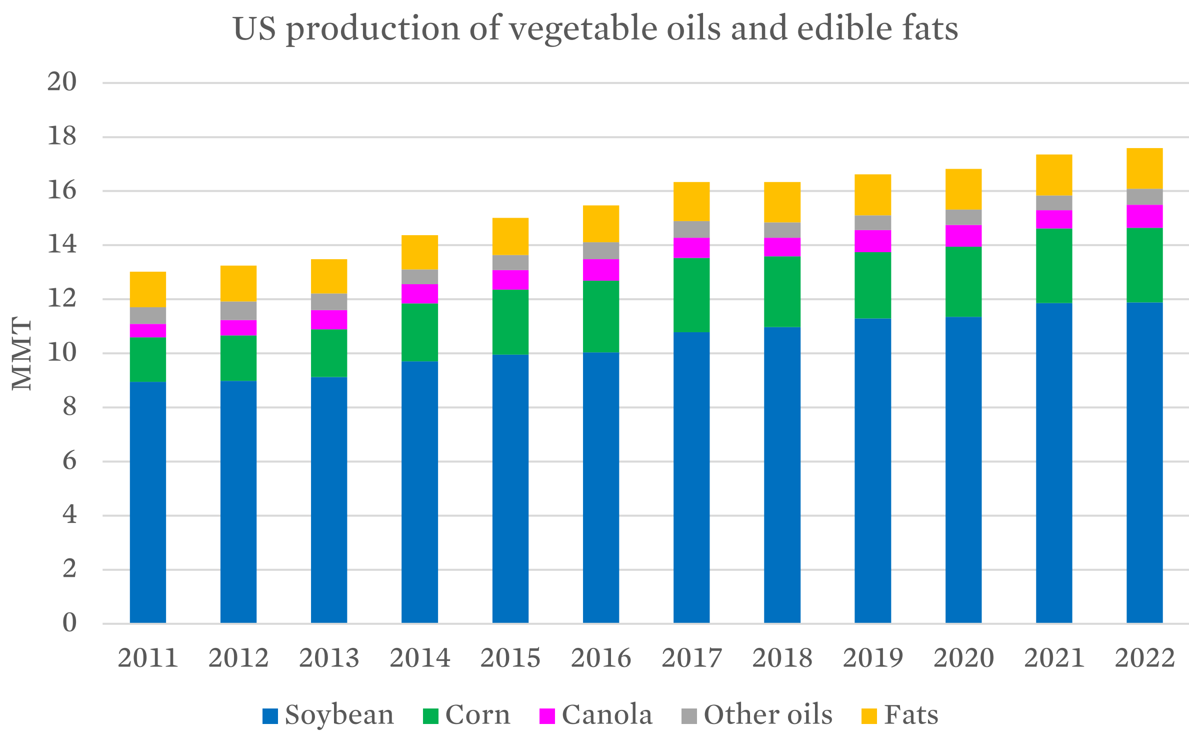


Figure A1. Soybean oil is the largest source of vegetable oil. Source USDA Economic Research Service Oil Crops Yearbook.

As shown in Figure 8, between 2006 and 2010 the US exported between 0.8 and 1.5 MMT of soybean oil, but has recently stopped exporting soybean oil and is projected by USDA to become a net importer of soybean oil in marketing year 2023/2024 (USDA ERS).

But US soybean oil production tells only part of the story since the US is a major exporter of whole soybeans. The soybeans exported by the US are processed, or crushed, in the importing countries into soybean oil and protein meal, used for animal feed. In recent decades the US has exported between a third and a half of the soybeans it produces, about 2 billion bushels in recent years. Crushing an additional 2 billion bushels of soybeans in the US would yield about 10.7 MMT of oil, or enough to produce 2.9 billion gallons of renewable diesel. Combining this with the soybean oil the US produced in 2022 leads to a total of over 22 MMT. Since only 5 MMT of soybean oil was used for fuel in 2022, the

US could more than double bio-based diesel production by redirecting US soybeans away from existing markets for vegetable oil and whole soybeans.

The idea that the US should scale up domestic production of bio-based diesel by crushing all of US soybeans for fuel production is effectively the argument made by the Advanced Biofuels Association backed up by an analysis suggesting that [US feedstock for bio-based diesel could rise to 32 MMT in 2030, primarily from soybean oil]. However, idea that the US could crush all of its soybeans ignores the practical barriers to crushing more soybeans and the more profound consequences of changes in global markets for food and agricultural commodities as the US redirects food into fuel markets.

Crushing more US soybeans

In the last few years, as renewable diesel producers made plans to increase production, so did the soybean crushing industry. Some of these were partnerships, such as the Marathon Petroleum partnership with [ADM in North Dakota]. By the end of the 2022, 23 [new facilities or expansions had been announced totaling 750 million bushels a year of new crushing capacity], equivalent to 4 MMT of soybean oil, which would increase US crushing capacity by 34 percent if they were all completed as planned.

Dramatically increasing US soybean crushing for domestic biofuel production has complex and uncertain implications for three commodities: (fuel, vegetable oil and meat) especially in three regions of the world (North America, South American and Asia).

Soybean economics

Soybeans are an interesting crop, connected to their sister crop corn in complex ways in the agriculture, food and fuel system. While you may occasionally encounter soybeans in their immature form as edamame, the majority of soybeans are crushed to make soybean oil and a high protein meal that is mixed with corn in animal feed.

Historically, soybean meal has been the more valuable product of soybean crushing, often worth twice as much as the oil. The economics of soybean production depend jointly on the oil and the meal. As you would expect, increased demand for soybean biodiesel will raise demand and prices for soybean oil, but meal goes the other direction. As more soybeans are crushed to supply oil, the price of soybean meal will fall as increased production meets unchanged demand.

Since soybean prices depend on the sum of oil and meal prices, the net result is that soybean prices are only weakly linked to soybean oil prices. In a specific example worked out and explained in [this analysis prepared by a Professor at Purdue University for the United Soybean Board], a 20 percent increase (0.84 MMT) in the use of US soybean oil for fuel led to an 8.2 percent increase in soybean oil prices, a 1.9 percent decrease in soybean meal prices and a 0.7 percent increase in soybean prices. The study also estimated changes in food prices, predicting a 4.4 percent in retail vegetable oil prices and much smaller decreases in the retail prices of eggs (0.16 percent), poultry (0.13 percent) and other animal products that benefit from reduced feed prices.

The consequence of all of this is that using more US soybean oil for fuel is expected to have a very small (0.2 percent) impact on US soybean production because meal prices that move the other direction will reduce the economic incentive to increase soybean production. The larger impacts occur overseas as the US trade patterns shift, with the US exporting fewer soybeans and increase net imports of vegetable oil, including not just soybean oil but also other oils that replace soybean oil.

Global consequences of increasing US soybean oil-based fuel production

There are three plausible consequences of increasing US production of soybean oil-based fuel: people eat less vegetable oil, soybean cultivation in increased or increased cultivation of other oils backfills the soybean oil used for fuel.

Decreased consumption of soybean oil for food

In the short term, higher prices for soybean oil prices lead to decreased consumption. Over the last few years, high prices for vegetable oil have been a major contributor to the food crisis**.** According to the food price index of the Food and Agriculture Organization of the United Nations, the vegetable oil price index reached 188 (versus 100 for 2014-2016), and was the leading contributor to a food price index that peaked at 144 overall in 2022. Biofuel policies were certainly not the primary contributor to these price spikes. But in an article from the International Food Policy Research Institute titled Food versus Fuel v2.0: Biofuel policies and the current food crisis, Joseph Glauber (former Chief Economist of USDA) and Charlotte Hebebrand showed that on a global basis, 15 percent of vegetable oils are now used for fuel production and while some countries temporarily reduced biofuel production in light of vegetable oil shortages, US consumption of vegetable oil for fuel rose steadily throughout the crisis. Prices, although still elevated, came down in 2023, and over time increased production will presumably stabilize prices.

It is important to remember that feedstocks for fuel are also food, and in a bidding war for vegetable oil, the lowest income food consumers are most likely to lose out. The previously cited study on the impact of increased use of soybean oil for fuel found that "a 20% increase in quantity of soybean oil demanded for use in biofuels increases the food-at-home component of the [Consumer Price Index] by only 0.05%." This very small impact on US consumers reflects that increased vegetable oil prices are partly offset by decreased prices for animal products, but mostly that agricultural commodity prices are a small share of US retail food prices. These mitigating factors are less relevant for the lowest income global consumers, who eat less animal protein and spend a much higher share of their food budget on basic commodities like vegetable oil.

Increased cultivation of soybeans outside the US

For reasons discussed above, increased US consumption of soybean oil for fuel will have a very modest impact on US production of soybeans but a larger impact in soybean exports. In the previously cited study, a 20% in US soybean oil consumption for fuel led to a 0.2 percent increase in US soybean production, but a much larger 1.1 percent decrease in US soybean exports.

The US and Brazil are the two largest global soybean producers, accounting for more than 70 percent of the global soybean production in 2022 between them, so reduced exports from the US are likely to be replaced by Brazil. China is by far the largest importer of soybeans, accounting for 68 percent of imports in 2022.

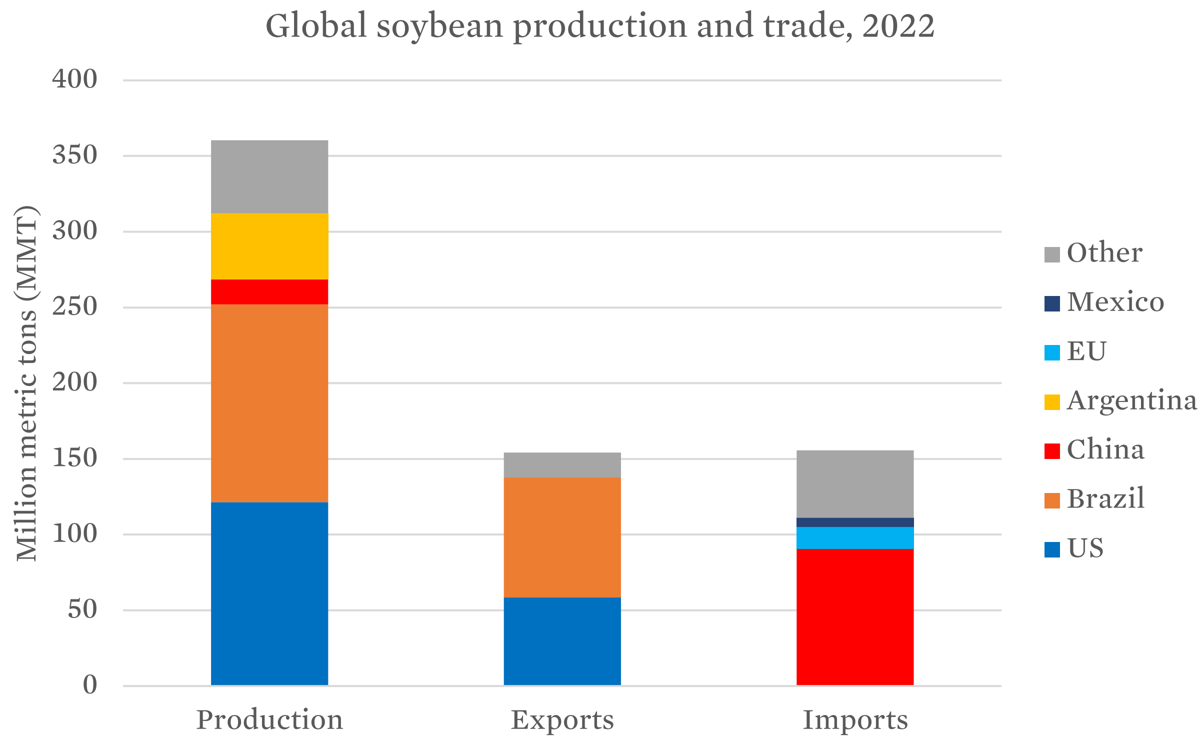


Figure A2: Source USDA Foreign Agricultural Service Oilseeds: World Markets and Trade.

Soybean production has grown rapidly in Brazil, and Brazil recently surpassed the US to become the world's leading producer and exporter of soybeans. Both increased acreage and increased yields have contributed to Brazil's increased soybean production, with acreage increasing 50 percent in the last decade, versus a 20 percent increase in yield (USDA FAS). Thus, increased cultivation of soybeans in Brazil contributes to the rapidly growing footprint of land used for soybean production, which is linked to deforestation and other damaging land use changes.

Soybean production around the world will likely continue to grow both through increases in yield and expanded acreage. But, as discussed previously, the growth of soybean cultivation will ultimately be limited by demand for soybean meal. If demand for soybean oil for both food and fuel uses outstrips demand for soybean meal, it will depress meal prices and mitigate demand for soybeans. For this reason, other oils will play a large role filling the gap left by diversion of soybean oil into fuel markets.

Increased US imports of vegetable oil

Because bio-based diesel is consuming an increasing share of US vegetable oil production, the US has also increased imports and decreased exports of vegetable oil. As shown in Figure 8, the US has increased imports of palm and canola oil, and decreased exports of soybean and corn oil. The net change since 2006 has been about 4 MMT. In the case of reduced exports of soybean and corn oil, trade was directly affected by use of these oils for fuel production, imported canola oil is used for both food and biofuel production, while imported palm oil replaced soybean oil diverted from food markets into fuel production.

Because of rising oil imports, the US is now the 4th largest vegetable oil importer in the world, after India, China and the European Union, and ahead of Pakistan. Notably, while the US and EU use 40 percent or more of their vegetable oil for fuel production, India and China consume more than 90 percent of vegetable oil as food (USDA FAS).

Notwithstanding common rhetoric describing biofuels as about home-grown fuels, it is increasingly clear that a growing share of the feedstock for new renewable diesel production will come from outside the US. A recent analysis from the USDA Economic Research Service on U.S. Biofuel Policies Impact on Vegetable Oil Trade concluded:

> *This structural shift in the U.S. vegetable oils market is likely to continue to affect trade flows moving forward as biofuel use continues to grow. With lower exportable supplies, the United States' key trading partners are likely to continue to shift to other markets, decrease usage, or seek other oils to fill the gaps. The strong domestic demand for vegetable oils is also forecast to continue increasing imports of vegetable oils. This is projected to push the United States to be a net importer of soybean oil in MY 2023/24.*

This analysis of national trends is reinforced by a recent LCFS pathway application Phillips 66 files with the California Air Resources Board for renewable diesel made from soybean oil from Argentina. In light of the trends discussed above, it is not be surprising that fuel producers are looking overseas, especially given the scale of oil required for a facility of this size. Running at full capacity, the Phillips 66 Rodeo facility would consume 2.5 MMT of feedstock a year. The Phillips 66 Rodeo facility presumably has the necessary logistics to unload oil directly from tanker ships coming from the Pacific Ocean. And Argentina is the world's largest exporter of soybean oil, exporting 4-6 MMT of soybean oil in recent years out of a total production of 6-8 MMT. This one huge facility could potentially consume about half Argentina's exports.

Total global soybean oil exports from all countries have been around 12 MMT in recent years, so increasing US soybean oil imports by several MMT could have a major impact on global vegetable oil trade, pushing current importers to reduce consumption and switch to palm and other vegetable oils. Argentina and Brazil are the largest exporter of soybean oi, and India is the largest importer. However, most soybeans are crushed in the country that consumes the oil, so a more complete comparison is between the countries where soybeans are grown to the countries where soybean oil is consumed. Soybean production is dominated by Brazil, the United States and Argentina, which account for 36, 34 and 12 percent respectively in 2022. China, the United States, Brazil and India were the largest soybean oil consumers, accounting for 28, 19, 13 and 10 percent respectively.

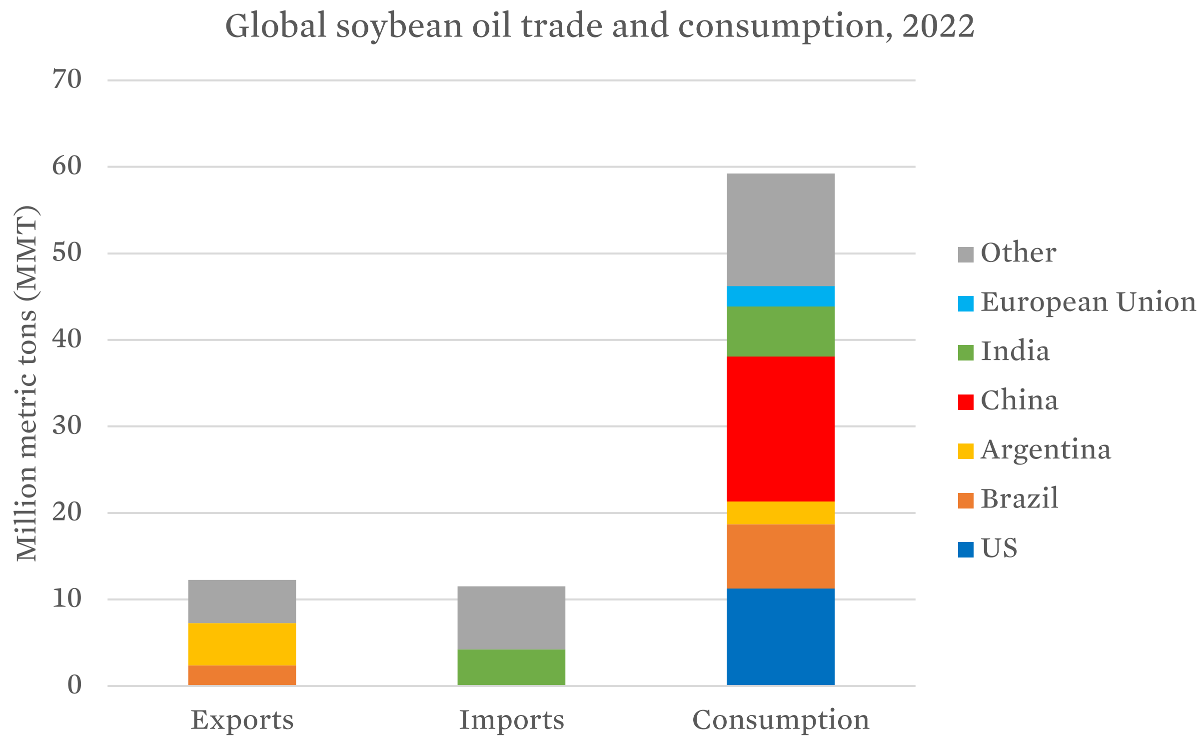


Figure A3: Source USDA Foreign Agricultural Service [Oilseeds: World Markets and Trade](#).

Other vegetable oils.

If US oil consumption of soybean oil for fuel increases faster than global demand for protein meal, it will create an imbalance in global markets for soybean oil and soybean meal. The way to rebalance these markets is to shift a larger share of vegetable oil production toward crops that produce more oil relative to meal. Of the major global oil crops, palm, canola and sunflowers produce a higher share of oil than soybeans. Corn oil is mostly a byproduct of ethanol production that is already almost fully utilized for bio-based diesel production, so it is not a plausible replacement for soybean oil.

Canola oil

Canola oil is the third largest source of vegetable oil produced in the US after soybean oil and corn oil. However, canola oil has a significantly higher yield of oil relative to protein meal compared to soybeans, so increasing cultivation of canola relative to soybeans can shift the balance of oilseed production in favor of oil. In 2022 Canola accounted for less than 1 MMT or about 5 percent of US vegetable oil production. So increased domestic production is likely to have a modest effect on US vegetable oil production in the near term. Globally canola/rapeseed oil accounts for 15 percent of vegetable oil production, and the US imported more than 2 MMT of canola oil in 2022. So canola oil imports are likely to play a larger role in the near term.

Longer term there are other promising oils crops in development, including camelina, winter hardy oilseeds and energy crops bred for high oil content. These crops have potential ecological advantages including improving water quality in addition to potentially significant vegetable oil production. But it will take time to develop and scale up these new crops, so they are not likely to supply millions of metric tons of oil in the next few years. Longer term these novel crops could be a potentially more significant source of increased US vegetable oil production.

Palm oil

Palm oil looms large over the vegetable oil debate because rapidly expanding palm oil cultivation in Indonesia and Malaysia has often come at the expense of draining peat forests, leading to major carbon emissions and other environmental and human rights harms. For this reason, palm oil is not an eligible feedstock for bio-based diesel fuel production under the federal RFS, and the California LCFS assigns land use change emissions to palm oil biodiesel that are 1.5 times higher than soybean oil biodiesel and 3.6 times higher than corn ethanol. Thus, it is very unlikely that palm oil is used to produce bio-based diesel in the US.

However, while palm oil won't be used directly to produce US biofuel, it is likely to play a primary role in replacing the soybean oil that is diverted from food markets to fuel production. As shown in Figure 8, palm oil and canola oil imports to the US have grown as soybean oil has increasingly been redirected to fuel production. But a potentially more significant shift is possible in global markets, particularly in Asia.

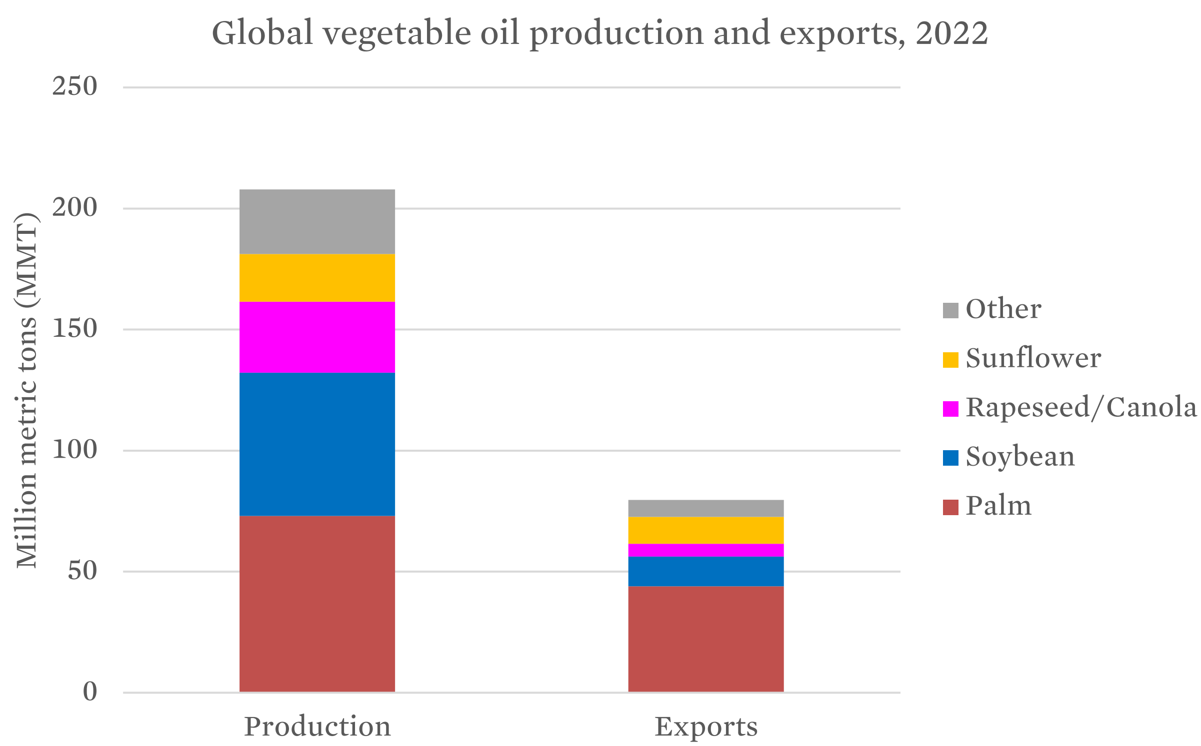


Figure A4: Source USDA Foreign Agricultural Service Oilseeds: World Markets and Trade.

Palm oil is the largest and fastest growing source of vegetable oil in the world, accounting for 35 percent of global vegetable oil production and 55 percent of global trade in vegetable oil in 2022, and is less expensive than many other vegetable oils. And while soybean oil production responds weakly to demand because it is produced jointly with soy meal, palm oil is the primary product of oil palm production, and thus much more responsive to increased demand for vegetable oil. For all these reasons, palm oil is likely to be the primary replacement for soybean oil that is diverted from global markets.

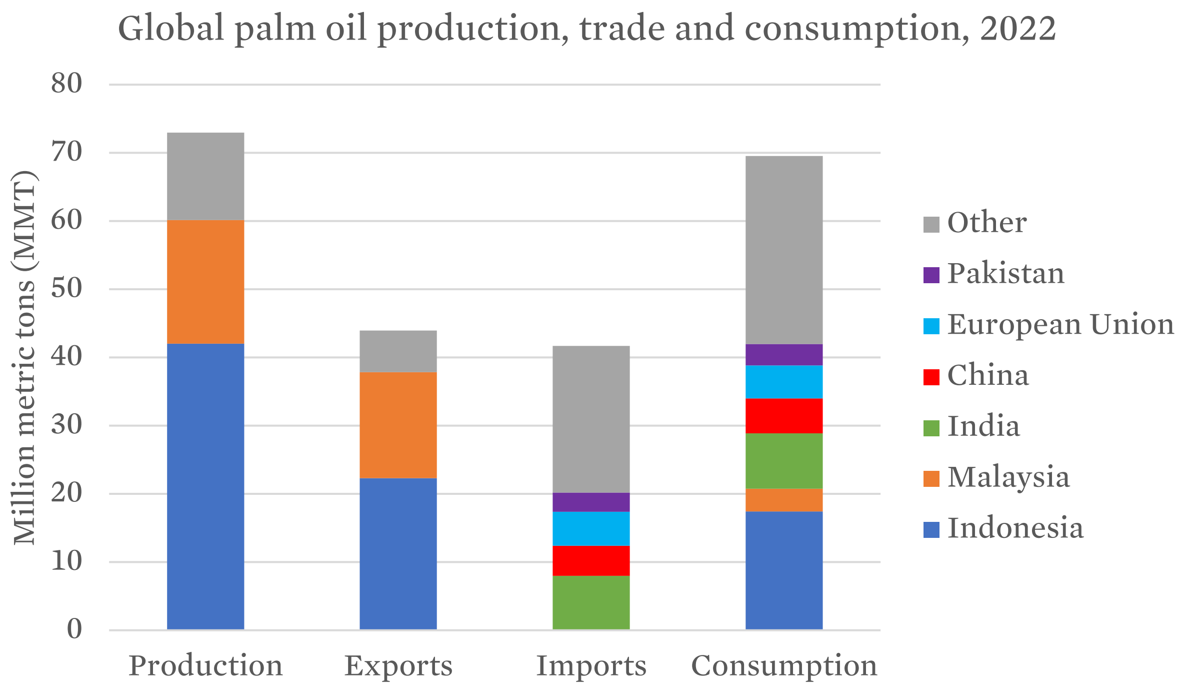


Figure A5: Source USDA Foreign Agricultural Service [Oilseeds: World Markets and Trade](#).

More than 80 percent of palm oil is produced in Indonesia and Malaysia, and India, China and the European Union are the largest palm oil importers. If the US starts importing a more soybean oil from global markets for fuel production, cost sensitive consumers in these and other countries will accelerate their shift toward less expensive palm oil. Additionally, if the US reduces its exports of whole soybeans and expands exports of soybean meal while using the oil for fuel production, China and other countries currently importing whole soybeans will need to find a replacement for the soybean oil they would have crushed domestically, further increasing consumption of palm oil.

Yellow grease and other secondary fats and oils

California's LCFS policy (and related policies in Oregon and Washington) include a substantial preference for fuels produced from secondary fats and oils, including used cooking oil, inedible distillers corn oil, and animal fats. At an LCFS credit price of $100 per ton of avoided CO2 This incentive is worth $0.25 – 0.75/gallon for renewable diesel made from yellow grease instead of soybean oil depending on the LCFS credit price[5]. The justification for this incentive is that consumption of these feedstocks will not expand the cultivation of crops, and thus not contribute to land use change. Because of these policy preferences, fuel producers making bio-based diesel fuel for these markets have a substantial incentive to use these feedstocks. Marathon Petroleum recently entered into a joint venture with Neste, an oil company from Finland, to supply used cooking oil and other feedstocks to the converted oil refinery in

[5] Calculated at credit prices of $66 and $200 per LCFS credit. Each credit represents one metric ton of carbon dioxide equivalent pollution below the standard.

Martinez California. Across the country in Louisiana, [Diamond Green filed an LCFS pathway application] that shows it plans to produce renewable diesel for California sourced from used cooking oil and animal fats from South America, Asia and Oceana.

While expanding fuel production without expanding crop production seems like free lunch of sorts, reality is not that simple. First, there is a very limited supply of secondary fats and oils, and the available supply in the US is almost fully utilized. That's why imports from around the world feature so prominently in the plans of the big renewable diesel producers. The generous incentives for recycled oils also create an increased risk of fraud. If palm oil is successfully passed off as used cooking oil, it would not only avoid the prohibitions and penalties associated with palm oil-based biofuel, it would receive the favorable treatment reserved for secondary fats and oils.

Moreover, the assumption that secondary fats and oils have no impact on crop production is an oversimplified view of these resources. Very little of the secondary fats and oils were truly a waste product but are instead used for animal feed or to produce soaps and detergents. Just as consumers of soybean oil can substitute other oils, current users of secondary fats and oils will switch to other resources if secondary fats and oils are expansive or unavailable. Used cooking oil and distillers corn oil are also used for animal feed. As these sources of oil are diverted to fuel production, the oil calories in feed are replaced by other sources of calories as animal feeds are reformulated to reflect the cost and availability of inputs.

The point is that even secondary fats and oils are no free lunch. There is a limited supply of used cooking or animal fat, and increasing demand for these in fuel markets will displace existing users of these products. So it is important to be realistic about available supply of secondary fats and oils and the impact of diverting them from existing uses to fuel production.

Attachment 2. A Cap on Vegetable Oil-Based Fuels Will Stabilize and Strengthen California's Low Carbon Fuel Standard

January 30, 2024. Available online at https://blog.ucsusa.org/jeremy-martin/a-cap-on-vegetable-oil-based-fuels-will-stabilize-and-strengthen-californias-low-carbon-fuel-standard/

I have long been a supporter of California's Low Carbon Fuel Standard (LCFS). The LCFS is the leading example of a Clean Fuel Standard, an approach to transportation fuel policy that holds oil refiners accountable to reduce the carbon intensity (CI) of transportation fuels. The CI is determined through a lifecycle analysis of the global warming pollution associated with the production and use of gasoline, diesel, biofuels, electricity, or other alternative fuels. Oil refiners comply with the LCFS by blending cleaner alternative fuels into the gasoline and diesel they sell, and also by buying credits generated by vehicles that don't use any gasoline or diesel at all, such as electric vehicles (EVs). The LCFS has delivered important benefits to California, including billions of dollars of support for transportation electrification, and has been a model for other states. Oregon and Washington have enacted similar policies, and Minnesota, Illinois, Michigan, New York, and New Mexico have taken up legislation to adopt similar policies. Federal transportation fuel policy would also benefit from a more comprehensive approach that supports electricity, among other alternatives to petroleum and focuses on emissions reductions rather than simply requiring the use of increased volumes of biofuels.

But California's LCFS has been struggling and is approaching a treacherous precipice. A flood of credits from renewable diesel and manure biomethane have depressed credit prices, undermining the support the LCFS provides for electrification and more scalable low carbon fuels. A rulemaking process is underway to amend the rules of the LCFS including updating the scheduled increases in stringency. The current rules require a 20 percent reduction in the CI of transportation fuels by 2030, which the proposed amendments would change to 30 percent in 2030 and 90 percent in 2045. The California Air Resources Board (CARB) is set to consider the proposed changes on March 21.

Getting this right is important, both for California and to ensure the LCFS remains a workable model for other states and the federal government. When the Board meets in March to update the LCFS, they should place a cap on vegetable-oil based fuels for four major reasons:

1. **Broken policies:** Counter-productive interactions of the LCFS with federal policy are leading oil companies to redirect most of the bio-based diesel (biodiesel and renewable diesel) they are required to sell in the United States to California, which now consumes more than half of the national supply, even though California consumes only 7 percent of the nation's overall diesel fuel (bio-based and fossil diesel combined). This is drawing bio-based diesel fuel out of other states and putting California and federal fuel policies into a vicious cycle that is contributing to ever more unsustainable and expensive fuel policies.
2. **Global hunger and deforestation:** Excessive consumption of bio-based diesel fuels has already contributed to the 2022 global food crisis, and is accelerating deforestation caused by increased soybean and palm oil cultivation around the world.
3. **Gas prices:** Without a cap, the flood of bio-based diesel into California will continue, requiring a rapid increase in stringency to stabilize LCFS credit markets, sending 2030 stringency from the 30 percent proposed in the regulation to 34.5 percent or even 39 percent with a commensurate increase in costs for California drivers.

4. **Credit price stabilization and support for EVs:** Limiting the use of vegetable oil-based biofuels, as CARB staff considered in a proposal to cap the use of fuels made from virgin oils, will stabilize LCFS credit markets with less dramatic increases in stringency, supporting a balanced set of clean transportation solutions, including EVs, while reducing costs for California drivers.

This post focuses on the need for a cap on vegetable oil-based fuels, which is one of several necessary reforms to the LCFS. For more information on our position on manure biomethane and other topics, see my post, "Something Stinks: California Must End Manure Biomethane Accounting Gimmicks in its Low Carbon Fuel Standard."

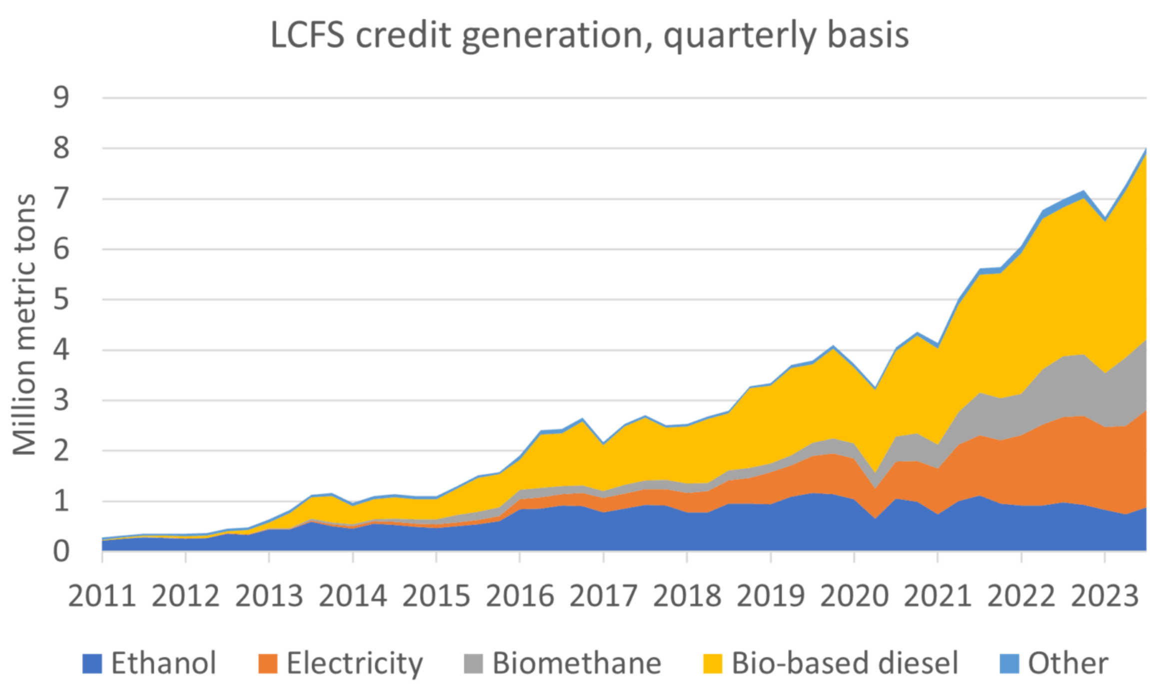


Figure 1. LCFS credit generation. Source California Air Resources Board.

What broke the LCFS?

To solve a problem, it is important to understand the root causes. California's transportation fuels policy creates a market for low carbon fuels, which are tracked using a system of credits and deficits shown in Figure 1 below. The supply of credits from low carbon fuels has been exceeding the requirements of the LCFS, leading to falling credit prices. You might think that low credit prices mean the program is meeting its goals at lower cost than expected, which would be great. Unfortunately, this is far from the truth. More than 60 percent of the credits flooding the program are coming from bio-based diesel and biomethane, crowding out the support the LCFS would otherwise provide to electric cars and trucks to support California's transition away from combustion fuels.

Stabilizing credit prices at a level that supports steady progress (roughly $150 per metric ton) is a key goal of the rulemaking process. Since credit prices are set by the balance of supply and demand, prices could be raised by either restricting the supply of credits or by increasing LCFS stringency to raise demand. During the two years of workshops that preceded the formal proposal, concepts discussed by

CARB staff included changes to the rules that would reduce the supply of credits from bio-based diesel and biomethane and increased stringency to increase demand for credits. But the official proposal abandoned any meaningful effort to address supply and focuses almost entirely on increasing stringency.

CARB has proposed increasing the 2030 stringency of the LCFS by 50 percent, from the current requirement of a 20 percent reduction in the carbon intensity in 2030 to a 30 percent reduction in 2030. CARB has also proposed an auto-acceleration mechanism, which could see the 2030 stringency rise to 34.5 percent or 39 percent if the supply of credits continue to substantially exceed demand.

In my feedback over the last 2 years, I argued CARB should cap support for bio-based diesel made from vegetable oil and phase out credits for avoided methane pollution to wind down what has become, in effect, a poorly run offset program. Bio-based diesel and manure biomethane generate a lot more credits than an accurate assessment of their climate benefits would support, and are causing additional problems to boot. Unfortunately, the official proposal ignores the oversupply of low value credits and focuses almost exclusively on increasing demand by accelerating the pace of the program. This won't work—and will make the LCFS needlessly costly for California drivers, while postponing the needed reforms that would restore the stability of the LCFS. Moreover, absent reform, the LCFS is not a replicable model for other states or the federal government.

Capping the renewable diesel boom

Bio-based diesel refers to two closely related fuels, biodiesel and renewable diesel that are made from vegetable oils and animal fats and blended into diesel fuel. I just posted a detailed article describing the surge in renewable diesel—used mostly in California and made increasingly from soybean oil—that threatens to create major problems in global vegetable oil markets and accelerate tropical deforestation caused by expanding cultivation of soybeans and palm oil.

California may seem like an unlikely driver of deforestation from soybean and palm oil biofuels. The California LCFS has, since its inception, included significant disincentives for the use of crop-based biofuels, including soybean and palm oil-based diesel. Instead, the LCFS encourages the use of fuels made from used cooking oil, animal fats or other secondary fats and oils. For almost a decade, these disincentives effectively kept crop-based diesel fuels out of the California market. However, for reasons explained below, this incentive-based safeguard has become ineffective, and since 2020 California's bio-based diesel has increasingly been made from soybean oil, some of it sourced directly from South America.

The proposed amendments to the LCFS acknowledge the risks posed by the rising use of soybean oil-based renewable diesel. This reflects concerns raised by many stakeholders, myself included, at LCFS workshops since December 2021 (I submitted technical feedback on this topic six times over the last two years, and coauthored a paper on the subject). The first page of the rulemaking document suggests CARB intends to "[strengthen] guardrails on crop-based fuels to prevent deforestation or other potential adverse impacts." The proposal considers a cap on the use of fuels made from virgin vegetable oils in Alternative 1, but then rejects it based on flawed arguments addressed below. Instead of a cap, the proposal suggests tracking the chain of custody for crop-based feedstocks, an ineffective approach that will not address the root causes of the problem.

I'll explain why the cap described in Alternative 1 is the right decision, why the arguments against it are wrong, and why the feedstock tracking proposal is not an adequate safeguard. But first it's important to understand how the implementation of the LCFS is being distorted by complicated interactions with federal biofuels policy, since this explains the root cause of the renewable diesel problem and points the way to a solution.

The LCFS operates on a playing field shaped by federal policy

If the California LCFS acted without the influence of federal policy, there would be no renewable diesel boom, and there would certainly not be a flood of soybean oil-based diesel. The limited support offered by the LCFS for soybean oil-based fuels would not come close to covering the cost of expensive soybean oil needed to make the fuel. It's the interaction of the California LCFS with federal policy, particularly the Renewable Fuel Standard (RFS), that has led to California's renewable diesel boom.

The RFS requires oil companies to blend increasing amounts of a few types of biofuels into the gasoline and diesel they sell. In its early years, between 2005 and 2010, the RFS helped launch the massive scaleup of corn ethanol that established 10 percent ethanol as the de facto standard for US gasoline. After 2010, bio-based diesel fuels (biodiesel and renewable diesel) have been the main beneficiary of the RFS.

Bio-based diesel fuels are expensive. Without substantial policy support, there would be little if any bio-based diesel fuel produced or consumed in the United States. Analysis by the Environmental Protection Agency (EPA) in the most recent RFS rulemaking finds that more than 90 percent of the costs of complying with the RFS, $7 to $8 billion a year, are associated with bio-based diesel fuels[6]. These costs are spread across all the diesel fuel consumed in the United States, adding 13 to 15 cents per gallon to the cost of diesel fuel in the United States, according to EPA.

The RFS sets national targets, but also includes a system of tradable credits that allow overcompliance in one region (or by one company) to offset undercompliance in another region (or by another company). This flexibility allows for higher levels of biofuel consumption in states with supportive policies to offset lower consumption elsewhere. Economic factors and practical limits on blending keep ethanol and biodiesel widely distributed. In 2020, every state except Alaska blended at least 9.5 percent ethanol into their gasoline versus a US average of 10.3 percent, while 35 states blended at least 2 percent biodiesel into their diesel, versus a US average of 3.8 percent.

Renewable diesel is a different story. Since renewable diesel is a replacement for diesel rather than an additive, there are no practical blending constraints. This has allowed oil companies to meet a rising share of their RFS obligations in California, where the same fuel also provides compliance for the LCFS. **In 2022 half of the bio-based diesel consumed in the United States was consumed in California, which accounts for just 12 percent of US population and just 7 percent of the nation's overall diesel (bio-based and fossil diesel combined).** The factors that concentrated half of US bio-based diesel in California are only getting stronger, as more renewable diesel production capacity comes on-line in California, and California raises the targets for the LCFS.

[6] US EPA. Renewable Fuel Standard (RFS) Program: Standards for 2023–2025 and Other Changes. Regulatory Impact Analysis. Section 10.4.2, specifically table 10..4.2.2-4. Online at nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017OW2.pdf

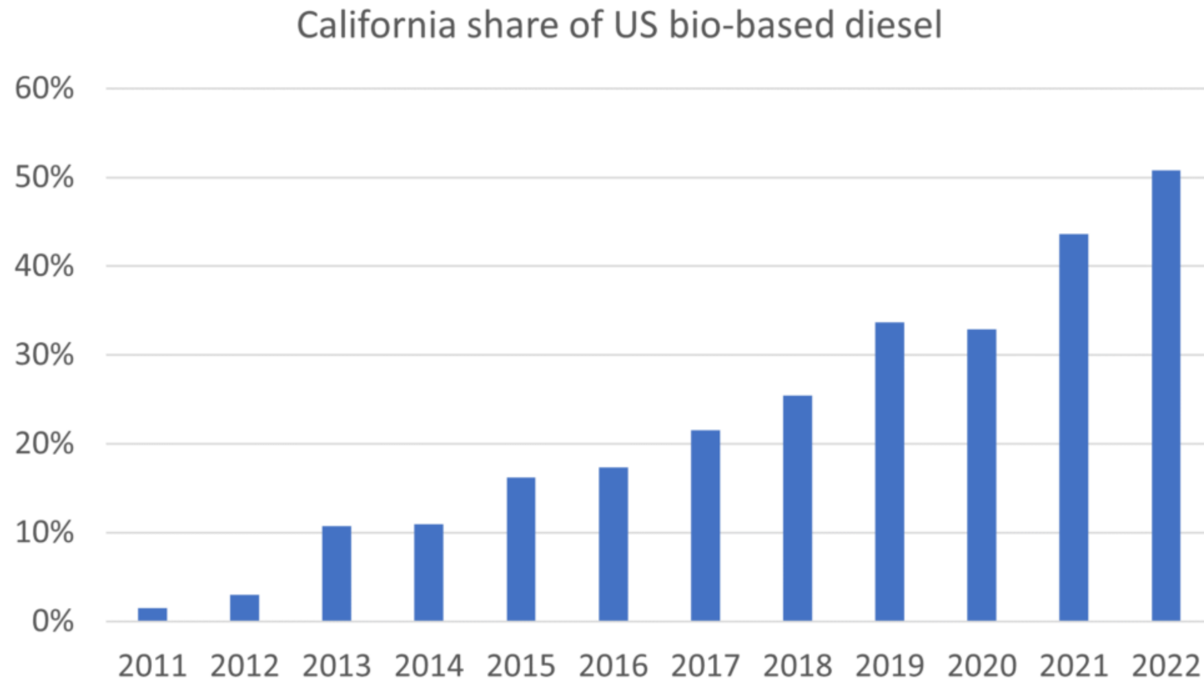


Figure 2: Share of California consumption of US bio-based diesel fuel (biodiesel and renewable diesel) weighted by their RFS compliance value. Source California Air Resources Board, US Energy Information Administration.

Unless CARB changes course, California is likely to consume well over half of US bio-based diesel, including increasing amounts of soybean oil-based fuel, putting pressure on the EPA to raise RFS targets to unsustainable levels that harm access to food and accelerate deforestation. Concentrating RFS compliance in California reduces oil companies' compliance costs, but it destabilizes both the RFS and LCFS. It makes no sense for California to consume most of the US supply of bio-based diesel.

Capping vegetable oil-based fuels is the right decision

The CARB rulemaking document called the Initial Statement of Reasons (ISOR) includes consideration of Alternative 1 on pages 88 to 102 that "includes a limit on total credits from diesel fuels or sustainable aviation fuel produced from virgin oil feedstocks." Because Alternative 1 reduces credit generation, the 2030 stringency is adjusted from 30 percent to 28 percent, but the 2045 stringency remains the same (90 percent). The lower stringency results in lower costs and reduced economic impact of the regulation. The ISOR says, "The macroeconomic impact analysis results shown in Table 23 indicate that Alternative 1 would result in more positive impacts on gross state product (GSP), personal income, employment (Figure 14), output (Figure 15) and private investment when compared to the proposed amendments." The main reasons CARB gives for rejecting Alternative 1 are the climate and air quality benefits CARB attributes to the higher use of renewable diesel. However, these apparent benefits result from faulty analysis.

According to official analysis from CARB and EPA, soybean oil-based diesel has lower lifecycle carbon emissions than fossil diesel, but this finding is quite uncertain. EPA recently conducted a model comparison exercise that found that the climate benefits attributed to soybean oil biodiesel depend entirely on which model is used to conduct the assessment. While the particular model used by CARB for the LCFS finds that soybean oil biodiesel has lower emissions than fossil diesel, other well-regarded models find that soybean oil biodiesel is more polluting than fossil diesel. But even putting aside this uncertainty, the ISOR overstates the climate benefits of using soybean oil-based fuels because it ignores the fact that use of this fuel in the United States is already mandated by the RFS, so if California uses less, another state will use more. In past rulemakings, CARB accounted for this policy overlap by only including climate benefits that exceed those required by federal law. But in the current rulemaking, CARB ignores the federal requirements, inflating the claimed climate benefits.

The inflated climate benefits attributed to renewable diesel are especially significant because California's renewable diesel boom has exhausted the supply of low-carbon sources of renewable diesel. Alternative 1 caps fuels made from virgin oils such as soybean oil, which produce few if any climate benefits not already required by the 50 percent emissions reduction requirements of the federal RFS. So Alternative 1 will have little if any real impact on global warming pollution, even putting aside the contested and uncertain benefits of soybean oil-based fuels in general.

The ISOR also attributes health benefits to increased use of renewable diesel in California, especially associated with reduced fine particulate matter, or PM2.5. This is based on a 2011 analysis and ignores a more recent 2021 study prepared for CARB that looks at the NOx and PM from biodiesel and renewable diesel used in legacy and new technology diesel engines. The key finding is that air quality benefits from older engines are not observed in new technology diesel engines, which are now required in California. This undercuts one of the main justifications offered to reject limits on renewable diesel. Ironically, because renewable diesel does offer PM and NOx emissions in older trucks that are still in use elsewhere in the US, concentrating most of US renewable diesel in California does not help Californians, but it does harm others across the United States.

Finally, the ISOR also claims that Alternative 1 has lower cost effectiveness than the proposed amendments, but this is a direct result of the inflated CO2 and health benefits. A corrected analysis would reduce or eliminate the difference in cost effectiveness.

Without a cap, things could get a lot worse

This ISOR has several deficiencies compared to previous rulemakings, starting with transparency. It is hard to understand precisely how CARB modeled Alternative 1. Based on my current understanding of the information in the proposal, it appears that the total amount of fuels made from oils and fats is projected to peak in 2025 and then to hover at roughly 2 billion gallons a year thereafter[7]. The share of bio-based diesel blend in overall diesel fuel consumption, or blend rate, is assumed to range between 44 and 56 percent through 2035, and then to increase as total diesel fuels consumption falls, as heavy-duty electrification starts to gain traction.

Reality is running well ahead of CARB projections. Bio-based diesel consumption in the first half of 2023 was at 59 percent, a level CARB modeling does not anticipate prior to 2037. I can't see any reason

[7] While there are a lot of long documents on the CARB rulemaking website, there is not a clear and quantitative description of the various alternatives, which are described inconsistently in different documents. There is no downloadable table of the quantities of fuels and credits associated with the different alternatives, or enough information to reproduce this information using the CATS tool CARB used for modelling fuel projections. In order to clarify what is at stake, I'll summarize my understanding based on the available documents. In the ISOR CARB projects that bio-based diesel will peak at 2 billion gallons in 2025, fall below 1.8 billion gallons by 2028 and then hover between 1.5 and 1.8 billion gallons thereafter. They also project several hundred million gallons of alternative jet fuel, of which half is made from virgin oils.

why bio-based diesel consumption in California would fall while renewable diesel production capacity in California is ramping up and CARB is proposing to substantially raise LCFS stringency. CARB projects total diesel consumption at 3 billion gallons or more until 2035, so actual consumption could be more than 50 percent higher than CARB's projection if bio-based diesel fully replaces fossil diesel, as a recent study from UC Davis found was 50 percent likely by 2028. If this happens, the extra credit generation beyond what is modelled in the ISOR could trigger the auto acceleration mechanism, pushing 2030 stringency to 34.5 or even 39 percent, with a commensurate increase in costs. Moreover, if all the diesel used in California is bio-based, all of the compliance costs associated with the LCFS will be borne by drivers of gasoline cars.

Alternative 1 described in the ISOR has roughly 25 percent less biobased diesel at the peak in 2025, so roughly 1.5 billion gallons. That is consistent with 2022 consumption of bio-based diesel in California, and since RFS standards are rising gradually, this would result in California consuming a little less than half of the bio-based diesel and related fuels required for RFS compliance in the United States.

The 2 billion gallons of bio-based diesel projected for the ISOR would satisfy about two-thirds of the 2025 RFS requirements, but if actual consumption exceeds the projection, California consumption could push the RFS mandate for bio-based diesel and related fuels into overcompliance. All sorts of weird things would happen if the RFS became non-binding, starting with RFS credit prices falling and the effective cost of renewable diesel available in California rising, with implications for the cost and feasibility of the LCFS[8]. A non-binding RFS is not a stable long-term situation, for both economic and political reasons. It could also create a lot of turbulence, not just in fuel markets but in food markets for vegetable oil as well.

A vicious cycle of bad fuel policy decisions

My biggest concern is that a feedback loop between California LCFS and the Federal RFS push US consumption of vegetable oil for fuel to ever more unsustainable levels. This feedback loop is influencing fuel policies today and could become a vicious cycle.

Interactions between the LCFS and the RFS have been a major contributor to the renewable diesel boom, which has flooded California with renewable diesel and depressed LCFS credit prices. Increased renewable diesel production capacity to serve the California market was one of the factors cited in EPA's decision to raise RFS standards for 2022-2025. And even with the higher RFS targets, increased renewable diesel production in and for California has at least temporarily pushed the RFS into overcompliance, sending credit prices down sharply.

If California regulators respond to low credits prices by dramatically increasing the stringency of the LCFS without a workable mechanism to avoid concentrating RFS compliance in the state, it will keep pulling a growing share of US bio-based diesel fuel into California. This puts the Midwestern biodiesel industry under pressure, and puts Midwestern soybean oil producers at a disadvantage compared to used cooking oil imported from as far away as Australia. This will create enormous political pressure on EPA to raise the RFS standards to ensure that they continue to support soybean biodiesel, renewable diesel, and growing consumption of sustainable aviation fuel in states outside of California. The resulting higher RFS standards will increase the use of vegetable oil-based fuels, driving up the cost of the RFS with uncertain climate benefits and very real risks to food markets and deforestation. Meanwhile, higher RFS standards

[8] For more on the implications of a non-binding RFS, see *Gerveni, M., T. Hubbs and S. Irwin. "Is the U.S. Renewable Fuel Standard in Danger of Going Over a RIN Cliff?" farmdoc daily (13):99, Department of Agricultural and Consumer Economics, University of Illinois at Urbana-Champaign, May 31, 2023.*

will support ever more vegetable oil-based fuel in California, further diluting the LCFS, and the vicious cycle continues.

This vicious cycle explains why raising LCFS stringency alone will not rebalance supply and demand for LCFS credits. **CARB can break this vicious cycle by limiting California's share of US bio-based diesel consumption to a reasonable level.** The proposal described in Alternative 1 to cap virgin oil-based fuels would do the job, while still leaving California as the largest consumer of bio-based diesel in the US. A cap would also leave space in the bio-based diesel market for other states that have or are considering policies like the LCFS.

As I explained in my earlier article on the renewable diesel boom, successful fuels policy in California and the United States requires being realistic about the available resources used to make biofuel. Vegetable oil is an expensive way to make biofuel with limited potential to sustainably increase scale, especially in the short term. A bidding war between the oil companies and people consuming vegetable oil for food already contributed to the recent food crisis, and may do so again. In the longer term, increased use of vegetable oil-based fuels leads to increased palm oil production to replace the soybeans diverted from food markets to make fuel, contributing to deforestation. Capping vegetable oil used for fuel at a reasonable level will encourage fuel producers to look beyond vegetable oil to more scalable feedstocks. A cap will also save California drivers money, by rebalancing supply and demand for LCFS credits without such a steep acceleration in stringency.

The guardrail proposed in the ISOR is inadequate

CARB's ISOR mentions the risks posed by crop-based fuels, but unfortunately, the proposed guardrail is inadequate. From page 32:

> CARB staff are proposing to require pathway holders to track crop-based and forestry-based feedstocks to their point of origin and require independent feedstock certification to ensure feedstocks are not contributing to impacts on other carbon stocks like forests. CARB staff are also proposing to remove palm-derived fuels from eligibility for credit generation, given that palm oil has been demonstrated to have the highest risk of being sourced from deforested areas.

Tracking the chain of custody won't work because there is more than enough soybean oil produced on existing cropland in the US, Argentina, and Brazil to produce 100 percent of California's diesel fuel. The problem with chain of custody tracking is that California won't be tracking the chain of custody of vegetable oils used to replace those diverted from global food markets for consumption in India or China.

As I mentioned in the appendix to my recent post on the renewable diesel boom, the Phillips 66 Rodeo facility is scaling up production of renewable diesel at a converted oil refinery near San Francisco. Phillips 66 filed paperwork recently indicating it plans to produce renewable diesel and other fuels using soybean oil from Argentina. At full capacity, the massive facility would consume 2.5 million metric tons (MMT) of vegetable oil a year. Argentina is the world's largest exporter of soybean oil, exporting 4-6 MMT of soybean oil in recent years out of total global soybean oil exports of about 12 MMT. This one huge facility could potentially consume about half Argentina's exports and 20 percent of global exports. To replace soybean oil from Argentina, major vegetable oil importers like India would import more soybean and palm oil that would not be subject to chain of custody tracking.

CARB has long been a leader in biofuel land use change (I served on an expert workgroup on the topic in 2010), so the staff should appreciate the complex and indirect ways demand for biofuel feedstocks can lead to deforestation. It is disappointing to see this obviously inadequate proposal in place of meaningful action to address a real problem. The proposal to remove eligibility for palm oil-based fuels is even more meaningless, given that the land use change values used in the current regulation already effectively do the same thing.

Ironically, the one place chain of custody tracking is needed is for used cooking oil, which the proposal ignores. The LCFS creates a large incentive to pass off virgin palm oil as used cooking oil. And with renewable diesel producers importing used cooking oil from around the globe, extra vigilance is merited.

Capping vegetable oil fuels and investing in alternatives to combustion

The oil industry is in transition. After a brazen display of fossil fuel industry interference at the global climate talks at COP28, it is clear that the only path to a stable climate is phasing out petroleum and other fossil fuels. Biofuels are not made from petroleum, but a realistic assessment of the available resources makes it clear that biofuels can only play a supporting role and must be limited to a sustainable scale to avoid creating more problems than they solve. Vegetable oil is expensive, its availability is limited, and expansion is linked to deforestation, so the large-scale diversion of vegetable oil to fuel production is an especially bad idea. Yet the oil industry has embraced the idea that their existing oil refineries can help solve climate change by tweaking them to process vegetable oil instead of petroleum.

Renewable diesel has recently overtaken biodiesel as the main bio-based diesel fuel used in the United States. Redirecting vegetable oil from biodiesel to renewable diesel does not reduce petroleum use or overall global warming pollution, but it does allow the oil industry to maximize the overlap in state and federal fuel regulations. The predictable next step is to move vegetable oils from renewable diesel production to jet fuel production, claiming generous tax credits while still generating RFS and LCFS credits and trumpeting an innovative new “climate solution.” Shifting the same limited supply of vegetable oil from one fuel to another will not do anything to address climate change, but it does enable misleading hype and greenwashing from the oil industry and airlines suggesting we can address climate change without phasing out combustion. Likewise, shifting more of the US supply of bio-based diesel into California won’t do anything to help the climate, but it is breaking the LCFS.

The oil industry was once the primary opponent of the LCFS, but they have found a way to work the system to their advantage. Oil companies are taking control of the bio-based diesel industry and trumpeting their plans to scale up biodiesel, renewable diesel, and sustainable aviation fuel, despite knowing there is not enough vegetable oil to make the rhetoric reality. The renewable diesel boom is partly a battle for market share as oil companies flush with fossil fuel profits fight to control the largest share of the small but symbolically important market for renewable fuels. But the collateral damage of this clash between the oil giants is not just the stability and viability of fuel policies, but food availability, deforestation, and the prices of food and transportation fuel.

California should modernize the LCFS to align with its goal of transitioning away from combustion to a zero emissions future. A sensible cap on vegetable oil-based fuels will break the vicious cycle between the RFS and the LCFS, make the LCFS less expensive and more effective, and make it easier for other states to adopt and implement LCFS-style policies. It will also help ensure the LCFS doesn’t exacerbate global hunger and deforestation. The board should send the ISOR back to staff and tell them to get this important policy back on track.

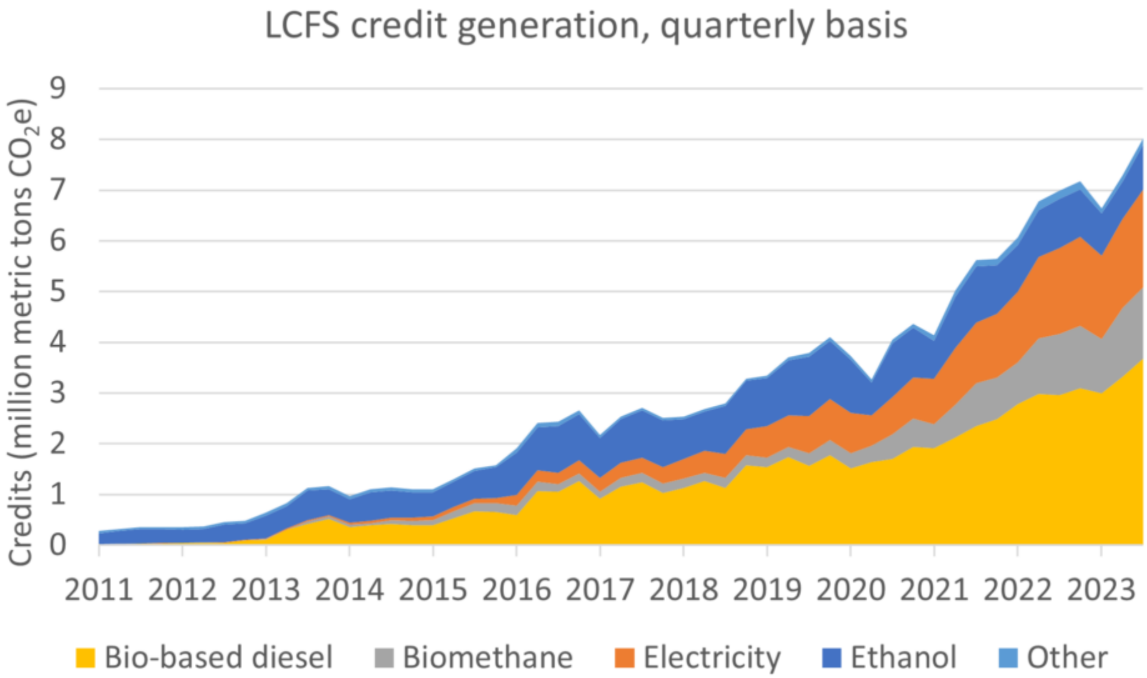
Attachment 3. Something Stinks: California Must End Manure Biomethane Accounting Gimmicks in its Low Carbon Fuel Standard

February 15, 2024. Available online at https://blog.ucsusa.org/jeremy-martin/something-stinks-california-must-end-manure-biomethane-accounting-gimmicks-in-its-low-carbon-fuel-standard/

California's transportation fuel policy is knee deep in cow poop, and it's not a good look. The California Air Resources Board (CARB) is considering amendments to its Low Carbon Fuel Standard (LCFS) regulation, but indicated they have no plans to address the problems caused by counter-productive subsidies for manure biomethane. CARB's use of the LCFS as a cash cow to fund manure digesters is bad transportation fuel policy and bad agricultural policy. Accounting gimmicks disguise a poorly run offset scheme as a magic carbon negative climate solution. CARB needs to phase out credits for "avoided methane pollution," refocus the LCFS on transportation and get to work developing a more suitable regulation for pollution from dairies.

The immediate goal of the current LCFS rulemaking is to stabilize LCFS credit markets so that the policy can continue to provide much needed support for transportation electrification. LCFS credit markets are out of whack because the supply of credits is outstripping the demand. CARB has proposed to rapidly increase the stringency of the standard to increase demand for credits, but it should also address the supply of credits, to make sure the fuels supported by the LCFS help move California towards a clean transportation future.

A quick glance at the latest data from CARB shows there are three large and growing sources of credits: bio-based diesel, biomethane and electricity.



Bio-based diesel, biomethane and electricity are the largest and fastest growing sources of LCFS credits in recent years. Each credit one metric ton of carbon dioxide equivalent pollution below the standard. Source California Air Resources Board.

I've written recently about why a Cap on Vegetable Oil-Based Fuels Will Stabilize and Strengthen California's Low Carbon Fuel Standard, which addresses the bio-based diesel credits. The growing credits for electricity reflect the growing number of EVs on the road in California, and support California's goal of phasing out combustion technologies in favor of zero emissions vehicles. But what about the rapidly increasing credits generated by biomethane? Vehicles powered by biomethane consume about one percent of California's transportation fuel, but in the first three quarters of 2023, biomethane used to fuel these vehicles accounted for 17 percent of LCFS credit generation. The reason a small amount of biomethane generates such a large amount of credit is that biomethane gets credit not only for reducing transportation emissions, but also for reducing methane pollution from manure lagoons at dairies and hog farms across the United States. CARB does not break down the share of credits awarded for avoided methane pollution, but according to my calculations 85 percent of credits awarded by the LCFS in 2023 have nothing to do with transportation but are a poorly disguised offset program creating a gold rush of unverified claims of avoided methane pollution from manure lagoons.

A recent post by UC Davis economist Aaron Smith puts the question quite directly, Cow Poop is Now a Big Part of California Fuel Policy: Are the state's new low-carbon fuel regulations full of BS? The short answer is yes, California's approach to subsidizing manure digesters through its transportation fuel policy is a disaster, and California officials need to wind down a poorly run offset program that is going to cost California drivers at the pump without creating a viable long term strategy to address the problem of manure methane pollution from huge dairies.

For the last few years, I have been getting deeper into manure policy than I ever expected. My primary expertise is in lifecycle-based transportation fuel policy, which has recently been providing increasing financial support for biomethane generated from anaerobic digesters at dairy manure lagoons. For a legal perspective on the topic, read the report (and summary blog) by Ruthie Lazenby at UCLA's Emmett

Institute, for an economic perspective see Aaron Smith at UC Davis, and to understand the impact of pollution from massive dairies on the people that live in adjacent communities, read this article on How a California Dairy Methane Project Threatens Residents' Air and Water.

In this blog, I will cover the following:

- Transportation fuel policies are based on lifecycle analysis.
- Negative carbon intensity scores are inconsistent with the LCFS and amount to an offset program.
- The LCFS manure methane offset program costs drivers more and delivers worse results than a similar policy designed to target dairy methane pollution.
- LCFS biomethane subsidies contribute to consolidation in the meat and dairy industry.
- California's LCFS is causing problems for other states and the federal government.

The LCFS is designed to hold fuel producers accountable for their supply chain emissions

The LCFS and related Clean Fuel Standard policies are performance standards for transportation fuel based on lifecycle analysis. This is a little different than other similar sounding policies like Renewable Energy Standards, which can create some confusion. A Renewable Energy Standard requires utilities to source an increasing amount of the energy they generate or sell from renewable sources like wind and solar, heading towards a 100 percent standard that would reflect a 100 percent renewable grid with no further combustion.

But while a Renewable Energy Standard treats all sources of qualifying renewable energy equally, the LCFS has a more complicated approach, based on lifecycle analysis. Under the LCFS each fuel pathway gets a unique carbon intensity (CI) based on a lifecycle analysis of the greenhouse gas emissions associated with the production and use of the fuel. This approach originated from the recognition that many alternative fuels, especially ethanol, involve a lot of fossil fuels and other pollution in their production. When I started working on biofuel policy back in 2008, there was a lot of criticism of corn ethanol because in some cases it had lifecycle emissions higher than gasoline. This conclusion came from adding up the emissions from coal used to power the production process, natural gas-based fertilizer and diesel fuel used to farm and transport the corn and ethanol. To address this concern some folks at UC Davis and Berkeley had the idea of giving transportation fuels partial credit based on how much they reduced emissions on a lifecycle basis compared to gasoline or diesel. This, in a nutshell, is the logic of the LCFS. For more information on this type of policy see our page on Clean Fuel Standards.

Gasoline has a CI of about 100 grams carbon dioxide equivalent pollution per megajoule of fuel energy (g/MJ) once the emissions from extracting oil, refining it into gasoline and burning it in cars and trucks are added up. The CI of an electric vehicle charged with solar power is zero, and most of the biofuels fall somewhere in the middle[9]. This approach holds fuel producers accountable for reducing fossil fuel use and other global warming pollution in their supply chains. When the LCFS eventually gets to a carbon intensity of zero, you would think all the fuels used to power transportation should be zero carbon fuels.

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[9] For more on the carbon intensity of transportation fuels, see my 2016 report, Fueling a Clean Transportation Future. For more technical discussion on lifecycle methodology issues, see the report of a 2022 National Academies committee on which I served, Current Methods for Life-Cycle Analyses of Low-Carbon Transportation Fuels in the United States.

But unfortunately, this is where the implementation of the LCFS has drifted away from this idea of partial credit to hold fuel producers accountable for their own supply chains.

Negative CI scores are nothing more than a poorly regulated offset program

As Professor Smith explains in his latest cow poop post, California has been giving manure digesters large negative CI scores. "The carbon intensity of dairy [biomethane] ranges between -102.79 and -790.41 depending on characteristics of the digester. The current average carbon intensity for dairy [biomethane] is -269." A negative CI score would suggest an almost magical climate solution that pulls several carbon dioxide molecules from the atmosphere for each one that comes from the tailpipe of a truck running on dairy biomethane. Unfortunately, this is far from the truth. The justification for negative CI scores is an assumption built into the lifecycle analysis that if the methane was not used as transportation fuel it would be emitted into the atmosphere. And because methane is such a potent heat trapping gas, credit for avoided methane emissions can be quite large.

Without the credit for avoided methane pollution the CI of dairy methane would be about 36 g/MJ[10] instead of -269 g/MJ, which means that 85 percent of the credit claimed by dairy biomethane is associated with avoided methane pollution at the manure lagoon. Only 15 percent of the climate benefit assigned to dairy biomethane is associated with replacing fossil fuels with bio-derived fuel used for transportation[11].

Blurring together the impact on transportation and agriculture creates confusion and leads to exaggerated claims of the benefits of manure digesters. Considered as a source of energy, anaerobic digesters are an expensive way to produce a small amount of energy. As Professor Smith explained in an earlier post, "the cost of an anaerobic digester is 10 times the market value of the gas it produces." Dairy manure digesters are also an expensive strategy to mitigate methane emissions. More optimistic assessments of cost effectiveness ignore the multiple subsidies digesters receive, double (or triple) counting the climate benefits while understating the costs.

Professor Smith's most recent blog explains that the main motivation to keep the avoided methane offset scheme in the LCFS is to continue to supply incentives to California dairy farmers to cover the high costs of installing and operating digesters as a means of reducing methane pollution from dairies.

Negative CI scores undermine California's goal of phasing out fossil fuels and combustion fuels in general. Imagine a fleet of 7 diesel trucks in California, owned by a progressive company that wants to achieve carbon neutrality. Under existing LCFS accounting, this hypothetical company can convert 2 of its 7 trucks to run on compressed natural gas and contract with a manure digester to purchase the rights to match the fossil gas consumption of the trucks to the digester operator's pipeline gas injection somewhere else in the continental United States (this is called book and claim accounting). According to the logic of the LCFS, the two biomethane fueled trucks now have negative emissions that more than offset the emissions of the 5 diesel trucks, so the fleet is notionally carbon neutral.

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[10] O'Malley, J., N. Pavlenko, Y.H. Kim. 2023. 2030 California Renewable Natural Gas Outlook: Resource Assessment, Market Opportunities, And Environmental Performance
[11] This calculation is based on average carbon intensity of a dairy digester of -269, as reported in Aaron Smith's January 2024 post, the 2024 LCFS standard for diesel of 87.89 g /MJ and a carbon intensity of 36.4 g/MJ for dairy biomethane without avoided methane credits, per O'Malley, J., N. Pavlenko, Y.H. Kim

The key word here is ***offset***. Obviously the 5 diesel trucks are still using fossil fuels and all 7 trucks are using internal combustion engines, creating tailpipe pollution that harms people in the communities in which the trucks operate. The claim embedded in the LCFS carbon intensity score is that avoided methane emissions from a manure lagoon offset the fossil CO2 emissions from the production and use of fossil diesel. Officially CARB claims that the LCFS includes no offset program. If it did, it would be subject to rules governing offsets that CARB would be required to enforce. I am not a lawyer, so I won't venture a legal opinion, but from where I sit this is a distinction without a difference. A negative CI score is an offset because it allows continued use of fossil fuels in a regime that claims to achieve zero emissions.

Negative CI scores are inconsistent with the logic of holding fuel producers accountable for the fossil fuel use and global warming pollution in their supply chains. It flips this logic on its head by allowing fossil fuel producers to continue to sell fossil fuels by claiming credit for offsetting methane emissions reductions that are part of a milk or meat producer's supply chain. And unfortunately, CARB's insistence that it is not running an offset scheme keeps them from running it properly. Thus, the LCFS does not require evidence that claimed methane emissions reductions are real and additional, as would be required from any credible offset program.

Transportation fuel regulations are not the right tool to reduce dairy methane pollution

As a general rule, public policies are more effective when they directly address the problem they are trying to solve. The LCFS regulates oil refiners, who are primarily responsible for the production of high carbon intensity transportation fuel. The use of carbon intensity as a metric for the LCFS adds complexity, but it allows for a comprehensive approach to an increasingly diverse set of transportation fuels, including gasoline and diesel, various biofuels and different sources of electricity. The LCFS does not stand alone, but complements regulations that require car and truck manufacturers, fleets, and electric utilities to reduce pollution from their products and services.

The primary business of dairies is to produce milk rather than transportation fuel, so using the LCFS to reduce pollution from dairies is quite indirect. To illustrate the problems caused by this indirect approach, consider how things would be different if the LCFS were adapted to directly target dairy pollution by creating a **Low Carbon Milk Standard** that operated alongside the LCFS. This hypothetical Low Carbon Milk Standard would resemble the LCFS but focus on milk rather than gasoline and diesel. It would assign a carbon intensity score to milk sold in California and set a steadily decreasing standard for the industry. I shared this idea with CARB staff and leadership last August, to help explain why focusing regulations on methane mitigation would be a better strategy to meet California's methane goals than subsidizing manure biomethane production through a poorly run offset program.

Benefits of a Low Carbon Milk Standard (or other agricultural methane regulations)

Just as the LCFS is based on the supply chain emissions of transportation fuel per unit of energy, a low carbon milk standard (LCMS) would be based on the supply chain emissions per unit of milk. While structurally similar, the milk supply chain emissions would include all the emissions associated with milk production, not just the manure, and would apply to all milk producers, whether they use a digester to capture and sell biomethane or use a different manure management strategy that minimizes the production of methane in the first place.

Under the LCFS, credits are only awarded for biomethane that is captured and used for fuel, and it is presumed that this methane is an inevitable consequence of milk production. Under a LCMS, there is no need for any such presumption, and all strategies that reduce methane pollution are treated equally. This avoids distorting the market for methane mitigation in favor of more polluting manure management strategies. California has an alternative manure management program (AMMP), that provides financial assistance for the implementation of non-digester manure management practices including composting and conversion to or expansion of pasture-based systems. These practices reduce climate pollution and provide other air and water quality benefits. Under the LCFS, dairies that use AMMP practices are at a competitive disadvantage compared to dairies that use digesters and can generate a substantial revenue stream from selling manure to operators of the digesters.

Opponents of dairy regulations claim that if California enacts stricter regulations on dairies than other states, dairies may just leave California, continuing to pollute but outside the reach of California regulations. This is called emissions leakage, and is discussed by both Ruthie Lazenby and Aaron Smith. The LCMS addresses leakage in the dairy sector the same way the LCFS does in the fuel sector. Out-of-state milk producers would be held to the same standards for pollution as California producers. The LCFS has survived legal challenges, and the same arguments should apply to an LCMS.

An LCMS would also address arguments that phasing out LCFS credits for avoided methane pollution would cause digesters to shut down, making it harder for California to meet its methane pollution targets. Digesters would continue to operate to meet the LCMS standard unless the dairies found a more cost-effective way to mitigate methane. Digesters make the most sense economically at large dairies, and at these facilities digesters would likely remain a cost-effective way to meet LCMS obligations. They can even keep selling biomethane to displace fossil gas, but the biomethane would not be credited with avoided methane emissions within transportation fuel or other energy policies.

Regulating manure methane directly would save California drivers money

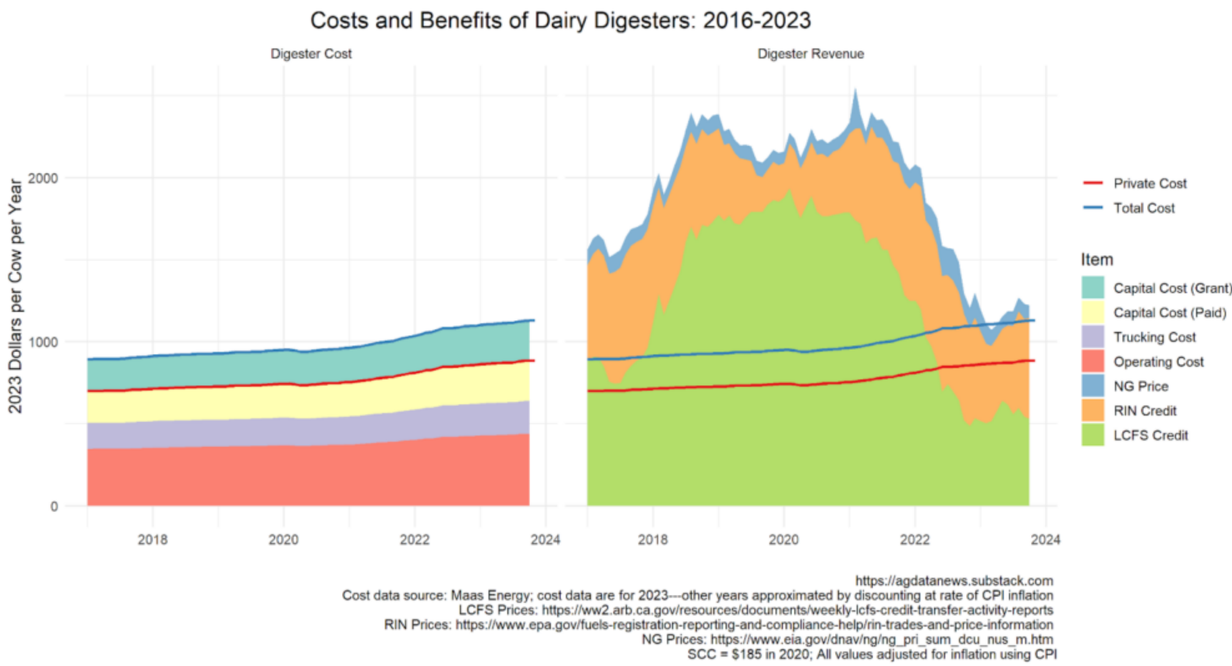
The California LCFS is designed to support the production of low carbon transportation fuel, and it applies the same lifecycle analysis methodology to all fuels, regardless of where they are produced, so long as they are used in California. As previously described, biomethane is allowed to use book and claim accounting. As a result, manure digesters at both dairies and swine concentrated animal feeding operations (CAFOs) all over the country have been granted LCFS pathways to produce biomethane with large negative CI scores. This means that California drivers are being asked to bear the cost of large subsidies for milk and meat producers nationwide, even though any reductions in methane pollution will not reduce California's emissions.

Regulating pollution from dairies through an LCMS or other regulation would shift the costs of reducing methane pollution to milk producers, and these costs will presumably be passed along to milk consumers. But these costs are likely to be quite a lot lower than current LCFS costs for three reasons. The LCFS is subsidizing manure digesters at dairy and swine CAFOs across the United States while the costs of a regulation would be limited to milk produced and/or sold in California, depending on the structure of the regulation. Second, a regulation developed for dairies should support a wider set of practices and technologies to mitigate pollution suitable for different types of dairies, which should bring down costs compared to limiting support to expensive digesters with gas cleanup and injection required to sell biomethane. And finally, a well-designed regulation should reduce the windfall profits that have accrued to biomethane developers selling credits into LCFS markets.

LCFS biomethane subsidies create a gold rush available only to very large farms, which encourages dairy (and meat) industry consolidation and distorts food markets

LCFS credits for avoided methane are one of several sources of support for digesters, with additional support coming from the Federal Renewable Fuels Standard Program (RFS) and grants from California's Department of Food and Agriculture and programs from the US Department of Agriculture. Professor Smith has analyzed how profitable these subsidies are in detail in his recent post.

> *Between mid 2018 and the end of 2021, revenues from selling biogas and the associated* [RFS credits, called RINs] *and LCFS credits were approximately double the cost of installing and running a typical digester, as shown in the figure below. LCFS credit prices have declined in the last two years, making the typical digester closer to a break even proposition. If and when credit prices go back up, then the profits will return.*



There has been an extensive coverage of the gold rush these generous subsidies started, in trade press and even the Wall Street Journal, which headlined its piece "California's Green-Energy Subsidies Spur a Gold Rush in Cow Manure: A lucrative state incentive to make natural gas from dairy waste is attracting companies from Amazon to Chevron."

These extremely profitable subsidies also contribute to consolidation. Building and operating a digester and the equipment required for gas cleanup and pipeline injection is very expensive, and even with large subsidies is generally only economic at very large dairy and swine CAFOs. At the largest CAFOs, the payments a farmer receives from a digester operator can be a significant portion of their income. But digesters generally don't make sense on smaller farms, because without thousands of cows or pigs, there is just not enough poop to make a digester and gas collection cost effective.

Smaller facilities can use other manure management strategies that reduce methane production in the first place or capture and flare methane, but since these strategies don't result in methane to sell to energy markets, they are excluded from LCFS biomethane subsidies. If digesters really were efficient producers of transportation fuel, LCFS support would make sense. But in reality, 85 percent of the LCFS subsidy is based on claims of avoided methane pollution, so excluding other strategies that can also avoid methane pollution distorts the lucrative market for avoided methane pollution by disguising it is a market for transportation fuel. This means that the largest dairies have preferential access to a lucrative revenue stream that is decoupled from the low margin high risk business of selling milk.

A 2020 report from the US Department of Agriculture on Consolidation in U.S. Dairy Farming highlights that "[t]he number of licensed U.S. dairy herds fell by more than half between 2002 and 2019, with an accelerating rate of decline in 2018 and 2019, even as milk production continued to grow." Several factors contribute to consolidation, and there is a heated argument over the evidence that LCFS subsidies have played a significant role. The basic economic arguments are clear enough. While key details are contested and not all the relevant data is publicly available, there is no real dispute that the LCFS biomethane subsidies have been a boon to large CAFO dairies and exclude smaller farms. This insight is not limited to opponents of the digesters and can also be found in the dairy trade press. A 2021 article explains the unintended consequences as follows:

> *The net effect will be that dairy farms with methane digesters and other green energy technologies will make decisions based more on returns from energy than returns from milk. It fundamentally changes dairy farm economics as well as milk and dairy product prices. If this comes to fruition, dairy market signals to raise or reduce milk production will be less effective. This could lead to a structural oversupply of milk in the domestic market[...]. Michael McCully. Hoard's Dairyman. 2021*

Structural oversupply in the milk market would certainly be hard for dairies without digesters whose business is limited to selling milk and are excluded from the LCFS biomethane gold rush.

The dispute is over the evidence that LCFS biomethane subsidies have already caused consolidation and how the role of the LCFS can be disentangled from other factors. The data question is complicated by the fact that key statistics are published only every 5 years. Until this week, the most recent data was from 2017, and comparing 2012 to 2017 does not say much about LCFS supported digester boom, which mostly happened after 2017. The data from the 2022 USDA Agriculture Census was released on February 13th and it confirms that dairy consolidation in California is continuing. The share of dairy cows in California on farms of 2500 cows or more grew from 46 percent in 2017 to 61 percent in 2022. Disentangling the role of the LCFS from other factors is beyond my expertise, so I am looking forward to reading what the experts have to say about it.

California's bad biomethane policy is causing problems across the United States

I work on transportation fuel policies across the United States. For several years I have been part of a Midwestern Clean Fuels Policy Initiative, and I have been working with Minnesota-based non-profits to develop a clean fuel policy for Minnesota. I was recently part of a Clean Transportation Standard Work Group run by the Minnesota Department of Transportation. The members of the work group have diverse perspectives on many things but agree that Minnesota should not copy California's LCFS but learn from it and create a policy that makes sense for Minnesota. Several Minnesota groups I have spoken with have major concerns that California LCFS subsidies for digesters are driving small dairies out of business. This is a very real concern in Minnesota, which ended in 2023 with 146 fewer dairy farms than it had at the beginning of the year. But a major challenge to crafting a Minnesota specific policy is that the largest dairies in Minnesota, run by a company called Riverview Farms, are already enrolled in the California LCFS. The result is that California drivers are spending increasing amounts of money to subsidize digesters in Minnesota in a manner that distorts dairy markets in Minnesota and is largely outside the control of Minnesota voters or policymakers.

The problem arises from treating manure digesters as a source of magic negative carbon energy instead of recognizing that their primary climate benefit is pollution mitigation from manure lagoons. Digesters do not pull methane out of the atmosphere; they capture methane that was created by the deliberate choice to collect and store manure in anaerobic conditions in huge lagoons. The idea that manure methane is uniquely valuable is leading to proposals from the biogas developers to truck manure from smaller farms to a central digester so that they too can participate in the digester gold rush, or to figure out how to install digesters at beef cattle feedlots that currently use dry manure management.

Crediting methane collected from these projects as if it is an inevitable consequence of manure management and assuming it would otherwise be vented into the atmosphere is clearly wrong from a technical perspective. It also sends a signal to farmers that they should get into the energy business and "get big or get out," in the infamous words of Nixon's Secretary of Agriculture Earl Butz. Most policymakers now recognize the harmful consequences of this attitude, so they should make sure their policies support their stated goals.

Decisions about the most suitable strategy for manure management are complex and depend on many local factors that affect not only the farm's profitability but also the local environment and community. These decisions should not be dominated by the results of a lifecycle analysis spreadsheet developed for a California transportation fuel regulation that only values "avoided methane pollution" when it is associated with transportation fuel production. If policymakers want to provide support to help farmers reduce methane pollution, they should provide at least equivalent support for methane pollution that is actually avoided because it was never created. When energy policy and agricultural policy intersect, we should make sure the results are supporting good outcomes in both spheres, and the California LCFS credits for avoided methane pollution are clearly failing that test.

What started as a clever way for California regulators to indirectly support expensive dairy digester projects in California is putting smaller farms across the United States at a disadvantage, especially those that use more sustainable manure management strategies, and potentially pushing them out of the business entirely. The problem is not limited to transportation fuel policy, it is also setting a damaging precedent that threatens to undermine the integrity of numerous new lifecycle-based tax credits, including the federal clean hydrogen production tax credit .

Agricultural methane policy should help food producers reduce pollution rather than paying for poop

Real harm results from disguising manure digesters as a magic negative carbon energy technology. Reducing pollution from food production is important, and so is scaling up renewable energy production to replace fossil fuels. Connecting these goals with a de facto offset regime is creating a lot of problems, and we need a better approach.

Policy makers must ensure that regulations and incentives shaping our food system not only address methane pollution from sources like manure lagoons but build a better food system—one that provides healthy, sustainably produced food for all and treats everyone at every stage of the system fairly. This is a big task, which can seem daunting and unrealistic. The magnitude of the challenge leads some to argue digester subsidies, by whatever means they can be financed, are a justifiable short-term expedient to address an urgent problem. But California's de facto offset regime is doing more harm than good, undermining California's transportation fuel policy, distorting milk and meat markets across the country in favor of the largest producers of manure and setting a damaging precedent that could undermine federal support for hydrogen or any other policy based on lifecycle analysis.

Negative carbon intensity scores have no place in transportation fuel policies. These policies should support the transition away from fossil fuels and hold all fuel producers accountable for pollution in their supply chains. The California Legislature gave regulators authority to start regulating dairy pollution in 2024, and they should start developing these regulations. My hypothetical Low Carbon Milk Standard illustrates the major structural problem with the LCFS biomethane offset program that is fixed by refocusing dairy methane policy on the primary polluter. But real policies that affect agriculture should be designed to meet the needs of farmers, farm communities and the environment, and not copied directly from the energy or transportation fuel sector.

Policymakers outside of California should understand that supporting methane pollution reduction using lifecycle analysis accounting gimmicks can seriously backfire and hurt small farms. Any policy that aims to reduce pollution from milk (or meat) production, whether as part of a regulation or an incentive, must be designed to reduce methane pollution, rather than to increase biomethane use. Fixing our broken food system requires a more thoughtful approach that grapples with the realities of the system, rather than just throwing money at the largest polluters.

Comment Log Display

Here is the comment you selected to display.

Comment 286 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Will
Last Name	Barrett
Email Address	william.barrett@lung.org
Affiliation	American Lung Association
Subject	Health organization comments on LCFS
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6956-lcfs2024-VTlTNl06VHQHXglh.pdf
Original File Name	LCFS health letter Feb 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 16:12:09

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

American Lung Association. California | CA·NURSES FOR ENVIRONMENTAL HEALTH & JUSTICE | ramp REGIONAL ASTHMA MANAGEMENT & PREVENTION

February 20, 2024

Liane Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Health Group Support for Strong LCFS Standards

Dear Chair Randolph:

On behalf of the undersigned health organizations, we are writing to provide comments in support of a more health-protective and effective Low Carbon Fuel Standard (LCFS) for California. As the California Air Resources Board (CARB) considers amendments, we urge you to better align the program with the critical transition to zero-emission transportation needed to meet health-protective clean air and climate standards.

Despite decades of progress, California remains home to significant air pollution burdens. The American Lung Association's "State of the Air" 2023 report noted that 98 percent of Californians live in a community impacted by unhealthy levels of ozone and/or particle pollution and that six of the ten most ozone-polluted cities in the nation are in California. The health harms of breathing unhealthy air are well known to CARB and represent the lived experience of too many in our state, especially due to transportation pollution. The Health Effects Institute's latest review of hundreds of peer-reviewed research papers found that exposures to traffic pollution are associated with all-cause mortality, deaths due to heart disease and lung cancer deaths as well as new cases of asthma among children and adults. The transition to zero-emission transportation is core to CARB's work and must be aligned throughout the LCFS policy.

We appreciate that CARB has postponed the hearing on the LCFS and will hold an informational workshop in the coming months. We believe that these are important steps toward building a stronger program that advances the transition away from combustion everywhere possible and toward the rapid and equitable distribution of the benefits of zero-emission technologies. Several opportunities for strengthening the LCFS program to protect public health have been noted in CARB's workshops, earlier proposals and the current staff report. As the board considers the updated staff proposal, we offer the following comments:

277.1
- We support the original staff proposal to place a cap on credits for crop-based fuels rather than the sustainability reporting requirements included in the current proposal.

277.2
- We support the staff proposal shifting the Clean Fuel Rewards program's focus to rebates for medium- and heavy-duty vehicles and the proposal to increase the equity-based focus of light-duty charging credits.

277.3
- We support the intention to eliminate avoided methane emission credits but urge the board to act much sooner than the proposed phaseout at 2040 to limit ongoing incentives for new projects that facilitate more methane production as a means to capture LCFS credits.

277.4 • We support the proposal to curb credits for out-of-state projects that do not actually send fuel to - or support displacement of fossil gas use in - California.

277.5 • We support the proposed expansion of eligibility for alternative jet fuels to include intra-state travel. We also encourage the board to further expand credit eligibility to aviation and shipping sector projects utilizing zero-emission technologies.

277.6 • We encourage the board to consider an earlier phaseout of credits for petroleum development projects than the proposed phaseout at 2040.

Overall, we urge the board to consider a stronger LCFS program that increases the role of zero-emission technologies and reduces crediting for projects based on accounting strategies that extend fossil fuel consumption and combustion technologies. We look forward to continuing to work with CARB staff and the Board on this issue. If you have any questions, please contact Will Barrett at William.Barrett@Lung.org.

Sincerely,

Will Barrett
Senior Director | Nationwide Advocacy, Clean Air
American Lung Association

Barb Sattler RN, MPH, DrPH
Leadership Council Member
California Nurses for Environmental Health and Justice

Joel Ervice
Associate Director
Regional Asthma Management and Prevention (RAMP)

Comment Log Display

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Comment 287 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jamie
Last Name	Hall
Email Address	jamie@evrealtyus.com
Affiliation	
Subject	Joint MHD EV Infrastructure Parties - Comments on LCFS Amendments
Comment	Please see attached comments from the Joint MHD EV Infrastructure Parties, a group of eight medium/heavy duty charging infrastructur providers.
Attachment	www.arb.ca.gov/lists/com-attach/6957-lcfs2024-AWxXOVM2VloHYgRs.pdf
Original File Name	MHD Charging Coalition LCFS Comments Final.pdf
Date and Time Comment Was Submitted	2024-02-20 15:35:58

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95815

RE: Proposed Low Carbon Fuel Standard Amendments

Dear California Air Resources Board Members and Staff,

Thank you for the opportunity to provide our comments and recommendations on the proposed Low Carbon Fuel Standard (LCFS) Amendments. We greatly appreciate the California Air Resources Board's (CARB) leadership in supporting and accelerating the transition to zero emission freight. California has led the way on cleaning up the transportation sector by designing and implementing a comprehensive suite of policies to address this multi-faceted challenge, including both sticks and carrots to increase vehicle supply, boost demand, and facilitate infrastructure deployment and grid integration. LCFS is a critical piece of this overall puzzle in terms of incentivizing infrastructure buildout and improving the total cost of ownership for electric vehicles, particularly for the medium- and heavy-duty vehicle sector.

The undersigned Joint MHD EV Infrastructure Parties develop single and multi-fleet EV charging hubs that provide third-party owned charging-as-a-service to medium and heavy duty (MHD) EV fleet owners. Multi-fleet EV charging hubs are especially important for enabling small (and many large) businesses without adequate onsite charging capability to electrify their fleet vehicles to reduce costs, improve employee and community health and achieve California policy goals for clean vehicle deployment and decarbonization. Multi-fleet EV charging hubs provide the added benefit of increasing charging infrastructure utilization, enabling more vehicles to charge per charger without triggering costly system upgrades, thereby reducing the overall cost for all utility ratepayers. Our collective business models foster the concentration of electrical loads in strategically chosen locations, facilitating a more seamless transition to MHD EVs for commercial fleets.

With critical adjustments, LCFS has the potential to be the single most important tool in helping the state meet its zero emission transportation goals and recent regulations – the Advanced Clean Trucks (ACT) and Advanced Clean Fleets (ACF) regulations in particular. We appreciate CARB staff's collaboration to date on the provisions most relevant to our businesses, particularly with regard to the MHD Fast Charging Infrastructure (MHD-FCI) provision. We strongly support the creation of the MHD-FCI program, though additional modifications are needed to maximize the clean air and climate benefits it can unlock. We also applaud staff for recognizing the need for program stringency updates to support credit prices as a robust market is needed for LCFS to truly catalyze private investment.

To fully realize the potential benefits of LCFS for truck electrification, we respectfully make the following recommendations.

1. **Maximize the benefits of the proposed medium- and heavy-duty fast charging infrastructure (MHD-FCI) program by increasing flexibility to better support the deployment of necessary charging infrastructure** in advance of truck deployment at the speed and scale to meet California's policy goals and regulations (e.g. CARB's recent Advanced Clean Fleets)
    A. **Eliminate geographic limitations** on MHD-FCI eligibility to improve program effectiveness, better align with fleet needs, mitigate delays, and reduce overall costs.
    B. **Eliminate the 10 FSE per-site cap** to enable the scale necessary to meet state goals and to encourage cost reductions that come with upfront investments and larger projects.

C. **Eliminate or reduce the 250kW minimum capacity** to enable infrastructure providers to provide the variety of solutions the market needs.
D. **Clarify rules around access requirements** for shared depots to avoid creating confusion around eligibility requirements.
E. **Increase overall MHD-FCI program size** to enable infrastructure deployment at the scale and pace required to meet California state goals.

2. **Strengthen and update the overall LCFS program to better align with long-term state goals and ambitions** by implementing changes that support credit prices.

We understand the board vote has been postponed to allow more time for consideration of potential program modifications, including some of what we outline above. We acknowledge the need for additional discussion, but also urge the board to move quickly with a decision in Q2 of this year. Market participants, including infrastructure providers, need certainty around program details and a lengthy delay will chill investment. Additional details and rationale for our highest priority recommendations can be found below.

1. **Maximize the benefits of the proposed medium- and heavy-duty fast charging infrastructure (MHD-FCI) program by increasing flexibility to better support the deployment of necessary charging infrastructure.**

At this early stage of the market, with under 1,000 medium- and heavy-duty electric trucks and vans on California roads based on recent data[1], the uncertainty around truck charger utilization in the near term creates a risk that many would-be infrastructure investors are unwilling to take. The result is a lack of sufficient investment in large scale charging for electric trucks, and this in turn is slowing the deployment of the electric trucks. The Fast-Charging Infrastructure (FCI) program has already proven to be an elegant and effective way to overcome this fundamental challenge, and we deeply appreciate CARB's proposal to add an FCI for the MHD sector (MHD-FCI) and the efforts to date to include multi-fleet charging hubs in program design.

With critical adjustments, MHD-FCI could be the single most powerful tool for attracting private capital to this sector, accelerating the rollout of charging infrastructure ahead of vehicle deployment. MHD-FCI has the potential to provide some certainty around revenue, thereby de-risking these projects and attracting private investment. The key is to design a program that is sufficiently robust and flexible to match California's clean air and climate ambitions. This is a unique opportunity to catalyze deployment of truck charging infrastructure just when it is needed most to support the state's clean truck regulations and programs. The draft proposal has laid the foundation for a strong program. With a few key modifications, MHD-FCI can deliver widespread health, air quality, and climate benefits while attracting private investment to a sector that will need it to scale up to meet the State's goals.

A. ***Eliminate geographic limitations on MHD-FCI eligibility to improve program effectiveness, better align with fleet needs, mitigate delays, and reduce overall costs, for both Private and Shared MHD-FCI charging site types.***

Section § 95486.3 outlines MHD-FCI eligibility requirements, including the following: *"Located within one mile of a reading or pending electric vehicle Federal Highway Administration Alternative Fuel Corridor or on or adjacent*

[1] California Energy Commission Medium- and Heavy-Duty Zero-Emission Vehicles in California. As of the end of 2022, the total medium- and heavy-duty ZEV population in California included 272 trucks and 340 vans.

to a property used for medium or heavy-duty vehicle overnight parking, or has received capital funding from a State or Federal competitive grant program that includes location evaluation as criteria." We recommend removing these geographic restrictions entirely as they will undercut program effectiveness, delay deployment, and increase costs for charging and grid upgrades for MHD-FCI Shared charging sites, and are also irrelevant to the MHD-FCI Private charging sites category; public navigability and accessibility are not merits of an MHD-FCI Private charging site that is by definition precisely on route for the associated Private fleet.

Corridor charging does not address operational needs for many high-priority market segments. While corridor-based charging may be part of the solution for long-haul trucking, it does not align well with the duty cycles and day-to-day operations of short haul and return-to-base fleets such as drayage, middle mile, and last mile delivery. These are the vehicles that are expected to electrify first due to ACF regulations and the overall "fit" of battery electric vehicle technology today. These vehicles would benefit from charging in areas where they operate and where they are domiciled, and these locations do not necessarily fall within one mile of a corridor. Additional flexibility is needed to meet needs for the broader MHD sector, beyond just long-haul applications, and to serve the market segments most ripe for rapid decarbonization.

Focusing the program on corridors also inadequately considers grid constraints and the implications that this may have on fleet electrification. Depots will generally have large power demands (often 5-15MW). Land with access to sufficient grid capacity on distribution feeders is very limited, and the number of suitable sites shrinks even further when factoring in zoning, permitting, and ingress/egress requirements. The proposed one-mile restriction would not only further limit where MHD charging can occur but also funnel depots to areas that would necessitate costly and lengthy grid upgrades – with the unfortunate consequence of slowing down charging infrastructure deployment and potentially increasing electric rates for all Californians. Additional flexibility is needed to account for the constraints on our grid and to facilitate timely, cost-effective infrastructure buildout.

The proposed program does include language allowing eligibility for sites adjacent to overnight parking and sites that have received certain state or federal funds. While we appreciate these provisions and they are directionally helpful, this language is still far too limiting. The language around existing parking does not account for grid constraints or for the fact that fleet operations are evolving and parking locations will not be static, particularly given the challenges associated with infrastructure deployment (e.g., grid constraints, landlord restrictions, etc.). Indeed, greenfield sites with overnight parking should not be excluded just because they are not currently providing truck parking. With regard to allowing MHD-FCI for sites that have won competitive grant solicitations, we appreciate the intention but note that (a) funding is limited and budgets are under pressure, so this is a relatively small number of sites, and (b) local funding appears to be excluded despite the fact that many local air districts have programs aimed at MHD-fleet electrification.

278.1 **We recommend completely eliminating geographic restrictions in order to maximize the benefits of the program**. Business models, amount of investment needed to build charging sites, and investor pressures will minimize the risk of stranded assets and ensure that charger deployments align with fleet operational needs for both Shared and Private charging sites in a network. If CARB ultimately decides that limits are needed, we recommend specific changes to provide added flexibility, open up additional sites, and avoid unintentional delays and potential cost increases.

- **Recommendation: Strike section §95486.3 (b)(1)(B)2** to provide implementation flexibility. This is the best course of action to accelerate progress on electrification and to avoid unintended consequences.
- **Suboptimal alternative:** We maintain that a program without geographic limits would best serve CARB goals and that limits are unnecessary given the natural market forces that will push for optimized locations. If, however, CARB determines that some geographic limits are necessary for shared charging sites, we suggest increasing flexibility with the following changes to existing language to address corridor distance, the realities of parking and fleet operations, and the importance of local decision-making in this sector:
  2. *located within ~~one mile~~ five miles of a ready~~ing~~ or pending electric vehicle Federal Highway Administration Alternative Fuel Corridor or on or adjacent to a property that allows ~~used for~~ medium or heavy-duty vehicle overnight parking at the time credits are claimed, or has received capital funding from a local, State or Federal competitive grant program. ~~that includes location evaluation as criteria~~*

B. Eliminate the 10 FSE per-site cap to enable the scale necessary to meet state goals and to encourage cost reductions that come with upfront investments and scale.

Section §95486.3 states *"The total number for all FSEs claiming MHDFCI credit owned by a single applicant within ¼ mile of an MHD-FCI site cannot exceed ten."* Limiting eligibility to 10 FSEs per site would severely restrict program effectiveness, and would hamstring the ability for charging infrastructure to be deployed at the speed and scale required by the Advanced Clean Fleets and Advanced Clean Trucks regulations.

Our companies are developing depots of various sizes, including within the 100-truck range, as depots of this size have the scale to bring down costs for customers. The purpose of the FCI program is to encourage the deployment of charging infrastructure in advance of truck availability by providing bridge revenue as truck deployments ramp up. Limiting participation to a small proportion of a site's chargers – in many instances a 90% reduction -- would make the program ineffective for these depots. With this restriction, the program would perversely only support the sites with higher per-port costs – which is not in California's best interests.

According to CEC analysis, we estimate that California must install an average of approximately 66 MHD chargers a day through 2035[2]. This is an astronomical rate of growth, and the FCI is an elegant tool to help achieve that. Limiting the eligible number of chargers in a depot would be catastrophic to our efforts to meet the scale and scope of infrastructure deployment required by CARB regulation.

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[2] This calculation is based on the CEC AB 2127 report: Assembly Bill 2127 Second Electric Vehicle Charging Infrastructure Assessment: Assessing Charging Needs to Support Zero-Emission Vehicles in 2030 and 2035 | California Energy Commission. To support medium- and heavy-duty plug-in electric vehicles, California will need about 109,000 depot chargers and 5,500 public chargers for 155,000 vehicles in 2030, and 256,000 depot chargers and 8,500 public chargers for 377,000 vehicles in 2035.

Given other provisions in the draft language, we believe it has been suggested that the intention behind the 10 FSE per site limit may be to force 1 MW chargers. If so, there are multiple reasons to reconsider. First, not all customers and use cases require megawatt charging, and there are cost tradeoffs with higher power charging. Secondly, there are also grid benefits to lower power charging -- maximizing the utilization of the existing distribution network thereby minimizes potential rate impacts. Thirdly, 1 MW chargers do not yet exist at broad commercial scale. Finally, there are no trucks currently commercially available that can take 1 MW; though some MW+ models are being developed, they are not expected to be commercially available at scale for some time.

Finally, as noted above, the proposed amendments also include a limit on individual entities claiming credits beyond 10 MW of nameplate charger capacity within ¼ of that entity's site. This overall site claiming capacity limit is sufficient to ensure a diversity of sites and applicants; there is no need for a separate FSE cap.

278.2

- **Recommendation: Eliminate the 10 FSE per site limit by striking section §95486.3(b)(2)(D)** to enable the scale necessary to meet state goals and to encourage cost reductions that come with upfront investments and larger projects. The 10 MW overall site claiming capacity limit is sufficient to meet policy objectives.

C. Eliminate or reduce the 250kW minimum capacity to enable infrastructure providers to provide the variety of solutions the market needs.

Section §95486.3 creates a minimum per-FSE power rating threshold: *"Each FSE at an MHD-FCI site must have a minimum nameplate power rating of 250 kW."* This is unnecessary and should be either removed or reduced.

The state has a policy interest in having vehicles charged as "low and slow" as possible. Lower power charging will maximize utilization of the existing distribution network, putting downward pressure on rates. For light duty vehicles, for example, home charging is encouraged at L1 and L2 levels. In the MHD sector, many trucks are not able to charge 'at home', as where they are domiciled may not have sufficient hosting capacity to serve the massive amounts of power that a fleet of trucks with very large batteries need, and small operators often do not own property or have long term leases sufficient to amortize the high costs of installing chargers. In these instances, 3rd party depots play the role of both 'home charging' (i.e. overnight dwell) and pulling into a DCFC on a highway for a mid-route refill.

There is a tradeoff between the speed of charging and the cost to serve the massive numbers of vehicles that must be electrified, and artificially biasing the market toward higher power charging through size minimums for all use cases will both increase costs and grid impacts. This is why many 3rd party depots are designed with a mix of fast opportunity chargers and slower (and cheaper) overnight or long dwell chargers - to have a mix of technologies aligned to varying use cases, designed to keep costs as low as possible while meeting a range of needs. We believe that the market can and should decide on the appropriate power levels for depot charging. Further, this is a matter of equity, as the entities that will be most impacted by the higher costs are the less-well-capitalized fleets and drivers that cannot charge 'at home' and must rely on 3rd party depots.

- **Recommendation: Eliminate the 250kW minimum by striking section §95486.3(b)(1)(E)** to allow
278.3 greater flexibility on site design and cost control. If CARB sees a need for a minimum to focus on fast
charging, establish 150kW as the minimum nameplate power rating.

D. *Clarify rules around access requirements for shared depots to avoid creating confusion around eligibility requirements.*

Appendix A-1 defines "shared MHD-FCI charging site" as *"…an EV fast charging site that is available to at least two MHD EV fleets under different ownership, or to the public for at least 12 hours each day…" and states that " The site must not have obstructions or obstacles precluding the fleet vehicles from entering site premises, and no registered equipment training shall be required for individuals to use the site."* It is our understanding that CARB intends to allow shared depot charging, which we strongly support. These sites generally will have security measures (e.g., security fencing and access control) to ensure safety of vehicles and cargo and to ensure access to customers from multiple authorized fleets. These sorts of standard security measures should not be considered obstacles. We recommend clarifying language to align with market needs and eliminate any future questions around eligibility.

- **Recommendation:** Clarify the definition of shared MHD-FCI charging site to remove uncertainty
around security measures at shared depot sites. Suggested language: *"'Shared MHD-FCI charging
278.4 site' means an EV fast charging site that is available to at least two MHD EV fleets under different
ownership, or to the public for at least 12 hours each day. ~~The site must not have obstructions or~~
Access controls and security measures are allowed so long as there are no obstacles precluding the
authorized fleet vehicles from entering site premises, and no registered equipment training shall be
required for individuals to use the site."*

E. *Increase overall MHD-FCI program size to enable infrastructure deployment at the scale and pace required to meet California state goals.*

The MHD-FCI program is limited to 2.5% of the previous quarter deficits. At 2025 deficit levels, we estimate this would support as little as 635 MW of MHD charging capacity, increasing as utilization ramps up over time.[3] According to the CEC's AB 2127 analysis, the state will need about 2,900 MW of MHD charging by 2025 and 11.6 GW of MHD charging by 2030.[4] Additional support is needed to attract the scale of private capital required,

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[3] This calculation was derived leveraging the formulas from Appendix A-2 Proposed Regulation Order, section § 95486.3.(b)(2)(G) and section § 95486.3.(b)(5)(G) with the following assumptions: previous quarter deficits = 8,082,115 MT (based on CARB CATS model 2025 forecast); shared MHD-FCI charging site model selection; 85% uptime; and 5% utilization. Supported capacity will vary with utilization, uptime, and other assumptions.

[4] The California Energy Commission's AB 2127 report uses the HEVI-load model to forecast the number of depot and public chargers required for MHD charging under the AATE3 primary scenario. This forecast predicts the number of chargers and their respective power ratings that will be required in 2025 and 2030, as seen in Appendix-H, Table H-1. The sum of the total MHD charging capacity based on this forecast was calculated to be 2,900 MW and 11,600 MW by 2025 and 2030, respectively, by taking the sum-product of the number of chargers and their respective power rating.

particularly at this nascent stage of the market with uncertainty around commercial-scale truck deployment timelines and with both fleets and OEMs citing infrastructure as a primary limiting factor.

278.5
- **Recommendation: Increase the program cap from 2.5% to 5%.** We are at a critical launch point for both ACT and ACF and believe a higher cap – we recommend at least 5% - is warranted to begin deploying a network that will enable the market to take off. As momentum builds and the on-road electric truck population grows, CARB might consider reducing the cap.

2. Strengthen and update the overall LCFS program to better align with long-term state goals and ambitions.

LCFS has played a critical role in reducing transportation-related emissions in California since its inception. However, the market has become imbalanced in recent years, credit prices have fallen precipitously, and the program is beginning to diverge from California's longer term market transformation goals for the transportation sector.

From our standpoint as a group of companies interested in rapid and widespread electrification, the primary overarching issue with the LCFS market is that historically low credit prices are undermining investor confidence in the market. When CARB prepared its TCO analysis for ACF, it modeled credit values of $200 through 2030[5] – but credit values have plummeted to around $60[6] and the market has not reacted positively to the most recent proposed language. CARB is proposing multiple regulatory changes to begin addressing the challenges undercutting this market, including a proposal to step down program stringency in 2025 as well as the creation of Automatic Acceleration Mechanism. We generally support these provisions and appreciate the recognition that both are necessary given recent market dynamics. However, despite these proposals, we have not yet identified any analysts or brokers who see a near-term rebound in credit prices absent additional changes to the proposed regulation.

278.6
- **Recommendation: Additional program modifications are needed to support credit prices and drive innovation and investment that supports California state goals.** CARB has multiple options to support credit prices:
    - Some fuel sector experts and advocates have called for **further increases in stringency and earlier implementation of the Automatic Acceleration Mechanism** as one way to address the oversupply issues undercutting the market.
    - Many environmental advocates and community-based organizations are calling for **caps on certain crop-based biofuels** and as an important part of the solution.[7]

We recognize that this is a complicated topic with many details falling outside of our core area of expertise. Others are better positioned to weigh in on expected renewable fuel volumes, land use change, and localized

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[5] Appendix G of ACF regulation, p. 21, accessed at: https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2022/acf22/appg.pdf

[6] Weekly LCFS Credit Transfer Activity Reports | California Air Resources Board. The average for February 5th-11th was $60.52.

[7] For example, see "Assembly Bill 32 Environmental Justice Advisory Committee (EJAC) DRAFT Recommendations to the California Air Resources Board (CARB) on the Low Carbon Fuel Standard Regulation Updates" (available online at 1-lcfs2024-VjMFaQNjUGABWFA0.pdf (ca.gov)) as well as comments submitted by the World Resources Institute (WRI) and others.

health impacts. It is clear that additional program changes are needed to address the supply/demand imbalance that is undercutting credit prices and we believe there is value in better aligning this policy with California's goal of a zero-emission transportation sector.

California continues to play a leadership role in reducing emissions, improving air quality, and supporting private sector innovation through strong market signals. The state has set very ambitious targets and timelines for electrifying medium- and heavy-duty vehicles, calling for a complete market transformation that will require massive investment, cross-sector collaboration, and forward-looking policy intervention. Companies like ours are stepping in to help achieve our shared goals, but infrastructure investment on the scale we need to see has not yet materialized. **With the modifications outlined above, LCFS can be the single most powerful tool California has to attract the private capital needed to build out truck charging infrastructure.** LCFS is one of the few remaining tools California has to drive investment in charging infrastructure with looming budget deficits and a crisis of rising electricity rates. We must not miss this opportunity to better align LCFS with California's goals.

We thank you for your efforts and are happy to follow up with you or CARB staff at any time.

Yours,

Adam Browning
EVP Policy and Communications
Forum Mobility
abrowning@forummobility.com

Suncheth Bhat
Chief Business Officer
EV Realty
suncheth@evrealtyus.com

Michelle Avary
VP External Affairs
Einride
michelle.avary@einride.tech

Jane Israel
Sr. Western Regional Manager, Market Development
Highland Electric Fleets
jane@highlandfleets.com

Alexis Moch
Director, Government Affairs
Prologis
amoch@prologis.com

Anthony Harrison
Head of Government and Regulatory Affairs
TeraWatt Infrastructure
anthony@terawattinfrastructure.com

Paul D. Hernandez
Sr. Policy Manager, Government and Utility Relations
Voltera Power LLC (Voltera)
phernandez@volterapower.com

Nicholas Raspanti
Senior Director, Business Development & Policy
Zeem Solutions
nraspanti@zeemsolutions.com

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Comment 288 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Kiki
Last Name	Velez
Email Address	kvelez@nrdc.org
Affiliation	NRDC
Subject	NRDC Comments on LCFS Staff Recommendations
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6958-lcfs2024-WzUFcVA1BTUAWQNg.pdf
Original File Name	NRDC Comments on LCFS Staff Proposal 2-20-24.pdf
Date and Time Comment Was Submitted	2024-02-20 16:13:19

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

Chair Randolph and Honorable Members of the Board
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: NRDC Recommendations for the Low-Carbon Fuel Standard Program

The LCFS Program is one of California's largest sources of funding for clean transportation. But, as NRDC and other commenters have extensively described, some aspects of the program's current design have unintended consequences that prove non-beneficial or worse for communities and the climate. In particular, the program channels billions of dollars to both biomethane, which CARB's own Scoping Plan finds is not a significant, long-term decarbonization solution for the transportation sector,[1] and to lipid-based biofuels, which have dubious carbon benefits and significant harmful impacts that are not effectively addressed by CARB's Staff Proposal.[2] The LCFS Program's reliance on these fuels exacerbates harm to communities that live near highways, refineries, and large livestock operations,[3] and it detracts from CARB's electric vehicle (EV) targets. The Staff Proposal represents a missed opportunity to fix the LCFS to make it into the truly effective and progressive climate measure it was intended to be.

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[1] California Air Resources Board 2022 Scoping Plan for Achieving Carbon Neutrality (Nov. 16, 2022) at 185-190 ("CARB Scoping Plan") *finding that* "[t]he primary ZEV technologies available today are battery-electric and hydrogen fuel cell electric vehicles" *and demonstrating a minimal role for biomethane in the transportation sector over the coming decades.* Available at https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp.pdf.
[2] Herein, we refer collectively to the "Staff Report: Initial Statement of Reasons" and its appendices as the "Staff Proposal." Accessible at https://ww2.arb.ca.gov/rulemaking/2024/lcfs2024.
[3] María Arévalo and Katherine Lee, "Popular California climate program lets polluters keep harming vulnerable communities," CalMatters (Aug. 1, 2023). Accessible at https://calmatters.org/commentary/2023/08/climate-program-polluters-harm-communities/.

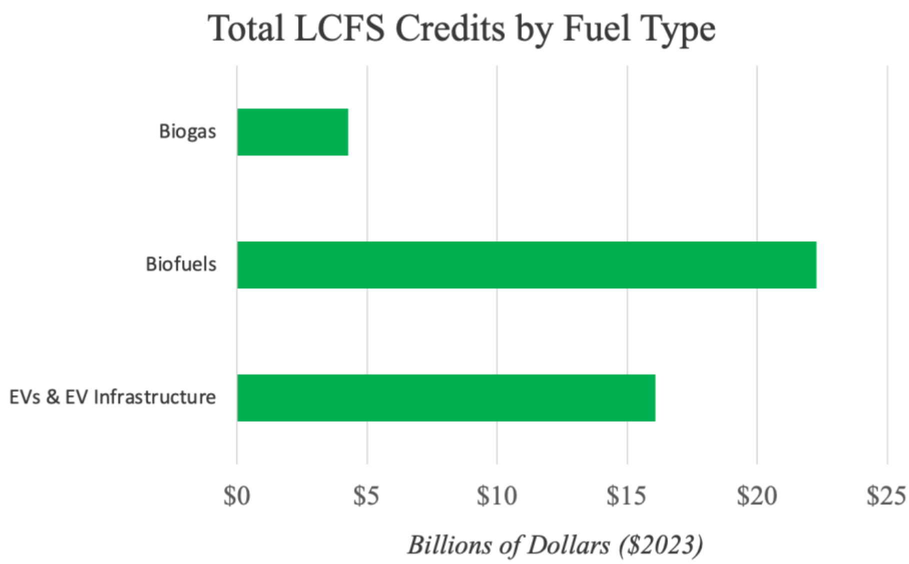

Figure 1: *LCFS funding by fuel type (2011-2022), based on data from UC Davis LCFS data visualization tool.[4] Source: NRDC*

Hundreds of public commenters and numerous environmental justice and environmental organizations have called on CARB to address these issues and to bring the LCFS Program into alignment with California's climate and environmental justice objectives.[5] Yet the Staff Proposal does not effectively address these concerns. Californians pay for the LCFS Program at the pump, and they deserve to see their hard-earned money supporting clean, non-polluting technologies that advance climate action, improve air quality, benefit communities, and provide a pathway to the state's clean transportation future. We urge CARB to reform the LCFS Program, starting by hosting at least two additional Board meetings to consider significant changes to the Staff Proposal.

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[4] Prof. Aaron Smith, U.C. Davis Department of Agricultural and Resource Economics, LCFS Calculator. Accessible at https://asmith.ucdavis.edu/data/LCFS. ("UC Davis LCFS Data Visualization Tool").
[5] See, e.g., comments responding to CARB's February 2023 Workshop (accessible at https://www.arb.ca.gov/lispub/comm2/iframe_bccommlog2.php?listname=lcfs-wkshp-feb23-ws&_ga=2.255679752.1654759407.1684780517-1745364582.1672094362); public comments at CARB's September 28, 2023 Board meeting; and recommendations from the Environmental Justice Advisory Committee (Accessible at https://ww2.arb.ca.gov/sites/default/files/2023-08/EJAC%20Low%20Carbon%20Fuel%20Standard%20Recommendations%20Version%201%2008242 3.pdf). Commenters include Animal Legal Defense Fund, Center for Food Safety, Central California Environmental Justice Network, Central Valley Air Quality Coalition, Earthjustice, Food & Water Watch, International Council on Clean Transportation, Leadership Counsel for Justice and Accountability, Sierra Club California, and Union of Concerned Scientists.

Below is a summary of the changes NRDC recommends to the Staff Proposal.

CARB Staff Proposal	NRDC Recommendations	
Extend avoided methane crediting for biomethane through 2040 for CNG vehicles and through 2045 for hydrogen production for any project that breaks ground before 2030.	**Correct the over-crediting of livestock biomethane this year** and utilize CARB's SB 1383 authority to open a proceeding by 2025 to regulate, track and report emissions from the agricultural sector.	279.1
Allow unrestricted crediting for lipid-based bioenergy produced from oil feedstocks in the food crop system, requiring only sustainability certification of the particular feedstock being refined.	**Establish a cap on lipid-biofuel feedstocks** to limit the use of food crop oils, and re-evaluate the carbon intensity of such fuels in a manner that considers feedstock fungibility and displacement.	279.2
Allow CO_2-enhanced oil recovery projects to continue to receive LCFS credits.	Disallow credit-generation for carbon capture projects that **utilize CO_2 for enhanced oil recovery**, in line with SB 1314.	279.3
Allow fossil hydrogen paired with biomethane environmental attributes to receive greater LCFS credits than green, electrolytic hydrogen.	**Ensure that credited hydrogen is truly climate-friendly** by requiring it to be produced with zero-carbon electricity that is incremental, deliverable, and hourly-matched.	279.4
Change the design of traditional LCFS credits for EVs by allowing base residential credits for charging stations in multi-family residences and establishing a new statewide rebate for MHD EVs, among other changes to base residential credits;	**Keep the design of base residential credits and the current program rules** (e.g., limits on credits, size of charging plazas) and extend the program to 2035;	279.5
Extend the current capacity credits for public DC fast chargers for light-duty EVs to 2030 but reduce the size of the program and limits it to rural and DAC areas;	**Allow emerging types of transportation electrification to earn credits** without a Tier 2 application;	279.6
	Grant larger credits to fixed guideways, transit buses and school buses;	279.7
Add a new capacity credit program for MHD EVs at public, shared depot and fleet locations to 2030 with many restrictions.	**Encourage more DCFC development,** including at shared depot and fleet locations for drayage, short-haul and delivery trucks.	279.8

Table 1: Comparison of the Staff Proposal with NRDC's recommended changes

279.1

1. **Avoided methane crediting for livestock biomethane is distorting the LCFS Program and the economics of the livestock industry, with detrimental consequences for communities and the climate.**

Staff proposes to extend avoided methane crediting for biomethane through 2040 for CNG vehicles and through 2045 for hydrogen production, with these extensions applying for any project that breaks ground before 2030. If approved, this recommendation would lock in the distortionary impacts of avoided methane crediting for decades – undermining California's clean transportation goals and harming communities that live near concentrated-animal feeding operations (CAFOs) and refineries. Instead, CARB must correct the over-crediting of livestock biomethane by the end of 2024 and utilize its SB 1383 authority to open a new proceeding specifically designed to regulate emissions from the agricultural sector.[6]

Today, the LCFS Program provides an outsized "avoided methane credit" to livestock biomethane based on the assumption that manure methane from CAFOs would be released into the atmosphere if not captured in digesters funded by the LCFS Program. This results in livestock biomethane (and fossil hydrogen produced with biomethane credits) receiving outsized carbon intensity (CI) scores that range from negative 300 to negative 400 tons CO_2e/Megajoule.[7] In comparison, the CI scores of renewable electricity and green, electrolytic hydrogen hover near zero. Since the program's inception, biomethane has received more than $1.26 billion ($2023) in LCFS credits due to avoided methane crediting.[8] This has spawned a digester industry that is reliant on these public resources and provides struggling industrial dairies with a new revenue stream.

[6] Senate Bill No. 1383 (Lara), Health and Safety Code § 39730.5(b)(1) (2016), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.
[7] Michael Wara et al., Stanford University, "Simulating an "EJ Scenario" for the Low Carbon Fuel Standard Rule update using the ARB CATS Model" (May 31, 2023). Accessible at https://ww2.arb.ca.gov/sites/default/files/2023-05/Stanford%20Presentation.pdf.
[8] See Figure 1 above.

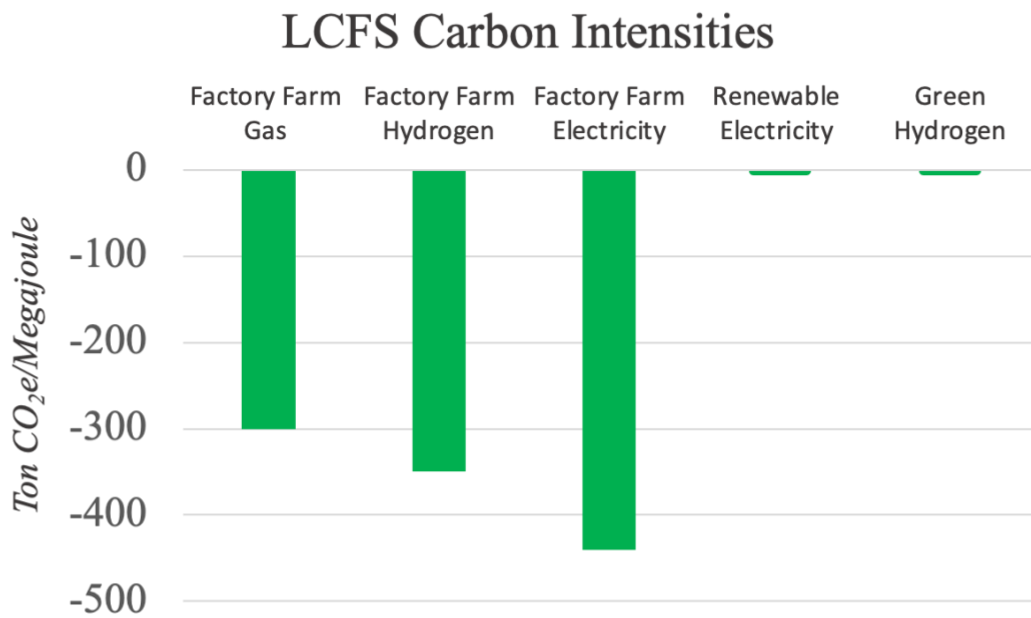

Figure 2: *Approximate carbon intensities under current LCFS CI scoring system, based on Stanford University Climate & Energy Policy Program modeling.*[9] *Source: NRDC*

Avoided methane crediting is distorting the LCFS Program. As shown above, the lowest possible CI score for renewable electricity is zero – placing it on an uneven playing field with biomethane and stifling the deployment of EVs and EV charging infrastructure. This results in one compressed natural gas (CNG) truck and three diesel trucks receiving the same amount of LCFS credits as four electric trucks[10] – despite CARB's objective of 100 percent zero-emission heavy-duty truck sales by 2036.[11] Similarly, under this scoring system, green electrolytic hydrogen with a minimum possible CI of zero receives far fewer credits than fossil hydrogen produced in a refinery that purchases biomethane's environmental attributes. Avoided methane crediting artificially sweetens the deal for biomethane in the LCFS, even as CARB

[9] Michael Wara et al., Stanford University, "Simulating an "EJ Scenario" for the Low Carbon Fuel Standard Rule update using the ARB CATS Model" (May 31, 2023). Accessible at https://ww2.arb.ca.gov/sites/default/files/2023-05/Stanford%20Presentation.pdf.

[10] Michael Wara, Stanford University, Joint Meeting of CARB and the Environmental Justice Advisory Committee (Sept. 14, 2023) at 12 (citing to Phoebe Seaton's 7/17/23 presentation to EJAC). Accessible at https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2023/091423/ejacpres.pdf.

[11] See CARB Advanced Clean Fleets Regulation. Accessible at https://ww2.arb.ca.gov/our-work/programs/advanced-clean-fleets.

acknowledges via other policies that biomethane has a negligible role to play in decarbonizing transportation.[12]

The LCFS program's current design is harming communities living near CAFOs and refineries. CARB staff's proposal will continue to do the same. Outsized incentives for biomethane particularly benefit large livestock operations, which pollute the air and water of the communities who live near them.[13] Troublingly, recent research finds that dairy biomethane incentives from the LCFS are so large that they may enable increases in herd sizes even as dairy demand decreases.[14] In other words, the LCFS may actually be incentivizing the growth of CAFOs whose main product is not milk, but rather methane that industrial farms can capture and sell as a transportation fuel under the current LCFS framework.

Proponents of the avoided methane credit for biomethane argue that the LCFS is helping clean up emissions from the agricultural sector. But as a transportation fuels program, the LCFS should drive California towards a zero-emissions transportation future – not direct resources to expensive methane digesters that have little to no role in the clean transportation future. Because the LCFS is designed to be a transportation program, it is also not effective at addressing all of the climate, air, and water emissions from CAFOs. To fix the LCFS Program and meaningfully address agricultural emissions, CARB should remove avoided methane crediting in 2024 and open a new proceeding under CARB's SB 1383 authority to consider separate, dedicated policies to comprehensively address methane emissions from CAFOs.[15]

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[12] See, e.g., CARB Scoping Plan at 190, Advanced Clean Cars II Regulation, and Advanced Clean Fleets Regulation.

[13] See, e.g., Leadership Counsel for Justice & Accountability, Food & Water Watch, Animal Legal Defense Fund, the Center for Food Safety, Institute for Agriculture & Trade Policy, Association of Irritated Residents, Campaign for Family Farms & the Environment, Central Valley Air Quality Coalition, Center on Race Poverty and the Environment, Valley Improvement Project, Center for Biological Diversity, Friends of the Earth, Central California Environmental Justice Network, Sierra Club California, and Defensores del Valle Central Para el Agua y Aire Limpio; "Comments on Potential Changes to the Low Carbon Fuel Standard Program" (Mar. 15, 2023). Accessible at https://www.arb.ca.gov/lists/com-attach/115-lcfs-wkshp-feb23-ws-UzlXPgBoVmtXJQNc.pdf.

[14] E. Merchant, "A Battle Is Underway Over California's Lucrative Dairy Biogas Market," Inside Climate News, (Dec. 2023). Accessible at https://insideclimatenews.org/news/28122023/milking-it-battle-underway-california-dairy-biogas-market/.

[15] Senate Bill No. 1383 (Lara), Health and Safety Code § 39730.5(b)(1) (2016), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.

2. **Hydrogen credited as zero-emission or lower under the LCFS Program should be green, electrolytic hydrogen produced according to the "three pillars" of incrementality, deliverability, and hourly matching.**

The Staff Proposal continues to encourage hydrogen production through the LCFS Program with little attention to the true carbon intensity of production pathways. As demonstrated in Figure 2 above, under the LCFS Program, a refinery can produce polluting hydrogen from fossil gas (which emits harmful local air pollution as well as greenhouse gases), purchase LCFS credits for factory farm gas from anywhere in North America, and then sell their hydrogen on the market with a negative CI. Meanwhile, green hydrogen produced from solar electricity achieves a minimum CI of zero.

NRDC continues to call on CARB to ensure that, where hydrogen is credited as zero-emission or lower in the LCFS Program, it is green, electrolytic hydrogen produced with clean electricity that meets the three pillars of incrementality, deliverability, and hourly matching.[16] This will ensure that hydrogen credited as zero-emission is truly delivering emissions reductions.

- **Incrementality:** Also referred to as additionality, this requires that an electrolyzer be powered by *new* clean energy, thereby ensuring that the electrolyzer does not lead to an increase in fossil fuel combustion on the grid from resource shuffling.
- **Deliverability:** For an electrolyzer to claim that a clean energy project is offsetting its grid electricity consumption by displacing fossil fuels, the clean energy project needs to be delivering power into the same grid where the electrolyzer is located.
- **Temporal matching:** An electrolyzer drawing grid power should only be allowed to claim that its consumption is offset by clean energy during times when this clean energy is actually generating. Therefore, there needs to be a strong correlation, or "temporal matching," between times of electrolyzer operations and times of clean energy generation. Matching should be demonstrated on an hourly basis from 2028.

[16] Rachel Fakhry, NRDC blog, "Success of IRA Hydrogen Tax Credit Hinges on IRS and DOE" (December 8, 2022). Accessible at https://www.nrdc.org/bio/rachel-fakhry/success-ira-hydrogen-tax-credit-hinges-irs-and-doe.

3. CARB's Staff's Proposed Measures to Address Biofuel Feedstock Sourcing Fail to Address the Problem of Fungibility

NRDC and numerous other commenters made a strong recommendation to CARB last year to impose caps on lipid bioenergy feedstocks. The specific reason given in support of that recommendation was that these feedstocks – in particular, virgin oils in the food crop market – are fungible. As explained in NRDC's 2023 Comment,[17] when large volumes of a feedstock such as soybean oil are diverted to energy production, the shortage created by that diversion will incentivize both additional land being devoted to grow more of the feedstock oil to address the shortage, and increased production of other types of oil that are fungible with the feedstock oil. The most problematic of these fungible oils, as explained, is palm oil, which is associated with large-scale deforestation and the ecological and carbon impacts that ensue. The 2023 Comment cited the extensive research supporting this concern by ICCT and others.

The solutions that CARB offers to this problem of food crop oil fungibility and displacement are incapable of addressing the issue. CARB proposes, first, that the specific feedstocks used in bioenergy refining must be traced to their point of origin and certified as not having caused recent deforestation; and second, that palm-derived fuels be removed from eligibility for credit generation. These proposals fail to address the fundamental challenges of fungibility and displacement.

Regarding the certification requirement, the fact that a particular quantum of oil used in biodiesel production is supply-chain certified says nothing about the degree of *displacement* in the market caused by consumption of that quantum, and the effects of that displacement on the environment. For example, if the Phillips 66 refinery were to process 2.5 million metric tons (MMT) of soybean oil per year,[18] it could certify pursuant to CARB's Staff Proposal that every

[17] "NRDC Recommendations for Updates to the Low Carbon Fuel Standard" (June 2023). Accessible at https://ww2.arb.ca.gov/form/public-comments/submissions/4036. ("2023 Comment").

[18] 2.5 MMT is the amount of vegetable oil the Phillips 66 project could consume per year operating at full capacity. J. Martin, "A Cap on Vegetable Oil-Based Fuels Will Stabilize and Strengthen California's Low Carbon Fuel Standard," *Union of Concerned Scientists* (Jan. 30, 2024) ("Martin 2024"). Accessible at https://blog.ucsusa.org/jeremy-martin/a-cap-on-vegetable-oil-based-fuels-will-stabilize-and-strengthen-californias-low-carbon-fuel-standard/#:~:text=The%20California%20LCFS%20has%2C%20since,other%20secondary%20fats%20and%20oils.

barrel of that soybean oil came from suppliers who had not recently cleared forests to grow the soybeans. But that information would have no bearing on the impact of the additional oil crops that would be planted to *replace* some or all of those 2.5 MMT of oil in the food crop market – which could be soybean oil, palm oil, or any combination of fungible oil crops. The planting of those replacement crops may well have devastating deforestation impacts, and merely certifying that the particular oil used by Phillips 66 was responsibly sourced would disclose nothing about such impacts.

The proposal to prohibit credits from palm oil-derived fuels is similarly ineffectual in the face of fungibility and displacement. The problem identified by ICCT and others is not that palm oil is likely to be used *directly* for bioenergy production. Indeed, as CARB Staff acknowledges in the ISOR, the high CI of palm oil production would effectively preclude it from eligibility already. The problem, rather, is that palm oil may well be grown in significant quantities to *replace* the food crop oils such as soybean oil with which it is fungible where the food crop oils are used in large volumes (as they are or will be in the two Bay Area refinery biofuel conversions).

The CARB Staff Proposal fails to take the one step that has the potential to reduce the incidence of palm oil being used as a bioenergy feedstock: requiring supply train tracking for used cooking oil. By requiring tracking only for crop- and forestry-based oils, CARB staff's proposal would exacerbate the existing risk that suppliers will try to pass off virgin palm oil as used cooking oil. This risk is particularly high given that renewable diesel producers are importing used cooking oil – or perhaps purported used cooking oil – from around the world.[19]

CARB's failure thus far to act in a meaningful manner to curb harmful lipid feedstocks is occurring against the background of unexpectedly high bioenergy production and consumption rates and worsening associated impacts, with information continuing to emerge consistent with studies cited in the 2023 Comment. Biodiesel consumption for the first half of 2023 ran well ahead of projections, at a level that CARB modeling did not anticipate prior to 2037. Soybean oil has been a fast-growing feedstock of choice in the renewable diesel industry, prompting

[19] *Ibid. See* ICCT, U.S. Biofuel Demand and the Potential for Used Cooking Oil from Major Asian Exporting Countries, ICCT February 2023, *available at* https://theicct.org/wp-content/uploads/2023/02/US-UCO-potential_fs_final.pdf.

investments in US soybean crush capacity instead of exports of whole soybeans to Asia – creating a high risk that the diverted soybeans will be replaced in Asia by soybeans as the cheapest substitute.[20] Aligned with this trend, the Phillips 66 refinery in Rodeo, a potentially enormous user of soybean oil feedstock, has approached completion of its bioenergy conversion project and is slated to begin production this quarter. This one facility – out of the many potentially supported by the LCFS – could potentially consume roughly half of the soybean oil exports of the entire nation of Argentina, the world largest soybean oil exporter.[21] And in keeping with concerns about these trends, recent analysis suggests that consumption of food crop oils in bioenergy production has already contributed to the global food crisis.[22]

These trends create an urgent need to isolate and analyze the potential impact of these specific trends in oil crop consumption to produce bioenergy. CARB, unfortunately, has not yet done that. The analysis of Alternative 1 lumps together feedstock caps with multiple other different potential policy choices and analyzes them collectively. It is impossible to discern from this collective analysis how specifically feedstock caps would affect indirect land-use change and other potential environmental impacts associated with food crop oil production.

We call on CARB to analyze the carbon and ecological impact of feedstock caps separately and in isolation from other types of policy measures, including but not limited to a re-evaluation of CI scores associated with lipid feedstocks; and develop appropriate caps on such feedstocks based upon that analysis. The analysis must take into account not only direct impacts of consumption of particular volumes of lipid feedstock for energy production, but also the indirect and substitution impacts that result from the fungibility of the lipid feedstocks. All such analysis, including modeling results, should be made publicly available with an opportunity for comment before any decision is finalized.

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[20] E. Usset, "High crush margins drive rapid expansion," *FarmProgress* December 20, 2023, *available at* https://www.farmprogress.com/soybean/high-crush-margins-drive-rapid-expansion.
[21] *Ibid.*
[22] J. Glauber and C. Hebebrand, "Food versus Fuel v2.0: Biofuel policies and the current food crisis," *International Food Policy Research Institute* April 11, 2023, *available at* https://www.ifpri.org/blog/food-versus-fuel-v20-biofuel-policies-and-current-food-crisis.

4. **Staff recommendations continue to provide LCFS credits to projects that use captured CO_2 to stimulate more oil production, at odds with California's climate goals and state law.**

Currently, projects that capture CO_2 and then inject the CO_2 into oil wells to stimulate more oil production – a process known as CO_2-enchanced oil recovery – are eligible for LCFS credits. The Staff Proposal does nothing to change this status quo. NRDC and numerous other parties have urged CARB to eliminate this practice, in line with SB 1314, which finds that incentivizing CO_2-enhanced oil recovery is incompatible with California's climate goals.[23] We continue to ask CARB to end this counterproductive practice by removing LCFS credits for projects that utilize captured CO_2 for enhanced oil recovery.

5. **Continue and Enhance the Electric Transportation Provisions in the LCFS**

The new LCFS should continue providing credits for various types of electric transportation, including electric forklifts and light duty vehicles, and should expand incentives for medium and heavy duty (MHD) charging and electric vessels, aircraft, and off-road equipment. Electric transportation technologies are critical to cost-effectively reach California's climate targets while reducing tailpipe emissions and related impacts to communities, and the LCFS should support their deployment.

EDU Credit Generation

The current structure of credit generation, whereby electric distribution utilities earn credits for residential charging, owners of the charging equipment earn the nonresidential credits, and various parties can earn incremental credits, is appropriate and should remain unchanged.[24] If CARB finalizes the proposed provision for owners of charging stations[25] at non-reserved parking spaces at multi-family residences to become credit generators, CARB should place reliability and consumer protections on these charging stations so that the customer experience is improved compared to today. For example, this could include reporting requirements with protections

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[23] Senate Bill 1314 (2022), § 2 (codified at Cal. Pub. Res. Code § 3132).

[24] Examples of non-residential credits include charging of light-duty, medium-duty, heavy duty and non-road vehicles away from home, fixed guideway electrification, and fleet charging of vehicles, marine vessels, material handling equipment, aircraft and similar non-road equipment.

[25] Or their designee such as a charging station provider or operator

against exorbitant charges on EV drivers (i.e., maintaining low operating costs), as well as a high degree of uptime.

We support many of the new proposed provisions on electric distribution utilities (EDUs), but recommend a few changes. While under the proposal, different EDUs are likely to offer LCFS rewards to reduce the purchase or lease price of new and used EV purchases for low-income individuals, EDUs should be required to have the identical eligibility rules in order to minimize confusion for consumers. The proposed five percent cap on administrative costs is premature, particularly for programs focused on outreach to under-served communities, and should instead look to the CPUC definitions and percentages. For example, the current ten percent cap could continue, with the regulatory amendments allowing the Executive Officer to lower it after workshops to examine the details (e.g., impact on small vs large EDUs, impact of credit prices, fixed vs. variable costs, and role of marketing, education and outreach on programs). We also recommend incentives be provided to encourage smaller EDUs to opt into the LCFS so that all areas can be served.

Medium and Heavy-Duty Fast Charge Infrastructure Program

We support many of the provisions in the proposed MHD Fast Charge Infrastructure (FCI) program. Unfortunately, the program rules are inadequate to maximize the potential business case for infrastructure, including near-term use cases such as drayage, short-haul and delivery trucks. While public charging locations are the focus of the MHD FCI program, more favorable rules are needed to help shared depots and fleets which struggle to find grid capacity, favorable zoning, permissive leases and sometimes land. Specially, LCFS should allow locations anywhere in California especially for shared depots, or within 5 miles from a corridor rather than just 1 mile. Sites should be able to have a mix of charging levels to meet different customer needs and be as large as 15 MW. Sites should also be allowed to be as large as 100 connectors to allow for future scaling as seen on the light-duty charging infrastructure side. Single fleets should also receive the same credit formula as public locations and shared depots. Finally, we also recommend the proposed cap on prior quarter deficits be raised to 5% based on the California

Energy Commission's analysis.[26] In this nascent stage, we need to focus more on near-term use cases. CARB has time to do course corrections in a few years in the next LCFS rulemaking.

Light-Duty Fast Charge Infrastructure Program

The LCFS has helped to spur the build-out of the initial, public-access fast-charging infrastructure needs for passenger vehicles as the state transitions to 100% Zero Emission Vehicle requirements by 2035. Based on discussions with numerous charging infrastructure providers, the FCI provisions have been critical for improving the business case for public fast charging stations. But we must continue to scale up public-access to charging infrastructure even more quickly. The FCI provisions that provide capacity credits for direct current fast charging (DCFC) for light-duty (LD) vehicles under the current program rules (e.g., cap of 2.5% of prior quarter deficits, 2.5 MW sites and locations statewide) should continue to 2035. The proposed LD FCI program ending in 2030 (e.g., cap of 0.5% of prior quarter deficits, four chargers per site, 1 MW per site and limited locations) should be rejected. Reliability and interoperability requirements should be added as soon as possible.

Including Other Categories of Electric Transportation

Finally, CARB should allow more types of electric transportation technologies to earn credits in the LCFS. Currently other fuels can earn credits for most end-use applications, but many types of electric vessels, aircraft, and off-road equipment cannot because they lack an approved Energy Economy Ratio ("EER"). Companies investing in emerging electric technologies, many of whom are start-ups, do not have the expertise and funds to go through the detailed application to CARB for an EER. The solution is for CARB to establish conservative default EERs (e.g., 3.0) in LCFS Table 1 that can be used by these emerging electric transportation technologies. This default set of EERs would incentivize electrification in hard-to-reach electric transportation applications such as mining equipment, agricultural equipment, forest equipment, boats, marine vessels,

[26] According to the CEC's AB 2127 analysis, the state will need about 11,600 MW of MHD charging by 2030. See https://efiling.energy.ca.gov/GetDocument.aspx?tn=247323 for November 2022 CEC workshop for more detail. We believe the proposed MHD FC program with deliver less than 1/10th of that need. The sum of the total MHD charging capacity based on this forecast was calculated to be 2,900 MW and 11,600 MW by 2025 and 2030, respectively, by taking the sum-product of the number of chargers and their respective power rating. See AATE primary scenario, Appendix H, Table H-1.

ferries, aircraft, locomotives, tow-tractors, sweepers and other off-road equipment. In addition, because a 3.0 EER is not optimal, some industries would still be motivated to submit an application to CARB in order to establish a higher, more favorable EER. We are also supportive of excluding from this default EER certain end-uses such as golf carts and indoor sweeper/scrubbers that are already electric. We also support the Earthjustice proposal for changing the fixed guideway crediting so that they receive a larger credit for this type of electric transportation including their pre-2010 projects, and for a “VMT multiplier” for zero-emission transit and school bus projects, as both of these serve a critical public need for priority communities. Supporting the development of clean, electric transportation technologies is essential to meeting California’s climate goals while reducing air pollution and health harm to vulnerable communities.

6. Conclusion

Numerous environmental justice and environmental organizations, alongside hundreds of public commenters, have called on CARB over the past year to improve the LCFS Program in alignment with California’s urgent climate and air quality objectives. The LCFS Program can serve as a critical tool to accelerate the transition to electric vehicles and zero-emissions heavy-duty transportation in a way that delivers meaningful benefits to communities – but only if CARB addresses the distortionary policies that continue to undermine the program.

Sincerely,

Kiki Velez
Equitable Gas Transition Advocate
Climate and Energy

Ann Alexander
Senior Attorney
Nature Program

Lena Brook
Acting Director
Food and Agriculture

David Pettit
Senior Attorney
Climate and Energy

Esther Portillo
Western City/State Advocate
Environmental Health

Pete Budden
Hydrogen Advocate
Climate and Energy

Merrian Borgeson
California Director
Climate and Energy

Simon Mui
Director
Transportation Team

Comment Log Display

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Comment 289 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jeremy
Last Name	Martin
Email Address	jmartin@ucsusa.org
Affiliation	Union of Concerned Scientists
Subject	Scientists and economists letter on vegetable oil fuel cap
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6959-lcfs2024-BXYAZQZuUmQGbgF1.pdf
Original File Name	Scientists letter on LCFS veg oil cap.pdf
Date and Time Comment Was Submitted	2024-02-20 16:15:49

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Liane M. Randolph, Chair
California Air Resources Board
1001 I Street Sacramento, CA 95814

Via Electronic Submittal

To: Chair Randolph

280.1 The unprecedented speed and magnitude of the expansion of renewable diesel used in California, increasingly made from soybean oil, is harming people, accelerating tropical deforestation and undermining California's climate policies. **We call on the California Air Resources Board to immediately cap the use of vegetable oil-based biofuels and to strengthen safeguards within the Low Carbon Fuel Standard (LCFS) to ensure that the use of biofuels does not directly or indirectly contribute to global food price shocks, agricultural expansion and deforestation.** Capping the use of crop-based biofuels is neither radical nor unprecedented[i], and is urgently required to align the LCFS with California's focus on transportation electrification and ensure that California remains a leader in effective and responsible climate policies.

Fifteen years ago, in the midst of rapid expansion of corn ethanol, more than 170 scientists urged the California Air Resources Board to "include indirect land use change in the lifecycle analyses of heat-trapping emissions from biofuels and other transportation fuels."[ii] The Board listened to the science, and for more than a decade this and other policy decisions effectively prevented large increases in the use of crop-based biofuels in California. But these safeguards are no longer functioning effectively.

In the last few years California's consumption of renewable diesel has outstripped the sustainable sources of waste oils and fats, and is increasingly produced from soybean oil, some of it imported directly from South America[iii]. California is on pace to consume 1.3 million metric tons of soybean oil for fuel in 2023, equivalent to 10 percent of global trade in soybean oil[iv]. As California consumes more of the world's supplies of soybean oil, palm oil cultivation is expanding to replace soybean oil diverted to fuel use.

Three primary reasons the California LCFS requires an immediate cap on the use of vegetable oil-based fuels are:

> **The global poor are at risk:** Use of vegetable oil for fuel contributed to a global food crisis in 2022. The World Food Price Index published by the Food and Agriculture Organization of the United Nations reached its highest level in a quarter century in 2022. Oils were the component of the index with the largest increase, with real prices up 84 percent compared to the 2014-2016 reference. Other factors were primarily responsible for this price spike, but despite the global food crisis, California consumption of renewable diesel increased by 47 percent in 2022 and more than 900 thousand metric tons of soybean oil were used to produce renewable diesel for consumption in California. California should not be bidding against the global poor to fuel its trucks.
>
> **Cropland continues to expand into sensitive ecosystems:** The expansion of soybean and palm oil (to replace soy oil used as fuel) is a major driver of tropical deforestation. Recent analysis finds that annual forest carbon loss in the tropics doubled during the early twenty first century[v]

and that oil palm and soybeans are the second and third largest drivers of deforestation after cattle[vi].

Support for renewable diesel is diverting resources from transportation electrification: Renewable diesel generated 40 percent of LCFS credits reported in the most recent quarter, and the large increase in credits from renewable diesel has depressed LCFS credit prices. Capping the use of renewable diesel and other fuels made from vegetable oil will focus more of the support provided by the LCFS on transportation electrification, which can be scaled up with clear climate benefits and without the harsh tradeoffs associated with vegetable oil and other crop-based fuels.

We therefore urge CARB to cap vegetable oil-based biofuels immediately in this rulemaking. Nothing short of a cap will effectively stem the widespread harms caused by the rapidly growing use of these fuels.

Meaningful safeguards must effectively ensure that the use of vegetable oil or other crops for biofuels does not divert food to fuel uses or expand the footprint of agriculture. California's existing land use safeguards within the LCFS rely on an estimation of land use change emissions developed using complex economic and land use models. More than 15 years of research has not led to a consensus estimate of these emissions. A 2022 study from the National Academy of Sciences[vii] describes the methodological problems arising from combining an attributional lifecycle for fuel production with a consequential assessment of the climate impacts of fuel pathways or policies. A recent Model Comparison Exercise[viii] conducted by the US Environmental Protection Agency highlights the deep uncertainty underlying the modeled climate benefits attributed to soybean oil-based biofuels. *In light of the methodological and modeling challenges with the current approach, more direct safeguards against excessive and damaging diversion of food to fuel use are required to effectively prevent bad outcomes.*

The data makes clear that there is no surplus vegetable oil available in the United States, which is projected by the US Department of Agriculture to become a net importer of soybean oil.[ix] In the global marketplace, as more soybean oil is redirected from food uses to fuel production, palm oil is the largest and fastest growing source of vegetable oil substituting for it in global food markets[x]. Because of this substitution, tracking the chain of custody of the oils used for fuel in California or banning the use of palm oil-based fuels is not an adequate safeguard. A cap on the total quantity of vegetable oil used for fuel is the most effective way to ensure California's LCFS does not contribute to harmful outcomes. While the rapid growth of vegetable oil-based fuels in California is the immediate concern, policymakers in all jurisdictions should develop comprehensive safeguards based on the availability and risks associated with inputs to all types of biofuels to anticipate and address future problems.

Signed,

(affiliations are for identification purposes only)

HOLLY GIBBS, PhD
Professor of Geography
University of Wisconsin-Madison
Madison, WI

JOSEPH GLAUBER, PhD
Senior Research Fellow
International Food Policy Research Institute

Washington, DC

DAVID LOBELL, PhD
Benjamin M. Page Professor Professor, Earth System Science
Senior Fellow at the Freeman Spogli Institute for International Studies
Senior Fellow at the Stanford Woods Institute for the Environment
Senior Fellow at the Stanford Institute for Economic Policy Research
Affiliate, Precourt Institute of Energy
Stanford University
Stanford, CA

DANIEL A. LASHOF, PhD
Director, United States
World Resources Institute
Berkeley, CA

JEREMY MARTIN, PhD
Director of Fuels Policy, Senior Scientist
Union of Concerned Scientists
Washington, DC

RICHARD PLEVIN, PhD
Portland, OR

RICARDO SALVADOR, PhD
Director, Food & Environment Program, Senior Scientist
Union of Concerned Scientists,
Washington, DC

MICHAEL WARA, J.D., PhD
Senior Director for Policy, Sustainability Accelerator
Stanford Doerr School of Sustainability
Director, Climate and Energy Policy Program and Senior Research Scholar
Woods Institute for the Environment
Stanford University
Stanford, CA

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[i] Amendments to the Renewable Energy Directive of the European Union. 2023. Link.
[ii] Scientists and Economists Letter on Indirect Land Use Change, 2009. Link
[iii] Phillips 66 LCFS Tier 2 Pathway Application No, B0520. 2023. Link
[iv] Soybean oil consumption projected based on data from CARB covering the first three quarters of 2023. Data on soybean oil trade from United States Department of Agriculture Foreign Agricultural Service. Oilseeds: World Markets and Trade. Link.
[v] Feng, Y., *et al*. 2022. Doubling of annual forest carbon loss over the tropics during the early twenty-first century. *Nat Sustain* **5**, 444–451. doi.org/10.1038/s41893-022-00854-3
[vi] World Resources Institute. 2021. Global Forest Review. Link.
[vii] National Academies of Sciences, Engineering, and Medicine. 2022. *Current Methods for Life-Cycle Analyses of Low-Carbon Transportation Fuels in the United States*. Washington, DC: The National Academies Press. Link.

[viii] US Environmental Protection Agency. 2023. Biofuel Greenhouse Gas Model Comparison Exercise. Link.
[ix] Bukowski, M., & Swearingen, B. 2023. *Oil crops outlook: December 2023* (Report No. OCS-23l). U.S. Department of Agriculture, Economic Research Service. Link.
[x] United States Department of Agriculture Foreign Agricultural Service. Oilseeds: World Markets and Trade. Link.

Comment Log Display

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Comment 290 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Sam
Last Name	Uden
Email Address	sam@csgcalifornia.com
Affiliation	
Subject	UCS, NRDC and WRI comments on crop-based biofuels
Comment	Submitted on behalf of UCS, NRDC and WRI.
Attachment	www.arb.ca.gov/lists/com-attach/6960-lcfs2024-UidTNI0vBwtXDIQ6.pdf
Original File Name	UCS, NRDC and WRI_Cap on Crop-Based Biofuels_LCFS.pdf
Date and Time Comment Was Submitted	2024-02-20 16:12:51

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

Liane Randolph, Chair
California Air Resources Board

Re: Proposed Low Carbon Fuel Standard Amendments

Dear Chair Randolph,

As key stakeholders who support the goals of the Low Carbon Fuel Standard (LCFS) we are writing to urge CARB to add a critical safeguard to the proposed LCFS amendments before the Board considers them for adoption. Specifically, to ensure that the LCFS advances California's climate protection and zero emissions transportation goals, we urge CARB to include a cap on
281.1 the use of crop-based biofuels or lipids for LCFS compliance.

The LCFS has the potential to substantially help California meet its climate goals by accelerating transportation electrification and promoting innovation in the use of waste-based biofuels (such as woody materials removed from California forests to reduce wildfire risks). In the absence of effective safeguards, however, the LCFS could drive a massive increase in biomass-based diesel (BBD) made from soybean oil and other crops, which would undermine the goals of the program.

Until recently most BBD used for LCFS compliance has come from waste fats, oils, and greases, but the supply of these feedstocks is limited. As a result, recent increases in BBD supply to California and expected future increases would mostly be produced from virgin vegetable oils.[1] According to a recent study by University of California researchers, if the LCFS Carbon Intensity (CI) reduction target is increased to 30% in 2030, in the absence of a limit on crop-based biofuels or lipids it is likely that BBD consumption in California will increase to over 4 billion gallons by 2030,[2] more than three-quarters of which would likely be supplied by virgin vegetable oils.

The Initial Statement of Reasons (ISOR) for the proposed amendments to the LCFS acknowledge that reliance on crop-based biofuels could add pressure to convert forests and other land for biofuel crop production.[3] For this reason, the proposed amendments include a ban on the use of palm-derived fuel for LCFS credit generation. The proposed amendments also include a requirement to track crop-based and forestry-based feedstocks to their point of origin. While
281.2 well-intentioned, these guardrails are completely insufficient to prevent the risk of deforestation that CARB acknowledges because vegetable oils are largely interchangeable

[1] https://theicct.org/publication/lipids-cap-ca-lcfs-aug22/
[2] https://energyathaas.wordpress.com/2023/10/02/petroleum-diesel-is-disappearing-from-california/
[3] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf, at page 32.

global commodities as demonstrated by the strong correlation between the price of palm oil and soybean oil. This means that the very large increase in demand for vegetable oil that the proposed amendments would cause is likely to drive deforestation and related carbon emissions regardless of whether the specific feedstocks used to generate LCFS credits can be traced to existing agricultural land. In short, there is no reasonable policy rationale for excluding the use of palm oil but placing no limits on the use of other virgin vegetable oils.

The U.S. EPA examined this issue in a recent technical study[4] and found that a 1 billion gallon increase in soybean biodiesel demand (far less than the increase the LCFS amendments would cause according to the University of California study) would result in net increases in GHG emissions according to two of the three energy and land-use models they used.[5] The net increase in GHG emissions caused by increased demand for virgin vegetable oil could more than offset the total benefits of the LCFS program according to an estimate by the World Resources Institute.[6]

281.3 The ISOR rejects alternatives that include a cap on lipid biofuels based, in part, on model results that suggest that NOx and PM emissions would not decline as much as under the proposed amendments because there would be more reliance on petroleum diesel rather than renewable diesel. However, more recent research by CARB itself shows that there is no statistically significant difference in PM or NOx emissions between petroleum diesel and renewable diesel when used in New Technology Diesel Engines[7]

Electrification of ground vehicles is the most effective pathway to decarbonization in the transportation system. CARB can accelerate the transition by better harnessing the LCFS towards this end, amongst other reforms. There is too much uncertainty surrounding the net GHG benefits of crop-based biofuels at this time to double down on them,[8] especially when other jurisdictions are looking to adopt LCFS programs of their own and will inevitably look to CARB for design and implementation guidance. Limiting the volume of crop-based biofuels that can be used for LCFS compliance is essential to prevent lock-in of counter-productive compliance strategies, preserve incentives to improve the environmental performance of biofuels that are used for compliance, and focus investment on electrification, hydrogen, and carbon removal strategies that are central to California's pathway to net zero emissions.

* * *

[4] https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf
[5] Also available at https://www.wri.org/insights/us-renewable-fuel-standards-emissions-impact
[6] WRI letter to Chair Randolph, September 26, 2023.
[7] https://ww2.arb.ca.gov/sites/default/files/2021-11/Low_Emission_Diesel_Study_Final_Report.pdf
[8] https://escholarship.org/uc/item/5wf035p8

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Comment 291 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Serj
Last Name	Berelson
Email Address	serj.berelson@mainspringenergy.com
Affiliation	
Subject	Mainspring Energy Comments on Proposed LCFS Amendments
Comment	See attached comment letter.
Attachment	www.arb.ca.gov/lists/com-attach/6961-lcfs2024-AmEHYFAjVGVRCAhk.pdf
Original File Name	CARB LCFS Letter_Mainspring_Final_Feb 20 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 16:12:27

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Mainspring Energy
3601 Haven Avenue
Menlo Park, CA 94025
mainspringenergy.com

February 20, 2024

Clerks' Office
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: *Proposed Amendments to the Low Carbon Fuel Standard*

Mainspring Energy, Inc. ("Mainspring") appreciates the opportunity to submit comments to the California Air Resources Board ("CARB") on the Proposed Amendments to the Low Carbon Fuel Standard ("LCFS") released December 19, 2023. Specifically, we appreciate the development of a biogas book-and-claim pathway under a Tier 2 framework and respectfully request amendments to expand eligibility for biomethane to electric vehicle ("EV") charging as well as transition biogas-to-electricity book-and-claim pathway for EV charging to a Tier 1 pathway to meet help California's/CARB's (e.g. Advanced Clean Fleet) EV deployment goals.

Background on Mainspring

Driven by its vision of the affordable, reliable, net-zero carbon grid of the future, Mainspring has developed and commercialized a new power generation technology —the linear generator— delivering local power that is dispatchable and fuel-flexible. Mainspring's linear generator offers a unique non-combustion capacity and energy solution that simultaneously addresses the critical need of reducing greenhouse gas and criteria pollutant emissions, while also enhancing grid reliability and resilience. Linear generators use a low-temperature, uniform non-combustion reaction that maintains peak temperatures below the levels at which NOx forms (1500°C), resulting in near-zero NOx emissions at all loads – including during start-up. This contrasts with the combustion of a fuel with a non-homogenous flame-front, a process that results in higher temperatures and high NOx emissions. California's South Coast Air Quality Management District recently adopted linear generator-specific requirements in the form of Proposed Rule 1110.3, highlighting the low NOx operation of this technology.[1]

[1] South Coast Air Quality Management District, "Rule 1110.3 Emissions From Linear Generators", Adopted November 3, 2023

Modular and scalable, Mainspring's linear generators can be deployed near load, either customer- or grid-sited, with the ability to immediately generate electricity from a range of renewable fuels – including both 100% hydrogen and ammonia (a hydrogen carrier). Mainspring's inverter-based technology offers a full range of valuable grid benefits including fast (and unlimited daily) starts/stops, a wide dispatch range from minimum to maximum load, quick ramping, and in many cases on-site fuel storage which allows linear generators to firm renewables for short or extended periods of time, thereby facilitating the continued rapid adoption of a reliable renewable energy grid. Our locally-sited linear generators add capacity and resilience to the grid while also providing enhanced flexibility to help avoid renewable curtailment.[2] Finally, by virtue of their modular size (20.5′ x 8.5′ x 9.5′) linear generators are space- and land-efficient and can be sited in load pockets, deferring or completely avoiding expensive transmission and distribution investment.

Comments and Proposed Amendments

Mainspring appreciates the development of the Proposed Amendments to the LCFS and the opportunity to provide our comments and recommendations. **We thank CARB for developing a book-and-claim pathway for biomethane to EV charging, and respectfully request an amendment to**
282.1 **expand the eligibility to allow book-and-claim for biomethane via renewable natural gas and hydrogen (meeting all appropriate deliverability and other requirements) used by offsite systems generating electricity exclusively for EV charging services as well.** Doing so will expand the pool of available low-carbon intensity ("CI") electricity as a transportation fuel that is essential to meeting the growing demand from medium- and heavy-duty fleets – including through CARB's own Advanced Clean Fleet ("ACF") regulation. To further streamline this pathway, **Mainspring recommends that the biogas-to-**
282.2 **electricity book-and-claim pathway for EV charging should be transitioned to a Tier 1 pathway to meet California's/CARB's (e.g. ACF) EV targets.** Enabling low-CI electricity to be used for EV charging more readily facilitates the deployment of charging infrastructure –particularly for medium- and heavy-duty vehicles– that is necessary to meet state, climate, and energy goals.

Specifically, we respectfully suggest the following amendments (underlined) regarding book-and-claim accounting accessibility for biomethane and hydrogen for EV charging pathways.

95488.8(i)(2)

"(2) Book-and-Claim Accounting for Pipeline-Injected Biomethane Used as a Transportation Fuel or to Produce Hydrogen or to generate Electricity. Indirect accounting may be used for RNG used as a transportation fuel or to produce hydrogen or to generate electricity for transportation purposes (including hydrogen that is used either in the production of a transportation fuel or in the generation of electricity exclusively for transportation purposes), provided the conditions set forth below are met:

[2] For additional information on technical specifications and performance benefits, visit https://www.mainspringenergy.com/technology/.

(A) RNG injected into the common carrier pipeline in North America (and thus commingled with fossil natural gas) can be reported as dispensed as bio-CNG, bio-LNG, or bio-L-CNG, or as an input to hydrogen production, <u>or as a fuel source for electric generation for the exclusive purpose of EV charging</u>, without regards to physical traceability. Entities may report natural gas as RNG within only a three-quarter time span. If a quantity of RNG (and all associated environmental attributes, including a beneficial CI) is pipeline-injected in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to natural gas sold in California as RNG no later than the end of the third calendar quarter. After that period is over, any unmatched RNG quantities expire for the purpose of LCFS reporting.

(B) To substantiate RNG quantities injected into the pipeline for dispensing as bio-CNG, bio-LNG, or bio-L-CNG or as an input to hydrogen production, <u>or electric generation for the exclusive purpose of EV charging,</u> the pathway application and subsequent Annual Fuel Pathway Reports must include the following documents linking the environmental attributes of RNG (in MMBtu or Therms) with corresponding quantities of natural gas withdrawn: unredacted monthly invoices showing the quantities of RNG (in MMBtu) sourced and the contracted price per unit; and the unredacted contract by which the fuel pathway holder obtained the environmental attributes.

95488.8(g)(1)(A)(2)

"Biomethane supplied using book-and-claim accounting pursuant to section 95488.8(i)(2) and is claimed as feedstock in pathways for bio-CNG, bio-LNG, bio-L-CNG, hydrogen via steam methane reformation, <u>and electricity generation</u>;"

These amendments enable a wide range of applications to which linear generators can be deployed in meeting CARB's and California's EV deployment goals. As an example, deploying linear generators to immediately power EV charging stations enables fleet operators to utilize biomethane to meet CARB's ACF Rule. The mass adoption of medium- and heavy-duty ("MHD") fleet EVs to meet the ACF Rule necessitates a sizable amount of additional capacity at a time when our current grid strains to meet even existing demand. Currently, utility timelines to install the capacity necessary to power and interconnect MHD projects is multiple years, driven by supply chain constraints arising from the period needed to manufacture and deliver new appurtenant equipment (e.g. the switchgear and transformers necessary to serve this new load), the volume of interconnection applications utilities are receiving, and other factors.

However, California cannot afford to wait for supply chain issues to be resolved, nor interconnection processes to be reformed to meet the ACF Rule. This is especially true for MHD EVs that need significant additions in charging capacity (routinely requiring multiple megawatts for each charging facility) and which are often replacing diesel-powered trucks operating in disadvantaged communities. Linear generators can immediately power EV charging stations, operating as microgrids before utility interconnection, and then serving as biogas- or renewable natural gas-powered clean resilience and flexible load after utility interconnection takes place. Prior to utility interconnection, microgrids can provide immediate power to get charging infrastructure up and running, accelerating the timeline for vehicle electrification and achievement of ACF Rule requirements, while also accelerating the impact of improved air quality for disadvantaged and under-resourced communities. After interconnection, microgrids provide much-needed clean and resilient capacity to the grid while displacing the need for polluting diesel backup generators for use during extreme weather and grid events. Without clean resilience, basic services provided by the growing number of EVs could come to a halt during grid outages.

Conclusion

Utilizing low-CI electricity through book-and-claim accounting can help overcome a range of key barriers to rapidly accelerate the reduction in carbon intensity of transportation fuels for medium and heavy-duty EV fleets. Mainspring appreciates the opportunity to comment on these important Proposed Amendments and looks forward to continuing to collaborate with CARB staff in the future.

Sincerely,

/s/ Serj Berelson

Serj Berelson,
Senior Policy Manager, West
Mainspring Energy, Inc.
3601 Haven Avenue
Menlo Park, CA 94025
Email: serj.berelson@mainspringenergy.com

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Comment 292 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Elton
Last Name	Page
Email Address	etpage@cotullajet.com
Affiliation	
Subject	Proposed Low Carbon Fuel Standard Amendments

Comment

The California Air Resources Board (CARB) has proposed changes to
the Low Carbon Fuel Standard (LCFS) that would remove the
Standard's original exemption for jet fuel. I oppose the proposal
to demerit jet fuel, as SAF production does not currently meet
uptake and an increase in jet fuel prices will negatively impact
283.1 industry, not to mention your entire state in general. Instead, I
support policies that will increase the production and supply of
SAF and policies that will support CARB to identify alternatives t
this proposal through continued industry cooperation and
communication. Of course, if you choose to go ahead and continue
with your proposal, I will be glad to accommodate those aircraft
and businesses that will choose to leave California for greener
pastures.

Attachment

Original File Name

Date and Time Comment Was Submitted	2024-02-20 16:11:09

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Comment 293 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Yuliya
Last Name	Shmidt
Email Address	yuliya.shmidt@bart.gov
Affiliation	BART
Subject	BART's comments on fixed guideway crediting
Comment	Dear CARB Board and staff, Please see the attached comments from BART on the LCFS amendments We urge CARB to establish parity for fixed guideway systems withir the LCFS program. Sincerely, Yuliya Shmidt
Attachment	www.arb.ca.gov/lists/com-attach/6963-lcfs2024-WjhSNQd0UXYGXwVm.docx
Original File Name	BART comments on LCFS amendments February 2024_vF.docx
Date and Time Comment Was Submitted	2024-02-20 16:21:49

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

SAN FRANCISCO BAY AREA RAPID TRANSIT DISTRICT
2150 Webster Street, P.O. Box 12688
Oakland, CA 94604-2688
(510) 464-6000

February 20, 2024

Chair Liane Randolph and Members of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Amendments to the LCFS Program

Dear Chair Liane Randolph and Members of the Board,

The San Francisco Bay Area Rapid Transit District (BART) appreciates the opportunity to comment on the proposed amendments to the Low Carbon Fuel Standard (LCFS) program. BART owns and operates an electrified fixed-guideway transit system along with electric vehicle charging at its parking facilities. We have participated in the LCFS as an opt-in entity since 2016 and relies on the revenue created by sales of its LCFS credits to help fund the transit system.

284.1 The LCFS program is a powerful tool to meet the state's climate goals by incentivizing use of fuels with lower carbon intensity and switching to modes of travel such as public transit. The LCFS is one of California's best instruments to get passengers out of cars and reduce Vehicle Miles Traveled (VMT).

BART runs 220,000 trains a year and operates in five counties (San Francisco, San Mateo, Alameda, Contra Costa, and Santa Clara) with 131 miles of track and 50 stations. The vast majority of BART trains are electric, with 100% of its electricity supplied by zero-carbon resources including solar, wind, and hydroelectric generators. Every weekday of 2022, BART prevented an estimated 40,000 car trips and reduced California greenhouse gas (GHG) emissions by 500,000 lbs. CO_2e.

284.2 BART appreciates CARB's efforts to support the price of LCFS credits as transit systems around the country have not recovered from the COVID passenger decline, with the Bay Area being most impacted. BART is coping with severe fiscal issues and relies on the revenue obtained from the sale of LCFS credits. The recent steep decline in credit prices has noticeably impacted BART's budget, which is still hundreds of millions of dollars in deficit.

284.3 We are supportive of most of the amendments issued by CARB staff on December 19, 2023, but one important issue remains unaddressed. BART and several other participants highlighted in written and verbal comments in Fall 2023 that the LCFS crediting process results in a discriminatory approach to electric rail. Namely, pre-2011 fixed guideway systems receive a fraction of the credits compared to post-2010 fixed guideway systems. BART contains a small number of extensions that were built after 2010 and those are granted 4.6 times more credits per kilowatt-hour used than 90% of BART's system that falls into the pre-2011 category.

284.3 cont. This differing treatment is a product of the modeling performed at the beginning of the LCFS program which established a baseline that treated all rail in place at that time as existing, and the rail after as new. New rail was presumed to reduce substantially more VMT than existing rail. However, the reality of an operating train system is that all sections of all-electric rail provide an alternative to driving for passengers. The newer sections of BART rail do not use electricity differently or more efficiently and, as a result, every kilowatt-hour used by the system operates the same as any other. While we understand the original modeling performed, granting different kilowatt-hours different amounts of LCFS credits is not equitable, as nearly all other fuel pathways in the LCFS program do not suffer from this artificial distinction.

Now is the time to remedy this aspect of the LCFS program. Transit systems all over the state are facing severe fiscal issues and the additional LCFS credits could help ameliorate. BART is one of only a few electric transit systems eligible under the program and is by far the largest generator of LCFS credits in that category. And it still receives less than half a percent of the program's credits, thereby having no discernible impact on credit prices.

We appreciate CARB staff taking time to meet and respond to our questions during this process. As follow up to our last meeting, we recognize the request to identify and demonstrate improved efficiency and reductions in VMT since 2011 and will share with CARB staff shortly.

284.4 BART also respectfully requests CARB to reduce the costs of the newly proposed verification system for electric fuel pathways. We recognize the importance of ensuring the legitimacy of LCFS credits but question if the proposed system, with its numerous site visits and annual third-party verifications, could not be simplified. In addition, public agencies like BART have lengthy and burdensome procurement systems and would find it difficult to change auditors every six years.

284.5 Public transit is essential to California's achievement of its climate goals. We urge CARB to establish parity for fixed guideway systems within the LCFS program. We look forward to continuing to work with CARB to help carry out the goals and objectives of the LCFS program.

Sincerely,

Yuliya Shmidt
Manager of Energy
yuliya.shmidt@bart.gov
(510) 287-4835

Comment Log Display

Here is the comment you selected to display.

Comment 294 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Frank
Last Name	Harris
Email Address	fharris@cmua.org
Affiliation	California Municipal Utilities Associati
Subject	CMUA Comments on the Proposed Amendments to the Low Carbon Fuel Standard
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6964-lcfs2024-BmVXPFQgWGoGX1U5.pdf
Original File Name	CMUA LCFS Comments 2.20.2024.pdf
Date and Time Comment Was Submitted	2024-02-20 16:22:46

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

915 L Street., Suite 1210
Sacramento, CA 95814
(916) 326-5800
CMUA.org

February 20, 2024 | Submitted electronically

Honorable Liane Randolph
Chair, California Air Resources Board
1001 I Street
Sacramento, California 95814

RE: Comments on the Proposed Amendments to the Low Carbon Fuel Standard Regulation

The California Municipal Utilities Association[1] appreciates the opportunity to provide comments on the Proposed Regulation Order: Proposed Amendments to the Low Carbon Fuel Standard (Proposed Amendments).

CMUA represents California's local publicly owned electric utilities (POUs), which are governed by a board of local officials that are accountable to the communities in which they serve. CMUA's member agencies are committed to maintaining reliable and affordable electric service in a manner that supports the state's climate goals.

CMUA supports the Low Carbon Fuel Standard (LCFS) program as key to reducing greenhouse gas (GHG) emissions from the transportation sector. California's POUs utilize LCFS credit value to develop programs to further promote transportation electrification consistent with the needs of the communities they serve. To best position the LCFS program to continue to promote clean mobility options, CMUA offers the following comments for consideration:

- The LCFS Should Not Require Specific Rate Structures in Order to Generate Base Credits
- The LCFS Equity Requirement for POUs Should Remain at 50%
- The Cap on Administrative Costs and Marketing, Education and Outreach (ME&O) for the Clean Fuel Rewards Program (CFR) Should Remain at 10%
- The Cap on Administrative Costs for Holdback Credit Equity Projects Should Remain at 10%
- CARB Should Clarify the Holdback and Equity Holdback Project Lists

[1] The California Municipal Utilities Association is a statewide organization of local public agencies in California that provide electricity and water service to California consumers. CMUA membership includes publicly owned electric utilities that operate electric distribution and transmission systems. In total, CMUA members provide approximately 25 percent of the electric load in California.

- Projects Supporting Medium- and Heavy-Duty (MHD) Electric Vehicles (EVs) Should Qualify as Equity Projects Irrespective of the Primary Location
- Targeted Education and Outreach Should Remain an Eligible Equity Holdback Project
- Low Volume Credit Generators Should be Exempt from Verification
- Site Visits Should Be Based on an Assessment of Risk

Comments

The LCFS Should Not Require Specific Rate Structures in Order to Generate Base Credits

285.1 Section 95483 (c)(1)(A)1. stipulates that to generate base credits, an electric distribution utility (EDU) "must provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid". Currently most medium and large POUs offer rate options to encourage off-peak charging. However, due to the nature of the local communities they serve, some POUs do not face the need to impose such a rate structure. Further, some of California's smaller POUs do not have the infrastructure needed to implement such rates. Maintaining reliable, safe, and affordable electric service is paramount to California's POUs. The rate structure of each POU is developed in a public process, with full approval of each POU's Governing Board. As part of this, each POU considers alternative rate structures as needed. However, if the LCFS regulation continues to require a specific rate option in order to be eligible for base credits, some POUs may continue to not participate or opt-out of the LCFS. Such a result would be inconsistent with California's clean transportation goals.

The LCFS Equity Requirement Should Remain at 50%

285.2 The Proposed Amendments increase the equity spend requirement from 50% to 75%. California's POUs vary widely along a variety of parameters, including local community needs. Each POU develops programs in a public process, consistent with the needs of the local community. As developed, the LCFS has been successful in promoting cleaner transportation options for targeted communities. Additionally, California's POUs are promoting cleaner transportation options in various ways, including public charging options, clean public transit options, and modernizing their local distribution systems. In order to support continued investment in this full array of local solutions, the LCFS program equity requirement should remain at 50%.

The Cap on Administrative Costs and ME&O for the CFR Program Should Remain at 10%

285.3 The Proposed Amendments lower the combined cap on administrative and ME&O costs for the Clean Fuel Rewards (CFR) program from 10% to 5%. Such a change would reduce the ability to manage and promote the CFR program. Making the public aware of programs available to aid the transition to transportation electrification is key to the success of the CFR program and ME&O funding is key to informing consumers of the program.

The Cap on Administrative Costs for Holdback Credit Equity Projects Should Remain at 10%

285.4 The Proposed Amendments reduce the administrative cost cap for equity projects from 10% to 5%. While CMUA understands and agrees with the intent to direct as much funding as possible into project development, reducing the administrative cost cap to 5% of project expenditures could limit the ability of POUs to implement these important programs. The success of such programs can be directly attributed to the efforts to develop and administer the programs. CMUA remains concerned that it is not possible to effectively administer these programs if administrative costs are limited to just 5% of project spending. CMUA agrees with comments offered by the Northern California Power Agency (NCPA), that reducing the administrative cost cap will be particularly difficult for smaller utilities that have fewer resources to support the deployment of EV charging infrastructure. Cutting the administrative cost cap in half further limits the ability of smaller utilities to participate in the LCFS program.

CARB Should Clarify the Holdback and Equity Holdback Project Lists

285.5 CMUA appreciates CARB's proposed expansion of eligible equity holdback and other holdback project categories. However, the inclusion of two separate and non-overlapping project lists within the Proposed Amendments creates confusion. For example, the "Other Holdback Project" list (95483(c)(1)(A)5. b.) omits several project categories found on the equity holdback project list (95483(c)(1)(A)5. a.). Such omission calls into question whether equity projects omitted from the Other Holdback list, when implemented in non-equity communities, could utilize non-equity holdback credit proceeds – even though such projects clearly further transportation electrification efforts in California, consistent with section 95491(e)(5).

For simplicity, CMUA recommends that CARB combine the equity and other holdback project categories into a single list. Further, CARB should clarify that projects from the list benefiting equity communities shall be considered eligible equity expenses. Alternatively, CARB should expand the other holdback list to include all projects on the equity holdback list to provide certainty that these projects are still allowable expenditures.

285.5 cont.

In addition, CMUA recommends that CARB further clarify several project categories. CMUA supports the inclusion of the re-skilling and workforce development project category, with clarification that such a program can be developed pursuant to a workforce development strategy adopted by the POU's Board. This additional flexibility is needed, as coordination with specific agencies may slow development of these programs. Additionally, CMUA supports the inclusion of panel and service upgrades as allowable equity expenses for low-income individuals. While there is an existing project category, listing these expenses will provide greater certainty for directing funds toward these purposes. Finally, CMUA supports combining the two equity project categories covering electric mobility solutions into a single list and clarification that the list is not restricted to EV charging equipment and infrastructure.

Projects Supporting MHD EVs Should Qualify as Equity Projects Irrespective of the Primary Location

285.6

CMUA supports language in the Proposed Amendments that includes an equity project category for MHD infrastructure investments. However, the LCFS regulation should clarify that all MHD infrastructure projects, regardless of location, qualify as equity projects. Irrespective of the primary charging location, pollutants from MHD vehicles significantly impact low-income communities, particularly along transportation corridors and logistics centers. By identifying all MHD electrification projects as equity, the LCFS can further remove pollutants that disproportionately impact these targeted communities.

Targeted Education and Outreach Should Remain an Eligible Equity Holdback Project

285.7

The Proposed Amendments would remove multilingual ME&O as an eligible equity project category. CMUA disagrees with this proposed change. Tailored multilingual education and outreach efforts are crucial to identifying the questions and needs of each community that subsequently inform the effective design of programs and projects that respond to those needs. Such education and outreach efforts may not be tied to specific projects but are significantly different from general marketing and advertising campaigns.

CMUA strongly encourages CARB to maintain a narrower equity project category for direct multilingual education and outreach serving equity communities. CMUA also requests CARB clarify that that non-equity holdback funds may be used to support other ME&O expenses.

Low Volume Credit Generators Should be Exempt from Verification

285.8 Section 95500(b)(2) of the Proposed Amendments stipulates that entities generating fewer than 6,000 credits may defer verification for up to two years. CMUA agrees with NCPA's proposal that entities generating 2,000 or fewer credits per year should continue to be exempt. Such entities are often in remote areas that do not offer sufficient profit opportunities for charging companies to invest in electric vehicle charging infrastructure. This requirement makes it less likely for local public agencies that do not generate enough credits to cover the cost of verification to participate in the LCFS. For this reason, the LCFS should only require verification for entities generating credits above a determined threshold.

Site Visits Should Be Based on an Assessment of Risk

285.9 The regulatory requirements for site visits should be modified to stipulate that a verifier should only conduct a site visit if such a visit is warranted by a reasonable concern about data accuracy following a risk assessment. A broad mandate to require site visits to all covered chargers, including residential chargers, is not practical. Additionally, the regulation should be modified to differentiate between fuel pathways. For example, EV charging equipment is already subject to accuracy regulations. Requiring site visits, without a desk review of potential risk, would not provide value for the cost.

<u>Conclusion</u>

CMUA appreciates the opportunity to provide these comments on the LCFS Proposed Amendments. CMUA looks forward to collaborating with CARB and other stakeholders in the LCFS proceeding.

Respectfully submitted,

______________/s/_______________

FRANK HARRIS, PhD
Manager of Energy Regulatory Policy
California Municipal Utilities Association
915 L Street, Suite 1210
Sacramento, CA 95814
(916) 890-6869
fharris@cmua.org

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Comment 295 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Michael
Last Name	Maguire
Email Address	Michael.Maguire@opr.ca.gov
Affiliation	Office of Planning and Research (OPR)
Subject	OPR Comment Letter to the LCFS
Comment	See attached letter from OPR Director, Sam Assefa.
Attachment	www.arb.ca.gov/lists/com-attach/6965-lcfs2024-BWNXOAZpWGoGbANc.pdf
Original File Name	Final_OPR Comment Letter to the LCFS (Feb. 2024).pdf
Date and Time Comment Was Submitted	2024-02-20 16:11:29

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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State of California
Governor's Office of Planning and Research
1400 10th Street. Sacramento, California, 95814
info@opr.ca.gov | opr.ca.gov

Governor Gavin Newsom

Director Sam Assefa

February 20, 2024

Matthew Botill
Chief, Industrial Strategies Division

Jordan Ramalingam
Manager, Alternative Fuels Section

Rachel Conners
Manager, Fuels Section

Anil Prabhu
Chief, Carbon Management Branch

Rui Chen
Manager, Fuel Project Evaluation Section

Greg Mayeur
Branch Chief, Program Planning and Management

Guihua Wang
Manager, Substance Evaluation Section

California Air Resources Board
1001 I Street
Sacramento, CA 95814

CC: Anthy Alexiades, Specialist, Methane Reduction Strategies
Adam Moreno, Manager, Nature-Based Strategies
Jeff Kessler, Decarbonization Policy Modelling Lead
Alex Yiu, Air Pollution Specialist Forest Offset and Natural Working Lands
Jeremy Loeb, Air Resources Engineer, Low Carbon Fuel Standard
Carmen Tubbesing, Air Pollution Specialist
Paul Furumo, CCST policy fellow, CARB Chair Office

Subject: OPR's comments on the role of biomass waste in supporting California's decarbonization goals

Dear Low Carbon Fuel Standard Program staff,

We commend you for your excellent work on the proposed amendments to the Low Carbon Fuel Standard (LCFS) Program. The Governor's Office of Planning and Research (OPR) is leading the state's Woody Feedstock Aggregation pilot program to establish reliable access to woody feedstock sourced from California's forested lands and to enhance community fire resilience. With this letter, we provide comments on the role of woody biomass feedstocks in the proposed LCFS amendments and their potential role in supporting the state's decarbonization goals.

Background

The 2022 Scoping Plan identified the need for expanding the use of woody biomass residue, particularly from forest and agricultural residues, as necessary for achieving carbon neutrality by 2045. This is because biomass conversion into energy products, such as clean hydrogen with carbon capture and sequestration, can provide carbon removal needed to compensate for residual emissions remaining in the economy beyond midcentury. Non-combustion technologies (i.e., gasification, pyrolysis) can also provide clean, non-fossil fuels for decarbonizing aviation, shipping, and other hard-to-abate industries.[1,2] Additionally, State-sponsored research has identified biomass conversion to liquid and gaseous transportation fuels as a key option for improving forest health and addressing the wildfire crisis.[3]

A robust innovative wood products market is needed to increase forest management and restoration in California and drive biomass residue utilization at the scale necessary to meet the state's ambitious climate goals.[4] The state has developed a number of market and technology development programs, including a grant program administered by the Department of Conservation that supports carbon-negative hydrogen and liquid fuels sourced from forest biomass. The Infrastructure and Economic Development Bank currently administers a public loan fund to support forest biomass management and

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[1] Lawrence Livermore National Laboratory. 2020. *Getting to Neutral: Options for Negative Carbon Emissions in California*. https://gs.llnl.gov/sites/gs/files/2021-08/getting_to_neutral.pdf

[2] Lawrence Livermore National Laboratory. 2023. *Roads to Removal: Options for Carbon Dioxide Removal in the United States*. https://roads2removal.org/

[3] Joint Institute for Wood Products Innovation. 2020. *Literature review and evaluation of research gaps to support wood products innovation*. https://bof.fire.ca.gov/media/9688/full-12-a-jiwpi_formattedv12_3_05_2020.pdf

[4] Joint Institute for Wood Products Innovation. 2020. *Joint Institute Recommendations to Expand Wood and Biomass Utilization in California*. https://bof.fire.ca.gov/media/31nfixsv/final-board-approved-joint-institute-wood-and-biomass-utilization-recommendations-_11-4-20_ada.pdf

utilization projects. The Department of Forestry and Fire Protection also administers a grant program to enhance wood utilization and bioenergy projects.

As a matter of practice however, biomass utilization projects have been difficult to launch. A key barrier to achieving this vision, that we have learned as part of implementing the pilot program at OPR, is a lack of a recurring revenue incentive for prospective project developers. LCFS is a policy tool that has the potential to support the development of woody biomass residue utilization projects because it can provide recurring incentives for these earlier stage projects. We provide recommendations on the proposed 2024 LCFS Program amendments that could ease the barriers for prospective biomass utilization projects.

Forest biomass

CARB is proposing to include Tier 2 pathways that utilize feedstocks from small-diameter, non-merchantable forest residues removed for the purpose of forest fuel reduction or forest stand improvement, as eligible to receive a reduced carbon intensity (CI) score under the LCFS Program.

This would be a positive change for prospective projects; however, this is unlikely to be sufficient to drive residue utilization consistent with the Scoping Plan. California currently produces tens of millions of tons of forest and agricultural waste annually that are typically left to decompose or be open burned, resulting in substantial emissions of greenhouse gases, criteria air pollutants and precursors. These impacts are anticipated to worsen as the state seeks to increase its wildfire prevention treatments to one million acres per year.

286.1 One suggestion, based on feedback from OPR's regional pilots, is to develop further guidance about how to more comprehensively evaluate the full emissions profile (e.g., emissions benefits from avoided pile burning, decay, etc.) for fuels created using biomass waste feedstocks, particularly forest and agricultural residues. It is currently unclear what an acceptable lifecycle assessment looks like for biomass waste-to-fuels pathways under the Low Carbon Fuel Standard. This uncertainty limits the ability of prospective developers to acquire credits.

Crop- and forest-based feedstocks

CARB is proposing to include third party–certified sustainability requirements for crop- and forest-based feedstocks used in LCFS fuel pathway applications. This would be useful for minimizing unsustainable or illegal forestry practices and improving the transparency and accountability of biomass feedstock supply chains.

Crop-based fuel production in the United States and globally has been identified as having potentially significant indirect global land use impacts, including deforestation and competition with food production .[5] More broadly, there is significant uncertainty in the

[5] California Air Resources Board. Low Carbon Fuel Standard Public Workshop: Potential Regulation Amendment Concepts. February 22, 2023. https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/lcfs_meetings/LCFSpresentation_02222023.pdf

ability to estimate the complete lifecycle emissions from crop-based biofuels.[6] There is also a risk that fuels produced from out-of-state crop-based feedstocks may compete with in-state waste feedstocks that are needed to address catastrophic wildfire. CARB should consider stricter requirements on crop-based fuels production given these inherent risks. We outline alternatives that would avoid perverse sustainability outcomes and encourage high-quality biomass waste utilization projects in California.

286.2

- *Prioritizing in-state biomass waste feedstocks*. CARB could consider options that prioritize biomass waste feedstocks sourced from within California. Prioritizing in-state biomass waste pathways under the LCFS Program would maximize the climate, air quality and local economic benefits of converting waste sourced from state lands.[7] For example, CARB could feasibly offer targeted incentives for fuel pathways that specifically use residues from fire management or forest restoration activities on California's forested lands.[8]

286.3

- *Cap on crop-based fuels*. CARB could consider placing a cap on crop-based fuels to avoid the proliferation of fuels pathways from out-of-state crops. Renewable diesel pathways under the LCFS Program have historically utilized waste fats, oil, and grease as the primary feedstock. However, these feedstocks are currently supply-limited.[9] Additionally, CARB anticipates an increase in renewable diesel consumption by 2025.[10] There is a risk that renewable diesel under the LCFS Program could become increasingly reliant on crop-based feedstocks such as soybean and other virgin vegetable oils.[11] The implication here is that an increase in demand for crop-based biofuels could feasibly incentivize the conversion of productive farmland into bioenergy crops and lead to deforestation.

Alternative jet fuel

286.4 CARB is proposing to require intrastate fossil jet fuel to comply with the LCFS Program starting in 2028. This would be an important change as the state's aviation sector contributes nearly 38 million tons of carbon dioxide–equivalent per year, an amount which exceeds that of all the oil refineries in the state. Biomass waste will be an important

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[6] Comment letter submitted to the U.S. Environmental Protection Agency on Renewable Fuel Standard Program proposed rule setting standards for 2023 through 2025. Comment submitted by Earthjustice and World Resources Institute. Docket ID No. EPA-HQ-OAR-2021-0427.

[7] Cabiyo, B. et al. Innovative wood use can enable carbon-beneficial forest management in California. *Proceedings of the National Academy of Sciences*. 2021. https://doi.org/10.1073/pnas.2019073118

[8] Sanchez et al. Policy Options for Deep Decarbonization and Wood Utilization in California's Low Carbon Fuel Standard. *Front. Clim.*, 14 May 2021 Sec. Carbon Dioxide Removal Volume 3 – 2021. https://doi.org/10.3389/fclim.2021.665778

[9] Christensen, A., and Hobbs, B. (2016). A model of state and federal biofuel policy: feasibility assessment of the California Low Carbon Fuel Standard. *Appl. Energy* 169, 799–812. https://doi.org/10.1016/j.apenergy.2016.01.121

[10] California Air Resources Board. *Low Carbon Fuel Standard 2023 Amendments – Standardized Regulatory Impact Assessment*. September 8, 2023.

[11] Bushnell, J. et al. Working paper: *Forecasting Credit Supply Demand Balance for the Low-Carbon Fuel Standard Program*. August 2023. https://haas.berkeley.edu/energy-institute/research/abstracts/wp-340/

feedstock for generating alternative jet fuel, as there are few feasible alternatives for producing low-carbon and carbon-negative aviation fuels. This is a needed step towards aligning California's aviation decarbonization efforts with national sustainable aviation fuel goals.

We commend CARB for its leadership in working to advance decarbonization in the transportation fuels sector. We hope this letter is informative to CARB staff as it explores potential revisions to the LCFS Program.

Sincerely,

Samuel Assefa

Samuel Assefa
Director, Governor's Office of Planning and Research

Comment Log Display

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Comment 296 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Linda
Last Name	White
Email Address	linda.white@bmwna.com
Affiliation	BMW of North America
Subject	BMW LCFS Comments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6966-lcfs2024-AGJSOQZwU25QNwFe.pdf
Original File Name	BMWNA Comments LCFS2024_signTR.pdf
Date and Time Comment Was Submitted	2024-02-20 16:25:00

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Board Comments Home

BMW Group

February 17, 2024

Clerk's Office
California Air Resources Board
1001 I Street
Sacramento, California 95814

Subject: Low Carbon Fuel Standard – Incentives for Light Duty Vehicles, Base Credits and Verification Requirement EV Data

BMW of North America, LLC (hereafter BMW) is pleased to submit comments to the proposed amendments to the Low Carbon Fuels Program (LCFS) - Clean Fuels Reward Program. BMW values the partnership and shared goals we share with the state to grow the ZEV market, reduce carbon intensity in fuels and increase consumer awareness. Recently, BMW a along with six other automakers, announced the launch of a new entity IONNA, to build out 30,000 high-powered EV chargers across North America. The goal is to make fast charging accessible, convenient, and reliable. BMW remains committed to invest in the ZEV market and to work cooperatively with all critical stakeholders.

BMW supports the comments of Auto Innovators. BMW is a longtime supporter of the LCFS program and believe that consumer incentives are still necessary to grow the light-duty market. We urge CARB to reconsider the current amendment that will direct critical incentives away from light-duty vehicles to medium and heavy-duty vehicles. The market is in a critical phase as we transition consumers to electric vehicles and look ahead to meet the state's ZEV goals and greenhouse gas targets. While California is leading the nation in the ZEV market, more is needed. Consumer education, investment in infrastructure, and consumer incentives will remain key drivers to transition California's fleet.

Base Credits

287.1 We believe that CARB should allocate part of the base residential credits from EV charging to automakers. OEMs are uniquely positioned to use this revenue to provide benefits in support of EV adoption. OEMs can move fast to execute programs, increasing the benefits from this spending. Splitting this revenue between OEMs and IOUs will provide new opportunities for collaborating between the two industries, unlocking opportunities for the electric vehicle space. This is particularly important now, as both industries are exploring how to accelerate the adoption of smart charging, public infrastructure development, and bidirectional charging.

Verification Requirement for EV Charging Data:

287.2 CARB proposes adding third-party verification requirements for electric vehicle charging data used to generate incremental LCFS credits. We ask that CARB implement simple verification requirement that are cost-efficient for voluntary credit generators. The data provided by these voluntary credit generators is valuable to CARB and utilities, as it is used to determine the amount of base credits that are generated. Costly verification requirements may disincentivize participation by EV charging entities, which would deny CARB and the utilities of vehicle data important to the LCFS program. As this data is beneficial to utilities for the generation of base credits, the cost of

287.3 verification should be shared with utilities. Additionally, we ask that CARB consider how verification processes can be implemented such that does not involve the use of personally-identifiable data.

Participation from Small Dairy Farms
BMW has partnered with dairy farmers as part of our participation in the LCFS program. Dairy farms can generate renewable energy through the application of biodigesters, which generate renewable by capture methane emissions from cow manure at these farms. Not only do biodigester systems create renewable energy, but they also reduce methane emissions that would otherwise occur at the farm, resulting in substantial carbon emission reduction opportunities.

Through our work with multiple dairy farms of different sizes, we have come to recognize that the current LCFS program rules significantly disadvantage small dairy farms. The LCFS rules require complex verification and data reporting requirements that are not financially feasible for small dairy farms, given relatively small energy generation for these projects. In order to support the participation of small dairy farms, we recommend that CARB make the following rule changes specific for dairy farms with biodigester systems under 150 KW:

287.4

- **Simplified Lookup Table for small biodigesters.** For small facilities looking for a simple way to participate in the LCFS, CARB could offer a Lookup Table Pathway option, with a fixed CI score set at the lower of the score of the highest currently approved dairy manure to electricity fuel pathway in the program. After ensuring that facilities meet minimum eligibility criteria, projects would then be able to be approved for immediate participation into the program. Projects that want to pursue a higher score would have the
287.5 option of going through the full verification process, allowing CARB to evaluate the efficiency of projects that claim larger emission reductions.

- **Eliminate 3rd Party Verification requirements.** The requirement to have a Third-Party
287.6 Verifier review the annual fuel reports represents a significant cost for small biodigesters and prohibits the participation of more small dairies, limiting LCFS to only the largest biodigesters. Eliminating this requirement will allow more small farms to participate in the program.

287.7
- **Simplify the Annual reporting requirements.** Reducing the data requirements for small farms would eliminate a substantial cost barrier facing small farms.

Thank you for considering BMW NA's comments during this rulemaking. We look forward to working with CARB staff and board members. Please feel free to reach out with any questions you may have.

Sincerely,

Manfred Grunert
Vice President, Government Affairs and Communications
BMW of North America, LLC

Thomas Ruemenapp
Vice President, Engineering
BMW of North America, LLC

BMW of North America, LLC
BMW of North America, LLC has been present in the United States since 1975. Rolls-Royce Motor Cars NA, LLC began distributing vehicles in 2003. The BMW Group in the United States has grown to include marketing, sales, and financial service organizations for the BMW brand of motor vehicles, including motorcycles, the MINI brand, and Rolls-Royce Motor Cars; Designworks, a strategic design consultancy based in California; a technology office in Silicon Valley and various other operations throughout the country. BMW Manufacturing Co., LLC in South Carolina is the BMW Group global center of competence for BMW X models and manufactures the X3, X4, X5, X6 and X7 Sports Activity Vehicles as well as the new BMW XM. The BMW Group sales organization is represented in the U.S. through networks of 350 BMW passenger car and BMW Sports Activity Vehicle centers, 146 BMW motorcycle retailers, 105 MINI passenger car dealers, and 38 Rolls-Royce Motor Car dealers. BMW (US) Holding Corp., the BMW Group's sales headquarters for North America, is located in Woodcliff Lake, New Jersey. Journalist note: Information about BMW Group and its products in the USA is available to journalists on-line at www.bmwgroupusanews.com and www.press.bmwna.com.

IONNA
IONNA is a limited liability company formed by BMW, GM, Honda, Hyundai, Kia, Mercedez-Benz and Stellantis. By the close of this decade, IONNA aims to become a leading force in providing convenient, accessible, and reliable North-American fast-charging infrastructure to significantly enhance the appeal of zero-emission driving for millions of customers.

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Comment 297 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Andrew
Last Name	Craig
Email Address	acraig@calbioenergy.com
Affiliation	
Subject	CalBio Comments on Dec 2023 LCFS Rulemaking
Comment	Please see attached CalBio's comments on the Dec 2023 LCFS rulemaking
Attachment	www.arb.ca.gov/lists/com-attach/6967-lcfs2024-BWYCZVM+BTRWOVI9.pdf
Original File Name	CalBio Comments on Dec 2023 LCFS Rulemaking 2.20.2024.pdf
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If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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February 20, 2024

Ms. Rajinder Sahota
Deputy Executive Officer - Climate Change & Research
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: California Bioenergy's Comments on the Low Carbon Fuel Standard Rulemaking Package

Dear Ms. Sahota,

Thank you for the opportunity to provide these comments to California Air Resources Board (CARB) relating to the Low Carbon Fuel Standard (LCFS) Rulemaking Package released on December 19, 2023. California Bioenergy LLC (CalBio) is appreciative of CARB's efforts over the past several years to develop the LCFS program into becoming one of the most impactful policies to support the transition from petroleum to clean fuel alternatives. There are few programs in the world which can boast the significant decarbonization of the transportation sector through sound science and policy. We write these comments with the notion that the climate emergency demands CARB strengthen the program to support achievement of California's legislatively-mandated greenhouse gas (GHG) reduction targets.

Founded in 2006, CalBio works closely with California dairy farm families, dairy co-ops and cheese producers, CARB, the California Department of Food and Agriculture (CDFA), the California Public Utility Commission (CPUC), the California Energy Commission (CEC), and the U.S. Environmental Protection Agency (EPA). We exist to reduce methane emissions and are committed to enhancing environmental sustainability for all Californians. CalBio's digester projects produce clean renewable natural gas and generate electricity, both used as a vehicle fuel to power low-emission trucks, buses, and cars thereby replacing petroleum-based fuels—diesel, gasoline, and natural gas. Our projects reduce GHGs, improve local air quality, create jobs in disadvantaged communities, and provide a new revenue stream along with other meaningful benefits to our dairy partners.

In our comments below, we suggest practical and necessary revisions which serve to improve the LCFS program in its ambition to reduce GHG emissions and implement a successful program.

1. **Addressing the Near-Term Credit Bank Surplus**
2. **Allow for Book & Claim of RNG to Off-site Electric Generators**
3. **Revise the True-Up Language to Apply to Temporary CI Scores**
4. **Establish a Temporary CI for Dairy Biogas to Electricity**
5. **Grandfather Existing Pathways Certified under GREET v3.0**

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1. **Addressing the Near-Term Credit Bank Surplus**

288.1 As of Q3 2023, the LCFS credit bank has swelled to more than 20.5 million credits, largely driven by growth in renewable diesel, electricity, and biomethane. The program has become a victim of its own success and now overcompliance threatens to stifle investment making it uneconomic to build new projects under the current market conditions. CalBio appreciates CARB's recognition of this problem by introducing both a near-term step down in the CI target in 2025 and the introduction of an Automatic Acceleration Mechanism (AAM). We believe these are fundamental concepts to bring down the LCFS credit bank surplus, however, they simply do not go far enough. Fortunately, there exists an extraordinary opportunity to increase ambition and ultimately achieve more GHG reductions by strengthening the near-term step down and enabling the AAM to begin one year earlier. Both actions will work in tandem create the near-term price signal necessary to drive investments in GHG reductions now and enable a faster, more dynamic response to changing market conditions, and help to achieve a CI reduction beyond the stated target of 30% by 2030.

288.2 The primary lever at CARB's disposal to have the most immediate impact in driving down the LCFS credit bank is to first increase the near-term step down from 5% in 2025 to at least 10%. Notably, as part of the proposed amendments, the diesel benchmark for years 2025 through 2045 has been revised from 100.45 gCO2e/MJ to 105.76 gCO2e/MJ from a 2010 base year which substantially reduces the impact of the originally proposed 5% step down in the diesel pool. For the proposed step down to be meaningful, an 10% or greater step down is required and that the increased step-down be propagated through the stringency curve translating into a revised 2030 target (e.g., a step down of 10% translates into approximately a 35% reduction in the CI in 2030 relative to 2010).

288.3 Another specific way to address the near-term credit bank surplus is to revise AAM to be triggered in 2026 based on 2025 credit bank data and increase the CI stringency target in 2027. As currently proposed, it will not kick in until 2028 based on 2026 data. However, if the proposed near-term step down, even if increased to 10%, is insufficient to draw down the credit bank, the AAM should be triggered provided the eligibility requirements are satisfied. Postponing the AAM by an additional year will undermine its ability to serve its intended purpose which is to guard against an oversupply of credits.

288.4 CalBio proposes CARB increase the 2030 CI target to at least 35%. This is one of the scenarios that CARB has been workshopping since 2022 and is the one which is expected to achieve the highest levels of GHG reductions[1]. A study from ICF found that the LCFS could accommodate a carbon intensity target of 41-44%[2]. Increasing the stringency to drive GHG reductions is in alignment with the 2022 Scoping Plan for Achieving Carbon Neutrality (2022 Scoping Plan)[3] which lays out a path to achieve targets for carbon neutrality and reduce GHG emissions by 85 percent below 1990 levels by 2045. The actions described

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[1] https://ww2.arb.ca.gov/sites/default/files/2022-11/LCFSPresentation.pdf
[2] https://ww2.arb.ca.gov/form/public-comments/submissions/4306
[3] https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

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288.4 cont. above are necessary to give confidence to investors that new projects can be built and allow for greater GHG reductions to be achieved.

2. Allow for Book & Claim of RNG to Off-site Electric Generators

288.5 An important opportunity for CARB to incentivize additional GHG reductions is to expand the language in §95488.8(i)(2) to allow for the book-and-claim of pipeline-injected biomethane to be used to generate Low-CI electricity as a transportation fuel. Currently, CARB recognizes electricity as a transportation fuel in §95482(b) and moreover in §95488.8(i)(1) recognizes that "Low-CI electricity used as a transportation fuel can be indirectly supplied through a green tariff program…or other contractual electricity supply relationship." This is achieved by REC-matching, where the reporting entity must demonstrate that the low-CI electricity is supplied through book-and-claim accounting to electric vehicle charging provided "that any renewable energy certificates associated with the low-CI electricity were retired in the WREGIS for the purpose of LCFS credit generation" (see §95491(d)(3)). However, in the context of electricity derived from low-CI dairy biogas, this pathway requires the RECs to be created from a generator co-located with the digester.

Given the recognition CARB has for 1) book-and-claim of Low-CI electricity production to be matched to electric vehicles, and 2) RNG injected into the commercial distribution pipeline and withdrawn at a CNG station in California, CalBio argues that by the same logic, RNG injected and withdrawn via book-and-claim should qualify for the purposes of generating electricity. In this construct, RECs generated from an electric generator located off-site from the dairy powered by gas fed through the utility pipeline should similarly be allowed to match RECs to electric.

This approach aligns with CARB's existing book-and-claim accounting framework and greater GHG reductions could be realized by making this targeted change to the regulatory text that is in keeping with CARB's objectives of supporting the transition to zero emission transportation. As noted, this recommendation is fully aligned with CARB's goals expressed in the Initial Statement of Reasons (ISOR), page 4, which states:

> *"This regulatory update proposal, which is described in detail in this staff report, is focused on the following key concepts:*
>
> - *Increasing the stringency of the program to reduce emissions and decarbonize the transportation fuel sector, which will also aggressively reduce our dependence on fossil fuels;*
> - *Strengthening the program's equity provisions to promote investment in disadvantaged, low-income and rural communities;*
> - ***<u>Supporting electric and hydrogen truck refueling;</u>***
> - *Incentivizing more production of clean fuels needed in the future, such as low-carbon hydrogen;*

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- ***Supporting methane emissions reductions and deploying biomethane for best uses across transportation;*** *(emphasis added)*

Further on page 6 of the ISOR, it states:

288.5 cont.

> *"The purpose of the LCFS regulation is to reduce the carbon intensity (CI) of transportation fuels used in California, thereby reducing GHG emissions, and to **incentivize the production of low-carbon and renewable alternatives, such as low-CI electricity** and renewable hydrogen, and biofuels to displace fossil fuels and allow more energy security in the transportation sector." (emphasis added)*

Further on page 30 of the ISOR, it states:

> *"**Biomethane can play a key role in decarbonizing stationary sources** or other energy applications, and the 2022 Scoping Plan Update identifies additional end uses in the industrial, commercial, and residential sectors; production of hydrogen; and **electricity generation by displacing the need for fossil gas.**" (emphasis added)*

CARB would be remiss to lose this opportunity to encourage and incentivize low-CI dairy biomethane to be used for electricity generation. This will create an additional market for RNG derived from dairy biogas, as CARB has signaled it is seeking to phase it out of combustion in CNG vehicles and "direct biomethane to sectors that are hard to decarbonize or as a feedstock for energy."[4] Directing RNG as a feedstock to electricity production is a readily available solution and further encourages grid resiliency which will be necessary as electric vehicle charging scales in the state.

3. Revise the True-Up Language to Apply to Temporary CI Scores

288.6

CalBio is appreciative to CARB for proposing a credit True-Up after provisional certification and recognizing the real GHG reductions that have occurred when a project's CI score decreases. Unfortunately, this approach fails to recognize, perhaps more importantly, the true GHG reductions that should be credited once the provisional certification is achieved relative to the GHG reductions credited while operating under the -150 CI Temporary Pathway for dairy digesters. It is unclear why CARB deviated from this approach in the proposed rule, particularly when it was workshopped in 2022 during which time it proposed *only* adjusting the temporary CI score and did not contemplate adjustments for subsequent verifications.[5]

A key point raised in those workshops was the idea that a True-Up would ease the pressure for CARB to review pathways and alleviate concerns with delays in certification. Considering CARB staffing shortages

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[4] https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf
[5] https://ww2.arb.ca.gov/sites/default/files/2022-08/August%202022%20Workshop%20Slide%20Deck%20Presentations.v16.pdf

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288.6 cont. leading to pathway review times often exceeding 18 months from the time they are submitted, it would be in CARB's own interest to give itself the necessary time to review projects without unfairly discounting legitimate GHG reductions for delays outside the project's control. The Temporary CI has been conservatively set to -150 gCO2e/MJ, this can cost a project millions of dollars while waiting for a return on investment. If this issue is left unresolved, it further poses risks to future investment in projects and reduces the potential for additional GHG reduction opportunities. CARB should be taking steps to encourage development, and credit projects appropriately in the interest of fairness and reflecting true environmental performance.

4. Establish a Temporary CI for Dairy Biogas to Electricity

288.7 It is of great concern to CalBio that no Temporary CI exists for Dairy Biogas-to-Electricity pathways has been established in the LCFS since the program's inception and that CARB has not sought to correct for this in the proposed amendments. The failure to include this provision discriminates and disadvantages in-state dairy digester projects which contribute to California's SB 1383 goals and provide renewable electricity as a grid resource and transportation fuel. As referenced in the ISOR and quoted in CalBio's comments under topic #2 above, one of the *primary purposes* of the LCFS regulation is to incentivize the production of low-carbon and renewable alternatives, such as low-CI electricity.

CARB should correct this oversight given dairy biogas-to-electricity pathways fully reduce methane in the same manner as dairy biogas-to-RNG pathways and thus should be treated equally. Project economics for dairy biogas-to-electricity are generally more challenging than RNG projects given they are currently not eligible to participate under the RFS program or BioMAT. Failure to allow electric projects to receive a Temporary CI score further exacerbates the concerns expressed in CalBio's comments under topic #3 by preventing beneficial projects from receiving revenue until the provisional certification is achieved, a process which can last several months to years.

It should be noted that CalBio has made significant financial investments in cleaner electricity generating technologies such as Bloom Fuel Cells and Mainspring Linear Generators which convert methane into electricity without combustion. These technologies should alleviate concerns around NOx emissions associated with internal combustion engines. CalBio would be supportive of CARB unlocking the Temporary CI for dairy biogas-to-electricity if it meant requiring the use of a non-combustion technology such as a fuel cell or linear generator.

5. Grandfather Existing Pathways Certified under GREET v3.0

288.8 CalBio is proposing CARB consider grandfathering in pathways which have already been certified under GREET v3.0. These pathways have already undergone public review and comment period and should remain under models which they have been validated and verified through the end of their crediting

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288.8 cont. periods. It would be administratively burdensome to deviate from the modeling that has been established for existing pathways and require unnecessary adjustments to the information CARB and 3rd party verifiers have already reviewed and approved.

CalBio commends CARB for developing the LCFS as the nation's leading and most successful example of a market-based carbon reduction program for the transportation sector. We thank you for considering these comments.

Sincerely,

Andrew Craig
Vice President, Greenhouse Gas Programs
California Bioenergy LLC

Comment Log Display

Here is the comment you selected to display.

Comment 298 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Andrew
Last Name	Craig
Email Address	acraig@calbioenergy.com
Affiliation	California Bioenergy
Subject	CalBio Comments on DSM CI Calculator
Comment	Please see attached CalBio's comments on the Proposed DSM CI Calculator
Attachment	www.arb.ca.gov/lists/com-attach/6968-lcfs2024-VTYCZQFsV2ZRPgBv.pdf
Original File Name	CalBio Comments 2024 Proposed DSM CI Calculator.pdf
Date and Time Comment Was Submitted	2024-02-20 16:29:07

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February 20, 2024

Ms. Rajinder Sahota
Deputy Executive Officer - Climate Change & Research
California Air Resources Board
1001 I Street
Sacramento, California 95814

Submitted via LCFS Comments Upload Link

RE: CalBio Comments on CARB's Proposed Tier 1 Simplified Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure released December 19, 2023

Dear Ms. Sahota,

Thank you for the opportunity to provide comments to the California Air Resources Board (CARB) on the proposed Tier 1 Simplified Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure released December 19, 2023.

California Bioenergy LLC (CalBio) is a leading developer of dairy digester projects. Founded in 2006, CalBio works closely with California dairy farm families, dairy co-ops and cheese producers, CARB, the California Department of Food and Agriculture (CDFA), the California Public Utility Commission (CPUC), the California Energy Commission (CEC), and the U.S. Environmental Protection Agency (EPA). We develop projects that reduce greenhouse gas (GHG) emissions, improve local air quality, protect water quality, and create local jobs. Our projects produce renewable natural gas and generate electricity, both used as a vehicle fuel to power low emission trucks, buses, and cars.

CalBio has extensive experience working with the Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure (DSM CI Calculator). With over 30 certified Tier 2 pathways, we have developed expertise in both using and understanding the complexities of this tool. In addition, both our in-house staff and consultants are skilled greenhouse gas (GHG) accountants that value incorporating the latest climate science and emission factors into the DSM CI Calculator analysis framework and our project pathways. CalBio is thankful for the opportunity to share our feedback on the proposed updates and commends CARB on implementing changes that will make the DSM CI calculator more streamlined, require less user modifications, and reflect the latest industry standards for GHG accounting.

A. Tier 1 Simplified CI Calculator for DSM Biogas-to-Electricity Pathways

CARB supports the electrification of the transportation sector in California and seeks to build more electric projects to help CARB meet goals of the Scoping Plan[1] and serve the growing demand for electric

[1] https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

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289.1 vehicles. Thus, CalBio strongly recommends that CARB develop a separate DSM biogas-to-electricity Tier 1 CI Calculator for such pathways to streamline the process for reviewing and approving biogas-to-electricity projects. The proposed CI Calculator would inherently include all the modifications and technical guidance included in CARB's LCFS Guidance 19-06 document. Absent a standard Tier 1 CI Calculator for biogas-to-electricity, all such projects will be forced into a Tier 2 application. This disadvantages in-state projects which help California to achieve its methane reduction goals and support electrification.

Based on our experience building the first dairy biogas-to-fuel cell project and successfully achieving pathway certification for the low-CI electricity produced by this project, CalBio also proposes the following modification for this new CI calculator:

- 289.2 CalBio recommends updating the guidance that CARB issued in LCFS Guidance 19-06 document to divide the final biogas electricity CI by the efficiency of the electric generator used in the project. The approach appears to introduce a cap in the CI value when the engine efficiency exceeds the 50% benchmark. When the CI is divided by a higher efficiency value, it effectively penalizes the project for being more efficient. CalBio proposes using the benchmark efficiency instead, which allows the credits to remain linear with increased generator efficiency. The CI calculator already caps avoided methane crediting based on either the lesser of biogas produced and the modeled emission reductions. It does not seem reasonable to further cap based on efficiency, especially when CARB's motivation has been to encourage projects to use more efficient and cleaner fuel cell technology.

  Suggested Modification: *In Cell E91 of the "Manure-to-Biogas" Worksheet, the formula for the Final Electricity CI for the 2018 CARB-modified electricity calculator should be: =IF(W52=0,0,(G68+G75+G88+G89+G90)/(IF('EF Table'!E89>0.5,'EF Table'!E91,'EF Table'!E89))). An equivalent formula should be added to a 2024 DSM biogas-to-electricity Tier 1 CI Calculator.*

B. Proposed DSM Biomethane CI Calculator

289.3 Please see below for CalBio's feedback on and additional recommendations for the Proposed DSM Biomethane CI calculator.

'Biogas-to-RNG' Worksheet

- **Field 2.7 Flared Biogas Biomethane Content:** The proposed calculator does not appear to include an emissions factor for the newly added Flared Biogas field in the LCFS pathway system boundary or resulting CI calculations. To solve this, CalBio proposes applying the same emission factor used in Sections 2.20 and 2.30 to apply to the CO2 emitted from the combustion of biogas based on the inputs to Sections 2.6 and 2.7. CalBio believes flared biogas at the digester should be treated consistently with how flared biomethane is accounted for at the upgrading facility, and the resulting emissions should be included in the LCFS pathway system boundary regardless of the biogas handling method (i.e., flaring or venting). The project should also demonstrate the flare was operational through a thermocouple or other instrument to demonstrate the gas was

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truly combusted. In the absence of operational data demonstrating combustion, the biogas flow should be treated as vented.

Suggested Modification: *Include an Emission Factor calculation in Cell F57. Also include row in the Raw Biogas Production-Digester in Section 4 to include "Biogas (flaring)".*

- **Field 2.22 On-Site Electricity from Biogas (upgrading and compression):**
    - 289.4 CARB has emphasized its goals for producers to choose more efficient, cleaner technologies for on-site power generation. In alignment with these goals, CalBio recommends that CARB recognize the biogenic nature of the CO_2 emissions occurring from the combustion of biogas for on-site electricity use. The default emission factor for the use of on-site electricity from biogas (641 gCO2e/kWh) assumes the fuel is fossil-based natural gas and is more than double the default emission factor for grid electricity in all but six of the eGRID regions. Thus, most renewable fuel producers are penalized if they choose to offset some of the power for their facilities using on-site electricity fueled by biogas rather than grid electricity.
    - For facilities that use biogas for electricity production, CARB's Instruction Manual instructs applicants to choose the User Defined Mix electricity option for Field 2.1 Select Regional Electricity Mix, however that User Defined Mix emission factor flows into all the Grid Electricity Fields, rather than the On-Site Electricity from Biogas (Field 2.22). CalBio recommends CARB allow users to select an electricity mix for each electricity field.
    - CalBio also recommends that CARB include a User-Defined Option for electricity generation equipment and associated technology-specific emission factors so users can appropriately model emissions from technologies other than conventional stationary reciprocating engines, such as fuel cells, linear generators, etc. Similar to the guidance issued for User-Defined Fuels in Section 2 of the calculator, applicants can consult with CARB Staff to develop the technology-specific emission factors.

Suggested Modification: *RNG producers which use biogas to generate electricity should be able to replace the Emission Factor calculation in Cell U57 with 0 recognizing that the CO2 emissions are biogenic.*

- **Field 2.6 Flared Biogas Flow (metered)**: User Input cells are formatted as "Percentage," but
289.5 should be formatted as "Number" like Sections 2.4 and 2.8. The formatting of cell E52 could also be updated to use the 1000 separator (,).

'Avoided Emissions' Worksheet

- **Accounting Errors in Cells C45 and C47 for Projects that use Biogas to Generate On-site**
289.6 **Electricity:** If a project seeks to generate on-site electricity from biogas, it is assumed the Biogas in MMBTUs will be entered into "2.20 Raw Biogas (as Process Fuel for upgrading and

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compression)" and the electricity generation will be entered into "2.22 On-Site Electricity from Biogas (upgrading and compression)" on the 'Biogas-to-RNG' Worksheet. However, when these values are entered, the "RNG associated with onsite electricity production" is not recognized in Cell C45 in the 'Avoided Emissions' Worksheet. The CI impact should be the same if the electricity is derived from Biogas as opposed to Biomethane.

Similarly, Cell C47 contains a note where CARB recognizes that if on-site power generation is used in the LCFS system boundary, the value of "RNG associated with onsite electricity production" can be included in the avoided CH4 calculation here. CARB should modify these cells to treat on-site electricity derived from biogas consistently since electricity can be generated from both and still be considered within the RNG production boundary.

Suggested Modification: *In the scenario described above, Cell C45 should be revised to the following =('Biogas-to-RNG'!S52+'Biogas-to-RNG'!AE52)/Reference!D16*Reference!E16 and Cell C47 should be revised to equal SUM(C45,C41)/C40*

'Manure-to-Biogas (LOP Inputs)' Worksheet

289.7
- **Field L3.7 Biomethane Content in Vented Biogas (metered)**: User Input cells are formatted as "Number" but should be "Percentage" for consistency with units identified in cell H53.

C. Proposed DSM Biomethane CI Calculator Instruction Manual

Please see below for CalBio's feedback on the Proposed DSM Biomethane CI calculator Instruction Manual.

289.8
- **Table 2, Field L1.(1-6).13 Fraction of Volatile Solids Sent to Anaerobic Storage/Treatment System:** The Description and Instructions for this Field states: "…*For modeling the manure (volatile solids) from more than six livestock categories/sources, please use a separate worksheet to calculate the weighted fraction of manure (volatile solids) average for each livestock category, and use the calculated weighted average as the inputs to Fields L1.(1-6).12*." However, Fields L1.(1-6).12 is the Van't Hoff-Arrhenius factor and is not a User Input. The calculated weighted average be the inputs to Fields L1.(1-6).13.

289.9
- **Table 9, Field 2.1 Select Regional Electricity Mix for Biomethane:** CARB publishes the prior year's grid electricity factors on an annual basis (https://ww2.arb.ca.gov/resources/documents/lcfs-pathways-requiring-public-comments). CARB should explicitly allow applicants to enter the CARB-published values as a User Defined Mix by stating these instructions directly in the Instruction Manual, to more accurately reflect the emissions from electricity utilized at their facilities.

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D. Proposed Data Substitution Requirements in § 95491.2.

289.10 CalBio believes the Data Substitution Requirements listed in Table 13 of Section 95491.2 do not appropriately consider the specific types of common data issues often observed by flow meters, methane analyzers, and other equipment used as inputs to the CI Calculator. The requirements are overly prescriptive and overly simplified and do not allow for more nuanced and appropriate data substitution.

First, CARB should specify a definition and a threshold for "Missing Data" where the requirements are only triggered if a certain duration or volume of missing data is observed. For instance, is a single missing 15-minute flow reading considered missing that must follow these procedures? In many cases, it would not make sense to substitute flow using the prescriptive language, especially if the meter totalizes flow and the volume of biogas which flowed through the meter during the data-outage period is known. Durations and volumes which stay under a certain limit should be able to be addressed within the project's data substitution procedures defined it is monitoring plan and subject to verifier review. What CARB is proposing may lead to more Alternate Methods as developers seek to justify why an approach is needed because it does not fit with the prescriptive requirements. Additionally, performing data substitution that is "conservative" for a particular project that exists in a cluster, may affect its gas allocation contribution which may inadvertently credit another project with a greater proportion of biogas production which may not be appropriate or conservative.

289.11 Lastly, the 10 day alternate method submittal requirement is not realistic as there are times when a process change occurred on the equipment or at the farm or in the data that is not observed until after a report is submitted when the project is undergoing verification. By prohibiting alternate methods which are not submitted within the specified timeframe and the outcome be that "no reporting entity may generate LCFS credits associated with the time period for which there is missing data" is not reasonable for something that is potentially de minimus to the integrity of the pathway. CARB and the project applicant should be able to work together to ensure a robust, accurate, and agreed upon approach to support the goals of a well-functioning program.

We would like to thank CARB for the opportunity to comment and we look forward to engaging further on the topics above.

Sincerely,

Andrew Craig
Vice President, Greenhouse Gas Programs
California Bioenergy LLC

Comment Log Display

Here is the comment you selected to display.

Comment 299 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ellison
Last Name	Folk
Email Address	folk@smwlaw.com
Affiliation	Shute, Mihaly & Weinberger LLP
Subject	Comments on the Proposed Amendments to the Low Carbon Fuel Standard
Comment	Please see the attached .zip file containing comments from Ellison Folk, on behalf of The League for Justice and Accountability, regarding the Proposed Amendments to the Low Carbon Fuel Standard Thank you.
Attachment	www.arb.ca.gov/lists/com-attach/app-zip/6969-lcfs2024-Am5RNFA3WXkGX1Az.zip
Original File Name	LCFS comments.zip
Date and Time Comment Was Submitted	2024-02-20 16:29:13

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SHUTE, MIHALY
& WEINBERGER LLP

396 HAYES STREET, SAN FRANCISCO, CA 94102
T: (415) 552-7272 F: (415) 552-5816
www.smwlaw.com

ELLISON FOLK
Attorney
Folk@smwlaw.com

February 20, 2024

Via Electronic Submittal

Clerk of the Board
California Air Resources Board
1001 I. Street
Sacramento, CA 95814

Re: Comments on the Proposed Amendments to the Low Carbon Fuel Standard

Dear Honorable Members of the California Air Resources Board:

290.1 This firm represents the Leadership Counsel for Justice and Accountability ("Leadership Counsel") in matters relating to the California Air Resources Board's ("CARB") Proposed Amendments to the Low Carbon Fuel Standard Regulation ("Proposed Amendments" or "Project"). Central Valley Defenders of Clean Water & Air, Animal Legal Defense Fund, and Food & Water Watch have informed us that they also join in this letter. CARB's adoption of the Proposed Amendments is subject to the California Environmental Quality Act ("CEQA").[1] CARB's Draft Environmental Impact Analysis ("Draft EIA") must therefore: evaluate all reasonably foreseeable impacts of the Proposed Amendments in sufficient detail; adopt all feasible mitigation measures to lessen the severity of the Proposed Amendments' environmental impacts; and consider all feasible alternatives that would achieve the goals of the Proposed Amendments while lessening the severity of the Proposed Amendments' environmental impacts. Public Res. Code §§ 21002.1; 21100. The Draft EIA fails to comply with each of these obligations.

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[1] CARB acts pursuant to a certified regulatory program which exempts the agency from preparing an Environmental Impact Report ("EIR") because the environmental analysis CARB is required to undertake is deemed the functional equivalent of an EIR. 17 Cal. Code. Regs. §§ 60000-60007; *POET, LLC v. State Air Resources Bd.* (2013) 218 Cal.App.4th 681, 710 CARB's actions are subject to all other applicable provisions of CEQA. 14 Cal. Code Regs. § 15250; *POET, LLC*, 218 Cal.App.4th at 710.

290.1 cont.

As discussed in more detail below, the Proposed Amendments will increase the already significant incentive concentrated animal feeding operations ("factory farms") have to create more Low Carbon Fuel Standard-eligible fuels and expand their operations to increase fuel production. Despite this inevitable effect of the Proposed Amendments, CARB's Draft EIA fails to mention—let alone analyze—the environmental impacts associated with factory farm expansions or anaerobic digestion-related fuel production. The Draft EIA acknowledges that the installation of anaerobic digesters, which are necessary to generate LCF-eligible fuel from manure methane emissions, will have significant environmental impacts. However, the Draft EIA fails to adequately discuss and analyze these impacts, which include impacts to air quality and water quality and adverse public health impacts on communities living in close proximity to factory farms.

In addition, the Draft EIA fails to propose adequate mitigation measures to address the project's impacts and fails to adequately analyze alternatives to the project. These inadequacies require that the Draft EIA be revised and recirculated so that the public and decision-makers are provided with a proper analysis of the project's significant environmental impacts and feasible mitigation for those impacts. See CEQA Guidelines § 15002(a)(1) (listing as one of the "basic purposes" of CEQA to "[i]nform governmental decision makers and the public about the potential, significant environmental effects of proposed activities").

This letter is submitted along with comments prepared by: Silvia Secchi, Ph.D., Professor, Department of Geographical and Sustainability Sciences, University of Iowa, Attachment A ("Secchi Comments"); and Paul Rosenfeld, Ph.D., Principal Environmental Chemist, Soil Water Air Protection Enterprise ("SWAPE"), Attachment B.

I. The Proposed Amendments incentivize factory far expansion and the installation of anaerobic digesters.

The Proposed Amendments will greatly increase the incentive that already exists under the Low Carbon Fuel Standard ("LCFS") for factory farm expansion and digester installation.

290.2

This is evidenced in the stated Project objectives, which specify the following objectives:

- Increase credit prices by increasing the carbon intensity benchmarks (Objectives 1-4, Draft EIA at 13)
- Incentivize more digesters to achieve the Senate Bill 1383, Senate Bill 32, and Assembly Bill 1279 GHG reduction targets (Objective 5, Draft EIA at 13).

- Use the LCFS to build out and then transition biomethane infrastructure from supplying transportation fuels to supplying hydrogen fuels for stationary sources (Objective 5, Draft EIA at 13).

Therefore, CARB has designed the Proposed Amendments to increase carbon intensity targets, which in turn, will increase demand for credits and increase credit prices. Currently, biomethane accounts for approximately 20 percent of credits generated but only 1 percent of energy used for transportation.[2] The quantity and growth of biomethane credits in the LCFS has contributed to a glut of credits at low prices and diminished incentive for biogas investors to expand their investments.[3] The Proposed Amendments would increase the value of LCFS credits and incentivize investors to build
290.2 cont. more digesters and generate more credits. The Proposed Amendments incentivize fuel production practices that will, in fact, increase GHG emissions and result in significant environmental impacts.

The Proposed Amendments include three distinct changes to the LCFS that will increase the incentives factory farms have to expand their operations and install anaerobic digesters: (1) strengthening the carbon intensity benchmark, thereby increasing the price of credits for eligible fuel pathways, including electricity, natural gas, and hydrogen generated from factory farm manure methane emissions; (2) limiting biomethane pathways eligible for LCFS credits with deliverability requirements, which will also increase the price of credits for eligible fuel pathways; and (3) restricting new compressed natural gas and hydrogen fuel pathways that qualify for 35 years of avoided methane crediting to those that CARB certifies or that break ground by December 31, 2029.

By strengthening the carbon intensity benchmark from a 20% reduction in carbon intensity by 2030 to 30% by 2030 and establishing a new 90% carbon intensity reduction benchmark by 2045, CARB will increase demand for LCFS credits in the near-term, especially with the "step down" in 2025.[4] The intended and inevitable effect of this change will be to increase the demand of LCFS credits available for purchase, thereby increasing credit prices. Thus, those fuel pathways that qualify for credits after the amendments go into effect—including electricity, natural gas, and hydrogen derived from

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[2] Aaron Smith, 2024.01.22 article https://asmith.ucdavis.edu/news/cow-poop-now-big-part-california-fuel-policy attached as Attachment C.
[3] Id.
[4] CARB Staff Report: Initial Statement of Reasons, at 22-26 (December 19, 2023) ("ISOR").

factory farm manure—will receive more money per credit sold. The Proposed Amendments will therefore incentivize factory farms to increase their herds to maximize manure methane production (credit generation). This proposed change will also provide incentives for the installation of digesters at factory farms, and thus result in GHG and air pollutant emissions.

Additionally, the amendments include new deliverability requirements that will limit the biomethane eligible for LCFS crediting to biomethane "carried through common carrier pipelines that physically flow within California or toward end use in California."[5] Currently, all factory farms across the nation can qualify for LCFS credits on the same basis as factory farms in California. As with the carbon intensity benchmark change, these deliverability requirements will further limit the supply of LCFS credits, thereby increasing the amount of money eligible fuel producers receive per credit. Also, by limiting eligibility to those factory farms that have a connection to California, these deliverability requirements will further incentivize factory farm expansion specifically in California along with the installation of digesters at livestock facilities in California.

290.2 cont.

Lastly, the Proposed Amendments draw a bright line between factory farm fuel pathways that are certified before, and after, January 1, 2030, with respect to avoided methane crediting.[6] If a factory farm fuel pathway is certified before January 1, 2030, that pathway is eligible to be renewed for up to three consecutive 10-year crediting periods. However, fuel pathways for bio-CNG, bio-LNG, and bio L-CNG from projects that break ground after December 31, 2029 can only generate avoided methane credits through December 31, 2040. Similarly, fuel pathways for hydrogen from projects that break ground after December 31, 2029 can only generate avoided methane credits through December 31, 2045. The Proposed Amendments therefore provide a significant incentive for factory farms to expand their herds and install digesters before December 31, 2029.

The Proposed Amendments' incentives to expand CAFO herds and install polluting anaerobic digesters by increasing the monetization of manure methane will have significant impacts on the environment which the Draft EIA fails to adequately analyze and fails to require feasible mitigation or project alternative, as described below.

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[5] ISOR, at 30-31.
[6] ISOR, at 31.

II. The Draft EIA's Environmental Impacts analysis violates CEQA.

A. The Draft EIA fails to analyze the Proposed Amendments' environmental impacts.

1. Expansion of factory farm herds is a reasonable expected result in response to the Proposed Amendments.

290.3

CEQA requires lead agencies to analyze all reasonably foreseeable environmental impacts caused by a project they are proposing to approve. *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 396-98; *Ebbets Pass Forest Watch v. Cal. Dept. of Forestry & Fire Protection* (2008) 43 Cal.4th 936, 954-55. A public agency can only omit analysis of its project's impact if it is "speculative." *Santa Rita Union School District v. City of Salinas* (2023) 94 Cal.App.5th 298, 334-36. An agency's conclusion that a particular environmental impact is too speculative to be adequately analyzed must be supported by substantial evidence. *Id* at 335. To support such a conclusion, the CEQA Guidelines require lead agencies to conduct a "thorough investigation" and "note its conclusion" that the impact is too speculative to be considered. 14 Cal. Code Regs. § 15145; *County of Butte v. Dept. of Water Resources* (2023) 90 Cal.App.5th 147, 161; *Citizens' Committee to Complete the Refuge v. City of Newark* (2021) 74 Cal.App.5th 460, 479.

The Draft EIA's analysis is "based on reasonably foreseeable compliance responses that are based on a set of reasonable assumptions" and purportedly "includes actions that could likely occur under a broad range of the potential scenarios."[7] As explained in Section I, *supra*, the Proposed Amendments include three distinct changes that increase factory farms' incentive to generate more LCFS-eligible fuel by expanding existing herds and installing digesters. The Draft EIA considers the installation of anaerobic digesters a reasonable compliance response because the Proposed Amendments would "incentivize the collection and use of biomethane gas from dairies."[8]

The same elements of the Proposed Amendments that incentivize collecting existing biomethane at factory farms also incentivize increasing the volume of biomethane at factory farms. This incentive to produce more methane necessarily includes expanding factory farm herds to generate more manure. However, the Draft EIA ignores this potential impact entirely. The Draft EIA fails to provide any evidence, let

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[7] ISOR, at 39.
[8] Draft EIA, at 64.

alone substantial evidence, supporting its omission of factory farm expansion as a reasonable compliance response.

290.3 cont.

As explained in Dr. Secchi's comments, the analysis of Project-related impacts related to resulting factory farm expansion fails for two reasons. First, the "ISOR offers no monitoring data showing whether the LCFS has caused, or the proposed amendments will cause, herd expansions at dairies or hog facilities located in California or outside of California."[9] Without such data, the Draft EIA has no evidence to support an assumption that the use of digesters at factory farms results in a reduction of methane emissions overall.

Second, the evidence demonstrates that since the adoption of the low carbon fuel standard and Federal subsidy programs encouraging use of digesters, factory farms have expanded both inside and outside of California.[10] Dr. Secchi posits that, in reality, the incentives created by the Proposed Amendments are likely to result in significant expansion of factory farms that will, in turn, increase the amount of methane produced.[11] Recent deregulation of biodigesters in Iowa is correlated with dairy expansions in that state.[12] As explained above, by increasing the carbon intensity benchmark and the value of credits, the Proposed Amendments will incentivize increased expansion and concentration of dairy operations leading to increased adverse environmental impacts (as discussed further below). The aforementioned is a reasonably foreseeable compliance response that is not accounted for in the ISOR or the Draft EIA.

Recent data from the USDA Ag Census further demonstrates that during the period that CARB has implemented its avoided methane crediting policy (since the 2018 LCFS amendments), the number of milk cows at large, California dairies have increased while the number of milk cows at smaller dairies have decreased, showing that the California dairy herd is consolidating into larger dairies that produce and store sufficient quantities of manure to finance and generate revenues from captured methane. The data show that for dairies with 2,500 or more milk cows, the milk cow herd increased from 808,503 milk cows in 2017 to 1,025,716 milk cows in 2022, or an increase of 28.6 percent. In contrast, the data show that for dairies with less than 1,000 cows, the milk cow herd *decreased* from 303,746 milk cows in 2017 to 144,472 milk cows in 2022, or a

[9] Attachment A, Secchi Comments, at 1.
[10] Id. at 5 and 6.
[11] Id.
[12] Id. at 3.

290.3 cont.

decrease of 52.4 percent.[13] While correlation does not establish causation, the data strongly suggest that the LCFS has had a substantial effect on the increase in milk cows at the largest dairies which are most likely to install digesters and monetize their manure.[14]

2. The Draft EIA fails to adequately analyze nitrogen-based emissions from digesters that contribute to PM2.5 nonattainment and climate change.

290.4

Having failed to properly analyze the foreseeable expansion of factory farms as a result of the Project, the Draft EIA fails to analyze the Project's related impacts. It is well-established that "industrial dairies in the San Joaquin Valley are a major source of local air and water pollution, nuisance odors, groundwater overdraft, and greenhouse gas emissions."[15] Specifically, dairies are the largest source of volatile organic compounds, in the San Joaquin Valley. Oxides of nitrogen result from combustion of fuels, including biogas fuels from anaerobic digesters. Volatile organic compounds and NOx are precursors to ozone formation, which can cause a variety of respiratory illnesses, especially in children and for people who have asthma.[16] Factory farms and the resulting digestate are also a significant source of ammonia, which impacts nearby residents as a toxic gas and also reacts to form ammonium nitrate, a form of fine particulate matter for which the EPA has classified the valley as nonattainment with the federal health-based National Ambient Air Quality Standard.[17]

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[13] The data also show that for dairies with more than 1,000 cows, the milk cow herd increased from 1,446,583 milk cows in 2017 to 1,543,730 milk cows in 2022, an increase of 6.9 percent.
[14] U.S. Department of Agriculture Census, attached as Attachment D.
[15] *See*, Briefing paper: Factory Farm Dairies, Biogas, and the Dangerous Path California is On, Leadership Counsel for Justice and Accountability, 2023, Attached as Attachment E.
[16] U.S. Environmental Protection Agency, "Health Effects of Ozone Pollution", attached as Attachment F and available at https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution#:~:text=Depending%20on%20the%20level%20of%20exposure%2C%20ozone%20can%3A,diseases%20such%20as%20asthma%2C%20emphysema%2C%20and%20chronic%20bronchitis.
[17] *See* 87 Fed. Reg. 60494 (Oct. 5, 2022) (proposed disapproval of plan to attain the 2012 annual PM2.5 standard), attached as Attachment G.

290.4 cont.

In addition, contaminated runoff can result in water pollution in both surface and ground water; the intensive water use required by factory farms results in overdraft of groundwater supplies; and caustic ammonia emissions can result in illness and odors. As discussed below, the Draft EIA's failure to analyze the impacts of the Proposed Amendments, both resulting in significant expansion of factory farms and due to increased use of digesters, implicates the EIA's analysis of all of the aforementioned environmental impacts. Even where the Draft EIA did purport to evaluate impacts, the analysis is perfunctory.

(a) Ammonia Emissions

290.5

Ammonia, a toxic, odorous gas, causes respiratory issues; irritation to the throat, lungs, and eyes; and lung damage if exposure to elevated ammonia levels is prolonged.[18] In addition to the health risks imposed by increased local emissions, ammonia also reacts with nitrogen oxides (e.g., NOx) in winter and contributes to the formation of ammonium nitrate, a fine particulate matter ("PM2.5").[19] In the United States, ammonia from agriculture accounts for the formation of almost one third of PM$_{2.5}$.[20] Exposure to PM 2.5 is linked to premature deaths in people with heart or lung disease, heart attacks, irregular heartbeat, aggravated asthma, decreased lung function and long-term lung conditions including cancer.[21] Yet, the Draft EIA's analysis of the Project's public health and safety impacts is cursory at best.

(b) Greenhouse Gases

290.6

The Draft EIA analysis omits a full accounting of greenhouse gas emissions resulting from both a foreseeable expansion of factory farms and increased use of digesters.[22] For example, as the Rosenfeld Comments explain, during biogas combustion in the anaerobic digestion process, ammonia is oxidized into nitrous oxides. Furthermore,

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[18] Attachment B, Rosenfeld comments, at 2.
[19] Johns Hopkins Center for a Livable Future comments on LCFS Amendments dated February 20, 2024.
[20] Id.
[21] USEPA, "Health and Environmental Effects of Particulate Matter", attached as Attachment H and available at https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing .
[22] Attachment A, Secchi Comments, at 6.

290.6 cont. digestate solids emit significant nitrous oxide emissions that negate methane captured by the digester. According to the EPA, nitrous oxide ("N2O") has a Global Warming Potential that is 273 times that of carbon dioxide ("CO2") for a 100-year timescale.[23] Therefore, N2O emitted today remains in the atmosphere for more than 100 years, on average.[24] Yet, the Draft EIA omits any evaluation impacts from Project-related increases of N2O.

In another example, NOx emissions react with volatile organic compounds in the presence of sunlight to form ozone, which also contributes to climate change. Ozone (O3) is the third most important anthropogenic greenhouse gas after carbon dioxide (CO2) and methane.[25] NOx also reacts with ammonia to form ammonium nitrate, a form of PM2.5. The San Joaquin Valley of California, where most factory farms and biodigesters are located, is a nonattainment area for both ozone and PM2.5National Ambient Air Quality Standards. However, the Draft EIA provides only a cursory—and internally inconsistent—discussion of the potential impacts related to ozone and PM2.5 formation. On the one hand, the Draft EIA states the Proposed Amendments "*could* result in an overall decrease in long-term operational NOx and PM2.5 emissions…in all state-designated ozone non-attainment areas from 2024 through 2046," (emphasis added) with a corresponding reduction in health impacts.[26] But the Draft EIA then pivots to conclude that long-term impacts from NOx and PM 2.5 emissions "could be potentially significant and unavoidable."[27]

The Draft EIA's conclusion that the Proposed Amendments could reduce NOx and PM2.5 emissions fails to account for emissions resulting both from the increased use of digesters and the expansion of factory farms. To the extent the Draft EIA makes any attempt to acknowledge the potentially significant impacts of increased NOx and PM2.5, it does not provide any of the information required by CEQA to explain the extent and severity of these impacts. The Draft EIA's failure to provide meaningful information about the significance of these impacts violates CEQA. *Cleveland Nat'l Forest Foundation v. San Diego Assn. of Governments* (2017) 3 Cal.5th 497, 514 ("an EIR's designation of a particular adverse environmental effect as 'significant' does not excuse

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[23] U.S. EPA, Understanding Global Warming Potentials", attached as Attachment I and available at
[24] Id.
[25] Aura Science: Greenhouse effect of tropospheric ozone, NASA, attached as Attachment J and available at https://aura.gsfc.nasa.gov/science/feature-20110403.html
[26] Draft EIA, at 57.
[27] Draft EIA, at 62.

290.6 cont. the EIR's failure to reasonably describe the nature and magnitude of the adverse effect"); *Berkeley Keep Jets Over the Bay Com. v. Board of Port Cmrs.* (2001) 91 Cal.App.4th 1344, 1371 ("simply labeling the effect 'significant' without accompanying analysis of the project's impacts … is inadequate to meet the environmental assessment requirements of CEQA").

3. The Draft EIA Fails to Adequately Analyze NOx emissions from Flaring.

290.7 The Draft EIA refers to the air quality analysis in the Standard Regulatory Impact Assessment ("SRIA") as the basis for its estimates of criteria pollutants.[28] In the SRIA, CARB estimated emissions from flaring at digesters. The Draft EIA states that "[S]taff assumed that about 10% of methane produced is flared. Hence, flaring is the only source of local emissions used in estimating emissions from dairy biomethane."[29] Ammonia in flared biogas causes increased NOx emissions.[30] However, the SRIA only used air district emission factors for flares.[31] Thus, the EIA fails to adequately analyze NOx emissions from flaring biogas. A revised EIA should recalculate digester flare emissions using flared biogas.

4. The Draft EIA Fails to Adequately Analyze NOx emissions from Biomethane Electric Fuel Pathways.

290.8 In its evaluation of Project-impacts related to biomethane electric vehicle fuel pathways, the Draft EIA indicates that "[T]he LCFS modeling assumes use of fuel cells to generate this electricity, which do not rely on combustion."[32] Thus, staff calculate near zero NOx from electricity production of biomethane using an emission factor of 0.00085 tons/GWh.[33] However, this assumption underlying the analysis is questionable for multiple reasons. First, to date, CARB has certified only one biomethane electric vehicle fuel pathway that relies on Bloom fuel cells at a dairy to produce electricity, and that is at

[28] Draft EIA, at 58.
[29] SRIA, Appendix C-1 at B-2 Table 49.
[30] Attachment B, Rosenfeld Comments at 4.
[31] SRIA, Appendix C-1 at B-2.
[32] Draft EIA, at 27; SRIA, Appendix C-1 at B-3, (citing a dead link Bloom Energy (2002). *The Bloom Energy Server 5 Data Sheet*. https://www.bloomenergy.com/wp-content/uploads/es5-300kw-datasheet-2022.pdf)] .
[33] Id.

Bar 20, one of the largest dairies in California. By contrast, CARB has certified 19 biomethane electric vehicle fuel pathways that rely on internal combustion engines[34] .

Second, Bloom fuel cells are more expensive to purchase and maintain than internal combustion engines, and the San Joaquin Valley Unified Air Pollution Control District has declined to find that fuel cells are cost-effective and thus Best Available Control Technology ("BACT"). Instead, the District has issued Authority to Construct Permits and found that internal combustion engines represented BACT. Therefore, CARB lacks substantial evidence to support its unfounded assumption Bloom fuel cells will be used for electric vehicle fuel pathways. And while Bar 20 has permits for and operates fuel cells, there is no record on the Air District public notice log of *any* BACT determination for fuel cells at Bar 20.[35]

290.8 cont.

Furthermore, the most recent internal combustion engine Authority To Construct Permit from the San Joaquin Valley Air District found that fuel cells were not cost-effective and not BACT. Instead, the Air District required internal combustion engines as BACT.[36] This approach is inconsistent – on the one hand, the Air District does not consider fuel cells as BACTs or cost effective and does not require fuel cells as BACT; on the other hand, CARB's analysis of impacts from digester projects that generate electric vehicle fuel contends that all such fuel pathways will rely on fuel cells to emit near-zero NOx.

NOx emissions from digester-related internal combustion engine used for electric vehicle fuel pathways are significant. For example, the Lakeview Dairy Biogas project in Kern County uses two internal combustion engines to produce over 1,000 kW of electricity on-site.[37] And this project, as permitted by the Air District with required internal combustion engines, still emits 4.58 tons/year of NOx, 1.98 tons/year of PM2.5,

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[34] CARB: Total Number of Applications or Pathways (excel spreadsheet), February 9, 2024, attached as Attachment K.

[35] SJVAPCD Bar 20 Bloom Energy Permits, attached as Attachment L.

[36] *See* Attachment M - 2020.04.20 Notice of Final Action – Authority to Construct, ATC Lone Oak Energy; 2020.02.21 Notice of Preliminary Decision – Authority to Construct Lone Oak Energy at 13, Appendix C.

[37] SJVAPCD, Notice of Preliminary Decision – Authority to Construct (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf, attached as Attachment N; CalEPA & Cal. Air Res. Bd., LCFS Tier 2 Pathway App. B0104 (certified TBD), attached as Attachment O and available at https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.

290.8 cont. and 3.18 tons/year of VOC *after* the imposition of BACTs as required by the State Implementation Plan.[38] Compared to a natural gas combined cycle power plant in Avenal, also permitted by the Air District, the Lakeview digester project produces much higher levels of NOx, sulfur oxides (SOx), and VOC emissions per unit of electricity generated.[39] However, unlike the natural gas plant, Lakeview Dairy Biogas is not required to purchase emission reduction credits for the air pollution emitted. This facility, and others like it with internal combustion engines, emit significant levels of NOx even after Clean Air Act-required controls.[40] Therefore, the Draft EIA wrongfully omitted analysis NOx emissions from these facilities and fuel pathways.[41]

In summary, given that (a) the Proposed Amendments increase carbon intensity benchmarks, and thus credit prices, and will incentivize more pathways for electricity from internal combustion engines, (b) CARB does not require fuel cells as mitigation, and (c) the San Joaquin Valley Unified Air Pollution Control District does not consider fuel cells as BACT, it is reasonably foreseeable that more digesters with IC engines will apply for such pathway certifications. For these reasons, the Draft EIA must be revised to correct this error and to evaluate NOx impacts from biomethane electric vehicle fuel pathways that rely on IC engines.

5. The Draft EIA Fails to Adequately Analyze NOx emissions after 2039.

290.9 The Draft EIA fails to analyze NOx emissions from biomethane fuel pathways after 2039, despite authorizing crediting for biomethane fuel pathways well beyond 2039. The Draft EIA's PM2.5 and NOx emissions analysis explicitly relied on the Standardized Regulatory Impact Assessment ("SRIA"), including Tables 47-59.[42] Table 47 of the SRIA assumes no hydrogen or electricity will be produced from dairy biomethane after 2039.[43] However, as discussed in Section I, the Proposed Amendments explicitly

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[38] SJVAPCD, *supra* note 137, at 14.
[39] SJVAPCD, Notice of Final Determination of Compliance, (December 17, 2010) Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01), attached as Attachment P.
[40] Id.; Attachment Q Comparison of Digester vs. Avenal; and Rosenfeld Comments at _.
[41] Johns Hopkins, Center for a Livable Future comments LCFS Amendments; Petition for Reconsideration at 28-30, attached as Attachment R.
[42] Draft EIA, at 58.
[43] CARB Staff Report: Initial Statement of Reasons for Proposed Amendments to the Low Carbon Fuel Standards, Appendix C-1: Standardized Regulatory Impact Assessment, at B-3 (September 9, 2023) ("SRIA").

290.9 cont. authorize CARB to certify electricity and hydrogen fuel pathways well beyond 2039. The Draft EIA's analysis of NOx emissions is grounded on an inaccurate assumption. The Draft EIA must evaluate the impacts of NOx emissions over the time period during which these emissions will occur. 14 Cal. Code Regs. § 15126 ("[a]ll phases of a project must be considered when evaluating its impact on the environment"); *Make UC a Good Neighbor v. Regents of University of California* (2023) 88 Cal.App.5th 656, 667; *In re Bay-Delta etc.* (2008) 43 Cal.4th 1143, 1169.

6. The Draft EIA fails to adequately analyze Project-related ammonia emissions associated with digestate.

290.10 Aside from omitting analysis of the impacts resulting from factory farm expansion and use of anaerobic digesters described above, the Draft EIA presents an incomplete analysis of the project's ammonia impacts because it fails to evaluate the impacts from production and application of substantial increases of anaerobic digestate.[44] Apart from the size of the herd, the production and application of digestate to agriculture land is much more polluting and more hazardous to public health compared to raw manure.[45] CEQA requires an analysis of these impacts.

The Draft EIA's conclusion that the Project may have significant air quality impacts—without consideration of the extent and severity of those impacts—cannot cure this deficiency. Merely stating that an impact will occur is insufficient; an EIR must also provide "information about how adverse the adverse impact will be." *Cleveland Nat'l Forest Foundation*, 3 Cal.5th at 514; *Berkeley Keep Jets Over the Bay Com.*, 91 Cal.App.4th at 1371. This information, of course, must be accurate and consist of more than mere conclusions or speculation. *Id.* The Draft EIA's analysis of air quality impacts fails to fulfill this mandate in several instances.

(a) Air pollution

290.11 Anaerobic digestate results in higher emissions in part because anaerobic digestion decomposes the waste into smaller molecules, which allows it to more easily volatilize into the atmosphere.[46] In this way, digestate results in significant releases of higher

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[44] Draft EIA at 56-62 (concludes impacts to air quality are significant); at 64-65 (concludes impacts from odor are not significant); Attachment B, Rosenfeld comments, at 2 and 3.
[45] Johns Hopkins Center for a Livable Future comments on LCFS Amendments at 2.
[46] Attachment B, Rosenfeld comments, at 3.

amounts of ammonia, a toxic gas, and NOx emissions than unprocessed manure.[47] The Draft EIA concludes that long-term operational air quality impacts related to PM2.5 and NOx would be significant and unavoidable.[48] We do not disagree that the Project's emissions would be significant. However, the DEIR fails to disclose the extent and
290.11 cont. severity of this impact.[49] A revised analysis must provide more details about the impacts and must account for increased application of digestate on agricultural land. *Cleveland Nat'l Forest Foundation*, 3 Cal.5th at 514; *Berkeley Keep Jets Over the Bay Com.*, 91 Cal.App.4th at 1371.

Furthermore, the Draft EIA's conclusion that odor impacts from ammonia emissions would not be significant is unsupported. As explained in the Rosenfeld Comments, ammonia emits a strong odor that is easily detectable at low concentrations and contributes to irritation such as immediate burning of the nose and respiratory tract.[50] In addition, anaerobic digestion significantly increases the amount of ammonia emissions compared to a dairy without an anaerobic digester.[51]

As discussed above, ammonia also contributes to the formation of $PM_{2.5}$ (e.g., formation of ammonium nitrate), exposure to which is linked to a variety of serious health problems).[52] CARB's own ammonia data show that ammonia contributes to PM2.5 formation.[53] Therefore, CARB must include a full evaluation of ammonia emissions.

(b) Public Health and Safety

Health and safety effects, including adverse health impacts from air pollutants,
290.12 may constitute significant environmental impacts for the purposes of CEQA. See, e.g., *Sierra Club v. County of Fresno* (2018) 6 Cal.5th 502, 517-22; *Bakersfield Citizens for*

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[47] Id.
[48] Draft EIA at 62.
[49] Draft EIA at 56-62.
[50] Rosenfeld Comments at 2.
[51] *Id*. at 3-4.
[52] Johns Hopkins Center for a Livable Future comments on LCFS Amendments comments at 3; See Attachment H https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing .
[53] 2023 CARB Ammonia Demonstration re 1997 PM2.5 plan standard SJV at 3, attached as Attachment S.

Local Control v. City of Bakersfield (2004) 124 Cal.App.4th 1184,1219-21. 14 CCR § 15126.2(a). Here, as discussed above, in the anaerobic digestion process substantial amounts of ammonia are produced as a byproduct.

290.12 cont.

In addition to the health risks imposed by increased local emissions, emissions and impacts on nearby communities, ammonia also contributes to the formation of $PM_{2.5}$.[54] In the United States, ammonia from agriculture accounts for the formation of almost one third of $PM_{2.5}$.[55] Exposure to PM 2.5 is linked to premature deaths in people with heart or lung disease, heart attacks, irregular heartbeat, aggravated asthma, decreased lung function and long-term lung conditions including cancer.[56] Yet, the Draft EIA's analysis of the Project's public health and safety impacts is cursory.[57] While the Draft EIA discloses that an increase in emissions of criteria pollutants associated with production of biofuels is possible, it falls short of actually evaluating the potential health impacts of these emissions.[58] Instead, once again the Draft EIA concludes that impacts would be significant, but then fails to describe the severity of those impacts.

Harmful emissions from expanded use of anaerobic digesters disproportionately affect communities in close proximity to dairies, which are often comprised of lower-income residents. Lower-income residents are often more vulnerable to the adverse effects of these emissions due to various factors, such as lack of resources, inadequate infrastructure, and the concentration of anaerobic digester facilities near these populations.

(c) Impacts Outside of California

290.13

The Draft EIA fails to analyze the Proposed Amendments' impacts outside of California. CEQA requires public agencies to analyze the potentially significant impacts of a proposed project that may occur in "the area which will be affected by [the] proposed project." 14 Cal. Code. Regs. § 15360; Public. Res. Code § 21060.5. CARB itself acknowledged its obligation to analyze out-of-state impacts in conducting its CEQA

[54] Id.
[55] Id.
[56] See Attachment H; https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing.
[57] Draft EIA, at 61 and 62.
[58] Id.

290.13 cont.

review for the Renewable Electricity Standard in 2010.[59] Factory farms across the nation are eligible for LCFS credits, and are thus incentivized by the Proposed Amendments to install anaerobic digesters and expand existing herds, just as in-state factory farms are. The Proposed Amendments will therefore have adverse environmental impacts out-of-state. CARB's refusal to analyze such impacts is clear legal error.

7. The Draft EIA fails to adequately analyze Project-related discharges to groundwater associated with digestate.

The Draft EIA's analysis of increased digestate on groundwater is equally flawed. As explained in the Rosenfeld Comments, anaerobic digestion breaks down waste into a digestate of smaller molecules that makes digestate more susceptible to leaching into the groundwater.[60] Anaerobic digestion also leads to higher concentrations of ammonia in digestate, which can subsequently convert to nitrate.[61]

290.14

"[N]itrate pollution leading to groundwater contamination is much more likely to occur with anaerobically digested digestate, as the ammonia is more readily available for conversion into nitrate, which can then leach into groundwater."[62] Nitrate contamination in drinking water and food can lead to severe illness in infants, such as the onset of blue baby syndrome, also known as methemoglobinemia.[63] Yet, the Draft EIA fails to include any analysis of these potential impacts.

Although the Draft EIA concludes that the Project's long-term operational impacts to water quality are significant and unavoidable, the document lacks a thorough analysis of these impacts. As the Rosenfeld Comments explain, increased amounts of digestate have the potential to result in groundwater nitrate contamination, excessive accumulation of soil phosphorus, and eutrophication of surface waters from anaerobic digesters.[64] These impacts to water quality and public health must be evaluated in a revised EIA.

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[59] California Air Resources Board, Functional Equivalent Document for the Renewable Electricity Standard, at E-77, E-82, E-83, E-105, E-107, E-108 (June 2010), attached as Attachment T and available at https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2010/res2010/res10e.pdf.
[60] Attachment B at 5.
[61] Id.
[62] Attachment B at 5 and 6.
[63] Id.
[64] Id. at 7.

290.14 cont. In summary, the Draft EIA fails to grapple with an analysis of all of the foreseeable, significant, direct and indirect environmental impacts of implementing the Proposed Amendments. As discussed above and in several comment letters from other stakeholders, these impacts include, but are not limited significant air quality, climate change, water quality, and public health impacts. Furthermore, as discussed below, the Draft EIA fails to identify feasible mitigation measures to minimize acknowledged significant impacts resulting from the project. A revised EIA must correct these deficiencies in order for the public and decision-makers to fully understand the Project's impacts.

III. The Draft EIA fails to identify any enforceable mitigation measures to lessen the severity of the Proposed Amendments' significant impacts.

290.15 If, as here, a lead agency determines its project will have one or more significant environmental effects, CEQA requires that agency to adopt all feasible mitigation measures to reduce the severity of those impacts. Public. Res. Code § 21002; *Sacramento Old City Assn. v. City Council* (1991) 229 Cal.App.3d 1011, 1027; *POET, LLC*, 218 Cal.App.4th at 734-35. Mitigation can take many forms, including avoiding the impact altogether by not taking a certain action or parts of an action and minimizing impacts by limiting the degree or magnitude of the action and its implementation. 14 Cal. Code Regs., § 15370. Mitigation measures are only legally valid if they are fully enforceable. Public Res. Code § 21081.6(b); *Assn. of Irritated Residents v. Kern County Bd of Supervisors* (2017) 17 Cal.App.5th 708, 752.

The Draft EIA's approach to mitigation measures is woefully deficient. CARB has not proposed *any* enforceable mitigation measures to be incorporated as part of the Proposed Amendments. The Draft EIA's reasoning for doing so is based on a fundamental legal error. Because CARB has no authority over the projects and actions that will be undertaken in response to the Proposed Amendments, the Draft EIA asserts that CARB has no obligation to incorporate feasible mitigation measures into the Proposed Amendments themselves. CARB does have jurisdiction over the Proposed Amendments, and it must include measures that will reduce or eliminate the reasonable foreseeable impacts of the Amendments. 14 Cal. Code Regs. § 15126.4.

The Draft EIA's illogical reasoning is compounded by its unsupported assumption that the projects it identifies as reasonably compliance responses will be subject to future CEQA review. Factory farm expansions and digester installations are commonly considered exempt from CEQA review by the local agencies in Central Valley that routinely approve such projects. The Leadership Counsel proposes numerous feasible mitigation measures CARB can, and must, incorporate into the Proposed Amendments to

290.15 cont. lessen the severity of its significant impacts associated with digester installation and factory farm expansion.

1. The Draft EIA's approach to mitigation measures is legally erroneous.

CARB has not proposed *any* enforceable mitigation measures, despite the Draft EIA concluding that the Proposed Amendments will have numerous significant environmental impacts. According to the Draft EIA, CARB—one of the most powerful regulators in the State—has no ability or authority to mitigate the impacts associated with
290.16 the Proposed Amendments. In attempting to off-load its obligation to impose feasible mitigation measures, CARB confuses the project before it—the Proposed Amendments—with the projects (e.g. anaerobic digesters, factory farm expansions) that will be undertaken *as a result* of the Proposed Amendments. Because CARB does not have authority over these projects, the Draft EIA asserts CARB has no ability to incorporate feasible mitigation measures within the Proposed Amendments.

However, CEQA requires CARB to determine whether changes or additions can be made to the *Proposed Amendments themselves* that will reduce the severity of their significant environmental impacts. 14 Cal. Code Regs. § 15126.4(a)(2) ("[i]n the case of the adoption of a plan, policy, regulation, or other public project, mitigation measures can be incorporated into the plan, policy, regulation, or project design"). CARB clearly has the authority to make changes or additions to its own Proposed Amendments, which will lessen the severity of their environmental impacts. Its failure to even consider doing so constitutes grave legal error.

2. CARB's EIA process is likely the last opportunity for environmental review and mitigation of the impacts of factory
290.17 **farm expansion and digester installation.**

CARB's faulty reasoning is compounded by its unsupported assumption that the projects which will be undertaken as a result of the Proposed Amendments will be subject to future CEQA review and, thus, the obligation to mitigate significant impacts. However, in the Central Valley, where factory farms are predominately located, the installation of anaerobic digesters and the expansion of factory farms are commonly considered by local agencies to be exempt from CEQA review on the grounds that the projects are ministerial or qualify for a categorical exemption. Therefore, with respect to these projects, the Draft EIA process is likely the last stop for both detailed environmental review and the imposition of meaningful mitigation measures.

290.17 cont.

For example, Kings County has adopted local guidelines that inform its implementation of CEQA.[65] Included in these guidelines are a list of categories of projects that are exempt from CEQA review because they are subject to ministerial review. These ministerial projects include "Site Plan Reviews." In 2023 alone, Kings County approved two anaerobic digester projects, exempting them from CEQA review on the grounds they were subject to ministerial review.[66] Kings County thus had no obligation under CEQA to analyze and mitigate the adverse impacts associated with either of these projects.

Other jurisdictions have exempted digester projects from CEQA review—and the obligation to mitigate significant impacts—on the grounds that these projects qualify for a Categorical Exemption. For example, Tulare County issued a Notice of Exemption in 2020 for a pipeline construction project intended to transport dairy biogas on the grounds the project qualified for the Class 1 (minor alterations to existing facilities) and Class 3 (new construction of small structures) Categorical Exemptions.[67] Tulare County also filed a Notice of Exemption to expand an existing biogas pipeline to connect an additional dairy digester to existing infrastructure. Other jurisdictions where similar projects have been exempted from CEQA review recently include Merced, Stanislaus, and Kern.

Tulare County also filed multiple Notices of Exemption in 2022 for factory farm herd consolidation projects, including a project that increased an existing herd size by

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[65] Kings County, *Local Guidelines for the Implementation of CEQA*, (January 5, 2016), attached as Attachment U and available at https://www.countyofkings.com/home/showpublisheddocument/12485/635919879294330000.

[66] Kings County Notice of Exemption for Felicita Dairy Anaerobic Digester Project (December 7, 2023), attached as Attachment V and available at https://files.ceqanet.opr.ca.gov/293555-1/attachment/CDzMvjy1XpNztMTMZYB397RSlELw_rWgq8tiJxKcc3SF7-nLFEgELbQwM06hiwOeTZEiJUhU6gqHLBNx0; Kings County Notice of Exemption for Countryside Dairy Anaerobic Digester Project (May 15, 2023), attached as Attachment W and available at https://files.ceqanet.opr.ca.gov/287881-1/attachment/q5K_P65aU7RUja-BYGe9-uDeE-Fz0Az_DAbus84Q28vqdXyG1cceIHq937esHc4jb7WmtPLcv9qGvzOn0.

[67] Tulare County Notice of Exemption for Tulare Biogas Gathering Line (August 18, 2020), attached as Attachment X and available at https://files.ceqanet.opr.ca.gov/264014-2/attachment/ZQ976ZUWit1klndpB1s5MYMKZJQBpo6c-8VIweVKasCVOsmAyGVogK05MqqmSLuQk994sssNab-A3-7Q0.

almost 3,000 animal units.[68] Kings County filed a Notice of Exemption for a project that expanded the herd size of an existing calf ranch in 2023 on the grounds that the underlying approval was ministerial.

290.17 cont.

CARB's attempt to justify its refusal to adopt any enforceable mitigation measures on the grounds that the projects incentivized by the Proposed Amendments will be subject to future CEQA review fails. CARB's discretionary approval of the Proposed Amendments is likely the last chance to rigorously analyze and mitigate the significant impacts associated with many future factory farm expansions and digester development projects. CARB must use its authority as the regulatory agency tasked with crafting the LCFS to ensure all identified significant impacts are mitigated to the extent feasible.

3. CARB must adopt feasible mitigation measures that will lessen the severity of the Proposed Amendments' impacts on factory farm expansion and digester installation.

CEQA explicitly acknowledges that feasible mitigation measures can include changes that are incorporated into the regulation itself. 14 Cal. Code Regs. § 15126.4(a)(2). Each of the following mitigation measures is feasible and within CARB's authority to incorporate within the Proposed Amendments; CARB's failure to do so would constitute a clear violation of CEQA:

290.18

- Limit the generation of credits for fuel pathway holders for biogas derived from livestock manure to the volume of feedstock at each associated dairy or livestock operation on January 1, 2017, or on the date the pathway was certified, whichever is earlier.

- Restrict the generation of credits for fuel pathway holders for biogas derived from livestock manure located in Disadvantaged Communities as designation by the Office of Environmental Health Hazard Assessment pursuant to Senate Bull 535.[69]

- When calculating the carbon intensity of fuel derived from livestock manure, include all emissions of greenhouse gases generated from the production of the

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[68] Cows, pigs, and other animals raised in factory farms and dairies are not "units," but are sentient beings, each of which has its own unique personality.
[69] An interactive map delineating the Disadvantaged Communities throughout the State is available at https://oehha.ca.gov/calenviroscreen/sb535. A copy of the state-wide map is attached as Attachment Y.

fuel and all emissions of greenhouse gases generated from the production of the feedstock. Update the carbon intensity of each pathway for fuel derived from livestock manure after making this calculation. These emissions include, but are not limited to,

290.18 cont.

- o Enteric emissions;
- o Emissions from production and storage of feed, transport of feedstock, or fuel;
- o Emissions resulting from digestate handling, composting, or treatment; and
- o Emissions resulting from land application of manure or digestate.

- Disapprove any application for a fuel pathway that includes the use of biogas derived from livestock manure which does not provide all information and calculations used to determine carbon intensity, including but not limited to:
  - o Herd size;
  - o Volume of feedstock produced or used;
  - o Volume of biogas produced.
- Make publicly available on CARB's website all information and calculations used to determine carbon intensity.

IV. The Draft EIA fails to analyze all reasonable alternatives by which the State can achieve its methane reduction goals.

290.19 As a preliminary matter, the Draft EIA's failure to disclose the extent and severity of the Project's broad-ranging impacts necessarily distorts the document's analysis of Project alternatives. As a result, the alternatives are evaluated against an inaccurate representation of the Project's impacts. Proper identification and analysis of alternatives is impossible until Project impacts are fully disclosed.

CEQA requires CARB's Draft EIA to describe a range of "reasonable alternatives to the project," which would "attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effect of the project," and evaluate the "comparative merits" of the alternatives. 14 Cal. Code. Regs. § 15126.6. The discussion of mitigation and alternatives is "the core" of CEQA analysis. *Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal.3d 553, 564.

290.19 cont.

The Draft EIA's alternatives analysis presents a series of false choices, that rests on the assumption that the only method by which the State can achieve its methane emissions reduction goals is through the LCFS's indirect, incentive-based regulation. Each alternative scenario is simply a version of the LCFS with different requirements than the Proposed Amendments. The Draft EIA fails to analyze a scenario where CARB uses its regulatory authority to directly regulate methane emissions from factory farms, as required by Health & Safety Code §§ 38562.5, 39730.7(b)(1), thereby achieving the State's methane reduction goals while reducing the incentive for factory farms to expand their environmentally damaging operations.

The Draft EIA must be amended to include analysis of an alternative scenario with the following components: (1) elimination of LCFS credits for fuel derived from manure methane emissions; (2) implementation of direct regulation of factory farms to achieve the same level of methane reduction CARB currently contemplates will be achieved through the LCFS; and (3) decrease the stringency of the LCFS' carbon intensity requirement, to ensure the elimination of credits for fuel derived from manure methane emissions does not affect credit prices negatively and risk the State failing to achieve its fuel decarbonization goals.

The State Legislature has granted CARB the regulatory authority to directly regulate the major sources of methane emissions within the State, including the dairy and livestock industry, landfills, and the oil and gas system. To date, CARB has taken action to directly regulate landfills (the Landfill Methane Regulation, Cal. Code of Regs., tit. 17 §§ 95460, et seq.) and the oil and gas system (the Oil and Gas Methane Regulation, Cal. Code of Regs., tit. 17, §§ 95665-77). However, CARB has yet to directly regulate the dairy and livestock industry—the largest source of methane emissions within the State.

The State Legislature, through Senate Bill 1383, mandated that CARB adopt regulations and mandated that CARB implement such regulations beginning in January of 2024 provided that CARB make certain findings. As CARB itself has stated, the agency shall adopt regulations and has authority to implement the regulations, "provided that CARB, in consultation with CDFA, determine the regulations are technologically and economically feasible, cost-effective, include provisions to minimize and mitigate potential leakage, and include an evaluation of the achievements made by incentive-based programs."[70]

CARB itself acknowledged in its 2022 Scoping Plan that direct regulation of the sources of methane emissions is integral to the State's methane emissions reduction strategy.[71] CARB's stated strategy for reducing the emissions of short-lived climate
290.19 cont. pollutants, most notably methane, is a "carrot-then-stick" approach.[72] This approach begins with the incentive-based, indirect regulations, such as the LCFS (the "carrot"), and then transitions into direct regulation, similar to those that have been promulgated for the landfill and oil and gas systems (the "stick"). The 2022 Scoping Plan ultimately recommends the carrot and stick approach for manure methane.[73] CARB acknowledged that the dairy and livestock industry must "achieve considerable methane emissions reductions to meet the 2030 target," which will "require implementation of additional methane emissions reductions strategies."[74]

Despite having the mandatory duty and authority to directly regulate methane emissions from the dairy and livestock industry, and explicitly stating that such regulation is integral to the State's emissions reduction strategy, CARB fails to analyze an alternative scenario where this direct regulatory authority is applied. The only alternatives CARB considers are those where the LCFS is the primary, if not sole, mechanism for achieving methane emissions reductions from the dairy and livestock industry. CARB has the authority to simultaneously reduce the methane emissions and adverse environmental impacts from factory farms, while not risking the State's fuel decarbonization goals. CARB's failure to consider such a scenario constitutes clear legal error.

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[70] California Air Resources Board, Analysis of Progress Toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target, at ES-4 (March 2022), attached as Attachment Z and available at https://ww2.arb.ca.gov/sites/default/files/2022-03/final-dairy-livestock-SB1383-analysis.pdf.
[71] California Air Resources Board, 2022 Scoping Plan, at 222-25 (2022), attached as Attachment AA and available at https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.
[72] *Id*. at 223.
[73] *Id*. at 232.
[74] CARB, Analysis of Progress Toward Achieving 2030 Methane Emissions Target, at ES-6.

V. Conclusion

290.20 Due to the foregoing and numerous adverse environmental impacts not fully disclosed and properly analyzed in the Draft EIA, the Leadership Counsel opposes the Project as proposed. Additional alternatives and mitigation measures are essential to avoid the Project's significant adverse impacts. The Leadership Counsel respectfully urges the Air Resources Board to delay further consideration of this Project until the agency recirculates a revised Draft EIA that fully complies with CEQA and the CEQA Guidelines.

Very truly yours,

SHUTE, MIHALY & WEINBERGER LLP

Ellison Folk

Attachments:

Attachment A: Comments of Silvia Secchi, Ph.D., Professor, Department of Geographical and Sustainability Sciences, University of Iowa

Attachment B: Comments of Paul Rosenfeld, Ph.D., Principal Environmental Chemist, Soil Water Air Protection Enterprise

Attachment C: Aaron Smith, "Cow poop is now a big part of California Fuel Policy", UC Davis, Jan. 22, 2024.

Attachment D: U.S. Department of Agriculture, 2017 Census of Agriculture – State Data, Table 17. Milk Cow Herd Size by Inventory and Sales: 2017 and Table 17. Milk Cow Herd Size by Inventory and Sales: 2022

Attachment E: Briefing paper: Factory Farm Dairies, Biogas, and the Dangerous Path California is On, Leadership Counsel for Justice and Accountability, 2023.

Attachment F: U.S. EPA, "Health Effects of Ozone Pollution"; https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution#:~:text=Depending%20on%20the%20level%20of%20exposure%2C%20ozone%20can%3A,diseases%20such%20as%20asthma%2C%20emphysema%2C%20and%20chronic%20bronchitis.

Attachment G: 87 Fed. Reg. 60494 (Oct. 5, 2022) (proposed disapproval of plan to attain the 2012 annual PM2.5 standard).

Attachment H: U.S. EPA, Health and Environmental Effects of Particulate Matter, https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing

Attachment I: U.S. EPA, Understanding Global Warming Potentials; https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

Attachment J: Aura Science: Greenhouse effect of tropospheric ozone, NASA, https://aura.gsfc.nasa.gov/science/feature-20110403.html

Attachment K: CARB: Total Number of Applications or Pathways (excel spreadsheet), February 9, 2024.

Attachment L: SJVAPCD Bar 20 Bloom Energy Permits

Attachment M: Notice of Final Action – Authority to Construct, ATC Lone Oak Energy; 2020.02.21 Notice of Preliminary Decision – Authority to Construct Lone Oak Energy

Attachment N: SJVAPCD, Notice of Preliminary Decision – Authority to Construct Lakeview Dairy Biogas (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf.

Attachment O: CalEPA & Cal. Air Res. Bd., LCFS Tier 2 Pathway App. B0104 Lakeview Dairy Biogas(certified TBD), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf

Attachment P: Notice of Final Determination of Compliance, Avenal Power Center, at 3, 27 (Dec. 17, 2010)

Attachment Q: Digester v. Avenal Comparison

Attachment R: Excerpt from Petition for Reconsideration Of The Denial Of The Petition For Rulemaking To Exclude All Fuels Derived From Biomethane From Dairy And Swine Manure From The Low Carbon Fuel Standard Program

Attachment S: 2023 CARB Ammonia Demonstration re 1997 PM2.5 plan standard SJV.

Attachment T: Excerpts of CARB Functional Equivalent Document for Renewable Electricity Standard, June 2010.
https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2010/res2010/res10e.pdf

Attachment U: Kings County, *Local Guidelines for the Implementation of CEQA*, January 5, 2016.

Attachment V: Kings County Notice of Exemption for Felicita Dairy Anaerobic Digester Project, December 7, 2023.

Attachment W: Kings County Notice of Exemption for Countryside Dairy Anaerobic Digester Project, May 15, 2023.

Attachment X: Tulare County Notice of Exemption for Tulare Biogas Gathering Line, August 18, 2020.

Attachment Y: OEHHA SB 535 Disadvantaged Communities Map, https://oehha.ca.gov/calenviroscreen/sb535.

Attachment Z: California Air Resources Board, Analysis of Progress Toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target (March 2022), https://ww2.arb.ca.gov/sites/default/files/2022-03/final-dairy-livestock-SB1383-analysis.pdf.

Attachment AA: California Air Resources Board, 2022 Scoping Plan https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

ATTACHMENT A

Comments on the Amendments to Low Carbon Fuel Standard

Silvia Secchi

My name is Silvia Secchi and I am a professor in the Department of Geographical and Sustainability Sciences at the University of Iowa. I have a Ph.D. in economics from Iowa State University and have been studying the environmental impacts of Midwestern agriculture for over a quarter of a century, my google scholar profile shows see my record of peer reviewed publications[1]. I have reviewed the Initial Statement of Reasons of the Proposed Amendments to California's Low Carbon Fuel Standard and associated Appendices. Based on my my professional expertise as an agricultural economist, I have several concerns about CARB's failure to adequately address the potential for changes in the Standard to encourage the development of concentrated animal feeding operations, both through the establishment of new dairies and the concentration of existing operations.

First, the ISOR offers no monitoring data showing whether the LCFS has caused, or the proposed amendments will cause, herd expansions at dairies or hog facilities located in California or outside of California. As a result, CARB cannot in good faith assert that the capturing of manure from CAFO is actually reducing methane emissions from dairy and/or hog operations, and that the LCFS will not result in rebound effect or Jevon's paradox: the technological improvement (in this case the biodigesters) change the behavior of consumers and producers so that the efficiency gains actually result in increased production and the net effects are not reductions but increases in resource use and – in this case – methane emissions. There is extensive evidence of this type of phenomenon in the agricultural sector[2].

CARB's lack of jurisdiction outside state borders exacerbates this problem by causing a "race to the bottom" in jurisdictions that build digesters as a way to attract new operations or allow existing operations to expand along with digester installation. Race to the bottom has been found to be a significant factor in determining location of Confined Animal Feeding Operations (CAFOs) for both dairy and hog operations[3].

Here I detail recent trends in dairy production in Iowa and the increase in biodigesters, to show that the LCFS is already having an impact. The data I present here are the result of several hours of search on the Iowa Department of Natural Resources (DNR) website. I conducted this research in the course of a project in which I am examining the effects of lax environmental regulations in the expansion of CAFOs, in particular in association with "climate smart" policies. This data is important because the EPA Agstar database[4] that experts like Prof. Aaron Smith at UC Davis have been using severely underreports the number of biodigesters compared to the Iowa DNR site. As a result, national level analyses are extremely likely to underestimate the rebound effect. This is likely to be compounded by the fact that the deployment of biodigesters and the expansion do not always occur in the same year, as evidenced in two cases reported in

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[1] https://scholar.google.com/citations?user=rXte6MIAAAAJ&hl=en&oi=ao

[2] Paul, C., Techen, A. K., Robinson, J. S., & Helming, K. (2019). Rebound effects in agricultural land and soil management: Review and analytical framework. Journal of cleaner production, 227, 1054-1067.

[3] Herath, D., Weersink, A., & Carpentier, C. L. (2005). Spatial Dynamics of the Livestock Sector in the United States: Do Environmental Regulations Matter? Journal of Agricultural and Resource Economics, 30(1), 45-68.

[4] https://www.epa.gov/agstar

Table 1. In these cases, the impacts of the biodigesters on expansion will easily be underestimated.

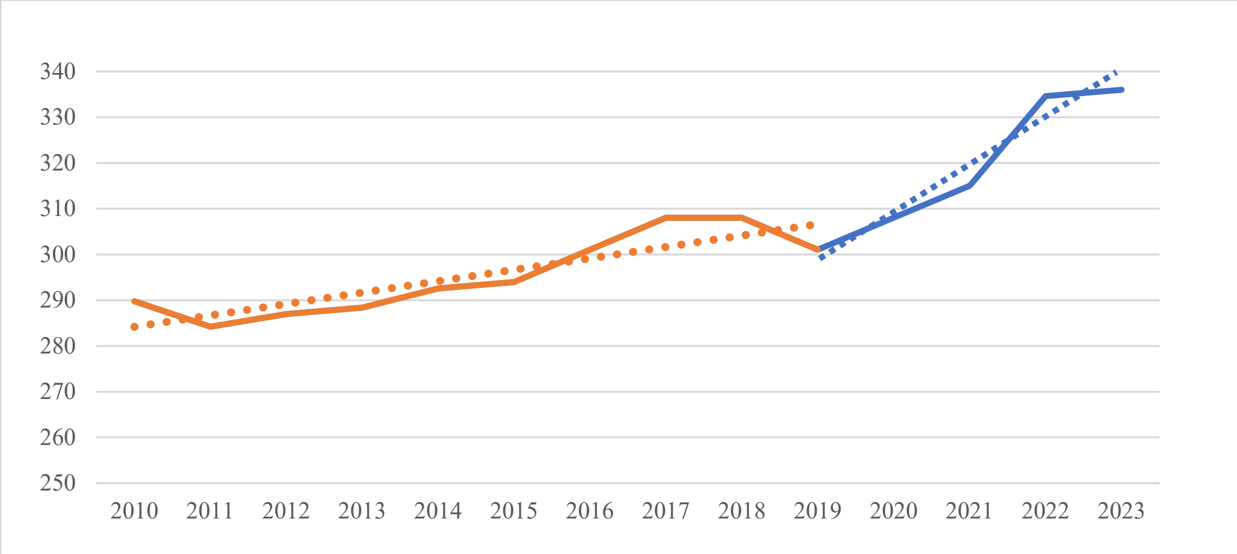
As Table 1 shows, there have been 15 digesters built in Iowa dairies since 2019. **The AgStar database only includes 4 of them.** These 15 digesters are associated with an increase of over 17,000 Animal Units (AUs). This corresponds to an increase of almost 20% in AUs. Milk production in Iowa had been growing, but it was doing so at a much slower pace before 2019 (Figure 1). Though it is not possible to formally attribute causality, it is notable that Iowa's dairy cows AUs increased by 35,000 between 2019 and 2023. **This means that a large portion of the increase in milk cows in the state is associated with biodigesters.**

Table 1 – Recent biodigesters installed in Iowa and associated capacity expansion

	Facility location	General Location	ID	Year	Initial size (AUs)	Final size (AUs)
Black Soil Dairy	Granville	North West	60565	2021	4,500	4,500
Geno	Blairstown	East Central	61209	2022	6,280	7,512
Kirkman Farms	Kirkman	West Central	64174	2021	8,500	11,900
Legacy Dairy	Sanborn	North West	60531	2022	3,920	6,160
Maassen	Maurice	North West	57177	2022	3,200	3,995
Marshall Ridge Farms	State Center	Central	60101	2020 digester 2023 expansion	8,499	11,425
Meadowvale Dairy North	Rock Valley	North West	62015	2021	20,300	20,300
Rock River Jerseys-Inwood Dairy	Doon	North West	66387	2019 digester 2022 expansion	8,499	14,000
Roorda Dairy	Paullina	North West	64981	2021	5,880	5,880
Salix Farms	Salix	North West	64623	2023	3,500	3,500
Sioux Jerseys	Salix	North West	62420	2023	6,300	6,300
Van Ess Dairy	Sanborn	North West	65143	2021	7,599	8,499
Winding Meadows Dairy	Rock Valley	North West	60218	2021	2,884	3,360

Source: Iowa DNR Animal Feeding Operation online application https://programs.iowadnr.gov/afoemmp/

Figure 1 – Iowa milk cow AUs (1,000s)



Source: USDA NASS Milk production reports
https://usda.library.cornell.edu/concern/publications/h989r321c?locale=en#release-items

Again, it is not possible to demonstrate unequivocally that this growth in dairy operations is directly linked to the expanded use of biodigesters. But two laws deregulating biodigesters were recently passed in Iowa. In 2019 SF 534[5] repealed the statutory requirement for rulemaking for all waste control technology facilities, including biodigesters, and in 2021, HF 522[6] allowed large dairies (over 8,500 AUs) to exceed confinement capacity if they install an anaerobic digester to treat all manure. There is a strong correlation between the deployment of biodigesters and the dairy expansions. As Table 1 shows, there were 3 such operations that expanded as they deployed biodigesters. In my professional opinion, this very strongly suggests that the increasing availability and decreasing regulation of biodigesters is contributing to dairy expansion and concentration.

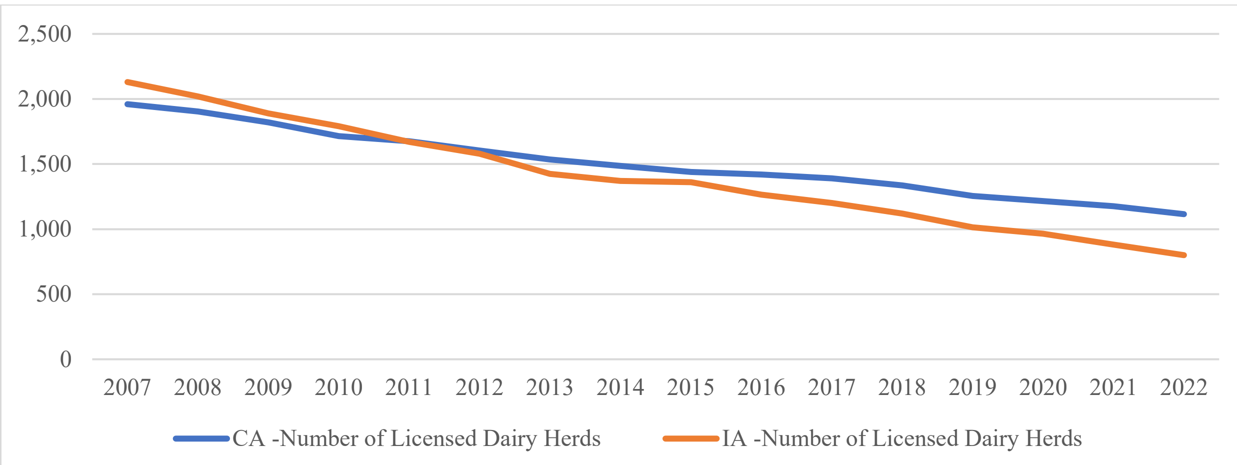
And while the dairies in Table 1 are not currently associated with approved pathways, biogas companies have already indicated their intent to avail themselves of the LCFS to generate credits at several of these facilities. Specifically, Gevo has announced that BP Canada Energy Marketing Corp. and BP Products North America Inc. will market Iowa-produced natural gas in California on its behalf[7]. Gevo is contracting with three of the dairies in Table 1, Meadowvale, Rock River Jerseys and Winding Meadows, two of which have expanded[8]. Another of the dairies

[5] https://www.legis.iowa.gov/docs/publications/LGE/88/SF534.pdf
[6] https://www.legis.iowa.gov/docs/publications/SOL/1224327.pdf#HF522
[7] https://investors.gevo.com/news-releases/news-release-details/gevos-northwest-iowa-rng-project-hits-major-milestone-begins
[8] Gevo appears as the common "cluster" for the dairies here: https://www.epa.gov/sites/default/files/2020-10/agstar-livestock-ad-database.xlsx.

expanding, Kirkman, is partnering with California's Brightmark RNG Origination LLC[9], which sells RNG to U.S. Gain, which is active in the California LCFS market[10].

Based on my study of the effect outside of California of policies to incentivize the use of biodigesters and my review of the literature, I believe similar expansion phenomena are likely taking place in California's dairy sector and elsewhere. The proposed LCFS amendments will increase expansion and concentration[11]. For example, very recently, a local expert has argued that the flattening of the dairy herd in California in the last five years could be linked to biodigesters. Notably, both in California and Iowa, flat and increasing total herd sizes respectively have both been associated with a reduction in the number of diaries, as shown in Figure 1. Consolidation should be a concern for CARB, since there is extensive evidence that it is associated with more water quality problems, among other things[12].

Figure 2 – Number of licensed dairy herds in California and Iowa, 2007-2022



Source: USDA NASS Milk production reports
https://usda.library.cornell.edu/concern/publications/h989r321c?locale=en#release-items

The evidence strongly suggests that the rebound effect is already at work outside California's borders because of race to the bottom policies being enacted by other states. The current policy approach allows for negative crediting of biogas as a way to avoid leakage: the concern is that making California farmers pay for their methane emissions would cause milk production to move (leak) out of state, where emissions are unregulated. But while the approach ensures California farmers do not face an added burden, it does nothing to limit the expansion of dairies in and out of state. As a result, the proposed LCFS amendments likely will cause another type of leakage through the rebound effect: the expansion and concentration of dairy operations resulting

[9] https://www.iowafarmbureau.com/Article/Carbon-neutral
[10] https://biomassmagazine.com/articles/us-gain-to-purchase-rng-from-brightmark-energy-16647
[11] Smith, A. (2022). The Dairy Cow Manure Goldrush. Retrieved from https://asmith.ucdavis.edu/news/revisiting-value-dairy-cow-manure; Smith, A. (2024). Cow Poop is Now a Big Part of California Fuel Policy. Retrieved from https://asmith.ucdavis.edu/news/cow-poop-now-big-part-california-fuel-policy .
[12] See for example Bian, Z., H. Tian, Q. Yang, R. Xu, S. Pan, and B. Zhang. 2021. "Production and application of manure nitrogen and phosphorus in the United States since 1860." Earth Syst. Sci. Data 13 (2):515-527. doi: 10.5194/essd-13-515-2021.

from the economic incentives provided by the LCFS and the decreased regulation of dairy operations will likely cause increased methane emissions that are not currently accounted for.

CARB's proposal to increase the carbon intensity target and therefore increase the economic value of methane captured from dairy operations will likely result in the expansion of dairy operations inside and outside of California.

I also want to note that the rebound effect has other substantial negative environmental impacts. In particular, as Table 1 shows, the expansion is occurring largely in Northwest Iowa, where CAFO production is already extremely elevated and there is little if any extra land available for spreading additional manure or digestate. This expansion will likely have both water quality and water quantity effects, and no entity is monitoring or assessing them. Notably, one of the Gevo dairies already leaked an estimated 376,000 gallons of manure water and was fined $10,000 in 2022. Another of the Gevo dairies started construction before receiving permission to do so[13].

This is particularly a concern because in 2017 EPA signed a settlement agreement limiting access to whatever information EPA has at its disposal regarding CAFOs[14] As a result, there is no national database that can be used to establish a national bottom-up[15] baseline of GHG emissions and other forms of pollution from CAFOs. This makes national level tracing of net changes in pollution and emissions as a result of the deployment of biodigesters extraordinarily difficult. In Iowa specifically, the DNR lack of monitoring capacity resulted in a de-delegation petition with EPA in 2007. As a result of the subsequent work plan[16], in 2017 the Iowa Department of Natural Resources identified 5,000 more animal feeding operations, some of which were CAFOs[17]. It is quite evident the Iowa DNR does not have the monitoring capacity to ensure compliance with the assumptions that CARB is making. CARB does not have that capacity either.

Recent changes to the USDA's Natural Resources Conservation Service (NRCS) list of practices eligible to receive subsidies under the Environmental Quality Incentive Program (EQIP) and substantial funding allocated to EQIP in the Inflation Reduction Act (IRA) also make it more likely that the rebound effect will increase in the United States. In particular, NRCS has added eligibility to receive subsidies to additional practices in their Climate-Smart Agriculture and Forestry (CSAF) Mitigation Activities List for FY2024 through EQIP and the Conservation Stewardship Program (CSP)[18]. These activities now include roofs and covers used to cover a waste management facility to capture biogas and waste storage facilities. The increased funding for the EQIP and CSP programs is substantial: $8.45 billion and $3.25 billion respectively[19]. Therefore, there are now subsidies available that will further incentivize the deployment of biodigesters. It is also important to note that CAFO operations that receive both federal subsidies to deploy biodigesters and LCFS subsidies for their methane could legitimately be considered a

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[13] https://iowacapitaldispatch.com/2022/07/22/company-with-major-manure-leak-didnt-get-permits-to-build-two-facilities-dnr-says/

[14] Miller, D. L., & Muren, G. (2019). *CAFOs: What We Don't Know Is Hurting Us*, retrieved from https://www.nrdc.org/resources/cafos-what-we-dont-know-hurting-us

[15] Bottom up baselines include individual facilities and can trace aggregate changes to each of them.

[16] https://www.iowadnr.gov/Portals/idnr/uploads/afo/epa_dnr_workplan.pdf

[17] https://publications.iowa.gov/33733/

[18] https://www.nrcs.usda.gov/conservation-basics/natural-resource-concerns/climate/climate-smart-mitigation-activities

[19] https://www.farmers.gov/loans/inflation-reduction-investments

form of double dipping, that is paying twice for the same activity. This raises questions about the additionality of the GHG emissions that could occur.

In my professional opinion, California's ill-conceived policy is poised to trigger a new iteration of Cochrane's treadmill that will result in overproduction, further consolidation, and multiple negative environmental consequences[20]. As in the past, landowners will be the main beneficiaries of the policy. Biodigesters' adopters will benefit from temporary increased profits, overproduction will ensue, and the government will be called in to address the fallout. The climate benefits of this approach are dubious at best.

In summary:

a) CARB has not adequately included a full accounting of greenhouse gas emissions that properly considers the impact of biogas market prices and state-level regulatory settings on the US dairy industry. CARB is also ignoring the expansionary effects of the Inflation Reduction Act and the lack of additionality for methane reductions from digesters funded by the IRA. The information I have shown here regarding already occurring out of state effects illustrates that there does not exist at the moment a comprehensive inventory of biodigesters and it is therefore impossible for CARB to adequately consider national level impacts and back up any claims that the incentives included in the proposed LCFS amendments will not result in industry expansion and consolidation. I have in fact presented evidence that expansion is already occurring in Iowa, it is very strongly associated with the deployment of biodigesters, and an increased market signal to produce more credits will further exacerbate that expansionary effect;

b) The economic incentive to monetize manure-methane emissions as proposed by CARB will likely lead to further expansion in the dairy sector in Iowa. If such expansion were to extend to hog CAFOs, given that Iowa already produces one third of US hogs, the environmental impacts could be devastating considering Iowa alone. The national level effects would be worse;

c) The amendments do not just have the potential to result in direct and indirect environmental impacts in California and other states. Combined with federal policy and enhanced by race to the bottom state deregulation, they will substantially alter incentives and result in industry expansion.

[20] Levins, Richard A., and Willard W. Cochrane. 1996. "The Treadmill Revisited." *Land Economics* 72 (4):550-553. doi: 10.2307/3146915.

SILVIA SECCHI

EDUCATION

1996 - 2000 Iowa State University Ames, IA, USA
Ph.D. in Economics
Concentrations: Environmental and Resource Economics, International Economics

1994-1995 University of Reading Reading, England
Master's Degree in Agricultural Economics
Fields: Econometrics and Economic Development

1987-1993 Università Commerciale L. Bocconi Milan, Italy
Laurea in economics
Specialization in International Economics

1985 - 1987 United World College of the Adriatic Duino, Italy
International Baccalaureate

ACADEMIC EXPERIENCE

2021-current University of Iowa Iowa City, IA
Professor *Department of Geographical and Sustainability Sciences*
2017-2021 University of Iowa Iowa City, IA
Associate Professor *Department of Geographical and Sustainability Sciences*

2014-2017 Southern Illinois University Carbondale, IL
Associate Professor *Department of Geography and Environmental Resources*
2008-2014 Southern Illinois University Carbondale, IL
Assistant Professor *Department of Agribusiness Economics*

2004-2008 Iowa State University Ames, IA
Associate Scientist *Center for Agricultural and Rural Development*
2001-2004 Iowa State University Ames, IA
Assistant Scientist *Center for Agricultural and Rural Development*

1996 – 2000 Iowa State University Ames, IA
Research Assistant *Center for Agricultural and Rural Development*

1995 - 1996 University of Reading Reading, England
Research Associate *Centre for Agricultural Strategy*

ADMINISTRATIVE EXPERIENCE

2016-2017 Southern Illinois University Carbondale, IL
Director, Environmental Resources & Policy Ph.D. Program
2009-2015 Southern Illinois University Carbondale, IL
Co-Director, Environmental Resources & Policy Ph.D. Program
Responsibilities included annual budgeting and personnel evaluations, recruiting, and representing the core curriculum at written and oral exams.

Department of Geographical and Sustainability Sciences
University of Iowa
310 Jessup Hall
Iowa City, Iowa 52242
Phone:(319) 335-1927 • E-Mail: silvia-secchi@uiowa.edu
Goigle Scholar: https://scholar.google.com/citations?user=rXte6MIAAAAJ&hl=en&oi=ao

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GUEST EDITORSHIPS

Guest Co-Editor for *Economics Research International*'s special issue on the economics of biofuels, http://www.hindawi.com/journals/ecri/si/306959/ .

Guest Co-Editor for *Biomass and Bioenergy*'s special issue on land use change – Vol. 35(6).

PAPERS UNDER REVIEW

Secchi S. 2023. Wither WOTUS? Understanding the Cost Benefit Analysis of the Waters of the US rule. Revise and resubmit at *Applied Economics Teaching Resources.*

GRANTS

31. USDA NIFA. #DiverseCornBelt: Resilient Intensification through Diversity in Midwestern Agriculture. (L. Prokopy project PI, Secchi UIowa PI). 2021-2026. $10,000,000 (UIowa $ 467,776).

30. Healthier Workforce Center of the Midwest (NIOSH funding). Agricultural production practices and stress: a pilot study of women farmers in Iowa. (with C. Nichols). 2020-2021, $29,979.

29. NSF EAGER Germination - What we talk about when we talk about big ideas: Using case studies to train PhD students in ideation and questioning processes. Consultant (with A. Charles, N. Becker). 2018-2020, $117,729.

28. UIowa CGRER. A river runs through it: Surveying Iowa City residents' on water use, water quality and flood management (with K.E. Dalrymple). 2018-2020, $30,000.

27. Iowa State University - Land Use Impacts of RFS-Induced Agricultural Expansion 2018-2019, 71,540.

26. Walton Family Foundation - A Scorecard to measure States' Nutrient Reduction Strategies 2017-2019, $19,585.

25. INTERNAL - SIUC Undergraduate Research Assistantship. Creating an Atlas of Southern Illinois' Ecosystem Services. 2015-2016, $2,700.

24. USDA NIFA – Costs of continuous conservation tillage: estimation with incomplete data (with L.A. Kurkalova, T. Wade and R. Claassen), 2016-2018, $499,995.

23. Argonne National Lab (DoE funds) – Landscape by Design – Valuation of Ecosystem Services, 2015-2017, $49,736.

22. National Science Foundation - DYN COUPLED NATURAL-HUMAN. People, Water, and Climate: Adaptation and Resilience in Agricultural Watersheds (with D. Bennett, N. Basu, M. Muste, W. Gutowski) 2011-2017, $1,011,832.

21. Illinois DNR – Training, Certification, Pilot Incentive, Marketing, And Removal Research Project for the long-term strategy in reducing and controlling Asian Carp populations (with J. Garvey), 2011, $1,500,000.

20. National Science Foundation - DYN COUPLED NATURAL-HUMAN. Climate Change, Hydrology, and Landscapes of America's Heartland: A Multi-scale Natural-Human System (With C. Lant, S. Kraft, G. Misma, J. Nicklow, and J. Schoof) 2010-2014, $1,430,000.

19. USDA ERS Cooperative Agreement 58-6000-0-0056. Estimating the costs of continuous conservation tillage. 2010-2014. $30,887.

18. USDA CSREES AFRI Agribusiness Markets and Trade. An Analysis of the Impact of Biofuel Expansion through Linking of Agricultural and Energy Markets (With A. Elobeid and L.A. Kurkalova) 2010-2014, $360,396.

17. The Nature Conservancy. Floodplain Restoration Strategies Integrating Biomass plantings and Ecosystem Service Payments (With S. Kraft) 2009-2013, $112,536.

16. INTERNAL - SIUC Seed Grant. Economic And Environmental Assessment of the Use of Woody Biomass for Energy Production in Southern Illinois, 2009-2010, $14,985 + 1 month of Summer support.

15. INTERNAL - SIUC Undergraduate Research Assistantship. The Role of Federal and State Policy in Promoting Renewable Energy Production. 2009-2010, $5,400.

14. National Science Foundation Cyber-Enabled Discovery and Innovation Type II. Understanding Water-Human Dynamics with Intelligent Digital Watersheds. (with J. Schnoor, M. Muste, A. Kusiak and D. Bennett). 2009-2012, $899,391.

13. EPA, Region 7. Biofuel Feedstock Landscape Coverage for Five Biofuel Industry Scenarios (with R. Cruse, A. Elobeid and S. Tokgoz) 2008-2010, $150,000.

12. Iowa State University Agricultural Systems Initiative. Assessing alternative crop choices and environmental impacts of the bioeconomy: an integrated landscape approach (with M. Duffy and P.W. Gassman) 2007-2008, $15,000.

11. Agricultural Marketing Resource Center. Helping Farmers Make Decisions in the Bioeconomy: Mapping the Potential for Switchgrass in Iowa Relative to Corn and Soybeans. 2007-2008. (with B. Babcock and P.W. Gassman), $75,000.

10. Department of Energy-USDA. Expansion of ethanol production: evaluation of costs and benefits to rural communities in the Upper Mississippi River Basin. (with L. Kurkalova, C.L. Kling, P.W. Gassman, M. Jha, A. Carriquiry and D. Otto) 2006-2009, $676,722.

9. USDA Natural Resources Conservation Service. Environmental Credit Trading Handbook. 2006-2007 (with C.L. Kling), $84,150.

8. Prairie Rivers of Iowa R.C. & D and USDA Natural Resources Conservation Service. Rapid Watershed Assessment for the Boone River, the Upper Iowa and the South Skunk Watersheds (with T. Isenhart, C.L. Kling, P.W. Gassman and M. Tomer) 2006-2007, $72,500.

7. NASA and USDA Cooperative State Research, Education, and Extension Service. Interactive Drivers of Land Use/Land Cover Change in Agricultural Areas: Climate and Land Manager Choices. (with C.L. Kling, H. Feng, P.W. Gassman, and E. Tackle) 2006-2008, $465,900.

6. Iowa Farm Bureau, Leopold Center for Sustainable Development, Iowa Soybean Association, Iowa Corn Growers Association. Assessment of Conservation Practices on Agricultural Cropland in Iowa (with C.L. Kling, H. Feng, P. Gassman, and M. Jha) 2006, $72,500.

5. USDA CSREES Integrated Projects. Water Resource Degradation in the Boone Watershed: Integrating Stakeholder Knowledge and Preferences with Economic and Watershed Models (with C.L. Kling, M. Duffy, L. Kurkalova, H. Feng, P.W. Gassman, and J. Cooper) 2005-2008, $590,000.

4. Prairie Rivers of Iowa R.C. & D and Leopold Center for Sustainable Development. Boone River Watershed and Gordon's Marsh Project (with C.L. Kling, and P.W. Gassman) 2005-2006, $35,000.

3. Iowa State Water Resources Research Institute. Improving Water Quality in Iowa Rivers: Cost-Benefit Analysis of Adopting New Conservation Practices and Changing Agricultural Land Use (with C.L. Kling, H. Feng, P.W. Gassman, and L. Kurkalova) 2005-2006, $39,600.

2. National Science Foundation. Biocomplexity of Integrated Perennial-Annual Agroecosystems (Senior Personnel. Principal Investigators: H. Asbjornsen, R. M Cruse, C.L. Kling, M. Z Liebman, J. D Opsomer) 2005-2007, $ 99,998.

1. Iowa Department of Natural Resources. Costs of Adopting Conservation Practices on Agricultural Cropland in Iowa and Possible Nutrient Standards (with C.L. Kling, H. Feng, P. Gassman, and L. Kurkalova) 2004, $53,360.

TEACHING EXPERIENCE

Introduction to Sustainability (GEOG 2013). Class for the University's Gen Ed sustainability requirement Average class size 65.

Environmental Economics and Policy (GEOG 3800/5800). Double listed class for undergraduate and graduate students. Average class size: 30.

Environmental Impact Analysis (GEOG 4750). Average class size: 11.

Contemporary Environmental Issues (GEOG 1070). Class for the University's Gen Ed sustainability requirement. Average class size: 370.

Environmental and Energy Economics (GENV 422). Double listed class for undergraduate and graduate students. Average class size: 20.

Geography, People and the Environment (GENV 300i). Class for the University's core curriculum social sciences and interdisciplinary requirement. Average class size: 70.

Environmental Decision Making (Environmental Resources & Policy 502). Core class for the interdisciplinary ER&P Ph.D program. Average class size: 12.

Interdisciplinary Approaches to Environmental Issues (ABE 470). Team taught class, capstone for the Minor in Environmental Studies.

GRADUATE STUDENT ADVISEMENT

MASTERS STUDENT ADVISER
Amy Kopale – Masters in Geography, UIowa, 2019
Aleesandria Gonzalez- Masters in Geography, SIUC, 2017
Daniel Fucik - Masters in Geography, SIUC, 2016
Andisiwe Stuurman - Masters in Geography, SIUC (Fulbright scholar), 2015
Mohamud Esmail – Masters in Agribusiness Economics, SIUC, 2011
Alison Britt – Masters in Agribusiness Economics, SIUC, 2011
Kent Rupp – Masters in Agribusiness Economics, SIUC, 2011

PH.D. STUDENT ADVISER
Austin Holland – Ph.D. in Geography, UIowa, 2022
Shanna McClain (with C. Bruch) – Ph.D. in Environmental Resources & Policy, SIUC (IGERT fellow), 2016
Mukesh Bhattarai – Ph.D. in Environmental Resources & Policy, SIUC, 2016
Awoke Teshager (with J. Schoof) – Ph.D. in Environmental Resources & Policy, SIUC, 2016
Tom Shaw – Ph.D. in Environmental Resources & Policy, SIUC, 2015
Sarah Varble – Ph.D. in Environmental Resources & Policy, SIUC, 2014

MASTERS STUDENT COMMITTEE MEMBER
Tracy Fidler – Masters in Natural Resources and Environmental Sciences, UIUC, 2017
Jodie Hancock – Masters in Forestry, SIUC, 2017
Ann Rushing – Masters in Geography, SIUC, 2015
Brent Ritzler – Masters in Public Administration, SIUC, 2015
Lance Odum – Masters in Public Administration, SIUC, 2012
Andrew Johnson – Masters in Geography, SIUC, 2012

PH.D. STUDENT COMMITTEE MEMBER
Asif Rahman – Ph.D. in Geography, UIowa, current
Enes Yildirim – Ph.D. in Water Resources, UIowa, current
Oronde Drakes – Ph.D. in Geography, UIowa, current
Rebecca Kauten – Ph.D. in Geography, UIowa, 2019
Clara Mundia – Ph.D. in Environmental Resources & Policy, SIUC, 2017
Amanda Marshall – Ph.D. in Environmental Resources & Policy, SIUC, 2017
Dat Tran- Ph.D. in Energy & Environmental Systems, NCA&T University, 2016
Ross Guida – Ph.D. in Environmental Resources & Policy, SIUC, 2016
Obed Quaicoe- Ph.D. in Energy & Environmental Systems, NCA&T University, 2016
Artur Rombenso – Ph.D. in Zoology, SIUC, 2016
Wahid Rahman – Ph.D. in Environmental Resources & Policy, SIUC, 2014
Tim Stoebner – Ph.D. in Environmental Resources & Policy, SIUC, 2014
Steve Randall - Ph.D. in Energy & Environmental Systems, NCA&T University, 2012
Caroline Gottschalk Druschke – Ph.D in Rethoric, University of Illinois at Chicago, 2011

PROCEEDINGS

Jones, C., & S. Secchi. 2019. Reconciling Climate Change with Nitrate Impairment of Drinking Water: Policies for Iowa's Largest City. SUS-RURI: Developing a Convergence SUS Agenda for Redesigning the Urban-Rural Interface along the Mississippi River Watershed, Iowa State University and NSF, August 12-13, Ames, Iowa.

Kurkalova L. A., S. Secchi & P. W. Gassman. 2009. Greenhouse Gas Mitigation Potential of Corn Ethanol: Accounting for Corn Acreage Expansion. Proceedings of the 2007 National Conference on Environmental Science and Technology. G.Uzochukwu,; Schimmel, K.; Chang, S.-Y.; Kabadi, V.; Luster-Teasley, S.; Reddy, G.; Nzewi, E. (Eds.). Springer. p. 251-257.

Secchi S., P. W. Gassman, M. Jha, L. Kurkalova, & C. L. Kling. 2008. Water Quality Effects of Corn Ethanol versus Switchgrass-Based Biofuels in the Midwest. Proceedings of the Farm Foundation Conference: "Transition to a Bioeconomy: Environmental and Rural Development Impacts", October 15-16, 2008, Hyatt Regency At Union Station, St. Louis, MO. URL: http://www.farmfoundation.org/news/articlefiles/401-Final_version_Farm_Foundation%20feb%2020%2009.pdf

Secchi S. 2008. The Environmental Sustainability of Ethanol and Biofuels. Proceedings of the Iowa State University Extension and Town/Craft Roundtable: "Biofuels and the Rural Economy Roundtable", May 14, 2008, Perry, IA.

Gassman, P.W., S. Secchi, & M. Jha. 2008. Assessment of bioenergy-related scenarios for the Boone River watershed in north central Iowa. In: Proceedings of the 21st Century Watershed Technology: Improving Water Quality and Environment Conference, March 29-April 3, American Society of Agricultural and Biological Engineers, Concepción, Chile.

Gassman, P.W., S. Secchi, & M. Jha. 2007. An alternative approach for analyzing wetlands in SWAT for the Boone River watershed in north central Iowa. In: *4th International SWAT Conference Book of Abstracts*, July 3-7, UNESCO-IHE, Institute for Water Education, Delft, Netherlands.

Gassman, P.W., S. Secchi, & M. Jha. 2006. Application of SWAT for the Boone River watershed in north central Iowa. Presented at the American Society of Agricultural and Biological Engineers Annual Meeting, July 9-12, Portland, OR. ASABE Paper 062234, St. Joseph, MI.

Secchi S., H. H. Feng, L. A. Kurkalova, C. L. Kling, P. W. Gassman, & M. Jha. 2005. Nonpoint source needs assessment for Iowa part II: the cost of improving Iowa's water quality. Watershed Management to Meet Water Quality Standards and Emerging TMDL (Total Maximum Daily Load), Proceedings of the 3rd Conference 5-9 March 2005 Atlanta, Georgia. ASAE, St. Joseph, Michigan, pp.522-532.

Gassman, P.W., S. Secchi, M. Jha, L.A. Kurkalova, H.Feng, & C.L. Kling. 2005. Nonpoint source needs assessment for Iowa part III: economic and environmental outcomes. Watershed Management to Meet Water Quality Standards and Emerging TMDL (Total Maximum Daily Load), Proceedings of the 3rd Conference 5-9 March 2005 Atlanta, Georgia. ASAE, St. Joseph, Michigan, pp.533-542.

Gassman, P.W., S. Secchi, C.L. Kling, M. Jha, L.A. Kurkalova, & H.Feng. 2005. An analysis of the 2004 Iowa Diffuse Pollution Needs assessment using SWAT. *Proceedings of the SWAT 2005 3rd International Conference*, pp. 291-30111-15 July, Zurich, Switzerland.

Jha, M., P.W. Gassman, S. Secchi, J.G. Arnold, L.A. Kurkalova, H. Feng, & C.L. Kling. 2005. An assessment of alternative conservation practice and land use strategies on the hydrology and water quality of the Upper Mississippi River Basin. In: *Proceedings of the SWAT 2005 3rd International Conference,* pp. 444-453, July 11-15, Zurich, Switzerland.

Takle, E. S., M. Jha, P. W. Gassman, C. J. Anderson, & S. Secchi. 2005. Climate change impacts on the hydrology and water quality of the Upper Mississippi River Basin. In: *Proceedings of the SWAT 2005 3rd International Conference,* pp. 599-608. July 11-15, Zurich, Switzerland.

Feng H., C. L. Kling, L. A. Kurkalova, S. Secchi, & P. W. Gassman. 2005. The Conservation Reserve Program in the Presence of a Working Land Alternative: Implications for Environmental Quality, Program Participation, and Income Transfer. *American Journal of Agricultural Economics* 87 (5).

Jha M., P. W. Gassman, S. Secchi, & J. Arnold. 2003. Configuration of SWAT for the Upper Mississippi River Basin: an application to two subwatersheds. Proceedings of the Total Maximum Daily Load (TMDL) Environmental Regulations II, 8-12 November 2003, Albuquerque, New Mexico.

Secchi S. & B. A. Babcock. 2002. Pearls before Swine? Potential Trade-Offs Between the Human and Animal Use of Antibiotics. *American Journal of Agricultural Economics* 84 (5).

WORKING PAPERS

Dodder R.S., A. Elobeid, T. L. Johnson, P. O. Kaplan, L. A. Kurkalova, S. Secchi, & S. Tokgoz. 2011. Environmental Impacts of Emerging Biomass Feedstock Markets: Energy, Agriculture, and the Farmer. CARD Working Paper [11-WP 526].

Secchi S. 2007. Watching corn grow: a hedonic study of the Iowa landscape. Working paper 07-WP 445, Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, H.H. Feng, T. Campbell, & C.L. Kling. 2005. The Cost of Clean Water: Assessing Agricultural Pollution Reduction at the Watershed Scale. Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S., M. Jha, L.A. Kurkalova, H.H. Feng, P.W. Gassman, & C.L. Kling. 2005. The Designation of Co-benefits and Its Implication for Policy: Water Quality versus Carbon Sequestration in Agricultural Soils. Working paper 05-WP 389, Center for Agricultural and Rural Development, Ames, Iowa.

Kurkalova L.A., C. Burkart, & S. Secchi. 2004. Cropland Cash Rental Rates in the Upper Mississippi River Basin. Technical report 04-TR 47, Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S. 2002. Patient Behavior and Antibiotic Prescriptions: the Equilibrium Level of Antibiotic Use and the Role of a Market Permit System. Center for Agricultural and Rural Development, Ames, Iowa.

Babcock B.A., J. Beghin, M. Duffy, H.H. Feng, B. Hueth, C.L. Kling, L.A. Kurkalova, U. Schneider, S. Secchi, Q. Weninger, & J. Zhao. 2001. Conservation Payments: Challenges in Design and Implementation. Working paper 01-BP 34, Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S. & B.A. Babcock. 2001. Optimal Antibiotic Usage with Resistance and Endogenous Technological Change. Working paper 01-WP 269, Center for Agricultural and Rural Development, Ames, Iowa.

Hurley T.M., S. Secchi, B.A. Babcock, & R. L. Hellmich. 1999. Managing the Risk of European Corn Borer Resistance to Transgenic Corn: An Assessment of Refuge Recommendations. Staff Report 99-Sr 88, Center for Agricultural And Rural Development, Ames, Iowa.

OTHER PUBLICATIONS

Vasto A., & Secchi S., 2021, Rural Water Systems in Iowa: Analysis of Opportunities and Challenges. Iowa Environmental Council. URL: https://www.iaenvironment.org/newsroom/water-and-land-news/council-releases-rural-water-system-report

Secchi S., & D. Cwiertny. 2019. Iowa's Grants to Counties Program: A Valuable but Underutilized Program for Protecting the Public Health of Private Well Users. University of Iowa Center for Health Effects of Environmental Contamination Policy Report 2019-01. URL: https://cheec.uiowa.edu/sites/cheec.uiowa.edu/files/CHEEC-2019-01_Grants_To_Counties_3_.pdf

Healy M.*, & S. Secchi. 2016. A Comparative Analysis of Ecosystem Service Valuation Decision Support Tools for Wetland Restoration. A Report Prepared for the Association of State Wetland Managers. URL: http://www.aswm.org/pdf_lib/ecosystem_service_valuation_032116.pdf

Secchi S. 2015. Background paper on Economic Valuation of Ecosystem Services from Working Lands Conservation, prepared for USDA's ERA and NRCS Economic Valuation of Conservation Based Ecosystem Services Workshop.

Braden J. & S. Secchi, 2014, C-FARE and AAEA Webinar "Policy Innovations in Nonpoint Source Pollution-policy". Friday, March 21, 2014.

Cooke S. L., A. C. Lloyd*, A. D. Monteblanco, & Silvia Secchi, 2013. Ecosystems, Economics, and Equity in the Floodplain. A case study developed for the National Socio-Environmental Synthesis Center Project Teaching Socio-Environmental Synthesis with Case Studies. URL: http://www.sesync.org/ecosystems-economics-and-equity-in-the-floodplain-case-study-5

Secchi S., 2009. Overview Presentation. NRCS and C-FARE Webinar "Environmental Markets: New Approaches for Natural Resources Management Webinar", February 23rd, 2009

Feng H., L. A. Kurkalova & S. Secchi. 2001. Multifunctionality: Market failure and options to internalise externalities: Applying the OECD framework - A review of literature in the USA, Consultant background paper for the OECD workshop "Multifunctionality: Applying the OECD Analytical Framework, Guiding Policy Design", July 2001.

INVITED CONFERENCE AND SEMINAR PRESENTATIONS

Invited plenary presentation, "Slaughtering Sacred Cows: Tech Fixes Won't Correct the Extractive Nature of US Agriculture", Sustainable Phosphorus Summit, November 1-2, 2022, Raleigh NC.

Invited presentation, Economic & Land Use Policies to Limit Nutrient Pollution: Perspectives from the Great Lakes and Beyond, Alliance for the Great Lakes, April 4, 2022, virtual event.

Seminar presentation, "A lonely stick amongst many carrots: The Conservation Compliance Program in the 21st Century", Paul H. O'Neill School, Indiana University, February 25, 2021, virtual event.

Seminar presentation, "The US census of agriculture as lens and mirror of long term changes in the rural Midwest", Faculty of Land and Food Systems, University of British Columbia, September 16 2020, virtual event.

Invited presentation "The role of policy in promoting sustainable floodplain management" at Emiquon Science 2015: River Floodplain Restoration and Connection, February 19th, 2015, Lewistown, IL

Invited Presentation "Understanding the links between humans, climate change, water and carbon in a Corn Belt Watershed", at the AGU Fall meeting, December 15-19th, 2014, San Francisco, CA.

Invited presentation "Promoting Bioenergy Crops: An economic perspective on challenges and opportunities" at the workshop Incorporating Bioenergy in Sustainable Landscape Designs Workshop Two: Agricultural Landscapes June 24–26th, 2014, Argonne National Laboratory, IL.

Invited presentation "Increased Biofuel Production and Water Resources" at the National Academies Roundtable on Science and Technology for Sustainability, May 20-21, 2014, Washington DC. URL:
http://sites.nationalacademies.org/cs/groups/pgasite/documents/webpage/pga_088191.pdf

Invited speaker at the Indiana University-Purdue University first "Rivers of the Anthropocene" conference, January 23-24th, 2014, Indianapolis, IN.

Invited speaker at the MISI-ZIIBI: Living with the Great Rivers, Climate Adaptation Strategies in the Midwest River Basins, co-sponsored by Washington University in St. Louis and the Royal Netherlands Embassy, March 23rd, 2013, St. Louis, MO.

Plenary speaker at the 2013 Missouri River Natural Resources Conference and BiOp Forum "Beyond the Banks" March 12th, 2013, Jefferson City, MO.

Luncheon speaker at the Soil and Water Conservation Society Modeling Summit 2011 - Advancing the Science of Modeling, March 30th, 2011, Denver, CO.

Invited lecture to the "Food, Energy, and Quality of Life in Iowa" graduate class at Iowa State University, on the difference between ecological and environmental economics approaches to agricultural policy, September 21st, 2009.

North Carolina A&T State University, Energy and Environmental Systems Seminar, April 12th, 2010.

Iowa State University Biobased Industry Center Energy Camp, May 21st 2010.

University of Minnesota, Applied Economics Department, Environmental and Resource Economics Seminar, April 26th 2010.

University of Illinois at Urbana-Champaign, Department of Agricultural and Consumer Economics Seminar, September 10th 2010.

University of Iowa, Department of Geography, Kohn Colloquium, October 29th 2010.

CONFERENCE PAPERS AND POSTERS

Secchi S. 2022. Water Quality and Adaptation to Climate Change. Iowa Organic Conference, November 20-21, Iowa City, IA.

Secchi S. 2022. Slaughtering Sacred Cows: Tech Fixes Won't Correct the Extractive Nature of US Agriculture. Phosphorus Week, November 1-4, Raleigh, NC.

Secchi S. 2020. Understanding the Cost Benefit Analysis of the Waters of the US rule. Presidential Session on Pedagogical Tools: Fundamental Concepts and Methods. Annual Meeting of the Southern Economic Association, November 21-23 (virtual).

Secchi S. 2020. Regulatory Environmental Cost-Benefit Analysis: A Case Study of the Waters of the United States Rule. Innovations in Teaching Environmental and Resource Economics ENV/TLC Track session of the Annual Meeting of the Agricultural & Applied Economics Association, August 5 (virtual).

Secchi S. 2019. The State of Water Quality Strategies in the Mississippi River Basin: Is Cooperative Federalism Working? American Water Resources Association, Annual Water Resources Conference, November 3-6, Salt Lake City, UT.

Secchi S. 2015. The push and pull of conservation, energy and climate mitigation policies on agricultural landscapes: the case of conservation tillage. Conference on Complex Systems, September 26-30, Tempe, AZ.

Secchi S. 2015. The potential of conservation tillage payments as a climate mitigation strategy. AAG Annual Meeting, April 21-25, Chicago, IL.

Eichholz M. W., R. T. Alisauskas, J. O. Leafloor, S. Varble, & S. Secchi. 2013. Feasibility of Commercial Wildlife Exploitation as a Management Tool: Snow Geese as a Case Study of Overabundance. 20th Annual Conference of The Wildlife Society, October 5-10, Milwaukee, WI.

Secchi S. & S. Varble. 2013. We Can Beat Them If We Eat Them: Assessing the Marketing Potential of the Asian Carp in the US. Symposium on the Culture, Biology, and Management of Asian Carps in North America, 143rd Annual Meeting of the American Fisheries Society, September 8-12, Little Rock, AR.

Wade T., L.A. Kurkalova, & S. Secchi. 2013. Estimation of Discrete Choice Models with Aggregate Data: An Application to the Adoption of Conservation Tillage. Presented at the USDA ERS and Farm Foundation workshop "Agricultural Markets for Ecosystem Services: Greenhouse Gases, Conservation Practice Adoption & Behavioral Responses", August 8th, Washington D.C.

Secchi S. & L.A. Kurkalova. 2013. Estimating the Cost of Supplying Greenhouse Gas Offsets with Continuous Conservation Tillage. Presented at the USDA ERS and Farm Foundation workshop "Agricultural Markets for Ecosystem Services: Greenhouse Gases, Conservation Practice Adoption & Behavioral Responses", August 8th, Washington D.C.

Varble S., & S. Secchi. The Role of Watershed Management Groups and Key Stakeholders in the Resilience and Sustainability on a Rural Iowa Watershed. SWCS Annual meeting, Reno, NV 21-24 July 2013.

Varble S., D. Varble & S. Secchi. Potential for Perennial Crops for Bioenergy Production: Results of a Survey from an Iowa Watershed. SWCS Annual meeting, Reno, NV 21-24 July 2013.

Smith S., S. Varble & S. Secchi. 2013. Fish Consumers: Purchasing Habits and Environmental concerns. Selected Poster for the 2013 Annual ICHRIE Summer Conference, July 24-27, St. Louis, MO.

Wade T., L.A. Kurkalova, & S. Secchi. 2012. Using the Logit Model with Aggregated Choice Data in Estimation of Iowa Corn Farmers' Conservation Tillage Subsidies. AAEA Annual Meeting, August 12-14, Seattle, WA.

Kurkalova L.A., S. M. Randall, & S. Secchi. 2012. The Impact of Energy Price Changes on Cropping Patterns in Iowa. 31st USAEE/IAEE North American Conference, November 4-7, Austin, TX.

Kurkalova L.A., S. M. Randall, & S. Secchi. 2012. The Impact of Energy Price Changes on Cropping Patterns in Iowa. AERE Session at the Southern Economics Association Annual Meeting Nov 16-18, New Orleans, LA.

Secchi S. 2012. Integrating Biofuel Production and Mitigation Strategies Into Agricultural Landscapes. Bioenergy and Biodiversity: Oxymoron or Opportunity? Symposium at the Ecological Society of America Annual Meeting, 5-10 August, Portland, OR.

Kurkalova L.A., R. Dodder, A. Elobeid, T. Johnson, O. Kaplan, S. Secchi, & S. Tokgoz. 2011. Land-Use Impacts of Emerging Biomass Feedstock Markets: Accounting for Agricultural and Energy Market Interactions and the Variability of Local Conditions. Association of Environmental and Resource Economists' Inaugural Summer Conference, 9 - 10 June, Seattle, WA.

Secchi S., S. Esling, C. Lant, & J. A. Koropchak. 2011. The Environmental Resources and Policy Ph.D. Program at Southern Illinois University Carbondale: a Success Story. Facilitating Interdisciplinary Research and Education Symposium, March 28-29, Boulder, CO.

Secchi S., J. Fargione, J. Remo, B. Moseley, T. Strole & S. Kraft. 2010. Stacking Ecosystem Services in Reconnected Floodplains: Linking Socioeconomic and Biophysical Analysis to Improve Floodplain Management. Selected paper at the Soil and Water Conservation Society Annual Meeting, July 18-21, St. Louis, MO.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2010. Potential Water Quality Changes Due to Corn Expansion in The Upper Mississippi River Basin. Selected paper at the 4th World Congress of Environmental and Resource Economists, June 28-July 2, 2010, Montréal, Canada.

Kurkalova, L.A., S. Randall, & S. Secchi. 2010. Land-Use Implications of the Changes in Energy Prices. Selected Poster at the Agricultural and Applied Economics Association 2010 Annual Meeting, July 25-27, 2010, Denver, CO.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2009. The Water Quality Effects of Corn Expansion in the Midwest. Selected poster at the USDA, USGS, EPA and SWCS "Science to Solutions (Gulf Hypoxia)" workshop on December 9-11, 2009 Des Moines, IA.

Secchi S. 2009. Balancing Conservation Policy: Targeting Ecosystem Service Provision with Feedstock Production for the Bioeconomy in the Midwestern U.S. Invited presentation at the organized Symposium: "Integrating science and policy for watershed sustainability: Balancing hydrological services, quality of life, and economic vitality" (OOS #4185) at the Ecological Society of American Annual Meeting August 2-7 2009, Albuquerque, NM.

Secchi S., L.A. Kurkalova P.W. Gassman, & B. Babcock. 2009. Land Use and Environmental Impacts of Corn Grain vs. Cellulosic Ethanol: Policy Implication. Selected paper at the 2009 SWCS Annual Conference July 11-15, Dearborn, MI.

Secchi S. (Invited speaker). 2009. Ethanol Production and the Mississippi River, an Economic Perspective. 2009 Mississippi River Conference: "Visions of a Sustainable Mississippi River: Merging Ecological, Economic, and Cultural Values", organized by the National Great Rivers Research and Education Center and The Nature Conservancy, August 10 – 13, 2009, Collinsville, IL.

Kurkalova, L.A., S. Secchi, & P.W. Gassman. 2009. Harvesting Corn Stover and Crop Residue Management: The Impact of Conflicting Economic Incentives, Selected Poster at the Annual AERE Workshop - 2009 Theme: Energy and the Environment, Washington, DC June 18-20, 2009.

Kurkalova, L.A., S. Secchi, & P.W. Gassman. 2009. Effectiveness of Environmental Policies and Bioenergy Production Incentives. Selected paper at the SWCS Annual Conference July 11-15, 2009, Dearborn, MI.

Kurkalova, L.A., S. Secchi, & P.W. Gassman. 2009. Effectiveness of Environmental Policies and Bioenergy Production Incentives. Selected Poster at the AAEA & ACCI Joint Annual Meeting in Milwaukee, WI, July 26–28, 2009.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2008. Rotation and Water Quality Effects of Harvesting Corn Stover, Selected AERE paper at the AAEA & ACCI Joint Annual Meeting, July 27-29 2008, Orlando, FL (session 3059).

Secchi S., P.W. Gassman, & B.A. Babcock. 2008. Land Use and Environmental Impacts of Corn Grain versus Cellulosic Ethanol: a GIS Approach, Selected paper at the 28th USAEE/IAEE North American Conference, "Unveiling the Future of Energy Frontiers.", December 3-5 2008, New Orleans, LA, USA.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2008. Quality Effects of Corn Ethanol versus Switchgrass-Based Biofuels in the Midwest, Selected paper at the Farm Foundation Conference: Transition to a Bioeconomy: Environmental and Rural Development Impacts, October 15-16 2008, St. Louis, MO.

Secchi S., L.A. Kurkalova, J.C. Tyndall, P.W. Gassman, & C.L. Kling. 2008. The Next Step for the Bioeconomy: Mapping the Impact of Corn Stover Use on Crop Choice, Land Use, and Environmental Quality". Selected poster at the AAEA & ACCI Joint Annual Meeting, July 27-29 2008, Orlando, FL (session M56).

Secchi S. 2008. The Environmental Sustainability of Ethanol and Biofuels, Overview presentation at the Iowa State University Extension and Town/Craft Roundtable: "Biofuels and the Rural Economy Roundtable", May 14, 2008, Perry, IA.

Secchi S., L.A. Kurkalova, C.L. Kling, J. Cooper, P.W. Gassman, & M. Jha. 2006. Water Resource Degradation in the Boone Watershed: Integrating Economic and Watershed Models. Soil and Water Conservation Society workshop "Managing Agricultural Landscapes for Environmental Quality: Strengthening the Science Base", Kansas City, MO, October 2006.

Secchi S. 2005. Watching Corn Grow: a Hedonic Study of the Iowa Landscape, Eastern Economic Association Annual Conference, New York City, NY, March 2005.

Secchi S. 2001. Models to Support TMDL Development Across the Midwest (Symposium), American Agricultural Economics Association Annual Meeting, Chicago, IL, August 2001.

Secchi S., & B.A. Babcock. 2001. Optimal Pesticide Usage with Resistance and Endogenous Technological Change, American Agricultural Economics Association Annual Meeting, Chicago, IL, August 2001.

Secchi S., T. M. Hurley, & R. L. Hellmich. 2001. Managing European Corn Borer Resistance to Bt Corn with Dynamic Refuges, 5th ICABR International Conference, Ravello, Italy, June 2001.

Secchi S., & B.A. Babcock. 1999. A Model of Pesticide Resistance as a Common Property and Exhaustible Resource, American Agricultural Economics Association Annual Meeting, Nashville, TN, August 1999.

Secchi S., & B.A. Babcock. 1999. Managing Pest Resistance: The Potential Of Crop Rotations And Shredding, American Agricultural Economics Association Annual Meeting, Nashville, TN, August 1999.

PROFESSIONAL ACTIVITIES

Editorial Board of Conservation, Review Editor, Frontiers, 2019-present

Editorial Board, Applied Economic Perspectives and Policy, 2015-present

Oklahoma EPSCoR External Advisory Board Member 2017-2018

Participant at invitation-only Purdue University University of Illinois workshop "Scientific Challenges to Operationalizing Payments for Agro-Ecosystem Services (PAgES)" (organized by Ben Gramig and Sylvie Brouder). Indianapolis, IN, November 2017

Consultant, Walton Family Foundation – Developing a Score Card for Iowa and Illinois' Nutrient Reduction Strategies. 2016-2017

Program Committee Member for the 6th World Congress of Environmental and Resource Economists, 2018

National Science Foundation, panelist, 2010, 2011, 2014, 2016, 2017, 2018, 2019 and 2023. Ad hoc reviewer, 2012, 2013, 2014, 2016, 2017

USDA – NIFA panelist, 2017 and 2018. Ad hoc reviewer 2014 and 2016

Reviewer for Selected Paper Sessions of the American Agricultural Economics Association meetings, 2002, 2003, 2008 and 2016

Author of working paper II for the USDA and C-FARE workshop, 'Economic Valuation of Conservation Based Ecosystem Services', July 21, 2015, Washington, DC

Participant, inaugural SESYNC short course, Teaching Socio-Environmental Synthesis with Case Studies, July 23-26, 2013, Annapolis, MD

Planning Committee Member, AWRA 2013 Spring Specialty Conference: "Agricultural Hydrology and Water Quality II", March 25-27, St. Louis, MO

Participant, NSF workshop on Developing and Sustaining Interdisciplinary Graduate Programs, 7-8 October 2012, Coeur d'Alene, ID

EPA Star Fellowship Panelist, 2012

Program Committee Member for the 18th and 19th Annual Meetings of the European Association of Environmental and Resource Economists, 2011 and 2012

Member of the Middle Mississippi Wetland Field Station Advisory Committee Southern Illinois University, 2009- 2017

Rapporteur at the JRC/EEA/OECD Expert Consultation: "Review and inter-comparison of modeling land use change effects of bioenergy", Paris, France, 29-30 January 2009

Reviewer for the National Institutes for Water Resource - U.S. Geological Survey Competitive Grants Program, 2009 and 2011

Reviewer for the Collaborative, Highly Interdisciplinary Research Program at the Swiss Federal Institute of Technology, Zurich Research Commission, 2009

Reviewer for Selected Paper Sessions of the 3rd World Congress of Environmental and Resource Economists, 2006

Reviewer for USDA-CSREES Conservation Effects Assessment Project, 2005 and 2006

Reviewer of the Union of Concerned Scientists' report "CAFOs Uncovered: The Untold Costs of Confined Animal Feeding Operations" URL: http://www.ucsusa.org/food_and_environment/sustainable_food/cafos-uncovered.html.

Reviewer for: Agriculture, Agricultural and Resource Economics Review, Agriculture and Human Values, Agronomy Journal, Appetite, American Journal of Agricultural Economics, Applied Economic Perspectives and Policy, Applied Geography, Biofuels, Biological Invasions, Biomass & Bioenergy, BioScience, Choices, Ecology, Ecological Applications, Ecological Economics, Ecosystem Services, Energy Policy, Environmental and Development Economics, Environmental and Resource Economics, Environmental Management, Environmental Research

Letters, Environmental Science & Technology, Frontiers of Ecology and the Environment, GCB Bioenergy, Intelligent Systems in Accounting, Finance and Management, International Journal of Digital Earth, Journal of Agricultural and Applied Economics, Journal of Agricultural and Resource Economics, Journal of Applied Geography, Journal of Environmental Economics and Management, Journal of Great Lakes Research, Journal of Soil and Water Conservation, Land Use Policy, Landscape and Urban Planning, Journal of Natural Resources Policy Research, Journal of Soil and Water Conservation, Nature Climate Change, PLoS ONE, SAGE Open (Article Editor), Science of the Total Environment, Society & Natural Resources, Sustainability, Proceedings of the National Academies of Science, Transactions of ASABE

UNIVERSITY SERVICE

2019 – current, Governmental Relations Committee

2019 – current, Office of Sustainability Advisory Board

2019 – current, Center for Global & Regional Environmental Research Executive Committee

2018 – current, Center for Health Effects of Environmental Contamination Executive Committee

2020 – 2021, Sustainability Investment & Purchasing Practices Subcommittee

2019 – 2022, Underrepresented Students in Sustainability Mentoring Program Mentor

2018 – 2022, Faculty Assembly

ACADEMIC HONORS AND AWARDS

Southern Illinois University Early Career Faculty Excellence Award, 2012 [inaugural winner].

Yellow Ribbon Poster Presentation, with L.A. Kurkalova, and P. W. Gassman, Agricultural and Applied Economics Association, 2009.

2009 Editor's Choice Award, Journal of Soil and Water Conservation: Secchi, S., J. Tyndall, L.A. Schulte, and H. Asbjornsen. 2008. High crop prices and conservation: Raising the stakes. *Journal of Soil and Water Conservation* 63(3):68A-73A.

Iowa State University College of Agriculture and Life Science Team Award, to the Resource and Environmental Policy Division. 2008.

Second Place Poster Presentation, with M. Jha, L.A. Kurkalova, C.L. Kling, H. Feng, P.W. Gassman, and T. Campbell, American Agricultural Economics Association, 2005 and 2006.

Second Place Poster Presentation, with C.L. Kling, H. Feng, L.A. Kurkalova, P.W. Gassman, M. Jha, T. Campbell, A. Bhaskar, C. Burkart, S. Sengupta and R. Olson, American Agricultural Economics Association, 2004.

First Place Poster Presentation, with C.L. Kling, L.A. Kurkalova, and P.W. Gassman, American Agricultural Economics Association, 2003.

Outstanding Ph.D. Dissertation (Honorable Mention), American Agricultural Economics Association, 2001.

Professional Advancement Travel Grant, Iowa State University, 1999.

Premium for Academic Excellence Award, Iowa State University, 1996.

OUTREACH PRESENTATIONS AND PODCASTS

2021-2023 – We All Want Clean Water – Podcast co-host and producer (31 episodes)

2023 - The Power of Big Pork – Foodprint podcast

2022 - Iowa's Industrial Agriculture – The Checkout podcast

2022 - "Cows, Climate and Culture Wars: Putting Bad Policy Out to Pasture" virtual panel, Center for Biological Diversity.

2022 - "Human Rights and Climate Change: Iowa's Challenges & Opportunities" virtual panel, UI Center for Human Rights and the Environmental Law Initiative.

2022 – "Celebrating 50 years of the Clean Water Act", panel, Sierra Club, Waterloo, IA.

2020 – Webinars on Agriculture and Climate Change for the Iowa Farmers Union and Environment Iowa

2019 – Science Café, The current state of the Paris agreement, Fairfield and Mount Vernon, IA

2018 – Wonk Wednesday, America out of Paris: the current state of global climate change policy, University of Iowa, Iowa City, Iowa, United States

2018 – Rapid Response History, Liquid Gold or Fool's Gold? Biofuels in the US, University of Iowa, Iowa City, Iowa, United States

2011 – Carbondale Science Café' – Presentation on Biofuels, March 24

2009 – Speaker, "No Silver Bullets: Unintended Consequences Of Oil And Water Solutions", May 18, Indo-American Center, Chicago, IL

2008-2013 – The View: Expert opinions on a special series on energy for The Southern Illinoisan newspaper. 22 short perspectives 2022

SELECTED MEDIA

- Farmers Could Be the Nation's Leading Environmentalists *Mother Jones* 2024
- The myths we tell ourselves about American farming *Vox* 2023
- The Biden Administration Bets Big on 'Climate Smart' Agriculture *FERN/Yale360* 2023
- Opinion/Solutions: Ancient grain may help with climate change *The Atlanta Journal Constitution*
- Don't be fooled by exaggerated 'benefits' of carbon pipelines *Des Moines Register Opinion* 2022
- As Congress funds high-tech climate solutions, it also bets on a low-tech one: Nature *The Washington Post* 2022
- Expansion of a Lucrative Dairy Digester Market is Sowing Environmental Worries in the U.S. *Inside Climate News.* 2022
- Climate change is making it harder to provide clean drinking water in farm country *NPR*
- How Corn Ethanol for Biofuel Fed Climate Change *Civil Eats* 2022
- North Carolina's Department of Environmental Quality is facing its second complaint for permitting hog waste operations in poor communities of color *The Counter* 2021
- The USDA Wants to Make Farms Climate-Friendly. Will It Work? *Mother Jones/FERN* 2021
- Regenerative agriculture needs a reckoning *The Counter* 2021
- Tom Vilsack for USDA? Expect more inaction on hunger, discrimination, pollution and rural decline *Des Moines Register Opinion* 2021
- The Approaching Climate Crisis: What EPA Rollbacks Mean For Water And Air Quality In The Midwest, *Iowa Public Radio River to River* 2020

- Iowa scientists urge state leaders to use pandemic, derecho to prep for climate change, *Iowa City Press-Citizen* 2020
- Iowa's water quality strategy is not working. Here's what should be done instead. *Des Moines Register Opinion* (with Neil Hamilton, Matt Liebman, and Chris Jones) 2020
- Iowa Farmers Face Climate-Fueled Destruction, While the Industry Says it's 'Just Weather', *Civil Eats* 2020
- Democrats court Iowa farmers on climate, conservation, *E&E News* 2020
- Report: Many Iowa counties underusing private well testing funds, *The Gazette* 2019

MEMBERSHIPS

Agricultural & Applied Economics Association

Association of American Geographers

Association of Environmental and Resource Economists

Ecological Society of America

ATTACHMENT B

SWAPE Technical Consultation, Data Analysis and Litigation Support for the Environment

2656 29th Street, Suite 201
Santa Monica, CA 90405
Paul E. Rosenfeld, PhD
(310) 795-2335
prosenfeld@swape.com

February 14, 2024

Ellison Folk
Shute Mihaly & Weinberger LLP
396 Hayes Street
San Francisco, CA 94102

Subject: Comments on the Proposed Amendments to the Low Carbon Fuel Standard

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Dear Ms. Folk,

SWAPE was retained by Shute Mihaly & Weinberger LLP to provide written comments on the Proposed Amendments to the Low Carbon Fuel Standard ("LCFS") released by the California Air Resources Board ("CARB"), specifically the *Staff Report: Initial Statement of Reasons* ("ISOR") and the *Appendix D: Draft Environmental Impact Analysis for the Proposed Low Carbon Fuel Standard Regulation* ("EIA").[1, 2] Upon review, I have found that the ISOR and EIA inadequately addressed the following:

- Anaerobic digestate increases the potential for nitrate contamination of groundwater; and
- Anaerobic digestate increases N_2O and NOx emissions into the atmosphere; and
- Anaerobic digestate increases ammonia emissions, which is an odorous compound. Odor associated with anaerobic digestate soil application can result in odor complaints to nearby communities which are often of lower socioeconomic status resulting in environmental justice issues.

In "Table 1.1: Summary of Potential Environmental Impacts" in the ISOR, CARB listed the following impacts as "Potentially Significant and Unavoidable":[3]

- "Short-term Construction-Related and Long-Term Operational-Related Impacts on Air Quality"

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[1] ISOR.pdf.
[2] EIA.pdf.
[3] ISOR. PDF Pg. 64-65.

- “Short-Term Construction-Related and Long-Term Operational-Related Impacts to Geology and Soils”
- “Short-Term Construction-Related and Long-Term Operational-Related Impacts to Hydrology and Water Quality”

Upon review, I find the ISOR and EIA are insufficient in addressing my concerns regarding anaerobic digesters’ air quality and groundwater impacts. The following are my comments regarding these documents.

Anaerobic Digestion

Anaerobic Digester Digestate Impact on Air

In the ISOR, CARB listed the impacts of “Short-term Construction-Related and Long-Term Operational-Related Impacts on Air Quality” as “Potentially Significant and Unavoidable”.[4] The following section highlights a clear indication that CARB’s analysis fell short in adequately assessing the significance of these impacts on air quality.

Anaerobic digestion efficiently decomposes waste into smaller molecules, enhancing their propensity to volatilize into the atmosphere. During the anaerobic digestion process, quantities of ammonia are produced as a byproduct. This odorous compound possesses the potential to cause irritation and discomfort to the throat, lungs, and eyes, and prolonged exposure to elevated ammonia levels can lead to lung damage.[5] Furthermore, ammonia emits a strong odor that is easily detectable at low concentrations and contributes to irritation such as immediate burning of the nose and respiratory tract.[6] From a study by Rosenfeld et. al. in 2000, anaerobic digestion can emit enough ammonia to contribute to odor emissions. The study mentions:

> *“Odor emissions from land application of biosolids have become a concern for biosolids managers. Chemical odorant emissions from biosolids were identified using gas chromatography-mass spectrometry and included dimethyl disulfide (DMDS), dimethyl sulfide (DMS), carbon disulfide (CS2), ammonia (NH3), trimethyl amine (TMA), and acetone.”*[7]

This confirms that ammonia emissions from biosolids (digestate) are broken down during the anaerobic digestion process, potentially leading to increased ammonia concentration and, consequently, odor and health irritation.

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[4] ISOR. PDF Pg. 64-65.

[5] Centers for Disease Control and Prevention. *Ammonia: Exposure, Decontamination, Treatment*. Last Reviewed: February 6, 2023.

[6] New York State Department of Health. The Facts About Ammonia. Updated: July 28, 2004.

[7] Rosenfeld, P.E., and Henry C. L., (2000). Wood ash control of odor emissions from biosolids application. Journal of Environmental Quality. Vol 29, 1662-1668.

Another study, conducted by Holly et al. in 2017, evaluated the effects of anaerobic digestion on greenhouse gas and ammonia emissions during manure storage. According to Holly et al., anaerobic digestion can increase ammonia emissions. The study stated that the anaerobic digestion process "resulted in a gas emission tradeoff as it increased NH_3 [ammonia] emissions by 81% during storage, which could be mitigated by subsequent SLS [solid-liquid separation], manure storage covers, or other beneficial management practices."[8] The study further explains:

> *"During the AD process, methanogens and other microorganisms break down proteins, amino acids, and urea forming NH4 (Bernet et al., 2000). In addition, mineralization of organic N and volatile fatty acids during AD increases manure pH and available N (Petersen and Sommer, 2011), factors which increase NH3 emissions."*[9]

Holly et al. also found that nitrous oxide emissions were increased from anaerobically digested solids during storage:

> *"Overall, the methane emissions from storage were reduced by manure processing by 25%, 46%, and 68% for AD, SLS, and AD+SLS, respectively. However, these reductions from storage were somewhat negated when examing [sic] total GHG's to 44% and 27% for SLS and AD+SLS due to N2O losses from solid storage."*[10]

They concluded that greenhouse gas emissions were not further reduced when solid-liquid separation was employed in addition to anaerobic digestion as opposed to anaerobic digestion alone, as "anaerobically stacking digested solids increased emissions of N2O negating abatement of total GHG."[11] The findings of this study show the importance of considering nitrous oxide emissions from digestate solids in cumulative GHG emissions, which CARB failed to adequately address in the EIA. Furthermore, the ISOR and EIA claim methane reductions are achieved by digesters without any discussion of digestate-related N_2O, which Holly (2017) found negated methane reductions by more than 40 percent.

As anaerobic digestion breaks down organic material, biogas is produced. Preble et. al. (2020) explained that during biogas combustion in the anaerobic digestion process, ammonia is oxidized to nitrous oxides, which, in turn, increases nitrous oxide emissions.[12] The study "quantifies emission rates of GHGs, criteria air pollutants, and toxic/odorous compounds from the AD composting process."[13] The study further states:

> *"In situ measurements of key sources at two large-scale industrial facilities in California were conducted to quantify pollutant emission rates across the AD composting*

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[8] Holly et al., (2017). Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application.
[9] Ibid.
[10] Id. PDF Pg. 7.
[11] Id. PDF Pg. 9.
[12] Preble et. al. (2020). *Air Pollutant Emission Rates for Dry Anaerobic Digestion and Composting of Organic Municipal Solid Waste*. PDF Pg 2.
[13] Ibid.

process. These measurements established a strong relationship between flared biogas ammonia (NH3) content and emitted nitrogen oxides (NOx), indicating that fuel NOx formation is significant and dominates over the thermal or prompt NOx pathways when biogas NH3 concentration exceeds ~200 ppm."[14]

The above study highlights a crucial aspect, noting that "biogas may contain significant amounts of ammonia (NH_3) that is produced during the degradation of amino acids during acidogenesis - one of the four primary stages in AD."[15] Additionally, it emphasizes the potential consequences, explaining that "the oxidation of NH_3 present in the biogas to nitrogen oxides ($NOx = NO + NO_2$) can cause elevated flare emissions that contribute to air quality problems and exceed permitted levels."[16]

Anaerobic digesters produce significant amounts of greenhouse gases, such as methane and carbon dioxide.[17] Notably, the combustion of biogas in an internal combustion engine yields high levels of air pollution, including carbon monoxide (CO), nitrogen oxides (NOx), sulfur dioxide (SO_2), and various hazardous air pollutants.[18] Biogas combustion also results in formaldehyde emissions. According to the EPA, formaldehyde is a "probable" carcinogen.[19] Based on an article by the Vermont Department of Environmental Conservation, anaerobic digesters can result in increased formaldehyde emissions from combustion of biogas. The article states:

"The use of internal combustion engines to burn biogas also generates substantially more formaldehyde emissions than would occur with other fuels or other combustion devices. According to the U.S. Environmental Protection Agency (US EPA), formaldehyde is ubiquitous and naturally occurring in the environment at low levels, contributing to asthma and eye and respiratory irritation. At higher concentration, it can cause severe irritation and is considered a probable human carcinogen by the US EPA."[20]

The impact of emissions from anaerobic digestion on nearby communities, especially those in close proximity to dairy farms, is a critical aspect of environmental justice and public health. The emissions from anaerobic digestion can disproportionately affect nearby communities, particularly those adjacent to dairy farms, often comprising lower-income residents. Lower-income residents are often more vulnerable to the adverse effects of these emissions due to various factors, such as lack of resources, inadequate infrastructure, and the concentration of anaerobic digester facilities near these populations.

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[14] Id. PDF Pg 1.
[15] Ibid.
[16] Id. PDF pg 2.
[17] Anaerobic Digesters. Vermont Department of Environmental Conservation. Accessed January 26, 2024.
[18] Ibid.
[19] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Formaldehyde. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.
[20] Anaerobic Digesters. Vermont Department of Environmental Conservation. Accessed January 26, 2024.

The above section clearly highlights CARB's lack of extensive analysis in assessing the potential impacts of anaerobic digestion on air quality.

Anaerobic Digester Digestate Impact on Groundwater

In the ISOR, CARB listed the impacts of "Short-Term Construction-Related and Long-Term Operational-Related Impacts to Geology and Soils" and "Short-Term Construction-Related and Long-Term Operational-Related Impacts to Hydrology and Water Quality" as "Potentially Significant and Unavoidable".[21] This section serves as a response to CARB's analysis of these impacts.

Anaerobic digestion breaks down waste into a digestate of smaller molecules that are more susceptible to leaching into the groundwater. Several studies have found that anaerobic digestion leads to higher concentrations of ammonia in digestate, which can subsequently convert to nitrate. The leaching of nitrates into drinking water and food can lead to the onset of blue baby syndrome, also known as methemoglobinemia.[22] The consumption of nitrate reduces the ability of red blood cells to transport oxygen, leading to illness in infants younger than 12 months and presenting as a distinctive blue or brown tint to their skin.[23]

Figure 1. Baby with methemoglobinemia [24]

[21] ISOR. PDF Pg. 64-65.

[22] Nitrates, Blue Baby Syndrome, and Drinking Water: A Fact Sheet for Families. PEHSU. March 2016. PDF Pg. 1.

[23] Nitrates, Blue Baby Syndrome, and Drinking Water: A Fact Sheet for Families. PEHSU. March 2016. PDF Pg. 1.

[24] St. Bartholomew's Hospital, London/Photo Researchers (n.d.). American Scientist.

Lamolinara et al. (2022) found that digestate, the nutrient-rich product from anaerobic digestion of organic waste, can "contribute to nutrient pollution without comprehensive management strategies."[25] This type of pollution can lead to harmful algal blooms, hypoxia, and eutrophication.[26] Improper application of digestate has the potential to adversely affect both plant growth and soil health.[27] The chemical composition of digestate can present challenges for sustainable disposal.[28] Early application of digestate may lead to nutrient loss, translocation to deeper soil layers, or discharges of $NO3^-$ into groundwater.[29]

Anaerobic digestion breaks down waste, rendering it more susceptible to seepage into groundwater than undigested manure. Treatment lagoons are used to facilitate the waste treatment process and are lined, inhibiting nitrate from entering the groundwater. Anaerobic digestate is more extensively broken down compared to sludge from treatment lagoons. One study by Agga et al. (2022) indicated that treatment lagoons can reduce nitrogen compared to aerobic digestion:

> *"Unlike anaerobic digesters, uncovered lagoons are open to the air, photosynthesizing bacteria may develop that act to reduce nitrogen and sulfur-containing compounds and help eliminate odor in the effluent storage layer."*[30]

Nitrate pollution leading to groundwater contamination is much more likely to occur with anaerobically digested digestate, as the ammonia is more readily available for conversion into nitrate, which can then leach into groundwater. A 2010 study titled "Biogas Digestates as Organic Fertilizer in Different Crop Rotations" assessed bioenergy cropping systems for yield performance, ecological impacts, and economic feasibility. The research revealed that treatments with high digestate application rates could elevate the risk of $NO3^-$ discharges into groundwater.[31] Another study, by Fermoso et al. in 2019, highlighted that the prolonged use of digestate from anaerobic digesters could result in rapid nitrification of ammonium (NH4+-N) in the soil, making it readily accessible to crops and prone to leaching, potentially causing groundwater pollution.[32] A study by Amon et al. (2006) found that anaerobic digester digestate increases nitrate loss potential.[33] The study states:

> *"Anaerobic digestion reduces manure carbon and dry matter content by about 50%. NH4-N content and pH in digested slurry are higher than in untreated slurry (Messner, 1988). Thus, potentials for NH3 emissions during slurry storage are enhanced. Due to*

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[25] Lamolinara et al. (2022). Anaerobic digestate management, environmental impacts, and techno-economic challenges. PDF Pg. 1.
[26] Ibid.
[27] Id. PDF Pg. 2.
[28] Ibid.
[29] Ibid.
[30] Agga et al. (2022). Lagoon, Anaerobic Digestion, and Composting of Animal Manure Treatments Impact on Tetracycline Resistance Genes. PDF Pg. 7.
[31] Formowitz and Fritz (2010). Biogas Digestates as Organic Fertilizer in Different Crop Rotations. PDF Pg. 4.
[32] Fermoso et al. (2019). Trace Elements in Anaerobic Biotechnologies. IWA. June 2019. PDF Pg. 187.
[33] Amon et al. (2006). Methane, nitrous oxide and ammonia emissions during storage and after application of dairy cattle slurry and influence of slurry treatment.

the reduced dry matter content, biogas slurry can infiltrate more rapidly into the soil, which reduces NH3 emissions after slurry application. However, the increased NH4-N content and pH give rise to higher NH3 loss potentials."[34]

There is a potential for nitrate contamination of groundwater, excessive accumulation of soil phosphorus, and eutrophication of surface waters from anaerobic digesters.[35] The above section clearly highlights CARB's lack of extensive analysis in assessing the potential impacts of anaerobic digestion on groundwater quality.

Conclusion: Anaerobic Digester Impacts Inadequately Evaluated

CARB failed to adequately address air quality, soil and geology, and groundwater quality issues in the ISOR and EIA. Further analysis is required to quantify the impact of increased anaerobic digesters and the impacts on groundwater and air quality, especially in locations where digestate is applied to soil. Further assessment is essential to properly evaluate the impact of emissions to air and discharges to groundwater from anaerobic digestion on nearby communities, specifically lower-income neighborhoods.

Disclaimer

SWAPE has received limited discovery regarding this project. Additional information may become available in the future; thus, we retain the right to revise or amend this report when additional information becomes available. Our professional services have been performed using that degree of care and skill ordinarily exercised, under similar circumstances, by reputable environmental consultants practicing in this or similar localities at the time of service. No other warranty, expressed or implied, is made as to the scope of work, work methodologies and protocols, site conditions, analytical testing results, and findings presented. This report reflects efforts which were limited to information that was reasonably accessible at the time of the work, and may contain informational gaps, inconsistencies, or otherwise be incomplete due to the unavailability or uncertainty of information obtained or provided by third parties.

Sincerely,

Paul Rosenfeld

Paul E. Rosenfeld, Ph.D.

Attachment A: Paul E. Rosenfeld CV

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[34] Ibid.

[35] Mahony et al. (2002) Feasibility Study for Centralised Anaerobic Digestion for Treatment of Various Waste and Wastewaters in Sensitive Catchment Areas. PDF Pg. 5.

SWAPE Technical Consultation, Data Analysis and Litigation Support for the Environment

SOIL WATER AIR PROTECTION ENTERPRISE
2656 29th Street, Suite 201
Santa Monica, California 90405
Attn: Paul Rosenfeld, Ph.D.
Mobil: (310) 795-2335
Office: (310) 452-5555
Fax: (310) 452-5550
Email: prosenfeld@swape.com

Paul Rosenfeld, Ph.D.

Chemical Fate and Transport & Air Dispersion Modeling

Principal Environmental Chemist

Risk Assessment & Remediation Specialist

Education

Ph.D. Soil Chemistry, University of Washington, 1999. Dissertation on volatile organic compound filtration.

M.S. Environmental Science, U.C. Berkeley, 1995. Thesis on organic waste economics.

B.A. Environmental Studies, U.C. Santa Barbara, 1991. Focus on wastewater treatment.

Professional Experience

Dr. Rosenfeld has over 25 years of experience conducting environmental investigations and risk assessments for evaluating impacts to human health, property, and ecological receptors. His expertise focuses on the fate and transport of environmental contaminants, human health risk, exposure assessment, and ecological restoration. Dr. Rosenfeld has evaluated and modeled emissions from oil spills, landfills, boilers and incinerators, process stacks, storage tanks, confined animal feeding operations, industrial, military and agricultural sources, unconventional oil drilling operations, and locomotive and construction engines. His project experience ranges from monitoring and modeling of pollution sources to evaluating impacts of pollution on workers at industrial facilities and residents in surrounding communities. Dr. Rosenfeld has also successfully modeled exposure to contaminants distributed by water systems and via vapor intrusion.

Dr. Rosenfeld has investigated and designed remediation programs and risk assessments for contaminated sites containing lead, heavy metals, mold, bacteria, particulate matter, petroleum hydrocarbons, chlorinated solvents, pesticides, radioactive waste, dioxins and furans, semi- and volatile organic compounds, PCBs, PAHs, creosote, perchlorate, asbestos, per- and poly-fluoroalkyl substances (PFOA/PFOS), unusual polymers, fuel oxygenates (MTBE), among other pollutants. Dr. Rosenfeld also has experience evaluating greenhouse gas emissions from various projects and is an expert on the assessment of odors from industrial and agricultural sites, as well as the evaluation of odor nuisance impacts and technologies for abatement of odorous emissions. As a principal scientist at SWAPE, Dr. Rosenfeld directs air dispersion modeling and exposure assessments. He has served as an expert witness and testified about pollution sources causing nuisance and/or personal injury at sites and has testified as an expert witness on numerous cases involving exposure to soil, water and air contaminants from industrial, railroad, agricultural, and military sources.

Professional History:

Soil Water Air Protection Enterprise (SWAPE); 2003 to present; Principal and Founding Partner
UCLA School of Public Health; 2007 to 2011; Lecturer (Assistant Researcher)
UCLA School of Public Health; 2003 to 2006; Adjunct Professor
UCLA Environmental Science and Engineering Program; 2002-2004; Doctoral Intern Coordinator
UCLA Institute of the Environment, 2001-2002; Research Associate
Komex H_2O Science, 2001 to 2003; Senior Remediation Scientist
National Groundwater Association, 2002-2004; Lecturer
San Diego State University, 1999-2001; Adjunct Professor
Anteon Corp., San Diego, 2000-2001; Remediation Project Manager
Ogden (now Amec), San Diego, 2000-2000; Remediation Project Manager
Bechtel, San Diego, California, 1999 – 2000; Risk Assessor
King County, Seattle, 1996 – 1999; Scientist
James River Corp., Washington, 1995-96; Scientist
Big Creek Lumber, Davenport, California, 1995; Scientist
Plumas Corp., California and USFS, Tahoe 1993-1995; Scientist
Peace Corps and World Wildlife Fund, St. Kitts, West Indies, 1991-1993; Scientist

Publications:

Rosenfeld P.E. and Spaeth K.R., (2023) Authors' Response to Letter to the Editor from Bullock and Ramacciotti, Volume 234, https://doi.org/10.1007/s11270-023-06165-3

Rosenfeld P.E., Spaeth K.R., Remy L.L., Byers V., Muerth S.A., Hallman R,C., Summers-Evans J., Barker S. (2023) Perfluoroalkyl substances exposure in firefighters: Sources and implications, Environmental Research, Volume 220, https://doi.org/10.1016/j.envres.2022.115164.

Rosenfeld P. E., Spaeth K., Hallman R., Bressler R., Smith, G., (2022) Cancer Risk and Diesel Exhaust Exposure Among Railroad Workers. *Water Air Soil Pollution.* **233,** 171.

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Cheremisinoff, N.P., & **Rosenfeld, P.E.** (2011). *Handbook of Pollution Prevention and Cleaner Production: Best Practices in the Agrochemical Industry*, Amsterdam: Elsevier Publishing.

Gonzalez, J., Feng, L., Sutherland, A., Waller, C., Sok, H., Hesse, R., **Rosenfeld, P.** (2010). PCBs and Dioxins/Furans in Attic Dust Collected Near Former PCB Production and Secondary Copper Facilities in Sauget, IL. *Procedia Environmental Sciences*. 113–125.

Feng, L., Wu, C., Tam, L., Sutherland, A.J., Clark, J.J., **Rosenfeld, P.E.** (2010). Dioxin and Furan Blood Lipid and Attic Dust Concentrations in Populations Living Near Four Wood Treatment Facilities in the United States. *Journal of Environmental Health*. 73(6), 34-46.

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Cheremisinoff, N.P., & **Rosenfeld, P.E.,** (2009). *Handbook of Pollution Prevention and Cleaner Production: Best Practices in the Petroleum Industry*. Amsterdam: Elsevier Publishing.

Wu, C., Tam, L., Clark, J., **Rosenfeld, P**. (2009). Dioxin and furan blood lipid concentrations in populations living near four wood treatment facilities in the United States. *WIT Transactions on Ecology and the Environment, Air Pollution,* 123 (17), 319-327.

Cheremisinoff, N.P., **Rosenfeld, P.E.** Davletshin, A.R. (2008). ***Responsible Care***. Gulf Publishing. Texas.

Tam L. K.., Wu C. D., Clark J. J. and **Rosenfeld, P.E.** (2008). A Statistical Analysis Of Attic Dust And Blood Lipid Concentrations Of Tetrachloro-p-Dibenzodioxin (TCDD) Toxicity Equivalency Quotients (TEQ) In Two Populations Near Wood Treatment Facilities. *Organohalogen Compounds*, 70, 002252-002255.

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Rosenfeld, P. E., M. Suffet. (2007). The Anatomy Of Odour Wheels For Odours Of Drinking Water, Wastewater, Compost And The Urban Environment. *Water Science & Technology* 55(5), 335-344.

Sullivan, P. J. Clark, J.J.J., Agardy, F. J., **Rosenfeld, P.E.** (2007). *Toxic Legacy, Synthetic Toxins in the Food, Water, and Air in American Cities.* Boston Massachusetts: Elsevier Publishing

Rosenfeld, P.E., and Suffet I.H. (2004). Control of Compost Odor Using High Carbon Wood Ash. *Water Science and Technology*. 49(9),171-178.

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Rosenfeld, P.E., and Suffet, I.H. (2004). Understanding Odorants Associated With Compost, Biomass Facilities, and the Land Application of Biosolids. *Water Science and Technology*. 49(9), 193-199.

Rosenfeld, P.E., and Suffet I.H. (2004). Control of Compost Odor Using High Carbon Wood Ash, *Water Science and Technology*, 49(9), 171-178.

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Rosenfeld, P.E., Grey, M and Suffet, M. (2002). Compost Demonstration Project, Sacramento California Using High-Carbon Wood Ash to Control Odor at a Green Materials Composting Facility. *Integrated Waste Management Board Public Affairs Office*, Publications Clearinghouse (MS–6), Sacramento, CA Publication #442-02-008.

Rosenfeld, P.E., and C.L. Henry. (2001). Characterization of odor emissions from three different biosolids. *Water Soil and Air Pollution*. 127(1-4), 173-191.

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Rosenfeld, P.E., and C.L. Henry. (2001). Activated Carbon and Wood Ash Sorption of Wastewater, Compost, and Biosolids Odorants. *Water Environment Research*, 73, 388-393.

Rosenfeld, P.E., and Henry C. L., (2001). High carbon wood ash effect on biosolids microbial activity and odor. *Water Environment Research*. 131(1-4), 247-262.

Chollack, T. and **P. Rosenfeld. (**1998). Compost Amendment Handbook For Landscaping. Prepared for and distributed by the City of Redmond, Washington State.

Rosenfeld, P. E. (1992). The Mount Liamuiga Crater Trail. *Heritage Magazine of St. Kitts*, 3(2).

Rosenfeld, P. E. (1993). High School Biogas Project to Prevent Deforestation On St. Kitts. *Biomass Users Network*, 7(1).

Rosenfeld, P. E. (1998). Characterization, Quantification, and Control of Odor Emissions From Biosolids Application To Forest Soil. Doctoral Thesis. University of Washington College of Forest Resources.

Rosenfeld, P. E. (1994). Potential Utilization of Small Diameter Trees on Sierra County Public Land. Masters thesis reprinted by the Sierra County Economic Council. Sierra County, California.

Rosenfeld, P. E. (1991). How to Build a Small Rural Anaerobic Digester & Uses Of Biogas In The First And Third World. Bachelors Thesis. University of California.

Presentations:

Rosenfeld, P.E., "The science for Perfluorinated Chemicals (PFAS): What makes remediation so hard?" Law Seminars International, (May 9-10, 2018) 800 Fifth Avenue, Suite 101 Seattle, WA.

Rosenfeld, P.E., Sutherland, A; Hesse, R.; Zapata, A. (October 3-6, 2013). Air dispersion modeling of volatile organic emissions from multiple natural gas wells in Decatur, TX. *44th Western Regional Meeting, American Chemical Society.* Lecture conducted from Santa Clara, CA.

Sok, H.L.; Waller, C.C.; Feng, L.; Gonzalez, J.; Sutherland, A.J.; Wisdom-Stack, T.; Sahai, R.K.; Hesse, R.C.; **Rosenfeld, P.E.** (June 20-23, 2010). Atrazine: A Persistent Pesticide in Urban Drinking Water. *Urban Environmental Pollution*. Lecture conducted from Boston, MA.

Feng, L.; Gonzalez, J.; Sok, H.L.; Sutherland, A.J.; Waller, C.C.; Wisdom-Stack, T.; Sahai, R.K.; La, M.; Hesse, R.C.; **Rosenfeld, P.E.** (June 20-23, 2010). Bringing Environmental Justice to East St. Louis, Illinois. *Urban Environmental Pollution.* Lecture conducted from Boston, MA.

Rosenfeld, P.E. (April 19-23, 2009). Perfluoroctanoic Acid (PFOA) and Perfluoroactane Sulfonate (PFOS) Contamination in Drinking Water From the Use of Aqueous Film Forming Foams (AFFF) at Airports in the United States. *2009 Ground Water Summit and 2009 Ground Water Protection Council Spring Meeting*, Lecture conducted from Tuscon, AZ.

Rosenfeld, P.E. (April 19-23, 2009). Cost to Filter Atrazine Contamination from Drinking Water in the United States" Contamination in Drinking Water From the Use of Aqueous Film Forming Foams (AFFF) at Airports in the United States. *2009 Ground Water Summit and 2009 Ground Water Protection Council Spring Meeting*. Lecture conducted from Tuscon, AZ.

Wu, C., Tam, L., Clark, J., **Rosenfeld, P**. (20-22 July (2009). Dioxin and furan blood lipid concentrations in populations living near four wood treatment facilities in the United States. Brebbia, C.A. and Popov, V., eds., *Air Pollution XVII: Proceedings of the Seventeenth International Conference on Modeling, Monitoring and Management of Air Pollution*. Lecture conducted from Tallinn, Estonia.

Rosenfeld, P. E. (October 15-18, 2007). Moss Point Community Exposure To Contaminants From A Releasing Facility. *The 23rd Annual International Conferences on Soils Sediment and Water.* Platform lecture conducted at University of Massachusetts, Amherst MA.

Rosenfeld, P. E. (October 15-18, 2007). The Repeated Trespass of Tritium-Contaminated Water Into A Surrounding Community Form Repeated Waste Spills From A Nuclear Power Plant. *The 23rd Annual International Conferences on Soils Sediment and Water*. Platform lecture conducted from University of Massachusetts, Amherst MA.

Rosenfeld, P. E. (October 15-18, 2007). Somerville Community Exposure To Contaminants From Wood Treatment Facility Emissions. The *23rd Annual International Conferences on Soils Sediment and Water*. Lecture conducted from University of Massachusetts, Amherst MA.

Rosenfeld P. E. (March 2007). Production, Chemical Properties, Toxicology, & Treatment Case Studies of 1,2,3-Trichloropropane (TCP). *The Association for Environmental Health and Sciences (AEHS) Annual Meeting*. Lecture conducted from San Diego, CA.

Rosenfeld P. E. (March 2007). Blood and Attic Sampling for Dioxin/Furan, PAH, and Metal Exposure in Florala, Alabama. *The AEHS Annual Meeting.* Lecture conducted from San Diego, CA.

Hensley A.R., Scott, A., **Rosenfeld P.E.,** Clark, J.J.J. (August 21 – 25, 2006). Dioxin Containing Attic Dust And Human Blood Samples Collected Near A Former Wood Treatment Facility. *The 26th International Symposium on Halogenated Persistent Organic Pollutants – DIOXIN2006*. Lecture conducted from Radisson SAS Scandinavia Hotel in Oslo Norway.

Hensley A.R., Scott, A., **Rosenfeld P.E.,** Clark, J.J.J. (November 4-8, 2006). Dioxin Containing Attic Dust And Human Blood Samples Collected Near A Former Wood Treatment Facility. *APHA 134 Annual Meeting & Exposition.* Lecture conducted from Boston Massachusetts.

Paul Rosenfeld Ph.D. (October 24-25, 2005). Fate, Transport and Persistence of PFOA and Related Chemicals. Mealey's C8/PFOA. *Science, Risk & Litigation Conference.* Lecture conducted from The Rittenhouse Hotel, Philadelphia, PA.

Paul Rosenfeld Ph.D. (September 19, 2005). Brominated Flame Retardants in Groundwater: Pathways to Human Ingestion, *Toxicology and Remediation PEMA Emerging Contaminant Conference*. Lecture conducted from Hilton Hotel, Irvine California.

Paul Rosenfeld Ph.D. (September 19, 2005). Fate, Transport, Toxicity, And Persistence of 1,2,3-TCP. *PEMA Emerging Contaminant Conference.* Lecture conducted from Hilton Hotel in Irvine, California.

Paul Rosenfeld Ph.D. (September 26-27, 2005). Fate, Transport and Persistence of PDBEs. *Mealey's Groundwater Conference.* Lecture conducted from Ritz Carlton Hotel, Marina Del Ray, California.

Paul Rosenfeld Ph.D. (June 7-8, 2005). Fate, Transport and Persistence of PFOA and Related Chemicals. *International Society of Environmental Forensics: Focus on Emerging Contaminants*. Lecture conducted from Sheraton Oceanfront Hotel, Virginia Beach, Virginia.

Paul Rosenfeld Ph.D. (July 21-22, 2005). Fate Transport, Persistence and Toxicology of PFOA and Related Perfluorochemicals. *2005 National Groundwater Association Ground Water and Environmental Law Conference*. Lecture conducted from Wyndham Baltimore Inner Harbor, Baltimore Maryland.

Paul Rosenfeld Ph.D. (July 21-22, 2005). Brominated Flame Retardants in Groundwater: Pathways to Human Ingestion, Toxicology and Remediation. *2005 National Groundwater Association Ground Water and Environmental Law Conference.* Lecture conducted from Wyndham Baltimore Inner Harbor, Baltimore Maryland.

Paul Rosenfeld, Ph.D. and James Clark Ph.D. and Rob Hesse R.G. (May 5-6, 2004). Tert-butyl Alcohol Liability and Toxicology, A National Problem and Unquantified Liability. *National Groundwater Association. Environmental Law Conference*. Lecture conducted from Congress Plaza Hotel, Chicago Illinois.

Paul Rosenfeld, Ph.D. (March 2004). Perchlorate Toxicology. *Meeting of the American Groundwater Trust*. Lecture conducted from Phoenix Arizona.

Hagemann, M.F., **Paul Rosenfeld, Ph.D.** and Rob Hesse (2004). Perchlorate Contamination of the Colorado River. *Meeting of tribal representatives*. Lecture conducted from Parker, AZ.

Paul Rosenfeld, Ph.D. (April 7, 2004). A National Damage Assessment Model For PCE and Dry Cleaners. *Drycleaner Symposium. California Ground Water Association*. Lecture conducted from Radison Hotel, Sacramento, California.

Rosenfeld, P. E., Grey, M., (June 2003) Two stage biofilter for biosolids composting odor control. *Seventh International In Situ And On Site Bioremediation Symposium Battelle Conference* Orlando, FL.

Paul Rosenfeld, Ph.D. and James Clark Ph.D. (February 20-21, 2003) Understanding Historical Use, Chemical Properties, Toxicity and Regulatory Guidance of 1,4 Dioxane. *National Groundwater Association. Southwest Focus Conference. Water Supply and Emerging Contaminants*.. Lecture conducted from Hyatt Regency Phoenix Arizona.

Paul Rosenfeld, Ph.D. (February 6-7, 2003). Underground Storage Tank Litigation and Remediation. *California CUPA Forum*. Lecture conducted from Marriott Hotel, Anaheim California.

Paul Rosenfeld, Ph.D. (October 23, 2002) Underground Storage Tank Litigation and Remediation. *EPA Underground Storage Tank Roundtable*. Lecture conducted from Sacramento California.

Rosenfeld, P.E. and Suffet, M. (October 7- 10, 2002). Understanding Odor from Compost, *Wastewater and Industrial Processes. Sixth Annual Symposium On Off Flavors in the Aquatic Environment. International Water Association*. Lecture conducted from Barcelona Spain.

Rosenfeld, P.E. and Suffet, M. (October 7- 10, 2002). Using High Carbon Wood Ash to Control Compost Odor. *Sixth Annual Symposium On Off Flavors in the Aquatic Environment. International Water Association*. Lecture conducted from Barcelona Spain.

Rosenfeld, P.E. and Grey, M. A. (September 22-24, 2002). Biocycle Composting For Coastal Sage Restoration. *Northwest Biosolids Management Association*. Lecture conducted from Vancouver Washington..

Rosenfeld, P.E. and Grey, M. A. (November 11-14, 2002). Using High-Carbon Wood Ash to Control Odor at a Green Materials Composting Facility. *Soil Science Society Annual Conferenc*e. Lecture conducted from Indianapolis, Maryland.

Rosenfeld. P.E. (September 16, 2000). Two stage biofilter for biosolids composting odor control. *Water Environment Federation.* Lecture conducted from Anaheim California.

Rosenfeld. P.E. (October 16, 2000). Wood ash and biofilter control of compost odor. *Biofest.* Lecture conducted from Ocean Shores, California.

Rosenfeld, P.E. (2000). Bioremediation Using Organic Soil Amendments. *California Resource Recovery Association*. Lecture conducted from Sacramento California.

Rosenfeld, P.E., C.L. Henry, R. Harrison. (1998). Oat and Grass Seed Germination and Nitrogen and Sulfur Emissions Following Biosolids Incorporation with High-Carbon Wood-Ash. *Water Environment Federation 12th Annual Residuals and Biosolids Management Conference Proceedings*. Lecture conducted from Bellevue Washington.

Rosenfeld, P.E., and C.L. Henry. (1999). An evaluation of ash incorporation with biosolids for odor reduction. *Soil Science Society of America*. Lecture conducted from Salt Lake City Utah.

Rosenfeld, P.E., C.L. Henry, R. Harrison. (1998). Comparison of Microbial Activity and Odor Emissions from Three Different Biosolids Applied to Forest Soil. *Brown and Caldwell.* Lecture conducted from Seattle Washington.

Rosenfeld, P.E., C.L. Henry. (1998). Characterization, Quantification, and Control of Odor Emissions from Biosolids Application To Forest Soil. *Biofest.* Lecture conducted from Lake Chelan, Washington.

Rosenfeld, P.E, C.L. Henry, R. Harrison. (1998). Oat and Grass Seed Germination and Nitrogen and Sulfur Emissions Following Biosolids Incorporation with High-Carbon Wood-Ash. Water Environment Federation 12th Annual Residuals and Biosolids Management Conference Proceedings. Lecture conducted from Bellevue Washington.

Rosenfeld, P.E., C.L. Henry, R. B. Harrison, and R. Dills. (1997). Comparison of Odor Emissions from Three Different Biosolids Applied to Forest Soil. *Soil Science Society of America*. Lecture conducted from Anaheim California.

Teaching Experience:

UCLA Department of Environmental Health (Summer 2003 through 20010) Taught Environmental Health Science 100 to students, including undergrad, medical doctors, public health professionals and nurses. Course focused on the health effects of environmental contaminants.

National Ground Water Association, Successful Remediation Technologies. Custom Course in Sante Fe, New Mexico. May 21, 2002. Focused on fate and transport of fuel contaminants associated with underground storage tanks.

National Ground Water Association; Successful Remediation Technologies Course in Chicago Illinois. April 1, 2002. Focused on fate and transport of contaminants associated with Superfund and RCRA sites.

California Integrated Waste Management Board, April and May, 2001. Alternative Landfill Caps Seminar in San Diego, Ventura, and San Francisco. Focused on both prescriptive and innovative landfill cover design.

UCLA Department of Environmental Engineering, February 5, 2002. Seminar on Successful Remediation Technologies focusing on Groundwater Remediation.

University Of Washington, Soil Science Program, Teaching Assistant for several courses including: Soil Chemistry, Organic Soil Amendments, and Soil Stability.

U.C. Berkeley, Environmental Science Program Teaching Assistant for Environmental Science 10.

Academic Grants Awarded:

California Integrated Waste Management Board. $41,000 grant awarded to UCLA Institute of the Environment. Goal: To investigate the effect of high carbon wood ash on volatile organic emissions from compost. 2001.

Synagro Technologies, Corona California: $10,000 grant awarded to San Diego State University.
Goal: investigate the effect of biosolids for restoration and remediation of degraded coastal sage soils. 2000.

King County, Department of Research and Technology, Washington State. $100,000 grant awarded to University of Washington: Goal: To investigate odor emissions from biosolids application and the effect of polymers and ash on VOC emissions. 1998.

Northwest Biosolids Management Association, Washington State. $20,000 grant awarded to investigate effect of polymers and ash on VOC emissions from biosolids. 1997.

James River Corporation, Oregon: $10,000 grant was awarded to investigate the success of genetically engineered Poplar trees with resistance to round-up. 1996.

United State Forest Service, Tahoe National Forest: $15,000 grant was awarded to investigating fire ecology of the Tahoe National Forest. 1995.

Kellogg Foundation, Washington D.C. $500 grant was awarded to construct a large anaerobic digester on St. Kitts in West Indies. 1993

Deposition and/or Trial Testimony:

In the United States District Court for the Western District of Louisiana
Ricky Bush v. Clean Harbors Colfax LLC
Case No. 1:22-cv-02026-DDD-JPM
Rosenfeld Deposition 12-18-2023

In United States District Court of Hawaii
Patrick Feindt, Jr. et al. vs. The United States of America
Case No. 1:22-cv-LEK-KJM
Rosenfeld Deposition 11-29-2023

In the Circuit Court for the Twentieth Judicial Circuit St. Clair County, Illinois
Timothy Gray vs. Rural King et al.
Case No 2022-LA-355
Rosenfeld Deposition 9-26-2023

In United States District Court Eastern District of Wisconsin
Gary L. Siepe vs. Soo Line Railroad Company
Case No. 2:21-cv-00919
Rosenfeld Deposition 9-15-2023

In the Circuit Court of Cook County Illinois
Donald Fox vs. BNSF
Case No. 2021 L12
Rosenfeld Deposition 9-12-2023

In the Court of Common Please Cuyahoga County, Ohio
Thomas Schleich vs. Penn Central Corporation
Lead Case No. CV-20-939184
Rosenfeld Deposition 8-27-2023

In the Circuit Court of Jackson County Missouri at Kansas City
Timothy Dalsing vs. BNSF
Case No. No. 2216-cv06539
Rosenfeld Deposition 7-28-2023

In the United States District Court for the Southern District of Texas Houston Division
International Terminals Company LLC Deer Park Fire Litigation
Lead Case No. 4:19-cv-01460
Rosenfeld Deposition 7-25-2023

In the Circuit Court of Livingston County Missouri
Shirley Ralls vs. Canadian Pacific Railway and Soo Lind Railroad
Case No. 28LV-CV0020
Rosenfeld Daubert Hearing 7-18-2023 Trial Testimony 7-19-2023

In the Circuit Court of Cook County Illinois
Brenda Wright vs. Penn Central and Conrail
Case No. No. 2032L003966
Rosenfeld Deposition 6-13-2023

In the Circuit Court Common Please Philadelphia of Jefferson County Alabama
Frank Belle vs. Birmingham Southern Railroad Company et al.
Case No. 01-cv-2021-900901.00
Rosenfeld Deposition 4-6-2023

In the Circuit Court of Jefferson County Alabama
Linda De Gregorio vs. Penn Central
Case No. 002278
Rosenfeld Deposition 3-27-20203

In the United States District Court Eastern District of New York
Rosalie Romano et al. vs. Northrup Grumman Corporation
Case No. 16-cv-5760
Rosenfeld Deposition 3-16-2023

In the Superior Court of Washington, Spokane County
Judy Cundy vs. BNSF
Case No. 21-2-03718-32
Rosenfeld Deposition 3-9-2023

In The Court of Common Pleas of Philadelphia County, PA Civil Trial Division
Feaster v Conrail
Case No. 001075
Rosenfeld Deposition 2-1-2023

In United States District Court for the Central District of Illinois
Sherman vs. BNSF
Case No. 3:17-cv-01192
Rosenfeld Deposition 1-18-2023

In United States District Court District of Colorado
Gonzales vs. BNSF
Case No. 1:21-cv-01690
Rosenfeld Deposition 1-17-2023

In United States District Court District of Colorado
Abeyta vs. BNSF
Case No. 1:21-cv-01689-KMT
Rosenfeld Deposition 1-3-2023

In United States District Court For The Easter District of Louisiana
Nathaniel Smith vs. Illinois Central Railroad
Case No. 2:21-cv-01235
Rosenfeld Deposition 11-30-2022

In the Superior Court of the State of California, County of San Bernardino
Billy Wildrick, Plaintiff vs. BNSF Railway Company
Case No. CIVDS1711810
Rosenfeld Deposition 10-17-2022

In the State Court of Bibb County, State of Georgia
Richard Hutcherson, Plaintiff vs Norfolk Southern Railway Company
Case No. 10-SCCV-092007
Rosenfeld Deposition 10-6-2022

In the Civil District Court of the Parish of Orleans, State of Louisiana
Millard Clark, Plaintiff vs. Dixie Carriers, Inc. et al.
Case No. 2020-03891
Rosenfeld Deposition 9-15-2022

In The Circuit Court of Livingston County, State of Missouri, Circuit Civil Division
Shirley Ralls, Plaintiff vs. Canadian Pacific Railway and Soo Line Railroad
Case No. 18-LV-CC0020
Rosenfeld Deposition 9-7-2022

In The Circuit Court of the 13th Judicial Circuit Court, Hillsborough County, Florida Civil Division
Jonny C. Daniels, Plaintiff vs. CSX Transportation Inc.
Case No. 20-CA-5502

Rosenfeld Deposition 9-1-2022

In The Circuit Court of St. Louis County, State of Missouri
Kieth Luke et. al. Plaintiff vs. Monsanto Company et. al.
Case No. 19SL-CC03191
Rosenfeld Deposition 8-25-2022

In The Circuit Court of the 13th Judicial Circuit Court, Hillsborough County, Florida Civil Division
Jeffery S. Lamotte, Plaintiff vs. CSX Transportation Inc.
Case No. NO. 20-CA-0049
Rosenfeld Deposition 8-22-2022

In State of Minnesota District Court, County of St. Louis Sixth Judicial District
Greg Bean, Plaintiff vs. Soo Line Railroad Company
Case No. 69-DU-CV-21-760
Rosenfeld Deposition 8-17-2022

In United States District Court Western District of Washington at Tacoma, Washington
John D. Fitzgerald Plaintiff vs. BNSF
Case No. 3:21-cv-05288-RJB
Rosenfeld Deposition 8-11-2022

In Circuit Court of the Sixth Judicial Circuit, Macon Illinois
Rocky Bennyhoff Plaintiff vs. Norfolk Southern
Case No. 20-L-56
Rosenfeld Deposition 8-3-2022, Trial 1-10-2023

In Court of Common Pleas, Hamilton County Ohio
Joe Briggins Plaintiff vs. CSX
Case No. A2004464
Rosenfeld Deposition 6-17-2022

In the Superior Court of the State of California, County of Kern
George LaFazia vs. BNSF Railway Company.
Case No. BCV-19-103087
Rosenfeld Deposition 5-17-2022

In the Circuit Court of Cook County Illinois
Bobby Earles vs. Penn Central et. al.
Case No. 2020-L-000550
Rosenfeld Deposition 4-16-2022

In United States District Court Easter District of Florida
Albert Hartman Plaintiff vs. Illinois Central
Case No. 2:20-cv-1633
Rosenfeld Deposition 4-4-2022

In the Circuit Court of the 4th Judicial Circuit, in and For Duval County, Florida
Barbara Steele vs. CSX Transportation
Case No.16-219-Ca-008796
Rosenfeld Deposition 3-15-2022

In United States District Court Easter District of New York
Romano et al. vs. Northrup Grumman Corporation
Case No. 16-cv-5760
Rosenfeld Deposition 3-10-2022

In the Circuit Court of Cook County Illinois
Linda Benjamin vs. Illinois Central
Case No. No. 2019 L 007599
Rosenfeld Deposition 1-26-2022

In the Circuit Court of Cook County Illinois
Donald Smith vs. Illinois Central
Case No. No. 2019 L 003426
Rosenfeld Deposition 1-24-2022

In the Circuit Court of Cook County Illinois
Jan Holeman vs. BNSF
Case No. 2019 L 000675
Rosenfeld Deposition 1-18-2022

In the State Court of Bibb County State of Georgia
Dwayne B. Garrett vs. Norfolk Southern
Case No. 20-SCCV-091232
Rosenfeld Deposition 11-10-2021

In the Circuit Court of Cook County Illinois
Joseph Ruepke vs. BNSF
Case No. 2019 L 007730
Rosenfeld Deposition 11-5-2021

In the United States District Court For the District of Nebraska
Steven Gillett vs. BNSF
Case No. 4:20-cv-03120
Rosenfeld Deposition 10-28-2021

In the Montana Thirteenth District Court of Yellowstone County
James Eadus vs. Soo Line Railroad and BNSF
Case No. DV 19-1056
Rosenfeld Deposition 10-21-2021

In the Circuit Court Of The Twentieth Judicial Circuit, St Clair County, Illinois
Martha Custer et al. vs Cerro Flow Products, Inc.
Case No. 0i9-L-2295
Rosenfeld Deposition 5-14-2021
Trial October 8-4-2021

In the Circuit Court of Cook County Illinois
Joseph Rafferty vs. Consolidated Rail Corporation and National Railroad Passenger Corporation d/b/a AMTRAK,
Case No. 18-L-6845
Rosenfeld Deposition 6-28-2021

In the United States District Court For the Northern District of Illinois
Theresa Romcoe vs. Northeast Illinois Regional Commuter Railroad Corporation d/b/a METRA Rail
Case No. 17-cv-8517
Rosenfeld Deposition 5-25-2021

In the Superior Court of the State of Arizona In and For the Cunty of Maricopa
Mary Tryon et al. vs. The City of Pheonix v. Cox Cactus Farm, L.L.C., Utah Shelter Systems, Inc.
Case No. CV20127-094749

Rosenfeld Deposition 5-7-2021

In the United States District Court for the Eastern District of Texas Beaumont Division
Robinson, Jeremy et al vs. CNA Insurance Company et al.
Case No. 1:17-cv-000508
Rosenfeld Deposition 3-25-2021

In the Superior Court of the State of California, County of San Bernardino
Gary Garner, Personal Representative for the Estate of Melvin Garner vs. BNSF Railway Company.
Case No. 1720288
Rosenfeld Deposition 2-23-2021

In the Superior Court of the State of California, County of Los Angeles, Spring Street Courthouse
Benny M Rodriguez vs. Union Pacific Railroad, A Corporation, et al.
Case No. 18STCV01162
Rosenfeld Deposition 12-23-2020

In the Circuit Court of Jackson County, Missouri
Karen Cornwell, Plaintiff, vs. Marathon Petroleum, LP, Defendant.
Case No. 1716-CV10006
Rosenfeld Deposition 8-30-2019

In the United States District Court For The District of New Jersey
Duarte et al, Plaintiffs, vs. United States Metals Refining Company et. al. Defendant.
Case No. 2:17-cv-01624-ES-SCM
Rosenfeld Deposition 6-7-2019

In the United States District Court of Southern District of Texas Galveston Division
M/T Carla Maersk vs. Conti 168., Schiffahrts-GMBH & Co. Bulker KG MS "Conti Perdido" Defendant.
Case No. 3:15-CV-00106 consolidated with 3:15-CV-00237
Rosenfeld Deposition 5-9-2019

In The Superior Court of the State of California In And For The County Of Los Angeles – Santa Monica
Carole-Taddeo-Bates et al., vs. Ifran Khan et al., Defendants
Case No. BC615636
Rosenfeld Deposition 1-26-2019

In The Superior Court of the State of California In And For The County Of Los Angeles – Santa Monica
The San Gabriel Valley Council of Governments et al. vs El Adobe Apts. Inc. et al., Defendants
Case No. BC646857
Rosenfeld Deposition 10-6-2018; Trial 3-7-19

In United States District Court For The District of Colorado
Bells et al. Plaintiffs vs. The 3M Company et al., Defendants
Case No. 1:16-cv-02531-RBJ
Rosenfeld Deposition 3-15-2018 and 4-3-2018

In The District Court Of Regan County, Texas, 112th Judicial District
Phillip Bales et al., Plaintiff vs. Dow Agrosciences, LLC, et al., Defendants
Cause No. 1923
Rosenfeld Deposition 11-17-2017

In The Superior Court of the State of California In And For The County Of Contra Costa
Simons et al., Plaintifs vs. Chevron Corporation, et al., Defendants
Cause No. C12-01481
Rosenfeld Deposition 11-20-2017

In The Circuit Court Of The Twentieth Judicial Circuit, St Clair County, Illinois
Martha Custer et al., Plaintiff vs. Cerro Flow Products, Inc., Defendants
Case No.: No. 0i9-L-2295
Rosenfeld Deposition 8-23-2017

In United States District Court For The Southern District of Mississippi
Guy Manuel vs. The BP Exploration et al., Defendants
Case No. 1:19-cv-00315-RHW
Rosenfeld Deposition 4-22-2020

In The Superior Court of the State of California, For The County of Los Angeles
Warrn Gilbert and Penny Gilber, Plaintiff vs. BMW of North America LLC
Case No. LC102019 (c/w BC582154)
Rosenfeld Deposition 8-16-2017, Trail 8-28-2018

In the Northern District Court of Mississippi, Greenville Division
Brenda J. Cooper, et al., Plaintiffs, vs. Meritor Inc., et al., Defendants
Case No. 4:16-cv-52-DMB-JVM
Rosenfeld Deposition July 2017

In The Superior Court of the State of Washington, County of Snohomish
Michael Davis and Julie Davis et al., Plaintiff vs. Cedar Grove Composting Inc., Defendants
Case No. 13-2-03987-5
Rosenfeld Deposition, February 2017
Trial March 2017

In The Superior Court of the State of California, County of Alameda
Charles Spain., Plaintiff vs. Thermo Fisher Scientific, et al., Defendants
Case No. RG14711115
Rosenfeld Deposition September 2015

In The Iowa District Court In And For Poweshiek County
Russell D. Winburn, et al., Plaintiffs vs. Doug Hoksbergen, et al., Defendants
Case No. LALA002187
Rosenfeld Deposition August 2015

In The Circuit Court of Ohio County, West Virginia
Robert Andrews, et al. v. Antero, et al.
Civil Action No. 14-C-30000
Rosenfeld Deposition June 2015

In The Iowa District Court for Muscatine County
Laurie Freeman et. al. Plaintiffs vs. Grain Processing Corporation, Defendant
Case No. 4980
Rosenfeld Deposition May 2015

In the Circuit Court of the 17th Judicial Circuit, in and For Broward County, Florida
Walter Hinton, et. al. Plaintiff, vs. City of Fort Lauderdale, Florida, a Municipality, Defendant.
Case No. CACE07030358 (26)
Rosenfeld Deposition December 2014

In the County Court of Dallas County Texas
Lisa Parr et al, Plaintiff, vs. Aruba et al, Defendant.
Case No. cc-11-01650-E
Rosenfeld Deposition: March and September 2013

Rosenfeld Trial April 2014

In the Court of Common Pleas of Tuscarawas County Ohio
John Michael Abicht, et al., Plaintiffs, vs. Republic Services, Inc., et al., Defendants
Case No. 2008 CT 10 0741 (Cons. w/ 2009 CV 10 0987)
Rosenfeld Deposition October 2012

In the United States District Court for the Middle District of Alabama, Northern Division
James K. Benefield, et al., Plaintiffs, vs. International Paper Company, Defendant.
Civil Action No. 2:09-cv-232-WHA-TFM
Rosenfeld Deposition July 2010, June 2011

In the Circuit Court of Jefferson County Alabama
Jaeanette Moss Anthony, et al., Plaintiffs, vs. Drummond Company Inc., et al., Defendants
Civil Action No. CV 2008-2076
Rosenfeld Deposition September 2010

In the United States District Court, Western District Lafayette Division
Ackle et al., Plaintiffs, vs. Citgo Petroleum Corporation, et al., Defendants.
Case No. 2:07CV1052
Rosenfeld Deposition July 2009

ATTACHMENT C

Aaron Smith
Department of Agricultural and Resource Economics

Cow Poop is Now a Big Part of California Fuel Policy

Are the state's new low-carbon fuel regulations full of BS?

by Aaron David Smith | January 22, 2024

Every day, California farmers milk 1.7 million cows. Each cow generates about 7 gallons of milk and 100 gallons of waste. Most farmers process the waste (mostly manure) by washing it into lagoons where microbes break it down and, in the process, emit methane, a potent greenhouse gas.

These facts raise two questions. First, can we prevent the manure-eating microbes from sending methane into the atmosphere? Second, can we capture the methane and use it for energy?

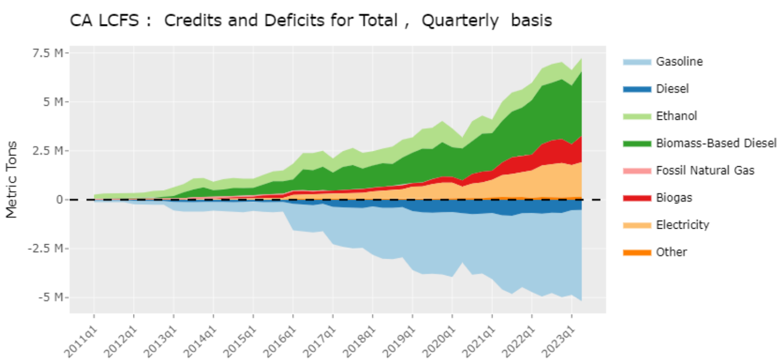
California has answered yes to both questions. On the first question, it aims to reduce methane emissions from livestock manure by 40% below 2013 levels by 2030 (codified in SB 1383). One way to achieve this goal would be to place the burden on farmers by charging them a methane emissions fee or requiring them to use practices or technologies that reduce methane emissions. This approach would raise the cost of producing milk and therefore increase the price consumers pay for dairy products. The cost increase may cause some farmers to move out of state, taking their methane emissions with them. This response, known as leakage, arises in many environmental policies, including in California's cap and trade program, as explained by Meredith in this blog.

California has chosen a different path. It has shoehorned dairy methane into a transportation program: the low carbon fuel standard (LCFS). This structure avoids leakage, but it makes consumers and producers of gasoline and diesel pay for reductions in dairy manure emissions.

Manure in the LCFS

To capture methane from manure lagoons, farmers install anaerobic digesters, which are essentially giant covers that seal manure in the lagoon to keep oxygen out while microbes feed on the contents. The captured methane — known as biogas — is then cleaned and injected into a natural gas pipeline, from which it has multiple uses including fueling a natural-gas powered vehicle and generating electricity.

This dairy biogas earns LCFS credits because it is considered a low carbon fuel. The LCFS sets a target for the average carbon intensity of transportation fuels consumed in the state. Fuels that are more carbon intensive than the target accrue deficits that must be balanced by credits earned by fuels that are less carbon intensive. The figure below shows that gasoline and diesel producers generate deficits, which they can offset by buying credits from producers of biogas and other lower-GHG fuels like electricity and renewable diesel.



Source: Our LCFS Data App. Click to view and download data using your web browser.

In the most recent LCFS data, dairy biogas contributed almost 20% of the credits in the LCFS program, yet it provided less than 1% of energy used for transportation. Dairy biogas has an outsized impact in the LCFS because it is treated very differently than most fuels. Last month's proposed LCFS amendments indicate that this differential treatment will continue.

The LCFS Assigns Dairy Biogas a Large Negative Carbon Intensity

Carbon intensity is the number of grams of carbon dioxide emissions produced per megajoule of energy. The California Air Resources Board (CARB) calculates this number for each fuel source using a life cycle analysis that accounts for tailpipe emissions as well as potential emissions throughout the fuel production process. For example, petroleum gasoline has a carbon intensity of 100.82 and an electric car powered by solar-generated electricity has a carbon intensity of zero. Most other fuels have carbon intensities between zero and 100.

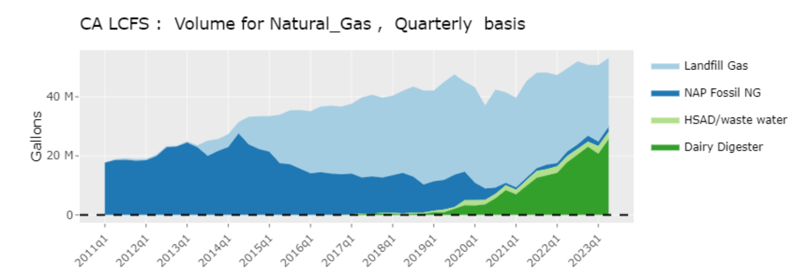
The carbon intensity of dairy biogas ranges between -102.79 and -790.41 depending on characteristics of the digester. The current average carbon intensity for dairy biogas is -269.

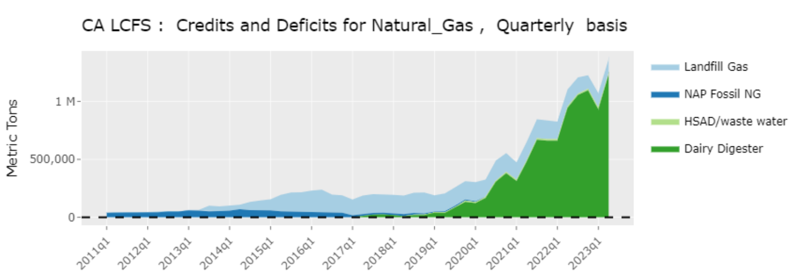
CARB assigns dairy biogas a negative carbon intensity because it gives credit for preventing methane emissions that would otherwise have occurred. Their argument is that, if a farmer had not installed a digester on a manure lagoon, then it would have sent methane into the atmosphere.

Microbes produce different amounts of gas inside a digester than they would in an open lagoon because of differing environmental factors such as oxygen exposure and temperature. The carbon intensity number is determined by the estimated emissions from the open lagoon (avoided methane) per unit of biogas produced. For example, in highly productive digesters, the amount of prevented methane is low as a proportion of the biogas produced, so such a digester would get a relatively small negative carbon intensity.

In the LCFS, fuels with a negative carbon intensity are very helpful in meeting the policy target because they can offset a lot of high-carbon fuel. For example, adding one average biogas-powered vehicle to the fleet would produce enough LCFS credits to cover the deficits incurred by 26 similar gasoline-powered vehicles.

This accounting scheme is one reason why dairy biogas has increased from almost non-existent five years ago to half of all natural gas used for transportation in the state. The other half is contributed by biogas captured from landfills. However, landfill gas gets a carbon intensity of 53 because it does not get credit for avoided-methane emissions. So, even though its fuel volumes are similar to dairy, it generates only a fraction of the credits, as shown in the figure below. Biogas can also earn LCFS credits by generating hydrogen or electricity for use in transportation, but these pathways have been used very little so far.





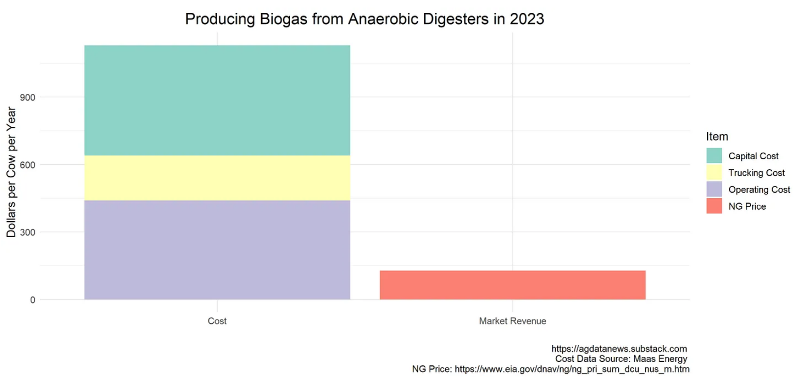
Source: Our LCFS Data App. Click to view and download data using your web browser.

Costs and Benefits of Anaerobic Digesters

In this 2023 blog, I showed that the cost of an anaerobic digester is about 10 times the market value of the gas it produces. A representative new digester costs about about $1130 per milking cow per year, comprising $490 in capital costs and $440 in operating costs, plus $200 in trucking costs if unable to connect directly to a gas pipeline. In 2023, revenue from selling gas was about $128, for a net cost of about $1000 per milking cow per year. This representative digester has a carbon intensity of -355, which corresponds to about 6 metric tons of CO2 equivalent emissions per milking cow per year.

So, for $1000 we reduce CO2 emissions by 6 metric tons, or $167 per ton.

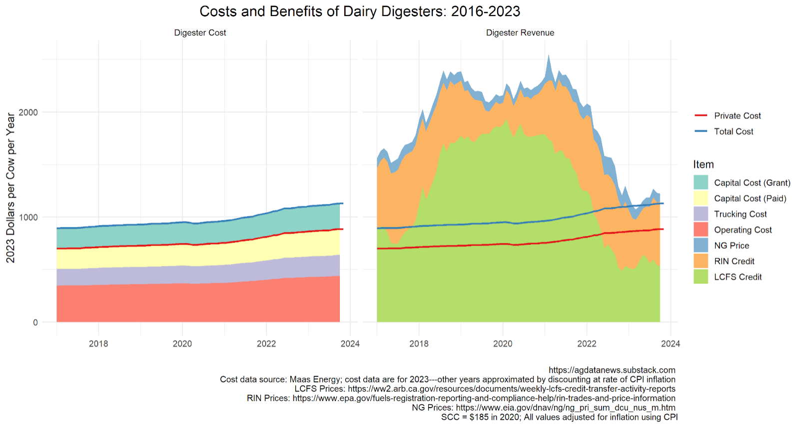
Methane is a far more powerful greenhouse gas than CO2, but it doesn't last nearly as long in the atmosphere. There is a vigorous scientific debate over how best to convert methane emissions into CO2 equivalent accounting for both how much it warms and when. Using an alternative approach would reduce the estimated emissions reduction by a factor of three and therefore raise the cost per ton by a factor of three. Moreover, all these numbers assume that CARB correctly estimates the amount of prevented emissions.



Incentives Facing Farmers

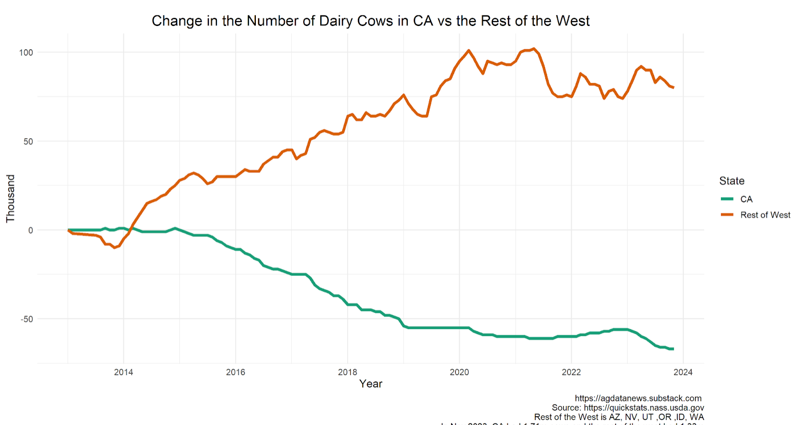
Anaerobic digesters receive government support through three programs. First, using proceeds from the state's cap and trade program, the California Department of Food and Agriculture offers grants to cover up to half the capital costs of building digesters. Second, sellers of dairy biogas generate credits in the federal renewable fuel standard (known as RINs). Third, they earn LCFS credits.

Between mid 2018 and the end of 2021, revenues from selling biogas and the associated RIN and LCFS credits were approximately double the cost of installing and running a typical digester, as shown in the figure below. LCFS credit prices have declined in the last two years, making the typical digester closer to a break even proposition. If and when credit prices go back up, then the profits will return.



High profits from operating digesters create the incentive for farmers to expand dairy herds for the purpose of generating manure rather than for producing milk. Between 2014 and 2019, California dairy cow numbers declined by 50,000 while the number of cows in other western states increased by 100,000 (see figure below). Since 2019, cow numbers have been relatively flat throughout the west.

It is possible that the advent of digesters in California stemmed the flow of cows out of the state. Dairy farmers outside California can access only two of the three digester programs accessible to California farmers. They are eligible to earn LCFS and RIN credits for their biogas, but they cannot receive California Department of Food and Agriculture grants to cover capital costs. Whether this grant funding is the difference between leaving and staying in California is an important topic for further research given the potential for emissions leakage if the state were to remove negative crediting but still require farmers to reduce manure methane emissions as per SB 1383.



What Next?

CARB is proposing several amendments to the LCFS. It considered removing the negative crediting of dairy biogas projects, but its proposal (which is currently out for comment) opted to continue negative credits until 2040 for biogas used directly in transportation and until 2045 for biogas used to produce hydrogen for transportation.

There is a long tradition in agriculture of governments paying farmers for environmental improvement, rather than placing the burden on farmers to make those improvements. As a result, consumers do not see the full cost to society of the food they eat. Instead, those costs are shifted to taxpayers or, in the case of dairy biogas, gasoline and diesel consumers. Such mispricing can cause costly misallocations of resources, as articulated often on this blog.

Leakage is the main argument given for continuing negative crediting. There are several ways to mitigate leakage. Some, such as border adjustments (tax dairy products coming into California) would be very difficult to operationalize. A good rule in policy is to directly target the problem you are trying to solve. In this case, the problem would be methane-mitigation costs imposed on farmers that cause them to move out of state. Negative crediting in the LCFS is a convoluted solution with numerous drawbacks. A direct solution could involve the state sharing the costs of methane mitigation practices, which they already do to some extent through California Department of Food and Agriculture programs.

I made the last three figures using this R code. This article is cross posted at the Energy Institute blog.

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ATTACHMENT D

Table 17. **Milk Cow Herd Size by Inventory and Sales: 2017**

[For meaning of abbreviations and symbols, see introductory text.]

Milk cow herd	Cattle and calves inventory							
	Total		Cows and heifers that calved		Milk cows		Other cattle (see text)	
	Farms	Number	Farms	Number	Farms	Number	Farms	Number
Farms with December 31, 2017 milk cow herd size of-								
1 to 9	380	20,704	380	11,584	380	767	237	9,120
10 to 19	26	1,307	26	767	26	306	17	540
20 to 49	32	2,009	32	1,467	32	919	22	542
50 to 99	20	3,102	20	1,971	20	1,467	14	1,131
100 to 199	62	23,398	62	15,780	62	9,209	55	7,618
200 to 499	249	139,592	249	83,919	249	81,452	231	55,673
500 to 999	296	368,808	296	211,922	296	209,626	278	156,886
1,000 to 2,499	390	1,117,162	390	648,456	390	638,080	369	468,706
2,500 to 4,999	163	988,072	163	550,937	163	546,617	154	437,135
5,000 or more	35	460,469	35	262,482	35	261,886	35	197,987
All farms with December 31, 2017 milk cow inventory	1,653	3,124,623	1,653	1,789,285	1,653	1,750,329	1,412	1,335,338
Farms with no milk cow inventory, on December 31, 2017	12,041	2,060,970	9,889	643,416	-	-	9,312	1,417,554
Total	13,694	5,185,593	11,542	2,432,701	1,653	1,750,329	10,724	2,752,892

Milk cow herd	Cattle and calves sales							Milk sales	
	Total			Cattle		Calves			
	Farms	Number	Value ($1,000)	Farms	Number	Farms	Number	Farms	Value ($1,000)
Farms with December 31, 2017 milk cow herd size of-									
1 to 9	203	(D)	21,310	170	(D)	94	(D)	24	176
10 to 19	19	(D)	727	17	511	10	(D)	14	693
20 to 49	31	1,456	1,406	31	1,312	11	144	31	3,384
50 to 99	20	1,190	985	20	834	14	356	17	5,040
100 to 199	62	9,566	7,206	62	(D)	45	(D)	60	30,513
200 to 499	239	50,907	36,800	237	28,036	183	22,871	249	324,622
500 to 999	293	109,999	73,414	292	(D)	230	(D)	296	829,287
1,000 to 2,499	381	383,639	245,585	371	185,095	321	198,544	390	2,385,176
2,500 to 4,999	160	350,862	250,365	158	184,466	130	166,396	163	1,967,972
5,000 or more	35	159,363	109,542	35	75,054	31	84,309	35	930,481
All farms with December 31, 2017 milk cow inventory	1,443	1,113,851	747,339	1,393	540,348	1,069	573,503	1,279	6,477,344
Farms with no milk cow inventory, on December 31, 2017	8,824	1,959,243	2,364,071	8,037	1,584,184	3,340	375,059	8	5,786
Total	10,267	3,073,094	3,111,410	9,430	2,124,532	4,409	948,562	1,287	6,483,130

Table 18. **Cattle and Calves - Number Sold Per Farm by Sales: 2017**

[For meaning of abbreviations and symbols, see introductory text.]

Number sold	Cattle and calves			Cattle weighing 500 pounds or more (see text)		Calves weighing less than 500 pounds	
	Farms	Number	Value ($1,000)	Farms	Number	Farms	Number
Total	10,267	3,073,094	3,111,410	9,430	2,124,532	4,409	948,562
Farms by number of cattle and calves sold-							
1 to 9	3,827	14,605	13,069	3,248	11,123	1,162	3,482
10 to 19	1,412	19,160	16,763	1,281	14,768	584	4,392
20 to 49	1,676	51,749	46,295	1,597	40,129	751	11,620
50 to 99	962	65,444	59,774	944	51,723	464	13,721
100 to 199	679	93,740	85,099	670	73,331	354	20,409
200 to 499	789	248,298	219,850	786	180,952	458	67,346
500 to 999	409	287,144	239,514	397	185,674	267	101,470
1,000 to 2,499	350	543,513	404,769	349	329,495	258	214,018
2,500 or more	163	1,749,441	2,026,277	158	1,237,337	111	512,104

Table 19. **Hogs and Pigs - Inventory: 2017 and 2012**

[For meaning of abbreviations and symbols, see introductory text.]

Hogs and pigs	2017		2012	
	Farms	Number	Farms	Number
Total hogs and pigs	1,389	96,456	1,437	111,893
Farms with -				
1 to 24	1,191	6,804	1,228	6,370
25 to 49	102	3,397	95	3,117
50 to 99	42	2,587	52	3,446
100 to 199	24	2,949	39	5,041
200 to 499	17	5,173	11	3,626
Total hogs and pigs - Con.				
Farms with - - Con.				
500 to 999	4	2,602	4	2,570
1,000 to 1,999	5	(D)	4	(D)
2,000 to 4,999	3	7,720	2	(D)
5,000 or more	1	(D)	2	(D)

Table 17. **Milk Cow Herd Size by Inventory and Sales: 2022**

[For meaning of abbreviations and symbols, see introductory text.]

Milk cow herd	Cattle and calves inventory							
	Total		Cows and heifers that calved		Milk cows		Other cattle	
	Farms	Number	Farms	Number	Farms	Number	Farms	Number
Farms with December 31, 2022 milk cow herd size of-								
1 to 9	256	2,675	256	1,686	256	549	142	989
10 to 19	20	634	20	474	20	221	10	160
20 to 49	9	474	9	300	9	247	6	174
50 to 99	10	1,379	10	949	10	739	6	430
100 to 199	20	6,352	20	3,907	20	2,947	18	2,445
200 to 499	79	46,997	79	28,378	79	25,889	75	18,619
500 to 999	153	207,253	153	117,051	153	113,880	149	90,202
1,000 to 2,499	315	909,087	315	525,903	315	518,014	304	383,184
2,500 or more	255	1,857,818	255	1,033,210	255	1,025,716	254	824,608
All farms with December 31, 2022 milk cow inventory	1,117	3,032,669	1,117	1,711,858	1,117	1,688,202	964	1,320,811
Farms with no milk cow inventory, on December 31, 2022	10,642	2,206,401	9,058	658,364	-	-	8,274	1,548,037
Total	11,759	5,239,070	10,175	2,370,222	1,117	1,688,202	9,238	2,868,848

Milk cow herd	Cattle and calves sales							Milk sales	
	Total			Cattle		Calves			
	Farms	Number	($1,000)	Farms	Number	Farms	Number	Farms	($1,000)
Farms with December 31, 2022 milk cow herd size of-									
1 to 9	113	947	950	91	703	44	244	7	49
10 to 19	16	2,240	(D)	14	(D)	14	(D)	4	(D)
20 to 49	8	394	(D)	7	(D)	5	(D)	7	1,303
50 to 99	10	919	918	10	633	8	286	10	4,256
100 to 199	20	2,318	2,345	19	1,568	13	750	20	16,207
200 to 499	79	18,132	16,040	79	10,253	58	7,879	79	149,465
500 to 999	153	68,727	55,500	153	34,030	129	34,697	153	677,867
1,000 to 2,499	315	362,613	285,505	315	171,601	277	191,012	315	3,083,205
2,500 or more	255	759,699	614,433	255	363,648	232	396,051	255	5,733,317
All farms with December 31, 2022 milk cow inventory	969	1,215,989	978,668	943	584,534	780	631,455	850	(D)
Farms with no milk cow inventory, on December 31, 2022	7,574	2,158,354	2,745,144	7,041	1,716,066	3,189	442,288	5	(D)
Total	8,543	3,374,343	3,723,812	7,984	2,300,600	3,969	1,073,743	855	9,675,301

Table 18. **Cattle and Calves - Number Sold per Farm by Sales: 2022**

[For meaning of abbreviations and symbols, see introductory text.]

Number sold	Cattle and calves			Cattle weighing 500 pounds or more		Calves weighing less than 500 pounds	
	Farms	Number	Value ($1,000)	Farms	Number	Farms	Number
Total	8,543	3,374,343	3,723,812	7,984	2,300,600	3,969	1,073,743
Farms by number of cattle and calves sold-							
1 to 9	3,004	11,780	11,174	2,562	8,911	938	2,869
10 to 19	1,088	14,487	13,647	1,012	11,161	469	3,326
20 to 49	1,460	44,805	42,102	1,438	33,330	733	11,475
50 to 99	767	52,773	52,539	761	40,178	409	12,595
100 to 199	614	84,987	84,399	611	67,048	316	17,939
200 to 499	666	204,620	204,669	666	154,158	390	50,462
500 to 999	351	245,642	227,405	351	171,526	237	74,116
1,000 to 2,499	344	552,451	479,768	344	311,896	291	240,555
2,500 or more	249	2,162,798	2,608,109	239	1,502,392	186	660,406

Table 19. **Hogs and Pigs - Inventory: 2022 and 2017**

[For meaning of abbreviations and symbols, see introductory text.]

Hogs and pigs	2022		2017	
	Farms	Number	Farms	Number
Total hogs and pigs	1,374	82,010	1,389	96,456
Farms with-				
1 to 24	1,157	7,121	1,191	6,804
25 to 49	110	3,745	102	3,397
50 to 99	52	3,153	42	2,587
100 to 199	24	3,339	24	2,949
200 to 499	22	5,298	17	5,173

Hogs and pigs	2022		2017	
	Farms	Number	Farms	Number
Total hogs and pigs - Con.				
Farms with- - Con.				
500 to 999	3	2,343	4	2,602
1,000 to 1,999	2	(D)	5	(D)
2,000 to 4,999	2	(D)	3	7,720
5,000 or more	2	(D)	1	(D)

ATTACHMENT E

Briefing Paper

FACTORY FARM DAIRIES, BIOGAS, AND THE DANGEROUS PATH CALIFORNIA IS ON

I. INTRODUCTION

Industrial dairies in the San Joaquin Valley, packing thousands, and sometimes tens of thousands of cows into a single facility, are a major source of local air and water pollution, nuisance odor, groundwater overdraft, and greenhouse gas emissions. Over the last decade, California has created a regulatory landscape that pays this industry to continue these polluting practices while producing factory farm gas, otherwise known as dairy biogas. These policies favor large-scale industrial dairies over smaller operations and lock in the most environmentally harmful industry practices that disproportionately harm low-income communities of color. And these policies actually *encourage dairies to create* methane and only *appear* to succeed in achieving massive greenhouse gas emissions reductions as a result of an overly narrow life cycle analysis for the fuel's "well-to-wheel" climate impacts. The good news is that California can, and must, choose another path — one that aligns with our climate and environmental health and equity objectives.

II. BACKGROUND — THE EVOLUTION OF MASSIVE DAIRIES IN THE SAN JOAQUIN VALLEY DESPITE KNOWN CLIMATE AND ENVIRONMENTAL IMPACTS WAS A POLICY CHOICE

The expansion and concentration of the California dairy industry over the last several decades has occurred with policymakers' knowledge of the industry's climate and community impacts. The California dairy sector in the 1950s milked about 800,000 cows on almost twenty thousand pasture-based farms. California land use and environmental policy allowed for the dairy industry to transition into gigantic, full confinement, industrial-style operations that liquefy and manage manure anaerobically in gigantic so-called lagoons. Now, the industry milks between 1.7 and 1.8 million cows on about 1,100 farms — the vast majority of which, and the largest of which are in the San Joaquin Valley.[1]

This shift to massive dairies concentrated in the San Joaquin Valley was a policy choice and business choice — it was neither accidental nor inevitable.

1 https://www.dairycares.com/post/keeping-cows-in-california-is-good-for-people-and-planet.

In the late 1990s, water quality regulators drove the relocation of the southern California dairy herd from the Chino Basin in San Bernardino County to the San Joaquin Valley when groundwater pollution from manure affected water quality. Rising housing costs in the Inland Empire produced a windfall for those dairies as they sold their land to developers and raced toward cheaper land – and fewer regulations – in the San Joaquin Valley. San Joaquin Valley counties welcomed those Chino-based dairy operators with open arms and authorized hundreds of new dairies and dairy expansions as the California dairy industry increased in size dramatically to over 1.8 million in 2008.[2] By 2008, there were about 1,900 dairy farms in California not only producing milk, but massive amounts of manure. For context, a 2,000 cow industrial dairy produces approximately the same amount of fecal waste as a city of one million people.[3] Many of the factory farms in the San Joaquin Valley are 3 to 5 times that size. Local county governments in the San Joaquin Valley supported this expansion as modern dairy operations overwhelmingly opted for liquefied manure management despite the known climate impacts from methane and known risks of groundwater contamination.[4] Local governments and the dairy operators themselves *knew* that the liquefied manure model of dairy production relied on an externalization of climate and adverse local pollution impacts, and adopted statements of overriding considerations to approve those projects despite "significant and unavoidable impacts" as allowed by the California Environmental Quality Act (CEQA). Several counties adopted land use policies that facilitated dairy citing and expansion while others allowed (and are continuing to allow) dairy expansions without requiring CEQA environmental review.

III. MASSIVE DAIRIES HAVE SIGNIFICANT AND HARMFUL ENVIRONMENTAL IMPACTS

A. Industrial Dairies Contribute to Dangerous Air Pollution

Dairies emit large amounts of volatile organic compounds (VOC), ammonia, nitrogen oxides (NOx), and dust which all contribute to extremely poor air quality in the San Joaquin Valley, a region out of compliance with state and federal air quality standards.

- VOCs are a precursor to ozone formation. The San Joaquin Valley has been designated as Extreme Nonattainment for EPA's 2008 8-hour ozone standard and 2012 8-hour ozone standard.[5] The San Joaquin Valley is also Severe Nonattainment for the state one hour ozone standard.[6] Dairies are the largest source of VOCs in the Valley.

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2 *Id.*

3 Agricultural Waste Management Field Handbook, USDA (March 2008), Table 4-5. Available at: https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=31475.wba. See: https://www.holsteinusa.com/pdf/fact_sheet_cattle.pdf. Also see: *The Characterization of Feces and Urine* (2015), available at: https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4500995/.

4 *See, e.g.* Kings County Dairy Element Program EIR at 4.2-83 to 4.2-85, available at https://www.countyofkings.com/home/showpublisheddocument/4358/635277478494870000 (last visited October 24, 2022).

5 *Ambient Air Quality Standards and Valley Attainment Status*. Accessed January 9, 2022. Available at: https://www.valleyair.org/aqinfo/attainment.htm.

6 *Id.*

- Dairies also emit significant amounts of ammonia, a PM2.5 precursor. Recent research estimates that 1,690 people die in California annually as a result of agricultural ammonia emissions because ammonia and NOx create ammonium nitrate, the most prevalent form of PM2.5 in the San Joaquin Valley. The Valley is Serious Nonattainment for the Federal 1997 annual, the 2006 24-hour, and the 2012 annual PM2.5 standards.[7] Dairies are the largest source of ammonia in the Valley.

- Dairies also emit large amounts of NOx from manure application on crop land, which contributes to increasing the ozone concentration and PM2.5.

Both Ozone and PM2.5 result in serious and long lasting health impacts. Ozone can trigger chest pain, coughing, throat irritation, congestion, worsen bronchitis, emphysema, and asthma. Ozone also can reduce lung function and inflame the lining of the lungs. PM2.5 can cause eye, nose, throat and lung irritation, coughing, sneezing, runny nose and shortness of breath. Both ozone and PM2.5 exposures are correlated to increases in hospitalization, emergency room visits, and premature death from cardiovascular and respiratory disease.

In addition to PM2.5 and Ozone, dairies cause significant odors. Many Californians glimpse the impacts when they drive through the San Joaquin Valley, catch a whiff of manure odors, and roll up the windows. However, for residents who live near these facilities, there is no driving away from these extreme odors. Even going inside their homes does not always provide respite. Residents report odors following them indoors, permeating their clothes, and causing headaches.

B. Industrial Dairies Degrade Water Quality

With the average dairy cow producing approximately 148 pounds of manure each day,[8] California dairies contribute tens of millions of tons of manure each year. Untreated manure cannot be applied to crops for human consumption so there is limited acreage upon which manure may be applied. And there simply isn't enough. **Nitrate from manure leaches into groundwater and pollutes drinking water supplies**. Manure from lagoons, corrals, and, above all, applied to land leads to nitrate contamination.

The dairy industry's own report on nitrate pollution revealed the breadth and degree of groundwater contamination from dairies. The Central Valley Summary Representative Monitoring Report was prepared by the Central Valley Dairy Representative Monitoring Program, a nonprofit association of dairy owners and operators. It presents years of monitoring data from forty-two Central Valley dairies chosen to be representative of the industry in the region. Some findings of note:

7 See: https://www3.epa.gov/airquality/greenbook/knca.html#PM-2.5.2012.San_Joaquin_Valley.

8 Agricultural Waste Management Field Handbook, USDA (March 2008), Table 4-5. Available at: https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=31475.wba.

- **Elevated nitrate-N (i.e., as nitrogen) concentrations were present beneath all monitored dairies.**[9]
- "...approximately 94 percent of nitrogen loading on dairies (that is, the portion of
- nitrogen that enters the soil and is not recovered by plants) occurs on cropland." [10]
- Dairies produce an "excess supply of nitrogen" in the form of manure than the amount that can be safely applied to cropland without causing or contributing to nitrate pollution.[11]

Larger, more concentrated herds mean more manure concentrated on the same or smaller land, thus exacerbating the issue of greater quantities of manure than cropland can absorb. A recent proposed dairy expansion in Merced notes that increased herd sizes (from under 3,000 to 7,300 cows) indicated in their environmental documents that manure exports would jump from about 9,000 tons to 49,000 tons annually. **No information was provided as to where that manure would be exported. Presumably, because there is nowhere for it to go.**

Nitrates in drinking water cause blue baby syndrome and have been linked to cancer.[12] The cost to treat drinking water – if treatment is even available – can make water bills unaffordable for many households and can be cost prohibitive for private well owners.

C. Industrial Dairies Are Water Hogs

The San Joaquin Valley is ground zero for critical groundwater overdraft and water scarcity.[13] Thousands of private and community water wells, upon which many Californians rely for drinking water, have already run dry.[14] Overdraft also impacts water quality. As groundwater supply decreases, concentrations of contaminants, especially arsenic, increase.[15]

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9 CENTRAL VALLEY DAIRY REPRESENTATIVE MONITORING PROGRAM, SUMMARY REPRESENTATIVE MONITORING REPORT (REVISED*) at 6 (Apr. 19, 2019), https://www.waterboards.ca.gov/centralvalley/water_issues/confined_animal_facilities/groundwater_monitoring/srmr_20190419.pdf.

10 *Id.* at 10.

11 *Id.*

12 Ward MH, Jones RR, Brender JD, de Kok TM, Weyer PJ, Nolan BT, Villanueva CM, van Breda SG. Drinking Water Nitrate and Human Health: An Updated Review. Int J Environ Res Public Health. 2018 Jul 23;15(7):1557. doi: 10.3390/ijerph15071557. PMID: 30041450; PMCID: PMC6068531.

13 Critically Overdrafted Basins, CAL. DEP'T OF WATER RES., https://water.ca.gov/programs/groundwater management/bulletin-118/critically-overdrafted-basins (last visited Mar. 22, 2022) (showing most groundwater basins and subbasins in the San Joaquin Valley are critically overdrafted); see ELLEN HANAK ET AL., WATER AND THE FUTURE OF THE SAN JOAQUIN VALLEY (2019), PUB. POL. INST. OF CAL., https://www.researchgate.net/publication/331476376_Water_and_the_Future_of_the_San_Joaquin_Valley.

14 Groundwater Management and Drought: An Interview with the San Joaquin Valley Partnership, CAL. DEP'T OF WATER RES., (Mar. 8, 2022), https://water.ca.gov/News/Blog/2022/March-22/Groundwater-Management-and-Drought-An-Interview-with-the-San-Joaquin-Valley-Partnership (noting that groundwater overdraft is causing domestic well owners to "lose access to their primary source of drinking water," leaving them unable to "afford or obtain services due to drilling backlogs or financial challenges" and forcing them to seek out and rely on emergency sources of drinking water); see Jelena Jezdimirovic et al., Will Groundwater Sustainability Plans End the Problem of Dry Drinking Water Wells?, PUB. POL'Y INST. OF CALIFORNIA (May 14, 2020), https://www.ppic.org/blog/will-groundwater-sustainability-plans-end-the-problem-of-dry-drinking-water-wells/.

15 See: https://environment-review.yale.edu/overpumping-california-groundwater-could-lead-dangerous-arsenic-water-and-food.

Industrial dairies use massive amounts of water including groundwater in the extremely fragile San Joaquin Valley ecosystem. In addition to supplying large amounts of drinking water to cows, dairies need large amounts of water for liquefying and flushing manure and other pollutants for storage in lagoons, cooling animals, cleaning facilities, and irrigating crops. In addition, dairies rely upon water-intensive crops to feed dairy cows such as alfalfa. California's large dairies use an estimated 142 million gallons per day,[16] or almost 52 billion gallons per year.

D. Industrial Dairies Cause Dispoportionate Environmental Impacts

San Joaquin Valley residents are disproportionately Latino/a/e as compared to California as a whole. Seven central and southern San Joaquin Valley Counties (Kern to Stanislaus) have higher Latino/a/e populations than the state, with populations ranging from almost 50 percent to over 66 percent, as compared to the state population with 40 percent of residents classified as Latino/a/e. At least seven of eight San Joaquin Valley counties have a lower proportion of white residents as compared to the state as a whole.[17] **Therefore, policies that entrench and exacerbate air and water pollution in these regions have a racially disparate impact on Latino/a/e communities.**

Similarly, San Joaquin Valley counties are lower income and have more residents facing economic insecurity than the state as a whole. While median household income in California is approximately $84,000 countywide household median incomes in the central and southern San Joaquin Valley Counties range from approximately $57,000 to $68,000 The highest producing dairy counties in the state and in the San Joaquin Valley, Merced and Tulare, show median household incomes at $59,000 and $57,000 , 70% or less of statewide median income. Poverty rates hover around 22% and 19% in Merced and Tulare, respectively.

IV. FACTORY FARM GAS – AN INADEQUATE CLIMATE SOLUTION AND A HARM-INDUCING STRATEGY

A. Industrial Livestock Operations Contribute Significant Greenhouse Gas Emissions to the Atmosphere

In addition to local and regional air and water pollution, dairies are a substantial source of California's greenhouse gas emissions. **Livestock methane emissions account for 6.1 percent of statewide GHG emissions.**[18]

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16 Big Ag, Big Oil and California's Big Water Problem, Food and Water Watch. Available at: https://www.foodandwaterwatch.org/wp-content/uploads/2021/10/CA-Water-White-Paper.pdf.

17 According to recent census data, 36.5 percent of the state population is classified as white, non-Latino, while 7 of the 8 counties in the San Joaquin Valley have white, non-Latino populations that range from only 26.5 to 33.2 percent. *Id.*

18 California Greenhouse Gas Emissions for 2000-2020, October 26. 2022, Page 9. Available at: https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

Liquid manure-filled lagoons produce a significant amount, although not all, of livestock methane emissions. About half of a typical large dairy's methane emissions come from the cow's digestion processes (called enteric emissions). The industry's intentional decision to store manure in lagoons and subsequently apply wet manure to land is the direct cause of methane and nitrous oxide emissions from manure. Livestock operations remain free from regulation for greenhouse gas emissions despite their significant impact.

B. Dairy Digesters Do Not Adequately Address Climate and Other Pollutants from Livestock Operations and Perpetuate Dependence on Polluting Fuels

Dairy digesters purport to address methane emissions from massive amounts of liquefied manure stored anaerobically in lagoons. Digesters basically cover the intentionally-created manure pits, capture the various gasses, and deliver the gas to facilities that combust the fuel onsite or scrub out impurities leaving methane gas for off site combustion. Digesters do not do anything to address the roughly equal amount of GHG emissions from enteric fermentation (intestinal gasses) or from the composting and application of digested manure to land. The captured methane gas can be combusted onsite, used as a transportation fuel, combusted as a fuel, converted through steam reformation to produce hydrogen, or upgraded and injected into gas pipelines for transportation fuel, gas in buildings, generating electricity, and other uses. Some dairies have stand-alone digesters and some dairies participate in a factory farm gas cluster. A factory farm gas cluster connects several dairies and dairy digesters with an upgrading facility so that the gas from many dairies can be processed at one site and then injected into the gas pipeline. This "pipeline quality" gas, marketed as clean yet molecularly almost identical to conventional fossil gas, is subsidized by ratepayers and used to justify the continued operation of gas pipelines that otherwise should be phased out.

Digesters do not do anything to decrease overall air pollution or groundwater pollution from dairies.

C. The Relevant Regulatory History Has Exacerbated the Impacts from Industrial Livestock Operations

The Global Warming Solutions Act of 2006 (AB 32 [Nunez]) tasked CARB with developing a plan to reduce GHG emissions generally and in 2013, Senate Bill 605 (Lara) required CARB to develop a plan to reduce emissions of Short-Lived Climate Pollutants, including methane. In 2016, the legislature passed both SB 32 (Pavley) which built upon AB 32's GHG reduction mandates, and SB 1383 (Lara), which focused on methane and other short-lived climate pollutants. SB 1383 set methane emission targets and required CARB to develop and begin implementing a strategy to meet those targets. The bill specifically included a target for methane emission reductions from livestock manure and created both insulation from direct regulation of livestock methane and policies and incentives designed to increase production of factory farm gas. Notably, SB 1383 prohibited direct regulation of methane emissions from livestock manure until 2024 and required CARB to make significant findings of economic feasibility prior to instituting regulations and even further limited the state's authority to regulate enteric emissions.

Furthermore, it required CARB and the CPUC to develop financial mechanisms and incentives to support the production of dairy-produced energy.[19] In so doing, California transitioned from allowing the dairy industry to expand and emit more unabated methane regardless of its impact to rewarding the industry for its polluting practices and incentivizing the creation of even more liquefied manure at ever larger dairies. Protection from regulation coupled with increased subsidies and incentives illustrate the preferential treatment the dairy industry has been granted compared to other polluting sectors.[20]

In 2018, CARB updated the Low Carbon Fuel Standard (LCFS) program to incorporate "avoided methane" into the calculation of carbon intensity scores. The result: factory farm gas became the most carbon negative fuel in the LCFS market, and thus, the most valuable. The LCFS also allows dairies that are already being paid with public funds to reduce methane with dairy digesters to double-dip by claiming the LCFS incentive was the reason for the reductions, blatantly evading the AB 32 prohibition on "non-additional" reductions from being sold into market-based mechanisms.

D. Factory Farm Gas Production and Deployment is Significantly Subsidized and Therefore Highly Profitable for Large Dairies

The current regulatory landscape provides significant subsidies to dairies to install digesters and produce factory farm gas. This funding includes CDFA's DDRDP, CPUC ratepayer funding, CEC's PIER, EPIC, and Clean Transportation funding, and CARB's Aliso Canyon Mitigation Funding. To date just these direct cash subsidies total close to $700 million with the majority of this funding coming from legislative appropriations to the Dairy Digester and Research Development Program (DDRDP) and utility rate-payers. The Legislature, through annual appropriations from the Greenhouse Gas Reduction Fund and General Fund, has allocated over $200 million to the DDRDP and the CPUC has directed almost $400 million of rate–payer funds to support development and operations of dairy digesters and related infrastructure.

In addition to these direct subsidies along with credit sales available through California's Cap-and-Trade offset program, the Low Carbon Fuel Standard (LCFS) creates a lucrative credit market for industrial dairies that install digesters. CARB designed a life cycle analysis that excludes upstream and downstream greenhouse gas emissions and **treats liquified manure lagoons (and the methane they create) not as an intentionally chosen cost-cutting measure but as a necessary, inevitable part of operating a dairy, which it plainly is not.**

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19 See "Veto Request – Senate Bill 1383 (Lara) – Dairy Industry Exemptions from short-lived climate pollutants: methane emissions" (September 13, 2016) https://drive.google.com/file/d/1OhQ4bpGX6eNEhgC64Mneel2jpH6Ja5xl/view?usp=sharing

20 The legislative hearing for Senate Bill 1383 sheds light on the unprecedented benefits the Legislature provided the dairy industry, provoking a lobbyist for the oil industry to warn that it would return to the Legislature for its version of special treatment. See Assembly Natural Resources Committee, Hearing on Senate Bill 1383, available at http://calchannel.granicus.com/MediaPlayer.php?view_id=23&clip_id=4009 (beginning at hour 1:12) (last visited October 24, 2022).

As noted earlier, CARB has determined that methane captured through the production of gas magically makes biomethane carbon negative, and thus generates far more credits for sale in the LCFS credit market than if CARB had treated it like every other fuel. The result has been a deluge of credits which creates a massive windfall for industrial dairies and factory farm gas producers.

The dairy industry is very aware of the monumental investment California made to support the production of factory farm gas and the lucrative LCFS credit market for gas. In fact, the dairy industry itself anticipates a future where "milk has become the by-product of manure production." [21]

Studies project that larger dairies can enjoy a third to a half of their revenue from LCFS credit revenues,[22] begging the question - what's worth more, a cow's milk or its poop?[23] And the necessary follow-up: if we're even asking these questions, what perverse incentives have we created and to what consequences will they lead?

E. The Resulting Profit Incentive Favors and Entrenches Harmful Practices and Drives Industrial Dairy Expansions

The narrative echoed by the dairy industry and those that profit from buying and selling LCFS credits treats the methane pollution as some kind of inevitable consequence, a natural by-product of dairy production that demands a solution. This narrative entirely ignores the fact that the liquefied manure and the associated massive methane problem was the path that state and local governments and dairy operators themselves chose to follow despite knowing the environmental degradation those decisions would create. And now the state's solution to our methane disaster has itself reinforced harmful manure management and industrial-scale dairy practices that entrench and intensify air and water pollution. Data show that all of these incentives have contributed to an intensification of dairy expansions as dairy operators and those profiting from the LCFS respond to the market demand for manure-based fuels and the lucrative credit markets by expanding dairy operations to produce more manure.

Merced County provides an apt example of the effect this regulatory landscape has on expanding industrial dairy operations. For instance, the Merced Planning Department posts recently prepared environmental documents on the Merced County website.Based solely on the information on this website, Merced County has permitted, or is in the process of permitting, two biogas pipeline and infrastructure projects, ten dairy expansions, and one new 28,000 cow dairy.[24]

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21 See: https://hoards.com/article-30925-energy-revenue-could-be-a-game-changer-for-dairy-farms.html. Also see: https://twitter.com/drcrystalheath/status/1587320922578378752?s=20&t=sm90vQRFTh91HZ9zY4Yzgg.

22 Younes, A. and Fingerman, K. (2021). Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard. Arcata, CA. Available at: https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf.

23 Smith, Aaron (2021) "What's Worth More: A Cow's Milk or its Poop?" Ag Data News Blog. (February 2021) Available at https://asmith.ucdavis.edu/news/cow-power-rising.

24 See Environmental Documents, available at https://www.countyofmerced.com/414/Environmental-Documents (last visited December 19, 2022).

The biogas cluster and pipeline projects facilitate dairy expansions to monetize and incentivize increased dairy herds and manure generation. The total additional number of dairy cows (milk cows and support stock) from the above-listed projects is 46,148 cows. It's important to note that several counties do not require environmental review for dairy expansions. In those counties, it is much harder – if not impossible – to assess the extent to which dairies have grown and/or consolidated.

Both the historical expansion of the California Dairy industry and the more recent perverse effects of the LCFS that drive herd expansions show how local land use and Senate Bill 1383 have encouraged both dairy industry expansion and dramatic increases in methane pollution. And instead of requiring the industry to limit its pollution, the Legislature rewarded the reckless expansion by paying operators to profit from the methane emissions they chose to create in the first place. As one study on the impacts of the LCFS notes, "in this instance the largest polluter is the one receiving a large subsidy." [25]

F. Factory Farm Gas Production Itself Exacerbates Existing Environmental Impacts from Industrial Dairies

Factory farm gas production requires liquified manure lagoons, a profit-maximizing practice that exacerbates water pollution and as discussed throughout this briefing paper, subsidies for factory farm gas incentivize the growth of herds and concentration of animals, which results in increased air and water pollution. Additionally, the very production and use of factory farm gas creates pollution of its own.

Anaerobic digesters increase ammonia emissions, which in turn react with oxides of nitrogen (NOx) to form ammonium nitrate, which significantly contributes to fine particulate matter (PM2.5) pollution.[26] One study found that use of an anaerobic digester increased ammonia emissions from manure as a result of changes in the composition of digested, as compared to undigested, manure. [27]

Combusting factory farm gas on-site, including digester engines powering turbines to generate LCFS credits for electric vehicle fuel, emit significant and unabated additional NOx, PM2.5, and volatile organic compound (VOC) emissions in the air basin. Combined, both effects exacerbate the PM2.5 pollution crisis in the San Joaquin Valley. When upgraded to be used in place of fossil natural gas, it produces all the same emissions when combusted, whether as transportation fuel or used in buildings.

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25 Younes, A. and Fingerman, K. (2021). Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard. Arcata, CA. Available at: https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf.

26 Michael A. Holly et al., Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application Agriculture, 239 ECOSYSTEMS AND ENV'T 410, 418 (Feb. 15, 2017), https://doi.org/10.1016/j.agee.2017.02.007.

27 See Michael A. Holly et al., Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application Agriculture, Ecosystems & Environment (2017).

Moreover, factory farm gas production relies upon methane digesters, which require "abundant water resources, with a ratio equal to 1:1 of the amount of water and manure to be loaded into the digester,"[28] to pump and dilute manure. In arid climates it may be necessary to pump groundwater for this purpose.[29]

G. Factory Farm Gas Credits Facilitate Ongoing Pollution from Fossil Fuel Production and Combustion

As described above, transportation fuels derived from dairy and swine manure receive LCFS credits and the amount of those credits entering the market has been drastically inflated as a result of improper negative carbon intensity values and non-additional credits. In 2021, these fuels represented approximately 10 percent of all credits sold.[30] Because the LCFS authorizes fuel producers to purchase credits to meet the LCFS market-based compliance mechanism's emission limits, the excessive and illegitimate credits generated by factory farm gas producers allow fossil fuel producers – oil companies – to refine and sell more of their fossil fuels. While communities in the San Joaquin Valley suffer the air, water, and nuisance pollution from factory farm gas fuel production, communities near refineries and near major transportation corridors endure racially disparate impacts from the production and combustion of fossil fuels benefitting from those credits. For example, Black Californians experience twice the PM2.5 burden of white Californians from Cap and Trade facilities, while "Black Californians experience PM2.5 concentrations from refineries that are three times greater than all other stationary source sectors combined that are covered by the Cap-and-Trade Program."[31] Further, "African American, Latino, and Asian Californians are exposed to more PM2.5 pollution from cars, trucks, and buses than white Californians. These groups are exposed to PM2.5 pollution 43, 39, and 21 percent higher, respectively, than white Californians." Additionally, "[T]he lowest-income households in the state live where PM2.5 pollution is 10 percent higher than the state average, while those with the highest incomes live where PM2.5 pollution is 13 percent below the state average."[32]

In other words, as a result of CARB's factory farm gas policies, communities on both sides of the LCFS credit transaction subsidize polluters with compromised health and well-being.

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28 Tatiana Nevzorova & Vladimir Kutcherov, Barriers to the wider implementation of biogas as a source of energy: A state-of-the-art review, 26 ENERGY STRATEGY REVIEWS 7 (Oct. 14, 2019), https://www.sciencedirect.com/science/article/pii/S2211467X19301075#bib113.

29 ENVTL. PROTECTION AGENCY, AGSTAR, PROJECT DEVELOPMENT HANDBOOK: A HANDBOOK FOR DEVELOPING ANAEROBIC DIGESTION/BIOGAS SYSTEMS ON FARMS IN THE UNITED STATES 9-5, https://www.epa.gov/sites/default/files/2014-12/documents/agstar-handbook.pdf (3rd Ed.).

30 See CARB, LCFS Quarterly Data Spreadsheet, available at https://ww2.arb.ca.gov/sites/default/files/2022-10/quarterlysummary_103122_1.xlsx (data available under "Feedstock" tab).

31 *Id.*

32 *Union of Concerned Sci., Inequitable Exposure to Air Pollution from Vehicles in California* (Feb. 2019), https://www.ucsusa.org/sites/default/files/attach/2019/02/cv-air-pollution-CA-web.pdf.

V. CHANGING COURSE: CREATING A NEW PATH FORWARD

We have the opportunity and need to reshape the regulatory framework for livestock methane and factory farm gas to effectively reduce greenhouse gas emissions from industrial livestock operations while cutting off profit motives for concentrating livestock and manure which intensify climate impacts, exacerbate environmental degradation, and perpetuate dumping on San Joaquin Valley communities. We lay out three approaches below for rectifying existing deficiencies: correcting inadequacies in the Low Carbon Fuel Standard program, regulating livestock methane emissions, and excluding factory farm gas from inclusion in our clean energy portfolio.

A. Fix the Low Carbon Fuel Standard Program

The legislature should step in to ensure an updating to the LCFS and other programs to account for full lifecycle emissions, prohibit claiming of non-additional reductions, prevent harm to lower income communities and communities of color, and eliminate windfall profits due to lack of regulation.

Although a number of regulatory actions are responsible for driving these troubling trends in California's dairy industry, the LCFS is currently the most directly responsible for incentivizing herd concentration and polluting manure management practices. CARB is preparing to open a rulemaking to update the LCFS yet,to date there has been no commitment to address the issues raised above. Although CARB staff have not released an official scope for the rulemaking, in a recent workshop CARB proposed continuing to issue the massively inflated credits until at least 2040.[33] Additionally, CARB has indicated that they will rely on the LCFS to ensure the ongoing profitability and viability of biomethane to facilitate its transition into industrial energy markets when its purported use as transportation fuels gives way to our electric vehicle future.

Given the urgency of the issue and CARB's demonstrated unwillingness to address the consequences of its failing regulatory approach, the Legislature is well-positioned to provide much-needed direction to CARB to ensure the program is in line with California's commitments to addressing GHG emissions and environmental injustice.

B. Eliminate Factory Farm Gas from Definitions of Renewable Energy

As brought to the forefront during hearings on SB 1020 last year, resources eligible to meet the requirements of the Renewable Portfolio Standard (RPS) and SB 100 (RPS plus zero carbon resources) include "digester gas" which includes factory farm gas.

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33 See presentation for CARB Low Carbon Fuel Standard Workshop November 9, 2022. Available at https://ww2.arb.ca.gov/sites/default/files/2022-11/LCFSPresentation.pdf.

The definition of factory farm gas as "renewable" supports its inclusion in existing climate programs, such as the LCFS[34] and emerging energy technologies, such as hydrogen[35] and opens up or expands markets and subsidies for the dirty fuel. By eliminating factory farm gas from the definition of renewable energy, California can ensure current and future efforts to transition California's energy and transportation systems are real environmental justice solutions and not a polluting cash cow. Cleaning up our energy sector is challenging enough already without false solutions muddying the water.

C. Regulate Livestock Greenhouse Gas Emissions

As stated above, SB 1383 permits CARB to directly regulate livestock methane emissions starting in 2024 but provides CARB discretion and several off-ramps that provide ready justifications for CARB to continue the failing LCFS-centered strategy, including using the LCFS to subsidize factory farm gas for to support its growth in industrial sectors. The Legislature must direct CARB to adopt mandatory regulations and acknowledge the last-minute dairy methane provisions in Senate Bill 1383 were an unprecedented and ill-advised industry giveaway. California must treat the dairy industry like every other major source of greenhouse gas emissions. We cannot continue to treat the most climate-impacting practices as inevitable and force the public to pay polluters to stop polluting thereby rewarding the biggest and worst polluters.

For more information contact: Jamie Katz, Staff Attorney, jbkatz@leadershipcounsel.org

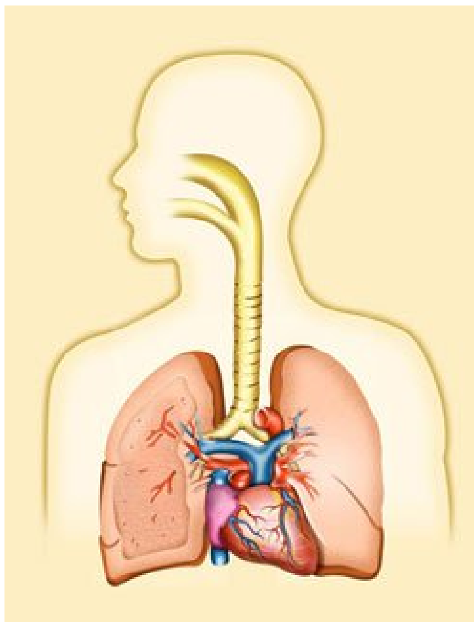
34 Cal. Code Regs. Tit 17 § 95481-95482.
35 Pub. Res. Code § 25664

LEADERSHIP COUNSEL FOR JUSTICE & ACCOUNTABILITY

ATTACHMENT F

Health Effects of Ozone Pollution

Ozone in the air we breathe can harm our health, especially on hot sunny days when ozone can reach unhealthy levels. Even relatively low levels of ozone can cause health effects.



Ozone is a powerful oxidant that can irritate the airways.

For Healthcare Providers

Ozone and Your Patients' Health: Training for Healthcare Providers <https://epa.gov/ozone-pollution-and-your-patients-health>

Who is at risk?

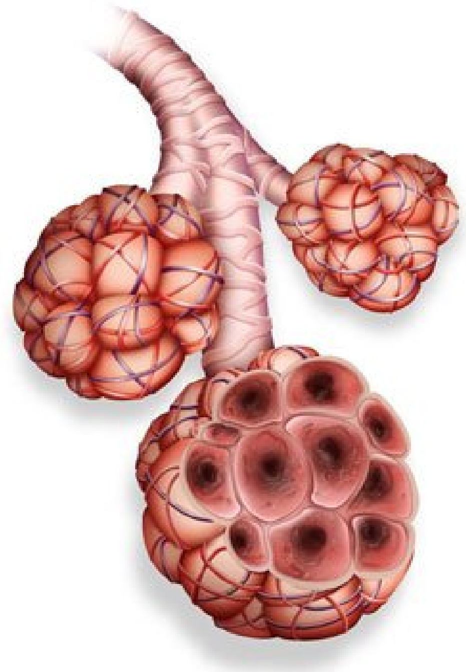
People most at risk from breathing air containing ozone include people with asthma, children, older adults, and people who are active outdoors, especially outdoor workers. In addition, people with certain genetic characteristics, and people with reduced intake of certain nutrients, such as vitamins C and E, are at greater risk from ozone exposure.

Children are at greatest risk from exposure to ozone because their lungs are still developing and they are more likely to be active outdoors when ozone levels are high, which increases their exposure. Children are also more likely than adults to have asthma.

What health problems can ozone cause?

Depending on the level of exposure, ozone can:

- Cause coughing and sore or scratchy throat.
- Make it more difficult to breathe deeply and vigorously and cause pain when taking a deep breath.
- Inflame and damage the airways.
- Make the lungs more susceptible to infection.
- Aggravate lung diseases such as asthma, emphysema, and chronic bronchitis.
- Increase the frequency of asthma attacks.



Ozone can cause the muscles in the airways to constrict, trapping air in the alveoli. This leads to wheezing and shortness of breath.

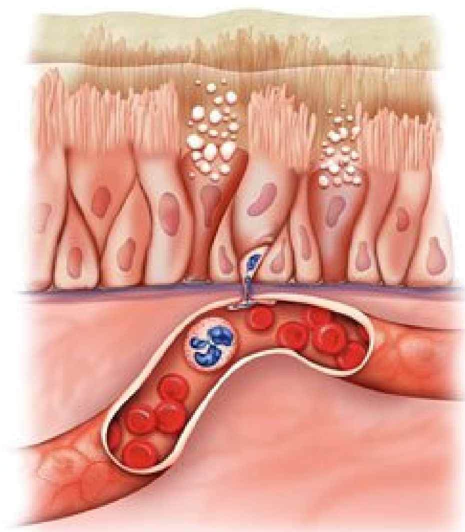
Some of these effects have been found even in healthy people, but effects can be more serious in people with lung diseases such as asthma. They may lead to increased school absences, medication use, visits to doctors and emergency rooms, and hospital admissions.

Long-term exposure to ozone is linked to aggravation of asthma, and is likely to be one of many causes of asthma development. Studies in locations with elevated concentrations also report associations of ozone with deaths from respiratory causes.

How can I reduce these health risks?

The AirNow Web site <http://www.airnow.gov/> provides daily air quality reports for many areas. These reports use the Air Quality Index (or AQI) to tell you how clean or polluted the air is.

EnviroFlash, a free service, can alert you via email when your local air quality is a concern. Sign up at www.enviroflash.info <http://www.enviroflash.info/>.



With inflammation, the airway lining is damaged. It has been compared to the skin inflammation caused by sunburn.

Pamphlets and other resources:

- Printable pamphlets and booklets about ozone effects on air quality and health. <https://epa.gov/ground-level-ozone-pollution/pamphlets-about-ozone-effects-air-quality-and-health>

- EPA's Air Quality Guide for Ozone <https://epa.gov/sites/production/files/2017-12/documents/air-quality-guide_ozone_2015.pdf> provides detailed information about what the Air Quality Index means. Helps determine ways to protect your family's health when ozone levels reach the unhealthy range, and ways you can help reduce ozone air pollution.
- Ozone and Your Patients' Health: Training for Health Care Providers <https://epa.gov/ozone-pollution-and-your-patients-health> is designed for family practice doctors, pediatricians, nurse practitioners, asthma educators, and other medical professionals who counsel patients about asthma and respiratory symptoms.
- AirNow Health Providers Information <https://www.airnow.gov/air-quality-and-health/your-health/> provides information on how to help patients protect their health by reducing their exposure to air pollution.
- EPA's Asthma Web Site <https://epa.gov/asthma> provides information for EPA's Communities in Action Asthma Initiative that includes programs to address indoor and outdoor environments that cause, trigger or exacerbate asthma symptoms.

Ozone Pollution Home <https://epa.gov/ground-level-ozone-pollution>

Ozone Basics <https://epa.gov/ground-level-ozone-pollution/ground-level-ozone-basics>

Health Effects

Ecosystem Effects <https://epa.gov/ground-level-ozone-pollution/ecosystem-effects-ozone-pollution>

Setting and Reviewing Ozone Standards <https://epa.gov/ground-level-ozone-pollution/setting-and-reviewing-standards-control-ozone-pollution>

Ozone Standards Regulatory Actions <https://epa.gov/ground-level-ozone-pollution/ozone-national-ambient-air-quality-standards-naaqs>

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Ozone Implementation Regulatory Actions <https://epa.gov/ground-level-ozone-pollution/ozone-implementation-regulatory-actions>

SIP Checklist Guide <https://epa.gov/ground-level-ozone-pollution/state-implementation-plan-sip-checklist-guide>

SIP Training Presentations and Assistance <https://epa.gov/ground-level-ozone-pollution/implementation-training-and-assistance-state-and-local-air-agencies>

Implementation Data and Reports <https://epa.gov/ground-level-ozone-pollution/technical-data-and-reports-ozone-measurements-and-sip-status>

Contact Us <https://epa.gov/ground-level-ozone-pollution/forms/contact-us-about-ozone-pollution> to ask a question, provide feedback, or report a problem.

LAST UPDATED ON MAY 24, 2023

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ATTACHMENT G

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R09–OAR–2021–0884; FRL–9292–03–R9]

Clean Air Plans; 2012 Fine Particulate Matter Serious Nonattainment Area Requirements; San Joaquin Valley, California

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: On December 29, 2021, the Environmental Protection Agency (EPA or ''Agency'') published a proposed rule to approve the State of California's Serious area plan for the San Joaquin Valley (SJV) for the 2012 annual fine particulate matter ($PM_{2.5}$) national ambient air quality standards (NAAQS) for all Serious $PM_{2.5}$ area planning requirements, except for contingency measures, which the EPA proposed to disapprove. Based on adverse comments submitted on that proposed rule and as a result of a Ninth Circuit Court of Appeals decision on a related SJV $PM_{2.5}$ rulemaking for the 2006 24-hour $PM_{2.5}$ NAAQS, the EPA has reconsidered its prior proposal and now proposes to disapprove the State's plan for certain Serious area planning requirements for the 2012 annual $PM_{2.5}$ NAAQS. The nonattainment plan elements that the EPA proposes to disapprove include the plan's best available control measures (BACM) demonstration for ammonia and building heating, demonstrations of attainment and reasonable further progress, quantitative milestones, and motor vehicle emission budgets. The EPA is also proposing to disapprove the State's optional precursor demonstration for ammonia. We are not re-proposing any action on the Serious area requirements for emissions inventories nor contingency measures; our prior proposal to approve the emissions inventory element and to disapprove the contingency measure element of the nonattainment plan requirements for the 2012 annual $PM_{2.5}$ NAAQS remains unchanged. The EPA will accept comments on this new proposed rule during a 45-day public comment period and public hearing, as described in this notice.

DATES: Any comments must arrive by November 21, 2022.

Public hearings: The EPA will host two public hearings on this proposed rule. The first will take place November 2, 2022, 7:30 p.m. to 8:30 p.m. The second will take place November 3, 2022, 7:00 p.m. to 8:00 p.m. The hearings will be held to accept oral comments on this proposed rule. Immediately prior to each public hearing, and on October 28, 2022, the EPA will host public meetings on this proposed rule. For further information on the public hearings and public meetings, please see the **ADDRESSES** and **SUPPLEMENTAL INFORMATION** sections.

ADDRESSES: The November 2, 2022 public hearing will take place at Fresno City College, Old Administration Building, Room 251, 1101 E University Ave., Fresno, CA 93741. The November 3, 2022 public hearing will take place at Bakersfield College, Norman Levan Center, 1801 Panorama Drive, Bakersfield, CA 93305.

Submit your comments, identified by Docket ID No. EPA–R09–OAR–2021–0884, at *https://www.regulations.gov.* For comments submitted at *Regulations.gov*, follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov*. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

FOR FURTHER INFORMATION CONTACT: For questions regarding this proposed rule, please contact Rory Mays, Air Planning Office (AIR–2), EPA Region IX, (415) 972–3227. For questions regarding the public hearings and related public meetings, please contact Kelley Xuereb, Immediate Office (AIR–1), EPA Region IX, (415) 947–4171. Both can be reached by emailing *SJVPublicMeetings@epa.gov.*

SUPPLEMENTARY INFORMATION: In addition to the two in-person public hearings, the EPA will host three public meetings. The public meetings are an informal opportunity to speak with EPA staff about the action. We will not accept public comments during the public meetings. The first meeting will be held virtually on October 28, 2022, 12:00 p.m. to 2:00 p.m. Participants can register to attend the meeting at: *https://usepa.zoomgov.com/meeting/register/vJItc-qppzooGCZI10LqoTXf6OpNZIVbWco.*

The second will take place on November 2, 2022, 5:30 p.m. to 7:00 p.m. prior to the public hearing at Fresno City College, Old Administration Building, Room 251, 1101 E University Ave., Fresno, CA 93741. The third will take place on November 3, 2022, 5:00 p.m. to 6:30 p.m. prior to the public hearing at Bakersfield College, Norman Levan Center, 1801 Panorama Drive, Bakersfield, CA 93305. Spanish translation will be available during all three events. If you would like to submit a request for reasonable accommodation, please email *SJVPublicMeetings@epa.gov.* For additional information and updates, please visit: *https://www.epa.gov/sanjoaquinvalley.*

Throughout this document, ''we,'' ''us,'' and ''our'' refer to the EPA.

Table of Contents

I. Background for Proposed Action

The EPA discussed background, applicable State implementation plan (SIP) submissions, completeness review, and Clean Air Act (CAA or ''Act'') requirements for the SJV Serious $PM_{2.5}$

nonattainment area [1] in sections I, II, and III of our December 29, 2021 proposed rule on California's Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS.[2] We refer to that proposed rule herein as the ''2021 Proposed Rule,'' briefly summarize the relevant CAA requirements and our previous proposed action with respect to those requirements here, and rely on the more detailed expositions in that proposed rule.

The EPA promulgated the primary annual $PM_{2.5}$ NAAQS of 12.0 micrograms per cubic meter (μg/m³) in 2012 (''2012 annual $PM_{2.5}$ NAAQS''),[3] designated and classified the SJV as Moderate nonattainment for this NAAQS in 2015,[4] and reclassified the SJV from Moderate to Serious nonattainment for this NAAQS in our final rule published November 26, 2021.[5] That reclassification action required California to submit a ''Serious area'' attainment plan. Such an attainment plan must include, among other things, provisions to assure that, under CAA section 189(b)(1)(B), the BACM for the control of direct $PM_{2.5}$ and $PM_{2.5}$ precursors are implemented no later than four years after reclassification of the area and a demonstration (including air quality modeling) that the plan provides for attainment of this NAAQS as expeditiously as practicable but no later than December 31, 2025. That reclassification action also triggered statutory deadlines for California to submit SIP submissions addressing the Serious area attainment plan requirements for the 2012 annual $PM_{2.5}$ NAAQS: June 27, 2023, for emissions inventories, BACM, and nonattainment new source review (NSR), and December 31, 2023, for the attainment demonstration and related planning requirements.

A. Applicable SIP Submissions, Completeness Review, and Clean Air Act Requirements

In this proposed rule, the EPA is proposing action on portions of two SIP submissions submitted by the California Air Resources Board (CARB) to address combined nonattainment plan requirements for the 1997, 2006, and 2012 $PM_{2.5}$ NAAQS in the SJV.[6] Specifically, the EPA is proposing to act only on those portions of the following two plan submissions that pertain to the Serious area requirements for the 2012 annual $PM_{2.5}$ NAAQS: (1) the ''2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards,'' adopted by the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD or District) on November 15, 2018, and by CARB on January 24, 2019 (''2018 $PM_{2.5}$ Plan''); [7] and (2) the ''San Joaquin Valley Supplement to the 2016 State Strategy for the State Implementation Plan,'' adopted by CARB on October 25, 2018 (''Valley State SIP Strategy'').

We refer to the relevant portions of these SIP submissions collectively in this proposal as the ''SJV $PM_{2.5}$ Plan'' or ''Plan.'' The SJV $PM_{2.5}$ Plan addresses attainment plan requirements for multiple $PM_{2.5}$ NAAQS in the SJV. CARB submitted the SJV $PM_{2.5}$ Plan to the EPA as a revision to the California SIP on May 10, 2019.[8] These SIP submissions became complete by operation of law on November 10, 2019.[9] In the 2021 Proposed Rule, we proposed to find that the 2018 $PM_{2.5}$ Plan and Valley State SIP Strategy each met the procedural requirements for public notice and hearing in CAA sections 110(a)(1) and (2) and 110(l) and 40 CFR 51.102.

In our 2021 Proposed Rule, we also summarized the CAA requirements applicable to Serious $PM_{2.5}$ nonattainment areas.[10] In the current proposed rule, we are proposing action with respect to the following requirements:

(1) Provisions to assure that BACM, including best available control technology (BACT), for the control of direct $PM_{2.5}$ and all $PM_{2.5}$ precursors shall be implemented no later than four years after the area is reclassified (CAA section 189(b)(1)(B)), unless the State elects to make an optional precursor demonstration that the EPA approves authorizing the State not to regulate one or more of these pollutants;

(2) A demonstration (including air quality modeling) that the plan provides for attainment as expeditiously as practicable but no later than the end of the tenth calendar year after designation as a nonattainment area (*i.e.,* December 31, 2025, for the SJV for the 2012 annual $PM_{2.5}$ NAAQS) (CAA sections 188(c)(2) and 189(b)(1)(A)(i));

(3) Plan provisions that require reasonable further progress (RFP) (CAA section 172(c)(2));

(4) Quantitative milestones that the State must meet every three years until the EPA redesignates the area to attainment and which demonstrate RFP toward attainment by the applicable date (CAA section 189(c)); and

(5) Motor vehicle emissions budgets (budgets) for 2025 (CAA section 176(c)).

We are also proposing to disapprove the State's optional precursor demonstration for ammonia.[11]

In addition, the State's Serious area plan must meet the general requirements applicable to all SIP submissions under section 110 of the CAA, including the requirement to provide necessary assurances that the implementing agencies have adequate personnel, funding, and authority under section 110(a)(2)(E); and the requirements concerning enforcement provisions in section 110(a)(2)(C).

[1] For a precise description of the geographic boundaries of the SJV $PM_{2.5}$ nonattainment area, see 40 CFR 81.305.

[2] 86 FR 74310 (December 29, 2021).

[3] 78 FR 3086 (January 15, 2013) and 40 CFR 50.18. Unless otherwise noted, all references to the $PM_{2.5}$ standards in this notice, including all instances of ''2012 annual $PM_{2.5}$ NAAQS,'' are to the 2012 primary annual NAAQS of 12.0 μg/m³ codified at 40 CFR 50.18.

[4] 80 FR 2206 (January 15, 2015) (codified at 40 CFR 81.305).

[5] 86 FR 67343 (November 26, 2021).

[6] In our 2021 Proposed Rule, we also proposed action on a third SIP submission dated July 19, 2019. 86 FR 74310, 74311. However, the relevant component of that submission pertained only to contingency measures, and we are not modifying our proposed action on contingency measures in this proposed rule.

[7] The 2018 $PM_{2.5}$ Plan was developed jointly by CARB and the District.

[8] Letter dated May 9, 2019, from Richard W. Corey, Executive Officer, CARB, to Mike Stoker, Regional Administrator, EPA Region IX. Previously, in separate rulemakings, the EPA has finalized action on the portions of the SJV $PM_{2.5}$ Plan that pertain to the 1997 annual $PM_{2.5}$ NAAQS, the 1997 24-hour $PM_{2.5}$ NAAQS, the 2006 24-hour $PM_{2.5}$ NAAQS, and the Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS. See 86 FR 67329 (November 26, 2021) (final rule regarding the 1997 annual $PM_{2.5}$ NAAQS); 87 FR 4503 (January 28, 2022) (final rule regarding the 1997 24-hour $PM_{2.5}$ NAAQS); 85 FR 44192 (July 22, 2020) (final rule regarding the 2006 24-hour $PM_{2.5}$ NAAQS, except contingency measures); and 86 FR 67343 (November 26, 2021) (final rule regarding the Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS and contingency measures for the 2006 24-hour $PM_{2.5}$ NAAQS).

[9] 87 FR 74310, 74311–74312. We note that, with respect to plans previously required for the 1997, 2006, and 2012 $PM_{2.5}$ NAAQS, including the Moderate area plan only for the 2012 annual $PM_{2.5}$ NAAQS, the EPA had made findings of failure to submit effective January 7, 2019, that triggered sanctions clocks. 83 FR 62720 (December 6, 2018). Following the May 10, 2019 submission of the 2018 $PM_{2.5}$ Plan and Valley State SIP Strategy, the EPA affirmatively determined that the SIP submissions addressed the deficiency that was the basis for such findings, resulting in the termination of the associated sanctions clocks. Letter dated June 24, 2020, from Elizabeth Adams, Director, Air and Radiation Division, EPA Region IX, to Richard W. Corey, Executive Officer, CARB. However, the findings of failure to submit did not apply to the Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS because it was not yet required, and the June 24, 2020 completeness letter did not address the Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS.

[10] 87 FR 74310, 74313.

[11] We are not re-proposing any action on the Serious area requirements for emissions inventories nor contingency measures; our prior proposal to approve the emissions inventory element and to disapprove the contingency measure element of the nonattainment plan requirements for the 2012 annual $PM_{2.5}$ NAAQS remains unchanged.

The EPA provided its preliminary views on the CAA's requirements for particulate matter plans under part D, title I of the Act in the following guidance documents: (1) ''State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990'' (''General Preamble''); [12] (2) ''State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental'' (''General Preamble Supplement''); [13] and (3) ''State Implementation Plans for Serious PM–10 Nonattainment Areas, and Attainment Date Waivers for PM–10 Nonattainment Areas Generally; Addendum to the General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990'' (''General Preamble Addendum'').[14] More recently, in an August 24, 2016 final rule entitled, ''Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements'' (''$PM_{2.5}$ SIP Requirements Rule''), the EPA established regulatory requirements and provided further interpretive guidance on the statutory SIP requirements that apply to areas designated nonattainment for all $PM_{2.5}$ NAAQS.[15] We discuss these regulatory requirements and interpretations of the Act as appropriate in our evaluation of the State's submissions below.

B. December 29, 2021 Proposed Rule

In our 2021 Proposed Rule, the EPA proposed to approve the SJV $PM_{2.5}$ Plan's: (1) emissions inventory for the 2013 base year; (2) precursor demonstrations that emissions of ammonia, sulfur oxides (SO_X), and volatile organic compounds (VOC) do not significantly contribute to exceedances of the 2012 annual $PM_{2.5}$ NAAQS in the SJV; (3) BACM demonstration for emission sources of direct $PM_{2.5}$ and nitrogen oxides (NO_X); (4) attainment demonstration based on air quality modeling [16] and emissions reductions related to aggregate commitments; (5) RFP demonstration; (6) quantitative milestones; and (7) motor vehicle emission budgets. We briefly summarize several aspects of those proposed approvals in the applicable sub-sections of section II of this proposed rule.

We also proposed to disapprove the Plan's contingency measures and noted the requirements for nonattainment NSR and the State's separate submission for the nonattainment NSR requirements. However, as we are not re-proposing any action on contingency measures nor nonattainment NSR in this proposed rule, we do not summarize those proposals herein.[17] In addition, we are not re-proposing any action on the Plan's precursor demonstrations for SO_X and VOC in this proposed rule; our 2021 Proposed Rule to approve the 2018 $PM_{2.5}$ Plan's demonstrations that emissions of SO_X and VOC do not significantly contribute to exceedances of the 2012 annual $PM_{2.5}$ NAAQS in the SJV remains unchanged.

Finally, we are not re-proposing any action in this proposed rule on the Plan's base year emissions inventory; our 2021 Proposed Rule to approve the 2018 $PM_{2.5}$ Plan's base year emissions inventory remains unchanged. Nevertheless, we briefly summarize our prior proposal [18] given the role that base year emissions inventories play in developing a plan's control strategy and attainment and RFP demonstrations.

The 2018 $PM_{2.5}$ Plan includes summaries of the planning emissions inventories for direct $PM_{2.5}$ and all $PM_{2.5}$ precursors (NO_X, SO_X,[19] VOC,[20] and ammonia) and related documentation. The Plan contains annual average daily emission inventories for 2013 through 2028 projected from the 2012 actual emissions inventory,[21] including the 2013 base year, the 2019 and 2022 RFP milestone years, the 2025 Serious area attainment year, and a 2028 post-attainment RFP year. The EPA proposed to approve the 2013 base year emissions inventory in the 2018 $PM_{2.5}$ Plan as meeting the requirements of CAA section 172(c)(3) and 40 CFR 51.1008. We also proposed to find that the future year baseline inventories in the 2018 $PM_{2.5}$ Plan satisfy the requirements of 40 CFR 51.1008(b)(2) and 51.1012(a)(2) and provide an adequate basis for the control measure, attainment, and RFP demonstrations for the 2012 annual $PM_{2.5}$ NAAQS in the 2018 $PM_{2.5}$ Plan.

C. Adverse Comments Submitted January 28, 2022

The EPA received adverse comments on our 2021 Proposed Rule from a coalition of 13 environmental, public health, and community organizations (collectively referred to herein as ''Public Justice'').[22] We are not responding to these comments (in the sense of a final rulemaking action) in this proposed rule, but the Agency has taken them into account with respect to the Serious area plan elements discussed in this proposed rule.

Overall, the commenters argue that the EPA must disapprove the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan based on alleged nonattainment plan requirement deficiencies in the submissions. We introduce these comments in this section of this proposed rule and present more detailed summaries and discussion of the comments in sections II.A (ammonia precursor demonstration), II.B.2 (BACM for ammonia emission sources), II.B.3 (BACM for building heating emission sources), II.C (attainment demonstration), and IV (Title VI of the Civil Rights Act).

Regarding CAA requirements for $PM_{2.5}$, Public Justice points to a history of failures to timely attain the 1997 annual $PM_{2.5}$ NAAQS in the SJV and states that ''[r]egulators point to a host of excuses from weather, to international sources, to Federal inaction, but repeatedly the State and Air District have refused to adopt feasible controls or regulate politically powerful entities'' such as agricultural sources of air pollution.[23] The commenters take issue with the EPA's proposal to approve the plan for the stricter 2012 standard ''without performing its duty to hold [CARB] and the [District] accountable to meet the

[12] 57 FR 13498 (April 16, 1992).

[13] 57 FR 18070 (April 28, 1992).

[14] 59 FR 41998 (August 16, 1994).

[15] 81 FR 58010 (August 24, 2016).

[16] We described 2018 $PM_{2.5}$ Plan's air quality modeling and our evaluation thereof in section IV.C of the 2021 Proposed Rule.

[17] Regarding nonattainment NSR, please see the EPA's separate rulemaking on the State's November 20, 2019 SIP submission of amendments to SJVUAPCD Rule 2201 (''New and Modified Stationary Source Review''). 87 FR 45730 (July 29, 2022) (proposed limited approval and limited disapproval of the Rule 2201 amendments).

[18] See section IV.A of the EPA's 2021 Proposed Rule.

[19] The SJV $PM_{2.5}$ Plan generally uses ''sulfur oxides'' or ''SO_X'' in reference to SO_2 as a precursor to the formation of $PM_{2.5}$. We use SO_X and SO_2 interchangeably throughout this notice.

[20] The SJV $PM_{2.5}$ Plan generally uses ''reactive organic gasses'' or ''ROG'' in reference to VOC as a precursor to the formation of $PM_{2.5}$. We use ROG and VOC interchangeably throughout this notice.

[21] 2018 $PM_{2.5}$ Plan, App. B, B–18.

[22] Comment letter dated and received January 28, 2022, from Brent Newell, Public Justice, et al., to Rory Mays, EPA, including Exhibits 1 through 47. We note, however, that there is no Exhibit 23; so, there are 46 exhibits in total. Email dated February 1, 2022, from Brent Newell, Public Justice, to Rory Mays, EPA Region IX. The 13 environmental, public health, and community organizations are Public Justice, Central Valley Environmental Justice Network, Association of Irritated Residents, Central Valley Air Quality Coalition, Leadership Counsel for Justice and Accountability, Valley Improvement Projects, The LEAP Institute, Little Manila Rising, Center for Race, Poverty, and the Environment, Central California Asthma Collaborative, Animal Legal Defense Fund, National Parks Conservation Association, and Food and Water Watch (collectively ''Public Justice'').

[23] Public Justice Comment Letter, 2.

minimum requirements Congress imposed to protect human health.'' [24] The commenters assert that the EPA relies on flawed, outdated information, ignores feasible controls, refuses to require regulation of ammonia, accepts aggregate commitments in lieu of other control strategies, and fails to address pollution sources in disadvantaged communities in the SJV.[25] With respect to specific CAA requirements, the commenters argue that the EPA must disapprove the Plan's emissions inventory, ammonia precursor demonstration, BACM demonstration, and aggregate commitments.

Regarding Title VI of the Civil Rights Act, the commenters argue that California must provide necessary assurances that the SIP complies with Title VI of the Civil Rights Act, pursuant to CAA section 110(a)(2)(E), and failed to do so.[26] The commenters state that ''$PM_{2.5}$ pollution has a disparate impact on the basis of race in the San Joaquin Valley'' and assert that the Plan fails to meet CAA requirements and ''deliberately ignores obvious sources and control options and inflicts disparate impacts on Black, Latino, Indigenous, and people of color'' in the SJV. Therefore, the commenters advocate that the EPA must disapprove the 2012 annual $PM_{2.5}$ portion of the SJV $PM_{2.5}$ Plan.[27] We address the commenters' Title VI comments in section IV of this proposed rule.

The EPA is now proposing to disapprove the Plan with respect to certain CAA requirements (BACM/BACT for ammonia emission sources, BACM/BACT for building heating emission sources, aggregate commitments, attainment demonstration, RFP demonstration, quantitative milestones, and motor vehicle emission budgets). However, we are not in this proposal comprehensively addressing all issues raised in the Public Justice comment letter.[28]

D. Ninth Circuit Decision on Related SJV $PM_{2.5}$ Plan

In a final rule published July 22, 2020, the EPA finalized approval of the portions of the SJV $PM_{2.5}$ Plan [29] that addressed the 2006 24-hour $PM_{2.5}$ NAAQS (except for contingency measures, which the EPA acted on in a subsequent action).[30] On September 17, 2020, a group of five environmental, public health, and community groups (collectively referred to herein as ''Medical Advocates'') petitioned the Ninth Circuit Court of Appeals (''Ninth Circuit'' or ''Court'') for review of the EPA's July 22, 2020 final rule.[31] On April 13, 2022, the Ninth Circuit issued a Memorandum opinion that granted in part and denied in part the petition (''Memorandum Opinion'').[32]

The Ninth Circuit denied the petitioners' challenge with respect to the EPA's approval of enforceable commitments in general and the EPA's approval of the Plan's demonstration of BACM, BACT, and most stringent measures (MSM) for emission sources of direct $PM_{2.5}$ and NO_X for purposes of the 2006 24-hour $PM_{2.5}$ NAAQS.

Significantly, however, the Ninth Circuit also denied in part and granted in part the petitioners' challenge with respect to the EPA's approval of the specific enforceable commitments employed as part of the SJV $PM_{2.5}$ Plan's control strategy to attain the 2006 24-hour $PM_{2.5}$ NAAQS in the SJV by December 31, 2024. The EPA evaluates enforceable commitments based on three factors: (1) the commitment represents a limited portion of the required emission reductions, (2) the State is capable of fulfilling its commitment, and (3) the commitment is for a reasonable and appropriate timeframe. The Ninth Circuit denied the petitioners' challenge with respect to the first and third factors but granted the petitioners' challenge with respect to the second factor.

The Ninth Circuit found that the EPA had misapplied the second factor concerning the State's ability to fulfill the aggregate commitments. The Court reasoned that EPA ''fail[ed] to provide evidence or a reasoned explanation for its conclusion that California will be able to fulfill its commitment'' in the face of a potential multi-billion dollar funding shortfall for incentive-based control measure commitments, ''which could result in emission reduction shortfalls of approximately 7% of the total NO_X reductions and 8% of the total $PM_{2.5}$ reductions necessary for attainment.'' [33] The Court also rejected the EPA's arguments that: (1) the funding shortfall may be smaller than projected, (2) emission reductions may be less expensive than the strategy predicts, (3) certain yet-to-be-quantified sources of reductions in the Plan may make up for shortfalls, and (4) California and the District may identify other measures to fulfill their commitments. Instead, the Court decided that, ''[b]ecause these speculative assertions are unsupported by the evidence, they fail to ensure that California and the District have a plausible strategy for achieving this portion of the attainment strategy, and therefore do not collectively satisfy the second factor of the EPA's three-factor test.'' [34] The Court concluded that the EPA's analysis with respect to the second factor for evaluating enforceable commitments was arbitrary and capricious, vacated the final rule with respect to this factor, and remanded the matter to the EPA for further consideration of the second factor.[35]

The EPA is currently considering how to address the Court's vacatur and remand with respect to the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan and is not proposing any action with respect to those standards in this proposed rule. However, the Ninth Circuit's decision is very relevant to this proposed rule because the State relied on a common control strategy, including the same enforceable commitments (*i.e.,* the same set of control measure commitments and aggregate tonnage commitments) for purposes of both the 2006 24-hour $PM_{2.5}$ NAAQS Serious area plan and the 2012 annual $PM_{2.5}$ NAAQS Serious area plan. The EPA acknowledges the deficiency in the factual support for the aggregate commitments identified by the Ninth Circuit and that this remains the case. If the EPA cannot approve the aggregate commitments, then this has a direct bearing on other elements of the State's Serious area SIP submissions for the 2012 annual $PM_{2.5}$ NAAQS. As discussed in section II.C of this proposed rule, based on our reconsideration of the facts concerning the enforceable commitments in the SJV $PM_{2.5}$ Plan with respect to the 2012 annual $PM_{2.5}$ NAAQS in light of the Ninth Circuit's decision, the EPA now proposes to disapprove the State's enforceable commitments and attainment demonstration.

[24] Id.

[25] Id. at 3.

[26] Id. at 10–14.

[27] Id. at 1 and 21.

[28] Additional source categories named by Public Justice include, for example, residential wood burning, open burning, conservation management practices at farming operations, soil NO_X emissions, stationary agricultural internal combustion engines, and cleaner mobile agricultural equipment engines. Public Justice Comment Letter, 18–20.

[29] 85 FR 44192.

[30] 86 FR 67343 (disapproving contingency measures for the 2006 24-hour $PM_{2.5}$ NAAQS).

[31] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #1 (9th Cir., September 17, 2020). The five environmental, public health, and community organizations, in order of appearance in the petition, are Medical Advocates for Healthy Air, National Parks Conservation Association, Association of Irritated Residents, and Sierra Club (collectively ''Medical Advocates'').

[32] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1 (9th Cir., April 13, 2022).

[33] Id. at 6.

[34] Id. at 7.

[35] Id. at 10.

II. Reconsideration of the San Joaquin Valley Serious $PM_{2.5}$ Plan

The EPA has reconsidered its 2021 Proposed Rule, based on adverse comments on that prior proposal and based on a Ninth Circuit Court of Appeals decision on a related SJV $PM_{2.5}$ rulemaking. After careful consideration of the issues raised by commenters and the court, the EPA now proposes to disapprove the State's plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV for certain Serious area planning requirements, including: (1) the Plan's precursor demonstration for ammonia; (2) BACM for ammonia emission sources and BACM for building heating emission sources; (3) the modeled attainment demonstration; (4) the RFP demonstration; (5) quantitative milestones; and (6) motor vehicle emission budgets.

In sections II.A through II.C of this proposed rule, pertaining to the Plan's precursor demonstration for ammonia as a $PM_{2.5}$ precursor; BACM/BACT analysis, and modeled attainment demonstration (including reliance on enforceable commitments), we present a brief summary of the 2021 Proposed Rule, a summary of the adverse comments and Ninth Circuit order, as appropriate, and our reconsidered proposal. In sections II.D and II.E, pertaining to the Plan's RFP demonstration, quantitative milestones, and motor vehicle emission budgets, we present a brief summary of the 2021 Proposed Rule and our reconsidered proposal.[36] We also note that sections II.A (ammonia precursor demonstration) and II.B.1 (BACM for ammonia emission sources) are inter-related in that potential control measures for ammonia emission sources play a role in both: (1) selecting a reasonable percent emission reduction to evaluate modeled ambient $PM_{2.5}$ responses to ammonia emission reductions; and (2) assessing the availability and application of BACM to such sources in the SJV.

A. Ammonia Precursor Demonstration

1. Summary of 2021 Proposed Rule

In our 2021 Proposed Rule, the EPA described the requirements for $PM_{2.5}$ precursor pollutants, summarized the State's submissions in the SJV $PM_{2.5}$ Plan, and presented our evaluation thereof.[37] We briefly summarize those here with respect to the Plan's demonstration for ammonia as a precursor to $PM_{2.5}$ for purposes of the 2012 annual $PM_{2.5}$ NAAQS in the SJV. For a comprehensive discussion of Federal requirements for $PM_{2.5}$ precursors and a summary of California's submission, please refer to the following headings in Section IV.B of the 2021 Proposed Rule: (1) Requirements for Control of $PM_{2.5}$ Precursors; and (2) Summary of State's Submission.

Regarding CAA requirements applicable to $PM_{2.5}$ precursors, we explained that the attainment plan requirements of Title I, subpart 4 apply to emissions of direct $PM_{2.5}$ and emissions of NO_X, ammonia, SO_2, and VOC as $PM_{2.5}$ precursors from all types of stationary, area, and mobile sources, except as otherwise provided in the Act. We further described how the EPA interprets section 189(e) concerning regulation of precursors from major stationary sources to authorize it to determine, under appropriate circumstances, that regulation of specific $PM_{2.5}$ precursors from other sources in a given nonattainment area is not necessary.

As explained in the $PM_{2.5}$ SIP Requirements Rule, a State may elect to submit to the EPA a ''comprehensive precursor demonstration'' for a specific nonattainment area to show that emissions of a particular precursor from existing sources located in the nonattainment area do not contribute significantly to $PM_{2.5}$ levels that exceed the standard in the area.[38] The contribution analysis may consider the sensitivity of $PM_{2.5}$ to decreases in emissions of the precursor, in addition to the contribution to ambient concentrations of $PM_{2.5}$.[39] If the EPA determines that the contribution of the precursor to $PM_{2.5}$ levels in the area is not significant and approves the demonstration, then the State is not required to control emissions of the relevant precursor in the attainment plan.[40]

The EPA issued the ''$PM_{2.5}$ Precursor Demonstration Guidance'' (''$PM_{2.5}$ Precursor Guidance''),[41] to provide recommendations to states for analyzing nonattainment area $PM_{2.5}$ and $PM_{2.5}$ precursor emissions and developing such optional precursor demonstrations, consistent with the $PM_{2.5}$ SIP Requirements Rule. The guidance also describes how the State may use a sensitivity-based test, in which the modeled sensitivity or response of ambient $PM_{2.5}$ concentrations to changes in emissions of the precursor is estimated and then compared to a contribution threshold. In addition to comparing the concentration or modeled response to the threshold, the State can consider other information in assessing whether the precursor significantly contributes. The EPA's recommended annual average contribution threshold for the 2012 annual $PM_{2.5}$ NAAQS is 0.2 $\mu g/m^3$.[42] In other words, if the estimated contribution of a precursor at monitors is below this threshold, the EPA considers this evidence that the precursor does not contribute significantly to levels above the $PM_{2.5}$ NAAQS in the area in question; above this threshold, the EPA considers this evidence that the precursor does contribute significantly. The EPA considers this evidence in conjunction with additional information that the State may provide, and determines whether or not the precursor contributes significantly, and so whether the State must evaluate and implement controls of the precursor emissions to the appropriate level (*e.g.,* BACM).

The State presents its precursor demonstration primarily in Appendix G of the 2018 $PM_{2.5}$ Plan, with additional clarifying information in a series of emails available in the docket for this proposed rule. The State estimates that anthropogenic emissions of NO_X, ammonia, SO_X, and VOC will decrease by 64 percent (%), 1%, 6%, and 9%, respectively, between 2013 and 2025 based on its projected emissions accounting for existing and additional control measures in the Serious area plan.[43] Through a concentration-based analysis, CARB found that ammonium nitrate constituted 5.2 $\mu g/m^3$ of the annual average $PM_{2.5}$ concentrations measured at the Bakersfield California Avenue monitor in 2015, exceeding the recommended threshold,[44] and proceeded to conduct a sensitivity-based analysis.

For analytical purposes in accordance with the EPA's guidance, the State then modeled the sensitivity of ambient $PM_{2.5}$ to hypothetical 30% and 70% reductions in anthropogenic emissions of ammonia in SJV for modeled years

[36] The Plan's RFP demonstration, quantitative milestones, and motor vehicle emission budgets were not the direct subject of adverse comments nor the Ninth Circuit decision. However, they are based on the Plan's control strategy to attain the 2012 annual $PM_{2.5}$ NAAQS and, thus, the flaws in the Plan's control strategy affect these additional required elements.

[37] 86 FR 74310, 74317–74321.

[38] 40 CFR 51.1006(a)(1).

[39] 40 CFR 51.1006(a)(1)(ii).

[40] 40 CFR 51.1006(a)(1)(iii).

[41] ''$PM_{2.5}$ Precursor Demonstration Guidance,'' EPA–454/R–19–004, May 2019, including Memo dated May 30, 2019, from Scott Mathias, Acting Director, Air Quality Policy Division and Richard Wayland, Director, Air Quality Assessment Division, Office of Air Quality Planning and Standards (OAQPS), EPA to Regional Air Division Directors, Regions 1–10, EPA.

[42] $PM_{2.5}$ Precursor Guidance, 17.

[43] 2018 $PM_{2.5}$ Plan, Ch. 7, 7–5 and Table 7–2.

[44] 2018 $PM_{2.5}$ Plan, App. G, 3.

2013, 2020, and 2024. The results for 2024 are a proxy for the Plan's modeled attainment year of 2025 for the 2012 annual $PM_{2.5}$ NAAQS. For the 30% reduction results for 2024, upon which the State primarily relied, 2 out of 15 monitoring sites in SJV (Madera and Hanford) had modeled responses to ammonia reductions that were above the threshold. The ambient $PM_{2.5}$ response declines substantially from 2020 to 2024, with the decline being generally larger for the sites with the highest projected $PM_{2.5}$ levels. The State supplements the sensitivity analysis for ammonia with consideration of additional information such as emission trends, the appropriateness of future year versus base year sensitivity, available emission controls, and the severity of nonattainment.[45]

The State's precursor demonstration for ammonia also presents a review of District agricultural rules that control VOC emissions, but also provide ammonia reduction co-benefits. The State concludes that a 30% reduction is a reasonable upper bound on the potential ammonia reductions to model. Finally, the State's precursor demonstration presents extensive support for the State's conclusion that there is an ambient excess of ammonia relative to nitrate, *i.e.,* that particulate ammonium nitrate formation in SJV is NO_X-limited, and will become increasingly NO_X-limited as NO_X reductions increase into the future from the State's motor vehicle control program and other measures the State intends to undertake in the Serious area plan. Based on the forgoing considerations, the State concludes that ammonia emissions do not contribute significantly to ambient $PM_{2.5}$ levels that exceed the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

The EPA presented its initial evaluation of the State's ammonia precursor demonstration in section IV.B.3.a of the 2021 Proposed Rule, with more detailed summaries and evaluation in two EPA technical support documents (TSDs): ''Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS,'' February 2020 (''EPA's $PM_{2.5}$ Precursor TSD''), and ''Technical Support Document, EPA Evaluation of Ammonia Precursor Demonstration, San Joaquin Valley Moderate Area $PM_{2.5}$ Plan for the 2012 $PM_{2.5}$ NAAQS,'' August 2021 (''EPA's Ammonia Precursor TSD'').

We noted that the EPA's $PM_{2.5}$ Precursor Guidance provides for consideration of future year sensitivity and that consideration of additional information beyond the concentration-based and sensitivity-based analyses may be appropriate in assessing a precursor's significance. We summarized the State's assertions that 30% is a reasonable upper bound for potential ammonia emission reductions based on research cited in Appendix C of the 2018 $PM_{2.5}$ Plan concerning ammonia emissions and potential control options for agricultural sources.[46] However, we did not elaborate in the 2021 Proposed Rule as to why we proposed to agree that 30% was a reasonable upper bound.

We stated that ambient $PM_{2.5}$ responses to ammonia emission reductions decline over time, and in concert with the large projected NO_X emission reductions, with the largest declines occurring at sites with highest projected $PM_{2.5}$ levels. For the two sites (Madera and Hanford) where the State's modeled response in 2024 to a 30% ammonia emission reduction exceeded the recommended 0.2 µg/m³ threshold, we evaluated additional information and, based on that information, gave the modeled projected responses above the threshold at these sites less weight.

We also considered studies cited by CARB on the 2013 DISCOVER–AQ aircraft measurements and 2017 satellite measurements, both of which suggest that ammonia concentrations are underestimated in the SJV. We noted that if modeled ammonia concentrations were closer to observations, then the modeled response to ammonia precursor reductions would be lower than shown in the 2018 $PM_{2.5}$ Plan's precursor demonstration. Similarly, an increase in modeled ambient ammonia concentrations would also make the model response more consistent with the evidence from the multiple ambient measurement studies that suggest a very low ambient sensitivity to ammonia, based on measured excess ammonia relative to NO_X, the abundance of particulate nitrate relative to gaseous NO_X, and the large abundance of ammonia relative to nitric acid. These ambient measurement studies all conclude that there is a large amount of ammonia left over after reacting with NO_X, so that ammonia emission reductions would be expected mainly to reduce the amount of ammonia excess, rather than to reduce the particulate ammonium nitrate, and thus provided strong evidence independent of the modeling that ambient $PM_{2.5}$ levels would respond comparatively weakly to ammonia emissions reductions.

Regarding changes in the effect of ammonia emission reductions over time as other pollutant levels change, we stated it was appropriate to consider changes in atmospheric chemistry that may occur between the base or current year and the attainment year because the changes may ultimately affect the nonattainment area's progress toward expeditious attainment. We stated that the 2024 model results would in this case better represent the point in time at which it is appropriate to evaluate what potential ammonia controls could achieve, because of the steep decline in NO_X emissions the State projects will occur by 2024 and 2025 as a result of existing or intended control measures. We also noted that the projected annual average $PM_{2.5}$ concentration of 12.0 µg/m³, occurring at the Bakersfield-Planz monitoring site in 2025, would be reduced by 0.12 µg/m³, which would not be considered significant (it is below the EPA's recommended threshold of 0.2 µg/m³).

In sum, we concluded that the State had evaluated the sensitivity of ambient $PM_{2.5}$ levels to potential reductions in ammonia emissions using appropriate modeling techniques; the modeled response to ammonia reductions is likely lower than reported; and the State's choice of 2024 and 2025 as the reference points for purposes of evaluating the sensitivity of ambient $PM_{2.5}$ levels to ammonia emission reductions was well-supported. Based on all of these considerations, the EPA previously proposed to approve the State's demonstration that ammonia emissions do not contribute significantly to ambient $PM_{2.5}$ levels that exceed the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

2. Summary of Adverse Comments

Public Justice states that the ''EPA must disapprove the ammonia precursor demonstration'' and that ''CARB's tortured analysis (and EPA's proposed acceptance of it)'' is arbitrary and capricious. The commenter makes several assertions in support of this comment.[47]

First, Public Justice notes that CARB's analysis concluded that ammonia contributes 5.2 µg/m³ to annual average $PM_{2.5}$ concentrations, and that this is well above the EPA's recommended annual average contribution threshold of 0.2 µg/m³.[48] The commenters also

[45] Id. at App. G, 5.

[46] EPA's $PM_{2.5}$ Precursor TSD, 13.

[47] Public Justice Comment Letter, 16–18.

[48] The commenters note that 38% of the annual average ambient $PM_{2.5}$ in Bakersfield is ammonium nitrate. Public Justice Comment Letter, 6. See also, 2018 $PM_{2.5}$ Plan, Ch. 3, Figure 3–2 (''Bakersfield $PM_{2.5}$ Speciation (Average 2011 to 2013)'').

took issue with CARB and the EPA's arguments that such results overstate the role of ammonia because NO_X emissions decline over time, and the EPA's decision to look at the results of sensitivity modeling for the response of ambient $PM_{2.5}$ levels to potential ammonia emission reductions in the future year 2024. The commenters assert that this analytical approach of considering the projected sensitivity to ammonia reductions in the future year ''ignores the statutory imperative to demonstrate attainment as expeditiously as practicable,'' per CAA section 172(a)(2)(A), and that, even after evaluating the impact ''for the most favorable date'' (2024), CARB still found significant contribution for ammonia above the EPA's recommended threshold.

Second, Public Justice questioned CARB's reliance and the EPA's proposed acceptance of a sensitivity analysis that assumed only a 30% modeled reduction of ammonia emissions. Public Justice points out that the EPA's guidance for precursor demonstrations suggests that states should evaluate the effect of reducing emissions between 30% and 70%, and states that ''CARB argues, and EPA agrees, that only the minimal 30 percent control level is reasonable'' despite large ammonia sources (*e.g.,* ''industrial dairy and poultry operations'') never having been regulated in the SJV and the prospect for relatively easier and cheaper emission reductions than those for NO_X.[49] The commenters argue that ''[t]he analysis of potential controls is particular[ly] weak and ignores the wealth of literature demonstrating that strategies for reducing ammonia emissions from agriculture . . . are among the most effective for reducing PM concentrations,'' and cite several studies in support of this argument. The commenters further state that reducing ammonia emissions may be achieved through ''strategies such as improving livestock feed to reduce excreted nutrients, altering manure storage and handling practices to prevent [ammonia] emissions, and improving synthetic fertilizer use efficiency,'' again citing numerous studies.[50] The commenters state that agriculture is responsible for over 80% of ammonia emissions, and that confined animal facilities (CAFs) and fertilizer application account for 57% and 36%, respectively.[51] Moreover, the commenters assert that ''[n]o real analysis of control potential is offered'' in the State's precursor demonstration.

Third, with respect to the State and the EPA's evaluation of modeled ambient $PM_{2.5}$ responses to ammonia emission reductions in 2024, Public Justice states that, in the low (30%) emission scenario, 2 of 15 monitoring sites have responses over the 0.2 $\mu g/m^3$ recommended threshold and that the EPA argues ''with extremely biased evidence, that the results at one of the two monitors could be ignored and that ammonia emissions area likely underestimated.'' The commenters assert that ''EPA points to evidence that 'the State did not discuss' to discount the results'' for the Madera monitor, and that the EPA ''offers no excuse for discrediting the results at the other monitor.''

Fourth, the commenters claim that the EPA's evaluation of the precursor demonstration looked at supplemental ammonia emission studies but ignored supplemental studies showing that NO_X emissions from soil (''soil NO_X'') may be significantly underestimated. Public Justice states that the State and the EPA ''assert that NO_X emissions will be significantly reduced by 2024 even though the Plan currently does not explain how those NO_X reductions will occur.'' The commenters state that such approach is ''a one-sided attempt to explain away modeled results that ammonia contributes significantly to $PM_{2.5}$'' in the SJV and cannot overcome the Act's presumption that precursors must be controlled.

Finally, beyond the assertion that the State's precursor demonstration with respect to ammonia, and the EPA's proposed approval of it are incorrect, the commenters also argue that the State's failure to address ammonia as a precursor to $PM_{2.5}$ has disparate impacts on certain communities within SJV and ''avoids difficult political fights by sacrificing communities of color.'' Finally, the commenters refer to a 2021 research study that estimates that 1,690 people in California die annually due to agricultural ammonia emissions.[52]

3. The EPA's Reconsidered Proposal

The EPA agrees with certain points made by the commenters with respect to ammonia and disagrees with others. Overall, based on the adverse comments from Public Justice and a re-evaluation of the information provided by the State, we now conclude that the weight of evidence is insufficient to establish that ammonia does not contribute significantly to $PM_{2.5}$ levels above the NAAQS in the SJV. The EPA's further evaluation indicates that it is appropriate to retain the statutory presumption that ammonia must be regulated as a precursor for the 2012 annual $PM_{2.5}$ NAAQS in the SJV. Accordingly, if the EPA finalizes disapproval of the State's ammonia precursor demonstration, ammonia would remain a plan precursor, and the SJV would remain subject to the requirements to identify and implement BACM, BACT, and additional feasible measures on sources of ammonia emissions.

We first address the portion of the comment related to the sensitivity of the modeled $PM_{2.5}$ response to reductions in ammonia emissions and then turn to the portion of the comment addressing the amount of ammonia reductions that may be available.

a. Comments Related to Sensitivity Modeling Results

The measured ammonium nitrate portion of the annual average $PM_{2.5}$ concentration in Bakersfield in 2015 was 5.2 $\mu g/m^3$.[53] This is well above the EPA's recommended threshold in the $PM_{2.5}$ Precursor Guidance. However, the $PM_{2.5}$ SIP Requirements Rule, as interpreted by that guidance, provides the option for a State to conduct an analysis of the sensitivity of ambient $PM_{2.5}$ concentrations to emission reductions of a precursor pollutant to evaluate the significance of that precursor,[54] as the State did for the 2012

[49] Public Justice Comment Letter, 2, 5, and 16–17, and Exhibits 31 through 34.

[50] Public Justice Comment Letter, 16–17, Exhibits 35 through 40 and three additional studies: N. Cole, et al., ''Influence of dietary crude protein concentration and source on potential ammonia emissions from beef cattle manure,'' J. Anim. Sci. 83, 722, 2005; N. Cole, P. Defoor, M. Galyean, G. Duff, J. Gleghorn, ''Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers,'' J. Anim. Sci. 12, 3421–3432, 2006; and R. Todd, N. Cole, R. Clark, ''Reducing crude protein in beef cattle diet reduces ammonia emissions from artificial feedyard surfaces,'' J. Environ. Qual. 35, 404–411, 2006.

[51] Public Justice Comment Letter, 5–6, 16, citing See EPA Region IX, ''Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS.'' We note that our TSD in turn cited to State data sources, including the 2018 $PM_{2.5}$ Plan, App. G, Figure 3.

[52] Public Justice Comment Letter, 18. See Domingo, N.G.G., Balasubramanian, S., Thakrar, S.K., Clark, M.A., Adams, P.J., Marshall, J.D., Muller, N.Z., Pandis, S.N., Polasky, S., Robinson, A.L., Tessum, C.W., Tilman, D., Tschofen, P., & Hill, J.D., ''Air quality–related health damages of food,'' Proceedings of the National Academy of Sciences (Vol. 118, Issue 20, p. e2013637118), 2021, available at *https://doi.org/10.1073/pnas.2013637118,* attached as Exhibit 35. See SUPPLEMENTARY INFORMATION for ''Air quality-related health damages of food,'' Table S2 (''Annual emissions and mortality caused by agricultural production in the 10 states where emissions of (A) primary $PM_{2.5}$, (B) NH_3, (C) NO_X, (D) SO_2, and (E) NMVOCs lead to the highest total mortality'').

[53] 86 FR 74310, 74318 and 2018 $PM_{2.5}$ Plan, App. G, 3.

[54] 40 CFR 51.1006(a)(1)(ii).

annual $PM_{2.5}$ NAAQS in the SJV. Thus, the concentration-based contribution analysis alone (*i.e.,* the 5.2 µg/m^3) is not necessarily determinative of a precursor's significance.

The commenters stated that reliance on a sensitivity-based test for 2024 ignores the statutory imperative for expeditious attainment. But, as noted in the preamble for the $PM_{2.5}$ SIP Requirements Rule in explaining the rationale for a sensitivity-based test, ''if conditions in a particular area are such that control of sources of one or more precursors does not reduce $PM_{2.5}$ concentrations in the area, then those controls will not help the area attain (expeditiously or otherwise).'' [55] Thus, if a precursor demonstration were to show that control of a particular precursor is not effective for reaching attainment, then the absence of such control would not violate the requirement for expeditious attainment.

As commenters noted, the State relied on its sensitivity-based contribution analysis for a future year (2024) to evaluate the significance of ammonia as a precursor to ambient $PM_{2.5}$ concentrations in the San Joaquin Valley. In our 2021 Proposed Rule, we discussed the State's selection of 2024 as an acceptable analysis year, given the projected steep decline in ambient $PM_{2.5}$ sensitivity to ammonia reductions over time as a result of projected changes in emissions (*i.e.,* large NO_X emission reductions as contemplated in the Plan, through existing measures and aggregate commitments), consistent with the facts and circumstances recommended for consideration in the EPA's $PM_{2.5}$ Precursor Guidance.[56]

The $PM_{2.5}$ Precursor Guidance provides for consideration of sensitivity in an appropriate future year.[57] Based on the State's control strategy, including baseline emission reduction measures and its control measure and aggregate tonnage commitments, the State estimated it would achieve over 200 tpd NO_X reductions by 2024, representing over 60% of the 2013 base year emissions inventory for NO_X.[58] Existing baseline measures already in the SIP are projected by the State to reduce annual average NO_X emissions in the SJV by 173.5 tpd, which is 83.7% of the 207.38 tpd of NO_X reductions modeled to attain the 2012 annual $PM_{2.5}$ NAAQS. Over 90% of the baseline NO_X reductions between 2013 and 2025 are due to the existing mobile source control program.[59] These reductions will occur regardless of any EPA action on the precursor demonstration or the 2018 $PM_{2.5}$ Plan as a whole. Similarly, additional measures adopted by the State through the end of 2021 further reduce NO_X emissions. Given the large NO_X emission reductions projected to occur by 2024 and 2025, the EPA has concluded that that the 2024 sensitivity model results better represent the atmospheric chemistry around the attainment date and in subsequent years than sensitivity modeling results from 2013 and even 2020.[60] Due to continued existing and anticipated NO_X reductions, the apparent $PM_{2.5}$ benefit of ammonia reductions in earlier years declines with time and does not reflect the ultimate, lower, benefit of such controls near the attainment year and later.

Thus, the EPA reasons that the Plan's baseline and additional control measures will change (and have already changed) the atmospheric chemistry conditions in the SJV, leading to ambient $PM_{2.5}$ formation that is much less sensitive to ammonia emission reductions in the attainment year. We maintain that the State's reliance on its sensitivity-based contribution analysis for 2024 to evaluate the significance of ammonia as a precursor is reasonable, well supported, and consistent with the $PM_{2.5}$ SIP Requirements Rule and EPA guidance.

The commenter correctly states that 2 of 15 sites in the 2024 model scenario based on a 30% reduction in ammonia emission were modeled to have an ambient $PM_{2.5}$ response greater than the EPA's recommended contribution threshold of 0.2 µg/m^3. However, we disagree with the commenter's characterization that our further review of the sensitivity of the Madera and Hanford sites to ammonia emission reductions was argued ''with extremely biased evidence.'' [61]

For the Madera monitor (estimated sensitivity of 0.21 µg/m^3 in 2024 to a 30% ammonia emission reduction), the commenter refers to the EPA's statement that the 2018 $PM_{2.5}$ Plan did not discuss the evidence for the 2013 monitored concentrations at this site being biased high (as a matter of the physical recordings of the monitor). However, the EPA did reference the State's prior analysis of such evidence, which we considered in our evaluation.[62] Aside from pointing out that this analysis was not included in the Plan itself, the comment does not offer analysis to the contrary, and the EPA continues to think that we reasonably weighed the technical information before us and, given the role of the 2013 monitored data in the sensitivity modeling conducted by the State, correctly concluded that ''if more typical Madera concentrations were used, it is likely that the 2024 Madera response to ammonia reductions would be below the contribution threshold'' and that the extra year of NO_X reductions from 2024 to 2025 would likely decrease the sensitivity below the recommended 0.2 µg/m^3 threshold.

We further disagree with the commenter's assertion that we offered no reason for giving less weight to modeled sensitivity results for the Hanford monitor (estimated sensitivity of 0.26 µg/m^3 in 2024 to a 30% ammonia emission reduction). We stated that we gave both Madera and Hanford modeled sensitivity lower weight in our overall assessment of ammonia as a precursor. Specifically for Hanford, we described evidence that the modeled sensitivity there was likely overestimated. That evidence included an independent study using data from the 2013 DISCOVER–AQ campaign that ''found that the [CMAQ] model underestimated ammonia at Hanford by a roughly a factor of four or five.'' [63] In our assessment, if the model's ammonia concentrations better matched the observations then there would be more of an ammonia excess in the model, and the modeled response to ammonia reductions would be lower.

More broadly, prior to publishing the 2021 Proposed Rule, the EPA reviewed available research including from supplemental materials from CARB, and found a consistent theme based on modeling analyses and ambient measurement studies—that ''there is a large amount of ammonia left over after reacting with NO_X, so that ammonia emission reductions would be expected mainly to reduce the amount of ammonia excess, rather than to reduce the particulate ammonium nitrate.'' [64] It is important to note that this ammonia excess is *measured,* and is independent

[55] 81 FR 58010, 58025.

[56] 86 FR 74310, 74320–74321 and $PM_{2.5}$ Precursor Guidance, 35.

[57] $PM_{2.5}$ Precursor Guidance, 35.

[58] 86 FR 74310, 74327, Table 4.

[59] 2018 $PM_{2.5}$ Plan, App. B, Table B–2.

[60] We address the potential impact of ammonia emissions on the requirement for expeditious attainment in our re-evaluation of the attainment demonstration in section II.C.3, below.

[61] Public Justice Comment Letter, 18.

[62] 86 FR 74310, 74320, fn. 91, and fn. 92. This analysis concluded that 2011–2013 Madera data did not fit the geographic pattern historically seen in relation to other monitors but returned to the historic pattern after corrections were made to the monitoring instrument operating procedures. Concentrations were estimated to be about 10% high during the period in question.

[63] 86 FR 74310, 74320.

[64] Id. See also, EPA's Ammonia Precursor TSD.

of any assumptions about the size of the ammonia or NO_X emissions inventories, and also independent of any uncertainties in the modeling exercise. The concerns raised by Public Justice about relative levels of ammonia and NO_X estimation are not sufficient to cause the EPA to revise the conclusion that $PM_{2.5}$ is likely to have low sensitivity to ammonia reductions, which is supported by the actual observed conditions. The ambient measurement evidence is strong and leads the EPA to believe that the modeled response to ammonia in the State's precursor demonstration may be overestimated. Therefore, we maintain that the EPA may give lower weight to the modeled sensitivities of ambient $PM_{2.5}$ concentrations to ammonia emission reductions at the Madera and Hanford sites.

The commenter states that the EPA's argument on the relative levels of ammonia and NO_X emissions looks at such ammonia studies but ''ignores supplemental studies showing that . . . soil NO_X emissions [may be significantly underestimated].'' [65] Unlike the general consensus in the ammonia studies described above, with respect to the amount of NO_X emitted by soil in the SJV the EPA believes that there is conflicting research. A conclusion of Almaraz et al. (2018) and Sha et al. (2021) cited by the commenters is that soil NO_X emissions are underestimated, and that they comprise 30–40% of total NO_X emission in California. While higher levels of soil NO_X (or NO_X more generally) would tend to increase the modeled sensitivity of ambient $PM_{2.5}$ to ammonia, we maintain that there is not a sufficient basis to conclude that higher soil NO_X emissions should be used in the air quality modeling for the SJV.[66]

In contrast to the studies just cited, Guo et al. (2020) [67] did not find such a discrepancy in emissions estimates, concluding that soil NO_X is about 1% of anthropogenic NO_X emissions. The fraction of nitrogen applied as fertilizer released as NO_X to the atmosphere was estimated by Almaraz et al. to be 15%, while seven other studies reviewed by Guo et al. estimated it to be 2% or less. Yet Almaraz et al., Sha et al., and Guo et al. all reported high agreement between their modeled and observed soil NO_X emissions. The Almaraz et al. study acknowledged the limited number of surface measurements that were available for purposes of comparing the model results and the difficulty in comparing the model results to the observations and noted the need for more field measurements. Guo et al. stated that obtaining an emission factor correlating NO_X emissions to fertilizer application from the data available in various studies (including Almaraz et al.) would be ''difficult or impossible'' due to the sparsity of data collected in terms of sampling length, sampling frequency, and the episodic nature of nitrogen gas emissions from soil.

In light of the uncertainties and disagreements among studies, the EPA does not believe that available research provides sufficient certainty about the magnitude and proportion of soil NO_X emissions attributable to agricultural fertilizer application to require substantial revisions in the NO_X emissions inventory nor the $PM_{2.5}$ modeling at this time.

In addition, as just described, multiple studies of ambient measurements show excess ammonia in the atmosphere, which is strong evidence of low sensitivity to ammonia reduction that is independent of the accuracy of estimates of precursor emissions from any source, including soil NO_X, and independent of any modeling. Thus, we disagree that the EPA ''ignored'' the supplemental soil NO_X studies; we were aware of and considered them, but they did not change our conclusion.

b. Comments Related to Scale of Potential Ammonia Emission Reductions

The 2018 $PM_{2.5}$ Plan includes modeling of 30% and 70% reductions in ammonia emissions and focuses on the results of the 30% reduction based on the assertion that the area could not achieve more than a 30% decrease in ammonia emissions. Public Justice questions the basis for the assertion that no more than 30% reductions are available. In this section, we examine, based on the submission, the $PM_{2.5}$ Precursor Guidance, and the Public Justice comment, the ammonia reductions that may be available in the SJV. Specifically, we explore the uncertainty with respect to both the current state of ammonia emissions and controls in the SJV and available research examining additional control options that may be available. We conclude that, based on the information before us, the 2018 $PM_{2.5}$ Plan does not provide sufficient support for the assertion that 30% is a reasonable upper bound on available ammonia reductions in the SJV.

The District presented its analysis of ammonia control for the primary ammonia source categories in the SJV in Appendix C, section C.25 (''Ammonia in the San Joaquin Valley'') of the 2018 $PM_{2.5}$ Plan. The EPA had reviewed this analysis for our assessment in the 2021 Proposed Rule that 30% was, for analytical purposes, a reasonable upper bound for ammonia emission reductions in the SJV, and referred to prior EPA analysis for our action on the 2006 24-hour $PM_{2.5}$ NAAQS portion of the 2018 $PM_{2.5}$ Plan.[68] In evaluating the Public Justice comments on the potential control of ammonia, however, we have re-evaluated other portions of the 2018 $PM_{2.5}$ Plan, including Appendix C, section C.25 and Appendix G,[69] and reviewed the studies cited by the commenters, as well as others from the EPA's own literature search.

As noted in the EPA's $PM_{2.5}$ Precursor Guidance,[70] and consistent with the $PM_{2.5}$ SIP Requirements Rule (40 CFR 51.1010(a)(2)(ii), 51.1006(a)(1)(ii)), the EPA may require the State to identify and evaluate potential control measures for a precursor to determine the potential emissions reductions achievable, as a part of the precursor analysis. The guidance states that this evaluation is particularly important when the $PM_{2.5}$ response to a 30% reduction in precursor emissions is close to the contribution threshold. In the case of a nonattainment area classified as Serious, this analysis would include identification and evaluation of measures that would constitute BACM/BACT level controls for such pollutant.[71]

[65] Public Justice Comment Letter, 18. Public Justice cited Almaraz et al. (2018), ''Agriculture is a major source of NO_X pollution in California,'' Science Advances, 4(1), doi:10.1126/sciadv.aao3477, 2018, available at *https://advances.sciencemag.org/content/4/1/eaao3477;* and Sha et al. (2021), ''Impacts of soil NO_X emission on O_3 air quality in rural California,'' Environmental Science & Technology, 55(10), 7113–7122, available at: doi:10.1021/acs.est.0c06834; available at *https://pubs.acs.org/doi/10.1021/acs.est.0c06834.*

[66] See also, EPA Region IX, ''Response to Comments Document for the EPA's Final Action on the San Joaquin Valley Serious Area Plan for the 2006 $PM_{2.5}$ NAAQS,'' June 2020, 148 and 158.

[67] Guo et al. (2020), ''Assessment of Nitrogen Oxide Emissions and San Joaquin Valley $PM_{2.5}$ Impacts From Soils in California,'' Journal of Geophysical Research: Atmospheres, 125(24), doi: 10.1029/2020JD033304; available at *https://doi.org/10.1029/2020JD033304.*

[68] 86 FR 74310, 74319. See also, 85 FR 17382, 17395 (March 27, 2020), and EPA's $PM_{2.5}$ Precursor TSD, 13.

[69] See, *e.g.,* 2018 $PM_{2.5}$ Plan, App. G, 13, where CARB states that ''CARB staff, District staff, and the public process have not identified specific controls that are technologically and economically feasible to achieve reductions at the low end of the recommended sensitivity range (*i.e.,* 30 percent), much less at the upper end of the range.''

[70] $PM_{2.5}$ Precursor Guidance, 31.

[71] The $PM_{2.5}$ Precursor Guidance provides: ''[c]onsistent with the $PM_{2.5}$ SIP Requirements Rule, the EPA may in some cases require air agencies to evaluate available emissions controls in support of a precursor demonstration that relies on a

Even when the modeled responses are below the recommended 0.2 μg/m³ contribution threshold, or when particular responses are given less weight as we have discussed above for Madera and Hanford, the outcome of a sufficiently thorough controls evaluation and its conclusions on achievable emissions reductions may be important information for the EPA to consider in deciding whether to approve the precursor demonstration. Here, the State's ammonia precursor demonstration strongly relies on the assertion that no more than 30% ammonia reductions below current levels is achievable, but there is not a sufficiently thorough controls evaluation to support that assertion. Because the 30% value has not been adequately supported, the EPA cannot evaluate whether the modeled $PM_{2.5}$ reductions associated with a 30% reduction in ammonia represent the reductions that may be possible in the SJV.

The EPA also emphasizes that the 30% control threshold is part of an analytical test to help evaluate whether the State must regulate ammonia as a precursor for the 2012 annual $PM_{2.5}$ NAAQS in the area; it does not mean that if the State cannot control 30% of ammonia with BACM/BACT-level controls that there is per se no need to regulate ammonia. For example, if control of 25% of ammonia is necessary for attainment of the $PM_{2.5}$ NAAQS, then the fact that this is below 30% is irrelevant. Our attention to the 30% threshold in this notice is to help interpret the $PM_{2.5}$ responses to modeled ammonia emissions reductions in the State's precursor demonstration, which modeled a 30% reduction. This point is important analytically because, insofar as potential ammonia reductions could be larger than 30%, the modeled responses could be larger than those relied upon in the State's precursor analysis to support its determination that ammonia is not a significant precursor.

With respect to the State's assertion that 30% is a reasonable upper bound for potential ammonia emission reductions, we agree with the commenters that the analysis of potential ammonia controls provided by the State and the evaluation of that information by the EPA lacked detailed support and is not a sufficient basis for the EPA to affirm that 30% is a reasonable upper bound for potential ammonia emission reduction in the SJV. This, in turn, affects the EPA's interpretation of the results of modeled responses to ammonia reductions. There are two general deficiencies in the submitted analysis that create uncertainty as to the potential for ammonia emission reductions, as discussed below: (1) incomplete quantification of existing ammonia emission reductions from the largest sources of ammonia; and 2) incomplete consideration and evaluation of potential additional controls of ammonia emissions for sources in the SJV. We walk through these uncertainties for each of the largest sources of ammonia in the SJV (*i.e.,* CAFs and fertilizer application).

As an initial matter, the commenters state that ''[the State] argues, and EPA agrees, that only the minimal 30 percent control level is reasonable'' despite major ammonia sources never having been regulated in the SJV and the relatively easier and cheaper sources of emission reductions relative to NO_X. We understand this reference to ''major ammonia sources'' to mean the main source categories of ammonia emissions in the SJV, including CAFs and fertilizer application, which the State estimated to emit 57% and 36%, respectively, of the annual average ammonia emissions in the SJV in 2013.[72]

We agree with the commenters that neither CARB nor the District have imposed controls specifically to regulate ammonia. We note, however, that ammonia-specific controls are not required for approval of an ammonia precursor demonstration. Moreover, although there are not ammonia-specific controls in place for the largest source categories in the SJV, many sources of ammonia are in fact regulated by District rules, such as Rule 4570 (''Confined Animal Facilities''), Rule 4565 (''Biosolids, Animal Manure, and Poultry Litter Operations''), and Rule 4566 (''Organic Material Composting Operations''), which include enforceable requirements for VOC emissions that would, in general, achieve some degree of ammonia emission reductions. We agree with the general assertion, presented by the District in section C–25 (''Ammonia in the San Joaquin Valley'') of Appendix C of the 2018 $PM_{2.5}$ Plan, that some management practices to reduce VOCs in those rules also collaterally reduce ammonia emissions by limiting ammonia formation and volatilization, even though ammonia reductions are not legally required by these measures.[73]

Although we expect that existing VOC regulations are achieving a degree of ammonia control, there are multiple reasons why it is not clear, based on the record before us, how much reduction is being achieved, and thus how much additional reduction may be available. For example, regarding CAFs, as the EPA has previously noted,[74] the State has not sufficiently substantiated its calculation of 100 tpd of ammonia emission reductions attributed to Rule 4570. In the 2018 $PM_{2.5}$ Plan, the State referenced an outdated analysis from 2006 that relied on a different baseline emissions inventory, but has not supplemented this analysis, or reconciled it with more recent emissions inventory data.[75] We note that CARB has provided the EPA with significantly lower estimates of ammonia emission reductions achieved by SJVUAPCD Rule 4570 based on more recent calculations of reductions from a 2012 baseline emissions inventory.[76] The 2018 $PM_{2.5}$ Plan does not reconcile these differences, nor update the emission reduction estimate from the 2006-era analysis to the emissions inventory basis of the 2018 $PM_{2.5}$ Plan.

sensitivity analysis. [See 40 CFR 51.1009(a)(2) and 51.1010(a)(2).] It is particularly important for states to evaluate available controls where the recommended contribution threshold—that is, the threshold used for identifying an impact that is 'insignificant'—is close to being exceeded at the low end of the recommended sensitivity range (*e.g.,* 30 percent). In these cases, the EPA may determine that to sufficiently evaluate whether the area is sensitive to reductions, the State must determine the potential precursor emission reductions achievable through the implementation of available and reasonable controls for a Moderate area (or best controls for a Serious area).'' $PM_{2.5}$ Precursor Guidance at 31.

[72] See Public Justice Comment Letter, 6, citing EPA Region IX, ''Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS.''

[73] See, *e.g.,* 2018 $PM_{2.5}$ Plan, App. C, C–313 (for CAFs). The lack of controls specifically regulating *ammonia emissions* from the largest source categories through enforceable SIP requirements in the SJV is not an inherent deficiency of the precursor demonstration, but it does result in challenges for determining the potential for ammonia emission controls (*i.e.,* in determining the reductions that have already been achieved, and what additional reductions are available).

[74] 81 FR 69396, 69397–69398 (October 6, 2016).

[75] 2018 $PM_{2.5}$ Plan, App. C, C–311 to C–339 and SJVUAPCD, ''Final Draft Staff Report, Proposed Re-Adoption of Rule 4570 (Confined Animal Facilities),'' June 18, 2009, at Appendix F, ''Ammonia Reductions Analysis for Proposed Rule 4570 (Confined Animal Facilities),'' June 15, 2006 (discussing various assumptions underlying the District's calculation of ammonia emission factors without identifying relevant emissions inventories).

[76] Email dated September 3, 2015, from Gabe Ruiz, CARB, to Larry Biland and Andrew Steckel, EPA Region IX, regarding ''SJV Livestock Ammonia Emissions with and without Rule 4570.'' This email notes that 2011 ammonia emissions (pre-rule) were 316.8 tpd, 2012 emissions (without rule) were 323.8 tpd, and 2012 emissions (with rule) were 250.9 tpd. Thus, application of Rule 4570 would have achieved either 72.9 tpd of ammonia reductions, measured within 2012 with and without the rule, or 65.9 tpd, measured from the 2011 level (without rule) to the 2012 level (with rule).

In short, although we agree that some existing VOC controls will also result in ammonia reductions, a more detailed analysis it required to determine both the effectiveness of existing controls, and the additional controls that may be available. In the following, the EPA notes various uncertainties concerning ammonia emissions and in the amount of reductions achieved by specific rules as a byproduct of the existing VOC control measures. For a number of key source categories, ammonia measures require additional analysis to evaluate their potential to achieve additional emissions reductions, in part based on research studies included as exhibits to the Public Justice Comment Letter.

For CAFs, the District discusses in detail how Rule 4570 is structured (*e.g.,* to address varying types of CAFs); the five main CAF operations/emission sources: feeding, housing (including distinctions for housing configurations), solid waste, liquid waste, and land application of manure; the control menu requirements for each of those five operations; and research papers that estimate ammonia emission reductions from some of the measures.[77] However, the 2018 $PM_{2.5}$ Plan does not specify, even in an aggregated form, which control measures were selected by CAFs in their permits-to-operate with the District for each of the five operations and the scale of those selections by CAF size, nor does it quantify the emission reductions from those selections and scales. Thus it is unclear what level of ammonia control is being achieved, and, importantly for the precursor demonstration, unclear what level of further ammonia control may be possible. This uncertainty is increased by several provisions in Rule 4570 that allow CAF owners/operators to implement ''alternative mitigation measures'' [78] *in lieu of* the mitigation measures listed in the rule, without any requirement to ensure that such alternative mitigation measures achieve any particular level of ammonia emission reductions, or any ammonia reductions at all.[79]

Furthermore, for certain requirements, the 2018 $PM_{2.5}$ Plan assumes that a less effective control measure may be implemented given that the more effective control measure may be more costly. For instance, the District describes some research studies that relate to one or more of the options, but it is not clear whether and how the requirements of each option align with the practices evaluated in each study. The District cites a 2005 University of California study that manure from lagoons, diluted with irrigation water, and applied via surface gravity irrigation systems (*e.g.,* not applied with a drag hose or similar apparatus) commonly minimized ammonia losses from volatilization to the air to 10% or less.[80] However, it is not clear how the requirements of option H.2.a (liquid manure treated in an aerobic or anaerobic lagoon) or option H.2.b (24-hour limit for liquid manure standing on fields) may correspond to the study, whether any particular level of lagoon treatment or dilution prior to application would be needed, nor whether a combination of the two would be required to minimize ammonia losses to air to that degree.

For option H.2.c, the District states that use of a drag hose or similar apparatus could significantly reduce ammonia emissions, but without specifying how much or pointing to any supporting document, and only qualitatively asserting a relatively higher cost for using such equipment, and its limitations when a crop is growing.[81] The District states that ''[a]pplication of liquid or slurry manure with a drag hose or similar apparatus could result in significant [ammonia] reductions, but has higher costs compared to flood or furrow irrigation of liquid manure.'' [82] However, higher cost does not necessarily translate to the measure being economically infeasible, and thus the option to use flood or furrow irrigation alone may not represent the most appropriate method or level of control of ammonia for the land application of liquid manure. As a result, the District has not demonstrated that additional reductions are not feasible.

The District assumes that all dairies and other cattle facilities would select option H.2.b (24-hour limit for liquid manure standing on fields) and cites two studies that suggest substantial ammonia emission reductions from this limitation, assuming no ammonia emissions into the air after soil incorporation.[83] Based on one study, dairy CAF operations in the SJV would have hypothetically already reduced ammonia emissions to the air from land application of liquid manure from 66% ammonium nitrogen to 25% ammonium nitrogen by implementing option H.2.b (a 41% absolute reduction, or 62% relative reduction). Uncertainty about the options that are being chosen and implemented by regulated entities gives rise to uncertainty in the ammonia emission reductions that are being achieved. The permits-to-operate submitted by each dairy CAF are required to indicate which option has been selected.[84] Accordingly these permits, and associated compliance records, should contain information that would help to address this uncertainty. Furthermore, if injection via drag hose or similar apparatus (option H.2.c) is economically feasible, even if more expensive, implementation of such a measure could further reduce ammonia by 25% based on the same study, at least for a portion of the operating cycle (*e.g.,* when crops are not growing). Lastly, a combination of measures (*e.g.,* requiring that liquid manure be both treated in an anaerobic lagoon, aerobic lagoon, or digester, and that it be incorporated into the soil within 24 hours) or adjustment to existing options (*e.g.,* requiring incorporation of liquid manure within 6 hours, rather than 24 hours, and during cooler hours when ammonia volatilization is less) could hypothetically reduce ammonia emissions at these sources by more than 30%.[85]

In general, with respect to dairy CAFs, on a qualitative basis CAF operators have likely reduced ammonia emissions

[77] 2018 $PM_{2.5}$ Plan, App. C, C–312 to C–323.

[78] ''Alternative Mitigation Measure'' is defined in SJVUAPCD Rule 4570 as ''a mitigation measure that is determined by the APCO, [CARB], and EPA to achieve reductions that are equal to or exceed the reductions that would be achieved by other mitigation measures listed in this rule that owners/operators could choose to comply with rule requirements.'' SJVUAPCD Rule 4570 (amended October 21, 2010), section 3.4. Because SJVUAPCD Rule 4570 explicitly applies only to VOC emissions, the requirement for equivalent ''reductions'' in section 3.4 applies only to VOC emission reductions and does not apply to ammonia emission reductions.

[79] See, *e.g.,* SJVUAPCD Rule 4570 (amended October 21, 2010) at section 5.6, Table 4.1.F.

[80] University of California, Division of Agricultural and Natural Resources, Committee of Experts on Dairy Manure Management, ''Managing Dairy Manure in the Central Valley of California,'' June 2005.

[81] 2018 $PM_{2.5}$ Plan, App. C, C–323, referring to a 2008 report by Alberta Agriculture and Food (Canada). Albert Agriculture and Food, ''Ammonia Volatilization from Manure Application,'' February 2008 (''2008 Alberta Report''). That report estimates that injection into soil would reduce the average ammonium-nitrogen fraction loss (*i.e.,* to air) to 0% compared to incorporation within one day from surface application (25%) or compared to surface application with no incorporation (66%). 2008 Alberta Report, Table 2.

[82] 2018 $PM_{2.5}$ Plan, App. C, C–322 to C–323.

[83] 2018 $PM_{2.5}$ Plan, App. C, C–323, referring to two studies: the 2008 Alberta Report, and Chadwick et al. ''Emissions of Ammonia, Nitrous Oxide and Methane from Cattle Manure Heaps: Effect of Compaction and Covering,'' Atmosphere Environment, 39: 787–799 (2005); available at: *http://www.sciencedirect.com/science/article/pii/S135223100400994X.*

[84] Under District Rule 4570, section 5.1, owners/operators of CAFs subject to the rule must obtain a permit-to-operate for the facility, and that permit must include a facility emission mitigation plan, a facility emission inventory, and identify the mitigation measures selected for the facility.

[85] 2008 Alberta Report.

to a degree consistent with the options selected. However, there is not a quantitative basis to specify the degree and potential for further reduction. For some of the options within the menu of mitigation measures for each type of CAF in Rule 4570, there are research studies to support the basis of existing ammonia emission reductions. The generalized assumptions used by the State could be evaluated by an analysis of the options selected by CAFs in permits-to-operate with the District. Further assessment of available compliance records and examination of combinations of measures or adjustments to existing measures could help quantify additional potential ammonia emission reductions.

In addition, Public Justice cites several studies to support its assertion that reductions in agricultural ammonia emissions may be achieved through ''strategies such as improving livestock feed to reduce excreted nutrients, altering manure storage and handling practices to prevent [ammonia] emissions, and improving synthetic fertilizer use efficiency,'' and cites several studies to support this assertion.[86] The EPA considers these approaches to warrant examination as potential means to reduce ammonia and believes that more information regarding their efficacy as control measures and their economic and technical feasibility is needed to determine the amount of the potential additional ammonia control in the SJV.

For livestock feed, studies in 2005 and 2006 cited by the commenter found that ''decreasing the crude protein concentration of beef cattle finishing diets based upon steam-flaked corn from 13 to 11.5 percent decreased ammonia emissions by 30 to 44 percent.''[87] A 2009 study cited by the commenter found that ''one feedyard feeding distillers grains averaged 149 grams of ammonia-N per head per day (NH3–N/head/day) over nine months, compared with 82 g NH3–N/head/day at another feedyard feeding lower protein steam-flaked, corn-based diets.''[88] Nominally this would represent a 45% reduction in ammonia emissions from manure by going to a lower protein diet. However, the net ammonia emission reduction either from reducing crude protein levels in feed, or by providing a lower protein steam-flaked, corn-based diet rather than a distiller grain diet is unclear given the role of protein intake on the time for beef cattle to reach market weight or on milk production for dairy cattle.

For manure handling and storage practices, a 2011 inventory of mitigation methods by Price et al. identifies many mitigation methods for various kinds of CAFs, some of which may reduce ammonia emissions by 50–90%.[89] For example, Method 44 (''Washing down dairy cow collecting yards'') involves areas where dairy cows are collected on a concrete yard prior to milking and, after each milking event, the urine and manure in the area are removed by pressure washing or by hosing and brushing, resulting in up to 90% ammonia emission reductions. Method 62 (''Cover solid manure stores with sheeting'') involves covering solid manure heaps with plastic sheeting, resulting in ammonia emission reductions up to 90%.[90] However, the authors note that, for both Method 44 and Method 62, reducing ammonia emission from the milking areas would increase the ammonium content of the slurry, potentially leading to higher ammonia emissions during storage and spreading, but by a lower amount than the initial reduction amount. Method 71 (''Use slurry injection application techniques'') involves shallow (5–10 cm depth) or deep (25 cm depth) injection of slurry into the soil, resulting in ammonia emission reductions of 70% to 90%, respectively.

Mitigation methods are also described for other kinds of CAFs, such as pig farms and chicken farms. For example, Method 48 (''Install air-scrubbers or biotrickling filters to mechanically ventilated pig housing'') involves pig housing where specific technologies are used to capture up to 90% of the ammonia emissions into recirculation water that can then be used as a nitrogen-based fertilizer. Method 51 (''In-house poultry manure drying'') involves installation of ventilation/drying systems that reduce the moisture content of poultry litter, resulting in up to 50% ammonia emission reductions, though, as with the cattle examples, this could result in some increased emissions at subsequent steps (*e.g.,* storing poultry litter).

In addition to the 2011 inventory of mitigation methods, in September 2017, the EPA and the U.S. Department of Agriculture, Natural Resource Conservation Service released the ''Agricultural Air Quality Conservation Measures, Reference Guide for Poultry and Livestock Production Systems'' (2017 EPA–USDA Reference Guide). This reference guide discusses air quality conservation measures relating to nutrition and feed management, animal confinement, manure management, land application, and other supplemental practices. Among other things it includes Appendix A.1 (''Table of Mitigation Effectiveness for Selected Measures''), which lists 12 measures that may reduce ammonia emissions by more than 30%, Appendix A.2 (''List of State Programs and Regulations for AFO Air Emissions''), and Appendix A.3 (''List of AFO Air Quality Programs & Land-Grant Universities'').

In sum, various research studies on mitigating ammonia emissions from CAFs suggest that there may be potential for additional ammonia reductions from activities such as animal feeding and housing to manure storage, handling, and land application. While the Plan refers to and describes some of the research studies described herein (*e.g.,* the 2008 Alberta Report and the 2005 Chadwick paper), it is unclear the extent to which the higher emission reduction measures have been or could be implemented in the SJV and, when aggregated across all CAF operations, it remains unclear whether the total reduction from additional measures would be greater than the State's estimate of maximum available

[86] Public Justice Comment Letter, 16–18.

[87] Public Justice Comment Letter, Exhibit 36, 9. Exhibit 36 is: Preece, Sharon L.M. et al., ''Ammonia Emissions from Cattle Feeding Operations,'' Texas A&M AgriLife Extension Service, referring to Cole, N.A., R.N. Clark, R.W. Todd, C.R. Richardson, A. Gueye, L.W. Greene, and K. McBride, ''Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure,'' Journal of Animal Science 83:(3), 722 (2005); and Todd, R.W., N.A. Cole, and R.N. Clark, ''Reducing Crude Protein in Beef Cattle Diet Reduces Ammonia Emissions from Artificial Feedyard Surfaces.'' Journal of Environmental Quality. 35:(2), 404–411 (2006).

[88] Public Justice Exhibit 36, 10, referring to a study by Todd, R.W., N.A. Cole, D.B. Parker, M. Rhoades, and K. Casey. 2009. ''Effect of Feeding Distillers Grains on Dietary Crude Protein and Ammonia Emissions from Beef Cattle Feedyards.'' In Proceedings of the Texas Animal Manure Management Issues Conference, 83–90.

[89] Public Justice Comment Letter, Exhibit 39. Exhibit 39 is: Price et al., ''An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide,'' December 2011. For mitigation measures that may reduce ammonia emissions by 50–90%, for example, methods 43, 44, 47–51, 54–55, 62, 64, 70–71, and 73–74 on pages 70–71, 74–78, 81–84, 93–94, 105–108, and 110–112 respectively, achievable control efficiencies from these measures in the SJV would depend on an applicability and feasibility review.

[90] We note that District Rule 4570, Table 3.1, section F and Table 4.1, section F provide mitigation measure options for the storage of solid manure and separated solids from large dairy CAFs, including measures that involve covering dry manure piles and separated solids, respectively, outside of pens with a weatherproof covering from May through October. Thus, such mitigation measures, if selected, would not be required for the remaining four months of the year (June through September). Similar mitigation measure options in Rule 4570 for covering dry manure piles apply for beef feedlots, other cattle, swine, poultry, and other CAF types.

reductions.[91] Accordingly, the EPA concludes that the available information in the Plan is insufficient to conclude that the State has sufficiently examined and justified its estimate for the ammonia emission reductions that may be available from CAFs, which emit a majority of the ammonia in the SJV.

Regarding fertilizer application, Rule 4570 and Rule 4565 have provisions addressing the land application of manure from CAFs and of biosolids, animal manure, and poultry litter from composting operations (though these lack specific enforceable requirements for ammonia). However, more broadly, the District states that fertilizer application is the second largest ammonia source in the SJV and that the District does not have statutory authority to regulate such activities.[92] Notwithstanding this statement, the District describes key research assessing nitrogen in California, as well as regulations adopted by the California Water Resources Control Board, including orders adopted by the Central Valley Regional Water Quality Control Board (*e.g.,* a Nutrient Management Plan), the Irrigated Lands Regulatory Program (*e.g.,* a Nitrogen Management Plan), or other individual mechanisms.[93] These orders subject agricultural operators, including dairies, bovine feedlots, poultry operations, and crop farmers to ''waste discharge requirements that protect both surface water and groundwater.'' [94]

The EPA anticipates that such regulations are, in practice, likely to enhance the retention of nitrogen (whether from manure or nitrogen-based chemical fertilizers) for productive purposes in the SJV (*e.g.,* growing crops and enhancing soil health) and limit the loss of nitrogen as pollution to water and air (*e.g.,* potentially reduce ammonia emissions). However, to our knowledge, these regulations do not impose any enforceable requirement for ammonia emissions to the air, and thus render quantification difficult, as with Rule 4570.[95]

In addition, the District states that ''the overall efficiency of nitrogen usage at California farms is expected to increase and emissions of reactive nitrogen, including [ammonia], are expected to decrease significantly.'' We agree that managing the amount of nitrogen applied to the environment should reduce the potential for pollution to air, water, and land. However, the District does not attempt to quantify or otherwise substantiate the scale and timing of such potential ammonia emission reduction benefits, nor their enforceability, nor does it attempt to analyze how much additional reductions may be available. Overall, the EPA finds that the available evidence is insufficient to conclude that the State has sufficiently examined and justified its estimate for the ammonia emission reductions that may be available from fertilizer application, the second largest ammonia emission source in the SJV.

c. The EPA's Conclusion for Ammonia Precursor Demonstration

The EPA does not believe that the State has presented sufficient evidence that ammonia does not contribute significantly to $PM_{2.5}$ levels above the NAAQS. In the absence of an approved precursor demonstration, ammonia remains a plan precursor subject to the requirements of BACM, BACT, and additional feasible measures.

As discussed in our 2021 Proposed Rule,[96] the modeled response to 30% ammonia emissions reductions is above the EPA's recommended contribution threshold of 0.20 μg/m^3 at two monitoring sites, Madera and Hanford, providing evidence that ammonia significantly contributes to $PM_{2.5}$ in SJV. In the previous proposal, we gave those responses less weight, because of specific evidence available for these sites that the responses were overestimated. For Madera, the monitoring data used in estimating the model response are biased high, and therefore the modeled response of 0.21 μg/m^3, just above contribution threshold, is likely overestimated. For Hanford, several analyses showed ambient ammonia concentrations are underestimated, and so we believe that the modeled response of 0.26 μg/m^3 is likely overestimated. Supporting that conclusion is the evidence from ambient concentrations of excess ammonia relative to nitrate, which suggest that $PM_{2.5}$ responses to reductions of ammonia emissions would be dampened by the NO_X-limited nature of ammonium nitrate formation in the SJV.

All of those considerations remain for the current proposal. But in light of comments received and re-evaluation of the available evidence, the EPA believes we should give the Hanford response more weight, because that response would be larger if the ammonia reductions modeled were larger than the 30% assumed in the State's precursor demonstration. The previous subsection gave several examples of the uncertainty and possible underestimation of the ammonia benefit of available control measures to the SJV. The EPA does not believe there is sufficient quantitative evidence to rely on 30% as the amount of achievable reductions, and as the amount to use an upper bound on the ammonia emission reductions modeled in the State's precursor demonstration. A robust controls evaluation could show that a larger amount of reductions is achievable. If it is, then not only would the Hanford modeled response be larger, but additional monitoring sites could have a modeled response above the contribution threshold.

For example, with respect to the modeled 2024 ambient $PM_{2.5}$ responses to a 70% emission reduction, we note that the modeled high site of Bakersfield-Planz would have a response of 0.36 μg/m^3, the site with the largest modeled response would be 0.75 μg/m^3 at Hanford, and six sites (including Hanford) would have modeled responses greater than 0.5 μg/m^3. As a more modest example, interpolating between the available 30% and 70% modeled results, if 32% reductions are achievable, then three additional monitoring sites (Turlock, Merced-S. Coffee St., and Modesto) would reach the 0.2 μg/m^3 contribution threshold. The uncertainty over the ammonia response means that we cannot rely on 30% as an upper bound for ammonia emission reductions, and so the weight of evidence shifts relative to that in the 2021 Proposed Rule.

The discussion in this proposed rule, and the heavy reliance in the 2021 Proposed Rule, on the State's use of a 30% upper bound for potential reduction from controls should not be interpreted as establishing a 30% ''bright line'' for deciding whether a precursor should be regulated. The $PM_{2.5}$ Precursor Guidance recommends that 30% to 70% emissions reductions be modeled as a way of implementing the $PM_{2.5}$ SIP Requirements Rule's option in 40 CFR 51.1006(a)(1)(ii) for a State to assess the sensitivity of the atmospheric $PM_{2.5}$ to precursor emission reductions. The sensitivity of the atmosphere to reductions is a separate question from what reductions are achievable from controls; the latter is properly part of the control evaluation for BACM, BACT, and additional feasible measures. However, it is important to note that under 40 CFR

[91] In evaluating the aggregate reductions available across all sub-activities, it may be important to evaluate the extent to which reductions at one sub-activity may affect emissions at other stages of the process.

[92] 2018 $PM_{2.5}$ Plan, App. C, C–311.

[93] 2018 $PM_{2.5}$ Plan, App. C, C–339 to C–343.

[94] Id. at C–341.

[95] Unlike Rule 4570, which has been approved into the California SIP to limit VOC emissions, the State's water-related regulations on fertilizer application have not been submitted for approval into the California SIP.

[96] 86 FR 74310, 74320.

51.1010(a)(2)(ii), the EPA may require a control evaluation to help the EPA evaluate the precursor demonstration. The $PM_{2.5}$ Precursor Guidance explains that the additional information from a control evaluation is particularly important when modeled precursor contributions are close to the threshold for a 30% reduction.[97] But the regulations and guidance do not establish an automatic ''off ramp'' for a State to be discharged from the requirements for BACM, BACT, and additional feasible measures via a showing that achievable reductions are below a particular percentage.

We have no evidence that emission reductions below current emissions levels from BACM on all ammonia sources in the SJV would be as large as 70%, but the lack of a developed record showing what ammonia control measures are feasible and what they could achieve makes it harder for the EPA to assess this point. We also lack sufficient evidence to conclude that reasonable ammonia control measures could achieve no more than 30% reductions, and so cannot rely on that supposition in weighing the modeled responses to reductions and other evidence. Better quantification of the possible ammonia reductions from current levels that could result from additional controls would help resolve this issue. Reconciliation of modeled sensitivity with that expected from ambient studies would also be appropriate.

The EPA has re-examined the 2024 sensitivity analyses to both 30% and 70% ammonia emission reductions in light of the uncertainty that 30% represents a reasonable upper bound for potential ammonia emission reductions. We note that the State modeled 30% reduction scenarios and predicted ambient $PM_{2.5}$ responses above 0.2 $\mu g/m^3$ at 2 of 15 sites in 2024; and modeled the 70% reduction scenarios and predicted responses above 0.2 $\mu g/m^3$ at all monitors in 2024.[98] The EPA maintains that the State's reliance on its sensitivity-based contribution analysis for a future year (2024) to evaluate the significance of ammonia as a precursor is reasonable, well supported, and consistent with the EPA's guidance. There are also good reasons for giving less weight to the modeled responses at the Madera and Hanford sites, although those are tempered by the consideration that there is not good support for limiting the modeled ammonia reductions to 30%, leading to the possibility of larger responses at Hanford and of additional sites with responses above the contribution threshold.

The weight of the evidence, including at least one site above the EPA's recommended contribution threshold and the possibility of additional ones depending on the unknown amount of reductions achievable, favor retaining the presumption that ammonia must be regulated as a $PM_{2.5}$ precursor for the 2012 annual $PM_{2.5}$ NAAQS in the SJV. For the reasons explained above, the Plan both indicates that there are levels of ammonia control that could have a significant impact on $PM_{2.5}$ levels at multiple monitors in the SJV and does not dispose the potential availability of ammonia emission reductions at a level that would have such impacts. Therefore, the EPA proposes to disapprove the State's ammonia precursor demonstration for the Serious area requirements for purposes of the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

B. Best Available Control Measures

1. Statutory and Regulatory Requirements

Section 189(b)(1)(B) of the Act requires for any Serious $PM_{2.5}$ nonattainment area that the State submit provisions to assure that the best available control measures (BACM), including controls that reflect best available control technology (BACT), for the control of $PM_{2.5}$ and $PM_{2.5}$ precursors shall be implemented no later than four years after the date the area is reclassified as a Serious area. The EPA has defined BACM in the $PM_{2.5}$ SIP Requirements Rule to mean ''any technologically and economically feasible control measure that can be implemented in whole or in part within 4 years after the date of reclassification of a Moderate $PM_{2.5}$ nonattainment area to Serious and that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ emissions and/or emissions of $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of reasonably available control measures (RACM) on the same source(s).''[99]

The EPA generally considers BACM a control level that goes beyond existing RACM-level controls, for example by expanding the use of RACM controls or by requiring preventative measures instead of remediation.[100] Indeed, because states are required to implement BACM and BACT when a Moderate nonattainment area is reclassified as Serious due to its inability to attain the NAAQS through implementation of ''reasonable'' measures, it is logical that ''best'' control measures should represent a more stringent and potentially more technologically advanced or more costly level of control.[101] If RACM and RACT level controls of emissions have been insufficient to reach attainment, then the CAA Title I, Part D, subpart 4 provisions for $PM_{2.5}$ nonattainment plans contemplate the implementation of more stringent controls, controls on more sources, or other adjustments to the control strategy necessary to attain the NAAQS in the area. Thus, BACM/BACT determinations are to be ''generally independent'' of attainment for purposes of implementing the $PM_{2.5}$ NAAQS.[102]

Consistent with longstanding guidance provided in the General Preamble Addendum, the preamble to the $PM_{2.5}$ SIP Requirements Rule discusses the following steps for states to use in identifying and selecting the emission controls needed to meet the BACM/BACT requirements of 40 CFR 51.1010:

1. Develop a comprehensive emission inventory of all sources of $PM_{2.5}$ and $PM_{2.5}$ precursors from major and non-major stationary point sources, area sources, and mobile sources;

2. Identify potential control measures for all sources or source categories of emissions of $PM_{2.5}$ and relevant $PM_{2.5}$ plan precursors;

3. Determine whether an available control measure or technology is technologically feasible;

4. Determine whether an available control measure or technology is economically feasible; and

5. Determine the earliest date by which a control measure or technology can be implemented in whole or in part.[103]

The EPA allows states to consider factors such as a source's processes and operating procedures, raw materials, physical plant layout, and potential environmental impacts such as increased water pollution, waste disposal, and energy requirements when

[97] $PM_{2.5}$ Precursor Guidance, 31.

[98] 2018 $PM_{2.5}$ Plan, App. G, tables 4 through 7.

[99] 40 CFR 51.1000 (definitions). In longstanding guidance, the EPA has similarly defined BACM to mean, ''among other things, the maximum degree of emissions reduction achievable for a source or source category, which is determined on a case-by-case basis considering energy, environmental, and economic impacts.'' General Preamble Addendum, 42010, 42013.

[100] 81 FR 58010, 58081 and General Preamble Addendum, 42011, 42013.

[101] 81 FR 58010, 58081 and General Preamble Addendum, 42009–42010.

[102] $PM_{2.5}$ SIP Requirements Rule, 58081–58082. See also, General Preamble Addendum, 42011.

[103] 81 FR 58010, 58083–58085.

considering technological feasibility.[104] For purposes of evaluating economic feasibility, the EPA allows states to consider factors such as the capital costs, operating and maintenance costs, and cost effectiveness (*i.e.,* cost per ton of pollutant reduced by a measure or technology) associated with the measure or control.[105] For any potential control measure identified through the process described above that is eliminated from consideration, states are required to provide detailed written justification for doing so on the basis of technological or economic feasibility, including how its criteria for determining such feasibility are more stringent than those used for determining RACM/RACT.[106]

Once these analyses are complete, the State must use this information to develop enforceable control measures for all relevant source categories in the nonattainment area and submit them to the EPA for evaluation as SIP provisions to meet the basic requirements of CAA section 110 and any other applicable substantive provisions of the Act.

2. BACM for Ammonia Sources

As previously noted, as part of the EPA's 2021 Proposed Rule, we reviewed the State's analysis of ammonia control for the primary source categories of ammonia in the context of our evaluation of the State's precursor demonstration.[107] Because our prior proposal to approve the State's ammonia precursor demonstration would have relieved the State of its obligation to implement BACM for ammonia sources, we did not present a summary of the 2018 $PM_{2.5}$ Plan with respect to the BACM requirements for ammonia for the 2012 annual $PM_{2.5}$ NAAQS, nor our evaluation thereof. Given our reconsidered proposal to disapprove the State's ammonia precursor demonstration, in the following sections of this proposed rule we evaluate the District's control analysis for the two most substantial source categories of ammonia, which together sum to more than 90% of the emissions in the SJV: CAFs and fertilizer application.

a. Summary of State's Submission

The District presents its analysis of ammonia controls for the primary ammonia source categories in the SJV in Appendix C, section C.25 (''Ammonia in the San Joaquin Valley'') of the 2018 $PM_{2.5}$ Plan. The District evaluated its emission control measures for compliance with BACM for CAFs and described water-related measures applicable to fertilizer application that have co-benefits to air quality. The District presents its reasoning that measures that control VOC emissions, such as Rule 4570 for CAFs, also reduce ammonia emissions due to the physical processes occurring in decomposing manure and subsequent volatilization of decomposition products (like VOC and ammonia). As part of its process for identifying candidate BACM, considering the technical and economic feasibility of additional control measures, the District reviewed the EPA's guidance documents on BACM, and control measures implemented in other nonattainment areas in California and other states.[108]

For CAFs, the District discusses in detail how Rule 4570 (''Confined Animal Facilities'') is structured (*e.g.,* to address varying types of CAFs, including applicability thresholds); the five main CAF operations/emission sources: feeding, housing (including distinctions for housing configurations), solid waste, liquid waste, and land application of manure; and the control menu requirements for each of those five operations.[109] The District summarizes the specific requirements applicable to each type of cattle-based CAF, including dairies, beef feedlots, and ''other cattle'' and describes its basis for ammonia emission reductions estimates, including cited research papers.

The District also compares Rule 4570 to other CAF rules imposed by the South Coast Air Quality Management District (AQMD), Bay Area AQMD, Sacramento Metropolitan AQMD, Imperial County Air Pollution Control District (APCD), and the State of Idaho.[110] The District evaluates a potential additional control measure—application of sodium bisulfate to reduce pH and bacterial levels in bedding for dairy cattle—and concludes that such measure is not feasible based on a number of factors, including health and safety of dairy workers and animals, impacts on water quality, and overall cost and effectiveness.[111]

For fertilizer application, as described in section II.A.3 of this proposed rule, the District states that fertilizer application is the second largest ammonia source in the SJV and that the District does not have statutory authority to regulate such activities.[112] Notwithstanding, the District describes how regulations adopted by the California Water Resources Control Board, including orders adopted by the Central Valley Regional Water Quality Control Board (*e.g.,* a Nutrient Management Plan), the Irrigated Lands Regulatory Program (*e.g.,* a Nitrogen Management Plan), or other individual mechanisms [113] subject agricultural operators, including dairies, bovine feedlots, poultry operations, and crop farmers to ''waste discharge requirements that protect both surface water and groundwater.'' [114]

Overall, the District concludes that ''the Valley's ammonia emissions have been significantly reduced through stringent regulations, that additional ammonia control measures are infeasible, and that Valley sources are already implementing BACM.'' [115]

b. Summary of Adverse Comments

Public Justice states that ''[w]eaker controls are consistently allowed for agricultural sources,'' including an ''expansive menu of control options'' in Rule 4570, that they assert provide little to no emission reduction benefit.[116] More broadly, as described in section II.A.2 of this proposed rule, the commenters assert that ''[t]he analysis of potential controls is particular[ly] weak and ignores the wealth of literature demonstrating that strategies for reducing ammonia emissions from agriculture . . . are among the most effective for also reducing PM concentrations,'' and cite several studies in support of this argument.[117] The commenters further state that reducing ammonia emissions may be achieved through ''strategies such as improving livestock feed to reduce excreted nutrients, altering manure storage and handling practices to prevent [ammonia] emissions, and improving synthetic fertilizer use efficiency,'' again citing numerous studies.[118] The commenters

[104] 40 CFR 51.1010(a)(3)(i).

[105] 40 CFR 51.1010(a)(3)(ii).

[106] 40 CFR 51.1010(a)(3)(iii).

[107] 86 FR 74310, 74319. See also, 85 FR 17382, 17395 (March 27, 2020), and the EPA's $PM_{2.5}$ Precursor TSD, 13.

[108] 2018 $PM_{2.5}$ Plan, Chapter 4, section 4.3.1.

[109] 2018 $PM_{2.5}$ Plan, App. C, C–312 to C–323.

[110] 2018 $PM_{2.5}$ Plan, App. C, C–323 to C–337.

[111] 2018 $PM_{2.5}$ Plan, App. C, C–338 to C–339.

[112] 2018 $PM_{2.5}$ Plan, App. C, C–311.

[113] 2018 $PM_{2.5}$ Plan, App. C, C–339 to C–343.

[114] 2018 $PM_{2.5}$ Plan, App. C, C–341.

[115] 2018 $PM_{2.5}$ Plan, App C., C–312.

[116] Public Justice Comment Letter, 20.

[117] Public Justice Comment Letter, 16, Exhibits 31 through 34.

[118] Public Justice Comment Letter, 17, Exhibits 35 through 40 and three additional studies: N. Cole, et al., ''Influence of dietary crude protein concentration and source on potential ammonia emissions from beef cattle manure,'' J. Anim. Sci. 83, 722, 2005; N. Cole, P. Defoor, M. Galyean, G. Duff, J. Gleghorn, ''Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers,'' J. Anim. Sci. 12, 3421–3432, 2006; and R. Todd, N. Cole, R. Clark, ''Reducing crude protein in beef cattle diet reduces

argue that the EPA ''should reject the plan's BACM analysis for failing to justify these weaker controls, and for being inconsistent with the Title VI prohibition against policies and practices that inflict disparate impacts.''

c. The EPA's Reconsidered Proposal

As a result of our proposed conclusion that ammonia remains a regulated precursor for the 2012 annual $PM_{2.5}$ NAAQS in the SJV, the EPA has evaluated potential ammonia emissions control measures for the two most substantial source categories in the SJV and evaluated whether the State has implemented ammonia controls with a BACM/BACT level of stringency. Thus, the EPA has also evaluated the existing control measures that the State claims are BACM for two of the main sources of ammonia in the area, including confined animal facilities (CAFs) and fertilizer application.[119] As discussed below, we conclude that the SJV has not established that it has enforceable requirements in the SIP that meet a BACM level of stringency to reduce ammonia emissions from these two categories. Therefore, we propose to disapprove BACM for ammonia sources in the SJV.

Our basis for proposing to disapprove BACM for ammonia sources flows from the controls analysis we have reviewed and discuss in section II.A.3 of this proposed rule. We agree with the commenters that the analysis of potential controls in the 2018 $PM_{2.5}$ Plan was weak in two general areas: (1) incomplete quantification of existing ammonia emission reductions, and (2) lack of consideration of potential ammonia control measures identified in research studies. In that section we describe the Plan's weaknesses with respect to quantifying emission reductions and rely on that description for purposes of evaluating BACM.

Similarly, in section II.A.3, we discuss additional options for ammonia control that we will not reiterate here. Based on our review of the additional research studies cited by the commenters with respect to CAFs, measures such as those for adjusting the protein content of livestock feed (*e.g.,* reducing the portion of beef cattle finishing diets by 1.5% steam-flaked corn), manure handling and storage (*e.g.,* washing dairy cow collecting yards after each milking event, covering solid manure stores with sheeting), and land application of slurry (*e.g.,* injection application techniques), it appears that additional measures may be available to evaluate. Absent a thorough and more current evaluation of technological and economic feasibility of potential measures as applied in the SJV, we propose to find that the State has not demonstrated whether or how additional measures (*e.g.,* in the form of existing options that could also be feasibly implemented, or new options that may lead to increased reductions) may have been evaluated, implemented (even partially) by the existing rules, or set aside for reasons of technological feasibility or economic feasibility, consistent with the BACM requirements.

For fertilizer application, as discussed in section II.A.3 of this proposed rule, the District indicates that it does not have authority to regulate ammonia emissions from fertilizer application. Regardless of which State entity, as a matter of State law, has authority over this class of activities, CAA section 189(b)(1) requires that the State include provisions to ensure implementation of BACM for direct $PM_{2.5}$ and plan precursor emissions, and CAA section 110(a)(2)(E)(i) requires the State to provide necessary assurances that it has adequate authority to carry out the implementation plan for the area. While the Plan describes certain water-related measures (*e.g.,* Nutrient Management Plans and Nitrogen Management Plan) that subject agricultural operators, including dairies, bovine feedlots, poultry operations, and crop farmers to waste discharge requirements, and likely limit ammonia emissions to the air, to our knowledge, these regulations do not impose any enforceable requirement for ammonia emissions to the air, and thus suffer a similar problem as Rule 4570.[120]

We agree that as a general matter, managing the amount of nitrogen applied to the environment should reduce the potential for pollution to air, water, and land. However, the 2018 $PM_{2.5}$ Plan does not quantify or otherwise substantiate the scale and timing of such potential ammonia emission reduction benefits, nor their enforceability. We propose that the State has not adequately identified potential control measures, evaluated for BACM/BACT, nor demonstrated the implementation of BACM/BACT for controlling ammonia emissions from fertilizer application, the second largest source of such emissions in the SJV.

As a result of our proposal that the State has not demonstrated that BACM/BACT controls are in place for CAFs and fertilizer application, two source categories that make up more than 90% of the ammonia emissions in the SJV, we propose to disapprove the State's BACM demonstration for ammonia sources.

3. BACM for Building Heating Emission Sources

a. Summary of 2021 Proposed Rule

In our 2021 Proposed Rule, the EPA summarized the State's submission in the 2018 $PM_{2.5}$ Plan for the SJV and presented our BACM evaluation for emission sources of direct $PM_{2.5}$ and NO_X.[121] We briefly summarize those components here with respect to the State's BACM demonstration for building heating emission sources, such as water heaters and space heaters (*e.g.,* furnaces), in the SJV.

In Appendix C of the 2018 $PM_{2.5}$ Plan, the District identifies the stationary and area sources of direct $PM_{2.5}$ and NO_X in the SJV that are subject to District emission control measures and provides its evaluation of these regulations for compliance with BACM requirements. As part of its process for identifying candidate BACM, the District reviewed the EPA's guidance documents on BACM, additional guidance documents on control measures for direct $PM_{2.5}$ and NO_X emission sources, and control measures implemented in other ozone and $PM_{2.5}$ nonattainment areas in California and other states.[122] Based on these analyses, the District concludes that all best available control measures for stationary and area sources are in place in the SJV for NO_X and directly emitted $PM_{2.5}$ for purposes of meeting the BACM/BACT requirement for the 2012 annual $PM_{2.5}$ NAAQS.

With respect to building heating emission sources, the District presents its evaluations of Rule 4902 (''Residential Water Heaters'') and Rule 4905 (''Natural Gas-Fired, Fan-Type Central Furnaces'') in sections C.20 and C.21, respectively, of Appendix C of the 2018 $PM_{2.5}$ Plan. Both rules are point of sale rules that limit what kinds of residential water heaters and furnaces may be sold in the SJV. The District describes the types of equipment covered by each rule, compares the specific provisions of each rule that

ammonia emissions from artificial feedyard surfaces,'' J. Environ. Qual. 35, 404–411, 2006.

[119] By focusing on these two source categories, the EPA is not indicating that this is an exhaustive list of ammonia source categories that must be evaluated for BACM. However, because these two categories amount to more than 90% of the ammonia emissions in the SJV, we focus our analysis on these two categories.

[120] Unlike Rule 4570, which has been approved into the California SIP to limit VOC emissions, the State's water-related regulations on fertilizer application have not been submitted for approval into the California SIP.

[121] 86 FR 74310, 74324–74325.

[122] 2018 $PM_{2.5}$ Plan, Ch. 4, section 4.3.1.

limit NO_X emissions [123] to comparable rules in other California air districts, and concludes that each rule represents BACM for their respective source category.

Rule 4902 applies to natural gas-fired, residential water heaters with heat input rates less than or equal to 75,000 British thermal units per hour (Btu/hr). The District tightened the rule's NO_X limits in 2009; and the EPA approved the rule into the SIP in 2010.[124] The District estimates that, due to Rule 4902, annual average emissions of NO_X would decrease from 2.15 tpd in 2013 to 1.91 tpd in 2025 (0.24 tpd decrease) and annual average emissions of direct $PM_{2.5}$ would increase from 0.21 tpd in 2013 to 0.23 tpd in 2025 (0.02 tpd increase).[125]

In addition to comparing the NO_X limits in its Rule 4902 to rules in other California air districts, the District also presents a multi-factor comparison of natural gas-fired and propane-fired, water heaters to electric water heaters.[126] The District discussed the likely impacts of requiring electric water heaters, including the advantages such as no NO_X emissions,[127] less expensive purchase price, and smaller size, and the disadvantages such as higher cost of electricity, and the costs of residence modifications to convert to electric. Based on 2017–2018 data, which is consistent with the timing of Plan adoption in 2018, the District calculated emission reductions and cost effectiveness of the three kinds of water heaters by fuel type and concluded that ''[w]hile the lifetime cost of an electric water heater is higher than that of propane and natural gas, the emissions benefits may make converting to electric water heating a viable control strategy.'' [128] The analysis does not explore the cost effectiveness of such controls and Rule 4902 does not include any requirements regarding electrification.

Rule 4905 applies to natural gas-fired, fan-type central furnaces with heat input rates less than 175,000 Btu/hr and combination heating and cooling units with a rated cooling capacity of less than 65,000 Btu/hr. In 2015, the District tightened the rule's NO_X limits for residential units and expanded the rule to include commercial units and manufactured homes according to a phase-in schedule. The EPA approved the rule into the SIP in 2016.[129] The District estimates that, due to Rule 4905, annual average emissions for NO_X will decrease from 2.44 tpd in 2013 to 2.13 tpd in 2025 (0.31 tpd decrease) and annual average emissions for direct $PM_{2.5}$ will increase from 0.20 tpd in 2013 to 0.22 tpd in 2025 (0.02 tpd increase).[130] Given the need to extend certain compliance deadlines in subsequent amendments to Rule 4905 due to limited supply of certified compliant units,[131] the District states that it had identified no additional emission reduction measures for this source category as of that point in time.[132]

As noted in the EPA's 2021 Proposed Rule, we provided our evaluation of the District's BACM demonstration for stationary and area sources in general, and several source categories in more detail, in three documents: (1) section III of the EPA's ''Technical Support Document, EPA Evaluation, San Joaquin Valley Serious Area Plan for the 2012 Annual $PM_{2.5}$ NAAQS,'' December 2021 (''EPA's 2012 Annual $PM_{2.5}$ TSD''); (2) the EPA's ''Technical Support Document, EPA Evaluation of BACM/MSM, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS,'' February 2020 (''EPA's BACM/MSM TSD''); and (3) the EPA's ''Response to Comments Document for the EPA's Final Action on the San Joaquin Valley Serious Area Plan for the 2006 $PM_{2.5}$ NAAQS,'' June 2020 (''EPA's 2020 Response to Comments''). In particular, the EPA's 2020 Response to Comments presented our evaluation of the District's BACM demonstration for residential water heaters and residential and commercial, natural gas-fired, fan-type central furnaces.[133] At that time we found that the requirements for residential fuel combustion covered by Rule 4902 and Rule 4905 represented BACM.[134] In addition, the EPA concluded that setting a zero-NO_X standard for heating appliances in new buildings reasonably requires additional consideration and analysis of technological and economic feasibility by the District because, per the 2018 $PM_{2.5}$ Plan, the most common types of residential water heaters and furnaces are those that use natural gas as fuel.

We also noted that the building codes referenced by commenters at that time appear to be green building code ordinances that restrict or prohibit installation of natural gas or propane appliances in new construction.[135] Such ordinances, most of which appeared to have been adopted in late 2019 and early 2020, fell within a category known as ''reach codes,'' which are city and county building code standards for energy efficiency that exceed California's State-wide standards. We stated that California law requires local governments to submit proposed ordinances to the California Energy Commission (CEC) for a determination that they will be both cost effective and more energy efficient than statewide standards; compliance with this procedure is necessary for such measures to be enforceable.[136] We also noted that ordinances adopted by city councils and county officials are legally distinct from measures adopted by the governing boards of the respective air districts and that it did not appear at the time that California air districts had adopted similar restrictions.

b. Summary of Adverse Comments

Public Justice states that further emission controls are available for building heating via the electrification of furnaces, water heaters, and other gas-fired appliances.[137] The commenters refer to comments submitted by a group of environmental, public health, and community organizations (collectively referred to herein as ''NPCA'') on the EPA's proposed rule on the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan,[138] noting that building electrification requirements to reduce emissions from such sources already

[123] The District notes that equipment subject to Rule 4902 are fired on natural gas that meets California Public Utility Commission standards and, therefore, emit only low amounts of SO_X and direct $PM_{2.5}$. 2018 $PM_{2.5}$ Plan, App. C, C–288.

[124] 75 FR 24408 (May 5, 2010).

[125] 2018 $PM_{2.5}$ Plan, App. C, C–283.

[126] 2018 $PM_{2.5}$ Plan, App. C, C–288 to C–289.

[127] The EPA notes that while the NO_X emissions of electric water heaters and furnaces are zero, there could be an increase in NO_X emissions from electric power plants.

[128] 2018 $PM_{2.5}$ Plan, App. C, C–289.

[129] 81 FR 17390 (March 29, 2016).

[130] 2018 $PM_{2.5}$ Plan, App. C, C–290.

[131] The District further amended Rule 4902 in 2018, 2020, and 2021 to extend the compliance deadline for specific units due to limited supply of certified compliant units, with each amendment applying to a smaller subset of those specific units. See, *e.g.,* San Joaquin Valley UAPCD, ''Item Number 10: Adopt Proposed Amendments to Rule 4905 (Natural Gas-Fired, Fan-Type Central Furnaces),'' December 16, 2021, 2–3.

[132] 2018 $PM_{2.5}$ Plan, App. C, C–293. Unlike the District's consideration of electric water heaters, the District did not present an evaluation of electric furnaces in its analysis of Rule 4905.

[133] EPA's 2020 Response to Comments, Comment 6.O and Response 6.O, 142–148.

[134] EPA's 2020 Response to Comments, 146–147.

[135] EPA's 2020 Response to Comments, 147–148.

[136] California 2019 Building Energy Standards, at California Code of Regulations (CCR), Title 24, Part 1, Article 1, Sec. 10–106 (''Locally Adopted Energy Standards''); see also *https://ww2.energy.ca.gov/title24/2016standards/ordinances.*

[137] Public Justice Comment Letter, 19.

[138] Comment letter dated and received April 27, 2020, from Mark Rose, NPCA, et al., to Rory Mays, EPA, including Appendices A through G. The seven environmental and community organizations, in order of appearance in the letter, are the National Parks Conservation Association (NPCA), Earthjustice, Central Valley Air Quality Coalition, Coalition for Clean Air, Central Valley Environmental Justice Network, The Climate Center, and Central Valley Asthma Collaborative (collectively ''NPCA'').

exist in over 30 jurisdictions in California and other states. The commenters state that, since that time, additional jurisdictions have moved forward with gas bans, appliance standards, and other strategies for building heating.[139]

With respect to the EPA's response to the NPCA comments in 2020,[140] Public Justice argues that the ''EPA merely asserted that the District had found increased building electrification infeasible,'' despite the record showing that other jurisdictions required such measures, and assert that the District noted the potential of such measures but rejected them without explanation. The commenters further argue that the EPA did not rebut evidence on the benefits and feasibility of such measures, instead noting the need for further consideration, and that two years later, the Plan does not provide further consideration.

c. The EPA's Reconsidered Proposal

Based on the adverse comments from Public Justice, the EPA has reconsidered our proposed approval of the State's demonstration of BACM for NO_X and direct $PM_{2.5}$ emissions from building heating appliances, such as residential water heating and residential and commercial space heating. As discussed below, we now propose to disapprove the State's BACM demonstration for such building heating emission sources.

Although the EPA has previously approved the State's BACM demonstration for building heating emission sources in 2020 with respect to the 2006 24-hour $PM_{2.5}$ NAAQS portion of the 2018 $PM_{2.5}$ Plan, and such approval was upheld by the Ninth Circuit Court of Appeals,[141] several factors have reshaped the facts and circumstances of controlling emissions from such sources as of 2022 and beyond. First, while building ordinances that restrict or prohibit installation of natural gas or propane appliances in new construction were starting to appear in 2019 and 2020, as Public Justice correctly asserts, two additional years have passed and additional jurisdictions have adopted gas bans, appliance standards, and other strategies for building heating.[142] A recent policy brief published by the UCLA School of Law states that 52 cities and counties in California have adopted building codes to reduce their reliance on gas for building heating appliances, and discusses several examples.[143] The growth in the number and types of local control measures to reduce pollution from building heating by restricting or limiting the use of natural gas-fired heaters support their general availability as technologically feasible measures.

Second, the time horizon of the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan is one year later (2025 attainment date) than that of the 2006 24-hour $PM_{2.5}$ NAAQS portion of the Plan (2024 attainment date), affording additional time for potential control measures to achieve emission reductions that may assist attainment of the 2012 annual $PM_{2.5}$ NAAQS. Even if full implementation of such new measures is not possible by the applicable attainment date, the State should evaluate whether they could be implemented in part, consistent with the fifth step for BACM/BACT evaluation discussed in the $PM_{2.5}$ SIP Requirements Rule and the General Preamble (*i.e.,* to determine the earliest date by which a control measure or technology can be implemented in whole or in part).[144]

Third, some of the underlying bases for the District's cost comparison for residential water heating may have changed since the District's 2018 adoption of the Plan. For example, in comparing emission reductions and cost effectiveness of low-NO_X natural gas, propane, and electric water heaters, the District used data on energy factors and purchase price from Grainger Industrial Supply as of June 14, 2018, and lifetime energy cost data from the U.S. Energy Information Administration as of 2017. Furthermore, as claimed by Public Justice, the District did not explain its rejection of additional control measures of this type, other than to assert that they were generally more costly. Regarding residential and commercial space heating, CARB and the District did not provide a detailed economic feasibility analysis in the Plan. CARB and the District simply stated that, due to limited supply of certified compliant natural gas-fired units to comply with Rule 4905, they could identify no additional emission reduction measures. The incomplete cost analyses presented by the District, changes in costs over time, and lack of justification for rejecting measures to reduce pollution from building heating by restricting or limiting the use of natural gas-fired heaters indicate an insufficient economic feasibility analysis.

Fourth, CARB and at least one other air district (Bay Area AQMD) are moving forward in developing measures to set zero-emission standards for space heaters and water heaters. In developing its 2022 State SIP Strategy (for the 2015 ozone NAAQS), CARB has stated that the ''fuels we use and burn in buildings, primarily natural gas, for space and water heating contribute significantly to building-related criteria pollutant and GHG emissions and provide an opportunity for substantial emissions reductions where zero-emission technology is available.'' [145] Accordingly, CARB is developing zero-emission standard concepts and, given the intersection of air quality needs and other areas of building and energy regulation, and identifying other regulatory entities that they plan to engage, including the U.S. Department of Energy, CEC, and the California Building Standards Commission, Department of Housing and Community Development. We note, however, that the proposed 2022 State SIP Strategy released August 12, 2022, anticipates implementation starting in 2030, pending rule development and CARB Board hearing in 2025.[146]

The Bay Area AQMD hosted public meetings in 2021 and developed draft amendments to certain rules that would reduce NO_X emissions from residential and commercial furnaces and water heaters.[147] Specifically, Bay Area AQMD has developed draft amendments to two rules: (1) Regulation 9, Rule 4 (''Nitrogen Oxides from Fan Type Residential Central Furnaces''), which applies to furnaces with a heat input rate of less than 175,000 Btu/hr and combination heating and cooling units with a rated cooling capacity of less than 65,000 Btu/hr (like SJVUAPCD Rule 4905); and (2) Regulation 9, Rule 6 (''Nitrogen Oxides Emissions from

[139] Public Justice Comment Letter, 19, and Exhibits 41 through 44. Commenters also state that studies suggest these measures may provide particularly notable benefits to winter $PM_{2.5}$ peaks in the SJV. Id. at 19.

[140] EPA, ''Response to Comments Document for the EPA's Final Action on the San Joaquin Valley Serious Area Plan for the 2006 $PM_{2.5}$ NAAQS,'' June 2020. See Comment 6.O and Response 6.O on pages 142–147.

[141] Ninth Circuit Memorandum Order, 9. Regarding increased building electrification requirements, the Court stated that ''the EPA considered such an approach and reasonably accepted the State's determination that it was not feasible at this time.''

[142] See Public Justice Comment Letter, Exhibits 41 through 44.

[143] Heather Dadashi, Cara Horowitz, and Julia Stein, ''Pritzker Environmental Law and Policy Briefs, How Air Districts Can End NO_X Pollution From Household Appliances,'' Emmett Institute on Climate Change and the Environment, UCLA School of Law, March 2022, 8.

[144] 81 FR 58010, 58083–58085.

[145] CARB, ''Draft 2022 State Strategy for the State Implementation Plan,'' January 31, 2022, 86–88.

[146] CARB, ''Proposed 2022 State Strategy for the State Implementation Plan,'' August 12, 2022, 101–103.

[147] A summary of the Bay Area AQMD's rule development is available at: *https://www.baaqmd.gov/rules-and-compliance/rule-development/building-appliances.*

Natural Gas-Fired Boilers and Water Heaters''), which applies to water heaters with a rated heat input capacity of 75,000 Btu/hr or less (like SJVUAPCD Rule 4902), as well as additional source types and sizes.[148]

For Rule 4, Bay Area AQMD staff have developed draft amendments to lower the current NO_X emission limit for applicable furnaces from 40 nanograms of NO_X per joule of useful heat (ng/j) to 14 ng/j (which would match the limit in SJVUAPCD Rule 4905) in the short term (with a compliance date of January 1, 2023); followed by a zero-NO_X emission requirement (with a compliance date of January 1, 2029); and expand the applicability beyond fan-type central furnaces to other types of equipment (*e.g.,* wall furnaces and direct vent units).[149] For Rule 6, which contains NO_X limits for small boilers and water heaters, Bay Area AQMD staff proposes a zero-NO_X emission requirement. However, staff also note that while technologies achieving zero-NO_X emissions exist, ''they are limited in availability and can be expensive,'' that such standards would be ''technology and market-forcing,'' and, therefore, staff proposes compliance dates of January 1, 2027, and January 1, 2031, depending on equipment heat rate (*i.e.,* the size of the boiler or water heater).[150]

CARB and Bay Area AQMD efforts in this area underscore the importance of building heating emission sources, such as water heaters and space heaters (*e.g.,* furnaces), throughout California and the continued effort to implement available control measures for these sources for criteria pollutant attainment planning requirements. At the same time, while SJVUAPCD, CARB, and Bay Area AQMD each acknowledge that zero-NO_X emission technology for small residential and commercial space and water heating is available, it is unclear what a feasible implementation horizon might be in light of CARB's strategy and the Bay Area AQMD's draft amendments. The plan as submitted did not address how such implementation considerations may or may not affect the feasibility of setting such zero-NO_X emission standards for space and water heating in small residential and commercial buildings in the SJV.

Given the factors discussed above, we now propose that the State has not adequately identified potential control measures, evaluated for BACM/BACT, nor demonstrated the implementation of BACM/BACT for controlling NO_X and direct $PM_{2.5}$ emissions from building emission heating sources in the SJV.

C. Attainment Demonstration

1. Summary of 2021 Proposed Rule

In sections IV.C (air quality modeling) and IV.F (attainment demonstration) of our 2021 Proposed Rule, the EPA summarized the CAA and regulatory requirements for air quality modeling and attainment demonstrations, the State's submission in the SJV $PM_{2.5}$ Plan, and our evaluation thereof.[151] We briefly summarize those components herein.

Sections 188(c)(2) and 189(b)(1)(A) of the CAA require that Serious area plans must include a demonstration (including air quality modeling) that provides for attainment of the $PM_{2.5}$ NAAQS as expeditiously as practicable, but no later than the end of the tenth calendar year after the area's designation as nonattainment. The $PM_{2.5}$ SIP Requirements Rule also specifies that the control strategy in a Serious area attainment plan must provide for attainment as expeditiously as practicable.[152] The outermost statutory Serious area attainment date for the 2012 annual $PM_{2.5}$ NAAQS in the SJV is December 31, 2025 (absent an EPA-approved attainment date extension request under CAA section 188(e)). For purposes of determining the attainment date that is as expeditious as practicable, the State must conduct future year modeling that takes into account emissions growth, known emissions controls (including any controls that were previously determined to be RACM/RACT or BACM/BACT), any other emissions controls required to meet BACM/BACT, and additional measures as needed for expeditious attainment of the NAAQS. The regulatory requirements for Serious area plans are codified at 40 CFR 51.1010 (control strategy requirements) and 40 CFR 51.1011(b) (attainment demonstration and modeling requirements). We also described the EPA's $PM_{2.5}$ modeling guidance (''Modeling Guidance''),[153] including our recommendations therein for photochemical modeling, inputs, procedures, performance evaluation, emissions simulation, and calculating relative response factors (RRFs).

With respect to air quality modeling, the 2018 $PM_{2.5}$ Plan included the State's modeled attainment demonstration projecting that the SJV will attain the 2012 annual $PM_{2.5}$ NAAQS by December 31, 2025; the State's primary discussion of the photochemical modeling appears in Appendix K (''Modeling Attainment Demonstration''). The State provides a conceptual model of $PM_{2.5}$ formation in the SJV as part of the modeling protocol in Appendix L (''Modeling Protocol'') and describes emission input preparation procedures. The State presents additional relevant information in Appendix C (''Weight of Evidence Analysis'') of CARB's staff report for the 2018 $PM_{2.5}$ Plan,[154] which includes ambient trends and other data in support of the demonstration of attainment by 2025.

In the 2021 Proposed Rule, the EPA presented its review of the State's modeling approach and its many interconnected facets, including model input preparation, model performance evaluation, use of the model output for the numerical NAAQS attainment test, and modeling documentation, and found it to be generally consistent with the EPA's recommendations in the Modeling Guidance. We incorporated our evaluation of the Plan's modeling for the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan [155] and extended that evaluation with information specific to the 2012 annual $PM_{2.5}$ NAAQS. Overall, in the 2021 Proposed Rule, we considered the State's analyses consistent with the EPA's guidance on modeling for $PM_{2.5}$ attainment planning purposes and proposed to find that the modeling in the 2018 $PM_{2.5}$ Plan was adequate for the purposes of supporting the State's RFP demonstration and the attainment demonstration.

With respect to the attainment demonstration, the SJV $PM_{2.5}$ Plan includes a modeled demonstration projecting attainment of the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, based on emission reductions

[148] As in the San Joaquin Valley, larger boilers and similar equipment used in industrial, institutional, and large commercial settings are subject to other rules of the Bay Area AQMD, and therefore not subject to Rule 4 or Rule 6.

[149] Bay Area AQMD, ''Workshop Report, Draft Amendments to Building Appliance Rules—Regulation 9, Rule 4: Nitrogen Oxides from Fan Type Residential Central Furnaces and Rule 6: Nitrogen Oxide Emissions from Natural Gas-Fired Boilers and Water Heaters,'' September 2021, 1.

[150] Id.

[151] 86 FR 74310, 74322–74324 (air quality modeling) and 74325–74338 (attainment demonstration).

[152] 40 CFR 51.1011(b)(1); 81 FR 58010, 58087.

[153] Memorandum dated November 29, 2018, from Richard Wayland, Air Quality Assessment Division, OAQPS, EPA, to Regional Air Division Directors, EPA, Subject: ''Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze,'' (''Modeling Guidance'').

[154] CARB, ''Staff Report, Review of the San Joaquin Valley 2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards,'' release date December 21, 2018 (''CARB Staff Report'').

[155] EPA Region IX, ''Technical Support Document, EPA Evaluation of Air Quality Modeling, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS,'' February 2020 (''EPA's 2006 NAAQS Modeling TSD'').

from implementation of baseline control measures and the development, adoption, and implementation of additional control measures to meet specific enforceable commitments. In the EPA's 2021 Proposed Rule, we described how the Plan's control strategy was to reduce emissions from sources of NO_X and direct $PM_{2.5}$ and that most of the projected emission reductions are achieved by baseline measures—*i.e.,* the combination of State and District measures adopted prior to the State's and District's adoption of the Plan—that will achieve ongoing emission reductions from the 2013 base year to the 2025 projected attainment year.

The remainder of the Plan's emission reductions are to be achieved by additional measures to meet enforceable commitments, including potential regulatory and incentive-based measures and, as necessary, substitute measures.[156] In the Valley State SIP Strategy and the 2018 $PM_{2.5}$ Plan, CARB and the District, respectively, included commitments to take action on specific measures by specific years or to develop substitute measures (referred to as ''control measure commitments'') and to achieve specified amounts of NO_X and direct $PM_{2.5}$ emission reductions by certain dates (referred to as ''aggregate tonnage commitments'').[157] We refer to these complementary commitments herein as ''aggregate commitments.''

In the 2021 Proposed Rule, the EPA described several findings relating to our evaluation of the SJV $PM_{2.5}$ Plan's attainment demonstration. First, we proposed to approve the Plan's emissions inventories and to find the Plan's air quality modeling adequate.[158] Second, we proposed to find that the Plan provides for expeditious attainment through the timely implementation of the control strategy to reduce emissions from sources of NO_X and direct $PM_{2.5}$, including RACM, BACM, and any other emission controls necessary for expeditious attainment.

Third, the EPA proposed to find that the emissions reductions that are relied on for attainment in the SIP submission are creditable. We noted that the SJV $PM_{2.5}$ Plan relies principally on already adopted and approved rules to achieve the emissions reductions needed to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, and that the balance of the reductions that the State has modeled to achieve attainment by this date is currently represented by enforceable commitments that account for 13.8% of the NO_X and 8.0% of the direct $PM_{2.5}$ emissions reductions needed for attainment. In terms of our evaluation of CARB and the District's enforceable commitments, we proposed to find that circumstances in the SJV for the 2012 annual $PM_{2.5}$ NAAQS warrant the consideration of enforceable commitments and that the EPA's three criteria for such commitments had been met: (1) the commitments constitute a limited portion of the required emissions reductions; (2) both CARB and the District have demonstrated their capability to meet their commitments; and (3) the commitments are for an appropriate timeframe. We therefore proposed to approve the State's reliance on these enforceable commitments in its attainment demonstration.

Overall, in the 2021 Proposed Rule, we proposed to approve the SJV $PM_{2.5}$ Plan's demonstration of attainment of the 2012 annual $PM_{2.5}$ NAAQS by December 31, 2025, consistent with the requirements of CAA section 189(b)(1)(A). We presented the basis for our proposed determination in sections IV.F.3.a through IV.F.3.e of the 2021 Proposed Rule and provided further detail of our evaluation of baseline measures and the additional measures and aggregate commitments in sections II and IV, respectively, of the EPA's 2012 Annual $PM_{2.5}$ TSD.

2. Summary of Ninth Circuit Order and Adverse Comments

As introduced in section I.D of this proposed rule, in response to a petition for review of the EPA's approval of the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan, the Ninth Circuit Court of Appeals issued a Memorandum Opinion that, in part, vacated the final action with respect the EPA's second factor for evaluating the validity of the State's enforceable commitments (*i.e.,* whether the State is capable of fulfilling its commitment). The Ninth Circuit's order is very relevant to this proposed rule because the State relied on the same common control strategy, including the same set of enforceable commitments (*i.e.,* the same set of control measure commitments and aggregate tonnage commitments) for both the 2006 24-hour $PM_{2.5}$ NAAQS Serious area plan and the 2012 annual $PM_{2.5}$ NAAQS Serious area plan.

The Ninth Circuit found that the EPA ''fail[ed] to provide evidence or a reasoned explanation for its conclusion that California will be able to fulfill its commitment'' in the face of a potential multi-billion dollar funding shortfall for incentive-based control measure commitments, ''which could result in emission reduction shortfalls of approximately 7% of the total NO_X reductions and 8% of the total $PM_{2.5}$ reductions necessary for attainment.'' [159] In response to the EPA's arguments that: (1) the funding shortfall may be smaller than projected; (2) emission reductions may be less expensive than the strategy predicts; (3) certain yet-to-be-quantified sources of reductions in the Plan may make up for shortfalls; and (4) California and the District may identify other measures to fulfill their commitments, the Court wrote that, ''[b]ecause these speculative assertions are unsupported by the evidence, they fail to ensure that California and the District have a plausible strategy for achieving this portion of the attainment strategy, and therefore do not collectively satisfy the second factor of the EPA's three-factor test.'' [160] It is important to emphasize that the State relied heavily on the projected emission reductions that it hopes to achieve through new control measures and emissions reductions reflected in the aggregate commitments. These reductions are crucial to the State meeting the modeled attainment demonstration and RFP requirements. If it is not credible that the State can meet the commitments, then the EPA cannot approve other nonattainment plan elements that rely upon them.

Separately, in comments on the EPA's 2021 Proposed Rule, Public Justice states that CARB and the District's aggregate tonnage commitments are to ''achieve a specific amount of reductions at the last possible moment prior to the attainment deadline with no concrete strategies for how that will be achieved.'' [161] They assert that prior plans with aggregate tonnage commitments for the 1997 annual $PM_{2.5}$ NAAQS by 2015 (*i.e.,* the 2008 $PM_{2.5}$ Plan) and then by 2020 (*i.e.,* the SJV $PM_{2.5}$ Plan) failed to attain those standards and that such past failures implies that the commitments failed to

[156] In this proposed rule, the term ''substitute measures'' means additional control measures that were not identified in CARB and the District's original control measure commitments in adopting the Valley State SIP Strategy and the 2018 $PM_{2.5}$ Plan, respectively. The ''substitute'' aspect primarily relates to emission reductions (*i.e.,* providing emission reductions where any adopted measure achieves less emission reductions than originally estimated, and/or providing emission reductions in lieu of any originally planned measure that is not adopted). They are also sometimes referred to as ''alternative measures'' in the SJV $PM_{2.5}$ Plan and adopting resolutions.

[157] CARB Resolution 18–49 and SJVUAPCD Governing Board Resolution 18–11–16, paragraph 6.

[158] Sections IV.A (emissions inventory) and IV.C (air quality modeling) of the 2021 Proposed Rule.

[159] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1 (9th Cir., April 13, 2022), 6.

[160] Id. at 7.

[161] Public Justice Comment Letter, 20.

deliver the promised clean air.[162] The commenters further state that ''deferred, unspecified, and last-minute promises to achieve reductions (*i.e.,* aggregate commitments), inflicts disparate impacts in violation of Title VI,'' irrespective of whether the commitments comply with the CAA.

3. The EPA's Reconsidered Proposal

As a result of the Ninth Circuit Memorandum Opinion with respect to the SJV $PM_{2.5}$ Plan's enforceable commitments, the EPA has reconsidered its proposed approval of the Plan's demonstration of attainment for the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, and now proposes to disapprove the Plan's attainment demonstration. The Ninth Circuit Memorandum Opinion raised concerns about the ability of CARB and the District to fulfill the commitments.

We present our reconsideration in the following sections of this proposed rule: (1) our reconsideration of CARB and the District's enforceable commitments and proposal that the commitments do not meet the second factor of the EPA's three-factor test (in section II.C.3.a); and (2) the effect of our proposed disapproval of the State's enforceable commitments and specific portions of the State's BACM demonstration on the modeled attainment demonstration (in section II.C.3.b).

a. Additional Measures and Enforceable Commitments

In this subsection we re-examine CARB and the District's enforceable commitments. We describe CARB and the District's progress in adopting specific measures that they committed to present for governing board adoption, and evaluate whether CARB and the District have demonstrated the capability to achieve specific tonnages of reductions that they committed to achieve by the 2025 attainment year. We first enumerate the measures that have already been approved into the SIP and quantify the amount of the tonnage commitment that these account for. We then calculate CARB and the District's remaining commitments as of the time of this notice, describe the strategy that CARB and the District have provided for achieving the remaining reductions (consisting of submitted measures that have not yet been approved into the SIP, adopted measures that have not yet been submitted to the EPA, measures under development, and other potential future measures), and calculate the reductions that may be associated with these measures. We conclude that although CARB and the District have made substantial progress toward achieving the committed-to reductions, CARB and the District have not presented a plausible strategy demonstrating that they are capable of achieving the *entirety* of the aggregate commitment.

In our 2021 Proposed Rule, the EPA described the SJV $PM_{2.5}$ Plan's series of CARB and District commitments to achieve emission reductions through additional control measures, beyond baseline measures, that are intended to contribute to expeditious attainment of the 2012 annual $PM_{2.5}$ NAAQS. For mobile sources, CARB identified a list of 12 State regulatory measures and 3 incentive-based measures that CARB has committed to propose to its Board for consideration by specific years.[163] For stationary sources, the District identified a list of nine regulatory measures and three incentive-based measures that the District has committed to propose to its Board for consideration by specific years.[164]

The Plan contains CARB's and the District's estimates of the emission reductions that could be achieved by each of these additional measures, if adopted as planned.[165] As we described in our 2021 Proposed Rule, CARB's commitments are contained in CARB Resolution 18–49 (October 25, 2018) and the Valley State SIP Strategy and consist of two parts: a control measure commitment and a tonnage commitment.

First, CARB has committed to ''begin the measure's public process and bring to the Board for consideration the list of proposed SIP measures outlined in the *Valley State SIP Strategy* and included in Attachment A, according to the schedule set forth.'' [166] By email dated November 12, 2019, CARB confirmed that it intended to begin the public process on each measure by discussing the proposed regulation or program at a public meeting (workshop, working group, or Board hearing) or in a publicly-released document, and to then propose the regulation or program to its Board.[167] Second, CARB has committed ''to achieve the aggregate emissions reductions outlined in the Valley State SIP Strategy of 32 tpd of NO_X and 0.9 tpd of $PM_{2.5}$ emissions reductions in the San Joaquin Valley by 2024 and 2025.'' [168] The Valley State SIP Strategy explains that CARB's overall commitment is to ''achieve the total emission reductions necessary to attain the Federal air quality standards, reflecting the combined reductions from the existing control strategy and new measures'' and that ''if a particular measure does not get its expected emissions reductions, the State is still committed to achieving the total aggregate emission reductions.'' [169]

Similarly, in our 2021 Proposed Rule, we explained that the District's commitments are contained in SJVUAPCD Governing Board Resolution 18–11–16 (November 15, 2018) and Chapter 4 of the 2018 $PM_{2.5}$ Plan and also consist of two parts: a control measure commitment and a tonnage commitment. First, the District has committed to ''take action on the rules and measures committed to in Chapter 4 of the Plan by the dates specified therein, and to submit these rules and measures, as appropriate, to CARB within 30 days of adoption for transmittal to EPA as a revision to the [SIP].'' [170] By email dated November 12, 2019, the District confirmed that it intended to take action on the listed rules and measures by beginning the public process on each measure, *i.e.,* discussing the proposed regulation or program at a public meeting, including a workshop, working group, or Board hearing, or in a publicly-released document, and then proposing the rule or measure to the SJVUAPCD Governing Board.[171] Second, the District has

[162] Public Justice refers specifically to the EPA's November 2016 finding of failure to attain and the EPA's November 2021 final disapproval of the 1997 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan. 81 FR 84481 (November 23, 2016) and 86 FR 67329 (November 26, 2021), respectively.

[163] CARB Resolution 18–49, Attachment A and Valley State SIP Strategy, Table 7 (''State Measures and Schedule for the San Joaquin Valley''). The schedule of proposed SIP measures in Table 7 includes two additional CARB measures: the second phase of the Advanced Clean Cars Program (''ACC 2'') and the ''Cleaner In-Use Agricultural Equipment'' measures. However, these measures are not scheduled for implementation until 2026 and 2030, respectively, which is after the January 1, 2025 implementation deadline under 40 CFR 51.1011(b)(5) for control measures necessary for attainment by December 31, 2025. Therefore, we are not reviewing these measures as part of the control strategy to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

[164] SJVUAPCD Governing Board Resolution 18–11–16 and 2018 $PM_{2.5}$ Plan, Table 4–4 (''Proposed Regulatory Measures'') and Table 4–5 (''Proposed Incentive-Based Measures'').

[165] 2018 $PM_{2.5}$ Plan, Ch. 4, Table 4–3 (''Emission Reductions from District Measures'') and Table 4–9 (''San Joaquin Valley Expected Emission Reductions from State Measures'') and Valley State SIP Strategy, Table 8 (''San Joaquin Valley Expected Emission Reductions from State Measures'').

[166] CARB Resolution 18–49, 5.

[167] Email dated November 12, 2019, from Sylvia Vanderspek, CARB, to Anita Lee, EPA Region IX, ''RE: SJV $PM_{2.5}$ information'' (attaching ''Valley State SIP Strategy Progress'') and CARB Staff Report, 14.

[168] CARB Resolution 18–49, 5.

[169] Valley State SIP Strategy, 7.

[170] SJVUAPCD Governing Board Resolution 18–11–16, 10–11.

[171] Email dated November 12, 2019, from Jon Klassen, SJVUAPCD, to Wienke Tax, EPA Region IX, ''RE: follow up on aggregate commitments in SJV $PM_{2.5}$ Plan'' (attaching ''District Progress in

committed to ''achieve the aggregate emissions reductions of 1.88 tpd of NO_X and 1.3 tpd of $PM_{2.5}$ by 2024/2025'' through adoption and implementation of these measures or, if the total emission reductions from these rules or measures are less than these amounts, ''to adopt, submit, and implement substitute rules and measures that achieve equivalent reductions in emissions of direct $PM_{2.5}$ or $PM_{2.5}$ precursors'' in the same implementation timeframes.[172]

In sections IV.F.3.c and IV.F.3.d of our 2021 Proposed Rule, the EPA described CARB's and the District's progress as of that point in time on their control measure commitments and progress towards fulfilling their respective aggregate commitments, respectively. Based on our reconsideration of the State's enforceable commitments in light of the Ninth Circuit Memorandum Opinion, while we propose to retain certain findings with respect to the State's progress, we now propose that the State has not adequately demonstrated that it can fulfill the remaining portions of its enforceable commitments (*i.e.,* the second factor of the EPA's three-factor test). We present our reconsidered evaluation of the status of CARB's and the District's control strategy and our three-factor test for enforceable commitments, as follows.

With respect to progress on the control measure commitments, CARB and the District together have adopted 18 measures of the 27 control measure commitments in the SJV $PM_{2.5}$ Plan and have begun the public process on 5 of the remaining control measure commitments, which is unchanged since the time of our 2021 Proposed Rule. This progress is described in further detail in CARB and the District's ''Progress Report and Technical Submittal for the 2012 $PM_{2.5}$ Standard San Joaquin Valley'' (2021 Progress Report).[173] For CARB's portion, CARB has adopted 10 of the 15 measures identified in its commitment (including one incentive-based measure) and begun the public process on 3 of the remaining 5 measures. For the District's portion of the control measure commitments, the District has adopted 8 of the 12 measures identified in its commitment (including one incentive-based measure) and begun the public process on 2 of the remaining 4 measures.

Although CARB and the District have made substantial progress in developing and adopting the regulatory measures listed in their respective control measure commitments, they have not yet fulfilled the commitments for several measures in accordance with the timeframes established in the SJV $PM_{2.5}$ Plan. We provide further detail on CARB and the District's control measure commitments in section IV.A of the EPA's 2012 Annual $PM_{2.5}$ TSD (including tables IV–A and IV–B regarding CARB and the District's control measure commitments, respectively).[174]

Regarding the remaining nine measures not yet proposed for board consideration, we continue to note that one measure, Rule 4550 (''Conservation Management Practices''), has an action year of 2022 in the 2018 $PM_{2.5}$ Plan (*i.e.,* the District has the remainder of 2022 to present a proposed measure for board consideration) and that four regulatory measures and four incentive-based measures are overdue. For the four regulatory measures, while CARB and the District have not proposed these measures to their respective boards, they began the public process on each of the four measures on time with respect to the schedule of their respective public process commitments. To our knowledge, CARB anticipates board consideration of the diesel fuel measures in 2022 and the forklift measure in 2022 or 2023[175] and continues to develop the airport ground support equipment measure; the District continues to evaluate potential amendments to Rule 4692 in the near future.[176]

For the four incentive-based measures, CARB and the District continue to invest in reducing emissions from heavy-duty trucks and buses, off-road equipment, agricultural operation internal combustion engines, and commercial under-fired charbroiling.[177] However, while CARB and the District have discussed the proposed programs at board hearings,[178] to our knowledge, CARB and the District have not started the public process for the four incentive-based control measure commitments as enforceable measures to be submitted to the EPA for approval and inclusion as control measures in the California SIP. Furthermore, as discussed in section IV.F.3.c of our 2021 Proposed Rule, for heavy-duty trucks and off-road equipment, CARB acknowledges that many of the project lives do not span the attainment year[179] and, thus, while these projects may accelerate emission reductions and benefit communities in the SJV, the projects that qualify for SIP credit may be limited for the purposes of the 2012 annual $PM_{2.5}$ NAAQS Serious area attainment demonstration.

Overall, while CARB and the District have made substantial progress in developing and adopting the regulatory measures listed in their respective control measure commitments that were submitted in the SJV $PM_{2.5}$ Plan, in light of the Ninth Circuit Memorandum Opinion, we have reconsidered the effect of the eight overdue measures of the original commitments and in particular the overdue incentive-based measures, on our evaluation of CARB and the District's aggregate tonnage commitments and our three-factor test. Under the second factor of the EPA's test for enforceable commitments, the

Implementing Commitments with 2018 $PM_{2.5}$ Plan'').

[172] SJVUAPCD Governing Board Resolution 18–11–16, 10–11.

[173] ''Progress Report and Technical Submittal for the 2012 $PM_{2.5}$ Standard San Joaquin Valley,'' October 19, 2021. Transmitted to the EPA by letter dated October 20, 2021, from Richard W. Corey, Executive Officer, CARB, to Deborah Jordan, Acting Regional Administrator, EPA Region IX. See sections of 2021 Progress Report entitled ''Progress in Implementing District Measures'' and ''Progress in Implementing CARB Measures.''

[174] We note that Table IV–A of the EPA's 2012 Annual $PM_{2.5}$ TSD contained an error with respect to the adoption date of CARB's measure for Transportation Refrigeration Units Used for Cold Storage. While CARB had heard proposed amendments to the measure on September 23, 2021, the measure was not actually adopted until February 24, 2022, following further process and rule adjustments required by the Board. CARB Resolution 22–5, February 24, 2022.

[175] In the 2021 Progress Report (dated October 19, 2021), page 20, CARB indicates that the Zero-Emission Off-Road Forklift Regulation Phase 1 would be presented for Board consideration ''as early as 2022,'' while CARB's updated ''SJV $PM_{2.5}$ SIP Measure Tracking'' (dated December 2021) anticipates presenting the measure to the Board in Summer 2023.

[176] 2021 Progress Report, 8–9, 20–22, and tables 2 and 3.

[177] CARB, ''Long-Term Heavy-Duty Investment Strategy, Including Fiscal Year 2020–21 Three-Year Recommendations for Low Carbon Transportation Investments,'' (App. D to CARB's ''Proposed Fiscal Year 2021–22 Funding Plan for Clean Transportation Incentives''), release date October 8, 2021; and SJVUAPCD, ''Comprehensive Annual Financial Report, Fiscal Year Ended June 30, 2020,'' release date December 23, 2020. See also, 2021 Progress Report, 3 and 15.

[178] For example, CARB staff discussed the Accelerated Turnover of Trucks and Buses Incentive Measure at its annual 2020 update to the CARB Board. CARB presentation, ''Update on the 2018 $PM_{2.5}$ SIP for the San Joaquin Valley,'' October 22, 2020. District staff discussed and adopted an emission reductions strategy for commercial under-fired charbroiling, including incentives, in December 2020. SJVUAPCD, ''Item Number 11: Adopt Proposed Commercial Under-Fired Charbroiling Emission Reduction Strategy,'' December 17, 2020.

[179] Id. at 24 and 32. Generally, mobile source incentive projects implemented under the Carl Moyer program are under contract only during the ''project life'' and may not be credited with SIP emission reductions after the project life ends. EPA Region IX, ''Technical Support Document for EPA's Rulemaking for the California State Implementation Plan California Air Resources Board Resolution 19–26 San Joaquin Valley Agricultural Equipment Incentive Measure,'' February 2020, 12–13.

Agency must evaluate whether a State is capable of fulfilling such commitments. The tardiness of presenting these control measures for board consideration renders the reductions from these measures more speculative under the second factor.

With respect to the aggregate tonnage commitments to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV, we reiterate that CARB committed to achieve 32 tpd of NO_X and 0.9 tpd of $PM_{2.5}$ emissions reductions, and the District committed to achieve 1.88 tpd of NO_X and 1.3 tpd of $PM_{2.5}$ emissions reductions by 2025. These aggregate tonnage commitments sum to 33.88 tpd NO_X and 2.2 tpd direct $PM_{2.5}$. CARB and the District have committed to achieve these reductions via the 27 control measure commitments, or such other substitute measures as may be necessary, to achieve the aggregate tonnage commitments for NO_X and direct $PM_{2.5}$.

For the purpose of our analysis of the State's progress toward achieving its aggregate tonnage commitments, of the 18 measures adopted by December 2021, as well as the adoption of an important substitute measure (the Agricultural Burning Phase-out Measure [180]), the State has submitted 12 measures as revisions to the California SIP (*i.e.,* more than the 9 measures submitted to EPA as of the time of the 2021 Proposed Rule). Since December 2021, the EPA finalized or proposed approval of three control measure SIP submissions that were control measure commitments in the SJV $PM_{2.5}$ Plan.

First, the EPA finalized approval of the Heavy-Duty Vehicle Inspection Program (HDVIP) and Periodic Smoke Inspection Program (PSIP).[181] However, as in our 2021 Proposed Rule, CARB has not yet provided its analysis of the basis for this emission reduction estimate (of 0.02 tpd direct $PM_{2.5}$, per the State's 2021 Progress Report). Therefore, the EPA is not proposing at this time to credit this measure with any particular amount of emission reductions towards attainment of the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

Second, the EPA finalized approval of the Agricultural Burning Phase-out Measure,[182] which includes a schedule to phase-out (*i.e.,* introduce prohibitions of) agricultural burning for additional crop categories or materials accounting for a vast majority of the tonnage of agricultural waste in phases that started January 1, 2022, and become fully implemented by January 1, 2025.[183] The EPA received comments from the District that supported approval of the Agricultural Burning Phase-out Measure into the SIP while also advocating for a higher rule effectiveness rate (*i.e.,* 95% instead of EPA's proposed 80%),[184] which in turn would increase the amount of emission reductions that the EPA would credit towards fulfilling the District's aggregate tonnage commitment. We continue to evaluate these comments and for now have retained our proposal to credit the measure for emission reductions of 0.83 tpd NO_X and 1.23 tpd direct $PM_{2.5}$, consistent with the 80% rule effectiveness rate used by the EPA in the 2021 Proposed Rule.

Third, the EPA has proposed approval of Rule 4311 (''Flares''), as amended December 17, 2020.[185] The District's staff report for Rule 4311 estimates that the emission reductions from these amendments would be 0.19 tpd NO_X and 0.03 tpd direct $PM_{2.5}$ in 2025.[186] The EPA continues to evaluate the District's estimate with respect to SIP-creditable emission reductions, though we note that they are relatively small when compared to the overall 207.38 tpd NO_X and 6.4 tpd direct $PM_{2.5}$ modeled to attain the 2012 $PM_{2.5}$ NAAQS and to the combined aggregate tonnage commitments of 33.88 tpd NO_X and 2.2 tpd direct $PM_{2.5}$.

Similar to our 2021 Proposed Rule, we propose to credit reductions from three measures, all of which are now approved into the SIP and have large associated emission reductions of direct $PM_{2.5}$ and/or NO_X in the SJV.[187] The three measures are: Rule 4901 (''Wood Burning Fireplaces and Wood Burning Heaters''); two of three parts of the Agricultural Equipment Incentive Measure (for which we described our proposed SIP credit in the 2021 Proposed Rule); and the Agricultural Burning Phase-out Measure (for which we described our proposed SIP credit in this proposed rule).[188]

Based on these SIP-approved measures, our estimate of the remaining aggregate tonnage commitments remains the same as in our 2021 Proposed Rule. Specifically, in Table 1 herein we summarize the total NO_X and direct $PM_{2.5}$ emission reductions that the State models as sufficient to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, the emission reductions attributed to baseline measures and new control strategy measures (including only measures currently approved into the California SIP), and the emission reductions remaining as aggregate tonnage commitments.

TABLE 1—REDUCTIONS FOR ATTAINMENT IN 2025 AND AGGREGATE TONNAGE COMMITMENTS

		NO_X (tpd)	Direct $PM_{2.5}$ (tpd)
A	Total reductions from baseline and control strategy measures modeled to achieve attainment	207.38	6.4
B	Reductions from baseline measures	173.5	4.2
C	Reductions from additional measures *approved* into the California SIP	5.29	1.69
D	Total reductions remaining as commitments (A–B–C)	28.59	0.51
E	Percent of total reductions needed remaining as commitments (D/A)	13.8%	8.0%

Sources: 2018 $PM_{2.5}$ Plan, Ch. 4, tables 4–3 and 4–7, and Appendix B, tables B–1 and B–2.

[180] See 87 FR 36222 (June 16, 2022).

[181] 87 FR 27949 (May 10, 2022).

[182] 87 FR 36222.

[183] SJVUAPCD, ''Supplemental Report and Recommendations on Agricultural Burning,'' June 17, 2021 (''2021 Supplemental Report''), including Table 2–1 (''Accelerated Reductions by Crop Category'').

[184] Letter dated January 25, 2022, from Jonathan Klassen, Director of Air Quality Science and Planning, SJVUPACD, to Michael Regan, Administrator, U.S. EPA.

[185] 87 FR 3736 (January 25, 2022).

[186] SJVUAPCD, ''Item Number 12: Adopt Proposed Amendments to Rule 4311 (Flares),'' December 17, 2020, Attachment C (''Final Draft Staff Report with Appendices for Proposed Amendments to Rule 4311''), 21–22.

[187] The seven additional measures submitted as SIP revisions for which the EPA has not proposed action as of August 2022 include: the Innovative Clean Transit measure (submitted February 13, 2020); Rules 4306 and 4320 (submitted March 12, 2021); Rule 4702 (submitted October 15, 2021); Rules 4352 and 4354 (submitted March 9, 2022), and the Residential Wood Burning Incentive Measure (submitted March 17, 2022).

[188] Final actions on these measures are as follows: 85 FR 44206 (July 22, 2020) (Rule 4901), 86 FR 73106 (December 27, 2021) (Agricultural Equipment Incentive Measure), and 87 FR 36222 (June 16, 2022) (Agricultural Burning Phase-out Measure).

As shown in Table 1, 13.8% of the NO_X reductions necessary for attainment and 8.0% of the direct $PM_{2.5}$ reductions necessary for attainment remain as aggregate tonnage commitments (*i.e.,* combining CARB and the District's remaining commitments).[189] Based on the direct $PM_{2.5}$ emission reductions that the EPA has credited to Rule 4901 (0.2 tpd) and the Agricultural Burning Phase-out Measure (1.23 tpd), which add up to 1.43 tpd, we conclude that the District has exceeded its 1.3 tpd direct $PM_{2.5}$ commitment by 0.13 tpd.

Beyond the measures that the EPA has taken final action to approve into the California SIP and proposed to credit herein, CARB has provided updated emission reduction estimates for 10 additional measures, including 9 that have been adopted, as well as one substitute measure in development, as described in the 2021 Progress Report. The CARB measure with the largest updated emission reduction estimates is the Heavy-Duty Vehicle Inspection and Maintenance Program (''Heavy-Duty I/M'').

The District has similarly provided updated emission reduction estimates for seven additional measures, including six that have been adopted. The District measures with the largest updated emission reduction estimates include amendments to Rule 4702 (''Internal Combustion Engines'') (0.61 tpd NO_X), the Residential Wood Burning Devices Incentive Projects measure (0.33 tpd direct $PM_{2.5}$), and Rule 4354 (''Glass Melting Furnaces'') (0.5 tpd NO_X and 0.04 tpd direct $PM_{2.5}$), as well as amendments planned in 2022 to Rule 4550 (''Conservation Management Practices'') (0.32 tpd direct $PM_{2.5}$).

The EPA is not proposing to credit towards the aggregate tonnage commitments the updated emission reduction estimates from these additional District measures. We will review and act on the CARB and District measures submitted to date (Innovative Clean Transit, Rule 4306, Rule 4320, Rule 4702, Rule 4352, Rule 4354, and the Residential Wood Burning Incentive Measure), as well as future measure submissions, in separate rulemakings, during which time the public will have an opportunity to review and provide comment.

Although we are not proposing to credit reductions from these measures at this time, in order to determine whether CARB and District have the capability to meet their aggregate tonnage commitments, we have re-evaluated the updated emission reduction estimates to assess whether they could meet the NO_X and/or direct $PM_{2.5}$ emission reduction commitments with these measures or, if not, how much would remain of CARB and the District's unfulfilled aggregate tonnage commitments.

TABLE 2—HYPOTHETICAL EMISSION REDUCTIONS FROM ESTIMATED, ADOPTED, AND/OR SUBMITTED ADDITIONAL MEASURES AND EFFECT ON REMAINING AGGREGATE TONNAGE COMMITMENTS FOR 2025

		NO_X (tpd)	Direct $PM_{2.5}$ (tpd)
A	Total reductions needed from baseline and control strategy measures (see Table 1, row A of this proposed rule).	207.38	6.4
B	Total reductions remaining as commitments after SIP credit (see Table 1, row D of this proposed rule).	28.59	0.51
	CARB:		
	Submitted Measures:		
	HDVIP and PSIP [a]	0	0.02
	Innovative Clean Transit	0.017	<<0.01
C	Sub-Total	0.017	0.02
	Additional Adopted Measures:		
	Heavy-Duty I/M	14.7	0.03
	Amended Warranty Requirements for Heavy-Duty Vehicles	0.34	<<0.01
	Heavy-Duty Low-NO_X Engine Standard—California Action	0	0
	Advanced Clean Local Trucks (Last Mile Delivery)	0.08	<<0.01
	Zero-Emission Airport Shuttle Buses	<<0.01	<<0.01
	Small Off-Road Engines	0.155	0.007
	Transport Refrigeration Units Used for Cold Storage	0.04	0.01
	Agricultural Equipment Incentive Measure-Phase 1 (NRCS portion)	0.64	0.04
	Agricultural Equipment Incentive Measure Phase 2	4.9	0.5
D	Sub-Total	15.955	0.087
	Measures Not Yet Presented for Board Consideration: [b]		
	Zero-Emission Off-Road Forklift Regulation Phase 1	0.02	<<0.01
E	Sub-Total	4.92	0.5
F	*Grand Total for CARB (C+D+E)*	20.892	0.607
	SJVUAPCD:		
	Submitted Measures:		
	Rule 4311 (''Flares'')	0.19	0.03
	Rule 4306 (''Boilers, Steam Generators, and Process Heaters—Phase 3'')	0.19	0
	Rule 4320 (''Advanced Emission Reduction Option for Boilers, Steam Generators, and Process Heaters greater than 5 MMBtu/hr'') [c].	0	0
	Rule 4352 (''Solid Fuel Fired Boilers, Steam Generators, and Process Heaters'')	0.5	0.04
	Rule 4354 (''Glass Melting Furnaces'')	0.2	0.04

[189] However, we note that if the EPA were to grant maximum credit for the emission reductions calculated by the District for Rule 4311 (0.19 tpd NO_X and 0.03 tpd direct $PM_{2.5}$), the remaining aggregate tonnage commitments would be 28.4 tpd NO_X (13.7% of total reductions needed to attain in 2025) and 0.48 tpd direct $PM_{2.5}$ (7.5% of total reductions needed to attain in 2025).

TABLE 2—HYPOTHETICAL EMISSION REDUCTIONS FROM ESTIMATED, ADOPTED, AND/OR SUBMITTED ADDITIONAL MEASURES AND EFFECT ON REMAINING AGGREGATE TONNAGE COMMITMENTS FOR 2025—Continued

		NO_X (tpd)	Direct $PM_{2.5}$ (tpd)
	Rule 4702 (''Internal Combustion Engines'')	0.61	0
	Residential Wood Burning Incentive Measure	0	0.33
G	Sub-Total	1.69	0.44
	Measures Not Yet Presented for Board Consideration:		
	Rule 4550 (''Conservation Management Practices'')	0	0.32
H	Sub-Total	0	0.32
I	*Grand Total for SJVUAPCD (G+H)*	1.69	0.76
J	*Grand Total (F+I)*	22.58	1.37
K	Assuming maximum SIP credit, total reductions remaining as commitments (B–J)	6.01	−0.86

Sources: 2021 Progress Report, Table 2 and Table 3.

[a] As discussed herein, the EPA has taken final action to approve CARB's HDVIP and PSIP measure into the California SIP but we are not yet proposing SIP credit for these two measures.

[b] Given the complexities involved in regulating locomotive emissions, we have conservatively excluded from our analysis the emission reduction estimates in the 2021 Progress Report for CARB's In-Use Locomotive Measure.

[c] The District's draft staff report for Rule 4306 and Rule 4320 estimate emission reductions of 0.19 tpd NO_X and 0.45 tpd NO_X, respectively, in 2024. However, the District notes that it is not proposing the emission reductions from Rule 4320 for SIP credit at this time. SJVUAPCD, ''Draft Staff Report, Proposed Amendments to Rule 4306 (Boilers, Steam Generators, and Process Heaters—Phase 3), Proposed Amendments to Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr),'' November 25, 2020, 4.

Assuming the EPA were to agree with the maximum credit for the emission reductions estimated by CARB and the District in the 2021 Progress Report, these additional measures could achieve emission reductions of 22.58 tpd NO_X and 1.37 tpd direct $PM_{2.5}$. Combined with the reductions from additional measures already approved by EPA into the California SIP (5.29 tpd NO_X and 1.69 tpd direct $PM_{2.5}$, per Row C of Table 1 of this proposed rule), the State would achieve emission reductions of 27.87 tpd NO_X and 3.06 tpd direct $PM_{2.5}$. Compared to the combined aggregate tonnage commitments, the State would have remaining aggregate tonnage commitments of 6.01 tpd NO_X and would have exceeded the aggregate tonnage commitments by 0.86 tpd direct $PM_{2.5}$. More specifically, CARB would have remaining commitments of 6.65 tpd NO_X and 0.03 tpd direct $PM_{2.5}$, and the District would have exceeded its commitments by 0.64 tpd NO_X and 0.89 tpd direct $PM_{2.5}$.

However, given the remaining NO_X commitments for CARB, which are approximately 3% of the NO_X emission reductions modeled to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by 2025, we have given additional consideration to the evidence of emission reductions for two source categories that have large emission reduction estimates: Heavy-Duty I/M and the Agricultural Equipment Incentive Measures, including the NRCS portion of the Phase 1 measure adopted by CARB in 2019 and the Phase 2 measure slated for 2024 consideration, per the 2021 Progress Report.

With respect to Heavy-Duty I/M, in the Valley State SIP Strategy, CARB originally estimated that it would achieve 6.8 tpd NO_X and <0.1 tpd direct $PM_{2.5}$ in 2025 and described the regulatory concepts that would reflect the current (as of 2018) ''advanced engine and exhaust control technologies, including on-board diagnostics (OBD).''[190] Since that time, as described in the State's 2021 Progress Report and the EPA's 2021 Proposed Rule, California has developed additional provisions related to Heavy-Duty I/M that the State estimates would achieve emission reductions of 14.7 tpd NO_X and 0.03 tpd direct $PM_{2.5}$ in 2025.[191]

While the EPA would still not propose to approve a specific amount of SIP-creditable reductions until after the State submits such measure in final form to the EPA as a revision to the SIP, we have re-examined the role of the potential additional emission reductions from Heavy-Duty I/M presented by CARB. As a qualitative matter, we agree that the requirements under California Senate Bill 210 (2019) that heavy-duty vehicles comply with Heavy-Duty I/M in order to register annually with the California Department of Motor Vehicles, as well as the implementation of roadside emissions monitoring (*i.e.,* the Portable Emissions AcQuisition System, ''PEAQS'') in the SJV to detect high emitting vehicles between periodic test cycles, are tangible additions that would increase the emission reductions relative to what was contemplated at the time of Plan adoption in November 2018 (by the District) and January 2019 (by CARB).

As a quantitative matter, however, the scale of the estimated 14.7 tpd NO_X emission reductions is roughly half the remaining aggregate commitment of 28.59 tpd NO_X and represents 7.1% of the 207.38 tpd NO_X modeled for attainment and a substantial increase from CARB's original estimate of 6.8 tpd NO_X (3.3% of the 207.38 tpd NO_X). This 14.7 tpd NO_X represents a substantial quantity that, pursuant to the Ninth Circuit Memorandum Opinion, must be supported by evidence to ''ensure that California and the District have a plausible strategy for achieving this portion of the attainment strategy'' in order to satisfy the second factor of the three-factor aggregate commitment test.[192] While CARB documented its extensive regulatory and technical

[190] Valley State SIP Strategy, 19–20 and Table 8.

[191] 2021 Progress Report, 19. CARB notes that further detail on emission reduction calculations can be found in the CARB staff report on Heavy-Duty I/M, released October 15, 2021. See, CARB, ''Staff Report: Initial Statement of Reasons, Public Hearing to Consider the Proposed Heavy-Duty Inspection and Maintenance Regulation,'' October 8, 2021, (''Heavy-Duty I/M ISOR'') and App. H (''Proposed Heavy-Duty Inspection and Maintenance Regulation, Standardized Regulatory Impact Assessment'').

[192] See *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1, 7 (9th Cir., April 13, 2022).

analyses in the measure's Initial Statement of Reasons and associated appendices,[193] CARB has not provided the detailed basis of its calculations of 14.7 tpd NO_X and 0.03 tpd direct $PM_{2.5}$ emission reductions to the EPA. Given that CARB may do so in a future control measure SIP submission, and we lack the record evidence to do so here, we do not suggest an alternative amount of emission reduction from Heavy-Duty I/M in this proposed rule. Rather, we note that the more detailed calculations and technical report necessary to support such an estimate, specific to the SJV and to annual average emission reductions in 2025, are not available, and therefore we do not have sufficient support in the record at this time to rely on the State's estimated reductions, in line with the Ninth Circuit Memorandum Opinion.

With respect to mobile agricultural equipment, the EPA has taken final action to approve the Funding Agricultural Replacement Measures for Emission Reductions (FARMER) program and the Carl Moyer Memorial Air Quality Standards Attainment Program (''Carl Moyer'') portions of CARB's first incentive measure on agricultural equipment in the SJV (''Agricultural Equipment Incentive Measure-Phase 1'') and proposed in our 2021 Proposed Rule to credit emission reductions of 4.46 tpd NO_X and 0.26 tpd direct $PM_{2.5}$ towards CARB's aggregate tonnage commitments.[194] CARB has estimated that it will achieve 4.9 tpd additional NO_X reductions, and 0.5 tpd additional direct $PM_{2.5}$ reductions through a second agricultural equipment incentive measure. In light of the Ninth Circuit Memorandum Opinion, and its finding that the EPA had not ensured that CARB and the District had a ''plausible strategy'' for achieving parts of the attainment strategy that relied on incentive-based reductions in the face of a budget shortfall for funding these measures, we must evaluate whether there is sufficient evidence in the record to establish a reasonable basis for concluding that any ''Phase 2'' agricultural equipment incentive measure will have sufficient funding to achieve the reductions ascribed to it.

As we noted in the EPA's 2021 Proposed Rule, fewer incentive-based emission reductions are needed to demonstrate attainment of the 2012 annual $PM_{2.5}$ NAAQS than were required in the portion of the SJV $PM_{2.5}$ Plan addressing the 2006 24-hour $PM_{2.5}$ NAAQS that was at issue in the *Medical Advocates* case.[195] In the Ninth Circuit Memorandum Opinion, the court pointed to a $2.6 billion shortfall between what the EPA calculated to be a need for $5 billion in funding and the more than $2 billion in funding that the State had ''identified or anticipated.''[196] Notably, funding for the Carl Moyer, California Assembly Bill 617, and FARMER programs were included in the ''identified or anticipated'' portion of the State's funding analysis, and not the ''incentive funding gap'' for which the Court found EPA's explanations justifying approval to be overly speculative.[197] Accordingly, we do not consider reliance on reductions from a Phase 2 agricultural equipment incentive measure to be prohibited by the Ninth Circuit Memorandum Opinion, to the extent that a Phase 2 rule would rely on the same, existing programs, and provided that evidence of sufficient identified or reasonably anticipated funding exists in the record.

As described in the EPA's analysis of the cost-effectiveness of the Agricultural Equipment Incentive Measure-Phase 1, based on information provided by CARB, the total project costs resulting in these emission reductions were $155 million for FARMER and $125 million for Carl Moyer, or $280 million combined.[198] As described in the EPA's 2021 Proposed Rule,[199] the SJV portion of the FARMER funding has typically been 80% of the State-wide allocation and the first three years of FARMER funding for the SJV were $108 million (fiscal year 2017–2018), $104.3 million (fiscal year 2018–2019), and $43.84 million (fiscal year 2019–2020).[200] For the current fiscal year (2021–2022), the District accepted $168.43 million in FARMER funds to replace agricultural equipment in the SJV.[201] Similarly, we noted that CARB expects Carl Moyer funding to increase in future years, following the enactment of California Assembly Bill 1274.[202]

Thus, while future funding allocations are subject to annual State and local funding cycles, given the renewed, large investment in the fiscal year 2021–2022 FARMER program, potential for increases in funding for the Carl Moyer program, and the success of these programs in meeting enforceability criteria for purposes of crediting emission reductions, the EPA anticipates that CARB will be able to develop an additional agricultural equipment incentive measure (''Agricultural Equipment Incentive measure-Phase 2'') that has funding levels comparable or larger than those for Phase 1 (*i.e.,* including the $168 million accepted by the District in March 2022) and that CARB's emission reduction estimates of 4.9 tpd NO_X and 0.5 tpd direct $PM_{2.5}$ by 2025, per the 2021 Progress Report, are reasonable and supported by identified or reasonably anticipated funding.

However, we have not yet taken final action on the NRCS portion of the Agricultural Equipment Incentive Measure-Phase 1 and, for this proposed rule, do not rely on the estimated emission reductions for that portion of the Agricultural Equipment Incentive Measure-Phase 1 (*i.e.,* 0.64 tpd NO_X and 0.04 tpd direct $PM_{2.5}$). Looking forward in time, this suggests some uncertainty regarding creditability of emission reductions from any portion of a Phase 2 agricultural equipment incentive measure that may be implemented through the NRCS program.

Furthermore, for any measure, to the extent that CARB or the District assumed a 100% rule effectiveness rate where the EPA is not able to confirm and approve such a rate, further discounts to the emission reductions estimated may be warranted in certain cases.[203] Accordingly, the overall remaining NO_X commitment could be larger than 6.01 tpd and the anticipated

[193] Heavy-Duty I/M ISOR and, for example, Heavy-Duty I/M ISOR, App. D (''Emissions Inventory Methods and Results, Proposed Heavy-Duty Inspection and Maintenance Regulation'') and App. H (''Proposed Heavy-Duty Inspection and Maintenance Regulation, Standardized Regulatory Impact Assessment'').

[194] 86 FR 74310, 74332; 86 FR 73106, 73109.

[195] 86 FR 74310, 74330. This is due to greater-than-expected reductions from committed to and substitute non-incentive regulatory measures, such as the Agricultural Burning Phase-Out Measure.

[196] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1, 7; 85 FR 44192, 44201.

[197] CARB Staff Report, 27 (Table 9).

[198] Memorandum dated June 22, 2020, from Rebecca Newhouse, EPA Region IX, to docket number EPA–R09–OAR–2019–0318, Subject: ''Cost-effectiveness of Emission Reductions from the Valley Incentive Measure and Estimated Future Funding Needs for Additional Agricultural Equipment Replacements'' (''EPA Cost-Effectiveness Memo'').

[199] 86 FR 74310, 74337.

[200] CARB, ''Funding Agricultural Replacement Measures for Emission Reductions (FARMER) Program, San Joaquin Valley APCD,'' as reported through September 30, 2020.

[201] SJVUAPCD, ''Item Number 9: Accept $168,425,600 in State FARMER Program Funds for Use in the District's Agricultural Equipment Replacement Project,'' March 17, 2022.

[202] 2021 Progress Report, 22.

[203] For example, the District originally sought SIP credit of 0.26 tpd direct $PM_{2.5}$ emission reductions from Rule 4901 and the EPA is proposing 0.2 tpd direct $PM_{2.5}$ based on a 75% rule effectiveness rate. Similarly, CARB and the District sought SIP credit of 1.04 tpd NO_X and 1.54 tpd direct $PM_{2.5}$ emission reductions from the Agricultural Burning Phase-out Measure and the EPA is proposing 0.83 tpd NO_X and 1.23 tpd direct $PM_{2.5}$ based on an 80% rule effectiveness rate.

excess emission reductions for direct $PM_{2.5}$ could be smaller than 0.86 tpd.

Notwithstanding some uncertainty as to the scale of emission reductions from the Heavy-Duty I/M and the Agricultural Equipment Incentive Measures (*i.e.,* assuming that the additional measures with discrete emission reduction estimates in the 2021 Progress Report achieve their respective emission reductions), there remains at least 6.65 tpd NO_X and 0.03 tpd direct $PM_{2.5}$ in CARB's commitment for which the record does not contain a specific and plausible strategy to achieve. In our 2021 Proposed Rule we discussed two possible ways that CARB could fill this gap: (1) additional reductions from committed or substitute measures named by CARB, and (2) a hypothetical inter-pollutant trading of excess direct $PM_{2.5}$ emission reductions by the District for any shortfall in NO_X emission reductions by CARB. The Ninth Circuit Memorandum Opinion has established that these concepts in the absence of a specific SIP revision are too speculative and do not constitute a ''plausible strategy'' for achieving this portion of the commitment.

With respect to additional reductions from committed measures, in the 2021 Proposed Rule, we explored potential reductions from two incentive-based measures: Accelerated Turnover of Trucks and Buses Incentive Projects, and Accelerated Turnover of Off-road Equipment Incentive Projects.[204] CARB initially estimated that they would achieve 8 tpd NO_X reductions from Accelerated Turnover of Trucks and Buses Incentive Projects, and 1.5 tpd NO_X reductions from Accelerated Turnover of Off-road Equipment Incentive Projects.[205] However, CARB did not propose a measure to its board for either measure by 2021, as it had committed to do, nor to our knowledge has CARB started the public process for enforceable measures to be submitted to the EPA for inclusion as control measures in the California SIP.

In the 2021 Progress Report, CARB acknowledged that many of the project lives do not span the attainment year[206] and, thus, while these projects accelerate emission reductions and benefit communities in the SJV, the projects that qualify for SIP credit may be limited for the purposes of the 2012 annual $PM_{2.5}$ NAAQS Serious area attainment demonstration. In our 2021 Proposed Rule, we acknowledged these weaknesses in these incentive programs, but we nonetheless assumed that these measures may ultimately result in SIP-creditable emission reductions for a portion of the combined 9.5 tpd NO_X.[207] In light of the Ninth Circuit Memorandum Opinion, the EPA does not consider it appropriate to rely on reductions that have been rendered substantially less likely to occur by the State's update indicating that few emissions from these projects may be creditable.

Furthermore, while the State continues to invest heavily in the replacement of older, dirty heavy-duty vehicles and equipment on a State-wide basis,[208] we are not aware of a document that identifies specific funding amounts applied to the replacement of such equipment in the SJV within the specific timeline of the Plan's demonstration of attainment of the 2012 annual $PM_{2.5}$ NAAQS by December 31, 2025. In brief, the amount of funding that is specific to the SJV for these two measures for purposes of attainment of the 2012 annual $PM_{2.5}$ NAAQS is unclear, and this renders more speculative at least a portion of the large scale of NO_X emission reductions originally anticipated.[209]

With respect to substitute measures under development, CARB points to the In-Use Locomotive Rule (and estimates emission reductions of 1.14 tpd NO_X and 0.03 tpd direct $PM_{2.5}$ by 2025 in the SJV), which is slated for 2022 Board consideration.[210] However, as noted in our 2021 Proposed Rule,[211] given the complexities involved in regulating locomotive emissions, we have conservatively excluded from our analysis the emission reduction estimates in the 2021 Progress Report for CARB's In-Use Locomotive Measure.

In addition, CARB has identified further measures that were not included in the original control measure commitments that may provide emission reductions toward CARB's aggregate tonnage commitments.[212] These measures include Cargo Handling Equipment Registration, Construction and Mining Equipment Measure, and Co-Benefits from the Climate Program. However, we do not have information as to what these measures might entail, when the State may adopt or implement them, and what scale of emission reductions they could potentially achieve.

Based on the lack of information on funding and process for heavy-duty and off-road equipment incentive-based measures and the lack of information on other potential substitute measures, such as a Construction and Mining Equipment Measure, and in light of the Ninth Circuit Memorandum Opinion, we have reconsidered our evaluation of this prospect and now propose that there is not sufficient evidence to show that the Valley State SIP Strategy contains a ''plausible strategy'' to achieve the remaining NO_X and direct $PM_{2.5}$ emission reductions needed for attainment.

The other approach that the 2021 Proposed Rule discusses for filling the gap in CARB's strategy for achieving its commitment is based on a hypothetical future SIP revision. In the 2021 Progress Report, CARB and the District provided additional emissions analysis to assess how excess direct $PM_{2.5}$ emission reductions could be converted to equivalent NO_X emission reductions using an inter-pollutant trading ratio rooted in the sensitivity analyses of the 2018 $PM_{2.5}$ Plan.[213] CARB and the District have not formally submitted this analysis as a SIP revision to the EPA or requested that the EPA apply such inter-pollutant trading for purposes of fulfilling the aggregate tonnage commitments through an equivalent amount of emission reductions.

Consistent with past EPA action on $PM_{2.5}$ planning SIP submissions for the SJV,[214] where the State submits a SIP

[204] 86 FR 74310, 74335.

[205] Valley State SIP Strategy, Table 7.

[206] 2021 Progress Report at 24 and 32. Generally, mobile source incentive projects implemented under the Carl Moyer program are under contract only during the ''project life'' and may not be credited with SIP emission reductions after the project life ends. EPA Region IX ''Technical Support Document for EPA's Rulemaking for the California State Implementation Plan California Air Resources Board Resolution 19–26 San Joaquin Valley Agricultural Equipment Incentive Measure,'' February 2020, 12–13.

[207] 86 FR 74310, 74335.

[208] See, *e.g.,* CARB, ''Proposed Fiscal Year 2021–22 Funding Plan for Clean Transportation Incentives, Appendix D: Long-Term Heavy-Duty Investment Strategy,'' release date October 8, 2021.

[209] The EPA also notes that, for regulatory measures that have large estimated emission reductions, rather than incentive-based measures, CARB estimated that its Low-Emission Diesel Fuel Requirement would achieve an additional 1 tpd NO_X and 0.1 tpd direct $PM_{2.5}$ reductions. However, without near-term adoption and submission, its associated emission reductions may not be creditable towards the aggregate tonnage commitment for 2025.

[210] 2021 Progress Report, 20–21. Additional information on CARB's regulatory concepts for the In-Use Locomotive Measure are available at: *https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california/locomotives-and-railyards-meetings-workshops.*

[211] 86 FR 74310, 74334, fn. 228.

[212] CARB, ''SJV $PM_{2.5}$ SIP Measure Tracking,'' September 2021, 3. Available at: *https://ww2.arb.ca.gov/resources/documents/2018-san-joaquin-valley-pm25-plan.*

[213] 2021 Progress Report, Table 4 and 33–37.

[214] For example, the EPA has approved an inter-pollutant trading mechanism for use in transportation conformity analyses for the 2006 24-hour $PM_{2.5}$ NAAQS. 85 FR 44192, 44204. In that same final rule, the EPA approved the State's demonstration that it had fulfilled prior aggregate tonnage commitments, in part, by using an inter-pollutant trading approach that the EPA found

revision that would substitute reductions in one pollutant to achieve a tonnage commitment concerning a different pollutant (*e.g.,* substituting excess direct $PM_{2.5}$ reductions to satisfy a NO_X reduction commitment), it must include an appropriate inter-pollutant trading (IPT) ratio and the technical basis for such ratio in the plan submission itself, along with the requisite public process. The EPA will review any such IPT ratio and its bases before approving or disapproving any such SIP revision. The possibility of a future SIP submission discussing IPT does not constitute a ''plausible strategy'' for achieving reductions that are modeled to result in attainment. Thus, at this time, we are not proposing to approve any particular inter-pollutant trading approach for purposes of meeting the aggregate tonnage commitments, nor applying any excess reductions of one pollutant towards fulfilling a portion of committed reductions of the other pollutant.

The additional evaluation we have discussed herein as part of our reconsideration of the State's enforceable commitments requires us to re-evaluate the EPA's three-factor test for enforceable commitments. Based on our reconsideration, and consistent with the Ninth Circuit Memorandum Opinion, we retain our proposed findings that the State's commitments meet the first factor (the commitment represents a limited portion of the required reductions, *i.e.,* 13.8% of the NO_X and 8.0% of the direct $PM_{2.5}$ emission reductions necessary to attain) and the third factor (the commitment is for a reasonable and appropriate timeframe) of the three-factor test. However, we now propose that the State's commitments do not meet the second factor (regarding the State's capability to fulfill its commitments). Our analysis and findings for the first and third factors are presented in section IV.F.3.e of the 2021 Proposed Rule. We provide our reconsidered evaluation of the second factor as follows in this proposed rule.

As the EPA noted in our 2021 Proposed Rule, CARB and the District have been capable of developing and adopting many of the regulatory measures listed in their respective control measure commitments. However, the question before us more precisely is whether such substantial progress, coupled with the strategy submitted by the State for achieving the remaining reductions which the State has modeled as leading to attainment, is sufficient to show that the State is capable of fulfilling its *entire* aggregate tonnage commitments by 2025. Several components of our reconsideration suggest that the State may not be capable of fulfilling the entire aggregate tonnage commitment, particularly with respect to NO_X emission reductions from additional CARB measures.

First, in terms of additional measures for which CARB and the District provided updated emission reduction estimates, we have given additional consideration to the evidence of emission reductions for two source categories that have large emission reduction estimates: Heavy-Duty I/M and the Agricultural Equipment Incentive Measures. For Heavy-Duty I/M, CARB has not provided to the EPA a sufficient basis for its increase in estimated emission reductions from 6.8 tpd NO_X to 14.7 tpd NO_X, where the 14.7 tpd reduction amounts to 7.1% of the total emission reductions modeled for attainment of the 2012 annual $PM_{2.5}$ NAAQS. Although the EPA is confident, based on its review, that emission reductions are available in this category, and that the State is capable of achieving some amount of reductions, the State has not sufficiently supported its assertion that it is capable of achieving 14.7 tpd of NO_X and 0.03 tpd of direct $PM_{2.5}$. As discussed above, due to uncertainty surrounding the NRCS portion of the Agricultural Equipment Incentive Measure-Phase 1, we are not relying on reductions from that portion of the rule, and the creditability of any NRCS portion of a potential future Phase 2 has not been established.

Furthermore, for any measure, to the extent that CARB or the District assumed a 100% rule effectiveness rate where the EPA is not able to confirm and approve such a rate, further discounts to the emission reduction estimates may be warranted in certain cases.

Accordingly, the overall remaining NO_X commitment could be larger than 6.01 tpd and the anticipated excess emission reductions for direct $PM_{2.5}$ could be smaller than 0.86 tpd.

Second, even if the EPA were to assume maximum credit for the additional measures for which CARB and the District provided updated emission reduction estimates, CARB, in combination with the District, would still need emission reductions of at least 6 tpd NO_X to fulfill its commitments.[215] Moreover, the reductions from CARB's remaining incentive measures for Heavy-Duty vehicles and off-road equipment appear to be limited relative to the combined emission reduction estimate of 9.5 tpd NO_X in the Plan. Without documentation supporting the funding amounts to be applied in the SJV within the timeline of the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan, it is not clear that the full amount of these estimated reductions is supported by a ''plausible strategy'' to achieve them, as required in the Ninth Circuit Memorandum Opinion. In addition, the identified substitute measures lack sufficient detail to provide support for making up for NO_X emission reduction shortfalls from CARB's control measure commitments.

Given the gap between the reductions needed and the reductions for which CARB and the District have presented a non-speculative plan for achieving, we now propose that the State has not demonstrated that it is capable of fulfilling the remaining aggregate tonnage commitments necessary to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, and therefore find that the SJV $PM_{2.5}$ Plan does not meet the second factor of our three-factor test for enforceable commitments.

b. Attainment Demonstration

Based on our reconsideration of the Plan's enforceable commitments described in section II.C.3.a of this proposed rule, and our reconsideration of the Plan's BACM demonstration for described in section II.B, we now propose to disapprove the SJV $PM_{2.5}$ Plan's modeled attainment demonstration for the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025. We discuss the interrelationship of these nonattainment plan elements as follows.

Regarding enforceable commitments, CAA section 110(a)(2)(A) provides that each SIP ''shall include enforceable emission limitations and other control measures, means or techniques . . . as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of [the Act].'' Section 172(c)(6) of the Act, which applies to nonattainment SIPs, is virtually identical to section 110(a)(2)(A). The EPA interprets the CAA to allow for approval of enforceable commitments that are limited in scope, where circumstances exist that warrant the use of such commitments in place of

adequate. 85 FR 44192, 44205; see also proposed rule at 85 FR 17382, 17406–17407 and associated EPA's General Evaluation TSD, Table III–C and section IV.

[215] As noted in this proposed rule, if the EPA were to assume credit for emission reductions from the additional District measures, the District would have exceeded its aggregate tonnage commitments by 0.64 tpd NO_X and 0.89 tpd direct $PM_{2.5}$.

adopted and submitted measures, and considers three factors in determining whether to approve the enforceable commitment.

Given our proposed finding above that the State has not met the second factor of the EPA's three-factor test (*i.e.,* whether the State is capable of fulfilling its commitment), the State is left with a gap between the reductions that it has modeled as necessary for attainment, and the reductions that the EPA may count as constituting the State's control plan. Therefore, the EPA proposes that the State's control strategy does not include sufficient enforceable measures, pursuant to CAA sections 110(a)(2)(A) and 172(c)(6), to achieve the necessary emission reductions to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025.

The lack of an approved control plan to achieve the reductions necessary to attain by 2025 is sufficient on its own to compel disapproval of the attainment demonstration. However, even if the State's control plan was sufficient to lead to attainment in 2025, the Public Justice Comment Letter and our reconsidered BACM analysis in section II.B of this notice raise additional issues regarding the sufficiency of the modeled attainment demonstration.

The State's attainment demonstration identifies the Bakersfield-Planz monitor as the design value monitor, and models this monitor as achieving the 12.0 µg/m³ concentration necessary for attainment in 2025.[216] The State's submission also indicates that the Bakersfield-Planz monitor is modeled to read 12.1 µg/m³ in 2024.[217] This represents a very narrow margin between modeled attainment in 2024 and 2025. In light of the Act's requirement to demonstrate attainment by the most expeditious date practicable, in order for the EPA to approve the Plan's demonstration that the area will attain by 2025, the State must also demonstrate that attainment by an earlier date is not practicable.

As explained in section II.B of this notice, the EPA now proposes to find that the State has not sufficiently demonstrated that it has implemented BACM for all necessary categories of sources. Most notably, the State has not sufficiently evaluated the amount of ammonia reductions that may be available. In light of the very small (0.1 µg/m³) gap between attaining in 2024 and 2025, and the State's sensitivity modeling in its precursor demonstration indicating that a 30% reduction in ammonia would reduce annual $PM_{2.5}$ concentrations at the Bakersfield-Planz monitor by 0.12 µg/m³ and a 70% reduction would reduce annual $PM_{2.5}$ concentrations at the Bakersfield-Planz monitor by 0.36 µg/m³, the State has not demonstrated that reductions from sources identified in section II.B could not expedite attainment.[218] As a result, even if the State's control plan was sufficiently concrete that the EPA could credit all reductions of NO_X and direct $PM_{2.5}$ that the State indicated that it intended to use to fulfill its aggregate commitments, the State is still required to demonstrate that the selected attainment year (*e.g.,* 2025) is as expeditious as practicable considering potential emission reductions from all plan precursors, including ammonia.

The EPA emphasizes that it is stating both that the Plan does not demonstrate that the SJV will attain by 2025 and that the State has not demonstrated that it could not attain sooner than 2025. These findings are not in tension with one another. Under the Act, the State must demonstrate that its control plan will be sufficient to attain the NAAQS, and to attain the NAAQS by the most expeditious date practicable. The State's failure to demonstrate that it could not attain sooner than 2025 is not inconsistent with the State also having other analytical or substantive flaws in its control plan to attain by 2025. The EPA is not proposing to find that the SJV can practicably attain by 2024, nor is the EPA proposing to find that the SJV could not possibly attain by 2025. Instead, the EPA is proposing, in light of the uncertainty regarding ammonia controls, to find that the State has failed to demonstrate that it could not practicably attain before 2025, and in light of identified deficiencies in the control plan, that the State's control strategy for attaining by 2025 is flawed.

Furthermore, for the 1997 annual $PM_{2.5}$ NAAQS, on November 8, 2021, the State submitted the ''Attainment Plan Revision for the 1997 Annual $PM_{2.5}$ Standard,'' which was adopted by the District on August 19, 2021, and by CARB on September 23, 2021 (''15 µg/m³ SIP Revision''). In that submission, the State updated its prior air quality modeling to account for more recent monitored air quality data. Specifically, the State estimated 2023 annual average concentrations starting from a 2018 monitored base year (*i.e.,* rather than a 2013 base year, in order to reflect updated monitored air quality data), and applied updated, scaled relative response factors (RRFs) to reflect emissions changes between 2018 and 2023.[219] Because this scaling indicated a significant change in the modeling results for the 1997 annual $PM_{2.5}$ NAAQS, and the modeling for the 2012 annual $PM_{2.5}$ NAAQS relies on many of the same models and assumptions, the result of the scaling analysis introduces additional uncertainty to the modeled attainment demonstration for the 2012 $PM_{2.5}$ NAAQS. Accordingly, we recommend updated modeling analysis for the 2012 annual $PM_{2.5}$ NAAQS.

As a result of our proposed disapproval of the control plan and the uncertainty regarding additional reductions that could be achieved by further BACM/BACT level controls for all appropriate plan precursors (particularly for ammonia), we now propose to disapprove the attainment demonstration for the 2012 annual $PM_{2.5}$ NAAQS.

D. Reasonable Further Progress Demonstration and Quantitative Milestones

1. Summary of 2021 Proposed Rule

In section IV.G of our 2021 Proposed Rule, the EPA described the requirements for RFP and quantitative milestones for a Serious $PM_{2.5}$ nonattainment area, summarized the State's submission in the 2018 $PM_{2.5}$ Plan for the SJV, and presented our evaluation thereof.[220] We briefly summarize those components here and rely on the more complete exposition in that proposed rule, except as described in section II.D.2 of this proposed rule (*i.e.,* the EPA's reconsidered proposal for RFP and quantitative milestones).

Regarding requirements, CAA section 172(c)(2) provides that all nonattainment area plans shall require RFP toward attainment. In addition, CAA section 189(c) requires that all $PM_{2.5}$ nonattainment area plans contain quantitative milestones for purposes of measuring RFP, as defined in CAA section 171(1), every three years until the EPA redesignates the area to attainment. Section 171(1) of the Act defines RFP as the annual incremental reductions in emissions of the relevant air pollutant as are required by part D, title I of the Act, or as may reasonably be required by the Administrator for the purpose of ensuring attainment of the

[216] 2018 $PM_{2.5}$ Plan, App. K, Table 39.

[217] Id. at Table 33.

[218] See 2018 $PM_{2.5}$ Plan, App. G, tables 4 through 7.

[219] 15 µg/m³ SIP Revision, Ch. 5, 5–9 to 5–12. See also 15 µg/m³ SIP Revision, App. K, 64–65. In the 15 µg/m³ SIP Revision, the State used existing modeling runs for 2020 and 2024 to compute RRFs for each $PM_{2.5}$ component using the standard approach recommended in the EPA's Modeling Guidance. Those RRFs were then scaled to reflect emissions changes between 2018 and 2023 to arrive at updated RRFs.

[220] 86 FR 74310, 74338–74345.

NAAQS by the applicable attainment date.

In addition to the EPA's longstanding guidance on the RFP requirements for PM, the Agency has established specific regulatory requirements for the $PM_{2.5}$ NAAQS in the $PM_{2.5}$ SIP Requirements Rule for purposes of satisfying the Act's RFP requirements and provided related guidance in the preamble to the rule. Specifically, under the $PM_{2.5}$ SIP Requirements Rule, for a $PM_{2.5}$ attainment plan a State must include an RFP analysis that includes, at minimum, the following four components: (1) an implementation schedule for control measures; (2) RFP projected emissions for direct $PM_{2.5}$ and all $PM_{2.5}$ plan precursors for each applicable milestone year, based on the anticipated control measure implementation schedule; (3) a demonstration that the control strategy and implementation schedule will achieve reasonable progress toward attainment between the base year and the attainment year; and (4) a demonstration that by the end of the calendar year for each triennial milestone date for the area, pollutant emissions will be at levels that reflect either generally linear progress or stepwise progress in reducing emissions on an annual basis between the base year and the attainment year.[221] Additionally, states should estimate the RFP projected emissions for each quantitative milestone year by sector on a pollutant-by-pollutant basis.[222]

Section 189(c) of the Act requires that $PM_{2.5}$ attainment plans include quantitative milestones that demonstrate RFP. The purpose of the quantitative milestones is to allow periodic evaluation of the State's progress towards attainment of the $PM_{2.5}$ NAAQS in the area consistent with RFP requirements. Because RFP is an annual emission reduction requirement and the quantitative milestones are to be achieved every three years, when a State demonstrates compliance with the quantitative milestone requirement, it should also demonstrate that RFP has been achieved during each of the relevant three years. Quantitative milestones should provide an objective means to evaluate progress toward attainment meaningfully, *e.g.,* through imposition of emissions controls in the attainment plan and the requirement to quantify those required emissions reductions on the schedule approved by the EPA and thus required to meet RFP.

As we noted in the 2021 Proposed Rule, the CAA does not specify the starting point for counting the three-year periods for quantitative milestones under CAA section 189(c). In the General Preamble and General Preamble Addendum, the EPA interpreted the CAA to require that the starting point for the first three-year period be the due date for the Moderate area plan submission.[223] Consistent with this longstanding interpretation of the Act, the $PM_{2.5}$ SIP Requirements Rule requires that each plan for a Serious $PM_{2.5}$ nonattainment area that demonstrates attainment by the end of the 10th calendar year following the date of designation contain quantitative milestones to be achieved no later than milestone dates 7.5 years and 10.5 years from the date of designation of the area.[224] The 2018 $PM_{2.5}$ Plan includes a demonstration designed to show attainment by the end of the 10th calendar year following designations (*i.e.,* December 31, 2025). Because the EPA designated the SJV nonattainment for the 2012 annual $PM_{2.5}$ NAAQS effective April 15, 2015,[225] the applicable quantitative milestone dates for purposes of the submitted Serious area plan for this NAAQS in the SJV are October 15, 2022, and October 15, 2025.

Quantitative milestones must provide for objective evaluation of reasonable further progress toward timely attainment of the $PM_{2.5}$ NAAQS in the area and include, at minimum, a metric for tracking progress achieved in implementing SIP control measures, including BACM and BACT, by each milestone date.[226]

The State presents its RFP demonstration and quantitative milestones for the 2012 annual $PM_{2.5}$ NAAQS in Appendix H of the 2018 $PM_{2.5}$ Plan. Following the identification of a transcription error in the RFP tables of Appendix H, the State submitted a revised version of Appendix H that corrects the transcription error and provides additional information on the RFP demonstration.[227] Given the State's conclusions that ammonia, SO_X, and VOC emissions do not contribute significantly to $PM_{2.5}$ levels that exceed the 2012 annual $PM_{2.5}$ NAAQS in the SJV, the RFP demonstration provided by the State only addresses emissions of direct $PM_{2.5}$ and NO_X.[228] Similarly, the State developed quantitative milestones based upon the Plan's control measure strategy to achieve emission reductions of direct $PM_{2.5}$ and NO_X.[229]

For the 2012 annual $PM_{2.5}$ NAAQS, the RFP demonstration in the Plan follows a stepwise approach due to the time required for CARB and the District "to amend rules, develop programs, and implement the emission reduction measures." [230] The revised Appendix H provides clarifying information on the RFP demonstration, including additional information to justify the Plan's stepwise approach to demonstrating RFP. This clarifying information did not affect the Plan's quantitative milestones. It is important to note that the State evaluated what would be necessary for purposes of meeting RFP premised upon its approach to regulating only direct $PM_{2.5}$ and NO_X emissions, and upon a December 31, 2025 attainment date that itself depended upon the State achieving certain additional emission reductions though the enforceable commitments.

In our 2021 Proposed Rule we further described the State's RFP demonstration and quantitative milestones in the SJV $PM_{2.5}$ Plan, including, for example, the anticipated implementation schedule for CARB and District control measures, projected emissions for each RFP year and attainment year, and percent reductions to be achieved in each milestone year, which would be consistent with a stepwise approach. We noted that the reductions between the 2013 base year and 2019 milestone year are consistent with generally linear progress toward the targeted attainment date, while the reductions by the 2022 milestone year would fall short of the rate of reductions to show generally linear RFP. We also noted that the State relies on more substantial direct $PM_{2.5}$ and NO_X emission reductions by January 1, 2025, due in large part to CARB and the District's reliance on enforceable commitments to achieve additional $PM_{2.5}$ and NO_X emission reductions from new measures implemented by 2024. Lastly, we noted the State's overall conclusion that the adopted control strategy and additional commitments for reductions from new control programs by this time are adequate to meet the RFP requirement for the 2012 annual $PM_{2.5}$ NAAQS with

[221] 40 CFR 51.1012(a).

[222] 81 FR 58010, 58056.

[223] General Preamble, 13539 and General Preamble Addendum, 42016.

[224] 40 CFR 51.1013(a)(2)(i).

[225] 80 FR 2206.

[226] 81 FR 58010, 58064 and 58092.

[227] Appendix H to 2018 $PM_{2.5}$ Plan, submitted February 11, 2020, via the EPA State Planning Electronic Collaboration System. This revised version of Appendix H replaces the version submitted with the 2018 $PM_{2.5}$ Plan on May 10, 2019. All references to Appendix H in this proposed rule are to the revised version of Appendix H submitted February 11, 2020.

[228] 2018 $PM_{2.5}$ Plan, App. H, H–1.

[229] Id. at App. H, H–23 to H–24 (for CARB milestones) and H–20 to H–22 (for District milestones).

[230] Id. at App. H, H–4.

the projected attainment date of December 31, 2025.

Regarding quantitative milestones, Appendix H of the 2018 $PM_{2.5}$ Plan identifies October 15 milestone dates for the 2019 and 2022 RFP milestone years, the 2025 attainment year, and a post-attainment milestone year of 2028.[231] Appendix H also identifies target emissions levels to meet the RFP requirement for direct $PM_{2.5}$ and NO_X emissions for each of these milestone years,[232] as shown in Table 6 of our 2021 Proposed Rule, and control measures that CARB and the District already have in place or plan to implement by each of these years, in accordance with the control strategy in the Plan.[233]

We noted, however, that while quantitative milestones are required for 2019 in the context of the Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV (corresponding to the 4.5 years after the date of designation), we have already evaluated and approved the State's quantitative milestones for 2019, as supplemented by the 2018 $PM_{2.5}$ Plan.[234] Therefore, the EPA is not evaluating the 2019 milestones for purposes of the State's Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

Although the State's attainment demonstration for the 2012 annual $PM_{2.5}$ NAAQS does not rely on CARB's and the District's control measure commitments for emission reductions until 2024,[235] the RFP and quantitative milestone elements of the 2018 $PM_{2.5}$ Plan rely on these control measure commitments to demonstrate that the plan requires RFP toward attainment.[236] In our 2021 Proposed Rule we summarized the specific milestones identified by the State for each milestone year and with respect to the control measure commitments in each three-year period.

The EPA presented its evaluation of the State's RFP demonstration and quantitative milestones in section IV.G.3 of the 2021 Proposed Rule, with additional information in section V of the EPA's 2012 Annual $PM_{2.5}$ TSD. We previously proposed to approve the State's RFP demonstration and quantitative milestones.

2. The EPA's Reconsidered Proposal

As discussed in section II.C.3, we are now proposing to disapprove the attainment demonstration for the Serious area plan portion of the 2018 $PM_{2.5}$ Plan for the 2012 annual $PM_{2.5}$ NAAQS because we are proposing to not approve the State's control plan to achieve the reductions modeled for 2025 and the attainment demonstration does not demonstrate that the SJV could not practicably attain before 2025. The RFP demonstration in the Plan is deficient because it sets out a timeline for implementing the deficient control plan, which is not sufficient to ''ensure attainment'' under CAA section 171(l). The quantitative milestones do not ''demonstrate [RFP] toward attainment by the applicable date'' under CAA section 189(c), both because the Plan does not sufficiently demonstrate that the control plan will result in attainment, and because the plan does not sufficiently establish what the applicable date should be.[237] As a result, the EPA proposes to disapprove the Plan's Serious area RFP demonstration and quantitative milestones for the 2012 annual $PM_{2.5}$ NAAQS.

E. Motor Vehicle Emission Budgets

1. Summary of 2021 Proposed Rule

In section IV.I of our 2021 Proposed Rule, the EPA described the requirements for motor vehicle emission budgets (''budgets'') for a Serious $PM_{2.5}$ nonattainment area, summarized the State's submission in the 2018 $PM_{2.5}$ Plan for the SJV, and presented our evaluation thereof.[238] We briefly summarize those components here and rely on the more complete exposition in that proposed rule, except as described in section II.E.2 of this proposed rule (*i.e.,* the EPA's reconsidered proposal for budgets).

Section 176(c) of the CAA requires federally funded or approved actions in nonattainment and maintenance areas to conform to the SIP's goals of eliminating or reducing the severity and number of violations of the NAAQS and achieving expeditious attainment of the NAAQS. Conformity to the SIP's goals means that such actions will not: (1) cause or contribute to new violations of a NAAQS; (2) increase the frequency or severity of an existing violation; or (3) delay timely attainment of any NAAQS or any interim milestone.

Actions involving Federal Highway Administration (FHWA) or Federal Transit Administration (FTA) funding or approval are subject to the EPA's transportation conformity rule, codified at 40 CFR part 93, subpart A (''Transportation Conformity Rule''). Under this rule, metropolitan planning organizations (MPOs) in nonattainment and maintenance areas coordinate with State and local air quality and transportation agencies, the EPA, FHWA, and FTA to demonstrate that an area's regional transportation plan (RTP) and transportation improvement programs (TIP) conform to the applicable SIP. The MPO's demonstration is typically done by showing that estimated emissions from existing and planned highway and transit systems are less than or equal to the applicable budgets contained in adequate or approved control strategy implementation plans. An attainment plan for the $PM_{2.5}$ NAAQS should include budgets for the attainment year and each required RFP milestone year for direct $PM_{2.5}$ and $PM_{2.5}$ precursors subject to transportation conformity analyses. Budgets are generally established for specific years and specific pollutants or precursors and must reflect all of the motor vehicle control measures contained in the attainment and RFP demonstrations.[239]

In our 2021 Proposed Rule, we described how states should identify budgets for direct $PM_{2.5}$, NO_X, and all other $PM_{2.5}$ precursors for which the State and/or the EPA has determined that on-road emissions significantly contribute to $PM_{2.5}$ levels in the area for each RFP milestone year and the attainment year if the plan demonstrates attainment.[240] All direct $PM_{2.5}$ SIP budgets should include direct $PM_{2.5}$ motor vehicle emissions from tailpipes, brake wear, and tire wear.

We described the process by which the State and the EPA should determine

[231] 2018 $PM_{2.5}$ Plan, App. H, Table H–12.

[232] Id. at Table H–5.

[233] Id. at H–23 to H–24 (for CARB milestones) and H–20 to H–22 (for District milestones).

[234] 86 FR 67343, 67346.

[235] 2018 $PM_{2.5}$ Plan, Ch. 4, Table 4–3 (''Emission Reductions from District Measures'') and Table 4–9 (''San Joaquin Valley Expected Emission Reductions from State Measures'').

[236] 2018 $PM_{2.5}$ Plan, App. H, H–4 to H–10 (describing commitments by CARB and SJVUAPCD to adopt additional measures to fulfill tonnage commitments for 2024 and 2025, including ''action'' and ''implementation'' dates occurring before 2024 to ensure expeditious progress toward attainment).

[237] In addition, as discussed in section II.C.3.a of this proposed rule, the EPA notes that of the State's 27 control measure commitments, four regulatory measures and four incentive-based measures are overdue (*i.e.,* were due for board consideration in 2020 or 2021). It is not clear, based on the evidence before the EPA, that such measures will be presented to the CARB and District boards in the 2022 calendar year. Furthermore, to the extent the State relies on substitute measures to ultimately fulfill its aggregate tonnage commitments in 2025 (*e.g.,* the Agricultural Burning Phase-out Measure), the State has not provided quantitative milestones as part of a SIP revision that would provide for periodic evaluation of the State's progress in implementing such substitute measures. In addition, the State has not provided quantitative milestones for ammonia.

[238] 86 FR 74310, 74347–74351.

[239] 40 CFR 93.118(e)(4)(v).

[240] 40 CFR 93.102(b)(2)(iv) and (v).

whether other pollutant emissions (*i.e.,* for re-entrained road dust, VOC, SO_2, and ammonia) contribute significantly to the $PM_{2.5}$ nonattainment problem, either with respect to the whole plan or with respect to on-road mobile emissions, and therefore be subject to the transportation conformity requirements (*i.e.,* budgets for such pollutant(s) must be included in the plan). We further noted that transportation conformity trading mechanisms are allowed under 40 CFR 93.124 where a State establishes appropriate mechanisms for such trades and where the basis for the trading mechanism is the SIP attainment modeling that establishes the relative contribution of each $PM_{2.5}$ precursor pollutant.

The EPA's process for determining the adequacy of a budget consists of three basic steps: (1) notifying the public of a SIP submittal; (2) providing the public the opportunity to comment on the budgets during a public comment period; and (3) making a finding of adequacy or inadequacy.[241] The EPA can notify the public by either posting an announcement on the EPA's adequacy website notifying the public that the EPA has received a SIP submission that will be reviewed to determine if the budgets in that submission are adequate for transportation conformity purposes (40 CFR 93.118(f)(1)), or through a **Federal Register** notice of proposed rulemaking when the EPA reviews the adequacy of submitted motor vehicle emission budgets simultaneously with its review and action on the SIP itself (40 CFR 93.118(f)(2)).

The State includes budgets for direct $PM_{2.5}$ and NO_X emissions for the 2019 and 2022 RFP milestone years, the projected attainment year (2025), and one post-attainment year quantitative milestone (2028) in the 2018 $PM_{2.5}$ Plan.[242] The State establishes separate direct $PM_{2.5}$ and NO_X subarea budgets for each county, or partial county (for Kern County), in the SJV.[243] CARB calculated the budgets using EMFAC2014,[244] which was, at the time, CARB's latest version of the EMFAC model for estimating emissions from on-road vehicles operating in California that had been approved by EPA at the time of Plan development, and the latest modeled vehicle miles traveled and speed distributions from the SJV MPOs from the Final 2017 Federal Transportation Improvement Programs, adopted in September 2016. The budgets reflect annual average emissions consistent with the annual averaging period of the 2012 annual $PM_{2.5}$ NAAQS and the 2018 $PM_{2.5}$ Plan's RFP demonstration.

In our 2021 Proposed Rule, the EPA noted the following: (1) 2022 and 2025 are the required budget years applicable to the Serious area plan portion of the 2018 $PM_{2.5}$ Plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV (and that the attainment year of 2025 coincided with the latter milestone year based on timing of designations); (2) the EPA had approved the budgets for the 2022 RFP milestone year in acting on the Moderate area plan and, therefore, will not be acting on them again in acting on the Serious area plan;[245] (3) the EPA is not evaluating the 2019 budgets, which would neither be used in any future conformity determinations (as the plan contains budgets for 2022 and other future years), nor required for the submitted Serious area plan; and (4) the EPA would begin the motor vehicle emissions budget adequacy and approval review processes for the 2028 post-attainment milestone year budgets only if the area were to fail to attain the standard by December 31, 2025 (the applicable Serious area attainment date if the EPA were to finalize approval of the 2018 $PM_{2.5}$ Plan's attainment demonstration).

The Plan's direct $PM_{2.5}$ budgets include tailpipe, brake wear, and tire wear emissions but do not include paved road dust, unpaved road dust, and road construction dust emissions.[246] The State did not include budgets for VOC, SO_2, or ammonia, consistent with its precursor demonstration that control of these precursors would not significantly contribute to attainment of the 2012 annual $PM_{2.5}$ NAAQS. The State also included a discussion of the significance/insignificance factors for motor vehicle emissions of ammonia, SO_2, and VOC to support a finding of insignificance under the transportation conformity rule.[247] The State is not required to include re-entrained road dust in the $PM_{2.5}$ budgets under section 93.103(b)(3) unless the EPA or the State has made a finding that these emissions are significant, and neither the State nor the EPA has made such a finding. Nevertheless, the Plan includes a discussion of the significance/insignificance factors for re-entrained road dust and concludes that such emissions are insignificant.[248] The budgets included in the 2018 $PM_{2.5}$ Plan are shown in Table 3 of this proposed rule, which is identical to Table 9 of our 2021 Proposed Rule.

TABLE 3—MOTOR VEHICLE EMISSION BUDGETS FOR THE SAN JOAQUIN VALLEY FOR THE 2012 $PM_{2.5}$ STANDARD

[Annual average, tpd]

County	2022 (RFP year) [a]		2025 (attainment year)	
	$PM_{2.5}$	NO_X	$PM_{2.5}$	NO_X
Fresno	0.9	21.2	0.8	14.3
Kern	0.8	19.4	0.8	12.8
Kings	0.2	4.1	0.2	2.7
Madera	0.2	3.5	0.2	2.3
Merced	0.3	7.6	0.3	5.0
San Joaquin	0.6	10.0	0.6	6.9
Stanislaus	0.4	8.1	0.4	5.6
Tulare	0.4	6.9	0.4	4.7

Source: 2018 $PM_{2.5}$ Plan, Appendix D, Table 3–3. Budgets are rounded to the nearest tenth of a ton.

[241] 40 CFR 93.118(f).

[242] 2018 $PM_{2.5}$ Plan, App. D, Table 3–3.

[243] 40 CFR 93.124(c) and (d).

[244] EMFAC is short for *EM*ission *FAC*tor. The EPA announced the availability of the EMFAC2014 model for use in State implementation plan development and transportation conformity in California on December 14, 2015. The EPA's approval of the EMFAC2014 emissions model for SIP and conformity purposes was effective on the date of publication of the notice in the **Federal Register**.

[245] 86 FR 67343, 67346.

[246] 2018 $PM_{2.5}$ Plan, App. D, D–122 to D–123.

[247] 40 CFR 93.109(f).

[248] 2018 $PM_{2.5}$ Plan, App. D, D–121.

[a] The EPA has already approved the 2022 RFP budgets in our final rule on the State's Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

In our 2021 Proposed Rule, we also described the State's proposed trading mechanism in the 2018 $PM_{2.5}$ Plan for transportation conformity analyses that would allow future decreases in NO_X emissions from on-road mobile sources to offset any on-road increases in direct $PM_{2.5}$ emissions.

We presented our evaluation of the State's Serious area budgets for the 2012 annual $PM_{2.5}$ NAAQS in the SJV and proposed to approve the 2025 budgets. We noted our preliminary review of the budgets submitted for adequacy, which preceded our proposed approval of the budgets, consistent with the EPA's general process. Based on information in the Plan, we proposed that budgets were not required for SO_2, VOC, and ammonia.

Based on our proposed approval of the State's RFP and attainment demonstrations, and our review of the budgets in the Plan, we proposed that the 2025 budgets for RFP and attainment were consistent with those demonstrations, were clearly identified and precisely quantified, and met all other applicable statutory and regulatory requirements including the adequacy criteria in 40 CFR 93.118(e)(4) and (5). We provided a more detailed discussion of the budgets in section VI of the EPA's 2012 Annual $PM_{2.5}$ TSD. We noted that our proposed approval of the budgets for the 2012 annual $PM_{2.5}$ NAAQS did not affect the status of the previously approved budgets for the 1997 $PM_{2.5}$ NAAQS and related trading mechanism, which remain in effect for that $PM_{2.5}$ NAAQS, nor the 2006 24-hour $PM_{2.5}$ NAAQS and related trading mechanism, which remain in effect for that $PM_{2.5}$ NAAQS.[249]

Based on our review of the State's trading mechanism for transportation conformity analyses for the 2012 annual $PM_{2.5}$ NAAQS, the EPA previously proposed to approve the trading mechanism, which would allow future decreases in NO_X emissions from on-road mobile sources to offset any on-road increases in $PM_{2.5}$, using a 6.5:1 NO_X:$PM_{2.5}$ ratio.[250] To ensure that the trading mechanism does not affect the ability to meet the NO_X budget, we noted the following: (1) the Plan provides that the NO_X emission reductions available to supplement the $PM_{2.5}$ budget would only be those remaining after the NO_X budget has been met; (2) the SJV MPOs would have to document clearly the calculations used in the trading when demonstrating conformity, along with any additional reductions of NO_X and $PM_{2.5}$ emissions in the conformity analysis; and (3) the trading calculations must be performed prior to the final rounding to demonstrate conformity with the budgets. We summarized the technical bases for our proposed approval of the trading mechanism in the 2021 Proposed Rule and in section VI of the EPA's 2012 Annual $PM_{2.5}$ TSD.

Regarding the duration of budgets for the 2012 annual $PM_{2.5}$ NAAQS, the EPA noted that once budgets are approved, they cannot be superseded by revised budgets submitted for the same CAA purpose and the same year(s) addressed by the previously approved SIP until the EPA approves the revised budgets as a SIP revision. While CARB had requested in its letter submitting the 2018 $PM_{2.5}$ Plan that the EPA limit the duration of the budgets (*i.e.,* to allow an adequacy finding, rather than approval, of future SIP revision of budgets to replace the initial budgets),[251] CARB later clarified that since they have submitted EMFAC2021 for EPA review, they no longer request that we limit the duration of our approval.[252]

Lastly, in our 2021 Proposed Rule, the EPA proposed to disapprove the contingency measure element of the 2018 $PM_{2.5}$ Plan with respect to the Serious area requirements for the 2012 annual $PM_{2.5}$ NAAQS, and we are not modifying our proposed action on contingency measures in this proposed rule. Accordingly, we noted that if the EPA were to finalize the proposed disapproval of the 2012 annual $PM_{2.5}$ NAAQS Serious area contingency measure element, the area would be eligible for a protective finding under the transportation conformity rule because the 2018 $PM_{2.5}$ Plan reflects adopted control measures that fully satisfy the emissions reductions requirements for the RFP and attainment year of 2025.[253]

2. The EPA's Reconsidered Proposal

Based on the EPA's reconsideration and proposed disapprovals of the attainment and RFP demonstrations discussed herein, we have reconsidered our proposed approval of the Serious area budgets for the 2012 annual $PM_{2.5}$ NAAQS in the SJV. As discussed below, the EPA now proposes to disapprove the 2025 RFP and attainment year budgets.

As noted in section I.B of this proposed rule, we are not re-proposing any action on the Plan's precursor demonstrations for SO_X and VOC (*i.e.,* we retain our proposed approval that SO_X and VOC are not plan precursors for the 2012 annual $PM_{2.5}$ NAAQS in the SJV, and therefore SO_2 and VOC budgets would not be required, consistent with the transportation conformity regulation (40 CFR 93.102(b)(2)(v))). However, as discussed in section II.A.3 of this proposed rule, the EPA now proposes to disapprove the State's precursor demonstration that ammonia does not significantly contribute to exceedances of the 2012 annual $PM_{2.5}$ NAAQS in the SJV, and therefore the Plan's precursor demonstration would not address the State's obligation to consider whether ammonia budgets are necessary in the Serious area plan.

In the Plan, the State provides a discussion of the significance/insignificance factors for motor vehicle emissions of ammonia (and SO_2 and VOC), which would demonstrate a finding of insignificance under the transportation conformity rule.[254] The factors typically addressed for significance include an examination of the on-road contribution of ammonia to the total emissions, and the likelihood of future motor vehicle emission controls. We note that annual average ammonia emissions from on-road mobile sources are an estimated 3.4 tpd of a total of 324.3 tpd from all sources in 2025, or about 1% of the total ammonia emissions.[255] Based on our

[249] 76 FR 69896, 69923–69924 (November 9, 2011) (final rule approving direct $PM_{2.5}$ and NO_X budgets for 2012 and 2014 for the 1997 annual and 24-hour $PM_{2.5}$ NAAQS); and 85 FR 44192, 44204 (final rule approving direct $PM_{2.5}$ and NO_X budgets for 2020, 2023, and 2024 for the 2006 24-hour $PM_{2.5}$ NAAQS); and 86 FR 53150, 53176–53179 (September 24, 2021) (proposed rule to approve budgets from the 2018 $PM_{2.5}$ Plan for direct $PM_{2.5}$ and NO_X for 2017 and 2020 for the 1997 24-hour $PM_{2.5}$ NAAQS). We note that, following our 2021 Proposed Rule on the 2012 annual $PM_{2.5}$ NAAQS portion of the Plan, the EPA finalized approval of the 2017 and 2020 budgets for the 1997 24-hour $PM_{2.5}$ NAAQS portion of the Plan. 87 FR 4503.

[250] For example, a 1 tpd excess of direct $PM_{2.5}$ emissions from on-road mobile sources in 2025 could be offset by a 6.5 tpd reduction in NO_X emissions below the NO_X budget for on-road mobile sources in 2025.

[251] Letter dated May 9, 2019, from Richard W. Corey, Executive Officer, CARB, to Mike Stoker, Regional Administrator, EPA Region IX, 3.

[252] Email dated November 30, 2021, from Nesamani Kalandiyur, Manager, Transportation Analysis Section, Sustainable Transportation and Communities Division, CARB, to Karina O'Connor, EPA Region IX.

[253] 40 CFR 93.120(a)(3).

[254] For the criteria and procedures for demonstrating a finding of insignificance under the transportation conformity rule, see 40 CFR 93.109(f).

[255] 2018 $PM_{2.5}$ Plan, App. B, Table B–5.

review, and the small contribution of ammonia emissions from on-road mobile sources, the EPA agrees with the State's finding that on-road mobile source emissions of ammonia are insignificant and therefore the State is not required to include budgets for ammonia in its Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

With respect to the 2025 RFP and attainment year, the EPA proposes to disapprove the direct $PM_{2.5}$ and NO_X budgets for 2025, as follows. While the 2025 budgets for RFP and attainment were clearly identified and precisely quantified, in this proposed rule the EPA proposes to disapprove the State's Serious area RFP and attainment demonstrations for the 2012 annual $PM_{2.5}$ NAAQS.[256] The EPA cannot approve budgets where the underlying CAA requirements (*i.e.,* RFP and attainment) are disapproved and therefore proposes to disapprove the 2025 budgets. The budgets, when considered together with all other emission sources, cannot be consistent with the applicable requirements for RFP and attainment of the 2012 annual $PM_{2.5}$ NAAQS given the proposed disapprovals of the RFP and attainment demonstrations. Therefore, we are proposing to disapprove the motor vehicle emissions budgets because they do not meet applicable statutory and regulatory requirements, including the adequacy criteria specified in the transportation conformity rule.[257] If the EPA finalizes the disapproval, the EPA would concurrently withdraw the adequacy finding for the 2025 RFP and attainment year motor vehicle emission budgets.[258]

Lastly, given that we now propose to disapprove the Plan's RFP and attainment demonstrations for the 2012 annual $PM_{2.5}$ NAAQS, rather than just the Serious area contingency measure element alone (as described in our 2021 Proposed Rule), the SJV would not be eligible for a protective finding under the transportation conformity rule because the 2018 $PM_{2.5}$ Plan's control measures do not fully satisfy the emissions reductions requirements for the RFP and attainment year of 2025.[259]

As a result, if the EPA finalizes our proposed disapproval of the budgets, upon the effective date of our final rule the area would be subject to a conformity freeze under 40 CFR 93.120 of the transportation conformity rule. No new transportation plan, TIP, or project may be found to conform until the State submits another control strategy implementation plan revision fulfilling the same CAA requirements, the EPA finds the budgets in the revised plan adequate or approves the budgets, the MPO makes a conformity determination for the new budgets, and the U.S. Department of Transportation makes a conformity determination.[260] In addition, only transportation projects outside of the first four years of the current conforming transportation plan and TIP or that meet the requirements of 40 CFR 93.104(f) during the resulting conformity freeze may be found to conform until California submits a new attainment and RFP plan for the 2012 annual $PM_{2.5}$ NAAQS and (1) the EPA finds the submitted budgets adequate per 40 CFR 93.118 or (2) the EPA approves the new attainment plan and conformity to the new plan is determined.[261] Furthermore, if, as a result of our final disapproval action, the EPA imposes highway sanctions under section 179(b)(1) of the Act two years from the effective date of our final rule, then the conformity status of the transportation plan and TIP will lapse on that date and no new transportation plan, TIP, or project may be found to conform until California submits a new plan for the 2012 annual $PM_{2.5}$ NAAQS, and conformity to the plan is determined.[262]

III. Environmental Justice Considerations

Executive Order 12898 (59 FR 7629, February 16, 1994) requires that Federal agencies, to the greatest extent practicable and permitted by law, identify and address disproportionately high and adverse human health or environmental effects of their actions on minority and low-income populations. Additionally, Executive Order 13985 (86 FR 7009, January 25, 2021) directs Federal Government agencies to assess whether, and to what extent, their programs and policies perpetuate systemic barriers to opportunities and benefits for people of color and other underserved groups, and Executive Order 14008 (86 FR 7619, February 1, 2021) directs Federal agencies to develop programs, policies, and activities to address the disproportionate health, environmental, economic, and climate impacts on disadvantaged communities.

To identify environmental burdens and susceptible populations in underserved communities in the SJV nonattainment area and to better understand the context of our proposed action on the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan on these communities, we conducted a screening-level analysis using the EPA's environmental justice (EJ) screening and mapping tool (''EJSCREEN'').[263] Our screening-level analysis indicates that all eight counties in the SJV score above the national average for the EJSCREEN ''Demographic Index'' (*i.e.,* ranging from 48% in Stanislaus County to 61% in Tulare County, compared to 36% nationally).[264] The Demographic Index is the average of an area's percent minority and percent low income populations, *i.e.,* the two populations explicitly named in Executive Order 12898.[265] All eight counties also score above the national average for demographic indices of ''linguistically isolated population'' and ''population with less than high school education.''

With respect to pollution, all eight counties score at or above the 97th percentile nationally for the $PM_{2.5}$ index and seven of the eight counties in the SJV score at or above the 90th percentile nationally for the $PM_{2.5}$ EJ index, which is a combination of the Demographic Index and the $PM_{2.5}$ index. Most counties also scored above the 80th percentile for each of 11 additional EJ indices included in the EPA's EJSCREEN analysis. In addition, several

[256] See 40 CFR 93.118(e)(4)(iii).

[257] 40 CFR 93.118(e)(4).

[258] The EPA found the 2025 budgets adequate in our 2021 Proposed Rule. See also, the EPA's 2012 Annual $PM_{2.5}$ TSD, 41.

[259] 40 CFR 93.120(a)(3).

[260] 40 CFR 93.120(a)(2).

[261] Id.

[262] 40 CFR 93.120(a)(1).

[263] EJSCREEN provides a nationally consistent dataset and approach for combining environmental and demographic indicators. EJSCREEN is available at *https://www.epa.gov/ejscreen/what-ejscreen.* The EPA used EJSCREEN to obtain environmental and demographic indicators representing each of the eight counties in the San Joaquin Valley. We note that the indicators for Kern County are for the entire county. While the indicators might have slightly different numbers for the SJV portion of the county, most of the county's population is in the SJV portion, and thus the differences would be small. These indicators are included in EJSCREEN reports that are available in the rulemaking docket for this action.

[264] EPA Region IX, ''EJSCREEN Analysis for the Eight Counties of the San Joaquin Valley Nonattainment Area,'' August 2022.

[265] EJSCREEN reports environmental indicators (*e.g.,* air toxics cancer risk, Pb paint exposure, and traffic proximity and volume) and demographic indicators (*e.g.,* people of color, low income, and linguistically isolated populations). The score for a particular indicator measures how the community of interest compares with the State, the EPA region, or the national average. For example, if a given location is at the 95th percentile nationwide, this means that only 5% of the US population has a higher value than the average person in the location being analyzed. EJSCREEN also reports EJ indexes, which are combinations of a single environmental indicator with the EJSCREEN Demographic Index. For additional information about environmental and demographic indicators and EJ indexes reported by EJSCREEN, see EPA, ''EJSCREEN Environmental Justice Mapping and Screening Tool—EJSCREEN Technical Documentation,'' section 2 (September 2019).

counties scored above the 90th percentile for certain EJ indices, including, for example, the Ozone EJ Index (Fresno, Kern, Madera, Merced, and Tulare counties), the National Air Toxics Assessment (NATA) Respiratory Hazard EJ Index (Madera and Tulare counties), and the Wastewater Discharge Indicator EJ Index (Merced, San Joaquin, Stanislaus, and Tulare counties).[266]

As discussed in the EPA's EJ technical guidance, people of color and low-income populations, such as those in the SJV, often experience greater exposure and disease burdens than the general population, which can increase their susceptibility to adverse health effects from environmental stressors.[267] Underserved communities may have a compromised ability to cope with or recover from such exposures due to a range of physical, chemical, biological, social, and cultural factors.[268] The EPA is committed to environmental justice for all people, and we acknowledge that the SJV nonattainment area includes minority and low income populations that are subject to higher levels of $PM_{2.5}$ and other pollution relative to State and national averages, and that such concerns could be affected by this action.

If the EPA were to finalize the proposed disapprovals described in section II of this proposed rule, California would be required to submit a plan revision for the SJV for the 2012 annual $PM_{2.5}$ NAAQS to address the identified deficiencies. In addition, as summarized in section V of this proposed rule, such final action would trigger clocks for the SJV for offset sanctions 18 months after the final rule effective date, highway funding sanctions six months after the offset sanctions, and the obligation for the EPA to promulgate a Federal implementation plan (FIP) within two years of the final rule effective date. These obligations ensure that the identified deficiencies are resolved in an expeditious manner, consistent with the principles of environmental justice.

We note that, in developing and proposing draft regulations for governing board consideration, both CARB and the District consider the potential benefits of proposed measures for reducing health hazards to disadvantaged communities, such as diesel PM exposure near Heavy-Duty truck corridors and indoor smoke exposure from residential wood burning. There may be further opportunities to address EJ concerns through such control development and implementation.

More broadly, California law has established additional requirements for community-focused action to reduce air pollution in the State. For example, in response to California Assembly Bill 617 (2017), CARB and the District have engaged communities in the SJV, performed technical evaluations, and ultimately selected four communities (South Central Fresno, Shafter, Stockton, and Arvin/Lamont) that are in varying stages of developing and implementing community air monitoring programs and community emission reduction programs.[269] Furthermore, grant programs implemented by the local, State, and Federal authorities may serve to smooth and accelerate emission reductions of $PM_{2.5}$ and its precursor pollutants in the SJV, thereby relieving some of the cumulative burden on disadvantaged communities in the SJV nonattainment area.[270]

IV. Title VI of the Civil Rights Act

As noted in section I.C of this proposed rule, the EPA received a comment letter dated January 28, 2022 (the Public Justice Comment Letter), on the 2021 Proposed Rule from a coalition of 13 organizations.

The commenters urge the EPA to disapprove the Serious area plan ''because EPA has failed to require CARB/SJV to provide necessary assurances that the State implementation plan complies with Title VI of the Civil Rights Act of 1964. The on-going environmental justice and air pollution crisis demand EPA reverse course and disapprove the 2012 plan.'' [271] To support this argument, the commenters provide information regarding the racial demographics of the SJV, the potential for disparate impacts from exposure to $PM_{2.5}$, and specific aspects of the SJV $PM_{2.5}$ Plan that the commenters believe result in disparate impacts. The commenters point to past precedent in which the EPA has considered compliance with Title VI of the Civil Rights Act (Title VI) in the SIP context through CAA section 110(a)(2)(E). The commenters also note that thus far California has provided no ''demonstration'' that the Serious area plan does not cause or exacerbate disparate impacts on affected communities in the SJV. Thus, the commenters assert that the EPA must disapprove the Serious area plan because the State did not provide ''required assurances'' of compliance with Title VI.

At this time, the EPA has not issued any guidance or regulations concerning what might be required for purposes of CAA section 110(a)(2)(E) as it regards Title VI. The EPA has addressed other aspects of section 110(a)(2)(E) in the context of infrastructure SIP submissions in its September 2013 ''Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2).'' Similarly, EPA regulations only address other aspects of section 110(a)(2)(E) in 40 CFR Sections 51.230–232.

A. Background on CAA Section 110(a)(2)(E)

For purposes of background, section 110(a)(2)(E) of the CAA, in relevant part and with emphasis added, reads as follows:

> (2) Each implementation plan submitted by a State under this chapter shall be adopted by the State after reasonable notice and public hearing. Each such plan shall—. . .
>
> (E) provide (i) *necessary assurances* that the State (or, except where the Administrator deems inappropriate, the general purpose local government or governments, or a regional agency designated by the State or general purpose local governments for such purpose) will have adequate personnel, funding, and authority under State (and, as appropriate, local) law to carry out such implementation plan *(and is not prohibited by any provision of Federal or State law from carrying out such implementation plan or portion thereof),* (ii) requirements that the State comply with the requirements respecting State boards under section 7428 of this title, and (iii) necessary assurances that, where the State has relied on a local or regional government, agency, or instrumentality for the implementation of any plan provision, the State has responsibility for ensuring adequate implementation of such plan provision.[272]

[266] Notably, Tulare County scores above the 90th percentile on six of the 12 EJ indices in the EPA's EJSCREEN analysis, including the $PM_{2.5}$ EJ Index, which is the highest count among all SJV counties.

[267] EPA, ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' section 4 (June 2016).

[268] Id. at section 4.1.

[269] For further information, see, *e.g.,* SJVUAPCD, ''Item Number 9: Receive Progress Reports on AB617 Community Emission Reduction Program Implementation,'' November 18, 2021.

[270] For example, through the EPA's Targeted Airshed Grant program, the District has competed for, and the EPA has granted 13 awards to the District from 2015 through 2021, totaling $77.4 million, to replace older, dirtier woodstoves, agricultural equipment, heavy-duty trucks and yard trucks, and agricultural nut harvesters with cleaner equipment. A list of the Targeted Airshed Grants the EPA awarded in fiscal years 2015–2020 is accessible online at *https://www.epa.gov/air-quality-implementation-plans/targeted-airshed-grant-recipients.* These EPA grants support projects to reduce emissions in areas facing the highest levels of ground-level ozone and $PM_{2.5}$.

[271] Public Justice Comment Letter, 2.

[272] 42 U.S.C. Section 7410(a)(2)(E) (emphasis added).

The EPA has previously addressed CAA section 110(a)(2)(E)(i), Title VI, and necessary assurances in a 2012 action on a nonattainment plan SIP submission from California for purposes of the ozone NAAQS.[273] Comments submitted on the EPA's April 24, 2012 proposed action contended that the SIP submission was not in compliance with CAA section 110(a)(2)(E) because of alleged violations of Title VI related to the regulation of pesticides as precursors to ozone (as volatile organic compounds). To evaluate the commenter's concerns, the EPA sought additional necessary assurances from the State concerning its regulation of pesticides. California submitted additional information to the EPA concerning the State's activities that were part of the resolution of a Title VI complaint, and additional information concerning the State's regulation of pesticides. California submitted this information to provide ''necessary assurances'' to the EPA that implementation of the requirements of the SIP submission would not violate Title VI. The EPA accepted this information as providing adequate necessary assurances for purposes of section 110(a)(2)(E) and did not require the State to make any substantive changes to support approval of the SIP revision.

Commenters in the 2012 action asserted that California had not provided sufficient necessary assurances. In the response to comments in the 2012 action, the EPA explained that ''Section 110(a)(2)(E), however, does not require a State to 'demonstrate' it is not prohibited by Federal or State law from implementing its proposed SIP revision. Rather, this section requires a State to provide 'necessary assurances' of this.'' [274] The EPA further explained,

> Courts have given EPA ample discretion in deciding what assurances are ''necessary'' and have held that a general assurance or certification is sufficient. (''EPA is entitled to rely on a state's certification unless it is clear that the SIP violates state law and proof thereof * * * is presented to EPA.'' *BCCA Appeal Group* v. *EPA,* 355 F.3d 817, 830 fn 11 (5th Cir. 2003)).[275]

The EPA received a petition for review (from groups overlapping with the groups that sent the Public Justice Comment Letter) of the EPA's October 26, 2012 final action which was reviewed and ultimately decided in EPA's favor by the Ninth Circuit Court of Appeals.[276] The Court used an arbitrary and capricious standard of review to evaluate the EPA's conclusion that the State had provided adequate ''necessary assurances'' that implementation of the SIP is not prohibited by Federal law—specifically, Title VI of the Federal Civil Rights Act of 1964—per the language of section 110(a)(2)(E). The Ninth Circuit found that the EPA fulfilled its duty to provide a reasoned judgment because its determination was cogently explained and supported by the record. In dismissing the petition, the Court explained that ''[t]he EPA has a duty to provide a reasoned judgment as to whether the State has provided 'necessary assurances,' but what assurances are 'necessary' is left to the EPA's discretion.'' [277]

B. Background on Title VI of the Civil Rights Act of 1964

For purposes of background context, Title VI prohibits recipients of Federal financial assistance from discriminating on the basis of race, color, or national origin. Under the EPA's nondiscrimination regulations, which implement Title VI and other civil rights laws,[278] recipients of EPA financial assistance are prohibited from taking actions in their programs or activities that are intentionally discriminatory and/or have an unjustified disparate impact.[279] This includes policies, criteria or methods of administering programs that are neutral on their face but have the effect of discriminating.[280] Under the EPA's regulation, recipients of EPA financial assistance are also required to have in place certain procedural safeguards, including grievance procedures that assure the prompt and fair resolution of external discrimination complaints.[281]

The EPA carries out its mandate to ensure that recipients of EPA financial assistance comply with their nondiscrimination obligations by investigating administrative complaints filed with the EPA alleging discrimination prohibited by Title VI and the other civil rights laws; [282] initiating affirmative compliance reviews; [283] and providing technical assistance to recipients to assist them in meeting their Title VI obligations. In the current matter being addressed in this action, no Title VI complaint was filed regarding CARB or the District.[284] Also, the EPA (through the External Civil Rights Compliance Office or ECRCO) has not initiated and is not currently conducting a compliance review of either CARB or SJVUAPCD.

C. Comments Received on 2021 Proposed Rule

The commenters raise the issue of compliance with section 110(a)(2)(E) with respect to Title VI. The commenters contend that the SIP submission for the SJV is not in compliance with CAA section 110(a)(2)(E) because California has not provided necessary assurances to ensure that implementation of the SIP is in compliance with Title VI. The commenters did not submit these specific comments to CARB or the SJVUAPCD during the State's development and adoption process of the proposed SIP revisions that are currently at issue. The commenters are not required to have done so to raise this issue with the EPA now, but as a result, the SIP submission to the EPA does not include any CARB or District response concerning this specific issue. In addition, the SIP submission does not include specifically identified necessary assurances per section 110(a)(2)(E) provided by the State.

At the outset, the EPA acknowledges the statements in the comment letter that the SJV area has historically been designated as nonattainment for the $PM_{2.5}$ NAAQS and that the SJV area includes higher representation of persons of color compared to the State average. Although in this action the EPA is not proposing to disapprove on the basis of CAA section 110(a)(2)(E), if the EPA disapproves the Serious area plan as proposed today, California would need to submit a revised Serious area plan for the SJV. The EPA expects that any such revision would comply with the requirements of section 110(a)(2)(E) and that CARB and the District will engage with the community through notice and comment during the SIP

[273] 77 FR 65294 (October 26, 2012) (final rule); 77 FR 24441 (April 24, 2012) (proposed rule).

[274] 77 FR 65294, 65302, column 2.

[275] Id.

[276] *El Comité Para El Bienstar de Earlimart et al. (El Comité)* v. *EPA,* 786 F.3d 688 (9th Cir. 2015).

[277] 786 F.3d at 700.

[278] 40 CFR part 7 and part 5.

[279] 40 CFR Sections 7.30 and 7.35.

[280] 40 CFR Section 7.35(b).

[281] 40 CFR Section 7.90.

[282] 40 CFR Section 7.120.

[283] 40 CFR Section 7.115.

[284] The EPA's External Civil Rights Compliance Office (ECRCO) contacted Mr. Brent Newell, signatory to the Public Justice Comment Letter, to see whether the commenters intended to file a Title VI administrative complaint with the EPA. In response, the commenters stated, ''[t]he comments submitted were neither intended nor styled as a Title VI complaint. The comments raise significant issues with respect to EPA's proposed approval, including the section 110(a)(2)(E) issues and EPA's authority and duty to enforce Title VI, and we expect EPA to respond to all of the issues in the final action/response to comments.'' Email exchange dated February 8, 2022, between Brent Newell, Public Justice and Lilian Dorka, Director, External Civil Rights Compliance Office, EPA Office of General Counsel.

development process for its revised Serious area plan prior to submitting a revised SIP to the EPA, and specifically with respect to necessary assurances relative to Title VI. The new SIP development process provides an important opportunity for CARB and the District to identify potential adverse disparate impacts on the basis of race, color, or national origin from its revised Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS and address them as appropriate.

The EPA acknowledges that it has not issued national guidance or regulations concerning implementation of section 110(a)(2)(E) as it pertains to consideration of Title VI and disparate impacts on the basis of race, color, or national origin in the context of the SIP program. Such guidance is forthcoming and will address CAA section 110(a)(2)(E)'s necessary assurance requirements as they relate to Title VI. In the interim, CARB and the District may find existing EPA and DOJ Title VI and environmental justice resources useful, even though these documents do not relate specifically to CAA section 110(a)(2)(E).[285] Additionally, the EPA's ECRCO is available to provide technical assistance regarding Title VI compliance to CARB and/or the District as they develop the revised Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS.

V. Summary of Proposed Actions and Request for Public Comment

For the reasons discussed in this proposed rule, under CAA section 110(k)(3), the EPA proposes to disapprove, as a revision to the California SIP, the following portions of the SJV $PM_{2.5}$ Plan for the 2012 annual $PM_{2.5}$ NAAQS to address the CAA's Serious area planning requirements in the SJV nonattainment area:

(1) the demonstration that BACM, including BACT, for the control of ammonia emission sources and for the control of NO_X and direct $PM_{2.5}$ building heating emission sources will be implemented no later than 4 years after the area was reclassified (CAA section 189(b)(1)(B) and 40 CFR 51.1010(a));

(2) the demonstration that the Plan provides for attainment as expeditiously as practicable but no later than December 31, 2025 (CAA sections 188(c)(2) and 189(b)(1)(A) and 40 CFR 51.1011(b));

(3) plan provisions that require RFP toward attainment by the applicable date (CAA section 172(c)(2) and 40 CFR 51.1012(a));

(4) quantitative milestones that are to be achieved every three years until the area is redesignated attainment and that demonstrate RFP toward attainment by the applicable attainment date (CAA section 189(c) and 40 CFR 51.1013(a)(2)(i)); and

(5) motor vehicle emissions budgets for 2025 as shown in Table 3 of this proposed rule (CAA section 176(c) and 40 CFR part 93, subpart A).

We are also proposing to disapprove the State's precursor demonstration for ammonia. Our proposed action on the emissions inventory and contingency measure elements remains unchanged from our 2021 Proposed Rule.

If we finalize the proposed disapprovals for BACM, the attainment demonstration, RFP, quantitative milestones, or motor vehicle emission budgets, the offset sanction in CAA section 179(b)(2) would apply in the SJV 18 months after the effective date of a final disapproval, and the highway funding sanctions in CAA section 179(b)(1) would apply in the area six months after the offset sanction is imposed.[286] Neither sanction will be imposed under the CAA if the State submits and we approve, prior to the implementation of the sanctions, a SIP revision that corrects the deficiencies that we identify in our final action. The EPA intends to work with CARB and the SJVUAPCD to correct the deficiencies in a timely manner.

In addition to the sanctions, CAA section 110(c)(1) provides that the EPA must promulgate a Federal implementation plan (FIP) addressing any disapproved elements of an attainment plan two years after the effective date of disapproval unless the State submits, and the EPA approves, a SIP submission that cures the disapproved elements.

Furthermore, if we take final action disapproving the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan, a conformity freeze will take effect upon the effective date of any final disapproval (usually 30 days after publication of the final action in the **Federal Register**). A conformity freeze means that only projects in the first four years of the most recent RTP and TIP can proceed. During a freeze, no new RTPs, TIPs, or RTP/TIP amendments can be found to conform.[287]

We will accept comments from the public on these proposals for the next 45 days. The deadline and instructions for submission of comments are provided in the **DATES** and **ADDRESSES** sections at the beginning of this proposed rule.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose an information collection burden under the PRA, because this proposed SIP disapproval, if finalized, will not in-and-of itself create any new information collection burdens, but will simply disapprove certain State requirements for inclusion in the SIP.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. This proposed SIP partial disapproval, if finalized, will not in-and-of itself create any new requirements but will simply disapprove certain State requirements for inclusion in the SIP.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action proposes to disapprove certain pre-existing requirements under State or local law, and imposes no new requirements. Accordingly, no additional costs to State, local, or tribal governments, or to the private sector, result from this action.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial

[285] See ECRCO's Toolkit Chapter I at: *https://www.epa.gov/sites/default/files/2017-01/documents/toolkit-chapter1-transmittal_letter-faqs.pdf,* January 18, 2017, and Department of Justice ''Title VI Legal Manual (Updated)'' at: *https://www.justice.gov/crt/fcs/T6Manual6.* See also, *e.g.,* EPA, ''Guidance on Considering Environmental Justice During the Development of Regulatory Actions,'' (May 2015), and EPA, ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' (June 2016).

[286] 40 CFR 52.31.

[287] See 40 CFR 93.120(a).

direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175, because the SIP revision that the EPA is proposing to partially disapprove would not apply on any Indian reservation land or in any other area where the EPA or an Indian tribe has demonstrated that a tribe has jurisdiction, and will not impose substantial direct costs on tribal governments or preempt tribal law. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because this proposed SIP partial disapproval, if finalized, will not in-and-of itself create any new regulations, but will simply disapprove certain State requirements for inclusion in the SIP.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

Section 12(d) of the NTTAA directs the EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. The EPA believes that this action is not subject to the requirements of section 12(d) of the NTTAA because application of those requirements would be inconsistent with the CAA.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Population

Executive Order 12898 (59 FR 7629 (February 16, 1994)) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. The EPA's evaluation of this issue is contained in the section of the preamble titled ''Environmental Justice Considerations.''

List of Subjects 40 CFR Part 52

Environmental protection, Air pollution control, Ammonia, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide, Volatile organic compounds.

Authority: 42 U.S.C. 7401 *et seq.*

Dated: September 28, 2022.

Martha Guzman Aceves,

Regional Administrator, Region IX.

[FR Doc. 2022–21492 Filed 10–4–22; 8:45 am]

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ATTACHMENT H

Health and Environmental Effects of Particulate Matter (PM)

Health Effects

The size of particles is directly linked to their potential for causing health problems. Small particles less than 10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream.

Exposure to such particles can affect both your lungs and your heart. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- premature death in people with heart or lung disease
- nonfatal heart attacks
- irregular heartbeat
- aggravated asthma <https://epa.gov/asthma>
- decreased lung function
- increased respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing.

People with heart or lung diseases, children, and older adults are the most likely to be affected by particle pollution exposure.

- AirNow <https://airnow.gov/> can help you monitor air quality near you, and protect yourself and your family from elevated PM levels.

Environmental Effects

Visibility impairment

Fine particles ($PM_{2.5}$) are the main cause of reduced visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas. Learn more about visibility and haze <https://epa.gov/visibility>

Environmental damage

Particles can be carried over long distances by wind and then settle on ground or water. Depending on their chemical composition, the effects of this settling may include:

- making lakes and streams acidic
- changing the nutrient balance in coastal waters and large river basins
- depleting the nutrients in soil
- damaging sensitive forests and farm crops
- affecting the diversity of ecosystems
- contributing to acid rain effects <https://epa.gov/acidrain/effects-acid-rain>.

Materials damage

PM can stain and damage stone and other materials, including culturally important objects such as statues and monuments. Some of these effects are related to acid rain effects on materials <https://epa.gov/acidrain/effects-acid-rain#materials>.

Further Reading

Particle Pollution and Your Health (PDF)(2 pp, 320 K, About PDF <https://epa.gov/home/pdf-files>): Learn who is at risk from exposure to particle pollution, what health effects you may experience as a result of particle exposure, and simple measures you can take to reduce your risk.

How Smoke From Fires Can Affect Your Health <https://www.airnow.gov/air-quality-and-health/fires-and-your-health/>: It is important to limit your exposure to smoke -- especially if you may be susceptible.

EPA research on airborne particulate matter <https://epa.gov/air-research>: EPA supports research that provides the critical science on PM and other air pollutants to develop and implement Clean Air Act regulations that protect the quality of the air we breathe.

PM Home <https://epa.gov/pm-pollution>

Particulate Matter (PM) Basics <https://epa.gov/pm-pollution/particulate-matter-pm-basics>

Health and Environmental Effects

Setting and Reviewing PM Standards <https://epa.gov/pm-pollution/setting-and-reviewing-standards-control-particulate-matter-pm-pollution>

PM Standards Regulatory Actions <https://epa.gov/pm-pollution/national-ambient-air-quality-standards-naaqs-pm>

Implementing PM Standards <https://epa.gov/pm-pollution/applying-or-implementing-particulate-matter-pm-standards>

PM Implementation Regulatory Actions <https://epa.gov/pm-pollution/particulate-matter-pm-implementation-regulatory-actions>

SIP Checklist Guide <https://epa.gov/pm-pollution/pm-state-implementation-plan-sip-checklist-guide>

PM SIP Training Presentations <https://epa.gov/pm-pollution/pm-naaqs-implementation-training-and-assistance-state-and-local-air-agencies>

PM Data and SIP Status Reports <https://epa.gov/pm-pollution/technical-data-and-reports-particulate-matter-pm-measurements-and-sip-status>

Other Criteria Air Pollutants <https://epa.gov/criteria-air-pollutants>

Contact Us <https://epa.gov/pm-pollution/forms/contact-us-about-particulate-matter-pm-pollution> to ask a question, provide feedback, or report a problem.

LAST UPDATED ON AUGUST 23, 2023

EPA www Web Snapshot

<https://epa.gov/utilities/wwwepagov-snapshots>

Grants

<https://epa.gov/grants>

No FEAR Act Data

<https://epa.gov/ocr/whistleblower-protections-epa-and-how-they-relate-non-disclosure-agreements-signed-epa>

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ATTACHMENT I

Understanding Global Warming Potentials

Greenhouse gases (GHGs) warm the Earth by absorbing energy and slowing the rate at which the energy escapes to space; they act like a blanket insulating the Earth. Different GHGs can have different effects on the Earth's warming. Two key ways in which these gases differ from each other are their ability to absorb energy (their "radiative efficiency"), and how long they stay in the atmosphere (also known as their "lifetime").

The Global Warming Potential (GWP) was developed to allow comparisons of the global warming impacts of different gases. Specifically, it is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of carbon dioxide (CO_2). The larger the GWP, the more that a given gas warms the Earth compared to CO_2 over that time period. The time period usually used for GWPs is 100 years. GWPs provide a common unit of measure, which allows analysts to add up emissions estimates of different gases (e.g., to compile a national GHG inventory), and allows policymakers to compare emissions reduction opportunities across sectors and gases.

- CO_2, by definition, has a GWP of 1 regardless of the time period used, because it is the gas being used as the reference. CO_2 remains in the climate system for a very long time: CO_2 emissions cause increases in atmospheric concentrations of CO_2 that will last thousands of years.
- Methane (CH_4) is estimated to have a GWP of 27-30 over 100 years. CH_4 emitted today lasts about a decade on average, which is much less time than CO_2. But CH_4 also absorbs much more energy than CO_2. The net effect of the shorter lifetime and higher energy absorption is reflected in the GWP. The CH_4 GWP also accounts for some indirect effects, such as the fact that CH_4 is a precursor to ozone, and ozone is itself a GHG.
- Nitrous Oxide (N_2O) has a GWP 273 times that of CO_2 for a 100-year timescale. N_2O emitted today remains in the atmosphere for more than 100 years, on average. (Learn why EPA's U.S. Inventory of Greenhouse Gas Emissions and Sinks uses a different value.)

- Chlorofluorocarbons (CFCs), hydrofluorocarbons (HFCs), hydrochlorofluorocarbons (HCFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) are sometimes called high-GWP gases because, for a given amount of mass, they trap substantially more heat than CO_2. (The GWPs for these gases can be in the thousands or tens of thousands.)

Frequently Asked Questions

Why do GWPs change over time?

> EPA and other organizations will update the GWP values they use occasionally. This change can be due to updated scientific estimates of the energy absorption or lifetime of the gases or to changing atmospheric concentrations of GHGs that result in a change in the energy absorption of 1 additional ton of a gas relative to another.

Why are GWPs presented as ranges?

> In the most recent report by the Intergovernmental Panel on Climate Change (IPCC), multiple methods of calculating GWPs were presented based on how to account for the influence of future warming on the carbon cycle. For this Web page, we are presenting the range of the lowest to the highest values listed by the IPCC.

What GWP estimates does EPA use for GHG emissions accounting, such as the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory) and the Greenhouse Gas Reporting Program?

The EPA considers the GWP estimates presented in the most recent IPCC scientific assessment to reflect the state of the science. In science communications, the EPA will refer to the most recent GWPs. The GWPs listed above are from the IPCC's Sixth Assessment Report, published in 2021.

The EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory) complies with international GHG reporting standards under the United Nations Framework Convention on Climate Change (UNFCCC). UNFCCC guidelines now require the use of the GWP values from the IPCC's Fifth Assessment Report (AR5), published in 2013. The Inventory also presents emissions by mass, so that CO_2 equivalents can be calculated using any GWPs, and emission totals using more recent IPCC values are presented in the annexes of the Inventory report for informational purposes.

The data collected by EPA's Greenhouse Gas Reporting Program is generally reported in mass units of greenhouse gas and is used in the Inventory. The Reporting Program, generally uses GWP values from the AR4 to determine whether facilities exceed reporting thresholds and to publish data in CO_2 equivalent values. The Reporting Program collects data about some industrial gases that do not have GWPs listed in the AR4; for these gases, the Reporting Program uses GWP values from other sources, such as the AR5.

EPA's CH_4 reduction voluntary programs also use CH_4 GWPs from the AR5 report for calculating CH_4 emissions reductions through energy recovery projects, for consistency with the national emissions presented in the Inventory.

Are there alternatives to the 100-year GWP for comparing GHGs?

The United States primarily uses the 100-year GWP as a measure of the relative impact of different GHGs. However, the scientific community has developed a number of other metrics that could be used for comparing one GHG to another. These metrics may differ based on timeframe, the climate endpoint measured, or the method of calculation.

For example, the 20-year GWP is sometimes used as an alternative to the 100-year GWP. Just like the 100-year GWP is based on the energy absorbed by a gas over 100 years, the 20-year GWP is based on the energy absorbed over 20 years. This 20-year GWP prioritizes gases with shorter lifetimes, because it does not consider impacts that happen more than 20 years after the emissions occur. Because all GWPs are calculated relative to CO_2, GWPs based on a shorter timeframe will be larger for gases with lifetimes shorter than that of CO_2, and smaller for gases with lifetimes longer than CO_2. For example, for CH_4, which has a short lifetime, the 100-year GWP of 27–30 is much less than the 20-year GWP of 81–83. For CF_4, with a lifetime of 50,000 years, the 100-year GWP of 7380 is larger than the 20-year GWP of 5300.

Another alternate metric is the Global Temperature Potential (GTP). While the GWP is a measure of the heat absorbed over a given time period due to emissions of a gas, the GTP is a measure of the temperature change at the end of that time period (again, relative to CO_2).The calculation of the GTP is more complicated than that for the GWP, as it requires modeling how much the climate system responds to increased concentrations of GHGs (the climate sensitivity) and how quickly the system responds (based in part on how the ocean absorbs heat).

GHG Emissions and Removals Home <https://epa.gov/ghgemissions>

Overview of Greenhouse Gases <https://epa.gov/ghgemissions/overview-greenhouse-gases>

Sources of GHG Emissions and Removals <https://epa.gov/ghgemissions/sources-greenhouse-gas-emissions>

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- Facility-Level Emissions <https://epa.gov/ghgreporting>
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ATTACHMENT J

[Atmospheric Chemistry]

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The greenhouse effect of tropospheric ozone

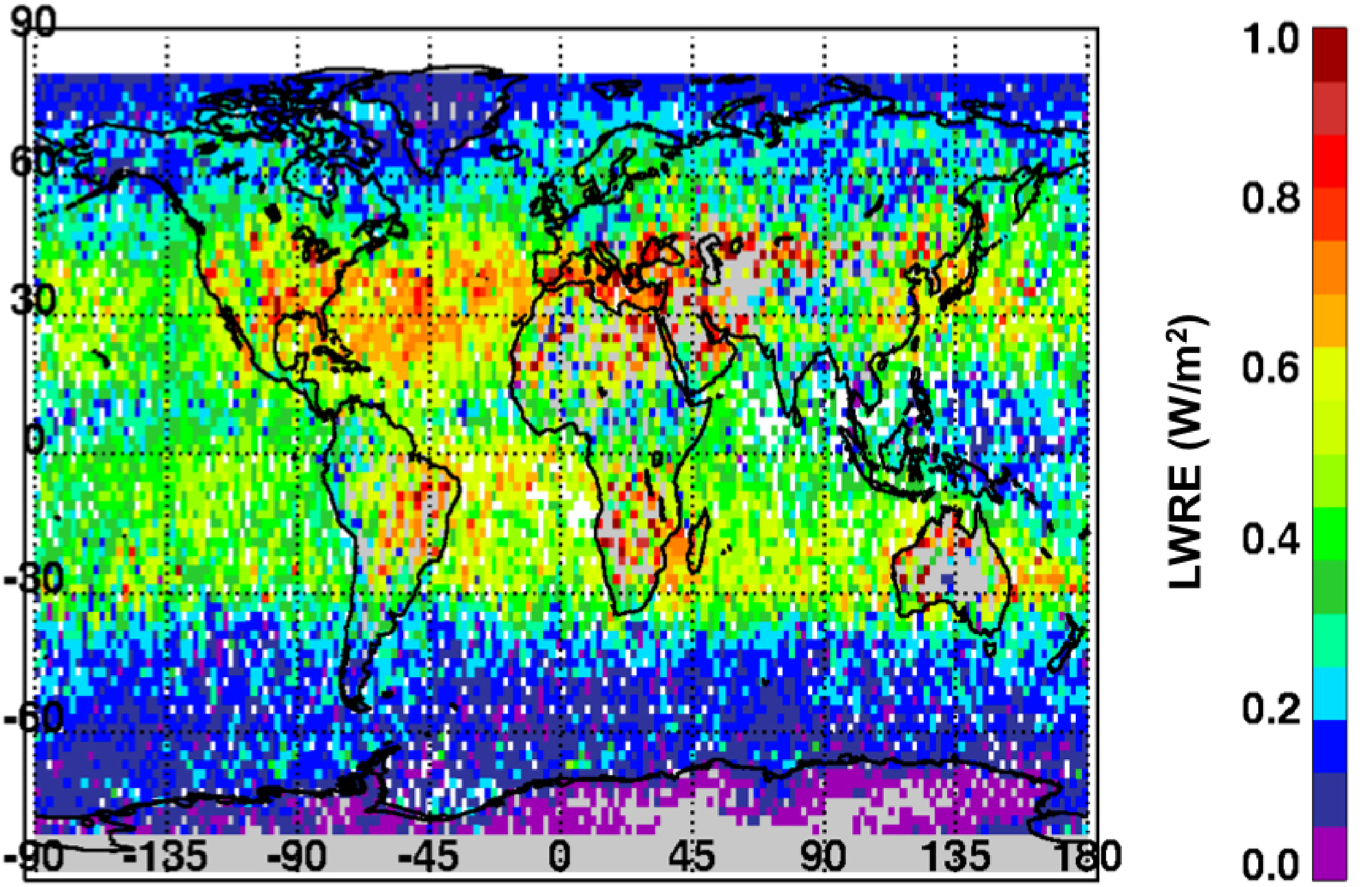
View by Year View by Sensor

Tropospheric ozone (O_3) is the third most important anthropogenic greenhouse gas after carbon dioxide (CO_2) and methane (CH_4). Ozone absorbs infrared radiation (heat) from the Earth's surface, reducing the amount of radiation that escapes to space.

This map shows the longwave radiative effect (LWRE) of infrared radiation absorbed by tropospheric ozone in Watts/meter^2 as estimated from Aura's Tropospheric Emission Spectrometer (TES) top-of- atmosphere (TOA) observations. Data are averaged for August 2006 and include both clear-sky and cloudy scenes. Areas with no data are indicated in white over oceans and grey over land.

Higher values of trapped infrared radiation are caused by lofted ozone pollution in the northern mid-latitudes and from sources of biomass burning in the southern hemisphere.

This map shows the longwave radiative effect of infrared radiation absorbed by tropospheric ozone as estimated from TES top-of-atmosphere observations.



April 2011

Contact

NASA Official : Bryan.N.Duncan
Web Curator : Jennifer Brill

ATTACHMENT K

Last Updated 2/9/2024 Total Number of Applications (2.0) or Pathways (3.0) 2243

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
T1N-1356	Tier 1	2.0	Fuel Producer: Adecoagro Brasil Participacoes (4192) Facility Name: Adecoagro Vale do Ivinhema Ltda. (70496): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS211	46.32	12/20/2016	None	Ethanol	Adecoagro Brasil Participacoes (4192)	Adecoagro Vale do Ivinhema Ltda (70496)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1078	Tier 1	2.0	Producer: BIOSEV S.A. (3869) Facility Name: Usina Cresciumal (71068). Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export.	Brazil	Molasses	Ethanol	None	None	ETHM221	46.34	12/20/2016	None	Ethanol	BIOSEV SA (3869)	Usina Cresciumal (71068)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export	None	Retired
T1R-1008	Tier 1	2.0	Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Tallow; Biodiesel Produced in Canada	Ontario, Canada	Tallow	Biodiesel	BIOD023	46.36	BDT200L	34.97	6/30/2016	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	North American Tallow; Biodiesel Produced in Canada	None	Retired
T1R-1009	Tier 1	2.0	Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Soybean; Biodiesel Produced in Canada	Ontario, Canada	Soybean	Biodiesel	BIOD024	88.59	BDS200L	56.03	6/30/2016	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	North American Soybean; Biodiesel Produced in Canada	None	Retired
T1R-1010	Tier 1	2.0	Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Canola; Biodiesel Produced in Canada	Ontario, Canada	Canola	Biodiesel	BIOD026	67.32	BDCA200L	57.39	6/30/2016	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	North American Canola; Biodiesel Produced in Canada	None	Retired
T1R-1012	Tier 1	2.0	Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Corn Oil from Wet DGS of a Corn Ethanol plant; Biodiesel Produced in Canada	Ontario, Canada	North American Corn Oil from Wet DGS	Biodiesel	BIOD030	35.23	BDC200L	32.80	6/30/2016	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	North American Corn Oil from Wet DGS of a Corn Ethanol plant; Biodiesel Produced in Canada	None	Retired
T1N-1069	Tier 1	2.0	Fuel Producer: Usina Sao Domingos Acucar e Alcool S.A. (4252) Facility Name: Usina Sao Domingos Acucar e Alcool SA (70533): Brazilian sugarcane juice-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	Brazil	Sugarcane	Ethanol	None	None	ETHS234	46.44	5/19/2017	None	Ethanol	Usina Sao Domingos Acucar e Alcool SA (4252)	Usina Sao Domingos Acucar e Alcool SA (70533)	Brazilian sugarcane juicetoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1141	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Santa Helena (70558): Brazilian sugarcane molasses-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	Brazil	Molasses	Ethanol	None	None	ETHM230	46.44	5/19/2017	None	Ethanol	Raízen Energia S/A (3805)	Santa Helena (70558)	Brazilian sugarcane molassestoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1460	Tier 1	2.0	Fuel Producer: Usina Delta SA (3852) Facility Name: Usina Delta S/A Unidade Volta Grande (70371). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS214	46.49	12/20/2016	None	Ethanol	Usina Delta SA (3852)	Usina Delta S/A Unidade Volta Grande (70371)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1073	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869) Facility Name: Usina Vale do Rosário (70440). Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM200	46.52	3/31/2016	None	Ethanol	BIOSEV SA (3869)	Usina Vale do Rosário (70440)	Brazilian sugarcane byproduct molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1392	Tier 1	2.0	Fuel Producer: Usina São Martinho S.A. (3867) Facility Name: Usina São Martinho S.A. (70373). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS219	46.61	12/20/2016	None	Ethanol	Usina São Martinho SA (3867)	Usina São Martinho SA (70373)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
T1R-1040	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Australian Rendered Tallow to Renewable Diesel. Renewable Diesel Produced in Singapore.	Singapore	Australian Tallow	Renewable Diesel	RNWD004	33.46	RDT200L	36.83	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Australian Rendered Tallow to Renewable Diesel; Renewable Diesel Produced in Singapore	None	Retired
T1R-1041	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). North American Rendered Tallow to Renewable Diesel Produced in Singapore.	Singapore	North American Tallow	Renewable Diesel	RNWD005	49.69	RDT201L	34.19	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	North American Rendered Tallow to Renewable Diesel Produced in Singapore	None	Retired
T1R-1042	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). South East Asia Fish Oil to Renewable Diesel Produced in Singapore.	Singapore	South East Asian Fish Oil	Renewable Diesel	RNWD006	30.48	RDF200L	33.08	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	South East Asia Fish Oil to Renewable Diesel Produced in Singapore	None	Retired
T1R-1043	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327): New Zealand Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore	Singapore	Tallow	Renewable Diesel	RNWD007	36.57	RDT203L	34.81	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	New Zealand Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore	None	Retired
T1R-1045	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Midwest Corn Oil to Renewable Diesel Produced in Singapore.	Singapore	Midwest Corn Oil from Wet DGS	Renewable Diesel	RNWD026	39.13	RDC200L	37.39	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Midwest Corn Oil to Renewable Diesel Produced in Singapore	None	Retired
T1R-1046	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Global Mixed Used Cooking Oil to Renewable Diesel Produced in Singapore.	Singapore	Global Used Cooking Oil	Renewable Diesel	RNWD027	30.72	RDU201L	25.61	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Global Mixed Used Cooking Oil to Renewable Diesel Produced in Singapore	None	Retired
T1N-1400	Tier 1	2.0	Fuel Producer: Branco Peres Acucar e Alcool SA (5985) Facility Name: Branco Peres Acucar e Alcool SA (71077): Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS210	46.71	12/20/2016	None	Ethanol	Branco Peres Acucar e Alcool SA (5985)	Branco Peres Acucar e Alcool SA (71077)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1R-1058	Tier 1	2.0	Fuel Producer: Consolidated Biofuels Ltd. (3919) Facility Name: Consolidated Biofuels Ltd. (80304): North American low-free fatty acids (Used Cooking Oil) where “cooking” is required; Biodiesel Produced in Canada	Canada	Used Cooking Oil	Biodiesel	BIOD029	21.34	BDU211L	20.38	6/30/2016	None	Biodiesel	Consolidated Biofuels Ltd (3919)	Consolidated Biofuels Ltd (80304)	North American lowfree fatty acids (Used Cooking Oil)where “cooking” is required; Biodiesel Produced in Canada	None	Retired
T1N-1391	Tier 1	2.0	Fuel Producer: Noble Brasil S.A. (4232) Facility Name: Noble Brasil S/A - NBSA (UNP) (70527). Ethanol production from Brazilian sugarcane juice feedstock, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS218	46.72	12/20/2016	None	Ethanol	Noble Brasil SA (4232)	Noble Brasil S/A NBSA (UNP)(70527)	Ethanol production from Brazilian sugarcane juice feedstock, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1393	Tier 1	2.0	Fuel Producer: Usina São Martinho S.A. (3867) Facility Name: Sao Martinho S/A (70479). Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS213	46.80	12/20/2016	None	Ethanol	Usina São Martinho SA (3867)	Sao Martinho S/A (70479)	Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting	None	Retired
T1N-1062	Tier 1	2.0	Fuel Producer: Noble Brasil S.A. (4232) Facility Name: NG Bioenergia S/A - Potirendaba (71036). Ethanol production from Brazilian sugarcane Juice feedstock, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS212	46.83	9/1/2016	None	Ethanol	Noble Brasil SA (4232)	NG Bioenergia S/A Potirendaba (71036)	Ethanol production from Brazilian sugarcane Juice feedstock, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1R-1093	Tier 1	2.0	Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): North American Used Cooking Oil (UCO); Biodiesel Produced in Arkansas	Arkansas	Used Cooking Oil	Biodiesel	BIOD027	23.81	BDU207L	24.36	6/30/2016	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	North American Used Cooking Oil (UCO)Biodiesel Produced in Arkansas	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
T2N-1161	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; re-gasified to L-CNG on-site; fuel dispensed on-site	California	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF246	9.97	6/22/2017	Pathway Details (PDF)	Bio-CNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; regasified to LCNG onsite; fuel dispensed onsite	None	Retired
T1R-1124	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: EIF KC Landfill Gas LLC (71155). Kansas City landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	Kansas	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF230L	45.31	CNGLF230LR	50.80	9/30/2016	Previous Tier 1 CNG030; 32.92	Bio-CNG	Clean Energy (5481)	EIF KC Landfill Gas LLC (71155)	Kansas City landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1101	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Westside Gas Producers LLC (71151). Michigan landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Michigan	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF200L	48.65	LNGLF200LR	54.14	9/30/2016	Previous Tier 1 LNG025; 30.12	Bio-LNG	Clean Energy (5481)	Westside Gas Producers LLC (71151)	Michigan landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T2N-1163	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; re-gasified to L-CNG in California; fuel delivered to Bay Area by Truck	California	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF247	10.32	6/22/2017	Pathway Details (PDF)	Bio-CNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; regasified to LCNG in California; fuel delivered to Bay Area by Truck	None	Retired
T1R-1104	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Pinnacle Gas Producers, LLC (71153). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Ohio	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF201L	44.78	LNGLF201LR	50.27	9/30/2016	Previous Tier 1 LNG020; 25.5	Bio-LNG	Clean Energy (5481)	Pinnacle Gas Producers, LLC (71153)	Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1R-1103	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Pinnacle Gas Producers, LLC (71153). Ohio landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA	Ohio	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF224L	50.52	CNGLF224LR	56.01	9/30/2016	Previous Tier 1 CNG023; 27.62	Bio-CNG	Clean Energy (5481)	Pinnacle Gas Producers, LLC (71153)	Ohio landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA	None	Retired
T1R-1106	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: CERF Shelby LLC (71163). CERF Shelby landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Tennessee	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF202L	54.57	LNGLF202LR	60.06	9/30/2016	Previous Tier 1 LNG028; 43.83	Bio-LNG	Clean Energy (5481)	CERF Shelby LLC (71163)	CERF Shelby landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T2N-1165	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; re-gasified to L-CNG in California; fuel delivered to Southern California by Truck	California	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF248	13.29	6/22/2017	Pathway Details (PDF)	Bio-CNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; regasified to LCNG in California; fuel delivered to Southern California by Truck	None	Retired
T1R-1111	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Dallas Clean Energy McCommas Bluff (71009). Texas landfill gas to biomethane, delivered by pipeline, liquefied in Boron CA; re-gasified and compressed to CNG	Texas	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF227L	48.41	CNGLF227LR	53.90	9/30/2016	Previous Tier 1 CNG017; 35.11	Bio-CNG	Clean Energy (5481)	Dallas Clean Energy McCommas Bluff (71009)	Texas landfill gas to biomethane, delivered by pipeline, liquefied in Boron CA; regasified and compressed to CNG	None	Retired
T1R-1109	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Seneca Energy II, LLC (71156).New York landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	New York	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF203L	53.61	LNGLF203LR	59.10	9/30/2016	Previous Tier 1 LNG023; 32.03	Bio-LNG	Clean Energy (5481)	Seneca Energy II, LLC (71156)	New York landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1N-1656	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154) Facility Name: East Texas Renewables (F2942): Greenwood Farms landfill gas (TX) to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California**(Provisional)**	Texas	Landfill Gas	Compressed Natural Gas	None	None	CNGLF252	38.62	6/27/2017	None	Bio-CNG	Shell Energy North America (6154)	East Texas Renewables (F2942)	Greenwood Farms landfill gas (TX) to pipelinequality biomethane; delivered via pipeline to CNG Stations in California(Provisional)	None	Retired
T1N-1383	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Needle Mountain LNG PLant (95116). Texas landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to California.	Texas	Landfill Gas - L-CNG	Compressed Natural Gas	None	None	CNGLF222	48.91	9/30/2016	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	Needle Mountain LNG PLant (95116)	Texas landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to California	None	Retired

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T1R-1112	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Dallas Clean Energy McCommas Bluff (71009). Texas landfill gas to biomethane; delivered by pipeline; liquefied in Boron, CA	Texas	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF204L	45.26	LNGLF204LR	50.75	9/30/2016	Previous Tier 1 LNG018; 32.99	Bio-LNG	Clean Energy (5481)	Dallas Clean Energy McCommas Bluff (71009)	Texas landfill gas to biomethane; delivered by pipeline; liquefied in Boron, CA	None	Retired
T1N-1541	Tier 1	2.0	Fuel Producer: Athens Services (A431) Facility Name: La Puente (V4048). River Birch landfill (Avondale, LA) gas to pipeline-quality biomethane; delivered via pipeline to La Puente California and compressed to CNG (Provisional)	Louisiana	Landfill Gas	Compressed Natural Gas	CNGLF239	39.46	CNGLF239R	43.44	2/6/2019	None	Bio-CNG	Athens Services (A431)	La Puente (V4048)	River Birch landfill (Avondale, LA) gas to pipelinequality biomethane; delivered via pipeline to La Puente California and compressed to CNG (Provisional)	None	Retired
T1R-1224	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Montana-Dakota Utilities Billings Regional Landfill (71193). Montana landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	Montana	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF231L	49.9	CNGLF231LR	55.39	9/30/2016	Previous Tier 1 CNG058; 51.88	Bio-CNG	Clean Energy (5481)	MontanaDakota Utilities Billings Regional Landfill (71193)	Montana landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1115	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: LES Renewable NG, LLC - SWACO Facility (71157). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Ohio	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF205L	61.68	LNGLF205LR	67.17	9/30/2016	Previous Tier 1 LNG022; 33.19	Bio-LNG	Clean Energy (5481)	LES Renewable NG, LLC SWACO Facility (71157)	Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1R-1116	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Cedar Hills Landfill, Bio-Energy, LLC (71109). Washington landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Washington	Landfill Gas - CNG	Compressed Natural Gas	CNG009_1	13.67	CNGLF210L	30.90	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Cedar Hills Landfill, BioEnergy, LLC (71109)	Washington landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1117	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Cedar Hills Landfill, Bio-Energy, LLC (71109). Washington landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	Washington	Landfill Gas - CNG	Compressed Natural Gas	CNGLF229L	37.29	CNGLF229LR	42.78	9/30/2016	Previous Tier 1 CNG011; 20.23	Bio-CNG	Clean Energy (5481)	Cedar Hills Landfill, BioEnergy, LLC (71109)	Washington landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1118	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Cedar Hills Landfill, Bio-Energy, LLC (71109). Washington landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Washington	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF206L	34.72	LNGLF206LR	40.21	9/30/2016	Previous Tier 1 LNG014; 18.14	Bio-LNG	Clean Energy (5481)	Cedar Hills Landfill, BioEnergy, LLC (71109)	Washington landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1R-1119	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Complexe Enviro Progressive Itee (71198). Quebec landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	Canada	Landfill Gas - CNG	Compressed Natural Gas	CNGLF211L	38.56	CNGLF211LR	44.05	9/30/2016	Previous Tier 1 CNG049; 13.96	Bio-CNG	Clean Energy (5481)	Complexe Enviro Progressive Itee (71198)	Quebec landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1120	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Complexe Enviro Progressive Itee (71198). Quebec landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Canada	Landfill Gas - CNG	Compressed Natural Gas	CNG048	7.36	CNGLF212L	31.96	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Complexe Enviro Progressive Itee (71198)	Quebec landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1121	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Complexe Enviro Progressive Itee (71198). Quebec landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Canada	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF207L	37.03	LNGLF207LR	41.44	9/30/2016	Previous Tier 1 LNG033; 11.84	Bio-LNG	Clean Energy (5481)	Complexe Enviro Progressive Itee (71198)	Quebec landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1N-1540	Tier 1	2.0	Fuel Producer: Athens Services (A431) Facility Name: Irwindale (V5355). River Birch landfill (Avondale, LA) gas to pipeline-quality biomethane; delivered via pipeline to Irwindale California and compressed to CNG (Provisional)	Louisiana	Landfill Gas	Compressed Natural Gas	CNGLF238	39.73	CNGLF238R	43.72	2/6/2019	None	Bio-CNG	Athens Services (A431)	Irwindale (V5355)	River Birch landfill (Avondale, LA) gas to pipelinequality biomethane; delivered via pipeline to Irwindale California and compressed to CNG (Provisional)	None	Retired
T1R-1100	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Westside Gas Producers LLC (71151). Michigan landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA	Michigan	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF223L	51.80	CNGLF223LR	57.29	9/30/2016	Previous Tier 1 CNG032; 32.24	Bio-CNG	Clean Energy (5481)	Westside Gas Producers LLC (71151)	Michigan landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA	None	Retired

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T1R-1125	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: EIF KC Landfill Gas LLC (71155). Kansas City landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Kansas	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF209L	48.53	LNGLF209LR	54.02	9/30/2016	Previous Tier 1 LNG024; 30.8	Bio-LNG	Clean Energy (5481)	EIF KC Landfill Gas LLC (71155)	Kansas City landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1N-1635	Tier 1	2.0	Fuel Producer: Nardini Agroindustrial Ltda (4229) Facility Name: Nardini Agroindustrial Ltda (70525): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS232	46.88	2/2/2017	None	Ethanol	Nardini Agroindustrial Ltda (4229)	Nardini Agroindustrial Ltda (70525)	Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1480	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina São José da Estiva S.A. - Açúcar e Álcool (70431); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS239	44.53	8/17/2017	None	Ethanol	Copersucar (3702)	Usina São José da Estiva SA Açúcar e Álcool (70431)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1481	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina São José da Estiva S.A. - Açúcar e Álcool (70431); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting and electricity credit.	Brazil	Molasses	Ethanol	ETHM208L	46.14	ETHM237	45.06	8/17/2017	None	Ethanol	Copersucar (3702)	Usina São José da Estiva SA Açúcar e Álcool (70431)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting and electricity credit	None	Retired
T1N-1139	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Barra (70210) - Ethanol production from Brazilian sugarcane by-product molasses feedstock, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM214	47.05	6/6/2016	None	Ethanol	Raízen Energia S/A (3805)	Barra (70210)	Ethanol production from Brazilian sugarcane byproduct molasses feedstock, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1R-1178	Tier 1	2.0	Fuel Producer: California Ethanol & Power [CE+P] IV1 (C088) Facility Name: CE+P IV1 (90-08). California Sugarcane to ethanol, mechanized harvesting, Electricity credit, CNG co-product	California	Sugarcane	Ethanol	ETHS026	54.47	ETHS202L	22.44	3/31/2016	None	Ethanol	California Ethanol & Power [CE+P] IV1 (C088)	CE+P IV1 (90-08)	California Sugarcane to ethanol, mechanized harvesting, Electricity credit, CNG coproduct	None	Retired
T1N-1394	Tier 1	2.0	Fuel Producer: Usina Alto Alegre S/A - Açúcar e Álcool (5565) Facility Name: Unidade Junqueira (71018). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS215	47.23	12/20/2016	None	Ethanol	Usina Alto Alegre S/A Açúcar e Álcool (5565)	Unidade Junqueira (71018)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1142	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Benálcool (70549): Brazilian sugarcane molasses-based ethanol pathway, with credit for mechanized harvesting	Brazil	Molasses	Ethanol	None	None	ETHM234	47.63	5/19/2017	None	Ethanol	Raízen Energia S/A (3805)	Benálcool (70549)	Brazilian sugarcane molassesbased ethanol pathway, with credit for mechanized harvesting	None	Retired
T1N-1065	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869) Facility Name: Unidade MB (70568): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS208	47.68	6/6/2016	None	Ethanol	BIOSEV SA (3869)	Unidade MB (70568)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1189	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) Facility Name: USINA FRUTAL AÇÚCAR E ÁLCOOL (70579): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS206	47.73	6/6/2016	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	USINA FRUTAL AÇÚCAR E ÁLCOOL (70579)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1145	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Junqueira (70553): Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM217	47.82	7/8/2016	None	Ethanol	Raízen Energia S/A (3805)	Junqueira (70553)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1061	Tier 1	2.0	Fuel Producer: Noble Brasil S.A. (4232) Facility Name: Unidade Cantaduva (71061): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS225	47.86	12/20/2016	None	Ethanol	Noble Brasil SA (4232)	Unidade Cantaduva (71061)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired

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T1N-1371	Tier 1	2.0	Fuel Producer: Guarani SA (3890) Facility Name: Andrade Açúcar e Álcool SA (70451): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS226	47.89	12/20/2016	None	Ethanol	Guarani SA (3890)	Andrade Açúcar e Álcool SA (70451)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1395	Tier 1	2.0	Fuel Producer: Usina São Martinho S.A. (3867) Facility Name: Santa Cruz S/A Açúcar e Álcool (70484). Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS223	48.22	12/20/2016	None	Ethanol	Usina São Martinho SA (3867)	Santa Cruz S/A Açúcar e Álcool (70484)	Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting	None	Retired
T1N-1463	Tier 1	2.0	Fuel Producer: Tonon Bioenergia SA (4214) Facility Name: Santa Candida (70500). Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS224	48.35	12/20/2016	None	Ethanol	Tonon Bioenergia SA (4214)	Santa Candida (70500)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1377	Tier 1	2.0	Fuel Producer: Odebrecht Agroindustrial SA (5580) Facility Name: Usina Conquista do Pontal S/A (70494): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS231	48.39	12/20/2016	None	Ethanol	Odebrecht Agroindustrial SA (5580)	Usina Conquista do Pontal S/A (70494)	Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1077	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869) Facility Name: Unidade MB (70568): Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM228	48.63	2/15/2017	None	Ethanol	BIOSEV SA (3869)	Unidade MB (70568)	Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1759	Tier 1	2.0	Fuel Producer: Questar Fueling Company (Q500) Facility Name: River Birch, LLC (Sharing) (K200W): River Birch landfill gas to pipeline-quality biomethane; delivered via pipeline to Questar CNG stations in Buttonwillow, California **(Provisional)**	Louisiana	Landfill Gas	Compressed Natural Gas	CNGLF245	40.62	CNGLF245R	43.98	2/6/2019	None	Bio-CNG	Questar Fueling Company (Q500)	River Birch, LLC (Sharing)(K200W)	River Birch landfill gas to pipelinequality biomethane; delivered via pipeline to Questar CNG stations in Buttonwillow, California (Provisional)	None	Retired
T1R-1108	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Seneca Energy II, LLC (71156).New York landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	New York	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF226L	56.21	CNGLF226LR	61.70	9/30/2016	Previous Tier 1 CNG028; 34.15	Bio-CNG	Clean Energy (5481)	Seneca Energy II, LLC (71156)	New York landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1225	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Montana-Dakota Utilities Billings Regional Landfill (71193). Montana landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Montana	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF210L	47.3	LNGLF210LR	52.79	9/30/2016	Previous Tier 1 LNG036; 49.76	Bio-LNG	Clean Energy (5481)	MontanaDakota Utilities Billings Regional Landfill (71193)	Montana landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1N-1482	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Santa Adélia S.A. (70404); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS238	46.05	8/17/2017	None	Ethanol	Copersucar (3702)	Usina Santa Adélia SA (70404)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1483	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Santa Adélia S.A. (70404); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM210L	45.85	ETHM236	47.27	8/17/2017	None	Ethanol	Copersucar (3702)	Usina Santa Adélia SA (70404)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1459	Tier 1	2.0	Fuel Producer: Usina Delta SA (3852) Facility Name: Usina Delta S/A Unidade Delta (70367). Ethanol production from Brazilian sugarcane by-product molasses feedstock, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS220	49.69	12/20/2016	None	Ethanol	Usina Delta SA (3852)	Usina Delta S/A Unidade Delta (70367)	Ethanol production from Brazilian sugarcane byproduct molasses feedstock, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1616	Tier 1	2.0	Fuel Producer: Usina de Açúcar Santa Terezinha Ltda. (3921) Facility Name: Usina de Açúcar Santa Terezinha - Unidade Tapejara (70464): Brazilian sugarcane molasses-based ethanol, with credit for mechanized harvesting, and export of surplus cogenerated electricity.	Brazil	Molasses	Ethanol	None	None	ETHM224	52.78	12/20/2016	None	Ethanol	Usina de Açúcar Santa Terezinha Ltda (3921)	Usina de Açúcar Santa Terezinha Unidade Tapejara (70464)	Brazilian sugarcane molassesbased ethanol, with credit for mechanized harvesting, and export of surplus cogenerated electricity	None	Retired

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T1N-1462	Tier 1	2.0	Fuel Producer: Tonon Bioenergia SA (4214) Facility Name: Vista Alegre (70499): Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS230	53.40	12/20/2016	None	Ethanol	Tonon Bioenergia SA (4214)	Vista Alegre (70499)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1R-1516	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). California Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC123	60.74	ETHC269L	53.49	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	California Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	None	Retired
T1R-1258	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Ehrenberg LNG (C0660). North American Natural Gas pipelined to Ehrenberg (AZ) for liquefaction, then transported by truck to CA	Arizona	North American NG - LNG	Liquefied Natural Gas	LNG010	76.25	LNGF200L	86.22	9/30/2016	None	Fossil LNG	Clean Energy (5481)	Ehrenberg LNG (C0660)	North American Natural Gas pipelined to Ehrenberg (AZ)for liquefaction, then transported by truck to CA	None	Retired
T1N-1614	Tier 1	2.0	Fuel Producer: Usina de Açúcar Santa Terezinha Ltda. (3921) Facility Name: Usina de Açúcar Santa Terezinha - Unidade Terra Rica (71032): Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity exports.	Brazil	Sugarcane	Ethanol	None	None	ETHS228	53.69	12/20/2016	None	Ethanol	Usina de Açúcar Santa Terezinha Ltda (3921)	Usina de Açúcar Santa Terezinha Unidade Terra Rica (71032)	Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity exports	None	Retired
T1R-1264	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Cocal - Comércio Indústria Canaã Açucar e Alcool Ltda. (70419). Brazilian sugarcane by-product molasses-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	Brazil	Molasses	Ethanol	ETHM013	67.64	ETHM209L	46.04	3/31/2016	None	Ethanol	Copersucar (3702)	Cocal Comércio Indústria Canaã Açucar e Alcool Ltda (70419)	Brazilian sugarcane byproduct molassesbased ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	None	Retired
T1N-1607	Tier 1	2.0	Fuel Producer: Usina de Açúcar Santa Terezinha Ltda. (3921) Facility Name: Usina de Açúcar Santa Terezinha - Unidade de Ivaté (71030): Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM222	54.37	12/20/2016	None	Ethanol	Usina de Açúcar Santa Terezinha Ltda (3921)	Usina de Açúcar Santa Terezinha Unidade de Ivaté (71030)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1R-1280	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) Facility Name: Blue Skies Energy (71132). Michigan Landfill gas to pipeline-quality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA	Michigan	Landfill Gas - LNG	Liquefied Natural Gas	LNG017	24.90	LNGLF211L	55.38	9/30/2016	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Blue Skies Energy (71132)	Michigan Landfill gas to pipelinequality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA	None	Retired
T1R-1329	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: McCarty Road LFG Recovery Facility (71135). Texas landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in AZ; transported by trucks to California; re gasified and compressed to L CNG in CA	Texas	Landfill Gas - L-CNG	Compressed Natural Gas	CNG034	27.85	CNGLF234L	57.58	9/30/2016	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	McCarty Road LFG Recovery Facility (71135)	Texas landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in AZ; transported by trucks to California; re gasified and compressed to L CNG in CA	None	Retired
T1R-1282	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) Facility Name: Blue Skies Energy (71132). Michigan Landfill gas to pipeline-quality biomethane, delivered to California via pipeline for liquefaction	Michigan	Landfill Gas - LNG	Liquefied Natural Gas	LNG019	21.68	LNGLF212L	44.25	9/30/2016	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Blue Skies Energy (71132)	Michigan Landfill gas to pipelinequality biomethane, delivered to California via pipeline for liquefaction	None	Retired
T1R-1105	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: CERF Shelby LLC (71163). CERF Shelby landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA	Tennessee	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF225L	57.72	CNGLF225LR	63.21	9/30/2016	Previous Tier 1 CNG035; 45.95	Bio-CNG	Clean Energy (5481)	CERF Shelby LLC (71163)	CERF Shelby landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA	None	Retired
T2N-1099	Tier 2	2.0	Fuel Producer: AltEn, LLC (6269) Facility Name: AltEn (70131): Midwest spent corn and sorghum seeds to produce ethanol, using grid electricity, natural gas, and biogas. (Provisional)	Nebraska	Spent Corn and Sorghum Seeds	Ethanol	None	None	ETHCSS200	59.29	12/26/2016	Application Package	Ethanol	AltEn, LLC (6269)	AltEn (70131)	Midwest spent corn and sorghum seeds to produce ethanol, using grid electricity, natural gas, and biogas(Provisional)	None	Retired
T1R-1305	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Pioneiros Bioenergia S.A. (70430). Brazilian sugarcane by-product molasses-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	Brazil	Molasses	Ethanol	ETHM017	58.48	ETHM211L	45.01	3/31/2016	None	Ethanol	Copersucar (3702)	Pioneiros Bioenergia SA (70430)	Brazilian sugarcane byproduct molassesbased ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	None	Retired

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T1R-1318	Tier 1	2.0	Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: RiverBirch LLC (K2000). Louisiana landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA (Provisional)	Louisiana	Landfill Gas - CNG	Compressed Natural Gas	CNGLF215L	37.23	CNGLF215LR	43.06	2/6/2019	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	RiverBirch LLC (K2000)	Louisiana landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA (Provisional)	None	Retired
T1R-1319	Tier 1	2.0	Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: McCarty Road Landfill (L9416). Texas landfill gas to pipeline-quality biomethane, delivered via pipeline, compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	CNG042	19.82	CNGLF216L	38.02	9/30/2016	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	McCarty Road Landfill (L9416)	Texas landfill gas to pipelinequality biomethane, delivered via pipeline, compressed to CNG in CA	None	Retired
T1R-1110	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Dallas Clean Energy McCommas Bluff (71009). Texas landfill gas to biomethane; delivered by pipeline; compressed in CA	Texas	Landfill Gas	Compressed Natural Gas	CNG016	28.42	CNGLF208L	41.35	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Dallas Clean Energy McCommas Bluff (71009)	Texas landfill gas to biomethane; delivered by pipeline; compressed in CA	None	Retired
T1R-1322	Tier 1	2.0	Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: BFI Usine de Triage Lachenaie Ltd (C3779). Quebec, Canada landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Canada	Landfill Gas - CNG	Compressed Natural Gas	CNG045	7.04	CNGLF218L	32.27	9/30/2016	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	BFI Usine de Triage Lachenaie Ltd (C3779)	Quebec, Canada landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1324	Tier 1	2.0	Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: Cedar Hills Landfill, LLC (71136). Washington landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	California	Landfill Gas - CNG	Compressed Natural Gas	CNG010	13.36	CNGLF219L	30.50	9/30/2016	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	Cedar Hills Landfill, LLC (71136)	Washington landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1326	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Needle Mountain LNG PLant (95116). North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck to CA	Arizona	North American NG - LNG	Liquefied Natural Gas	LNG011_1	76.48	LNGF201L	87.73	9/30/2016	None	Fossil LNG	Applied Natural Gas Fuels, Inc. (6174)	Needle Mountain LNG PLant (95116)	North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck to CA	None	Retired
T1R-1327	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Needle Mountain LNG PLant (95116). North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck; re-gasified and compressed to L-CNG in CA	Arizona	North American NG - L-CNG	Compressed Natural Gas	CNG015	76.87	CNGF202L	90.33	9/30/2016	None	Fossil CNG	Applied Natural Gas Fuels, Inc. (6174)	Needle Mountain LNG PLant (95116)	North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck; regasified and compressed to LCNG in CA	None	Retired
T1R-1328	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: McCarty Road LFG Recovery Facility (71135). Texas landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; transported by trucks to CA	Texas	Landfill Gas - LNG	Liquefied Natural Gas	LNG027	27.45	LNGLF213L	55.05	9/30/2016	None	Bio-LNG	Applied Natural Gas Fuels, Inc. (6174)	McCarty Road LFG Recovery Facility (71135)	Texas landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; transported by trucks to CA	None	Retired
T1R-1333	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fresh Kills Landfill (71203). New York landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in Arizona; transported by trucks to California; re-gasified and compressed to L-CNG in CA	New York	Landfill Gas - L-CNG	Compressed Natural Gas	CNG046	32.24	CNGLF236L	59.34	9/30/2016	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	Fresh Kills Landfill (71203)	New York landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in Arizona; transported by trucks to California; regasified and compressed to LCNG in CA	None	Retired
T1R-1330	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fort Bend Landfill Recovery (71139). North American Landfill Gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA	Arizona	Landfill Gas - LNG	Liquefied Natural Gas	LNG012_1	40.91	LNGLF214L	76.61	9/30/2016	None	Bio-LNG	Applied Natural Gas Fuels, Inc. (6174)	Fort Bend Landfill Recovery (71139)	North American Landfill Gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA	None	Retired
T1R-1281	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) Facility Name: Blue Skies Energy (71132). Michigan Landfill gas to pipeline-quality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA; re-gasified and compressed to L-CNG	Michigan	Landfill Gas - L-CNG	Compressed Natural Gas	CNG014	25.30	CNGLF232L	59.36	9/30/2016	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Blue Skies Energy (71132)	Michigan Landfill gas to pipelinequality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA; regasified and compressed to LCNG	None	Retired
T1R-1332	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fresh Kills Landfill (71203). New York landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to CA	New York	Landfill Gas - LNG	Liquefied Natural Gas	LNG032	31.84	LNGLF215L	56.74	9/30/2016	None	Bio-LNG	Applied Natural Gas Fuels, Inc. (6174)	Fresh Kills Landfill (71203)	New York landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to CA	None	Retired

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T1R-1114	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: LES Renewable NG, LLC - SWACO Facility (71157). Ohio landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	Ohio	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF228L	64.28	CNGLF228LR	71.31	9/30/2016	Previous Tier 1 CNG026; 35.31	Bio-CNG	Clean Energy (5481)	LES Renewable NG, LLC SWACO Facility (71157)	Ohio landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1359	Tier 1	2.0	Fuel Producer: SunLine Transit Agency (S317) Facility Name: Sunline Transit (H2505). Quebec, Canada landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Canada	Landfill Gas - CNG	Compressed Natural Gas	CNG050	6.28	CNGLF220L	31.17	9/30/2016	None	Bio-CNG	SunLine Transit Agency (S317)	Sunline Transit (H2505)	Quebec, Canada landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1364	Tier 1	2.0	Fuel Producer: Universal Biofuels Private, Ltd (6213) Facility Name: Universal Biofuels Private, Ltd (82702): Indian sourced high energy rendered tallow; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks); grid and backup diesel generator electricity	Biodiesel	Tallow	Biodiesel	BIOD039	57.84	BDT207L	37.97	12/20/2016	None	Biodiesel	Universal Biofuels Private, Ltd (6213)	Universal Biofuels Private, Ltd (82702)	Indian sourced high energy rendered tallow; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks)grid and backup diesel generator electricity	None	Retired
T1R-1365	Tier 1	2.0	Fuel Producer: Universal Biofuels Private, Ltd (6213) Facility Name: Universal Biofuels Private, Ltd (82702): Used Cooking Oil sourced world-wide where “cooking” is required; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks); grid and backup diesel generator electricity	Biodiesel	UCO	Biodiesel	BIOD040	24.45	BDU212L	26.07	12/20/2016	None	Biodiesel	Universal Biofuels Private, Ltd (6213)	Universal Biofuels Private, Ltd (82702)	Used Cooking Oil sourced worldwide where “cooking” is required; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks)grid and backup diesel generator electricity	None	Retired
T1R-1396	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Texas landfill gas to pipeline-quality biomethane, delivered via pipeline, compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	CNG043	24.49	CNGLF221L	38.02	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Texas landfill gas to pipelinequality biomethane, delivered via pipeline, compressed to CNG in CA	None	Retired
T2R-1044	Tier 2	2.0	Fuel Producer: Trestle Energy LLC (T315) Facility Name: Golden Grain Energy, LLC (shared facility) (7069S). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG	Iowa	Corn	Ethanol	ETHC116	70.65	ETHC273L	59.60	3/31/2016	None	Ethanol	Trestle Energy LLC (T315)	Golden Grain Energy, LLC(shared facility)(7069S)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T2R-1047	Tier 2	2.0	Fuel Producer: Poet DSM Project Liberty LLC (6232) Facility Name: Poet DSM Project Liberty LLC (71164). Corn Stover residue-based cellulosic ethanol with surplus steam and biogas export co-product credits	Iowa	Corn Stover	Ethanol	ETHB004	21.58	ETHCS201L	21.58	3/31/2016	None	Ethanol - Cellulosic	Poet DSM Project Liberty LLC (6232)	Poet DSM Project Liberty LLC (71164)	Corn Stover residuebased cellulosic ethanol with surplus steam and biogas export coproduct credits	None	Retired
T2R-1015	Tier 2	2.0	Fuel Producer: Abengoa Bioenergia Agroindustria Ltda (3924) Facility Name: Abengoa - São Luiz (70473). Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	Brazil	Molasses	Ethanol	ETHM010	54.92	ETHM213L	42.06	3/31/2016	None	Ethanol	Abengoa Bioenergia Agroindustria Ltda (3924)	Abengoa São Luiz (70473)	Brazilian sugarcane byproduct molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T2R-1033	Tier 2	2.0	Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). Landfill gas to hydrogen production via cracking of methane and transport by tube trailer	California	Landfill Gas	Hydrogen	HYGN010	-32.36	HYGLF200L	-5.28	9/30/2016	None	Hydrogen	LytEn (L700)	LytEn (K4933)	Landfill gas to hydrogen production via cracking of methane and transport by tube trailer	None	Retired
T2R-1034	Tier 2	2.0	Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). North American fossil NG and landfill gas to on-site hydrogen production via cracking of methane	California	Fossil NG & Landfill Gas	Hydrogen	HYGN007	15.29	HYGFLF200L	40.36	9/30/2016	None	Hydrogen	LytEn (L700)	LytEn (K4933)	North American fossil NG and landfill gas to onsite hydrogen production via cracking of methane	None	Retired
T2R-1035	Tier 2	2.0	Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). Landfill gas to on-site hydrogen production via cracking of methane	California	Landfill Gas	Hydrogen	HYGN008	-46.91	HYGLF201L	-12.65	9/30/2016	None	Hydrogen	LytEn (L700)	LytEn (K4933)	Landfill gas to onsite hydrogen production via cracking of methane	None	Retired
T2R-1036	Tier 2	2.0	Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). North American fossil NG and landfill gas to hydrogen production via cracking of methane and transport by tube trailer	California	Fossil NG & Landfill Gas	Hydrogen	HYGN009	29.84	HYGFLF201L	47.73	9/30/2016	None	Hydrogen	LytEn (L700)	LytEn (K4933)	North American fossil NG and landfill gas to hydrogen production via cracking of methane and transport by tube trailer	None	Retired

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T2R-1038	Tier 2	2.0	Fuel Producer: California Ethanol & Power [CE+P] IV1 (C088) Facility Name: CE+P IV1 (90-08). Sweet Sorghum to ethanol, mechanized harvesting, Electricity credit, CNG co-product	California	Sorghum	Ethanol	ETHG022	39.00	ETHG213L	30.63	3/31/2016	None	Ethanol	California Ethanol & Power [CE+P] IV1 (C088)	CE+P IV1 (90-08)	Sweet Sorghum to ethanol, mechanized harvesting, Electricity credit, CNG coproduct	None	Retired
T2R-1039	Tier 2	2.0	Fuel Producer: Biocom Energia (6099) Facility Name: Biocom Energia (81607): Spain sourced low-free fatty acids (Used Cooking Oil) where "cooking" is required; Biodiesel Produced in Spain	Spain	Used Cooking Oil (Spain)	Biodiesel	BIOD036	20.74	BDU208L	22.17	6/30/2016	None	Biodiesel	Biocom Energia (6099)	Biocom Energia (81607)	Spain sourced lowfree fatty acids (Used Cooking Oil)where "cooking" is required; Biodiesel Produced in Spain	None	Retired
T2R-1040	Tier 2	2.0	Fuel Producer: Biocom Energia (6099) Facility Name: Biocom Energia (81607): European sourced low-free fatty acids (Used Cooking Oil) where "cooking" is required; Biodiesel Produced in Spain	Spain	Used Cooking Oil (Europe)	Biodiesel	BIOD037	21.17	BDU209L	21.77	6/30/2016	None	Biodiesel	Biocom Energia (6099)	Biocom Energia (81607)	European sourced lowfree fatty acids (Used Cooking Oil)where "cooking" is required; Biodiesel Produced in Spain	None	Retired
T2R-1041	Tier 2	2.0	Fuel Producer: Biocom Energia (6099) Facility Name: Biocom Energia (81607): Low-free fatty acids (Used Cooking Oil) sourced from Rest of the World where "cooking" is required; Biodiesel Produced in Spain	Spain	Used Cooking Oil (Global)	Biodiesel	BIOD038	26.03	BDU210L	26.83	6/30/2016	None	Biodiesel	Biocom Energia (6099)	Biocom Energia (81607)	Lowfree fatty acids (Used Cooking Oil)sourced from Rest of the World where "cooking" is required; Biodiesel Produced in Spain	None	Retired
T2R-1043	Tier 2	2.0	Fuel Producer: Fulcrum Sierra BioFuels, LLC (F197) Facility Name: Fulcrum Sierra BioFuels, LLC (P3600). Fisher-Tropsch (FT) Diesel via Gasification and FT Synthesis of Municipal Solid Waste (MSW)	Nevada	Municipal Solid Waste (MSW)	Fischer-Tropsch Diesel (FTD)	FTD001	37.47	FTDMW200L	14.78	9/30/2016	None	FT Diesel	Fulcrum Sierra BioFuels, LLC (F197)	Fulcrum Sierra BioFuels, LLC (P3600)	FisherTropsch (FT)Diesel via Gasification and FT Synthesis of Municipal Solid Waste (MSW)	None	Retired
T2R-1077	Tier 2	2.0	Fuel Producer: Abengoa Bioenergy Biomass of Kansas (6254) Facility Name: Abengoa Bioenergy Biomass of Kansas, LLC (71183). Wheat Straw residue-based cellulosic ethanol with electricity co-product credit	Kansas	Wheat Straw	Ethanol	ETHB003	23.36	ETHWS200L	24.20	3/31/2016	None	Ethanol - Cellulosic	Abengoa Bioenergy Biomass of Kansas (6254)	Abengoa Bioenergy Biomass of Kansas, LLC (71183)	Wheat Straw residuebased cellulosic ethanol with electricity coproduct credit	None	Retired
T2R-1011	Tier 2	2.0	Fuel Producer: Abengoa Bioenergy Biomass of Kansas (6254) Facility Name: Abengoa Bioenergy Biomass of Kansas, LLC (71183). Corn Stover residue-based cellulosic ethanol with electricity co-product credit	Brazil	Corn Stover	Ethanol	ETHB002	29.52	ETHCS200L	32.82	3/31/2016	None	Ethanol - Cellulosic	Abengoa Bioenergy Biomass of Kansas (6254)	Abengoa Bioenergy Biomass of Kansas, LLC (71183)	Corn Stover residuebased cellulosic ethanol with electricity coproduct credit	None	Retired
T2R-1068	Tier 2	2.0	Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewable gasoline from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by rail to CA	Canada	Pyrolysis Oil from Forest Residue	Renewable Gasoline	RNWG001	20.12	RGFRP200L	21.17	9/30/2016	None	Renewable Gasoline	Ensyn Technologies Inc (6179)	Ensyn Ontario Facility (82219)	Renewable gasoline from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by rail to CA	None	Retired
T2R-1069	Tier 2	2.0	Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewable gasoline from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by truck to CA	Canada	Pyrolysis Oil from Forest Residue	Renewable Gasoline	RNWG002	25.03	RGFRP201L	26.08	9/30/2016	None	Renewable Gasoline	Ensyn Technologies Inc (6179)	Ensyn Ontario Facility (82219)	Renewable gasoline from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by truck to CA	None	Retired
T2R-1070	Tier 2	2.0	Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewable diesel from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by rail to CA	Canada	Pyrolysis Oil from Forest Residue	Biodiesel	RNWD028	21.67	RDFRP200L	22.42	9/30/2016	None	Renewable Diesel	Ensyn Technologies Inc (6179)	Ensyn Ontario Facility (82219)	Renewable diesel from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by rail to CA	None	Retired
T2R-1071	Tier 2	2.0	Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewbale diesel from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by truck to CA	Canada	Pyrolysis Oil from Forest Residue	Renewable Diesel	RNWD029	25.58	RDFRP201L	27.33	9/30/2016	None	Renewable Diesel	Ensyn Technologies Inc (6179)	Ensyn Ontario Facility (82219)	Renewbale diesel from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by truck to CA	None	Retired
T2R-1050	Tier 2	2.0	Fuel Producer: GranBio Investimentos S.A (6260) Facility Name: Bioflex AgroIndustrial SA (71192). Brazilian sugarcane straw residue-based cellulosic ethanol, with credit for electricity cogeneration and surplus export	Brazil	Sugarcane Straw	Ethanol	ETHB001	6.98	ETHSS200L	33.82	3/31/2016	None	Ethanol - Cellulosic	GranBio Investimentos S.A (6260)	Bioflex AgroIndustrial SA (71192)	Brazilian sugarcane straw residuebased cellulosic ethanol, with credit for electricity cogeneration and surplus export	None	Retired

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T2R-1080	Tier 2	2.0	Fuel Producer: Alameda-Contra Costa Transit District (A149) Facility Name: Division 2 (F1600). Hydrogen production via electrolysis using solar electricity	California	Solar Elericity via Electrolysis	Hydrogen	HYGN006	0.00	HYGE200L	0.00	9/30/2016	None	Hydrogen	AlamedaContra Costa Transit District (A149)	Division 2 (F1600)	Hydrogen production via electrolysis using solar electricity	None	Retired
T1R-1193	Tier 1	2.0	Fuel Producer: Green Plains Hereford LLC (6327) Facility Name: Green Plains Hereford LLC (70534). Midwest, Corn Ethanol, Dry Mill, NG	Texas	Corn	Ethanol	ETHC072	78.90	ETHC248L	67.60	3/31/2016	None	Ethanol	Green Plains Hereford LLC (6327)	Green Plains Hereford LLC (70534)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T2R-1117	Tier 2	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Asian Used Cooking Oil to Renewable Diesel Produced in Singapore.	Singapore	Asian Used Cooking Oil	Renewable Diesel	RNWD009	16.21	RDU200L	16.89	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Asian Used Cooking Oil to Renewable Diesel Produced in Singapore	None	Retired
None	Lookup Table	3.0	California grid electricity used as a transportation fuel in California	California	Grid Electricity (039)	Electricity (ELC)	None	None	ELC000L00072019	81.49	NA	None	Electricity	NA	NA	California grid electricity used as a transportation fuel in California	None	Retired
T1N-1063	Tier 1	2.0	Fuel Producer: Noble Brasil S.A. (4232) Facility Name: Noble Brasil S/A - NBSA (UM) (70528): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS227	45.22	12/20/2016	None	Ethanol	Noble Brasil SA (4232)	Noble Brasil S/A NBSA (UM)(70528)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1079	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869) Facility Name: Usina Santa Elisa (71070). Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM201	45.50	3/31/2016	None	Ethanol	BIOSEV SA (3869)	Usina Santa Elisa (71070)	Brazilian sugarcane byproduct molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1085	Tier 1	2.0	Fuel Producer: USJ Açúcar e Álcool SA (3878) Facility Name: USJ Açúcar e Álcool S/A (70441): Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS209	46.26	7/8/2016	None	Ethanol	USJ Açúcar e Álcool SA (3878)	USJ Açúcar e Álcool S/A (70441)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1096	Tier 1	2.0	Fuel Producer: Glencane Bioenergia SA (4429) Facility Name: Glencane Bioenergia SA (71008). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS222	46.30	12/20/2016	None	Ethanol	Glencane Bioenergia SA (4429)	Glencane Bioenergia SA (71008)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1R-1214	Tier 1	2.0	Fuel Producer: Green Plains Central City (3368) Facility Name: Green Plains Central City LLC (70141). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC023	82.17	ETHC252L	70.71	3/31/2016	None	Ethanol	Green Plains Central City (3368)	Green Plains Central City LLC (70141)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1070	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	Texas	Corn	Ethanol	None	None	ETHC200	70.79	3/31/2016	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	None	Retired
T1N-1134	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Serra (70559): Brazilian sugarcane molasses-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM226	42.84	2/2/2017	None	Ethanol	Raízen Energia S/A (3805)	Serra (70559)	Brazilian sugarcane molassestoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1135	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Ipaussu (71058): Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export.	Brazil	Molasses	Ethanol	None	None	ETHM220	44.39	12/20/2016	None	Ethanol	Raízen Energia S/A (3805)	Ipaussu (71058)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export	None	Retired

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T1N-1569	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Corn to Ethanol, Dry Mill, Midwest, NG, 100% WDGS	Kansas	Corn	Ethanol	None	None	ETHC281	72.32	2/2/2017	None	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Corn to Ethanol, Dry Mill, Midwest, NG, 100% WDGS	None	Retired
T1N-1147	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Univalem (70550): Brazilian sugarcane molasses-to-ethanol pathway, with credit for mechanized harvesting	Brazil	Molasses	Ethanol	None	None	ETHM233	44.94	5/19/2017	None	Ethanol	Raízen Energia S/A (3805)	Univalem (70550)	Brazilian sugarcane molassestoethanol pathway, with credit for mechanized harvesting	None	Retired
T1N-1187	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) Facility Name: USINA MOEMA AÇÚCAR E ÁLCOOL LTDA (70386). Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS200	46.19	3/31/2016	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	USINA MOEMA AÇÚCAR E ÁLCOOL LTDA (70386)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1R-1088	Tier 1	2.0	Fuel Producer: Granite Falls Energy, LLC (4769) Facility Name: Granite Falls Energy, LLC (70071). Midwest, Corn Ethanol, Dry Mill, Mixed DDGS and MDGS, NG	Minnesota	Corn	Ethanol	ETHC094	85.08	ETHC242L	74.30	3/31/2016	None	Ethanol	Granite Falls Energy, LLC (4769)	Granite Falls Energy, LLC (70071)	Midwest, Corn Ethanol, Dry Mill, Mixed DDGS and MDGS, NG	None	Retired
T1R-1270 T1R-1271	Tier 1	2.0	Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels Albion (70283). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG	Nebraska	Corn	Ethanol	ETHC106 ETHC107	86.49 82.37	ETHC261L	74.66	3/31/2016	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Albion (70283)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG	None	Retired
T1N-1277	Tier 1	2.0	Fuel Producer: Elkhorn Valley Ethanol LLC (4833) Facility Name: Elkhorn Valley Ethanol LLC (70095). Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG	Nebraska	Corn	Ethanol	None	None	ETHC222	74.74	3/31/2016	None	Ethanol	Elkhorn Valley Ethanol LLC (4833)	Elkhorn Valley Ethanol LLC (70095)	Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG	None	Retired
T1N-1306	Tier 1	2.0	Fuel Producer: SeQuential (6129) Facility Name: SeQuential-Pacific Biodiesel, LLC. (83525): Raw Used Cooking Oil and Rendered Used Cooking Oil from close source (within 500 miles) to Biodiesel produced in Oregon	Oregon	Used Cooking Oil	Biodiesel	None	None	BDU213	25.67	7/1/2016	None	Biodiesel	SeQuential (6129)	SeQuentialPacific Biodiesel, LLC(83525)	Raw Used Cooking Oil and Rendered Used Cooking Oil from close source (within 500 miles)to Biodiesel produced in Oregon	None	Retired
T1R-1221	Tier 1	2.0	Fuel Producer: Green Plains Ord LLC (3360) Facility Name: Green Plains Ord LLC (70138). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC040	85.84	ETHC255L	74.84	3/31/2016	None	Ethanol	Green Plains Ord LLC (3360)	Green Plains Ord LLC (70138)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1320	Tier 1	2.0	Fuel Producer: Los Angeles County Metropolitan Transportation Authority (L440) Facility Name: LA Metro Aggregate (G0001). North American NG delivered via pipeline; compressed in CA	California	North American NG - CNG	Compressed Natural Gas	None	None	CNGF200	80.59	9/30/2016	None	Fossil CNG	Los Angeles County Metropolitan Transportation Authority (L440)	LA Metro Aggregate (G0001)	North American NG delivered via pipeline; compressed in CA	None	Retired
T1R-1219	Tier 1	2.0	Fuel Producer: Green Plains Shenandoah LLC (5073) Facility Name: Green Plains Shenandoah LLC (70149). Midwest, Corn Ethanol, Dry Mill, NG	Iowa	Corn	Ethanol	ETHC041	85.73	ETHC254L	74.87	3/31/2016	None	Ethanol	Green Plains Shenandoah LLC (5073)	Green Plains Shenandoah LLC (70149)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1186	Tier 1	2.0	Fuel Producer: Highwater Ethanol, LLC (3303) Facility Name: Highwater Ethanol, LLC (70235). Midwest, Corn Ethanol, Dry Mill, NG	Minnesota	Corn	Ethanol	ETHC115	85.90	ETHC247L	75.15	3/31/2016	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1336	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): Biodiesel produced from Midwest Canola Oil; Fuel produced in California	Stockton, California	Canola	Biodiesel	None	None	BDCA201	54.97	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Biodiesel produced from Midwest Canola Oil; Fuel produced in California	None	Retired

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T1N-1338	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF200	33.56	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1339	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): Biodiesel produced from Midwest Corn Oil; Fuel produced in California	Stockton, California	Corn Oil from Wet DGS	Biodiesel	None	None	BDC204	29.42	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Biodiesel produced from Midwest Corn Oil; Fuel produced in California	None	Retired
T1N-1340	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): Midwest Soybean; Biodiesel produced in California	Stockton, California	Soybean	Biodiesel	None	None	BDS201	52.45	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Midwest Soybean; Biodiesel produced in California	None	Retired
T1N-1341	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): North American high energy rendered Tallow; Biodiesel Produced in California	Stockton, California	Tallow	Biodiesel	None	None	BDT205	32.34	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	North American high energy rendered Tallow; Biodiesel Produced in California	None	Retired
T1N-1343	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): California high energy rendered Used Cooking Oil (UCO); Biodiesel Produced in California	Stockton, California	Used Cooking Oil	Biodiesel	None	None	BDU206	16.31	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	California high energy rendered Used Cooking Oil (UCO)Biodiesel Produced in California	None	Retired
T1N-1756	Tier 1	2.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169) Facility Name: Hankinson Renewable Energy, LLC (70288): Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, and Syrup; NG	North Dakota	Corn	Ethanol	None	None	ETHC287	75.23	6/27/2017	None	Ethanol	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, and Syrup; NG	None	Retired
T1N-1346	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF201	36.17	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1347	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF202	34.82	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1348	Tier 1	2.0	Fuel Producer: Pacific Gas and Electric Company (C460) Facility Name: PG&E CNG Fueling Stations (M4675). North American NG delivered via pipeline; compressed in California	California	North American NG	Compressed Natural Gas	None	None	CNGF204	80.59	11/2/2016	None	Fossil CNG	Pacific Gas and Electric Company (C460)	PG&E CNG Fueling Stations (M4675)	North American NG delivered via pipeline; compressed in California	None	Retired
T1N-1354	Tier 1	2.0	Fuel Producer: CEVASA - Central Energetica Vale do Sapucai (3666) Facility Name: CEVASA - Central Energetica Vale do Sapucai (70701). Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS201	44.02	3/31/2016	None	Ethanol	CEVASA Central Energetica Vale do Sapucai (3666)	CEVASA Central Energetica Vale do Sapucai (70701)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1368	Tier 1	2.0	Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): U.S. sourced high energy rendered Tallow, Biodiesel produced in Arkansas and transported by rail to California	Arkansas	Tallow	Biodiesel	None	None	BDT210	40.69	12/20/2016	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	US sourced high energy rendered Tallow, Biodiesel produced in Arkansas and transported by rail to California	None	Retired
T1N-1279	Tier 1	2.0	Fuel Producer: Louis Dreyfus Commodities Grand Junction LLC (3137) Facility Name: Louis dreyfus Commodities Grand Junction LLC (70139). Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG	Iowa	Corn	Ethanol	None	None	ETHC224	76.01	3/31/2016	None	Ethanol	Louis Dreyfus Commodities Grand Junction LLC (3137)	Louis dreyfus Commodities Grand Junction LLC (70139)	Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG	None	Retired

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T1N-1372	Tier 1	2.0	Fuel Producer: Guarani SA (3890) Facility Name: Usina Vertente Ltda. (70447): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS217	44.21	12/20/2016	None	Ethanol	Guarani SA (3890)	Usina Vertente Ltda (70447)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1373	Tier 1	2.0	Fuel Producer: SunLine Transit Agency (S317) Facility Name: Sunline Transit (H2505). River Birch landfill gas to biomethane; delivered by pipeline; compressed in CA	Louisiana	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF203	37.77	9/30/2016	None	Bio-CNG	SunLine Transit Agency (S317)	Sunline Transit (H2505)	River Birch landfill gas to biomethane; delivered by pipeline; compressed in CA	None	Retired
T1N-1375	Tier 1	2.0	Fuel Producer: Odebrecht Agroindustrial SA (5580) Facility Name: Alto Taquari (71019). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS216	41.91	12/20/2016	None	Ethanol	Odebrecht Agroindustrial SA (5580)	Alto Taquari (71019)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1R-1157	Tier 1	2.0	Fuel Producer: Flint Hill Resources (4071) Facility Name: Fairmont (70103). Midwest, Corn Ethanol, Dry Mill, 91% DDGS, 9% MDGS, NG	Nebraska	Corn	Ethanol	ETHC064	86.62	ETHC243L	76.14	3/31/2016	None	Ethanol	Flint Hill Resources (4071)	Fairmont (70103)	Midwest, Corn Ethanol, Dry Mill, 91% DDGS, 9% MDGS, NG	None	Retired
T1R-1331	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fort Bend Landfill Recovery (71139). North American Landfill Gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA; re-gasified and compressed to L-CNG	Arizona	Landfill Gas - L-CNG	Compressed Natural Gas	CNG008_1	41.68	CNGLF235L	80.62	9/30/2016	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	Fort Bend Landfill Recovery (71139)	North American Landfill Gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA; regasified and compressed to LCNG	None	Retired
T1R-1169	Tier 1	2.0	Fuel Producer: Adkins Energy LLC (4767) Facility Name: Adkins Energy, LLC (70070). Midwest, Corn Ethanol, Dry Mill, 41% Dry DGS, 56% WDGS, NG	Illinois	Corn	Ethanol	ETHC114	86.33	ETHC244L	76.27	3/31/2016	None	Ethanol	Adkins Energy LLC (4767)	Adkins Energy, LLC (70070)	Midwest, Corn Ethanol, Dry Mill, 41% Dry DGS, 56% WDGS, NG	None	Retired
T1N-1235	Tier 1	2.0	Fuel Producer: Red Trail Energy LLC (4803) Facility Name: Red Trail Energy LLC (70077). Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG	North Dakota	Corn	Ethanol	None	None	ETHC219	76.46	3/31/2016	None	Ethanol	Red Trail Energy LLC (4803)	Red Trail Energy LLC (70077)	Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG	None	Retired
T1N-1397	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF204	33.85	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1398	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF205	34.38	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1399	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: GHI Energy, LLC (B8000). North American NG delivered via pipeline; compressed in CA	Texas	North American NG - CNG	Compressed Natural Gas	None	None	CNGF201	79.58	9/30/2016	None	Fossil CNG	GHI Energy, LLC (6156)	GHI Energy, LLC (B8000)	North American NG delivered via pipeline; compressed in CA	None	Retired
T1N-1403	Tier 1	2.0	Fuel Producer: New Leaf Biofuel (7768) Facility Name: New Leaf Biofuel (83541). Off-site Rendered Used Cooking Oil Biodiesel Produced in California	San Diego, California	Used Cooking Oil	Biodiesel	None	None	BDU201	15.86	6/30/2016	None	Biodiesel	New Leaf Biofuel (7768)	New Leaf Biofuel (83541)	Offsite Rendered Used Cooking Oil Biodiesel Produced in California	None	Retired
T1N-1406	Tier 1	2.0	Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Agri Industries (81926): Canola oil (produced in western Canada) biodiesel transported by rail from Lloydminster Alberta, Canada to Los Angeles, CA (the plant is co-located with crushing operation)	Canada	Canola	Biodiesel	None	None	BDCA202	51.33	6/30/2016	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Agri Industries (81926)	Canola oil (produced in western Canada)biodiesel transported by rail from Lloydminster Alberta, Canada to Los Angeles, CA (the plant is colocated with crushing operation)	None	Retired

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T1N-1457	Tier 1	2.0	Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Velva (82790): Canola oil biodiesel transported by rail from Velva, ND to Minot, ND to Los Angeles, CA (the plant is co-located with crushing operation)	North Dakota	Canola	Biodiesel	None	None	BDCA203	52.25	6/30/2016	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Velva (82790)	Canola oil biodiesel transported by rail from Velva, ND to Minot, ND to Los Angeles, CA (the plant is colocated with crushing operation)	None	Retired
T1R-1272 T1R-1273	Tier 1	2.0	Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels Aurora (70041). Midwest, Corn Ethanol, Dry Mill, NG	South Dakota	Corn	Ethanol	ETHC108 ETHC109	88.85 85.39	ETHC262L	76.74	3/31/2016	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1323	Tier 1	2.0	Fuel Producer: Prairie Horizon Agri-Energy, LLC (4760) Facility Name: Prairie Horizon Agri Energy, LLC (70659). Midwest, Corn Ethanol, Dry Mill, NG	Kansas	Corn	Ethanol	None	None	ETHC226	76.84	3/31/2016	None	Ethanol	Prairie Horizon AgriEnergy, LLC (4760)	Prairie Horizon Agri Energy, LLC (70659)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1464	Tier 1	2.0	Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Mexico (82791). Soybean oil biodiesel transported by rail from Mexico, Missouri to Richmond, CA	Mexico, Missouri	Soybean	Biodiesel	None	None	BDS202	50.85	6/30/2016	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Mexico (82791)	Soybean oil biodiesel transported by rail from Mexico, Missouri to Richmond, CA	None	Retired
T1N-1465	Tier 1	2.0	Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Mexico (82791). Soybean oil biodiesel transported by rail from Deerfield, MO to Richmond, CA (Soybean oil from adjacent crushing facility (81.9%) and 18.1% rail 311mi)	Deerfield, Missouri	Soybean	Biodiesel	None	None	BDS203	49.16	6/30/2016	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Mexico (82791)	Soybean oil biodiesel transported by rail from Deerfield, MO to Richmond, CA (Soybean oil from adjacent crushing facility (819% and 181% rail 311mi)	None	Retired
T1N-1466	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Pedra Agroindustrial S.A. (70415): Brazilian sugarcane juice-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS233	45.40	3/17/2017	None	Ethanol	Copersucar (3702)	Pedra Agroindustrial SA (70415)	Brazilian sugarcane juicetoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1467	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Pedra Agroindustrial S.A. (70415): Brazilian sugarcane molasses-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM229	46.06	3/17/2017	None	Ethanol	Copersucar (3702)	Pedra Agroindustrial SA (70415)	Brazilian sugarcane molassestoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1468	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Usina Iacanga Açúcar e Álcool Ltda. (70398): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS229	43.56	12/20/2016	None	Ethanol	Copersucar (3702)	Usina Iacanga Açúcar e Álcool Ltda (70398)	Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1469	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Usina Iacanga Açúcar e Álcool Ltda. (70398): Brazilian sugarcane molasses-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM225	44.77	12/20/2016	None	Ethanol	Copersucar (3702)	Usina Iacanga Açúcar e Álcool Ltda (70398)	Brazilian sugarcane molassestoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1489	Tier 1	2.0	Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Crossett Biodiesel Pant (82217): High energy rendered Tallow; Biodiesel produced in Arkansas and transported by rail to California	Arkansas	Tallow	Biodiesel	None	None	BDT213	32.96	3/17/2017	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Crossett Biodiesel Pant (82217)	High energy rendered Tallow; Biodiesel produced in Arkansas and transported by rail to California	None	Retired
T1N-1490	Tier 1	2.0	Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Crossett Biodiesel Pant (82217): Biodiesel produced from Soybean Oil in Arkansas; Fuel transported via rail to California	Arkansas	Soybean	Biodiesel	None	None	BDS208	51.11	3/17/2017	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Crossett Biodiesel Pant (82217)	Biodiesel produced from Soybean Oil in Arkansas; Fuel transported via rail to California	None	Retired
T1N-1502	Tier 1	2.0	Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): U.S. sourced corn oil to Biodiesel produced in Arkansas; Fuel transported by rail to California	Arkansas	Corn Oil	Biodiesel	None	None	BDC210	38.75	5/19/2017	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	US sourced corn oil to Biodiesel produced in Arkansas; Fuel transported by rail to California	None	Retired

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T1N-1503	Tier 1	2.0	Fuel Producer: Rothsay, A Division of Darling International Canada Inc. (6190) Facility Name: Rothsay Biodiesel (83210). High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Canada, shipped by rail and truck to California	Canada	Used Cooking Oil	Biodiesel	None	None	BDU216	27.45	11/7/2016	None	Biodiesel	Rothsay, A Division of Darling International Canada Inc (6190)	Rothsay Biodiesel (83210)	High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Canada, shipped by rail and truck to California	None	Retired
T1R-1174	Tier 1	2.0	Fuel Producer: Heron Lake BioEnergy (4015) Facility Name: Heron Lake BioEnergy (70097). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG	Minnesota	Corn	Ethanol	ETHC091	88.69	ETHC245L	77.33	3/31/2016	None	Ethanol	Heron Lake BioEnergy (4015)	Heron Lake BioEnergy (70097)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T1N-1512	Tier 1	2.0	Fuel Producer: Rothsay, A Division of Darling International Canada Inc. (6190) Facility Name: Rothsay Biodiesel (83210). High energy rendered Tallow, Biodiesel produced in Canada, shipped by rail and truck to California	Canada	Tallow	Biodiesel	None	None	BDT209	36.15	11/7/2016	None	Biodiesel	Rothsay, A Division of Darling International Canada Inc (6190)	Rothsay Biodiesel (83210)	High energy rendered Tallow, Biodiesel produced in Canada, shipped by rail and truck to California	None	Retired
T1N-1534	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728). Biodiesel produced from tallow (poultry fat) feedstock sourced in California only.	Stockton, California	Tallow	Biodiesel	None	None	BDT206	28.90	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Biodiesel produced from tallow (poultry fat)feedstock sourced in California only	None	Retired
T1R-1123	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: EIF KC Landfill Gas LLC (71155). Kansas City landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Kansas	Landfill Gas	Compressed Natural Gas	CNG029	26.38	CNGLF213L	41.49	9/30/2016	None	Bio-CNG	Clean Energy (5481)	EIF KC Landfill Gas LLC (71155)	Kansas City landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1102	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Pinnacle Gas Producers, LLC (71153). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Ohio	Landfill Gas	Compressed Natural Gas	CNG022	21.01	CNGLF206L	41.61	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Pinnacle Gas Producers, LLC (71153)	Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1661	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154) Facility Name: Cambrian Energy/Southtex Fort Smith Treaters (C5950): Fort Smith landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in Califirnia **(Provisional)**	Arkansas	Landfill Gas	Compressed Natural Gas	None	None	CNGLF254	42.15	7/10/2017	None	Bio-CNG	Shell Energy North America (6154)	Cambrian Energy/Southtex Fort Smith Treaters (C5950)	Fort Smith landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in Califirnia (Provisional)	None	Retired
T1N-1667	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154) Facility Name: Edinburg Renewables LLC (J8601): Edinburg landfill gas (TX) to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California**(Provisional)**	Texas	Landfill Gas	Compressed Natural Gas	None	None	CNGLF249	43.26	6/27/2017	None	Bio-CNG	Shell Energy North America (6154)	Edinburg Renewables LLC (J8601)	Edinburg landfill gas (TX)to pipelinequality biomethane; delivered via pipeline to CNG Stations in California(Provisional)	None	Retired
T1R-1223	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Montana-Dakota Utilities Billings Regional Landfill (71193). Montana landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Montana	Landfill Gas	Compressed Natural Gas	CNG057	45.24	CNGLF214L	46.65	9/30/2016	None	Bio-CNG	Clean Energy (5481)	MontanaDakota Utilities Billings Regional Landfill (71193)	Montana landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1099	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Westside Gas Prodcuers LLC (71151). Michigan landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Michigan	Landfill Gas	Compressed Natural Gas	CNG031	25.62	CNGLF237L	47.40	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Westside Gas Prodcuers LLC (71151)	Michigan landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1551	Tier 1	2.0	Fuel Producer: REG Grays Harbor, LLC (6326) Facility Name: REG Grays Harbor, LLC (82954). Canola Oil Biodiesel produced in Washington; BD transported by rail to California	Hoquiam, Washinton	Canola	Biodiesel	None	None	BDCA204	52.87	8/11/2016	None	Biodiesel	REG Grays Harbor, LLC (6326)	REG Grays Harbor, LLC (82954)	Canola Oil Biodiesel produced in Washington; BD transported by rail to California	None	Retired
T1N-1562	Tier 1	2.0	Fuel Producer: REG Grays Harbor, LLC (6326) Facility Name: REG Grays Harbor, LLC (82954). Used Cooking Oil (UCO) to Biodiesel produced in Washington, where cooking is not required; BD transported by rail to California	Hoquiam, Washinton	Used Cooking Oil	Biodiesel	None	None	BDU214	18.62	8/25/2016	None	Biodiesel	REG Grays Harbor, LLC (6326)	REG Grays Harbor, LLC (82954)	Used Cooking Oil (UCO)to Biodiesel produced in Washington, where cooking is not required; BD transported by rail to California	None	Retired

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T1N-1505	Tier 1	2.0	Fuel Producer: NuGen Energy, LLC (3332) Facility Name: NuGen Energy, LLC (70195). Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil; NG	South Dakota	Corn	Ethanol	None	None	ETHC277	77.93	11/2/2016	None	Ethanol	NuGen Energy, LLC (3332)	NuGen Energy, LLC (70195)	Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil; NG	None	Retired
T1N-1274	Tier 1	2.0	Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043). Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, NG	Iowa	Corn	Ethanol	None	None	ETHC220	78.14	3/31/2016	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC Fort Dodge (70043)	Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, NG	None	Retired
T1R-1177	Tier 1	2.0	Fuel Producer: Advanced BioEnergy, LLC (4094) Facility Name: ABE South Dakota, LLC (70104). Midwest, Corn Ethanol, Dry Mill, 84% DDGS, 16% WDGS, NG	South Dakota	Corn	Ethanol	ETHC065	88.59	ETHC246L	78.32	3/31/2016	None	Ethanol	Advanced BioEnergy, LLC (4094)	ABE South Dakota, LLC (70104)	Midwest, Corn Ethanol, Dry Mill, 84% DDGS, 16% WDGS, NG	None	Retired
T1N-1574	Tier 1	2.0	Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): Canola oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	Iowa	Canola Oil	Biodiesel	None	None	BDCA205	61.94	2/2/2017	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Canola oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	None	Retired
T1N-1575	Tier 1	2.0	Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): Corn Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	Iowa	Corn Oil	Biodiesel	None	None	BDC206	29.46	2/2/2017	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Corn Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	None	Retired
T1N-1576	Tier 1	2.0	Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): Soy Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	Iowa	Soybean Oil	Biodiesel	None	None	BDS206	54.50	2/2/2017	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Soy Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	None	Retired
T1N-1577	Tier 1	2.0	Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): U.S. sourced rendered Tallow; Biodiesel Produced in Wall Lake, Iowa and transported by rail to California	Iowa	Tallow	Biodiesel	None	None	BDT211	31.19	2/2/2017	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	US sourced rendered Tallow; Biodiesel Produced in Wall Lake, Iowa and transported by rail to California	None	Retired
T1N-1583	Tier 1	2.0	Fuel Producer: Ag Processing Inc (4552) Facility Name: Ag Processing Inc - Sgt. Bluff (81733): Soybean Oil Biodiesel produced in Sergeant Bluff, Iowa; steam from coal-boiler used; Fuel transported by rail to California	Iowa	Soybean	Biodiesel	None	None	BDS207	52.22	2/2/2017	None	Biodiesel	Ag Processing Inc (4552)	Ag Processing Inc Sgt Bluff (81733)	Soybean Oil Biodiesel produced in Sergeant Bluff, Iowa; steam from coalboiler used; Fuel transported by rail to California	None	Retired
T1R-1268 T1R-1269	Tier 1	2.0	Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels LLC - Albert City (70142). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG	Iowa	Corn	Ethanol	ETHC104_1 ETHC105_1	88.15 84.06	ETHC260L	78.62	3/31/2016	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC Albert City (70142)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG	None	Retired
T1N-1072	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG	Texas	Sorghum	Ethanol	None	None	ETHG200	79.03	3/31/2016	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG	None	Retired
T1N-1596	Tier 1	2.0	Fuel Producer: SunLine Transit Agency (S317) Facility Name: Sunline Transit (H2505). North American NG delivered via pipeline and compressed at Indio and Thousand Oaks California	California	North American NG	Compressed Natural Gas	None	None	CNGF203	78.21	11/2/2016	None	Fossil CNG	SunLine Transit Agency (S317)	Sunline Transit (H2505)	North American NG delivered via pipeline and compressed at Indio and Thousand Oaks California	None	Retired
T1N-1598	Tier 1	2.0	Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): Biodiesel produced from Midwest Soybean oil in Arkansas; Fuel transported via rail to California	Arkansas	Soybean	Biodiesel	None	None	BDS211	59.53	5/19/2017	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	Biodiesel produced from Midwest Soybean oil in Arkansas; Fuel transported via rail to California	None	Retired

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T1N-1602	Tier 1	2.0	Fuel Producer: Imperial Western Products (9871) Facility Name: Imperial Western Products (81066): Average U.S. sourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California **(Provisional)**	California	Used Cooking Oil	Biodiesel	None	None	BDU219	21.73	1/27/2017	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Average US sourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California (Provisional)	None	Retired
T1N-1604	Tier 1	2.0	Fuel Producer: Imperial Western Products (9871) Facility Name: Imperial Western Products (81066): U.S. sourced corn oil to Biodiesel produced from Southern California, distributed to Southern California **(Provisional)**	California	Corn Oil	Biodiesel	None	None	BDC205	34.66	1/27/2017	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	US sourced corn oil to Biodiesel produced from Southern California, distributed to Southern California (Provisional)	None	Retired
T1R-1086 T1R-1087	Tier 1	2.0	Fuel Producer: Glacial Lakes Corn Processors (4764) Facility Name: Glacial Lakes Energy (70064). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG	South Dakota	Corn	Ethanol	ETHC058 ETHC059	91.18 86.69	ETHC241L	79.21	3/31/2016	None	Ethanol	Glacial Lakes Corn Processors (4764)	Glacial Lakes Energy (70064)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG	None	Retired
T1N-1610	Tier 1	2.0	Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236): High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Hamilton, Ontario and transported by rail to California	Ontario, Canada	Used Cooking Oil	Biodiesel	None	None	BDU218	22.38	12/20/2016	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Hamilton, Ontario and transported by rail to California	None	Retired
T1N-1276	Tier 1	2.0	Fuel Producer: Elkhorn Valley Ethanol LLC (4833) Facility Name: Elkhorn Valley Ethanol LLC (70095). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	Nebraska	Corn	Ethanol	None	None	ETHC221	79.83	3/31/2016	None	Ethanol	Elkhorn Valley Ethanol LLC (4833)	Elkhorn Valley Ethanol LLC (70095)	Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T1N-1278	Tier 1	2.0	Fuel Producer: Louis Dreyfus Commodities Grand Junction LLC (3137) Facility Name: Louis dreyfus Commodities Grand Junction LLC (70139). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	Iowa	Corn	Ethanol	None	None	ETHC223	80.18	3/31/2016	None	Ethanol	Louis Dreyfus Commodities Grand Junction LLC (3137)	Louis dreyfus Commodities Grand Junction LLC (70139)	Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T1N-1620	Tier 1	2.0	Fuel Producer: Clinton Biodiesel, LLC (6485) Facility Name: Clinton Biodiesel LLC (82595): Soy oil Biodiesel produced from Midwest, transported by rail to California **(Provisional)**	Iowa	Soybean	Biodiesel	None	None	BDS205	54.81	12/20/2016	None	Biodiesel	Clinton Biodiesel, LLC (6485)	Clinton Biodiesel LLC (82595)	Soy oil Biodiesel produced from Midwest, transported by rail to California (Provisional)	None	Retired
T1R-1321	Tier 1	2.0	Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: Monroeville LFG, LLC (71136). Pennsylvania landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Pennsylvania	Landfill Gas	Compressed Natural Gas	CNG047	33.30	CNGLF217L	49.55	9/30/2016	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	Monroeville LFG, LLC (71136)	Pennsylvania landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1546	Tier 1	2.0	Fuel Producer: Athens Services (A431) Facility Name: Irwindale (V5355). Seneca Meadows solid waste landfill (Waterloo NY) gas to pipeline-quality biomethane; delivered via pipeline to Irwindale California and compressed to CNG	New York	Landfill Gas	Compressed Natural Gas	None	None	CNGLF241	50.37	11/2/2016	None	Bio-CNG	Athens Services (A431)	Irwindale (V5355)	Seneca Meadows solid waste landfill (Waterloo NY)gas to pipelinequality biomethane; delivered via pipeline to Irwindale California and compressed to CNG	None	Retired
T1N-1484	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Pioneiros Bioenergia S.A. (70430); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS237	46.51	8/17/2017	None	Ethanol	Copersucar (3702)	Pioneiros Bioenergia SA (70430)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1R-1107	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Seneca Energy II, LLC (71156). New York landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	New York	Landfill Gas	Compressed Natural Gas	CNG027	27.53	CNGLF207L	52.77	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Seneca Energy II, LLC (71156)	New York landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1629	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Canton Renewables (71041): Sauk Trails Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona	Michigan	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF216	64.74	7/10/2017	None	Bio-LNG	Clean Energy (5481)	Canton Renewables (71041)	Sauk Trails Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona	None	Retired

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T1R-1022 T1R-1023	Tier 1	2.0	Fuel Producer: Glacial Lakes Corn Processors (4764) Facility Name: Aberdeen Energy (70299). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG	South Dakota	Corn	Ethanol	ETHC060 ETHC061	92.15 87.66	ETHC237L	80.19	3/31/2016	None	Ethanol	Glacial Lakes Corn Processors (4764)	Aberdeen Energy (70299)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG	None	Retired
T1N-1636	Tier 1	2.0	Fuel Producer: Usina Alta Mogiana S/A (4225) Facility Name: Usina Alta Mogiana S.A. - Acucar e Alcool (70498): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM227	46.29	2/2/2017	None	Ethanol	Usina Alta Mogiana S/A (4225)	Usina Alta Mogiana SA Acucar e Alcool (70498)	Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1647	Tier 1	2.0	Fuel Producer: Titan El Toro LLC (T153) Facility Name: Titan El Toro (T4201): North American NG delivered via pipeline; compressed in California	California	North American NG	Compressed Natural Gas	None	None	CNGF206	80.59	3/17/2017	None	Fossil CNG	Titan El Toro LLC (T153)	Titan El Toro (T4201)	North American NG delivered via pipeline; compressed in California	None	Retired
T1N-1626	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Canton Renewables (71041): Sauk Trails Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	Michigan	Landfill Gas	Compressed Natural Gas	None	None	CNGLF251	57.35	6/27/2017	None	Bio-CNG	Clean Energy (5481)	Canton Renewables (71041)	Sauk Trails Hills landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California	None	Retired
T1N-1666	Tier 1	2.0	Fuel Producer: GeoGreen Biofuels (3885) Facility Name: GeoGreen Biofuels (81199): California sourced Waste Oil (Used Cooking Oil) Biodiesel produced in California **(Provisional)**	California	Used Cooking Oil	Biodiesel	None	None	BDU222	18.26	3/17/2017	None	Biodiesel	GeoGreen Biofuels (3885)	GeoGreen Biofuels (81199)	California sourced Waste Oil (Used Cooking Oil)Biodiesel produced in California (Provisional)	None	Retired
T1N-1545	Tier 1	2.0	Fuel Producer: Athens Services (A431) Facility Name: Irwindale (V5355). Landfill gas from SWACO landfill in Grove City, OH is transported via pipeline to Irwindale California and compressed to CNG	Ohio	Landfill Gas	Compressed Natural Gas	None	None	CNGLF240	58.21	11/2/2016	None	Bio-CNG	Athens Services (A431)	Irwindale (V5355)	Landfill gas from SWACO landfill in Grove City, OH is transported via pipeline to Irwindale California and compressed to CNG	None	Retired
T1N-1704	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Ehrenberg LNG (C0660): North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona	Arizona	North American NG	Liquefied Natural Gas	None	None	LNGF202	91.03	7/10/2017	None	Fossil LNG	Clean Energy (5481)	Ehrenberg LNG (C0660)	North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona	None	Retired
T1N-1705	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Ehrenberg LNG (C0660): North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona; re-gasified to L-CNG in California	Arizona	North American NG	Liquefied Compressed Natural Gas	None	None	CNGF207	93.59	7/10/2017	None	Fossil CNG	Clean Energy (5481)	Ehrenberg LNG (C0660)	North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona; regasified to LCNG in California	None	Retired
T1N-1707	Tier 1	2.0	Fuel Producer: REG Newton, LLC (3514) Facility Name: REG Newton, LLC (80162): High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Iowa and transported by rail to California	Iowa	Used Cooking Oil	Biodiesel	None	None	BDU223	22.50	3/17/2017	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Iowa and transported by rail to California	None	Retired
T1N-1708	Tier 1	2.0	Fuel Producer: REG Newton, LLC (3514) Facility Name: REG Newton, LLC (80162): U.S. sourced Corn Oil Biodiesel produced in Iowa and transported by rail to California	Iowa	Corn Oil	Biodiesel	None	None	BDC208	34.10	3/17/2017	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	US sourced Corn Oil Biodiesel produced in Iowa and transported by rail to California	None	Retired
T1N-1711	Tier 1	2.0	Fuel Producer: Imperial Western Products (9871) Facility Name: Imperial Western Products (81066): CA-sourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California **(Provisional)**	California	Used Cooking Oil	Biodiesel	None	None	BDU220	20.96	1/27/2017	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	CAsourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California (Provisional)	None	Retired
T1N-1089	Tier 1	2.0	Fuel Producer: Heartland Corn Products (4827) Facility Name: Heartland Corn Products (70089). Midwest Corn, Ethanol, Dry Mill, DDGS, NG	Minnesota	Corn	Ethanol	None	None	ETHC204	80.24	3/31/2016	None	Ethanol	Heartland Corn Products (4827)	Heartland Corn Products (70089)	Midwest Corn, Ethanol, Dry Mill, DDGS, NG	None	Retired

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T1N-1721	Tier 1	2.0	Fuel Producer: Bio Etanol, S.A. (5834) Facility Name: Bio Etanol (Pantaleon), S.A. (71037): Guatemalan sugarcane by-product molasses-based ethanol with average production processes and electricity co-product credit	Guatemala	Molasses	Ethanol	None	None	ETHM231	40.20	5/19/2017	None	Ethanol	Bio Etanol, SA (5834)	Bio Etanol (Pantaleon), SA (71037)	Guatemalan sugarcane byproduct molassesbased ethanol with average production processes and electricity coproduct credit	None	Retired
T1N-1722	Tier 1	2.0	Fuel Producer: Bio Etanol, S.A. (5834) Facility Name: Bio Etanol (Concepcion), S.A. (71037): Guatemalan sugarcane by-product molasses-based ethanol with average production processes and co-product credit for surplus electricity export, and mechanized harvesting	Guatemala	Molasses	Ethanol	None	None	ETHM232	41.93	5/19/2017	None	Ethanol	Bio Etanol, SA (5834)	Bio Etanol (Concepcion), SA (71037)	Guatemalan sugarcane byproduct molassesbased ethanol with average production processes and coproduct credit for surplus electricity export, and mechanized harvesting	None	Retired
T1N-1733	Tier 1	2.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 650 miles, Biodiesel produced in Texas, shipped by rail to California	Texas	Used Cooking Oil (UCO)	Biodiesel	BDU227	20.83	BDU227R	22.45	11/28/2018	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 650 miles, Biodiesel produced in Texas, shipped by rail to California	None	Retired
T1N-1735	Tier 1	2.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by truck to California	Texas	Used Cooking Oil (UCO)	Biodiesel	BDU225	28.54	BDU225R	30.15	11/28/2018	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by truck to California	None	Retired
T1N-1736	Tier 1	2.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); Soybean Oil shipped by rail, biodiesel produced from soybean oil in Texas, shipped by rail to California	Texas	Soybean Oil	Biodiesel	BDS210	51.94	BDS210R	53.43	11/28/2018	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	Soybean Oil shipped by rail, biodiesel produced from soybean oil in Texas, shipped by rail to California	None	Retired
T1N-1571	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% WDGS	Kansas	Sorghum	Ethanol	None	None	ETHG216	80.38	2/2/2017	None	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% WDGS	None	Retired
T1N-1742	Tier 1	2.0	Fuel Producer: Lakeview Biodiesel, LLC (L430) Facility Name: Lakeview Biodiesel, LLC (W0607): Biodiesel produced from Soybean oil in Missouri; Fuel transported via rail to California **(Provisional)**	Missouri	Soybean	Biodiesel	None	None	BDS212	56.20	6/30/2017	None	Biodiesel	Lakeview Biodiesel, LLC (L430)	Lakeview Biodiesel, LLC (W0607)	Biodiesel produced from Soybean oil in Missouri; Fuel transported via rail to California (Provisional)	None	Retired
T1N-1568	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Corn to Ethanol, Dry Mill, Midwest, NG, 100% DDGS	Kansas	Corn	Ethanol	None	None	ETHC282	80.85	2/2/2017	None	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Corn to Ethanol, Dry Mill, Midwest, NG, 100% DDGS	None	Retired
T1N-1751	Tier 1	2.0	Fuel Producer: BUSTER BIOFUELS LLC (4166) Facility Name: BUSTER BIOFUELS LLC (83449): High energy rendered Used Cooking Oil (UCO) sourced locally and transported by truck, Biodiesel produced in California**(Provisional)**	California	Used Cooking Oil	Biodiesel	None	None	BDU230	21.53	6/28/2017	None	Biodiesel	BUSTER BIOFUELS LLC (4166)	BUSTER BIOFUELS LLC (83449)	High energy rendered Used Cooking Oil (UCO)sourced locally and transported by truck, Biodiesel produced in California(Provisional)	None	Retired
T1R-1241	Tier 1	2.0	Fuel Producer: Green Plains Holdings II LLC - Lakota (4755) Facility Name: Green Plains Holdings II LLC - Lakota (70051). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC024	91.60	ETHC256L	81.42	3/31/2016	None	Ethanol	Green Plains Holdings II LLC Lakota (4755)	Green Plains Holdings II LLC Lakota (70051)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1113	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: LES Renewable NG, LLC - SWACO Facility (71157). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Ohio	Landfill Gas	Compressed Natural Gas	CNG025	28.68	CNGLF209L	60.92	9/30/2016	None	Bio-CNG	Clean Energy (5481)	LES Renewable NG, LLC SWACO Facility (71157)	Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T2R-1067	Tier 2	2.0	Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: Archer Daniels Midland Compnay - Columbus Dry Mill (70355). Midwest, Corn Ethanol, Dry Mill, NG, Closed-loop heat recovery, Cogeneration	Nebraska	Corn	Ethanol	ETHC018_2	87.11	ETHC274L	81.47	3/31/2016	None	Ethanol	Archer Daniels Midland Co (4888)	Archer Daniels Midland Compnay Columbus Dry Mill (70355)	Midwest, Corn Ethanol, Dry Mill, NG, Closedloop heat recovery, Cogeneration	None	Retired

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T1N-1234	Tier 1	2.0	Fuel Producer: Red Trail Energy LLC (4803) Facility Name: Red Trail Energy LLC (70077). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	North Dakota	Corn	Ethanol	None	None	ETHC218	82.30	3/31/2016	None	Ethanol	Red Trail Energy LLC (4803)	Red Trail Energy LLC (70077)	Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T1N-1506	Tier 1	2.0	Fuel Producer: NuGen Energy, LLC (3332) Facility Name: NuGen Energy, LLC (70195). Midwest Sorghum, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil, NG	South Dakota	Sorghum	Ethanol	None	None	ETHG214	85.72	11/2/2016	None	Ethanol	NuGen Energy, LLC (3332)	NuGen Energy, LLC (70195)	Midwest Sorghum, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil, NG	None	Retired
T1N-1143	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Bonfim (70548) - Ethanol production from Brazilian sugarcane by-product molasses feedstock, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM216	44.24	6/6/2016	None	Ethanol	Raízen Energia S/A (3805)	Bonfim (70548)	Ethanol production from Brazilian sugarcane byproduct molasses feedstock, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1570	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% DDGS	Kansas	Sorghum	Ethanol	None	None	ETHG217	88.90	2/2/2017	None	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% DDGS	None	Retired
T1N-1191	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) Facility Name: USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS207	46.24	6/6/2016	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1491	Tier 1	2.0	Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398): High energy rendered Tallow; Biodiesel produced in Texas and transported by rail to California	Texas	Tallow	Biodiesel	None	None	BDT217	38.27	3/22/2017	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	High energy rendered Tallow; Biodiesel produced in Texas and transported by rail to California	None	Retired
T1N-1492	Tier 1	2.0	Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398): Biodiesel produced from Soybean Oil in Texas; Fuel transported via rail to California	Texas	Soybean	Biodiesel	None	None	BDS209	58.55	3/22/2017	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	Biodiesel produced from Soybean Oil in Texas; Fuel transported via rail to California	None	Retired
T1N-1493	Tier 1	2.0	Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398): High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas, shipped by rail to California	Texas	Used Cooking Oil	Biodiesel	None	None	BDU224	28.40	3/22/2017	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas, shipped by rail to California	None	Retired
T1N-1617	Tier 1	2.0	Fuel Producer: REG Newton, LLC (3514) Facility Name: REG Newton, LLC (80162): U.S. sourced rendered Tallow; Biodiesel Produced in Iowa and transported by rail to California	Iowa	Tallow	Biodiesel	None	None	BDT212	35.94	2/2/2017	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	US sourced rendered Tallow; Biodiesel Produced in Iowa and transported by rail to California	None	Retired
T2N-1116	Tier 2	2.0	Fuel Producer: New Leaf Biofuel (7768) Facility Name: New Leaf Biofuel (83541). Self-rendered Used Cooking Oil Biodiesel Produced in California **(Provisional)**	San Diego, California	Used Cooking Oil	Biodiesel	None	None	BDU202	8.63	4/1/2016	None	Biodiesel	New Leaf Biofuel (7768)	New Leaf Biofuel (83541)	Selfrendered Used Cooking Oil Biodiesel Produced in California (Provisional)	None	Retired
T2N-1154	Tier 2	2.0	Fuel Producer: Biodico Westside (6231) Facility Name: Biodico Plant (83027): California Used Cooking Oil; Biodiesel produced in Five Points, California **(Provisional)**	California	Used Cooking Oil	Biodiesel	None	None	BDU229	14.97	6/1/2017	Pathway Details (PDF)	Biodiesel	Biodico Westside (6231)	Biodico Plant (83027)	California Used Cooking Oil; Biodiesel produced in Five Points, California (Provisional)	None	Retired
T2N-1159	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel dispensed on-site	California	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF217	7.39	6/22/2017	Pathway Details (PDF)	Bio-LNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel dispensed onsite	None	Retired

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T2N-1162	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Bay Area by Truck	California	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF218	7.74	6/22/2017	Pathway Details (PDF)	Bio-LNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Bay Area by Truck	None	Retired
T1N-1630	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Canton Renewables (71041): Sauk Trails Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; re-gasified to L-CNG in California	Michigan	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF244	67.29	7/10/2017	None	Bio-CNG	Clean Energy (5481)	Canton Renewables (71041)	Sauk Trails Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; regasified to LCNG in California	None	Retired
T2N-1164	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Southern California by Truck	California	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF219	10.71	6/22/2017	Pathway Details (PDF)	Bio-LNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Southern California by Truck	None	Retired
T1N-1485	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Pioneiros Bioenergia S.A. (70430); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM235	47.56	8/17/2017	None	Ethanol	Copersucar (3702)	Pioneiros Bioenergia SA (70430)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T2N-1192	Tier 2	2.0	Fuel Producer: BUSTER BIOFUELS LLC (4166) Facility Name: BUSTER BIOFUELS LLC (83449): Raw Used Cooking Oil (UCO) sourced locally and transported by truck, Biodiesel produced in California **(Provisional)**	California	Used Cooking Oil	Biodiesel	None	None	BDU231	16.90	7/10/2017	Pathway Details (PDF)	Biodiesel	BUSTER BIOFUELS LLC (4166)	BUSTER BIOFUELS LLC (83449)	Raw Used Cooking Oil (UCO)sourced locally and transported by truck, Biodiesel produced in California (Provisional)	None	Retired
T1N-1627	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: Canton Renewables (71041); Sauk Trail Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California	Michigan	Landfill Gas	Liquefied Natural Gas	LNGLF221	66.93	LNGLF221R	72.42	8/16/2017	None	Bio-LNG	Clean Energy (5481)	Canton Renewables (71041)	Sauk Trail Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California	None	Retired
T1N-1628	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: Canton Renewables (71041); Sauk Trail Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California; re-gassified to L-CNG in California	Michigan	Landfill Gas	Liquefied Compressed Natural Gas	CNGLF255	69.48	CNGLF255R	74.97	8/16/2017	None	Bio-CNG	Clean Energy (5481)	Canton Renewables (71041)	Sauk Trail Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California; regassified to LCNG in California	None	Retired
T1N-1651	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: JDP Renewables (L6161); Jefferson David Parish Sanitary landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Louisiana	Landfill Gas	Compressed Natural Gas	None	None	CNGLF260	39.31	8/24/2017	None	Bio-CNG	Shell Energy North America (6154)	JDP Renewables (L6161)	Jefferson David Parish Sanitary landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1654	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: JDP Renewables (L6161); Jefferson David Parish Sanitary landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	Louisiana	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF224	47.28	8/24/2017	None	Bio-LNG	Shell Energy North America (6154)	JDP Renewables (L6161)	Jefferson David Parish Sanitary landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	None	Retired
T1N-1655	Tier 1	2.0	Shell Energy North America (6154); JDP Renewables (L6161); Jefferson David Parish Sanitary landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; re-gasified in California (Provisional)	Louisiana	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF259	49.82	8/24/2017	None	Bio-CNG	Shell Energy North America (6154)	JDP Renewables (L6161)	Jefferson David Parish Sanitary landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; regasified in California (Provisional)	None	Retired
T1N-1659	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: East Texas Renewables (F2942); Greenwood Farms landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	Texas	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF223	46.60	8/24/2017	None	Bio-LNG	Shell Energy North America (6154)	East Texas Renewables (F2942)	Greenwood Farms landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	None	Retired
T1N-1660	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: East Texas Renewables (F2942); Greenwodd Farms landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; re-gasified in California (Provisional)	Texas	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF258	49.15	8/24/2017	None	Bio-LNG	Shell Energy North America (6154)	East Texas Renewables (F2942)	Greenwodd Farms landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; regasified in California (Provisional)	None	Retired

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T1N-1664	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Cambrian Energy/Southtex Fort Smith Treaters (C5950); Fort Smith landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	Arkansas	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF222	50.15	8/24/2017	None	Bio-LNG	Shell Energy North America (6154)	Cambrian Energy/Southtex Fort Smith Treaters (C5950)	Fort Smith landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	None	Retired
T1N-1665	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Cambrian Energy/Southtex Fort Smith Treaters (C5950); Fort Smith landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; re-gasified and compressed in California (Provisional)	Arkansas	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF257	52.70	8/24/2017	None	Bio-CNG	Shell Energy North America (6154)	Cambrian Energy/Southtex Fort Smith Treaters (C5950)	Fort Smith landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; regasified and compressed in California (Provisional)	None	Retired
T1N-1782	Tier 1	2.0	Fuel Producer: Usina Batatais S/A - Açúcar e Álcool (6446); Facility Name: Usina Batatais S.A. - Açucar e Álcool - Batatais Unit (70408); Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS236	48.71	8/17/2017	None	Ethanol	Usina Batatais S/A Açúcar e Álcool (6446)	Usina Batatais SA Açucar e Álcool Batatais Unit (70408)	Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting	None	Retired
T1N-1784	Tier 1	2.0	Fuel Producer: Usina Batatais S/A - Açúcar e Álcool (6446); Facility Name: Usina Batatais S.A. - Açucar e Álcool (70409); Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS235	47.53	8/17/2017	None	Ethanol	Usina Batatais S/A Açúcar e Álcool (6446)	Usina Batatais SA Açucar e Álcool (70409)	Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting	None	Retired
T1R-1787	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Costa Pinto (70552): Raizen Energia S.A., COPI: Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM219	44.19	ETHM219R	47.02	8/9/2017	Former T1N-1566, FPC: ETHM219	Ethanol	Raízen Energia S/A (3805)	Costa Pinto (70552)	Raizen Energia SA, COPI Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1R-1788	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Gasa (70551); Raizen Energia S.A., Usina Gasa, Sao Paulo, Brazil. Brazilian sugarcane -to-ethanol, with credit for mechanized harvesting	Brazil	Sugarcane	Ethanol	ETHS221	46.07	ETHS221R	46.91	8/9/2017	Former T1N-1210, FPC: ETHS221	Ethanol	Raízen Energia S/A (3805)	Gasa (70551)	Raizen Energia SA, Usina Gasa, Sao Paulo, Brazil. Brazilian sugarcane toethanol, with credit for mechanized harvesting	None	Retired
T1R-1789	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Rafard (70557): Raizen Energia S.A., Rafard Mill: Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM215	47.17	ETHM215R	48.76	8/9/2017	Former T1N-1140, FPC: ETHM215	Ethanol	Raízen Energia S/A (3805)	Rafard (70557)	Raizen Energia SA, Rafard Mill; Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1R-1790	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Paraguaçu (71057): Raizen Energia S.A., Paraguacu Mill, Sao Paulo, Brazil: Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM223	46.71	ETHM223R	49.32	8/9/2017	Former T1N-1146, FPC:ETHM223	Ethanol	Raízen Energia S/A (3805)	Paraguaçu (71057)	Raizen Energia SA, Paraguacu Mill, Sao Paulo, Brazil; Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1771	Tier 1	2.0	Fuel Producer: EM Gas Marketing, LLC (6287); Facility Name: Fresh Kills Landfill EMGM (7120t); Fresh Kills landfill gas to pipeline-quality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in California	New York	Landfill Gas	Compressed Natural Gas	None	None	CNGLF262	37.13	8/29/2017	None	Bio-CNG	EM Gas Marketing, LLC (6287)	Fresh Kills Landfill EMGM (7120t)	Fresh Kills landfill gas to pipelinequality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in California	None	Retired
T1N-1775	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Meadow Branch Landfill Gas Processing Facility (71252); Meadow Branch landfill gas to pipeline-quality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in CA (Provisional)	Tennessee	Landfill Gas	CNG	CNGLF261	38.51	CNGLF261R	52.14	5/11/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Meadow Branch Landfill Gas Processing Facility (71252)	Meadow Branch landfill gas to pipelinequality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in CA (Provisional)	None	Retired
T1N-1755	Tier 1	2.0	Fuel Producer: REG New Boston, LLC (6067); Facility Name: REG New Boston, LLC (81490); High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas and transported by rail to California	Texas	Used Cooking Oil	Biodiesel	None	None	BDU232	20.23	8/31/2017	None	Biodiesel	REG New Boston, LLC (6067)	REG New Boston, LLC (81490)	High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas and transported by rail to California	None	Retired
T2N-1191	Tier 2	2.0	Fuel Producer: USL Parallel Products of California (4018); Facility Name: USL Parallel Products of California (70122); Tier 2 Method 2B Pathway: Ethanol derived from recycled beverages in Rancho Cucamonga, California	California	Waste Beverage	Ethanol	None	None	ETHWB201	69.82	9/1/2017	Application Package	Ethanol	USL Parallel Products of California (4018)	USL Parallel Products of California (70122)	Tier 2 Method 2B Pathway Ethanol derived from recycled beverages in Rancho Cucamonga, California	None	Retired

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T1N-1693	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Santa Lúcia (70426); Brazilian sugarcane juice-to-ethanol pathway, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS241	46.88	9/1/2017	None	Ethanol	Copersucar (3702)	Usina Santa Lúcia (70426)	Brazilian sugarcane juicetoethanol pathway, with credit for mechanized harvesting	None	Retired
T1N-1643	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations	Ohio	Landfill Gas	Compressed Natural Gas	None	None	CNGLF264	43.97	9/5/2017	None	Bio-CNG	WM Renewable Energy, LLC (W978)	WM Renewable Energy of Ohio American Landfill (71222)	American landfill gas (Ohio)to pipelinequality biomethane; delivered via pipeline to California CNG Stations	None	Retired
T1N-1754	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; Re-gasified in CA	Ohio	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF263	59.12	9/5/2017	None	Bio-CNG	WM Renewable Energy, LLC (W978)	WM Renewable Energy of Ohio American Landfill (71222)	American landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; Regasified in CA	None	Retired
T1N-1477	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Barra Grande de Lençóis S.A. (70412); Brazilian sugarcane molases-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM205L	T1R-1259	ETHM239	48.90	9/5/2017	None	Ethanol	Copersucar (3702)	Usina Barra Grande de Lençóis SA (70412)	Brazilian sugarcane molasestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1753	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ (Provisional)	Ohio	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF225	56.57	9/5/2017	None	Bio-LNG	WM Renewable Energy, LLC (W978)	WM Renewable Energy of Ohio American Landfill (71222)	American landfill gas (Ohio)to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ (Provisional)	None	Retired
T2N-1197	Tier 2	2.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Rendered Used Cooking Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional)	Louisiana	Used Cooking Oil	Renewable Diesel	None	None	RDU203	24.35	9/11/2017	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Tier 2 Method 2B Pathway Renewable Diesel produced from Rendered Used Cooking Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional)	None	Retired
T2N-1198	Tier 2	2.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Non-Rendered Used Cooking Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional)	Louisiana	Used Cooking Oil	Renewable Diesel	None	None	RDU204	18.99	9/11/2017	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Tier 2 Method 2B Pathway Renewable Diesel produced from NonRendered Used Cooking Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional)	None	Retired
T2N-1199	Tier 2	2.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Corn Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional)	Louisiana	Corn Oil	Renewable Diesel	None	None	RDC202	34.32	9/11/2017	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Tier 2 Method 2B Pathway Renewable Diesel produced from Corn Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional)	None	Retired
T2N-1200	Tier 2	2.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Tallow, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional)	Louisiana	Tallow	Renewable Diesel	None	None	RDT206	35.71	9/11/2017	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Tier 2 Method 2B Pathway Renewable Diesel produced from Tallow, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional)	None	Retired
T2N-1201	Tier 2	2.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Soy Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional)	Louisiana	Soybean Oil	Renewable Diesel	None	None	RDS201	56.57	9/11/2017	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Tier 2 Method 2B Pathway Renewable Diesel produced from Soy Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional)	None	Retired
T1N-1478	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S.A. (70406); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS242	48.86	9/19/2017	None	Ethanol	Copersucar (3702)	Açucareira Quatá SA (70406)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1479	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S.A. (70406); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM207L	45.97	ETHM240	50.69	9/19/2017	None	Ethanol	Copersucar (3702)	Açucareira Quatá SA (70406)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired

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T1N-1472	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Cerradão Ltda (70425); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS243	47.53	9/25/2017	None	Ethanol	Copersucar (3702)	Usina Cerradão Ltda (70425)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1473	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Cerradão Ltda (70425); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM212L	44.6	ETHM241	48.80	9/25/2017	None	Ethanol	Copersucar (3702)	Usina Cerradão Ltda (70425)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1474	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Açúcareira Zillo Lorenzetti S.A. (70432); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	ETHS205L	45.21	ETHS244	45.07	9/25/2017	None	Ethanol	Copersucar (3702)	Açúcareira Zillo Lorenzetti SA (70432)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1475	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Açúcareira Zillo Lorenzetti S.A. (70432); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM206L	46.32	ETHM242	46.26	9/25/2017	None	Ethanol	Copersucar (3702)	Açúcareira Zillo Lorenzetti SA (70432)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1757	Tier 1	2.0	Fuel Producer: REG New Boston, LLC (6067) ; Facility Name: REG New Boston, LLC (81490); U.S. sourced rendered Tallow; Biodiesel Produced in Texas and transported by rail to California	Texas	Tallow	Biodiesel	None	None	BDT218	34.27	9/25/2017	None	Biodiesel	REG New Boston, LLC (6067)	REG New Boston, LLC (81490)	US sourced rendered Tallow; Biodiesel Produced in Texas and transported by rail to California	None	Retired
T2N-1227	Tier 2	2.0	Fuel Producer: White Energy, Inc. (4745) ; Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038); Tier 2 Method 2B Pathway: Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Wet DGS, NG	Kansas	Wheat Starch Slurry	Ethanol	None	None	ETHWSS200	45.20	10/11/2017	Application Package	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Tier 2 Method 2B Pathway Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Wet DGS, NG	None	Retired
T2N-1228	Tier 2	2.0	Fuel Producer: White Energy, Inc. (4745) ; Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038); Tier 2 Method 2B Pathway: Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Dry DGS, NG	Kansas	Wheat Starch Slurry	Ethanol	None	None	ETHWSS201	53.73	10/11/2017	Application Package	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Tier 2 Method 2B Pathway Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Dry DGS, NG	None	Retired
T2N-1190	Tier 2	2.0	Fuel Producer: Linde LLC (L012); Facility Name: Linde Canada LH2 Plant (R1980); Tier 2 Method 2B Pathway: Compressed H2 from Central Reforming of North American Natural Gas includes liquefaction and regasification steps. (Provisional)	California	North American NG	Hydrogen	None	None	HYGFCR200	165.88	10/13/2017	Application Package	Hydrogen	Linde LLC (L012)	Linde Canada LH2 Plant (R1980)	Tier 2 Method 2B Pathway Compressed H2 from Central Reforming of North American Natural Gas includes liquefaction and regasification steps (Provisional)	None	Retired
T1N-1192	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Facility Name: USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483); Brazilian sugarcane molasses-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM246	46.78	11/6/2017	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483)	Brazilian sugarcane molassestoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1190	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Facility Name: USINA FRUTAL AÇÚCAR E ÁLCOOL (70579); Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM245	48.32	11/6/2017	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	USINA FRUTAL AÇÚCAR E ÁLCOOL (70579)	Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1188	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Facility Name: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM244	48.60	11/6/2017	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1074	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Cresciumal (71068); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export.	Brazil	Sugarcane	Ethanol	None	None	ETHS245	47.72	11/6/2017	None	Ethanol	BIOSEV SA (3869)	Usina Cresciumal (71068)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export	None	Retired

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T1N-1075	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Santa Elisa (71070); Brazilian sugarcane juice-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS246	50.16	11/6/2017	None	Ethanol	BIOSEV SA (3869)	Usina Santa Elisa (71070)	Brazilian sugarcane juicebased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1076	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Vale do Rosário (70440); Brazilian sugarcane juice-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS247	52.07	11/6/2017	None	Ethanol	BIOSEV SA (3869)	Usina Vale do Rosário (70440)	Brazilian sugarcane juicebased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1171	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Araraquara (71055); Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS248	46.16	11/6/2017	None	Ethanol	Raízen Energia S/A (3805)	Araraquara (71055)	Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1136	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Araraquara (71055); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM243	47.63	11/6/2017	None	Ethanol	Raízen Energia S/A (3805)	Araraquara (71055)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1786	Tier 1	2.0	Fuel Producer: Show Me Ethanol, LLC (7464); Facility Name: Show Me Ethanol (70300); Dry mill corn ethanol with co-production of DDGS, MDGS, and Corn Oil using natural gas and electricity power.	Missouri	Corn	Ethanol	None	None	ETHC294	77.26	12/21/2017	None	Ethanol	Show Me Ethanol, LLC (7464)	Show Me Ethanol (70300)	Dry mill corn ethanol with coproduction of DDGS, MDGS, and Corn Oil using natural gas and electricity power	None	Retired
T1N-1785	Tier 1	2.0	Fuel Producer: Homeland Energy Solutions LLC (3220) ; Facility Name: Homeland Energy Solutions LLC (70188); Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power (Provisional)	Iowa	Corn	Ethanol	None	None	ETHC292	73.11	12/21/2017	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Dry mill corn ethanol with coproduction of DDGS, MDGS, and corn oil using natural gas and electricity power (Provisional)	None	Retired
T1N-1470	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Cocal - Comércio Indústria Canaã Açucar e Alcool Ltda. (70419); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS249	47.66	11/29/2017	None	Ethanol	Copersucar (3702)	Cocal Comércio Indústria Canaã Açucar e Alcool Ltda (70419)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1471	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Cocal - Comércio Indústria Canaã Açucar e Alcool Ltda. (70419); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM209L	46.04	ETHM247	48.41	11/29/2017	None	Ethanol	Copersucar (3702)	Cocal Comércio Indústria Canaã Açucar e Alcool Ltda (70419)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1637	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: GSF Energy - Rumpke Landfill (71138); Rumpke landfill gas (OH) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ	Ohio	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF227	64.62	12/21/2017	None	Bio-LNG	WM Renewable Energy, LLC (W978)	GSF Energy Rumpke Landfill (71138)	Rumpke landfill gas (OH)to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ	None	Retired
T1N-1638	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: GSF Energy - Rumpke Landfill (71138); Rumpke landfill gas (OH) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; re-gasified in CA	Ohio	Landfill Gas	Compressed Natural Gas	None	None	CNGLF268	67.17	12/21/2017	None	Bio-CNG	WM Renewable Energy, LLC (W978)	GSF Energy Rumpke Landfill (71138)	Rumpke landfill gas (OH)to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; regasified in CA	None	Retired
T1N-1634	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: GSF Energy - Rumpke Landfill (71138); Rumpke landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations	Ohio	Landfill Gas	Compressed Natural Gas	None	None	CNGLF265	52.32	12/1/2017	None	Bio-CNG	WM Renewable Energy, LLC (W978)	GSF Energy Rumpke Landfill (71138)	Rumpke landfill gas (Ohio)to pipelinequality biomethane; delivered via pipeline to California CNG Stations	None	Retired
T2N-1195	Tier 2	2.0	Fuel Producer: REG New Boston, LLC (6067) ; Facility Name: REG New Boston, LLC (81490): Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in New Boston, Texas and transported by rail to California.	Texas	Used Cooking Oil	Biodiesel	None	None	BDU237	14.75	1/8/2018	Application Package	Biodiesel	REG New Boston, LLC (6067)	REG New Boston, LLC (81490)	Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in New Boston, Texas and transported by rail to California	None	Retired

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T2N-1208	Tier 2	2.0	Fuel Producer: 3 Phases Renewables Inc. (P306) ; Facility Name: 3PR (P1225): Solar-based (Photovoltaic) Electricity for a Single Dual Port Electric Vehicle Charging Station.	California	Solar or Wind	Electricity	None	None	ELCR200	0.00	1/26/2018	Application Package	Electricity	3 Phases Renewables Inc (P306)	3PR (P1225)	Solarbased (Photovoltaic)Electricity for a Single Dual Port Electric Vehicle Charging Station	None	Retired
T2N-1166	Tier 2	2.0	Fuel Producer: REG Newton, LLC (3514) ; Facility Name: REG Newton, LLC (80162): Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in Newton, Iowa and transported by rail to California.	Iowa	Used Cooking Oil	Biodiesel	None	None	BDU235	15.49	1/8/2018	Application Package	Biodiesel	REG Newton, LLC (3514) ;	REG Newton, LLC (80162)	Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in Newton, Iowa and transported by rail to California	None	Retired
T2N-1158	Tier 2	2.0	Fuel Producer: FirstElement Fuel (E426): North American fossil NG to Hydrogen (H2) gas production by Steam Reforming of methane via pipeline to California then liquefied, re-gasified, and trucked to multiple H2 dispensing locations	California	North American Natural Gas	Hydrogen	None	None	HYGN001_2	151.01	4/5/2017	None	Hydrogen	FirstElement Fuel (E426)	North American fossil NG to Hydrogen (H2)	gas production by Steam Reforming of methane via pipeline to California then liquefied, regasified, and trucked to multiple H2 dispensing locations	None	Retired
T2N-1233	Tier 2	2.0	Fuel Producer: JC Chemical Co., Ltd. (6094) ; Facility Name: JC Chemical Co., Ltd. (81585); Tier 2 Method 2B Pathway: Rendered Used Cooking Oil (UCO), Biodiesel produced in Ulsan, South Korea and transported by ocean tanker to California	Korea, South	Used Cooking Oil	Biodiesel	None	None	BDU238	20.15	3/1/2018	Application Package	Biodiesel	JC Chemical Co Ltd (6094)	JC Chemical Co Ltd (81585)	Tier 2 Method 2B Pathway Rendered Used Cooking Oil (UCO), Biodiesel produced in Ulsan, South Korea and transported by ocean tanker to California	None	Retired
T2N-1216	Tier 2	2.0	Fuel Producer: General Biodiesel Seattle, LLC (3367); Facility Name: General Biodiesel Seattle, LLC (80086); Tier 2 Method 2B Pathway: Biodiesel produced from US sourced Used Cooking Oil (UCO). Fuel produced in Seattle, Washington and transported by rail to California (Provisional)	Washington	Used Cooking Oil	Biodiesel	None	None	BDU239	28.81	3/7/2018	Application Package	Biodiesel	General Biodiesel Seattle, LLC (3367)	General Biodiesel Seattle, LLC (80086)	Tier 2 Method 2B Pathway Biodiesel produced from US sourced Used Cooking Oil (UCO)Fuel produced in Seattle, Washington and transported by rail to California (Provisional)	None	Retired
T1N-1476	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Barra Grande de Lençóis S.A. (70412); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting	Brazil	Sugarcane	Ethanol	None	None	ETHS250	47.71	3/13/2018	None	Ethanol	Copersucar (3702)	Usina Barra Grande de Lençóis SA (70412)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1761	Tier 1	2.0	Fuel Producer: Dakota Spirit AgEnergy (6286) Facility Name: Dakota Spirit AgEnergy (71202): Corn Ethanol, Dry Mill, Midwest, Steam, NG	North Dakota	Corn	Ethanol	None	None	ETHC288	69.47	7/5/2017	None	Ethanol	Dakota Spirit AgEnergy (6286)	Dakota Spirit AgEnergy (71202)	Corn Ethanol, Dry Mill, Midwest, Steam, NG	None	Retired
T1N-1210	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Gasa (70551). Brazilian sugarcane juice-to-ethanol pathway, with credit for surplus cogenerated electricity export and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS221	46.07	12/20/2016	None	Ethanol	Raízen Energia S/A (3805)	Gasa (70551)	Brazilian sugarcane juicetoethanol pathway, with credit for surplus cogenerated electricity export and mechanized harvesting	None	Retired
T1N-1382	Tier 1	2.0	Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Global high Energy Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore	Singapore	Tallow	Renewable Diesel	None	None	RDT202	39.06	7/1/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Global high Energy Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore	None	Retired
T2N-1012	Tier 2	2.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066) (provisional); Tier 2 Method 2B Pathway: Uncooked Used Cooking Oil (UCO), Biodiesel produced in Coachella, California and transported by truck to locations in California (Provisional)	California	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU240	19.00	3/29/2018	Application Package	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Tier 2 Method 2B Pathway Uncooked Used Cooking Oil (UCO), Biodiesel produced in Coachella, California and transported by truck to locations in California (Provisional)	None	Retired
T2N-1229	Tier 2	2.0	Fuel Producer: SeQuential Pacific Biodiesel LLC (6129) ; Facility Name: SeQuential-Pacific Biodiesel, LLC. (83525); Tier 2 Method 2B Pathway: Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO). Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California (Provisional)	Oregon	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU241	18.43	3/29/2018	Application Package	Biodiesel	SeQuential Pacific Biodiesel LLC (6129)	SeQuentialPacific Biodiesel, LLC(83525)	Tier 2 Method 2B Pathway Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO)Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California (Provisional)	None	Retired
T1N-1768	Tier 1	2.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Rendered Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California	Illinois	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU242	21.84	4/2/2018	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Rendered Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California	None	Retired

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T1N-1770	Tier 1	2.0	Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: REG Seneca, LLC (80232); U.S. sourced rendered Tallow; Biodiesel Produced in Seneca, Illinois and transported by rail to California	Illinois	Tallow & Animal Fat	Biodiesel	None	None	BDT219	35.79	4/2/2018	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	US sourced rendered Tallow; Biodiesel Produced in Seneca, Illinois and transported by rail to California	None	Retired
T2N-1242	Tier 2	2.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953) ; Facility Name: Dansuk Industrial Co., Ltd (81302); Tier 2 Method 2B Pathway: Rendered Used Cooking Oil (UCO), Biodiesel produced in Shiheung-City, South Korea and transported by ocean tanker to California	South Korea	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU243	27.00	4/9/2018	Application Package	Biodiesel	Dansuk Industrial Co Ltd (5953)	Dansuk Industrial Co Ltd (81302)	Tier 2 Method 2B Pathway Rendered Used Cooking Oil (UCO), Biodiesel produced in ShiheungCity, South Korea and transported by ocean tanker to California	None	Retired
T1N-1621	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: CERF Shelby LLC (71163) (Provisional); North Shelby landfill gas (TN) to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	Tennessee	Landfill Gas	CNG	CNGLF250	54.87	CNGLF250R	55.00	4/25/2018	None	Bio-CNG	Clean Energy (5481)	CERF Shelby LLC (71163)(Provisional)	North Shelby landfill gas (TN)to pipelinequality biomethane; delivered via pipeline to CNG Stations in California	None	Retired
T1N-1624	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: CERF Shelby LLC (71163); North Shelby landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona	California	Landfill Gas	LNG	LNGLF220	62.18	LNGLF220R	62.30	4/25/2018	None	Bio-LNG	Clean Energy (5481)	CERF Shelby LLC (71163)	North Shelby landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona	None	Retired
T1N-1625	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: CERF Shelby LLC (71163) (Provisional); North Shelby landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; re-gasified in California	California	Landfill Gas - L-CNG	CNG	CNGLF253	64.71	CNGLF253R	64.85	4/25/2018	None	Bio-CNG	Clean Energy (5481)	CERF Shelby LLC (71163)(Provisional)	North Shelby landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; regasified in California	None	Retired
T1N-1812	Tier 1	2.0	Fuel Producer: Victor Valley Transit Authority (V056) ; Facility Name: River Birch Landfill (R7407); River Birch landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Texas	Landfill Gas	CNG	CNGLF269	40.73	CNGLF269R	44.33	2/6/2019	None	Bio-CNG	Victor Valley Transit Authority (V056)	River Birch Landfill (R7407)	River Birch landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T2N-1250	Tier 2	2.0	Fuel Producer: Apple (A449) ; Facility Name: VP02 (V8866); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity for 26 dual head ChargePoint electric vehicle charging stations (Provisional)	California	Solar or Wind	Electricity	None	None	ELCR201	0.00	5/4/2018	Application Package	Electricity	Apple (A449)	VP02 (V8866)	Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity for 26 dual head ChargePoint electric vehicle charging stations (Provisional)	None	Retired
T2N-1251	Tier 2	2.0	Fuel Producer: Apple (A449) ; Facility Name: HS01 (H3518); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity for seven dual head ChargePoint electric vehicle charging stations (Provisional)	California	Solar or Wind	Electricity	None	None	ELCR202	0.00	5/4/2018	Application Package	Electricity	Apple (A449)	HS01 (H3518)	Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity for seven dual head ChargePoint electric vehicle charging stations (Provisional)	None	Retired
T1N-1822	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154) ; Facility Name: Pine Hill Renewables, LLC (71288); Pine Hill landfill gas in Kilgore, TX to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Texas	Landfill Gas	CNG	None	None	CNGLF272	39.83	6/7/2018	None	Bio-CNG	Shell Energy North America (6154)	Pine Hill Renewables, LLC (71288)	Pine Hill landfill gas in Kilgore, TX to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T2N-1236	Tier 2	2.0	Fuel Producer: Adkins Energy LLC (4767) ; Facility Name: Adkins Energy, LLC (70070); Tier 2 Method 2B Pathway: Midwest sourced corn oil, Biodiesel produced in Lena, Illinois and transported by rail to California (Provisional)	Illinois	Corn Oil	Biodiesel	None	None	BDC214	37.31	6/15/2018	Application Package	Biodiesel	Adkins Energy LLC (4767)	Adkins Energy, LLC (70070)	Tier 2 Method 2B Pathway Midwest sourced corn oil, Biodiesel produced in Lena, Illinois and transported by rail to California (Provisional)	None	Retired
T2N-1232	Tier 2	2.0	Fuel Producer: ASB Biodiesel Hong Kong (6347) ; Facility Name: ASB Biodiesel Hong Kong (83359); Tier 2 Method 2B Pathway: Rendered Waste Oils and Greases, Biodiesel produced in Hong Kong and transported by ocean tanker to California	Hong Kong	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU245	27.80	6/21/2018	Application Package	Biodiesel	ASB Biodiesel Hong Kong (6347)	ASB Biodiesel Hong Kong (83359)	Tier 2 Method 2B Pathway Rendered Waste Oils and Greases, Biodiesel produced in Hong Kong and transported by ocean tanker to California	None	Retired
T2N-1202	Tier 2	2.0	Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: REG Seneca, LLC (80232); Tier 2 Method 2B Pathway: Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in Seneca, Illinois and transported by rail to California	Illinois	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU244	16.57	6/21/2018	Application Package	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Tier 2 Method 2B Pathway Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in Seneca, Illinois and transported by rail to California	None	Retired

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T2N-1257	Tier 2	2.0	Fuel Producer: Albertsons Companies, Inc. (A505) ; Facility Name: Safeway Tracy Distribution Center (17814); Tier 2 Method 2B Pathway: Wind electricity for charging electric forklifts in Tracy, California (Provisional)	California	Solar or Wind	Electricity	None	None	ELCR203	0.00	6/21/2018	Application Package	Electricity	Albertsons Companies, Inc (A505)	Safeway Tracy Distribution Center (17814)	Tier 2 Method 2B Pathway Wind electricity for charging electric forklifts in Tracy, California (Provisional)	None	Retired
T2N-1189	Tier 2	2.0	Fuel Producer: Linde LLC (L012); Facility Name: Linde Canada LH2 Plant (R1980); Tier 2 Method 2B Pathway: Compressed Hydrogen from co-product hydrogen produced at a sodium chlorate plant (includes liquefaction and regasification steps) and transported by truck to fueling stations in California (Provisional)	Canada	Sodium Chlorate Production Process	Hydrogen	None	None	HYGSC200	56.06	6/26/2018	Application Package	Hydrogen	Linde LLC (L012)	Linde Canada LH2 Plant (R1980)	Tier 2 Method 2B Pathway Compressed Hydrogen from coproduct hydrogen produced at a sodium chlorate plant (includes liquefaction and regasification steps)and transported by truck to fueling stations in California (Provisional)	None	Retired
T1N-1809	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Shade (71134); JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Pennsylvania	Landfill Gas	CNG	None	None	CNGLF273	49.77	6/27/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy Shade (71134)	JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1781	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Southern Alleghenies (PA) landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Pennsylvania	Landfill Gas	CNG	None	None	CNGLF274	58.84	6/27/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy Southern Alleghenies (71133)	Southern Alleghenies (PA)landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1831	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Raeger (71131); Laurel Highlands (PA) landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Pennsylvania	Landfill Gas	CNG	None	None	CNGLF275	42.86	6/27/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy Raeger (71131)	Laurel Highlands (PA)landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T2N-1243	Tier 2	2.0	Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: REG Seneca, LLC (80232); Tier 2 Method 2B Pathway: U.S. sourced Brown/Trap Grease as Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California	Illinois	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU246	23.18	7/27/2018	Application Package	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Tier 2 Method 2B Pathway US sourced Brown/Trap Grease as Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California	None	Retired
T2N-1247	Tier 2	2.0	Fuel Producer: Southwest Iowa Renewable Energy (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Tier 2 Method 2B Pathway: Midwest, dry mill, corn ethanol produced using coal-derived steam and natural gas for process heat in Council Bluffs, Iowa and transported by rail to California	Iowa	Corn	Ethanol	None	None	ETHC298	79.79	8/2/2018	Application Package	Ethanol	Southwest Iowa Renewable Energy (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Tier 2 Method 2B Pathway Midwest, dry mill, corn ethanol produced using coalderived steam and natural gas for process heat in Council Bluffs, Iowa and transported by rail to California	None	Retired
T1N-1835	Tier 1	2.0	Fuel Producer: Ag Processing Inc (4552) ; Facility Name: AGP Methyl Ester (St Joseph) (81732); Biodiesel produced from Soybean Oil (self-extraction) in St. Joseph, Missouri and transported by rail to California.	Missouri	Soybean Oil	Biodiesel	None	None	BDS213	50.48	8/27/2018	None	Biodiesel	Ag Processing Inc (4552)	AGP Methyl Ester (St Joseph)(81732)	Biodiesel produced from Soybean Oil (selfextraction)in St Joseph, Missouri and transported by rail to California	None	Retired
T1N-1855	Tier 1	2.0	Fuel Producer: Ag Processing Inc (4552) ; Facility Name: Ag Processing Inc - Sgt. Bluff (81733); Biodiesel produced from Soybean Oil in Sergeant Bluff, Iowa (self-extraction) and transported by rail to California.	Iowa	Soybean Oil	Biodiesel	None	None	BDS214	50.03	8/27/2018	None	Biodiesel	Ag Processing Inc (4552)	Ag Processing Inc Sgt Bluff (81733)	Biodiesel produced from Soybean Oil in Sergeant Bluff, Iowa (selfextraction)and transported by rail to California	None	Retired
T2N-1249	Tier 2	2.0	Fuel Producer: Thumb BioEnergy (3862) ; Facility Name: Thumb BioEnergy (03862); Tier 2 Method 2B Pathway: Locally sourced, Self-Rendered Used Cooking Oil. Biodiesel produced in Sandusky, MI and transported by rail to California	Michigan	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU248	20.90	9/20/2018	Application Package	Biodiesel	Thumb BioEnergy (3862)	Thumb BioEnergy (03862)	Tier 2 Method 2B Pathway Locally sourced, SelfRendered Used Cooking Oil;Biodiesel produced in Sandusky, MI and transported by rail to California	None	Retired
T1N-1851	Tier 1	2.0	Fuel Producer: Solfuels USA LLC (S357) ; Facility Name: Solfuels USA LLC (82892); Biodiesel produced from Soybean Oil in Helena, Arkansas; Soybean extracted in the Midwest; Fuel transported by rail to California (Provisional)	Arkansas	Soybean Oil	Biodiesel	None	None	BDS215	55.10	9/20/2018	None	Biodiesel	Solfuels USA LLC (S357)	Solfuels USA LLC (82892)	Biodiesel produced from Soybean Oil in Helena, Arkansas; Soybean extracted in the Midwest; Fuel transported by rail to California (Provisional)	None	Retired
T1N-1861	Tier 1	2.0	Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); U.S. sourced rendered Tallow; Biodiesel Produced in Danville, Illinois and transported by rail to California (Provisional)	Illinois	Tallow & Animal Fat	Biodiesel	None	None	BDT220	36.80	9/20/2018	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	US sourced rendered Tallow; Biodiesel Produced in Danville, Illinois and transported by rail to California (Provisional)	None	Retired

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T1N-1862	Tier 1	2.0	Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); Rendered Used Cooking Oil (UCO), Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional)	Illinois	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU249	22.58	9/20/2018	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Rendered Used Cooking Oil (UCO), Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional)	None	Retired
T1N-1860	Tier 1	2.0	Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); U.S. sourced corn oil, Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional)	Illinois	Corn Oil	Biodiesel	None	None	BDC215	35.13	9/20/2018	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	US sourced corn oil, Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional)	None	Retired
T1N-1864	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154) ; Facility Name: Melissa Renewables, LLC (71407); Melissa landfill gas in Melissa, TX to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Texas	Landfill Gas	Compressed Natural Gas	None	None	CNGLF276	40.63	9/24/2018	None	Bio-CNG	Shell Energy North America (6154)	Melissa Renewables, LLC (71407)	Melissa landfill gas in Melissa, TX to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1811	Tier 1	2.0	Fuel Producer: Fuel Producer: San Diego Metropolitan Transit Center (S304) ; Facility Name: Facility Name: EBI Energie In (71254); EBI landfill gas in Saint-Thomas, Quebec to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	California	Landfill Gas	CNG	None	None	CNGLF277	32.28	10/3/2018	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	EBI Energie In (71254)	EBI landfill gas in SaintThomas, Quebec to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1863	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Charleston Landfill Gas Processing Facility (71314); Landfill gas in Charleston, West Virginia to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	West Virginia	Landfill Gas	CNG	None	None	CNGLF278	66.55	10/9/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Charleston Landfill Gas Processing Facility (71314)	Landfill gas in Charleston, West Virginia to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1832	Tier 1	2.0	Fuel Producer: Imperial Western Products (9871) ; Facility Name: Imperial Western Products (81066); U.S. sourced rendered Tallow; Biodiesel produced in Coachella, California (Provisional)	California	Tallow & Animal Fat	Biodiesel	None	None	BDT221	38.36	10/15/2018	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	US sourced rendered Tallow; Biodiesel produced in Coachella, California (Provisional)	None	Retired
T2N-1275	Tier 2	2.0	Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); Tier 2 Method 2B Pathway: Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in Danville, Illinois and transported by rail to California (Provisional)	Illinois	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU250	17.33	10/23/2018	Application Package	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Tier 2 Method 2B Pathway Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in Danville, Illinois and transported by rail to California (Provisional)	None	Retired
T1N-1837	Tier 1	2.0	Fuel Producer: POET Biorefining - Big Stone (4736) ; Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill, Wet, Modified, Dry DGS, and corn oil using natural gas, coal, and electricity; Starch ethanol produced from Corn using BPX process in Big Stone, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn	Ethanol	None	None	ETHC306	81.86	12/4/2018	None	Ethanol	POET Biorefining Big Stone (4736)	POET Biorefining Big Stone (70025)	Midwest Corn, Dry Mill, Wet, Modified, Dry DGS, and corn oil using natural gas, coal, and electricity; Starch ethanol produced from Corn using BPX process in Big Stone, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1259	Tier 2	2.0	Fuel Producer: POET Biorefining - Big Stone (4736) ; Facility Name: POET Biorefining - Big Stone (70025); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Big Stone, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS, and corn oil using natural gas, coal, and electricity; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Kernel Fiber	Ethanol	None	None	ETHCF206	38.58	12/4/2018	Application Package	Ethanol - Cellulosic	POET Biorefining Big Stone (4736)	POET Biorefining Big Stone (70025)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Big Stone, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS, and corn oil using natural gas, coal, and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1268	Tier 2	2.0	Fuel Producer: Powerflex (P343) ; Facility Name: Mountain View HS (50381); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity directly supplied to Electric Vehicle charging at Mountain View High School, California	California	Solar or Wind	Electricity	None	None	ELCR205	0.00	12/11/2018	Application Package	Electricity	Powerflex (P343)	Mountain View HS (50381)	Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity directly supplied to Electric Vehicle charging at Mountain View High School, California	None	Retired
T2N-1269	Tier 2	2.0	Fuel Producer: Powerflex (P343) ; Facility Name: Los Altos HS (45044); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity directly supplied to Electric Vehicle charging at Los Altos High School, California	California	Solar or Wind	Electricity	None	None	ELCR204	0.00	12/11/2018	Application Package	Electricity	Powerflex (P343)	Los Altos HS (45044)	Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity directly supplied to Electric Vehicle charging at Los Altos High School, California	None	Retired
T2N-1278	Tier 2	2.0	Fuel Producer: Pinal Energy LLC (4744); Facility Name: Pinal Energy LLC (70136); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Maricopa, Arizona; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Dry DGS; Corn Oil, Syrup; Ethanol transported by truck to California (Provisional)	Arizona	Corn	Ethanol	None	None	ETHC312	38.06	12/18/2018	Application Package	Ethanol	Pinal Energy LLC (4744)	Pinal Energy LLC (70136)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Maricopa, Arizona; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Dry DGS; Corn Oil, Syrup; Ethanol transported by truck to California (Provisional)	None	Retired

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T2N-1248	Tier 2	2.0	Fuel Producer: California Renewable Power LLC (CARP) (C196) ; Facility Name: California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270); Tier 2 Method 2B Pathway; Biogas produced from the anaerobic digestion of 100% green waste in Perris, California, upgraded to biomethane onsite, injected into pipeline, and compressed to transportation fuel in California (Provisional)	California	HSAD Food & Green Waste	CNG	None	None	CNGGW201	0.34	12/20/2018	Application Package	Bio-CNG	California Renewable Power LLC (CARP) (C196)	California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270)	Tier 2 Method 2B Pathway; Biogas produced from the anaerobic digestion of 100% green waste in Perris, California, upgraded to biomethane onsite, injected into pipeline, and compressed to transportation fuel in California (Provisional)	None	Retired
T1N-1865	Tier 1	2.0	Fuel Producer: W2Fuels (LVA Adrian Biofuel LLC) (3251) ; Facility Name: W2Fuels (LVA Adrian Biofuel LLC dba W2Fuel Adrian) (81095); Biodiesel produced from Soybean Oil in Adrian, Michigan and transported by rail to California (Provisional)	Michigan	Soybean Oil	Biodiesel	None	None	BDS216	55.74	12/21/2018	None	Biodiesel	W2Fuels (LVA Adrian Biofuel LLC)(3251)	W2Fuels (LVA Adrian Biofuel LLC dba W2Fuel Adrian)(81095)	Biodiesel produced from Soybean Oil in Adrian, Michigan and transported by rail to California (Provisional)	None	Retired
T1N-1883	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Cambrian Energy (C5950S); Landfill gas from Fort Smith, Arkansas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Arkansas	Landfill Gas	CNG	None	None	CNGLF279	44.51	12/31/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Cambrian Energy (C5950S)	Landfill gas from Fort Smith, Arkansas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T2N-1239	Tier 2	2.0	Fuel Producer: Neste Renewable Fuels Oy (3734) ; Facility Name: Neste Renewable Fuels - Porvoo (80272); Tier 2 Method 2B Pathway: Renewable Diesel produced from Globally Sourced Tallow, Fuel produced in Neste Porvoo Plant and transported by ocean tanker to California	Finland	Tallow & Animal Fat	Renewable Diesel	None	None	RDT208	45.08	1/16/2019	Application Package	Renewable Diesel	Neste Renewable Fuels Oy (3734)	Neste Renewable Fuels Porvoo (80272)	Tier 2 Method 2B Pathway Renewable Diesel produced from Globally Sourced Tallow, Fuel produced in Neste Porvoo Plant and transported by ocean tanker to California	None	Retired
T2N-1264	Tier 2	2.0	Fuel Producer: Neste Renewable Fuels Oy (3734) ; Facility Name: Neste Renewable Fuels - Porvoo (80272); Tier 2 Method 2B Pathway: Renewable Diesel produced from Globally Sourced Tallow. Shipped to Sluiskil Pre-treatment site. Fuel produced in Neste Porvoo Plant and transported to California (Provisional)	Finland	Tallow & Animal Fat	Renewable Diesel	None	None	RDT207	51.90	1/16/2019	Application Package	Renewable Diesel	Neste Renewable Fuels Oy (3734)	Neste Renewable Fuels Porvoo (80272)	Tier 2 Method 2B Pathway Renewable Diesel produced from Globally Sourced Tallow Shipped to Sluiskil Pretreatment site; Fuel produced in Neste Porvoo Plant and transported to California (Provisional)	None	Retired
T2N-1289	Tier 2	2.0	Fuel Producer: Neste Renewable Fuels Oy (3734) ; Facility Name: Neste Renewable Fuels - Porvoo (80272); Tier 2 Method 2B Pathway: Renewable Diesel produced from Globally Sourced UCO, Fuel produced in Neste Finland Plant and transported by ocean tanker to California (Provisional)	Finland	Used Cooking Oil (UCO)	Renewable Diesel	None	None	RDU205	30.97	1/16/2019	Application Package	Renewable Diesel	Neste Renewable Fuels Oy (3734)	Neste Renewable Fuels Porvoo (80272)	Tier 2 Method 2B Pathway Renewable Diesel produced from Globally Sourced UCO, Fuel produced in Neste Finland Plant and transported by ocean tanker to California (Provisional)	None	Retired
T2N-1246	Tier 2	2.0	Fuel Producer: Eco Solutions Co., Ltd (6266) ; Facility Name: Eco Solutions Co., Ltd (83159); Tier 2 Method 2B Pathway: Rendered Used Cooking Oil (UCO) sourced in South Korea, Biodiesel produced in Jeongeup-si, South Korea using bottom distillates as thermal energy, and transported by ocean tanker to California (Provisional)	South Korea	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU251	22.31	3/18/2019	Application Package	Biodiesel	Eco Solutions Co Ltd (6266)	Eco Solutions Co Ltd (83159)	Tier 2 Method 2B Pathway Rendered Used Cooking Oil (UCO)sourced in South Korea, Biodiesel produced in Jeongeupsi, South Korea using bottom distillates as thermal energy, and transported by ocean tanker to California (Provisional)	None	Retired
B001101	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to Los Angeles, California (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B00110100	-372.35	4/10/2019	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ruckman Farm (71256)	Renewable Natural Gas (RNG)sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to Los Angeles, California (Provisional)	None	Retired
B001102	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	Missouri	Swine Manure (044)	Liquefied Natural Gas (LNG)	None	None	LNG044B00110200	-360.37	4/10/2019	Application Package	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Ruckman Farm (71256)	Renewable Natural Gas (RNG)sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	None	Retired
B001103	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to and re-gasified in California (Provisional)	Missouri	Swine Manure (044)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN044B00110300	-356.83	4/10/2019	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ruckman Farm (71256)	Renewable Natural Gas (RNG)sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to and regasified in California (Provisional)	None	Retired
A003301	Tier 1	3.0	Fuel Producer: CORN, LP (5065) ; Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill, Dry DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Goldfield, Iowa; Ethanol transported by rail to California **(Provisional)**	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00330100	70.34	4/15/2019	None	Ethanol	CORN, LP (5065)	CORN, LP (70145)	Midwest Corn, Dry Mill, Dry DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Goldfield, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A001701	Tier 1	3.0	Fuel Producer: Husker Ag LLC (5078) ; Facility Name: Husker Ag LLC (70151); Midwest Corn Starch Ethanol, Dry and Modified DGS, Natural Gas	Nebraska	Corn (009)	Ethanol (ETH)	ETHC295	74.03	ETH009A00170100	66.19	4/15/2019	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn Starch Ethanol, Dry and Modified DGS, Natural Gas	None	Retired

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A004301	Tier 1	3.0	Fuel Producer: Kansas Ethanol, LLC (5810); Facility Name: Kansas Ethanol, LLC (70279); Dry Mill Ethanol, using both Corn and Sorghum, Natural Gas, Grid Electricity, DDGS and wetcake **(Provisional)**	Kansas	Corn (009)	Ethanol (ETH)	ETHC299	67.83	ETH009A00430100	62.79	4/15/2019	None	Ethanol	Kansas Ethanol, LLC (5810)	Kansas Ethanol, LLC (70279)	Dry Mill Ethanol, using both Corn and Sorghum, Natural Gas, Grid Electricity, DDGS and wetcake (Provisional)	None	Retired
A006801	Tier 1	3.0	Fuel Producer: Kansas Ethanol, LLC (5810) ; Facility Name: Kansas Ethanol, LLC (70279); Midwest Sorghum, Dry Mill, Dry and Wet DGS, and Sorghum Oil; Natural Gas and grid electricity; Sorghum starch Ethanol produced in Lyons, Kansas and transported by rail to California (Provisional)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A00680100	67.59	4/15/2019	None	Ethanol	Kansas Ethanol, LLC (5810)	Kansas Ethanol, LLC (70279)	Midwest Sorghum, Dry Mill, Dry and Wet DGS, and Sorghum Oil; Natural Gas and grid electricity; Sorghum starch Ethanol produced in Lyons, Kansas and transported by rail to California (Provisional)	None	Retired
A006901	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754) ; Facility Name: Trenton Agri Products, LLC (70053; Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Trenton, Nebraska and transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC210	69.75	ETH009A00690100	65.13	4/16/2019	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053	Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Trenton, Nebraska and transported by rail to California	None	Retired
A008601	Tier 1	3.0	Fuel Producer: Bridgeport Ethanol, LLC 5934; Facility Name: Bridgeport Ethanol, LLC 70217; Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC229	67.43	ETH009A00860100	62.37	4/16/2019	None	Ethanol	Bridgeport Ethanol, LLC 5934;	Bridgeport Ethanol, LLC (70217)	Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California	None	Retired
A000701	Tier 1	3.0	Fuel Producer: Great Plains Ethanol (4727) ; Facility Name: Great Plains Ethanol, LLC (70012); Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC300	69.04	ETH009A00070100	65.21	5/6/2019	None	Ethanol	Great Plains Ethanol (4727)	Great Plains Ethanol, LLC (70012)	Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California	None	Retired
A000702	Tier 1	3.0	Fuel Producer: Great Plains Ethanol (4727) ; Facility Name: Great Plains Ethanol, LLC (70012); Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETHCF203	27.69	ETH012A00070200	25.06	5/6/2019	None	Ethanol - Cellulosic	Great Plains Ethanol (4727)	Great Plains Ethanol, LLC (70012)	Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California	None	Retired
A003401	Tier 1	3.0	Fuel Producer: Siouxland Ethanol, LLC (5026) ; Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC343	69.28	ETH009A00340100	66.23	5/6/2019	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A003402	Tier 1	3.0	Fuel Producer: Siouxland Ethanol, LLC (5026) ; Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00340200	26.67	5/6/2019	None	Ethanol - Cellulosic	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A003601	Tier 1	3.0	Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC313	71.98	ETH009A00360100	67.09	5/6/2019	None	Ethanol	Mid America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A003602	Tier 1	3.0	Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETHC311	38.12	ETH012A00360200	32.40	5/6/2019	None	Ethanol - Cellulosic	Mid America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A003701	Tier 1	3.0	Fuel Producer: E Energy Adams, LLC (4831) ; Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Adams, Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC310	70.76	ETH009A00370100	66.53	3/29/2019	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Adams, Nebraska; Ethanol transported by rail to California (Provisional)	None	Retired
A004101	Tier 1	3.0	Fuel Producer: Marquis Energy - Wisconsin LLC (5750) ; Facility Name: Marquis Energy - Wisconsin LLC (70269); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Necedah, Wisconsin; Ethanol transported by rail to California	Wisconsin	Corn (009)	Ethanol (ETH)	None	None	ETH009A00410100	72.25	5/7/2019	None	Ethanol	Marquis Energy Wisconsin LLC (5750)	Marquis Energy Wisconsin LLC (70269)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Necedah, Wisconsin; Ethanol transported by rail to California	None	Retired

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A004601	Tier 1	3.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Madera LLC (70061); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas, on-site solar power, and grid electricity; Corn starch ethanol produced in Madera, California; Ethanol transported by rail to California (Provisional)	California	Corn (009)	Ethanol (ETH)	ETHC207R	72.94	ETH009A00460100	66.76	3/29/2019	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Madera LLC (70061)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas, onsite solar power, and grid electricity; Corn starch ethanol produced in Madera, California; Ethanol transported by rail to California (Provisional)	None	Retired
A005101	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00510100	69.86	5/7/2019	None	Ethanol	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005102	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00510200	30.32	5/7/2019	None	Ethanol - Cellulosic	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005301	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786); Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00530100	73.81	5/6/2019	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A005302	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00530200	66.94	5/6/2019	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A005303	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00530300	26.95	5/6/2019	None	Ethanol - Cellulosic	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A005201	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00520100	75.97	5/6/2019	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005202	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00520200	68.75	5/6/2019	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005203	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00520300	28.78	5/6/2019	None	Ethanol - Cellulosic	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005701	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782) ; Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00570100	76.25	5/6/2019	None	Ethanol	POET Biorefining Ashton (4782)	POET BIOREFINING ASHTON (OTTER CREEK ETHANOL, LLC)(70032)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005702	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782) ; Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00570200	67.07	5/6/2019	None	Ethanol	POET Biorefining Ashton (4782)	POET BIOREFINING ASHTON (OTTER CREEK ETHANOL, LLC)(70032)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005703	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782) ; Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00570300	28.39	5/6/2019	None	Ethanol - Cellulosic	POET Biorefining Ashton (4782)	POET BIOREFINING ASHTON (OTTER CREEK ETHANOL, LLC)(70032)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired

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A005801	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A00580100	81.17	5/7/2019	None	Ethanol	POET Biorefining Bingham Lake (4780)	POET BIOREFINING BINGHAM LAKE (ETHANOL 2000, LLP)(70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005802	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A00580200	71.82	5/7/2019	None	Ethanol	POET Biorefining Bingham Lake (4780)	POET BIOREFINING BINGHAM LAKE (ETHANOL 2000, LLP)(70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005803	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00580300	31.75	5/7/2019	None	Ethanol - Cellulosic	POET Biorefining Bingham Lake (4780)	POET BIOREFINING BINGHAM LAKE (ETHANOL 2000, LLP)(70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006201	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC307	79.20	ETH009A00620100	75.24	5/7/2019	None	Ethanol	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006202	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789) ; Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC307	79.20	ETH009A00620200	67.72	5/7/2019	None	Ethanol	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006203	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETHCF207	35.67	ETH012A00620300	27.36	5/7/2019	None	Ethanol - Cellulosic	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006301	Tier 1	3.0	Fuel Producer: POET Biorefining - Groton (4793); Facility Name: POET Biorefining - Groton (70013); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC308	78.56	ETH009A00630100	75.15	5/7/2019	None	Ethanol	POET Biorefining Groton (4793)	POET Biorefining Groton (70013)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006302	Tier 1	3.0	Fuel Producer: POET Biorefining - Groton (4793) ; Facility Name: POET Biorefining - Groton (70013); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC308	78.56	ETH009A00630200	67.60	5/7/2019	None	Ethanol	POET Biorefining Groton (4793)	POET Biorefining Groton (70013)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006303	Tier 1	3.0	Fuel Producer: POET Biorefining - Groton (4793) ; Facility Name: POET Biorefining - Groton (70013); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETHCF208	34.79	ETH012A00630300	27.48	5/7/2019	None	Ethanol - Cellulosic	POET Biorefining Groton (4793)	POET Biorefining Groton (70013)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006401	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC309	78.06	ETH009A00640100	75.04	5/7/2019	Legacy CI is from a composite pathway containing both dry and wet DGS.	Ethanol	POET Biorefining Gowrie (4784)	POET Biorefining Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006402	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC309	78.06	ETH009A00640200	68.04	5/7/2019	Legacy CI is from a composite pathway containing both dry and wet DGS.	Ethanol	POET Biorefining Gowrie (4784)	POET Biorefining Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006403	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETHCF209	34.30	ETH012A00640300	27.72	5/7/2019	None	Ethanol - Cellulosic	POET Biorefining Gowrie (4784)	POET Biorefining Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired

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A007401	Tier 1	3.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Stockton LLC (70319); Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	California	Corn (009)	Ethanol (ETH)	ETHC216	69.64	ETH009A00740100	65.77	3/29/2019	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	None	Retired
A007402	Tier 1	3.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Stockton LLC (70319); Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	California	Corn (009)	Ethanol (ETH)	ETHC217	65.36	ETH009A00740200	61.54	3/29/2019	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	None	Retired
A007403	Tier 1	3.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Stockton LLC (70319); Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	California	Corn Fiber (012)	Ethanol (ETH)	ETHCF202	39.45	ETH012A00740300	32.62	3/29/2019	None	Ethanol - Cellulosic	Pacific Ethanol West (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	None	Retired
A008801	Tier 1	3.0	Fuel Producer: Yuma Ethanol, LLC (4735) ; Facility Name: Yuma Ethanol, LLC (70024); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California	Colorado	Corn (009)	Ethanol (ETH)	ETHC228	67.68	ETH009A00880100	64.61	5/17/2019	None	Ethanol	Yuma Ethanol, LLC (4735)	Yuma Ethanol, LLC (70024)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California	None	Retired
A008901	Tier 1	3.0	Fuel Producer: Sterling Ethanol, LLC (4766) ; Facility Name: Sterling Ethanol, LLC (70660); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol produced in Sterling, Colorado; Ethanol transported by rail to California	Colorado	Corn (009)	Ethanol (ETH)	ETHC283	69.39	ETH009A00890100	64.10	5/17/2019	None	Ethanol	Sterling Ethanol, LLC (4766)	Sterling Ethanol, LLC (70660)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol produced in Sterling, Colorado; Ethanol transported by rail to California	None	Retired
A009901	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC303	78.68	ETH009A00990100	73.79	5/17/2019	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional)	None	Retired
A009902	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805) ; Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC302	66.74	ETH009A00990200	63.23	5/17/2019	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional)	None	Retired
A009401	Tier 1	3.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) ; Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas (cogen) and grid electricity; Corn starch Ethanol produced in Ceres, California (Provisional)	California	Corn (009)	Ethanol (ETH)	ETHC211	70.23	ETH009A00940100	67.03	5/21/2019	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas (cogen)and grid electricity; Corn starch Ethanol produced in Ceres, California (Provisional)	None	Retired
A005501	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779) ; Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A00550100	77.80	5/24/2019	None	Ethanol	POET Biorefining Glenville (4779)	POET BIOREFINING GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	None	Retired
A005502	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779) ; Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A00550200	69.57	5/24/2019	None	Ethanol	POET Biorefining Glenville (4779)	POET BIOREFINING GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	None	Retired
A005503	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779) ; Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00550300	29.51	5/24/2019	None	Ethanol - Cellulosic	POET Biorefining Glenville (4779)	POET BIOREFINING GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	None	Retired
A007801	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Shreveport Biogas (70121); Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to L-CNG in California (Provisional)	Louisiana	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A00780100	61.21	5/29/2019	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Shreveport Biogas (70121)	Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to LCNG in California (Provisional)	None	Retired

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A007802	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Shreveport Biogas (70121); Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to L-CNG in California (Provisional)	Louisiana	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A00780200	64.29	5/29/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Shreveport Biogas (70121)	Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to LCNG in California (Provisional)	None	Retired
A009801	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805) ; Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Minden, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC225	67.10	ETH009A00980100	61.48	5/29/2019	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Minden, Nebraska; Ethanol transported by rail to California	None	Retired
A007201	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Shreveport Biogas (70121); Landfill gas from Shreveport, Louisiana to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Louisiana	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A00720100	40.37	5/29/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Shreveport Biogas (70121)	Landfill gas from Shreveport, Louisiana to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
A011001	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01100100	46.54	5/29/2019	None	Bio-CNG	U.S. Venture, Inc. (5504)	Ameresco Woodland Meadows Romulus, LLC (A0833)	Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	None	Retired
A011002	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	Michigan	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A01100200	63.69	5/29/2019	None	Bio-LNG	U.S. Venture, Inc. (5504)	Ameresco Woodland Meadows Romulus, LLC (A0833)	Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	None	Retired
A011003	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	Michigan	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A01100300	66.78	5/29/2019	None	Bio-CNG	U.S. Venture, Inc. (5504)	Ameresco Woodland Meadows Romulus, LLC (A0833)	Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	None	Retired
A008101	Tier 1	3.0	Fuel Producer: East Kansas Agri-Energy, LLC (4483) ; Facility Name: East Kansas Agri-Energy, LLC (83483); Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Garnett, Kansas and transported by truck and rail to California	Kansas	Corn (009)	Ethanol (ETH)	None	None	ETH009A00810100	67.53	5/30/2019	None	Ethanol	East Kansas Agri-Energy, LLC (4483)	East Kansas Agri-Energy, LLC (83483)	Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Garnett, Kansas and transported by truck and rail to California	None	Retired
A005001	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	Missouri	Corn (009)	Ethanol (ETH)	None	None	ETH009A00500100	70.67	6/3/2019	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	None	Retired
A005002	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	Missouri	Corn (009)	Ethanol (ETH)	None	None	ETH009A00500200	62.76	6/3/2019	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	None	Retired
A005003	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	Missouri	Corn (009)	Ethanol (ETH)	None	None	ETH012A00500300	23.18	6/3/2019	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	None	Retired
A009501	Tier 1	3.0	Fuel Producer: Clean Energy (5481); Facility Name: CEFARI RNG OKC, LLC (F00022); Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Oklahoma	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A00950100	51.74	6/3/2019	None	Bio-CNG	Clean Energy (5481)	CEFARI RNG OKC, LLC (F00022)	Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
A006101	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC305	80.94	ETH009A00610100	76.85	6/5/2019	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006102	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC305	80.94	ETH009A00610200	69.76	6/5/2019	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired

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A006103	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETHCF205	36.92	ETH012A00610300	29.51	6/5/2019	None	Ethanol - Cellulosic	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A008303	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Distillers' Corn Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	Minnesota	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC211	33.52	BIO003A00830300	24.55	6/7/2019	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Distillers' Corn Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A008304	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A00830400	17.72	6/7/2019		Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A008305	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A00830500	11.99	6/7/2019		Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A008306	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	Minnesota	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT215	36.29	BIO002A00830600	28.89	6/7/2019	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A010002	Tier 1	3.0	Fuel Producer: The Andersons, Inc (5872); Facility Name: The Andersons Denison Ethanol (70135); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC275	76.35	ETH009A01000200	67.48	6/7/2019	None	Ethanol	The Andersons, Inc (5872)	The Andersons Denison Ethanol (70135)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	None	Retired
A005401	Tier 1	3.0	Fuel Producer: Poet Biorefining Corning (5046); Facility Name: Poet Biorefining Corning (70143); Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00540100	73.97	6/10/2019	None	Ethanol	Poet Biorefining Corning (5046)	Poet Biorefining Corning (70143)	Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005402	Tier 1	3.0	Fuel Producer: Poet Biorefining Corning (5046); Facility Name: Poet Biorefining Corning (70143); Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00540200	67.03	6/10/2019	None	Ethanol	Poet Biorefining Corning (5046)	Poet Biorefining Corning (70143)	Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005403	Tier 1	3.0	Fuel Producer: Poet Biorefining Corning (5046); Facility Name: Poet Biorefining Corning (70143); Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00540300	27.26	6/10/2019	None	Ethanol - Cellulosic	Poet Biorefining Corning (5046)	Poet Biorefining Corning (70143)	Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005601	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00560100	74.83	6/10/2019	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005602	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00560200	68.44	6/10/2019	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005603	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00560300	28.47	6/10/2019	None	Ethanol - Cellulosic	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired

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A006001	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC301	79.55	ETH009A00600100	73.99	6/10/2019	None	Ethanol	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006002	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC301	79.55	ETH009A00600200	66.22	6/10/2019	None	Ethanol	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006003	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETHCF204	35.39	ETH012A00600300	26.08	6/10/2019	None	Ethanol - Cellulosic	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A010301	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC234L	67.73	ETH009A01030100	75.50	6/28/2019	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	None	Retired
A010305	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054) ; Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	None	None	ETH009A01030500	63.21	6/28/2019	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	None	Retired
A010306	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054) ; Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG003	73.39	ETH010A01030600	77.77	6/28/2019	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	None	Retired
A010307	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A01030700	65.48	6/28/2019	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	None	Retired
A010101	Tier 1	3.0	Fuel Producer: American Greenfuels, LLC (6341) ; Facility Name: AMERICAN GREENFUELS LLC (83357); New England sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in New Haven, Connecticut and transported by rail to California (Provisional)	Connecticut	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01010100	21.04	8/5/2019	None	Biodiesel	American Greenfuels, LLC (6341)	AMERICAN GREENFUELS LLC (83357)	New England sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in New Haven, Connecticut and transported by rail to California (Provisional)	None	Retired
A011201	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC315	72.14	ETH009A01120100	68.75	8/5/2019	None	Ethanol	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional)	None	Retired
A011202	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Marcus, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETHCF200R	44.19	ETH012A01120200	30.06	8/5/2019	None	Ethanol - Cellulosic	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Marcus, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A011203	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A01120300	65.90	8/5/2019	None	Ethanol	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional)	None	Retired
A012101	Tier 1	3.0	Fuel Producer: Golden Grain Energy, LLC (4829) ; Facility Name: Golden Grain Energy (70691); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC212	77.43	ETH009A01210100	73.76	8/5/2019	None	Ethanol	Golden Grain Energy, LLC (4829)	Golden Grain Energy (70691)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired

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A012102	Tier 1	3.0	Fuel Producer: Golden Grain Energy, LLC (4829); Facility Name: Golden Grain Energy (70691); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC213	73.86	ETH009A01210200	70.53	8/5/2019	None	Ethanol	Golden Grain Energy, LLC (4829)	Golden Grain Energy (70691)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A012103	Tier 1	3.0	Fuel Producer: Golden Grain Energy, LLC (4829); Facility Name: Golden Grain Energy (70691); Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Mason City, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01210300	29.09	8/5/2019	None	Ethanol - Cellulosic	Golden Grain Energy, LLC (4829)	Golden Grain Energy (70691)	Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Mason City, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A011801	Tier 1	3.0	Fuel Producer: Pacific Ethanol West (3697); Facility Name: Pacific Ethanol Magic Valley LLC (70291); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Burley, Idaho; Ethanol transported by rail to California	Idaho	Corn (009)	Ethanol (ETH)	ETHC251L	68.89	ETH009A01180100	66.44	8/6/2019	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Magic Valley LLC (70291)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Burley, Idaho; Ethanol transported by rail to California	None	Retired
A012502	Tier 1	3.0	Fuel Producer: Plymouth Energy LLC (5474); Facility Name: Plymouth Energy LLC (70183); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC286	75.94	ETH009A01250200	68.41	8/6/2019	None	Ethanol	Plymouth Energy LLC (5474)	Plymouth Energy LLC (70183)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California	None	Retired
A013701	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810) ; Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC208R	76.65	ETH009A01370100	72.86	8/5/2019	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	None	Retired
A013702	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC208R	76.65	ETH009A01370200	69.05	8/5/2019	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	None	Retired
A013703	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810) ; Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC208R	76.65	ETH009A01370300	65.76	8/5/2019	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	None	Retired
A014501	Tier 1	3.0	Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC240L	74.00	ETH009A01450100	69.60	8/6/2019	None	Ethanol	Redfield Energy, LLC (4061)	Redfield Energy, LLC (70111)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California	None	Retired
A010201	Tier 1	3.0	Fuel Producer: Guardian Energy, LLC (3383); Facility Name: Guardian Energy, LLC (70289); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Janesville, Minnesota; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	ETHC289	75.43	ETH009A01020100	69.29	8/9/2019	None	Ethanol	Guardian Energy, LLC (3383)	Guardian Energy, LLC (70289)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Janesville, Minnesota; Ethanol transported by rail to California (Provisional)	None	Retired
A010202	Tier 1	3.0	Fuel Producer: Guardian Energy, LLC (3383); Facility Name: Guardian Energy, LLC (70289); Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Janesville, Minnesota using SOLITON conversion method; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01020200	26.35	8/9/2019	None	Ethanol - Cellulosic	Guardian Energy, LLC (3383)	Guardian Energy, LLC (70289)	Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Janesville, Minnesota using SOLITON conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A010901	Tier 1	3.0	Fuel Producer: SIMPLE FUELS BIODIESEL INC (3717) ; Facility Name: SIMPLE FUELS BIODIESEL (80207); U.S. sourced, Non-Rendered UCO; Biodiesel and Grid Electricity; Biodiesel produced in Chilcoot, CA; Biodiesel transported by truck to stations in California (Provisional)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01090100	14.73	9/24/2019	None	Biodiesel	SIMPLE FUELS BIODIESEL INC (3717)	SIMPLE FUELS BIODIESEL (80207)	U.S. sourced, Non-Rendered UCO; Biodiesel and Grid Electricity; Biodiesel produced in Chilcoot, CA; Biodiesel transported by truck to stations in California (Provisional)	None	Retired
A012001	Tier 1	3.0	Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC239L	70.04	ETH009A01200100	63.44	9/5/2019	None	Ethanol	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired

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A012002	Tier 1	3.0	Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Sioux Center, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETHCF201R	42.17	ETH012A01200200	45.82	9/5/2019	None	Ethanol - Cellulosic	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Sioux Center, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A012701	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01270100	28.33	9/24/2019	None	Ethanol - Cellulosic	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012702	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A01270200	75.89	9/24/2019	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012703	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A01270300	67.79	9/24/2019	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012801	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) ; Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A01280100	77.91	9/24/2019	None	Ethanol	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012802	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A01280200	67.99	9/24/2019	None	Ethanol	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012803	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) ; Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01280300	28.29	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012901	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A01290100	74.62	9/24/2019	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Minnesota; Ethanol transported by rail to California (Provisional)	None	Retired
A012902	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A01290200	67.54	9/24/2019	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Minnesota; Ethanol transported by rail to California (Provisional)	None	Retired
A012903	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01290300	27.44	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Minnesota; Ethanol transported by rail to California (Provisional)	None	Retired
A013001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01300100	74.35	9/24/2019	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	None	Retired
A013002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01300200	67.34	9/24/2019	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	None	Retired

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A013003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01300300	27.54	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	None	Retired
A013601	Tier 1	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Live Oak Landfill Gas Plant (70002); Live Oak Landfill Gas plant landfill gas to pipelie-quality biomethane in Conley, GA; Deliverd via pipeline; Compressed to CNG in California (Provisional)	Georgia	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01360100	44.64	9/25/2019	None	Bio-CNG	Shell Energy North America (6154)	Live Oak Landfill Gas Plant (70002)	Live Oak Landfill Gas plant landfill gas to pipelie-quality biomethane in Conley, GA; Deliverd via pipeline; Compressed to CNG in California (Provisional)	None	Retired
A014101	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846); Facility Name: HPB - St. Joe Biodiesel LLC (80059); Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	Missouri	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC212	37.30	BIO003A01410100	29.40	9/25/2019	None	Biodiesel	High Plains Bioenergy (4846)	HPB - St. Joe Biodiesel LLC (80059)	Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	None	Retired
A014102	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846); Facility Name: HPB - St. Joe Biodiesel LLC (80059); Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	Missouri	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A01410200	34.21	9/25/2019	None	Biodiesel	High Plains Bioenergy (4846)	HPB - St. Joe Biodiesel LLC (80059)	Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	None	Retired
A013901	Tier 1	3.0	Fuel Producer: Midwest Renewable Energy (5214); Facility Name: Midwest Renewable Energy (70160); Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC279	69.83	ETH009A01390100	62.81	9/9/2019	None	Ethanol	Midwest Renewable Energy (5214)	Midwest Renewable Energy (70160)	Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California (Provisional)	None	Retired
A014001	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC297	69.11	ETH009A01400100	63.69	9/9/2019	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A014002	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715) ; Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC296	78.63	ETH009A01400200	72.42	9/9/2019	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A014003	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG219	76.92	ETH010A01400300	66.76	9/9/2019	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A014004	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG218	86.22	ETH010A01400400	75.50	9/9/2019	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A014601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	Michigan	Corn (009)	Ethanol (ETH)	None	None	ETH009A01460100	72.59	9/24/2019	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	None	Retired
A014602	Tier 1	3.0	Fuel Producer: Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	Michigan	Corn (009)	Ethanol (ETH)	None	None	ETH009A01460200	67.10	9/24/2019	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	None	Retired
A014603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	Michigan	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01460300	27.33	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	None	Retired

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A015501	Tier 1	3.0	Fuel Producer: Absolute Energy, LLC (5049) ; Facility Name: Absolute Energy, LLC (70144); Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC203	76.69	ETH009A01550100	67.97	9/24/2019	None	Ethanol	Absolute Energy, LLC (5049)	Absolute Energy, LLC (70144)	Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI (Provisional)	None	Retired
A017001	Tier 1	3.0	Fuel Producer: Pratt Energy, LLC (6127) ; Facility Name: Pratt Energy, LLC (70158); Midwest Corn, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site cogen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC317	65.03	ETH009A01700100	62.21	9/6/2019	None	Ethanol	Pratt Energy, LLC (6127)	Pratt Energy, LLC (70158)	Midwest Corn, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site cogen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	None	Retired
A017002	Tier 1	3.0	Fuel Producer: Pratt Energy, LLC (6127) ; Facility Name: Pratt Energy, LLC (70158); Midwest Corn, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC304	77.71	ETH009A01700200	76.40	9/6/2019	None	Ethanol	Pratt Energy, LLC (6127)	Pratt Energy, LLC (70158)	Midwest Corn, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	None	Retired
A017003	Tier 1	3.0	Fuel Producer: Pratt Energy, LLC (6127) ; Facility Name: Pratt Energy, LLC (70158); Midwest Sorghum, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A01700300	65.67	9/6/2019	None	Ethanol	Pratt Energy, LLC (6127)	Pratt Energy, LLC (70158)	Midwest Sorghum, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	None	Retired
A017004	Tier 1	3.0	Fuel Producer: Pratt Energy, LLC (6127); Facility Name: Pratt Energy, LLC (70158); Midwest Sorghum, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A01700400	79.86	9/6/2019	None	Ethanol	Pratt Energy, LLC (6127)	Pratt Energy, LLC (70158)	Midwest Sorghum, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	None	Retired
A013101	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Soybean Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Soybean Oil (005)	Biodiesel (BIO)	BDS204	59.99	BIO005A01310100	57.00	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Soybean Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013102	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A01310200	52.00	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013103	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Corn Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC207	37.94	BIO003A01310300	27.90	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Corn Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013104	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU215	25.46	BIO001A01310400	21.00	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013105	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130) ; Facility Name: REG Mason City, LLC (82968); U.S. sourced Non-Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU236	18.34	BIO001A01310500	16.20	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Non-Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013106	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Rendered Animal Fat Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT208	39.70	BIO002A01310600	32.50	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Rendered Animal Fat Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013201	Tier 1	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Northeast Mississippi Landfill Gas Recovery Project (71317); Mississippi Landfill Gas to pipeline-quality biomethane in Walnut, MS; Delivered via pipeline; Compressed to CNG in California (Provisional)	Mississippi	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01320100	40.08	9/30/2019	None	Bio-CNG	Clean Energy (5481)	Northeast Mississippi Landfill Gas Recovery Project (71317)	Mississippi Landfill Gas to pipeline-quality biomethane in Walnut, MS; Delivered via pipeline; Compressed to CNG in California (Provisional)	None	Retired

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A015001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01500100	74.83	10/3/2019	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	None	Retired
A015003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01500300	27.72	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	None	Retired
A015101	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01510100	74.44	10/3/2019	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California (Provisional)	None	Retired
A015103	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108; Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01510300	27.69	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	None	Retired
A015201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A01520100	74.15	10/3/2019	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	None	Retired
A015203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	Ohio	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01520300	27.00	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	None	Retired
A015202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A01520200	67.32	10/3/2019	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	None	Retired
A015102	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) ; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01510200	67.72	10/3/2019	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	None	Retired
A016101	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	Texas	Corn (009)	Ethanol (ETH)	ETHC206	70.43	ETH009A01610100	64.69	10/8/2019	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Texas Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	None	Retired
A016103	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETHG202	77.05	ETH010A01610300	66.62	10/8/2019	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Texas Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	None	Retired
A016104	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	Texas	Corn (009)	Ethanol (ETH)	ETHC205	78.02	ETH009A01610400	72.64	10/8/2019	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Texas Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	None	Retired
A016105	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETHG201	84.64	ETH010A01610500	74.57	10/8/2019	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Texas Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	None	Retired

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A015002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) ; Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01500200	68.05	10/14/2019	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	None	Retired
A016401	Tier 1	3.0	Fuel Producer: BUSHMILLS ETHANOL, INC. (4063); Facility Name: BUSHMILLS ETHANOL, INC. (70109); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	ETHC236L	76.96	ETH009A01640100	67.23	10/15/2019	None	Ethanol	BUSHMILLS ETHANOL, INC. (4063)	BUSHMILLS ETHANOL, INC. (70109)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI. (Provisional)	None	Retired
A017501	Tier 1	3.0	Fuel Producer: Front Range Energy LLC (4758); Facility Name: Front Range Energy LLC (70058); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Windsor, Colorado; Ethanol transported by rail to California	Colorado	Corn (009)	Ethanol (ETH)	ETH009A01220100	63.60	ETH009A01750100	64.25	10/21/2019	None	Ethanol	Front Range Energy LLC (4758)	Front Range Energy LLC (70058)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Windsor, Colorado; Ethanol transported by rail to California	None	Retired
A015401	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional)	Kentucky	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01540100	54.66	11/5/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional)	None	Retired
A015402	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional)	Kentucky	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A01540200	71.50	11/5/2019	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional)	None	Retired
A015403	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional)	Kentucky	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A01540300	74.59	11/5/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional)	None	Retired
T2N-1019	Tier 2	2.0	Biomethane produced from the high-solids (greater than 15 percent total solids) anaerobic digestion of food and green wastes; compressed in CA	California	HSAD Food & Green Waste	Compressed Natural Gas	None	None	CNG005_1	-22.93	9/25/2018	None	Bio-CNG	Blue Line Transfer, Inc. (L500)	Blue Line Transfer, Inc. (B1725)	Biomethane produced from the highsolids (greater than 15 percent total solids)anaerobic digestion of food and green wastes; compressed in CA	None	Retired
None	Lookup Table	2.0	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling; export to the grid of surplus cogenerated electricity.	NA	Waste Water	Compressed Natural Gas (CNG)	None	None	CNG020_1	7.75	NA	None	Bio-CNG	NA	NA	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling; export to the grid of surplus cogenerated electricity.	None	Retired
None	Lookup Table	2.0	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling.	NA	Waste Water	Compressed Natural Gas (CNG)	None	None	CNG021_1	30.92	NA	None	Bio-CNG	NA	NA	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling.	None	Retired
None	Lookup Table	2.0	Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps)	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYGN001_1	151.01	NA	None	Hydrogen	NA	NA	Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps)	None	Retired
None	Lookup Table	2.0	Liquid H2 from central reforming of NG	NA	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYGN002_1	143.51	NA	None	Hydrogen	NA	NA	Liquid H2 from central reforming of NG	None	Retired
None	Lookup Table	2.0	Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps)	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYGN003_1	105.65	NA	None	Hydrogen	NA	NA	Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps)	None	Retired

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None	Lookup Table	2.0	Compressed H2 from on-site reforming of NG	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYGN004_1	105.13	NA	None	Hydrogen	NA	NA	Compressed H2 from on-site reforming of NG	None	Retired
None	Lookup Table	2.0	Compressed H2 from on-site reforming with renewable feedstocks	NA	Any Other Feedstock (998)	Gaseous Hydrogen (HYG)	None	None	HYGN005_1	88.33	NA	None	Hydrogen	NA	NA	Compressed H2 from on-site reforming with renewable feedstocks	None	Retired
A016501	Tier 1	3.0	Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California (Provisional)	Rhode Island	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01650100	15.24	12/16/2019	None	Biodiesel	NEWPORT BIODIESEL INC (7764)	NEWPORT BIODIESEL LLC (83532)	Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California (Provisional)	None	Retired
A016502	Tier 1	3.0	Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California (Provisional)	Rhode Island	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01650200	18.60	12/16/2019	None	Biodiesel	NEWPORT BIODIESEL INC (7764)	NEWPORT BIODIESEL LLC (83532)	Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California (Provisional)	None	Retired
A016301	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California	Texas	Corn (009)	Ethanol (ETH)	ETHC200	70.79	ETH009A01630100	64.74	12/16/2019	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California	None	Retired
A016302	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Kansas and Texas Sorghum, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETHG200	79.03	ETH010A01630200	66.63	12/16/2019	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Kansas and Texas Sorghum, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California	None	Retired
T1N-1753	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ	Ohio	Landfill Gas	LNG	LNGLF225	56.57	LNGLF225R	65.22	12/18/2019	None	Bio-LNG	WM Renewable Energy, LLC (W978)	WM Renewable Energy of Ohio - American Landfill (71222)	American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ	None	Retired
T1N-1785	Tier 1	2.0	Fuel Producer: Homeland Energy Solutions LLC (3220) ; Facility Name: Homeland Energy Solutions LLC (70188); Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power.	Iowa	Corn	Ethanol	ETHC292	73.11	ETHC292R	74.42	12/18/2019	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power.	None	Retired
T2N-1229	Tier 2	2.0	Fuel Producer: SeQuential Pacific Biodiesel LLC (6129) ; Facility Name: SeQuential-Pacific Biodiesel, LLC. (83525); Tier 2 Method 2B Pathway: Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO). Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California	Oregon	Used Cooking Oil (UCO)	Biodiesel	BDU241	18.43	BDU241R	18.71	12/18/2019	Application Package	Biodiesel	SeQuential Pacific Biodiesel LLC (6129)	SeQuential-Pacific Biodiesel, LLC. (83525)	Tier 2 Method 2B Pathway: Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO). Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California	None	Retired
T1N-1809	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Shade (71134); JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	Pennsylvania	Landfill Gas	CNG	CNGLF273	49.77	CNGLF273R	52.94	12/18/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Shade (71134)	JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	None	Retired
A010501	Tier 1	3.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Pyeongtaek 2 (80202); South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker	South Korea	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01050100	27.89	12/17/2019	None	Biodiesel	Dansuk Industrial Co., Ltd (5953)	Pyeongtaek 2 (80202)	South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker	None	Retired
A017601	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311) ; Facility Name: Meadow Branch (A2316); Landfill Gas generated at the Meadow Branch Landfill; upgraded to pipeline-quality biomethane in Athens, Tennesse; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01760100	49.24	12/18/2019	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Meadow Branch (A2316)	Landfill Gas generated at the Meadow Branch Landfill; upgraded to pipeline-quality biomethane in Athens, Tennesse; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	None	Retired
A011501	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	Texas	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNGWW201	43.02	CNG030A01150100	37.33	12/19/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ameresco San Antonio Biogas (71204)	Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	None	Retired
A016001	Tier 1	3.0	Fuel Producer: Iogen D3 Biofuel Partners LLC (6486); Facility Name: GSF Energy-Rumpke Landfill (71138S); Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01600100	44.90	12/20/2019	None	Bio-CNG	Iogen D3 Biofuel Partners LLC (6486)	GSF Energy-Rumpke Landfill (71138S)	Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	None	Retired

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B005402	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) ; Facility Name: Diamond Green Diesel LLC (81496); Renewable Diesel produced from U.S. sourced Rendered Used Cooking Oil/Waste Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RDU202R1	19.73	RND001B00540200	19.92	12/19/2019	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from U.S. sourced Rendered Used Cooking Oil/Waste Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	None	Retired
B005401	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Renewable Diesel produced from U.S. sourced Distillers' Corn Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	Louisiana	Distillers' Corn Oil (003)	Renewable Diesel (RND)	RDC201	31.27	RND003B00540100	27.42	12/19/2019	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from U.S. sourced Distillers' Corn Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	None	Retired
B005403	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Renewable Diesel produced from U.S. sourced Rendered Tallow (animal and poultry fat); Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RDT204R1	30.79	RND002B00540300	31.86	12/19/2019	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from U.S. sourced Rendered Tallow (animal and poultry fat); Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	None	Retired
A013501	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846); Facility Name: High Plains Bioenergy (82883); Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (Provisional)	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT202	35.57	BIO002A01350100	32.07	12/20/2019	None	Biodiesel	High Plains Bioenergy (4846)	High Plains Bioenergy (82883)	Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (Provisional)	None	Retired
B003101	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied hydrogen from Mississippi landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gas to fueling stations	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B00310100	131.39	12/31/2019	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Liquefied hydrogen from Mississippi landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gas to fueling stations	None	Retired
B004501	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B00450100	25.08	12/27/2019	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Jet produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	None	Retired
B004502	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Renewable Diesel produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B00450200	25.08	12/27/2019	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Diesel produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B004503	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B00450300	25.08	12/27/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Naphtha produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B004401	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B00440100	42.91	12/27/2019	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Jet produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	None	Retired
B004301	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B00430100	37.13	12/27/2019	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	None	Retired
B004302	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Diesel produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RDT209	38.75	RND002B00430200	37.13	12/27/2019	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Diesel produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B004303	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNWN200	39.75	RNT002B00430300	37.13	12/27/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired

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B004402	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Diesel produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B00440200	42.91	12/27/2019	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Diesel produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B004403	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B00440300	42.91	12/27/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B004601	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491) ; Facility Name: Praxair Liquid H2 Source (F00053); Liquefied hydrogen North American fossil NG produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, CA and gaseous hydrogen transport by tube trailer to stations in Southern CA	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B00460100	158.15	12/31/2019	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Praxair Liquid H2 Source (F00053)	Liquefied hydrogen North American fossil NG produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, CA and gaseous hydrogen transport by tube trailer to stations in Southern CA	None	Retired
B004602	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Praxair Liquid H2 Source (F00053); Liquefied hydrogen from Mississippi landfill gas produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, California and gaseous hydrogen transport by tube trailer to stations in Southern CA	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B00460200	136.31	12/31/2019	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Praxair Liquid H2 Source (F00053)	Liquefied hydrogen from Mississippi landfill gas produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, California and gaseous hydrogen transport by tube trailer to stations in Southern CA	None	Retired
B004701	Tier 2	3.0	Fuel Producer: Sinclair Wyoming Refining Company (3994); Facility Name: Sinclair Wyoming Refining Company (83388); Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California (Provisional)	Wyoming	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B00470100	58.34	12/27/2019	Application Package	Renewable Diesel	Sinclair Wyoming Refining Company (3994)	Sinclair Wyoming Refining Company (83388)	Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California (Provisional)	None	Retired
B004901	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Sacramento Liquid Sacramento (F00103); Liquefied hydrogen from fossil natural gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B00490100	158.28	12/31/2019	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Air Products Sacramento Liquid Sacramento (F00103)	Liquefied hydrogen from fossil natural gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California	None	Retired
B004902	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Sacramento Liquid Sacramento (F00103); Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B00490200	136.44	12/31/2019	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Air Products Sacramento Liquid Sacramento (F00103)	Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California	None	Retired
A019501	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060); Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01950100	43.37	12/31/2019	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060)	Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	None	Retired
T2R-1105	Tier 2	2.0	Fuel Producer: Tracy Renewable Energy LLC (T534) Facility Name: Tracy Renewable Energy LLC (A0640): Ethanol Produced from California Energy Beets using biogas derived from anaerobic digestion of green wastes, manure and glycerin; with credit for avoided waste management and co-products (compost and animal feed).	California	Sugarbeets	Ethanol	ETHBE001	13.64	ETHB200L	7.18	5/16/2016	None	Ethanol	Tracy Renewable Energy LLC (T534)	Tracy Renewable Energy LLC (A0640)	Ethanol Produced from California Energy Beets using biogas derived from anaerobic digestion of green wastes, manure and glycerin; with credit for avoided waste management and coproducts (compost and animal feed)	None	Retired
T2R-1073	Tier 2	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). California, Dry Mill, Waste Wine Ethanol, NG	California	Waste Wine	Ethanol	ETHWB002	18.70	ETHWB200L	22.06	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	California, Dry Mill, Waste Wine Ethanol, NG	None	Retired
T1R-1518	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC125	67.92	ETHC271L	56.44	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	None	Retired
T1R-1248	Tier 1	2.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, California Corn, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC120	62.76	ETHC257L	56.82	3/31/2016	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	California Ethanol, California Corn, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer	None	Retired

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T1R-1195	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). California Corn, California Ethanol, Dry Mill, WDGS, North American LFG	California	Corn	Ethanol	ETHC117	65.07	ETHC249L	58.11	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	California Corn, California Ethanol, Dry Mill, WDGS, North American LFG	None	Retired
T1R-1250	Tier 1	2.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, Midwest Corn, Dry Mill, WDGS, North American LFG	California	Corn	Ethanol	ETHC122	69.78	ETHC259L	58.31	3/31/2016	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	California Ethanol, Midwest Corn, Dry Mill, WDGS, North American LFG	None	Retired
T1R-1199	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Corn, California Ethanol, Dry Mill, WDGS, North American, LFG	California	Corn	Ethanol	ETHC119	70.56	ETHC250L	59.04	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest Corn, California Ethanol, Dry Mill, WDGS, North American, LFG	None	Retired
T1R-1515	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). California Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC128	68.20	ETHC268L	60.27	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	California Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	None	Retired
T1R-1517	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). California Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC124	68.43	ETHC270L	61.94	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	California Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer	None	Retired
T1R-1513	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC127	75.34	ETHC267L	63.23	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	None	Retired
T1R-1520	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	California	Sorghum	Ethanol	ETHG023	69.19	ETHG211L	64.34	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	None	Retired
T1R-1519	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC126	75.77	ETHC272L	64.89	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer	None	Retired
T1N-1231	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). California Corn, Ethanol, Dry Mill, NG	California	Corn	Ethanol	None	None	ETHC217	65.36	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	California Corn, Ethanol, Dry Mill, NG	None	Retired
T1R-1251	Tier 1	2.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol; Midwest Grain Sorghum, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer	California	Sorghum	Ethanol	ETHG020	68.24	ETHG208L	66.07	3/31/2016	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	California Ethanol; Midwest Grain Sorghum, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer	None	Retired
T1N-1358	Tier 1	2.0	Fuel Producer: Bridgeport Ethanol, LLC (5934) Facility Name: Bridgeport Ethanol, LLC (70217). Midwest Corn, Ethanol, Dry Mill, WDGS, NG	Nebraska	Corn	Ethanol	None	None	ETHC229	67.43	3/31/2016	None	Ethanol	Bridgeport Ethanol, LLC (5934)	Bridgeport Ethanol, LLC (70217)	Midwest Corn, Ethanol, Dry Mill, WDGS, NG	None	Retired
T1R-1249	Tier 1	2.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, California Corn, Dry Mill, WDGS, NG With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC121	72.42	ETHC258L	67.46	3/31/2016	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	California Ethanol, California Corn, Dry Mill, WDGS, NG With Lime Use in Fertilizer	None	Retired

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None	Lookup Table	3.0	California grid electricity used as a transportation fuel in California	California	Grid Electricity (039)	Electricity (ELC)	None	None	ELC000L00072019	81.49	NA	None	Electricity	NA	NA	California grid electricity used as a transportation fuel in California	None	Retired
T1R-1197	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, North American LFG	California	Sorghum	Ethanol	ETHG018	68.19	ETHG206L	68.62	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, North American LFG	None	Retired
T1N-1230	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Corn, Ethanol, Dry Mill, NG	California	Corn	Ethanol	None	None	ETHC216	69.64	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest Corn, Ethanol, Dry Mill, NG	None	Retired
T1N-1609	Tier 1	2.0	Fuel Producer: Great Plains Ethanol (4727) Facility Name: Great Plains Ethanol, LLC (70012): Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, Corn Oil, and Syrup, Using NG, Wood, and Biogas	South Dakota	Corn	Ethanol	None	None	ETHC280	69.68	1/10/2017	None	Ethanol	Great Plains Ethanol (4727)	Great Plains Ethanol, LLC (70012)	Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, Corn Oil, and Syrup, Using NG, Wood, and Biogas	None	Retired
T1N-1152	Tier 1	2.0	Fuel Producer: Trenton Agri Products, LLC (4754) Facility Name: Trenton Agri Products, LLC (70053). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	None	None	ETHC210	69.75	3/31/2016	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1592	Tier 1	2.0	Fuel Producer: Western Plains Energy, LLC (4740) Facility Name: Western Plains Energy, LLC (70030). Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, and Corn Oil, NG	Kansas	Corn	Ethanol	None	None	ETHC278	70.60	11/2/2016	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, and Corn Oil, NG	None	Retired
T1N-1070	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	Texas	Corn	Ethanol	None	None	ETHC200	70.79	3/31/2016	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	None	Retired
T1R-1514	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	California	Sorghum	Ethanol	ETHG025	76.91	ETHG210L	70.80	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	None	Retired
T1N-1500	Tier 1	2.0	Fuel Producer: POET Biorefining Mitchell (4789) Facility Name: POET Biorefining Mitchell (70016). Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	South Dakota	Corn	Ethanol	None	None	ETHC231	71.14	3/31/2016	None	Ethanol	POET Biorefining Mitchell (4789)	POET Biorefining Mitchell (70016)	Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	None	Retired
T1R-1013 T1R-1052	Tier 1	2.0	Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095) Facility Name: Mid America Agri Products/Wheatland LLC (70153). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC110 ETHC111	82.76 76.68	ETHC235L	71.78	3/31/2016	None	Ethanol	Mid America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1003	Tier 1	2.0	Fuel Producer: Arkalon Ethanol, LLC (5715) Facility Name: Arkalon Ethanol, LLC (70247). Midwest, Corn Ethanol, Dry Mill, NG	Kansas	Corn	Ethanol	ETHC037	80.17	ETHC233L	71.79	3/31/2016	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1015	Tier 1	2.0	Fuel Producer: BUSHMILLS ETHANOL, INC. (4063) Facility Name: BUSHMILLS ETHANOL, INC. (70109). Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG	Minnesota	Corn	Ethanol	ETHC113	79.18	ETHC232L	72.55	3/31/2016	None	Ethanol	BUSHMILLS ETHANOL, Inc (4063)	BUSHMILLS ETHANOL, Inc (70109)	Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG	None	Retired

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T1R-1521	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Sorghum, California Ethanol, Dry Mill, Wet DGS, 100% NG, With Lime Use in Fertilizer	California	Sorghum	Ethanol	ETHG024	77.04	ETHG212L	72.59	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Sorghum, California Ethanol, Dry Mill, Wet DGS, 100% NG, With Lime Use in Fertilizer	None	Retired
T1N-1539	Tier 1	2.0	Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn, Ethanol, Dry Mill, NG and Landfill Gas as process fuels	Nebraska	Corn	Ethanol	None	None	ETHC276	72.63	11/2/2016	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest, Corn, Ethanol, Dry Mill, NG and Landfill Gas as process fuels	None	Retired
T1N-1132	Tier 1	2.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Madera LLC (70061); Midwest Corn, CA Ethanol, Dry Mill, WDGS, NG	California	Corn	Ethanol	ETHC207	72.73	ETHC207R	72.94	5/16/2018	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Madera LLC (70061)	Midwest Corn, CA Ethanol, Dry Mill, WDGS, NG	None	Retired
T1N-1082	Tier 1	2.0	Fuel Producer: Little Sioux Corn Processors, LLLP (4728) Facility Name: LSCP, LLLP (70015). Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG **(Provisional)**	Iowa	Corn	Ethanol	None	None	ETHC202	73.55	3/31/2016	None	Ethanol	Little Sioux Corn Processors, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG (Provisional)	None	Retired
T1N-1176	Tier 1	2.0	Fuel Producer: High Plains Bioenergy (4846) Facility Name: High Plains Bioenergy (82883). Mixture of tallow & choice white grease biodiesel transported by rail to CA (30% tallow from local, the rest from KS,TX and NE)	Guymon, Oklahoma	Mixture of Tallow and Choice White Grease	Biodiesel	None	None	BDT202	35.57	6/30/2016	None	Biodiesel	High Plains Bioenergy (4846)	High Plains Bioenergy (82883)	Mixture of tallow & choice white grease biodiesel transported by rail to CA (30% tallow from local, the rest from KS,TX and NE)	None	Retired
T1R-1294	Tier 1	2.0	Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, 87% NG, 13% LFG	Nebraska	Corn	Ethanol	ETHC047	83.74	ETHC266L	73.78	3/31/2016	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest, Corn Ethanol, Dry Mill, 87% NG, 13% LFG	None	Retired
T1R-1292	Tier 1	2.0	Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, 90% NG, 10% LFG	Nebraska	Corn	Ethanol	ETHC046	84.41	ETHC265L	74.05	3/31/2016	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest, Corn Ethanol, Dry Mill, 90% NG, 10% LFG	None	Retired
T1R-1291	Tier 1	2.0	Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, 93% NG, 7% LFG	Nebraska	Corn	Ethanol	ETHC045	85.16	ETHC264L	74.37	3/31/2016	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest, Corn Ethanol, Dry Mill, 93% NG, 7% LFG	None	Retired
T1R-1216	Tier 1	2.0	Fuel Producer: Husker Ag LLC (5078) Facility Name: Husker Ag LLC (70151). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC092	81.92	ETHC253L	74.56	3/31/2016	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1032	Tier 1	2.0	Fuel Producer: E Energy Adams, LLC (4831) Facility Name: E energy Adams, LLC (70093). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC067_1	86.31	ETHC238L	74.62	3/31/2016	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1006	Tier 1	2.0	Fuel Producer: Bonanza BioEnergy, LLC (4054) Facility Name: Bonanza BioEnergy, LLC (70117). Midwest, Sorghum Ethanol, Dry Mill, NG	Kansas	Sorghum	Ethanol	ETHG003	73.39	ETHG205L	74.83	3/31/2016	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest, Sorghum Ethanol, Dry Mill, NG	None	Retired
T1R-1286	Tier 1	2.0	Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC043	88.14	ETHC263L	75.27	3/31/2016	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired

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T1R-1198	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, NG	California	Sorghum	Ethanol	ETHG019	79.97	ETHG207L	76.14	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, NG	None	Retired
T1R-1252	Tier 1	2.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, Midwest Grain Sorghum, Dry Mill, WDGS, NG, With Lime Use in Fertilizer	California	Sorghum	Ethanol	ETHG021	79.60	ETHG209L	76.33	3/31/2016	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	California Ethanol, Midwest Grain Sorghum, Dry Mill, WDGS, NG, With Lime Use in Fertilizer	None	Retired
T1N-1217	Tier 1	2.0	Fuel Producer: Western Plains Energy, LLC (4740) Facility Name: Western Plains Energy, LLC (70030). Midwest, Corn Ethanol, Dry Mill, MDGS, DDGS, NG	Kansas	Corn	Ethanol	None	None	ETHC214	76.66	3/31/2016	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest, Corn Ethanol, Dry Mill, MDGS, DDGS, NG	None	Retired
T1N-1081	Tier 1	2.0	Fuel Producer: Little Sioux Corn Processors, LLLP (4728) Facility Name: LSCP, LLLP (70015). Midwest Corn, Ethanol, Dry Mill, 100 % DDGS, NG **(Provisional)**	Iowa	Corn	Ethanol	None	None	ETHC201	77.66	3/31/2016	None	Ethanol	Little Sioux Corn Processors, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Ethanol, Dry Mill, 100 % DDGS, NG (Provisional)	None	Retired
T1N-1222	Tier 1	2.0	Fuel Producer: Poet Biorefining Emmetsburg (4792) Facility Name: Poet Biorefining Emmetsburg (70021). Midwest, Corn, Mixed DGS, Ethanol, Dry Mill, NG	Iowa	Corn	Ethanol	None	None	ETHC215	77.98	3/31/2016	None	Ethanol	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest, Corn, Mixed DGS, Ethanol, Dry Mill, NG	None	Retired
T1N-1593	Tier 1	2.0	Fuel Producer: Western Plains Energy, LLC (4740) Facility Name: Western Plains Energy, LLC (70030). Midwest Sorghum, Ethanol, Dry Mill, DDGS, WDGS, NG	Kansas	Sorghum	Ethanol	None	None	ETHG215	78.55	11/2/2016	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Sorghum, Ethanol, Dry Mill, DDGS, WDGS, NG	None	Retired
T1N-1072	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG	Texas	Sorghum	Ethanol	None	None	ETHG200	79.03	3/31/2016	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG	None	Retired
T1R-1004	Tier 1	2.0	Fuel Producer: Arkalon Ethanol, LLC (5715) Facility Name: Arkalon Ethanol, LLC (70247). Midwest, Sorghum Ethanol, Dry Mill, NG	Kansas	Sorghum	Ethanol	ETHG004	76.22	ETHG204L	79.28	3/31/2016	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest, Sorghum Ethanol, Dry Mill, NG	None	Retired
T1N-1133	Tier 1	2.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Madera LLC (70061); Midwest Sorghum CA Ethanol, Dry Mill, DDGS, NG	California	Sorghum	Ethanol	ETHG203	80.51	ETHG203R	81.84	5/16/2018	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Madera LLC (70061)	Midwest Sorghum CA Ethanol, Dry Mill, DDGS, NG	None	Retired
T1N-1499	Tier 1	2.0	Fuel Producer: POET Biorefining Mitchell (4789) Facility Name: Poet Biorefining Mitchell (70016). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	South Dakota	Corn	Ethanol	None	None	ETHC230	81.74	3/31/2016	None	Ethanol	POET Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T1N-1151	Tier 1	2.0	Fuel Producer: Cornhusker Energy Lexington, LLC (7365) Facility Name: Lexington Ethanol Plant (70241). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, WDGS, NG	Nebraska	Corn	Ethanol	None	None	ETHC209	85.58	3/31/2016	None	Ethanol	Cornhusker Energy Lexington, LLC (7365)	Lexington Ethanol Plant (70241)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, WDGS, NG	None	Retired
T2N-1137	Tier 2	2.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Soybean, Fuel produced in Louisiana and transported to California	Louisiana	Soybean	Renewable Diesel	None	None	RDS200	53.86	3/21/2017	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from US Soybean, Fuel produced in Louisiana and transported to California	None	Retired

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T2N-1138	Tier 2	2.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Used Cooking Oil, Fuel produced in Louisiana and transported to California	Louisiana	Used Cooking Oil	Renewable Diesel	None	None	RDU202	20.28	3/21/2017	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from US Used Cooking Oil, Fuel produced in Louisiana and transported to California	None	Retired
T2N-1144	Tier 2	2.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Corn Oil, Fuel produced in Louisiana and transported to California	Louisiana	Corn Oil	Renewable Diesel	None	None	RDC201	31.27	3/21/2017	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from US Corn Oil, Fuel produced in Louisiana and transported to California	None	Retired
T2R-1204	Tier 2	2.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Used Cooking Oil, Fuel produced in Louisiana and transported to California	Louisiana	Used Cooking Oil	Renewable Diesel	RDU202	20.28	RDU202R1	19.73	6/23/2017	None	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from US Used Cooking Oil, Fuel produced in Louisiana and transported to California	None	Retired
T2R-1205	Tier 2	2.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Tallow, Fuel produced in Louisiana and transported to California	Louisiana	Tallow	Renewable Diesel	RDT204	30	RDT204R1	30.79	6/23/2017	None	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from US Tallow, Fuel produced in Louisiana and transported to California	None	Retired
T1N-1572	Tier 1	2.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Dry mill corn ethanol with co-production of MDGS and corn oil using natural gas and electricity power.	Nebraska	Corn	Ethanol	None	None	ETHC293	68.89	12/21/2017	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Dry mill corn ethanol with coproduction of MDGS and corn oil using natural gas and electricity power	None	Retired
T2N-1210	Tier 2	2.0	Fuel Producer: Siouxland Energy Cooperative (4060) Facility Name: Siouxland Energy Cooperative (70112):Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Sioux Center, Iowa; Midwest Corn, Dry Mill, Wet DGS, Corn Oil, and Syrup; using natural gas and electricity; Ethanol transported by rail to California (Provisional)	Iowa	Corn Kernel Fiber	Ethanol	ETHCF201	29.93	ETHCF201R	42.17	11/29/2018	Pathway Details (PDF)	Ethanol - Cellulosic	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Sioux Center, Iowa; Midwest Corn, Dry Mill, Wet DGS, Corn Oil, and Syrup; using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1156	Tier 2	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ameresco San Antonio Biogas (71204); Tier 2 Method 2B Pathway: Pipeline quality biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a POTW using grid-based electricity, and delivered to CNG dispensing stations in California via pipeline	Texas	Waste Water	CNG	None	None	CNGWW201	43.02	3/16/2018	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ameresco San Antonio Biogas (71204)	Tier 2 Method 2B Pathway Pipeline quality biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a POTW using gridbased electricity, and delivered to CNG dispensing stations in California via pipeline	None	Retired
T1N-1814	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); Waste Management's Milam landfill, St. Louis, Illinois gas to pipeline-quality biomethane; delivered via pipeline to WM fueling stations in California (Provisional)	Illinois	Landfill Gas	CNG	None	None	CNGLF270	62.72	6/1/2018	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	Waste Management's Milam landfill, St Louis, Illinois gas to pipelinequality biomethane; delivered via pipeline to WM fueling stations in California (Provisional)	None	Retired
T1N-1815	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); Waste Management's Milam landfill, St. Louis, Illinois gas pipeline-quality biomethane; delivered via pipeline to liquifaction plant in Topock AZ, and transported by truck to WM fueling stations in California (Provisional)	Illinois	Landfill Gas	LNG	None	None	LNGLF228	76.13	6/1/2018	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	Waste Management's Milam landfill, St Louis, Illinois gas pipelinequality biomethane; delivered via pipeline to liquifaction plant in Topock AZ, and transported by truck to WM fueling stations in California (Provisional)	None	Retired
T1N-1816	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); Waste Management's Milam landfill, St. Louis, Illinois gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; Re-gasified and compressed in California. (Provisional)	Illinois	Landfill Gas	CNG	None	None	CNGLF271	78.68	6/1/2018	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	Waste Management's Milam landfill, St Louis, Illinois gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; Regasified and compressed in California(Provisional)	None	Retired
T1N-1828	Tier 1	2.0	Fuel Producer: Husker Ag LLC (5078) ; Facility Name: Husker Ag LLC (70151); Midwest Corn, Ethanol, Dry Mill, NG, 100% DDGS, NG (Provisional)	Nebraska	Corn	Ethanol	None	None	ETHC295	74.03	7/9/2018	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn, Ethanol, Dry Mill, NG, 100% DDGS, NG (Provisional)	None	Retired
T1N-1859	Tier 1	2.0	Fuel Producer: Kansas Ethanol, LLC ; Facility Name: Kansas Ethanol, LLC (70279); Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuels. DDGS, WDGS, and corn oil as co-products (Provisional)	Kansas	Corn	Ethanol	None	None	ETHC299	67.83	8/27/2018	None	Ethanol	Kansas Ethanol, LLC (5810)	Kansas Ethanol, LLC (70279)	Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuelsDDGS, WDGS, and corn oil as coproducts (Provisional)	None	Retired

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T2N-1235	Tier 2	2.0	Fuel Producer: Pacific Ethanol West LLC (3697); Facility Name: Pacific Ethanol Stockton LLC (70319; Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Stockton, California; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Modified DGS (Provisional)	California	Corn Kernel Fiber	Ethanol	None	None	ETHCF202	39.45	9/28/2018	Application Package	Ethanol - Cellulosic	Pacific Ethanol West LLC (3697)	Pacific Ethanol Stockton LLC (70319)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Stockton, California; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Modified DGS (Provisional)	None	Retired
T2N-1252	Tier 2	2.0	Fuel Producer: Great Plains Ethanol (4727) ; Facility Name: Great Plains Ethanol, LLC (70012); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Chancellor, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas, and electricity; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Kernel Fiber	Ethanol	None	None	ETHCF203	27.69	9/28/2018	Application Package	Ethanol - Cellulosic	Great Plains Ethanol (4727)	Great Plains Ethanol, LLC (70012)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Chancellor, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas, and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1266	Tier 2	2.0	Fuel Producer: Poet Biorefining Emmetsburg (4792) ; Facility Name: Poet Biorefining Emmetsburg (70021); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Emmetsburg, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Ethanol transported by rail to California (Provisional)	Iowa	Corn Kernel Fiber	Ethanol	None	None	ETHCF204	35.39	9/28/2018	Application Package	Ethanol - Cellulosic	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Emmetsburg, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1153	Tier 2	2.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Marcus, Iowa; Midwest Corn, Dry Mill, Modified and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California	Iowa	Corn Kernel Fiber	Ethanol	ETHCF200	31.23	ETHCF200R	44.19	11/29/2018	Application Package	Ethanol - Cellulosic	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Marcus, Iowa; Midwest Corn, Dry Mill, Modified and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California	None	Retired
T2N-1258	Tier 2	2.0	Fuel Producer: POET Biorefining - Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Hudson, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Kernel Fiber	Ethanol	None	None	ETHCF205	36.92	12/4/2018	Application Package	Ethanol - Cellulosic	POET Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Hudson, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1262	Tier 2	2.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Gowrie, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	Iowa	Corn Kernel Fiber	Ethanol	None	None	ETHCF209	34.30	12/4/2018	Application Package	Ethanol - Cellulosic	POET Biorefining Gowrie (4784)	POET Biorefining Gowrie (70033)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Gowrie, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1261	Tier 2	2.0	Fuel Producer: POET Biorefining - Groton (4793) ; Facility Name: POET Biorefining - Groton (70013); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Groton, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Kernel Fiber	Ethanol	None	None	ETHCF208	34.79	12/4/2018	Application Package	Ethanol - Cellulosic	POET Biorefining Groton (4793)	POET Biorefining Groton (70013)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Groton, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1260	Tier 2	2.0	Fuel Producer: POET Biorefining - Mitchell (4789) ; Facility Name: Poet Biorefining Mitchell (70016); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Mitchell, South Dakota; Midwest Corn, Dry Mill, Wet, Dry DGS, corn oil, and syrup using natural gas, and electricity; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Kernel Fiber	Ethanol	None	None	ETHCF207	35.67	12/4/2018	Application Package	Ethanol - Cellulosic	POET Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Mitchell, South Dakota; Midwest Corn, Dry Mill, Wet, Dry DGS, corn oil, and syrup using natural gas, and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1263	Tier 2	2.0	Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095) ; Facility Name: Mid America Agri Products/Wheatland LLC (70153); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Madrid, Nebraska; using natural gas and electricity; Midwest Corn, Dry Mill, Wet DGS and Corn Oil; Ethanol transported by rail to California (Provisional)	Nebraska	Corn	Ethanol	None	None	ETHC311	38.12	12/18/2018	Application Package	Ethanol	Mid America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Madrid, Nebraska; using natural gas and electricity; Midwest Corn, Dry Mill, Wet DGS and Corn Oil; Ethanol transported by rail to California (Provisional)	None	Retired
T1N-1870	Tier 1	2.0	Fuel Producer: Pinal Energy LLC (4744); Facility Name: Pinal Energy LLC (70136); Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California (Provisional)	Arizona	Corn	Ethanol	None	None	ETHC314	74.77	12/21/2018	None	Ethanol	Pinal Energy LLC (4744)	Pinal Energy LLC (70136)	Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1279	Tier 2	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354); Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317); Tier 2 Method 2B Pathway: Corn starch ethanol produced in Pixley, California; using natural gas, dairy biomethane, and electricity; Midwest corn, dry mill, wet DGS (Provisional)	California	Corn	Ethanol	None	None	ETHC316	63.01	12/31/2018	Application Package	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Tier 2 Method 2B Pathway Corn starch ethanol produced in Pixley, California; using natural gas, dairy biomethane, and electricity; Midwest corn, dry mill, wet DGS (Provisional)	None	Retired
T2N-1290	Tier 2	2.0	Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Diesel produced from North American Tallow, in Paramount, California (Provisional)	California	Tallow & Animal Fat	Renewable Diesel	None	None	RDT209	38.75	1/16/2019	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Tier 2 Method 2B ApplicationRenewable Diesel produced from North American Tallow, in Paramount, California (Provisional)	None	Retired

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T2N-1287	Tier 2	2.0	Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Naphtha produced from North American Tallow, Naphtha produced in Paramount, California (Provisional)	California	Tallow & Animal Fat	Renewable Naphtha	None	None	RNWN200	39.75	3/14/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Tier 2 Method 2B ApplicationRenewable Naphtha produced from North American Tallow, Naphtha produced in Paramount, California (Provisional)	None	Retired
T1N-1805	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697); Facility Name: Pacific Ethanol Madera LLC (70061); Dry mill corn ethanol with co-production of WDGS, DDGS, corn oil, and syrup using natural gas and electricity power	California	Corn	Ethanol	ETHC290	69.81	ETHC290R	69.94	12/18/2019	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Madera LLC (70061)	Dry mill corn ethanol with co-production of WDGS, DDGS, corn oil, and syrup using natural gas and electricity power	None	Retired
T1N-1870	Tier 1	2.0	Fuel Producer: Pinal Energy LLC (4744); Facility Name: Pinal Energy LLC (70136); Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California	Arizona	Corn	Ethanol	ETHC314	74.77	ETHC314R	75.62	12/18/2019	None	Ethanol	Pinal Energy LLC (4744)	Pinal Energy LLC (70136)	Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California	None	Retired
T1N-1869	Tier 1	2.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	Nebraska	Corn	Ethanol	ETHC302	66.74	ETHC302R	68.86	12/18/2019	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	None	Retired
T1N-1868	Tier 1	2.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	Nebraska	Corn	Ethanol	ETHC303	78.68	ETHC303R	79.25	12/18/2019	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	None	Retired
T1N-1874	Tier 1	2.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727) ; Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas,and electricity; Starch ethanol produced from Corn using BPX process in Chancellor, South Dakota; Ethanol transported by rail to California	South Dakota	Corn	Ethanol	ETHC300	69.04	ETHC300R	69.07	12/18/2019	None	Ethanol	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas,and electricity; Starch ethanol produced from Corn using BPX process in Chancellor, South Dakota; Ethanol transported by rail to California	None	Retired
T1N-1895	Tier 1	2.0	Fuel Producer: E Energy Adams, LLC (4831) ; Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Adams, Nebraska; Ethanol transported by rail to California	Nebraska	Corn	Ethanol	ETHC310	70.76	ETHC310R	71.08	12/18/2019	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Adams, Nebraska; Ethanol transported by rail to California	None	Retired
B003201	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: LAX Station (L0324); Gaseous Hydrogen from landfill gas from onsite SMR at the LAX station and dispensed in vehicles	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B00320100	158.25	1/13/2020	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	LAX Station (L0324)	Gaseous Hydrogen from landfill gas from onsite SMR at the LAX station and dispensed in vehicles	None	Retired
B003202	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: LAX Station (L0324); Gaseous Hydrogen from NA fossil natural gas from onsite SMR at the LAX station and dispensed in vehicles	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031B00320200	176.43	1/13/2020	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	LAX Station (L0324)	Gaseous Hydrogen from NA fossil natural gas from onsite SMR at the LAX station and dispensed in vehicles	None	Retired
T1N-1785	Tier 1	2.0	Fuel Producer: Homeland Energy Solutions LLC (3220) ; Facility Name: Homeland Energy Solutions LLC (70188); Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power	Iowa	Corn	Ethanol	ETHC292R	74.42	ETHC292R1	74.18	1/16/2020	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power	None	Retired
T1N-1869	Tier 1	2.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	Nebraska	Corn	Ethanol	ETHC302R	68.86	ETHC302R1	66.94	1/16/2020	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	None	Retired
T1N-1868	Tier 1	2.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	Nebraska	Corn	Ethanol	ETHC303R	79.25	ETHC303R1	79.21	1/16/2020	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	None	Retired

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B001801	Tier 2	3.0	Fuel Producer: BP Products North America, Inc (4320); Facility Name: Cherry Point Refinery (83736); U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA (Provisional)	Washington	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B00180100	26.92	12/6/2019	Application Package	Renewable Diesel	BP Products North America, Inc (4320)	Cherry Point Refinery (83736)	U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA (Provisional)	None	Retired
B003601	Tier 2	3.0	Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Facility Name: Praxair Ontario (F00084); Gaseous Hydrogen from Altamont landfill gas-derived biomethane liquefied and trucked from Livermore, CA to Ontario, CA; used as feedstock for hydrogen by SMR, distributed via tube trailer to stations in California (Provisional)	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B00360100	76.71	1/21/2020	Application Package	Hydrogen	HIGH MOUNTAIN FUELS LLC (4293)	Facility Name: Praxair Ontario (F00084)	Gaseous Hydrogen from Altamont landfill gas-derived biomethane liquefied and trucked from Livermore, CA to Ontario, CA; used as feedstock for hydrogen by SMR, distributed via tube trailer to stations in California (Provisional)	None	Retired
B003602	Tier 2	3.0	Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Praxair Ontario (F00084); Liquified Hydrogen from liquefied landfill gas at the landfill, transported to an SMR, gasified at a transfill, and dispensed in vehicles (Provisional)	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B00360200	96.41	1/21/2020	Application Package	Hydrogen	HIGH MOUNTAIN FUELS LLC (4293)	Praxair Ontario (F00084)	Liquified Hydrogen from liquefied landfill gas at the landfill, transported to an SMR, gasified at a transfill, and dispensed in vehicles (Provisional)	None	Retired
B004801	Tier 2	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Sacramento Hydrogen Plant (F00102); Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gaseous hydrogen to fueling stations in CA	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B00480100	138.90	1/29/2020	Application Package	Hydrogen	Shell Energy North America (6154)	Sacramento Hydrogen Plant (F00102)	Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gaseous hydrogen to fueling stations in CA	None	Retired
B000901	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Locust Ridge Farm (71298); Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B00090100	-323.83	1/31/2020	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Locust Ridge Farm (71298)	Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	None	Retired
B000902	Tier 2	3.0	Fuel Producer: Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Locust Ridge Farm (71298); Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Ridge Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ delivered by truck to and re-gasified in CA (Provisional)	Missouri	Swine Manure (044)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN044B00090200	-308.93	1/31/2020	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Locust Ridge Farm (71298)	Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Ridge Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ delivered by truck to and re-gasified in CA (Provisional)	None	Retired
B000903	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Locust Ridge Farm (71298); Liquefied Natural Gas (LNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	Missouri	Swine Manure (044)	Liquefied Natural Gas (LNG)	None	None	LNG044B00090300	-312.47	12/31/2019	Application Package	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Locust Ridge Farm (71298)	Liquefied Natural Gas (LNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	None	Retired
B001001	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B00100100	-345.68	1/31/2020	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	None	Retired
B001002	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	Missouri	Swine Manure (044)	Liquefied Natural Gas (LNG)	None	None	LNG044B00100200	-334.41	1/31/2020	Application Package	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	None	Retired
B001003	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to and re-gasified in CA (Provisional)	Missouri	Swine Manure (044)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN044B00100300	-330.87	1/31/2020	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to and re-gasified in CA (Provisional)	None	Retired
None	Lookup Table	3.0	California grid electricity used as a transportation fuel in California	California	Grid Electricity (039)	Electricity (ELC)	None	None	ELC000L00072020	82.92	NA	None	Electricity	NA	NA	California grid electricity used as a transportation fuel in California	None	Retired
T1R-1119	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: Complexe Enviro Progressive Itee (71198); Quebec LFG to LNG then to L-CNG	California	Landfill Gas	CNG	CNGLF211LR	44.05	CNGLF211LR1	44.07	3/30/2020	None	Bio-CNG	Clean Energy (5481)	Complexe Enviro Progressive Itee (71198)	Quebec LFG to LNG then to L-CNG	None	Retired

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T1R-1120	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: Complexe Enviro Progressive Itee (71198); Quebec LFG to CNG for California CNG stations	California	Landfill Gas	CNG	CNGLF212L	31.96	CNGLF212LR	31.98	3/30/2020	None	Bio-CNG	Clean Energy (5481)	Complexe Enviro Progressive Itee (71198)	Quebec LFG to CNG for California CNG stations	None	Retired
T1R-1121	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: Complexe Enviro Progressive Itee (71198); Quebec LFG to LNG facility in Boron for use in California	California	Landfill Gas	LNG	LNGLF207LR	41.44	LNGLF207LR1	41.46	3/30/2020	None	Bio-LNG	Clean Energy (5481)	Complexe Enviro Progressive Itee (71198)	Quebec LFG to LNG facility in Boron for use in California	None	Retired
T2N-1154	Tier 2	2.0	Fuel Producer: Biodico Westside (6231); Facility Name: Biodico Plant (83027); California Used Cooking Oil, Biodiesel produced in Five Points, California.	California	Used Cooking Oil (UCO)	Biodiesel	BDU229	14.97	BDU229R	25.91	4/2/2020	Application Package	Biodiesel	Biodico Westside (6231)	Biodico Plant (83027)	California Used Cooking Oil, Biodiesel produced in Five Points, California.	None	Retired
T1N-1572	Tier 1	2.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Dry mill corn ethanol with co-production of MDGS and corn oil using natural gas and electricity power.	Nebraska	Corn	Ethanol	ETHC293	68.89	ETHC293R	69.02	4/2/2020	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Dry mill corn ethanol with co-production of MDGS and corn oil using natural gas and electricity power.	None	Retired
T1N-1811	Tier 1	2.0	Fuel Producer: Fuel Producer: San Diego Metropolitan Transit Center (S304) ; Facility Name: Facility Name: EBI Energie In (71254); EBI landfill gas in Saint-Thomas, Quebec to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	California	Landfill Gas	CNG	CNGLF277	32.28	CNGLF277R	37.39	4/2/2020	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	EBI Energie In (71254)	EBI landfill gas in Saint-Thomas, Quebec to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	None	Retired
T1N-1859	Tier 1	2.0	Fuel Producer: Kansas Ethanol, LLC ; Facility Name: Kansas Ethanol, LLC (70279); Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuels. DDGS, WDGS, and corn oil as co-products	Kansas	Corn	Ethanol	ETHC299	67.83	ETHC299R	68.72	4/2/2020	None	Ethanol	Kansas Ethanol, LLC	Kansas Ethanol, LLC (70279)	Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuels. DDGS, WDGS, and corn oil as co-products	None	Retired
T2N-1287	Tier 2	2.0	Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Naphtha produced from North American Tallow, Naphtha produced in Paramount, California	California	Tallow & Animal Fat	Renewable Naphtha	RNWN200	39.75	RNWN200R	43.14	4/2/2020	Application Package	Renewable Gasoline	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Tier 2 Method 2B Application: Renewable Naphtha produced from North American Tallow, Naphtha produced in Paramount, California	None	Retired
T2N-1290	Tier 2	2.0	Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Diesel produced from North American Tallow, in Paramount, California	California	Tallow & Animal Fat	Renewable Diesel	RDT209	38.75	RDT209R	39.91	4/2/2020	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Tier 2 Method 2B Application: Renewable Diesel produced from North American Tallow, in Paramount, California	None	Retired
A021201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California (Provisional)	Missouri	Corn (009)	Ethanol (ETH)	None	None	ETH009A02120100	75.09	4/28/2020	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California (Provisional)	None	Retired
A021202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California (Provisional)	Missouri	Corn (009)	Ethanol (ETH)	None	None	ETH009A02120200	65.67	4/28/2020	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California (Provisional)	None	Retired
A021203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) ; Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California (Provisional)	Missouri	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A02120300	26.19	4/28/2020	None	Ethanol - Cellulosic	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California (Provisional)	None	Retired
T1N-1384	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average North American Sourced Used Cooking Oil (energy required to render) to Biodiesel Produced in California	Bakersfield, California	North American Used Cooking Oil	Biodiesel	BDU203	18.18	BDU203R	18.31	6/9/2020	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average North American Sourced Used Cooking Oil (energy required to render)to Biodiesel Produced in California	None	Retired

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T1N-1386	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average U.S. Sourced Tallow to Biodiesel Produced in California	Bakersfield, California	North American Tallow	Biodiesel	BDT203	30.60	BDT203R	31.39	6/9/2020	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average US Sourced Tallow to Biodiesel Produced in California	None	Retired
T1N-1389	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average California Sourced Tallow to Biodiesel Produced in California	Bakersfield, California	California Tallow	Biodiesel	BDT204	28.45	BDT204R	28.92	6/9/2020	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average California Sourced Tallow to Biodiesel Produced in California	None	Retired
T2N-1107	Tier 2	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average North American Sourced Used Cooking Oil (energy not required to render) to Biodiesel Produced in California	Bakersfield, California	Used Cooking Oil	Biodiesel	BDU204	13.93	BDU204R	14.70	6/9/2020	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average North American Sourced Used Cooking Oil (energy not required to render) to Biodiesel Produced in California	None	Retired
T1N-1800	Tier 1	2.0	Fuel Producer: Crimson Renewable Enegy LP (4814) ; Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); Average California sourced Used Cooking Oil UCO) to Biodiesel produced in California	California	Used Cooking Oil	Biodiesel	BDU233	18.16	BDU233R	18.22	6/9/2020	None	Biodiesel	Crimson Renewable Enegy LP (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	Average California sourced Used Cooking Oil (UCO) to Biodiesel produced in California	None	Retired
A022801	Tier 1	3.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174); Facility Name: Apex LFG Energy (F00034); Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional)	Arizona	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02280100	77.65	6/16/2020	None	Bio-LNG	Applied Natural Gas Fuels, Inc. (6174)	Apex LFG Energy (F00034)	Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional)	None	Retired
A022802	Tier 1	3.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174); Facility Name: Apex LFG Energy (F00034); Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in CA (Provisional)	Arizona	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02280200	80.74	6/16/2020	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	Apex LFG Energy (F00034)	Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in CA (Provisional)	None	Retired
A022701	Tier 1	3.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174); Facility Name: Timberline Energy, LLC (F00028); Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional)	Arizona	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02270100	63.13	6/16/2020	None	Bio-LNG	Applied Natural Gas Fuels, Inc. (6174)	Timberline Energy, LLC (F00028)	Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional)	None	Retired
A022702	Tier 1	3.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) ; Facility Name: Timberline Energy, LLC (F00028); Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in CA (Provisional)	Arizona	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02270200	66.21	6/16/2020	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	Timberline Energy, LLC (F00028)	Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in California (Provisional)	None	Retired
A021802	Tier 1	3.0	Fuel Producer: PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080); Facility Name: H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301); Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Washington	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02180200	50.02	6/22/2020	None	Bio-LNG	PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080)	H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301)	Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A021803	Tier 1	3.0	Fuel Producer: PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080); Facility Name: H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301); Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations; regassified, and compressed to L-CNG (Provisional)	Washington	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02180300	53.11	6/22/2020	None	Bio-CNG	PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080)	H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301)	Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations; regassified, and compressed to L-CNG (Provisional)	None	Retired
A021901	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc, pipelined to California for compression to CNG (Provisional)	Canada	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02190100	38.64	6/22/2020	None	Bio-CNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc in Quebec, Canada; pipelined to California for compression to CNG (Provisional)	None	Retired
A021902	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stationso California by pipeline, liquefied in California (Provisional)	Canada	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02190200	51.69	6/22/2020	None	Bio-LNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stations by pipeline, liquefied in California (Provisional)	None	Retired

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A021903	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified and compressed to L-CNG (Provisional)	Canada	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02190300	54.77	6/22/2020	None	Bio-CNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified and compressed to L-CNG (Provisional)	None	Retired
A021301	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00070100	65.21	ETH009A02130100	61.55	6/22/2020	None	Ethanol	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI (Provisional)	None	Retired
A021302	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00070200	25.06	ETH012A02130200	21.31	6/22/2020	None	Ethanol - Cellulosic	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
A019801	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00980100	61.48	ETH009A01980100	61.26	6/24/2020	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI (Provisional)	None	Retired
A019802	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01980200	23.46	6/24/2020	None	Ethanol - Cellulosic	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California (Provisional)	None	Retired
A020901	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A01370100	72.86	ETH009A02090100	73.74	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
A020902	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A01370200	69.05	ETH009A02090200	70.47	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
A020903	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A01370300	65.76	ETH009A02090300	66.86	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
A020904	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A02090400	27.48	6/24/2020	None	Ethanol - Cellulosic	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
A022401	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01120100	68.75	ETH009A02240100	69.32	6/24/2020	None	Ethanol	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A022402	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01120300	65.90	ETH009A02240200	66.23	6/24/2020	None	Ethanol	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A022403	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A02240300	63.27	6/24/2020	None	Ethanol	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	None	Retired

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A022404	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A01120200	30.06	ETH012A02240400	23.96	6/24/2020	None	Ethanol - Cellulosic	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A020001	Tier 1	3.0	Fuel Producer: GHI Energy, LLC (6156); Facility Name: Waste Management American Landfill (70421); Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF264	43.97	CNG025A02000100	40.13	6/29/2020	None	Bio-CNG	GHI Energy, LLC (6156)	Waste Management American Landfill (70421)	Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional)	None	Retired
B010001	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount California for Alternative Jet Fuel production (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B01000100	23.93	6/29/2020	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount California for Alternative Jet Fuel production (Provisional)	None	Retired
B010002	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount, California for Renewable Diesel production (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01000200	23.93	6/29/2020	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount, California for Renewable Diesel production (Provisional)	None	Retired
B010003	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount, California for Renewable Naphtha production (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01000300	23.93	6/29/2020	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Rendered Animal Fat Oil from Greely, Colorado transported by train to AltAir Paramount plant in Paramount, California for Renewable Naphtha production (Provisional)	None	Retired
B005901	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00590100	-558.62	6/30/2020	Application Package	Electricity	California Bioenergy LLC (B194)	ABEC Bidart-Old River LLC (F00113)	Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	None	Retired
B008901	Tier 2	3.0	Fuel Producer: Gallo Cattle Company, LP (C1029) ; Facility Name: Cottonwood Dairy (F00094); Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00890100	-108.43	6/30/2020	Application Package	Electricity	Gallo Cattle Company, LP (C1029)	Cottonwood Dairy (F00094)	Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional)	None	Retired
B009801	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980100	-355.35	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional)	None	Retired
B009802	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980200	-377.83	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	None	Retired
B009805	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980500	-368.04	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	None	Retired
B009806	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980600	-374.10	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	None	Retired
A021701	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	North Dakota	Corn (009)	Ethanol (ETH)	ETHC287	75.23	ETH009A02170100	69.84	7/27/2020	None	Ethanol	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired

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A021702	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); MMidwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	North Dakota	Corn (009)	Ethanol (ETH)	ETHC287	75.23	ETH009A02170200	66.96	7/27/2020	None	Ethanol	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	MMidwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired
A021703	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	North Dakota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A02170300	25.72	7/27/2020	None	Ethanol - Cellulosic	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired
A023201	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Renovar Arlington, LTD RNG Project (70501); Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG. (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02320100	43.15	7/24/2020	None	Bio-CNG	U.S. Venture, Inc. (5504)	Renovar Arlington, LTD RNG Project (70501)	Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG. (Provisional)	None	Retired
A023301	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional)	Kansas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02330100	45.91	7/24/2020	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional)	None	Retired
A023805	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Sanimax (Quebec City) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	Canada	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A02380500	36.98	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	Sanimax (Quebec City) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	None	Retired
A023808	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Sanimax (Hamilton) Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	Canada	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A02380800	22.81	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	Sanimax (Hamilton) Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	None	Retired
A024901	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A02490100	74.54	7/24/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional)	None	Retired
A024902	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A02490200	67.28	7/24/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional)	None	Retired
T1R-1184	Tier 1	2.0	Fuel Producer: BP Biofuels (4427) ; Facility Name: Ituiutaba Bioenergia Ltda (71006); Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	Brazil	Sugarcane (018)	Ethanol	ETHS204L	38.98	ETHS204LR	41.52	8/13/2020	None	Ethanol	BP Biofuels (4427)	Ituiutaba Bioenergia Ltda (71006)	Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	None	Retired
T1R-1185	Tier 1	2.0	Fuel Producer: BP Biofuels (4427) ; Facility Name: Ituiutaba Bioenergia Ltda (71006); Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	Brazil	Molasses (019)	Ethanol	ETHM204L	38.30	ETHM204LR	40.84	8/13/2020	None	Ethanol	BP Biofuels (4427)	Ituiutaba Bioenergia Ltda (71006)	Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	None	Retired
T1R-1183	Tier 1	2.0	Fuel Producer: BP Biofuels (4427) ; Facility Name: Central Itumbiara de Bioenergia e Alimentos Ltda (71007); Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	Brazil	Molasses (019)	Ethanol	ETHM203L	39.84	ETHM203LR	42.42	8/13/2020	None	Ethanol	BP Biofuels (4427)	Central Itumbiara de Bioenergia e Alimentos Ltda (71007)	Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	None	Retired
T1R-1182	Tier 1	2.0	Fuel Producer: BP Biofuels (4427) ; Facility Name: Central Itumbiara de Bioenergia e Alimentos Ltda (71007); Brazilian sugarcane juice-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	Brazil	Sugarcane (018)	Ethanol	ETHS203L	40.74	ETHS203LR	43.32	8/13/2020	None	Ethanol	BP Biofuels (4427)	Central Itumbiara de Bioenergia e Alimentos Ltda (71007)	Brazilian sugarcane juice-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	None	Retired

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B005801	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) produced from Dairy Manure at T&M Bos Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00580100	-167.04	12/31/2019	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) produced from Dairy Manure at T&M Bos Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional)	None	Retired
B005802	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure at T&M Herrema Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00580200	-151.41	12/31/2019	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure at T&M Herrema Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional)	None	Retired
B005803	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure at T&M Windy Ridge Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00580300	-257.78	12/31/2019	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure at T&M Windy Ridge Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional)	None	Retired
B006001	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00600100	-255.74	2/24/2020	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Fair Oaks Upgrader, LLC (71001)	Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional)	None	Retired
T1N-1387	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average California Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California (Provisional)	Bakersfield, California	CA Corn Oil from Wet DGS	Biodiesel	None	None	BDC202	27.45	6/30/2016	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average California Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California (Provisional)	None	Retired
T1N-1388	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average U.S. Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California **(Provisional)**	Bakersfield, California	U.S. Corn Oil from Wet DGS	Biodiesel	None	None	BDC203	28.48	6/30/2016	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average US Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California (Provisional)	None	Retired
T1N-1543	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average Global Sourced Used Cooking Oil (energy required to render) to Biodiesel Produced in California **(Provisional)**	Bakersfield, California	Global Used Cooking Oil	Biodiesel	None	None	BDU205	23.28	6/30/2016	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average Global Sourced Used Cooking Oil (energy required to render)to Biodiesel Produced in California (Provisional)	None	Retired
T1N-1670	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Valley LFG, LLC (71137); Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ	Pennsylvania	Landfill Gas	Liquefied Natural Gas	LNGLF226	66.92	LNGLF226R	70.36	9/22/2020	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Valley LFG, LLC (71137)	Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ	None	Retired
T1N-1671	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Valley LFG, LLC (71137); Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; re-gasified in CA.	Pennsylvania	Landfill Gas	Compressed Natural Gas	CNGLF266	69.47	CNGLF266R	72.91	9/22/2020	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Valley LFG, LLC (71137)	Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; re-gasified in CA.	None	Retired
T1N-1669	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Valley LFG, LLC (71137); Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations	Pennsylvania	Landfill Gas	Compressed Natural Gas	CNGLF267	54.61	CNGLF267R	57.83	9/22/2020	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Valley LFG, LLC (71137)	Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations	None	Retired
A027101	Tier 1	3.0	Fuel Producer: Jaxon Energy, LLC (6454) ; Facility Name: Jaxon Energy, LLC (83608); Distilled Corn Oil transported by truck to Renewable Diesel plant in Jackson, Missouri; Natural Gas and Electricity; Renewable Diesel transported by rail to California (Provisional)	Mississippi	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003A02710100	78.60	10/2/2020	None	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	Distilled Corn Oil transported by truck to Renewable Diesel plant in Jackson, Missouri; Natural Gas and Electricity; Renewable Diesel transported by rail to California (Provisional)	None	Retired
A026501	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: HUB CITY ENERGY LLC (70721); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A02650100	73.16	10/9/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	HUB CITY ENERGY LLC (70721)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI (Provisional)	None	Retired

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A024701	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02470100	49.78	10/13/2020	None	Bio-CNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG	None	Retired
B007201	Tier 2	3.0	Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180); Facility Name: WOF PNW Threemile Project (F00100); Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use (Provisional)	Oregon	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00720100	-188.78	9/30/2020	Application Package	Bio-CNG	IOGEN D3 BIOFUEL PARTNERS II LLC (7180)	WOF PNW Threemile Project (F00100)	Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use (Provisional)	None	Retired
B007901	Tier 2	3.0	Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B00790100	30.48	9/30/2020	Application Package	Renewable Diesel	Kern Oil & Refining Co. (5038)	Kern Oil & Refining Co. (80105)	Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional)	None	Retired
B007902	Tier 2	3.0	Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B00790200	41.85	9/30/2020	Application Package	Renewable Diesel	Kern Oil & Refining Co. (5038)	Kern Oil & Refining Co. (80105)	Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional)	None	Retired
B010901	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01090100	-453.10	9/30/2020	Application Package	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	None	Retired
B010902	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01090200	-308.48	9/30/2020	Application Package	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	None	Retired
B010903	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01090300	-236.96	9/30/2020	Application Package	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	None	Retired
B009601	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Dairy Dreams (F00127); Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00960100	-532.74	9/30/2020	Application Package	Bio-CNG	Clean Energy (5481)	Calumet - Dairy Dreams (F00127)	Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use (Provisional)	None	Retired
B009701	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Ponderosa (F00128); Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00970100	-372.20	9/30/2020	Application Package	Bio-CNG	Clean Energy (5481)	Calumet - Ponderosa (F00128)	Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use (Provisional)	None	Retired
B010801	Tier 2	3.0	Fuel Producer: AgPower Jerome, LLC (C1036); Facility Name: AgPower Jerome RNG Project (F00077); Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use (Provisional)	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01080100	-230.13	9/30/2020	Application Package	Bio-CNG	AgPower Jerome, LLC (C1036)	AgPower Jerome RNG Project (F00077)	Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use (Provisional)	None	Retired
A024201	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF250	54.87	CNG025A02420100	47.53	10/29/2020	None	Bio-CNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG	None	Retired
A024202	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations	Tennessee	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02420200	60.15	10/29/2020	None	Bio-LNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations	None	Retired

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A024203	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	Tennessee	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02420300	63.24	10/29/2020	None	Bio-CNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	None	Retired
A027201	Tier 1	3.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC295	74.03	ETH009A02720100	65.63	10/21/2020	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI. (Provisional)	None	Retired
A027202	Tier 1	3.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A02720200	26.60	10/21/2020	None	Ethanol - Cellulosic	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional)	None	Retired
A025901	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Distillers' Corn Oil (003)	Biodiesel (BIO)	None	None	BIO003A02590100	36.62	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	None	Retired
A025902	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A02590200	66.13	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	None	Retired
A025903	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A02590300	41.88	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	None	Retired
A024101	Tier 1	3.0	Fuel Producer: COMPLEXE ENVIRO CONNEXIONS LTEE (6282); Facility Name: Complexe Enviro Connexions (F00139); Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to California for compression to CNG (Provisional)	Canada	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02410100	29.92	11/12/2020	None	Bio-CNG	COMPLEXE ENVIRO CONNEXIONS LTEE (6282)	Complexe Enviro Connexions (F00139)	Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to California for compression to CNG (Provisional)	None	Retired
A024102	Tier 1	3.0	Fuel Producer: COMPLEXE ENVIRO CONNEXIONS LTEE (6282); Facility Name: Complexe Enviro Connexions (F00139); Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations in California (Provisional)	Canada	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02410200	42.70	11/12/2020	None	Bio-LNG	COMPLEXE ENVIRO CONNEXIONS LTEE (6282)	Complexe Enviro Connexions (F00139)	Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations in California (Provisional)	None	Retired
A024103	Tier 1	3.0	Fuel Producer: COMPLEXE ENVIRO CONNEXIONS LTEE (6282); Facility Name: Complexe Enviro Connexions (F00139); Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations; regasified, and compressed to L-CNG (Provisional)	Canada	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02410300	45.78	11/12/2020	None	Bio-CNG	COMPLEXE ENVIRO CONNEXIONS LTEE (6282)	Complexe Enviro Connexions (F00139)	Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations; regasified, and compressed to L-CNG (Provisional)	None	Retired
A024801	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Starch Ethanol produced from Midwest corn, dry milled, produced with grid electricity and natural gas with DDGs, MDGS, and corn oil co-products	Iowa	Corn (009)	Ethanol (ETH)	ETHC220	78.14	ETH009A02480100	70.62	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Fort Dodge (70043)	Starch Ethanol produced from Midwest corn, dry milled, produced with grid electricity and natural gas with DDGs, MDGS, and corn oil co-products	None	Retired
A024802	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Fort Dodge, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC220	78.14	ETH009A02480200	67.47	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Fort Dodge (70043)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Fort Dodge, Iowa; Ethanol transported by rail to California	None	Retired
A025601	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Aurora, South Dakota (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC262L	76.74	ETH009A02560100	71.32	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Aurora, South Dakota (70041)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California	None	Retired

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A025602	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Aurora, South Dakota (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC262L	76.74	ETH009A02560200	68.05	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Aurora, South Dakota (70041)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California	None	Retired
A025401	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California; Composite CI	Iowa	Corn (009)	Ethanol (ETH)	ETHC260L	78.62	ETH009A02540100	69.55	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Albert City (70142)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California; Composite CI	None	Retired
A025402	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC260L	78.62	ETH009A02540200	66.07	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Albert City (70142)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California	None	Retired
A024301	Tier 1	3.0	Fuel Producer: LES RENEWABLE NG LLC (6223); Facility Name: LES RENEWABLE NG LLC (71157); Biomethane from SWACO Landfill in Grove City, Ohio, upgrading at LES Renewable NG LLC, pipelined to California for compression to CNG	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02430100	60.40	11/19/2020	None	Bio-CNG	LES RENEWABLE NG LLC (6223)	LES RENEWABLE NG LLC (71157)	Biomethane from SWACO Landfill in Grove City, Ohio, upgrading at LES Renewable NG LLC, pipelined to California for compression to CNG	None	Retired
A028201	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail (Provisional)	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT202	35.57	BIO002A02820100	27.02	11/20/2020	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail (Provisional)	None	Retired
B011401	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied hydrogen from landfill gas at Fresno, Texas; liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to H2 stations in Northern California	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B01140100	109.68	11/25/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Liquefied hydrogen from landfill gas at Fresno, Texas; liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to H2 stations in Northern California	None	Retired
B011501	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426) ; Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Biomethane from BlueRidge landfill, Texas, hydrogen produced at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to fueling stations in Southern California.	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B01150100	73.14	11/25/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products and Chemicals SMR Wilmington. CA (F00068)	Biomethane from BlueRidge landfill, Texas, hydrogen produced at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to fueling stations in Southern California.	None	Retired
B012801	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied hydrogen from North American Natural Gas, produced at Air Products & Chemicals Inc., Sacramento, California transported as liquid hydrogen to liquid fueling stations in California	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B01280100	153.91	11/25/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Liquefied hydrogen from North American Natural Gas, produced at Air Products & Chemicals Inc., Sacramento, California transported as liquid hydrogen to liquid fueling stations in California	None	Retired
B010201	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020100	-408.6	CNG026B01020101	-408.62	12/3/2020	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	None	Retired
B010202	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01020200	-289.76	12/3/2020	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	None	Retired
B010203	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01020300	-308.74	12/3/2020	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	None	Retired
A024501	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00570100	76.25	ETH009A02450100	69.92	12/4/2020	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired

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A024502	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00570200	67.07	ETH009A02450200	62.54	12/4/2020	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A024503	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00570300	28.39	ETH012A02450300	22.56	12/4/2020	None	Ethanol - Cellulosic	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A025501	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Albion (702830); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC106	86.49	ETH009A02550100	71.02	12/3/2020	None	Ethanol	Valero Renewable Fuels (3201)	Albion (702830)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California	None	Retired
A025502	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Albion (702830); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC107	82.37	ETH009A02550200	67.05	12/3/2020	None	Ethanol	Valero Renewable Fuels (3201)	Albion (702830)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California	None	Retired
A029701	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Kansas	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02970101	58.34	12/15/2020	None	Bio-LNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A029702	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Kansas	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02970200	61.43	12/15/2020	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
B011901	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable jet fuel produced from animal fat; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B01190100	19.51	12/18/2020	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable jet fuel produced from animal fat; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	None	Retired
B011902	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable diesel produced from animal fat; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01190200	19.51	12/18/2020	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable diesel produced from animal fat; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional)	None	Retired
B011903	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable naphtha produced from animal fat; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01190300	19.51	12/18/2020	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable naphtha produced from animal fat; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional)	None	Retired
B008002	Tier 2	3.0	Fuel Producer: Bridge To Renewables, Benefit LLC (C1006); Facility Name: Blake's Landing Farms (F00019); Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI (Provisional)	California	Other Organic Waste (029)	Electricity (ELC)	None	None	ELC029B00800200	-233.49	12/31/2020	Application Package	Electricity	Bridge To Renewables, Benefit LLC (C1006)	Blake's Landing Farms (F00019)	Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI (Provisional)	None	Retired
B009901	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Midwest Corn Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Corn (009)	Ethanol (ETH)	ETHC282	80.85	ETH009B00990101	74.02	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	Midwest Corn Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired
B009902	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Midwest Corn Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Corn (009)	Ethanol (ETH)	ETHC281	72.32	ETH009B00990200	63.64	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	Midwest Corn Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B009903	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); US-sourced Grain Sorghum Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG217	88.90	ETH010B00990300	77.27	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	US-sourced Grain Sorghum Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired
B009904	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); US-sourced Grain Sorghum Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG216	80.38	ETH010B00990400	66.90	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	US-sourced Grain Sorghum Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired
B009905	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Ethanol produced from Dry Mill, Wheat Starch Slurry, Dry DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Wheat Starch Slurry (014)	Ethanol (ETH)	ETHWSS201	53.73	ETH014B00990500	52.76	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	Ethanol produced from Dry Mill, Wheat Starch Slurry, Dry DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired
B009906	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Ethanol produced from Dry Mill, Wheat Starch Slurry, Wet DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Wheat Starch Slurry (014)	Ethanol (ETH)	ETHWSS200	45.2	ETH014B00990600	47.78	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	Ethanol produced from Dry Mill, Wheat Starch Slurry, Wet DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired
A024601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A02460100	77.21	12/29/2020	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	None	Retired
A024602	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A02460200	69.47	12/29/2020	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	None	Retired
A024603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A02460300	29.41	12/29/2020	None	Ethanol - Cellulosic	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	None	Retired
B012701	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01270100	-417.35	12/31/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	None	Retired
B012702	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007) ; Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01270200	-417.27	12/31/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	None	Retired
B012703	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01270300	-418.90	12/31/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	None	Retired
B012704	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01270400	-392.44	12/31/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	None	Retired
B014501	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B01450100	-287.07	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products and Chemicals SMR Wilmington. CA (F00068)	Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California	None	Retired

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B014502	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B01450200	-216.05	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products and Chemicals SMR Wilmington. CA (F00068)	Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California	None	Retired
B014601	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from landfill gas at Fresno, Texas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California; and transported as gaseous hydrogen to fueling stations in California	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B01460100	120.04	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Biomethane from landfill gas at Fresno, Texas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California; and transported as gaseous hydrogen to fueling stations in California	None	Retired
B014602	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); North American Natural Gas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California and transported as gaseous hydrogen to fueling stations in California	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B01460200	164.27	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	North American Natural Gas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California and transported as gaseous hydrogen to fueling stations in California	None	Retired
B016401	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to hydrogen stations in California	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B01640100	-251.36	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to hydrogen stations in California	None	Retired
B016402	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B01640200	-241.00	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California	None	Retired
B016403	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California, transported to hydrogen stations in California	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B01640300	-179.71	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California, transported to hydrogen stations in California	None	Retired
B016404	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B01640400	-169.35	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California	None	Retired
B010201	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020100	-408.60	CNG026B01020101	-408.62	12/3/2020	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	None	Retired
A027401	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Renovar Arlington, LTD RNG Project (70501); Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional)	Texas	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A02740100	38.37	3/1/2021	None	Bio-CNG	U.S. Venture, Inc. (5504)	Renovar Arlington, LTD RNG Project (70501)	Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional)	None	Retired
A033001	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00990100	73.79	ETH009A03300100	73.75	3/1/2021	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	None	Retired
A027901	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	Arkansas	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC210	38.75	BIO003A02790100	33.97	3/9/2021	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	None	Retired
A027902	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	Arkansas	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU207L	24.36	BIO001A02790200	27.05	3/9/2021	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	None	Retired

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A029801	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional)	Washington	Landfill Gas (025)	Compressed Natural Gas (CNG)	LNGLF206LR	40.21	CNG025A02980100	28.24	3/12/2021	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional)	None	Retired
A029802	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Washington	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNGLF206LR	40.21	LNG025A02980200	41.09	3/12/2021	None	Bio-LNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A029803	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Washington	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	CNGLF229LR	42.78	LCN025A02980300	44.18	3/12/2021	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A026703	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02670300	55.90	3/18/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Raeger (71131)	Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A026702	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02670200	52.82	3/18/2021	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Raeger (71131)	Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A026701	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF275	42.86	CNG025A02670100	35.51	3/18/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Raeger (71131)	Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG (Provisional)	None	Retired
A026203	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Shade (71134); Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to California for compression to CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF273R	49.77	CNG025A02620300	52.21	3/18/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Shade (71134)	Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to California for compression to CNG (Provisional)	None	Retired
A026202	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Shade (71134); Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02620200	72.80	3/18/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Shade (71134)	Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A026201	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Shade (71134); Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02620100	69.71	3/18/2021	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Shade (71134)	Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A026401	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02640100	77.89	3/17/2021	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Southern Alleghenies (71133)	Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A026402	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02640200	80.98	3/17/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Southern Alleghenies (71133)	Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A026403	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF274	58.84	CNG025A02640300	60.28	3/17/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Southern Alleghenies (71133)	Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG (Provisional)	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A029401	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETH009A01400200	72.42	ETH009A02940100	70.88	3/22/2021	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A029402	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETH009A01400100	63.69	ETH009A02940200	61.90	3/22/2021	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A029403	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum from Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A01400400	75.50	ETH010A02940300	74.04	3/22/2021	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Sorghum from Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A029404	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum from Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California.	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A01400300	66.76	ETH010A02940400	65.06	3/22/2021	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Sorghum from Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California.	None	Retired
A031002	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Louisiana	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A03100200	53.73	3/18/2021	None	Bio-LNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A031003	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Louisiana	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A03100300	56.81	3/18/2021	None	Bio-CNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A031201	Tier 1	3.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	California	Soybean Oil (005)	Biodiesel (BIO)	BDS201	52.45	BIO005A03120100	57.16	3/23/2021	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	None	Retired
A031202	Tier 1	3.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	California	Canola Oil (006)	Biodiesel (BIO)	BDCA201	54.97	BIO006A03120200	51.65	3/23/2021	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	None	Retired
A031204	Tier 1	3.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production.	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT205	32.24	BIO002A03120400	31.28	3/23/2021	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production.	None	Retired
A031205	Tier 1	3.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT206	28.90	BIO002A03120500	32.45	3/23/2021	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	None	Retired
A031206	Tier 1	3.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A03120600	21.27	3/23/2021	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	None	Retired
B005901	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00590100	-558.62	ELC026B00590101	-562.50	3/25/2021	Application Package	Electricity	California Bioenergy LLC (B194)	ABEC Bidart-Old River LLC (F00113)	Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	None	Retired

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B008901	Tier 2	3.0	Fuel Producer: Gallo Cattle Company, LP (C1029) ; Facility Name: Cottonwood Dairy (F00094); Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00890100	-108.43	ELC026B00890101	-126.52	3/25/2021	Application Package	Electricity	Gallo Cattle Company, LP (C1029)	Cottonwood Dairy (F00094)	Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional)	None	Retired
B013311	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01331100	26.5	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013312	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01331200	28.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
A029501	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU219	21.73	BIO001A02950100	21.93	4/1/2021	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	None	Retired
A029502	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU240	19	BIO001A02950200	16.98	4/1/2021	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	None	Retired
A030601	Tier 1	3.0	Fuel Producer: MONROEVILLE LFG, LLC (6317); Facility Name: MONROEVILLE LFG, LLC (71136); Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A03060100	41.93	4/6/2021	None	Bio-CNG	MONROEVILLE LFG, LLC (6317)	MONROEVILLE LFG, LLC (71136)	Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional)	None	Retired
B018908	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01890800	27.00	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018909	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01890900	28.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018917	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891700	27.00	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018918	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891800	28.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
None	Lookup Table	3.0	California grid electricity used as a transportation fuel in California	California	Grid Electricity (039)	Electricity (ELC)	None	None	ELC000L00072021	75.93	NA	None	Electricity	NA	NA	California grid electricity used as a transportation fuel in California	None	Retired
A028807	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Self Rendered Animal Fat Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	Iowa	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A02880700	24.50	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	Self Rendered Animal Fat Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	None	Retired

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A030901	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03090100	24.46	5/4/2021	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	Retired
A030902	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	ETHC247L	75.15	ETH009A03090200	71.95	5/4/2021	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	Retired
A036702	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional)	Tennessee	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A03670200	62.18	5/11/2021	None	Bio-LNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A036703	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional)	Tennessee	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A03670300	65.26	5/11/2021	None	Bio-CNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional)	None	Retired
A028501	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Zero Energy Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU204R	14.7	BIO001A02850100	12.91	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	US sourced Zero Energy Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	None	Retired
A028502	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); California sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A02850200	12.93	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	California sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	None	Retired
A028503	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU203R	18.31	BIO001A02850300	17.86	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	US sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	None	Retired
A028504	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A02850400	15.81	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	US sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	None	Retired
A028505	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel ditribution by truck.	California	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC202 and BDC203	27.45 and 28.48	BIO003A02850500	25.22	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel ditribution by truck.	None	Retired
A028506	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT203R	31.39	BIO002A02850600	30.94	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	None	Retired

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A035101	Tier 1	3.0	Fuel Producer: E Energy Adams, LLC (4831); Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00370100	66.53	ETH009A03510100	65.93	6/1/2021	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional)	None	Retired
A029002	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	Illinois	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A02900200	57.00	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	None	Retired
A029003	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	Illinois	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A02900300	53.00	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	None	Retired
A029006	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU246	23.18	BIO001A02900600	20.25	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	None	Retired
A034701	Tier 1	3.0	Fuel Producer: SENECA ENERGY II, LLC (6222); Facility Name: SENECA ENERGY (71156); Biomethane from biogas produced at the Seneca Meadows Landfill in Waterloo, New York; upgraded at Seneca Energy II facility; pipelined to California for compression to CNG. (Provisional)	New York	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF207L	52.77	CNG025A03470100	44.49	6/10/2021	None	Bio-CNG	SENECA ENERGY II, LLC (6222)	SENECA ENERGY (71156)	Biomethane from biogas produced at the Seneca Meadows Landfill in Waterloo, New York; upgraded at Seneca Energy II facility; pipelined to California for compression to CNG. (Provisional)	None	Retired
A030401	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Point Loma Digester Gas Project (F00027); Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional)	California	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A03040100	30.31	6/14/2021	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Point Loma Digester Gas Project (F00027)	Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional)	None	Retired
A034601	Tier 1	3.0	Fuel Producer: PINNACLE GAS PRODUCERS, LLC (6220); Facility Name: PINNACLE GAS PRODUCERS, LLC (71153); Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; upgrading at Pinnacle Gas Producers, LLC, pipelined to California for compression to CNG	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF206L	41.61	CNG025A03460100	63.75	6/16/2021	None	Bio-CNG	PINNACLE GAS PRODUCERS, LLC (6220)	PINNACLE GAS PRODUCERS, LLC (71153)	Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; upgrading at Pinnacle Gas Producers, LLC, pipelined to California for compression to CNG	None	Retired
A034602	Tier 1	3.0	Fuel Producer: PINNACLE GAS PRODUCERS, LLC (6220); Facility Name: PINNACLE GAS PRODUCERS, LLC (71153); Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California LNG stations	Ohio	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNGLF201LR	50.27	LNG025A03460200	76.91	6/16/2021	None	Bio-LNG	PINNACLE GAS PRODUCERS, LLC (6220)	PINNACLE GAS PRODUCERS, LLC (71153)	Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California LNG stations	None	Retired
A034603	Tier 1	3.0	Fuel Producer: PINNACLE GAS PRODUCERS, LLC (6220); Facility Name: PINNACLE GAS PRODUCERS, LLC (71153); Biomethane from Pinnacle Road Landfill at Moraine; Stony Hollow Landfill at Dayton, Ohio; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	Ohio	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	CNGLF224LR	56.01	LCN025A03460300	80.00	6/16/2021	None	Bio-CNG	PINNACLE GAS PRODUCERS, LLC (6220)	PINNACLE GAS PRODUCERS, LLC (71153)	Biomethane from Pinnacle Road Landfill at Moraine; Stony Hollow Landfill at Dayton, Ohio; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	None	Retired
A034501	Tier 1	3.0	Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG.	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF237L	47.40	CNG025A03450100	52.66	6/16/2021	None	Bio-CNG	WESTSIDE GAS PRODUCERS, LLC (6218)	WESTSIDE GAS PRODUCERS, LLC (71151)	Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG.	None	Retired
B016301	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Hilarides (F00006); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01630100	-758.46	6/21/2021	Application Package	Electricity	CleanFuture, Inc. (C1001)	Hilarides (F00006)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California. (Provisional)	None	Retired

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B019001	Tier 2	3.0	Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	Kansas	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B01900100	46.31	6/25/2021	Application Package	Renewable Diesel	East Kansas Agri-Energy, LLC (4483)	East Kansas Agri-Energy, LLC (83483)	Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	None	Retired
B019002	Tier 2	3.0	Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	Kansas	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	None	None	RNT003B01900200	46.31	6/25/2021	Application Package	Renewable Naphtha	East Kansas Agri-Energy, LLC (4483)	East Kansas Agri-Energy, LLC (83483)	Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	None	Retired
B019301	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity, then to California By rail and ocean tanker (Provisional)	North Dakota	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B01930100	34.90	6/25/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity, then to California By rail and ocean tanker (Provisional)	None	Retired
B019302	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by Rail and Ocean Tanker to California. (Provisional)	North Dakota	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B01930200	64.24	6/25/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by Rail and Ocean Tanker to California. (Provisional)	None	Retired
B019303	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Distillers' Corn Oil transported by Truck and Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional)	North Dakota	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	None	None	RNT003B01930300	34.90	6/25/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Distillers' Corn Oil transported by Truck and Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional)	None	Retired
B019304	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional)	North Dakota	Soybean Oil (005)	Renewable Naphtha (RNT)	None	None	RNT005B01930400	64.24	6/25/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional)	None	Retired
B014301	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B00100100	-345.68	CNG044B01430100	-429.05	6/29/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations	None	Retired
B014901	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: South Meadows Farm (F00195); Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B01490100	-359.66	6/29/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	South Meadows Farm (F00195)	Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	None	Retired
B016801	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B01680100	33.42	6/29/2021	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	None	Retired
B016802	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable diesel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01680200	33.42	6/29/2021	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable diesel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional)	None	Retired
B016803	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable naphtha produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01680300	33.42	6/29/2021	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable naphtha produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional)	None	Retired
B019101	Tier 2	3.0	Fuel Producer: California Renewable Power LLC(C196); Facility Name: California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270); Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles. (Provisional)	California	Urban Landscaping Waste (028)	Compressed Natural Gas (CNG)	None	None	CNG028B01910100	2.51	6/29/2021	Application Package	Bio-CNG	California Renewable Power LLC(C196)	California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270)	Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles. (Provisional)	None	Retired

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A037601	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced and transported by truck in California (Provisional)	California	Distillers' Corn Oil (003)	Biodiesel (BIO)	None	None	BIO003A03760100	32.12	6/30/2021	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced and transported by truck in California (Provisional)	None	Retired
A036601	Tier 1	3.0	Fuel Producer: World Energy Rome, LLC (4533); Facility Name: World Energy Rome, LLC (82470); Midwest Soybean Oil transported by truck to Biodiesel Plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional)	Georgia	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A03660100	61.39	7/7/2021	None	Biodiesel	World Energy Rome, LLC (4533)	World Energy Rome, LLC (82470)	Midwest Soybean Oil transported by truck to Biodiesel Plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional)	None	Retired
A036602	Tier 1	3.0	Fuel Producer: World Energy Rome, LLC (4533); Facility Name: World Energy Rome, LLC (82470); US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional)	Georgia	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A03660200	24.94	7/7/2021	None	Biodiesel	World Energy Rome, LLC (4533)	World Energy Rome, LLC (82470)	US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional)	None	Retired
A036603	Tier 1	3.0	Fuel Producer: World Energy Rome, LLC (4533); Facility Name: World Energy Rome, LLC (82470); US Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Finished Fuel Transported to California By Rail (Provisional)	Georgia	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A03660300	36.60	7/7/2021	None	Biodiesel	World Energy Rome, LLC (4533)	World Energy Rome, LLC (82470)	US Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Finished Fuel Transported to California By Rail (Provisional)	None	Retired
A038601	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02560100	71.32	ETH009A03860100	72.20	7/13/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired
A038602	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02560200	68.05	ETH009A03860200	69.20	7/13/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired
A034801	Tier 1	3.0	Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional)	Texas	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT217	38.27	BIO002A03480100	30.80	7/28/2021	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional)	None	Retired
A037501	Tier 1	3.0	Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Seabreeze Energy Producers (70281); Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A03750100	37.82	8/20/2021	None	Bio-CNG	BLUE SOURCE LLC (6086)	Seabreeze Energy Producers (70281)	Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional)	None	Retired
B017301	Tier 2	3.0	Fuel Producer: DF-AP #1, LLC (C1122); Facility Name: Big Sky Dairy Digester (F00329); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California (Provisional)	Idaho	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01730100	-545.71	9/22/2021	Application Package	Electricity	DF-AP #1, LLC (C1122)	Big Sky Dairy Digester (F00329)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California (Provisional)	None	Retired
B017401	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	South Dakota	Corn (009)	Ethanol (ETH)	ETHC306	81.86	ETH009B01740100	75.91	9/24/2021	Application Package	Ethanol	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	None	Retired
B017402	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	South Dakota	Corn (009)	Ethanol (ETH)	ETHC306	81.86	ETH009B01740200	68.73	9/24/2021	Application Package	Ethanol	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	None	Retired
B017403	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California.	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETHCF206	38.58	ETH012B01740300	29.14	9/24/2021	Application Package	Ethanol - Cellulosic	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California.	None	Retired

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B018701	Tier 2	3.0	Fuel Producer: Dry Creek RNG LLC (C1098); Facility Name: Dry Creek RNG Project (F00342); Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional)	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01870100	-435.22	9/30/2021	Application Package	Bio-CNG	Dry Creek RNG LLC (C1098)	Dry Creek RNG Project (F00342)	Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
B021401	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Milford Farm (71483); Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (Provisional)	Utah	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B02140100	-413.67	9/30/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Milford Farm (71483)	Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (Provisional)	None	Retired
B021901	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: HOMAN FARM (71343); RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B02190100	-412.71	9/30/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	HOMAN FARM (71343)	RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use (Provisional)	None	Retired
B016501	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use (Provisional)	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020200	-289.76	CNG026B01650100	-406.35	9/30/2021	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
B018501	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01850100	-389.66	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	None	Retired
B018502	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01850200	-388.91	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	None	Retired
B019801	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01980100	-388.29	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
A039401	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00360100	67.09	ETH009A03940100	66.71	10/14/2021	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional)	None	Retired
A039402	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A00360200	32.40	ETH012A03940200	27.87	10/14/2021	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	None	Retired
A040201	Tier 1	3.0	Fuel Producer: Siouxland Ethanol, LLC (5026); Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00340100	66.23	ETH009A04020100	63.73	10/11/2021	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	None	Retired
A037903	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional)	Texas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A03790300	64.00	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional)	None	Retired
A037803	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A01610300	66.62	ETH010A03780300	66.28	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	None	Retired

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A037805	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (70039); Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A01610500	74.57	ETH010A03780500	73.81	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (70039)	Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	None	Retired
A042301	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC292	73.11	ETH009A04230100	70.88	10/26/2021	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional)	None	Retired
A042302	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04230200	24.02	10/26/2021	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional)	None	Retired
T1N-1769	Tier 1	2.0	Fuel Producer: Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: Fuel Producer: REG Seneca, LLC (80232) ; U.S. sourced corn oil, Biodiesel produced in Seneca, Illinois and transported by rail to California	Illinois	Corn Oil	Biodiesel	None	None	BDC213	34.02	4/2/2018	None	Biodiesel	REG Seneca, LLC (3652)	Fuel Producer: REG Seneca, LLC (80232)	U.S. sourced corn oil, Biodiesel produced in Seneca, Illinois and transported by rail to California	None	Retired
A038001	Tier 1	3.0	Fuel Producer: GHI Energy, LLC (6156); Facility Name: Fort Bend Power Producers (shared facility) (7113s); Biomethane from Fort Bend Regional Landfill in Needville, Texas, pipelined to California for compression to CNG.	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A03800100	34.94	11/4/2021	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers (shared facility) (7113s)	Biomethane from Fort Bend Regional Landfill in Needville, Texas, pipelined to California for compression to CNG.	None	Retired
A041601	Tier 1	3.0	Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Greentree Landfill Gas Company (F00212); Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG.	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04160100	66.18	11/23/2021	None	Bio-CNG	TRUSTAR ENERGY LLC (6523)	Greentree Landfill Gas Company (F00212)	Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG.	None	Retired
A042601	Tier 1	3.0	Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced tallow; finished fuel transported to California by rail for use as a transportation fuel. (Provisional)	Iowa	(animal and poultry fat	Biodiesel (BIO)	BDT211	31.19	BIO002A04260100	29.23	12/22/2021	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Biodiesel produced from US sourced tallow; finished fuel transported to California by rail for use as a transportation fuel. (Provisional)	None	Retired
A042602	Tier 1	3.0	Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel. (Provisional)	Iowa	Soybean Oil (005)	Biodiesel (BIO)	BDS206	54.50	BIO005A04260200	55.05	12/22/2021	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel. (Provisional)	None	Retired
B020701	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02070100	-135.37	12/29/2021	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional)	None	Retired
B020702	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02070200	-211.01	12/29/2021	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional)	None	Retired
B022001	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: SOMERSET FARM (71381); Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02200100	-345.80	CNG044B02200101	-410.57	12/31/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	SOMERSET FARM (71381)	Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
B024001	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Distillers' Corn Oil (003	Renewable Diesel (RND)	RND003B01930100	None	RND003B02400100	29.79	12/28/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired

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B024002	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Soybean Oil (005)	Renewable Diesel (RND)	RND005B01930200	None	RND005B02400200	57.64	12/28/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024003	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S Sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	(animal and poultry fat	Renewable Diesel (RND)	None	None	RND002B02400300	33.34	12/28/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S Sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024004	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Distillers' Corn Oil (003	Renewable Naphtha (RNT)	RNT003B01930300	34.90	RNT003B02400400	29.79	12/28/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024005	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Soybean Oil (005)	Renewable Naphtha (RNT)	RNT005B01930400	64.24	RNT005B02400500	57.64	12/28/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024006	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	oking Oil/Waste Oil (UC	Renewable Naphtha (RNT)	None	None	RNT001B02400600	21.09	12/28/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024007	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	(animal and poultry fat	Renewable Naphtha (RNT)	None	None	RNT002B02400700	33.34	12/28/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024008	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	oking Oil/Waste Oil (UC	Renewable Diesel (RND)	None	None	RND001B02400800	21.09	12/28/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024101	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	California	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B02410100	54.68	12/28/2021	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	None	Retired
B024103	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	California	Canola Oil (006)	Renewable Diesel (RND)	None	None	RND006B02410300	51.87	12/28/2021	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A043602	Tier 1	3.0	Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04360200	24.89	2/1/2022	None	Ethanol	AL CORN CLEAN FUEL, LLC (4825)	AL CORN CLEAN FUEL, LLC (70087)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	Retired
B025101	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B02510100	60.13	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025102	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Distillers' Corn Oil (003	Renewable Diesel (RND)	RND003B00540100	27.42	RND003B02510200	27.64	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025103	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Diesel (RND)	RND001B00540200	19.92	RND001B02510300	19.75	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025104	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Diesel (RND)	None	None	RND001B02510400	18.16	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025105	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Diesel (RND)	RND002B00540300	31.86	RND002B02510500	32.14	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025106	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Diesel (RND)	None	None	RND002B02510600	42.48	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025107	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Soybean Oil (005)	Renewable Naphtha (RNT)	None	None	RNT005B02510700	60.13	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025108	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Distillers' Corn Oil (003	Renewable Naphtha (RNT)	None	None	RNT003B02510800	27.64	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025109	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Naphtha (RNT)	None	None	RNT001B02510900	19.75	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025110	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Naphtha (RNT)	None	None	RNT001B02511000	18.16	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025111	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Naphtha (RNT)	None	None	RNT002B02511100	32.14	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired

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B025112	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Naphtha (RNT)	None	None	RNT002B02511200	42.48	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B026801	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B00450100	25.08	AJF002B02680100	18.87	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired
B026802	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B00450200	25.08	RND002B02680200	18.87	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026803	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B00450300	25.08	RNT002B02680300	18.87	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B026810	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B01680100	33.42	AJF002B02681000	29.26	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired
B026811	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B01680200	33.42	RND002B02681100	29.26	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026812	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B01680300	33.42	RNT002B02681200	29.26	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B021601	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02160100	-382.83	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	None	Retired
B021602	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	None	None	LNG026B02160200	-369.56	3/30/2022	Application Package	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional)	None	Retired
B021603	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN026B02160300	-366.02	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional)	None	Retired
B021701	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02170100	-303.92	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	None	Retired
B021702	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	None	None	LNG026B02170200	-290.16	3/30/2022	Application Package	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional)	None	Retired

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B021703	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN026B02170300	-286.62	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional)	None	Retired
B026701	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	Distillers' Corn Oil (003	Biodiesel (BIO)	BIO003A02850500	25.22	BIO003B02670100	28.67	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	None	Retired
B026702	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	(animal and poultry fat	Biodiesel (BIO)	BIO002A02850600	30.94	BIO002B02670200	32.53	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	None	Retired
B028001	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	California	Swine Manure (044)	Gaseous Hydrogen (HYG)	None	None	HYG044B02800100	-374.14	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	None	Retired
B028002	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	California	Swine Manure (044)	Gaseous Hydrogen (HYG)	None	None	HYG044B02800200	-390.47	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	None	Retired
A045501	Tier 1	3.0	Fuel Producer: BLUE SOURCE LLC (6086) ; Facility Name: Theresa Street Water Resource Recovery Facility (F00343); Biomethane from Waste Water Treatment Plant in Lincoln Nebraska, pipelined to California, compressed to CNG as indirect accounting of RNG dispensed in California (Provisional)	Nebraska	Vastewater Sludge (03	Compressed Natural Gas (CNG)	None	None	CNG030A04550100	43.12	4/14/2022	None	Bio-CNG	BLUE SOURCE LLC (6086)	Theresa Street Water Resource Recovery Facility (F00343)	Biomethane from Waste Water Treatment Plant in Lincoln Nebraska, pipelined to California, compressed to CNG as indirect accounting of RNG dispensed in California (Provisional)	None	Retired
B037802	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B03780200	75.16	12/19/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	None	Retired
A016501	Tier 1	3.0	Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California	Rhode Island	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A01650100	15.24	BIO001A01650102	15.02	12/16/2019	None	Biodiesel	NEWPORT BIODIESEL INC (7764)	NEWPORT BIODIESEL LLC (83532)	Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California	2021 AFPR Recert Complete	Retired
B004303	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	None	None	RNT002B00430300	37.13	12/27/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
A016001	Tier 1	3.0	Fuel Producer: Iogen D3 Biofuel Partners LLC (6486); Facility Name: GSF Energy-Rumpke Landfill (71138S); Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01600100	44.90	CNG025A01600102	45.59	12/20/2019	None	Bio-CNG	Iogen D3 Biofuel Partners LLC (6486)	GSF Energy-Rumpke Landfill (71138S)	Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	2021 AFPR Recert Complete	Retired
A016502	Tier 1	3.0	Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California	Rhode Island	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A01650200	18.60	BIO001A01650202	17.61	12/16/2019	None	Biodiesel	NEWPORT BIODIESEL INC (7764)	NEWPORT BIODIESEL LLC (83532)	Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California	2021 AFPR Recert Complete	Retired
B008901	Tier 2	3.0	Fuel Producer: Gallo Cattle Company, LP (C1029) ; Facility Name: Cottonwood Dairy (F00094); Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California.	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00890101	-126.52	ELC026B00890103	-93.58	3/25/2021	None	Electricity	Gallo Cattle Company, LP (C1029)	Cottonwood Dairy (F00094)	Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California.	2021 AFPR Recert Complete	Retired

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A029701	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Kansas	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02970101	58.34	LNG025A02970102	60.50	12/15/2020	None	Bio-LNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	2021 AFPR Recert Complete	Retired
B004301	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B00430100	37.13	AJF002B00430102	38.93	12/27/2019	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B004403	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B00440300	42.91	RNT002B00440302	44.72	12/27/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California	2021 AFPR Recert Complete	Retired
B016801	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B01680100	33.42	AJF002B01680101	35.53	6/29/2021	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	2021 AFPR Recert Complete	Retired
A006402	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00640200	68.04	ETH009A00640200	64.75	5/7/2019	None	Ethanol	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
None	Lookup Table	3.0	CARBOB - based on the average crude oil supplied to California refineries and average California refinery efficiencies	California	Crude Oil	CARBOB	None	None	CBO000L00072019	100.82	NA	None	CARBOB	NA	NA	CARBOB based on the average crude oil supplied to California refineries and average California refinery efficiencies	None	
T1N-1734	Tier 1	2.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by rail to California	Texas	Used Cooking Oil (UCO)	Biodiesel	BDU226	22.80	BDU226R	24.41	11/28/2018	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by rail to California	None	
A007701	Tier 1	3.0	Fuel Producer: Western Plains Energy, LLC (4740) ; Facility Name: Western Plains Energy, LLC (70030); Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC278	70.60	ETH009A00770100	62.91	4/15/2019	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California	None	
A007702	Tier 1	3.0	Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Pathway Description: Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG215	78.55	ETH010A00770200	66.64	4/15/2019	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California	None	
A003201	Tier 1	3.0	Fuel Producer: Scott Petroleum Inc. (4840); Facility Name: Scott Petroleum Biodiesel Refinery (82908); U.S. sourced Rendered UCO; Biodiesel produced in Greenville, MS and transported by rail to California	Mississippi	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU217	27.90	BIO001A00320100	20.92	5/28/2019	None	Biodiesel	Scott Petroleum Inc (4840)	Scott Petroleum Biodiesel Refinery (82908)	U.S. sourced Rendered UCO; Biodiesel produced in Greenville, MS and transported by rail to California	None	Retired
A003202	Tier 1	3.0	Fuel Producer: Scott Petroleum Inc. (4840); Facility Name: Scott Petroleum Biodiesel Refinery (82908); U.S. sourced Distillers' Corn Oil; Biodiesel produced in Greenville, MS and transported by rail to California	Mississippi	Distillers' Corn Oil (003)	Biodiesel (BIO)	None	None	BIO003A00320200	28.43	5/28/2019	None	Biodiesel	Scott Petroleum Inc (4840)	Scott Petroleum Biodiesel Refinery (82908)	U.S. sourced Distillers' Corn Oil; Biodiesel produced in Greenville, MS and transported by rail to California	None	Retired
None	Lookup Table	3.0	ULSD – based on the average crude oil supplied in California refineries and average California refinery efficiencies	NA	Crude Oil	Diesel	None	None	ULS000L00072019	100.45	NA	None	Diesel	NA	NA	ULSD – based on the average crude oil supplied in California refineries and average California refinery efficiencies	None	

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None	Lookup Table	3.0	Compressed Natural Gas from Pipeline Average North Amer	NA	North American Fossil NG (031)	Compressed Natural Gas (CNG)	None	None	CNG000L00072019	79.21	NA	None	Fossil CNG	NA	NA	Compressed Natural Gas from Pipeline Average North American Fossil Natural Gas	None	
None	Lookup Table	3.0	Fossil LPG from crude oil refining and natural gas processin	NA	Crude Oil	Propane (LPG)	None	None	LPG000L00072019	83.19	NA	None	Propane	NA	NA	Fossil LPG from crude oil refining and natural gas processing used as a transport fuel	None	
None	Lookup Table	3.0	Electricity that is generated from 100 percent zero-CI source	NA	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	NA	None	Electricity	NA	NA	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
None	Lookup Table	3.0	Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	NA	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025L00072019	99.48	NA	None	Hydrogen	NA	NA	Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
None	Lookup Table	3.0	Compressed H2 produced in California from central SMR of North American fossil-based NG	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	NA	None	Hydrogen	NA	NA	Compressed H2 produced in California from central SMR of North American fossil-based NG	None	
None	Lookup Table	3.0	Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	NA	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	None	None	HYG037L00072019	10.51	NA	None	Hydrogen	NA	NA	Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	None	
None	Lookup Table	3.0	Compressed H2 produced in California from electrolysis using California average grid electricity	NA	Grid Electricity (039)	Gaseous Hydrogen (HYG)	None	None	HYG039L00072019	164.46	NA	None	Hydrogen	NA	NA	Compressed H2 produced in California from electrolysis using California average grid electricity	None	
None	Lookup Table	3.0	Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	NA	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025L00072019	129.09	NA	None	Hydrogen	NA	NA	Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
None	Lookup Table	3.0	Liquefied H2 produced in California from central SMR of North American fossil-based NG	NA	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	NA	None	Hydrogen	NA	NA	Liquefied H2 produced in California from central SMR of North American fossil-based NG	None	
A008302	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	Minnesota	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A00830200	48.49	6/7/2019	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A008301	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	Minnesota	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A00830100	53.68	6/7/2019	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A010001	Tier 1	3.0	Fuel Producer: The Andersons, Inc (5872); Facility Name: The Andersons Denison Ethanol (70135); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC275	76.35	ETH009A01000100	71.62	6/7/2019	None	Ethanol	The Andersons, Inc (5872)	The Andersons Denison Ethanol (70135)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	None	Retired

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None	Lookup Table	3.0	Fuel Producer: BMW of North America, LLC (C1033); Smart Charging Lookup Table Pathway	NA	Smart Charging or Smart Electrolysis (047)	Electricity (ELC)	None	None	NA	N/A	6/30/2019	See CI's	Electricity	BMW of North America, LLC (C1033)	NA	Smart Charging Lookup Table Pathway	None	
A012501	Tier 1	3.0	Fuel Producer: Plymouth Energy LLC (5474); Facility Name: Plymouth Energy LLC (70183); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC285	83.47	ETH009A01250100	75.16	8/6/2019	None	Ethanol	Plymouth Energy LLC (5474)	Plymouth Energy LLC (70183)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California	None	
None	Lookup Table	3.0	Fuel Producer: Southern California Edison; Smart Charging Lookup Table Pathway	NA	Smart Charging or Smart Electrolysis (047)	Electricity (ELC)	None	None	NA	N/A	9/30/2019	See CI's	Electricity	Southern California Edison	NA	Smart Charging Lookup Table Pathway	None	
A014103	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846); Facility Name: HPB - St. Joe Biodiesel LLC (80059); Rendered Used Cooking Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	Missouri	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01410300	22.62	9/25/2019	None	Biodiesel	High Plains Bioenergy (4846)	HPB - St. Joe Biodiesel LLC (80059)	Rendered Used Cooking Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	None	
A017401	Tier 1	3.0	Fuel Producer: Nebraska Corn Processing (3516); Facility Name: Nebraska Corn Processing LLC (70230); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC227	71.84	ETH009A01740100	65.77	10/17/2019	None	Ethanol	Nebraska Corn Processing (3516)	Nebraska Corn Processing LLC (70230)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California	None	Retired
A011701	Tier 1	3.0	Fuel Producer: Raízen Tarumã S/A (3807); Facility Name: Maracaí (70347); Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Maracai, Brazil; Ethanol transported by Ocean Tanker to California	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A01170100	51.88	11/5/2019	None	Ethanol	Raízen Tarumã S/A (3807)	Maracaí (70347)	Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Maracai, Brazil; Ethanol transported by Ocean Tanker to California	None	
A015301	Tier 1	3.0	Fuel Producer: Raízen Tarumã S/A (3807); Facility Name: Tarumã (70338); Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Taruma, Brazil; Ethanol transported by Ocean Tanker to California	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A01530100	56.35	11/5/2019	None	Ethanol	Raízen Tarumã S/A (3807)	Tarumã (70338)	Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Taruma, Brazil; Ethanol transported by Ocean Tanker to California	None	
A008201	Tier 1	3.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) ; Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317); Midwest Corn, Dry Mill; Wet DGS and Corn oil; Natural Gas and Biogas; Starch Ethanol produced in Pixley,California; Ethanol transported by truck to fueling stations (Provisional)	California	Corn (009)	Ethanol (ETH)	ETHC316	63.01	ETH009A00820100	58.95	12/17/2019	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Corn, Dry Mill; Wet DGS and Corn oil; Natural Gas and Biogas; Starch Ethanol produced in Pixley,California; Ethanol transported by truck to fueling stations (Provisional)	None	
A016901	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California. (Provisional)	Arizona	Wastewater Sludge (030)	Liquefied Natural Gas (LNG)	None	None	LNG030A01690100	41.58	12/18/2019	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California. (Provisional)	None	Retired
A016902	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as (Provisional)	Arizona	Wastewater Sludge (030)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN030A01690200	44.67	12/18/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as (Provisional)	None	Retired
A011401	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in CA	Texas	Wastewater Sludge (030)	Liquefied Natural Gas (LNG)	None	None	LNG030A01140100	54.76	12/19/2019	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Ameresco San Antonio Biogas (71204)	Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in CA	None	
A011402	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling; upgraded to pipeline-quality biomethane in San Antonio, TX; delivered via pipeline to liquefaction facility in Topock, AZ; liquefied & transported by truck to CA; re-gasified & dispensed as CNG	Texas	Wastewater Sludge (030)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN030A01140200	57.84	12/19/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ameresco San Antonio Biogas (71204)	Biomethane generated at the SAWS Dos Rios Water Recycling; upgraded to pipeline-quality biomethane in San Antonio, TX; delivered via pipeline to liquefaction facility in Topock, AZ; liquefied & transported by truck to CA; re-gasified & dispensed as CNG	None	

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A013502	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846) ; Facility Name: High Plains Bioenergy (82883); Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	Oklahoma	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A01350200	55.82	12/20/2019	None	Biodiesel	High Plains Bioenergy (4846)	High Plains Bioenergy (82883)	Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	None	Retired
A013503	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846); Facility Name: High Plains Bioenergy (82883); Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	Oklahoma	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01350300	20.68	12/20/2019	None	Biodiesel	High Plains Bioenergy (4846)	High Plains Bioenergy (82883)	Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	None	Retired
B003301	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Air Products and Chemicals, Inc. (F00080); Liquefied Hydrogen from North American fossil natural gas at Air Products & Chemicals Inc., Sacramento, delivered to Compton, California by liquid hydrogen truck for use in forklifts	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B00330100	153.17	12/31/2019	Application Package	Hydrogen	CleanFuture, Inc. (C1001)	Air Products and Chemicals, Inc. (F00080)	Liquefied Hydrogen from North American fossil natural gas at Air Products & Chemicals Inc., Sacramento, delivered to Compton, California by liquid hydrogen truck for use in forklifts	None	
B003701	Tier 2	3.0	Fuel Producer: SMUD (S338); Facility Name: Van Warmerdam Dairy Digester (V4907); Low CI electricity from dairy manure biogas using reciprocating engine at Van Warmerdam Dairy in Galt, California for use as transportation fuel in California	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00370100	-592.68	12/31/2019	Application Package	Electricity	SMUD (S338)	Van Warmerdam Dairy Digester (V4907)	Low CI electricity from dairy manure biogas using reciprocating engine at Van Warmerdam Dairy in Galt, California for use as transportation fuel in California	None	
B003801	Tier 2	3.0	Fuel Producer: SMUD (S338); Facility Name: Van Steyn Dairy Digester (V1125); Low-CI electricity from dairy manure biogas using reciprocating engine at Van Steyn Dairy in Elk Grove, California for use as transportation fuel in California	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00380100	-630.72	12/31/2019	Application Package	Electricity	SMUD (S338)	Van Steyn Dairy Digester (V1125)	Low-CI electricity from dairy manure biogas using reciprocating engine at Van Steyn Dairy in Elk Grove, California for use as transportation fuel in California	None	
A016601	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Milam High Btu Gas Plant (71208); East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline; Compression to CNG stations in California	Illinois	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF270	62.72	CNG025A01660100	60.09	12/20/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline; Compression to CNG stations in California	None	
A016602	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California LNG stations	Illinois	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNGLF228	76.13	LNG025A01660200	80.27	12/20/2019	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California LNG stations	None	
A016603	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Milam High Btu Gas Plant (71208); East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California to regasified and compressed to L-CNG	Illinois	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	CNGLF271	78.68	LCN025A01660300	83.36	12/20/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California to regasified and compressed to L-CNG	None	
B005001	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen from fossil natural gas at Praxair-Linde Ontario, delivered to stations in Northern California by liquid hydrogen truck for use in fuel cell vehicles.	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B00500100	153.36	1/13/2020	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied Hydrogen from fossil natural gas at Praxair-Linde Ontario, delivered to stations in Northern California by liquid hydrogen truck for use in fuel cell vehicles.	None	
L000301	Lookup Table	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: CleanFuture (F00024); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	Oregon	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/28/2019	None	Electricity	CleanFuture, Inc. (C1001)	CleanFuture (F00024)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L000701	Lookup Table	3.0	Fuel Producer: EVgo Services LLC (C1101); Facility Name: EVgo Services LLC (F00033); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/3/2019	None	Electricity	EVgo Services LLC (C1101)	EVgo Services LLC (F00033)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L001301	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018) ; Facility Name: SRECTrade, Inc. Zero CI Electricity (F00043); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	5/7/2019	None	Electricity	SRECTrade, Inc (C1018)	SRECTrade, Inc. Zero CI Electricity (F00043)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

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L005901	Lookup Table	3.0	Fuel Producer: Alameda Municipal Power (C1021); Facility Name: Alamedia Municipal Power (F00056); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/14/2019	None	Electricity	Alameda Municipal Power (C1021)	Alamedia Municipal Power (F00056)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L006501	Lookup Table	3.0	Fuel Producer: ChargePoint, Inc. (C1028); Facility Name: Chargepoint, Inc. (F00061); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/27/2019	None	Electricity	ChargePoint, Inc. (C1028)	Chargepoint, Inc. (F00061)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L007501	Lookup Table	3.0	Fuel Producer: East Bay Community Energy Authority (C1022); Facility Name: East Bay Community Energy (F0054); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/25/2019	None	Electricity	East Bay Community Energy Authority (C1022)	East Bay Community Energy (F0054)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L008101	Lookup Table	3.0	Fuel Producer: BMW of North America, LLC (C1033); Facility Name: BMW of North America, LLC Corporate Headquarters (F00076); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	New Jersey	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/6/2019	None	Electricity	BMW of North America, LLC (C1033)	BMW of North America, LLC Corporate Headquarters (F00076)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L008201	Lookup Table	3.0	Fuel Producer: Port of Oakland (C1035); Facility Name: Port of Oakland (F00078); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/16/2019	None	Electricity	Port of Oakland (C1035)	Port of Oakland (F00078)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L008301	Lookup Table	3.0	Fuel Producer: Jaguar Land Rover North America, LLC (C1032); Facility Name: Jaguar Land Rover North America, LLC (F00083); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	New Jersey	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/29/2019	None	Electricity	Jaguar Land Rover North America, LLC (C1032)	Jaguar Land Rover North America, LLC (F00083)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L008701	Lookup Table	3.0	Fuel Producer: Sonoma Clean Power Authority (C1012); Facility Name: Golden Hills North Wind Energy Center (F00087); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/29/2019	None	Electricity	Sonoma Clean Power Authority (C1012)	Golden Hills North Wind Energy Center (F00087)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L009001	Lookup Table	3.0	Fuel Producer: Beyond Energy, LLC (C1041); Facility Name: Beyond Energy, LLC (F00090); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/25/2019	None	Electricity	Beyond Energy, LLC (C1041)	Beyond Energy, LLC (F00090)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L009301	Lookup Table	3.0	Fuel Producer: Bridge to Renewables, Benefit LLC (C1006); Facility Name: Bridge to Renewables Corporate Headquarters (F00099); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	Washington D.C.	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/3/2019	None	Electricity	Bridge to Renewables, Benefit LLC (C1006)	Bridge to Renewables Corporate Headquarters (F00099)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L009801	Lookup Table	3.0	Fuel Producer: San Deigo Metropolitan Transit Center (S304); Facility Name: San Deigo Metropolitian Transit System (F00106); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/3/2019	None	Electricity	San Deigo Metropolitan Transit Center (S304)	San Deigo Metropolitian Transit System (F00106)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L009901	Lookup Table	3.0	Fuel Producer: SMUD (S338); Facility Name: Sacramento Municipal Utility District (F00116); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/3/2019	None	Electricity	SMUD (S338)	Sacramento Municipal Utility District (F00116)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L010001	Lookup Table	3.0	Fuel Producer: Smart Charging Technologies (C1050); Facility Name: Smart Charging Technologies 0CI (F00122); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	Florida	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/17/2019	None	Electricity	Smart Charging Technologies (C1050)	Smart Charging Technologies 0CI (F00122)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

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L010101	Lookup Table	3.0	Fuel Producer: Enel X North America, Inc. (C1051); Facility Name: Enel X North America - eMobility (F00124); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	Massachusetts	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/18/2019	None	Electricity	Enel X North America, Inc. (C1051)	Enel X North America - eMobility (F00124)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L010201	Lookup Table	3.0	Fuel Producer: JC Sales (C1031); Facility Name: JC Sales (F00125); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/18/2019	None	Electricity	JC Sales (C1031)	JC Sales (F00125)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L010401	Lookup Table	3.0	Fuel Producer: Volta Industries, Inc. (C1025); Facility Name: Volta Industries, Inc. (F00115); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	1/10/2020	None	Electricity	Volta Industries, Inc. (C1025)	Volta Industries, Inc. (F00115)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
B001901	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Open Sky (F00007); Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00190100	-352.89	11/14/2019	Application Package	Electricity	CleanFuture, Inc. (C1001)	Open Sky (F00007)	Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California	None	Retired
L009501	Lookup Table	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	12/17/2019	None	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied H2 produced in California from central SMR of North American fossil-based NG	None	
L009701	Lookup Table	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025L00072019	129.09	12/4/2019	None	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
L005801	Lookup Table	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Central SMR (F00051); Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025L00072019	99.48	7/16/2019	None	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Air Products Central SMR (F00051)	Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
L005701	Lookup Table	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Central SMR (F00051); Compressed H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	7/16/2019	None	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Air Products Central SMR (F00051)	Compressed H2 produced in California from central SMR of North American fossil-based NG	None	
L007601	Lookup Table	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Carson Hydrogen Plant (F00059); Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025L00072019	99.48	7/12/2019	None	Hydrogen	Shell Energy North America (6154)	Carson Hydrogen Plant (F00059)	Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
L007701	Lookup Table	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025L00072019	99.48	7/12/2019	None	Hydrogen	FirstElement Fuel (E426)	Air Products and Chemicals SMR Wilmington. CA (F00068)	Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
L008901	Lookup Table	3.0	Fuel Producer: San Francisco Public Utilities Commission (C1003); Facility Name: R.C. Kirkwood Power House Units #1, #2, #3 (F00089); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/27/2019	None	Electricity	San Francisco Public Utilities Commission (C1003)	R.C. Kirkwood Power House Units #1, #2, #3 (F00089)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L009401	Lookup Table	3.0	Fuel Producer: Oxnard Harbor District (C1030); Facility Name: Oxnard Harbor District (F00105); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/30/2019	None	Electricity	Oxnard Harbor District (C1030)	Oxnard Harbor District (F00105)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

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L010301	Lookup Table	3.0	Fuel Producer: Grant Farm dba Momentum Zero CI Electricity (C1054); Facility Name: Grant Farm dba Momentum (Zero-CI Lookup Table Pathway) (F00133); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	2/11/2020	None	Electricity	Grant Farm dba Momentum Zero CI Electricity (C1054)	Grant Farm dba Momentum (Zero-CI Lookup Table Pathway) (F00133)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L010501	Lookup Table	3.0	Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: 3Degrees Group, Inc. (F00137); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/9/2020	None	Electricity	3Degrees Group, Inc. (C1055)	3Degrees Group, Inc. (F00137)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L010801	Lookup Table	3.0	Fuel Producer: Cruise LLC (C1064); Facility Name: Cruise Corporate Headquarters (F00144); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/30/2020	None	Electricity	Cruise LLC (C1064)	Cruise Corporate Headquarters (F00144)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L010601	Lookup Table	3.0	Fuel Producer: Energy Mission Control (C1058); Facility Name: Energy Mission Control (F00142); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/27/2020	None	Electricity	Energy Mission Control (C1058)	Energy Mission Control (F00142)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
A019702	Tier 1	3.0	Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698) ; Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Soybean Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	Iowa	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A01970200	55.00	6/16/2020	None	Biodiesel	IOWA RENEWABLE ENERGY LLC (4698)	IOWA RENEWABLE ENERGY LLC (82854)	Midwest Sourced Soybean Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	None	
A019703	Tier 1	3.0	Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698) ; Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	Iowa	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A01970300	30.23	6/16/2020	None	Biodiesel	IOWA RENEWABLE ENERGY LLC (82854)	IOWA RENEWABLE ENERGY LLC (82854)	Midwest Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	None	
A019704	Tier 1	3.0	Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698) ; Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Used Cooking Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	Iowa	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01970400	19.34	6/16/2020	None	Biodiesel	IOWA RENEWABLE ENERGY LLC (82854)	IOWA RENEWABLE ENERGY LLC (82854)	Midwest Sourced Used Cooking Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	None	
A020701	Tier 1	3.0	Fuel Producer: MEM RNG, LLC (2141); Facility Name: Blue Ridge Landfill, LLC (F00132); Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02070100	38.07	6/16/2020	None	Bio-CNG	MEM RNG, LLC (2141)	Blue Ridge Landfill, LLC (F00132)	Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel (Provisional)	None	Retired
A019701	Tier 1	3.0	Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698); Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Canola Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	Iowa	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A01970100	49.91	6/16/2020	None	Biodiesel	IOWA RENEWABLE ENERGY LLC (4698)	IOWA RENEWABLE ENERGY LLC (82854)	Midwest Sourced Canola Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	None	
A021801	Tier 1	3.0	Fuel Producer: PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080); Facility Name: H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301); Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to California for compression to CNG (Provisional)	Washington	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02180100	37.19	6/22/2020	None	Bio-CNG	PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080)	H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301)	Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to California for compression to CNG (Provisional)	None	Retired
B009803	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980300	-192.49	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional)	None	Retired
B009804	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980400	-323.10	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	None	Retired

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A023801	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758) ; Facility Name: BIOX Canada Limited (80236); US Sourced Canola Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	Canada	Canola Oil (006)	Biodiesel (BIO)	BDCA200L	57.39	BIO006A02380100	54.22	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	US Sourced Canola Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	None	
A023802	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758) ; Facility Name: BIOX Canada Limited (80236); US Sourced Soybean Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	Canada	Soybean Oil (005)	Biodiesel (BIO)	BDS200L	56.03	BIO005A02380200	59.63	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	US Sourced Soybean Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	None	
A023803	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758) ; Facility Name: BIOX Canada Limited (80236); US Sourced Corn Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	Canada	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC200L	32.8	BIO003A02380300	30.86	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	US Sourced Corn Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	None	
A023804	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); U.S. Sourced (Various Products) Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	Canada	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT200L	34.97	BIO002A02380400	34.92	7/27/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	U.S. Sourced (Various Products) Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	None	
A023806	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Sanimax (Montreal) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	Canada	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A02380600	27.09	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	Sanimax (Montreal) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	None	
A023807	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	Canada	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU218	22.38	BIO001A02380700	22.88	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	None	
A017101	Tier 1	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNGDD201	-254.94	CNG026A01710100	-329.76	12/24/2019	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Fair Oaks Upgrader, LLC (71001)	Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California	None	Retired
L010901	Lookup Table	3.0	Fuel Producer: Marin Clean Energy (C1066); Facility Name: Marin Clean Energy (F00147); Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California	California	Zero-CI Sources Supplied via Green Tariff (048)	Electricity (ELC)	None	None	ELC048L00072019	0.00	5/12/2020	None	Electricity	Marin Clean Energy (C1066)	Marin Clean Energy (F00147)	Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California	None	
L011201	Lookup Table	3.0	Fuel Producer: City of Anaheim, Public Utilities Department (C1068); Facility Name: City of Anaheim, Public Utilities Department (F00157); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/30/2020	None	Electricity	City of Anaheim, Public Utilities Department (C1068)	City of Anaheim, Public Utilities Department (F00157)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L011501	Lookup Table	3.0	Fuel Producer: Powerflex (P343); Facility Name: PowerFlex Systems (F00162); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/30/2020	None	Electricity	Powerflex (P343)	PowerFlex Systems (F00162)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L011601	Lookup Table	3.0	Fuel Producer: Marin Clean Energy (C1066); Facility Name: Marin Clean Energy (F00147); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	5/14/2020	None	Electricity	Marin Clean Energy (C1066)	Marin Clean Energy (F00147)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L011801	Lookup Table	3.0	Fuel Producer: Wonderful Renewable Energy, LLC (C1080); Facility Name: Wonderful Renewable Energy, LLC (F00170); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/1/2020	None	Electricity	Wonderful Renewable Energy, LLC (C1080)	Wonderful Renewable Energy, LLC (F00170)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

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L012001	Lookup Table	3.0	Fuel Producer: 3 Phases Renewables Inc. (P306); Facility Name: 3 Phases Renewables Inc. (P1225); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/10/2020	None	Electricity	3 Phases Renewables Inc. (P306)	3 Phases Renewables Inc. (P1225)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L012201	Lookup Table	3.0	Fuel Producer: PowerFlex Systems, INC (C1092); Facility Name: PowerFlex Systems, Inc (F00197); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/30/2020	None	Electricity	PowerFlex Systems, INC (C1092)	PowerFlex Systems, Inc (F00197)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L012101	Lookup Table	3.0	Fuel Producer: San Diego Unified Port District (C1026); Facility Name: Port of San Diego (F00057); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/30/2020	None	Electricity	San Diego Unified Port District (C1026)	Port of San Diego (F00057)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L012301	Lookup Table	3.0	Fuel Producer: Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: Praxair - Ontario, CA (F00208); Liquefied H2 produced in California from central SMR of North American fossil-based NG	Canada	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	6/30/2020	None	Hydrogen	3Degrees Group, Inc. (C1055)	Praxair - Ontario, CA (F00208)	Liquefied H2 produced in California from central SMR of North American fossil-based NG	None	
L012401	Lookup Table	3.0	Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Hydrogen Research and Fueling Facility (F00145); Compressed H2 produced in California from electrolysis using California average grid electricity	California	Grid Electricity (039)	Gaseous Hydrogen (HYG)	None	None	HYG039L00072019	164.46	8/11/2020	None	Hydrogen	Cal State LA (C1063)	Cal State LA Hydrogen Research and Fueling Facility (F00145)	Compressed H2 produced in California from electrolysis using California average grid electricity	None	
L012701	Lookup Table	3.0	Fuel Producer: Pacific Merchant Shipping Association (C1099); Facility Name: Pacific Merchant Shipping Association (F00220); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/10/2020	None	Electricity	Pacific Merchant Shipping Association (C1099)	Pacific Merchant Shipping Association (F00220)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L010701	Lookup Table	3.0	Fuel Producer: CSG EV LLC (C1060); Facility Name: CSG EV LLC (F00141); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	5/6/2020	None	Electricity	CSG EV LLC (C1060)	CSG EV LLC (F00141)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L011401	Lookup Table	3.0	Fuel Producer: PCS Energy (C1070); Facility Name: PCS Energy (F00159); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	5/13/2020	None	Electricity	PCS Energy (C1070)	PCS Energy (F00159)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L013501	Lookup Table	3.0	Fuel Producer: Eco Credit Traders LLC (C1107); Facility Name: Eco Credit Traders LLC (F00234); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/14/2020	None	Electricity	Eco Credit Traders LLC (C1107)	Eco Credit Traders LLC (F00234)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L013101	Lookup Table	3.0	Fuel Producer: Element Markets EV, LLC (C1093) ; Facility Name: Element Markets EV, LLC (F00232); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	Texas	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/18/2020	None	Electricity	Element Markets EV, LLC (C1093)	Element Markets EV, LLC (F00232)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A020101	Tier 1	3.0	Fuel Producer: Thumb BioEnergy (3862); Facility Name: Thumb BioEnergy (03862); Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail	Michigan	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU248	20.9	BIO001A02010100	15.80	9/29/2020	None	Biodiesel	Thumb BioEnergy (3862)	Thumb BioEnergy (03862)	Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail	None	Retired
A027801	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764) ; Facility Name: Aberdeen Energy (70299); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Mina, SD Ethanol transported by rail to California; Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETHC237L	80.19	ETH009A02780100	71.77	10/9/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Aberdeen Energy (70299)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Mina, SD Ethanol transported by rail to California; Composite CI	None	

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A024702	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations	Michigan	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02470200	62.68	10/13/2020	None	Bio-LNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations	None	Retired
A024703	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	California	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02470300	65.77	10/13/2020	None	Bio-CNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	None	Retired
A025904	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A02590400	31.60	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	None	Retired
L013001	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc. Zero CI HYER (F00226); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	None	None	HYG037L00072019	10.51	9/30/2020	None	Hydrogen	SRECTrade, Inc (C1018)	SRECTrade, Inc. Zero CI HYER (F00226)	Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	None	
L013301	Lookup Table	3.0	Fuel Producer: Element Markets EV, LLC (C1093); Facility Name: 32-505 Harry Oliver Trail (F00233); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	None	None	HYG037L00072019	10.51	7/1/2020	None	Hydrogen	Element Markets EV, LLC (C1093)	32-505 Harry Oliver Trail (F00233)	Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	None	
L013701	Lookup Table	3.0	Fuel Producer: MYNT SYSTEMS (C1112); Facility Name: MYNT SYSTEMS (F00294); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	11/2/2020	None	Electricity	MYNT SYSTEMS (C1112)	MYNT SYSTEMS (F00294)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
B011301	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C104); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced from biomethane of North American landfill gas at Linde-Praxair in Ontario, California; delivered to stations in Northern California by heavy-duty diesel truck, then compressed as gaseous hydrogen for use in hydrogen-fueled vehicles.	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B01130100	131.51	11/12/2020	Application Package	Hydrogen	Iwatani Corporation of America (C104)	Linde-Praxair (F00088)	Liquefied Hydrogen produced from biomethane of North American landfill gas at Linde-Praxair in Ontario, California; delivered to stations in Northern California by heavy-duty diesel truck, then compressed as gaseous hydrogen for use in hydrogen-fueled vehicles.	None	
A028401	Tier 1	3.0	Fuel Producer: BIOX Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Canadian Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	Canada	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02380800	22.81	BIO001A02840100	22.40	11/12/2020	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	Canadian Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	None	
L013801	Lookup Table	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Compressed H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	11/12/2020	None	Hydrogen	FirstElement Fuel (E426)	Air Products and Chemicals SMR Wilmington. CA (F00068)	Compressed H2 produced in California from central SMR of North American fossil-based NG	None	
L013901	Lookup Table	3.0	Fuel Producer: Penske Truck Leasing, Co., L.P. (C1116); Facility Name: Penske Truck Leasing (F00310); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	11/25/2020	None	Electricity	Penske Truck Leasing, Co., L.P. (C1116)	Penske Truck Leasing (F00310)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L014001	Lookup Table	3.0	Fuel Producer: NFI Industries (C1117); Facility Name: NFI Industries (F00311); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	11/25/2020	None	Electricity	NFI Industries (C1117)	NFI Industries (F00311)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A028001	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Glacial Lakes Energy (70064); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Watertown, South Dakota; Ethanol transported by rail to California, Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETHC241L	79.21	ETH009A02800100	72.66	12/8/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Glacial Lakes Energy (70064)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Watertown, South Dakota; Ethanol transported by rail to California, Composite CI	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B002401	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Coronado Dairy Farm (F00009); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00240100	-525.14	12/10/2020	Application Package	Electricity	CleanFuture, Inc. (C1001)	Coronado Dairy Farm (F00009)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California	None	Retired
A028301	Tier 1	3.0	Fuel Producer: BIOX Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Rendered Animal Fat Sourced from Sanimax Quebec City, Canada transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; transported by rail to California	Canada	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A02380500	36.98	BIO002A02830100	28.29	12/15/2020	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	Rendered Animal Fat Sourced from Sanimax Quebec City, Canada transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; transported by rail to California	None	
L014301	Lookup Table	3.0	Fuel Producer: The Regents of the University of California (C1121); Facility Name: The Regents of the University of California (F00324); Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California	California	Zero-CI Sources Supplied via Green Tariff (048)	Electricity (ELC)	None	None	ELC048L00072019	0.00	12/28/2020	None	Electricity	The Regents of the University of California (C1121)	The Regents of the University of California (F00324)	Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California	None	
L014401	Lookup Table	3.0	Fuel Producer: S. C. Valley Transportation Authority (C1119); Facility Name: S.C. Valley Transportation Authority (F00328); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/24/2020	None	Electricity	S. C. Valley Transportation Authority (C1119)	S.C. Valley Transportation Authority (F00328)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L014801	Lookup Table	3.0	Fuel Producer: Toyota Motor North America (C1069); Facility Name: Toyota Motor North America (F00338); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	2/16/2021	None	Electricity	Toyota Motor North America (C1069)	Toyota Motor North America (F00338)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L015001	Lookup Table	3.0	Fuel Producer: Redwood Coast Energy Authority (R704); Facility Name: Redwood Coast Energy Authority (F00031); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	2/24/2021	None	Electricity	Redwood Coast Energy Authority (R704)	Redwood Coast Energy Authority (F00031)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L015201	Lookup Table	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. Venture, Inc. (F00345); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	2/24/2021	None	Electricity	U.S. Venture, Inc. (5504)	U.S. Venture, Inc. (F00345)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A033002	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00990200	63.23	ETH009A03300200	63.46	3/1/2021	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	None	Retired
A033003	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03300300	25.32	3/1/2021	None	Ethanol - Cellulosic	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California. (Provisional)	None	Retired
L015101	Lookup Table	3.0	Fuel Producer: PineSpire, LLC (C1128); Facility Name: PineSpire (F00344); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/4/2021	None	Electricity	PineSpire, LLC (C1128)	PineSpire (F00344)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A028701	Tier 1	3.0	Fuel Producer: Elkhorn Valley Ethanol LLC (4833); Facility Name: Elkhorn Valley Ethanol LLC (70095); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Norfolk, Nebraska; Ethanol transported by rail to California, Composite CI	Nebraska	Corn (009)	Ethanol (ETH)	T1N-1277, T1N-1276	74.74, 79.83	ETH009A02870100	71.99	3/22/2021	None	Ethanol	Elkhorn Valley Ethanol LLC (4833)	Elkhorn Valley Ethanol LLC (70095)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Norfolk, Nebraska; Ethanol transported by rail to California, Composite CI	None	Retired
A031001	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG (Provisional)	Louisiana	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A03100100	41.18	3/18/2021	None	Bio-CNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG (Provisional)	None	Retired

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B011101	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Stotz Dairy Southern (F00155); Dairy Biogas produced in Maricopa County, AZ from dairy manure covered anaerobic lagoons to produce electricity for import into California for electric vehicle charging	Arizona	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01110100	-762.09	3/23/2021	Application Package	Electricity	CleanFuture, Inc. (C1001)	Stotz Dairy Southern (F00155)	Dairy Biogas produced in Maricopa County, AZ from dairy manure covered anaerobic lagoons to produce electricity for import into California for electric vehicle charging	None	Retired
B012301	Tier 2	3.0	Fuel Producer: South San Francisco Scavengers (S283); Facility Name: South San Francisco Scavenger Company (J0500); Renewable Natural Gas (RNG) produced from Food Scraps and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling	California	Food Scraps/Waste (027)	Compressed Natural Gas (CNG)	None	None	CNG027B01230100	-79.91	3/29/2021	Application Package	Bio-CNG	South San Francisco Scavengers (S283)	South San Francisco Scavenger Company (J0500)	Renewable Natural Gas (RNG) produced from Food Scraps and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling	None	
B012302	Tier 2	3.0	Fuel Producer: South San Francisco Scavengers (S283); Facility Name: South San Francisco Scavenger Company (J0500); Renewable Natural Gas (RNG) produced from Urban Landscaping Waste and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling	California	Other Organic Waste (029)	Compressed Natural Gas (CNG)	None	None	CNG028B01230200	0.28	3/29/2021	Application Package	Bio-CNG	South San Francisco Scavengers (S283)	South San Francisco Scavenger Company (J0500)	Renewable Natural Gas (RNG) produced from Urban Landscaping Waste and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling	None	
A027601	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Meadow Branch Landfill Gas Processing Facility (71252); Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel (Provisional)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF261R	52.14	CNG025A02760100	47.41	3/25/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Meadow Branch Landfill Gas Processing Facility (71252)	Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel (Provisional)	None	Retired
B014802	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Triple G Dairy (F00156); Low-CI electricity from biogas produced from dairy manure and organic substrates using reciprocating engine at Triple G Dairy in Maricopa County, Arizona for use as transportation fuel in California.	Arizona	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01480200	-493.57	3/30/2021	Application Package	Electricity	CleanFuture, Inc. (C1001)	Triple G Dairy (F00156)	Low-CI electricity from biogas produced from dairy manure and organic substrates using reciprocating engine at Triple G Dairy in Maricopa County, Arizona for use as transportation fuel in California.	None	Retired
B017201	Tier 2	3.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566); Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI (Provisional)	California	Corn (009)	Ethanol (ETH)	ETH009A00940100	67.03	ETH009B01720100	65.68	3/29/2021	Application Package	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI (Provisional)	None	Retired
B013302	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B01330200	32.50	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013303	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B01330300	25.50	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013304	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B01330400	20.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013305	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B01330500	26.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013307	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01330700	37.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013308	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01330800	38.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired

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B013309	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01330900	43.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
A029503	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); California sourced Rendered Animal Fat, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A02950300	33.86	4/1/2021	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	California sourced Rendered Animal Fat, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	None	
B018901	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	None	None	RNT003B01890100	33.00	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018902	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01890200	37.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018903	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT002B01890300	26.00	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018904	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B01890400	20.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018905	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B01890500	26.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018906	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01890600	38.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018907	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01890700	43.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018910	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891000	33.00	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018911	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891100	26.00	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018912	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891200	20.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B018913	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891300	26.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018914	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891400	37.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018915	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891500	38.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018916	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891600	43.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
A023901	Tier 1	3.0	Fuel Producer: M&N Participações S/A (C1082); Facility Name: Usina Giasa Ltda (F00192); Ethanol from sugarcane juice, with co-product credit for surplus cogenerated electricity exports; transport to California port via ocean tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A02390100	48.82	5/7/2021	None	Ethanol	M&N Participações S/A (C1082)	Usina Giasa Ltda (F00192)	Ethanol from sugarcane juice, with co-product credit for surplus cogenerated electricity exports; transport to California port via ocean tanker.	None	Retired
A028801	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Midwest Soybean Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	Iowa	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A02880100	58.00	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	Midwest Soybean Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	None	
A028802	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Canola Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail.	Iowa	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A02880200	54.00	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	Canola Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail.	None	
A028803	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Corn Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail.	Iowa	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC208	34.10	BIO003A02880300	28.50	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	Corn Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail.	None	
A028804	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); U.S. Sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	Iowa	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU223	22.50	BIO001A02880400	21.00	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	U.S. Sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	None	
A028805	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Self Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	Iowa	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU235	15.49	BIO001A02880500	16.00	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	Self Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	None	
A028806	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); U.S. Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	Iowa	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT212	35.94	BIO002A02880600	33.50	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	U.S. Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	None	
A029601	Tier 1	3.0	Fuel Producer: Green Plains Central City (3368); Facility Name: Green Plains Central City LLC (70141); Ethanol from Corn Starch, MDGS, Corn Oil, NG & Grid Electricity; Transport by Rail to California.	Nebraska	Corn (009)	Ethanol (ETH)	ETHC023 (T1R-1214)	82.17	ETH009A02960100	65.97	5/7/2021	None	Ethanol	Green Plains Central City (3368)	Green Plains Central City LLC (70141)	Ethanol from Corn Starch, MDGS, Corn Oil, NG & Grid Electricity; Transport by Rail to California.	None	Retired

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A030903	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A03090300	68.76	5/4/2021	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	Retired
A036701	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG (Provisional)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A03670100	49.53	5/11/2021	None	Bio-CNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG (Provisional)	None	Retired
A028901	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Corn Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC215	35.13	BIO003A02890100	29.00	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Corn Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	
A028902	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Rendered Animal Fat Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT220	36.80	BIO002A02890200	33.50	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Rendered Animal Fat Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	
A028903	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Canola Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A02890300	53.00	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Canola Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	
A028904	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Midwest Soybean Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A02890400	58.30	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Midwest Soybean Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	
A028905	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU249	22.58	BIO001A02890500	21.50	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	Retired
A028906	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); U.S sourced Used Cooking Oil; Zero rendering energy; transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU250	17.33	BIO001A02890600	17.00	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	U.S sourced Used Cooking Oil; Zero rendering energy; transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	
A036101	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A03610100	70.52	6/7/2021	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	None	Retired
A036102	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A03610200	63.38	6/7/2021	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	None	Retired
A036103	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03610300	23.59	6/7/2021	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	None	Retired
A029001	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Corn Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail	Illinois	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC213	34.02	BIO003A02900100	28.00	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Corn Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail	None	

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A029004	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU242	21.84	BIO001A02900400	20.75	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	None	Retired
A029005	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU244	16.57	BIO001A02900500	16.25	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail	None	Retired
A029007	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail	Illinois	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT219	35.79	BIO002A02900700	32.75	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail	None	
L001701	Lookup Table	3.0	Fuel Producer: Tesla, Inc. (C1016); Facility Name: Tesla, Inc. (F00045); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	5/29/2019	None	Electricity	Tesla, Inc. (C1016)	Tesla, Inc. (F00045)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L006301	Lookup Table	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Carson Hydrogen Plant (F00059); Compressed H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	7/12/2019	None	Hydrogen	Shell Energy North America (6154)	Carson Hydrogen Plant (F00059)	Compressed H2 produced in California from central SMR of North American fossil-based NG.	None	
L007801	Lookup Table	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Praxair Liquid H2 Source (F00053); Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills.	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025L00072019	129.09	7/16/2019	None	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Praxair Liquid H2 Source (F00053)	Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills.	None	
L007901	Lookup Table	3.0	Fuel Producer: American Honda Motor Co., Inc. (C1023); Facility Name: American Honda Motor Co., Inc. (F00074); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/6/2019	None	Electricity	American Honda Motor Co., Inc. (C1023)	American Honda Motor Co., Inc. (F00074)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L009101	Lookup Table	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Air Products and Chemicals, Inc. (SFS) (F00092); Liquefied H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	9/26/2019	None	Hydrogen	CleanFuture, Inc. (C1001)	Air Products and Chemicals, Inc. (SFS) (F00092)	Liquefied H2 produced in California from central SMR of North American fossil-based NG.	None	
L009201	Lookup Table	3.0	Fuel Producer: Air Products and Chemicals, Inc. (C1042); Facility Name: APCI Wilmington Transfill (F00095); Compressed H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	9/27/2019	None	Hydrogen	Air Products and Chemicals, Inc. (C1042)	APCI Wilmington Transfill (F00095)	Compressed H2 produced in California from central SMR of North American fossil-based NG.	None	
L009601	Lookup Table	3.0	Fuel Producer: Paired Power (P995); Facility Name: McCalmont Engineering (22575); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	California	Directly Supplied Zero-CI Sources (049)	Electricity (ELC)	None	None	ELC049L00072019	0.00	3/30/2020	None	Electricity	Paired Power (P995)	McCalmont Engineering (22575)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	None	
L011301	Lookup Table	3.0	Fuel Producer: Trillium USA Company, LLC (C1056); Facility Name: Trillium USA Company, LLC (F00152); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	Texas	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/30/2020	None	Electricity	Trillium USA Company, LLC (C1056)	Trillium USA Company, LLC (F00152)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L012501	Lookup Table	3.0	Fuel Producer: Green Commuter (C1096) ; Facility Name: Green Commuter (F00214); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/8/2020	None	Electricity	Green Commuter (C1096)	Green Commuter (F00214)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	

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L012601	Lookup Table	3.0	Fuel Producer: EV CHARGING SOLUTIONS, INC. (C1095); Facility Name: EV Charging Solutions, Inc. (F00215); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/8/2020	None	Electricity	EV CHARGING SOLUTIONS, INC. (C1095)	EV Charging Solutions, Inc. (F00215)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L012801	Lookup Table	3.0	Fuel Producer: Ingram Micro, Inc. (C1102); Facility Name: Ingram Micro, Inc. (F00222); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/25/2020	None	Electricity	Ingram Micro, Inc. (C1102)	Ingram Micro, Inc. (F00222)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L012901	Lookup Table	3.0	Fuel Producer: Zeco Systems Inc. d/b/a Greenlots (C1097) ; Facility Name: Zeco Systems Inc. d/b/a Greenlots (F00225); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/11/2020	None	Electricity	Zeco Systems Inc. d/b/a Greenlots (C1097)	Zeco Systems Inc. d/b/a Greenlots (F00225)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L013601	Lookup Table	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Shell Energy North America (F00017); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	Texas	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	10/16/2020	None	Electricity	Shell Energy North America (6154)	Shell Energy North America (F00017)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L014101	Lookup Table	3.0	Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: Praxair - Ontario, CA (F00208); Liquified H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	12/7/2020	None	Hydrogen	3Degrees Group, Inc. (C1055)	Praxair - Ontario, CA (F00208)	Liquefied H2 produced in California from central SMR of North American fossil-based NG.	None	
L015301	Lookup Table	3.0	Fuel Producer: Green Water and Power (C1123); Facility Name: Green Water and Power (F00322); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/15/2021	None	Electricity	Green Water and Power (C1123)	Green Water and Power (F00322)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L015501	Lookup Table	3.0	Fuel Producer: City of Santa Clara/Silicon Valley Power (C1130); Facility Name: BEAM EVARC Unit #334 (F00358); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	California	Directly Supplied Zero-CI Sources (049)	Electricity (ELC)	None	None	ELC049L00072019	0.00	5/25/2021	None	Electricity	City of Santa Clara/Silicon Valley Power (C1130)	BEAM EVARC Unit #334 (F00358)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	None	
L015401	Lookup Table	3.0	Fuel Producer: City of Santa Clara/Silicon Valley Power (C1130); Facility Name: BEAM EVARC Unit #333 (F00357); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	California	Directly Supplied Zero-CI Sources (049)	Electricity (ELC)	None	None	ELC049L00072019	0.00	5/25/2021	None	Electricity	City of Santa Clara/Silicon Valley Power (C1130)	BEAM EVARC Unit #333 (F00357)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	None	
L015601	Lookup Table	3.0	Fuel Producer: San Jose Clean Energy (C1120); Facility Name: San Jose Clean Energy (F00323); Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California.	California	Zero-CI Sources Supplied via Green Tariff (048)	Electricity (ELC)	None	None	ELC048L00072019	0.00	4/30/2021	None	Electricity	San Jose Clean Energy (C1120)	San Jose Clean Energy (F00323)	Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California.	None	
L015701	Lookup Table	3.0	Fuel Producer: AMPLY Power, Inc. (C1134); Facility Name: AMPLY Power, Inc (F00364); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/21/2021	None	Electricity	AMPLY Power, Inc. (C1134)	AMPLY Power, Inc (F00364)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L015801	Lookup Table	3.0	Fuel Producer: Muza Energy (C1136); Facility Name: Muza Energy (F00369); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/3/2021	None	Electricity	Muza Energy (C1136)	Muza Energy (F00369)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A030201	Tier 1	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Melissa Renewables, LLC (71407); Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF276	40.63	CNG025A03020100	34.00	6/16/2021	None	Bio-CNG	Shell Energy North America (6154)	Melissa Renewables, LLC (71407)	Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG (Provisional)	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A029101	Tier 1	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Pine Hill Renewables, LLC (71288); Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF272	39.83	CNG025A02910100	34.17	6/16/2021	None	Bio-CNG	Shell Energy North America (6154)	Pine Hill Renewables, LLC (71288)	Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG (Provisional)	None	Retired
A034502	Tier 1	3.0	Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations	Michigan	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNGLF200LR	54.14	LNG025A03450200	65.55	6/16/2021	None	Bio-LNG	WESTSIDE GAS PRODUCERS, LLC (6218)	WESTSIDE GAS PRODUCERS, LLC (71151)	Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations	None	
A034503	Tier 1	3.0	Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California stations	Michigan	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	CNGLF223LR	57.29	LCN025A03450300	68.64	6/16/2021	None	Bio-CNG	WESTSIDE GAS PRODUCERS, LLC (6218)	WESTSIDE GAS PRODUCERS, LLC (71151)	Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California stations	None	
A037301	Tier 1	3.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); Used Cooking Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail.	Texas	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU226R	24.41	BIO001A03730100	18.30	6/21/2021	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	Used Cooking Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail.	None	
A037302	Tier 1	3.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); Midwest Soybean Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail.	Texas	Soybean Oil (005)	Biodiesel (BIO)	BDS210R	53.43	BIO005A03730200	53.55	6/21/2021	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	Midwest Soybean Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail.	None	
L015901	Lookup Table	3.0	Fuel Producer: Sol Systems LLC (C1133); Facility Name: Sol Systems, LLC (F00370); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	Washington D.C.	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/21/2021	None	Electricity	Sol Systems LLC (C1133)	Sol Systems, LLC (F00370)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
B017907	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); North America Sourced Corn Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	Singapore	Distillers' Corn Oil (003)	Renewable Diesel (RND)	RDC200L	37.39	RND003B01790700	36.43	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	North America Sourced Corn Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	None	
B017904	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); Globally Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	Singapore	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RDU201L	25.61	RND001B01790400	32.83	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Globally Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	None	
B017906	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); North America Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	Singapore	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B01790600	28.64	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	North America Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	None	
B017905	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); South East Asia Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	Singapore	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RDU200L	16.89	RND001B01790500	24.29	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	South East Asia Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	None	
B017902	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); North America Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	Singapore	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RDT201L	34.19	RND002B01790200	40.10	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	North America Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	None	
B017903	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); Oceanic Sourced Rendered Animal Fat Oil transported by Truck and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	Singapore	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RDT200L	36.83	RND002B01790300	38.26	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Oceanic Sourced Rendered Animal Fat Oil transported by Truck and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	None	

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B017901	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); Globally Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	Singapore	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RDT202	39.06	RND002B01790100	42.77	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Globally Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	None	
B014001	Tier 2	3.0	Fuel Producer: Degrees3 Transportation Solutions, LLC (C1111); Facility Name: New Energy One (F00274); Low-CI electricity from dairy manure using reciprocating engine at Cedar Ridge in Filer, Idaho for use as transportation fuel in California	Idaho	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01400100	-698.21	6/29/2021	Application Package	Electricity	Degrees3 Transportation Solutions, LLC (C1111)	New Energy One (F00274)	Low-CI electricity from dairy manure using reciprocating engine at Cedar Ridge in Filer, Idaho for use as transportation fuel in California	None	
B013901	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) from Swine Manure of Ruckman Farm, Allbany, Missouri; RNG is delivered via pipeline to Los Angeles, California and central California locations	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B00110100	-372.35	CNG044B01390100	-431.79	6/29/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ruckman Farm (71256)	Renewable Natural Gas (RNG) from Swine Manure of Ruckman Farm, Allbany, Missouri; RNG is delivered via pipeline to Los Angeles, California and central California locations	None	
B014101	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Locust Ridge Farm (71298); Renewable Natural Gas (RNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California areas	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B00090100	-323.83	CNG044B01410100	-449.66	6/29/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Locust Ridge Farm (71298)	Renewable Natural Gas (RNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California areas	None	
B016601	Tier 2	3.0	Fuel Producer: SMUD (S338); Facility Name: New Hope Dairy Digester (F00255); Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01660100	-750.81	6/28/2021	Application Package	Electricity	SMUD (S338)	New Hope Dairy Digester (F00255)	Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California. (Provisional)	None	Retired
A033901	Tier 1	3.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Cresciumal (71068); Ethanol from Brazilian sugarcane juice and molasses; road transport to port, ocean transport to California	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM221	46.34	ETH018A03390100	48.08	6/30/2021	None	Ethanol	BIOSEV S.A. (3869)	Usina Cresciumal (71068)	Ethanol from Brazilian sugarcane juice and molasses; road transport to port, ocean transport to California	None	
L016101	Lookup Table	3.0	Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Hydrogen Research and Fueling Facility (F00145); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources.	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	None	None	HYG037L00072019	10.51	6/28/2021	None	Hydrogen	Cal State LA (C1063)	Cal State LA Hydrogen Research and Fueling Facility (F00145)	Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources.	None	
L016201	Lookup Table	3.0	Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Structure E (F00376); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/29/2021	None	Electricity	Cal State LA (C1063)	Cal State LA Structure E (F00376)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A031501	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Ipiranga Agroindustrial SA (70398); Ethanol produced from Sugarcane juice and molasses in Brazil; co-product credit for surplus cogenerated electricity export; ethanol transported to California by ocean tanker via Cape Horn.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS229	43.56	ETH018A03150100	49.06	6/30/2021	None	Ethanol	Copersucar (3702)	Ipiranga Agroindustrial SA (70398)	Ethanol produced from Sugarcane juice and molasses in Brazil; co-product credit for surplus cogenerated electricity export; ethanol transported to California by ocean tanker via Cape Horn.	None	
A031701	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Usina São José da Estiva S.A. - Açúcar e Álcool (70431); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM237	45.06	ETH018A03170100	51.28	6/30/2021	None	Ethanol	Copersucar (3702)	Usina São José da Estiva S.A. - Açúcar e Álcool (70431)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A033301	Tier 1	3.0	Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Santa Cruz S/A Açúcar e Álcool (70484); Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS223	48.22	ETH018A03330100	50.06	7/1/2021	None	Ethanol	Usina São Martinho S.A. (3867)	Santa Cruz S/A Açúcar e Álcool (70484)	Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker.	None	Retired
A033201	Tier 1	3.0	Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Usina São Martinho S.A. (71100); Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS219	46.61	ETH018A03320100	50.99	6/30/2021	None	Ethanol	Usina São Martinho S.A. (3867)	Usina São Martinho S.A. (71100)	Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker.	None	Retired

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A033701	Tier 1	3.0	Fuel Producer: JC Chemical Co., Ltd. (6094); Facility Name: JC Chemical Co., Ltd. (81585); South Korea sourced rendered Used Cooking Oil transported by truck to Biodiesel plant in South Korea; Natural Gas, Grid Electricity; Biodiesel transported to California By Ocean Tanker (Provisional)	South Korea	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU238	20.15	BIO001A03370100	24.35	7/9/2021	None	Biodiesel	JC Chemical Co., Ltd. (6094)	JC Chemical Co., Ltd. (81585)	South Korea sourced rendered Used Cooking Oil transported by truck to Biodiesel plant in South Korea; Natural Gas, Grid Electricity; Biodiesel transported to California By Ocean Tanker (Provisional)	None	
A034101	Tier 1	3.0	Fuel Producer: Ag Processing Inc (4552); Facility Name: AGP Methyl Ester (St Joseph) (81732); Midwest Soybean Oil Extraction Facility co-located with a Biodiesel plant in St. Joseph, Missouri; Grid Electricity; Biodiesel produced in St. Joseph, Missouri; Finished Fuel transported to California By Rail	Missouri	Soybean Oil (005)	Biodiesel (BIO)	BDS213	50.48	BIO005A03410100	54.06	7/9/2021	None	Biodiesel	Ag Processing Inc (4552)	AGP Methyl Ester (St Joseph) (81732)	Midwest Soybean Oil Extraction Facility co-located with a Biodiesel plant in St. Joseph, Missouri; Grid Electricity; Biodiesel produced in St. Joseph, Missouri; Finished Fuel transported to California By Rail	None	
A038603	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03860300	28.03	7/13/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired
A025201	Tier 1	3.0	Fuel Producer: Companhia Alcoolquimica Nacional (C1086); Facility Name: Companhia Alcoolquimica Nacional (F00194); Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A02520100	56.50	7/15/2021	None	Ethanol	Companhia Alcoolquimica Nacional (C1086)	Companhia Alcoolquimica Nacional (F00194)	Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity.	None	Retired
B019201	Tier 2	3.0	Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: Praxair - Ontario, CA (F00208); Liquefied hydrogen from North American Natural Gas; produced at Praxair, Ontario, California transported as liquid to Hydrogen stations in California	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B01920100	153.90	7/14/2021	Application Package	Hydrogen	3Degrees Group, Inc. (C1055)	Praxair - Ontario, CA (F00208)	Liquefied hydrogen from North American Natural Gas; produced at Praxair, Ontario, California transported as liquid to Hydrogen stations in California	None	
L016001	Lookup Table	3.0	Fuel Producer: InCharge Energy Inc. (C1137); Facility Name: InCharge Energy Inc Corporate Headquarters (F00375); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	7/22/2021	None	Electricity	InCharge Energy Inc. (C1137)	InCharge Energy Inc Corporate Headquarters (F00375)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A033501	Tier 1	3.0	Fuel Producer: COFCO International Brasil S.A. (C1110); Facility Name: Unidade POTIRENDABA (F00327); Ethanol produced from Sugarcane Juice and Molasses; exported to California by Ocean Tanker.; Co-Product Credit for surplus cogenerated electricity export.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS212	46.83	ETH018A03350100	52.19	7/28/2021	None	Ethanol	COFCO International Brasil S.A. (C1110)	Unidade POTIRENDABA (F00327)	Ethanol produced from Sugarcane Juice and Molasses; exported to California by Ocean Tanker.; Co-Product Credit for surplus cogenerated electricity export.	None	
A034001	Tier 1	3.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Santa Elisa (71070); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS246	50.16	ETH018A03400100	52.45	7/27/2021	None	Ethanol	BIOSEV S.A. (3869)	Usina Santa Elisa (71070)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity.	None	
A033801	Tier 1	3.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Unidade MB (70568); Ethanol produced from Brazilian Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS208 and ETHM228	47.68 and 48.63	ETH018A03380100	54.03	7/28/2021	None	Ethanol	BIOSEV S.A. (3869)	Unidade MB (70568)	Ethanol produced from Brazilian Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity.	None	
A035001	Tier 1	3.0	Fuel Producer: Delek Renewables, LLC (5998); Facility Name: DELEK RENEWABLES NEW ALBANY BIODIESEL PLANT (80701); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Electricity; Biodiesel transported to California By Rail	Mississippi	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A03500100	31.11	7/29/2021	None	Biodiesel	Delek Renewables, LLC (5998)	DELEK RENEWABLES NEW ALBANY BIODIESEL PLANT (80701)	U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Electricity; Biodiesel transported to California By Rail	None	
A037401	Tier 1	3.0	Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Altamont Bio-LNG Plant (70526); Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations; regasified, and compressed to L-CNG. (Provisional)	California	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	CNGLF246, CNGLF247, and CNGLF248	9.97, 10.32 and 13.29	LCN025A03740100	18.96	7/29/2021	None	Bio-CNG	HIGH MOUNTAIN FUELS LLC (4293)	Altamont Bio-LNG Plant (70526)	Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations; regasified, and compressed to L-CNG. (Provisional)	None	Retired
A037402	Tier 1	3.0	Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Altamont Bio-LNG Plant (70526); Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations. (Provisional)	California	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNGLF217 and LNGLF218	7.39 and 7.74	LNG025A03740200	15.87	7/29/2021	None	Bio-LNG	HIGH MOUNTAIN FUELS LLC (4293)	Altamont Bio-LNG Plant (70526)	Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations. (Provisional)	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A035701	Tier 1	3.0	Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Crossett Biodiesel Plant (82217); U.S Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Crossett, Arkansas; Grid Electricity; Biodiesel fuel transported to California by rail.	Arkansas	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT213	32.96	BIO002A03570100	28.97	8/4/2021	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Crossett Biodiesel Plant (82217)	U.S Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Crossett, Arkansas; Grid Electricity; Biodiesel fuel transported to California by rail.	None	
A039901	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO HARTLEY PLANT (70275); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A03990100	72.80	8/4/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO HARTLEY PLANT (70275)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional)	None	
A039902	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO HARTLEY PLANT (70275); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A03990200	68.94	8/4/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO HARTLEY PLANT (70275)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional)	None	
A039903	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO HARTLEY PLANT (70275); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03990300	26.60	8/4/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO HARTLEY PLANT (70275)	Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California (Provisional)	None	
L016301	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc Zero CI Direct Renewable Energy Stockton (F00378); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	California	Directly Supplied Zero-CI Sources (049)	Electricity (ELC)	None	None	ELC049L00072019	0.00	8/2/2021	None	Electricity	SRECTrade, Inc (C1018)	SRECTrade, Inc Zero CI Direct Renewable Energy Stockton (F00378)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	None	
L016401	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc Zero CI Direct Renewable Energy Dispersed (F00379); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	California	Directly Supplied Zero-CI Sources (049)	Electricity (ELC)	None	None	ELC049L00072019	0.00	8/5/2021	None	Electricity	SRECTrade, Inc (C1018)	SRECTrade, Inc Zero CI Direct Renewable Energy Dispersed (F00379)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	None	
L016601	Lookup Table	3.0	Fuel Producer: SunHarvest Partners LLC (C1147); Facility Name: SunHarvest Partners LLC (F00386); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/2/2021	None	Electricity	SunHarvest Partners LLC (C1147)	SunHarvest Partners LLC (F00386)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L016701	Lookup Table	3.0	Fuel Producer: Degrees3 Transportation Solutions, LLC (C1111); Facility Name: Degrees3 Transportation Solutions (F00385); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/5/2021	None	Electricity	Degrees3 Transportation Solutions, LLC (C1111)	Degrees3 Transportation Solutions (F00385)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L016501	Lookup Table	3.0	Fuel Producer: Peninsula Clean Energy (C1142); Facility Name: Peninsula Clean Energy (F00381); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/5/2021	None	Electricity	Peninsula Clean Energy (C1142)	Peninsula Clean Energy (F00381)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A015601	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Arizona	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A01560100	26.58	12/18/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	None	Retired
A039501	Tier 1	3.0	Fuel Producer: Just Biodiesel Pty. Ltd. (C1037); Facility Name: Just Biodiesel Pty. Ltd. (F00079); Australia Sourced Used Cooking Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional)	Australia	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A03950100	31.34	8/20/2021	None	Biodiesel	Just Biodiesel Pty. Ltd. (C1037)	Just Biodiesel Pty. Ltd. (F00079)	Australia Sourced Used Cooking Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional)	None	
A039502	Tier 1	3.0	Fuel Producer: Just Biodiesel Pty. Ltd. (C1037); Facility Name: Just Biodiesel Pty. Ltd. (F00079); Australia Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional)	Australia	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A03950200	43.33	8/20/2021	None	Biodiesel	Just Biodiesel Pty. Ltd. (C1037)	Just Biodiesel Pty. Ltd. (F00079)	Australia Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional)	None	

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L016801	Lookup Table	3.0	Fuel Producer: Disneyland Resort (C1150); Facility Name: Disneyland Resort (F00388); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/17/2021	None	Electricity	Disneyland Resort (C1150)	Disneyland Resort (F00388)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A035301	Tier 1	3.0	Fuel Producer: South Platte Renew (8380); Facility Name: 2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel. (Provisional)	Colorado	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A03530100	52.36	8/24/2021	None	Bio-CNG	South Platte Renew (8380)	2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641)	Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel. (Provisional)	None	Retired
A038501	Tier 1	3.0	Fuel Producer: Los Angeles County Sanitation District (L375); Facility Name: Biogas Conditioning System Facility (F00308); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite. (Provisional)	California	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A03850100	19.28	8/20/2021	None	Bio-CNG	Los Angeles County Sanitation District (L375)	Biogas Conditioning System Facility (F00308)	Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite. (Provisional)	None	Retired
A025801	Tier 1	3.0	Fuel Producer: Agro Industrial Tabu S.A. (C1088); Facility Name: Agro Industrial Tabu (F00205); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A02580100	51.59	9/3/2021	None	Ethanol	Agro Industrial Tabu S.A. (C1088)	Agro Industrial Tabu (F00205)	Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal.	None	Retired
A037201	Tier 1	3.0	Fuel Producer: USINAS ITAMARATI SA (1150); Facility Name: USINAS ITAMARATI SA (70942); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A03720100	58.21	9/17/2021	None	Ethanol	USINAS ITAMARATI SA (1150)	USINAS ITAMARATI SA (70942)	Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker.	None	
L017001	Lookup Table	3.0	Fuel Producer: Smart Charging Technologies (C1050) ; Facility Name: Burlington Distribution Hydrogen (F00396); Liquefied H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	9/13/2021	None	Hydrogen	Smart Charging Technologies (C1050)	Burlington Distribution Hydrogen (F00396)	Liquefied H2 produced in California from central SMR of North American fossil-based NG	None	
A037901	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (Provisional)	Texas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03790100	23.13	9/28/2021	None	Ethanol - Cellulosic	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (Provisional)	None	Retired
B019701	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (Provisional)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00580100	-167.04	CNG026B01970100	-177.03	9/28/2021	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (Provisional)	None	Retired
B019702	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00580200	-151.41	CNG026B01970200	-156.78	9/28/2021	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	None	Retired
B019703	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00580300	-257.78	CNG026B01970300	-295.26	9/28/2021	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	None	Retired
B017502	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Giacomini Dairy (F00305); Low-CI Electricity from Dairy Manure and Cheese Wastewater Biogas using reciprocating engine at Giacomini Dairy in Point Reyes Station, California for use as transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01750200	-431.65	9/30/2021	Application Package	Electricity	CleanFuture, Inc. (C1001)	Giacomini Dairy (F00305)	Low-CI Electricity from Dairy Manure and Cheese Wastewater Biogas using reciprocating engine at Giacomini Dairy in Point Reyes Station, California for use as transportation fuel in California. (Provisional)	None	
B018503	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01850300	-382.11	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	None	Retired

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B019802	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01980200	-414.26	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
B019804	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01980400	-405.41	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
B019805	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01980500	-385.40	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
A041801	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Ferrari Agroindustrial S.A. (70435); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04180100	51.83	9/30/2021	None	Ethanol	Copersucar (3702)	Ferrari Agroindustrial S.A. (70435)	Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker	None	
A040202	Tier 1	3.0	Fuel Producer: Siouxland Ethanol, LLC (5026); Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill; Edniq Fiber Conversion Process; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A00340200	26.67	ETH012A04020200	24.18	10/11/2021	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest Corn, Dry Mill; Edniq Fiber Conversion Process; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional)	None	
A037902	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional)	Texas	Corn (009)	Ethanol (ETH)	ETH009A01630100	64.74	ETH009A03790200	63.93	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional)	None	Retired
B019803	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01980300	-420.69	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
A040801	Tier 1	3.0	Fuel Producer: Ag Processing Inc (4552); Facility Name: Ag Processing Inc - Sgt. Bluff (81733); Midwest Soybean Oil; Extraction Facility co-located with a Biodiesel plant in Sergeant Bluff, Iowa; Grid Electricity; Natural Gas; Finished Fuel transported to California by rail.	Iowa	Soybean Oil (005)	Biodiesel (BIO)	BDS214	50.03	BIO005A04080100	53.32	10/18/2021	None	Biodiesel	Ag Processing Inc (4552)	Ag Processing Inc - Sgt. Bluff (81733)	Midwest Soybean Oil; Extraction Facility co-located with a Biodiesel plant in Sergeant Bluff, Iowa; Grid Electricity; Natural Gas; Finished Fuel transported to California by rail.	None	
A041201	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Dry DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02480100	70.62	ETH009A04120100	73.30	10/18/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Fort Dodge (70043)	Midwest Corn, Dry Mill; Dry DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional)	None	
A041202	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Modified DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02480200	67.47	ETH009A04120200	69.83	10/18/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Fort Dodge (70043)	Midwest Corn, Dry Mill; Modified DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional)	None	
A041203	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Fiber ethanol via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa and transported by rail to California. (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04120300	26.83	10/18/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Fort Dodge (70043)	Midwest Corn, Dry Mill; Fiber ethanol via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa and transported by rail to California. (Provisional)	None	
A043001	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00690100	65.13	ETH009A04300100	64.99	10/18/2021	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A043002	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04300200	27.97	10/18/2021	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	None	
A037801	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process ; Ethanol transported by rail to California (Provisional)	Texas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03780100	25.36	9/28/2021	None	Ethanol - Cellulosic	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process ; Ethanol transported by rail to California (Provisional)	None	Retired
A037802	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Corn (009)	Ethanol (ETH)	ETH009A01610100	64.69	ETH009A03780200	66.38	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	None	Retired
A037804	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Corn (009)	Ethanol (ETH)	ETH009A01610400	72.64	ETH009A03780400	73.91	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	None	Retired
A041301	Tier 1	3.0	Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Imperial Landfill Gas Company, LLC (F00219); Biomethane from Imperial Landfill in Imperial, Pennsylvania, pipelined to California for compression to CNG.	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04130100	53.19	11/23/2021	None	Bio-CNG	TRUSTAR ENERGY LLC (6523)	Imperial Landfill Gas Company, LLC (F00219)	Biomethane from Imperial Landfill in Imperial, Pennsylvania, pipelined to California for compression to CNG.	None	
A039601	Tier 1	3.0	Fuel Producer: Adecoagro Brasil Participacoes (4192); Facility Name: Adecoagro Vale do Ivinhema Ltda. (70496); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS211 (T1N-1356)	46.32	ETH018A03960100	52.79	11/30/2021	None	Ethanol	Adecoagro Brasil Participacoes (4192)	Adecoagro Vale do Ivinhema Ltda. (70496)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	Retired
L017201	Lookup Table	3.0	Fuel Producer: ChargeLab Inc. (C1153); Facility Name: ChargeLab Inc. (F00448); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/8/2021	None	Electricity	ChargeLab Inc. (C1153)	ChargeLab Inc. (F00448)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L017301	Lookup Table	3.0	Fuel Producer: Clean Skies USA LLC (C1161); Facility Name: Clean Skies USA (F00452); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/3/2021	None	Electricity	Clean Skies USA LLC (C1161)	Clean Skies USA (F00452)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A042501	Tier 1	3.0	Fuel Producer: ADM Agri-Industries Company (6137); Facility Name: ADM Agri Industries (81926); Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel.	Canada	Canola Oil (006)	Biodiesel (BIO)	BDCA202 (T1N-1406)	51.33	BIO006A04250100	47.65	12/16/2021	None	Biodiesel	ADM Agri-Industries Company (6137)	ADM Agri Industries (81926)	Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel.	None	Retired
A043301	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO CHARLES CITY PLANT (70042); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04330100	72.56	12/23/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO CHARLES CITY PLANT (70042)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	None	
A043302	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO CHARLES CITY PLANT (70042); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04330200	69.05	12/23/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO CHARLES CITY PLANT (70042)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	None	
A043303	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO CHARLES CITY PLANT (70042); Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04330300	26.79	12/23/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO CHARLES CITY PLANT (70042)	Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	None	

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A044501	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Bonfim (70548); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM216	44.24	ETH018A04450100	51.75	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Bonfim (70548)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A044601	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Ipaussu (71058); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM220	44.39	ETH018A04460100	48.27	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Ipaussu (71058)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A044801	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Paraguaçu (71057); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM223	46.71	ETH018A04480100	52.03	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Paraguaçu (71057)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A044901	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Rafard (70557); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM215R	48.76	ETH018A04490100	50.10	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Rafard (70557)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A044401	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Barra (70210); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04440100	53.17	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Barra (70210)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A043101	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Gasa (70551); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS221R	46.91	ETH018A04310100	48.01	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Gasa (70551)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
B021801	Tier 2	3.0	Fuel Producer: Degrees3 Transportation Solutions, LLC (C1111) ; Facility Name: Blue Mountain Biogas, LLC; Low-CI Electricity from Swine Manure using reciprocating engine at Blue Mountain Biogas, LLC near Milford, Utah for use as transportation fuel in California (Provisional)	Utah	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	ELC026B02180100	-485.51	1/14/2022	Application Package	Electricity	Degrees3 Transportation Solutions, LLC (C1111)	Blue Mountain Biogas, LLC	Low-CI Electricity from Swine Manure using reciprocating engine at Blue Mountain Biogas, LLC near Milford, Utah for use as transportation fuel in California (Provisional)	None	
B024102	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Soybean Oil transported by rail and barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	California	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B02410200	58.16	12/28/2021	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Soybean Oil transported by rail and barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	None	
B024201	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as compressed hydrogen in tube trailers to fueling stations in California.	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B02420100	-293.72	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as compressed hydrogen in tube trailers to fueling stations in California.	None	
B024202	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as gaseous hydrogen in tube trailers to fueling stations in California.	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B02420200	-259.22	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as gaseous hydrogen in tube trailers to fueling stations in California.	None	
B024203	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as compressed hydrogen in tube trailers to fueling stations in California	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B02420300	74.70	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as compressed hydrogen in tube trailers to fueling stations in California	None	
B024204	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as compressed hydrogen in tube trailers to fueling stations in California	California	h American Fossil NG (	Gaseous Hydrogen (HYG)	None	None	HYG031B02420400	115.15	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as compressed hydrogen in tube trailers to fueling stations in California	None	

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B024205	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as liquefied hydrogen in tanker trailers to fueling stations in California.	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B02420500	-254.95	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as liquefied hydrogen in tanker trailers to fueling stations in California.	None	
B024206	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B02420600	-239.31	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California	None	
B024207	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as liquefied hydrogen in tankers to fueling stations in California	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B02420700	-220.45	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as liquefied hydrogen in tankers to fueling stations in California	None	
B024208	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; regasified and distributed as compressed H2 in tube trailers to fueling stations in California	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B02420800	-204.81	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; regasified and distributed as compressed H2 in tube trailers to fueling stations in California	None	
B024209	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as liquefied Hydrogen in tankers to fueling stations in California	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B02420900	109.81	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as liquefied Hydrogen in tankers to fueling stations in California	None	
B024210	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from LFG generated at Blue Ridge Renewables in Fresno, Texas; regasified and distributed as compressed H2 in tube trailers to fueling stations in California	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B02421000	125.44	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from LFG generated at Blue Ridge Renewables in Fresno, Texas; regasified and distributed as compressed H2 in tube trailers to fueling stations in California	None	
B024211	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California from North American Natural Gas; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California	California	h American Fossil NG (	Liquid Hydrogen (HYL)	None	None	HYL031B02421100	169.55	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, California from North American Natural Gas; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California	None	
B024212	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as liquefied Hydrogen in tanker trailers to fueling stations in California	California	h American Fossil NG (	Liquid Hydrogen (HYL)	None	None	HYL031B02421200	153.91	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as liquefied Hydrogen in tanker trailers to fueling stations in California	None	
A043601	Tier 1	3.0	Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04360100	71.53	2/1/2022	None	Ethanol	AL CORN CLEAN FUEL, LLC (4825)	AL CORN CLEAN FUEL, LLC (70087)	Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	Retired
A044701	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Junqueira (70553); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM217	47.82	ETH018A04470100	55.75	1/5/2022	None	Ethanol	Raízen Energia S/A (3805)	Junqueira (70553)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A039701	Tier 1	3.0	Fuel Producer: Archer Daniels Midland Co (4888); Facility Name: ADM Velva (82790); Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel.	North Dakota	Canola Oil (006)	Biodiesel (BIO)	BDCA203 (T1N-1457)	52.25	BIO006A03970100	47.44	12/20/2021	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Velva (82790)	Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel.	None	Retired
A040701	Tier 1	3.0	Fuel Producer: Guarani SA (3833); Facility Name: Tereos Açúcar e Etanol Brasil S.A. – Unidade Tanabi (F00098); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04070100	47.51	2/4/2022	None	Ethanol	Guarani SA (3833)	Tereos Açúcar e Etanol Brasil S.A. – Unidade Tanabi (F00098)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A041701	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S/A – Filial Barra Grande (70412); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS250	47.71	ETH018A04170100	52.85	2/4/2022	None	Ethanol	Copersucar (3702)	Açucareira Quatá S/A – Filial Barra Grande (70412)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A042001	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S/A – Filial São José (70432); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04200100	49.11	2/22/2022	None	Ethanol	Copersucar (3702)	Açucareira Quatá S/A – Filial São José (70432)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A045001	Tier 1	3.0	Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional)	Pennsylvania	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A04500100	58.09	2/22/2022	None	Biodiesel	WORLD ENERGY HARRISBURG LLC (6425)	WORLD ENERGY HARRISBURG LLC (81499)	Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional)	None	Retired
A045002	Tier 1	3.0	Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional)	Pennsylvania	oking Oil/Waste Oil (UC	Biodiesel (BIO)	None	None	BIO001A04500200	21.59	2/22/2022	None	Biodiesel	WORLD ENERGY HARRISBURG LLC (6425)	WORLD ENERGY HARRISBURG LLC (81499)	US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional)	None	Retired
A044001	Tier 1	3.0	Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional)	Kansas	Corn (009)	Ethanol (ETH)	None	None	ETH009A04400100	72.37	3/2/2022	None	Ethanol	Element, LLC (C1020)	Element (F00048)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional)	None	Retired
A044002	Tier 1	3.0	Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional)	Kansas	Corn (009)	Ethanol (ETH)	None	None	ETH009A04400200	62.07	3/2/2022	None	Ethanol	Element, LLC (C1020)	Element (F00048)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional)	None	Retired
L017401	Lookup Table	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Compressed H2 produced in California from central SMR of North American fossil-based NG	California	h American Fossil NG (	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	2/25/2022	None	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Compressed H2 produced in California from central SMR of North American fossil-based NG	None	
A041901	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S.A. (70406); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04190100	53.36	3/21/2022	None	Ethanol	Copersucar (3702)	Açucareira Quatá S.A. (70406)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
B026804	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B01000100	23.93	AJF002B02680400	19.54	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired
B026805	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B01000200	23.93	RND002B02680500	19.54	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026806	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B01000300	23.93	RNT002B02680600	19.54	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B026807	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B01190100	19.51	AJF002B02680700	15.64	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired

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B026808	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B01190200	19.51	RND002B02680800	15.64	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026809	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B01190300	19.51	RNT002B02680900	15.64	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B026813	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B00430100	37.13	AJF002B02681300	32.93	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired
B026814	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B00430200	37.13	RND002B02681400	32.93	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026815	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B00430300	37.13	RNT002B02681500	32.93	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B026816	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B00440100	42.91	AJF002B02681600	38.43	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired
B026817	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B00440200	42.91	RND002B02681700	38.43	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026818	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B00440300	42.91	RNT002B02681800	38.43	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B021501	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02150100	-310.71	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	None	Retired
B021502	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	None	None	LNG026B02150200	-296.99	3/30/2022	Application Package	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG (Provisional)	None	Retired
B021503	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN026B02150300	-293.45	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG (Provisional)	None	Retired
A044201	Tier 1	3.0	Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04420100	72.16	3/29/2022	None	Ethanol	Lincolnway Energy, LLC (4830)	Lincolnway Energy (70092)	Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (Provisional)	None	Retired

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A044203	Tier 1	3.0	Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04420300	24.70	3/29/2022	None	Ethanol - Cellulosic	Lincolnway Energy, LLC (4830)	Lincolnway Energy (70092)	Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (Provisional)	None	Retired
B026703	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02850100	12.91	BIO001B02670300	15.71	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	None	Retired
B026704	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02850400	15.81	BIO001B02670400	16.34	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	None	Retired
B026705	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02850300	17.86	BIO001B02670500	20.86	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	None	Retired
B028003	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, California using Biomethane generated at Dos Rios Water Recycling Center, San Antonio, Texas; transported as L.H2 in tanker trailers to refueling stations in California.	California	Vastewater Sludge (030	Liquid Hydrogen (HYL)	None	None	HYL030B02800300	109.01	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, California using Biomethane generated at Dos Rios Water Recycling Center, San Antonio, Texas; transported as L.H2 in tanker trailers to refueling stations in California.	None	
B028004	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane generated at SAWS Dos Rios Water Recycling Center in San Antonio, TX; transported as G.H2 in tube trailers to fueling stations in California.	California	Vastewater Sludge (030	Gaseous Hydrogen (HYG)	None	None	HYG030B02800400	76.98	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane generated at SAWS Dos Rios Water Recycling Center in San Antonio, TX; transported as G.H2 in tube trailers to fueling stations in California.	None	
B028005	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Homan Farm, King City, MO; transported as L.H2 in tanker trailers to refueling stations in California.	California	Swine Manure (044)	Liquid Hydrogen (HYL)	None	None	HYL044B02800500	-338.45	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Homan Farm, King City, MO; transported as L.H2 in tanker trailers to refueling stations in California.	None	
B028006	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Valley View Farm, Greencastle, MO; transported as L.H2 in tanker trailers to refueling stations in California.	California	Swine Manure (044)	Liquid Hydrogen (HYL)	None	None	HYL044B02800600	-354.78	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Valley View Farm, Greencastle, MO; transported as L.H2 in tanker trailers to refueling stations in California.	None	
A043701	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (Provisional)	Oklahoma	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04370100	37.00	4/11/2022	None	Bio-CNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (Provisional)	None	Retired
A043702	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Oklahoma	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A04370200	50.61	4/11/2022	None	Bio-LNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A043703	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Oklahoma	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A04370300	53.70	4/11/2022	None	Bio-CNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A045201	Tier 1	3.0	Fuel Producer: VALE DO PARANA S.A ALCOOL E ACUCAR (6079); Facility Name: VALE DO PARANA S.A ALCOOL E ACUCAR (71119); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04520100	50.69	4/11/2022	None	Ethanol	VALE DO PARANA S.A ALCOOL E ACUCAR (6079)	VALE DO PARANA S.A ALCOOL E ACUCAR (71119)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	

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A045601	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	California	istillers' Corn Oil (003	Biodiesel	BIO003A03760100	32.12	BIO003A04560100	30.15	4/7/2022	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	None	Retired
A045602	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel	None	None	BIO001A04560200	23.48	4/7/2022	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	None	Retired
A045603	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	California	(animal and poultry fat	Biodiesel (BIO)	None	None	BIO002A04560300	36.09	4/7/2022	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	None	Retired
A045801	Tier 1	3.0	Fuel Producer: New Leaf Biofuel (7768); Facility Name: New Leaf Biofuel (83541); California Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	None	None	BIO001A04580100	14.69	5/10/2022	None	Biodiesel	New Leaf Biofuel (7768)	New Leaf Biofuel (83541)	California Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional)	None	Retired
A045802	Tier 1	3.0	Fuel Producer: New Leaf Biofuel (7768); Facility Name: New Leaf Biofuel (83541); California Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	None	None	BIO001A04580200	20.58	5/10/2022	None	Biodiesel	New Leaf Biofuel (7768)	New Leaf Biofuel (83541)	California Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional)	None	Retired
B030201	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	Minnesota	istillers' Corn Oil (003	Biodiesel (BIO)	BIO003A00830300	24.55	BIO003B03020100	24.50	6/3/2022	Application Package	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	None	Retired
B030202	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	Minnesota	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A00830400	17.72	BIO001B03020200	18.50	6/3/2022	Application Package	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	None	Retired
B030203	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	Minnesota	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A00830500	11.99	BIO001B03020300	12.50	6/3/2022	Application Package	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	None	Retired
B030204	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California (Provisional)	Minnesota	(animal and poultry fat	Biodiesel (BIO)	BIO002A00830600	28.89	BIO002B03020400	29.00	6/3/2022	Application Package	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California (Provisional)	None	Retired
A046101	Tier 1	3.0	Fuel Producer: GARLAND RENEWABLES, LLC (1639); Facility Name: GARLAND RENEWABLES, LLC (71921; Landfill Gas generated at Garland Landfill in Rowlett, Texas upgraded to Biomethane at Garland Renewables; pipelined to California for compression and distribution to CNG refueling stations. (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04610100	32.52	5/13/2022	None	Bio-CNG	GARLAND RENEWABLES, LLC (1639)	GARLAND RENEWABLES, LLC (71921	Landfill Gas generated at Garland Landfill in Rowlett, Texas upgraded to Biomethane at Garland Renewables; pipelined to California for compression and distribution to CNG refueling stations. (Provisional)	None	
A046601	Tier 1	3.0	Fuel Producer: INNOLTEK (C1126); Facility Name: INNOLTEK (F00340); Rendered Animal Fat Oil transported by truck to biodiesel plant in St-Jean-sur-Richelieu, Quebec, Canada; NG, grid electricity; finished fuel transported to California by Rail.	Canada	(animal and poultry fat	Biodiesel (BIO)	None	None	BIO002A04660100	34.76	6/13/2022	None	Biodiesel	INNOLTEK (C1126)	INNOLTEK (F00340)	Rendered Animal Fat Oil transported by truck to biodiesel plant in St-Jean-sur-Richelieu, Quebec, Canada; NG, grid electricity; finished fuel transported to California by Rail.	None	
A040601	Tier 1	3.0	Fuel Producer: EDINBURG RENEWABLES, LLC (6401); Facility Name: CITY OF EDINBURG LANDFILL (71223); Biomethane from City of Edinburg Landfill in Edinburg, Texas, upgrading at Edinburg Renewables, LLC, pipelined to California for compression to CNG.	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04060100	37.12	12/31/2021	None	Bio-CNG	EDINBURG RENEWABLES, LLC (6401)	CITY OF EDINBURG LANDFILL (71223)	Biomethane from City of Edinburg Landfill in Edinburg, Texas, upgrading at Edinburg Renewables, LLC, pipelined to California for compression to CNG.	None	

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B025001	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02500100	-182.67	6/28/2022	Application Package	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	None	Retired
B025002	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02500200	-267.51	6/28/2022	Application Package	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	None	Retired
B025003	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02500300	-255.34	6/28/2022	Application Package	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	None	Retired
B030701	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03070100	-353.38	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	None	Retired
B030702	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03070200	-405.57	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	None	Retired
B030703	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03070300	-255.83	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	None	Retired
B030705	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03070500	-366.91	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	None	Retired
B030704	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03070400	-249.43	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	None	Retired
B032901	Tier 2	3.0	Fuel Producer: Messer LLC (f.k.a. Linde LLC) (L012); Facility Name: Linde Praxair (F00477); Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; distributed 414 miles by liquid tanker to refueling stations.	California	h American Fossil NG (	Liquid Hydrogen (HYL)	None	None	HYL031B03290100	153.28	6/23/2022	Application Package	Hydrogen	Messer LLC (f.k.a. Linde LLC) (L012)	Linde Praxair (F00477)	Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; distributed 414 miles by liquid tanker to refueling stations.	None	
A044101	Tier 1	3.0	Fuel Producer: GREENAMERICA BIOFUELS ORD LLC (1481); Facility Name: GREEN PLAINS ORD, LLC (71641); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ord, Nebraska; Ethanol transported by truck and rail to California , Composite CI.	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A04410100	70.65	6/29/2022	None	Ethanol	GREENAMERICA BIOFUELS ORD LLC (1481)	GREEN PLAINS ORD, LLC (71641)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ord, Nebraska; Ethanol transported by truck and rail to California , Composite CI.	None	
B028301	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: DEER RUN RNG PROJECT (71482); Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02830100	-195.09	6/29/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	DEER RUN RNG PROJECT (71482)	Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	Retired
B030801	Tier 2	3.0	Fuel Producer: WOF SW GGP 1 LLC (W009); Facility Name: Green Gas Partners Stanfield (F00003); Biogas from dairy manure at Shamrock Farms, T&K Red River, and Zinke Dairy in Stanfield and Maricopa, AZ; upgraded to pipeline quality at Green Gas Partners Stanfield and pipelined to CA for transportation use (Provisional)	Arizona	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03080100	-362.84	6/30/2022	Application Package	Bio-CNG	WOF SW GGP 1 LLC (W009)	Green Gas Partners Stanfield (F00003)	Biogas from dairy manure at Shamrock Farms, T&K Red River, and Zinke Dairy in Stanfield and Maricopa, AZ; upgraded to pipeline quality at Green Gas Partners Stanfield and pipelined to CA for transportation use (Provisional)	None	

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B031001	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100100	-349.17	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B031002	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100200	-210.67	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B031004	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100400	-417.26	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B031003	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100300	-406.28	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B031005	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100500	-417.24	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B031006	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100600	-356.29	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
A046201	Tier 1	3.0	Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04620101	33.08	6/23/2022	None	Ethanol	CORN, LP (5065)	CORN, LP (70145)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A046202	Tier 1	3.0	Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00330101	71.09	ETH009A04620201	70.62	6/23/2022	None	Ethanol	CORN, LP (5065)	CORN, LP (70145)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (Provisional)	None	Retired
L018801	Lookup Table	3.0	Fuel Producer: Silicon Valley Clean Energy (C1183); Facility Name: Silicon Valley Clean Energy Authority (F00484); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/14/2022	None	Electricity	Silicon Valley Clean Energy (C1183)	Silicon Valley Clean Energy Authority (F00484)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019101	Lookup Table	3.0	Fuel Producer: Southern California Edison (C1185); Facility Name: Southern California Edison (F00489); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/28/2022	None	Electricity	Southern California Edison (C1185)	Southern California Edison (F00489)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019301	Lookup Table	3.0	Fuel Producer: Skyview Finance Company 2, LLC (C1174); Facility Name: Skyview Finance Company 2, LLC ZCI CA B&C (F00492); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/28/2022	None	Electricity	Skyview Finance Company 2, LLC (C1174)	Skyview Finance Company 2, LLC ZCI CA B&C (F00492)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019401	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc. Zero CI Direct Renewable Energy Avenal (F00490); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Supplied Zero-CI Sourc	Electricity (ELC)	None	None	ELC049L00072019	0.00	4/8/2022	None	Electricity	SRECTrade, Inc (C1018)	SRECTrade, Inc. Zero CI Direct Renewable Energy Avenal (F00490)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

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L019601	Lookup Table	3.0	Fuel Producer: Redwood City School District (C1205); Facility Name: Redwood City School District (F00524); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/22/2022	None	Electricity	Redwood City School District (C1205)	Redwood City School District (F00524)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019701	Lookup Table	3.0	Fuel Producer: The Mobility House (C1200); Facility Name: The Mobility House (F00525); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/24/2022	None	Electricity	The Mobility House (C1200)	The Mobility House (F00525)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019801	Lookup Table	3.0	Fuel Producer: 7-Eleven, Inc. (C1204); Facility Name: 7-Eleven, Inc. (F00526); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/24/2022	None	Electricity	7-Eleven, Inc. (C1204)	7-Eleven, Inc. (F00526)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A041001	Tier 1	3.0	Fuel Producer: JAPUNGU AGROINDUSTRIAL LTDA (C1145); Facility Name: Japungu Agroindustrial Ltda (F00383); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04100100	52.77	7/18/2022	None	Ethanol	JAPUNGU AGROINDUSTRIAL LTDA (C1145)	Japungu Agroindustrial Ltda (F00383)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	Retired
A045701	Tier 1	3.0	Fuel Producer: BP Biofuels (4427); Facility Name: Tropical Bioenergia SA (71078); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04570100	50.57	7/18/2022	None	Ethanol	BP Biofuels (4427)	Tropical Bioenergia SA (71078)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
L019001	Lookup Table	3.0	Fuel Producer: San Francisco Bay Area Rapid Transit District (BART) (C1176); Facility Name: SF BART (F00482); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.0	3/17/2022	None	Electricity	San Francisco Bay Area Rapid Transit District (BART) (C1176)	SF BART (F00482)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A046702	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO LINDEN PLANT (70196); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A04670200	73.37	7/18/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO LINDEN PLANT (70196)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	None	
A046701	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO LINDEN PLANT (70196); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04670100	27.73	7/18/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO LINDEN PLANT (70196)	Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	None	
A046703	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO LINDEN PLANT (70196); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A04670300	70.15	7/18/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO LINDEN PLANT (70196)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	None	
L020201	Lookup Table	3.0	Fuel Producer: County of Santa Clara (C1208); Facility Name: County of Santa Clara (F00530); Zero-CI electricity from solar PV generated in CA	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	7/11/2022	None	Electricity	County of Santa Clara (C1208)	County of Santa Clara (F00530)	Zero-CI electricity from solar PV generated in CA	None	
L020301	Lookup Table	3.0	Fuel Producer: City of Palo Alto Utilities (P600); Facility Name: City of Palo Alto Utilities (F00499); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	7/13/2022	None	Electricity	City of Palo Alto Utilities (P600)	City of Palo Alto Utilities (F00499)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A046801	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO WELCOME PLANT (70276); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04680100	26.52	7/20/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO WELCOME PLANT (70276)	Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	None	

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A046802	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO WELCOME PLANT (70276); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04680200	72.15	7/20/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO WELCOME PLANT (70276)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	None	
A046803	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO WELCOME PLANT (70276); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04680300	68.59	7/20/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO WELCOME PLANT (70276)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	None	
A046902	Tier 1	3.0	Fuel Producer: BADGER STATE ETHANOL LLC (4469); Facility Name: Badger State Ethanol (70130); Midwest Corn, Dry Mill; Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin ; Ethanol transported by rail to California (Provisional)	Wisconsin	Corn (009)	Ethanol (ETH)	None	None	ETH009A04690200	69.34	9/19/2022	None	Ethanol	BADGER STATE ETHANOL LLC (4469)	Badger State Ethanol (70130)	Midwest Corn, Dry Mill; Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin ; Ethanol transported by rail to California (Provisional)	None	
A046903	Tier 1	3.0	Fuel Producer: BADGER STATE ETHANOL LLC (4469); Facility Name: Badger State Ethanol (70130); Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wisconsin and transported by rail to California (Provisional)	Wisconsin	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04690300	27.41	9/19/2022	None	Ethanol	BADGER STATE ETHANOL LLC (4469)	Badger State Ethanol (70130)	Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wisconsin and transported by rail to California (Provisional)	None	
A046901	Tier 1	3.0	Fuel Producer: BADGER STATE ETHANOL LLC (4469); Facility Name: Badger State Ethanol (70130); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin; Ethanol transported by rail to California (Provisional)	Wisconsin	Corn (009)	Ethanol (ETH)	None	None	ETH009A04690100	74.18	9/19/2022	None	Ethanol	BADGER STATE ETHANOL LLC (4469)	Badger State Ethanol (70130)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin; Ethanol transported by rail to California (Provisional)	None	
L020601	Lookup Table	3.0	Fuel Producer: STX Commodities LLC (C1195) ; Facility Name: STX Commodities LLC 2.0 (F00539); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity	None	None	ELC037L00072019	0.00	9/14/2022	None	Electricity	STX Commodities LLC (C1195)	STX Commodities LLC 2.0 (F00539)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
B028201	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY S&S (71361); Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02820100	-272.08	9/23/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	U.S. GAIN RNG FACILITY S&S (71361)	Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	Retired
B032301	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	California	Distillers' Corn Oil (003	Renewable Diesel (RND)	None	None	RND003B03230100	25.46	9/20/2022	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	None	
B033801	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: DALHART RNG, LLC (70981); Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (Provisional)	Texas	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B03380100	-417.96	9/23/2022	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	DALHART RNG, LLC (70981)	Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (Provisional)	None	Retired
B031101	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110101	-418.04	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031102	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110200	-383.14	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031103	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110300	-419.34	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired

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B031105	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110500	-276.38	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031104	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110400	-299.39	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031107	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110700	-341.84	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031106	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110600	-403.86	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031108	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110800	-273.88	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031501	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03150100	-403.96	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B034601	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAMB RNG PROJECT (71101); Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (Provisional)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03460100	-311.72	9/28/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET LAMB RNG PROJECT (71101)	Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (Provisional)	None	Retired
B034801	Tier 2	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Air Products and Chemicals SMR Wilmington (F00384); Gaseous Hydrogen produced in California by Central SMR of biomethane sourced from the District 45 dairy digester in Minnesota. Finished fuel is distributed to refueling stations in California by tube trailers, (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03480100	-147.20	9/29/2022	Application Package	Hydrogen	Shell Energy North America (6154)	Air Products and Chemicals SMR Wilmington (F00384)	Gaseous Hydrogen produced in California by Central SMR of biomethane sourced from the District 45 dairy digester in Minnesota. Finished fuel is distributed to refueling stations in California by tube trailers, (Provisional)	None	
B034901	Tier 2	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Carson Hydrogen Plant (F00059); Gaseous Hydrogen produced at the Carson Hydrogen Plant using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported via pipeline to refueling station in Torrance, California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03490100	-151.76	9/29/2022	Application Package	Hydrogen	Shell Energy North America (6154)	Carson Hydrogen Plant (F00059)	Gaseous Hydrogen produced at the Carson Hydrogen Plant using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported via pipeline to refueling station in Torrance, California. (Provisional)	None	
B035001	Tier 2	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Sacramento Hydrogen Plant (F00102); L.H2 produced at Sacramento Hydrogen Plant using digester gas derived from District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported to trans-fill facility, re-gasified, recompressed; distributed to refueling stations. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03500100	-89.98	9/29/2022	Application Package	Hydrogen	Shell Energy North America (6154)	Sacramento Hydrogen Plant (F00102)	L.H2 produced at Sacramento Hydrogen Plant using digester gas derived from District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported to trans-fill facility, re-gasified, recompressed; distributed to refueling stations. (Provisional)	None	Retired
B035301	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY DALLMAN (71341); Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03530100	-344.72	9/29/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	U.S. GAIN RNG FACILITY DALLMAN (71341)	Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use (Provisional)	None	Retired
B036001	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03600100	-159.04	9/27/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (Provisional)	None	Retired

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B036003	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03600300	-104.64	9/27/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (Provisional)	None	Retired
B036002	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03600200	-120.27	9/27/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (Provisional)	None	Retired
B037301	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03730100	-107.85	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional)	None	
B037302	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03730200	-192.70	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional)	None	Retired
B037303	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03730300	-146.62	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional)	None	
B037304	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03730400	-231.46	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional)	None	Retired
B037305	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas procured from District 45 Dairy Digester; L.H2 transported to trans-fill, regasified, and distributed to refuling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03730500	-92.22	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas procured from District 45 Dairy Digester; L.H2 transported to trans-fill, regasified, and distributed to refuling stations in California. (Provisional)	None	
B037306	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03730600	-177.06	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (Provisional)	None	Retired
L020701	Lookup Table	3.0	Fuel Producer: Apple (A449); Facility Name: VP02 (V8866); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/28/2022	None	Electricity	Apple (A449)	VP02 (V8866)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L020901	Lookup Table	3.0	Fuel Producer: Revolv Global Inc. (C1210); Facility Name: Revolv Global Inc. (F00553); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/28/2022	None	Electricity	Revolv Global Inc. (C1210)	Revolv Global Inc. (F00553)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A048401	Tier 1	3.0	Fuel Producer: Heartland Corn Products (4827); Facility Name: Heartland Corn Products (70089); Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04840100	72.78	10/12/2022	None	Ethanol	Heartland Corn Products (4827)	Heartland Corn Products (70089)	Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	
A048402	Tier 1	3.0	Fuel Producer: Heartland Corn Products (4827); Facility Name: Heartland Corn Products (70089); Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04840200	26.07	10/12/2022	None	Ethanol - Cellulosic	Heartland Corn Products (4827)	Heartland Corn Products (70089)	Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California (Provisional)	None	

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A048901	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Albion (70283); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A04890100	74.58	10/12/2022	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Albion (70283)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional)	None	
A048902	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Albion (70283); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A04890200	70.52	10/12/2022	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Albion (70283)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional)	None	
A048903	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Albion (70283); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04890300	27.18	10/12/2022	None	Ethanol - Cellulosic	Valero Renewable Fuels (3201)	Valero Renewable Fuels Albion (70283)	Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California (Provisional)	None	
A049001	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04900100	71.51	10/12/2022	None	Ethanol	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (Provisional)	None	Retired
A049002	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04900200	61.15	10/12/2022	None	Ethanol	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (Provisional)	None	Retired
A049003	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04900300	22.33	10/12/2022	None	Ethanol - Cellulosic	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A049401	Tier 1	3.0	Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Tres Rios Water Reclamation Facility (F00443); Biomethane derived from anaerobic digestion of wastewater sludge. (Provisional)	Arizona	Vastewater Sludge (030	Compressed Natural Gas (CNG)	None	None	CNG030A04940100	27.41	10/10/2022	None	Bio-CNG	BLUE SOURCE LLC (6086)	Tres Rios Water Reclamation Facility (F00443)	Biomethane derived from anaerobic digestion of wastewater sludge. (Provisional)	None	
A047101	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A04710101	73.70	11/8/2022	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional)	None	
A047102	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A04710201	64.99	11/8/2022	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest Corn, Dry Mill; Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional)	None	
A047103	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Fiber ethanol from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Trenton, Nebraska and transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04710301	27.35	11/8/2022	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest Corn, Dry Mill; Fiber ethanol from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Trenton, Nebraska and transported by rail to California (Provisional)	None	
B032501	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline from soybean oil transported by barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	California	Soybean Oil (005)	Renewable Gasoline (RNG)	None	None	RNG005B03250100	63.35	12/20/2022	Application Package	Renewable Gasoline	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable gasoline from soybean oil transported by barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	None	
B032502	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline produced from soybean oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	California	Soybean Oil (005)	Renewable Gasoline (RNG)	None	None	RNG005B03250200	60.38	12/20/2022	Application Package	Renewable Gasoline	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable gasoline produced from soybean oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	None	

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B032503	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline produced from canola oil transported by rail and ship to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	California	Canola Oil (006)	Renewable Gasoline (RNG)	None	None	RNG006B03250300	58.48	12/20/2022	Application Package	Renewable Gasoline	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable gasoline produced from canola oil transported by rail and ship to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	None	
B033701	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	California	Distillers' Corn Oil (003	Renewable Gasoline (RNG)	None	None	RNG003B03370100	30.86	12/20/2022	Application Package	Renewable Gasoline	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable gasoline produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	None	
B035201	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03520100	-411.77	12/5/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (Provisional)	None	Retired
B035202	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03520200	-351.51	12/5/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (Provisional)	None	Retired
A048601	Tier 1	3.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Dansuk Industrial Co., Ltd (81302); South Korean Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in Siwha, South Korea ; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port and to California by Ocean tanker.	South Korea	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A01050100	27.89	BIO001A04860100	25.98	12/19/2022	None	Biodiesel	Dansuk Industrial Co., Ltd (5953)	Dansuk Industrial Co., Ltd (81302)	South Korean Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in Siwha, South Korea ; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port and to California by Ocean tanker.	None	
A048602	Tier 1	3.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Dansuk Industrial Co., Ltd (81302); South Korean Sourced Rendered Tallow transported by truck to Biodiesel plant in Siwha, South Korea; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port to California by Ocean tanker.	South Korea	(animal and poultry fat	Biodiesel (BIO)	None	None	BIO002A04860200	37.80	12/19/2022	None	Biodiesel	Dansuk Industrial Co., Ltd (5953)	Dansuk Industrial Co., Ltd (81302)	South Korean Sourced Rendered Tallow transported by truck to Biodiesel plant in Siwha, South Korea; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port to California by Ocean tanker.	None	
B036601	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: MILFORD FARM (71483); Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use (Provisional)	Utah	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02140100	-413.67	CNG044B03660100	-414.59	12/7/2022	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	MILFORD FARM (71483)	Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use (Provisional)	None	Retired
B037801	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as liquefied Hydrogen in tanker trailers and re-gasified, recompressed, at refueling stations in California.	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B03780100	107.19	12/19/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as liquefied Hydrogen in tanker trailers and re-gasified, recompressed, at refueling stations in California.	None	
B038501	Tier 2	3.0	Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Green Valley Dairy LLC (F00198); Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03850100	-180.73	12/21/2022	Application Package	Bio-CNG	BLUE SOURCE LLC (6086)	Green Valley Dairy LLC (F00198)	Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	Retired
B039101	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported in tanker trailers; re-gasified, recompressed, and then dispensed as gaseous Hydrogen at the refueling stations in California.	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03910100	-197.27	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported in tanker trailers; re-gasified, recompressed, and then dispensed as gaseous Hydrogen at the refueling stations in California.	None	
B039102	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03910200	-236.03	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	None	
B039103	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in California; dispensed as gaseous Hydrogen.	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03910300	-181.64	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)Verification Body Name:	Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in California; dispensed	None	

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B039201	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied hydrogen from dairy manure at DALLMAN RNG Project; liquid hydrogen production at Praxair Inc., Ontario, California transported as liquid to H2 stations in California.	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03920100	-269.91	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied hydrogen from dairy manure at DALLMAN RNG Project; liquid hydrogen production at Praxair Inc., Ontario, California transported as liquid to H2 stations in California.	None	
B039202	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03920200	-308.67	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	None	
B039203	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in California; dispensed as gaseous Hydrogen.	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03920300	-254.28	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in	None	
B034501	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAKESHORE RNG PROJECT (71321); Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03450100	-318.35	12/27/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET LAKESHORE RNG PROJECT (71321)	Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	Retired
B034701	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET BOXLER RNG PROJECT (71222); Biogas from dairy manure at Boxler Dairy in Varysburg, NY; upgraded to pipeline quality at Yellow Jacket Boxler RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03470100	-206.88	12/27/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET BOXLER RNG PROJECT (71222)	Biogas from dairy manure at Boxler Dairy in Varysburg, NY; upgraded to pipeline quality at Yellow Jacket Boxler RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	
A048101	Tier 1	3.0	Fuel Producer: BP Bunge Bioenergia SA (C1196); Facility Name: USINA OUROESTE AÇÚCAR E ALCOOL (F00509); Ethanol derived from Brazilian sugarcane juice and molasses; mechanized harvesting, and credit for export of surplus cogenerated electricity; finished fuel exported to California via Panama Canal by ocean tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH019A04810100	49.73	12/27/2022	None	Ethanol	BP Bunge Bioenergia SA (C1196)	USINA OUROESTE AÇÚCAR E ALCOOL (F00509)	Ethanol derived from Brazilian sugarcane juice and molasses; mechanized harvesting, and credit for export of surplus cogenerated electricity; finished fuel exported to California via Panama Canal by ocean tanker.	None	
A048301	Tier 1	3.0	Fuel Producer: BP Bunge Bioenergia SA (C1196); Facility Name: AGROINDUSTRIAL SANTA JULIANA (F00507); Ethanol produced from Brazilian sugarcane juice and molasses; credit for mechanized harvesting and surplus cogenerated electricity export; finished fuel exported to California via Panama Canal by ocean tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH019A04830100	51.34	12/27/2022	None	Ethanol	BP Bunge Bioenergia SA (C1196)	AGROINDUSTRIAL SANTA JULIANA (F00507)	Ethanol produced from Brazilian sugarcane juice and molasses; credit for mechanized harvesting and surplus cogenerated electricity export; finished fuel exported to California via Panama Canal by ocean tanker.	None	
B037001	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: GREEN HILLS FARM (71881); Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B03700100	-408.25	12/28/2022	Application Package	Bio-CNG	Anew RNG, LLC (5877)	GREEN HILLS FARM (71881)	Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (Provisional)	None	Retired
B037101	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: WHITETAIL FARM (71882); Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B03710100	-412.77	12/28/2022	Application Package	Bio-CNG	Anew RNG, LLC (5877)	WHITETAIL FARM (71882)	Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (Provisional)	None	Retired
L018901	Lookup Table	3.0	Fuel Producer: 4GEN LOGISTICS, L.L.C. (C1156); Facility Name: 4GEN Fastlane (F00432); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	00.00	3/25/2022	None	Electricity	4GEN LOGISTICS, L.L.C. (C1156)	4GEN Fastlane (F00432)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019201	Lookup Table	3.0	Fuel Producer: Linde LLC (L012); Facility Name: Linde Praxair (F00477); Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; grid electricity; finished fuel distributed less than 100 miles to refueling stations by tanker truck.	California	h American Fossil NG (	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	6/30/2022	None	Hydrogen	Linde LLC (L012)	Linde Praxair (F00477)	Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; grid electricity; finished fuel distributed less than 100 miles to refueling stations by tanker truck.	None	
L020501	Lookup Table	3.0	Fuel Producer: Total Warehouse Inc. (C1214); Facility Name: Total Warehouse Inc. (F00541); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity	None	None	ELC037L00072019	00.00	9/16/2022	None	Electricity	Total Warehouse Inc. (C1214)	Total Warehouse Inc. (F00541)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

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A010501	Tier 1	3.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Pyeongtaek 2 (80202); South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker	South Korea	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A01050100	27.89	BIO001A01050101	25.00	12/17/2019	None	Biodiesel	Dansuk Industrial Co., Ltd (5953)	Pyeongtaek 2 (80202)	South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker	None	Retired
A012903	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A01290300	27.44	ETH012A01290301	27.01	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A013003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01300300	27.54	ETH012A01300301	25.09	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A014603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	Michigan	Corn Fiber (012)	Ethanol (ETH)	ETH012A01460300	27.33	ETH012A01460301	27.03	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A015003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01500300	27.72	ETH012A01500301	27.19	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A015103	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108; Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01510300	27.69	ETH012A01510301	26.17	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A015203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A01520300	27.00	ETH012A01520301	25.89	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A019802	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A01980200	23.46	ETH012A01980201	23.04	6/24/2020	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California	2021 AFPR Recert Complete	Retired
A020904	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A02090400	27.48	ETH012A02090401	25.14	6/24/2020	None	Ethanol - Cellulosic	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	
A021203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) ; Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California	Missouri	Corn Fiber (012)	Ethanol (ETH)	ETH012A02120300	26.19	ETH012A02120301	25.32	4/28/2020	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A021703	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	North Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A02170300	25.72	ETH012A02170301	24.41	7/27/2020	None	Ethanol - Cellulosic	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
A022404	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A02240400	23.96	ETH012A02240402	26.00	6/24/2020	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

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A024503	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A02450300	22.56	ETH012A02450303	24.71	12/4/2020	None	Ethanol - Cellulosic	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A024603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A02460300	29.41	ETH012A02460302	28.47	12/29/2020	None	Ethanol - Cellulosic	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A027202	Tier 1	3.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A02720200	26.60	ETH012A02720201	26.40	10/21/2020	None	Ethanol - Cellulosic	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	
A030901	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A03090100	24.46	ETH012A03090101	24.84	5/4/2021	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
B017403	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California.	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012B01740300	29.14	ETH012B01740301	29.48	9/24/2021	Application Package	Ethanol - Cellulosic	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
B019001	Tier 2	3.0	Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	Kansas	Distillers' Corn Oil (003	Renewable Diesel (RND)	RND003B01900100	46.31	RND003B01900101	56.37	6/25/2021	Application Package	Renewable Diesel	East Kansas Agri-Energy, LLC (4483)	East Kansas Agri-Energy, LLC (83483)	Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	2021 AFPR Recert Complete	
B019002	Tier 2	3.0	Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail	Kansas	Distillers' Corn Oil (003	Renewable Naphtha (RNT)	RNT003B01900200	46.31	RNT003B01900201	56.37	6/25/2021	Application Package	Renewable Naphtha	East Kansas Agri-Energy, LLC (4483)	East Kansas Agri-Energy, LLC (83483)	Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail	2021 AFPR Recert Complete	
A039402	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A03940200	27.87	ETH012A03940201	27.95	10/14/2021	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
A042302	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A04230200	24.02	ETH012A04230201	24.42	10/26/2021	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
B024103	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline	California	Canola Oil (006)	Renewable Diesel (RND)	RND006B02410300	51.87	RND006B02410301	52.90	12/28/2021	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline	2021 AFPR Recert Complete	
B024101	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline	California	Soybean Oil (005)	Renewable Diesel (RND)	RND005B02410100	54.68	RND005B02410101	55.39	12/28/2021	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline	2021 AFPR Recert Complete	
A043602	Tier 1	3.0	Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A04360200	24.89	ETH012A04360201	25.15	2/1/2022	None	Ethanol	AL CORN CLEAN FUEL, LLC (4825)	AL CORN CLEAN FUEL, LLC (70087)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired

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A037903	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California.	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03790300	64.00	ETH010A03790301	65.92	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California.	2021 AFPR Recert Complete	Retired
A049301	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill, Dry DGS and Corn Oil Co-Products; Natural Gas and Electricity. Ethanol produced from corn in Albert City, Iowa and transported by Rail to California (Provisional)	Iowa	Corn (009)		ETH009A02540100	69.55	ETH009A04930100	73.97	1/23/2023	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Albert City (70142)	Midwest Corn, Dry Mill, Dry DGS and Corn Oil Co-Products; Natural Gas and Electricity. Ethanol produced from corn in Albert City, Iowa and transported by Rail to California (Provisional)	None	
A049302	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201) ; Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Modified DGS, and Corn Oil Co-Products; Natural Gas, Grid Electricity; Ethanol produced in Albert City, Iowa and transported by Rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02540200	66.07	ETH009A04930200	70.72	1/23/2023	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Albert City (70142)	Midwest Corn, Dry Mill; Modified DGS, and Corn Oil Co-Products; Natural Gas, Grid Electricity; Ethanol produced in Albert City, Iowa and transported by Rail to California (Provisional)	None	
A049303	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201) ; Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Dry and Modified DGS Co-Products; Ethanol produced from BPX Fiber Conversion Process; Natural Gas, and Grid Electricity; Ethanol produced in Albert City, Iowa, and transpsorted by Rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04930300	27.65	1/23/2023	None	Ethanol - Cellulosic	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Albert City (70142)	Midwest Corn, Dry Mill; Dry and Modified DGS Co-Products; Ethanol produced from BPX Fiber Conversion Process; Natural Gas, and Grid Electricity; Ethanol produced in Albert City, Iowa, and transpsorted by Rail to California (Provisional)	None	
A008601	Tier 1	3.0	Fuel Producer: Bridgeport Ethanol, LLC 5934; Facility Name: Bridgeport Ethanol, LLC 70217; Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00860100	62.37	ETH009A00860101	63.00	4/16/2019	None	Ethanol	Bridgeport Ethanol, LLC 5934	Bridgeport Ethanol, LLC 70217	Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A021201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California	Missouri	Corn (009)	Ethanol (ETH)	ETH009A02120100	75.09	ETH009A02120102	75.47	4/28/2020	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A031201	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	California	Soybean Oil (005)	Biodiesel (BIO)	BIO005A03120100	57.16	BIO005A03120101	63.92	3/23/2021	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	2021 AFPR Recert Complete	Retired
A031202	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	California	Canola Oil (006)	Biodiesel (BIO)	BIO006A03120200	51.65	BIO006A03120201	59.19	3/23/2021	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	2021 AFPR Recert Complete	Retired
A031204	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production.	California	(animal and poultry fat	Biodiesel (BIO)	BIO002A03120400	31.28	BIO002A03120401	38.49	3/23/2021	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production.	2021 AFPR Recert Complete	Retired
A031205	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	California	(animal and poultry fat	Biodiesel (BIO)	BIO002A03120500	32.45	BIO002A03120501	39.35	3/23/2021	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	2021 AFPR Recert Complete	Retired
A031206	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A03120600	21.27	BIO001A03120601	26.60	3/23/2021	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	2021 AFPR Recert Complete	Retired
A034801	Tier 1	3.0	Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional)	Texas	(animal and poultry fat	Biodiesel (BIO)	BIO002A03480100	30.80	BIO002A03480101	31.95	7/28/2021	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional)	2021 AFPR Recert Complete	Retired

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A042602	Tier 1	3.0	Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel.	Iowa	Soybean Oil (005)	Biodiesel (BIO)	BIO005A04260200	55.05	BIO005A04260201	54.75	12/22/2021	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel.	2021 AFPR Recert Complete	
A042601	Tier 1	3.0	Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced tallow; finished fuel transported by rail to California by rail for use as a transportation fuel.	Iowa	(animal and poultry fat	Biodiesel (BIO)	BIO002A04260100	29.23	BIO002A04260101	29.39	12/22/2021	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Biodiesel produced from US sourced tallow; finished fuel transported to California by rail for use as a transportation fuel.	2021 AFPR Recert Complete	
A043901	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Skyline RNG Facility (F00217); Biomethane from Landfill at Ferris, Texas upgrading at Waste Management, pipelined to California for compression to CNG (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04390100	53.17	2/22/2022	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Skyline RNG Facility (F00217)	Biomethane from Landfill at Ferris, Texas upgrading at Waste Management, pipelined to California for compression to CNG (Provisional)	None	
A043902	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Skyline RNG Facility (F00217); Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Texas	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A04390200	68.92	2/22/2022	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Skyline RNG Facility (F00217)	Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	
A043903	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Skyline RNG Facility (F00217); Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Texas	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LCN025A04390300	72.00	2/22/2022	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Skyline RNG Facility (F00217)	Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	
B026701	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	Distillers' Corn Oil (003	Biodiesel (BIO)	BIO003B02670100	28.67	BIO003B02670101	28.80	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2021 AFPR Recert Complete	Retired
B026702	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	(animal and poultry fat	Biodiesel (BIO)	BIO002B02670200	32.53	BIO002B02670201	32.73	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2021 AFPR Recert Complete	Retired
A012001	Tier 1	3.0	Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01200101	65.30	ETH009A01200102	64.69	9/5/2019	None	Ethanol	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	
A012901	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01290100	74.62	ETH009A01290101	73.48	9/24/2019	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A012902	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01290200	67.54	ETH009A01290201	66.73	9/24/2019	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A013001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01300100	74.35	ETH009A01300101	72.10	9/24/2019	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A049101	Tier 1	3.0	Fuel Producer: REG Grays Harbor, LLC (6326); Facility Name: REG Grays Harbor, LLC (82954); North American Sourced Canola Oil transported by truck, rail, and ocean tanker to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California	Washington	Canola Oil (006)	Biodiesel (BIO)	BDCA204	52.87	BIO006A04910100	49.00	2/13/2023	None	Biodiesel	REG Grays Harbor, LLC (6326)	REG Grays Harbor, LLC (82954)	North American Sourced Canola Oil transported by truck, rail, and ocean tanker to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A049102	Tier 1	3.0	Fuel Producer: REG Grays Harbor, LLC (6326); Facility Name: REG Grays Harbor, LLC (82954); North American Sourced Soybean Oil transported by rail to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California	Washington	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A04910200	55.00	2/13/2023	None	Biodiesel	REG Grays Harbor, LLC (6326)	REG Grays Harbor, LLC (82954)	North American Sourced Soybean Oil transported by rail to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California	None	
A049501	Tier 1	3.0	Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota ; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04950100	73.15	2/14/2023	None	Ethanol	RING-NECK ENERGY & FEED, LLC (6274)	RING-NECK ENERGY & FEED, LLC (70361)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota ; Ethanol transported by rail to California. (Provisional)	None	
A049502	Tier 1	3.0	Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274) ; Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04950200	65.12	2/14/2023	None	Ethanol	RING-NECK ENERGY & FEED, LLC (6274)	RING-NECK ENERGY & FEED, LLC (70361)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	
A049503	Tier 1	3.0	Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04950300	26.69	2/14/2023	None	Ethanol - Cellulosic	RING-NECK ENERGY & FEED, LLC (6274)	RING-NECK ENERGY & FEED, LLC (70361)	Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	
A049505	Tier 1	3.0	Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Grain Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A04950500	77.07	2/14/2023	None	Ethanol	RING-NECK ENERGY & FEED, LLC (6274)	RING-NECK ENERGY & FEED, LLC (70361)	Midwest Grain Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	
A049506	Tier 1	3.0	Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A04950600	69.04	2/14/2023	None	Ethanol	RING-NECK ENERGY & FEED, LLC (6274)	RING-NECK ENERGY & FEED, LLC (70361)	Midwest Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	
A050601	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations	Louisiana	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A05060100	59.61	2/17/2023	None	Bio-LNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations	None	
A050602	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	Louisiana	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A05060200	62.70	2/17/2023	None	Bio-LNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	None	
A050702	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations	Canada	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A05070200	51.26	2/24/2023	None	Bio-LNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations	None	
A050703	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	Canada	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A05070300	54.35	2/24/2023	None	Bio-LNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	None	
A027201	Tier 1	3.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI.	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A02720100	65.63	ETH009A02720101	65.00	10/21/2020	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI.	2021 AFPR Recert Complete	
B001801	Tier 2	3.0	Fuel Producer: BP Products North America, Inc (4320); Facility Name: Cherry Point Refinery (83736); U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA	Washington	(animal and poultry fat	Renewable Diesel (RND)	RND002B00180100	26.92	RND002B00180102	35.02	12/6/2019	None	Renewable Diesel	BP Products North America, Inc (4320)	Cherry Point Refinery (83736)	U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA	2021 AFPR Recert Complete	

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A010002	Tier 1	3.0	Fuel Producer: The Andersons, Inc (5872); Facility Name: The Andersons Denison Ethanol (70135); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01000200	67.48	ETH009A01000201	67.11	6/7/2019	None	Ethanol	The Andersons, Inc (5872)	The Andersons Denison Ethanol (70135)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	2021 AFPR Recert Complete	Retired
A011501	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	Texas	Wastewater Sludge (030	Compressed Natural Gas (CNG)	CNG030A01150100	37.33	CNG030A01150101	36.77	12/19/2019	None	Bio-CNG	Anew RNG, LLC (5877)	Ameresco San Antonio Biogas (71204)	Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	2021 AFPR Recert Complete	Retired
A013002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01300200	67.34	ETH009A01300201	65.09	9/24/2019	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A013901	Tier 1	3.0	Fuel Producer: Midwest Renewable Energy (5214); Facility Name: Midwest Renewable Energy (70160); Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A01390100	62.81	ETH009A01390102	65.76	9/9/2019	None	Ethanol	Midwest Renewable Energy (5214)	Midwest Renewable Energy (70160)	Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A014501	Tier 1	3.0	Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A01450100	69.60	ETH009A01450102	68.61	8/6/2019	None	Ethanol	Redfield Energy, LLC (4061)	Redfield Energy, LLC (70111)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A014601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	Michigan	Corn (009)	Ethanol (ETH)	ETH009A01460100	72.59	ETH009A01460101	72.29	9/24/2019	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	2021 AFPR Recert Complete	Retired
A014602	Tier 1	3.0	Fuel Producer: Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	Michigan	Corn (009)	Ethanol (ETH)	ETH009A01460200	67.10	ETH009A01460201	66.61	9/24/2019	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	2021 AFPR Recert Complete	Retired
A015001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01500100	74.83	ETH009A01500101	74.03	10/3/2019	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A015002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) ; Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01500200	68.05	ETH009A01500201	67.28	10/14/2019	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A015101	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01510100	74.44	ETH009A01510101	73.56	10/3/2019	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California	2021 AFPR Recert Complete	Retired
A015201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01520100	74.15	ETH009A01520101	72.75	10/3/2019	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A015202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01520200	67.32	ETH009A01520201	65.82	10/3/2019	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

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A015401	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional)	Kentucky	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01540100	54.66	CNG025A01540102	54.69	11/5/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional)	2021 AFPR Recert Complete	Retired
A015402	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional)	Kentucky	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A01540200	71.50	LNG025A01540202	72.09	11/5/2019	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional)	2021 AFPR Recert Complete	Retired
A015403	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional)	Kentucky	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A01540300	74.59	LCN025A01540302	75.18	11/5/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional)	2021 AFPR Recert Complete	Retired
A015102	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) ; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01510200	67.72	ETH009A01510201	66.14	10/3/2019	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A015501	Tier 1	3.0	Fuel Producer: Absolute Energy, LLC (5049) ; Facility Name: Absolute Energy, LLC (70144); Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01550100	67.97	ETH009A01550101	67.61	9/24/2019	None	Ethanol	Absolute Energy, LLC (5049)	Absolute Energy, LLC (70144)	Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI	2021 AFPR Recert Complete	
A016401	Tier 1	3.0	Fuel Producer: BUSHMILLS ETHANOL, INC. (4063); Facility Name: BUSHMILLS ETHANOL, INC. (70109); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI.		Corn (009)	Ethanol (ETH)	ETH009A01640100	67.23	ETH009A01640101	66.71	10/15/2019	None	Ethanol	BUSHMILLS ETHANOL, INC. (4063)	BUSHMILLS ETHANOL, INC. (70109)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI.	2021 AFPR Recert Complete	
B004701	Tier 2	3.0	Fuel Producer: Wyoming Renewable Diesel Company LLC (1440); Facility Name: Wyoming Renewable Diesel Company LLC (82441); Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California	Wyoming	Soybean Oil (005)	Renewable Diesel (RND)	RND005B00470100	58.34	RND005B00470102	57.20	12/27/2019	None	Renewable Diesel	Wyoming Renewable Diesel Company LLC (1440)	Wyoming Renewable Diesel Company LLC (82441)	Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California	2021 AFPR Recert Complete	
A019501	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060); Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01950100	43.37	CNG025A01950101	44.78	12/31/2019	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060)	Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	2021 AFPR Recert Complete	Retired
B005901	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00590101	-562.50	ELC026B00590102	-568.21	3/25/2021	None	Electricity	California Bioenergy LLC (B194)	ABEC Bidart-Old River LLC (F00113)	Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	2021 AFPR Recert Complete	Retired
B006001	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00600100	-255.74	CNG026B00600102	-237.77	2/24/2020	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Fair Oaks Upgrader, LLC (71001)	Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California	2021 AFPR Recert Complete	
A020901	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02090100	73.74	ETH009A02090102	72.71	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	
A020902	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02090200	70.47	ETH009A02090201	67.82	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	

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A020903	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02090300	66.86	ETH009A02090301	64.08	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	
B007201	Tier 2	3.0	Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180); Facility Name: WOF PNW Threemile Project (F00100); Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use	Oregon	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00720100	-188.78	CNG026B00720102	-171.65	9/30/2020	None	Bio-CNG	IOGEN D3 BIOFUEL PARTNERS II LLC (7180)	WOF PNW Threemile Project (F00100)	Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
A021202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California	Missouri	Corn (009)	Ethanol (ETH)	ETH009A02120200	65.67	ETH009A02120201	64.95	4/28/2020	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A021301	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02130100	61.55	ETH009A02130101	61.55	6/22/2020	None	Ethanol	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI	2021 AFPR Recert Complete	Retired
A021701	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	North Dakota	Corn (009)	Ethanol (ETH)	ETH009A02170100	69.84	ETH009A02170101	68.72	7/27/2020	None	Ethanol	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
A021702	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	North Dakota	Corn (009)	Ethanol (ETH)	ETH009A02170200	66.96	ETH009A02170201	65.89	7/27/2020	None	Ethanol	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
A021901	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc in Quebec, Canada; pipelined to California for compression to CNG	Canada	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02190100	38.64	CNG025A02190101	31.80	6/22/2020	None	Bio-CNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc in Quebec, Canada; pipelined to California for compression to CNG	2021 AFPR Recert Complete	
A021902	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stations by pipeline, liquefied in California	Canada	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02190200	51.69	LNG025A02190201	45.63	6/22/2020	None	Bio-LNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stations by pipeline, liquefied in California	2021 AFPR Recert Complete	
A021903	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	Canada	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02190300	54.77	LCN025A02190301	48.72	6/22/2020	None	Bio-LNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2021 AFPR Recert Complete	
A022401	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02240100	69.32	ETH009A02240102	73.00	6/24/2020	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A022402	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02240200	66.23	ETH009A02240202	68.00	6/24/2020	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
B010901	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01090100	-453.10	CNG026B01090102	-288.39	9/30/2020	None	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	

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B010902	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01090200	-308.48	CNG026B01090202	-278.19	9/30/2020	None	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B010903	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01090300	-236.96	CNG026B01090302	-247.83	9/30/2020	None	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B009601	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Dairy Dreams (F00127); Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00960100	-532.74	CNG026B00960102	-372.40	9/30/2020	None	Bio-CNG	Clean Energy (5481)	Calumet - Dairy Dreams (F00127)	Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B009701	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Ponderosa (F00128); Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00970100	-372.20	CNG026B00970101	-445.37	9/30/2020	None	Bio-CNG	Clean Energy (5481)	Calumet - Ponderosa (F00128)	Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B010202	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020200	-289.76	CNG026B01020201	-392.30	12/3/2020	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B010203	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020300	-308.74	CNG026B01020301	-399.36	12/3/2020	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
A023301	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional)	Kansas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02330100	45.91	CNG025A02330102	47.10	7/24/2020	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional)	2021 AFPR Recert Complete	Retired
B010801	Tier 2	3.0	Fuel Producer: AgPower Jerome, LLC (C1036); Facility Name: AgPower Jerome RNG Project (F00077); Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01080100	-230.13	CNG026B01080101	-240.91	9/30/2020	None	Bio-CNG	AgPower Jerome, LLC (C1036)	AgPower Jerome RNG Project (F00077)	Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
A026501	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: HUB CITY ENERGY LLC (70721); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02650100	73.16	ETH009A02650101	71.88	10/9/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	HUB CITY ENERGY LLC (70721)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI	2021 AFPR Recert Complete	
A024501	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02450100	69.92	ETH009A02450103	73.16	12/4/2020	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A024502	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02450200	62.54	ETH009A02450203	64.79	12/4/2020	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A024201	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02420100	47.53	CNG025A02420102	57.00	10/29/2020	None	Bio-CNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG	2021 AFPR Recert Complete	Retired

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A024601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	Ohio	Corn (009)	Ethanol (ETH)	ETH009A02460100	77.21	ETH009A02460101	76.22	12/29/2020	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A024602	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	Ohio	Corn (009)	Ethanol (ETH)	ETH009A02460200	69.47	ETH009A02460201	68.53	12/29/2020	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A024701	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02470100	49.78	CNG025A02470102	48.20	10/13/2020	None	Bio-CNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG	2021 AFPR Recert Complete	Retired
A024901	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02490100	74.54	ETH009A02490102	76.29	7/24/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	2021 AFPR Recert Complete	Retired
A024902	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02490200	67.28	ETH009A02490201	68.82	7/24/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	2021 AFPR Recert Complete	Retired
A026701	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02670100	35.51	CNG025A02670102	35.69	3/18/2021	None	Bio-CNG	Anew RNG, LLC (5877)	Johnstown Regional Energy - Raeger (71131)	Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG	2021 AFPR Recert Complete	
A026403	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02640300	60.28	CNG025A02640302	58.15	3/17/2021	None	Bio-CNG	Anew RNG, LLC (5877)	Johnstown Regional Energy - Southern Alleghenies (71133)	Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG	2021 AFPR Recert Complete	
A027401	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Renovar Arlington, LTD RNG Project (70501); Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional)	Texas	Wastewater Sludge (030	Compressed Natural Gas (CNG)	CNG030A02740100	38.37	CNG030A02740102	41.71	3/1/2021	None	Bio-CNG	U.S. Venture, Inc. (5504)	Renovar Arlington, LTD RNG Project (70501)	Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional)	2021 AFPR Recert Complete	Retired
B012701	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01270100	-417.35	CNG026B01270102	-419.62	12/31/2020	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B012702	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01270200	-417.27	CNG026B01270201	-420.14	12/31/2020	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B012703	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01270300	-418.90	CNG026B01270302	-420.70	12/31/2020	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B012704	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01270400	-392.44	CNG026B01270401	-410.41	12/31/2020	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	

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A029501	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02950100	21.93	BIO001A02950101	22.03	4/1/2021	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	2021 AFPR Recert Complete	Retired
A029502	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02950200	16.98	BIO001A02950201	16.71	4/1/2021	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	2021 AFPR Recert Complete	Retired
A029702	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Kansas	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02970200	61.43	LCN025A02970201	63.59	12/15/2020	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	2021 AFPR Recert Complete	Retired
A029801	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional)	Washington	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02980100	28.24	CNG025A02980101	28.80	3/12/2021	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional)	2021 AFPR Recert Complete	Retired
A029802	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Washington	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02980200	41.09	LNG025A02980201	42.58	3/12/2021	None	Bio-LNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	2021 AFPR Recert Complete	Retired
A029803	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Washington	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02980300	44.18	LCN025A02980301	45.67	3/12/2021	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	2021 AFPR Recert Complete	Retired
A030601	Tier 1	3.0	Fuel Producer: MONROEVILLE LFG, LLC (6317); Facility Name: MONROEVILLE LFG, LLC (71136); Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03060100	41.93	CNG025A03060101	42.85	4/6/2021	None	Bio-CNG	MONROEVILLE LFG, LLC (6317)	MONROEVILLE LFG, LLC (71136)	Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional)	2021 AFPR Recert Complete	Retired
B014301	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B01430100	-429.05	CNG044B01430101	-432.11	6/29/2021	None	Bio-CNG	Anew RNG, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations	2021 AFPR Recert Complete	Retired
A030902	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A03090200	71.95	ETH009A03090201	72.02	5/4/2021	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
B014901	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: South Meadows Farm (F00195); Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B01490100	-359.66	CNG044B01490101	-319.70	6/29/2021	None	Bio-CNG	Anew RNG, LLC (5877)	South Meadows Farm (F00195)	Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California	2021 AFPR Recert Complete	
B016501	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01650100	-406.35	CNG026B01650101	-392.30	9/30/2021	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use	2021 AFPR Recert Complete	
A033001	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03300100	73.75	ETH009A03300101	73.79	3/1/2021	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired

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B016301	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Hilarides (F00006); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California.	California	Dairy Manure (026)	Electricity (ELC)	ELC026B01630100	-758.46	ELC026B01630101	-756.24	6/21/2021	None	Electricity	CleanFuture, Inc. (C1001)	Hilarides (F00006)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California.	2021 AFPR Recert Complete	
B017301	Tier 2	3.0	Fuel Producer: DF-AP #1, LLC (C1122); Facility Name: Big Sky Dairy Digester (F00329); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California	Idaho	Dairy Manure (026)	Electricity (ELC)	ELC026B01730100	-545.71	ELC026B01730101	-548.10	9/22/2021	None	Electricity	DF-AP #1, LLC (C1122)	Big Sky Dairy Digester (F00329)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California	2021 AFPR Recert Complete	Retired
B017402	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	South Dakota	Corn (009)	Ethanol (ETH)	ETH009B01740200	68.73	ETH009B01740201	69.33	9/24/2021	None	Ethanol	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
B017401	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	South Dakota	Corn (009)	Ethanol (ETH)	ETH009B01740100	75.91	ETH009B01740101	76.65	9/24/2021	None	Ethanol	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
A034501	Tier 1	3.0	Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG.	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03450100	52.66	CNG025A03450101	53.05	6/16/2021	None	Bio-CNG	WESTSIDE GAS PRODUCERS, LLC (6218)	WESTSIDE GAS PRODUCERS, LLC (71151)	Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG.	2021 AFPR Recert Complete	Retired
A035101	Tier 1	3.0	Fuel Producer: E Energy Adams, LLC (4831); Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03510100	65.93	ETH009A03510101	67.49	6/1/2021	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional)	2021 AFPR Recert Complete	Retired
A036703	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional)	Tennessee	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A03670300	65.26	LCN025A03670301	66.26	5/11/2021	None	Bio-CNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional)	2021 AFPR Recert Complete	Retired
A036702	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional)	Tennessee	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A03670200	62.18	LNG025A03670201	63.18	5/11/2021	None	Bio-LNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional)	2021 AFPR Recert Complete	Retired
A037501	Tier 1	3.0	Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Seabreeze Energy Producers (70281); Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03750100	37.82	CNG025A03750101	38.37	8/20/2021	None	Bio-CNG	BLUE SOURCE LLC (6086)	Seabreeze Energy Producers (70281)	Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional)	2021 AFPR Recert Complete	Retired
B019101	Tier 2	3.0	Fuel Producer: California Renewable Power LLC(C196); Facility Name: California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270); Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles.	California	n Landscaping Waste (	Compressed Natural Gas (CNG)	CNG028B01910100	2.51	CNG028B01910101	72.26	6/29/2021	None	Bio-CNG	California Renewable Power LLC(C196)	California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270)	Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles.	2021 AFPR Recert Complete	
B021901	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: HOMAN FARM (71343); RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02190100	-412.71	CNG044B02190101	-359.22	9/30/2021	None	Bio-CNG	Anew RNG, LLC (5877)	HOMAN FARM (71343)	RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	Retired
A008801	Tier 1	3.0	Fuel Producer: Yuma Ethanol, LLC (4735) ; Facility Name: Yuma Ethanol, LLC (70024); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California	Colorado	Corn (009)	Ethanol (ETH)	ETH009A00880100	64.61	ETH009A00880101	64.00	5/17/2019	None	Ethanol	Yuma Ethanol, LLC (4735)	Yuma Ethanol, LLC (70024)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

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A019801	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A01980100	61.26	ETH009A01980103	62.37	6/24/2020	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI	2021 AFPR Recert Complete	Retired
A021302	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A02130200	21.31	ETH012A02130203	21.93	6/22/2020	None	Ethanol - Cellulosic	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
B007901	Tier 2	3.0	Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B00790100	30.48	RND002B00790103	34.32	9/30/2020	Application Package	Renewable Diesel	Kern Oil & Refining Co. (5038)	Kern Oil & Refining Co. (80105)	Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution	2021 AFPR Recert Complete	
B007902	Tier 2	3.0	Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B00790200	41.85	RND002B00790203	43.24	9/30/2020	Application Package	Renewable Diesel	Kern Oil & Refining Co. (5038)	Kern Oil & Refining Co. (80105)	Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution	2021 AFPR Recert Complete	
B010201	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020101	-408.62	CNG026B01020106	-403.57	12/3/2020	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
A025901	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Distillers' Corn Oil (003	Biodiesel (BIO)	BIO003A02590100	36.62	BIO003A02590102	37.49	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A025902	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Soybean Oil (005)	Biodiesel (BIO)	BIO003A02590100	36.62	BIO005A02590202	66.85	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A025903	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	(animal and poultry fat	Biodiesel (BIO)	BIO003A02590100	36.62	BIO002A02590302	42.58	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A029002	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	Illinois	Soybean Oil (005)	Biodiesel (BIO)	BIO005A02900200	57.00	BIO005A02900201	58.00	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	2021 AFPR Recert Complete	Retired
A029003	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	Illinois	Canola Oil (006)	Biodiesel (BIO)	BIO006A02900300	53.00	BIO006A02900301	54.50	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	2021 AFPR Recert Complete	
A029006	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	Illinois	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02900600	20.25	BIO001A02900601	22.00	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	2021 AFPR Recert Complete	Retired
A030401	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Point Loma Digester Gas Project (F00027); Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional)	California	Vastewater Sludge (030	Compressed Natural Gas (CNG)	CNG030A03040100	30.31	CNG030A03040102	38.91	6/14/2021	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Point Loma Digester Gas Project (F00027)	Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional)	2021 AFPR Recert Complete	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B018502	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01850200	-388.91	CNG026B01850201	-366.51	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
B018701	Tier 2	3.0	Fuel Producer: Dry Creek RNG LLC (C1098); Facility Name: Dry Creek RNG Project (F00342); Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional)	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01870100	-435.22	CNG026B01870101	-421.53		Application Package	Bio-CNG	Dry Creek RNG LLC (C1098)	Dry Creek RNG Project (F00342)	Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
B019801	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980100	-388.29	CNG026B01980101	-294.40	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
A039401	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California.	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03940100	66.71	ETH009A03940101	66.77	10/14/2021	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California.	2021 AFPR Recert Complete	Retired
B020702	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02070200	-211.01	CNG026B02070201	-193.95	12/29/2021	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional)	2021 AFPR Recert Complete	Retired
B020701	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02070100	-135.37	CNG026B02070101	-132.51	12/29/2021	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional)	2021 AFPR Recert Complete	Retired
A040201	Tier 1	3.0	Fuel Producer: Siouxland Ethanol, LLC (5026); Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A04020100	63.73	ETH009A04020101	63.80	10/11/2021	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	2021 AFPR Recert Complete	
B021601	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02160100	-382.83	CNG026B02160101	-333.34	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
B021603	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	LCN026B02160300	-366.02	LCN026B02160301	-315.22	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional)	2021 AFPR Recert Complete	Retired
B021602	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	LNG026B02160200	-369.56	LNG026B02160201	-318.76	3/30/2022	Application Package	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional)	2021 AFPR Recert Complete	Retired
B021702	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	LNG026B02170200	-290.16	LNG026B02170201	-259.30	3/30/2022	Application Package	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional)	2021 AFPR Recert Complete	Retired
B021703	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	LCN026B02170300	-286.62	LCN026B02170301	-255.76	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional)	2021 AFPR Recert Complete	Retired

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B021701	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02170100	-303.92	CNG026B02170101	-274.25	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
B022001	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: SOMERSET FARM (71381); Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02200101	-410.57	CNG044B02200102	-370.44	12/31/2021	Application Package	Bio-CNG	Anew RNG, LLC (5877)	SOMERSET FARM (71381)	Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
A041601	Tier 1	3.0	Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Greentree Landfill Gas Company (F00212); Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A04160100	66.18	CNG025A04160101	71.21	11/23/2021	None	Bio-CNG	TRUSTAR ENERGY LLC (6523)	Greentree Landfill Gas Company (F00212)	Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (Provisional)	2021 AFPR Recert Complete	Retired
A042301	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A04230100	70.88	ETH009A04230101	72.01	10/26/2021	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
A037803	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03780300	66.28	ETH010A03780301	66.40	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A037805	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (70039); Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03780500	73.81	ETH010A03780502	74.69	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (70039)	Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
B025106	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Diesel (RND)	RND002B02510600	42.48	RND002B02510601	47.48	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025112	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B02511200	42.48	RNT002B02511201	47.48	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B026802	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B02680200	18.87	RND002B02680201	18.93	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B026810	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B02681000	29.26	AJF002B02681001	29.78	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B026812	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B02681200	29.26	RNT002B02681201	29.78	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B026811	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B02681100	29.26	RND002B02681101	29.78	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2021 AFPR Recert Complete	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B026803	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B02680300	18.87	RNT002B02680301	18.93	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B026801	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B02680100	18.87	AJF002B02680101	18.93		Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B036901	Tier 2	3.0	Fuel Producer: MONTAUK ENERGY HOLDINGS, LLC (6139); Facility Name: Pico Energy, LLC (71221); Biogas from dairy manure at B2 Dairy, B6 Dairy, Crossbred Dairy in Jerome, ID, and B5 Dairy in Wendell, ID; upgraded to pipeline quality at Pico Energy, LLC, and pipeline to CA for transportation use. (Provisional)	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03690100	-260.56	3/27/2023	Application Package	Bio-CNG	MONTAUK ENERGY HOLDINGS, LLC (6139)	Pico Energy, LLC (71221)	Biogas from dairy manure at B2 Dairy, B6 Dairy, Crossbred Dairy in Jerome, ID, and B5 Dairy in Wendell, ID; upgraded to pipeline quality at Pico Energy, LLC, and pipeline to CA for transportation use. (Provisional)	None	
A048801	Tier 1	3.0	Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional)	Kansas	Corn (009)	Ethanol (ETH)	None	None	ETH009A04880100	62.50	3/14/2023	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional)	None	
A048802	Tier 1	3.0	Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Midwest Grain Sorghum, Dry Mill; Wet DGS, Grain Sorghum oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A04880200	65.50	3/14/2023	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Grain Sorghum, Dry Mill; Wet DGS, Grain Sorghum oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional)	None	
A048803	Tier 1	3.0	Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Midwest Corn, Dry Mill; Fiber ethanol, Edeniq Fiber Conversion Protocol; Natural Gas, Grid Electricity, Zero-CI Electrcity; Starch Ethanol produced in Oakley,KS; Ethanol transported by rail to California (Provisional)	Kansas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04880300	24.50	3/14/2023	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Corn, Dry Mill; Fiber ethanol, Edeniq Fiber Conversion Protocol; Natural Gas, Grid Electricity, Zero-CI Electrcity; Starch Ethanol produced in Oakley,KS; Ethanol transported by rail to California (Provisional)	None	
B038201	Tier 2	3.0	Fuel Producer: Madera Renewable Energy, LLC (C1140); Facility Name: Madera Renewable Energy, LLC (F00436); Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B03820100	-758.40	3/28/2023	Application Package	Electricity	Madera Renewable Energy, LLC (C1140)	Madera Renewable Energy, LLC (F00436)	Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California. (Provisional)	None	Retired
B039301	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY CLOVER HILL (71261); Biogas from Dairy Manure at Clover Hill Dairy in Campbellsport, WI; upgraded to pipeline quality at US Gain RNG Facility Clover Hill; pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03930100	-204.42	3/30/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	U.S. GAIN RNG FACILITY CLOVER HILL (71261)	Biogas from Dairy Manure at Clover Hill Dairy in Campbellsport, WI; upgraded to pipeline quality at US Gain RNG Facility Clover Hill; pipelined to California for transportation use (Provisional)	None	
B040101	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: YELLOW JACKET SWISS VALLEY RNG PROJECT (71161); Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (Provisional)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04010100	-216.27	3/30/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET SWISS VALLEY RNG PROJECT (71161)	Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (Provisional)	None	Retired
B040401	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: AUGEAN RNG PROJECT (71081); Biogas from dairy manure at Augean RNG project, Outlook, WA; upgraded to pipeline quality at Augean RNG Project; currently trucked to pipeline injection and pipelined to CA for transportation use. (Provisional)	Washington	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04040100	-216.63	3/28/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	AUGEAN RNG PROJECT (71081)	Biogas from dairy manure at Augean RNG project, Outlook, WA; upgraded to pipeline quality at Augean RNG Project; currently trucked to pipeline injection and pipelined to CA for transportation use. (Provisional)	None	
B042001	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: RIALTO Bioenergy (F00475); Bio-CNG from landfill-diverted food scraps sourced from multiple materials recovery facilities and upgraded at RIALTO Bioenergy facility in Bloomington, CA; Bio-CNG injected into California natural gas pipeline for transportation use (Provisional)	California	ood Scraps/Waste (02	Compressed Natural Gas (CNG)	None	None	CNG027B04200100	-28.20	3/22/2023	Application Package	Bio-CNG	Anew RNG, LLC (5877)	RIALTO Bioenergy (F00475)	Bio-CNG from landfill-diverted food scraps sourced from multiple materials recovery facilities and upgraded at RIALTO Bioenergy facility in Bloomington, CA; Bio-CNG injected into California natural gas pipeline for transportation use (Provisional)	None	
B042801	Tier 2	3.0	Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	Mississippi	Distillers' Corn Oil (003	Renewable Diesel (RND)	RND003A02710100	78.60	RND003B04280100	51.80	3/30/2023	Application Package	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	None	Retired

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B042802	Tier 2	3.0	Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	Mississippi	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04280200	80.81	3/30/2023	Application Package	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	None	Retired
A049701	Tier 1	3.0	Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Midwest Soybean Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	Canada	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A04970100	59.69	4/21/2023	None	Biodiesel	Canary Biofuels Inc. (1773)	Canary 1 (F00502)	Midwest Soybean Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	None	
A049702	Tier 1	3.0	Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Canola Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	Canada	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A04970200	54.45	4/21/2023	None	Biodiesel	Canary Biofuels Inc. (1773)	Canary 1 (F00502)	Canola Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	None	
A049703	Tier 1	3.0	Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Corn Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	Canada	Distillers' Corn Oil (003	Biodiesel (BIO)	None	None	BIO003A04970300	29.99	4/21/2023	None	Biodiesel	Canary Biofuels Inc. (1773)	Canary 1 (F00502)	Corn Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	None	
A049704	Tier 1	3.0	Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Rendered Animal Fat Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	Canada	(animal and poultry fat	Biodiesel (BIO)	None	None	BIO002A04970400	34.62	4/21/2023	None	Biodiesel	Canary Biofuels Inc. (1773)	Canary 1 (F00502)	Rendered Animal Fat Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	None	
A049705	Tier 1	3.0	Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Used Cooking Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	Canada	oking Oil/Waste Oil (UC	Biodiesel (BIO)	None	None	BIO001A04970500	22.66	4/21/2023	None	Biodiesel	Canary Biofuels Inc. (1773)	Canary 1 (F00502)	Used Cooking Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	None	
A051201	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A02940201	62.64	ETH009A05120100	63.80	5/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	None	Retired
A051202	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A02940101	71.64	ETH009A05120200	72.75	5/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	None	Retired
A051203	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715) ; Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A02940401	65.71	ETH010A05120300	65.71	5/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	None	Retired
A051204	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A02940301	74.71	ETH010A05120400	74.66	5/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	None	Retired
A005101	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00510100	69.86	ETH009A00510102	70.77	5/7/2019	None	Ethanol	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005102	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00510200	30.32	ETH012A00510202	30.54	5/7/2019	None	Ethanol - Cellulosic	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

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A049601	Tier 1	3.0	Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Fiber ethanol Edeniq 2.0; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center. AI ; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04960100	23.77	4/26/2023	None	Ethanol - Cellulosic	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Midwest Corn, Dry Mill; Fiber ethanol Edeniq 2.0; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center. AI ; Ethanol transported by rail to California (Provisional)	None	
A049602	Tier 1	3.0	Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center, IA ; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04960200	63.19	4/26/2023	None	Ethanol	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center, IA ; Ethanol transported by rail to California (Provisional)	None	
A020001	Tier 1	3.0	Fuel Producer: GHI Energy, LLC (6156); Facility Name: Waste Management American Landfill (70421); Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02000100	40.13	CNG025A02000101	37.64	6/29/2020	None	Bio-CNG	GHI Energy, LLC (6156)	Waste Management American Landfill (70421)	Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional)	2021 AFPR Recert Complete	Retired
B025104	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Diesel (RND)	RND001B02510400	18.16	RND001B02510401	17.92	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025101	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Soybean Oil (005)	Renewable Diesel (RND)	RND005B02510100	60.13	RND005B02510101	57.13	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025107	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Soybean Oil (005)	Renewable Naphtha (RNT)	RNT005B02510700	60.13	RNT005B02510701	57.13	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025109	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Naphtha (RNT)	RNT001B02510900	19.75	RNT001B02510901	19.77	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025108	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Distillers' Corn Oil (003	Renewable Naphtha (RNT)	RNT003B02510800	27.64	RNT003B02510801	28.00	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025110	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Naphtha (RNT)	RNT001B02511000	18.16	RNT001B02511001	17.92	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025111	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B02511100	32.14	RNT002B02511101	33.08	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025102	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge.	Louisiana	Distillers' Corn Oil (003	Renewable Diesel (RND)	RND003B02510200	27.64	RND003B02510201	28.00	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge.	2021 AFPR Recert Complete	
B025103	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge.	Louisiana	oking Oil/Waste Oil (UC	Renewable Diesel (RND)	RND001B02510300	19.75	RND001B02510301	19.77	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge.	2021 AFPR Recert Complete	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B025105	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Diesel (RND)	RND002B02510500	32.14	RND002B02510501	33.08	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
A038602	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A03860200	69.20	ETH009A03860201	69.61	7/13/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
A038601	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A03860100	72.20	ETH009A03860101	72.76	7/13/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
A050201	Tier 1	3.0	Fuel Producer: Plymouth Energy LLC (5474) ; Facility Name: Plymouth Energy LLC (70183); Midwest Corn, Dry Mill; Dry and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Merrill, Iowa and transported by Rail to California; Composite CI (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01250200	68.41	ETH009A05020100	63.91	5/18/2023	None	Ethanol	Plymouth Energy LLC (5474)	Plymouth Energy LLC (70183)	Midwest Corn, Dry Mill; Dry and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Merrill, Iowa and transported by Rail to California; Composite CI (Provisional)	None	
L021101	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade Inc (F00567); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC049L00072019	0.00	2/17/2023	None	Electricity	SRECTrade, Inc (C1018)	SRECTrade Inc (F00567)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California	None	
A051801	Tier 1	3.0	Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180) ; Facility Name: ResilientIG Threemile Acquisition LLC (F00100); Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to CA and regasifed for use as LCNG	Oregon	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN026A05180100	-156.47	5/26/2023	None	Bio-LNG	IOGEN D3 BIOFUEL PARTNERS II LLC (7180)	ResilientIG Threemile Acquisition LLC (F00100)	Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to CA and regasifed for use as LCNG	None	
A051802	Tier 1	3.0	Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180) ; Facility Name: ResilientIG Threemile Acquisition LLC (F00100); Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC ; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to California for use as LNG	Oregon	Dairy Manure (026)	Liquefied Natural Gas (LNG)	None	None	LNG026A05180200	-152.93	5/26/2023	None	Bio-LNG	IOGEN D3 BIOFUEL PARTNERS II LLC (7180)	ResilientIG Threemile Acquisition LLC (F00100)	Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC ; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to California for use as LNG	None	
A005301	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786); Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00530100	73.81	ETH009A00530103	72.85	5/6/2019	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005302	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00530200	66.94	ETH009A00530203	65.95	5/6/2019	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005303	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00530300	26.95	ETH012A00530303	25.98	5/6/2019	None	Ethanol - Cellulosic	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005201	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00520100	75.97	ETH009A00520103	74.36	5/6/2019	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005202	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00520200	68.75	ETH009A00520203	66.04	5/6/2019	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

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A005203	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00520300	28.78	ETH012A00520303	26.29	5/6/2019	None	Ethanol - Cellulosic	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A006101	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00610100	76.85	ETH009A00610102	75.21	6/5/2019	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A006102	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00610200	69.76	ETH009A00610202	65.67	6/5/2019	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A006103	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00610300	29.51	ETH012A00610302	26.04	6/5/2019	None	Ethanol - Cellulosic	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A012701	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A01270100	28.33	ETH012A01270103	28.29	9/24/2019	None	Ethanol - Cellulosic	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A012702	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01270200	75.89	ETH009A01270203	77.34	9/24/2019	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A012703	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01270300	67.79	ETH009A01270303	68.22	9/24/2019	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005601	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00560100	74.83	ETH009A00560102	73.89	6/10/2019	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005602	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00560200	68.44	ETH009A00560202	67.49	6/10/2019	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005603	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00560300	28.47	ETH012A00560302	28.27	6/10/2019	None	Ethanol - Cellulosic	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005801	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00580100	81.17	ETH009A00580102	73.74	5/7/2019	None	Ethanol	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005802	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00580200	71.82	ETH009A00580202	68.00	5/7/2019	None	Ethanol	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A005803	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00580300	31.75	ETH012A00580302	28.21	5/7/2019	None	Ethanol - Cellulosic	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A006401	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00640100	75.04	ETH009A00640102	72.37	5/7/2019	None	Ethanol	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A006403	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00640300	27.72	ETH012A00640302	24.60	5/7/2019	None	Ethanol - Cellulosic	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A013501	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A01350100	32.07	BIO002A01350102	31.65	12/20/2019	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	2021 AFPR Recert Complete	Retired
A014101	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	Missouri	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003A01410100	29.40	BIO003A01410102	27.16	9/25/2019	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441)	Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	2021 AFPR Recert Complete	Retired
A014102	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	Missouri	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A01410200	34.21	BIO002A01410202	32.08	9/25/2019	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441)	Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	2021 AFPR Recert Complete	Retired
A028201	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A02820100	27.02	BIO002A02820102	24.60	11/20/2020	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail	2021 AFPR Recert Complete	Retired
A027901	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	Arkansas	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003A02790100	33.97	BIO003A02790101	33.53	3/9/2021	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A027902	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	Arkansas	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02790200	27.05	BIO001A02790202	26.13	3/9/2021	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
B028001	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	California	Swine Manure (044)	Gaseous Hydrogen (HYG)	HYG044B02800100	-374.14	HYG044B02800101	-296.05	6/7/2023	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	None	
B028002	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	California	Swine Manure (044)	Gaseous Hydrogen (HYG)	HYG044B02800200	-390.47	HYG044B02800201	-368.94	6/7/2023	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	None	
B037802	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	HYG025B03780200	75.16	HYG025B03780201	99.94	6/7/2023	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	None	

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A023201	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Renovar Arlington, LTD RNG Project (70501); Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG.	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02320100	43.15	CNG025A02320101	42.66	7/24/2020	None	Bio-CNG	U.S. Venture, Inc. (5504)	Renovar Arlington, LTD RNG Project (70501)	Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG.	2021 AFPR Recert Complete	
B038301	Tier 2	3.0	Fuel Producer: EEC MARKET GROUP LLC (6496); Facility Name: NLC Energy Denmark LLC (70242); Biogas from dairy manure at Rolling Hills I, Rolling Hills II, Leiterman, Barta, Heim's Hillcrest, Branch View, and D&D in WI; upgraded to pipeline quality at NLC Energy Denmark LLC; pipelined to CA for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03830100	-284.21	6/22/2023	Application Package	Bio-CNG	EEC MARKET GROUP LLC (6496)	NLC Energy Denmark LLC (70242)	Biogas from dairy manure at Rolling Hills I, Rolling Hills II, Leiterman, Barta, Heim's Hillcrest, Branch View, and D&D in WI; upgraded to pipeline quality at NLC Energy Denmark LLC; pipelined to CA for transportation use (Provisional)	None	
B042603	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Hydrogen produced at Linde-Praxair SMR using North American Fossil Natural Gas; finished fuel transported as gaseous Hydrogen in tube-trailers to refueling stations in California.	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031B04260300	142.27	6/23/2023	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Hydrogen produced at Linde-Praxair SMR using North American Fossil Natural Gas; finished fuel transported as gaseous Hydrogen in tube-trailers to refueling stations in California.	None	
A050801	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Eugene/Springfield Water Pollution Control Facility (F00546); RNG produced from the mesophillic anaerobic digestion of wastewater sludge at the MWMC Regional Wastewater Treatment Plant using grid-based electricity, NG; CNG transported via pipeline; dispensed at refueling stations in California. (Provisional)	Oregon	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A05080100	34.26	6/23/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Eugene/Springfield Water Pollution Control Facility (F00546)	RNG produced from the mesophillic anaerobic digestion of wastewater sludge at the MWMC Regional Wastewater Treatment Plant using grid-based electricity, NG; CNG transported via pipeline; dispensed at refueling stations in California. (Provisional)	None	
B041601	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Canola Oil (006)	Renewable Diesel (RND)	RND005B02400200	57.64	RND006B04160100	51.93	6/28/2023	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041602	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional)	North Dakota	Distillers' Corn Oil (003)	Renewable Diesel (RND)	RND003B02400100	29.79	RND003B04160200	29.65	6/28/2023	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional)	None	
B041603	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313; U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02400301	33.43	RND002B04160300	32.91	6/28/2023	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313	U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041604	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Soybean Oil (005)	Renewable Diesel (RND)	RND005B02400200	57.64	RND005B04160400	57.25	6/28/2023	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041605	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RND001B02400800	21.09	RND001B04160500	20.19	6/28/2023	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041606	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Canola Oil (006)	Renewable Naphtha (RNT)	None	None	RNT006B04160600	51.93	6/28/2023	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041607	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional)	North Dakota	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	RNT003B02400400	29.79	RNT003B04160700	29.65	6/28/2023	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional)	None	
B041608	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02400701	33.43	RNT002B04160800	32.91	6/28/2023	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	

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B041609	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Soybean Oil (005)	Renewable Naphtha (RNT)	RNT005B02400500	57.64	RNT005B04160900	57.25	6/28/2023	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Facility Name: Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041610	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	RNT001B02400600	21.09	RNT001B04161000	20.19	6/28/2023	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041701	Tier 2	3.0	Fuel Producer: WYNNEWOOD REFINING COMPANY, LLC (4148); Facility Name: WYNNEWOOD REFINING COMPANY (82420); Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	Oklahoma	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04170100	67.05	6/28/2023	Application Package	Renewable Diesel	WYNNEWOOD REFINING COMPANY, LLC (4148)	WYNNEWOOD REFINING COMPANY (82420)	Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	None	
B041702	Tier 2	3.0	Fuel Producer: WYNNEWOOD REFINING COMPANY, LLC (4148); Facility Name: WYNNEWOOD REFINING COMPANY (82420); Midwest Sourced Corn Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	Oklahoma	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B04170200	37.82	6/28/2023	Application Package	Renewable Diesel	WYNNEWOOD REFINING COMPANY, LLC (4148)	WYNNEWOOD REFINING COMPANY (82420)	Midwest Sourced Corn Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	None	
B042101	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	Louisiana	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04210100	61.50	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B042102	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B04210200	32.50	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042103	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04210300	26.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042104	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04210400	20.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042105	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04210500	26.50	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042106	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04210600	31.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042107	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04210700	37.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042108	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04210800	39.50	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B042109	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04210900	48.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042110	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04211000	24.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	None	
B042111	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	Louisiana	Soybean Oil (005)	Renewable Naphtha (RNT)	None	None	RNT005B04211100	62.00	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B042112	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	None	None	RNT003B04211200	33.00	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042113	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B04211300	26.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042114	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B04211400	20.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042115	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B04211500	27.00	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042116	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B04211600	31.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042117	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B04211700	37.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042118	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B04211800	40.00	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042119	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B04211900	48.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042120	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B04212000	24.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	None	

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B042121	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212100	62.00	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B042122	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212200	33.00	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042123	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212300	26.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042124	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212400	20.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042125	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212500	27.00	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042126	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212600	31.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042127	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212700	37.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042128	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212800	40.00	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042129	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212900	48.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042130	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04213000	24.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	None	
B042131	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	Louisiana	Soybean Oil (005)	Alternative Jet Fuel (AJF)	None	None	AJF005B04213100	62.00	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B042132	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Distillers' Corn Oil (003)	Alternative Jet Fuel (AJF)	None	None	AJF003B04213200	33.00	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	

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B042133	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04213300	26.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042134	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04213400	20.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042135	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04213500	27.00	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042136	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04213600	31.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042137	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04213700	37.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042138	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04213800	40.00	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042139	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04213900	48.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042140	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04214000	24.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	None	
B043001	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04300100	-236.90	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	None	
B043002	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04300200	-243.54	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	None	
B043003	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility using Biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04300300	-132.07	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility using Biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	None	
B043004	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tube-trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300400	-275.67	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tube-trailers to refueling stations in California. (Provisional)	None	

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B043005	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR using Biomethane procured from at Yellow Jacket Lakeshore RNG Project, Wilson, NY; finished fuel transported in tube-trailers to Hydrogen refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300500	-282.30	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR using Biomethane procured from at Yellow Jacket Lakeshore RNG Project, Wilson, NY; finished fuel transported in tube-trailers to Hydrogen refueling stations in California. (Provisional)	None	
B043006	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; transported in tube-trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300600	-170.83	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; transported in tube-trailers to refueling stations in California. (Provisional)	None	
B043007	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300700	-221.27	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	None	
B043008	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lakeshore RNG Project, Wilson, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300800	-227.91	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lakeshore RNG Project, Wilson, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	None	
B043009	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA; biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300900	-116.43	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, CA; biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	None	
B039401	Tier 2	3.0	Fuel Producer: Chevron Products Company (5086) ; Facility Name: Chevron El Segundo (01013); Soybean oil transported by rail to California; natural gas, steam, grid electricity and hydrogen; renewable diesel produced from co-processing soybean oil with fossil feedstock in a diesel hydrotreater (VGO unit) in El Segundo, California (PROV3.0)	California	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B03940100	51.74	6/30/2023	Application Package	Renewable Diesel	Chevron Products Company (5086)	Chevron El Segundo (01013)	Soybean oil transported by rail to California; natural gas, steam, grid electricity and hydrogen; renewable diesel produced from co-processing soybean oil with fossil feedstock in a diesel hydrotreater (VGO unit) in El Segundo, California (Provisional)	None	
B039601	Tier 2	3.0	Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at Lone Oak #1 Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use. (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03960100	-411.32	6/30/2023	Application Package	Bio-CNG	Lakeside Pipeline, LLC (C1158)	Lakeside Pipeline, LLC (F00480)	Biogas from dairy manure at Lone Oak #1 Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use. (Provisional)	None	
B039602	Tier 2	3.0	Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at Dixie Creek Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California For transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03960200	-416.41	6/30/2023	Application Package	Bio-CNG	Lakeside Pipeline, LLC (C1158)	Lakeside Pipeline, LLC (F00480)	Biogas from dairy manure at Dixie Creek Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California For transportation use (Provisional)	None	
B039603	Tier 2	3.0	Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at River Ranch Dairy In Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use. (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03960300	-417.71	6/30/2023	Application Package	Bio-CNG	Lakeside Pipeline, LLC (C1158)	Lakeside Pipeline, LLC (F00480)	Biogas from dairy manure at River Ranch Dairy In Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use. (Provisional)	None	
B039604	Tier 2	3.0	Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at Decade Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03960400	-418.87	6/30/2023	Application Package	Bio-CNG	Lakeside Pipeline, LLC (C1158)	Lakeside Pipeline, LLC (F00480)	Biogas from dairy manure at Decade Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use (Provisional)	None	
B040301	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from dairy manure at Belonave Biogas LLC in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC; pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04030100	-419.40	6/30/2023	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from dairy manure at Belonave Biogas LLC in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC; pipelined to California for transportation use (Provisional)	None	
A050101	Tier 1	3.0	Fuel Producer: BIOENERGETICA VALE DO PARACATU SA (1431); Facility Name: BIOENERGETICA VALE DO PARACATU SA (71521); Ethanol produced from sugarcane juice and molasses in Minas Gerais (Brazil); co-product credit for export of surplus cogenerated electricity; ethanol transported to California by Ocean tanker via Cape Horn; distributed to refueling stations by truck. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A05010100	50.89	7/3/2023	None	Ethanol	BIOENERGETICA VALE DO PARACATU SA (1431)	BIOENERGETICA VALE DO PARACATU SA (71521)	Ethanol produced from sugarcane juice and molasses in Minas Gerais (Brazil); co-product credit for export of surplus cogenerated electricity; ethanol transported to California by Ocean tanker via Cape Horn; distributed to refueling stations by truck.	None	

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B043801	Tier 2	3.0	Fuel Producer: Lone Oak Energy, LLC (C1177); Facility Name: Lone Oak Energy, LLC (F00542); Biogas from dairy manure at Lone Oak Farms #2 in Fresno, CA; upgraded to pipeline quality at Lone Oak Energy, LLC, trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04380100	-404.74	6/30/2023	Application Package	Bio-CNG	Lone Oak Energy, LLC (C1177)	Lone Oak Energy, LLC (F00542)	Biogas from dairy manure at Lone Oak Farms #2 in Fresno, CA; upgraded to pipeline quality at Lone Oak Energy, LLC, trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	
B045001	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: DEMETER RNG PROJECT (71302); Biogas from dairy manure at Endres Dairy, Maiers White Gold, Ripps Dairy Valley, Endres Berry Ridge, and Wagner Dairy in WI; upgraded to pipeline quality at DEMETER RNG PROJECT; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04500100	-191.29	6/30/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	DEMETER RNG PROJECT (71302)	Biogas from dairy manure at Endres Dairy, Maiers White Gold, Ripps Dairy Valley, Endres Berry Ridge, and Wagner Dairy in WI; upgraded to pipeline quality at DEMETER RNG PROJECT; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	
B046701	Tier 2	3.0	Fuel Producer: Lime (C1014); Facility Name: Lime Headquarters (F00036); Electricity from zero-CI sources used to power Lime's battery-electric scooters and bicycles in California. (3.0)	California	Solar (033)	Electricity (ELC)	None	None	ELC033B04670100	80.29	8/1/2023	Application Package	Electricity	Lime (C1014)	Lime Headquarters (F00036)	Electricity from zero-CI sources used to power Lime's battery-electric scooters and bicycles in California.	None	
L021801	Lookup Table	3.0	Fuel Producer: Swift Transportation Company of Arizona, LLC (C1230) ; Facility Name: Swift Transportation Co. of Arizona, LLC. (F00642); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	7/7/2023	None	Electricity	Swift Transportation Company of Arizona, LLC (C1230)	Swift Transportation Co. of Arizona, LLC. (F00642)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L021901	Lookup Table	3.0	Fuel Producer: Prologis Mobility (C1234); Facility Name: Prologis Mobility LLC (F00637); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	7/20/2023	None	Electricity	Prologis Mobility (C1234)	Prologis Mobility LLC (F00637)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L022001	Lookup Table	3.0	Fuel Producer: TeraWatt Infrastructure, Inc. (C1240); Facility Name: TeraWatt Infrastructure, Inc. (F00650); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/14/2023	None	Electricity	TeraWatt Infrastructure, Inc. (C1240)	TeraWatt Infrastructure, Inc. (F00650)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
B042201	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Five H in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220100	-416.31	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Five H in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
B042202	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Red Rock in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220200	-429.59	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Red Rock in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
B042203	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Vista Verde in Chowchilla, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220300	-249.95	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Vista Verde in Chowchilla, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
B042204	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Vander Woude in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220400	-260.14	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Vander Woude in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
B042205	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Rockshar in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220500	-411.49	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Rockshar in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
B042206	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Michael De Hoog in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220600	-418.96	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Michael De Hoog in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	

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B042207	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Double Diamond in El Nido, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220700	-328.54	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Double Diamond in El Nido, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
A051001	Tier 1	3.0	Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: NOBLE ROAD RNG LLC (72142); Biomethane from Noble Road Landfill in Shiloh, OH; upgrading at Noble Road RNG LLC, pipelined to California for compression to CNG (PROV3.0)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A05100100	48.84	8/31/2023	None	Bio-CNG	TRUSTAR ENERGY LLC (6523)	NOBLE ROAD RNG LLC (72142)	Biomethane from Noble Road Landfill in Shiloh, OH; upgrading at Noble Road RNG LLC, pipelined to California for compression to CNG (Provisional)	None	
B047701	Tier 2	3.0	Fuel Producer: Cheyenne Renewable Diesel Company LLC (1647); Facility Name: Cheyenne Renewable Diesel Company LLC (F00494); Renewable Diesel produced from Soybean Oil pre-treated in Artesia, NM and transported by rail and truck to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (PROV3.0)	Wyoming	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04770100	69.78	9/28/2023	Application Package	Renewable Diesel	Cheyenne Renewable Diesel Company LLC (1647)	Cheyenne Renewable Diesel Company LLC (F00494)	Renewable Diesel produced from Soybean Oil pre-treated in Artesia, NM and transported by rail and truck to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (Provisional)	None	
B047702	Tier 2	3.0	Fuel Producer: Cheyenne Renewable Diesel Company LLC (1647); Facility Name: Cheyenne Renewable Diesel Company LLC (F00494); Renewable Diesel produced from Soybean Oil transported by rail to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (PROV3.0)	Wyoming	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04770200	69.41	9/28/2023	Application Package	Renewable Diesel	Cheyenne Renewable Diesel Company LLC (1647)	Cheyenne Renewable Diesel Company LLC (F00494)	Renewable Diesel produced from Soybean Oil transported by rail to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (Provisional)	None	
B047703	Tier 2	3.0	Fuel Producer: Cheyenne Renewable Diesel Company LLC (1647); Facility Name: Cheyenne Renewable Diesel Company LLC (F00494); Renewable Diesel produced from U.S. sourced tallow transported to Cheyenne, WY by truck and rail; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (PROV3.0)	Wyoming	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04770300	44.56	9/28/2023	Application Package	Renewable Diesel	Cheyenne Renewable Diesel Company LLC (1647)	Cheyenne Renewable Diesel Company LLC (F00494)	Renewable Diesel produced from U.S. sourced tallow transported to Cheyenne, WY by truck and rail; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (Provisional)	None	
L022201	Lookup Table	3.0	Fuel Producer: VERDANT ENERGY SERVICES LLC (C1048) ; Facility Name: Verdant Energy Services 0CI (F00661); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/26/2023	None	Electricity	VERDANT ENERGY SERVICES LLC (C1048)	Verdant Energy Services 0CI (F00661)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L022101	Lookup Table	3.0	Fuel Producer: Republic Services Procurement, Inc. (C1239); Facility Name: Republic Services Procurement, Inc. (F00660); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/22/2023	None	Electricity	Republic Services Procurement, Inc. (C1239)	Republic Services Procurement, Inc. (F00660)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L022601	Lookup Table	3.0	Fuel Producer: Neutron Holdings, Inc. (dba Lime) (C1014); Facility Name: Neutron Holdings, Inc. (dba Lime) (F00036); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/28/2023	None	Electricity	Neutron Holdings, Inc. (dba Lime) (C1014)	Neutron Holdings, Inc. (dba Lime) (F00036)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
B044901	Tier 2	3.0	Fuel Producer: USL Parallel Products of California (4018); Facility Name: USL Parallel Products of California (70122); Ethanol from spoiled beverages produced by USL Parallel Products of California in Rancho Cucamonga, CA; ethanol blended in California for transportation use. (3.0)	California	Any Sugar Feedstock (040)	Ethanol (ETH)	ETHWB201	69.82	ETH040B04490100	126.33	10/2/2023	Application Package	Ethanol	USL Parallel Products of California (4018)	USL Parallel Products of California (70122)	Ethanol from spoiled beverages produced by USL Parallel Products of California in Rancho Cucamonga, CA; ethanol blended in California for transportation use.	None	
A051601	Tier 1	3.0	Fuel Producer: Granite Falls Energy, LLC (4769); Facility Name: Granite Falls Energy, LLC (70071); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (PROV3.0)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05160100	70.52	10/18/2023	None	Ethanol	Granite Falls Energy, LLC (4769)	Granite Falls Energy, LLC (70071)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (Provisional)	None	
A051602	Tier 1	3.0	Fuel Producer: Granite Falls Energy, LLC (4769); Facility Name: Granite Falls Energy, LLC (70071); Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (PROV3.0)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05160200	69.50	10/18/2023	None	Ethanol	Granite Falls Energy, LLC (4769)	Granite Falls Energy, LLC (70071)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (Provisional)	None	
A051603	Tier 1	3.0	Fuel Producer: Granite Falls Energy, LLC (4769); Facility Name: Granite Falls Energy, LLC (70071); Midwest Corn, Dry Mill; Fiber ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (PROV3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05160300	23.39	10/18/2023	None	Ethanol - Cellulosic	Granite Falls Energy, LLC (4769)	Granite Falls Energy, LLC (70071)	Midwest Corn, Dry Mill; Fiber ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (Provisional)	None	

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A052901	Tier 1	3.0	Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70150); Midwest Corn, Dry Mill; Corn Fiber Ethanol using the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05290100	41.63	10/10/2023	None	Ethanol - Cellulosic	Chief Ethanol Fuels, Inc (5110)	CHIEF ETHANOL FUELS INC (70150)	Midwest Corn, Dry Mill; Corn Fiber Ethanol using the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (Provisional)	None	
A052902	Tier 1	3.0	Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70150); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A05290200	80.80	10/10/2023	None	Ethanol	Chief Ethanol Fuels, Inc (5110)	CHIEF ETHANOL FUELS INC (70150)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (Provisional)	None	
A052903	Tier 1	3.0	Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70150); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A05290300	100.10	10/10/2023	None	Ethanol	Chief Ethanol Fuels, Inc (5110)	CHIEF ETHANOL FUELS INC (70150)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (Provisional)	None	
A051901	Tier 1	3.0	Fuel Producer: Heron Lake BioEnergy (4015); Facility Name: Heron Lake BioEnergy (70097); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (PROV3.0)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05190100	72.01	10/18/2023	None	Ethanol	Heron Lake BioEnergy (4015)	Heron Lake BioEnergy (70097)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (Provisional)	None	
A051902	Tier 1	3.0	Fuel Producer: Heron Lake BioEnergy (4015); Facility Name: Heron Lake BioEnergy (70097); Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (PROV3.0)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05190200	70.62	10/18/2023	None	Ethanol	Heron Lake BioEnergy (4015)	Heron Lake BioEnergy (70097)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (Provisional)	None	
A051903	Tier 1	3.0	Fuel Producer: Heron Lake BioEnergy (4015); Facility Name: Heron Lake BioEnergy (70097); Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Heron Lake, Minnesota, and transported by Rail to California. (PROV3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05190300	27.90	10/18/2023	None	Ethanol - Cellulosic	Heron Lake BioEnergy (4015)	Heron Lake BioEnergy (70097)	Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Heron Lake, Minnesota, and transported by Rail to California. (Provisional)	None	
A052001	Tier 1	3.0	Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70241); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00380100	77.4	ETH009A05200100	77.86	10/30/2023	None	Ethanol	Chief Ethanol Fuels, Inc (5110)	CHIEF ETHANOL FUELS INC (70241)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by Rail to California. (Provisional)	None	
A052002	Tier 1	3.0	Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70241); Midwest Corn, Dry Mill; Corn Kernel Fiber Ethanol produced by the EDENIQ Fiber Conversion Process in Lexington, NE; Natural Gas, Grid Electricity; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05200200	38.12	10/30/2023	None	Ethanol - Cellulosic	Chief Ethanol Fuels, Inc (5110)	CHIEF ETHANOL FUELS INC (70241)	Midwest Corn, Dry Mill; Corn Kernel Fiber Ethanol produced by the EDENIQ Fiber Conversion Process in Lexington, NE; Natural Gas, Grid Electricity; Ethanol transported by Rail to California. (Provisional)	None	
A052101	Tier 1	3.0	Fuel Producer: Green Plains Central City, LLC (3368); Facility Name: Green Plains Central City LLC (70141); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A05210100	75.51	10/31/2023	None	Ethanol	Green Plains Central City, LLC (3368)	Green Plains Central City LLC (70141)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (Provisional)	None	
A052102	Tier 1	3.0	Fuel Producer: Green Plains Central City, LLC (3368); Facility Name: Green Plains Central City LLC (70141); Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A02960100	65.97	ETH009A05210200	64.86	10/31/2023	None	Ethanol	Green Plains Central City, LLC (3368)	Green Plains Central City LLC (70141)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (Provisional)	None	
B045801	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04580100	27.39	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B045802	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04580200	33.70	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	

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B045803	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04580300	47.95	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B045804	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04580400	41.15	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B045806	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04580600	43.66	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B045807	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California ocean t (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04580700	27.61	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California ocean t	None	
B045808	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California by ocea (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04580800	33.92	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California by ocea	None	
B045809	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04580900	41.36	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California	None	
B045810	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04581000	48.17	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California	None	
B045811	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and Ocean Tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; tr (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04581100	43.87	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and Ocean Tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; tr	None	
B045813	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California ocean tank (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04581300	27.61	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California ocean tank	None	
B045814	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by ocean t (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04581400	33.92	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by ocean t	None	
B045815	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04581500	48.17	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by	None	
B045816	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04581600	41.36	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B045817	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; trans (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04581700	43.87	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; trans	None	
B045819	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California ocean (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04581900	29.42	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California ocean	None	
B045820	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California by oc (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04582000	35.72	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California by oc	None	
B045821	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californ (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04582100	49.97	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californ	None	
B045822	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californi (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04582200	43.17	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californi	None	
B045824	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04582400	45.68	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel;	None	
B045825	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California ocean ta (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04582500	29.42	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California ocean ta	None	
B045826	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California by ocean (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04582600	35.72	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California by ocean	None	
B045827	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04582700	43.17	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b	None	
B045828	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04582800	49.97	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b	None	
B045829	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; tra (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04582900	45.68	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; tra	None	
A052301	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05230100	73.75	11/6/2023	None	Ethanol	POET BIOREFINING - ARTHUR (1578)	Poet Biorefining - Arthur (71682)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional)	None	

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A052302	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05230200	70.13	11/6/2023	None	Ethanol	POET BIOREFINING - ARTHUR (1578)	Poet Biorefining - Arthur (71682)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052303	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, ; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05230300	66.14	11/6/2023	None	Ethanol	POET BIOREFINING - ARTHUR (1578)	Poet Biorefining - Arthur (71682)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, ; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052304	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05230400	26.37	11/6/2023	None	Ethanol - Cellulosic	POET BIOREFINING - ARTHUR (1578)	Poet Biorefining - Arthur (71682)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional)	None	
A053101	Tier 1	3.0	Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Redfield, SD; Ethanol transported by Rail to California. (PROV3.0)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05310100	29.36	11/6/2023	None	Ethanol - Cellulosic	Redfield Energy, LLC (4061)	Redfield Energy, LLC (70111)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Redfield, SD; Ethanol transported by Rail to California. (Provisional)	None	
A053102	Tier 1	3.0	Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Redfield, SD; Ethanol transported by Rail to California; Composite CI. (PROV3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A01450102	68.61	ETH009A05310200	67.95	11/6/2023	None	Ethanol	Redfield Energy, LLC (4061)	Redfield Energy, LLC (70111)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Redfield, SD; Ethanol transported by Rail to California; Composite CI. (Provisional)	None	
A052201	Tier 1	3.0	Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05220100	73.95	11/17/2023	None	Ethanol	Poet Biorefining - Shell Rock, LLC (1584)	Poet Biorefining - Shell Rock (71686)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052202	Tier 1	3.0	Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05220200	69.64	11/17/2023	None	Ethanol	Poet Biorefining - Shell Rock, LLC (1584)	Poet Biorefining - Shell Rock (71686)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052203	Tier 1	3.0	Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05220300	65.44	11/17/2023	None	Ethanol	Poet Biorefining - Shell Rock, LLC (1584)	Poet Biorefining - Shell Rock (71686)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052204	Tier 1	3.0	Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05220400	26.04	11/17/2023	None	Ethanol - Cellulosic	Poet Biorefining - Shell Rock, LLC (1584)	Poet Biorefining - Shell Rock (71686)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052501	Tier 1	3.0	Fuel Producer: HEREFORD ETHANOL PARTNERS, LP (1501); Facility Name: HEREFORD ETHANOL PARTNERS, LP (21601; Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (PROV3.0)	Texas	Corn (009)	Ethanol (ETH)	ETHC248L	67.6	ETH009A05250100	65.34	11/16/2023	None	Ethanol	HEREFORD ETHANOL PARTNERS, LP (1501)	HEREFORD ETHANOL PARTNERS, LP (21601	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (Provisional)	None	
A052502	Tier 1	3.0	Fuel Producer: HEREFORD ETHANOL PARTNERS, LP (1501); Facility Name: HEREFORD ETHANOL PARTNERS, LP (21601; Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Sorghum Starch produced in Hereford, Texas; Ethanol transported by rail to California (PROV3.0)	Texas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A05250200	66.44	11/16/2023	None	Ethanol	HEREFORD ETHANOL PARTNERS, LP (1501)	HEREFORD ETHANOL PARTNERS, LP (21601	Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Sorghum Starch produced in Hereford, Texas; Ethanol transported by rail to California (Provisional)	None	
A052503	Tier 1	3.0	Fuel Producer: HEREFORD ETHANOL PARTNERS, LP (1501); Facility Name: HEREFORD ETHANOL PARTNERS, LP (21601; Midwest Corn and Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Hereford, Texas using Edeniq conversion method; Ethanol transported by rail to California (PROV3.0)	Texas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05250300	26.15	11/16/2023	None	Ethanol - Cellulosic	HEREFORD ETHANOL PARTNERS, LP (1501)	HEREFORD ETHANOL PARTNERS, LP (21601	Midwest Corn and Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Hereford, Texas using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	

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A052701	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05270100	71.98	11/17/2023	None	Ethanol	POET BIOREFINING - MENLO (1583)	MENLO (71685)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052702	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05270200	68.33	11/17/2023	None	Ethanol	POET BIOREFINING - MENLO (1583)	MENLO (71685)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052703	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05270300	64.40	11/17/2023	None	Ethanol	POET BIOREFINING - MENLO (1583)	MENLO (71685)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052704	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05270400	25.02	11/17/2023	None	Ethanol - Cellulosic	POET BIOREFINING - MENLO (1583)	MENLO (71685)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional)	None	
A053301	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05330100	72.65	11/17/2023	None	Ethanol	POET BIOPROCESSING - FAIRBANK (1581)	FAIRBANK (71683)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional)	None	
A053302	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05330200	69.00	11/17/2023	None	Ethanol	POET BIOPROCESSING - FAIRBANK (1581)	FAIRBANK (71683)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional)	None	
A053303	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05330300	64.38	11/17/2023	None	Ethanol	POET BIOPROCESSING - FAIRBANK (1581)	FAIRBANK (71683)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional)	None	
A053304	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05330400	24.65	11/17/2023	None	Ethanol - Cellulosic	POET BIOPROCESSING - FAIRBANK (1581)	FAIRBANK (71683)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052801	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05280100	72.60	11/28/2023	None	Ethanol	POET BIOPROCESSING - IOWA FALLS (1582)	IOWA FALLS (71684)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052802	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05280200	70.11	11/28/2023	None	Ethanol	POET BIOPROCESSING - IOWA FALLS (1582)	IOWA FALLS (71684)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052803	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05280300	64.89	11/28/2023	None	Ethanol	POET BIOPROCESSING - IOWA FALLS (1582)	IOWA FALLS (71684)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052804	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poets's proprietary Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05280400	24.29	11/28/2023	None	Ethanol - Cellulosic	POET BIOPROCESSING - IOWA FALLS (1582)	IOWA FALLS (71684)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poets's proprietary Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional)	None	

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B047301	Tier 2	3.0	Fuel Producer: SUNOMA RENEWABLE BIOFUEL, LLC (1781); Facility Name: Sunoma Renewable Biofuel, LLC (F00497); Biogas from dairy manure at Paloma dairy in Gila Bend, AZ; upgraded to pipeline quality at Sunoma Renewable Biofuel, LLC; pipelined to California for transportation use (PROV3.0)	Arizona	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04730100	-386.78	12/4/2023	Application Package	Bio-CNG	SUNOMA RENEWABLE BIOFUEL, LLC (1781)	Sunoma Renewable Biofuel, LLC (F00497)	Biogas from dairy manure at Paloma dairy in Gila Bend, AZ; upgraded to pipeline quality at Sunoma Renewable Biofuel, LLC; pipelined to California for transportation use (Provisional)	None	
B048201	Tier 2	3.0	Fuel Producer: Wyoming Renewable Diesel Company LLC (1440); Facility Name: Wyoming Renewable Diesel Company LLC (82441); North American sourced Animal Fat transported by rail to Renewable Diesel plant in Sinclair Wyoming; Natural Gas, Hydrogen, and Grid Electricity; transported to California by rail (3.0)	Wyoming	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04820100	33.19	12/6/2023	Application Package	Renewable Diesel	Wyoming Renewable Diesel Company LLC (1440)	Wyoming Renewable Diesel Company LLC (82441)	North American sourced Animal Fat transported by rail to Renewable Diesel plant in Sinclair Wyoming; Natural Gas, Hydrogen, and Grid Electricity; transported to California by rail	None	
B049201	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Canola Oil (006)	Renewable Diesel (RND)	None	None	RND006B04920100	54.20	12/6/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049202	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B04920200	28.60	12/6/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049203	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04920300	58.00	12/6/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049204	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04920400	33.20	12/6/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049205	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04920500	20.70	12/6/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049206	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Canola Oil (006)	Renewable Naphtha (RNT)	None	None	RNT006B04920600	54.20	12/6/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049207	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	None	None	RNT003B04920700	28.60	12/6/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049208	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Soybean Oil (005)	Renewable Naphtha (RNT)	None	None	RNT005B04920800	58.00	12/6/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049209	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B04920900	33.20	12/6/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049210	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B04921000	20.70	12/6/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	

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B049501	Tier 2	3.0	Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); North American sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas and Grid Electricity; transported to California by rail (PROV3.0)	Mississippi	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04950100	63.29	12/18/2023	Application Package	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	North American sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas and Grid Electricity; transported to California by rail (Provisional)	None	
A052601	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A05120200	72.75	ETH009A05260100	71.72	12/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional)	None	
A052602	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A05120100	63.8	ETH009A05260200	64.93	12/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional)	None	
A052603	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Corn/Sorghum Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0)	Kansas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05260300	24.31	12/8/2023	None	Ethanol - Cellulosic	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Corn/Sorghum Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional)	None	
A052604	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A05120400	74.66	ETH010A05260400	74.26	12/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Sorghum, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional)	None	
A052605	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A05120300	65.71	ETH010A05260500	67.47	12/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Sorghum, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional)	None	
B042401	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: North Las Vegas Liquid Hydrogen Plant (F00371); Liquefied Hydrogen produced in North Las Vegas, Nevada by steam methane reformation (SMR) of fossil-derived Natural Gas; NG, Grid Electricity; Liquid Hydrogen transported in tanker trailers to refueling stations in Northern and Southern California. (PROV3.0)	Nevada	North American NG	Liquid Hydrogen (HYL)	None	None	HYL031B04240100	188.60	12/21/2023	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	North Las Vegas Liquid Hydrogen Plant (F00371)	Liquefied Hydrogen produced in North Las Vegas, Nevada by steam methane reformation (SMR) of fossil-derived Natural Gas; NG, Grid Electricity; Liquid Hydrogen transported in tanker trailers to refueling stations in Northern and Southern California. (Provisional)	None	
B050101	Tier 2	3.0	Fuel Producer: ARTESIA RENEWABLE DIESEL COMPANY LLC (1646); Facility Name: RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381); U.S sourced Soybean Oil transported by Rail and pre-treated at the Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (PROV3.0)	New Mexico	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B05010100	57.67	12/20/2023	Application Package	Renewable Diesel	ARTESIA RENEWABLE DIESEL COMPANY LLC (1646)	RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381)	U.S sourced Soybean Oil transported by Rail and pre-treated at the Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (Provisional)	None	
B050102	Tier 2	3.0	Fuel Producer: ARTESIA RENEWABLE DIESEL COMPANY LLC (1646); Facility Name: RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381); U.S. sourced Distillers Corn Oil transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (PROV3.0)	New Mexico	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B05010200	30.05	12/20/2023	Application Package	Renewable Diesel	ARTESIA RENEWABLE DIESEL COMPANY LLC (1646)	RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381)	U.S. sourced Distillers Corn Oil transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (Provisional)	None	
B050103	Tier 2	3.0	Fuel Producer: ARTESIA RENEWABLE DIESEL COMPANY LLC (1646); Facility Name: RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381); U.S.-sourced Tallow transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (PROV3.0)	New Mexico	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05010300	34.05	12/20/2023	Application Package	Renewable Diesel	ARTESIA RENEWABLE DIESEL COMPANY LLC (1646)	RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381)	U.S.-sourced Tallow transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (Provisional)	None	
B046101	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: HOLSUM RNG PROJECT (71481); Biogas from dairy manure at Holsum Elm Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (PROV3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04610100	-130.23	12/28/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	HOLSUM RNG PROJECT (71481)	Biogas from dairy manure at Holsum Elm Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (Provisional)	None	
B046102	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: HOLSUM RNG PROJECT (71481); Biogas from dairy manure at Holsum Irish Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (PROV3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04610200	-385.43	12/28/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	HOLSUM RNG PROJECT (71481)	Biogas from dairy manure at Holsum Irish Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (Provisional)	None	

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B045901	Tier 2	3.0	Fuel Producer: Still Water Power, LLC (C1180); Facility Name: Still Water Power, LLC (F00552); Biogas from Dairy Manure at Still Water Dairy in Hanford, CA; upgraded to pipeline quality at Still Water Power, LLC; trucked to pipeline injection and pipelined to CA for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04590100	-332.64	12/29/2023	Application Package	Bio-CNG	Still Water Power, LLC (C1180)	Still Water Power, LLC (F00552)	Biogas from Dairy Manure at Still Water Dairy in Hanford, CA; upgraded to pipeline quality at Still Water Power, LLC; trucked to pipeline injection and pipelined to CA for transportation use	None	
B049001	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: Bar 20 Biogas LLC (F00510); Low-CI electricity from dairy manure biogas using Solid Oxide Fuel Cell generator at Bar 20 Dairy in Kerman, CA for use as a transportation fuel in California (PROV3.0)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B04900100	-790.41	12/28/2023	Application Package	Electricity	California Bioenergy LLC (B194)	Bar 20 Biogas LLC (F00510)	Low-CI electricity from dairy manure biogas using Solid Oxide Fuel Cell generator at Bar 20 Dairy in Kerman, CA for use as a transportation fuel in California (Provisional)	None	
B049401	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at the Air Liquide North Las Vegas Hydrogen Plant in Las Vegas, NV using Biomethane procured from the Yellow Jacket Lamb RNG Project in Oakfield, NY; finished fuel dispensed at Hydrogen refueling stations in California. (PROV3.0)	Nevada	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04940100	-158.06	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at the Air Liquide North Las Vegas Hydrogen Plant in Las Vegas, NV using Biomethane procured from the Yellow Jacket Lamb RNG Project in Oakfield, NY; finished fuel dispensed at Hydrogen refueling stations in California. (Provisional)	None	
B049402	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide North Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at refuelng stations in California. (PROV3.0)	Nevada	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04940200	-181.75	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide North Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at refuelng stations in California. (Provisional)	None	
B049403	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; finished fuel transported and dispensed at Hydrogen refueling stations in California. (PROV3.0)	Nevada	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04940300	-119.24	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; finished fuel transported and dispensed at Hydrogen refueling stations in California. (Provisional)	None	
B049404	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lamb RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations in California. (PROV3.0)	Nevada	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04940400	-141.61	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lamb RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations in California. (Provisional)	None	
B049405	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations. (PROV3.0)	Nevada	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04940500	-165.30	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations. (Provisional)	None	
B049406	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Boxler RNG in Varysburg, NY; re-gasified & compressed in Livermore, CA; finished fuel dispensed at refueling stations in California. (PROV3.0)	Nevada	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04940600	-102.79	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Boxler RNG in Varysburg, NY; re-gasified & compressed in Livermore, CA; finished fuel dispensed at refueling stations in California. (Provisional)	None	
B049407	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using N.A. Natural Gas; transported to trans-fill station in Livermore, CA in liquid tankers; re-gasified & compressed; finished fuel dispensed at refueling stations in California. (PROV3.0)	Nevada	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031B04940700	205.05	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using N.A. Natural Gas; transported to trans-fill station in Livermore, CA in liquid tankers; re-gasified & compressed; finished fuel dispensed at refueling stations in California. (Provisional)	None	
B050601	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Soybean Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (PROV3.0)	California	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B05060100	62.93	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	North American sourced Soybean Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (Provisional)	None	
B050602	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Canola Oil transported by rail and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (PROV3.0)	California	Canola Oil (006)	Renewable Diesel (RND)	None	None	RND006B05060200	56.54	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	North American sourced Canola Oil transported by rail and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (Provisional)	None	
B050603	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Distillers' Corn Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (PROV3.0)	California	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B05060300	35.24	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	North American sourced Distillers' Corn Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (Provisional)	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B050604	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Used Cooking Oil, pre-treated at various facilities, transported by truck and rail to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (PROV3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B05060400	29.22	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	North American sourced Used Cooking Oil, pre-treated at various facilities, transported by truck and rail to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (Provisional)	None	
B050605	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, barge, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05060500	37.14	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	North American sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, barge, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (Provisional)	None	
B050606	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); Globally sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05060600	46.40	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	Globally sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (Provisional)	None	
B051401	Tier 2	3.0	Fuel Producer: FM Jerseys Dairy Biogas, LLC (C1178); Facility Name: FM Jerseys Dairy Digester (F00479); Biogas from dairy manure at FM Jerseys Dairy in Tipton, CA; upgraded to pipeline quality at FM Jerseys Dairy Digester; trucked to pipeline injection and pipelined to CA for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B05140100	-426.46	12/28/2023	Application Package	Bio-CNG	FM Jerseys Dairy Biogas, LLC (C1178)	FM Jerseys Dairy Digester (F00479)	Biogas from dairy manure at FM Jerseys Dairy in Tipton, CA; upgraded to pipeline quality at FM Jerseys Dairy Digester; trucked to pipeline injection and pipelined to CA for transportation use	None	
B052001	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Argentinian soybean oil transported by ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge (3.0)	California	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B05200100	61.98	12/26/2023	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Argentinian soybean oil transported by ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge	None	
B054001	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American sourced canola oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker (3.0)	Louisiana	Canola Oil (006)	Renewable Diesel (RND)	None	None	RND006B05400100	55.11	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American sourced canola oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker	None	
B054002	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B05400200	29.76	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054003	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05400300	46.07	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054004	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05400400	37.24	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054005	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B05400500	39.77	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054006	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05400600	46.43	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054007	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American sourced canola oil transported by truck, rail and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker (3.0)	Louisiana	Canola Oil (006)	Renewable Naphtha (RNT)	None	None	RNT006B05400700	55.11	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American sourced canola oil transported by truck, rail and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker	None	

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B054008	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B05400800	29.76	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054009	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B05400900	46.07	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054010	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B05401000	37.24	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054011	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B05401100	39.77	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054012	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B05401200	46.43	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
A005001	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (3.0)	Missouri	Corn (009)	Ethanol (ETH)	ETH009A00500102	71.21	ETH009A00500103	70.13	10/17/2023	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport	2022 AFPR Recert Complete	
A005002	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (3.0)	Missouri	Corn (009)	Ethanol (ETH)	ETH009A00500202	63.83	ETH009A00500203	63.10	10/17/2023	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport	2022 AFPR Recert Complete	
A005003	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (3.0)	Missouri	Corn (009)	Ethanol (ETH)	ETH012A00500302	23.97	ETH012A00500303	23.19	10/17/2023	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport	2022 AFPR Recert Complete	
A005101	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00510102	70.77	ETH009A00510103	69.15	11/7/2023	None	Ethanol	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005102	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00510202	30.54	ETH012A00510203	29.19	11/7/2023	None	Ethanol - Cellulosic	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005201	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785); Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00520103	74.36	ETH009A00520104	75.43	11/6/2023	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005202	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785); Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00520203	66.04	ETH009A00520204	66.02	11/6/2023	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	

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A005203	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785); Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00520303	26.29	ETH012A00520304	26.30	11/6/2023	None	Ethanol - Cellulosic	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005301	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786); Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00530103	72.85	ETH009A00530104	73.25	10/20/2023	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005302	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00530203	65.95	ETH009A00530204	66.39	10/20/2023	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005303	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00530303	25.98	ETH012A00530304	26.35	10/20/2023	None	Ethanol - Cellulosic	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005501	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779); Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00550101	77.66	ETH009A00550102	77.57	10/17/2023	None	Ethanol	POET Biorefining - Glenville (4779)	POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005502	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779); Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00550201	69.88	ETH009A00550202	69.86	10/17/2023	None	Ethanol	POET Biorefining - Glenville (4779)	POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005503	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779); Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00550301	29.92	ETH012A00550302	30.11	10/17/2023	None	Ethanol - Cellulosic	POET Biorefining - Glenville (4779)	POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005601	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00560102	73.89	ETH009A00560103	73.50	10/23/2023	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005602	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00560202	67.49	ETH009A00560203	66.85	10/23/2023	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005603	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00560302	28.27	ETH012A00560303	27.47	10/23/2023	None	Ethanol - Cellulosic	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005801	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00580102	73.74	ETH009A00580103	78.77	10/23/2023	None	Ethanol	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005802	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00580202	68.00	ETH009A00580203	68.77	10/23/2023	None	Ethanol	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	

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A005803	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00580302	28.21	ETH012A00580303	29.07	10/23/2023	None	Ethanol - Cellulosic	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006001	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00600102	76.01	ETH009A00600103	74.07	10/17/2023	None	Ethanol	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006002	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00600202	66.53	ETH009A00600203	64.20	10/17/2023	None	Ethanol	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006003	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00600302	26.40	ETH012A00600303	24.45	10/17/2023	None	Ethanol - Cellulosic	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006101	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791); Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00610102	75.21	ETH009A00610103	74.60	10/23/2023	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006102	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791); Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00610202	65.67	ETH009A00610203	64.82	10/23/2023	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006103	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791); Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00610302	26.04	ETH012A00610303	25.35	10/23/2023	None	Ethanol - Cellulosic	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006201	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00620101	74.47	ETH009A00620102	73.69	10/17/2023	None	Ethanol	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006202	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789) ; Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00620201	67.18	ETH009A00620202	65.82	10/17/2023	None	Ethanol	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006203	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00620301	27.03	ETH012A00620302	25.91	10/17/2023	None	Ethanol - Cellulosic	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006401	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784); Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00640102	72.37	ETH009A00640103	72.70	11/7/2023	None	Ethanol	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006402	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784); Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00640202	64.75	ETH009A00640203	64.56	11/7/2023	None	Ethanol	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	

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A006403	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784); Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00640302	24.60	ETH012A00640303	24.25	11/7/2023	None	Ethanol - Cellulosic	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A008301	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Soybean Oil (005)	Biodiesel (BIO)	BIO005A00830100	53.68	BIO005A00830102	54.50	12/4/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	2022 AFPR Recert Complete	
A008302	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Canola Oil (006)	Biodiesel (BIO)	BIO006A00830200	48.49	BIO006A00830201	49.00	12/4/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	2022 AFPR Recert Complete	
A008304	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A00830401	18.00	BIO001A00830402	18.00	12/6/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	2022 AFPR Recert Complete	
A008305	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A00830501	13.00	BIO001A00830502	13.00	12/6/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	2022 AFPR Recert Complete	
A008306	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A00830601	29.25	BIO002A00830602	29.25	12/6/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	2022 AFPR Recert Complete	
A008601	Tier 1	3.0	Fuel Producer: Bridgeport Ethanol, LLC 5934; Facility Name: Bridgeport Ethanol, LLC 70217; Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00860101	63.00	ETH009A00860102	63.66	11/7/2023	None	Ethanol	Bridgeport Ethanol, LLC 5934	Bridgeport Ethanol, LLC 70217	Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A008801	Tier 1	3.0	Fuel Producer: Yuma Ethanol, LLC (4735); Facility Name: Yuma Ethanol, LLC (70024); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California (3.0)	Colorado	Corn (009)	Ethanol (ETH)	ETH009A00880101	64.00	ETH009A00880102	63.52	11/7/2023	None	Ethanol	Yuma Ethanol, LLC (4735)	Yuma Ethanol, LLC (70024)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A010001	Tier 1	3.0	Fuel Producer: The Andersons Marathon Holdings LLC (1143); Facility Name: DENISON ETHANOL PLANT (70884); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01000100	71.62	ETH009A01000101	72.26	11/7/2023	None	Ethanol	The Andersons Marathon Holdings LLC (1143)	DENISON ETHANOL PLANT (70884)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	2022 AFPR Recert Complete	
A010002	Tier 1	3.0	Fuel Producer: The Andersons Marathon Holdings LLC (1143); Facility Name: DENISON ETHANOL PLANT (70884); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01000201	67.11	ETH009A01000202	67.12	11/7/2023	None	Ethanol	The Andersons Marathon Holdings LLC (1143)	DENISON ETHANOL PLANT (70884)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	2022 AFPR Recert Complete	
A009501	Tier 1	3.0	Fuel Producer: CEFARI RNG OKC, LLC (2220); Facility Name: CEFARI RNG OKC, LLC (70101); Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (3.0)	Oklahoma	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A00950101	49.80	CNG025A00950102	52.00	11/14/2023	None	Bio-CNG	CEFARI RNG OKC, LLC (2220)	CEFARI RNG OKC, LLC (70101)	Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	2022 AFPR Recert Complete	
A010501	Tier 1	3.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Pyeongtaek 2 (80202); South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker (3.0)	South Korea	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A01050101	25.00	BIO001A01050102	25.28	11/6/2023	None	Biodiesel	Dansuk Industrial Co., Ltd (5953)	Pyeongtaek 2 (80202)	South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker	2022 AFPR Recert Complete	

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A011001	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (3.0)	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01100101	48.21	CNG025A01100102	46.33	11/6/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	Ameresco Woodland Meadows Romulus, LLC (A0833)	Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California	2022 AFPR Recert Complete	
A011501	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (3.0)	Texas	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A01150101	36.77	CNG030A01150102	36.73	11/3/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Ameresco San Antonio Biogas (71204)	Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	2022 AFPR Recert Complete	
B001901	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Open Sky (F00007); Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00190100	-352.89	ELC026B00190101	-364.41	11/13/2023	None	Electricity	CleanFuture, Inc. (C1001)	Open Sky (F00007)	Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California	2022 AFPR Recert Complete	
A012701	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A01270103	28.29	ETH012A01270104	27.92	11/7/2023	None	Ethanol - Cellulosic	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012702	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01270203	77.34	ETH009A01270204	77.70	11/7/2023	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012703	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01270303	68.22	ETH009A01270304	67.61	11/7/2023	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012801	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01280102	75.31	ETH009A01280103	75.28	10/17/2023	None	Ethanol	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012802	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01280202	68.32	ETH009A01280203	67.59	10/17/2023	None	Ethanol	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012803	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A01280302	28.66	ETH012A01280303	28.18	10/17/2023	None	Ethanol - Cellulosic	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012901	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01290101	73.48	ETH009A01290102	73.58	11/7/2023	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012902	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01290201	66.73	ETH009A01290202	67.04	11/7/2023	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012903	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A01290301	27.01	ETH012A01290302	27.13	11/7/2023	None	Ethanol - Cellulosic	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	

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A013001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01300101	72.10	ETH009A01300102	72.00	11/7/2023	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A013002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01300201	65.09	ETH009A01300202	64.54	11/7/2023	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A013003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California (3.0)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01300301	25.09	ETH012A01300302	24.63	11/7/2023	None	Ethanol - Cellulosic	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A013102	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California (3.0)	Iowa	Canola Oil (006)	Biodiesel (BIO)	BIO006A01310202	50.11	BIO006A01310203	50.75	10/30/2023	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	2022 AFPR Recert Complete	
A013501	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (3.0)	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A01350102	31.65	BIO002A01350103	31.65	12/11/2023	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	2022 AFPR Recert Complete	
A013502	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846) ; Facility Name: High Plains Bioenergy (82883); Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (3.0)	Oklahoma	Soybean Oil (005)	Biodiesel (BIO)	BIO005A01350200	55.82	BIO005A01350201	55.82	12/11/2023	None	Biodiesel	High Plains Bioenergy (4846)	High Plains Bioenergy (82883)	Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	2022 AFPR Recert Complete	
A013503	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (3.0)	Oklahoma	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A01350300	20.68	BIO001A01350301	20.68	12/11/2023	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	2022 AFPR Recert Complete	
A013901	Tier 1	3.0	Fuel Producer: Midwest Renewable Energy (5214); Facility Name: Midwest Renewable Energy (70160); Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A01390102	65.76	ETH009A01390103	65.20	12/21/2023	None	Ethanol	Midwest Renewable Energy (5214)	Midwest Renewable Energy (70160)	Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A014101	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California (3.0)	Missouri	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003A01410102	27.16	BIO003A01410103	27.78	10/31/2023	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441)	Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	2022 AFPR Recert Complete	
A014102	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California (3.0)	Missouri	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A01410202	32.08	BIO002A01410203	31.88	10/31/2023	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441)	Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	2022 AFPR Recert Complete	
A014601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (3.0)	Michigan	Corn (009)	Ethanol (ETH)	ETH009A01460101	72.29	ETH009A01460102	72.48	10/23/2023	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	2022 AFPR Recert Complete	
A014602	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (3.0)	Michigan	Corn (009)	Ethanol (ETH)	ETH009A01460201	66.61	ETH009A01460202	66.75	10/23/2023	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	2022 AFPR Recert Complete	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A014603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (3.0)	Michigan	Corn Fiber (012)	Ethanol (ETH)	ETH012A01460301	27.03	ETH012A01460302	27.27	10/23/2023	None	Ethanol - Cellulosic	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California	2022 AFPR Recert Complete	
A015001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01500101	74.03	ETH009A01500102	73.74	11/13/2023	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01500201	67.28	ETH009A01500202	66.96	11/13/2023	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (3.0)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01500301	27.19	ETH012A01500302	26.95	11/13/2023	None	Ethanol - Cellulosic	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015101	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01510101	73.56	ETH009A01510102	73.60	10/23/2023	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California	2022 AFPR Recert Complete	
A015103	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (3.0)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01510301	26.17	ETH012A01510302	26.30	10/23/2023	None	Ethanol - Cellulosic	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01520101	72.75	ETH009A01520102	72.34	11/13/2023	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01520201	65.82	ETH009A01520202	65.13	11/13/2023	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (3.0)	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A01520301	25.89	ETH012A01520302	26.01	11/13/2023	None	Ethanol - Cellulosic	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015401	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (3.0)	Kentucky	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01540102	54.69	CNG025A01540103	55.00	12/11/2023	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California	2022 AFPR Recert Complete	
A015402	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (3.0)	Kentucky	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A01540202	72.09	LNG025A01540203	73.15	12/11/2023	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations	2022 AFPR Recert Complete	
A015403	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (3.0)	Kentucky	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A01540302	75.18	LCN025A01540303	76.24	12/11/2023	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG	2022 AFPR Recert Complete	

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A015102	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01510201	66.14	ETH009A01510202	66.24	10/23/2023	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015601	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel (3.0)	Arizona	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A01560100	26.58	CNG030A01560101	25.35	10/27/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel	2022 AFPR Recert Complete	
A016901	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California. (3.0)	Arizona	Wastewater Sludge (030)	Liquefied Natural Gas (LNG)	LNG030A01690100	41.58	LNG030A01690101	42.61	11/20/2023	None	Bio-LNG	Anew RNG, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California.	2022 AFPR Recert Complete	
A016902	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as (3.0)	Arizona	Wastewater Sludge (030)	Liquefied Compressed Natural Gas (LCN)	LCN030A01690200	44.67	LCN030A01690201	45.70	11/20/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as	2022 AFPR Recert Complete	
A017101	Tier 1	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California (3.0)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026A01710100	-329.76	CNG026A01710101	-185.00	10/25/2023	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Fair Oaks Upgrader, LLC (71001)	Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California	2022 AFPR Recert Complete	
A017401	Tier 1	3.0	Fuel Producer: Nebraska Corn Processing (3516); Facility Name: Nebraska Corn Processing LLC (70230); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A01740100	65.77	ETH009A01740101	65.55	10/17/2023	None	Ethanol	Nebraska Corn Processing (3516)	Nebraska Corn Processing LLC (70230)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A019501	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060); Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (3.0)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01950101	44.78	CNG025A01950102	46.75	11/6/2023	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060)	Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	2022 AFPR Recert Complete	
B005901	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California. (3.0)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00590102	-568.21	ELC026B00590103	-613.23	11/14/2023	None	Electricity	California Bioenergy LLC (B194)	ABEC Bidart-Old River LLC (F00113)	Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	2022 AFPR Recert Complete	
A020001	Tier 1	3.0	Fuel Producer: GHI Energy, LLC (6156); Facility Name: Waste Management American Landfill (70421); Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (3.0)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02000101	37.64	CNG025A02000102	37.59	11/6/2023	None	Bio-CNG	GHI Energy, LLC (6156)	Waste Management American Landfill (70421)	Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel.	2022 AFPR Recert Complete	
A020101	Tier 1	3.0	Fuel Producer: Thumb BioEnergy (3862); Facility Name: Thumb BioEnergy (03862); Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail (3.0)	Michigan	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02010100	15.80	BIO001A02010101	15.14	10/31/2023	None	Biodiesel	Thumb BioEnergy (3862)	Thumb BioEnergy (03862)	Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail	2022 AFPR Recert Complete	
A020701	Tier 1	3.0	Fuel Producer: MEM RNG, LLC (2141); Facility Name: Blue Ridge Landfill, LLC (F00132); Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel (3.0)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02070100	38.07	CNG025A02070101	36.38	11/17/2023	None	Bio-CNG	MEM RNG, LLC (2141)	Blue Ridge Landfill, LLC (F00132)	Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel	2022 AFPR Recert Complete	
A021201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California (3.0)	Missouri	Corn (009)	Ethanol (ETH)	ETH009A02120102	75.47	ETH009A02120103	74.18	10/24/2023	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California	2022 AFPR Recert Complete	

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A021202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California (3.0)	Missouri	Corn (009)	Ethanol (ETH)	ETH009A02120201	64.95	ETH009A02120202	64.00	10/24/2023	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A021203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California (3.0)	Missouri	Corn Fiber (012)	Ethanol (ETH)	ETH012A02120301	25.32	ETH012A02120302	24.65	10/24/2023	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A021301	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02130101	61.55	ETH009A02130102	61.85	11/13/2023	None	Ethanol	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI	2022 AFPR Recert Complete	
A021302	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California (3.0)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A02130203	21.93	ETH012A02130204	22.00	11/13/2023	None	Ethanol - Cellulosic	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California	2022 AFPR Recert Complete	
B008002	Tier 2	3.0	Fuel Producer: Bridge To Renewables, Benefit LLC (C1006); Facility Name: Blake's Landing Farms (F00019); Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI (3.0)	California	Other Organic Waste (029)	Electricity (ELC)	ELC029B00800201	-221.76	ELC029B00800202	-346.47	12/11/2023	None	Electricity	Bridge To Renewables, Benefit LLC (C1006)	Blake's Landing Farms (F00019)	Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI	2022 AFPR Recert Complete	
A022401	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02240102	73.00	ETH009A02240103	73.85	12/12/2023	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A022402	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02240202	68.00	ETH009A02240203	67.75	12/12/2023	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A022403	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02240301	64.13	ETH009A02240302	66.00	12/12/2023	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A022404	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A02240402	26.00	ETH012A02240403	26.00	12/12/2023	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
B009801	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980101	-401.33	CNG026B00980102	-419.92	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California	2022 AFPR Recert Complete	
B009802	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980201	-402.07	CNG026B00980202	-418.16	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California	2022 AFPR Recert Complete	
B009803	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980300	-192.49	CNG026B00980301	-420.09	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California	2022 AFPR Recert Complete	

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B009804	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980400	-323.10	CNG026B00980401	-419.74	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California	2022 AFPR Recert Complete	
B009805	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980501	-304.08	CNG026B00980502	-419.77	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California	2022 AFPR Recert Complete	
B009806	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980601	-279.38	CNG026B00980602	-227.28	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California	2022 AFPR Recert Complete	
A023301	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (3.0)	Kansas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02330102	47.10	CNG025A02330103	45.13	11/17/2023	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG	2022 AFPR Recert Complete	
B002401	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Coronado Dairy Farm (F00009); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00240100	-525.14	ELC026B00240101	-760.21	11/13/2023	None	Electricity	CleanFuture, Inc. (C1001)	Coronado Dairy Farm (F00009)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California	2022 AFPR Recert Complete	
A024501	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02450103	73.16	ETH009A02450104	73.27	10/18/2023	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A024502	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02450203	64.79	ETH009A02450204	65.00	10/18/2023	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A024503	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A02450303	24.71	ETH012A02450304	25.42	10/18/2023	None	Ethanol - Cellulosic	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A024201	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG (3.0)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02420102	57.00	CNG025A02420104	60.50	11/28/2023	None	Bio-CNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A024202	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations (3.0)	Tennessee	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02420201	63.35	LNG025A02420203	76.47	11/28/2023	None	Bio-LNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A024203	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0)	Tennessee	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02420301	66.44	LCN025A02420303	79.55	11/28/2023	None	Bio-CNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
A024601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A02460101	76.22	ETH009A02460102	73.94	10/24/2023	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	

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A024602	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A02460201	68.53	ETH009A02460202	66.40	10/24/2023	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A024603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A02460302	28.47	ETH012A02460303	26.48	10/24/2023	None	Ethanol - Cellulosic	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A024701	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896); Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG (3.0)	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02470102	48.20	CNG025A02470104	50.00	11/28/2023	None	Bio-CNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A024702	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896); Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations (3.0)	Michigan	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02470200	62.68	LNG025A02470201	58.89	11/28/2023	None	Bio-LNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A024703	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896); Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0)	Michigan	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02470300	65.77	LCN025A02470301	61.98	11/28/2023	None	Bio-CNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
A024901	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02490102	76.29	ETH009A02490103	76.56	10/24/2023	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	2022 AFPR Recert Complete	
A024902	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02490201	68.82	ETH009A02490202	68.67	10/24/2023	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	2022 AFPR Recert Complete	
A025901	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0)	Tennessee	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003A02590102	37.49	BIO003A02590103	36.92	11/1/2023	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (83730)	U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California	2022 AFPR Recert Complete	
A025902	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0)	Tennessee	Soybean Oil (005)	Biodiesel (BIO)	BIO005A02590202	66.85	BIO005A02590203	67.83	11/1/2023	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (83730)	U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California	2022 AFPR Recert Complete	
A025903	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0)	Tennessee	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A02590302	42.58	BIO002A02590303	41.61	11/1/2023	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (83730)	U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California	2022 AFPR Recert Complete	
A025904	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0)	Tennessee	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02590400	31.60	BIO001A02590401	29.54	11/1/2023	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (83730)	U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California	2022 AFPR Recert Complete	
A027401	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Renovar Arlington, LTD RNG Project (70501); Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (3.0)	Texas	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A02740102	41.71	CNG030A02740103	41.23	10/27/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	Renovar Arlington, LTD RNG Project (70501)	Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California	2022 AFPR Recert Complete	

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A027901	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (3.0)	Arkansas	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003A02790101	33.53	BIO003A02790102	34.29	11/2/2023	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California	2022 AFPR Recert Complete	
A027902	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (3.0)	Arkansas	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02790202	26.13	BIO001A02790203	26.62	11/2/2023	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California	2022 AFPR Recert Complete	
A028201	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail (3.0)	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A02820102	24.60	BIO002A02820103	24.60	12/11/2023	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail	2022 AFPR Recert Complete	
A028905	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. (3.0)	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02890500	21.50	BIO001A02890501	21.60	10/31/2023	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	2022 AFPR Recert Complete	
A029002	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. (3.0)	Illinois	Soybean Oil (005)	Biodiesel (BIO)	BIO005A02900201	58.00	BIO005A02900202	57.50	12/4/2023	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	2022 AFPR Recert Complete	
A029004	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. (3.0)	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02900400	20.75	BIO001A02900401	21.25	11/8/2023	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	2022 AFPR Recert Complete	
A029005	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail (3.0)	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02900500	16.25	BIO001A02900501	16.50	11/8/2023	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail	2022 AFPR Recert Complete	
A029006	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. (3.0)	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02900601	22.00	BIO001A02900602	23.50	12/4/2023	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	2022 AFPR Recert Complete	
B013302	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Distillers' Corn Oil (003)	Renewable Diesel (RND)	RND003B01330200	32.50	RND003B01330202	32.50	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B013303	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RND001B01330300	25.50	RND001B01330302	25.50	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B013304	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RND001B01330400	20.00	RND001B01330402	20.00	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B013305	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RND001B01330500	26.00	RND001B01330502	26.00	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	

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B013307	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B01330700	37.00	RND002B01330702	37.00	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B013308	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B01330800	38.00	RND002B01330802	38.00	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B013309	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B01330900	43.00	RND002B01330902	43.00	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
A029501	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. (3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02950101	22.03	BIO001A02950102	22.52	11/2/2023	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	2022 AFPR Recert Complete	
A029502	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. (3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02950201	16.71	BIO001A02950202	16.80	11/2/2023	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	2022 AFPR Recert Complete	
A029701	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (3.0)	Kansas	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02970102	60.50	LNG025A02970103	52.93	11/16/2023	None	Bio-LNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A029702	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0)	Kansas	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02970201	63.59	LCN025A02970202	56.01	11/16/2023	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
A029801	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (3.0)	Washington	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02980101	28.80	CNG025A02980102	29.30	11/28/2023	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A029802	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (3.0)	Washington	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02980201	42.58	LNG025A02980202	38.46	11/28/2023	None	Bio-LNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A029803	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0)	Washington	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02980301	45.67	LCN025A02980302	41.55	11/28/2023	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
A027601	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Meadow Branch Landfill Gas Processing Facility (71252); Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel (3.0)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02760100	47.41	CNG025A02760101	45.83	11/6/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Meadow Branch Landfill Gas Processing Facility (71252)	Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel	2022 AFPR Recert Complete	
A030601	Tier 1	3.0	Fuel Producer: MONROEVILLE LFG, LLC (6317); Facility Name: MONROEVILLE LFG, LLC (71136); Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (3.0)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03060101	42.85	CNG025A03060102	43.27	11/17/2023	None	Bio-CNG	MONROEVILLE LFG, LLC (6317)	MONROEVILLE LFG, LLC (71136)	Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG	2022 AFPR Recert Complete	

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A029101	Tier 1	3.0	Fuel Producer: Morrow Renewables, LLC (C1224); Facility Name: Pine Hill Renewables, LLC (71288); Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG (3.0)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02910100	34.17	CNG025A02910101	35.12	11/14/2023	None	Bio-CNG	Morrow Renewables, LLC (C1224)	Pine Hill Renewables, LLC (71288)	Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A030201	Tier 1	3.0	Fuel Producer: Morrow Renewables, LLC (C1224); Facility Name: Melissa Renewables, LLC (71407); Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG (3.0)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03020100	34.00	CNG025A03020101	34.04	11/14/2023	None	Bio-CNG	Morrow Renewables, LLC (C1224)	Melissa Renewables, LLC (71407)	Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A030401	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Point Loma Digester Gas Project (F00027); Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (3.0)	California	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A03040102	38.91	CNG030A03040103	48.72	10/27/2023	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Point Loma Digester Gas Project (F00027)	Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California.	2022 AFPR Recert Complete	
B014301	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations (3.0)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B01430101	-432.11	CNG044B01430102	-429.14	11/3/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations	2022 AFPR Recert Complete	
A030901	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A03090101	24.84	ETH012A03090102	24.86	10/18/2023	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A030902	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A03090201	72.02	ETH009A03090202	71.85	10/18/2023	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A030903	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A03090300	68.76	ETH009A03090301	68.28	10/18/2023	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A031001	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG (3.0)	Louisiana	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03100100	41.18	CNG025A03100101	41.37	11/28/2023	None	Bio-CNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A031002	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations (3.0)	Louisiana	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A03100201	55.55	LNG025A03100202	50.02	11/28/2023	None	Bio-LNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A031003	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0)	Louisiana	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A03100301	58.64	LCN025A03100302	53.11	11/28/2023	None	Bio-CNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
A031201	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production (3.0)	California	Soybean Oil (005)	Biodiesel (BIO)	BIO005A03120101	63.92	BIO005A03120102	63.92	11/8/2023	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	2022 AFPR Recert Complete	
A031202	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production (3.0)	California	Canola Oil (006)	Biodiesel (BIO)	BIO006A03120201	59.19	BIO006A03120202	59.19	11/8/2023	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	2022 AFPR Recert Complete	

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A031204	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production. (3.0)	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A03120401	38.49	BIO002A03120402	38.49	11/8/2023	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production.	2022 AFPR Recert Complete	
A031205	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production (3.0)	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A03120501	39.35	BIO002A03120502	39.35	11/8/2023	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	2022 AFPR Recert Complete	
A031206	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production (3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A03120601	26.60	BIO001A03120602	26.60	11/8/2023	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	2022 AFPR Recert Complete	
B016601	Tier 2	3.0	Fuel Producer: SMUD (S338); Facility Name: New Hope Dairy Digester (F00255); Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California. (3.0)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B01660100	-750.81	ELC026B01660101	-752.17	10/11/2023	None	Electricity	SMUD (S338)	New Hope Dairy Digester (F00255)	Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California.	2022 AFPR Recert Complete	
A033001	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03300101	73.79	ETH009A03300102	73.76	11/13/2023	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A033002	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03300200	63.46	ETH009A03300201	62.43	11/13/2023	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A033003	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California. (3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A03300300	25.32	ETH012A03300301	24.72	11/13/2023	None	Ethanol - Cellulosic	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A033201	Tier 1	3.0	Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Usina São Martinho S.A. (71100); Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A03320100	50.99	ETH018A03320101	52.31	10/24/2023	None	Ethanol	Usina São Martinho S.A. (3867)	Usina São Martinho S.A. (71100)	Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker.	2022 AFPR Recert Complete	
A033301	Tier 1	3.0	Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Santa Cruz S/A Açúcar e Álcool (70484); Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A03330100	50.06	ETH018A03330101	50.36	10/25/2023	None	Ethanol	Usina São Martinho S.A. (3867)	Santa Cruz S/A Açúcar e Álcool (70484)	Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker.	2022 AFPR Recert Complete	
A025201	Tier 1	3.0	Fuel Producer: Companhia Alcoolquimica Nacional (C1086); Facility Name: Companhia Alcoolquimica Nacional (F00194); Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A02520100	56.50	ETH018A02520101	58.50	11/13/2023	None	Ethanol	Companhia Alcoolquimica Nacional (C1086)	Companhia Alcoolquimica Nacional (F00194)	Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity.	2022 AFPR Recert Complete	
B017201	Tier 2	3.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566); Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI (3.0)	California	Corn (009)	Ethanol (ETH)	ETH009B01720100	65.68	ETH009B01720101	64.07	11/27/2023	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc. (3566)	Aemetis Advanced Fuels Keyes, Inc. (70234)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI	2022 AFPR Recert Complete	
B017301	Tier 2	3.0	Fuel Producer: DF-AP #1, LLC (C1122); Facility Name: Big Sky Dairy Digester (F00329); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California (3.0)	Idaho	Dairy Manure (026)	Electricity (ELC)	ELC026B01730101	-548.10	ELC026B01730102	-506.69	10/11/2023	None	Electricity	DF-AP #1, LLC (C1122)	Big Sky Dairy Digester (F00329)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California	2022 AFPR Recert Complete	

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A034501	Tier 1	3.0	Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG. (3.0)	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03450101	53.05	CNG025A03450102	60.00	11/28/2023	None	Bio-CNG	WESTSIDE GAS PRODUCERS, LLC (6218)	WESTSIDE GAS PRODUCERS, LLC (71151)	Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG.	2022 AFPR Recert Complete	
A034801	Tier 1	3.0	Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (3.0)	Texas	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A03480101	31.95	BIO002A03480102	31.97	11/8/2023	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail	2022 AFPR Recert Complete	
A035101	Tier 1	3.0	Fuel Producer: E Energy Adams, LLC (4831); Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03510101	67.49	ETH009A03510102	68.01	11/27/2023	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI.	2022 AFPR Recert Complete	
A035301	Tier 1	3.0	Fuel Producer: South Platte Renew (8380); Facility Name: 2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel. (3.0)	Colorado	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A03530100	52.36	CNG030A03530101	46.66	11/14/2023	None	Bio-CNG	South Platte Renew (8380)	2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641)	Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel.	2022 AFPR Recert Complete	
A036101	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A03610100	70.52	ETH009A03610101	69.86	11/27/2023	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A036102	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A03610200	63.38	ETH009A03610201	62.96	11/27/2023	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A036103	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (3.0)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A03610300	23.59	ETH012A03610301	23.24	11/27/2023	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A036701	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG (3.0)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03670100	49.53	CNG025A03670101	51.45	11/20/2023	None	Bio-CNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A036702	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (3.0)	Tennessee	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A03670201	63.18	LNG025A03670202	58.99	11/20/2023	None	Bio-LNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A036703	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (3.0)	Tennessee	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A03670301	66.26	LCN025A03670302	62.07	11/20/2023	None	Bio-CNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
B018501	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01850101	-294.20	CNG026B01850102	-271.24	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use	2022 AFPR Recert Complete	
B018502	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01850201	-366.51	CNG026B01850202	-282.99	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use	2022 AFPR Recert Complete	

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B018503	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01850300	-382.11	CNG026B01850301	-401.96	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use	2022 AFPR Recert Complete	
A037501	Tier 1	3.0	Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Seabreeze Energy Producers (70281); Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (3.0)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03750101	38.37	CNG025A03750102	41.43	11/6/2023	None	Bio-CNG	BLUE SOURCE LLC (6086)	Seabreeze Energy Producers (70281)	Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
B018701	Tier 2	3.0	Fuel Producer: Dry Creek RNG LLC (C1098); Facility Name: Dry Creek RNG Project (F00342); Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (3.0)	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01870101	-421.53	CNG026B01870102	-421.46	10/30/2023	None	Bio-CNG	Dry Creek RNG LLC (C1098)	Dry Creek RNG Project (F00342)	Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
A037801	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process; Ethanol transported by rail to California (3.0)	Texas	Corn Fiber (012)	Ethanol (ETH)	ETH012A03780100	25.36	ETH012A03780101	24.89	11/27/2023	None	Ethanol - Cellulosic	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037802	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0)	Texas	Corn (009)	Ethanol (ETH)	ETH009A03780200	66.38	ETH009A03780201	65.58	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037803	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03780301	66.40	ETH010A03780302	66.40	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037804	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0)	Texas	Corn (009)	Ethanol (ETH)	ETH009A03780400	73.91	ETH009A03780401	73.91	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037805	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (70039); Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03780502	74.69	ETH010A03780503	74.69	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (70039)	Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037901	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (3.0)	Texas	Corn Fiber (012)	Ethanol (ETH)	ETH012A03790100	23.13	ETH012A03790101	23.13	11/27/2023	None	Ethanol - Cellulosic	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037902	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (3.0)	Texas	Corn (009)	Ethanol (ETH)	ETH009A03790200	63.93	ETH009A03790201	63.93	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A037903	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (3.0)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03790301	65.92	ETH010A03790302	65.92	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
B018901	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	RNT003B01890100	33.00	RNT003B01890102	33.00	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	

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B018902	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B01890200	37.50	RNT002B01890202	37.50	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018903	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	RNT002B01890300	26.00	RNT002B01890302	26.00	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018904	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	RNT001B01890400	20.50	RNT001B01890402	20.50	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018905	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	RNT001B01890500	26.50	RNT001B01890502	26.50	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018906	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B01890600	38.50	RNT002B01890602	38.50	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018907	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B01890700	43.50	RNT002B01890702	43.50	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018910	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891000	33.00	LPG029B01891002	33.00	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018911	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891100	26.00	LPG029B01891102	26.00	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018912	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891200	20.50	LPG029B01891202	20.50	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018913	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891300	26.50	LPG029B01891302	26.50	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018914	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891400	37.50	LPG029B01891402	37.50	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018915	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891500	38.50	LPG029B01891502	38.50	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	

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B018916	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891600	43.50	LPG029B01891602	43.50	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B019701	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (3.0)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01970100	-177.03	CNG026B01970101	-208.60	10/30/2023	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	2022 AFPR Recert Complete	
B019702	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (3.0)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01970200	-156.78	CNG026B01970201	-149.41	10/30/2023	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	2022 AFPR Recert Complete	
B019703	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (3.0)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01970300	-295.26	CNG026B01970301	-332.22	10/30/2023	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	2022 AFPR Recert Complete	
A038501	Tier 1	3.0	Fuel Producer: Los Angeles County Sanitation District (L375); Facility Name: Biogas Conditioning System Facility (F00308); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite. (3.0)	California	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A03850100	19.28	CNG030A03850101	19.28	10/30/2023	None	Bio-CNG	Los Angeles County Sanitation District (L375)	Biogas Conditioning System Facility (F00308)	Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite.	2022 AFPR Recert Complete	
B019801	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980101	-294.40	CNG026B01980102	-343.44	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
B019802	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980200	-414.26	CNG026B01980201	-419.15	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
B019803	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980300	-420.69	CNG026B01980301	-413.34	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
B019804	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980400	-405.41	CNG026B01980401	-324.70	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
B019805	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980500	-385.40	CNG026B01980501	-420.53	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
A025801	Tier 1	3.0	Fuel Producer: Agro Industrial Tabu S.A. (C1088); Facility Name: Agro Industrial Tabu (F00205); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A02580100	51.59	ETH018A02580101	53.00	10/18/2023	None	Ethanol	Agro Industrial Tabu S.A. (C1088)	Agro Industrial Tabu (F00205)	Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal.	2022 AFPR Recert Complete	
A038601	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A03860101	72.76	ETH009A03860102	72.28	11/27/2023	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	

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A038602	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A03860201	69.61	ETH009A03860202	69.01	11/27/2023	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A038603	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (3.0)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A03860300	28.03	ETH012A03860301	26.18	11/27/2023	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A039401	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03940101	66.77	ETH009A03940102	66.96	11/27/2023	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A039402	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A03940201	27.95	ETH012A03940202	27.99	11/27/2023	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California.	2022 AFPR Recert Complete	
A039601	Tier 1	3.0	Fuel Producer: Adecoagro Brasil Participacoes (4192); Facility Name: Adecoagro Vale do Ivinhema Ltda. (70496); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A03960100	52.79	ETH018A03960101	53.07	11/13/2023	None	Ethanol	Adecoagro Brasil Participacoes (4192)	Adecoagro Vale do Ivinhema Ltda. (70496)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	2022 AFPR Recert Complete	
A039701	Tier 1	3.0	Fuel Producer: Archer Daniels Midland Co (4888); Facility Name: ADM Velva (82790); Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel. (3.0)	North Dakota	Canola Oil (006)	Biodiesel (BIO)	BIO006A03970100	47.44	BIO006A03970101	46.43	10/31/2023	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Velva (82790)	Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel.	2022 AFPR Recert Complete	
B020701	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02070101	-132.51	CNG026B02070102	-136.71	10/30/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations	2022 AFPR Recert Complete	
B020702	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02070201	-193.95	CNG026B02070202	-185.59	10/30/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations	2022 AFPR Recert Complete	
A040401	Tier 1	3.0	Fuel Producer: Cargill Biodiesel (3683); Facility Name: Cargill Incorporated (36833); Midwest Soybean Oil produced onsite at the co-located crushing facility, and imported by truck and rail to the Biodiesel plant in Iowa Falls, Iowa; finished biodiesel transported to California by rail for transportation fuel. (3.0)	Iowa	Soybean Oil (005)	Biodiesel (BIO)	BIO005A04040100	54.36	BIO005A04040101	54.75	11/16/2023	None	Biodiesel	Cargill Biodiesel (3683)	Cargill Incorporated (36833)	Midwest Soybean Oil produced onsite at the co-located crushing facility, and imported by truck and rail to the Biodiesel plant in Iowa Falls, Iowa; finished biodiesel transported to California by rail for transportation fuel.	2022 AFPR Recert Complete	
B021401	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Milford Farm (71483); Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (PROV3.0)	Utah	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02140100	-413.67	CNG044B02140101	-417.05	12/11/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Milford Farm (71483)	Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (Provisional)	2022 AFPR Recert Complete	
B021501	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02150100	-310.71	CNG026B02150101	-337.05	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use	2022 AFPR Recert Complete	
B021502	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	LNG026B02150200	-296.99	LNG026B02150201	-320.23	11/22/2023	None	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG	2022 AFPR Recert Complete	

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B021503	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	LCN026B02150300	-293.45	LCN026B02150301	-316.68	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG	2022 AFPR Recert Complete	
B021601	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02160101	-333.34	CNG026B02160102	-225.64	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use	2022 AFPR Recert Complete	
B021602	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	LNG026B02160201	-318.76	LNG026B02160202	-207.44	11/22/2023	None	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG	2022 AFPR Recert Complete	
B021603	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	LCN026B02160301	-315.22	LCN026B02160302	-203.89	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG	2022 AFPR Recert Complete	
B021701	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02170101	-274.25	CNG026B02170102	-234.87	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use	2022 AFPR Recert Complete	
B021702	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	LNG026B02170201	-259.30	LNG026B02170202	-217.46	11/22/2023	None	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use	2022 AFPR Recert Complete	
B021703	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	LCN026B02170301	-255.76	LCN026B02170302	-213.91	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG	2022 AFPR Recert Complete	
B021901	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: HOMAN FARM (71343); RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use (3.0)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02190101	-359.22	CNG044B02190102	-403.69	11/3/2023	None	Bio-CNG	Anew RNG, LLC (5877)	HOMAN FARM (71343)	RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use	2022 AFPR Recert Complete	
B022001	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: SOMERSET FARM (71381); Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (3.0)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02200102	-370.44	CNG044B02200103	-382.99	10/30/2023	None	Bio-CNG	Anew RNG, LLC (5877)	SOMERSET FARM (71381)	Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
A041601	Tier 1	3.0	Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Greentree Landfill Gas Company (F00212); Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (PROV3.0)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A04160101	71.21	CNG025A04160102	74.90	10/31/2023	None	Bio-CNG	TRUSTAR ENERGY LLC (6523)	Greentree Landfill Gas Company (F00212)	Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (Provisional)	2022 AFPR Recert Complete	
A042301	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A04230101	72.01	ETH009A04230102	72.25	11/28/2023	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
A042302	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A04230201	24.42	ETH012A04230202	24.71	11/28/2023	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional)	2022 AFPR Recert Complete	

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A042501	Tier 1	3.0	Fuel Producer: ADM Agri-Industries Company (6137); Facility Name: ADM Agri Industries (81926); Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel. (3.0)	Canada	Canola Oil (006)	Biodiesel (BIO)	BIO006A04250100	47.65	BIO006A04250101	46.82	10/31/2023	None	Biodiesel	ADM Agri-Industries Company (6137)	ADM Agri Industries (81926)	Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel.	2022 AFPR Recert Complete	
A043601	Tier 1	3.0	Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (PROV3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A04360100	71.53	ETH009A04360101	72.42	11/28/2023	None	Ethanol	AL CORN CLEAN FUEL, LLC (4825)	AL CORN CLEAN FUEL, LLC (70087)	Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
A043602	Tier 1	3.0	Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (PROV3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A04360201	25.15	ETH012A04360202	25.90	11/28/2023	None	Ethanol	AL CORN CLEAN FUEL, LLC (4825)	AL CORN CLEAN FUEL, LLC (70087)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
A043701	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (PROV3.0)	Oklahoma	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A04370100	37.00	CNG025A04370101	37.00	11/20/2023	None	Bio-CNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (Provisional)	2022 AFPR Recert Complete	
A043702	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (PROV3.0)	Oklahoma	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A04370200	50.61	LNG025A04370201	53.28	11/20/2023	None	Bio-LNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (Provisional)	2022 AFPR Recert Complete	
A043703	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (PROV3.0)	Oklahoma	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A04370300	53.70	LCN025A04370301	56.37	11/20/2023	None	Bio-CNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	2022 AFPR Recert Complete	
B025001	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (PROV3.0)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02500100	-182.67	CNG026B02500101	-187.55	10/25/2023	None	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B025002	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (PROV3.0)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02500200	-267.51	CNG026B02500201	-258.09	10/25/2023	None	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B025003	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (PROV3.0)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02500300	-255.34	CNG026B02500301	-224.53	10/25/2023	None	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
A044001	Tier 1	3.0	Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (3.0)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A04400100	72.37	ETH009A04400101	74.48	11/27/2023	None	Ethanol	Element, LLC (C1020)	Element (F00048)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A044002	Tier 1	3.0	Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (3.0)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A04400200	62.07	ETH009A04400201	64.11	11/27/2023	None	Ethanol	Element, LLC (C1020)	Element (F00048)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A044201	Tier 1	3.0	Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A04420100	72.16	ETH009A04420101	72.23	10/17/2023	None	Ethanol	Lincolnway Energy, LLC (4830)	Lincolnway Energy (70092)	Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (Provisional)	2022 AFPR Recert Complete	

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A044203	Tier 1	3.0	Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A04420300	24.70	ETH012A04420301	24.99	10/17/2023	None	Ethanol - Cellulosic	Lincolnway Energy, LLC (4830)	Lincolnway Energy (70092)	Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
B026701	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0)	California	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003B02670101	28.80	BIO003B02670102	28.73	10/31/2023	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2022 AFPR Recert Complete	
B026702	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002B02670201	32.73	BIO002B02670202	32.74	10/31/2023	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2022 AFPR Recert Complete	
B026703	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001B02670300	15.71	BIO001B02670301	15.58	10/31/2023	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2022 AFPR Recert Complete	
B026704	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001B02670400	16.34	BIO001B02670401	16.15	10/31/2023	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2022 AFPR Recert Complete	
B026705	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001B02670500	20.86	BIO001B02670501	20.74	10/31/2023	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2022 AFPR Recert Complete	
A045001	Tier 1	3.0	Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (3.0)	Pennsylvania	Soybean Oil (005)	Biodiesel (BIO)	BIO005A04500100	58.09	BIO005A04500101	57.93	11/2/2023	None	Biodiesel	WORLD ENERGY HARRISBURG LLC (6425)	WORLD ENERGY HARRISBURG LLC (81499)	Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail.	2022 AFPR Recert Complete	
A045002	Tier 1	3.0	Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (3.0)	Pennsylvania	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A04500200	21.59	BIO001A04500201	20.78	11/2/2023	None	Biodiesel	WORLD ENERGY HARRISBURG LLC (6425)	WORLD ENERGY HARRISBURG LLC (81499)	US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail.	2022 AFPR Recert Complete	
B026801	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02680101	18.93	AJF002B02680103	22.00	12/14/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	
B026802	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02680201	18.93	RND002B02680203	22.00	12/14/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026803	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02680301	18.93	RNT002B02680303	22.00	12/14/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B026804	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02680400	19.54	AJF002B02680402	22.00	12/14/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B026805	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02680500	19.54	RND002B02680502	22.00	12/14/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026806	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02680600	19.54	RNT002B02680602	22.00	12/14/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B026807	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02680700	15.64	AJF002B02680701	17.98	12/12/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	
B026808	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02680800	15.64	RND002B02680801	17.98	12/12/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026809	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02680900	15.64	RNT002B02680901	17.98	12/12/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B026810	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02681001	29.78	AJF002B02681003	32.00	12/14/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	
B026811	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02681101	29.78	RND002B02681103	32.00	12/14/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026812	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02681201	29.78	RNT002B02681203	32.00	12/14/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B026813	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02681300	32.93	AJF002B02681301	37.00	12/12/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	
B026814	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02681400	32.93	RND002B02681401	37.00	12/12/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026815	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02681500	32.93	RNT002B02681501	37.00	12/12/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B026816	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02681600	38.43	AJF002B02681601	43.00	12/12/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B026817	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02681700	38.43	RND002B02681701	43.00	12/12/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026818	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02681800	38.43	RNT002B02681801	43.00	12/12/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B028201	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY S&S (71361); Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02820100	-272.08	CNG026B02820101	-360.00	10/30/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	U.S. GAIN RNG FACILITY S&S (71361)	Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use	2022 AFPR Recert Complete	
B028301	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: DEER RUN RNG PROJECT (71482); Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02830100	-195.09	CNG026B02830101	-194.44	10/27/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	DEER RUN RNG PROJECT (71482)	Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
A045601	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (3.0)	California	Distillers' Corn Oil (003)	Biodiesel	BIO003A04560100	30.15	BIO003A04560101	34.64	11/3/2023	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals	2022 AFPR Recert Complete	
A045602	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel	BIO001A04560200	23.48	BIO001A04560201	27.73	11/3/2023	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals	2022 AFPR Recert Complete	
A045603	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (3.0)	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A04560300	36.09	BIO002A04560301	40.98	11/3/2023	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals	2022 AFPR Recert Complete	
A041001	Tier 1	3.0	Fuel Producer: JAPUNGU AGROINDUSTRIAL LTDA (C1145); Facility Name: Japungu Agroindustrial Ltda (F00383); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A04100100	52.77	ETH018A04100101	53.00	10/25/2023	None	Ethanol	JAPUNGU AGROINDUSTRIAL LTDA (C1145)	Japungu Agroindustrial Ltda (F00383)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	2022 AFPR Recert Complete	
B030201	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (3.0)	Minnesota	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003B03020100	24.50	BIO003B03020102	24.50	12/4/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California	2022 AFPR Recert Complete	
B030202	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001B03020200	18.50	BIO001B03020202	18.50	12/4/2023	None	Renewable Diesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California	2022 AFPR Recert Complete	
B030203	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001B03020300	12.50	BIO001B03020302	12.50	12/4/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California	2022 AFPR Recert Complete	
B030204	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California (3.0)	Minnesota	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002B03020400	29.00	BIO002B03020402	29.00	12/4/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California	2022 AFPR Recert Complete	

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B030701	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03070100	-353.38	CNG026B03070101	-325.32	10/27/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B030702	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03070200	-405.57	CNG026B03070201	-361.69	10/27/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B030703	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03070300	-255.83	CNG026B03070301	-256.77	10/27/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B030704	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03070400	-249.43	CNG026B03070401	-247.40	10/27/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B030705	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03070500	-366.91	CNG026B03070501	-411.56	10/27/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031001	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100100	-349.17	CNG026B03100101	-420.78	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031002	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100200	-210.67	CNG026B03100201	-257.14	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031003	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100300	-406.28	CNG026B03100301	-415.27	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031004	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100400	-417.26	CNG026B03100401	-372.09	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031005	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100500	-417.24	CNG026B03100501	-369.61	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031006	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100600	-356.29	CNG026B03100601	-324.13	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031101	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110101	-418.04	CNG026B03110102	-348.56	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	

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B031102	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110200	-383.14	CNG026B03110201	-336.76	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031103	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110300	-419.34	CNG026B03110301	-423.14	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031104	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110400	-299.39	CNG026B03110401	-334.72	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031105	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110500	-276.38	CNG026B03110501	-307.02	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031106	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110600	-403.86	CNG026B03110601	-392.14	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031107	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110700	-341.84	CNG026B03110701	-318.92	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031108	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110800	-273.88	CNG026B03110801	-331.28	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
A046201	Tier 1	3.0	Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (PROV3.0)		Corn Fiber (012)	Ethanol (ETH)	ETH012A04620101	33.08	ETH012A04620103	34.36	10/17/2023	None	Ethanol	CORN, LP (5065)	CORN, LP (70145)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	2022 AFPR Recert Complete	
A046202	Tier 1	3.0	Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (PROV3.0)		Corn (009)	Ethanol (ETH)	ETH009A04620201	70.62	ETH009A04620202	73.77	10/17/2023	None	Ethanol	CORN, LP (5065)	CORN, LP (70145)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (Provisional)	2022 AFPR Recert Complete	
B031501	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03150100	-403.96	CNG026B03150101	-409.96	12/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B033801	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: DALHART RNG, LLC (70981); Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (PROV3.0)	Texas	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B03380100	-417.96	CNG044B03380101	-430.20	12/11/2023	None	Bio-CNG	Anew RNG, LLC (5877)	DALHART RNG, LLC (70981)	Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B034501	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAKESHORE RNG PROJECT (71321); Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03450100	-318.35	CNG026B03450101	-296.42	10/27/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET LAKESHORE RNG PROJECT (71321)	Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	

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B034601	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAMB RNG PROJECT (71101); Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (PROV3.0)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03460100	-311.72	CNG026B03460101	-272.73	11/22/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET LAMB RNG PROJECT (71101)	Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (Provisional)	2022 AFPR Recert Complete	
B035301	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY DALLMAN (71341); Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03530100	-344.72	CNG026B03530101	-319.04	10/30/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	U.S. GAIN RNG FACILITY DALLMAN (71341)	Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use	2022 AFPR Recert Complete	
B035201	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03520100	-411.77	CNG026B03520101	-423.12	12/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B035202	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03520200	-351.51	CNG026B03520201	-353.82	12/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B036601	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: MILFORD FARM (71483); Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use (3.0)	Utah	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B03660100	-414.59	CNG044B03660101	-427.14	10/30/2023	None	Bio-CNG	Anew RNG, LLC (5877)	MILFORD FARM (71483)	Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use	2022 AFPR Recert Complete	
B036001	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	HYG026B03600100	-159.04	HYG026B03600101	-154.83	11/6/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	
B036002	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	HYL026B03600200	-120.27	HYL026B03600201	-118.90	11/6/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	
B036003	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	HYL026B03600300	-104.64	HYL026B03600301	-100.09	11/6/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	
B037001	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: GREEN HILLS FARM (71881); Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (PROV3.0)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B03700100	-408.25	CNG044B03700101	-402.51	10/27/2023	None	Bio-CNG	Anew RNG, LLC (5877)	GREEN HILLS FARM (71881)	Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B037101	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: WHITETAIL FARM (71882); Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (PROV3.0)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B03710100	-412.77	CNG044B03710101	-374.61	10/27/2023	None	Bio-CNG	Anew RNG, LLC (5877)	WHITETAIL FARM (71882)	Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B037302	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	HYL026B03730200	-192.70	HYL026B03730201	-182.54	11/13/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	
B037304	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	HYG026B03730400	-231.46	HYG026B03730401	-218.47	11/13/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	

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B037306	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	HYL026B03730600	-177.06	HYL026B03730601	-163.73	11/13/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	
A049001	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A04900100	71.51	ETH009A04900101	71.65	10/25/2023	None	Ethanol	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
A049002	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A04900200	61.15	ETH009A04900201	61.71	10/25/2023	None	Ethanol	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
A049003	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A04900300	22.33	ETH012A04900301	23.74	10/25/2023	None	Ethanol - Cellulosic	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (Provisional)	2022 AFPR Recert Complete	
B038201	Tier 2	3.0	Fuel Producer: Madera Renewable Energy, LLC (C1140); Facility Name: Madera Renewable Energy, LLC (F00436); Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California. (3.0)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B03820100	-758.40	ELC026B03820101	-756.17	11/27/2023	None	Electricity	Madera Renewable Energy, LLC (C1140)	Madera Renewable Energy, LLC (F00436)	Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California.	2022 AFPR Recert Complete	
B038501	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Green Valley Dairy LLC (F00198); Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03850100	-180.73	CNG026B03850101	-180.62	11/28/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Green Valley Dairy LLC (F00198)	Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B040101	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET SWISS VALLEY RNG PROJECT (71161); Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (PROV3.0)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B04010100	-216.27	CNG026B04010101	-187.99	11/22/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET SWISS VALLEY RNG PROJECT (71161)	Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (Provisional)	2022 AFPR Recert Complete	
B042801	Tier 2	3.0	Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (PROV3.0)	Mississippi	Distillers' Corn Oil (003)	Renewable Diesel (RND)	RND003B04280100	51.80	RND003B04280101	53.52	11/6/2023	None	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	2022 AFPR Recert Complete	
B042802	Tier 2	3.0	Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (PROV3.0)	Mississippi	Soybean Oil (005)	Renewable Diesel (RND)	RND005B04280200	80.81	RND005B04280201	83.76	11/6/2023	None	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	2022 AFPR Recert Complete	
B048501	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: SANCO Services Anaerobic Digestor Plant (F00478); Biogas from landfill-diverted food scraps and urban landscaping waste upgraded at SANCO Services Anaerobic Digestor Plant facility in Escondido, CA; Bio-CNG injected into California natural gas pipeline for transportation use. (PROV3.0)	California	Other Organic Waste (029)	Compressed Natural Gas (CNG)	None	None	CNG029B04850100	-38.80	1/2/2024	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	SANCO Services Anaerobic Digestor Plant (F00478)	Biogas from landfill-diverted food scraps and urban landscaping waste upgraded at SANCO Services Anaerobic Digestor Plant facility in Escondido, CA; Bio-CNG injected into California natural gas pipeline for transportation use. (Provisional)	None	
B052101	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528) ; Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline is derived from Argentinian soybean oil (soybean oil is produced in Argentina and transported by ocean tanker to California); Natural gas, steam, off-gases, grid electricity, and hydrogen are distributed in California via pipeline. (3.0)	California	Soybean Oil (005)	Renewable Gasoline (RNG)	None	None	RNG005B05210100	67.35	12/29/2023	Application Package	Renewable Gasoline	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable gasoline is derived from Argentinian soybean oil (soybean oil is produced in Argentina and transported by ocean tanker to California); Natural gas, steam, off-gases, grid electricity, and hydrogen are distributed in California via pipeline.	None	
A019801	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A01980103	62.37	ETH009A01980105	62.23	1/9/2024	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI	2022 AFPR Recert Complete	

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A019802	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California (3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A01980201	23.04	ETH012A01980202	22.96	11/13/2023	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California	2022 AFPR Recert Complete	
A053001	Tier 1	3.0	Fuel Producer: Guarani SA (3833); Facility Name: Usina Vertente Ltda. (70447); Sugarcane-derived ethanol produced in Brazil from sugarcane juice and molasses; mechanized harvesting; co-product credit for export of cogenerated electricity; finished fuel exported to California by Ocean Tanker. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A05300100	48.78	1/8/2024	None	Ethanol	Guarani SA (3833)	Usina Vertente Ltda. (70447)	Sugarcane-derived ethanol produced in Brazil from sugarcane juice and molasses; mechanized harvesting; co-product credit for export of cogenerated electricity; finished fuel exported to California by Ocean Tanker.	None	
A053201	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Atlantic, Iowa; Ethanol transported by Rail to California , Composite CI (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05320100	66.20	1/11/2024	None	Ethanol	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Atlantic, Iowa; Ethanol transported by Rail to California , Composite CI (Provisional)	None	
A053202	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Atlantic, Iowa and transported by Rail to California (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05320200	26.80	1/11/2024	None	Ethanol - Cellulosic	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Atlantic, Iowa and transported by Rail to California (Provisional)	None	
A054001	Tier 1	3.0	Fuel Producer: NuGen Energy, LLC (3332); Facility Name: NuGen Energy, LLC (70195); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (PROV3.0)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05400100	72.33	1/23/2024	None	Ethanol	NuGen Energy, LLC (3332)	NuGen Energy, LLC (70195)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil; Natural Gas, Grid Electricity, Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (Provisional)	None	
A054002	Tier 1	3.0	Fuel Producer: NuGen Energy, LLC (3332); Facility Name: NuGen Energy, LLC (70195); Sorghum from Dry Mill; Dry DGS and Modified DGS, Corn Oil; Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (PROV3.0)	South Dakota	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A05400200	76.07	1/23/2024	None	Ethanol	NuGen Energy, LLC (3332)	NuGen Energy, LLC (70195)	Sorghum from Dry Mill; Dry DGS and Modified DGS, Corn Oil; Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (Provisional)	None	
A053601	Tier 1	3.0	Fuel Producer: Green Plains Superior LLC (5851); Facility Name: GREEN PLAINS SUPERIOR, LLC (70304); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Superior, Iowa; Finished fuel transported by Rail to California; Composite CI. (3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05360100	70.98	1/31/2024	None	Ethanol	Green Plains Superior LLC (5851)	GREEN PLAINS SUPERIOR, LLC (70304)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Superior, Iowa; Finished fuel transported by Rail to California; Composite CI.	None	
A054101	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California , Composite CI. (PROV3.0)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A01030102	71.24	ETH009A05410100	63.36	1/26/2024	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California , Composite CI. (Provisional)	None	
A054102	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Sorghum from Midwest; Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California; Composite CI. (PROV3.0)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A01030602	73.44	ETH010A05410200	67.05	1/26/2024	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Sorghum from Midwest; Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California; Composite CI. (Provisional)	None	
A054103	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill; Corn-Sorghum Fiber Ethanol produced by the EDENIQ conversion method; Cellulosic Ethanol produced in Garden City, Kansas, and transported to California by Rail. (PROV3.0)	Kansas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05410300	25.05	1/26/2024	None	Ethanol - Cellulosic	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn and Sorghum, Dry Mill; Corn-Sorghum Fiber Ethanol produced by the EDENIQ conversion method; Cellulosic Ethanol produced in Garden City, Kansas, and transported to California by Rail. (Provisional)	None	
A053701	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03070100	74.08	ETH009A05370100	78.02	2/9/2024	None	Ethanol	POET BIOREFINING - FAIRMONT (1579)	FAIRMONT (71681)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional)	None	
A053702	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03070200	69.42	ETH009A05370200	75.27	2/9/2024	None	Ethanol	POET BIOREFINING - FAIRMONT (1579)	FAIRMONT (71681)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional)	None	

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A053703	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A05370300	69.59	2/9/2024	None	Ethanol	POET BIOREFINING - FAIRMONT (1579)	FAIRMONT (71681)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional)	None	
A053704	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poet's proprietary fiber conversion process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05370400	30.06	2/9/2024	None	Ethanol - Cellulosic	POET BIOREFINING - FAIRMONT (1579)	FAIRMONT (71681)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poet's proprietary fiber conversion process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional)	None	
A053901	Tier 1	3.0	Fuel Producer: Green Plains Otter Tail LLC (4180); Facility Name: GREEN PLAINS OTTER TAIL, LLC (70110); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Fergus Falls, MN; Finished fuel transported by Rail to California; Composite CI. (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05390100	72.83	2/1/2024	None	Ethanol	Green Plains Otter Tail LLC (4180)	GREEN PLAINS OTTER TAIL, LLC (70110)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Fergus Falls, MN; Finished fuel transported by Rail to California; Composite CI.	None	

ATTACHMENT L

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-9169-1-0 **EXPIRATION DATE**: 10/31/2026

EQUIPMENT DESCRIPTION:
DIGESTER GAS OPERATION CONSISTING OF A 36,000,000 GALLON (EQUIVALENT TO 412'X507'X21.5') ANAEROBIC DIGESTER LAGOON WITH AN AIR/OXYGEN INJECTION SYSTEM FOR H2S CONTROL AND A GAS COLLECTION AND HANDLING SYSTEM SERVED BY A H2S SCRUBBER

PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. The digester system shall be designed to allow gas generated to be stored for more than 24 hours prior to venting in the event that the gas cannot be combusted in digester gas-fired engines or sent to another device with a VOC control efficiency of at least 95% by weight as determined by the APCO. [District Rule 2201]
4. The air/oxygen injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]
5. The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
6. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rule 1070]

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-9169-4-0 **EXPIRATION DATE**: 10/31/2026

EQUIPMENT DESCRIPTION:
250 KW BLOOM ENERGY MODEL ES5-EB2AAN DIGESTER GAS-FUELED FUEL CELL

PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-9169-5-0 **EXPIRATION DATE**: 10/31/2026

EQUIPMENT DESCRIPTION:
250 KW BLOOM ENERGY MODEL ES5-EB2AAN DIGESTER GAS-FUELED FUEL CELL

PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-9169-6-0 **EXPIRATION DATE**: 10/31/2026

EQUIPMENT DESCRIPTION:
249.5 KW BLOOM ENERGY MODEL ES5-DB2AAC DIGESTER GAS-FUELED FUEL CELL

PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-9169-7-0 **EXPIRATION DATE**: 10/31/2026

EQUIPMENT DESCRIPTION:
249.5 KW BLOOM ENERGY MODEL ES5-DB2AAC DIGESTER GAS-FUELED FUEL CELL

PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

ATTACHMENT M

FEB 21 2020

Doug Bryant
Maas Energy Works, Inc
3711 Meadow View Dr, #100
Redding, CA 96002

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: C-9133
Project Number: C-1193519

Dear Mr. Bryant:

Enclosed for your review and comment is the District's analysis of Lone Oak Energy LLC's application for an Authority to Construct for the installation of a 1,306 bhp digester gas-fired IC engine powering an electrical generator, at 10014 S McMullin Grade, Hanford.

The notice of preliminary decision for this project has been posted on the District's website (www.valleyair.org). After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Jesse A. Garcia of Permit Services at (559) 230-5918.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:jag

Enclosures

cc: Courtney Graham, CARB (w/ enclosure) via email

San Joaquin Valley Air Pollution Control District

Authority to Construct Application Review

Installation of a Digester Gas-Fired IC Engine with SCR

Facility Name:	Lone Oak Energy LLC	Date:	January 22, 2020
Mailing Address:	2911 Hanford Armona Rd Hanford, CA 93230	Engineer:	Jesse A. Garcia
		Lead Engineer:	Jerry Sandhu
Contact Person:	Doug Bryant		
Telephone:	(207) 691-8068		
E-Mail:	doug@maasenergy.com		
Application #(s):	C-9133-3-0		
Project #:	C-1193519		
Deemed Complete:	December 9, 2019		

I. Proposal

Lone Oak Energy LLC has requested an Authority to Construct (ATC) to install a 1,306 bhp digester gas-fired IC engine powering an electrical generator. This IC engine was originally permitted under ATC C-9133-1-0; however, the applicant has requested higher NO_X, CO and VOC emission factors during normal operation after the commissioning period. A summary of the emission factors from ATC -1-0 and the ones proposed under this project are shown in the following table:

Summary of Emission Factor Changes (ppmv)		
Pollutant	**From ATC -1-0**	**Proposed in this Project**
NO_X	5	10
CO	15	223
VOC	10	20

Since the equipment being permitted in this project was also authorized under ATC -1-0, the ATC issued in this project will cancel and supersede ATC -1-0 and the following condition will be included on the ATC:

- This Authority to Construct (ATC) cancels and supersedes ATC C-9133-1-0. [District Rule 2201]

II. Applicable Rules

Rule 1070 Inspections (12/17/92)
Rule 2201 New and Modified Stationary Source Review Rule (8/15/19)
Rule 2410 Prevention of Significant Deterioration (6/16/11)

Rule 2520 Federally Mandated Operating Permits (8/15/19)
Rule 4001 New Source Performance Standards (4/14/99)
Rule 4002 National Emission Standards for Hazardous Air Pollutants (5/20/04)
Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4701 Internal Combustion Engines - Phase 1 (8/21/03)
Rule 4702 Internal Combustion Engines (11/14/13)
Rule 4801 Sulfur Compounds (12/17/92)
CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notice
Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. Project Location

The facility is located at 10014 S McMullin Grade in Hanford, CA. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

The applicant is proposing to install one 1,306 bhp Caterpillar lean burn digester gas-fired IC engine. The engine will be equipped with an SCR system and an oxidation catalyst for emissions control and will power a generator. The electricity generated by this operation will be sold to utility grid. The engine will be permitted to operate up to 24 hours per day and 120 hours per year during the commissioning period (the time allowed during initial startup of the engine to perform testing, adjustment, tuning, and calibration of the IC engine without full operation of the SCR system and/or oxidation catalyst) and up to 24 hours per day and 8,500 hours per year after the commissioning period.

V. Equipment Listing

C-9133-3-0: 1,306 BHP CATERPILLAR MODEL G3516LE DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING MODEL COMBIKAT CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

VI. Emission Control Technology Evaluation

The proposed engine will be equipped with:

- Turbocharger
- Intercooler
- Positive Crankcase Ventilation (PCV)
- Air/Fuel Ratio or an O_2 Controller
- Lean Burn Technology

- Oxidation Catalyst
- Selective Catalytic Reduction (SCR)

The turbocharger reduces the NOx emission rate from the engine by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NOx.

The PCV system reduces crankcase VOC and PM_{10} emissions by at least 90% over an uncontrolled crankcase vent.

The fuel/air ratio controller (oxygen controller) is used to maintain the amount of oxygen in the exhaust stream to optimize catalyst function.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NOx formation.

An oxidation catalyst converts CO and VOC emissions to CO_2 and water. Typically, these catalysts are located prior to the urea injection site since the oxidation catalyst would otherwise convert the excess ammonia into NOx.

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent, in this case urea, are passed through an appropriate catalyst. Urea, will be injected upstream of the catalyst where it reacts and reduces NOx, over the catalyst bed, to form elemental nitrogen and other by-products. The use of a catalyst typically reduces the NOx emissions by up to 90%.

Additionally, prior to being combusted in the engine, the digester gas will be treated in a gas conditioning system to reduce the H_2S such that the sulfur content will not exceed 40 ppmv as H_2S.

VII. General Calculations

A. Assumptions

- To streamline emission calculations, $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.
- Higher Heating Value (HHV) for Digester Gas: 700 Btu/scf (proposed by the applicant, based on 70% methane content, also used in other similar District projects)
- Typical EPA F-factor for digester gas: 9,100 dscf/MMBtu (Estimated based on previous source tests and District practice)
- MMBtu/hr to bhp conversion 392.75 bhp-hr/MMBtu (per AP-42, Appendix A)

- Average sulfur content of the scrubbed digester gas: 40 ppmv as H_2S (proposed by applicant)
- Molar Specific Volume = 379.5 scf/lb-mol (60°F)
- Molecular weights:
  NO_X (as NO_2) = 46 lb/lb-mol   CO = 28 lb/lb-mol NH_3 = 17 lb/lb-mol
  VOC (as CH_4) = 16 lb/lb-mol SO_X (as SO_2) = 64.06 lb/lb-mol
- Efficiency of engine = 30% (District practice)
- A commissioning period to perform testing, adjustment, tuning, and calibration of the IC engine without full operation of the SCR system or oxidation catalyst will be allowed during initial startup of the engine. The duration of the commissioning period shall last no more than 120 hours of operation of the engine without the SCR system or oxidation catalyst installed and operating at its maximum efficiency (proposed by applicant)
- During normal operation the engine will operate 24 hours/day and 8,500 hours per year (proposed by the applicant)
- Ammonia slip from SCR = 10 ppm (proposed by applicant)

B. Emission Factors

Emission Factors during the Commissioning Period:

The commissioning period precedes normal operation of a power plant. Activities conducted during the commissioning period typically include: checking all mechanical, electrical, and control systems for the units and related equipment; confirming the performance measures specified for the equipment; test firing the units; and tuning of the units and the generators. The early stages of commissioning are conducted prior to the installation of the emission control equipment to prevent its damage. In accordance with EPA's guidance, the commissioning period is considered the final phase of the construction process rather than initial startup of the equipment.[1] Therefore, other than quantifying emissions for New and Modified Source Review (NSR), source-specific emission limitations from applicable rules and regulations are generally not effective until completion of the commissioning period. Because emission control devices are not in place and functioning during commissioning, higher emission limits are required during this time.

[1] See US EPA Implementation Question and Answer Document for National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, April 2, 2013, Question 39 (http://www.epa.gov/ttn/atw/rice/20120717riceqaupdate.pdf)

Emission Factors for Digester Gas-Fired Engine (Commissioning Period)			
Pollutant	**g/bhp·hr**	**ppmvd (@ 15%O_2)**	**Source**
NO_x	1.0	--	Information from Engine Supplier (Caterpillar)
SO_x	0.04	40 ppmvd in fuel gas	BACT Requirement/Mass Balance Equation on the Following Page
PM_{10}	0.08	--	AP-42, Table 2.4-4, October 2008, See Equation on the Following Page
CO	4.4	--	Information from Engine Supplier (Caterpillar)
VOC	1.1	--	Information from Engine Supplier (Caterpillar)
NH_3	0.06	10 ppmvd	Proposed by the Applicant, See Conversion on the Following Page

Emission Factors during Normal Operation after the Commissioning Period:

The emission factors for NO_x, CO, and VOC from the proposed engine during normal operation were proposed by the applicant and supported by information provided by the engine and catalyst supplier. The emission factors for NO_x, CO, and VOC will be achieved with the use of the SCR and catalyst system. The emission factors for SO_x, PM_{10}, and ammonia slip during normal operation are the same as the emission factors presented above for during the commissioning period. The unit conversions (from ppmvd to g/bhp-hr) for the emission factors are also shown below.

Emission Factors for Digester Gas-Fired Engine (Normal Operation)			
Pollutant	**g/bhp·hr**	**ppmvd (@ 15%O_2)**	**Source**
NO_x	0.15	10 ppmvd	Proposed by the Applicant, See Conversion Below
SO_x	0.04	40 ppmvd in fuel gas	Proposed by the Applicant, See Equation on the Following Page
PM_{10}	0.08	--	AP-42, Table 2.4-4, October 2008, See Conversion on the Following Page
CO	2.0	223 ppmvd	Proposed by the Applicant, See Conversion on the Following Page
VOC	0.10	20 ppmvd	Proposed by the Applicant, See Conversion on the Following Page
NH_3	0.06	10 ppmvd	Proposed by the Applicant, See Conversion on the Following Page

NO_x – 10 ppmvd @ 15% O_2 as proposed by the Applicant

$$\frac{10\ \text{ft}^3\ \text{NOx}}{10^6\ \text{ft}^3} \times \frac{9{,}100\ \text{ft}^3}{1\text{MMBtu}} \times \frac{46\ \text{lb NOx}}{1\ \text{lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1\ \text{lb-mole}}{379.5\ \text{ft}^3} \times \frac{\text{MMBtu}}{392.75\ \text{bhp-hr}} \times \frac{453.6\ \text{g}}{\text{lb}} \times \frac{\text{Btu}_{\text{in}}}{0.30\ \text{Btu}_{\text{out}}} = 0.15\ \frac{\text{g-NOx}}{\text{bhp-hr}}$$

SOx – 40 ppmvd H_2S @ 15% O_2 in fuel gas

$$\frac{40\ \text{ft}^3\ H_2S}{10^6\ \text{ft}^3} \text{x} \frac{32.06\ \text{lb S}}{\text{lb - mol}\ H_2S} \text{x} \frac{\text{lb - mole}}{379.5\ \text{ft}^3} \text{x} \frac{64.06\ \text{lb}\ SO_2}{32.06\ \text{lb S}} \text{x} \frac{\text{ft}^3}{700\ \text{Btu}} \text{x} \frac{10^6\ \text{Btu}}{\text{MMBtu}} = 0.00965\ \frac{\text{lb SOx}}{\text{MMBtu}}$$

$$0.00965\ \frac{\text{lb SOx}}{\text{MMBtu}} \text{x} \frac{\text{MMBtu}}{392.75\ \text{bhp - hr}} \text{x} \frac{\text{Btu}_{\text{in}}}{0.30\ \text{Btu}_{\text{out}}} \text{x} \frac{453.59\ \text{g}}{\text{lb}} = 0.04\ \frac{\text{g - SOx}}{\text{bhp - hr}}$$

PM10 – AP-42, Table 2.4-4: 15 lb/10^6 dscf

15 lb-PM10/10^6 dscf x 1 scf/ 700 Btu = 0.021 lb/MMBtu

$$0.021\ \frac{\text{lb PM10}}{\text{MMBtu}} \text{x} \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \text{x} \frac{\text{Btu}_{\text{in}}}{0.30\ \text{Btu}_{\text{out}}} \text{x} \frac{2{,}545\ \text{Btu}}{\text{hp - hr}} \text{x} \frac{453.59\ \text{g}}{\text{lb}} = 0.08\ \frac{\text{g - PM10}}{\text{bhp - hr}}$$

CO – 223 ppmvd @ 15% O2

$$\frac{223\ \text{ft}^3\ \text{CO}}{10^6\ \text{ft}^3} \text{x} \frac{9{,}100\ \text{ft}^3}{1\text{MMBtu}} \text{x} \frac{28\ \text{lb CO}}{1\ \text{lb - mole}} \text{x} \frac{20.9}{20.9 - 15} \text{x} \frac{1\ \text{lb - mole}}{379.5\ \text{ft}^3} \text{x} \frac{\text{MMBtu}}{392.75\ \text{bhp - hr}} \text{x} \frac{453.6\ \text{g}}{\text{lb}} \text{x} \frac{\text{Btu}_{\text{in}}}{0.30\ \text{Btu}_{\text{out}}} = 2.0\ \frac{\text{g - CO}}{\text{bhp - hr}}$$

VOC – 20 ppmvd @ 15% O_2 as proposed by the Applicant

$$\frac{20\ \text{ft}^3\ \text{VOC}}{10^6\ \text{ft}^3} \text{x} \frac{9{,}100\ \text{ft}^3}{1\text{MMBtu}} \text{x} \frac{16\ \text{lb VOC}}{1\ \text{lb - mole}} \text{x} \frac{20.9}{20.9 - 15} \text{x} \frac{1\ \text{lb - mole}}{379.5\ \text{ft}^3} \text{x} \frac{\text{MMBtu}}{392.75\ \text{bhp - hr}} \text{x} \frac{453.6\ \text{g}}{\text{lb}} \text{x} \frac{\text{Btu}_{\text{in}}}{0.30\ \text{Btu}_{\text{out}}} = 0.10\ \frac{\text{g - VOC}}{\text{bhp - hr}}$$

NH_3 – 10 ppmvd @ 15% O_2 as proposed by the Applicant

$$\frac{10\ \text{ft}^3\ NH_3}{10^6\ \text{ft}^3} \text{x} \frac{9{,}100\ \text{ft}^3}{\text{MMBtu}} \text{x} \frac{17\ \text{lb}\ NH_3}{\text{lb - mole}} \text{x} \frac{20.9}{20.9 - 15} \text{x} \frac{1\ \text{lb - mole}}{379.5\ \text{ft}^3} \text{x} \frac{\text{MMBtu}}{392.75\ \text{bhp - hr}} \times \frac{453.6\ \text{g}}{\text{lb}} \times \frac{\text{Btu}_{\text{in}}}{0.30\ \text{Btu}_{\text{out}}} = 0.06\ \frac{\text{g - }NH_3}{\text{bhp - hr}}$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since this is a new emissions unit, PE1 = 0 for all pollutants.

2. Post-Project Potential to Emit (PE2)

PE2 (lb/day) = [EF (g/hp-hr) x Rating (bhp) x 24 (hr/day)] / 453.6 (g/lb)

Daily PE2 During the Commissioning Period									
NO_x	1.0	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	69.1	(lb/day)
SO_x	0.04	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	2.8	(lb/day)
PM_{10}	0.08	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	5.5	(lb/day)
CO	4.4	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	304.0	(lb/day)
VOC	1.1	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	76.0	(lb/day)
NH_3	0.06	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	4.1	(lb/day)

Daily PE2 for the Engine after Completion of the Commissioning Period:

Daily PE for the proposed engine after completion of the commissioning period is calculated in the table below:

PE2 (lb/day) = [EF (g/hp-hr) x Rating (bhp) x 24 (hr/day)] / 453.6 (g/lb)

Daily PE2 After the Commissioning Period (Normal Operation)								
NO_x	0.15	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	10.4	(lb/day)
SO_x	0.04	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	2.8	(lb/day)
PM_{10}	0.08	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	5.5	(lb/day)
CO	2.0	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	138.2	(lb/day)
VOC	0.10	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	6.9	(lb/day)
NH_3	0.06	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	4.1	(lb/day)

Maximum Annual PE2 for the Engine Including the Commissioning Period:

As discussed above, the proposed engine will be allowed to operate up to 120 hours for commissioning during the first year of operation. The maximum annual PE for the engine will be calculated based on the maximum hours of operation during the commissioning period and the remaining hours during normal operation.

Annual PE2 During the Commissioning Period								
NO_x	1.0	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	346	(lb/yr)
SO_x	0.04	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	14	(lb/yr)
PM_{10}	0.08	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	28	(lb/yr)
CO	4.4	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	1,520	(lb/yr)
VOC	1.1	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	380	(lb/yr)
NH_3	0.06	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	21	(lb/yr)

First Year Annual PE2 After the Commissioning Period								
NO_x	0.15	(g/bhp·hr) x	1,306	(bhp) x	8,380	(hr/yr) ÷ 453.6 (g/lb) =	3,619	(lb/yr)
SO_x	0.04	(g/bhp·hr) x	1,306	(bhp) x	8,380	(hr/yr) ÷ 453.6 (g/lb) =	965	(lb/yr)
PM_{10}	0.08	(g/bhp·hr) x	1,306	(bhp) x	8,380	(hr/yr) ÷ 453.6 (g/lb) =	1,930	(lb/yr)
CO	2.0	(g/bhp·hr) x	1,306	(bhp) x	8,380	(hr/yr) ÷ 453.6 (g/lb) =	48,255	(lb/yr)
VOC	0.10	(g/bhp·hr) x	1,306	(bhp) x	8,380	(hr/yr) ÷ 453.6 (g/lb) =	2,413	(lb/yr)
NH_3	0.06	(g/bhp·hr) x	1,306	(bhp) x	8,380	(hr/yr) ÷ 453.6 (g/lb) =	1,448	(lb/yr)

Maximum Annual PE2 from the Engine during 1st year, Including Commissioning:

Maximum Post-Project Daily and Annual PE2				
Pollutant	**Daily (lb/day)**	**During Commissioning (lb/year)**	**After Commissioning (lb/year)**	**Total (lb/year)**
NO_x	69.1	346	3,619	3,965
SO_x	2.8	14	965	979
PM_{10}	5.5	28	1,930	1,958
CO	304.0	1,520	48,255	49,775
VOC	76.0	380	2,413	2,793
NH_3	4.1	21	1,448	1,469

Annual PE2 for the Engine in years with no Commissioning:

The annual PE2 for the engine after completion of the first year of operation when there will not be any commissioning period is calculated as follows:

Annual PE2 After Year 1 with no Commissioning (Normal Operation)								
NO_x	0.15	(g/bhp·hr) x	1,306	(bhp) x	8,500	(hr/yr) ÷ 453.6 (g/lb) =	3,671	(lb/yr)
SO_x	0.04	(g/bhp·hr) x	1,306	(bhp) x	8,500	(hr/yr) ÷ 453.6 (g/lb) =	979	(lb/yr)
PM_{10}	0.08	(g/bhp·hr) x	1,306	(bhp) x	8,500	(hr/yr) ÷ 453.6 (g/lb) =	1,958	(lb/yr)
CO	2.0	(g/bhp·hr) x	1,306	(bhp) x	8,500	(hr/yr) ÷ 453.6 (g/lb) =	48,946	(lb/yr)
VOC	0.10	(g/bhp·hr) x	1,306	(bhp) x	8,500	(hr/yr) ÷ 453.6 (g/lb) =	2,447	(lb/yr)
NH_3	0.06	(g/bhp·hr) x	1,306	(bhp) x	8,500	(hr/yr) ÷ 453.6 (g/lb) =	1,468	(lb/yr)

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site. Pursuant to the applicant, the digester gas operation permitted under ATC C-9133-2-0 will be implemented and should be included in the SSPE1 calculation; however, as calculated in project C-1170074, the PE2 for the digester gas operation is 0 lb/year. Therefore, SSPE1 = 0 lb/year for all pollutants.

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

SSPE2 (lb/year)						
Permit Unit	**NO_X**	**SO_X**	**PM_{10}**	**CO**	**VOC**	**NH_3**
C-9133-2-0	0	0	0	0	0	0
C-9133-3-0	3,965	979	1,958	49,775	2,793	1,469
SSPE2	**3,965**	**979**	**1,958**	**49,775**	**2,793**	**1469**

5. Major Source Determination

Rule 2201 Major Source Determination:

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)						
	NO_X	**SO_X**	**PM_{10}**	**$PM_{2.5}$**	**CO**	**VOC**
SSPE1	0	0	0	0	0	0
SSPE2	3,965	979	1,958	1,958	49,775	2,793
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	No	No

Note: $PM_{2.5}$ assumed to be equal to PM_{10}

As seen in the table above, the facility is not an existing Major Source and is not becoming a Major Source as a result of this project.

Rule 2410 Major Source Determination:

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Estimated Facility PE before Project Increase	0	0	0	0	0	0
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source?	No	No	No	No	No	No

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

Since this is a new emissions unit, BE = PE1 = 0 for all pollutants.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification.

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- Hydrogen sulfide (H2S)

I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Total PE from New and Modified Units	2.0	1.4	0.5	24.9	1.0	1.0
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	N	N	N	N	N	N

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix E.

VIII. Compliance Determination

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

Pursuant to District Rule 2201, Section 4.1, BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

As seen in Section VII.C.2 above, the proposed engine will have a PE greater than 2.0 lb/day for NO_x, SO_x, PM_{10}, CO, and VOC. Therefore, BACT is triggered for NO_x, SO_x, PM_{10}, and VOC. However, BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

The proposed engine will have a PE greater than 2.0 lb/day for NH3. However, NH3 slip emissions are the result from operation of an emissions control device (SCR) and not the emissions unit; therefore, this project does not trigger BACT for NH3 emissions.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore BACT is not triggered.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 and/or Federal Major Modification for any pollutant. Therefore BACT is not triggered for any pollutant.

2. BACT Guideline

BACT Guideline 3.3.15 applies to the proposed digester gas-fired IC engine. [Waste Gas-Fired IC Engines] (See Appendix B)

3. Top-Down BACT Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

Pursuant to the Top-Down BACT Analysis (See Appendix C), BACT has been satisfied with the following:

NO_X: NO_X emissions ≤ 0.15 g/bhp-hr
SO_X: Fuel sulfur content ≤ 40 ppmv (as H_2S)
PM_{10}: Fuel sulfur content ≤ 40 ppmv (as H_2S)
VOC: VOC emissions ≤ 0.10 g/bhp-hr

The following conditions will be placed on the ATC to ensure compliance with the BACT requirements during normal operation:

- This engine shall be fired on digester gas fuel only. [District Rule 2201]
- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

B. Offsets

1. Offset Applicability

Pursuant to District Rule 2201, Section 4.5, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
SSPE2	3,965	979	1,958	49,775	2,793
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

C. Public Notification

1. Applicability

Pursuant to District Rule 2201, Section 5.4, public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed,
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant, and/or
e. Any project which results in a Title V significant permit modification

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

b. PE > 100 lb/day

The PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

PE > 100 lb/day Public Notice Thresholds			
Pollutant	**PE2 (lb/day)**	**Public Notice Threshold**	**Public Notice Triggered?**
NO_X	69.1	100 lb/day	No
SO_X	2.8	100 lb/day	No
PM_{10}	5.5	100 lb/day	No
CO	304.0	100 lb/day	Yes
VOC	76.0	100 lb/day	No
NH_3	4.1	100 lb/day	No

Therefore, public noticing for PE > 100 lb/day purposes is required.

c. Offset Threshold

Public notification is required if the pre-project Stationary Source Potential to Emit (SSPE1) is increased to a level exceeding the offset threshold levels. The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Thresholds				
Pollutant	**SSPE1 (lb/year)**	**SSPE2 (lb/year)**	**Offset Threshold**	**Public Notice Required?**
NO_X	0	3,965	20,000 lb/year	No
SO_X	0	979	54,750 lb/year	No
PM_{10}	0	1,958	29,200 lb/year	No
CO	0	49,775	200,000 lb/year	No
VOC	0	2,793	20,000 lb/year	No

As demonstrated above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_x	3,965	0	3,965	20,000 lb/year	No
SO_x	979	0	979	20,000 lb/year	No
PM_{10}	1,958	0	1,958	20,000 lb/year	No
CO	49,775	0	49,775	20,000 lb/year	Yes
VOC	2,793	0	2,793	20,000 lb/year	No
NH_3	1,469	0	1,469	20,000 lb/year	No

As demonstrated above, the SSIPE for CO was greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating permit, this change is not a Title V significant Modification, and therefore public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project for CO emissions in excess of 100 lb/day and SSIPE greater than 20,000 lb/year. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be electronically published on the District's website prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions

Proposed Rule 2201 (DEL) Conditions for Engine during Both Commissioning and Normal Operation:

- This engine shall be fired on digester gas fuel only. [District Rule 2201]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H_2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit.[2] [District Rules 2201, 4102, 4702, and 4801]
- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]
- Ammonia (NH_3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]
- All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Commissioning Period:

For the proposed engine, the DELs for NO_X, SO_X, PM_{10}, CO, and VOC are stated in the form of maximum emission factors (g/bhp-hr), the maximum engine horsepower rating (1,306 bhp), and maximum number of hours allowed for commissioning activities. The following conditions will be placed on the permit as a mechanism to ensure compliance.

- The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
- Commissioning activities are defined as, but not limited to, all adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The commissioning period shall terminate when the initial engine tuning has completed and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation of the engine. [District Rule 2201]

[2] Due to variations in sulfur content of the digester gas, an averaging time cannot be established until the unit has operated in a steadystate manner.

- The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rules 2201 and 4102]
- Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.08 g-PM_{10}/bhp-hr, 4.4 g-CO/bhp-hr, 1.1 g-VOC/bhp-hr. [District Rule 2201]
- At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
- At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
- The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system and oxidation catalyst, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system and oxidation catalyst. [District Rule 2201]

<u>Proposed Rule 2201 (DEL) Conditions during Normal Operation</u>:

- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

  Additionally, to limit annual emissions, the following condition will be included on the ATC:

- This engine shall not operate more than 8,500 hours per calendar year. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

In accordance with District Policy APR 1705, source testing for NO_x, CO and VOC emissions from the digester gas fired IC engine served by a catalyst control system (including SCR and an oxidation catalyst) shall be conducted initially and at least once every 24 months thereafter. In addition, in order to assure compliance with the ammonia slip limit from the SCR system, source testing of the ammonia emissions will also be required initially and at least once every 24 months thereafter.

For PM_{10} emissions, the applicant has proposed to use an emission factor from AP-42, Section 2.4, which is applicable to municipal solid waste landfills. The digester gas fired in this engine should have a similar makeup to that of gas generated by a landfill. However, in order to assure that the engine is able to demonstrate compliance with the proposed PM_{10} emission factor, initial source testing will be required.

The engine is not served by any control devices for PM_{10} emissions. Therefore, it is not expected that the PM_{10} emissions will change much over time as long as the quality of the gas combusted in this unit remains fairly consistent. The facility will be required to monitor the sulfur content of the digester gas combusted in this unit at least once per quarter. The results of this quarterly monitoring should demonstrate that the quality of the gas combusted is consistent. Therefore, ongoing periodic source testing for PM_{10} emissions will not be required.

The following conditions will be placed on the permit to ensure compliance:

- Source testing to measure NO_x, CO, VOC, PM_{10}, and ammonia (NH_3) emissions from this unit shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201, and 4702]
- Source testing to measure NO_x, CO, VOC, and ammonia (NH_3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH_3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]
- The following methods shall be used for emissions source testing: NOx (ppmv) - EPA Method 7E; CO (ppmv) - EPA Method 10; VOC (ppmv) - EPA Method 18, 25A or 25B; stack gas oxygen - EPA Method 3 or 3A; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, ARB Method 5 (front half and back half), or ARB Method 5 (front half and back half) in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]
- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

2. Monitoring

The proposed digester gas-fired engine is subject to District Rule 4702 - Internal Combustion Engines. Section 5.8.1 of District Rule 4702 requires engines rated at least 1,000 bhp that can operate more than 2,000 hour per calendar year or equipped with external control devices to install, operate, and maintain an APCO-approved alternate monitoring plan. Section 5.8.9 of District Rule 4702 requires monitoring of NOx emissions at least once every calendar quarter for a non-agricultural spark-ignited IC engine. However, Section 6.5.3 of District Rule 4702 requires monthly monitoring for engines equipped with non-certified control devices in order to demonstrate compliance with the emission limits in District Rule 4702. Therefore, monthly monitoring of NOx, CO, and O_2 concentrations in accordance pre-approved alternate monitoring plan "A" will be required. Since the engine will be equipped with SCR, quarterly monitoring of ammonia slip will also be required.

The following conditions will be placed on the permit to ensure compliance:

- The permittee shall monitor and record the stack concentration of NO_x, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if 2 consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- The permittee shall monitor and record the stack concentration of NH_3 at least once every calendar quarter in which a source test is not performed. NH_3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]
- If the NOx, CO, or NH_3 concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the allowable emission concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 8 hours, the permittee shall notify the District within the following 1 hour, and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

In addition, Section 5.10.1 of District Rule 4702 requires an annual analysis of the sulfur content of engine fuel. Because of the variable content of digester gas, additional monitoring of the fuel sulfur content will be required.

The following conditions will be placed on the permits to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
- The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of

the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rules 2201 and 4702]

- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a digital analyzer approved for gaseous fuel analysis; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rules 2201 and 4702]

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following recordkeeping conditions will be listed on the permit:

- The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
- Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]
- The permittee shall maintain records of: (1) the date and time of NO_x, CO, O2, and NH_3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH_3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rule 2201]
- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]
- Records of hydrogen sulfide analyzer(s) installed or utilized and the calibration records of such analyzer(s) shall be maintained. Records are only required on such analyzer(s) utilized to demonstrate compliance with this permit. [District Rule 2201]
- The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201
- {4051} The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

Section 4.14 of District Rule 2201 requires that an AAQA be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to Appendix D of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_x, CO, and SO_x. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_x, CO, or SO_x.

The proposed location is in a non-attainment area for the state's PM_{10} as well as federal and state $PM_{2.5}$ thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM_{10} and $PM_{2.5}$.

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII.C.9 above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

Rule 4001 New Source Performance Standards (NSPS)

This rule incorporates NSPS from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR) and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

40 CFR 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

The purpose of 40 CFR 60 Subpart JJJJ is to establish New Source Performance Standards to reduce emissions of NO_x, SO_x, PM, CO, and VOC from new stationary spark ignition (SI) internal combustion (IC) engines.

Pursuant to Section 60.4230, compliance with this subpart is required for owners and operators of stationary SI IC engines that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: (a) on or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP); (b) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP; (c) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or (d) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

The engine is a 1,306 bhp SI ICE that was constructed after June 12, 2006 and manufactured after July 1, 2007; therefore, the engine is subject to this subpart. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, the requirements from this subpart will not be included in the permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

This rule incorporates NESHAPs from Part 63, Chapter 1, Title 40, Code of Federal Regulations (CFR) and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 63.

40 CFR 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Internal Combustion Engines

40 CFR 63 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. A major source of HAP emissions is a facility that has the potential to emit any single HAP at a rate of 10 tons/year or greater or any combinations of HAPs at a rate of 25 tons/year or greater. An area source of HAPs is a facility is not a major source of HAPs.

Pursuant to Section 63.6590(c), an affected source that is a new or reconstructed stationary Reciprocating Internal Combustion Engine (RICE) located at an area source must meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60, Subpart JJJJ, for spark ignition engines and no further requirements apply for such engines under this part.

As with 40 CFR 60, Subpart JJJJ, the District has not been delegated the authority to implement 40 CFR 63, Subpart ZZZZ for non-Major Sources; therefore, no requirements from this subpart will be included in the permit. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

Rule 4101 Visible Emissions

Rule 4101 states that no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

Since the engine is fired solely on gaseous fuel, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity.

The following condition will be listed on the permit as a mechanism to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

The following nuisance prohibition condition will be included on the permits:

- No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Appendix D), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

HRA Summary		
Unit	**Cancer Risk**	**T-BACT Required**
C-9133-3-0	0.0823 per million	No

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 20 in a million). As outlined by the HRA Summary in Appendix D of this report, the emissions increases for this project was determined to be less than significant.

The following condition will be listed on the permit as a mechanism to ensure compliance.

- The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rules 2201 and 4102]
- The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot. The higher of the two emission factors (0.08 g-PM_{10}/bhp-hr and 0.03 g-PM_{10}/bhp-hr) for the engine will be used to demonstrate compliance for the engine:

$$\frac{0.08\text{ g}}{\text{hp}\cdot\text{hr}}\times\frac{1\text{ hp}\cdot\text{hr}}{2{,}545\text{ Btu}}\times\frac{10^6\text{ Btu}}{9{,}100\text{ dscf}}\times\frac{0.3\text{Btu}_{out}}{1\text{Btu}_{in}}\times\frac{15.43\text{ grain}}{\text{g}}=0.02\ \frac{\text{grain}}{\text{dscf}}$$

Since 0.02 grain/dscf is less than 0.1 grain/dscf, compliance with this rule is expected.

The following condition will be listed on the permits as a mechanism to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4701 Internal Combustion Engines – Phase I

The purpose of this rule is to limit the emissions of nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion (IC) engines.

The requirements of Rule 4702 are equivalent or more stringent than the requirements of this Rule. Since the proposed IC engines are subject to both Rules 4701 and 4702, compliance with Rule 4702 is sufficient to demonstrate compliance with this rule.

Rule 4702 Internal Combustion Engines

The purpose of this rule is to limit the emissions of nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOC), and sulfur oxides (SOx) from IC engines.

This rule applies to any internal combustion engine with a rated brake horsepower of 25 brake horsepower or greater.

Section 5.2.1 requires that the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall not operate it in such a manner that results in emissions exceeding the limits in Table 1 of Rule 4702 until such time that the engine has demonstrated compliance with emission limits in Table 2 of Rule 4702 pursuant to the compliance deadlines in Section 7.5. In lieu of complying with Table 1 emission limits, the operator of a spark-ignited engine shall comply with the applicable emission limits pursuant to Section 8.0.

The engines are required to immediately comply with the emission limits contained in Table 2 since the applicable compliance dates have passed (except for an operator with at least 12 existing engines at one stationary source); therefore, the emissions limits in Table 1 of Rule 4702 are not applicable to the engine.

Section 5.2.2 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall comply with all the applicable requirements of the rule and the requirements of Section 5.2.2.1, 5.2.2.2, or 5.2.2.3, on an engine-by-engine basis.

Section 5.2.2.1 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited engine that is used exclusively in non-agricultural operations shall comply with Sections 5.2.2.1.1 through 5.2.2.1.3 on an engine-by-engine basis:

5.2.2.1.1 NOx, CO, and VOC emission limits pursuant to Table 2;
5.2.2.1.2 SOx control requirements of Section 5.7, pursuant to the deadlines specified in Section 7.5; and
5.2.2.1.3 Monitoring requirements of Section 5.10, pursuant to the deadlines specified in Section 7.5.

Section 5.2.2.2 allows that in lieu of complying with the NOx emission limit requirement of Section 5.2.2.1.1, an operator may pay an annual fee to the District, as specified in Section 5.6, pursuant to Section 7.6. As shown below, the applicant is proposing to comply with the NOx emission limit requirement of Table 2 as required by Section 5.2.2.1.1; therefore, no further discussion is required.

Section 5.2.2.3 allows that in lieu of complying with the NOx, CO, and VOC limits of Table 2 on an engine-by-engine basis, an operator may elect to implement an alternative emission control plan pursuant to Section 8.0. As shown below, the applicant is proposing to comply with the NOx, CO, and VOC emission limit requirements of Table 2; therefore, no further discussion is required.

Rule 4702, Table 2 Emission Limits/Standards for Spark-Ignited IC Engines rated >50 bhp Used in Non-Agricultural Operations (Emission Limits are effective according to the compliance schedule specified in Rule 4702, Section 7.5.)			
Engine Type	**NOx Emission Limit (ppmv @ 15% O_2, dry)**	**CO Emission Limit (ppmv @ 15% O_2, dry)**	**VOC Emission Limit (ppmv @ 15% O_2, dry)**
2. e. Lean-Burn, Not Listed Above	11 ppmv	2,000 ppmv	750 ppmv

The engine is operated as a separate stationary source on land leased from an existing dairy, and the District has determined that the engine is a non-agricultural IC engine. The engine is fired on digester gas which does not satisfy the definition of waste gas; therefore, the engine is required to comply with the following emissions limits from Table 2, Row 2.e: 11 ppmvd NOx, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2).

Therefore, the following, previously presented, condition will be listed on the permit as a mechanism to ensure compliance:

- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

Section 5.2.3 applies to spark-ignited engines used exclusively in agricultural operations. As stated above, the engine is operated as part of a separate non-agricultural stationary source; therefore, Section 5.2.3 does not apply to the engine.

Section 5.2.4 applies to certified compression-ignited engines. The engine is not a compression-ignited engine; therefore, Section 5.2.4 does not apply to the engine.

Section 5.2.5 applies to non-certified compression-ignited engines. The engine is not a compression-ignited engine; therefore, Section 5.2.5 does not apply to the engine.

Section 5.3 requires that all continuous emission monitoring systems (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes. Any 15-consecutive minute block average CEMS measurement exceeding the applicable emission limits of this rule shall constitute a violation of this rule. The engine does not have CEMS installed; therefore this section of the rule is not applicable.

Section 5.4 specifies procedures to calculate percent emission reductions if percent emission reductions are used to comply with the NOx emission limits of Section 5.2. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the engine under this project; therefore, this section of the rule is not applicable.

Section 5.5 requires the operator of an internal combustion engine that uses percent emission reduction to comply with the NOx emission limits of Section 5.2 shall provide an accessible inlet and outlet on the external control device or the engine as appropriate for taking emission samples and as approved by the APCO. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the engine under this project; therefore, this section of the rule is not applicable.

Section 5.6 specifies procedures that operators of non-agricultural spark-ignited IC engines who elect to comply under Section 5.2.2.2 must use for calculation of the annual emissions fee. The applicant has proposed that the engine complies with the applicable emission limits of Table 2 of District Rule 4702; therefore, payment of annual emissions fees for the engine is not required and this section of the rule is not applicable.

Section 5.7 requires that on and after the compliance schedule specified in Section 7.5, operators of non-agricultural spark-ignited engines and non-agricultural compression-ignited engines shall comply shall comply with Sections 5.7.1, 5.7.2, 5.7.3, 5.7.4, 5.7.5, or 5.7.6:

5.7.1 Operate the engine exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or
5.7.2 Limit gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or
5.7.3 Use California Reformulated Gasoline for gasoline-fired spark-ignited engines; or
5.7.4 Use California Reformulated Diesel for compression-ignited engines; or
5.7.5 Operate the engine on liquid fuel that contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.4.6; or
5.7.6 Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

The average sulfur content of the digester gas fuel for the engine is limited to 40 ppmv or 0.04 g/bhp-hr (approximately equal to 0.008 grains sulfur per standard cubic feet[3]). The following condition will be listed on the permit as a mechanism to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H_2S. The applicant may utilize an averaging period of up to 24 hours in length for

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$$0.04\ \frac{g}{hp\cdot hr}\times\frac{39275hp\cdot hr}{MMBtu}\times\frac{MMBtu}{9{,}100dscf}\times\frac{0.30Btu_{out}}{1Btu_{in}}\times\frac{15.43grain}{g}=\ 0.008\ \frac{grain}{dscf}$$

demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

Section 5.8 requires that the operator of a non-agricultural spark-ignited IC engine subject to the requirements of Section 5.2 or any engine subject to the requirements of Section 8.0 shall comply with the following requirements of Sections 5.8.1 – 5.8.11:

Section 5.8.1 stipulates that for each engine with a rated brake horsepower of 1,000 hp or greater and which is allowed to operate more than 2,000 hours per calendar year, or with an external emission control device, shall either install, operate, and maintain continuous monitoring equipment for NOx, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install, operate, and maintain APCO-approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system (CEMS), a parametric emissions monitoring system (PEMS), or an alternative monitoring system approved by the APCO. APCO-approved alternate monitoring shall consist of one or more of the following:

5.8.1.1 Periodic NOx and CO emission concentrations,
5.8.1.2 Engine exhaust oxygen concentration,
5.8.1.3 Air-to-fuel ratio,
5.8.1.4 Flow rate of reducing agents added to engine exhaust,
5.8.1.5 Catalyst inlet and exhaust temperature,
5.8.1.6 Catalyst inlet and exhaust oxygen concentration, or
5.8.1.7 Other operational characteristics.

The applicant has proposed to comply with this section of the rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic monitoring of NOx, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, the following condition will be placed on the permit as a mechanism to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

Section 5.8.2 requires that for each non-agricultural spark-ignited IC engine not subject to Section 5.8.1, the operator shall monitor operational characteristics recommended by the engine manufacturer or emission control system supplier, and approved by the APCO. The engine is subject to Section 5.8.1; therefore this section is not applicable.

Section 5.8.3 requires that for each engine with an alternative monitoring system, the operator shall submit to, and receive approval from the APCO, adequate verification of the alternative monitoring system's acceptability. The engine includes a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NOx, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, this section is satisfied.

Section 5.8.4 requires that for each engine with an APCO approved CEMS, operate the CEMS in compliance with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Appendix B (Performance Specifications), 40 CFR Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). The engine does not have CEMS installed; therefore, this section of the rule is not applicable.

Section 5.8.5 requires that each engine have the data gathering and retrieval capabilities of an installed monitoring system described in Section 5.8 approved by the APCO. As stated above, the engine includes an alternate emissions monitoring plan that has been pre-approved by the APCO. Therefore, this section is satisfied.

Section 5.8.6 requires that for each non-agricultural spark-ignited IC engine, the operator shall install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the operator may use an alternative device, method, or technique in determining operating time provided that the alternative is approved by the APCO. The operator shall maintain and operate the required meter in accordance with the manufacturer's instructions. The applicant has proposed a nonresettable elapsed operating time meter for the engine in this project. Therefore, the following condition will be placed on the permit as a mechanism to ensure compliance:

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]

Section 5.8.7 requires that for each engine, the operator shall implement the Inspection and Monitoring (I&M) plan submitted to and approved by the APCO pursuant to Section 6.5. The applicant has submitted an I&M program with this ATC application and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this rule.

Section 5.8.8 requires that for each engine, the operator shall collect data through the I&M plan in a form approved by the APCO. The applicant has submitted an I&M program and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this rule.

Section 5.8.9 requires for each non-agricultural spark-ignited IC engine, the operator shall use a portable NOx analyzer to take NOx emission readings to verify compliance with the emission requirements of Section 5.2 or Section 8.0 during each calendar quarter in which a source test is not performed. If an engine is operated less than 120 calendar days per calendar year, the operator shall take one NOx emission reading during the calendar year in which a source test is not performed and the engine is operated. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. All NOx emissions readings shall be reported to the APCO in a manner approved by the APCO. NOx emission readings taken pursuant to this section shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period. Therefore, the following conditions will be placed on the permit as a mechanism to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.8.10 specifies that the APCO shall not approve an alternative monitoring system unless it is documented that continued operation within ranges of specified emissions related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits and that the operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards. The permit for the engine includes a pre-approved alternate emissions monitoring plan that requires periodic NOx, CO, and O_2 emissions concentrations. Therefore, this section is satisfied.

Section 5.8.11 requires that for each non-agricultural spark-ignited IC engine subject to the Alternate Emission Control Plan (AECP) of Section 8.0, the operator shall install and operate a nonresettable fuel meter. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the engine; therefore this section of the rule is not applicable.

Section 5.9 specifies monitoring requirements for all other engines that are not subject to the requirements of Section 5.8. The engine is subject to the requirements of Section 5.8; therefore this section of the rule is not applicable.

Section 5.10 specifies SOx Emissions Monitoring Requirements. On and after the compliance schedule specified in Section 7.5, an operator of a non-agricultural IC engine shall comply with the following requirements:

5.10.1 An operator of an engine complying with Sections 5.7.2 or 5.7.5 shall perform an annual sulfur fuel analysis in accordance with the test methods in Section 6.4. The operator shall keep the records of the fuel analysis and shall provide it to the District upon request,

5.10.2 An operator of an engine complying with Section 5.7.6 by installing and operating a control device with at least 95% by weight SOx reduction efficiency shall submit for approval by the APCO the proposed the key system operating parameters and frequency of the monitoring and recording not later than July 1, 2013, and

5.10.3 An operator of an engine complying with Section 5.7.6 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit-to-Operate. Source tests shall be performed in accordance with the test methods in Section 6.4.

The following condition will be listed on the permit as a mechanism to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

Section 5.11 requires operators of engines used exclusively in agricultural operations that are not required to have a Permit-to-Operate pursuant to California Health and Safety Code Section 42301.16 but are required to comply with Section 5.2 of Rule 4702 shall register such engines pursuant to Rule 2250 (Permit-Exempt Equipment Registration). The engine is required to have a District Permit to Operate; therefore this section of the rule is not applicable.

Section 6.1 requires that the operator of an engine subject to the requirements of Rule 4702 shall submit to the APCO an approvable emission control plan of all actions to be taken to satisfy the emission requirements of Section 5.2 and the compliance schedules of Section 7.0. If there is no change to the previously-approved emission control plan, the operator shall submit a letter to the District indicating that the previously approved plan is still valid.

Section 6.1.1 specifies that the requirement to submit an emission control plan shall apply to the following engines:

6.1.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;

6.1.1.2 Engines subject to Section 8.0;

6.1.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;

6.1.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

Section 6.1.2 specifies that the emission control plan shall contain the following information, as applicable for the engines:

6.1.2.1 Permit-to-Operate number, Authority-to-Construct number, or Permit-Exempt Equipment Registration number,
6.1.2.2 Engine manufacturer,
6.1.2.3 Model designation and engine serial number,
6.1.2.4 Rated brake horsepower,
6.1.2.5 Type of fuel and type of ignition,
6.1.2.6 Combustion type: rich-burn or lean-burn,
6.1.2.7 Total hours of operation in the previous one-year period, including typical daily operating schedule,
6.1.2.8 Fuel consumption (cubic feet for gas or gallons for liquid) for the previous one-year period,
6.1.2.9 Stack modifications to facilitate continuous in-stack monitoring and to facilitate source testing,
6.1.2.10 Type of control to be applied, including in-stack monitoring specifications,
6.1.2.11 Applicable emission limits,
6.1.2.12 Documentation showing existing emissions of NO_x, VOC, and CO, and
6.1.2.13 Date that the engine will be in full compliance with this rule.

Section 6.1.3 requires that the emission control plan shall identify the type of emission control device or technique to be applied to each engine and a construction/removal schedule, or shall provide support documentation sufficient to demonstrate that the engines are in compliance with the emission requirements of this rule.

Section 6.1.4 requires that for an engine being permanently removed from service, the emission control plan shall include a letter of intent pursuant to Section 7.2. The applicant has submitted all the required information for Section 6.1 in the application for the engine evaluated under this project.

Section 6.2.1 requires that the operator of an engine subject to the requirements of Section 5.2 shall maintain an engine operating log to demonstrate compliance with Rule 4702. This information shall be retained for a period of at least five years, shall be readily available, and be made available to the APCO upon request. The engine operating log shall include, on a monthly basis, the following information:

6.2.1.1 Total hours of operation,
6.2.1.2 Type of fuel used,
6.2.1.3 Maintenance or modifications performed,
6.2.1.4 Monitoring data,
6.2.1.5 Compliance source test results, and
6.2.1.6 Any other information necessary to demonstrate compliance with this rule.
6.2.1.7 For an engine subject to Section 8.0, the quantity (cubic feet of gas or gallons of liquid) of fuel used on a daily basis.

The following condition will be placed on the permit as a mechanism to ensure compliance:

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.8 and Section 5.9 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request.

The following, previously presented, condition will be listed on the permit as a mechanism to ensure compliance:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

Section 6.2.3 requires that an operator claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. The applicant is not claiming an exemption for the engines under Section 4.2 or Section 4.3; therefore, this section does not apply.

Section 6.3 requires that the operator of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.2, shall comply with the compliance testing requirements of Section 6.3.

Section 6.3.1 specifies that the requirements of Sections 6.3.2 through Section 6.3.4 shall apply to the following engines:

6.3.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.3.1.2 Engines subject to Section 8.0;
6.3.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.3.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

Section 6.3.2 requires demonstration of compliance with applicable limits, ppmv or percent reduction, in accordance with the test methods in Section 6.4, as specified below:

6.3.2.1 By the applicable date specified in Section 5.2, and at least once every 24 months thereafter, except for an engine subject to Section 6.3.2.2.
6.3.2.2 By the applicable date specified in Section 5.2 and at least once every 60 months thereafter, for an agricultural spark-ignited engine that has been retro-fitted with a catalytic emission control device.

6.3.2.3 A portable NOx analyzer may be used to show initial compliance with the applicable limits/standards in Section 5.2 for agricultural spark-ignited engines, provided the criteria specified in Sections 6.3.2.3.1 to 6.3.2.3.5 are met, and a source test is conducted in accordance with Section 6.3.2 within 12 months from the required compliance date.

The following condition will be included in the permit as a mechanism to ensure compliance:

- Source testing to measure NOx, CO, VOC, and ammonia (NH_3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

Section 6.3.3 requires the operator to conduct emissions source testing with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. For emissions source testing performed pursuant to Section 6.3.2 for the purpose of determining compliance with an applicable standard or numerical limitation, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC shall be reported as methane. VOC, NOx, and CO concentrations shall be reported in ppmv, corrected to 15 percent oxygen. For engines that comply with a percent reduction limit, the percent reduction of NOx emissions shall also be reported.

The following conditions will be included in the permit as a mechanism to ensure compliance:

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH_3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

Section 6.3.4 requires that in addition to other information, the source test protocol shall describe which critical parameters will be measured and how the appropriate range for these parameters shall be established. The range for these parameters shall be incorporated into the I&M plan.

Section 6.3.5 specifies that engines that are limited by Permit-to-Operate or Permit-Exempt Equipment Registration condition to be fueled exclusively with PUC quality natural gas shall not be subject to the reoccurring source test requirements of Section 6.3.2 for VOC emissions. The engine is fueled by digester gas; therefore, this section does not apply.

Section 6.3.6 specifies requirements for spark-ignited engines for testing a unit or units that represent a specified group of units, in lieu of compliance with the applicable requirements of Section 6.3.2. Testing of representative units is not being proposed for the engine; therefore, this section does not apply.

Section 6.4 requires that the compliance with the requirements of Section 5.2 shall be determined, as required, in accordance with the following test procedures or any other method approved by EPA and the APCO:

6.4.1 Oxides of nitrogen - EPA Method 7E, or ARB Method 100.
6.4.2 Carbon monoxide - EPA Method 10, or ARB Method 100.
6.4.3 Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.
6.4.4 Volatile organic compounds - EPA Method 25A or 25B, or ARB Method 100. Methane and ethane, which are exempt compounds, shall be excluded from the result of the test.
6.4.5 Operating horsepower determination - any method approved by EPA and the APCO.
6.4.6 SO_x Test Methods

6.4.6.1 Oxides of sulfur – EPA Method 6C, EPA Method 8, or ARB Method 100.
6.4.6.2 Determination of total sulfur as hydrogen sulfide (H_2S) content – EPA Method 11 or EPA Method 15, as appropriate.
6.4.6.3 Sulfur content of liquid fuel – American Society for Testing and Materials (ASTM) D 6920-03 or ASTM D 5453-99.
6.4.6.4 The SO_x emission control system efficiency shall be determined using the following:
% Control Efficiency = $[(C_{SO2,\ inlet} - C_{SO2,\ outlet}) / C_{SO2,\ inlet}] \times 100$
Where:
$C_{SO2,\ inlet}$ = concentration of SO_x (expressed as SO_2) at the inlet side of the SO_x emission control system, in lb/Dscf
$C_{SO2,\ outlet}$ = concentration of SO_x (expressed as SO_2) at the outlet side of the SO_x emission control system, in lb/Dscf

6.4.7 The Higher Heating Value (hhv) of the fuel shall be determined by one of the following test methods:

6.4.7.1 ASTM D 240-02 or ASTM D 3282-88 for liquid hydrocarbon fuels.
6.4.7.2 ASTM D 1826-94 or ASTM 1945-96 in conjunction with ASTM D 3588-89 for gaseous fuel.

The following conditions will be listed on the permit as a mechanism to ensure compliance:

- The following methods shall be used for source testing: NO_x (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH_3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

- The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

Section 6.5 requires that the operator of an engine that is subject to the requirements of Section 5.2 or the requirements of Section 8.0 shall submit to the APCO for approval, an Inspection & Maintenance (I&M) plan that specifies all actions to be taken to satisfy the requirements of Sections 6.5.1 through Section 6.5.9 and the requirements of Section 5.8. The actions to be identified in the I&M plan shall include, but are not limited to, the information specified below. If there is no change to the previously approved I&M plan, the operator shall submit a letter to the District indicating that previously approved plan is still valid.

Section 6.5.1 specifies that the I&M plan requirements of Sections 6.5.2 through Section 6.5.9 shall apply to the following engines:

6.5.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.5.1.2 Engines subject to Section 8.0;
6.5.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0.
6.5.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

The engine is equipped with an SCR system for control of NOx and oxidation catalyst for control of CO and VOC. Therefore, the requirements of Sections 6.5.2 through 6.5.9 are applicable to the engine.

Section 6.5.2 requires procedures requiring the operator to establish ranges for control equipment parameters, engine operating parameters, and engine exhaust oxygen concentrations that source testing has shown result in pollutant concentrations within the rule limits.

Section 6.5.3 requires procedures for monthly inspections as approved by the APCO. The applicable control equipment parameters and engine operating parameters will be inspected and monitored monthly in conformance with a regular inspection schedule in the I&M plan.

Section 6.5.4 requires procedures for the corrective actions on the noncompliant parameter(s) that the operator will take when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NOx, CO, VOC, or oxygen concentrations.

Section 6.5.5 requires procedures for the operator to notify the APCO when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NOx, CO, VOC, or oxygen concentrations.

Section 6.5.6 requires procedures for and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that the engine is operated and maintained per the manufacturer's specifications.

Section 6.5.7 requires procedures and a schedule for using a portable NOx analyzer to take NOx emission readings pursuant to Section 5.8.9.

Section 6.5.8 requires procedures for collecting and recording required data and other information in a form approved by the APCO including, but not limited to, data collected through the I&M plan and the monitoring systems described in Sections 5.8.1 and 5.8.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO.

NOx Emissions:

In order to satisfy the I&M requirements for NOx emissions, the applicant has proposed to perform the following:

1. The applicant will take periodic NOx emission concentration measurements with a portable analyzer at least once every calendar quarter.

2. To ensure that NOx emissions concentrations are not being exceeded between periodic NOx portable analyzer measurements, the applicant is proposing to determine a correlation between the SCR system's reagent injection rate and NOx emissions. The appropriate ranges for each operating load will be established during initial source testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on the permit as a mechanism to ensure compliance:

- The SCR system reagent injection rate may be reestablished during a performance test by monitoring the SCR system reagent injection rate concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the performance test that result in compliance with the NOx emission limits shall be imposed as a condition in the Permit to Operate. [District Rule 4702]
- If the SCR system reagent injection rate is outside of the established acceptable range, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

- The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]
- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]
- If the NOx, CO, or NH_3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

In order to satisfy the I&M requirements for CO and VOC emissions, the applicant has proposed to perform the following:

1. The applicant will take periodic CO emission concentration measurements with a portable analyzer at least once every calendar quarter. Per the catalyst manufacturer, if the oxidation catalyst is controlling CO emissions, it should also be achieving the desired removal efficiency for VOC emissions. Therefore, quarterly emission concentration measurements with a portable analyzer for VOC emissions will not be required.

2. To ensure that CO and VOC emissions concentrations are not being exceeded between periodic CO emission concentration measurements, the applicant proposed to determine a correlation between the catalyst control system inlet exhaust temperature and back pressure. The appropriate ranges for each operating load were established during initial source testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on the permit as a mechanism to ensure compliance:

- The inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system may be reestablished during a performance test by monitoring concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system demonstrated during the performance test that result in compliance with the CO and VOC emission limits shall by imposed as a condition in the Permit to Operate [District Rule 4702]
- The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]
- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]
- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the

dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

Section 6.5.9 specifies procedures for revising the I&M plan. The I&M plan shall be updated to reflect any change in operation. The I&M plan shall be updated prior to any planned change in operation. An engine operator that changes significant I&M plan elements must notify the District no later than seven days after the change and must submit an updated I&M plan to the APCO no later than 14 days after the change for approval. The date and time of the change to the I&M plan shall be recorded in the engine operating log. For new engines and modifications to existing engines, the I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit-to-Operate or Permit-Exempt Equipment Registration. The operator of an engine may request a change to the I&M plan at any time. The applicant has proposed to comply with the I&M plan modification requirements per this section of the rule. The following condition will be listed on the permit as a mechanism to ensure compliance:

- {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

Section 7.0 specifies the schedules for compliance with the general requirements of Section 5.0 and the Alternative Emission Control Plan (AECP) option of Section 8.0. The engine was required to comply with the applicable sections of District Rule 4702 upon initial startup of the equipment; therefore, compliance with this section is expected.

Section 8.0 specifies requirements for use of an Alternative Emission Control Plan (AECP) to comply with the NOx emission requirements of Section 5.2 for a group of engines. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the engine; therefore, this section of the rule is not applicable.

Section 9.0 specifies requirements for certification of exhaust control systems for compliance with District Rule 4702. Certification under this section for the exhaust control systems for the proposed engine is not currently being proposed; therefore, this section of the rule is not applicable at this time.

Conclusion

As shown above, the engine satisfies all the requirements of Rule 4702. The following conditions will be added to the permit as a mechanism to ensure continued compliance:

- {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
- {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

Rule 4801 Sulfur Compounds

The purpose of this District Rule 4801 is to limit the emissions of sulfur compounds. The limit is that sulfur compound emissions (as SO_2) shall not exceed 0.2% by volume. Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume of SO_x as (SO_2) = (n x R x T) ÷ P

Where:

n = moles SO_x
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73 \text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

To demonstrate compliance with the sulfur compound emission limit of Rule 4801, the maximum sulfur compound emissions from the engine will be calculated using the maximum sulfur content allowed for the digester gas, which is 40 ppmv, equivalent to 0.00965 lb-SO_x/MMBtu.

$$0.00965 \frac{lb}{MMBtu} \times \frac{1\,MMBtu}{9{,}100 scf_{exhaust}} \times \frac{1\,lb \cdot mol}{64\,lb \cdot SO_2} \times \frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot {}^\circ R} \times \frac{520^\circ R}{14.7\,psi} \times 1{,}000{,}000\,ppm = 6.29 \quad \text{ppmv}$$

Since 6.29 ppmv is ≤ 2000 ppmv, the engine is expected to comply with Rule 4801. The following condition will be placed on the permit as a mechanism to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702, and 4801]

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

Greenhouse Gas (GHG) Significance Determination

It is determined that no other agency has prepared or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

The proposed project is for installation of an IC engine that will combust dairy digester gas to produce electricity. The digester system at this facility diverts manure from an adjacent dairy to covered lagoon digester(s), which will result in the capture of the methane that would otherwise be released into the atmosphere from open basin(s)/pond(s) at the dairy. Combustion of the dairy digester gas in the engine will oxidize the methane in the gas to carbon dioxide and water vapor. Because methane has a global warming potential at least 21 times that of carbon dioxide, combustion of the methane from the dairy digester(s) will result in a large net decrease in the global warming potential emitted from the dairy when compared to uncontrolled levels. Therefore, the project will not result in an increase in project specific greenhouse gas emissions. The District therefore concludes that the project would have a less than cumulatively significant impact on global climate change.

District CEQA Findings

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that the activity will occur at an existing facility and the project involves negligible expansion of the existing or former use. Furthermore, the District determined that the activity will not have a significant effect on the environment. Therefore, the District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15301 (Existing Facilities), and finds that the project is exempt per the common sense exemption that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

Indemnification Agreement/Letter of Credit Determination

According to District Policy APR 2010 (CEQA Implementation Policy), when the District is the Lead or Responsible Agency for CEQA purposes, an indemnification agreement and/or a letter of credit may be required. The decision to require an indemnity agreement and/or a letter of credit is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The criteria pollutant emissions and toxic air contaminant emissions associated with the proposed project are not significant, and there is minimal potential for public concern for this particular type of facility/operation. Therefore, an Indemnification Agreement and/or a Letter of Credit will not be required for this project in the absence of expressed public concern.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATC C-9133-3-0 subject to the permit conditions on the attached draft ATC in Appendix A.

X. Billing Information

Annual Permit Fees			
Permit Number	**Fee Schedule**	**Fee Description**	**Annual Fee**
C-9133-3-0	3020-10-F	1,306 bhp IC engine	$900.00

Appendixes

A: Draft ATC
B: BACT Guideline
C: BACT Analysis
D: RMR and AAQA Summary
E: Quarterly Net Emissions Change

APPENDIX A
Draft ATC

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: C-9133-3-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: LONE OAK ENERGY LLC
MAILING ADDRESS: 2911 HANFORD ARMONA RD
HANFORD, CA 93230

LOCATION: 10014 S MCMULLIN GRDE
FRESNO, CA 93706

EQUIPMENT DESCRIPTION:
1,306 BHP CATERPILLAR MODEL G3516LE DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING MODEL COMBIKAT CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This Authority to Construct (ATC) cancels and supersedes ATC C-9133-1-0. [District Rule 2201]
2. {1407} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]
9. This engine shall be fired on digester gas fuel only. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

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Arnaud Marjollet, Director of Permit Services
C-9133-3-0 : Jan 21 2020 6:32PM -- GARCIAJ : Joint Inspection NOT Required

10. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702 and 4801]
11. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]
12. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
13. Commissioning activities are defined as, but not limited to, all adjustments, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
14. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The commissioning period shall terminate when the initial engine tuning has completed and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation of the engine. [District Rule 2201]
15. The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]
16. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
17. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
18. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
19. Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.08 g-PM10/bhp-hr, 4.4 g-CO/bhp-hr, 1.1 g-VOC/bhp-hr. [District Rule 2201]
20. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]
21. Operation of this engine shall not exceed 8,500 hours per year. [District Rule 2201]
22. After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]
23. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rule 2201 and 4702]
24. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]
25. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

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CONDITIONS CONTINUE ON NEXT PAGE

26. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201 and 4702]

27. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201 and 4702]

28. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

29. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

30. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

31. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

32. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

33. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

34. The results of each source test shall be submitted to the District within 60 days after completion of source test. [District Rule 1081]

35. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

36. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a digital analyzer approved for gaseous fuel analysis; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

37. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

CONDITIONS CONTINUE ON NEXT PAGE

38. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

39. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

40. If the NOx, CO, or NH3 concentrations, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

41. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

42. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

43. The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]

44. During initial performance testing, the SCR system reagent injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the initial performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

45. The SCR system reagent injection rate may be reestablished during a performance test by monitoring the SCR system reagent injection rate concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

46. If the SCR system reagent injection rate is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

47. During initial performance testing, the inlet temperature to the SCR system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). For each operating load, the established acceptable inlet temperature and back pressure ranges demonstrated during the initial performance test that result in compliance with the CO emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

48. The inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system may be reestablished during a performance test by monitoring concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system demonstrated during the performance test that result in compliance with the CO and VOC emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

49. The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]

50. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

52. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

53. Records of hydrogen sulfide analyzer(s) installed or utilized and the calibration records of such analyzer(s) shall be maintained. Records are only required on such analyzer(s) utilized to demonstrate compliance with this permit. [District Rule 2201]

54. {4051} The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

55. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

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APPENDIX B
BACT Guideline

SJVAPCD Best Available Control Technology (BACT) Guideline 3.3.15*

Last Update: 3/6/2013

Waste Gas-Fired IC Engine**

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NO_X	0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent)		1. Fuel Cells (<0.05 lb/MW-hr) 2. Microturbines (<9 ppmv @ 15% O_2) 3. Gas Turbine (<9 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
SO_X	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S) (dry absorption, wet absorption, chemical H_2S reduction, water scrubber, or equivalent) (may be averaged up to 24 hours for compliance)		
PM_{10}	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S)		
CO	2.0 g/bhp-hr		1. Fuel Cells (<0.10 lb/MW-hr) 2. Microturbines (<60 ppmv @ 15% O_2) 3. Gas Turbine (<60 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
VOC	0.10 g/bhp-hr (lean burn and positive crankcase ventilation (PCV) or a 90% efficient crankcase control device or equivalent)		Fuel Cells (<0.02 lb-VOC/MW-hr as CH_4)

*** For the purposes of this determination, waste gas is a gas produced from the digestion of material excluding municipal sources such as waste water treatment plants, landfills, or any source where siloxane impurities are a concern.*

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Pages**

APPENDIX C
BACT Analysis

Top-Down BACT Analyses for the Digester Gas-Fired Engine

As stated above, the information form the existing District BACT Guideline 3.3.15 for Waste Gas-Fired IC Engines will be utilized for the BACT analysis for the proposed engine.

I. BACT Analysis for NOx Emissions:

a. Step 1 - List all control technologies

1) NOx emissions ≤ 0.15 g/bhp-hr = 10 ppmv NOx @ 15% O_2[4] (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

2) Fuel Cell (≤ 0.05 lb/MW-hr = 1.1 ppmv NOx @ 15% O_2[5]) (Alternate Basic Equipment)

3) Microturbine (< 9 ppmv NOx @ 15% O_2) (Alternate Basic Equipment)

4) Gas Turbine (< 9 ppmv NOx @ 15% O_2) (Alternate Basic Equipment)

Description of Control Technologies

1) NOx emissions ≤ 0.15 g/bhp-hr (10 ppmv NOx @ 15% O_2) (Selective Catalytic Reduction (SCR) or equivalent) (Achieved in Practice)

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NOx, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NOx emissions by up to 90%.

2) Fuel Cell (≤ 0.05 lb- NOx/MW-hr) (Alternate Basic Equipment)

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell. Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and

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4 $$\frac{0.15\text{ g NOx}}{\text{bhp - hr}} \times \frac{\text{MMBtu}}{9{,}100\text{ dscf}} \times \frac{30\%}{1} \times \frac{1\text{ lb - mol}}{46\text{ lb}} \times \frac{20.9 - 15}{20.9} \times \frac{379.5\text{ dscf}}{1\text{ lb mol}} \times \frac{393.75\text{ bhp - hr}}{\text{MMBtu}} \times \frac{\text{lb}}{453.6\text{ g}} = 10\text{ ppmv @ 15 \% O2}$$

5 $$\frac{0.05\text{ lb NOx}}{\text{MW - hr}} \times \frac{\text{MW}}{1{,}341\text{ bhp}} \times \frac{\text{MMBtu}}{9{,}100\text{ dscf}} \times \frac{30\%}{1} \times \frac{1\text{ lb - mol}}{46\text{ lb}} \times \frac{20.9 - 15}{20.9} \times \frac{379.5\text{ dscf}}{1\text{ lb mol}} \times \frac{393.75\text{ bhp - hr}}{\text{MMBtu}} = 1.1\text{ ppmv @ 15 \% O2}$$

solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these high temperature fuel cells are tolerant of CO_2 that is found in digester gas.

Fuel cells have recently been commercialized and offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells is the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense and, for digester gas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cell catalysts. Although this expense can be substantial, digester gas-fueled fuel cells have been installed at some wastewater treatment plants and fuel cells have also been fueled with other types of biogas (e.g. landfill gas and brewery wastewater gas).

3) Gas Turbine (< 9 ppmv NO_x @ 15% O_2) (Alternate Basic Equipment)

Gas turbines are internal combustion engines that operate on the Brayton (Joule) combustion cycle rather than the Otto combustion cycle used in reciprocating internal combustion engines or the diesel cycle for diesel engines. In the Brayton cycle the air flow and fuel injection are steady, and the different parts of the cycle occur continuously within different components of the system. In a gas turbine, fuel is continually injected into the combustion chamber or combustor and air is constantly drawn into the turbine and compressed. All elements of the Brayton cycle occur simultaneously in a gas turbine.

Gas turbines are one of the cleanest means of generating electricity. With the use of lean pre-mixed combustion or catalytic exhaust cleanup, NO_x emissions from large gas-fired turbines are generally in the single-digit ppmv range. These levels are generally for natural gas-fired units but they are considered technologically feasible for digester gas-fired units.

Gas turbines are available in sizes ranging from 500 kW - 25 MW. Based on contacts with turbine suppliers, digester gas-fired turbines used to produce electricity are expected to be available in the size range of 2 - 7 MW. According to Solar Turbines, the smaller digester gas-fired turbines are no longer actively produced or marketed since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

4) Microturbine (< 9 ppmv NO_x @ 15% O_2) (Alternate Basic Equipment)

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gases. According to the California Air Resources Board (ARB), there were approximately 200 digester gas-fired microturbines operating in

California as of the year 2006.[6] Microturbines generally have electrical efficiencies of 25 - 30%; however, the electrical efficiency of larger microturbines (≥ 200 kW) can range from 30 - 33%. Microturbine manufacturers include Capstone Microturbines and FlexEnergy.

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of NO_X, CO, and VOC than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low NO_X, or DLN) combustion technology. Microturbines manufacturers will generally guarantee NO_X emissions of 9 - 15 ppmv @ 15% O_2. However, several emission tests performed on digester gas-fired microturbines have demonstrated even lower emissions. A small number of dairy digester gas-fired microturbines have been installed[7], including Twin Birch Dairy and New Hope Farm View dairy and Twin Birch Dairy in New York, and den Dulk Dairy in Michigan.

The proposed project is for a large waste gas to energy facility and, although larger microturbines have recently become available, several microturbines (at least 5) would still be required to replace each engine. The applicant states that when they investigated microturbines they found that there were difficulties related to the loss of power and efficiency because of heat de-rating in warmer climates and the very high pressure requirement and parasitic load, which increased overall costs. In addition, a different applicant for digester gas projects recently permitted by the District (Projects S-1143770 and S-1143771) indicated that when they investigated microturbines they found that they could not secure the necessary financing for a waste gas to energy project of this size using microturbines and that the major microturbines vendors were unable to secure the debt. Although microturbines may not currently be a practical option for this particular project, they will be considered in the cost analysis below.

b. Step 2 - Eliminate technologically infeasible options

Option 3 - Gas Turbine (≤ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Option 3, Gas Turbine, was determined to be infeasible for the proposed project because the available information indicates that the principal suppliers of gas turbines (Solar Turbines, Allison, and General Electric) do not currently produce or market waste gas-fired gas turbines rated less than 3 MW since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

The cost information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[8] (March 2015) and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][9] (October 5, 2015) also supports that gas turbines rated approximately 3 MW are not generally available. The smallest turbine

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[6] "Staff Report: Initial Statement of Reasons for Proposed Amendments to the Distributed Generation Certification Regulation" (9/1/2006), Cal EPA - ARB, Executive Summary Pg. ii (http://www.arb.ca.gov/regact/dg06/dgisor.pdf)
[7] See EPA AgStar Program "AgStar Project Profiles", http://www2.epa.gov/agstar/agstar-project-profiles
[8] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies
[9] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

for which the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies provides cost information is 3,304 kW and the smallest turbine for which the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] provides cost information is 2,500 kW.

The proposed project would require a gas turbine rated 1,028 kW, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas turbines are not considered feasible for this particular project and will be eliminated from consideration at this time.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NOx @ 15% O_2) (Alternate Basic Equipment)
2) Digester gas-fueled microturbines (Alternate Basic Equipment)
3) NOx emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy, a cost effectiveness analysis is required for the options that have not been determined to be achieved in practice. In accordance with the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), to determine the cost effectiveness of particular technologically feasible control options or alternate equipment options, the amount of emissions resulting from each option will be quantified and compared to the District Standard Emissions allowed by the District Rule that is applicable to the particular unit. The emission reductions will be equal to the difference between the District Standard Emissions and the emissions resulting from the particular option being evaluated.

The District has determined that the proposed digester gas-fueled IC engine is a non-agricultural IC engine. The lean burn, digester gas-fired, engine is subject to the following emission limits for non-agricultural, lean burn, waste gas fueled IC engines contained in District Rule 4702, Section 5.2.2, Table 2, 2.e: 11 ppmvd NOx (or 0.17 g/bhp-hr)[10], 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2). The proposed digester gas-fired digester engine is also subject to the New Source Performance Standards (NSPS) for IC Engines contained in 40 CFR 60 Subpart JJJJ, which includes a VOC emissions limit of 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane) for landfill and digester gas-fired IC engines. Therefore, the District Standard Emissions used for the BACT cost analysis below for the proposed engine will be based on the emission limits contained in these applicable regulations.

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$$\frac{11\,\text{ft}^3\ \text{NOx}}{10^6\ \text{ft}^3} \times \frac{9{,}100\,\text{ft}^3}{1\,\text{MMBtu}} \times \frac{46\,\text{lb NOx}}{1\,\text{lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1\,\text{lb-mole}}{379.5\,\text{ft}^3} \times \frac{\text{MMBtu}}{392.75\,\text{bhp-hr}} \times \frac{453.6\,\text{g}}{\text{lb}} \times \frac{\text{Btu}_{in}}{0.30\,\text{Btu}_{out}} = 0.17\ \frac{\text{g-NOx}}{\text{bhp-hr}}$$

Option 1: Fuel Cells ($\leq$ 0.05 lb/MW-hr $\approx$ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Because fuel cells have reduced NO_X and VOC emissions in comparison to a reciprocating IC engine, a Multi-Pollutant Cost Effectiveness Threshold (MCET) will be used to determine if this option is cost-effective. The following cost analysis will examine if the replacement of the proposed engine with a fuel cell is cost effective even when the additional operation costs of a fuel cell are not considered.

Assumptions

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 700 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Price for electricity: $127.72/MW-hr (*based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)*[11] *beginning June 1, 2016*)
- MMBtu/hr to bhp conversion: 392.75 (per AP-42, Appendix A)
- Btu to kW-hr conversion: 3,413 Btu/kW-hr (per AP-42, Appendix A)
- The initial capital costs and the operation costs for the digester gas-fueled IC engine and fuel cell will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[8] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][9]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and fuel cells, additional capital costs for the use of digester gas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [9]

Assumptions for the Proposed Digester Gas-Fired IC Engine

- The engine will operate at full load for 24 hours/day and 8,500 hours/year
- Typical thermal efficiencies for IC engines range from 30-35%. A worst case thermal efficiency of 30% will be used.
- The maximum total daily heating value of the digester gas used by the engine will be: 266.02 MMBtu/day (*1,306 bhp_{out}/engine x 1 bhp_{in}/0.30 bhp_{out} x 1 $MMBtu_{in}$/ 392.75 bhp_{in}-hr x 24 hr/day*)
- The maximum total annual heating value for of the digester gas used by the engine will be: 94,216 MMBtu/year (*1,306 bhp_{out}/engine x 1 bhp_{in}/0.30 bhp_{out} 1 $MMBtu_{in}$/ 392.75 bhp_{in}-hr x 8,500 hr/year*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,028 kW without add-on air pollution control equipment: $1,223/kW (*average of interpolated*

11 See: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/BioMAT/index.page, https://scebiomat.accionpower.com/biomat/home.asp, and http://www.sdge.com/procurement/bioenergy-market-adjusting-tariff-bio-mat)

values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies on page 2-15 and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] on page A-33)

- Additional capital investment for digester gas conditioning and cleanup for the engine: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for digester-fueled IC engine rated 1,028 kW: $1,610/kW
- Estimated operation costs for CHP IC engine rated 1,028 kW without add-on air pollution control costs: $0.028/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies on page 2-17 and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] on page A-33*)
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that digester gas conditioning/cleanup costs are highly dependent on the quantity of digester gas being processed and contaminants being removed and that the differences in clean-up costs for digester gas-fired IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engine must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because required level of sulfur removal is adequate for use in the engine, there will be no increase in operating costs related to cleaning the digester gas for use in the engine.
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 11 ppmv @ 15% O_2 = 0.165 lb/MMBtu
- Rule 4702 VOC emission limit for non-agricultural, lean burn IC engines: 750 ppmv @ 15% O_2 as CH_4 = 1.0193 lb/MMBtu
- 40 CFR 60 Subpart JJJJ VOC emission limit for landfill and digester gas-fired IC engines: 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane)

<u>Assumptions for Fuel Cell System</u>

- Net electrical efficiency for a molten carbonate fuel cell (MCFC): 45% (*US EPA Combined Heat and Power Partnership Catalog of CHP Technologies gives efficiencies of 47% for a 300 kW MCFC and 42.5% for a 1,400 kW MCFC*)
- Size of fuel cell system needed to replace the proposed engine: 1,463 kW (estimated based on 266.02 MMBtu/day and 45% efficiency[12])
- Estimated Purchase and Installation Cost for Molten Carbonate Fuel Cell: $4,474/kW (*Average of the two costs for largest Molten Carbonate Fuel Cells given in US EPA Combined Heat and Power Partnership document Catalog of CHP Technologies on page 6-16 and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] on page A-13; The U.S. Department of Energy Federal energy management Program (FEMP) document "Fuel Cells and Renewable Energy" (last updated 12-1-2014 and available at: <u>http://www.wbdg.org/resources/fuelcell.php</u>)*

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12 $$\frac{266.02\text{ MMBtu}}{\text{day}} \times \frac{\text{kW - hr}}{3{,}410\text{ Btu}} \times \frac{10^6\text{Btu}}{\text{MMBtu}} \times \frac{\text{day}}{24\text{ hrs}} \times 45\% = 1{,}463\text{ kW}$$

states, "Installation costs of a fuel cell system can range from $5,000/kW to $10,000/kW." Therefore, this estimate may be actually too low based on the recently reported costs for fuel cell power plants, such as the "Bloom Box".)

- Additional capital investment for digester gas conditioning and cleanup for the fuel cell: $563/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for digester gas-fueled fuel cells rated ≥ 1,200 kW (the larger the capacity, the cheaper the cost) will be used: $5,037/kW
- Typical operation costs for natural gas-fueled fuel cells, including stack replacement costs: $0.04/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional operational costs for digester gas conditioning and cleanup for large fuel cells: $0.15/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Operation Cost for digester gas-fueled fuel cells rated ≥ 1,200 kW(conservatively using the cheaper cost of the larger capacity fuel cell): $0.19/kW-hr
- Unlike the proposed engine, a high-temperature fuel cell power plant must primarily operate at steady state conditions; there would not be the ability to store gas to generate more electricity during peak hours, which is the current business plan of the applicant. Because the price paid for electricity is greater during peak hours and less during other times, the price paid for electricity generated by a fuel cell power plant would be less. This would require the operator to alter their plans of operation and result in less revenue per kW-hr of electricity generated potentially offsetting the revenue from increased power generating capacity because of the higher efficiency of a fuel cell power plant. For more conservative analysis, the difference in the cost of peak and off-peak electricity was not considered in this comparison.

<u>Capital Cost</u>

The estimated increased incremental capital cost for replacement of the proposed engine with a fuel cell is calculated based on the difference in cost of a fuel cell power plant and the proposed IC engine.

The incremental capital cost for replacement of the proposed IC engine with a fuel cell power plant is calculated as follows:

(1,463 kW x $5,037/kW) - (1,028 kW x $1,610/kW) = $5,714,051

<u>Annualized Capital Cost</u>

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(I+1)^n]/[(I+1)^n-1]$$

Where:
A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$$A = [\$5{,}714{,}051 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \mathbf{\$931{,}390/year}$$

Annual Costs

Annual Operation and Maintenance Cost

The annual operation and maintenance costs for each option are calculated as follows:

Proposed 1,028 kW IC Engine

8,738,000 kW-hr/yr x $0.028/kW-hr = $244,664/year

Fuel Cells (Alternate Equipment)

12,435,500 kW-hr/yr x $0.19/kW-hr = $2,362,745/year

Annual Costs of Increased Maintenance

$2,362,745/yr - $244,664/yr = $2,118,081/year

Total Increased Annual Costs for Fuel Cell as an Alternative to the Proposed Engine

$931,390/year + $2,118,081/year = **$3,049,471/year**

Emission Reductions

NO_x and VOC Emission Factors

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_x emissions from the engine will be based on the NO_x emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.2, Table 2, 2.e. The District Standard Emissions for VOC emissions from the engine will be based on the New Source Performance Standard (NSPS) VOC emission limit for landfill and digester gas-fired IC engines from 40 CFR 60 Subpart JJJJ, since this limit is more stringent than the applicable emission limit in District Rule 4702.

The following emissions factors will be used for the cost analysis:

District Standard Emissions

0.165 lb-NO_x/MMBtu (11 ppmv NO_x @ 15% O_2)
0.111 lb-VOC/MMBtu (75 ppmv VOC @ 15% O_2)

Emissions from Fuel Cells as Alternative Equipment

0.016 lb-NO_x/MMBtu (0.05 lb-NO_x/MW-hr)
0.006 lb-VOC/MMBtu (0.02 lb-VOC/MW-hr)

Emission Reductions

The Proposed Engine Compared to Fuel Cells based on District Standard Emission Reductions

NO_x Emission Reductions (11 ppmv @ 15% O_2 → 0.05 lb-NO_x/MW-hr)

94,216 MMBtu/year x (0.165 lb-NO_x/MMBtu – 0.016 lb-NO_x/MMBtu)
= 14,038 lb-NO_x/year (7.0 ton-NO_x/year)

VOC Emission Reductions (1.0 g/bhp-hr → 0.02 lb-VOC/MW-hr)

94,216 MMBtu/year x (0.111 lb-VOC/MMBtu – 0.006 lb-VOC/MMBtu)
= 9,893 lb-VOC/year (4.9 ton-VOC/year)

Multi-Pollutant Cost Effectiveness Thresholds (MCET) for NO_x and VOC Reductions based on District Standard Emission Reductions

(7.0 ton-NO_x/year x $24,500/ton-$NO_x$) + (4.9 ton-VOC/year x $17,500/ton-VOC)
= **$257,250/year**

As shown above, the annualized capital cost of this alternate option ($3,049,471) exceeds the Multi-Pollutant Cost Effectiveness Threshold (MCET) calculated for the NO_x and VOC emission reductions ($257,250). Therefore, this option is not cost effective and is being removed from consideration.

Options 2 and 3 – Microturbine and IC Engine with NO_x Emissions ≤ 0.15 g/bhp-hr

The applicant is proposing a NO_x limit of 0.08 g/bhp-hr. Since this proposed limit is lower than the remaining options, per District BACT Policy APR 1305, Section IX.D.1, a cost effectiveness analysis is not required and no further analysis is required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for the Digester Gas-fired Engine must be satisfied with the following: NO_x emissions ≤ 0.15 g/bhp-hr

The applicant has proposed to use an SCR system for the digester gas-fired lean burn IC engine to limit NO_x emissions to ≤ 0.15 g/bhp-hr. Therefore, the BACT requirements are satisfied.

2. BACT Analysis for SO_x Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce SO_x emissions from the proposed engine:

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice/Contained in SIP)

There are no options listed in the SJVUAPCD BACT Clearinghouse as alternate basic equipment.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

The control efficiency of each of the options above is estimated and the controls are ranked below based on the control effectiveness.

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for SO_x emissions from the proposed engine is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use addition of iron oxide chemicals to the digester, a biological sulfur removal system, and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engine to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_x are satisfied.

3. **BACT Analysis for PM_{10} Emissions:**

a. Step 1 - Identify all control technologies

Combustion of gaseous fuels generally does not result in significant emissions of particulate matter. Dairy anaerobic digester gas is the planned fuel for the proposed IC engine. The anaerobic digester gas will be composed primarily of methane (approximately 60% molar composition) and CO_2 (approximately 40% molar composition) and is expected to burn in a fairly clean manner. Particulate emissions from combustion of the digester gas are expected to primarily result from the incineration of fuel-born sulfur compounds (mostly H_2S) resulting in the formation of sulfur-containing particulate. Therefore, scrubbing of the digester gas is the principal means to reduce particulate emissions.

The following control was identified to reduce particulate matter emissions from combustion of the digester gas as fuel in the proposed engine:

1) Sulfur Content of fuel ≤ 40 ppmv as H_2S (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Sulfur Content of fuel gas ≤ 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for PM_{10} emissions from the proposed engine is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use addition of iron oxide chemicals to the digester, a biological sulfur removal system, and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engine to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for PM_{10} are satisfied.

4. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce VOC emissions:

1) VOC emissions ≤ 0.10 g/bhp-hr (lean burn or equivalent and positive crankcase ventilation) (Achieved in Practice)
2) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)
2) VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cell (≤ 0.02 lb/MW-hr VOC as CH_4) (Alternate Basic Equipment)

The multi-pollutant cost analysis performed above for the NO_X and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the NO_X and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

This has been identified as achieved in practice and has been proposed by the applicant. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the proposed engine is VOC emissions ≤ 0.10 g/bhp-hr. The applicant has proposed an IC engine with VOC emissions ≤ 0.10 g/bhp-hr. Therefore, the BACT requirements for VOC are satisfied.

APPENDIX D
HRA and AAQA Summary

San Joaquin Valley Air Pollution Control District
Risk Management Review and Ambient Air Quality Analysis

To:	Manuel Salinas – Permit Services
From:	Will Worthley – Technical Services
Date:	December 10, 2019
Facility Name:	LONE OAK ENERGY LLC
Location:	10014 S MCMULLIN GRDE, FRESNO
Application #(s):	C-9133-3-0
Project #:	C-1193519

1. Summary

1.1 RMR

Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required	Special Permit Requirements
3-0	13.88	0.37	0.02	8.23E-08	No	Yes
Project Totals	13.88	0.37	0.02	8.23E-08		
Facility Totals	>1	0.64	0.03	1.41E-07		

1.2 AAQA

Pollutant	Air Quality Standard (State/Federal)				
	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass		Pass		
NO_x	Pass				Pass
SO_x	Pass	Pass		Pass	Pass
PM10				Pass[3]	Pass[3]
PM2.5				Pass[4]	Pass[4]

Notes:
1. Results were taken from the attached AAQA Report.
2. The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2) unless otherwise noted below.
3. Modeled PM10 concentrations were below the District SIL for non-fugitive sources of 5 μg/m³ for the 24-hour average concentration and 1 μg/m³ for the annual concentration.
4. Modeled PM2.5 concentrations were below the District SIL for non-fugitive sources of 1.2 μg/m³ for the 24-hour average concentration and 0.2 μg/m³ for the annual concentration.

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

Unit # 3-0

1. The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rules 2201 and 4102]
2. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction.

2. Project Description

Technical Services received a request on December 4, 2019 to perform a Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA) for the following:

- Unit -3-0: 1,306 BHP CATERPILLAR, MODEL G3516LE, DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING, MODEL COMBIKAT, CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

3. RMR Report

3.1 Analysis

The District performed an analysis pursuant to the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015) to determine the possible cancer and non-cancer health impact to the nearest resident or worksite. This policy requires that an assessment be performed on a unit by unit basis, project basis, and on a facility-wide basis. If a preliminary prioritization analysis demonstrates that:

- A unit's prioritization score is less than the District's significance threshold and;
- The project's prioritization score is less than the District's significance threshold and;
- The facility's total prioritization score is less than the District's significance threshold

Then, generally no further analysis is required.

The District's significant prioritization score threshold is defined as being equal to or greater than1.0. If a preliminary analysis demonstrates that either the unit(s) or the project's or the facility's total prioritization score is greater than the District threshold, a screening or a refined assessment is required

If a refined assessment is greater than one in a million but less than 20 in one million for carcinogenic impacts (Cancer Risk) and less than 1.0 for the Acute and Chronic hazard indices(Non-Carcinogenic) on a unit by unit basis, project basis and on a facility-wide basis the proposed application is considered less than significant. For unit's that exceed a cancer risk of 1 in one million, Toxic Best Available Control Technology (TBACT) must be implemented.

Toxic emissions for this project were calculated using the following methods:

- Toxic emissions for this Dairy Gas Fired internal combustion (2 Stroke Lean Burn, or 4 Stroke Lean Burn, or 4 Stroke Rich Burn) Engine were calculated using emission factors from 2000, AP 42, Fifth Edition, Volume I, Chapter 3: Stationary Internal Combustion Sources, Section 2: Natural Gas-Fired Reciprocating Engines and Dairy Biomethane characterization from 2009 report, Pipeline Quality Biomethane: North American Guidance Document for Introduction o f Dairy Waste Derived Biomethane Into Existing Natural Gas Networks.

These emissions were input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy, risks from the proposed unit's toxic emissions were prioritized using the procedure in the 2016 CAPCOA Facility Prioritization Guidelines. The prioritization score for this proposed facility was greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required.

The AERMOD model was used, with the parameters outlined below and meteorological data for 2013-2017 from Fresno (rural dispersion coefficient selected) to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Source Process Rates					
Unit ID	**Process ID**	**Process Material**	**Process Units**	**Hourly Process Rate**	**Annual Process Rate**
3	1	Fuel Usage (Commissioning)	MMscf	0.013	1.59
3	1	NH3 (Commissioning)	Lbs	0.15	19
3	2	Fuel Usage (Non-Commissioning)	MMscf	0.013	112.9
3	2	NH3 (Non-Commissioning)	Lbs	0.16	1327

Point Source Parameters						
Unit ID	**Unit Description**	**Release Height (m)**	**Temp. (°K)**	**Exit Velocity (m/sec)**	**Stack Diameter (m)**	**Vertical/ Horizontal/ Capped**
3	Digester Engine (Non-Comissioning Period)	6.71	709	38.31	0.36	Vertical
3	Digester Engine (Comissioning Period)	6.71	709	38.31	0.36	Vertical

4. AAQA Report

The District modeled the impact of the proposed project on the National Ambient Air Quality Standard (NAAQS) and/or California Ambient Air Quality Standard (CAAQS) in accordance with District Policy APR-1925 (Policy for District Rule 2201 AAQA Modeling) and EPA's Guideline for Air Quality Modeling (Appendix W of 40 CFR Part 51). The District uses a progressive three level approach to perform AAQAs. The first level (Level 1) uses a very conservative approach. If this analysis indicates a likely exceedance of an AAQS or Significant Impact Level (SIL), the analysis proceeds to the second level (Level 2) which implements a more refined approach. For the 1-hour NO_2 standard, there is also a third level that can be implemented if the Level 2 analysis indicates a likely exceedance of an AAQS or SIL.

The modeling analyses predicts the maximum air quality impacts using the appropriate emissions for each standard's averaging period. Required model inputs for a refined AAQA include background ambient air quality data, land characteristics, meteorological inputs, a receptor grid, and source parameters including emissions. These inputs are described in the sections that follow.

Ambient air concentrations of criteria pollutants are recorded at monitoring stations throughout the San Joaquin Valley. Monitoring stations may not measure all necessary pollutants, so background data may need to be collected from multiple sources. The following stations were used for this evaluation:

Monitoring Stations				
Pollutant	**Station Name**	**County**	**City**	**Measurement Year**
CO	Tranquillity	Fresno	Fresno	2016
NOx	Fresno-Drummond	Fresno	Fresno	2016
PM10	Fresno-Drummond	Fresno	Fresno	2016
PM2.5	Tranquillity	Fresno	Fresno	2016
SOx	Fresno - Garland	Fresno	Fresno	2016

Technical Services performed modeling for directly emitted criteria pollutants with the emission rates below:

Emission Rates (lbs/hour)						
Unit ID	**Process**	**NOx**	**SOx**	**CO**	**PM10**	**PM2.5**
3	1	2.89	0.12	12.67	0.23	0.23

Emission Rates (lbs/year)						
Unit ID	**Process**	**NOx**	**SOx**	**CO**	**PM10**	**PM2.5**
3	1	3,965	979	49,776	1,958	1,958

The AERMOD model was used to determine if emissions from the project would cause or contribute to an exceedance of any state of federal air quality standard. The parameters outlined below and meteorological data for 2013-2017 from Fresno (rural dispersion coefficient selected) were used for the analysis:

The following parameters were used for the review:

Point Source Parameters						
Unit ID	**Unit Description**	**Release Height (m)**	**Temp. (°K)**	**Exit Velocity (m/sec)**	**Stack Diameter (m)**	**Vertical/ Horizontal/ Capped**
3	Digester Engine	6.71	709	38.31	0.36	Vertical

5. Conclusion

5.1 RMR

The cumulative acute and chronic indices for this facility, including this project, are below 1.0; and the cumulative cancer risk for this facility, including this project, is less than 20 in a million. In addition, the cancer risk for each unit in this project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit requirements listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

5.2 AAQA

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

6. Attachments

A. Modeling request from the project engineer

B. Additional information from the applicant/project engineer

C. Prioritization score w/ toxic emissions summary

D. Facility Summary

E. AAQA results

APPENDIX E
Quarterly Net Emissions Change (QNEC)

Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post-Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

$PE2_{quarterly} = PE2_{annual} \div 4$ quarters/year

$PE1_{quarterly} = PE1_{annual} \div 4$ quarters/year

Quarterly NEC [QNEC]			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	991.25	0	991.25
SO_X	244.75	0	244.75
PM_{10}	489.50	0	489.50
CO	12,443.75	0	12,443.75
VOC	698.25	0	698.25

April 13, 2020

Doug Bryant
Maas Energy Works, Inc
3711 Meadow View Dr, #100
Redding, CA 96002

RE: Notice of Final Action - Authority to Construct for Lone Oak Energy LLC
Facility Number: C-9133
Project Number: C-1193519

Dear Mr. Bryant:

The Air Pollution Control Officer has issued the Authority to Construct permit to Lone Oak Energy LLC for the installation of a 1,306 bhp digester gas-fired IC engine powering an electrical generator, at 10014 S McMullin Grade, Hanford. Enclosed are the Authority to Construct permit and a copy of the notice of final action that has been posted on the District's website (www.valleyair.org).

Notice of the District's preliminary decision to issue the Authority to Construct permit was posted on February 21, 2020. The District's analysis of the proposal was also sent to CARB on February 21, 2020. No comments were received following the District's preliminary decision on this project.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Errol Villegas at (559) 230-6000.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:jag

Enclosures

cc: Courtney Graham, CARB (w/ enclosure) via email

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

Facility # C-9133
LONE OAK ENERGY LLC
2911 HANFORD ARMONA RD
HANFORD, CA 93230

AUTHORITY TO CONSTRUCT (ATC)

QUICK START GUIDE

1. **Pay Invoice**: Please pay enclosed invoice before due date.

2. **Fully Understand ATC**: Make sure you understand ALL conditions in the ATC prior to construction, modification and/or operation.

3. **Follow ATC**: You must construct, modify and/or operate your equipment as specified on the ATC. Any unspecified changes may require a new ATC.

4. **Notify District**: You must notify the District's Compliance Department, at the telephone numbers below, upon start-up and/or operation under the ATC. Please record the date construction or modification commenced and the date the equipment began operation under the ATC. You may NOT operate your equipment until you have notified the District's Compliance Department. A startup inspection may be required prior to receiving your Permit to Operate.

5. **Source Test**: Schedule and perform any required source testing. See http://www.valleyair.org/busind/comply/source_testing.htm for source testing resources.

6. **Maintain Records**: Maintain all records required by ATC. Records are reviewed during every inspection (or upon request) and must be retained for at least 5 years. Sample record keeping forms can be found at http://www.valleyair.org/busind/comply/compliance_forms.htm.

By operating in compliance, you are doing your part to improve air quality for all Valley residents.

For assistance, please contact District Compliance staff at any of the telephone numbers listed below.

AUTHORITY TO CONSTRUCT

PERMIT NO: C-9133-3-0 **ISSUANCE DATE:** 04/03/2020

LEGAL OWNER OR OPERATOR: LONE OAK ENERGY LLC
MAILING ADDRESS: 2911 HANFORD ARMONA RD
HANFORD, CA 93230

LOCATION: 10014 S MCMULLIN GRDE
FRESNO, CA 93706

EQUIPMENT DESCRIPTION:
1,306 BHP CATERPILLAR MODEL G3516LE DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING MODEL COMBIKAT CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This Authority to Construct (ATC) cancels and supersedes ATC C-9133-1-0. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
3. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]
9. This engine shall be fired on digester gas fuel only. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

Arnaud Marjollet, Director of Permit Services
C-9133-3-0 : Apr 3 2020 3:32PM -- GARCIAJ : Joint Inspection NOT Required

10. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H_2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702 and 4801]

11. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]

12. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]

13. Commissioning activities are defined as, but not limited to, all adjustments, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]

14. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The commissioning period shall terminate when the initial engine tuning has completed and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation of the engine. [District Rule 2201]

15. The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]

16. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]

17. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

18. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]

19. Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.08 g-PM10/bhp-hr, 4.4 g-CO/bhp-hr, 1.1 g-VOC/bhp-hr. [District Rule 2201]

20. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

21. Operation of this engine shall not exceed 8,500 hours per year. [District Rule 2201]

22. After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O_2), NOx referenced as NO_2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O_2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O_2), VOC referenced as CH_4. [District Rules 2201 and 4702]

23. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rule 2201 and 4702]

24. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]

25. Ammonia (NH_3) emissions from this engine shall not exceed 10 ppmvd @ 15% O_2. [District Rules 2201 and 4102]

CONDITIONS CONTINUE ON NEXT PAGE

26. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH_3) emissions from this unit shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201 and 4702]

27. Source testing to measure NOx, CO, VOC, and ammonia (NH_3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201 and 4702]

28. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

29. Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

30. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH_3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

31. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with 501; NH_3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

32. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

33. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

34. The results of each source test shall be submitted to the District within 60 days after completion of source test. [District Rule 1081]

35. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

36. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H_2S; a digital analyzer approved for gaseous fuel analysis; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H_2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

37. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O_2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

CONDITIONS CONTINUE ON NEXT PAGE

38. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

39. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

40. If the NOx, CO, or NH3 concentrations, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

41. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

42. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

43. The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]

44. During initial performance testing, the SCR system reagent injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the initial performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

45. The SCR system reagent injection rate may be reestablished during a performance test by monitoring the SCR system reagent injection rate concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

46. If the SCR system reagent injection rate is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

47. During initial performance testing, the inlet temperature to the SCR system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). For each operating load, the established acceptable inlet temperature and back pressure ranges demonstrated during the initial performance test that result in compliance with the CO emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

48. The inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system may be reestablished during a performance test by monitoring concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system demonstrated during the performance test that result in compliance with the CO and VOC emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

49. The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]

50. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

51. The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

52. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

53. Records of hydrogen sulfide analyzer(s) installed or utilized and the calibration records of such analyzer(s) shall be maintained. Records are only required on such analyzer(s) utilized to demonstrate compliance with this permit. [District Rule 2201]

54. The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

55. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

ATTACHMENT N

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

MAR 2 2 2016

N. Ross Buckenham
ABEC #3 LLC dba Lakeview Dairy Biogas
c/o California Bioenergy, LLC
2828 Routh St, Suite 500
Dallas, TX 75201-1438

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: S-8637
Project Number: S-1143770

Dear Mr. Buckenham:

Enclosed for your review and comment is the District's analysis of ABEC #3 LLC dba Lakeview Dairy Biogas's application for an Authority to Construct for installation of an anaerobic digester system and two 1,468 bhp digester gas-fired IC engines with selective catalytic reduction (SCR) systems for emissions control at Lakeview Farms dairy, at 17702 Bear Mountain Blvd, Bakersfield, CA.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Ramon Norman of Permit Services at (559) 230-5909.

Sincerely,

Arnaud Marjollet

Arnaud Marjollet
Director of Permit Services

AM:rn

Enclosures

cc: Tung Le, CARB (w/ enclosure) via email

San Joaquin Valley Air Pollution Control District

Authority to Construct Application Review

Digester System and Two Digester Gas-Fired IC Engines with SCR

Facility Name:	ABEC #3 LLC dba Lakeview Dairy Biogas	Date:	March 7, 2016
Mailing Address:	ABEC #3 LLC c/o California Bioenergy, LLC 2828 Routh Street, Suite 500 Dallas, TX 75201-1438	Engineer: Lead Engineer:	Ramon Norman Jerry Sandhu
Contact Person:	N. Ross Buckenham - California Bioenergy/ ABEC #3 LLC		
Telephone:	(214) 849-9886	Cell Phone:	(214) 906-9359
E-Mail:	rbuckenham@calbioenergy.com		
Application #(s):	S-8637-1-0, -2-0, and -3-0		
Project #:	S-1143770		
Deemed Complete:	May 14, 2015		

I. Proposal

ABEC #3 LLC dba Lakeview Dairy Biogas, a subsidiary of California Bioenergy, LLC, has requested Authority to Construct (ATC) permits to construct a covered lagoon anaerobic digester system (ATC S-8637-1-0) and to install two 1,468 bhp digester gas-fired IC engines (or approved engines of equal or lesser bhp) (ATCs S-8637-2-0 and -3-0) at Lakeview Farms dairy (Facility S-5254). Each engine will be equipped with a selective catalytic reduction (SCR) system for emissions control and will power an electrical generator that will produce up to 1,059 kW. The new digester will be constructed in an area of the existing dairy that is currently used for manure drying and storage. Lakeview Farms dairy will send manure from the dairy to the ABEC #3 LLC anaerobic digesters located on the dairy site. The digester system will produce renewable biogas that will be used to fuel the IC engine generator sets.

ABEC #3 LLC dba Lakeview Dairy Biogas and Lakeview Farms dairy, which are separate companies, are undertaking the project as a partnership. ABEC #3 LLC has provided information supporting that the dairy and the ABEC #3 LLC biogas facility will be separately owned and operated. The following is a summary of some of the information provided by the applicant. The proposed digester system at the dairy will be operated and maintained by ABEC #3 LLC. The responsibility of the dairy will be limited to providing the manure feedstock and disposing of the effluent, which the dairy already must do for compliance with water quality regulations. ABEC #3 LLC will not be involved at all in the dairy's primary activity, production of milk. The feedstock and lease agreements specify that ABEC #3 LLC will build, own, and operate the biogas facility and also allows ABEC #3 LLC to make plant and equipment improvements. The proposed digester gas-fired IC engine generator sets that will be constructed on land leased from the dairy site and will be owned, operated, and maintained by ABEC #3 LLC. ABEC #3 LLC will be solely responsible for ensuring that the digester system and digester gas-fired IC engines comply with all applicable air quality regulations. The generator sets will sell all the power generated to the grid and will not provide any power directly to the dairy. Because the dairy and the proposed digester gas power plant at the site will be separately owned and operated and will have different two-digit Standard Industrial Classification (SIC) codes (Industry Group 24: Dairy Farms for the dairy vs. Industry Group 49: Electric, Gas, And Sanitary Services for the IC engine generator sets), pursuant to Section 3.39 of District Rule 2201, the proposed digester system and the digester gas-fired IC engines will not be part of the dairy agricultural stationary source. Therefore, the digester system and digester gas-fired IC engines will be permitted as a separate non-agricultural stationary source (Facility S-8637).

II. Applicable Rules

Rule 2201 New and Modified Stationary Source Review Rule (4/21/11)
Rule 2410 Prevention of Significant Deterioration (6/16/11)
Rule 2520 Federally Mandated Operating Permits (6/21/01)
Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4701 Stationary Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702 Stationary Internal Combustion Engines (11/14/13)
Rule 4801 Sulfur Compounds (12/17/92)
40 CFR Part 60, Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
40 CFR Part 63, Subpart ZZZZ National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notice
Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. Project Location

The ABEC #3 LLC Stationary Source (Facility S-8637) is located on Lakeview Farms dairy at 17702 Bear Mountain Blvd, Bakersfield, CA (Mt. Diablo Meridian T 31S, R 26E, Sec 20 in Kern County). The proposed equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

Anaerobic Digester System

An anaerobic digester is a sealed basin or tank that is designed to accelerate and control the decomposition of organic matter by microorganisms in the absence of oxygen. Anaerobic decomposition results in the conversion of organic compounds in the substrate into methane (CH_4), carbon dioxide (CO_2), and water rather than intermediate Volatile Organic Compounds (VOCs). The gas generated by this process is known as biogas, waste gas, or digester gas. In addition to methane and carbon dioxide, biogas may also contain small amounts of Nitrogen (N_2), Oxygen (O_2), Hydrogen Sulfide (H_2S), and Ammonia (NH_3). Biogas may also include trace amounts of various VOCs that remain from incomplete digestion of the volatile solids in the incoming substrate. Because biogas is mostly composed of methane, the main component of natural gas, the gas produced in the digester can be cleaned to remove H_2S and other impurities and used as fuel.

The proposed anaerobic digester system will be designed to process the manure generated by the cattle at Lakeview Farms dairy. The manure will be flushed from the cow housing areas at the dairy to a mechanical separation system prior to the digester system. This pre-digester mechanical separation system will remove fibrous solids from the manure. After the mechanical separation system, the liquid manure will flow to a sand settling lane that is designed to remove heavy solids by sedimentation. After the separation systems, the liquid manure will gravity flow into the proposed covered lagoon digesters. The liquid effluent from the covered lagoon digesters will be pumped to the existing large storage pond at the dairy from where it can be used to irrigate and fertilize adjacent cropland.

The proposed anaerobic digester system will process the liquid fraction from the dairy manure solid separation system. The anaerobic digester system will consist of an in-ground, covered lagoon anaerobic digester that will be divided into one or more cells. The final number of covered lagoon anaerobic digester cells and the final dimensions of each cell will be determined based on borings to locate subsurface sand and groundwater that are required to demonstrate compliance with the requirements of the Regional Water Quality Control Board. The preliminary information submitted by the applicant indicates that the first cell of the covered lagoon anaerobic digester will have the following approximate dimensions: 655 ft long by 262 ft wide at the top, with an average depth of 23 ft, and a side slope (run/rise) of 2.0 and that the second cell of the covered lagoon anaerobic digester will have the following approximate dimensions: 500 ft long by 200 ft wide at the top, with an average depth of 22.75 ft, and a side slope (run/rise) of 2.0. The covered lagoon digester will operate at ambient temperatures; however, the covered lagoon digester may utilize heat from the engines to warm the substrate to promote more efficient anaerobic digestion. An area located east of the existing lagoons at the dairy, which is currently used for drying and storage of solid manure, will be excavated to create the proposed covered lagoon anaerobic digester.

The applicant indicates that the lagoon cell(s) will be covered in accordance with Natural Resources Conservation Services (NRCS) Practice Standard Code 367 – Roofs and Covers. The bottom and the walls of the new lagoon cell(s) will be lined with high-density polyethylene (HDPE) membranes and a gas collection system will be installed. The new lagoon cells will be fitted with HDPE covers. The gas collection system will consist of perforated piping under the HDPE covers of the covered lagoons.

The covered lagoon digester will be equipped with an air injection system for removal of H_2S from the digester gas. The continuous injection of controlled quantities of air under the digester covers increases the amount of oxygen in the space under the digester covers and in the surface layer of the digester liquid, which facilitates oxidation of sulfides in the digester gas and at the surface of the liquid to elemental sulfur and water. Injection of air also promotes biological removal of H_2S from the digester gas by facilitating the establishment of sulfur oxidizing microorganisms, such as Thiobacillus species, which have the ability to grow under various environmental conditions and oxidize H_2S to elemental sulfur. The digester gas will be captured by the covered lagoon gas collection system and will be piped to the gas conditioning system for polishing to remove additional H_2S and for removal of moisture. The gas will then be sent to the engines for use as fuel to generate electricity for sale to a utility and to produce heat for the digester system. When the gas cannot be used in the engines, the digester gas will collect under the lagoon covers. As the gas collects under the lagoon covers, the pressure in the digesters will rise. In rare emergency situations when the gas cannot be combusted in the engines for an extended period, the pressure will cause the relief valves to open and release the digester gas, composed primarily of methane and carbon dioxide, into the atmosphere. As the pressure decreases, the gas relief valves will automatically close and normal operation will proceed.

When operating at full capacity, the digester system is expected to produce an average of 360,000 ft^3 of biogas per day. The applicant has indicated that the biogas produced by the covered lagoon digester will be composed of approximately 60-70% methane and 30-40% carbon dioxide. Because the proposed digester system will be able to store the biogas for extended periods under the digester covers and the proposed engines at the ABEC #3 LLC Stationary Source (Facility S-8637) will have more than sufficient capacity to combust all of the gas generated, no flare is being proposed for the digester installation at this facility.

Covered Lagoon Anaerobic Digester Measurements

The measurements given below for the proposed covered lagoon anaerobic digester cells at the ABEC #3 LLC Stationary Source (Facility S-8637) are based on the preliminary information provided by the applicant. As discussed above, the final number of covered lagoon anaerobic digester cells and the final dimensions of each cell will be determined based compliance with the requirements of the Regional Water Quality Control Board.

- 1st Covered Lagoon Anaerobic Digester Cell
  - Top Dimensions: 655 ft long x 262 ft wide
  - Average Depth: 23 ft
  - Side Slope (run/rise): 2.0
  - Approximate Volume (not including 2 ft. freeboard): 2,705,808 ft^3 (~20,239,444 gal)
- 2nd Covered Lagoon Anaerobic Digester Cell
  - Top Dimensions: 500 ft long x 200 ft wide
  - Average Depth: 22.75 ft
  - Side Slope (run/rise): 2.0
  - Approximate Volume (not including 2 ft. freeboard): 1,613,210 ft^3 (~10,612,380 gal)

Digester Gas-Fired IC Engines

The applicant is proposing to install two 1,468 bhp GE Jenbacher model J 320 GS-C82 lean burn digester gas-fired IC engines (or equivalent engines of equal or lesser rating approved by the District, such as 1,412 bhp Caterpillar model A3516A+ IC engines or 1,431 bhp Dresser Rand Guascor model SFGLD 560 IC engines). Each engine will be equipped with an SCR system and will power an electrical generator that will produce up to 1,059 kWe. Digester gas, which consists mostly of methane, the main component of natural gas, will be combusted in the IC engines to produce power. After initial removal of H_2S in the digester system, the digester gas will be piped to the gas conditioning system for polishing to remove H_2S using an iron sponge and/or activated carbon H_2S scrubber or an equivalent H_2S removal system and for removal of moisture. The digester gas will then be piped to the IC engines for use as fuel. The engines will power electrical generators that will produce power to be sold to a utility. Excess heat from the engines will be used in the first covered lagoon anaerobic digester (West

Lagoon Digester) to promote more efficient production of digester gas. The engines will be permitted to operate up to 24 hr/day and 8,760 hr/year.

In addition to the use of digester gas as fuel, the engines will also be permitted to use natural gas as fuel for no more than 96,000 kW-hrs of operation during initial utility interconnect testing in the event that insufficient digester gas is available for the engines at the time that the required utility testing is scheduled. The engines will remain subject to the same emission limits during the limited period that allows the use of natural gas fuel for required utility testing.

V. Equipment Listing

S-8637-1-0: ANAEROBIC DIGESTER SYSTEM CONSISTING OF COVERED LAGOON ANAEROBIC DIGESTER CELL(S) WITH PRESSURE/VACUUM VALVE(S) AND AN AIR INJECTION SYSTEM FOR CONTROL OF H2S

S-8637-2-0: 1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

S-8637-3-0: 1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

VI. Emission Control Technology Evaluation

Digester System (S-8637-1-0)

The digester system will be equipped with a pressure-vacuum (PV) relief valves or an emergency venting system. The digester gas will be scrubbed to remove hydrogen sulfide (H_2S) and will be used to fuel engines to generate electricity. Combustion of the digester gas in the engines will convert any VOCs present in the gas into carbon dioxide and water. As stated above, because the digester system will be able to store the gas for extended periods and the engines will have more than enough capacity to combust all of the gas generated, no flare is being proposed for this digester project.

H_2S Removal

As described above, the covered lagoon anaerobic digester will utilize an air injection system for removal of H_2S from the digester gas. The continuous injection of controlled quantities of air under the lagoon covers increases the amount of oxygen in the space under the digester covers and the surface layer of the liquid in the covered lagoon digester, which facilitates oxidation of sulfides in the digester gas and in the liquid surface to elemental sulfur and water.

The sulfur dissolves in the liquid in the digester and can be removed from the digester system by deposition and filtration. Injection of air also promotes biological removal of H_2S from the digester gas by facilitating the establishment of sulfur oxidizing microorganisms, such as Thiobacillus species, which have the ability to grow under various environmental conditions and oxidize H_2S to elemental sulfur and sulfates that can be removed from the digester system. Use of air injection to remove H_2S from digester gas has been shown to have higher effectiveness in covered lagoon digesters because the large areas under the lagoon covers facilitate contact with the digester gas and lagoon surface, which enables improved oxidation and biological reduction of sulfides. Successful installations of the air injection sulfur removal system have demonstrated significantly reduced operation costs when compared to other methods of sulfur removal.

For final polishing, the digester gas will be sent through an iron sponge H_2S scrubber and/or an activated carbon H_2S scrubber or an equivalent system to remove H_2S from the gas prior to combustion in the proposed engines.

An iron sponge scrubber is comprised of vessel(s) containing iron sponge, which consists of a hydrated form of iron oxide infused onto wood shavings. The wood shavings serve only as a carrier for the iron oxide powder. Iron oxide infused into the wood surface will not wash off or migrate with the gas. As the gas passes through the iron sponge material, the H_2S is removed by the following chemical reaction producing black iron sulfide and water:

$$H_2S + Fe(OH)_2 \rightarrow FeS + 2H_2O + \text{heat}$$

For the iron sponge to perform effectively, it must be maintained within a defined range of sufficient moisture content. This requirement is typically satisfied if the gas is saturated with water vapor, as is frequently the case with digester gas. If the iron sponge becomes dry, it can be re-wet and remain effective. The iron sponge reaction is not pressure sensitive.

Specially treated activated carbon can also be used to remove H_2S from gas streams. H_2S will be adsorbed as the gas flows through the activated carbon bed. Activated carbon has a large number of pores, which greatly increase the surface area for adsorption. Contaminants in the gas diffuse into these pores and are retained on the carbon surface due to both chemical and physical forces. Activated carbon used for the removal of H_2S is usually treated with chemical bases to increase the holding capacity for H_2S.

The proposed scrubber will consist of enclosed vessels filled with iron sponge and/or treated activated carbon. The digester gas will flow through the scrubber and then to a dryer and chiller to remove moisture. For continuous operation, there will be a secondary unit that will be brought online at specified times or when monitoring indicates that the primary unit is nearing saturation. Valves can be arranged so either bed can operate while the other is serviced. The useful life of the iron sponge and activated carbon vessels will vary depending on the inlet concentration of H_2S, the flow rate, and the mass in the vessels. Before a scrubber is completely spent, it must be regenerated or replaced. Spent iron sponge or activated carbon vessels will be sent to a regeneration facility or to an appropriate disposal facility.

The proposed scrubber will be capable of reducing H_2S concentrations in the digester gas to 40 ppmv or less. Reducing the H_2S concentration in the gas will minimize SO_X emissions from combustion and will also reduce the maintenance requirements for the engines and will protect catalysts from masking, plugging, and poisoning.

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

The proposed engines will be equipped with:
- Turbocharger
- Aftercooler
- Air/Fuel Ratio or an O_2 Controller
- Lean Burn Technology
- Positive Crankcase Ventilation (PCV) or 90% efficient control device
- Selective Catalytic Reduction (SCR)

The turbocharger reduces NO_X emissions from engines by increasing the efficiency and promoting more complete burning of the fuel.

The aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X.

The fuel/air ratio controller (oxygen controller) is used to maintain the amount of oxygen in the exhaust stream to optimize engine operation and catalyst function.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_X formation.

The PCV system or 90% efficient control device reduces crankcase VOC and PM_{10} emissions by at least 90% over an uncontrolled crankcase vent.

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent, in this case urea, pass through an appropriate catalyst. Urea, will be injected upstream of the catalyst where it is converted to ammonia. The ammonia is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%.

VII. General Calculations

A. Assumptions

- ABEC #3 LLC dba Lakeview Dairy Biogas (Facility S-8637) and Lakeview Farms dairy (Facility S-5254) are separate stationary sources at the same site.
- Because of the high moisture content of separated manure solids, PM emissions from the handling of separated solids for the digester system are considered negligible.
- Because the manure for the digester system will be taken from the mechanical separation system at Lakeview Farms dairy and the digested solids and effluent from the digester system will be returned to Lakeview Farms dairy for use, all emissions from the manure

processed in the digester system will be allocated to the liquid manure handling system at Lakeview Farms dairy.

- The proposed digester system will reduce potential VOC emissions from manure generated by the cattle at Lakeview Farms dairy. Manure that is currently stored in uncovered lagoon(s) and pond(s) will instead be placed in covered ponds at the ABEC #3 LLC facility, thereby decreasing volatilization of compounds from the manure. In a digester, most VOCs present will be converted to methane (an exempt compound) and carbon dioxide further reducing the potential for VOC emissions. Because results of dairy digester analyses have indicated very low VOC content (less than 1% by weight), fugitive VOC emissions from the digester system are assumed to be negligible, consistent with District Policy SSP 2015. During operation, the digester gas will be directed to the engines where the gas will be combusted resulting in the oxidation of gaseous hydrocarbons into carbon dioxide and water. Therefore, VOC emissions from the digester system are considered negligible.
- Molar composition of typical digester gas is about 60% methane and 40% carbon dioxide with trace amounts of hydrogen sulfide, VOC, and other compounds.[1]
- Typical Higher Heating Value for Digester Gas: 600 Btu/scf (Per AP-42 (4/00) - notes to Tables Table 3.1-1, Table 3.1-2b, Table 3.1-7, and Table 3.1-8)
- Typical EPA F-factor for Digester Gas: 9,100 dscf/MMBtu (dry, adjusted to 60 °F), (Estimated based on previous digester gas fuel analyses for source tests)
- Average sulfur content of the scrubbed digester gas: 40 ppmv as H_2S (required as BACT; approximately 2.4 grains/100 scf)
- bhp to Btu/hr conversion: 2,545 Btu/hp-hr
- Thermal efficiency of engines: commonly ≈ 33%
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Molecular weights:

  NO_X (as NO_2) = 46 lb/lb-mol   CO = 28 lb/lb-mol   NH3 = 17 lb/lb-mol

  VOC (as CH_4) = 16 lb/lb-mol SO_X (as SO_2) = 64.06 lb/lb-mol
- Each of the engines will be permitted to operate 24 hours/day and 365 days per year.
- There will be no increase in permitted emissions for the limited use of natural gas for required initial utility testing in the event that sufficient digester gas is not available for the engines at the time that the required initial utility testing is scheduled.
- PM2.5 emissions from the digester gas-fired IC engines are assumed to be equal to PM10 emissions.

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[1] U.S. EPA AgSTAR (http://www2.epa.gov/agstar), "Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities" (November 2011, http://www2.epa.gov/agstar/agstar-market-opportunities-report); American Biogas Council – Frequent Questions (https://www.americanbiogascouncil.org/biogas_questions.asp); "Anaerobic Digestion Overview", David Schmidt, University of Minnesota Department of Biosystems and Agricultural Engineering (http://www.extension.umn.edu/agriculture/manure-management-and-air-quality/manure-treatment/docs/anaerobic-digestion-overview.pdf); and "Anaerobic Digestion of Animal Wastes: Factors to Consider", ATTRA - National Sustainable Agriculture Information Service (https://attra.ncat.org/attra-pub/summaries/summary.php?pub=307)

Assumptions for Commissioning Period

- The applicant has requested that the ATC permits include a commissioning period to allow testing, adjustment, tuning, and calibration of the engines without the SCR systems installed. The duration of the commissioning period shall consist of no more than 120 hours of operation of each engine without an SCR system installed.
- Engine emissions during the commissioning period will be calculated as uncontrolled based on information provided by the engine supplier.

B. Emission Factors

Emission Factors during the Commissioning Period:

The commissioning period precedes normal operation of a power plant. Activities conducted during the commissioning period typically include: checking all mechanical, electrical, and control systems for the units and related equipment; confirming the performance measures specified for the equipment; test firing the units; and tuning of the units and the generators. The early stages of commissioning are conducted prior to the installation of the emission control equipment to prevent damage to this equipment. In accordance with EPA's guidance, the commissioning period is considered the final phase of the construction process rather than initial startup of the equipment.[2] Therefore, other than quantifying emissions for New and Modified Source Review (NSR), source-specific emission limitations from applicable rules and regulations are generally not effective until completion of the commissioning period. Because emission control devices are not in place and functioning during commissioning, higher emission limits are required during this time.

The emission factors for NO_X (1.0 g/bhp-hr), CO (4.85 g/bhp-hr), and VOC (1.0 g/bhp-hr) for the commissioning period are the emission factors provided by the engine supplier for the engines without SCR systems or oxidation catalysts. The emission factors during the commissioning period for SO_X (0.04 g/bhp-hr), PM_{10} (0.07 g/bhp-hr), and ammonia slip (0.05 g/bhp-hr) after initial installation of the SCR system are assumed to be the same emissions factors as during normal operation. SO_X emissions are based on the maximum sulfur content of the dairy digester gas (required as BACT; approximately 2.4 grains/100 scf). PM_{10} emissions on a lb/MMBtu basis are assumed to be similar to natural gas-fueled IC engines. For more conservative PM_{10} emission calculations, the PM emission factor for rich burn natural gas-fueled engines given in EPA's Compilation of Air Pollutant Emission Factors (AP-42) is used because it is higher than the value for lean burn natural gas-fueled engines listed in EPA AP-42. The ammonia emission factor is based on the ammonia slip limit of 10 ppmv NH_3.

[2] See US EPA Implementation Question and Answer Document for National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, April 2, 2013, Question 39 (http://www.epa.gov/airtoxics/icengines/docs/20120717riceqaupdate.pdf)

Commissioning Period Emission Factors for Digester Gas-Fired Engines		
Pollutant	g/bhp·hr	Source
NO_X	1.0	Engine Supplier's Information
SO_X	0.04	40 ppmvd in fuel gas; BACT Requirement/Mass Balance equation below
PM_{10}	0.07	AP-42 (7/00) Table 3.2-3 (Conservative Value based on Rich-Burn Natural Gas Engines)
CO	4.85	Engine Supplier's Information
VOC	1.0	Engine Supplier's Information
NH_3	0.05	10 ppmvd @ 15% O_2 in exhaust; Required/Proposed – See equation below

SO_X – 40 ppmvd H_2S in fuel gas

$$\frac{40\,\text{ft}^3\,\text{H}_2\text{S}}{10^6\,\text{ft}^3} \times \frac{32.06\,\text{lb S}}{\text{lb - mol}\,\text{H}_2\text{S}} \times \frac{\text{lb - mole}}{379.5\,\text{ft}^3} \times \frac{64.06\,\text{lb SO}_2}{32.06\,\text{lb S}} \times \frac{\text{ft}^3}{600\,\text{Btu}} \times \frac{10^6\,\text{Btu}}{\text{MMBtu}} = 0.0113\,\frac{\text{lb SOx}}{\text{MMBtu}}$$

$$0.0113\,\frac{\text{lb SOx}}{\text{MMBtu}} \times \frac{1\,\text{MMBtu}}{10^6\,\text{Btu}} \times \frac{\text{Btu}_{\text{in}}}{0.33\text{Btu}_{\text{out}}} \times \frac{2{,}545\,\text{Btu}}{\text{hp - hr}} \times \frac{453.59\,\text{g}}{\text{lb}} = 0.040\,\frac{\text{g SOx}}{\text{bhp - hr}}$$

NH_3 – 10 ppmvd @ 15% O_2 in exhaust

$$\frac{10\,\text{ppmv NH}_3}{10^6} \times \frac{17\,\text{lb NH}_3}{\text{lb - mole}} \times \frac{\text{lb - mole}}{379.5\,\text{ft}^3} \times \frac{9{,}100\,\text{ft}^3}{\text{MMBtu}} \times \frac{20.9\%\,\text{O}_2}{(20.9-15)\%\,\text{O}_2} = 0.0144\,\frac{\text{lb NH}_3}{\text{MMBtu}}$$

$$0.0144\,\frac{\text{lb NH}_3}{\text{MMBtu}} \times \frac{1\,\text{MMBtu}}{10^6\,\text{Btu}} \times \frac{\text{Btu}_{\text{in}}}{0.33\text{Btu}_{\text{out}}} \times \frac{2{,}545\,\text{Btu}}{\text{hp - hr}} \times \frac{453.59\,\text{g}}{\text{lb}} = 0.05\,\frac{\text{g NH}_3}{\text{bhp - hr}}$$

Emission Factors during Normal Operation after the Commissioning Period:

The emission factors for NO_X (0.15 g/bhp-hr), CO (1.75 g/bhp-hr), and VOC (0.10 g/bhp-hr) for the proposed engines during normal operation were proposed by the applicant and are supported by information provided by the engine supplier. The emission factors for NO_X and VOC were required as BACT. The emission factors for SO_X (0.04 g/bhp-hr), PM_{10} (0.07 g/bhp-hr), and ammonia slip (0.05 g/bhp-hr) during normal operation are same as the emission factors presented above for the commissioning period.

Emission Factors for Digester Gas-Fired Engines (Normal Operation)				
Pollutant	g/bhp·hr	lb/MMBtu	ppmvd (@ 15%O_2)	Source
NO_X	0.15	0.0429	11 ppmvd	BACT Requirement; Proposed by Applicant – See equation on Page 11 below
SO_X	0.04	0.0113	40 ppmvd in fuel gas	BACT Requirement/Mass Balance equation above
PM_{10}	0.07	0.01941	--	AP-42 (7/00) Table 3.2-3 (Conservative Value based on Rich-Burn Natural Gas Engines)
CO	1.75	0.500	210 ppmvd	Proposed by Applicant – See equation on Page 11 below
VOC	0.10	0.0286	21 ppmvd as CH_4	BACT Requirement; Proposed by Applicant – See equation on Page 11 below
NH_3	0.05	0.0144	10 ppmvd	Required/Proposed – See equation above

NO_X – 0.15 g/bhp-hr

$$0.15\frac{\text{g NOx}}{\text{bhp-hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp-hr}}{2{,}545\,\text{Btu}} \times \frac{0.33\text{Btu}_{out}}{1\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.0429\frac{\text{lb NOx}}{\text{MMBtu}}$$

$$0.0429\frac{\text{lb NOx}}{\text{MMBtu}} \times \frac{(20.9-15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb-mole}} \times \frac{\text{lb-mole}}{46\,\text{lb NOx}} \times \frac{10^6\,\text{ppmv}}{1} = 11\ \text{ppmvd NOx @ 15\% } O_2$$

CO – 1.75 g/bhp-hr

$$1.75\frac{\text{g CO}}{\text{bhp-hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp-hr}}{2{,}545\,\text{Btu}} \times \frac{0.33\text{Btu}_{out}}{1\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.500\frac{\text{lb CO}}{\text{MMBtu}}$$

$$0.500\frac{\text{lb CO}}{\text{MMBtu}} \times \frac{(20.9-15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb-mole}} \times \frac{\text{lb-mole}}{28\,\text{lb CO}} \times \frac{10^6\,\text{ppmv}}{1} = 210\ \text{ppmvd CO @ 15\% } O_2$$

VOC – 0.10 g/bhp-hr

$$0.10\frac{\text{g VOC}}{\text{bhp-hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp-hr}}{2{,}545\,\text{Btu}} \times \frac{0.33\text{Btu}_{out}}{1\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.0286\frac{\text{lb VOC}}{\text{MMBtu}}$$

$$0.0286\frac{\text{lb VOC}}{\text{MMBtu}} \times \frac{(20.9-15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb-mole}} \times \frac{\text{lb-mole}}{16\,\text{lb VOC}} \times \frac{10^6\,\text{ppmv}}{1} = 21\ \text{ppmvd VOC @ 15\% } O_2$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since the digester system and the engines are new emissions units, PE1 = 0 for all affected pollutants.

2. Post Project Potential to Emit (PE2)

Digester System (S-8637-1-0)

As explained above, the digester system will be composed of sealed lagoons that will reduce VOC emissions from the manure and will have negligible fugitive emissions; therefore, VOC emissions from the manure will only be attributed to Lakeview Farms dairy for manure prior to entering the digester system and when returned to the dairy and emissions from the digester system are considered negligible.

Digester Gas-Fired Engines (S-8637-2-0 and -3-0)

Daily PE2 for Each Engine during the Commissioning Period:

Daily PE during the commissioning period for each of the proposed engines is calculated in the table below:

Daily PE for Engines S-8637-2-0 &-3-0 During the Commissioning Periods								
NO_X	1.0	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**77.7**	(lb/day)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.1**	(lb/day)
PM_{10}	0.07	(g/hp·hr) . x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.4**	(lb/day)
CO	4.85	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**376.7**	(lb/day)
VOC	1.0	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**77.7**	(lb/day)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.9**	(lb/day)

Daily PE2 for Each Engine during Normal Operation after the Commissioning Period:

Daily PE for each of the proposed engines during normal operation after completion of the commissioning periods is calculated in the table below:

Daily PE for Engines S-8637-2-0 &-3-0 After Commissioning								
NO_X	0.15	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**11.7**	(lb/day)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.1**	(lb/day)
PM_{10}	0.07	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.4**	(lb/day)
CO	1.75	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**135.9**	(lb/day)
VOC	0.10	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**7.8**	(lb/day)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.9**	(lb/day)

Maximum Annual PE2 for Each Engine During the first Year Including the Commissioning Periods:

As discussed above, each of the proposed engines will be allowed to operate up to 120 hours for commissioning during the first year of operation. The maximum annual PE for each engine will calculated based on the maximum hours of operation during the commissioning period and the remaining hours during normal operation.

NO_X
1,468 bhp x (1.0 g-NO_X/bhp-hr x 120 hr + 0.15 g-NO_X/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **4,583 lb-NO_X**

SO_X
1,468 bhp x (0.04 g-SO_X/bhp-hr x 120 hr + 0.04 g-SO_X/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **1,134 lb-SO_X**

PM_{10}
1,468 bhp x (0.07 g-PM_{10}/bhp-hr x 120 hr + 0.07 g-PM_{10}/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **1,985 lb-PM_{10}**

CO
1,468 bhp x (4.85 g-CO/bhp-hr x 120 hr + 1.75 g-CO/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **50,818 lb-CO**

VOC
1,468 bhp x (1.0 g-VOC/bhp-hr x 120 hr + 0.10 g-VOC/bhp-hr x 8,640 hr) ÷ 453.59 g/lb
= **3,185 lb-VOC**

NH_3
1,468 bhp x (0.05 g-NH_3/bhp-hr x 120 hr + 0.05 g-NH_3/bhp-hr x 8,640 hr) ÷ 453.59 g/lb
= **1,418 lb-NH_3**

Maximum Total Combined Annual PE2 from Both Engines, Including Commissioning:

The maximum total combined annual PE2 for both the engines, including commissioning emissions, is calculated as follows:

NO_X: 4,583 lb-NO_X/yr-engine x 2 engines = **9,166 lb-NO_X/yr**
SO_X: 1,134 lb-SO_X/yr-engine x 2 engines = **2,268 lb-SO_X/yr**
PM_{10}: 1,985 lb-PM_{10}/yr-engine x 2 engines = **3,970 lb-PM_{10}/yr**
CO: 50,818 lb-CO/yr-engine x 2 engines = **101,636 lb-CO/yr**
VOC: 3,185 lb-VOC/yr-engine x 2 engines = **6,370 lb-VOC/yr**
NH_3: 1,418 lb-NH_3/yr-engine x 2 engines = **2,836 lb-NH_3/yr**

Annual PE2 for Each Engine in years with no Commissioning:

The annual PE2 for each of the engines after completion of the first year of operation when there will not be any commissioning emissions is calculated as follows:

Annual PE2 for Engines S-8637-2-0 &-3-0 with no Commissioning								
NO_X	0.15	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**4,253**	(lb/yr)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,134**	(lb/yr)
PM_{10}	0.07	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,985**	(lb/yr)
CO	1.75	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**49,614**	(lb/yr)
VOC	0.10	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**2,835**	(lb/yr)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,418**	(lb/yr)

Max Total Combined Annual PE2 from Both Engines in years with no Commissioning:

The maximum total combined annual PE2 for both the engines in years with no commissioning is calculated as follows:

NO_X: 4,253 lb-NO_X/yr-engine x 2 engines = **8,506 lb-NO_X/yr**
SO_X: 1,134 lb-SO_X/yr-engine x 2 engines = **2,268 lb-SO_X/yr**
PM_{10}: 1,985 lb-PM_{10}/yr-engine x 2 engines = **3,970 lb-PM_{10}/yr**
CO: 49,614 lb-CO/yr-engine x 2 engines = **99,228 lb-CO/yr**
VOC: 2,835 lb-VOC/yr-engine x 2 engines = **5,670 lb-VOC/yr**
NH_3: 1,418 lb-NH_3/yr-engine x 2 engines = **2,836 lb-NH_3/yr**

Maximum Daily and Annual PE2 from Calculations Above:

The maximum daily and annual emissions for each pollutant calculated above, including commissioning emissions, are shown in the table below.

Max. Post-Project Potential to Emit (PE2) for S-8637-2-0 &-3-0			
	Max. Daily Emissions for each engine (lb/day)	Max. Annual Emissions for each engine (lb/year)	Max. Total Combined Annual Emissions for both engines (lb/year)
NO_X	77.7	4,583	9,166
SO_X	3.1	1,134	2,268
PM_{10}	5.4	1,985	3,970
CO	376.7	50,818	101,636
VOC	77.7	3,185	6,370
NH_3	3.9	1,418	2,836

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site.

Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 is equal to zero for all pollutants.

4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

SSPE2 (lb/year)						
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC	NH_3
ATC S-8637-1-0 (Digester System)	0	0	0	0	0	0
ATC S-8637-2-0 (1,468 bhp Digester Gas Engine)[3]	4,583	1,134	1,985	50,818	3,185	1,418
ATC S-8637-3-0 (1,468 bhp Digester Gas Engine)[3]	4,583	1,134	1,985	50,818	3,185	1,418
SSPE2	9,166	2,268	3,970	101,636	6,370	2,836

[3] The SSPE2 values listed in this table include the worst case annual emissions during the 120 hours of allowed commissioning time where the engines are allowed to operate uncontrolled for setup and tuning purposes. After the first year, the PE for NO_X, CO, and VOC emissions will go down as the engines will no longer be allowed to operate without controls in place for these pollutants.

5. Major Source Determination

Rule 2201 Major Source Determination:

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. transportable IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
SSPE1	0	0	0	0	0	0
SSPE2	9,166	2,268	3,970	3,970	101,636	6,370
Major Source Threshold	20,000	140,000	140,000	200,000*	200,000	20,000
Major Source?	No	No	No	No	No	No

* The application for this project was deemed complete before 2/18/2016, which was when the District's PM2.5 Major Source Threshold was lowered to 140,000 lb/year

Note: PM2.5 assumed to be equal to PM10

Rule 2410 Major Source Determination:

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tons per year (tpy) for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO2	VOC	SO2	CO	PM	PM10
Estimated Facility PE before Project Increase	0	0	0	0	0	0
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source ? (Y/N)	N	N	N	N	N	N

Because this is a new facility, the PE for all regulated NSR pollutants prior to the project is equal to zero.

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

Since the proposed digester system and engines are new emissions units, BE = PE1 = 0 for all pollutants from each unit.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification. Additionally, since the facility is not a major source for PM_{10} (140,000 lb/year), it is not a major source for PM2.5 (200,000 lb/year since the application for the project was deemed complete before 2/18/2016).

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO_2 (as a primary pollutant)
- SO_2 (as a primary pollutant)
- CO
- PM
- PM10
- Hydrogen sulfide (H_2S)[4]
- Total reduced sulfur (inlcuding H_2S)[4]

I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is 250 tons per year (tpy) for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO2	VOC	SO2	CO	PM	PM10
Total PE from New and Modified Units	4.6	3.2	1.1	50.8	2.0	2.0
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	N	N	N	N	N	N

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix A.

[4] Because the facility is not included in the specific source categories listed in 40 CFR 51.165, for PSD purposes only non-fugitive emissions from the engine exhaust stacks must be addressed for this project. Although the sulfur (primarily H_2S) in the fuel will be converted almost entirely to SO_X during combustion, the maximum possible amount of H_2S and total reduced sulfur compounds from the engine stacks can be calculated by assuming that all sulfur in the fuel is emitted as H_2S. Based on the fuel sulfur limit of 40 ppmv as H_2S, the maximum possible H_2S emission factor for the engines is calculated to be 0.02 g-H_2S/bhp (0.0056 lb-H_2S/MMBtu), resulting in a total combined maximum of < 0.06 tpy H_2S from the exhaust stacks of both engines. This is well below the applicable PSD threshold of 250 tpy.

VIII. Compliance

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

As seen in Section VII.C.2 above, the applicant is proposing to install a new digester system with and two new digester gas-fired IC engines.

<u>Digester System (S-8637-1-0)</u>

As explained above, the digester system will consist of sealed lagoon(s) that will reduce VOC emissions from the manure at the dairy and emissions from the digester system are considered negligible. Therefore BACT for new units with PE > 2 lb/day purposes is not required for the digester system.

<u>Digester Gas-Fired Engines (S-8637-2-0 and -3-0)</u>

The proposed engines will each have a PE greater than 2.0 lb/day for NO_X, SO_X, PM_{10}, CO, VOC, and NH_3. Therefore, BACT is triggered for NO_X, SO_X, PM_{10}, and VOC. As part of the BACT requirements, NH_3 slip from the SCR systems will also be limited. The PE for CO from each unit also exceeds 2.0 lb/day; however, BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 above.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered for relocation of an emissions unit.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore, BACT is not triggered for modification of a unit.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 or Federal Major Modification. Therefore BACT is not triggered for Major Modification purposes.

2. BACT Guideline

S-8637-2-0 & -3-0

BACT Guideline 3.3.15 applies to the proposed digester gas-fired IC engines. (See Appendix B)

3. Top-Down BACT Analysis

Pursuant to the Top-Down BACT Analysis (See Appendix B), BACT has been satisfied with the following:

NO_X: NO_X emissions ≤ 0.15 g/bhp-hr
SO_X: Fuel sulfur content ≤ 40 ppmv (as H_2S)
PM_{10}: Fuel sulfur content ≤ 40 ppmv (as H_2S)
VOC: VOC emissions ≤ 0.10 g/bhp-hr
NH_3: NH_3 slip emissions ≤ 10 ppmv @ 15% O_2

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
SSPE2	9,166	2,268	3,970	101,636	6,370
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

C. Public Notification

1. Applicability

Public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.
e. Any project which results in a Title V significant permit modification

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. As shown in Section VII.C.5 above, the SSPE2 is not greater than the Major Source threshold for any pollutant. Therefore, public noticing is not required for this project for new Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements.

The PE2 for the proposed new IC engines is compared to the daily PE Public Notice thresholds in the following table:

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO_X	77.7	100 lb/day	No
SO_X	3.1	100 lb/day	No
PM_{10}	5.4	100 lb/day	No
CO	376.7	100 lb/day	**Yes**
VOC	77.7	100 lb/day	No
NH_3	3.9	100 lb/day	No

Therefore, public noticing for PE > 100 lb/day purposes is required.

c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

Offset Thresholds				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	0	9,166	20,000 lb/year	No
SO_X	0	2,268	54,750 lb/year	No
PM_{10}	0	3,970	29,200 lb/year	No
CO	0	101,636	200,000 lb/year	No
VOC	0	6,370	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for surpassing an offset threshold.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_x	9,166	0	9,166	20,000 lb/year	No
SO_x	2,268	0	2,268	20,000 lb/year	No
PM_{10}	3,970	0	3,970	20,000 lb/year	No
CO	101,636	0	101,636	20,000 lb/year	**Yes**
VOC	6,370	0	6,370	20,000 lb/year	No
NH_3	2,836	0	2,836	20,000 lb/year	No

As demonstrated above, the SSIPE for CO was greater than 20,000 lb/year; therefore public noticing for SSIPE > 20,000 lbs is required.

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating, this change is not a Title V Significant Modification, and therefore public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project for CO emissions from an emissions unit in excess of 100 lb/day and for an SSIPE for CO that exceeds 20,000 lb/yr. Therefore, public notice documents will be submitted to the California Air Resources Board (ARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and must be enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions for the Digester System (S-8637-1-0)

As stated above, the digester system will reduce emissions from the manure produced by cattle at Lakeview Farms dairy. The following condition will be placed on the ATC permit to ensure that fugitive emissions from the digester system will be negligible:

- The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
- The air injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions for the Digester Gas-Fired Engines (S-8637-2-0 & -3-0)

Proposed Rule 2201 (DEL) Conditions for Engines during Both Commissioning and Normal Operation:

- This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]

- During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
- The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
- Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Commissioning Period:

For these digester gas-fired IC engines, the DELs for NO_X, PM_{10}, CO, and VOC are stated in the form of maximum emission factors (g/bhp-hr) and maximum number of hours allowed for commissioning activities.

- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
- The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
- During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
- The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Normal Operation:

For the proposed digester gas-fired IC engines, the DELs for NO_X, PM_{10}, CO, and VOC during normal operation are stated in the form of emission factors (g/hp-hr & ppmv), the maximum engine horsepower rating (1,468 bhp), and the maximum operational time of 24 hours per day.

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

E. Compliance Assurance

1. Source Testing

The proposed 1,468 bhp digester gas-fired engines are subject to District Rule 4702 - Internal Combustion Engines. Section 6.3.2.1 of District Rule 4702 requires source testing of NO_X, CO, and VOC emissions at least once every 24 months for a non-agricultural spark-ignited IC engine. The periodic source testing required by District Rule 4702 will ensure compliance with the applicable New Source Review (NSR) requirements NO_X, CO, and VOC. Therefore, source testing for NO_X, CO, and VOC will be required within 90 days of initial start-up and at least once 24 months thereafter. Since the control equipment will include an SCR system, periodic testing of ammonia slip will also be required. In addition, Section 5.10.1 of District Rule 4702 requires an annual analysis of the sulfur content of engine fuel. The PM_{10} emissions from the engine are not expected to change much over time as long as the quality of the gas used to fuel the engines remains consistent. The facility will be required to periodically monitor the sulfur content of the digester gas fuel, which should ensure that the quality of the digester gas fuel is consistent. Therefore, initial PM_{10} source testing will be required to demonstrate compliance with the PM_{10} emission limit, but ongoing PM_{10} source testing will not be required.

The proposed engines are also subject to 40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, no testing requirements from this subpart will be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

The following conditions will be placed on the engine permits to ensure compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]
- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]
- Fuel sulfur analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided it to the District upon request. [District Rules 2201 and 4702]
- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

2. Monitoring

As stated above the engines are subject to District Rule 4702. Section 5.8.1 of District Rule 4702 requires engines rated at least 1,000 bhp that can operate more than 2,000 hour per calendar year or equipped with external control devices to install, operate, and maintain an APCO-approved alternate monitoring plan. Section 5.8.9 of District Rule 4702 requires monitoring of NO_X emissions at least once every calendar quarter for a non-agricultural spark-ignited IC engine. Therefore, quarterly monitoring of NO_X, CO, and O_2 concentrations in accordance with pre-approved alternate monitoring plan "A" within District Policy SSP 1810 will be required. Since the engines will be equipped with SCR, quarterly monitoring of ammonia slip will also be required.

The following conditions will be placed on the engine permits to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]
- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Because of the variable composition of digester gas, additional monitoring of the fuel sulfur content of the digester gas will be required. The following conditions will be placed on the engine permits to ensure compliance:

- The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]
- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201.

The following conditions will be listed on the engine permits:

- The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]
- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or

volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

4. Reporting

No reporting is required to demonstrate compliance with District Rule 2201.

As stated above, the proposed 1,468 bhp engines are subject to 40 CFR 60, Subpart JJJJ. 40 CFR 60, Subpart JJJJ requires uncertified engines rated 500 bhp or more to submit an initial notification to EPA. As explained above, the District has not been delegated the authority to implement this regulation for non-Major Sources; therefore, this requirement will not be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

F. Ambient Air Quality Analysis (AAQA)

District Rule 2201 requires that an ambient air quality analysis (AAQA) be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Appendix C of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X. The proposed location is in a non-attainment area for the state's PM_{10} as well as federal and state $PM_{2.5}$ thresholds.

The results of the Criteria Pollutant Modeling conducted for the AAQA are summarized in the following table:

Criteria Pollutant Modeling Results*					
Digester Gas-Fired IC Engines	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_X	Pass[1]	X	X	X	Pass
SO_X	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[2]	Pass[2]
H2S	Pass	X	X	X	X

* Results were taken from the PSD spreadsheet.

[1] The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.

[2] The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

[3] H_2S emissions must be limited to the value listed in the Proposed Permit Conditions section in order for this project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS).

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII. C. 9. above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

Rule 4101 Visible Emissions

Rule 4101 states that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity.

Since the IC engines are fired solely on gaseous fuel, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

A Health Risk Assessment (HRA) is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Appendix C), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project. The results of the health risk assessment are summarized in the table below.

RMR Summary			
Categories	**1,468 bhp Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)**	**Project Totals**	**Facility Totals**
Prioritization Score[1]	107 (each)	214	>1
Acute Hazard Index	0.48 (each)[1]	0.95	0.95
Chronic Hazard Index	0.16 (each)	0.31	0.31
Maximum Individual Cancer Risk (10^{-6})	0.002 (each)	0.004	0.004
T-BACT Required?	**No**		
Special Permit Conditions?	**Yes**		

[1] H_2S emissions must be limited in order to achieve the acute hazard index score in this project and for the project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS). Please see special condition below.

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 20 in a million). As outlined by the HRA Summary in Appendix C of this report, the emissions increases for this project was determined to be less than significant.

To ensure compliance with the HRA; the following condition will be listed on the engine permits:

<u>Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)</u>

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

This condition, along with the engine rating in the equipment description, will ensure that the H_2S emissions from the engine exhaust stack shall not exceed 1.97 lb/hr, as required by the Health Risk Assessment.

Rule 4201 Particulate Matter Concentration

The purpose of this rule is to protect the ambient air quality by establishing a particulate matter emission standard. Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

$$0.07 \quad \frac{g}{hp\cdot hr}\times\frac{1hp\cdot hr}{2{,}545Btu}\times\frac{10^6\,Btu}{9{,}100dscf}\times\frac{0.33Btu_{out}}{1Btu_{in}}\times\frac{15.43grain}{g}= \quad 0.015 \quad \frac{grain}{dscf}$$

Since 0.015 grain/dscf is less than 0.1 grain/dscf, compliance with this rule is expected.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4701 Stationary Internal Combustion Engines – Phase I

The requirements of Rule 4702 are equivalent or more stringent than the requirements of this Rule. Since the proposed IC engines are subject to both Rules 4701 and 4702, compliance with Rule 4702 is sufficient to demonstrate compliance with this rule.

Rule 4702 Internal Combustion Engines

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and sulfur oxides (SO_X) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower of 25 brake horsepower or greater.

Section 5.2.1 requires that the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall not operate it in such a manner that results in emissions exceeding the limits in Table 1 of Rule 4702 until such time that the engine has demonstrated compliance with emission limits in Table 2 of Rule 4702 pursuant to the compliance deadlines in Section 7.5. In lieu of complying with Table 1 emission limits, the operator of a spark-ignited engine shall comply with the applicable emission limits pursuant to Section 8.0. The proposed new engines are required to immediately comply with the emission limits contained in Table 2 since the applicable compliance dates have passed (except for an operator with at least 12 existing engines at one stationary source); therefore, the emissions limits in Table 1 of Rule 4702 are not applicable to the proposed engines.

Section 5.2.2 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall comply with all the applicable requirements of the rule and the requirements of Section 5.2.2.1, 5.2.2.2, or 5.2.2.3, on an engine-by-engine basis.

Section 5.2.2.1 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited engine that is used exclusively in non-agricultural operations shall comply with Sections 5.2.2.1.1 through 5.2.2.1.3 on an engine-by-engine basis:

5.2.2.1.1 NO_X, CO, and VOC emission limits pursuant to Table 2;

5.2.2.1.2 SO_X control requirements of Section 5.7, pursuant to the deadlines specified in Section 7.5; and

5.2.2.1.3 Monitoring requirements of Section 5.10, pursuant to the deadlines specified in Section 7.5.

Section 5.2.2.2 allows that in lieu of complying with the NO_X emission limit requirement of Section 5.2.2.1.1, an operator may pay an annual fee to the District, as specified in Section 5.6, pursuant to Section 7.6. Pursuant to Section 5.2.2.2.1, engines in the fee payment program shall have actual emissions not greater than the applicable limits in Table 1 during the entire time the engine is part of the fee payment program. Pursuant to Section 5.2.2.2.2, compliance with Section 5.7 and 5.10, pursuant to the deadlines specified in Section 7.5, is also required as part of the fee payment option.

Section 5.2.2.3 allows that in lieu of complying with the NO_X, CO, and VOC limits of Table 2 on an engine-by-engine basis, an operator may elect to implement an alternative emission control plan pursuant to Section 8.0. An operator electing this option shall not be eligible to participate in the fee payment option outlined in Section 5.2.2.2 and Section 5.6.

Rule 4702, Table 2 Emission Limits/Standards for Spark-Ignited IC Engines rated >50 bhp Used in Non-Agricultural Operations
(Emission Limits are effective according to the compliance schedule specified in Rule 4702, Section 7.5.)

Engine Type	NO_X Emission Limit (ppmv @ 15% O_2, dry)	CO Emission Limit (ppmv @ 15% O_2, dry)	VOC Emission Limit (ppmv @ 15% O_2, dry)
1. a. Rich-Burn, Waste Gas Fueled	50 ppmv	2,000 ppmv	250 ppmv
1. b. Rich-Burn, Cyclic Loaded, Field Gas Fueled	50 ppmv	2,000 ppmv	250 ppmv
1. c. Rich-Burn, Limited Use	25 ppmv	2,000 ppmv	250 ppmv
1. d. Rich-Burn, Not Listed Above	11 ppmv	2,000 ppmv	250 ppmv
2. a. Lean-Burn, 2-Stroke, Gaseous Fueled, >50 bhp & <100 bhp	75 ppmv	2,000 ppmv	750 ppmv
2. b. Lean-Burn, Limited Use	65 ppmv	2,000 ppmv	750 ppmv
2. c. Lean-Burn Engine used for gas compression	65 ppmv or 93% reduction	2,000 ppmv	750 ppmv
2. d. Waste Gas Fueled	65 ppmv or 90% reduction	2,000 ppmv	750 ppmv
2. e. Lean-Burn, Not Listed Above	11 ppmv	2,000 ppmv	750 ppmv

The proposed digester gas-fired engines will be operated as a separate stationary source than the dairy farm and the District has determined that the IC engines are a non-agricultural IC engines. The digester gas-fired, engines are waste gas-fired engines and are required to comply with the following emissions limits from Table 2, Row 2.d: 65 ppmvd NO_X, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2).

Therefore, the following previously presented condition will be listed on the proposed ATC permits for the engines to ensure compliance:

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

Section 5.2.3.1 requires that the operator of a spark-ignited internal combustion engine rated > 50 bhp that is used exclusively in agricultural operations shall not operate it in such a manner that results in emissions exceeding the limits in Table 3 of Rule 4702 for the appropriate engine type on an engine-by-engine basis.

Section 5.2.3.2 allows that in lieu of complying with the NO_X, CO, and VOC limits of Table 3 on an engine-by-engine basis, an operator of a spark-ignited agricultural IC engine may elect to implement an alternative emission control plan pursuant to Section 8.0.

Section 5.2.3.3 requires an operator of an agricultural IC engine in that is subject to the applicable requirements of Table 3 shall not replace such engine with an engine that emits more emissions of NOx, VOC, and CO, on a ppmv basis, (corrected to 15% oxygen on a dry basis) than the engine being replaced.

As stated above, the proposed digester gas-fired engines will be operated as part of a separate non-agricultural stationary source; therefore, Section 5.2.3 does not apply to the proposed engines.

Section 5.2.4 requires the operator of a certified compression-ignited engine rated >50 bhp shall comply with the following requirements of Sections 5.2.4.1, 5.2.4.2, 5.2.4.3, 5.2.4.3, and 5.2.4.4. The proposed digester gas-fired engines are not compression-ignited engines; therefore, Section 5.2.4 does not apply to the proposed engines.

Section 5.3 requires that all continuous emission monitoring systems (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes. Any 15-consecutive minute block average CEMS measurement exceeding the applicable emission limits of this rule shall constitute a violation of this rule. The IC engines proposed under this project will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.4 specifies procedures to calculate percent emission reductions if percent emission reductions are used to comply with the NO_X emission limits of Section 5.2. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.5 requires the operator of an internal combustion engine that uses percent emission reduction to comply with the NO_X emission limits of Section 5.2 shall provide an accessible inlet and outlet on the external control device or the engine as appropriate for taking emission samples and as approved by the APCO. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.6 specifies procedures that operators of non-agricultural spark-ignited IC engines who elect to comply under Section 5.2.2.2 must use for calculation of the annual emissions fee. The applicant has proposed that the digester gas-fired engines comply with the applicable emission limits of Table 2 of District Rule 4702; therefore payment of annual emissions fees for the engines is not required and this section of the Rule is not applicable.

Section 5.7 requires that on and after the compliance schedule specified in Section 7.5, operators of non-agricultural spark-ignited engines and non-agricultural compression-ignited engines shall comply shall comply with Sections 5.7.1, 5.7.2, 5.7.3, 5.7.4, 5.7.5, or 5.7.6:

5.7.1 Operate the engine exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or

5.7.2 Limit gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or

5.7.3 Use California Reformulated Gasoline for gasoline-fired spark-ignited engines; or

5.7.4 Use California Reformulated Diesel for compression-ignited engines; or

5.7.5 Operate the engine on liquid fuel that contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.4.6; or

5.7.6 Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

To satisfy BACT, the average sulfur content of the digester gas fuel for the engine will be limited to 40 ppmv (approximately equal to 2.4 grains sulfur per 100 standard cubic feet). The following condition will be listed on the proposed engine ATC permits to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702, and 4801]

Section 5.8 requires that the operator of a non-agricultural spark-ignited IC engine subject to the requirements of Section 5.2 or any engine subject to the requirements of Section 8.0 shall comply with the following requirements of Sections 5.8.1 – 5.8.11:

Section 5.8.1 stipulates that for each engine with a rated brake horsepower of 1,000 hp or greater and which is allowed to operate more than 2,000 hours per calendar year, or with an external emission control device, shall either install, operate, and maintain continuous monitoring equipment for NO_X, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install, operate, and maintain APCO-approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system (CEMS), a parametric emissions monitoring system (PEMS), or an alternative monitoring system approved by the APCO. APCO-approved alternate monitoring shall consist of one or more of the following:

5.8.1.1 Periodic NO_X and CO emission concentrations,

5.8.1.2 Engine exhaust oxygen concentration,

5.8.1.3 Air-to-fuel ratio,
5.8.1.4 Flow rate of reducing agents added to engine exhaust,
5.8.1.5 Catalyst inlet and exhaust temperature,
5.8.1.6 Catalyst inlet and exhaust oxygen concentration, or
5.8.1.7 Other operational characteristics.

The applicant has proposed to comply with this section of the Rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, the following condition will be placed on the engine ATC permits:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

Section 5.8.2 requires that for each non-agricultural spark-ignited IC engine not subject to Section 5.8.1, the operator shall monitor operational characteristics recommended by the engine manufacturer or emission control system supplier, and approved by the APCO. The proposed engines will be subject to Section 5.8.1; therefore this section is not applicable.

Section 5.8.3 requires that for each engine with an alternative monitoring system, the operator shall submit to, and receive approval from the APCO, adequate verification of the alternative monitoring system's acceptability. The proposed ATC permits for the digester gas-fired engines include a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, this section is satisfied.

Section 5.8.4 requires that for each engine with an APCO approved CEMS, operate the CEMS in compliance with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Appendix B (Performance Specifications), 40 CFR Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). The IC engines proposed under this project will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.8.5 requires that each engine have the data gathering and retrieval capabilities of an installed monitoring system described in Section 5.8 approved by the APCO. As stated above, the proposed ATC permits for the proposed digester gas-fired engines include an alternate emissions monitoring plan that has been pre-approved by the APCO. Therefore, this section is satisfied.

Section 5.8.6 requires that for each non-agricultural spark-ignited IC engine, the operator shall install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the operator may use an alternative device, method, or technique in determining operating time provided that the alternative is approved by the APCO. The operator shall maintain and operate the required meter in accordance with the manufacturer's instructions. The applicant has proposed a nonresettable elapsed operating time meter for the engines in this project. Therefore, the following condition will be placed on the engine ATC permits to ensure compliance:

- This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]

Section 5.8.7 requires that for each engine, the permittee shall implement the Inspection and Monitoring (I&M) plan submitted to and approved by the APCO pursuant to Section 6.5. The applicant has submitted an I&M program with this ATC application and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.8 requires that for each engine, collect data through the I&M plan in a form approved by the APCO. The applicant has submitted an I&M program and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.9 requires for each non-agricultural spark-ignited IC engine, use of a portable NO_X analyzer to take NO_X emission readings to verify compliance with the emission requirements of Section 5.2 or Section 8.0 during each calendar quarter in which a source test is not performed. If an engine is operated less than 120 calendar days per calendar year, the operator shall take one NO_X emission reading during the calendar year in which a source test is not performed and the engine is operated. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. All NO_X emissions readings shall be reported to the APCO in a manner approved by the APCO. NO_X emission readings taken pursuant to this section shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period. Therefore, the following conditions will be placed on the ATC permits:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.8.10 specifies that the APCO shall not approve an alternative monitoring system unless it is documented that continued operation within ranges of specified emissions related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits and that the operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards. The proposed ATC permits for the digester gas-fired engines include a pre-approved alternate emissions monitoring plan that requires periodic NO_X, CO, and O_2 emissions concentrations. Therefore, this section is satisfied.

Section 5.8.11 requires that for each non-agricultural spark-ignited IC engine subject to the Alternate Emission Control Plan (AECP) of Section 8.0, the operator shall install and operate a nonresettable fuel meter. In lieu of installing a nonresettable fuel meter, the operator may use an alternative device, method, or technique in determining daily fuel consumption provided that the alternative is approved by the APCO. The operator shall maintain, operate, and calibrate the required fuel meter in accordance with the manufacturer's instructions. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.9 specifies monitoring requirements for all other engines that are not subject to the requirements of Section 5.8. The proposed spark-ignited non-agricultural digester gas-fired engines are subject to the requirements of Section 5.8; therefore this section of the Rule is not applicable.

Section 5.10 specifies SO_X Emissions Monitoring Requirements. On and after the compliance schedule specified in Section 7.5, an operator of a non-agricultural IC engine shall comply with the following requirements:

5.10.1 An operator of an engine complying with Sections 5.7.2 or 5.7.5 shall perform an annual sulfur fuel analysis in accordance with the test methods in Section 6.4. The operator shall keep the records of the fuel analysis and shall provide it to the District upon request,

5.10.2 An operator of an engine complying with Section 5.7.6 by installing and operating a control device with at least 95% by weight SOx reduction efficiency shall submit for approval by the APCO the proposed the key system operating parameters and frequency of the monitoring and recording not later than July 1, 2013, and

5.10.3 An operator of an engine complying with Section 5.7.6 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit-to-Operate. Source tests shall be performed in accordance with the test methods in Section 6.4.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

Section 5.11 requires operators of engines used exclusively in agricultural operations that are not required to have a Permit-to-Operate pursuant to California Health and Safety Code Section 42301.16 but are required to comply with Section 5.2 of Rule 4702 shall register such engines pursuant to Rule 2250 (Permit-Exempt Equipment Registration). The proposed spark-ignited non-agricultural digester gas-fired engines are required to have a District Permit to Operate; therefore this section of the Rule is not applicable.

Section 6.1 requires that the operator of an engine subject to the requirements of Rule 4702 shall submit to the APCO an approvable emission control plan of all actions to be taken to satisfy the emission requirements of Section 5.2 and the compliance schedules of Section 7.0. If there is no change to the previously-approved emission control plan, the operator shall submit a letter to the District indicating that the previously approved plan is still valid.

Section 6.1.1 specifies that the requirement to submit an emission control plan shall apply to the following engines:

6.1.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.1.1.2 Engines subject to Section 8.0;
6.1.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.1.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

Section 6.1.2 specifies that the emission control plan shall contain the following information, as applicable for each engine:

6.1.2.1 Permit-to-Operate number, Authority-to-Construct number, or Permit-Exempt Equipment Registration number,
6.1.2.2 Engine manufacturer,
6.1.2.3 Model designation and engine serial number,
6.1.2.4 Rated brake horsepower,
6.1.2.5 Type of fuel and type of ignition,
6.1.2.6 Combustion type: rich-burn or lean-burn,
6.1.2.7 Total hours of operation in the previous one-year period, including typical daily operating schedule,
6.1.2.8 Fuel consumption (cubic feet for gas or gallons for liquid) for the previous one-year period,
6.1.2.9 Stack modifications to facilitate continuous in-stack monitoring and to facilitate source testing,
6.1.2.10 Type of control to be applied, including in-stack monitoring specifications,
6.1.2.11 Applicable emission limits,
6.1.2.12 Documentation showing existing emissions of NO_X, VOC, and CO, and
6.1.2.13 Date that the engine will be in full compliance with this rule.

Section 6.1.3 requires that the emission control plan shall identify the type of emission control device or technique to be applied to each engine and a construction/removal schedule, or shall provide support documentation sufficient to demonstrate that the engine is in compliance with the emission requirements of this rule.

Section 6.1.4 requires that for an engine being permanently removed from service, the emission control plan shall include a letter of intent pursuant to Section 7.2.

The applicant has submitted all the required information for Section 6.1 in the application for the IC engines evaluated under this project.

Section 6.2.1 requires that the operator of an engine subject to the requirements of Section 5.2 shall maintain an engine operating log to demonstrate compliance with Rule 4702. This information shall be retained for a period of at least five years, shall be readily available, and be made available to the APCO upon request. The engine operating log shall include, on a monthly basis, the following information:

- 6.2.1.1 Total hours of operation,
- 6.2.1.2 Type of fuel used,
- 6.2.1.3 Maintenance or modifications performed,
- 6.2.1.4 Monitoring data,
- 6.2.1.5 Compliance source test results, and
- 6.2.1.6 Any other information necessary to demonstrate compliance with this rule.
- 6.2.1.7 For an engine subject to Section 8.0, the quantity (cubic feet of gas or gallons of liquid) of fuel used on a daily basis.

The following condition will be placed on the ATC permits:

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.8 and Section 5.9 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request.

The following previously presented condition will be listed on the proposed ATC permits to ensure compliance:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

Section 6.2.3 requires that an operator claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and provided to the APCO upon request. The records shall include, but are not limited to, the following:

6.2.3.1 Total hours of operation,
6.2.3.2 The type of fuel used,
6.2.3.3 The purpose for operating the engine,
6.2.3.4 For emergency standby engines, all hours of non-emergency and emergency operation shall be reported, and
6.2.3.5 Other support documentation necessary to demonstrate claim to the exemption

The applicant is not claiming an exemption for the proposed engines under Section 4.2 or Section 4.3; therefore, this section does not apply.

Section 6.3 requires that the operator of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.2, shall comply with the compliance testing requirements of Section 6.3.

Section 6.3.1 specifies that the requirements of Section 6.3.2 through Section 6.3.4 shall apply to the following engines:

6.3.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.3.1.2 Engines subject to Section 8.0;
6.3.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.3.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

Section 6.3.2 requires demonstration of compliance with applicable limits, ppmv or percent reduction, in accordance with the test methods in Section 6.4, as specified below:

6.3.2.1 By the applicable date specified in Section 5.2, and at least once every 24 months thereafter, except for an engine subject to Section 6.3.2.2.
6.3.2.2 By the applicable date specified in Section 5.2 and at least once every 60 months thereafter, for an agricultural spark-ignited engine that has been retro-fitted with a catalytic emission control device.
6.3.2.3 A portable NOx analyzer may be used to show initial compliance with the applicable limits/standards in Section 5.2 for agricultural spark-ignited engines, provided the criteria specified in Sections 6.3.2.3.1 to 6.3.2.3.5 are met, and a source test is conducted in accordance with Section 6.3.2 within 12 months from the required compliance date.

The following conditions will be included the ATC permits to ensure compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

Section 6.3.3 requires the operator to conduct emissions source testing with the engine operating either at conditions representative of normal operations or conditions specified in the

Permit-to-Operate or Permit-Exempt Equipment Registration. For emissions source testing performed pursuant to Section 6.3.2 for the purpose of determining compliance with an applicable standard or numerical limitation, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC shall be reported as methane. VOC, NO_X, and CO concentrations shall be reported in ppmv, corrected to 15 percent oxygen. For engines that comply with a percent reduction limit, the percent reduction of NO_X emissions shall also be reported.

The following conditions will be included in the ATC permits to ensure compliance:

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

Section 6.3.4 requires that in addition to other information, the source test protocol shall describe which critical parameters will be measured and how the appropriate range for these parameters shall be established. The range for these parameters shall be incorporated into the I&M plan.

Section 6.3.5 specifies that engines that are limited by Permit-to-Operate or Permit-Exempt Equipment Registration condition to be fueled exclusively with PUC quality natural gas shall not be subject to the reoccurring source test requirements of Section 6.3.2 for VOC emissions. The proposed engines will be fueled on digester gas; therefore this section does not apply.

Section 6.3.6 specifies requirements for spark-ignited engines for testing a unit or units that represent a specified group of units, in lieu of compliance with the applicable requirements of Section 6.3.2. Testing of representative units is not being proposed for the engines; therefore this section does not apply.

Section 6.4 requires that the compliance with the requirements of Section 5.2 shall be determined, as required, in accordance with the following test procedures or any other method approved by EPA and the APCO:

6.4.1 Oxides of nitrogen - EPA Method 7E, or ARB Method 100.
6.4.2 Carbon monoxide - EPA Method 10, or ARB Method 100.
6.4.3 Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.
6.4.4 Volatile organic compounds - EPA Method 25A or 25B, or ARB Method 100. Methane and ethane, which are exempt compounds, shall be excluded from the result of the test.
6.4.5 Operating horsepower determination - any method approved by EPA and the APCO.
6.4.6 SO_X Test Methods
6.4.6.1 Oxides of sulfur – EPA Method 6C, EPA Method 8, or ARB Method 100.

6.4.6.2 Determination of total sulfur as hydrogen sulfide (H_2S) content – EPA Method 11 or EPA Method 15, as appropriate.

6.4.6.3 Sulfur content of liquid fuel – American Society for Testing and Materials (ASTM) D 6920-03 or ASTM D 5453-99.

6.4.6.4 The SO_X emission control system efficiency shall be determined using the following:

% Control Efficiency = $[(C_{SO2,\ inlet} - C_{SO2,\ outlet}) / C_{SO2,\ inlet}] \times 100$

Where:

$C_{SO2,\ inlet}$ = concentration of SO_X (expressed as SO_2) at the inlet side of the SO_X emission control system, in lb/Dscf

$C_{SO2,\ outlet}$ = concentration of SO_X (expressed as SO_2) at the outlet side of the SO_X emission control system, in lb/Dscf

6.4.7 The Higher Heating Value (hhv) of the fuel shall be determined by one of the following test methods:

6.4.7.1 ASTM D 240-02 or ASTM D 3282-88 for liquid hydrocarbon fuels.

6.4.7.2 ASTM D 1826-94 or ASTM 1945-96 in conjunction with ASTM D 3588-89 for gaseous fuel.

The following conditions will be listed on the proposed ATC permits to ensure compliance:

- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
- The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

Section 6.5 requires that the operator of an engine that is subject to the requirements of Section 5.2 or the requirements of Section 8.0 shall submit to the APCO for approval, an Inspection & Maintenance (I&M) plan that specifies all actions to be taken to satisfy the requirements of Sections 6.5.1 through Section 6.5.9 and the requirements of Section 5.8. The actions to be identified in the I&M plan shall include, but are not limited to, the information specified below. If there is no change to the previously approved I&M plan, the operator shall submit a letter to the District indicating that previously approved plan is still valid.

Section 6.5.1 specifies that the I&M plan requirements of Sections 6.5.2 through Section 6.5.9 shall apply to the following engines:

6.5.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;

6.5.1.2 Engines subject to Section 8.0;

6.5.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0.

6.5.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

The digester gas-fired IC engines evaluated under this project will be equipped with SCR systems for control of NO_X and oxidation catalysts for control of CO and VOC. Therefore, the requirements of Sections 6.5.2 through 6.5.9 are applicable to the engines.

Section 6.5.2 requires procedures requiring the operator to establish ranges for control equipment parameters, engine operating parameters, and engine exhaust oxygen concentrations that source testing has shown result in pollutant concentrations within the rule limits.

Section 6.5.3 requires procedures for monthly inspections as approved by the APCO. The applicable control equipment parameters and engine operating parameters will be inspected and monitored monthly in conformance with a regular inspection schedule in the I&M plan.

The digester gas-fired IC engines evaluated under this project will be equipped with SCR systems for control of NO_X and oxidation catalysts for control of CO and VOC. The applicant has proposed the following alternate monitoring program to ensure compliance with Sections 6.5.2 and 6.5.3 of the Rule.

<u>NO_X Emissions:</u>

In order to satisfy the I & M requirements for NO_X emissions, the applicant has proposed to perform the following:

1. Measurement of NOx emissions concentrations with a portable analyzer at least once every calendar quarter.

2. To ensure that NOx emissions concentrations are not being exceeded between periodic NOx portable analyzer measurements, the applicant is proposing to determine a correlation between the SCR system's reagent injection rate and the catalyst control system inlet exhaust temperature and NO_X emissions. The appropriate ranges for each operating load will be established during performance testing and will be monitored at least once per month.

<u>CO and VOC Emissions:</u>

In order to satisfy the I & M requirements for CO and VOC emissions, the applicant has proposed to perform the following:

1. Measurement of CO emissions concentrations with a portable analyzer at least once every calendar quarter. Generally, if the oxidation catalyst is controlling CO emissions, it should also be achieving the desired removal efficiency for VOC emissions. Therefore, no additional monitoring for VOC emissions is required.

2. To ensure that CO and VOC emissions concentrations are not being exceeded between periodic CO emissions concentration measurements, the applicant is proposing to determine a correlation between the catalyst control system inlet exhaust temperature and back pressure and CO emissions. The appropriate ranges for each operating load will be established during performance testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on the proposed ATC permits to ensure compliance with the I & M requirements for NO_X, CO, and VOC:

- Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]
- If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]
- Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature(s) and back pressure(s) demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]
- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s)

within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

- The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

Section 6.5.4 requires procedures for the corrective actions on the noncompliant parameter(s) that the operator will take when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_X, CO, VOC, or oxygen concentrations.

Section 6.5.5 requires procedures for the operator to notify the APCO when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_X, CO, VOC, or oxygen concentrations.

The applicant has proposed that the alternate monitoring program will ensure compliance with these two sections of the Rule. Therefore, the following conditions will be listed on the proposed ATC permits to ensure compliance:

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control

system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

Section 6.5.6 requires procedures for and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that the engines will be operated and maintained per the specifications of the manufacturer or emissions control system supplier. Therefore, the following conditions will be listed on the proposed ATC permits:

- {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
- {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

Section 6.5.7 requires procedures and a schedule for using a portable NO_X analyzer to take NO_X emission readings pursuant to Section 5.8.9. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the Rule. The following previously proposed condition will be listed on the proposed ATC permits:

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 6.5.8 requires procedures for collecting and recording required data and other information in a form approved by the APCO including, but not limited to, data collected through the I&M plan and the monitoring systems described in Sections 5.8.1 and 5.8.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the Rule.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

Section 6.5.9 specifies procedures for revising the I&M plan. The I&M plan shall be updated to reflect any change in operation. The I&M plan shall be updated prior to any planned change in operation. An engine operator that changes significant I&M plan elements must notify the District no later than seven days after the change and must submit an updated I&M plan to the APCO no later than 14 days after the change for approval. The date and time of the change to the I&M plan shall be recorded in the engine operating log. For new engines and modifications to existing engines, the I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit-to-Operate or Permit-Exempt Equipment Registration. The operator of an engine may request a change to the I&M plan at any time.

The applicant has proposed to comply with the I&M plan modification requirements per this section of the Rule. The following condition will be listed on the proposed ATC permits to ensure compliance:

- {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

Section 7.0 specifies the schedules for compliance with the general requirements of Section 5.0 and the Alternative Emission Control Plan (AECP) option of Section 8.0. The proposed IC engines will be required to comply with the applicable sections of District Rule 4702 upon initial startup of the equipment; therefore, compliance with this section is expected.

Section 8.0 specifies requirements for use of an Alternative Emission Control Plan (AECP) to comply with the NO_X emission requirements of Section 5.2 for a group of engines. Requirements for use of an AECP include: only engines subject to Section 5.2 are eligible for inclusion in an AECP; during any seven consecutive day period, the operator shall operate all engines in the AECP to achieve an actual aggregate NO_X emission level that is ≤ 90% of the NO_X emissions that would be obtained by controlling the engines to comply individually with the NO_X limits in Section 5.2; the operator shall establish a NO_X emission factor limit for each engine; the operator must submit the AECP at least 18 months before compliance with the emission limits in Section 5.2 is required and receive approval from the APCO; the operator must submit and updated or modified AECP for approval by the APCO prior to any modifications; and the operator must maintain records necessary to demonstrate compliance with AECP. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engines proposed under this project; therefore this section of the Rule is not applicable.

Section 9.0 specifies requirements for certification of exhaust control systems for compliance with District Rule 4702. Certification under this section for the exhaust control systems for the IC engines under this project is not currently being proposed and, in addition, certification under this section of the Rule would require that the engines or identical units with the same fuel supply and exhaust control systems were operating and could be source tested to demonstrate compliance with the applicable limits; therefore this section of the Rule is not applicable.

Conclusion

As shown above, the proposed non-agricultural, digester gas-fired, lean burn, IC engines are expected to comply with the applicable requirements of Rule 4702 upon initial operation and no further discussion is required.

Rule 4801 Sulfur Compounds

The purpose of this District Rule 4801 is to limit the emissions of sulfur compounds. The limit is that sulfur compound emissions (as SO_2) shall not exceed 0.2% by volume. Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume of SO_X as (SO_2) = (n x R x T) ÷ P
Where:

n = moles SO_X
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot °R}$

$$0.0113 \quad \frac{lb}{MMBtu} \times \frac{1\,MMBtu}{9{,}100scf_{exhaust}} \times \frac{1\,lb \cdot mol}{64\,lb \cdot SO_2} \times \frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot °R} \times \frac{520°R}{14.7\,psi} \times 1{,}000{,}000\,ppm = \quad 7.4 \quad ppmv$$

Since 7.4 ppmv is ≤ 2000 ppmv, the engines are expected to comply with Rule 4801. The following condition will be placed on the engine ATC permits to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

40 CFR 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

This rule incorporates the New Source Performance Standards (NSPS) from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

The purpose of 40 CFR 60 Subpart JJJJ is to establish New Source Performance Standards to reduce emissions of NO_X, SO_X, PM, CO, and VOC from new stationary spark ignition (SI) internal combustion (IC) engines.

Pursuant to Section 60.4230, compliance with this subpart is required for owners and operators of stationary SI IC engines that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: (a) on or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP); (b) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP; (c) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or (d) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

The proposed engines are 1,468 bhp SI ICEs that will be constructed after June 12, 2006 and manufactured after July 1, 2007; therefore, the engines are subject to this subpart. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, the requirements from this subpart will not be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

40 CFR 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Internal Combustion Engines

40 CFR 63 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. A major source of HAP emissions is a facility that has the potential to emit any single HAP at a rate of 10 tons/year or greater or any combinations of HAPs at a rate of 25 tons/year or greater. An area source of HAPs is a facility is not a major source of HAPs.

Pursuant to Section 63.6590(c), an affected source that is a new or reconstructed stationary Reciprocating Internal Combustion Engine (RICE) located at an area source must meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60, Subpart JJJJ, for spark ignition engines and no further requirements apply for such engines under this part. As with 40 CFR 60, Subpart JJJJ, the District has not been delegated the authority to implement 40 CFR 63, Subpart ZZZ for non-Major Sources; therefore, no requirements from this subpart will be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

Greenhouse Gas (GHG) Significance Determination

It is determined that no other agency has or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

The proposed project is for construction of a renewable energy plant at an existing dairy facility. The proposed renewable energy plant will combust dairy digester gas in IC engines to produce electricity. The proposed project will involve diverting manure from existing open basin(s) and pond(s) at the dairy to covered lagoon digester(s), which will result in the capture of much of the methane that is currently released into the atmosphere from the open basins and pond at the dairy. Combustion of the dairy digester gas at the proposed renewable energy plant will oxidize the methane in the gas to carbon dioxide and water vapor. Because methane has a global warming potential at least 21 times that of carbon dioxide, combustion of the methane from the dairy digesters will result in a large net decrease in the global warming potential emitted from the dairy when compared to current levels. Therefore, the project will not result in an increase in project specific greenhouse gas emissions. The District therefore concludes that the project would have a less than cumulatively significant impact on global climate change.

District CEQA Findings

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that, although the project is considered to take place at a separate stationary source for NSR purposes, the activity will occur on previously developed land at an existing dairy facility and the project involves negligible expansion of the existing use. Furthermore, the District determined that the activity will not have a significant effect on the environment. The District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15301 (Existing Facilities), and finds that the project is exempt per the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATCs S-8637-1-0, -2-0, and -3-0 subject to the permit conditions on the attached draft ATC in Appendix D.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-8367-1-0	3020-06	Covered Lagoon Digester	$111.00
S-8367-2-0	3020-10-F	1,468 bhp IC engine	$785.00
S-8367-3-0	3020-10-F	1,468 bhp IC engine	$785.00

Appendixes

A: Quarterly Net Emissions Change (QNEC)
B: BACT Analysis for the Proposed Digester Gas-Fired IC Engines
C: Summary of Health Risk Assessment (HRA) and Ambient Air Quality Analysis (AAQA)
D: Draft ATCs (S-8367-1-0, -2-0, & -3-0)

APPENDIX A
Quarterly Net Emissions Change (QNEC)

Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

S-8637-1-0 (Digester System)

PE1 (lb/qtr) S-8637-1-0					
	PE1 (lb/year)	÷	4 qtr/year	=	PE1 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

PE2 (lb/qtr) S-8637-1-0					
	PE2 (lb/year)	÷	4 qtr/year	=	PE2 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

Quarterly NEC [QNEC] S-8637-1-0					
	PE2 (lb/qtr)	-	PE1 (lb/qtr)	=	NEC (lb/qtr)
NO_X	0.0	-	0.0	=	0.0
SO_X	0.0	-	0.0	=	0.0
PM_{10}	0.0	-	0.0	=	0.0
CO	0.0	-	0.0	=	0.0
VOC	0.0	-	0.0	=	0.0

S-8637-2-0 & -3-0 (1,468 bhp Digester Gas-Fired, Lean Burn, IC Engines)

PE1 (lb/qtr) S-8637-2-0 & -3-0					
	PE1 (lb/year)	÷	4 qtr/year	=	PE1 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

PE2 (lb/qtr) S-8637-2-0 & -3-0					
	PE2 (lb/year)	÷	4 qtr/year	=	PE2 (lb/qtr)
NO_X	4,583	÷	4 qtr/year	=	1,145.8
SO_X	1,134	÷	4 qtr/year	=	283.5
PM_{10}	1,985	÷	4 qtr/year	=	496.3
CO	50,818	÷	4 qtr/year	=	12,704.5
VOC	3,185	÷	4 qtr/year	=	796.3

Quarterly NEC [QNEC] S-8637-2-0 & -3-0					
	PE2 (lb/qtr)	-	PE1 (lb/qtr)	=	NEC (lb/qtr)
NO_X	1,145.8	-	0.0	=	1,145.8
SO_X	283.5	-	0.0	=	283.5
PM_{10}	496.3	-	0.0	=	496.3
CO	12,704.5	-	0.0	=	12,704.5
VOC	796.3	-	0.0	=	796.3

APPENDIX B

BACT Analysis for Digester Gas-Fired IC Engines

SJVAPCD Best Available Control Technology (BACT) Guideline 3.3.15*

Last Update: 3/6/2013

Waste Gas-Fired IC Engine**

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NO_X	0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent)		1. Fuel Cells (<0.05 lb/MW-hr) 2. Microturbines (<9 ppmv @ 15% O_2) 3. Gas Turbine (<9 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
SO_X	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S) (dry absorption, wet absorption, chemical H_2S reduction, water scrubber, or equivalent) (may be averaged up to 24 hours for compliance)		
PM_{10}	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S)		
CO	2.0 g/bhp-hr		1. Fuel Cells (<0.10 lb/MW-hr) 2. Microturbines (<60 ppmv @ 15% O_2) 3. Gas Turbine (<60 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
VOC	0.10 g/bhp-hr (lean burn and positive crankcase ventilation (PCV) or a 90% efficient crankcase control device or equivalent)		Fuel Cells (<0.02 lb-VOC/MW-hr as CH_4)
Ammonia (NH_3) Slip	≤ 10 ppmv @ 15% O_2		

*** For the purposes of this determination, waste gas is a gas produced from the digestion of material excluding municipal sources such as waste water treatment plants, landfills, or any source where siloxane impurities are a concern.*

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Pages**

3.3.15

Top-Down BACT Analysis for Project S-1143770
Digester Gas-Fired IC Engines

Current District BACT Guideline 3.3.15 applies to the proposed waste gas-fired IC engines. In accordance with the District BACT policy, information from District BACT Guideline 3.3.15 will be utilized for the BACT analysis for the digester gas-fired engines proposed under this project.

I. Proposal and Process Description

ABEC #3 LLC dba Lakeview Dairy Biogas, a subsidiary of California Bioenergy, LLC, has requested Authority to Construct (ATC) permits to construct a covered lagoon anaerobic digester system (ATC S-8637-1-0) and to install two 1,468 bhp digester gas-fired IC engines (or approved engines of equal or lesser bhp) (ATCs S-8637-2-0 and -3-0) at Lakeview Farms dairy (Facility S-5254). Each engine will be equipped with a selective catalytic reduction (SCR) system for emissions control and will power an electrical generator that will produce up to 1,059 kWe. The covered lagoon digester will utilize an air injection system for biological removal of H_2S from the digester gas. After initial removal of H_2S in the covered lagoon digester, the digester gas will be captured by the covered the lagoon gas collection system and will be piped to the gas conditioning system for polishing to remove additional H_2S by an iron sponge scrubber and/or activated carbon or an equivalent H_2S removal system and for removal of moisture. The cleaned digester gas, which consists mostly of methane, the main component of natural gas, will then be sent to the engines for use as fuel to generate electricity for sale to a utility and to produce heat for the digester system.

II. BACT Applicability

New emissions units – PE > 2.0 lb/day

New Emissions Unit BACT Applicability for S-8637-2-0 & -3-0 After Commissioning				
Pollutant	PE2 for each unit after commissioning (lb/day)	BACT Threshold (lb/day)	SSPE2 (lb/yr)	BACT Triggered?
NO_X	11.7	> 2.0	N/A	**Yes**
SO_X	3.1	> 2.0	N/A	**Yes**
PM_{10}	5.4	> 2.0	N/A	**Yes**
CO	135.9	> 2.0 and SSPE2 ≥ 200,000 lb/yr	101,636	No
VOC	7.8	> 2.0	N/A	**Yes**
NH_3	3.9	> 2.0	N/A	**Yes**

* BACT is not required for CO from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

III. Top-Down BACT Analyses for the Digester Gas-Fired Engines

As stated above, the information form the existing District BACT Guideline 3.3.15 for Waste Gas-Fired IC Engines will be utilized for the BACT analysis for the proposed digester gas-fired IC engines under this project.

1. BACT Analysis for NO_X Emissions:

a. Step 1 - List all control technologies

District BACT Guideline 3.3.15 lists the following options to reduce NO_X emissions from waste gas-fired IC engines:

1) NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)
2) Fuel Cell (≤ 0.05 lb/MW-hr) (Alternate Basic Equipment)
3) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)
4) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Description of Control Technologies

1) NO_X emissions ≤ 0.15 g/bhp-hr (9-11 ppmv NO_X @ 15% O_2) (Selective Catalytic Reduction (SCR) or equivalent) (Achieved in Practice)

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%.

2) Fuel Cell (≤ 0.05 lb- NO_X/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell. Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these high temperature fuel cells are tolerant of CO_2 that is found biogas.

Fuel cells have recently been commercialized and offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells is the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense and, for biogas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cell catalysts. Although this expense can be substantial, biogas-fueled fuel cells have been installed at some wastewater treatment plants and fuel cells have also been fueled with other types of biogas (e.g. landfill gas and brewery wastewater gas).

3) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Gas turbines are internal combustion engines that operate on the Brayton (Joule) combustion cycle rather than the Otto combustion cycle used in reciprocating internal combustion engines or the diesel cycle for diesel engines. In the Brayton cycle the air flow and fuel injection are steady, and the different parts of the cycle occur continuously within different components of the system. In a gas turbine, fuel is continually injected into the combustion chamber or combustor and air is constantly drawn into the turbine and compressed. All elements of the Brayton cycle occur simultaneously in a gas turbine.

Gas turbines are one of the cleanest means of generating electricity. With the use of lean pre-mixed combustion or catalytic exhaust cleanup, NO_X emissions from large gas-fired turbines are generally in the single-digit ppmv range. These levels are generally for natural gas-fired units but they are considered technologically feasible for biogas-fired units.

Gas turbines are available in sizes ranging from 500 kW - 25 MW. Based on contacts with turbine suppliers, biogas-fired turbines used to produce electricity are expected to be available in the size range of 2 - 7 MW. According to Solar Turbines, the smaller biogas-fired turbines are no longer actively produced or marketed since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

4) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gases. According to the California Air Resources Board (ARB), there were approximately 200 biogas-fired microturbines operating in California as of the year 2006.[5] Microturbines generally have electrical efficiencies

[5] "Staff Report: Initial Statement of Reasons for Proposed Amendments to the Distributed Generation Certification Regulation" (9/1/2006), Cal EPA - ARB, Executive Summary Pg. ii (http://www.arb.ca.gov/regact/dg06/dgisor.pdf)

of 25-30%; however, the electrical efficiency of larger microturbines (≥ 200 kW) can range from 30-33%. Microturbine manufacturers include Capstone Microturbines and FlexEnergy.

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of NO_X, CO, and VOC than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low NO_X, or DLN) combustion technology. Microturbines manufacturers will generally guarantee NO_X emissions of 9-15 ppmv @ 15% O_2. However, several emission tests performed on biogas-fired microturbines have demonstrated even lower emissions. A small number of dairy digester gas-fired microturbines have been installed[6], including Twin Birch Dairy and New Hope Farm View dairy and Twin Birch Dairy in New York, and den Dulk Dairy in Michigan.

The proposed project is for a large waste gas to energy facility and, although larger microturbines have recently become available, several microturbines (at least 4) would still be required to replace each engine. The applicant states that when they investigated microturbines they found that they could not secure the necessary financing for a waste gas to energy project of this size using microturbines and that the major microturbines vendors were unable to secure the debt. Although microturbines may not currently be a practical option for this particular project, they will be considered in the cost analysis below.

b. Step 2 - Eliminate technologically infeasible options

Option 3 - Gas Turbine (≤ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Option 3, Gas Turbine, was determined to be infeasible for the proposed project because the available information indicates that the principal suppliers of gas turbines (Solar Turbines, Allison, and General Electric) do not currently produce or market waste gas-fired gas turbines rated less than 3 MW since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

The cost information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[7] (March 2015) and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8] (October 5, 2015) also supports that gas turbines rated approximately 3 MW are not generally available. The smallest turbine for which the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies provides cost information is 3,304 kW and the smallest turbine for which the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] provides cost information is 2,500 kW.

[6] See EPA AgStar Program "AgStar Project Profiles", http://www2.epa.gov/agstar/agstar-project-profiles
[7] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies
[8] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

The proposed project would require gas turbines rated 1,059 kW each, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas turbines are not considered feasible for this particular project and will be eliminated from consideration at this time.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)
2) Digester gas-fueled microturbines (Alternate Basic Equipment)
3) NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy, a cost effectiveness analysis is required for the options that have not been determined to be achieved in practice. In accordance with the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), to determine the cost effectiveness of particular technologically feasible control options or alternate equipment options, the amount of emissions resulting from each option will be quantified and compared to the District Standard Emissions allowed by the District Rule that is applicable to the particular unit. The emission reductions will be equal to the difference between the District Standard Emissions and the emissions resulting from the particular option being evaluated.

The District has determined that the proposed digester gas-fueled IC engines are non-agricultural IC engines. The lean burn, digester gas-fired, engines are subject to the following emission limits for non-agricultural, lean burn, waste gas fueled IC engines contained in District Rule 4702, Section 5.2.2, Table 2, 2.d: 65 ppmvd NO_X (or 90% reduction), 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2). The proposed digester engines are also subject to the New Source Performance Standards (NSPS) for IC Engines contained in 40 CFR 60 Subpart JJJJ, which includes a more stringent VOC emissions limit of 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane) for landfill and digester gas-fired IC engines. Therefore, the District Standard Emissions used for the BACT cost analysis below for the proposed engines will be based on the emission limits contained in these applicable regulations.

<u>Option 1: Fuel Cells (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)</u>

Because fuel cells have reduced NO_X and VOC emissions in comparison to a reciprocating IC engine, a Multi-Pollutant Cost Effectiveness Threshold (MCET) will be used to determine if this option is cost-effective. The following cost analysis demonstrates that replacement of the proposed engines with a fuel cell is not cost effective even when the additional operation costs of a fuel cell are not considered.

Assumptions

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 600 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Price for electricity: $127.72/MW-hr (*based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)*[9] *in February 2016*)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engines and fuel cells will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[7] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and fuel cells, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [8]

<u>Assumptions for Proposed Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)</u>

- Each engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines: 33% (*Conservative estimate, as discussed above, US EPA Combined Heat and Power Partnership Catalog of CHP Technologies lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system*)
- The maximum total daily heating value of the digester gas used by each engine will be: 271.71 MMBtu/day (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 24 hr/day x 1 engine*)
- The maximum total annual heating value for of the digester gas used by each engine will be: 99,175.4 MMBtu/year (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 8,760 hr/year x 1 engine*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,059 kW without add-on air pollution control equipment: $1,752/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engines: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)

[9] See: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/BioMAT/index.page, https://scebiomat.accionpower.com/biomat/home.asp, and http://www.sdge.com/procurement/bioenergy-market-adjusting-tariff-bio-mat)

- Total Installation Cost for biogas-fueled IC engine rated 1,059 kW: $2,139/kW
- Estimated operation costs for CHP IC engine rated 1,059 kW without add-on air pollution control costs: $0.020/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engines must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because required level of sulfur removal is adequate for use in the engines, there will be no increase in operating costs related to cleaning the digester gas for use in IC engines.
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% O_2 = 0.2540 lb/MMBtu
- Rule 4702 VOC emission limit for non-agricultural, lean burn IC engines: 750 ppmv @ 15% O_2 as CH_4 = 1.0193 lb/MMBtu
- 40 CFR 60 Subpart JJJJ VOC emission limit for landfill and digester gas-fired IC engines: 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane)

<u>Assumptions for Fuel Cell System</u>

- Net electrical efficiency for a molten carbonate fuel cell (MCFC): 45% (*US EPA Combined Heat and Power Partnership Catalog of CHP Technologies gives efficiencies of 47% for a 300 kW MCFC and 42.5% for a 1,400 kW MCFC*)
- Size of fuel cell system needed to replace each proposed engine: 1,500 kW (estimated based on 271.71 MMBtu/day and 45% efficiency)
- Estimated Purchase and Installation Cost for Molten Carbonate Fuel Cell: $4,550/kW (*Average of the two costs for largest Molten Carbonate Fuel Cells given in US EPA Combined Heat and Power Partnership document Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]; The U.S. Department of Energy Federal energy management Program (FEMP) document "Fuel Cells and Renewable Energy" (last updated 12-1-2014 and available at: http://www.wbdg.org/resources/fuelcell.php) states, "Installation costs of a fuel cell system can range from $5,000/kW to $10,000/kW." Therefore, this estimate may be actually too low based on the recently reported costs for fuel cell power plants, such as the "Bloom Box".*)
- Additional capital investment for biogas conditioning and cleanup for fuel cells: $563/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled fuel cells rated ≥ 1,200 kW: $5,113/kW

- Typical operation costs for natural gas-fueled fuel cells, including stack replacement costs: \$0.04/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional operational costs for biogas conditioning and cleanup for large fuel cells: \$0.15/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Operation Cost for biogas-fueled fuel cells rated ≥ 1,200 kW: \$0.19/kW-hr
- Fuel Cell NO_X emissions: 0.01 - 0.02 lb/MW-hr *(Note: Fuel cells have been certified to the ARB Distributed Generation Certification level of 0.07 lb-NO_X/MW-hr but measured emissions from fuel cells are generally much lower)*
- Fuel Cell VOC emissions: 0.02 lb-VOC/MW-hr (≤ 2.0 ppmv VOC @ 15% O_2 as CH_4 based on ARB Distributed Generation Certification level of 0.02 lb-VOC/MW-hr and emission tests on fuel cells)
- Unlike the proposed engines, a high-temperature fuel cell power plant must primarily operate at steady state conditions; there would not be the ability to store gas to generate more electricity during peak hours, which is the current business plan of the applicant. Because the price paid for electricity is greater during peak hours and less during other times, the price paid for electricity generated by a fuel cell power plant would be less. This would require the operator to alter their plans of operation and result in less revenue per kW-hr of electricity generated potentially offsetting the revenue from increased power generating capacity because of the higher efficiency of a fuel cell power plant. For more conservative analysis, the difference in the cost of peak and off-peak electricity was not considered in this comparison.

Capital Cost

The estimated increased incremental capital cost for replacement of the proposed engines with fuel cells is calculated based on the difference in cost of a fuel cell power plant and the proposed IC engines.

The incremental capital cost for replacement of the proposed IC engines with a fuel cell power plant is calculated as follows:

(1,500 kW x \$5,113/kW) - (1,059 kW x \$2,139/kW) = \$5,404,299

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(I+1)^n]/[(I+1)^n-1]$$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$$A = [\$5{,}404{,}299 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \mathbf{\$879{,}525/year}$$

Annual Costs

Electricity Generated

The amount of electricity potentially generated by each option is calculated as follows:

Each Proposed IC Engine
1,059 kW x 8,760 hr/yr = 9,276,840 kW-hr/year

Fuel Cells (Alternate Equipment)
271.71 MMBtu/day x 10^6 Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,413 Btu x 0.45 (electrical efficiency) = 1,493 kW

99,175.4 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.45 (electrical efficiency) = 13,076,159 kW-hr /year

Cost Decrease from Increased Revenue for Power Generation from Replacing each Proposed 1,059 kW Engine with a Fuel Cell
(9,276,840 kW-hr/yr - 13,076,159 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = -$485,249/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Each Proposed 1,059 IC kW Engine
9,276,840 kW-hr/yr x $0.020/kW-hr = $185,537/year

Fuel Cells (Alternate Equipment)
13,076,159 kW-hr/yr x $0.19/kW-hr = $2,484,470/year

Annual Costs of Increased Maintenance
$2,484,470/yr - $185,537/yr = $2,298,933/year

Total Increased Annual Costs for Fuel Cell as an Alternative to Each Proposed Engine

$879,525/year + (-$485,249/year) + $2,298,933/year = **$2,693,209/year**

Emission Reductions:

NO_X and VOC Emission Factors:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_X emissions from the engines will be based on the NO_X emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.1, Table 1, 2.b. The District Standard Emissions for VOC emissions from the engines will be based on the New Source Performance Standard (NSPS) VOC emission limit for landfill and digester gas-fired IC engines from 40 CFR 60 Subpart JJJJ, since this limit is more stringent than the applicable emission limit in District Rule 4702.

The following emissions factors will be used for the cost analysis:

District Standard Emissions: 0.2540 lb-NO_X/MMBtu (65 ppmv NO_X @ 15% O_2) and 1.0 g-VOC/bhp-hr

Emissions from Fuel Cells as Alternative Equipment: 0.01 lb-NO_X/MW-hr and 0.02 lb-VOC/MW-hr as CH_4

Emission Reductions:

Each Proposed Engine Compared to Fuel Cells based on District Standard Emission Reductions

NO_X Emission Reductions (65 ppmv @ 15% O_2 → 0.01 lb-NO_X/MW-hr)
(99,175.4 MMBtu/yr x 0.2540 lb-NO_X/MMBtu) – (13,076,159 kW-hr/yr x 1 MW/1,000 kW x 0.01 lb-NO_X/MW)
= 25,060 lb-NO_X/year (12.53 ton-NO_X/year)

VOC Emission Reductions (1.0 g/bhp-hr → 0.02 lb-VOC/MW-hr)
(1,468 bhp/engine x 8,760 hr/yr x 1 engine x 1.0 g-VOC/bhp-hr x 1 lb/453.59 g) – (13,076,159 kW-hr/yr x 1 MW/1,000 kW x 0.02 lb-VOC/MW)
= 28,089 lb-VOC/year (14.04 ton-VOC/year)

Multi-Pollutant Cost Effectiveness Thresholds (MCET) for NO_X and VOC Reductions based on District Standard Emission Reductions

(12.53 ton-NO_X/year x $24,500/ton-$NO_X$) + (14.04 ton-VOC/year x $17,500/ton-VOC)
= **$552,685/year**

As shown above, the annualized capital cost of this alternate option exceeds the Multi-Pollutant Cost Effectiveness Threshold (MCET) calculated for the NO_X and VOC emission reductions. Therefore, this option is not cost effective and is being removed from consideration.

Option 2 - Microturbines (≤ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

The cost analysis below demonstrates that the NO_X emission reductions achieved by replacement of the proposed engines with microturbines would not be cost effective based on the District's Revised BACT Cost Effectiveness Thresholds (May 14, 2008).

In addition, it should be noted that large lean burn IC engines generally have higher overall efficiencies than microturbines. The difference in efficiency between engines and microturbines will minimize and possibly eliminate any overall differences in NO_X emissions between these options. For example, information from a Capstone Turbine Corporation specification sheet indicates that the guaranteed NO_X emissions rate of 9 ppmvd @ 15% O_2 for their 1,000 kW renewable gas fuel microturbine package is equivalent to 0.14 g-NO_X/hp-hr.[10] This level is not significantly different than the current BACT requirement for waste gas-fired engines of 0.15 g-NO_X/bhp-hr.

The following discussion demonstrates how the difference the efficiency of engines and microturbines can affect the emission rate. NO_X emissions from the engines will be limited to no more than 0.15 g/bhp-hr (approximately 11 ppmv NO_X @ 15% O_2). Microturbine suppliers will generally guarantee NO_X emissions ≤ 9 ppmv @ 15% O_2 For digester gas-fired microturbines. The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11] (March 2015), Table 2-2: Gas Spark Ignition Engine CHP - Typical Performance Parameters, lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12] (October 5, 2015), Page A-28 indicates that "Typical observed efficiencies on IC engines deployed in the SGIP are 27% for electrical conversion (HHV)..." Therefore, the expected HHV electrical efficiency of each of the proposed 1,059 kW engines is between 27-36.8%.

The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11], Table 5-2: Gas Spark Ignition Engine CHP - Microturbine Cost and Performance Characteristics, lists HHV electrical efficiencies of 26-28% for microturbine systems rated at least 200 kW. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12], Table A-15: Microturbine Electrical Conversion Efficiency, lists a HHV electrical efficiencies of 21% for microturbines based on SGIP metered data. Therefore, the expected HHV electrical efficiency of large microturbines is between 21-28%.

The maximum expected NO_X emission factor for the proposed engine-generator sets is approximately 0.47 lb/MW-hr (based on 0.15 g/bhp-hr and 95% generator efficiency). Based on 9 ppmv NO_X @ 15% O2 and the expected range of microturbine electrical conversion efficiency given above, the NO_X emission factor from large digester gas-

[10] See: http://www.adigo.no/wordpress/wp-content/uploads/2015/02/CR1000-teknisk-spesifikasjon-engelsk.pdf. Note that because of lower efficiencies for smaller microturbines, the guaranteed emission rate of 9 ppmvd NO_X @ 15% O_2 from smaller units will actually be higher than 0.15 g-NO_X/bhp-hr

[11] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies

[12] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

fueled microturbines is expected to range from 0.43 – 0.57 lb/MW-hr. Because, the maximum NO_X emission factor for the proposed engine-generator sets falls within this range, the options could be considered equivalent.

Assumptions

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 600 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engines and microturbines will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[11] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and microturbines, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [12]
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engines or microturbines must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because required level of sulfur removal is adequate for use in both engines and microturbines and the same amount of total digester gas will be available for either option, there will be no difference in operating costs related to cleaning the digester gas for use in IC engines or microturbines.
- Price for electricity: \$127.72/MW-hr (based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)[9] in February 2016)

<u>Assumptions for Proposed Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)</u>

- Each engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines: 33% (*Conservative estimate, as discussed above, the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system*)
- The maximum total daily heating value of the digester gas used by each engine will be: 271.71 MMBtu/day (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 24 hr/day x 1 engine*)

- The maximum total annual heating value for of the digester gas used by each engine will be: 99,175.4 MMBtu/year (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 8,760 hr/year x 1 engine*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,059 kW without add-on air pollution control equipment: $1,752/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engines: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled IC engine rated 1,059 kW: $2,139/kW
- Estimated operation costs for CHP IC engine rated 1,059 kW without add-on air pollution control costs: $0.020/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% O_2 = 0.2540 lb/MMBtu

<u>Assumptions for Microturbines</u>

- Net HHV electrical efficiency for a 950 kW net (1,000 kW nominal capacity) microturbine package: 24.5% (*conservative estimate, SGIP metered data indicates an efficiency of 21%*)
- Estimated Size of microturbine system needed to replace each engine: 950 kW net (1,000 kW nominal capacity)
- Estimated Purchase and Installation Cost for 950 kW net (1,000 kW nominal capacity) microturbine package: $2,500/kW (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- Estimated additional capital investment for biogas conditioning and cleanup for microturbines: $744/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled microturbine system rated 950 kW net (1,000 kW nominal capacity): $3,244/kW
- Typical operation costs for a 950 kW net (1,000 kW nominal capacity) microturbine package: $0.012/kW-hr (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- NO_X Emissions for Digester gas-fueled microturbines: ≤ 9 ppmv NO_X @ 15% O_2 (~ 0.0352 lb-NOx/MMBtu)

Capital Cost

The estimated increased incremental capital cost for replacement of each the proposed engines with microturbines is calculated based on the difference in cost of a microturbine system and the proposed IC engines.

The incremental capital cost for replacement of the proposed IC engines with a microturbine system is calculated as follows:

(950 kW x $3,244/kW) - (1,059 kW x $2,139/kW) = $816,599

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(I+1)^n]/[(I+1)^n-1]$$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$$A = [\$816,599 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \mathbf{\$132,898/year}$$

Annual Costs

Electricity Generated

The amount of electricity potentially generated by each option is calculated as follows:

Each Proposed IC Engine
1,059 kW x 8,760 hr/yr = 9,276,840 kW-hr/year

950 kW (net) Microturbine Package (Alternate Equipment)
271.71 MMBtu/day x 10^6 Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,413 Btu x 0.245 (electrical efficiency) = 813 kW

99,175.4 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.245 (electrical efficiency) = 7,119,242 kW-hr /year

Cost of Decreased Revenue from Power Generation from Replacing each Proposed 1,059 kW Engine with Microturbines
(9,276,840 kW-hr/yr - 7,119,242 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = $275,568/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Each Proposed 1,059 kW IC Engine
9,276,840 kW-hr/yr x $0.020/kW-hr = $185,537/year

Microturbines (Alternate Equipment)
7,119,242 kW-hr/yr x $0.012/kW-hr = $85,431/year

Cost from Annual Decrease in Maintenance Costs
$85,431/yr - $185,537/yr = -$100,106/year

Total Increased Annual Costs for Microturbines as an Alternative to Each Proposed Engine

$132,898/year + $275,568/year + (-$100,106/year) = **$308,360/year**

Emission Reductions:

NO_X Emission Factors:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_X emissions from the engines will be based on the NO_X emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.1, Table 1, 2.b.

The following emissions factors will be used for the cost analysis:

District Standard Emissions: 0.2540 lb-NO_X/MMBtu (65 ppmv NO_X @ 15% O_2)

Emissions from Microturbines as Alternative Equipment: 0.0352 lb-NO_X/MMBtu (9 ppmv NO_X @ 15% O_2)

Emission Reductions for Each Proposed Engine Compared to Microturbines based on District Standard Emission Reductions

NO_X Emission Reductions (65 ppmv @ 15% O_2 → 9 ppmv @ 15% O_2)
99,175.4 MMBtu/yr x (0.2540 lb-NO_X/MMBtu – 0.0352 lb-NO_X/MMBtu)
= 21,700 lb-NO_X/year (10.85 ton-NO_X/year)

Cost of NO_X Emission Reductions

Cost of reductions = ($308,360/year)/[(21,700 lb-NO_X/year)(1 ton/2000 lb)]
= **$28,420/ton of NO_X reduced**

As shown above, the cost of the NO_X emission reductions for replacing each of the proposed engines with microturbines exceeds the $24,500/ton cost effectiveness threshold of the District BACT policy. Therefore, this option is not cost effective and is being removed from consideration.

Option 3: NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

This option is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for the Digester Gas-fired Engines must be satisfied with the following: NO_X: NO_X emissions to ≤ 0.15 g/bhp-hr

The applicant has proposed to use SCR systems for the digester gas-fired lean burn IC engines to reduce NO_X emissions to ≤ 0.15 g/bhp-hr. Therefore, the BACT requirements are satisfied.

2. BACT Analysis for SO_X Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce SO_X emissions from the proposed engine:

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice/Contained in SIP)

There are no options listed in the SJVUAPCD BACT Clearinghouse as alternate basic equipment.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

The control efficiency of each of the options above is estimated and the controls are ranked below based on the control effectiveness.

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for SO_X emissions from the proposed engines is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use a biological sulfur removal system and iron sponge and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_X are satisfied.

3. BACT Analysis for PM_{10} Emissions:

a. Step 1 - Identify all control technologies

Combustion of gaseous fuels generally does not result in significant emissions of particulate matter. Dairy anaerobic digester gas is the planned fuel for the proposed IC engines. The anaerobic digester gas will be composed primarily of methane (approximately 60% molar composition) and CO_2 (approximately 40% molar composition) and is expected to burn in a fairly clean manner. Particulate emissions from combustion of the digester gas are expected to primarily result from the incineration of fuel-born sulfur compounds (mostly H_2S) resulting in the formation of sulfur-containing particulate. Therefore, scrubbing of the digester gas is the principal means to reduce particulate emissions.

The following control was identified to reduce particulate matter emissions from combustion of the digester gas as fuel in the proposed engines:

1) Sulfur Content of fuel ≤ 40 ppmv as H_2S (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Sulfur Content of fuel gas ≤ 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for PM_{10} emissions from the proposed engines is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use a biological sulfur removal system and iron sponge and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_X are satisfied.

4. **BACT Analysis for VOC Emissions:**

a. Step 1 - Identify all control technologies

The following options were identified to reduce VOC emissions:

1) VOC emissions ≤ 0.10 g/bhp-hr (lean burn or equivalent and positive crankcase ventilation) (Achieved in Practice)
2) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)
2) VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cell (≤ 0.02 lb/MW-hr VOC as CH_4) (Alternate Basic Equipment)

The multi-pollutant cost analysis performed above for the NO_X and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the NO_X and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

This has been identified as achieved in practice and has been proposed by the applicant. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the proposed engines is VOC emissions ≤ 0.10 g/bhp-hr. The applicant has proposed IC engines with VOC emissions ≤ 0.10 g/bhp-hr. Therefore, the BACT requirements for VOC are satisfied.

5. **BACT Analysis for NH_3 Slip Emissions:**

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%. Ammonia slip is the result of unreacted ammonia exiting the SCR system.

a. Step 1 - Identify all control technologies

The District has not established a cost effectiveness threshold for ammonia. Therefore, only options that are determined to be Achieved-in-Practice controls will be considered for ammonia in this analysis.

District BACT Guideline 3.3.15 lists an ammonia slip emission limit of 10 ppmvd @ 15% O_2 as an Achieved in Practice BACT requirement for waste gas-fired IC engines.

1) NH_3 emissions ≤ 10 ppmvd @ 15% O_2 (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) NH_3 emissions ≤ 10 ppmvd @ 15% O_2 (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved in practice and has been proposed by the applicant. Additionally, as stated above, a cost effectiveness threshold for ammonia has not been established by the District. Therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for NH_3 slip emissions from the proposed engines is NH_3 slip emissions ≤ 10 ppmvd @ 15% O_2. The applicant has proposed IC engines with NH_3 slip emissions ≤ 10 ppmvd @ 15% O_2. Therefore, the BACT requirements for NH_3 slip are satisfied.

APPENDIX C

Summary of Health Risk Assessment (HRA) and Ambient Air Quality Analysis (AAQA)

San Joaquin Valley Air Pollution Control District
REVISED Risk Management Review

To:	Ramon Norman – Permit Services
From:	Yu Vu – Technical Services
Date:	October 22, 2015
Facility Name:	ABEC #3 dba Lakeview Dairy Biogas
Location:	17702 Bear Mountain Blvd, Bakersfield, CA 93311 at Lakeview Dairy (S-5254)
Application #(s):	S-8637-2-0, 3-0
Project #:	S-1143770

A. RMR SUMMARY

RMR Summary			
Categories	**1,468 BHP Bio Gas Engines (Unit 2-0 & 3-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	107 (ea.)	214	>1
Acute Hazard Index	0.48 (ea.)[1]	0.95	0.95
Chronic Hazard Index	0.16 (ea.)	0.31	0.31
Maximum Individual Cancer Risk (10^{-6})	0.002 (ea.)	0.004	0.004
T-BACT Required?	**No**		
Special Permit Conditions?	**Yes**		

[1] H_2S emissions must be limited in order to achieve the acute hazard index score in this project and for the project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS). Please see special condition below.

<u>**Proposed Permit Conditions**</u>

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

<u>Unit # 2-0, 3-0</u>

1) The H_2S emissions from the engine shall not exceed 1.97 lbs/hr. as determined by source testing. [District Rule 2201]

B. RMR REPORT

I. Project Description

Technical Services received a request on October 7, 2015, to perform a revised Risk Management Review for a proposed installation of two 1,468 BHP Dairy Bio gas-fired full time IC engines. Per the project engineer, the following changes to the project were made in this revision:

1) An increase in each engine's rating from 1,412 bhp to 1,468 bhp.
2) An increase in digester gas consumption of each engine from 16,303 scf/hr and 142,812,528 scf/yr to 16,327 scf/hr and 143,024,520 scf/yr.
3) A change in the stack parameters, resulting in the stack exit velocity of each engine increasing from 19.766 m/s to 23.636 m/s.

II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required. Emissions calculated using District approved Dairy Bio Gas emission factors for internal combustion were input into the HEARTs database. The AERMOD model was used, with the parameters outlined below and meteorological data for 2004-2008 from Fellows to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 2-0, 3-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	9.144	**Closest Receptor (m)**	Various
Stack Diameter. (m)	0.4572	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	23.636	**Max Hours per Year**	8,760
Stack Exit Temp. (°K)	699.817	**Fuel Type**	Dairy Bio Gas
BHP	1,468		

Technical Services performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR. The emission rates used for criteria pollutant modeling were:

Pollutant	lb/hr	lb/yr
CO	15.6966	50,818
NO_x	3.2364	4,582.7
SO_x	0.1295	1,134.0
PM_{10}	0.2265	1,984.6
H_2S	6.0834	N/A

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

Bio-Gas Engine	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass[1]	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[2]	Pass[2]
H_2S	Pass[3]	X	X	X	X

*Results were taken from the attached PSD spreadsheet.
[1]The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.
[2]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).
[3]H_2S emissions must be limited to the value listed in the Proposed Permit Conditions section in order for this project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS).

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with the project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

IV. Attachments

A. RMR request from the project engineer
B. Additional information from the applicant/project engineer
C. Toxic emissions summary
D. Prioritization score
E. Facility Summary

APPENDIX D
Draft ATCs
(S-8637-1-0, -2-0, & -3-0)

FOR PROJECT FILE
Emissions Profiles

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-8637-1-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
MAILING ADDRESS: 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION: 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
ANAEROBIC DIGESTER SYSTEM CONSISTING OF COVERED LAGOON ANAEROBIC DIGESTER CELL(S) WITH PRESSURE/VACUUM VALVE(S) AND AN AIR INJECTION SYSTEM FOR CONTROL OF H2S

CONDITIONS

1. {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
4. The digester system cover(s) shall be designed and installed in accordance with Natural Resources Conservation Services (NRCS) Practice Standard Code 367 - Roofs and Covers. [District Rule 2201]
5. The digester system shall be designed to allow gas generated during summer conditions to be stored for more than 24 hours prior to venting in the event that the gas cannot be combusted in digester gas-fired engines or sent to another device with a VOC control efficiency of at least 95% by weight as determined by the APCO. [District Rule 2201]
6. The air injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]
7. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070 and 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services
S-8637-1-0 : Mar 16 2016 1:06PM – NORMANR : Joint Inspection NOT Required

8. {3658} This permit does not authorize the violation of any conditions established for this facility in the Conditional Use Permit (CUP), Special Use Permit (SUP), Site Approval, Site Plan Review (SPR), or other approval documents issued by a local, state, or federal agency. [Public Resources Code 21000-21177: California Environmental Quality Act]

DRAFT

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-8637-2-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
MAILING ADDRESS: 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION: 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This facility (Facility S-8637) and the adjacent dairy operation (Facility S-5254) shall be operated as separate stationary sources. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services

9. This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]

10. During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]

11. The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]

12. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H_2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

13. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]

14. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]

15. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]

16. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]

17. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]

18. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]

19. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

20. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]

21. During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]

22. The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]

23. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

DRAFT

CONDITIONS CONTINUE ON NEXT PAGE

24. Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

25. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]

26. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

27. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]

28. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

29. Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]

30. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

31. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

32. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

33. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

34. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

35. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

36. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

37. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

38. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

40. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

41. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

42. If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

43. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

44. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

45. Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

46. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

47. Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature and back pressure demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

48. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

49. The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

50. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

52. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

53. The permittee shall obtain written District approval for the use of any equivalent control equipment not specifically approved by this Authority to Construct. Approval of the equivalent control equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate control equipment is equivalent to the specifically authorized equipment. [District Rule 2010]

54. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

55. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

56. No emission factor and no emissions shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

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San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-8637-3-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
MAILING ADDRESS: 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION: 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This facility (Facility S-8637) and the adjacent dairy operation (Facility S-5254) shall be operated as separate stationary sources. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

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Arnaud Marjollet, Director of Permit Services

9. This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]
10. During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
11. The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
12. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
13. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]
14. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]
15. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
16. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
17. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
18. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
19. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
20. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
21. During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
22. The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]
23. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

24. Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]
25. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
26. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]
27. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]
28. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]
29. Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]
30. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
31. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
32. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]
33. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
34. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]
35. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
36. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]
37. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

38. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

40. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

41. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

42. If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

43. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

44. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

45. Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

46. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

47. Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature and back pressure demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

48. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

49. The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

50. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

52. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

53. The permittee shall obtain written District approval for the use of any equivalent control equipment not specifically approved by this Authority to Construct. Approval of the equivalent control equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate control equipment is equivalent to the specifically authorized equipment. [District Rule 2010]

54. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

55. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

56. No emission factor and no emissions shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

ATTACHMENT O

Application No. B0104

Staff Summary

California Bioenergy LLC
ABEC #3 LLC dba Lakeview Farms Dairy Biogas, Bakersfield, CA
Electricity from Dairy Manure Biogas

Intermediate Facility:
Lakeview Farms Dairy, Bakersfield, CA

Deemed Complete: 5/15/2020
Posted for Comment: 11/9/2020
Certified: TBD
CI Effective: TBD

Pathway Summary

California Bioenergy LLC seeks certification of a Tier 2 pathway for electricity from dairy manure biogas produced by a reciprocating internal combustion (IC) engine and generator at the ABEC #3 LLC dba Lakeview Farms Dairy Biogas (ABEC #3) and supplied to the California electricity grid for use in transportation using book-and-claim accounting for low-CI electricity.[1]

The covered lagoon digester captures methane that would otherwise be vented to the atmosphere. The ABEC #3 digester is registered with the Climate Action Reserve (CAR1316/CALS6316; listed date: 09/05/2018; crediting period expiration: 12/31/2027) and has previously generated ARB Offset Credits under California's Cap & Trade program.

The dairy has an average cattle population of about 9,000. In the baseline scenario, manure is either collected via a flush system or left in a dry lot. For the baseline, manure from open lot corrals and milking parlor was collected via flush and scraped for heifers in open lot corrals. Flushed manure was sent to anaerobic storage after solids separation using a stationary screen with a portion of the manure collected from milking cows in open lot corral sent directly to anaerobic storage. Separated solids and scrapped manure was piled in open lots and exported off farm on an annual basis. Prior to installation of the digester, incomplete removal of volatile solids (VS) occurred annually in the anaerobic storage and as a result, no lagoon cleanouts were modeled.

[1] All citations to the LCFS Regulation are found in Title 17, California Code of Regulations (CCR), section 95480-95503. Book-and-claim accounting for low-CI electricity is primarily addressed in section 95488.8(i) of the LCFS Regulation.

With the installation of the project, manure that was sent to anaerobic storage was diverted to the digester. Additionally, manure from heifers in open lot corrals was collected via vacuum and sent to the anaerobic digestion. The covered lagoon digester captures methane that would otherwise be vented to the atmosphere.

Biogas captured by the covered lagoon is either sent to a 1MW Caterpillar internal combustion engine for electricity generation or vented. The compressor draws the gas through the hydrogen sulfide (H_2S) removal system, which consists of an iron sponge and an activated carbon tank that reduces the H_2S concentration to below air permitted levels. The internal combustion engine converts roughly one third of energy in biogas to electricity. A portion of the biogas produced by the covered lagoon digester that is not destroyed by the engine generator is vented rather than flared. This vented methane is separately metered and included in the pathway emissions in the Simplified Calculator. Grid and on-site generated electricity is used to power the mixers in the digester, blowers to move gas through the system, electronic instrumentation, and internal combustion engine.

Carbon Intensity of Electricity Pathway

The CI is determined from life cycle analysis conducted using a modified version of the Board-approved Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure.[2] The calculator was modified in accordance with regulatory requirements and LCFS Guidance Document 19-06,[3] and has been determined to be equivalent to CA-GREET3.0 pursuant to section 95488.7(a)(1) of the LCFS regulation. The applicant has provided operational data and supporting documentation for assessment of baseline emissions, biogas production, electricity generation from dairy biogas, and venting for a period of 24 months, from March 2018 to February 2020.

The following table lists the proposed CI for this pathway.

[2] The Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure (August 13, 2018), incorporated by reference in the LCFS Regulation, section 95488.3(b).
[3] LCFS Guidance 19-06 (Revised October 2019): Determining Carbon Intensity of Dairy and Swine Manure Biogas to Electricity Pathways

Proposed Pathway CI

Fuel & Feedstock	Pathway FPC	Pathway Description	Carbon Intensity (gCO2e/MJ)
Low-CI Electricity from Dairy Manure Biogas	TBD	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at ABEC #2 LLC dba West Star North Dairy Biogas in Bakersfield, California for use as transportation fuel in California.	-382.98

Operating Conditions

The certified CI value in the above table may be used to report and generate credits for fuel quantities that are produced at the facility in the manner described in the applicant's Life Cycle Analysis (LCA) report, and dispensed for transportation use in California, subject to the following requirements and conditions:

1. Fuel pathway holders are subject to the requirements of the California Air Resources Board's (CARB) Low Carbon Fuel Standard (LCFS) regulation, which appears at sections 95480 to 95503 of title 17, California Code of Regulations. Requirements include ongoing monitoring, reporting, recordkeeping, and third-party verification of operational CI and a controlled process for providing product transfer documents or other similar records to counterparties or CARB.

2. No later than October 1, 2020, equipment to continuously measure and record methane concentration in biogas at least every 15 minutes must be installed to report the monthly weighted average methane concentration in fields 2.5 and 2.7 in the Annual Fuel Pathway Report submitted to CARB for third-party verification of the operational CI.

3. To confirm compliance with LCFS Regulation section 95488.8(h) and demonstrate use of directly supplied low-CI process energy in annual Fuel Pathway Reports, the fuel pathway holder must demonstrate retirement of the corresponding quantity of Renewable Electricity Certificates (RECs) that were generated for the quantity of low-CI electricity consumed within the fuel pathway (use of onsite electricity from biogas in field 2.17). For each quarter of operation, the number of RECs that are associated with process energy must be retired in a WREGIS retirement sub-account named "Low-CI Process Energy at LCFS Facility [ID number]", where the LCFS Facility ID is the number assigned in the AFP at the time of facility registration. These RECs and the associated environmental attributes can no longer be sold, transferred, or claimed by any entity or for any other purpose. The WREGIS report demonstrating REC retirement must be downloaded from WREGIS and uploaded to the AFP as part

of each annual Fuel Pathway Report to demonstrate the quantity of electricity from biogas that is consumed within the fuel pathway and claimed to lower the CI of the produced fuel.

Note that this retirement account for process energy is distinct from and in addition to the requirement for any fuel reporting entity claiming electricity as supplied for use as transportation fuel in the LRT under this pathway to demonstrate quarterly REC retirement as part of each quarterly report.

4. The electricity, including the environmental attributes associated with the electricity, claimed under this pathway shall not be claimed under any other program notwithstanding the exceptions listed in LCFS Regulation section 95488.8(i)(1). The LCFS places no restrictions on the use of any voluntary emissions reductions credits generated by the project for emissions that are demonstrated to be additional to reductions claimed under the LCFS.

5. The fuel pathway holder must include the assumptions and calculations used to establish the fraction of solids input to each manure management system in its annual Fuel Pathway Report submitted to CARB for third-party verification of the operational CI.

6. Any quantity of biomethane metered as captured that cannot be demonstrated by meter records to have been destroyed, must be calculated by energy balance and accounted for in the CI as a fugitive methane emission if the calculated value exceeds the default 2% fugitive emission.

Staff Analysis and Recommendation

Staff has reviewed the application and has replicated, using the Tier 2 modified version of the Simplified CI Calculator, the CI values calculated by the applicant. EcoEngineers (H3-20-008) submitted a positive validation statement. Staff recommends this application be certified after all the comments received during the 10-day comment period are addressed satisfactorily by the applicant. The certification is subject to the operating conditions set forth in this document.

ATTACHMENT P

DEC 17 2010

Jim Rexroad
Avenal Power Center LLC
500 Dallas Street, Level 31
Houston, TX 77002

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Rexroad:

Enclosed is the District's final determination of compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

The changes made to the PDOC were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

cc: Gary Rubenstein, Sierra Research

DEC 17 2010

Mike Tollstrup, Chief
Project Assessment Branch
Stationary Source Division
California Air Resources Board
PO Box 2815
Sacramento, CA 95812-2815

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Tollstrup:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

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Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Gerardo C. Rios (AIR 3)
Chief, Permits Office
Air Division
U.S. E.P.A. - Region IX
75 Hawthorne Street
San Francisco, CA 94105

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Rios:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

The changes made to the Preliminary Determination of Compliance (PDOC) were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

Southern Region
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: 661-392-5500 FAX: 661-392-5585

www.valleyair.org www.healthyairliving.com

DEC 17 2010

Joseph Douglas
Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Douglas:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

The changes made to the Preliminary Determination of Compliance (PDOC) were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not significantly increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

Fresno Bee

NOTICE OF FINAL DETERMINATION OF COMPLIANCE

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District has issued a Final Determination of Compliance (FDOC) to Avenal Power Center LLC for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

All comments received following the District's preliminary decision on this project were considered. Changes were made to the DOC in direct response to comments received from the oversight agencies and other interested parties. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements.

The application review for project C-1100751 is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and the **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

FINAL DETERMINATION OF COMPLIANCE EVALUATION

Avenal Power Center Project
California Energy Commission
Application for Certification Docket #: 08-AFC-01

Facility Name:	Avenal Power Center, LLC
Mailing Address:	500 Dallas Street, Level 31 Houston, TX 77002
Contact Name:	Jim Rexroad
Telephone:	(713) 275-6147
Fax:	(713) 275-6115
Cell:	(832) 748-1060
E-Mail:	jim.Rexroad@macquarie.com
Alternate Contact:	Eric Walther
Telephone:	(916) 444-6666
Fax:	(916) 444-8373
Cell:	(916) 883-8774
E-Mail:	ewalther@sierraresearch.com
Alternate Contact:	Tracey Gilliland
Telephone:	(713) 275-6148
Cell:	(512) 217-3002
E-Mail:	tracey.gilliland@macquarie.com
Engineer:	Derek Fukuda, Air Quality Engineer
Lead Engineer:	Joven Refuerzo, Supervising Air Quality Engineer
Project #:	C-1100751
Application #'s:	C-3953-10-1, C-3953-11-1, C-3953-12-1, C-3953-13-1, and C-3953-14-1
Submitted:	March 3, 2010

Table of Contents

I. PROPOSAL:

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 564 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

While Avenal Power Center, LLC has already received a Determination of Compliance for the above described facility, they are now proposing to limit the annual facility wide NO_X emissions from 288,618 lb/year to 198,840 lb/year, and the annual facility wide CO emissions from 1,205,418 lb/year to 197,928 lb/year. The effect of these limits will be two-fold: one, should the facility operate to its full permitted extent, it will have the lowest annual average permitted emissions of NO_X (0.045 lb-NOx/MWh) and CO (0.044 lb-CO/MWh) of any natural gas fired power plant known to the District; and two, the facility will be limited to less than the 100 tons/year major source thresholds of the federal prevention of significant deterioration program.

The Avenal Energy Project is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

The California Energy Commission (CEC) is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

The facility submitted an application to revise their existing DOC issued under Project C-1080386. This revision consists of limiting the annual facility wide NO_X emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year. The equipment the DOC was issued for in project C-1080386 has not been implemented. All units in this project will be treated as new emissions units.

II. APPLICABLE RULES:

Rule 1080 Stack Monitoring (12/17/92)
Rule 1081 Source Sampling (12/16/93)
Rule 1100 Equipment Breakdown (12/17/92)
Rule 2010 Permits Required (12/17/92)
Rule 2201 New and Modified Stationary Source Review Rule (9/21/06)
Rule 2520 Federally Mandated Operating Permits (6/21/01)
Rule 2540 Acid Rain Program (11/13/97)

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
Rule 4001 New Source Performance Standards (4/14/99)
Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
Subpart GG - Standards of Performance for Stationary Gas Turbines
Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Subpart JJJJ -Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
Rule 4002 National Emissions Standards for Hazardous Air Pollutants (5/20/2004)
Subpart ZZZZ - National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4202 Particulate Matter Emission Rate (12/17/92)
Rule 4301 Fuel Burning Equipment (12/17/92)
Rule 4305 Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3 (10/16/08)
Rule 4351 Boilers, Steam Generators and Process Heaters – Phase 1 (8/21/03)
Rule 4701 Stationary Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702 Stationary Internal Combustion Engines – Phase 2 (1/18/07)
Rule 4703 Stationary Gas Turbines (9/20/07)
Rule 4801 Sulfur Compounds (12/17/92)
Rule 8011 General Requirements (8/19/04)
Rule 8021 Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
Rule 8031 Bulk Materials (8/19/04)
Rule 8041 Carryout and Trackout (8/19/04)
Rule 8051 Open Areas (8/19/04)
Rule 8061 Paved and Unpaved Roads (8/19/04)
Rule 8071 Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
Rule 8081 Agricultural Sources (9/16/04)
California Environmental Quality Act (CEQA)
California Code of Regulations (CCR), Section 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment)
California Health & Safety Code (CH&S), Sections 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment) 41700 (Health Risk Analysis), 42301.6 (School Notice), 44300 (Air Toxic "Hot Spots"), and 93115 (Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines)

III. PROJECT LOCATION:

The proposed equipment will be located within NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 (See Attachment B). The closest population center is the residential district of Avenal approximately 6 miles to the southwest. The City of Huron is located approximately 8 miles to the north, and the City of Coalinga is located approximately 16 miles to the west.

The site is located northeast of the city of Avenal, in Kings County. The proposed location is not within 1,000' of a K-12 school.

IV. PROCESS DESCRIPTION:

Combined-Cycle Combustion Turbine Generators
Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_X combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_X (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.0 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 2.0 ppmvd @ 15% O_2
SO_X: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf))
PM_{10}: 0.0048 lb/MMBtu (without duct burner firing)
0.0050 lb/MMBtu (with duct burner firing)

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)
The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the

HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_X in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_X to nitrogen and water, resulting in a reduced concentration of NO_X in the exhaust gases exiting the stack.

Duct Burners

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_X burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump
Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator
One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

V. EQUIPMENT LISTING:

C-3953-10-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

C-3953-11-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

C-3953-12-1: 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

C-3953-13-1: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-1: 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

i. C-3953-10-1 and C-3953-11-1 (Turbines)

Each CTG will be equipped with a Dry Low NO_X combustor and will exhaust into a Selective Catalytic Reduction [SCR] system with ammonia injection, and a CO catalyst. The use of Dry Low NO_X combustors and a SCR system with ammonia injection can achieve a NO_X emission rate of 2.0 ppmvd @ 15% O_2. CO emissions of 2.0 ppmvd @ 15% O_2 have been demonstrated with the use of an oxidation catalyst [(1)]. And the use of DLN combustors and good combustion practices can achieve VOC emissions of 2.0 ppmvd @ 15% O_2.

Emissions from natural gas-fired turbines include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NO_X emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule. There are two mechanisms by which NO_X is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_X and prompt NO_X), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_X).

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO_X. Prompt NO_X is formed in both fuel-rich flame zones and dry low NO_X (DLN) combustion zones. The contribution of prompt NO_X to overall NO_X emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is an increasingly significant percentage of overall thermal NO_X emissions in DLN combustors. For this reason prompt NO_X becomes an important consideration for DLN combustor designs, and establishes a minimum NO_X level attainable in lean mixtures.

Fuel NO_X is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some natural gas, does not contribute significantly to fuel NO_X formation. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_X, fuel NO_X is not currently a major contributor to overall NO_X emissions from stationary gas turbines firing natural gas.

The level of NO_X formation in a gas turbine, and hence the NO_X emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_X generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

[1] Based on information supplied by the CTG manufacturer and information contained in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document.

The design of the combustor is the most important factor influencing the formation of NO_X. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal NO_X formation. Thermal NO_X formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NO_X formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_X production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal NO_X formation. Premixing air and fuel at a lean ratio approaching the lean flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum NO_X formation during combustion. This is known as dry low NO_X (DLN) combustion.

Selective Catalytic Reduction systems selectively reduce NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NO_X reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% O_2.

Carbon monoxide is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. Carbon monoxide formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion to limit NO_X formation can result in increased CO emissions.

Post-combustion CO controls, such as oxidizing catalysts can also be used to reduce CO emissions. An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO_2).

Inlet air temperature and density directly affects turbine performance. The hotter and drier the inlet air temperature, the lower the efficiency and capacity of the turbine. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The inlet air cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

The inlet air filter will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted.

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

ii. C-3953-12-1 (Boiler)

Emissions from natural gas-fired boilers include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when burning natural gas. NO_X formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_X) or due to conversion of chemically bound nitrogen in the fuel (fuel NO_X). Due to the low fuel nitrogen content of natural gas, nearly all NO_X emissions are thermal NO_X. Formation of thermal NO_X is affected by four furnace zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

The Cleaver Brooks boiler will control the formation of thermal NO_X with an Cleaver Brooks ultra low NO_X burner. Cleaver Brooks burners reduce NO_X by pre-mixing gaseous fuel and combustion air in a region near the burner exit, at a stoichiometry that minimizes Prompt NO_X. This also eliminates the traditional NO_X versus CO tradeoff.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The diesel-fired emergency IC engine (fire pump) will be equipped with a turbocharger, an intercooler/aftercooler, and will be fired on very low (0.0015%) sulfur diesel.

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.[2]

The turbocharger reduces the NO_X emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

The use of low sulfur (0.0015% by weight sulfur maximum) diesel fuel reduces SO_X emissions by approximately 99% from standard diesel fuel.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

The natural gas-fired emergency IC engine (generator) will be equipped with an intercooler/aftercooler, lean burn technology, and will be fired on PUC-Regulated natural gas.

The emission control devices/technologies and their effect on natural gas engine emissions are detailed below.

[2] From "Non-catalytic NO_x Control of Stationary Diesel Engines", by Don Koeberlein, CARB.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_X formation.

VII. GENERAL CALCULATIONS:

The facility has proposed to limit the annual facility wide NO_X emission to 198,840 lb/year, and the annual facility wide CO emission to 197,928 lb/year.

All PM_{10} emissions are assumed to be $PM_{2.5}$ emissions.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- Maximum daily emissions for each CTG for VOC, PM_{10} and SO_X during the commissioning period are estimated assuming twenty-four (24) hours operating while firing at full load.
- The commissioning period will not exceed 408 hours per CTG and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.
- Maximum daily emissions for each CTG for NO_X, CO, and VOC are estimated assuming six (6) hours operating in startup and shutdown mode and eighteen (18) hours operating while firing at full load with operation of the duct burner.
- Maximum daily emissions for each CTG for PM_{10}, SO_X, and NH_3 are estimated assuming twenty-four (24) hours operating while firing at full load with the operation of the duct burner.
- Maximum annual emissions for each CTG for VOC are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was

operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule.

- The facility has proposed a facility wide NO_X emission limit of 198,840 lb/year. To determine the validity of this limit, the maximum annual emissions for each CTG for NO_X are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated NO_X emissions from an individual turbine operating at this scenario (calculated in Section VII.C.2) is not greater than the proposed facility wide NO_X emission limit; however the NO_X emissions from the operation of both turbines according to this scenario are far greater than the proposed facility wide NO_X emission limit. Therefore, the facility wide limit is a valid limit and the NO_X emissions from the turbines will ultimately be restricted by this limit.

- The facility has proposed a facility wide CO emission limit of 197,928 lb/year. To determine the validity of this limit, the maximum annual emissions for each CTG for CO are estimated assuming the CTG is operated according to a weekend shutdown and weekday hot start scenario. The weekend shutdown and weekday hot start scenario results in CTG operation of 624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated CO emissions from this scenario (calculated in Section VII.C.2) are greater than the proposed facility wide CO emission limit; therefore the facility wide emissions limit is a valid limit and the turbine's CO emissions will ultimately be restricted by this limit.

- Maximum annual emissions for each CTG for PM_{10}, SO_X, and NH_3 are estimated assuming the CTG is operated according to a baseload scenario. The baseload scenario results in CTG operation of 800 hours operating while firing at full load with the duct burner and 7,960 hours operating while firing at full load without the duct burner.

ii. C-3953-12-1 (Boiler)

- External O_2 stack gas concentration is 3%.
- Natural gas F factor is 8,710 dscf/MMBtu (Ref. 40 CFR Part 60, Appendix A, Method 19).
- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- The applicant is proposing a maximum natural gas usage rate of 37.4 MMBtu/hr.
- Maximum SO_X emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

(1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
= 0.00282 lb/MMBtu

- Maximum daily and annual emissions for all pollutants are estimated assuming twelve (12) hours per day and 1,248 hours per year operating at full load.[3]
- Operating schedule of 12 hr/day and 1,248 hrs/year.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

- Diesel F factor (adjusted to 60 °F) is 9,051 dscf/MMBtu.
- Density of diesel is 7.1 lb/gal.
- Higher heating value of diesel is 137,000 Btu/scf.
- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

iv. C-3953–14-1 (Natural gas IC engine powering electrical generator)

- EPA F-factor (adjusted to 60 °F) is 8,578 dscf/MMBtu (40 CFR 60 Appendix B)
- Fuel heating value 1,013 Btu/dscf (per applicant)
- Maximum daily SO_X emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

(1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
= 0.00282 lb/MMBtu

- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

[3] Applicant has indicated that the unit will be used a maximum of 12 hours on a startup day.

B. Emission Factors

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The maximum air contaminant mass emission rates (lb/hr) during the commissioning period estimated by the facility (see Attachment C) for the proposed CTGs are summarized below:

Commissioning Period Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A[5]	N/A[4]

The maximum air contaminant mass emission rates (lb/hr) with and without duct burner firing, concentrations (ppmvd @ 15% O_2), and startup and shutdown emissions rates (lb/hr) provided by the applicant (see Attachment D for applicant proposed emissions) for the proposed CTGs are summarized below.

The emission rates from the turbines and duct burners are calculated below:

Maximum Emission Rate Without Duct Burner Firing:

The worst-case NO_X, PM_{10}, CO, VOC, and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 32 °F. The worst-case SO_X mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG without the duct burner firing:

Emission Rate (lb/hr) = CTG Max Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= 13.55 lb-NO_X/hr

CO Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= 8.35 lb-CO/hr

VOC Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0018 lb-VOC/MMBtu)
= 3.34 lb-VOC/hr

PM_{10} Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0048 lb-PM_{10}/MMBtu)
= 8.91 lb-PM_{10}/hr

[4] PM_{10} and SO_X emissions during commissioning period are equal to the maximum hourly emissions during baseload facility operation.

SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= 5.23 lb-SO_X/hr

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:
ppm is the emission concentration in ppmvd @ 15% O_2 (10 ppmv)
MW is the molecular weight of the pollutant: (MW_{NH3} = 17 lb/lb-mol)
2.64×10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w/o duct burner 1.832 MMscf/hour, as calculated below)
(1,856.3 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 1.832 MMscf/hr
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 1.832 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= 25.31 lb-NH3/hr

Maximum Emission Rates and Concentrations Without Duct Burner Firing (@ 100% Load & 32 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	13.55	8.35	3.34	8.91	5.23	25.31
ppmvd @ 15% O_2 limits	2.0	2.0	1.4	--	--	10.0
lb/MMBtu*	0.0073	0.0045	0.0018	0.0048	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

<u>Maximum Emission Rate With Duct Burner Firing:</u>

The worst-case NO_X, SO_X, PM_{10}, CO, VOC, and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 101 °F. The worst-case SO_X mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG with the duct burner firing:

Emission Rate (lb/hr) = [CTG Max Heat Input + Duct Burner Max Heat Input] (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= 17.20 lb-NO_X/hr

CO Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= **10.60 lb-CO/hr**

VOC Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0025 lb-VOC/MMBtu)
= **5.89 lb-VOC/hr**

PM_{10} Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0050 lb-PM_{10}/MMBtu)
= **11.78 lb-PM_{10}/hr**

SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= **6.65 lb-SO_X/hr**

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:
ppm is the emission concentration in ppmvd @ 15% O_2 (10 ppmv)
MW is the molecular weight of the pollutant: (MW_{NH3} = 17 lb/lb-mol)
2.64 x 10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w duct burner 2.326 MMscf/hour, as calculated below)
(2,356.5 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 2.326 MMscf/hr
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 2.326 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= 32.13 lb-NH3/hr

Maximum Emission Rates and Concentrations With Duct Burner Firing (@ 100% Load & 101 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	17.20	10.60	5.89	11.78	6.65	32.13
ppmvd @ 15% O_2 limits	2.0	2.0	2.0	--	--	10.0
lb/MMBtu*	0.0074	0.0045	0.0025	0.0050	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Startup and Shutdown Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Maximum Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A[6]	N/A[5]
Average Mass Emission Rate (per turbine, lb/hr)	80	900	16	N/A[6]	N/A[6]

ii. C-3953-12-1 (Boiler)

For the new boiler, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant. The SO_X emission factor is calculated as shown below.

Boiler Emission Factors*		
Pollutant	ppmv @ 3%O_2	lb/MMBtu
NO_X	9.0	0.011
CO	50.0	0.037
VOC	10.0	0.0043
PM_{10}	--	0.005
SO_X**	--	0.00282

*Note: lb/MMBtu equivalent of ppmv values @ 3% O_2 as provided by the Applicant
** SO_X emission factor based on the maximum proposed sulfur content of 1 gr/100 dscf.

(1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
= 0.00282 lb/MMBtu

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

For the new emergency diesel-fired IC engine powering a fire water pump, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the sulfur content in the diesel fuel (0.0015% sulfur).

Diesel-fired IC Engine Emission Factors		
	g/hp·hr	Source
NO_X	3.4	Engine Manufacturer
CO	0.447	Engine Manufacturer
VOC	0.38	Engine Manufacturer
PM_{10}	0.059	Engine Manufacturer
*SO_X	0.005	Mass Balance Equation Below

[5] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions during baseload facility operation.

$$^{*}0.0015\% \times \frac{7.1\,lb \cdot fuel}{gallon} \times \frac{2\,lb \cdot SO_2}{1\,lb \cdot S} \times \frac{1\,gal}{137{,}000\,Btu} \times \frac{1\,hp\ input}{0.35\,hp\ out} \times \frac{2{,}542.5\,Btu}{hp \cdot hr} \times \frac{453.6\,g}{lb} = 0.005\,\frac{g\,SOx}{hp \cdot hr}$$

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

For the new emergency natural gas-fired IC engine powering an electrical generator, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the fuel sulfur content from District Policy APR 1720.

Natural Gas-fired IC Engine Emission Factors		
	g/hp·hr	Source
NO_X	1.0	Engine Manufacturer
CO	0.6	Engine Manufacturer
VOC	0.33	Engine Manufacturer
PM_{10}	0.034	Engine Manufacturer
**SO_X	0.0094	Mass Balance Equation Below

**SO_X is calculated as follows:

$$0.00285\ \frac{lb-SO_x}{MMBtu} \times \frac{1\,MMBtu}{1{,}000{,}000\,Btu} \times \frac{2{,}542.5\,Btu}{bhp-hr} \times \frac{1\,bhp\ input}{0.35\,bhp\ out} \times \frac{453.6\,g}{lb} = 0.0094\ \frac{g-SO_x}{bhp-hr}$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Section 3.26 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Since this is a brand new facility, the pre-project potential to emit (PE1) for all the emissions units associated with this project is equal to zero.

2. Post Project Potential to Emit (PE2):

i. C-3953-10-1 and C-3953-11-1 (Turbines)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_X, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit					
	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO_X	160	17.20	13.55	13.55	240.00
CO	1,000	10.60	8.35	8.35	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM_{10}	N/A(6)	11.78	8.91	8.91	23.56
SO_X	N/A(7)	6.65	5.23	5.23	13.30
NH_3	N/A	32.13	25.31	25.31	64.26

b. Maximum Daily PE

Maximum daily emissions for NO_X, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for PM_{10}, SO_X, and NH3 are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for PM_{10}, SO_X, and NH3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

Maximum Daily Potential to Emit (w/ Startup and Shutdown)				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (101° F)	Emissions Rate @ 100% Load without duct burner (32° F)	DEL (per CTG)
NO_X	80 lb/hr (avg)	17.20 lb/hr	13.03 lb/hr	789.6 lb/day
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	5,590.8 lb/day
VOC	16 lb/hr (avg)	5.89 lb/hr	3.34 lb/hr	202.0 lb/day
PM_{10}	N/A(7)	11.78 lb/hr	8.91 lb/hr	282.7 lb/day
SO_X	N/A(7)	6.65 lb/hr	5.23 lb/hr	159.6 lb/day
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	771.1 lb/day

[6] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

c. Maximum Annual PE

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_X emission factors used to calculate the annual potential emissions will be based on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

SO_X EF = (0.36 ~~gr S~~/100 ~~dscf~~) x (1 ~~lb S~~/7000 ~~gr~~) x (64 lb SO_X/32 ~~lb S~~) x (1 ~~scf~~/1013 ~~Btu~~) x (10^6 ~~Btu~~/MMBtu)
= 0.001 lb-SO_X/MMBtu

CTG w/o Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 1.86 lb-SO_X/hr

CTG w/ Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 2.36 lb-SO_X/hr

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

Scenario 1) Weekend and Weekday Hot Start:

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	**143,951 lb/year**
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	557,033 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	**34,489 lb/year**
PM_{10}	N/A(7)	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO_X	N/A(7)	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

<u>Scenario 2) Weekend Shutdown and Weekday Hot Start:</u>

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 2) Weekend Shutdown and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	601,810 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM_{10}	N/A(7)	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO_X	N/A(7)	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Baseload Scenario*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	74,946 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,777 lb/year
PM_{10}	N/A(7)	11.27 lb/hr	9.00 lb/hr	**80,656 lb/year**
SO_X	N/A(7)	2.36 lb/hr	1.86 lb/hr	**16,694 lb/year**
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	**219,972 lb/year**

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit		
	Annual PE (per CTG)	Scenario
NO_X	143,951 lb/year	Scenario 1
CO	197,928 lb/year	Facility Wide Limit
VOC	34,489 lb/year	Scenario 2
PM_{10}	80,656 lb/year	Scenario 3
SO_X	16,694 lb/year	Scenario 3
NH_3	219,972 lb/year	Scenario 3

d. Maximum Quarterly PE

Maximum quarterly emissions for each unit will be determined by dividing the maximum annual emissions into 4 quarters:

Maximum Quarterly Potential to Emit						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
1st Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
2nd Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
3rd Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
4th Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993

ii. C-3953-12-1 (Boiler)

The potential to emit for the boiler is calculated as follows, and summarized in the table below.

PE_{NOx} = (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.41 lb NO_X/hr**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **4.9 lb NO_X/day**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **513 lb NO_X/year**

= (513 lb NO_X/year) ÷ (4 qtr/year)
= **128 lb NO_X/qtr**

PE_{CO} = (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **1.38 lb CO/hr**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **16.6 lb CO/day**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **1,727 lb CO/year**

= (1,727 lb CO/year) ∗ (4 qtr/year)
= **432 lb CO/qtr**

PE_{VOC} = (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.16 lb VOC/hr**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.9 lb VOC/day**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **201 lb VOC/year**

= (201 lb/year) ∗ (4 qtr/year)
= **50 lb VOC/qtr**

PE_{PM10} = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb PM_{10}/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb PM_{10}/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb PM_{10}/year**

= (233 lb/year) ∗ (4 qtr/year)
= **58 lb PM_{10}/qtr**

PE_{SOx} = (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.11 lb SO_X/hr**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.3 lb SO_X/day**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **132 lb SO_X/year**

= (132 lb/year) ∗ (4 qtr/year)
= **33 lb SO_X/qtr**

Post Project Potential to Emit (PE2) (C-3953-12-1)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	0.41	4.9	128	513
CO	1.38	16.6	432	1,727
VOC	0.16	1.9	50	201
PM_{10}	0.19	2.2	58	233
SO_X	0.11	1.3	33	132

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{NOx} = (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **2.16 lb NO_X/hr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **51.8 lb NO_X/day**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **27 lb NO_X/qtr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **108 lb NO_X/year**

PE_{CO} = (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.28 lb CO/hr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb ∗ (24 hr/day)
= **6.8 lb CO/day**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **4 lb CO/qtr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **14 lb CO/year**

PE_{VOC} = (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.24 lb VOC/hr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **5.8 lb VOC/day**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **3 lb VOC/qtr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **12 lb VOC/year**

PE_{PM10} = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb PM_{10}/year**

PE_{SOx} = (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.00 lb SO_X/hr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.1 lb SO_X/day**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **0 lb SO_X/year**

Post Project Potential to Emit (PE2) (C-3953-13-1)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	2.16	51.8	27	108
CO	0.28	6.8	4	14
VOC	0.24	5.8	3	12
PM_{10}	0.04	0.9	0.5	2
SO_X	0.00	0.1	0	0

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

The emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

PE_{NOx} = (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.90 lb NO_X/hr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **45.5 lb NO_X/day**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **24 lb NO_X/qtr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **95 lb NO_X/year**

PE_{CO} = (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.14 lb CO/hr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **27.3 lb CO/day**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **14 lb CO/qtr**

= (0.6 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **57 lb CO/year**

PE_{VOC} = (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.63 lb VOC/hr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **15.0 lb VOC/day**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **8 lb VOC/qtr**

= (0.33 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **31 lb VOC/year**

PE_{PM10} = (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb PM_{10}/hr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **1.5 lb PM_{10}/day**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **1 lb PM_{10}/qtr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **3 lb PM_{10}/year**

PE_{SOx} = (0.0094 g/hp·hr) * (860 hp) ÷ (453.6 g/lb)
= **0.02 lb SO_X/hr**

= (0.0094 g/hp·hr) * (860 hp) ÷ (453.6 g/lb) * (24 hr/day)
= **0.4 lb SO_X/day**

= (0.0094 g/hp·hr) * (860 hp) ÷ (453.6 g/lb) * (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.0094 g/hp·hr) * (860 hp) ÷ (453.6 g/lb) * (50 hr/year)
= **1 lb SO_X/year**

Post Project Potential to Emit (PE2) (C-3953-14-1)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	1.90	45.5	24	95
CO	1.14	27.3	14	57
VOC	0.63	15.0	8	31
PM_{10}	0.06	1.5	1	3
SO_X	0.02	0.4	0	1

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 will be equal to zero.

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. The District is issuing a DOC for this project and not individual ATC's. Therefore, the SSPE2 will be determined by summing the potential emissions from the units included in the DOC.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)							
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3	$PM_{2.5}$ ***
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972	80,656
C-3953-11-1			34,489	80,656	16,694	219,972	80,656
C-3953-12-1			201	233	132	0	233
C-3953-13-1			12	2	0	0	2
C-3953-14-1			31	3	1	0	3
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,222**	**161,550**	**33,521**	**439,944**	**161,550**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.
*** All PM_{10} emissions are $PM_{2.5}$.

5. Major Source Determination

Pursuant to Section 3.24 of District Rule 2201, a major source is a stationary source with post-project emissions or a Post-project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values.

Major Source Determination						
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)	$PM_{2.5}$ (lb/year)
Post-project SSPE (SSPE2)	198,840	197,928	69,222	161,550	33,521	161,550
Major Source Threshold	50,000	200,000	50,000	140,000	140,000	200,000
Major Source?	Yes	No	Yes	Yes	No	No

6. Annual Baseline Emissions (BE)

Per District Rule 2201, Section 3.7, the baseline emissions, for a given pollutant, shall be equal to the pre-project potential to emit for:

- Any emission unit located at a non-major source,
- Any highly utilized emission unit, located at a major source,
- Any fully-offset emission unit, located at a major source, or
- Any clean emission unit located at a major source

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.22 of District Rule 2201

As shown above, this facility will be a major source for NO_X, VOC, and PM_{10} emissions after this project. However, since the units in this project are all new emissions units, there are no historical actual emissions or pre-project potential to emit. Therefore, the baseline NO_X, CO, VOC, PM_{10} and SO_X emissions will be set equal to the following:

BE = 0 lb/year

7. Major Modification

Major Modification is defined in 40 CFR Part 51.165 as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*"

Since this is a new facility, this project cannot be considered a Major Modification.

8. Federal Major Modification

As shown above, this project does not constitute a Major Modification. Therefore, in accordance with District Rule 2201, Section 3.17, this project does not constitute a Federal Major Modification and no further discussion is required.

VIII. COMPLIANCE:

Rule 1080 Stack Monitoring

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The two CTGs will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

- Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

- Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

ii. C-3953-12-1 (Boiler)

The boiler will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

- {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

Rule 1081 Source Sampling

This Rule requires adequate and safe facilities for use in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

- Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

- Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

- Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001]

- Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

ii. C-3953-12-1 (Boiler)

The requirements of this Rule will be included in the operating permit. Compliance with this Rule is anticipated.

<u>Proposed Rule 1081 Conditions</u>:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Rule 1100 Equipment Breakdown

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1100 Conditions:

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

Rule 2010 Permits Required

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of a DOC application, Avenal Power Center, LLC is complying with the requirements of this Rule.

Rule 2201 New and Modified Stationary Source Review Rule

A. BACT:

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

As seen in Section VII.C.2.b of this evaluation, the applicant is proposing to install two new combustion turbine generators with PEs greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, PM_{10}, and SO_X criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

The PE of ammonia is greater than two pounds per day for the two CTGs. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NO_X. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

ii. C-3953-12-1 (Boiler)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new boiler with a PE greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, and PM_{10} criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new diesel-fired IC engine (fire pump) with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new natural gas-fired IC engine (generator) with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

2. BACT Guidance

The District BACT Clearinghouse was created to assist applicants in selecting appropriate control technology for new and modified sources, and to assist the District staff in conducting the necessary BACT analysis. The Clearinghouse will include, for various class and category of sources, available control technologies and methods that meet one or more of the following conditions:

- Have been achieved in practice for such emissions unit and class of source; or
- Are contained in any SIP approved by the EPA for such emissions unit category and class of source; or
- Are any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found to be technologically feasible for such class or category of sources or for a specific source.

Attachment E will include the BACT Guidelines from the BACT Clearinghouse applicable to the new emissions units associated with this project.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

BACT Guideline 3.4.2 is applicable to the two combustion turbine generator installations [Gas Fired Turbine = or > 50 MW, Uniform Load, with Heat Recovery].

ii. C-3953-12-1 (Boiler)

BACT Guideline 1.1.2 is applicable to the 37.4 MMBtu/hr boiler. [Boiler - > 20 MMBtu/hr, Natural gas-fired, base-loaded or with small load swings.]

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

BACT Guideline 3.1.4, applies to the diesel-fired emergency IC engine powering a fire pump. [Emergency Diesel I.C. Engine Driving a Fire Pump]

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

BACT Guideline 3.1.8, applies to the natural gas-fired emergency IC engine powering an electrical generator. [Emergency Gas-Fired I.C. Engine > or = 250 hp, Lean Burn]

3. Top-Down Best Available Control Technology (BACT) Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

For Permit Units C-3953-10-1 and -11-1 see Attachment F.

For Permit Unit C-3953-12-1 see Attachment F.

For Permit Unit C-3953-13-1 see Attachment F.

For Permit Unit C-3953-14-1 see Attachment F.

4. BACT Summary:

i. C-3953-10-1 and C-3953-11-1 (Turbines)

BACT has been satisfied by the following:

NO_X: 2.0 ppmv @ 15% O_2 (1-hour rolling average, except during startup/shutdown) with Dry Low NO_X Combustors, SCR with ammonia injection and natural gas fuel.

VOC: 1.5 ppmv @ 15% O_2 (without duct burner firing; 3-hour rolling average).
2.0 ppmv @ 15% O_2 (with duct burner firing; 3-hr rolling average).

PM_{10}: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel

SO_X: PUC regulated natural gas with a sulfur content of 1.0 gr/100 scf or less

ii. C-3953-12-1 (Boiler)

BACT has been satisfied by the following:

NO_X: 9.0 ppmv @ 15% O_2 with Ultra Low NO_X burners and natural gas fuel.

VOC: Natural gas fuel.

PM_{10}: Natural gas fuel.

SO_X: Natural gas fuel.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

BACT has been satisfied by the following:

NO_X: Certified NO_X emissions of 6.9 g/hp·hr or less

VOC: No VOC control. Any add on VOC control device would void the Underwriters Laboratory (UL) certification.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

BACT has been satisfied by the following:

NO_X: = or < 1.0 g/bhp-hr (lean burn natural gas fired engine, or equal)

VOC: 90% control efficiency (oxidation catalyst, or equal)

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

C. Offsets:

1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for NO_X and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for SO_X and 29,200 lbs/year for PM_{10}. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for NO_X, CO, VOC, PM_{10}, and SO_X emissions. Therefore, offset calculations are necessary.

Offset Determination					
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
Post-project SSPE (SSPE2)	198,840	197,928	69,222	161,550	33,521
Offset Threshold	20,000	200,000	20,000	29,200	54,750
Offsets Required?	Yes	No	Yes	Yes	No

2. Quantity of Offsets Required:

Per District Rule 2201, Section 4.6.1, emission offsets shall not be required for increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

Per Sections 4.7.2 and 4.7.3, the quantity of offsets in pounds per year for NO_X, VOC, and PM_{10} is calculated as follows for sources with an SSPE1 less than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = ([SSPE2 – Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
SSPE2 = Post Project Facility Potential to Emit, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, permit units C-3953-13-1 and C-3953-14-1 will be exempt from providing offsets and the emissions associated with these permit units contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

Offset = ([SSPE2 – Emergency Equipment - Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

<u>NO_X Offset Calculations:</u>

The facility has proposed to provide the same quarterly offsets that were required to be provided in the facility's initial project (C-1080386). The reason for this request is to enable the facility to preserve full flexibility to operate the facility at the previously permitted rates during any calendar quarter, provided the new annual emission limits are not exceeded. The facility is required to maintain a 12 month rolling calculation of their NO_X and CO emissions; therefore compliance with this quarterly limit will be enforceable. The quarterly offsets from project C-1080386 are shown below.

Quarterly Emissions to be Offset (Project C-1080386)

Annual Offsets = 268,415 lb/year * DOR

Quarterly Offsets $_{1st\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{2nd\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{3rd\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{4th\ Qtr}$ = 67,103.75 lbs of NO_X * DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of NO_X ERC's that need to be withdrawn is:

Offsets Required = 268,415 lb-NO_X/year x 1.5
Offsets Required = 402,623 lb-NO_X/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
NO_X	100,655	100,656	100,656	100,656	402,623

The applicant has stated that the facility plans to use ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 to offset the increases in NO_X emissions associated with this project. The above Certificates have available quarterly NO_X credits as follows:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-899-2	2,243	2,243	2,243	2,243	**8,972**
ERC #C-902-2	13,879	6,131	1,086	8,539	**29,635**
ERC #N-720-2	0	9	1,255	437	**1,701**
ERC #N-722-2	0	1,166	88,317	1,422	**90,905**
ERC #N-726-2	0	0	4,728	0	**4,728**
ERC #N-728-2	10,542	3,731	2,487	5,171	**21,931**
ERC #S-2814-2	6,121	13,869	18,914	11,461	**50,365**
ERC #S-2321-2*	51,000	51,000	51,000	51,000	**204,000**
Total	**83,784**	**78,147**	**170,027**	**80,269**	**412,227**

*ERC certificate split from this ERC.

Project NO_X offset requirements

The applicant states that NO_X ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 will be utilized to supply the NO_X offset requirements.

Per Rule 2201 Section 4.13.8, Actual Emission Reductions (i.e. ERCs) that occurred from April through November (i.e. 2nd and 3rd Quarter), inclusive, may be used to offset increases in NO_X or VOC during any period of the year. Since 3rd quarter NO_X ERCs will be used to offset NO_X emissions, the above applies to the NO_X ERCs.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
NO_X Emissions to be offset: (at a 1.5:1 DOR):	100,655	100,656	100,656	100,656
Available ERCs from certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2*:	83,784	78,147	170,027	80,269
3rd qtr. ERCs applied to 1st qtr. ERCs:	16,871	0	-16,871	0
3rd qtr. ERCs applied to 2nd qtr. ERCs:	0	22,509	-22,509	0
3rd qtr. ERCs applied to 4th qtr. ERCs:	0	0	-20,387	20,387
Remaining ERCs from certificates S-2321-2:	0	0	9,604	0
Remaining NO_X emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly NO_X emissions increases associated with this project.

VOC Offset Calculations:

VOC SSPE2 = 69,222 lb/year
C-3953-13-1 (VOC) = 12 lb/year
C-3953-14-1 (VOC) = 31 lb/year
VOC offset threshold = 20,000 lb/year

Offsets = [69,222 – (12) – (31) – 20,000]
= 49,179 lb/year ∗ DOR

Calculating the appropriate quarterly emissions to be offset is as follows:

Offsets = (49,179 lb/year ÷ 4 qtr/year) ∗ DOR
= 12,294.75 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of VOC ERC's that need to be withdrawn is:

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
VOC	18,442	18,442	18,442	18,442	73,769

The applicant has stated that the facility plans to use ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 to offset the increases in VOC emissions associated with this project. The above Certificates have available quarterly VOC credits as follows:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-897-1	45	45	45	45	**180**
ERC #C-898-1	5,480	6,496	4,696	6,616	**23,288**
ERC #N-724-1	0	0	241	0	**241**
ERC #N-725-1	0	0	709	0	**709**
ERC #S-2812-1	31,432	31,424	31,417	31,417	**125,690**
ERC #S-2813-1	12,500	12,500	12,500	12,500	**50,000**
ERC #S-2817-1	11,431	11,424	11,417	11,417	**45,689**
Total	**60,887**	**61,887**	**61,022**	**61,991**	**245,787**

Project VOC offset requirements

The applicant states that NO_X ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 will be utilized to supply the VOC offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
VOC Emissions to be offset: (at a 1.5:1 DOR):	18,442	18,442	18,442	18,442
Available ERCs from certificates C-897-1, C-898-1, N-724-1, N-725-1,	5,525	6,541	5,691	6,661
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
VOC Emissions to be offset: (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
Available ERCs from certificates S-2812-1, S-2813-1, and S-2817-1	55,363	55,348	55,334	55,334
Remaining ERCs from certificates S-2812-1, S-2813-1, and S-2817-1:	42,446	43,447	42,583	43,553
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

PM_{10} Offset Calculations:

PM_{10} SSPE2 = 161,550 lb/year
C-3953-13-1 (PM_{10}) = 2 lb/year
C-3953-14-1 (PM_{10}) = 3 lb/year
PM_{10} Offset threshold = 29,200 lb/year

Offsets = [(161,550 – (2) – (3) - 29,200 + 0) x DOR]
= 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Offsets = (132,345 lb/year ÷ 4 qtr/year) ∗ DOR
= 33,086 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{2nd\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{3rd\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{4th\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
PM_{10}	49,630	49,629	49,629	49,630	198,518

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-896-4	80	80	80	80	**320**
ERC #N-721-4	0	0	3,215	0	**3,215**
ERC #N-723-4	0	0	985	0	**985**
ERC #S-2791-5	92,179	23,666	69,157	96,288	**281,290**
ERC #S-2790-5	12,862	491	0	8,499	**21,852**
ERC #S-2789-5	6	14	12	8	**40**
ERC #S-2788-5	5	7	3	6	**21**
ERC #N-762-5	21,000	21,000	21,000	21,000	**84,000**
Total	**126,131**	**45,256**	**94,449**	**125,877**	**391,723**

Project PM_{10} offset requirements

The applicant states either PM_{10} ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} at an interpollutant ratio of 1.0:1 (see Attachment H). Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_X ERCs are being used to offset PM_{10} emissions, the above applies to the SO_X ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM_{10} emissions to be offset with SO_X ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1st qtr. ERCs applied to 2nd qtr. ERCs:	-4,371	4,371	0	0
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM_{10} emissions increases associated with this project.

Offset Conditions:

The following conditions will ensure compliance with the offset requirements of this rule:

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

- ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

D. Public Notification:

1. Applicability

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Major Modifications
- New emission units with a PE > 100 lb/day of any one pollutant (IPE Notifications)
- Any project which results in the offset thresholds being surpassed (Offset Threshold Notification), and/or
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant. (SSIPE Notice)

a. New Major Source Notice Determination

New Major Sources are new facilities, which are also Major Sources.

As shown in Section VII.C.6 above, the SSPE2 is greater than the Major Source threshold for NO_X, VOC, and PM_{10}. Therefore, public noticing is required for this project for new Major Source purposes because this facility is becoming a new Major Source.

b. Major Modification

As demonstrated in Section VII.C.7 above, this project does not constitute a Major Modification; therefore, public noticing for Major Modification purposes is not required.

c. PE Notification

Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. The potential to emit for each unit is summarized in the table below.

Post-Project Potential to Emit						
Permit Unit	NO_X (lb/day)	CO (lb/day)	VOC (lb/day)	PM_{10} (lb/day)	SO_X (lb/day)	NH_3 (lb/day)
C-3953-10-1	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-11-1	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-12-1	4.9	16.6	1.9	2.2	1.3	0
C-3953-13-1	51.8	6.8	5.8	0.9	0.1	0
C-3953-14-1	45.5	27.3	15.0	1.5	0.4	0
Threshold (lb/day)	**100**	**100**	**100**	**100**	**100**	**100**
Notification Required?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

According to the table above, permit units C-3953-10-1 and -11-1 will each have a Potential to Emit greater than 100 lb/day for NO_X, CO, VOC, PM_{10}, SO_X, or NH_3 emissions. Therefore, public noticing will be required for PE > 100 lbs/day purposes.

e. Offset Threshold

Public notification is required if the Pre-Project Stationary Source Potential to Emit (SSPE1) is increased from a level below the offset threshold to a level exceeding the emissions offset threshold, for any pollutant.

The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	0	198,840	20,000 lb/year	Yes
CO	0	197,928	200,000 lb/year	No
VOC	0	69,222	20,000 lb/year	Yes
PM_{10}	0	161,550	29,200 lb/year	Yes
SO_X	0	33,521	54,750 lb/year	No

As detailed above, offset thresholds were surpassed for NO_X, VOC, and PM_{10} emissions with this project; therefore public noticing is required for offset purposes.

f. SSIPE Notification

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary

Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

SSIPE Notification					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_X	198,840	0	198,840	20,000 lb/year	Yes
CO	197,928	0	197,928	20,000 lb/year	Yes
VOC	69,222	0	69,222	20,000 lb/year	Yes
PM_{10}	161,550	0	161,550	20,000 lb/year	Yes
SO_X	33,521	0	33,521	20,000 lb/year	Yes

As demonstrated above, the SSIPE's for NO_X, CO, VOC, PM_{10} and SO_X emissions were greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Requirements

Section 5.5 details the actions taken by the District when pubic noticing is triggered according to the application types above. Since public noticing requirements are triggered for this project (i.e. New Major Source, PE's > 100 lbs/day, offset thresholds being exceeded, and SSIPEs greater than 20,000 lbs/year), the District shall public notice this project according to the requirements of Section 5.5.

E. Daily Emission Limits:

Daily emissions limitations (DELs) and other enforceable conditions are required by Section 3.15 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity.

Proposed Rule 2201 (DEL) Conditions:

The following condition will be included to demonstrate compliance with facility wide annual NO_X and CO emissions limits.

- Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

i. C-3953-10-1 and C-3953-11-1 (Turbines)

For the turbines, the DELs for NO_X, CO, VOC, PM_{10}, SO_X, and NH_3 will consist of lb/day and/or emission factors.

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

- Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

- Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

- The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

- Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

In addition to the daily emissions limits specified above, the following conditions will also be included to ensure continued compliance for the proposed turbines:

- Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

- Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

ii. C-3953-12-1 (Boiler)

The DELs for the boiler will consist of lb/MMBtu and ppmv emissions limits. This will be sufficient to establish a maximum daily potential to emit based on the maximum daily fuel use limit.

- Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00282 lb/MMBtu. [District Rules 2201, 4305, 4306, and 4351]

In addition the following permit conditions will appear on the permit:

- {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

iii. C-3953-13-1 (Diesel IC engine fire pump)

For the emergency IC engine powering a fire pump, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

For the emergency IC engine powering a generator, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

F. Compliance Certification:

Section 4.15.2 of this Rule requires the owner of a new major source or a source undergoing a major modification to demonstrate to the satisfaction of the District that all other major sources owned by such person and operating in California are in compliance with all applicable emission limitations and standards. As discussed above, this facility is a new major source; therefore this requirement is applicable. Included in Attachment I is Avenal Power Center's certification for the Avenal Energy Project.

G. Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether the operation of the proposed equipment will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Attachment G of this document for the AQIA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the table below, the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X.

AAQA Results Summary					
Pollutant	1 hr Average	3 hr Average	8 hr Average	24 hr Average	Annual Average
CO	Pass	N/A	Pass	N/A	N/A
NO_x	Pass	N/A	N/A	N/A	Pass
SO_x	Pass	Pass	N/A	Pass	Pass

The proposed location is in a non-attainment area for PM_{10}. The increase in the ambient PM_{10} concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	5	N/A	N/A	N/A

Calculated Contribution					
Pollutant	Calculated Contributions ($\mu g/m^3$)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	0.38	1.6	N/A	N/A	N/A

As shown, the calculated contribution of PM_{10} will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

H. Compliance Assurance:

1. Source Testing

i. C-3953-10-1 and C-3953-11-1

District Rule 4703 requires NO_X and CO emission testing as well as percent turbine efficiency testing on an annual basis. The District Source Test Policy (APR 1705 10/09/97) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and PM_{10} emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for NO_X, CO, VOC, PM_{10}, and ammonia slip will be required within 60 days after the end of the commissioning period and at least once every 12 months thereafter.

Also, initial source testing of NO_X, CO, and VOC startup emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

Each CTG will have a separate exhaust stack. The units will be equipped with CEMs for NO_X, CO, and O_2. Each CTG will be equipped with an individual CEM. Each CEM will have two ranges to allow accurate measurements of NO_X and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

40 CFR Part 60 subpart KKKK requires that fuel sulfur content be documented or monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

40 CFR Part 60 subpart Db requires NO_X testing for the duct burners. The District will accept the NO_X source testing required by District Rule 4703 as equivalent to NO_X testing required by 40 CFR 60 subpart Db.

ii. C-3953-12-1

This unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*. Source testing requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

iii. C-3953-13-1 and C-3953-14-1

Pursuant to District Policy APR 1705, source testing is not required for emergency standby IC engines to demonstrate compliance with Rule 2201.

2. Monitoring

i. C-3953-10-1 and C-3953-11-1

Monitoring of NO_X emissions is required by District Rule 4703. The applicant has proposed a CEMS for NO_X.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

40 CFR Part 60 Subpart KKKK and District Rule 4703 requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas & Electric (PG&E), may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to allow the facility to demonstrate compliance with the limit by providing gas purchase contracts, supplier certification, tariff sheet or transportation contract; or, if these documents cannot be provided, physically monitor the fuel sulfur content weekly for eight consecutive weeks and semi-annually thereafter if the fuel sulfur content remains below 1.0 gr/scf. Avenal Power Center, LLC will be operating these turbines in compliance with the fuel sulfur content monitoring requirements as described in the Rule 4001, Subpart KKKK discussion below. Therefore, compliance with the monitoring requirements will be satisfied.

ii. C-3953-12-1

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to monitoring requirements. Monitoring requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

iii. C-3953-13-1 and C-3953-14-1

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

i. C-3953-10-1 and C-3953-11-1

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.F.2 of this document for a discussion of the parameters that will be monitored.

ii. C-3953-12-1

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

The following permit condition will be listed on permit as follows:

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

iii. C-3953-13-1 and C-3953-14-1

Recordkeeping is required to demonstrate compliance with the offset, public notification, and daily emission limit requirements of Rule 2201. As required by District Rule 4702, *Stationary Internal Combustion Engines - Phase 2*, these IC engines are subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

4. Reporting

i. C-3953-10-1 and C-3953-11-1

40 CFR Part 60 Subpart KKKK requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart KKKK requires the reporting of exceedences of the NO_X emission limit of the permit. Such reporting will be required.

ii. C-3953-12-1

No reporting is required to demonstrate compliance with Rule 2201.

iii. C-3953-13-1 and C-3953-14-1

No reporting is required to demonstrate compliance with Rule 2201.

Rule 2520 Federally Mandated Operating Permits

This project will be subject to Rule 2520 (Title V) because it will meet the following criteria specified in section 2.0:

- Section 2.3 states, "Any major source." The facility will be a major source for NO_X, VOC, and PM_{10} after this project.
- Section 2.4 states, "Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA..." The turbines are subject to NSPS.
- Section 2.5 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA." The turbines are subject to the acid rain program.
- Section 2.6 states, "Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act." This facility is not required to obtain a PSD permit.

Pursuant to Rule 2520 section 5.3.1 Avenal Power Center must submit a Title V application within 12 months of commencing operations. No action is required at this time.

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

Rule 2540 Acid Rain Program

The proposed CTG's are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility anticipates beginning commercial operation in November of 2011.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_X and SO_X emissions and a relatively small quantity of SO_X allowances (from a national SO_X allowance bank) will be required as well as the use of a NO_X CEM.

The following condition will be placed on permits C-3953-10-1, -11-1 and -14-1 to ensure that Avenal Power Center, LLC submits an application to comply with the requirements of the acid rain program within the appropriate timeframe:

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Section 2.0 states, "*The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998.*" The applicant has provided the following analysis for Noncriteria pollutants/HAPs.

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[7]

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The SJVAPCD has also published a list of compounds it defines as potential toxic air contaminants (Toxics Policy, May 1991; Rule 2-1-316). Any pollutant that may be emitted from the project and is on the federal New Source Review List, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated.

Noncriteria pollutant emission factors for the analysis of emissions from the gas turbines were obtained from AP-42 (Table 3.1-3, 4/00, and Table 3.4-1 of the Background Document for Section 3.1), from the California Air Resources Board's CATEF database for gas turbines, and from source tests on a similar turbine. Specifically, factors for all pollutants except formaldehyde, hexane, propylene, and naphthalene and other PAHs were taken from AP-42.[8] AP-42 did not contain factors for hexane or propylene, and did not include speciated data for PAHs. Factors for these pollutants and for naphthalene were taken from the CATEF database (mean values). The emission factor for formaldehyde was taken from the results of a June 2000 source test on a dry Low NO_X combustor-equipped large frame turbine.

[7] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).
[8] Factors for acrolein and benzene reflect the use of an oxidation catalyst and were taken from Table 3.4-1 of the Background Document for Section 3.1.

Hazardous Air Pollutant Emissions (per CATEF)
Avenal Energy Project – GE Frame 7 (with Duct Burners)

Hazardous Air Pollutant	CATEF Emission Factor (lb/MMSCF)(1)	Maximum Hourly Emissions per Turbine (lb/hr) (2)	Maximum Annual Emissions per Turbine (tpy) (3)	Maximum Annual Emissions both Turbines (tpy)
Acetaldehyde	4.08E-02	0.09	0.33	0.67
Acrolein	3.69E-03	0.01	0.03	6.04E-02
Benzene	3.33E-03	0.01	0.03	5.45E-02
1,3-Butadiene	4.39E-04	9.38E-04	3.59E-03	7.19E-03
Ethyl benzene	3.26E-02	0.07	0.27	0.53
Formaldehyde	1.65E-01	0.35	1.35	2.70
Hexane	2.59E-01	0.55	2.12	4.24
Naphthalene	1.33E-03	2.84E-03	1.09E-02	2.18E-02
Polycyclic aromatic hydrocarbons (PAH)	---	---	---	---
Anthracene	3.38E-05	7.22E-05	2.77E-04	5.53E-04
Benzo(a)anthracene	2.26E-05	4.83E-05	1.85E-04	3.70E-04
Benzo(a)pyrene	1.39E-05	2.97E-05	1.14E-04	2.28E-04
Benzo(b)fluoranthrene	1.13E-05	2.41E-05	9.25E-05	1.85E-04
Benzo(k)fluoranthrene	1.10E-05	2.35E-05	9.00E-05	1.80E-04
Chrysene	2.52E-05	5.38E-05	2.06E-04	4.12E-04
Dibenz(a,h)anthracene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Indeno(1,2,3-cc)pyrene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Propylene oxide	2.96E-02	6.32E-02	2.42E-01	0.48
Toluene	1.33E-01	0.28	1.09	2.18
Xylenes	6.53E-02	0.14	0.53	1.07
Total			**6.01**	**12.02**

(1) From AP-42 and CATEF databases and source tests.
(2) Based on a maximum hourly turbine fuel use of 2,224.1 MMBtu/hr (with duct burner) and fuel HHV of 1,021 Btu/scf. (2.14 MMscf/hr)
(3) Based on a maximum annual turbine fuel use of 16,711,728 MMBtu/year (with duct burner) and fuel HHV of 1,021 Btu/scf. (16,368 MMscf/yr)

Although the turbines/HRSGs will be equipped with oxidation catalyst systems, only the acrolein and benzene emission factors reflect any control effectiveness. As discussed above, these factors are based on test data rather than any assumption regarding catalyst control efficiency.

Therefore, as emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the Avenal Power Center, LLC Project will not be a major air toxics source and the provisions of this rule do not apply.

Rule 4001 New Source Performance Standards

40 CFR 60 – Subpart Dc

NSPS Subpart Dc applies to steam generating units that are constructed, reconstructed, or modified after 6/9/89 and have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Subpart Dc has standards for SO_X and PM_{10}.

60.42c – Standards for Sulfur Dioxide

Since coal is not combusted by the boiler in this project, the requirements of this section are not applicable.

60.43c – Standards for Particulate Matter

The boiler is not fired on coal, combusts mixtures of coal with other fuels, combusts wood, combusts mixtured of wood with other fuels, or oil; therefore it will not be subject to the requirements of this section.

60.44c – Compliance and Performance Tests Methods and Procedures for Sulfur Dioxide.

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.45c – Compliance and Performance Test Methods and Procedures for Particulate Matter

Since the boiler in this project is not subject to the particulae matter requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.46c – Emission Monitoring for Sulfur Dioxide

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.47c – Emission Monitoring for Particulate Matter

Since the boiler in this project is not subject to the particulate matter requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.48c – Reporting and Recordingkeeping Requirements

Section 60.48c (a) states that the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

The design heat input capacity and type of fuel combusted at the facility will be listed on the unit's equipment description. No conditions are required to show compliance with this requirement.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel mixture of fuels under §60.42c or §40.43c.

This requirement is not applicable since the units are not subject to §60.42c or §40.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

The facility has not proposed an annual capacity factor; therefore one will not be required.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator

This requirement is not applicable since the units will not be equipped with an emerging technology used to control SO_2 emissions.

Section 60.48 c (g) states that the owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The following conditions will be added to the permit to assure compliance with this section.

- A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

- Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

Section 60.48 c (i) states that all records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. District Rule 4306 requires that records be kept for five years.

40 CFR 60 – Subpart GG

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines also meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to these proposed turbines. Therefore, they are exempt from the requirements of 40 CFR 60 Subpart GG and no further discussion is required.

40 CFR 60 - Subpart IIII

§60.4200 - Applicability

40 CFR Part 60 Subpart IIII applies to all owners and operators of stationary compression ignited internal combustion engines that commence construction after July 11, 2005, where the engines are:

1) Manufactured after April 1, 2006, if not a fire pump engine.
2) Manufactured as a National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Since the proposed engines will be installed after July 11, 2005 and will be manufactured after April 1, 2006, this subpart applies.

All of the applicable standards of this subpart are less restrictive than current District requirements. This engine will comply with all current District standards so further discussion is required.

40 CFR Part 60, Subpart JJJJ

The engine in this project is rated at over 100 bhp and per 60.4233(e) is subject to the limits presented in Table 1 of this subpart. The Table 1 limits as well as the proposed emissions are shown on the following table. This regulation does not specify an emissions averaging period.

	Table 1 Limit	Proposed Emissions	Compliant
NOx (g/bhp-hr)	2.0	1.0	Yes
CO (g/bhp-hr)	4.0	0.6	Yes
VOC (g/bhp-hr)	1.0	0.33	Yes

Therefore, the natural gas-fired IC engine in this project meets all applicable requirements of this subpart.

40 CFR 60 – Subpart KKKK

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbines involved in this project have a rating of 1,794.5 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to these gas turbines.

Subpart KKKK established requirements for nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions.

Section 60.4320 - Standards for Nitrogen Oxides:

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new, modified, or reconstructed turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh).

Avenal Power Center is proposing a NO_X emission concentration limit of 2.0 ppmvd @ 15% O_2 for each turbine. Therefore, the proposed turbines will be operating in compliance with the NO_X emission requirements of this subpart. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.44 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 6.13 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.72 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.28 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.23 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.97 lb/hr; or SOx (as SO2) – 5.11 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

<u>Section 60.4330 - Standards for Sulfur Dioxide:</u>

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or
(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

Avenal Power Center is proposing to burn natural gas fuel in each of these turbines with a maximum sulfur content of 1.0 grain/ 100 scf (0.00285 lb/MMBtu). Therefore, the proposed turbines will be operating in compliance with the SO_X emission requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

<u>Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection:</u>

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Avenal Power Center does not use water or steam injection in their turbines therefore; the requirements of this section are not applicable to the turbines in this project.

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection:

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
(2) Continuous parameter monitoring

Avenal Power Center has proposed to install a CEMS system as described in §§60.4335(b) and 60.4345 therefore; the following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

Section 60.4345 – CEMS Equipment Requirements:

Paragraph (a) states that each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

Avenal Power Center will be required to install and operate a NO_X CEMS in accordance with the requirements of this section. As discussed above, Avenal Power Center is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

<u>Section 60.4350 – CEMS Data and Excess NO_X Emissions:</u>

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

Avenal Power Center is proposing to monitor the NO_X emissions rates from the turbines with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_X emissions are released to the atmosphere from the turbine exhaust stacks. The CEMS will be operated in accordance with the methods and procedures described above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

<u>Section 60.4355 – Parameter Monitoring Plan:</u>

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, Avenal Power Center is proposing to install CEMS on each of these turbines that will directly measure NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content:

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

Avenal Power Center is proposing to operate these turbines on natural gas that contains a maximum sulfur content of 1.0 grains/100 scf. Primarily, the natural gas supplier should be able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with the natural gas sulfur content limit. However, Avenal Power Center has asked that the option of either using a purchase contract, tariff sheet or transportation contract or actually physically monitoring the sulfur content be incorporated into their permit.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

When actually required to physically monitor the sulfur content in the fuel burned in these turbines, Avenal Power Center is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. Avenal Power Center is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for the turbines. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions:

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, Avenal Power Center is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_X emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_X emission controls. Avenal Power Center is not proposing to monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

The following condition will ensure continued compliance with the requirements of this section:

- Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess SO_X Emissions:

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

Avenal Power Center will be following the definitions and procedures specified above for determining periods of excess SO_X emissions. Therefore, the proposed turbines will be operating in compliance with the requirements of this section.

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. Avenal Power Center is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing:

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Susequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set fourth the requirements for the methods that are to be used during source testing.

Avenal Power Center will be required to source test the exhaust of these turbines within 120 days of initial startup and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). Avenal Power Center has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, Avenal Power Center is proposing to install a CEMS system to monitor the NO_X emissions from each of these turbines and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– SO_X Performance Testing:

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

Avenal Power Center is proposing to periodically determine the sulfur content of the fuel combusted in each of these turbines when valid purchase contracts, tariff sheets or transportation contract is not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. Avenal Power Center is not proposing to measure the SO_2 in the exhaust stream of the turbines. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

<u>Conclusion:</u>

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected and no further discussion is required.

Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

<u>40 CFR 63 Subpart ZZZZ</u>

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§6585(b) states, "A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site."

§6585(c) states, "An area source of HAP emissions is a source that is not a major source."

The facility is not a major source as defined in §6585(b). Therefore, this facility is an area source of HAP emissions.

§6590(a) states, "An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand." Since the engines in this project are new stationary RICE's at an area source of HAP emissions, they are defined as affected sources.

§6590(a)(2) defines the criteria for an new stationary RICE as follows:

(i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.

(ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

(iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

This facility is an area source of HAP emissions. The engines at this facility have not been constructed and therefore meets the definition of an new stationary RICE as defined in §6590(a)(2)(iii).

§6590(b)(1) states that an affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

(i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

(ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

Since the enignes in this project are not located at a major source of HAP emissions they do not qualify for the limited requirements stated above.

§6590(b)(2) and (3) apply to landfill or digester gas fired RICE's and existing RICE's. Since the engines in ths project are not exsiting RICE's and are fired on diesel fuel or natural gas, these sections do not apply to the RICE's in this project.

§6590(c) states that an affected source that is listed below must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

- new or reconstructed stationary RICE located at an area source,
- new or reconstructed stationary RICE located at a major source of HAP emissions and is a spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of less than 500 brake HP, a spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of less than 250 brake HP, or a 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP, a stationary RICE with a site rating of less than or equal to 500 brake HP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP,
- or a compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP,

Since both the RICE's in this project are new stationary RICE's located at an area source, they will demonstrate compliance with this Subpart by demonstrating compliance with the requirements of 40 CFR part 60 subpart IIII and for compression ignition engines and 40 CFR part 60 subpart JJJJ for spark ignited engines. As shown previously in this evaluation, the RICE's in this project meet the requirements of 40 CFR part 60 subpart IIII and subpart JJJJ; therefore they meet the requirements of this subpart.

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

ii. C-3953-12-1 (Boiler)

Based on past experiences with natural gas-fired boilers, no visible emissions are expected to be as dark as or darker than Ringelmann 1 (or 20% opacity). The following condition will be placed on the DOC to assure compliance with this rule.

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore, the following condition will be added to the permit to assure compliance with this rule.

- {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

A. California Health & Safety Code 41700 (Health Risk Analysis)

A Health Risk Assessment (HRA) is required for any increase in hourly or annual emissions of hazardous air pollutants (HAPs). HAPs are limited to substances included on the list in CH&SC 44321 and that have an OEHHA approved health risk value. The installation of the permit units for the power plant results in increases in emissions of HAPs.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Under the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit as shown in the table below:

Screen HRA Summary				
	Acute Hazard Index	Chronic Hazard Index	70 yr Cancer Risk	T-BACT Required?
C-3953-10-1 (Turbine #1)	0.0	0.0	0.02	No
C-3953-11-1 (Turbine #2)	0.0	0.0	0.02	No
C-3953-12-1 (Auxiliary Boiler)	0.0	0.0	0.01	No
C-3953-13-1 (Diesel-Fired IC Engine Fire Pump)	N/A*	N/A*	0.01	No
C-3953-14-1 (NG-Fired IC Engine Generator)	0.2	0.0	0.0	No

* Acute and Chronic Hazard Indices were not calculated since there is not a risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

B. Discussion of Toxics BACT (TBACT)

TBACT is triggered if the cancer risk exceeds one in one million and if either the chronic or acute hazard index exceeds 1. The results of the health risk assessment show that none of the TBACT thresholds are exceeded. TBACT is not triggered.

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

i. C-3953-10-1 and –11-1 (Turbines)

PM Conc. (gr/scf) = (PM emission rate) x (7000 gr/lb)

PM_{10} emission rate = 11.78 lb/hr. Assuming 100% of PM is PM_{10}
Exhaust Gas Flow = 1,071,653 dscfm

PM Conc. (gr/scf)=[(11.78 lb/hr) $*$ (7,000 gr/lb)] $\div$ [(1,071,653 ft^3/min) $*$ (60 min/hr)]
PM Conc. = 0.0012 gr/scf

Calculated emissions are well below the allowable emissions level. It can be assumed that emissions from all these turbines will not exceed the allowable 0.1 gr/scf. Therefore, compliance with Rule 4201 is expected.

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

ii. C-3953-12-1 (Boiler)

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

F-Factor for NG: 8,578 dscf/MMBtu at 60 °F
PM10 Emission Factor: 0.005 lb-PM10/MMBtu
Percentage of PM as PM10 in Exhaust: 100%
Exhaust Oxygen (O_2) Concentration: 3%
Excess Air Correction to F Factor = $\dfrac{20.9}{(20.9 - 3)}$ = 1.17

$$GL = \left(\frac{0.005\ lb-PM}{MMBtu} \times \frac{7{,}000\,grain}{lb-PM}\right) / \left(\frac{8{,}578\ ft^3}{MMBtu} \times 1.17\right)$$

$$GL = 0.0035\ grain/dscf < 0.1\,grain/dscf$$

Therefore, compliance with District Rule 4201 requirements is expected and a permit condition will be listed on the permit as follows:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iii. C-3953-13-1 (Diesel IC engine fire pump)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.059\ \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1\,bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.014\ \frac{grain-PM}{dscf}$$

Since 0.014 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.034 \frac{g-PM_{10}}{bhp-hr} \times \frac{1 g-PM}{0.96 g-PM_{10}} \times \frac{1 bhp-hr}{2{,}542.5 Btu} \times \frac{10^6 Btu}{9{,}051 dscf} \times \frac{0.35 Btu_{out}}{1 Btu_{in}} \times \frac{15.43 grain}{g} = 0.008 \frac{grain-PM}{dscf}$$

Since 0.008 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to any of the permit units in this project, and no further discussion is required.

Rule 4301 *Fuel Burning Equipment*

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer".

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The CTG's primarily produce power mechanically, i.e. the products of combustion pass across the power turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity. Because the CTG's primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Therefore, Rule 4301 does not apply to the affected equipment and no further discussion is required.

ii. C-3953-12-1 (Boiler)

District Rule 4301 Limits			
Pollutant	NO_2	Total PM	SO_2
C-3953-12-1 (lb/hr)	0.41	0.19	0.10
Rule Limit (lb/hr)	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule; therefore, continued compliance is expected.

iii. C-3953-13-1 (Diesel IC engine fire pump)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

Rule 4304 Tuning Procedure for Boilers, Steam Generators and Process Heaters

This rule is only applicable to unit C-3953-12-1.

Pursuant to District Rules 4305 and 4306, Section 6.3.1, the boiler is not required to tune since it follows a District approved Alternate Monitoring scheme where the applicable emission limits are periodically monitored. Therefore, the unit is not subject to this rule.

Rule 4305 Boilers Steam Generators and Process Heaters – Phase 2

This rule is only applicable to unit C-3953-12-1.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4305, the unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters – Phase 2.*

In addition, the unit is also subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

Since emissions limits of District Rule 4306 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4306 requirements will satisfy requirements of District Rule 4305.

Conclusion

Therefore, compliance with District Rule 4305 requirements is expected and no further discussion is required.

Rule 4306 Boilers Steam Generators and Process Heaters – Phase 3

This rule is only applicable to unit C-3953-12-1.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306.

Section 5.1, NO_X and CO Emissions Limits

Section 5.1.1 requires that except for units subject to Sections 5.2, NO_X and carbon monoxide (CO) emissions shall not exceed the limits specified in the following table. All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen in accordance with Section 8.1.

With a maximum heat input of 37.4 MMBtu/hr, the applicable emission limit category is listed in Section 5.1.1, Table 1, Category B, from District Rule 4306.

Rule 4306 Emissions Limits				
Category	Operated on gaseous fuel		Operated on liquid fuel	
	NO_X Limit	CO Limit	NO_X Limit	CO Limit
B. Units with a rated heat input greater than 20.0 MMBtu/hr, except for categories C, D, E, F, G, H, and I units	9 ppmv or 0.011 lb/MMBtu	400 ppmv	40 ppmv or 0.052 lb/MMBtu	400 ppmv

For the unit:

- the proposed NO_x emission factor is 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu), and
- the proposed CO emission factor is 50 ppmvd @ 3% O_2 (0.037 lb/MMBtu).

Therefore, compliance with Section 5.1 of District Rule 4306 is expected.

A permit condition listing the emissions limits will be listed on permit as shown in the DEL section above.

Section 5.2, Low Use

The unit annual heat input will exceed the 9 billion Btu heat input per calendar year criteria limit addressed by this section. Since the unit is not subject to Section 5.2, the requirements of this section do not apply to the unit.

Section 5.3, Startup and Shutdown Provisions

Section 5.3 states that on and after the full compliance schedule specified in Section 7.1, the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 shall not apply during start-up or shutdown provided an operator complies with the requirements specified in Sections 5.3.1 through 5.3.4.

According to boiler manufacturers, low NO_X burners will achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated emission factor following startup, the unit will be subject to the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 while in operation.

Section 5.4, Monitoring Provisions

Section 5.4.2 requires that permit units subject to District Rule 4306, Section 5.1 emissions limits shall either install and maintain Continuous Emission Monitoring (CEM) equipment for NO_X, CO and O_2, or install and maintain APCO-approved alternate monitoring.

The facility has proposed to install a CEMS system to satisfy the requirements of this section. The following condition will assure compliance with this section.

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

Since the unit is not subject to the requirements listed in Section 5.2.1 or 5.2.2, it is not subject to Section 5.4.3 requirements.

Since the unit is not subject to the requirements of category H (maximum annual heat input between 9 billion and 30 billion Btu/year) listed in Section 5.1.1, it is not subject to Section 5.4.4 requirements.

Section 5.5, Compliance Determination

Section 5.5.1 requires that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.1. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). Therefore, the following condition will be listed on the permit as follows:

- {2976} The source plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

Section 5.5.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following permit condition will be listed on the permit as follows:

- {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

Section 5.5.4 requires that for emissions monitoring pursuant to Sections 5.4.2, 5.4.2.1, and 6.3.1 using a portable NO_X analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period.

Since the applicant does not use a portable analyzer to satisfy the monitoring requirements of District Rule 4306 the requirements of Section 5.5.4 do not apply.

Section 5.5.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following permit condition will be listed on the permit as follows:

- {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

Section 6.1, Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.3 shall be maintained for five calendar years and shall be made available to the APCO upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

A permit condition will be listed on the permit as follows:

- {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

Section 6.1.2 requires that the operator of a unit subject to Section 5.2 shall record the amount of fuel use at least on a monthly basis. Since the unit is not subject to the requirements listed in Section 5.2, it is not subject to Section 6.1.2 requirements.

Section 6.1.3 requires that the operator of a unit subject to Section 5.2.1 or 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics have been performed. The unit is not subject to Section 6.1.3. Therefore, the requirements of this section do not apply to the unit.

Section 6.2, Test Methods

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Pollutant	Units	Test Method Required
NO_X	ppmv	EPA Method 7E or ARB Method 100
NO_X	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O_2	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2
Stack Gas Moisture Content	%	EPA Method 4

The following permit conditions will be listed on the permit as follows:

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- {2977} NO_X emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]
- {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]
- {2979} Stack gas oxygen (O_2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

Section 6.3, Compliance Testing

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.1 and 5.2.3 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to thirty-six months.

The following permit conditions will be listed on the permit as follows:

- {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]
- {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]
- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Section 6.4, Emission Control Plan (ECP)

Section 6.4.1 requires that the operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0 of District Rule 4306.

The proposed modified unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule and with periodic monitoring and source testing requirements. Therefore, this current application for the new proposed unit satisfies the requirements of the Emission Control Plan, as listed in Section 6.4 of District Rule 4306. No further discussion is required.

Section 7.0, Compliance Schedule

Section 7.0 indicates that an operator with multiple units at a stationary source shall comply with this rule in accordance with the schedule specified in Table 2, Section 7.1 of District Rule 4306.

The unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule, and periodic monitoring and source testing as required by District Rule 4306. Therefore, requirements of the compliance schedule, as listed in Section 7.1 of District Rule 4306, are satisfied. No further discussion is required.

Conclusion

Conditions will be incorporated into the permit in order to ensure compliance with each section of this rule, see attached draft permit(s). Therefore, compliance with District Rule 4306 requirements is expected.

Rule 4351 Boilers Steam Generators and Process Heaters – Phase 1

This rule is only applicable to unit C-3953-12.

This rule applies to boilers, steam generators, and process heaters at NO_x Major Sources that are not located west of Interstate 5 in Fresno, Kings, or Kern counties. If applicable, the emission limits, monitoring provisions, and testing requirements of this rule are satisfied when the unit is operated in compliance with Rule 4306. Therefore, compliance with this rule is expected.

Rule 4701 Internal Combustion Engines – Phase 1

This rule is only applicable to units C-3953-13-1 and –14-1.

Pursuant to Section 7.5.2.3 of District Rule 4702, as of June 1, 2006 District Rule 4701 is no longer applicable to diesel-fired emergency standby or emergency IC engines. Therefore, this diesel-fired emergency IC engine will comply with the requirements of District Rule 4702 and no further discussion is required.

Rule 4702 Internal Combustion Engines – Phase 2

This rule is only applicable to units C-3953-13-1 and –14-1.

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower greater than 50 horsepower.

Pursuant to Section 4.2, except for the requirements of Sections 5.7 and 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following condition:

1) An emergency standby engine as defined in Section 3.0 of this rule, and provided that it is operated with a nonresettable elapsed operating time meter. In lieu of a nonresettable time meter, the owner of an emergency engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Section 3.15 defines an "Emergency Standby Engine" as an internal combustion engine which operates as a temporary replacement for primary mechanical or electrical power during an unscheduled outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the operator. An engine shall be considered to be an emergency standby engine if it is used only for the following purposes: (1) periodic maintenance, periodic readiness testing, or readiness testing during and after repair work; (2) unscheduled outages, or to supply power while maintenance is performed or repairs are made to the primary power supply; and (3) if it is limited to operate 100 hours or less per calendar year for non-emergency purposes. An engine shall not be considered to be an emergency standby engine if it is used: (1) to reduce the demand for electrical power when normal electrical power line service has not failed, or (2) to produce power for the utility electrical distribution system, or (3) in conjunction with a voluntary utility demand reduction program or interruptible power contract.

Therefore, unit C-3953-14-1, the emergency standby IC engine powering an electrical generator involved with this project will only have to meet the requirements of Sections 5.7 and 6.2.3 of this Rule.

Pursuant to Section 4.3, except for the requirements of Section 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following conditions:

1) The engine is operated exclusively to preserve or protect property, human life, or public health during a disaster or state of emergency, such as a fire or flood, and
2) Except for operations associated with Section 4.3.1.1, the engine is limited to operate no more than 100 hours per calendar year as determined by an operational nonresettable elapsed operating time meter, for periodic maintenance, periodic readiness testing, and readiness testing during and after repair work of the engine, and
3) The engine is operated with a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, unit C-3953-13-1, the emergency IC engine powering a firewater pump involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

Section 5.7 of this Rule requires that the owner of an emergency standby engine shall comply with the requirements specified in Section 5.7.2 through Section 5.7.5 below:

1) Properly operate and maintain each engine as recommended by the engine manufacturer or emission control system supplier.

2) Monitor the operational characteristics of each engine as recommended by the engine manufacturer or emission control system supplier.

3) Install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO and is allowed by Permit-to-Operate or Stationary Equipment Registration condition. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, the following conditions will be listed on the DOC to ensure compliance:

<u>C-3953-14-1 (Natural Gas IC engine electrical generator)</u>

- This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

- During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

- An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

- This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

- This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

Section 6.2.3 requires that an owner claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and submitted to the APCO upon request and at the end of each calendar year in a manner and form approved by the APCO. Therefore, the following conditions will be listed on the DOC to ensure compliance:

C-3953-13-1 (Diesel IC engine fire pump)

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

In addition, the following condition will be listed on the DOC to ensure compliance:

- {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

- {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

- {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

C-3953-14-1 (Natural Gas IC engine electrical generator)

- The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

Rule 4703 Stationary Gas Turbines

This rule is only applicable to units C-3953-10-1 and -11-1.

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility proposes to install two 180 MW gas turbines. Therefore the requirements of this rule apply to the proposed turbines.

Section 5.1 – NO_X Emission Requirements:

Section 5.1.1 (Tier I) of this rule limits the NO_X emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR). Since the proposed turbines will meet the more stringent Tier 2 emission equirements in Section 5.1.2, compliance with this section is assured.

Section 5.1.2 (Tier 2) of this rule limits the NO_X emissions from combined cycle, stationary gas turbine systems rated at greater than 10 MW to 5 ppmv @ 15% O_2 (Standard option) and 3 ppmv @ 15% O_2 (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbines will be limited to 2.0 ppmv @ 15% O_2 (based on a 1-hour average), therefore compliance with this section is expected. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

Section 5.2 – CO Emission Requirements:

Per Table 5-3 of section 5.2, the CO emissions concentration from the proposed turbines (General Electric Frame 7) must be less than 25 ppmvd @ 15% O_2. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three hour period.

Avenal Power Center is proposing a CO emission concentration limit of 2 ppmvd @ 15% O_2 and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbines will be operating the turbine in compliance with the CO emission requirements of this rule. The DEL conditions shown in the Section 5.1.2 compliance section will ensure continued compliance with the requirements of this section.

Section 5.3 – Startup and Shutdown Requirements:

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during startup, shutdown, or a reduced load period provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, and the duration of each reduced load period shall not exceed one hour, except as provided below.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown, or a reduced load period.
- An operator may submit an application to allow more than two hours for each startup or each shutdown or more than one hour for each reduced load period provided the operator meets all of the conditions specified in the rule.

Avenal Power Center is proposing to incorporate startup and shutdown provisions into the operating requirements for each of the proposed turbines. They have proposed that the duration of each startup or shutdown event will last no more than six hours per day. Since this proposed duration is longer than what is allowed in Section 5.3.1.1, the facility must meet the requirements of Section 5.3.3.2. Section 5.3.3.2 states that at a minimum, a justification for the increased duration shall include the following:

A clear identification of the control technologies or strategies to be utilized; and

The facility has identified the following control technologies:

- Dry low-NOx combustors in the turbines;
- Oxidation catalyst in the HRSGs;
- SCR in the HRSGs;
- Good combustion practices;

- Upon startup, the ammonia injection upstream of the SCR catalyst will be started as soon as the catalyst and ammonia injection system warm to their minimum operating temperatures specified by the SCR vendor.

<u>A description of what physical conditions prevail during the period that prevent the controls from being effective; and</u>

The combined-cycle equipment startup duration depends on how fast the thick steel walls of the common steam turbine can be warmed to operating temperature without generating stress cracks. Steam developed in the HRSG from the heated turbine exhaust is admitted into the steam turbine at a controlled temperature to heat it as rapidly as possible without causing stress cracking. The steam temperature is controlled by limiting the load on the gas turbine. The allowable rate of temperature increase at the steam turbine is the limiting factor determining how quickly the gas turbines can achieve higher loads. This, in turn, limits how quickly the gas turbine combustors can achieve the lowest emitting operating mode, and this latter step is necessary for the units to be able to comply with the limits of Rule 4703.

<u>A reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions; and</u>

Startup information provided by the turbine and HRSG vendors indicates that for a cold startup, a minimum of four hours is required for the unit to come into compliance with the limits of Rule 4703. Depending on the temperature of the steam turbine at the time the start is initiated, shorter durations may be possible.

<u>A detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity; and</u>

The facility has provided the District with a detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity.

<u>A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and</u>

The startup duration depends on the allowable ramp rate of the steam temperature to the steam turbine, which depends on the acceptable rate of increase of the metal temperature of the HRH and HP bowls at the steam turbine inlets. The maximum steam temperature is set by applying an allowable differential above the metal temperature. The differential is determined by the steam turbine supplier, and is imposed by the supplier's control system to avoid damage to the steam turbine from thermal stress. The control system limits gas turbine load to control the steam temperature. Manual override of the gas turbine load limit by the operator reduces the life expectancy of the steam turbine.

In addition, the time prior to initiation of ammonia flow to the SCR system depends on the temperature of the SCR catalyst. The catalyst bed is warmed by the exhaust flow from the gas turbine. The total mass of metal and water in the HRSG tubes, piping, and drums removes heat from the gas turbine exhaust as it warms. This extends the time required to heat the SCR catalyst to the minimum temperature at which ammonia may be injected upstream of the catalyst bed to begin reducing NOx to N_2. The steam turbine and SCR catalyst temperatures are all monitored by the plant control system, and the turbine ramp rate and SCR initiation sequence are governed by the equipment/system manufactúrer's recommended procedures.

The basis for the requested additional duration.

The startup curve in Attachment I and the description of activities above demonstrate that the minimum time required for a cold startup of the plant as currently configured is approximately 4 hours. This startup time is contingent upon all of the activities being performed in time to support subsequent activities. Any delay in preparation of the supporting systems will result in a corresponding delay in startup and/or loading of the gas turbines. To be confident that the startup time allowed is adequate and will not be exceeded, one hour is added to the above startup time to account for possible delays.

Since the facility has demonstrated compliance and provided all the information asked for in Section 5.3.3.2, the proposed increase in startup and shutdown emissions is compliant with District Rule 4703. The following conditions will ensure continued compliance with the requirements of this section:

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

- The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

Section 6.2 - Monitoring and Recordkeeping:

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for NO_X and oxygen, or install and maintain APCO-approved alternate monitoring. As discussed earlier in this evaluation, the applicant operates a Continuous Emissions Monitoring System (CEMS) that monitors the NO_X and oxygen content of the turbine exhaust. Therefore, the requirements of this section have been satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. Each of the proposed turbines will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbines have not been installed. Therefore, they were not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. Avenal Power Center will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbines will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_X output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_X available or when the continuous emissions monitoring system is not operating properly. Avenal Power Center will be required, by permit condition, to submit information correlating the NO_X control system operating parameters to the associated measured NO_X output. Therefore, the proposed turbines will be operating in compliance with the control system operating parameter requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

Section 6.2.6 requires the facility to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. Avenal Power Center will be required to maintain records of each item listed above. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NO_x mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. Each of the proposed turbines is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.8 requires owners or operators performing startups or shutdowns to keep records of the duration of each startup and shutdown. As discussed in the Section 6.2.6 discussion above for this rule, Avenal Power Center will be required, by permit condition, to maintain records of the date, time and duration or each startup and shutdown. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule.

Sections 6.3 and 6.4 - Compliance Testing:

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO_X and CO concentrations. The turbines operated by Avenal Power Center are subject to the provisions of Section 5.0 of this rule. Therefore, each turbine is required to test annually to demonstrate compliance with the exhaust gas NO_X and CO concentrations. The following condition will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbines will be allowed to operate in excess of 877 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 states that units with intermittently operated auxiliary burners shall demonstrate compliance with the auxiliary burner both on and off. The following condition will ensure continued compliance with the requirements of this section:

- Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

Section 6.4 states that the facility must demonstrate compliance annually with the NO_X and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of Rule 4703 is expected and no further discussion is required.

Rule 4801 Sulfur Compounds

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes:

i. C-3953-10-1 and –11-1 (Turbines)

The sulfur of the natural gas fuel is 1.0 gr/100 dscf.

The ratio of the volume of the SO_X exhaust to the entire exhaust for one MMBtu of fuel combusted is:

Volume of SO_X: $V = \frac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of SO_X produced per MMBtu of fuel.
- Weight of SO_X as SO_2 is 64 lb/(lb-mol)
- $n = \frac{0.00282\ lb}{MMBtu} \times \frac{1\ (lb-mol)}{64\ lb} = 0.000045\ (lb-mol)$

- $R = \dfrac{0.7302\,ft^3 \cdot atm}{(lb - mol)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000045\ (lb - mol) \cdot \dfrac{0.7302\ ft^3 \cdot atm}{(lb - mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.016\ ft^3$$

Since the total volume of exhaust per MMBtu is 8,578 scf, the ratio of SO_X volume to exhaust volume is

$$= \frac{0.016}{8{,}578} = 0.0000019 = 1.9\ ppmv = 0.00019\%\ by\ volume$$

1.9 ppmv ≤ 2000 ppmv, therefore the turbines, the boiler, and the gas engine are expected to comply with Rule 4801.

ii. C-3953-12-1 (Boiler)

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

Volume SO_2 = $\dfrac{n\ RT}{P}$

With:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi
R (Universal Gas Constant) = $\dfrac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot °R}$

$$\frac{0.00282\,lb - SOx}{MMBtu} \times \frac{MMBtu}{8{,}578\,dscf} \times \frac{1\,lb \cdot mol}{64\,lb} \times \frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot °R} \times \frac{520°R}{14.7\,psi} \times \frac{1{,}000{,}000 \cdot parts}{million} = 1.97\,\frac{parts}{million}$$

$$SulfurConcentration = 1.97 \frac{parts}{million}$$ < 2,000 ppmv (or 0.2%)

Therefore, compliance with District Rule 4801 requirements is expected.

iii. C-3953-13-1 (Diesel IC engine powering a fire water pump)

Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73 \text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

$$\frac{0.000015\, lb - S}{lb - fuel} \times \frac{7.1\,\text{lb}}{\text{gal}} \times \frac{64\,\text{lb} - SO_2}{32\,\text{lb} - \text{S}} \times \frac{1\,\text{MMBtu}}{9{,}051\,\text{scf}} \times \frac{1\,\text{gal}}{0.137\,\text{MMBtu}} \times \frac{\text{lb} - \text{mol}}{64\,\text{lb} - SO_2} \times \frac{10.73\,\text{psi} - \text{ft}^3}{\text{lb} - \text{mol} - {}^\circ\text{R}} \times \frac{520^\circ\text{R}}{14.7\,\text{psi}} \times 1{,}000{,}000 = 1.0 \text{ ppmv}$$

Since 1.0 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-1 (Natural gas IC engine powering an electrical generator)

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73 \text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

$$2.85 \frac{lb - S}{MMscf - gas} \times \frac{1\,scf - gas}{1{,}000\,Btu} \times \frac{1\,MMBtu}{8{,}578\,scf} \times \frac{1\,lb - mol}{64\,lb - S} \times \frac{10.73\,psi - ft^3}{lb - mol - {}^\circ R} \times \frac{520^\circ R}{14.7\,psi} \times 1{,}000{,}000 = 1.97 \text{ ppmv}$$

Since 1.97 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

District Rule 8011	***General Requirements***
District Rule 8021	***Construction, Demolition, Excavation, Extraction And Other Earthmoving Activities***
District Rule 8031	***Bulk Materials***
District Rule 8041	***Carryout And Trackout***
District Rule 8051	***Open Areas***
District Rule 8061	***Paved And Unpaved Roads***
District Rule 8071	***Unpaved Vehicle/Equipment Traffic Areas***
District Rule 8081	***Agricultural Sources***

The construction of this new facility will involve excavation, extraction, construction, demolition, outdoor storage piles, paved and unpaved roads.

The regulations from the 8000 Series District Rules contain requirements for the control of fugitive dust. These requirements apply to various sources, including construction, demolition, excavation, extraction, mining activities, outdoor storage piles, paved and unpaved roads. Compliance with these regulations will be required by the following permit conditions, which will be listed on each permit as follows:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

California Environmental Quality Act (CEQA)

The District determined that the California Energy Commission (CEC) is the public agency having principal responsibility for approving the project, therefore establishing the CEC as the Lead Agency (CEQA Guidelines §15051(b). The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). The District's engineering evaluation of the project (this document) demonstrates that compliance with District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's significance thresholds for criteria pollutants. The District has determined that no additional findings are required (CEQA Guidelines §15096(h)).

California Health & Safety Code, Section 42301.6 (School Notice)

As discussed in Section III of this evaluation, this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.

2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.

3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment (Required by Title 17 CCR, Section 93115 for New Emergency Diesel IC Engines)

The requirements of this section are only applicable to C-3953-13-1.

Particulate Matter and VOC + NO_X, and CO Exhaust Emissions Standards:

This regulation stipulates that off-road compression-ignition engines shall not exceed the following applicable emissions standards.

Title 13 CCR, Section 2423 lists a diesel particulate emission standard of 0.15 g/bhp-hr (with 1.341 bhp/kW, equivalent to 0.20 g/kW-hr) for 2003 - 2005 model year engines with maximum power ratings of 174.3 - 301.6 bhp (equivalent to 130 - 225 kW). The PM standards given in Title 13 CCR, Section 2423 are less stringent than the PM standards given in Title 17 CCR, Section 93115 (ATCM), thus the ATCM standards are the required standards and will be discussed in the following section.

Title 17 CCR, Section 93115, (e)(2)(A)(3)(b) stipulates that new stationary emergency diesel-fueled CI engines (> 50 bhp) must meet the VOC + NO_X, and CO standards for off-road engines of the same model year and maximum rated power as specified in the Off-Road Compression-Ignition Engine Standards (Title 13 CCR, Section 2423) or the Tier 1 standards for an off-road engine if no standards have been established for an off-road engine of the same model year and maximum rated power.

In addition, Title 17 CCR, Section 93115, (e)(2)(A)(4)(a)(II) allows new direct-drive emergency fire pump engines to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (title 13 CCR, section 2423) until three years after the date the Tier 3 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 3 emission standards, until three years after the date the Tier 4 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 4 emission standards; and not operate more than the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 – "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition, which is incorporated herein by reference. In addition, this subsection does not limit engine operation for emergency use and for emission testing to show compliance with (e)(2)(A)4. For this project the proposed emergency diesel IC engine will be used to power a firewater pump and is therefore allowed to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines three years after the applicable dates specified. This additional three-year allowance is reflected in the following table.

The engine involved with this project is a certified 2007 model engine. The following table compares the requirements of Title 13 CCR, Section 2423 to the emissions factors for the 288 bhp Cummins Model #CFP83-F40 diesel-fired emergency IC engine as given by the manufacturer (for NO_X + VOC and PM emissions).

Requirements of Title 13 CCR, Section 2423							
Source	Maximum Rated Power	Model Year	NO_X	VOC	NO_X + VOC	CO	PM
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	1996-2002 (Tier 1)	6.9 g/bhp-hr (9.2 g/kW-hr)	1.0 g/bhp-hr (1.3 g/kW-hr)	--	8.5 g/bhp-hr (11.4 g/kW-hr)	0.40 g/bhp-hr (0.54 g/kW-hr)
Title 13 CCR, §2423	**174.3 – 301.6 bhp (130 - 225 kW)**	**2003-2005, extended to 2008 (Tier 2)**	**--**	**--**	**4.9 g/bhp-hr (6.6 g/kW-hr)**	**2.6 g/bhp-hr (3.5 g/kW-hr)**	**0.15 g/bhp-hr (0.20 g/kW-hr)**
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	2006 and later, extended to 2009 (Tier 3)	--	--	3.0 g/bhp-hr (4.0 g/kW-hr)	2.6 g/bhp-hr (3.5 g/kW-hr)	0.15 g/bhp-hr (0.20 g/kW-hr)
Cummins, Model #CFP83-F40	288 bhp	2007	--	--	3.8g/bhp-hr (5.1 g/kW-hr)	0.447 g/bhp-hr (0.60 g/kW-hr)	0.059 g/bhp-hr (0.079 g/kW-hr)
Meets Standard?			N/A	N/A	Yes	Yes	Yes

As presented in the table above, the proposed engine will satisfy the requirements of this section and compliance is expected.

The engine manufacturer's data and/or CARB/EPA engine certification for this engine lists a NO_X emissions factor of 3.4 g/bhp-hr, a VOC emissions factor of 0.38 g/bhp-hr, a NO_X + VOC emission factor of 3.8 g/bhp-hr, a CO emission factor of 0.447 g/bhp-hr, and a PM_{10} emissions factor of 0.059 g/bhp-hr, all of which satisfy the requirements of 13 CCR, Section 2423. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

<u>Right of the District to Establish More Stringent Standards:</u>

This regulation also stipulates that the District:

1. May establish more stringent diesel PM, NO_X + VOC, VOC, NO_X, and CO emission rate standards; and

2. May establish more stringent limits on hours of maintenance and testing on a site-specific basis; and
3. Shall determine an appropriate limit on the number of hours of operation for demonstrating compliance with other District rules and initial start-up testing

The District has not established more stringent standards at this time. Therefore, the standards previously established in this Section will be utilized.

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

The requirements of this section are only applicable to C-3953-13-1.

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

This section applies to emergency standby IC engines that are permitted to operate during non-emergency conditions for the purpose of providing electrical power. However, District Rule 4702 states that emergency standby IC engines may only be operated during non-emergency conditions for the purposes of maintenance and testing. Therefore, this section does not apply and no further discussion is required.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engine involved with this project is a new or in-use stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

At-School and Near-School Provisions:

This regulation stipulates that no owner or operator shall operate a new stationary emergency diesel-fueled CI engine, with a PM_{10} emissions factor > than 0.01 g/bhp-hr, for non-emergency use, including maintenance and testing, during the following periods:

1. Whenever there is a school sponsored activity, if the engine is located on school grounds, and
2. Between 7:30 a.m. and 3:30 p.m. on days when school is in session, if the engine is located within 500 feet of school grounds.

The District has verified that the engine is not located within 500 feet of a K-12 school. Therefore, conditions prohibiting non-emergency usage of the engine during school hours will not be placed on the permit.

<u>Recordkeeping Requirements:</u>

This regulation stipulates that as of January 1, 2005, each owner or operator of an emergency diesel-fueled CI engine shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

a. Emergency use hours of operation;
b. Maintenance and testing hours of operation;
c. Hours of operation for emission testing;
d. Initial start-up hours; and
e. If applicable, hours of operation to comply with the testing requirements of National Fire Protection Association (NFPA) 25 — "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition;
f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
g. For in-use emergency diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:

    I. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
    II. Amount of fuel purchased;
    III. Date when the fuel was purchased;
    IV. Signature of owner or operator or representative of owner or operator who received the fuel; and
    V. Signature of fuel provider indicating fuel was delivered.

The proposed new emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

PM Emissions and Hours of Operation Requirements for New Diesel Engines:

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency diesel-fueled CI engine that has a rated brake horsepower greater than 50, unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and
3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

The proposed emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

IX. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Final Determination of Compliance for the facility subject to the conditions presented in Attachment A.

X. BILLING INFORMATION:

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-3953-10-1	3020-08B-B	180,000 kW	$12,229.00
C-3953-11-1	3020-08B-B	180,000 kW	$12,229.00
C-3953-12-1	3020-02-H	37.4 MMBtu/hr boiler	$953.00
C-3953-13-1	3020-10-C	288 bhp IC engine	$222.00
C-3953-14-1	3020-10-E	860 bhp IC engine	$557.00

ATTACHMENT A

FDOC CONDITIONS

EQUIPMENT DESCRIPTION, UNIT C-3953-10-1:
180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

7. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

12. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

13. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

14. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

15. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

16. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in

accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

18. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

19. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

20. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

21. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

22. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

23. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

24. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

25. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

26. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated

emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

35. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from

the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

37. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

38. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

42. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

43. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

44. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance

with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

45. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

48. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

49. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

50. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

52. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

53. The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

54. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

55. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

56. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

57. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

58. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

59. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

60. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

61. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

62. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

63. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

64. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

65. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

66. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

67. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-3953-11-1:
180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

7. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

12. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

13. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

14. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

15. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

16. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality

assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

18. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

19. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

20. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

21. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

22. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

23. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

24. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

25. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

26. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the

equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

35. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

37. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

38. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

42. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

43. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

44. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with

the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

45. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

48. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

49. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

50. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

52. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

53. The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

54. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

55. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

56. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

57. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

EQUIPMENT DESCRIPTION, UNIT C-3953-12-1:
37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

5. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

6. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this DOC. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

7. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

8. Alternate equipment shall be of the same class and category of source as the equipment authorized by the DOC. [District Rule 2201]

9. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

10. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

11. {1407} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

12. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

13. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

14. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

15. {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

16. Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00285 lb/MMBtu. [District Rules 2201, 4305, and 4306]

17. {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

18. {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]

19. {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]

20. {2976} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

21. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

22. {2977} NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]

23. {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]

24. {2979} Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

25. {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

26. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

27. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

28. Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

29. {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

30. {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

27. {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

28. {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

29. {1835} The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

30. {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

31. {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

32. {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

33. {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

EQUIPMENT DESCRIPTION, UNIT C-3953-13-1:
288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

7. {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

8. {3403} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

9. Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

10. Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

11. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

12. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

13. {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

14. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

EQUIPMENT DESCRIPTION, UNIT C-3953-14-1:
860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

3. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

4. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

5. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

6. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

7. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

8. {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

9. {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

10. Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

11. {3405} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

12. {3478} During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

13. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

14. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

15. {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

16. {3496} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

17. {3497} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

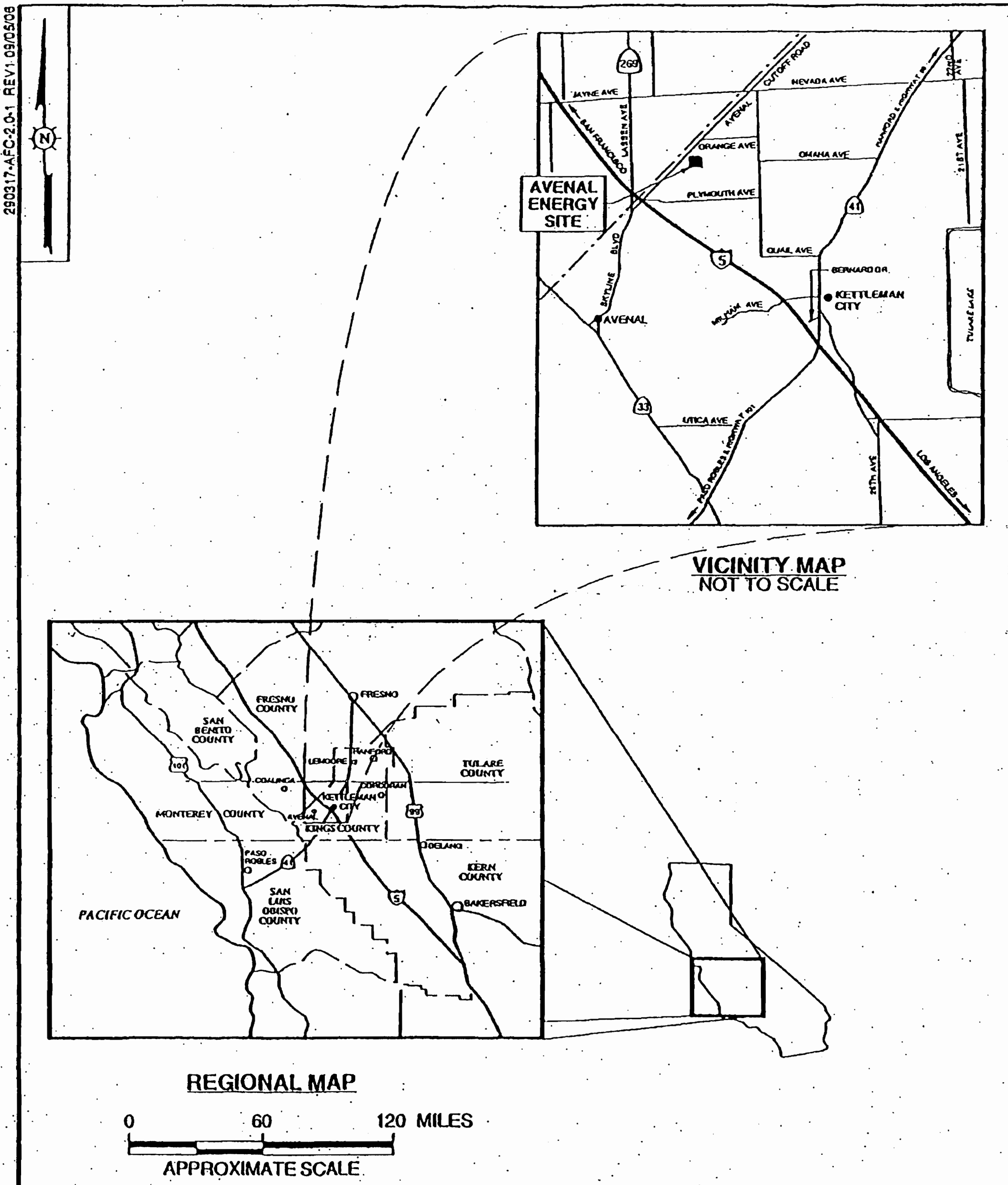
ATTACHMENT B

Project Location and Site Plan

ATTACHMENT C

CTG Commissioning Period Emissions Data

290317-AFC-2.0-1 REV1 09/05/08

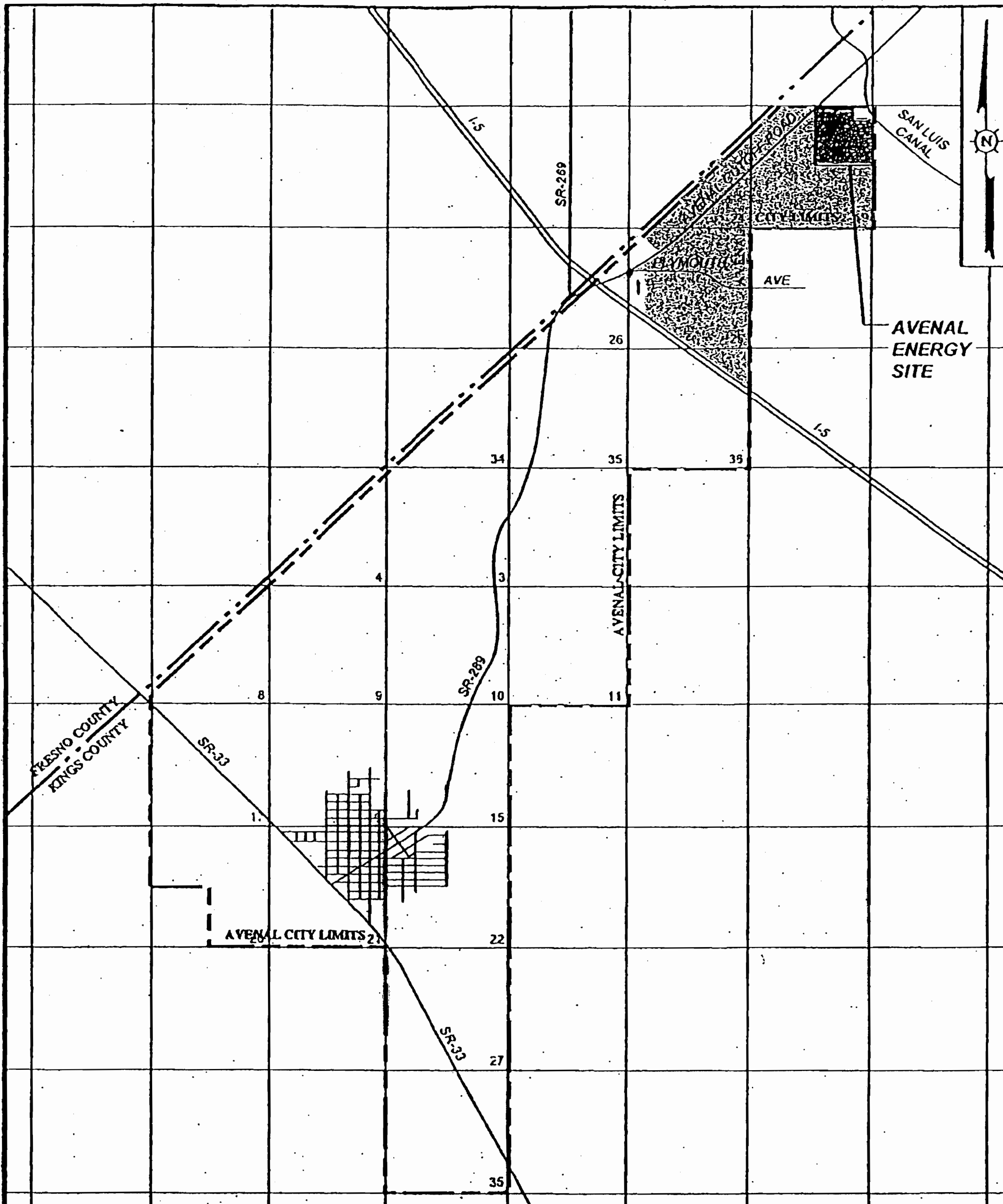


REGIONAL LOCATION MAP

FEDERAL ENERGY AVENAL, LLC

AVENAL ENERGY	FIGURE 2.0-1

280317-AFC-2.0-2 REV.09/13/01



LEGEND

INDUSTRIAL ZONE (CITY OF AVENAL GENERAL PLAN AND ZONING ORDINANCE)

0 6,000 12,000 FEET

SCALE

REFERENCE: CITY OF AVENAL GENERAL PLAN.

1 36.074 -120.093

AV

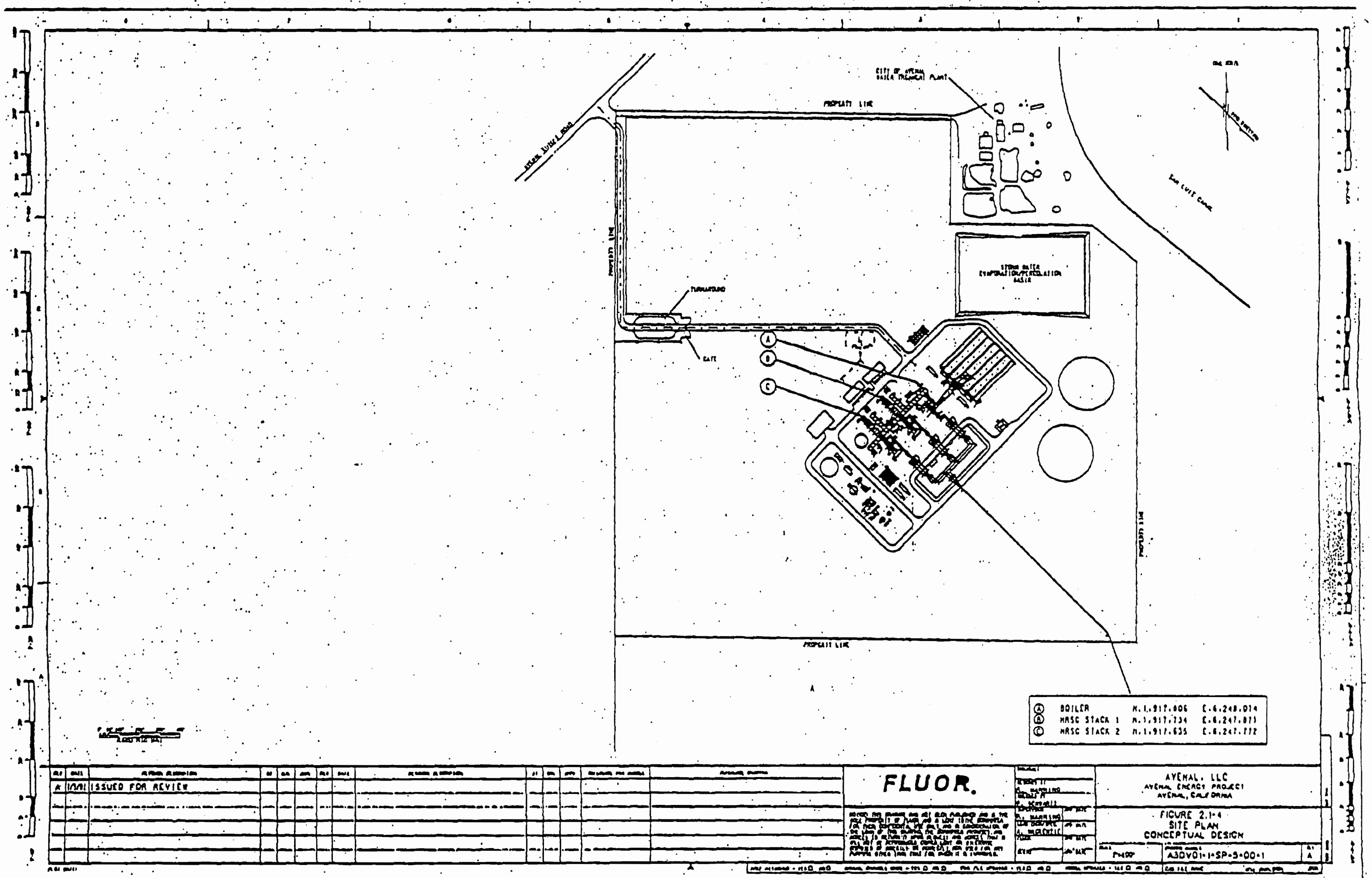
SITE LOCATION

② Rd crosses horiz rd near development

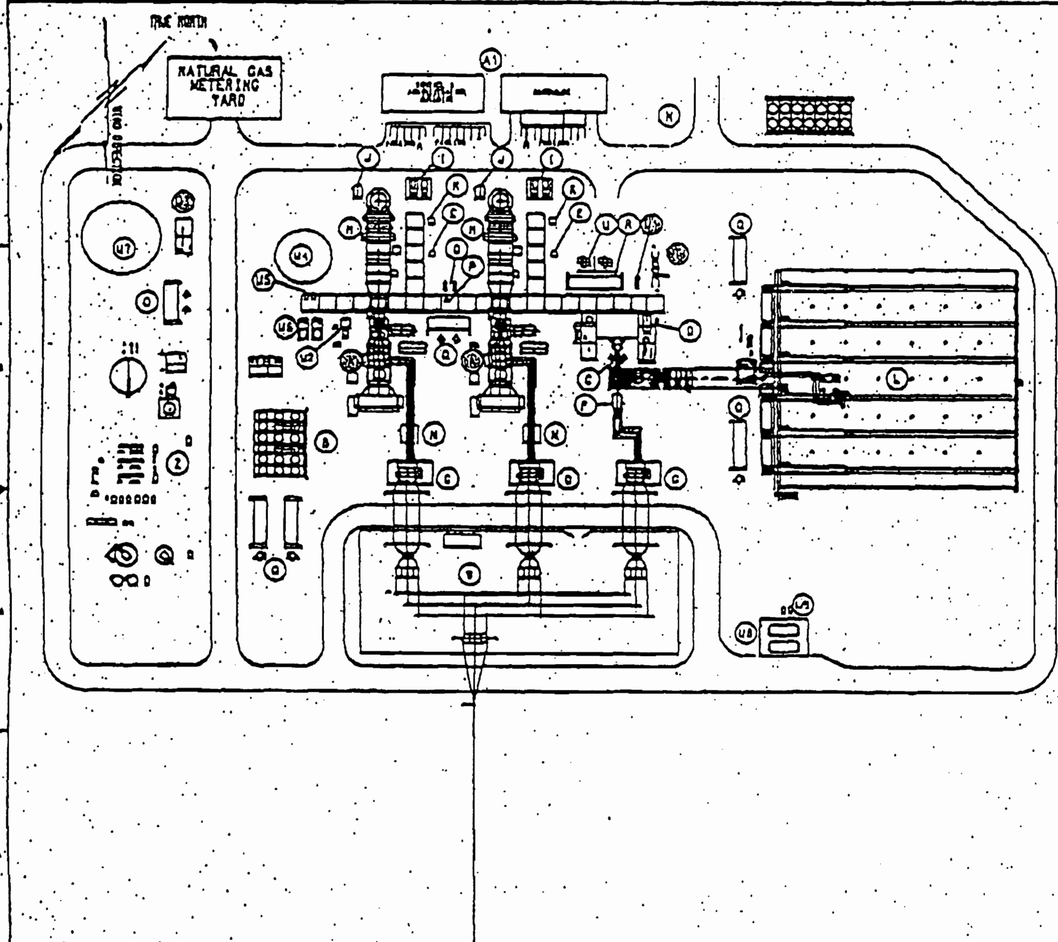
36.109 -120.0486

FEDERAL POWER AVENAL, LLC

AVENAL ENERGY	**FIGURE 2.0-2**



PROPERTY LINE
TURNAROUND
GATE
STORM WATER EVAPORATION/PERCOLATION BASIN
(A) BOILER N.1,917,806 E.6,248,014
(B) HRSC STACK 1 N.1,917,734 E.6,247,873
(C) HRSC STACK 2 N.1,917,635 E.6,247,772
A 1/99 ISSUED FOR REVIEW
FLUOR.
AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA
FIGURE 2.1-4
SITE PLAN
CONCEPTUAL DESIGN
A3DV01-1-SP-5-00-1



MAJOR EQUIPMENT LIST

A GAS TURBINE GENERATOR
B INLET AIR CHILLERS
C STEAM TURBINE
D STG LUBE OIL SKID
E HRSG BLOW DOWN DRUM
F STG GENERATOR
G MAIN TRANSFORMERS
H HEAT RECOVERY STEAM GENERATOR
I HP/IP BOILER FEED WATER PUMPS
J CONTINUOUS EMISSIONS MONITORING SYSTEM
K HRSG BLOWDOWN SUMP
L AIR COOLED CONDENSER
M GENERATOR BREAKERS
N CLOSED COOLING WATER AIR COOLER
O CIRCULATING COOLING WATER PUMPS
P CLOSED COOLING WATER EXPANSION TANK
Q POWER DISTRIBUTION CENTER (480 V)
R POWER DISTRIBUTION CENTER (4160 V)
S
T AUXILIARY BOILER
U UNIT AUXILIARY TRANSFORMER
V
W SWITCHYARD
X RAW WATER SOFTENER CLARIFIERS (RWSC)
Y RWSC FILTER PRESS
Z ZERO LIQUID DISCHARGE FACILITY (ZLDF)

A1 SEPTIC TANK & LEACH FIELD (IMMEDIATELY NW)
A2 STORM WATER EVAPORATION/PERCOLATION BASIN

UTILITIES

U1 STANDBY DIESEL GENERATOR
U2 OIL/WATER SEPARATOR
U3 FIREWATER PUMP HOUSE
U4 DEMINERALIZED WATER STORAGE TANK
U5 DEMINERALIZED WATER PUMPS
U6 PLANT/INSTRUMENT AIR COMPRESSORS
U7 RAW WATER/FIREWATER STORAGE TANKS
U8 AMMONIA STORAGE TANKS
U9 AMMONIA TRANSFER PUMPS

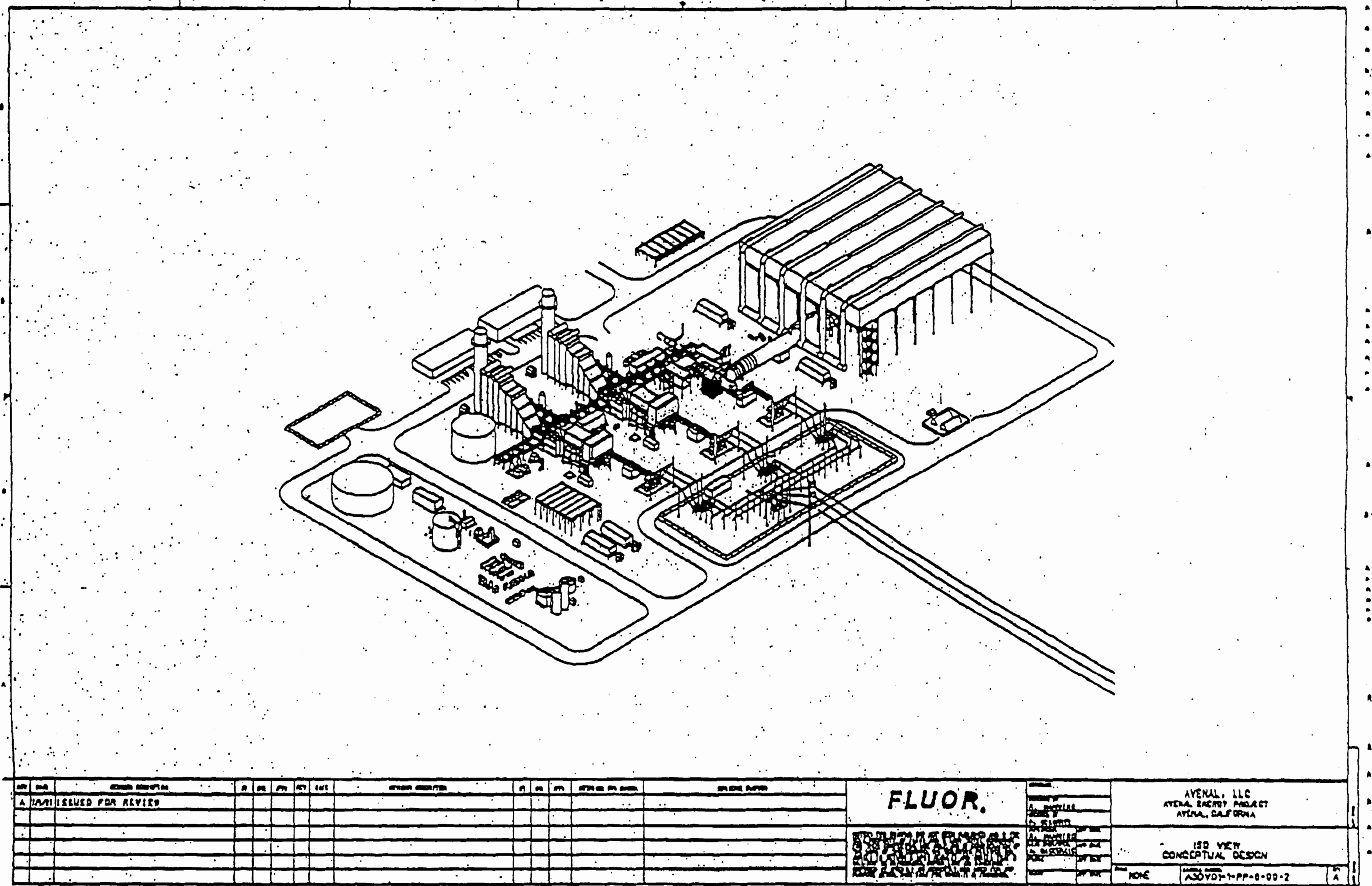
A	7/1/01	ISSUED FOR REVIEW

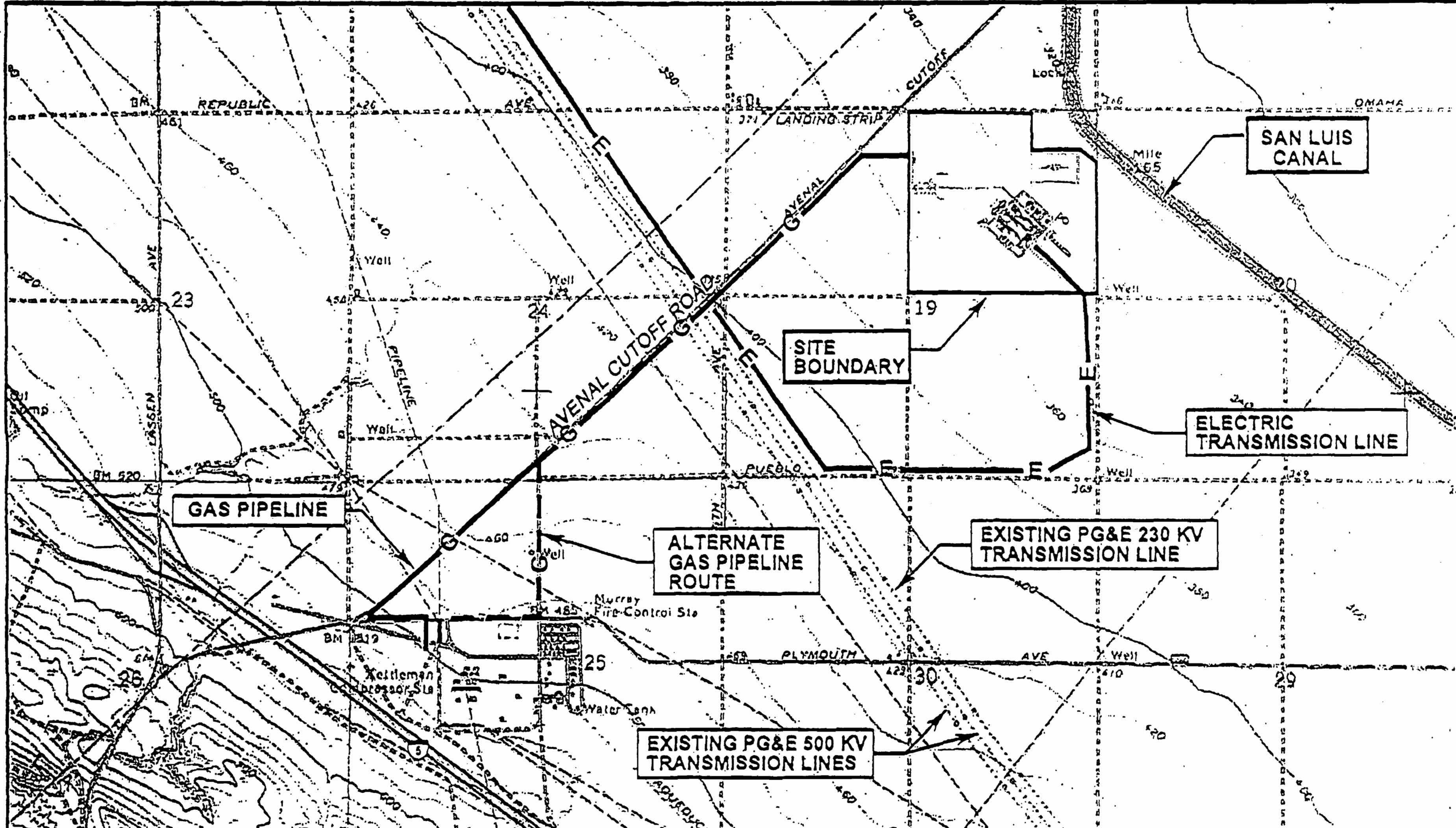
FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

FIGURE 2.3-3
PLOT PLAN
CONCEPTUAL DESIGN

F-126' A3OY01-1-PP-G-00-1 A


A
ISSUED FOR REVIEW
FLUOR.
AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA
ISO VIEW
CONCEPTUAL DESIGN
NONE
A30Y01-1-PP-0-00-2
A



REFERENCE:
U.S.G.S 7.5 MINUTE TOPOGRAPHIC SERIES MAP OF LA CIMA, CALIFORNIA, DATED 1978.

0 2,000 4,000 FEET
SCALE

NATURAL GAS AND ELECTRICAL INTERCONNECTION ROUTES

FEDERAL POWER AVENAL LLC

AVENAL ENERGY | FIGURE 2.1-1A

ATTACHMENT D

CTG Emissions Data

The maximum heat input rates (fuel consumption rates) for the gas turbines, duct burners, and auxiliary boiler are shown in Table 6.2-22.

TABLE 6.2-22
MAXIMUM FACILITY FUEL USE, MMBTU (HHV)

Period	Gas Turbines and Duct Burners (each[a])	Auxiliary Boiler	Total Fuel Use (all Units)
Per Hour	2,356.5	37.4	4,750
Per Day	56,555[b]	449[c]	113,111[d]
Per Year	16,176,000[e]	46,650[f]	32,353,000[g]

Notes:
[a] Each of two trains.
[b] Based on 24 hours per day of duct firing.
[c] Based on a startup day, during which the auxiliary boiler would be used 12 hours.
[d] The maximum facility fuel use day, during which the turbines run 24 hours with duct firing, has no use of the auxiliary boiler (i.e., no startup).
[e] Based on maximum fuel use of 7,960 hours per year without duct firing, and 800 hours per year with duct firing, per turbine.
[f] Based on 1,248 hours of operation per year.
[g] Based on baseload scenario (see Footnote d) that includes no operation of the auxiliary boiler.

CTG Emissions During Startup and Shutdown

Maximum emission rates expected to occur during a startup or shutdown are shown in Table 6.2-23. PM_{10} and SO_2 emissions have not been included in this table because emissions of these pollutants depend on fuel flow, which will be lower during a startup period than during baseload facility operation.

TABLE 6.2-23
FACILITY STARTUP/SHUTDOWN EMISSION RATES[a]

	NOx	CO	VOC
Startup/Shutdown, lb/hour, average	80	900	16
Startup/Shutdown, lb/~~start,~~ hour maximum	160	1,000	16

[a] Estimated based on vendor data and source test data. See Appendix 6.2-1, Table 6.2-1.6 and -1.7.

The analysis of maximum facility emissions of each criteria pollutant was based on the turbine/HRSG and auxiliary boiler emission factors shown in Tables 6.2-19, 6.2-20, and 6.2-21; the startup emission rates shown in Table 6.2-23; the three operating scenarios described above, and the ambient conditions that result in the highest emission rates. The maximum annual, daily, and hourly emissions of each criteria pollutant for the Project are shown in Table 6.2-24 and are based on the following operating conditions and scenario parameters:

CTG Emissions During Commissioning

Gas turbine commissioning is the process of initial startup, tuning and adjustment of the new CTGs and auxiliary equipment and of the emission control systems. The commissioning process consists of sequential test operation of each of the two gas turbines up through increasing load levels, and with successive application of the air pollution control systems. The total set of commissioning tests will require approximately 410 operating hours for each CTG. With the planned sequential testing of the two gas turbines, the overall length of the commissioning period would be approximately 3 months. Commissioning of the proposed project may be phased into two commissioning periods each approximately 1.5 months long.

There are several commissioning modes. The first is the period prior to SCR system installation, when the combustor is being tuned. During this mode, the NO_x emissions control system would not be functioning and the combustor would not be tuned for optimum performance. CO emissions would also be affected because combustor performance would not yet be optimized. The second emissions scenario will occur when the combustor has been tuned but the SCR installation is not complete, and other parts of the gas turbine operating system are being checked out. Because the combustor would be tuned but the emission control system installation would not be complete, NO_x and CO levels could again be affected.

Noncriteria Pollutant Emissions

Noncriteria pollutants are compounds that have been identified as pollutants that pose a potential health hazard. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[24] In addition to these nine compounds, the federal Clean Air Act listed 187 to 189[25] substances at different times as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The State of California defined a set of toxic air contaminants through Assembly Bill (AB) 2588, the Air Toxics "Hot Spots" Information and Assessment Act. The SJVAPCD published a list of compounds it defined as potential toxic air contaminants in its May 1991 Toxics Policy. Any pollutant that may be emitted from the Project and is on the federal New Source Review list, the federal Clean Air Act list, the AB2588 list or

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[24] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission.
[25] Currently 187 substances are listed.

ATTACHMENT D

CTG Emissions Data

Table 8.2-1.1
Emissions and Operating Parameters for New Turbines
Avenal Energy Project

	Case 1 101°F Full Load w/ DB[1]	Case 5 63°F Full Load w/ DB[1]	Case 9 32°F Full Load w/ DB[1]	Case 2 101°F Full Load no DB	Case 6 63°F Full Load no DB	Case 10 32°F Full Load no DB	Case 4 101°F 50% Load	Case 8 63°F 50% Load	Case 12 32°F 50% Load
Ambient Temp, °F	101	63	32	101	63	32	101	63	32
GT Load, %	100%	100%	100%	100%	100%	100%	50%	50%	50%
Both GTs Gross Power, MW	344.8	345.0	359.0	345.5	345.6	359.5	144.1	168.6	183.2
STG Gross Power, MW	290.8	273.3	254.7	171.6	176.1	177.7	118.3	127.6	130.6
Plant Gross Power Output, MW	635.6	618.3	613.7	517.2	521.7	537.2	262.5	296.2	313.9
Plant Net Power Output, MW	600.0	600.0	600.0	483.7	506.5	525.5	250.3	286.3	304.8
GTs Fuel Flow, kpph	156.4	156.4	161.8	156.4	156.4	161.8	87.2	96.2	102.2
DBs Fuel Flow, kpph	49.0	39.8	31.0	0.0	0.0	0.0	0.0	0.0	0.0
GTs Heat Input, MMBtu/hr (HHV)	1,794.2	1,794.3	1,855.4	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
DBs Heat Input, MMBtu/hr (HHV)	562.3	454.4	356.3	0.0	0.0	0.0	0.0	0.0	0.0
Total Heat Input, MMBtu/hr (HHV)	2,356.5	2,248.6	2,211.8	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
Stack Flow, lb/hr	3,653,000	3,650,000	3,759,000	3,628,000	3,630,000	3,743,000	2,232,700	2,336,800	2,413,300
Stack Flow, acfm	1,044,365	1,025,495	1,069,836	1,051,631	1,037,822	1,071,653	620,528	644,316	666,146
Stack Temp, °F	195.3	184.9	189.0	207.4	198.8	200.9	180.2	175.8	177.4
Stack exhaust, vol%									
O_2 (dry)	11.40%	11.87%	12.34%	13.76%	13.77%	13.78%	14.46%	14.11%	13.93%
CO_2 (dry)	5.42%	5.16%	4.89%	4.09%	4.08%	4.06%	3.70%	3.89%	3.89%
H_2O	10.54%	10.03%	9.12%	8.39%	8.28%	7.78%	8.07%	7.97%	7.63%
Emissions									
NO_x, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NO_x, lb/hr[4]	17.13	16.34	16.06	13.03	13.03	13.47	7.26	8.01	8.51
NO_x, lb/MMBtu (HHV)	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
SO_2, ppmvd @ 15% O_2 [3]	0.139	0.139	0.140	0.140	0.140	0.140	0.140	0.140	0.140
SO_2, lb/hr[2,3]	1.66	1.59	1.56	1.27	1.27	1.31	0.71	0.78	0.83
SO_2, lb/MMBtu (HHV)[3]	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
CO, ppmvd @ 15% O_2	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
CO, lb/hr[2]	20.88	19.90	19.56	15.86	15.88	16.39	8.84	9.75	10.36
CO, lb/MMBtu (HHV)	0.0089	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088
VOC, ppmvd @ 15% O_2[4]	2.0	2.0	2.0	1.4	1.4	1.4	1.4	1.4	1.4
VOC, lb/hr[2,4]	5.98	5.68	5.59	3.17	3.17	3.28	1.77	1.95	2.07
VOC, lb/MMBtu (HHV)[4]	0.0025	0.0025	0.0025	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018
PM_{10}, lb/hr[2,5]	11.81	11.27	10.78	9.00	9.00	9.00	9.00	9.00	9.00
PM_{10}, lb/MMBtu (HHV)[5]	0.0050	0.0050	0.0049	0.0050	0.0050	0.0048	0.0090	0.0081	0.0077
PM_{10}, gr/SCF (dry)[5]	0.00189	0.00179	0.00165	0.00142	0.00142	0.00137	0.00230	0.00220	0.00212
NH_3, ppmvd @ 15% O_2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
NH_3, lb/hr[2]	35.39	33.57	32.88	26.28	26.25	26.98	14.60	16.08	17.02
CO_2, lb/MMBtu (HHV)[7]	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
CH_4, lb/MMBtu (HHV)[8]	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
N_2O, lb/MMBtu (HHV)[8]	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022
CO_2, lb/hr[9]	275,599	262,984	258,674	210,000	209,976	217,102	117,114	129,153	137,055
CH_4, lb/hr[9]	30.7	29.2	28.8	23.4	23.4	24.1	13.0	14.4	15.2
N_2O, lb/hr[9]	0.52	0.50	0.49	0.40	0.40	0.41	0.22	0.24	0.26

1) Includes duct burner firing only up to plant maximum output of 600 MW.

2) All mass flow values reported are on a per stack basis. Plant total mass flows are double these values.

3) All of the assumed 0.25 gr S in 100 scf of the fuel is assumed to be converted to SO_2 with no SO_3 conversion.

4) Based on an assumption that 20% of reported UHC emissions are VOCs.

5) Includes front-half (filterable) portion only. Back-half (condensible) portion is excluded.

6) CH_4 emission factor (kg/MMBtu) = 0.0059

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.

7) CO_2 emission factor (kg/MMBtu) = 53.06

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Carbon Dioxide Emission Factors and Oxidation Rates for Stationary Combustion, August 10, 2007.

8) N_2O emission factor (kg/MMBtu) = 0.0001

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.

ATTACHMENT E

SJVAPCD BACT Guidelines 1.1.2, 3.1.4, 3.1.8, and 3.4.2

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 1.1.2*

Last Update: 3/14/2002

Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings.**

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	Natural gas fuel with LPG backup		
NOx	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Ultra-Low NOx main burner system burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire).	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NOx@ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire).	
PM10	Natural gas fuel with LPG backup		
SO	Natural gas fuel with LPG backup		
VOC	Natural gas fuel with LPG backup		

** For the purpose of this determination, "small load swings" are defined as normal operational load fluctuations which are within the operational response range of an Ultra-Low NOx burner system(s).

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.4*

Last Update: 6/30/2001

Emergency Diesel I.C. Engine Driving a Fire Pump

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO		Oxidation Catalyst	
NOx	Certified NOx emissions of 6.9 g/bhp-hr or less		
PM10	0.1 grams/bhp-hr (if TBACT is triggered) (corrected 7/16/01) 0.4 grams/bhp-hr (if TBACT is not triggered)		
SOx	Low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-sulfur diesel fuel (15 ppmw sulfur or less), where available.		
VOC	Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]	Catalytic Oxidation	

1. Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 grams/bhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 grams/bhp-hr requirement.
2. A site-specific Health Risk Analysis is used to determine if TBACT is triggered. (Clarification added 05/07/01)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.8*

Last Update: 4/4/2002

Emergency Gas-Fired IC Engine - > or = 250 hp, Lean Burn

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	= or < 2.75 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	> or = 80% control efficiency (Rich-burn engine with NSCR, or equal)
NOx	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)		= or > 90% control efficiency (Rich-burn engine with NSCR, or equal)
PM10	Natural gas fuel		
VOC	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	= or > 50% control efficiency (Rich-burn engine with NSCR, or equal)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.2*

Last Update: 10/1/2002

Gas Turbine - = or > 50 MW, Uniform Load, with Heat Recovery

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	4.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	
NOx	2.5 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	2.0 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	
PM10	Air inlet filter cooler, lube oil vent coalescer and natural gas fuel, or equal		
SOx	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more that 0.75 grams S/100 dscf, or equal.		
VOC	2.0 ppmv @ 15% O2	1.5 ppmv @ 15% O2	

** Applicability lowered to > 50 MW pursuant to CARB Guidance for Permitting Electrical Generation Technologies. Change effective 10/1/02. Corrected error in applicability to read 50 MW not 50 MMBtu/hr effective 4/1/03.

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

ATTACHMENT F

Top Down BACT Analysis (C-3953-10-1, -11-1, -12-1, -13-1, and –14-1)

Units C-3953-10-1 and –11-1 (Turbines)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)
2. 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing the use of a selective catalytic reduction system with NO_X emissions of 2.0 ppmv @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of a Selective Catalytic Reduction system with emissions of less than or equal to 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). The facility has proposed to use an inlet air filtration and cooling system, water injection, and a Selective Catalytic Reduction system on each of these turbines to achieve NO_X emissions of less than or equal to 2.0 ppmv @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). Therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.0 ppmvd VOC @ 15% O_2

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 1.5 ppmvd VOC @ 15% O_2

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 1.5 ppmvd VOC @ 15% O_2
2. 2.0 ppmvd VOC @ 15% O_2

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing VOC emissions of 1.4 ppmvd @ 15% O_2 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O_2 when it is fired with the duct burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O_2 did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O_2 emission factor will be determine to meet the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel or LPG with emissions of less than or equal to 2.0 ppmv @ 15% O_2. The facility has proposed to use natural gas fuel with emissions of less than or equal to 2.0 ppmv @ 15% O_2; therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

III. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM_{10} emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use an air in inlet filter, lube oil vent coalescer and natural gas fuel or equal. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of an air inlet filter, lube oil vent coalescer and natural gas fuel or equal. Avenal Power Center is proposing to use an air inlet filter, lube oil vent coalescer and natural gas fuel or equal; therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

IV. SO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- PUC-regulated natural gas fuel; or
- Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PUC-regulated natural gas fuel
2. Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use PUC-regulated natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of PUC-regulated natural gas fuel. Avenal Power Center has proposed to fire each of the turbines solely on PUC-regulated natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies technologically feasible BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)
2. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NOx emissions from the boiler will not exceed 9.0 ppmv @ 3% O_2. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be NO_X emissions of less than 9.0 ppmvd @ 3% O_2. The facility has proposed NO_X emissions of less than 9.0 ppmv @ 3% O_2. Therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for VOC emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

III. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM_{10} emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-13-1 (Diesel IC engine powering fire water pump)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Certified NO_X emissions of 6.9 g/bhp-hr or less

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. Certified NO_X emissions of 6.9 g/bhp-hr or less

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NOx emissions from the engine will not exceed 3.4 g/bhp-hr. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be Certified NO_X emissions of 6.9 g/bhp-hr or less. The facility has proposed NO_X emissions of less than 6.9 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-13-1 (Diesel IC engine powering fire water pump)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies technologically feasible BACT as the following:

- Catalytic Oxidation

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. Catalytic Oxidation
2. Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

However, this engine has been UL Certified, and the UL certification does not include a catalytic oxidation system or a positive crankcase ventilation system, and the addition of a catalytic oxidation system or a positive crankcase ventilation system would void the UL certification, which is required for firewater pump engines. Therefore, both the catalytic oxidation system and the positive crankcase ventilation system options will not be required.

Step 5 - Select BACT

BACT for VOC emissions from this emergency diesel IC engine powering a firewater pump is having no control technology for VOC emissions. The applicant has proposed to install a 288 bhp emergency diesel IC engine powering a firewater pump with no control technology for VOC emissions; therefore BACT for VOC emissions is satisfied.

Units C-3953-14-1 (Natural gas IC engine powering electrical generator)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 90% control efficiency (rich-burn engine with NSCR or equal)

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. ≥ 90% control efficiency (rich-burn engine with NSCR or equal)
2. NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

1. ≥ 90% control efficiency (rich-burn engine with NSCR or equal)

District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for NO_X reduction is $9,700 per ton of NO_X reduced.

Based upon the fact that there are only a few existing IC engine installations within this class and category of source that operate with emissions of ≤ 1.0 g NO_X/hp-hr, the District will assume that the Industry Standard will be 2.8 g NO_X/hp-hr (lb/MMBtu converted to g/hp-hr, Attachment I), pursuant to a AP-42 (07/00) values of uncontrolled four-stroke lean burn IC engines (< 90% load).

AP-42 publishes an uncontrolled NO_X value of 2.21 lb/MMBtu (90 – 105% load), which is approximately 13.4 g NO_X/hp-hr. Several major engine manufacturers were surveyed (Cummins, Caterpillar, and Waukesha) and the District found that lean burn engines sold by these engine manufacturers do not emit emissions close to the uncontrolled value for 90 – 105% load, published in AP-42. Based on the discussions with service representatives of each engine manufacturer, emissions were closer to the AP-42 value published for the < 90% load, which was around 2.5 g NO_X/hp-hr than it was for the value published for the 90 – 105% load. Therefore, industry standard for lean burn natural gas-fired emergency IC engine will be 2.8 g NO_X/hp-hr.

The proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>NO_X (annual):</u>

$$\begin{array}{c|c|c|c}
2.8\ \cancel{g} & 860\ \cancel{hp} & lb & 50\ \cancel{hr} \\
\hline
\cancel{hp\text{-}hr} & 1 & 453.6\ \cancel{g} & year
\end{array} = 265\ lb\ NO_X/year$$

PE_{NOx} = 265 lb NO_X/year = 0.1325 tons NO_X/year

The proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a NO_X control efficiency of ≥ 90% can be calculated as:

<u>NO_X (annual):</u>

$$\begin{array}{c|c|c|c|c}
7.4\ \cancel{g}^{(1)} & (1 - 0.9) & 860\ \cancel{hp} & lb & 50\ \cancel{hr} \\
\hline
\cancel{hp\text{-}hr} & 1 & 1 & 453.6\ \cancel{g} & year
\end{array} = 70\ lb\ NO_X/year$$

PE_{NOx} = 70 lb NO_X/year = 0.035 tons NO_X/year

District BACT policy demonstrates how to calculate the cost effectiveness of alternate basic equipment or process:

$$CE_{alt} = (Cost_{alt} - Cost_{basic}) \div (Emission_{basic} - Emission_{alt})$$

[1] Pursuant to AP-42 (07/00) the NO_X value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)

where,

CE_{alt} = the cost effectiveness of alternate basic equipment expressed as dollars per ton of emissions reduced

$Cost_{alt}$ = the equivalent annual capital cost of the alternate basic equipment plus its annual operating cost

$Cost_{basic}$ = the equivalent annual capital cost of the proposed basic equipment, without BACT, plus its annual operating cost

$Emission_{basic}$ = the emissions from the proposed basic equipment, without BACT.

$Emission_{alt}$ = the emissions from the alternate basic equipment

The District conducted research to determine the appropriate cost information for installing a rich burn IC engine with a Non-Selective Catalytic Reduction System versus the cost information for installing a uncontrolled lean burn IC engine. Based on information from various engine manufacturers, the initial costs for installing an uncontrolled rich burn engine versus an uncontrolled lean burn engine would be minimal. The main difference in cost would be incurred in the installation of the NSCR system and the air to fuel ratio controller to the rich burn IC engine.

According to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" (pgs. V-2 & V-3), the approximate capital cost for installing a NSCR system for a 1,000 hp engine would be approximately $28,000, the capital cost for installing an air to fuel ratio controller would be $5,300, and the overall installation cost would be $2,500. The CARB RACT/BARCT document also states the annual cost for operating and maintenance is between $8,000 – 10,000, but these values are assuming full time operation. Since the proposed installation will be limited only to emergency operation and testing and maintenance, a conservative assumption of $1,000 per year will be utilized for this evaluation.

Per District BACT Policy, the equivalent annual capital cost is calculated as follows:

$$A\ (\$/yr) = P \times [i \times (1 + i)^n] \div [(1 + i)^n - 1]$$

Where:
A = Equivalent annual capital cost of the control equipment
P = Present value of the control equipment including installation
i = interest rate (10% used as default value)
n = equipment life (10 years used as default value)

Using a total capital cost of $35,800 in the above equation results in an equivalent annual cost of $5,826/year. Adding this equivalent annual cost to the annual operating cost of $1,000/year, the ($Cost_{alt}$ - $Cost_{basic}$) is equal to $6,826/year. It should be noted that the operating the rich burn IC engine versus a lean burn IC engine would result in an efficiency loss and would potentially result in higher annual fuel expenses. These costs will be set aside for the present and only a partial cost analysis will be performed.

District BACT policy also requires the use of a Multi-Pollutant Cost Effectiveness Threshold (MCET) for a BACT option controlling more than one pollutant. The installation of a NSCR system will control NO_X, CO, and VOC emissions. Therefore, the MCET is calculated as follows:

$$MCET\ (\$/yr) = (E_{NOx} \times T_{NOx}) + (E_{CO} \times T_{CO}) + (E_{VOC} \times T_{VOC})$$

Where:
E_{NOx} = tons-NO_X controlled/yr
E_{CO} = tons-CO controlled/yr
E_{VOC} = tons-VOC controlled/yr
T_{NOx} = District's cost effectiveness threshold for NO_X
= \$9,700/ton-NO_X
T_{CO} = District's cost effectiveness threshold for CO
= \$300/ton-CO
T_{VOC} = District's cost effectiveness threshold for VOCs
= \$5,000/ton-VOCs

Since this BACT cost effectiveness analysis is analyzing alternate basic equipment with a control technology which controls multiple pollutants; in order to calculate the cost effectiveness for the alternate basic equipment, the District will take the MCET and compare that value with the ($Cost_{alt} - Cost_{basic}$), to determine if this control technology is cost effective.

To determine E_{CO}, the District has to establish what Industry Standard is for CO emissions. As detailed above, engines with NO_X emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for CO emissions @ < 90% load (1.83 g CO/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>CO (annual):</u>

$$\frac{1.83\ \cancel{g}}{\cancel{hp\text{-}hr}} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 173\ lb\ CO/year$$

PE_{CO} = 173 lb CO/year = 0.0865 ton CO/year

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB (pg. B-20), the CO control effectiveness from a NSCR system is greater than 80%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a CO control efficiency of ≥ 80% can be calculated as:

CO (annual):

$$\frac{11.6\ \cancel{g}^{(2)}}{\cancel{hp\text{-}hr}} \left| \frac{(1-0.8)}{1} \right| \frac{860\ \cancel{hp}}{1} \left| \frac{lb}{453.6\ \cancel{g}} \right| \frac{50\ \cancel{hr}}{year} = 220\ lb\ CO/year$$

PE_{CO} = 220 lb CO/year = 0.11 ton CO/year

As demonstrated above, the CO emissions from the rich burn IC engine with a NSCR system are higher than the uncontrolled CO emissions from the lean burn IC engine. Therefore, CO will not be included in the MCET calculations.

To determine E_{VOC}, the District has to establish what Industry Standard is for VOC emissions. Again, as detailed above, engines with NO_X emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for VOC emissions (0.39 g VOC/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

VOC (annual):

$$\frac{0.39\ \cancel{g}}{\cancel{hp\text{-}hr}} \left| \frac{860\ \cancel{hp}}{1} \right| \frac{lb}{453.6\ \cancel{g}} \left| \frac{50\ \cancel{hr}}{year} \right. = 37\ lb\ VOC/year$$

PE_{VOC} = 37 lb VOC/year = 0.0185 ton VOC/year

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB, the VOC control effectiveness from a NSCR system is greater than 50%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a VOC control efficiency of ≥ 50% can be calculated as:

VOC (annual):

$$\frac{0.10\ \cancel{g}^{(3)}}{\cancel{hp\text{-}hr}} \left| \frac{(1-0.5)}{1} \right| \frac{860\ \cancel{hp}}{1} \left| \frac{lb}{453.6\ \cancel{g}} \right| \frac{50\ \cancel{hr}}{year} = 5\ lb\ VOC/year$$

PE_{VOC} = 5 lb VOC/year = 0.0025 ton VOC/year

[2] Pursuant to AP-42 (07/00) the CO value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)

[3] Pursuant to AP-42 (07/00) the VOC value for uncontrolled four-stroke rich burn IC engines. (lb/MMBtu converted to g/hp-hr, Attachment I)

Calculating for the MCET derives the following:

E_{NOx} = 0.1325 tpy – 0.035 tpy = 0.0975 tpy
E_{VOC} = 0.0185 tpy – 0.0025 tpy = 0.016 tpy

MCET (\$/yr) = (0.0975 x \$9,700) + (0.016 x \$5,000) = \$1,026/year

As presented above, ($Cost_{alt}$ – $Cost_{basic}$) is equal to \$6,826/year.

This value is greater than the MCET; therefore, it has been determine that the installation of a rich burn IC engine with a NSCR system as alternate basic equipment is not cost effective using just the partial cost analysis.

2. NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

The applicant has proposed that the NOx emissions from the engine will not exceed 1.0 g/bhp-hr. This is the highest ranking remaining control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - <u>Select BACT</u>

BACT for the emission unit is determined to be NO_X emissions of 1.0 g/bhp-hr or less. The facility has proposed NO_X emissions of less than 1.0 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-14-1 (Natural gas IC engine powering electrical generator)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies technologically feasible BACT as the following:

- 90% control efficiency (Oxidation catalyst, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. 90% control efficiency (Oxidation catalyst, or equal)
2. ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)
3. ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the engine will be equipped with an oxidation catalyst with 90% control of VOC emissions. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the used of an oxidation catalyst with 90% control of VOC emissions. The facility has proposed to install an oxidation catalyst with 90% control of VOC emission. Therefore, BACT is satisfied.

ATTACHMENT G

Health Risk Assessment and Ambient Air Quality Analysis

San Joaquin Valley Unified
Air Pollution Control District

MEMORANDUM

DATE: June 14, 2014

TO: Derek Fukuda, AQE—Permit Services

FROM: Leland Villalvazo, SAQS—Technical Services

SUBJECT: Revised NO_2 1-hour NAAQA Assessment for Avenal Power Center

Technical Services was requested to revise the RMR and AAQA assessment performed for project C-1011324, dated June 25, 2002, to lower the NOx and CO annual emission levels.

A review of the previous project indicated that the major item of concern was the 1-hour standard for NO_2. The previous assessment was based on the State standard of 339 ug/m^3 whereas the new federal standard 188.68 ug/m^3. The assessment contained in this memo will primarily address the new federal NO_2 NAAQS and any updates needed to the previous RMR assessment.

Background:
EPA has revised the primary NO_2 NAAQS in order to provide requisite protection of public health. Specifically, EPA has established a new 1-hour standard at a level of 100 ppb (188.68 ug/m^3), based on the 3-year average of the annual 98th percentile of the daily maximum 1-hour concentrations, to supplement the existing annual standard. EPA has also established requirements for NO_2 monitoring network that will include monitors at locations where maximum NO_2 concentrations are expected to occur, including within 50 meters of major roadways, as well as monitors sited to measure the area-wide NO_2 concentrations that occur more broadly across communities.

The final rule was signed on January 22, 2010. The effective date of the new 1 hour standard is 60 days after the final rule has been published in the Federal Register. The final rule was published in the Federal Register on Feb 9, 2010. The effective date is April 12, 2010.

Results:
Based on guidance from EPA dated February 25, 2010, the District has updated the AAQA assessment to include the new NO_2 1-hour standard, see below. The results follow the procedure outlined in the District's interim draft guidance document entitled "Modeling Procedure to Address The New Federal 1 Hour NO_2 Standard".

Commissioning	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**142.21**	**103.15**	245.36	188.68	F	-56.68
Tier II (max 8th)	**90.10**	**103.15**	193.25	188.68	F	-4.57
Tier III (ave.5yr)	**71.94**	**103.15**	175.09	188.68	**P**	13.58
Tier IV	**140.37**		140.37	188.68	**P**	48.31

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**142.21398**	**107.17307**	**110.4651**	**109.99858**	**105.1162**	**142.21**
Tier II (max 8th)	**80.85338**	**85.86045**	**84.64008**	**88.85226**	**90.10016**	**90.1**

*Ozone from Visalia

Operational	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**152.79**	**103.15**	255.94	188.68	F	-67.26
Tier II (max 8th)	**87.94**	**103.15**	191.09	188.68	F	-2.41
Tier III (ave.5yr)	**82.43**	**103.15**	185.58	188.68	**P**	3.10
Tier IV			0.00	188.68	P	188.68

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**152.79148**	**91.1532**	**93.47387**	**93.23991**	**90.56206**	**152.79**
Tier II (max 8th)	**87.7931**	**86.3495**	**86.51813**	**87.38902**	**87.93997**	**87.94**

*Ozone from Visalia

Conclusion

Based on the updated RMR, the risk from this facility is less than 10 in one million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed below must be included for the proposed unit(s).

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

Conditions

1. PM_{10} emission rate shall not exceed **0.059 g/HP-hr (note method) for the 288 hp engine** (C-3953-13-1).

2. The 860 hp engine (C-3953-14-1) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **50 hours per year**.

Commissioning	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**142.21**	**103.15**	245.36	188.68	F	-56.68
Tier II (max 8th)	**90.10**	**103.15**	193.25	188.68	F	-4.57
Tier III (ave.5yr)	**71.94**	**103.15**	175.09	188.68	P	13.58
Tier IV	**140.37**		140.37	188.68	P	48.31

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**142.21398**	**107.17307**	**110.4651**	**109.99858**	**105.1162**	**142.21**
Tier II (max 8th)	**80.85338**	**85.86045**	**84.64008**	**88.85226**	**90.10016**	**90.1**

*Ozone from Visalia

Operational	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**152.79**	**103.15**	255.94	188.68	F	-67.26
Tier II (max 8th)	**87.94**	**103.15**	191.09	188.68	F	-2.41
Tier III (ave.5yr)	**82.43**	**103.15**	185.58	188.68	P	3.10
Tier IV			0.00	188.68	P	188.68

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**152.79148**	**91.1532**	**93.47387**	**93.23991**	**90.56206**	**152.79**
Tier II (max 8th)	**87.7931**	**86.3495**	**86.51813**	**87.38902**	**87.93997**	**87.94**

*Ozone from Visalia

Diesel I.C. Engines (DICE)
Screening Risk Tool

Project Information

Region	C
Facility ID:	3953
Unit #:	13-1
Project #:	110751
Date:	7/14/2010

Met Station

District	SJVAPCD
Met Site	HANFORD
Model Type	RURAL
Year:	2008

Engine Data

BHP:	288
% Load:	100
PM10 EF (g/BHP):	0.059
Hours / Yr:	100
Lbs / Yr:	3.75

Convert to G/BHP

Convert to G/KW

Update Emissions

Receptor Data

Quad	QUAD 1
Distance(m)	50
Miles:	
Feet	
Yards:	
10th Mi:	

NW N NE

W Quad 4 Quad 1 E

Quad 3 Quad 2

SW S SE

Cancer Risk

Resident Risk: In a Million	0.24
Maximum Res. Risk	1.98
Worker Adjustment Factor %	37.91
Worker Risk: In a Million	0.09
Maximum Worker Risk	0.75
Quad:	2
Distance:	50

Calculate Risk

Print Form

New | View Eng Data | SAVE | Close Form

14-1

Print Worksheet

INTERNAL COMBUSTION (NG)
EMISSION FACTORS
(LBS. / MMCF)

FACILITY NAME:
DATE:

Receptor Distance: 1206

Priority Score: 0.092999134

Total hrs. of operation: 50.00

MMCF/HR: 0.0071

MMCF/YR: 0.36

POLLUTANT	EMISSION FACTOR (MMCF/HR) <1000	>1000	TURBINE	Acute REL	Chronic REL	Cancer URF
Acetaldehyde	0.944	1.1328	0.037	0	9	2.70E-06
Acrolein	0.3783	0.454	0.009	0.19	2.00E-02	0
Benzene	3.257	3.9084	0.0113	1300	71	2.90E-05
Formaldehyde	32.4963	38.9956	0.094	94	3.6	6.00E-06
Naphthalene	0.1785	0.1785	0.0008	0	14	0
PAH's	0.0179	0.0179	0.0002	0		1.70E-03
Propylene	16.2259	19.4711	1.0522	0	0	0
Toluene	1.1145	1.3374	0.0726	37000	200	0
Xylenes	0.4048	0.4858	0.0289	22000	300	0
Ethyl Benzene	0.3257	0.3908	0.0132	0	0	0
Hexane	0.7491	0.8989	1.75	0	0	0

	<1000 EMISSION FACTORS	LBS./HR.	G/SEC	LBS./YR.	G/SEC	Acute Score	Chronic Score	Carcinogenic Score	Non-Carcinogenic Score
Acetaldehyde	0.944	6.70E-03	**8.45E-04**	3.35E-01	**4.82E-06**	0	0.11170667	0.001538201	0.111706667
Acrolein	0.3783	2.69E-03	**3.39E-04**	1.34E-01	**1.93E-06**	21.204711	20.144475	0	21.20471053
Benzene	3.257	2.31E-02	**2.92E-03**	1.16E+00	**1.66E-05**	0.0266823	0.048855	0.057002386	0.048855
Formaldehyde	32.4963	2.31E-01	**2.91E-02**	1.15E+01	**1.66E-04**	3.6817616	9.61348875	0.117669102	9.61348875
Naphthalene	0.1785	1.27E-03	**1.60E-04**	6.34E-02	**9.12E-07**	0	0.01357875	0	0.01357875
PAH's	0.0179	1.27E-04	**1.60E-05**	6.35E-03	**9.15E-08**	0	0	0.018364505	0
Propylene	16.2259	1.15E-01	**1.45E-02**	5.76E+00	**8.29E-05**	0	0	0	0
Toluene	1.1145	7.91E-03	**9.98E-04**	3.96E-01	**5.70E-06**	0.0003208	0.00593471	0	0.005934713
Xylenes	0.4048	2.87E-03	**3.62E-04**	1.44E-01	**2.07E-06**	0.000196	0.00143704	0	0.00143704
Ethyl Benzene	0.3257	2.31E-03	**2.92E-04**	1.16E-01	**1.66E-06**	0	0	0	0
Hexane	0.7491	5.32E-03	**6.71E-04**	2.66E-01	**3.83E-06**	0	0	0	0

San Joaquin Valley Unified Air Pollution Control District

MEMORANDUM

DATE: June 25, 2002

TO: Errol Villegas, SAQE—Permit Services

FROM: Esteban Gutierrez, AQS—Technical Services

SUBJECT: AAQA and RMR Modeling request for Duke energy Avenal LLC.

As per your request, Technical Service performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR for, two turbines, two IC engines, nineteen (19) cooling towers and a boiler for a power plant. The engineer supplied the maximum fuel rate as well as process rates for all of the units described above. ISCST3 model was used to determine dispersion value for cancer risk exposure.

The results from the RMR modeling runs and Criteria Pollutant Modeling are as follows:

RMR Modeling Results

REFINED HRA SUMMARY			
Device	**(2) Turbines**	**Boiler**	**(3) 4 cell tower**
Fuel	**NG**	**NG**	
Prioritization Score	0.8242	.0107	N/A
Cancer Risk	N/A	N/A	N/A
Acute Hazard Index	N/A	N/A	N/A
Chronic Hazard Index	N/A	N/A	N/A
TBACT Required?	No	No	No

REFINED HRA SUMMARY			
Device	**7 cell tower**	**300 Hp ICE**	**660 HP ICE**
Fuel		**Diesel**	**Diesel**
Prioritization Score	N/A	N/A	N/A
Cancer Risk	N/A	2.01E-6	1.00E-6
Acute Hazard Index	N/A	N/A	N/A
Chronic Hazard Index	N/A	N/A	N/A
Maximum operating Hrs		200	38
TBACT Required?	No	Yes	No

Criteria Pollutant Modeling Results*

Values are in ug/m^3

	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass***	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass**	Pass**

*Results were taken from the attached PSD spreadsheet.
**The criteria pollutants noted by a double asterisk (**) are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2). Operating time for 24 hour risk was adjusted for PM10 levels.
*** Passing score was obtained from running OLM (Ozone Limiting Method.)

(2) NG Turbines Stack Parameters			
Source Type	Point	**Process Rate (T1) MMbtu/yr**	16,958,390
Stack Height (m)	44.2	**Process Rate (T2) MMbtu/yr**	20,582,010
Stack Diam. (m)	5.49	**Hours of operation yr (T1)**	8400
Gas Exit Velocity (m/sec) T1	20.4	**Hours of operation yr (T2)**	8760
Stack Gas Temp (°K)	356	**Receptor Distance (m)**	1609
Location Type	Rural		

7 Cell Cooling Tower Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	13.7	**Process Rate Gal/Yr**	57,153,744,000
Stack Diam. (m)	9.64	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	8.10	**Hours of operation**	8760
Stack Gas Temp (°K)	293		

(3) 4 Cell Cooling Towers Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	16.08	**Process Rate Gal/Yr**	5,308,560,000
Stack Diam. (m)	3.57	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	11.46	**Hours of operation**	8760
Stack Gas Temp (°K)	293		

Boiler Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	11.28	**Process Rate MMbtu/yr**	93,500
Stack Diam. (m)	0.812	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	12.2	**Hours of operation**	2500
Stack Gas Temp (°K)	476		

Diesel Engine (300 Hp)			
Source Type	Point	**Closest Receptor (m)**	1609
Stack Height (m)	3.04	**Location Type**	RURAL
Stack Diam. (m)	0.13	**Max Operating (hr/yr)**	**100**
Gas Exit Velocity (m/sec)	67.1	**Fuel Type**	Diesel
Stack Gas Temp (°K)	716	**PM10 g/bhp-hr**	0.09

Diesel Engine (660 Hp)			
Source Type	Point	**Closest Receptor (m)**	1609
Stack Height (m)	3.04	**Location Type**	RURAL
Stack Diam. (m)	0.23	**Max Operating (hr/yr)**	**38**
Gas Exit Velocity (m/sec)	45.0	**Fuel Type**	Diesel
Stack Gas Temp (°K)	799	**PM10 g/bhp-hr**	0.4

Conclusion:

The Criteria modeling runs indicate that the emissions from the proposed equipment will not have an adverse impact on the State and National AAQS. Therefore, no further modeling will be required to demonstrate that the AAQS or EPA's level of significance would be exceeded.

The carcinogenic risk for the 300 hp engine is 2.01E-06, which is below the maximum allowable risk of 10 in a million for diesel IC engines emitting $\leq$ 0.149g PM_{10}/bhp/hr. The risk for the 660 hp engine is 1.00E-06 which is the allowable risk of one in a million for engines emitting > 0.149g PM_{10}/bhp/hr. Therefore, **the project is approved for permitting, and TBACT is required for the 300 hp engine.** In order to assure compliance with the assumptions made for the risk management review the following conditions listed on the PTO are required:

1. Only CARB certified fuel containing not more than 0.05% sulfur by weight is to be used in these engines.

2. PM_{10} emission rate shall not exceed **0.09 g/HP-hr (note method) for the 300 hp engine** (C-3953-8-0).

3. PM_{10} emission rate shall not exceed **0.40 g/HP-hr (note method) for the 660 hp engine** (C-3953-9-0).

4. The exhaust stacks shall not be fitted with a rain caps, or any other similar devices, that impedes vertical exhaust flow.

5. The 300 hp engine (C-3953-8-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **100 hours per year**.

6. The 660 hp engine (C-3953-9-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **38 hours per year**.

7. The 660 hp engine (C-3953-9-0) shall not operate more than **7 hours in any rolling 24 hr period during maintenance, testing, and required regulatory purposes.**

ATTACHMENT H

SO_X for PM_{10} Interpollutant Offset Analysis

SO_X for PM_{10} Interpollutant Offset Analysis
Avenal Power Center, LLC

Facility Name:	Avenal Power Center, LLC	Date:	June 30, 2010
Mailing Address:	500 Dallas Street. Level 31 Houston, TX 77002	Engineer: Lead Engineer:	Derek Fukuda Joven Refuerzo
Contact Person:	Jim Rexroad		
Telephone:	(713) 275-6147		
Application #:	C-3953-10-1, -11-1, -12-1, -13-1, and -14-1		
Project #:	C-1100751		
Location:	NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-032		
Complete:	March 18, 2010		

I. Proposal

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 562.3 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

In addition, Avenal Power Center, LLC has proposed to limit the annual facility wide NO_X emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year.

Facility C-3953 will become a major source for NO_X, VOC, and PM_{10}. There will be an increase in emissions for all pollutants and offsets are required for NO_X, VOC, and PM_{10} emissions.

II. Applicable Rules

Rule 2201 New and Modified Stationary Source Review Rule (9/21/06)
(Section 3.30 and 4.13.3.2)

III. Process Description

Combined-Cycle Combustion Turbine Generators

Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_X combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_X (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.0 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 2.0 ppmvd @ 15% O_2
SO_X: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf))
PM_{10}: 0.0107 lb/MMBtu

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_X in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_X to nitrogen and water, resulting in a reduced concentration of NO_X in the exhaust gases exiting the stack.

Duct Burners

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_X burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump

Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator
One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

IV. Equipment Listing:

C-3953-10-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

C-3953-11-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

C-3953-12-1: 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

C-3953-13-1: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-1: 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

V. Interpollutant Offset Ratio Proposal SO_X for PM_{10}

Rule 2201, New and Modified Stationary Source Review, specifically allows the use of PM_{10} precursor ERCs to offset PM_{10} increases:

> *4.13.3 Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, that the emission increases from the new or modified source will not cause or contribute to a violation of an Ambient Air Quality Standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements of this rule.*
>
> *4.13.3.2 Interpollutant offsets between PM10 and PM10 precursors may be allowed.*

Based on this language, an applicant must demonstrate an appropriate interpollutant offset ratio, based on an air quality analysis (that is, based on the science of the precursor-to-PM_{10} relationship given the atmospheric chemistry and the meteorology of the locale).

The SO_X for PM_{10} interpollutant ratio of 1.000:1 is based on District analysis (see Appendix A). The originating location of reduction of the proposed ERC certificates are greater than 15 miles from the proposed project. Therefore, a distance offset ratio of 1.5 applies. Combining the interpollutant and distance offset ratio, an overall SO_X for PM10 offset ratio of 1.000 x 1.5 = 1.5:1 is valid for project C-1100751.

IV. Project Offset Calculations

i. C-3953-10-1 and C-3953-11-1 (Turbines)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_X, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit					
	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO_X	160	17.20	13.55	13.55	240.00
CO	1,000	10.60	8.35	8.35	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM_{10}	N/A[1]	11.78	8.91	8.91	23.56
SO_X	N/A[7]	6.65	5.23	5.23	13.30
NH_3	N/A	32.13	25.31	25.31	64.26

b. Maximum Daily PE

Maximum daily emissions for NO_X, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for PM_{10}, SO_X, and NH3 are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for PM_{10}, SO_X, and NH3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

Maximum Daily Potential to Emit (w/ Startup and Shutdown)				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (101° F)	Emissions Rate @ 100% Load without duct burner (32° F)	DEL (per CTG)
NO_X	80 lb/hr (avg)	17.20 lb/hr	13.03 lb/hr	789.6 lb/day
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	5,590.8 lb/day
VOC	16 lb/hr (avg)	5.89 lb/hr	3.34 lb/hr	202.0 lb/day
PM_{10}	N/A[8]	11.78 lb/hr	8.91 lb/hr	282.7 lb/day
SO_X	N/A[8]	6.65 lb/hr	5.23 lb/hr	159.6 lb/day
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	771.1 lb/day

c. Maximum Annual PE

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_X emission factors used to calculate the annual potential emissions will be based

[1] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

SO_X EF = (0.36 ~~gr-S~~/100 ~~dscf~~) x (1 ~~lb-S~~/7000 ~~gr~~) x (64 lb SO_X/32 ~~lb-S~~) x (1 ~~scf~~/1013 ~~Btu~~) x (10^6 ~~Btu~~/MMBtu)
= 0.001 lb-SO_X/MMBtu

CTG w/o Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **1.86 lb-SO_X/hr**

CTG w/ Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **2.36 lb-SO_X/hr**

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

Scenario 1) Weekend and Weekday Hot Start:

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	**143,951 lb/year**
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	557,033 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	**34,489 lb/year**
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 2) Weekend Shutdown and Weekday Hot Start:

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 2) Weekend Shutdown and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	601,810 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Baseload Scenario*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	74,946 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,777 lb/year
PM_{10}	N/A[8]	11.27 lb/hr	9.00 lb/hr	**80,656 lb/year**
SO_X	N/A[8]	2.36 lb/hr	1.86 lb/hr	**16,694 lb/year**
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	**219,972 lb/year**

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit		
	Annual PE (per CTG)	Scenario
NO_X	143,951 lb/year	Scenario 1
CO	197,928 lb/year	Facility Wide Limit
VOC	34,489 lb/year	Scenario 2
PM_{10}	80,656 lb/year	Scenario 3
SO_X	16,694 lb/year	Scenario 3
NH_3	219,972 lb/year	Scenario 3

ii. C-3953-12-0 (Boiler)

The PM_{10} potential to emit for the boiler is calculated as follows, and summarized in the table below.

PE_{PM10} = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb PM_{10}/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb PM_{10}/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb PM_{10}/year**

= (233 lb/year) ∗ (4 qtr/year)
= **58 lb PM_{10}/qtr**

Post Project Potential to Emit (PE2) (C-3953-12-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.19	2.2	58	233

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The PM_{10} emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb PM_{10}/year**

Post Project Potential to Emit (PE2) (C-3953-13-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.04	0.9	0.5	2

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

The PM_{10} emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb PM_{10}/hr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **1.5 lb PM_{10}/day**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **1 lb PM_{10}/qtr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **3 lb PM_{10}/year**

Post Project Potential to Emit (PE2) (C-3953-14-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.06	1.5	1	3

Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)						
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972
C-3953-11-1			34,489	80,656	16,694	219,972
C-3953-12-1			201	233	132	0
C-3953-13-1			12	2	0	0
C-3953-14-1			31	3	1	0
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,222**	**161,550**	**33,521**	**439,944**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

Total Emissions to be Offset

Pursuant to District Rule 2201, Section 4.6, emission offsets shall not be required for emergency equipment that is used exclusively as emergency standby equipment for electric power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year for non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power. Therefore the emission from the diesel-fired fire water pump and the natural gas-fired emergency standby generator are not required to be offset.

Emission to be Offset (lb/year)						
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972
C-3953-11-1			34,489	80,656	16,694	219,972
C-3953-12-1			201	233	132	0
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,179**	**161,545**	**33,520**	**439,944**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

Offset Calculations:

PM_{10}:

SSPE2 (PM_{10}) = 161,545 lb/year
Offset threshold (PM_{10}) = 29,200 lb/year
ICCE = 0 lb/year

Offsets Required (lb/year) = [(161,545 – 29,200 + 0) x DOR]
= 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
33,087	33,086	33,086	33,086

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year
= 99.26 ton/yr

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
49,630	49,629	49,629	49,630

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-896-4	80	80	80	80
ERC #N-721-4	0	0	3,215	0
ERC #N-723-4	0	0	985	0
ERC #S-2791-5	92,179	23,666	69,157	96,288
ERC #S-2790-5	12,862	491	0	8,499
ERC #S-2789-5	6	14	12	8
ERC #S-2788-5	5	7	3	6
ERC #N-762-5	21,000	21,000	21,000	21,000

Project PM_{10} offset requirements

The applicant states either PM_{10} ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} at an interpollutant ratio of 1.0:1 (see Appendix A). This interpollutant ratio has been evaluated by the District's modeler, James Sweet, Air Quality Project Planner. Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_X ERCs are being used to offset PM_{10} emissions, the above applies to the SO_X ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM_{10} emissions to be offset with SO_X ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1st qtr. ERCs applied to 2nd qtr. ERCs:	-4,371	4,371	0	0
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM_{10} emissions increases associated with this project.

V. Conclusion

Approve use of an overall SO_X for PM_{10} interpollutant offset ratio of 1.5:1 (1.000 x 1.5).

VI. Recommendation

Compliance with all applicable rules and regulations is expected. Issue Authorities to Construct C-3953-10-1, -11-1, -12-1, -13-1, and -14-1 with a SO_X for PM_{10} interpollutant offset ratio of 1.000:1.

Appendix

A: District Review and Approval

Appendix A

District Review and Approval

Interpollutant Offset Ratio Explanation

The Air District's Rule 2201, "New and Modified Source Review", requires facilities to supply "emissions offsets" when a permittee requests new or modified permits that allow emissions of air contaminants above certain annual emission offset thresholds. In addition, Rule 2201 allows interpollutant trading of offsets amongst criteria pollutants and their precursors upon the appropriate scientific demonstration of an adequate trading ratio, herein referred to as the interpollutant ratio. A technical analysis is required to determine the interpollutant offset ratio that is justified by evaluation of atmospheric chemistry. This evaluation has been conducted using the most recent modeling analysis available for the San Joaquin Valley. The results of the analysis are designed to be protective of health for the entire Valley for the entire year, by applying the most stringent interpollutant ratio throughout the Valley.

It is appropriate for District particulate offset requirements to be achieved by either a reduction of directly emitted particulate or by reduction of the gases, called particulate precursors, which become particulates from chemical and physical processes in the atmosphere. The District interpollutant offset relationship quantifies precursor gas reductions sufficient to serve as a substitute for a required direct particulate emissions reduction. Emission control measures that reduce gas precursor emissions at the facility may be used to provide the offset reductions. Alternatively, emission credits for precursor reductions may be used in accordance with District regulations.

The amount of particulate formed by the gaseous emissions must be evaluated to determine how much credit should be given for the gaseous reductions. Gases combine and merge with other material adding molecular weight when forming into particles. Some of the gases do not become particulate matter and remain a gas. Both the extent of conversion into particles and resulting weight of the particles are considered to establish mass equivalency between direct particulate emissions and particulate formed from gas precursors. The Interpollutant offset ratio is expressed as a per-ton equivalency.

The District interpollutant analysis uses the most recent and comprehensive modeling of San Joaquin Valley particulate formation from sulfur oxides (SOx) and nitrogen oxides (NOx). Modeling compares industrial directly emitted particulate to particulate matter from precursor emissions. The interpollutant modeling procedure, assumptions and uncertainties are documented in an extensive analysis file. Additional documentation of the modeling procedure for the San Joaquin Valley is contained in the 2008 PM2.5 Plan and its appendices. The 2008 PM2.5 Plan provides evaluation of the atmospheric relationships for direct particulate emissions and precursor gases when they are highest during the fourth quarter of the year. The southern portion of the Valley is evaluated by both receptor modeling and regional modeling of chemical relationships for precursor particulate formation. Regional modeling was conducted for the entire Valley through 2014. The two modeling approaches are combined to determine interpollutant offset ratios applicable to, and protective of, the entire Valley (SOx for PM 1:1 and NOx for PM 2.629:1).

DEVELOPMENT OF THE INTERPOLLUTANT RATIO

For the proposed substitution of reductions of sulfur oxides (SOx) or nitrogen oxides (NOx) for directly emitted particulate matter

March 2009

Introduction

Goal of Interpollutant Evaluation: Establish the atmospheric exchange relationship for substitution of alternative pollutant or precursor reductions for required reductions of directly emitted particulate

Evaluation to establish the atmospheric relationship of different pollutants is required as a prerequisite for establishing procedures for allowing a required reduction to be met by substitution of a reduction of a different pollutant or pollutant precursor. Proposed new facility construction or facility modifications may result in increased emissions of a pollutant. The District establishes requirements for reductions of the pollutant to "offset" the proposed increase. A facility may propose a reduction of an alternative pollutant or pollutant precursor where reductions of that material have already been achieved at the facility beyond the amount required by District regulations or where emission reductions credits for reductions achieved by other facilities are economically available; however, for such a substitution to be allowed the District must establish equivalency standards for the substitution. The equivalency relationship used for offset requirements is referred to in this discussion as the interpollutant ratio. The interpollutant ratio is a mathematical formula expressing the amount of alternative pollutant or precursor reduction required to be substituted for the required regulatory reduction. This discussion is limited to the atmospheric relationships and does not address other policy or regulatory requirements for offsets such as are contained in District Rule 2201.

The following description is provided to explain key elements of the analysis conducted to develop the atmospheric relationship between the commonly requested substitutions. Emission reductions of sulfur oxide emissions or nitrogen oxide emissions are proposed by many facilities as a substitution for reduction of directly emitted particulates. Elemental and organic carbon emissions are the predominant case and dominant contribution to directly emitted particulate mass from industrial facilities, although other types of directly emitted particulates do occur. Therefore this atmospheric analysis examines directly emitted carbon particulates from industrial sources in comparison to the formation of particles from gaseous emissions of sulfur oxides and nitrogen oxides.

Analyses included in Interpollutant evaluation

Factors Considered

The foundation for this analysis is provided by the atmospheric modeling conducted for the 2008 PM2.5 Plan. Modeling conducted for this State Implementation Plan was conducted by the District and the California Air Resources Board using a variety of modeling approaches. Each separate model has technical limitations and uncertainties. To reduce the uncertainty of findings, a combined evaluation of results of all of the modeling methods is used to establish "weight of evidence" support for technical analysis and conclusions. The modeling methods are supported by a modeling protocol which was sent to ARB and EPA Region IX for review and was included in the appendices to the Plan.

The analysis file prepared for the interpollutant ratio evaluation includes emissions inventories, regional model daily output files, chemical mass balance modeling and speciated rollback modeling as produced for the 2008 PM2.5 Plan. This well examined and documented modeling information was used as a starting point for additional evaluation to determine interrelationships between directly emitted pollutants and particulates from precursors.

The interpollutant ratio analysis is limited to evaluation of directly emitted PM2.5 from industrial sources and formation of PM2.5 from precursor gases. While both directly emitted particulates and particulate from precursor gases also occur in the PM10 size range, there is much more uncertainty associated with deposition rates and particle formation rates for the larger size ranges. Additionally, because PM2.5 is a subset of PM10; all reductions of PM2.5 are fully creditable as reductions towards PM10 requirements. This analysis concentrates on the quarter of the year when both directly emitted carbon from industrial sources and secondary particulates are measured at the highest levels. Assessing atmospheric ratios at low concentrations is subject to much greater uncertainty and has limited value toward assessment of actions to comply with the air quality standards.

Elements from 2008 PM 2.5 Plan

- Regional modeling daily output for eleven locations
- Chemical Mass Balance (CMB) modeling for four locations – source analysis, speciation profile selection, event meteorology evaluation
- Receptor speciated rollback modeling with adjustment for nitrate nonlinearity for four locations, evaluation of spatial extent of contributing sources
- Emission inventories and projections to future years as developed for the 2008 PM 2.5 Plan

- Modeling protocols for receptor modeling, regional modeling, and Positive matrix Factorization (PMF) analysis and evaluation of technical issues applicable to particulate formation in the San Joaquin Valley
- Model performance analysis as documented in appendices to the 2008 PM 2.5 Plan

Extension by additional analysis

Additional evaluation was conducted to evaluate the receptor modeling relationship between direct PM from industrial sources and sulfate and nitrate particulate formed from SOx and NOx precursor gases. Area of influence adjustments were evaluated to ensure appropriate consideration of contributing source area for different types of pollutants for both directly emitted and secondary particulate. This evaluation was possible only for the southern four Valley counties and was conducted for both 2000 and 2009.

The regional model output was evaluated for the fourth quarter to evaluate general atmospheric chemistry in 2005 and 2014 to determine the correlation between northern and southern areas of the Valley. This evaluation determined that the atmospheric chemistry observed and modeled in the north was within the range of values observed and modeled in the southern SJV. This establishes that a ratio protective of the southern Valley will also be protective in the north.

The District determined from the additional analyses of both receptor and regional modeling that the most stringent ratio determined for the southern portion of the Valley would also be protective of the northern portion of the Valley. Due to the regional nature of these pollutants, actions taken in other counties must be assumed to have at least some influence on other counties; therefore to achieve attainment at the earliest practical date it is appropriate to require all counties to establish a consistent interpollutant ratio for the entire District.

Strengths

The interpollutant ratio analysis uses established and heavily reviewed modeling and outputs as foundation data. Analysis of model performance has already been completed for the models and for the emissions inventories used for this analysis. The modeling was performed in accordance with protocols developed by the District and ARB and in accordance with modeling guidelines established by EPA. The combination of modeling approaches provides an analysis for the current year and provides projection to 2014. Weight of evidence comparison of various modeling approaches establishes the reliability of the foundation modeling, with all modeling approaches showing strong agreement in predicted results. Additional analysis performed to develop the interpollutant ratio uses both regional and receptor evaluations which were the primary models used for the 2008 PM 2.5 Plan.

Limitations

Both industrial direct emissions and secondary formed particulate may be both PM2.5 and PM10. The majority of secondary particulates formed from precursor gases are in the PM2.5 range as are most combustion emissions from industrial stacks, however both secondary and stack emissions do contain particles larger than PM2.5. Regional modeling is more reliable for the smaller fraction due to travel distances and deposition rates. Large particles have much higher deposition and are much more difficult to replicate with a regional model. This leads to a strong technical preference for evaluating both emission types in terms of PM2.5 because the integration of receptor analysis and regional modeling for coarse particle size range up to PM10 has a much greater associated uncertainty.

Analyses contained in Receptor modeling

Factors Considered

This modeling approach uses speciated linear modeling based on chemical mass balance evaluation of contributing sources with San Joaquin Valley specific identification of contributing source profiles, adjustments from regional modeling for the nonlinearity of nitrate formation, adjustments for area of influence impacts of contributing sources developed from back trajectory analysis of high concentration particulate episodes and projections of future emission inventories as developed for the 2008 PM2.5 Plan.

Analyses in receptor modeling that use input from regional modeling

The receptor modeling analysis uses a modified projection of nitrate particulate formation from nitrogen oxides based upon results of regional modeling. The atmospheric chemistry associated with nitrate particulate formation has been determined to be nonlinear; while the default procedures for speciated rollback modeling assume a linear relationship. This adjustment has been demonstrated as effective in producing reliable atmospheric projections for the prior PM10 Plans.

Extension by additional analysis

Additional evaluations were added to results of the receptor modeling performed for the 2008 PM2.5 Plan. Calculations determine the observed micrograms per ton of emission for each contributing source category that can be resolved by chemical mass balance modeling methods. These ten categories allow differentiation of industrial direct emissions of organic and elemental carbon from other sources that emit elemental and organic carbon. The interpollutant calculation is developed as an addition to the receptor analysis by calculating the ratio of emissions per ton of directly emitted industrial PM2.5 to the per ton ratio of secondary particulate formed from NOx and SOx emissions. Summary tables and issue and documentation discussion was added to the analysis.

Strengths

Receptor modeling provides the ability to separately project the effect of different key sources contributing to carbon and organic carbon. This is critical for establishing the atmospheric relationship between industrial emissions and the observed concentrations due to industrial emissions. Regional modeling methods at this time do not support differentiation of vegetative and motor vehicle carbon contribution from the emissions form industrial sources. The area of influence of contributing sources was also considered as a factor with the methods developed by the District to incorporate the gridded footprint of contributing sources into the receptor analysis. While regional models use gridded emissions, current regional modeling methods do not reveal the resulting area of influence of contributing sources.

Limitations

Receptor modeling uses linear projections for future years and cannot account for equilibrium limitations that would occur if a key reaction became limited by reduced availability of a critical precursor due to emission reductions. The regional model was used to investigate this concern and did not project any unexpected changes due to precursor limitations.

Analyses contained in Regional modeling

Factors Considered

The analysis file includes the daily modeling output representing modeled values for the base year 2005 and predicted values for 2014 for each of the eleven Valley sites that have monitoring data for evaluation of the models performance in predicting observed conditions. These sites are located in seven of the eight Valley counties. Madera County does not have monitoring site data for this comparison.

Modeling data for all quarters of the year was provided. Due to the higher values that occur due to stagnation events in the fourth quarter, both industrial carbon concentrations and secondary particulates forming from gases are highest in the fourth quarter. Evaluating the interpollutant ratio for other quarters would be less reliable and of less significance to assisting in the reduction of high particulate concentrations. Modeling for lower values has higher uncertainty. Modeling atmospheric ratios when the air quality standard is being met are axiomatically not of value to determining offset requirements intended to assist in achieving compliance with the air quality standard. However, for consistency of analysis between sites, days when the standard was being met during the fourth quarter were not excluded from the interpollutant ratio analysis. Bakersfield fourth quarter modeled data included only eight days that were at or below the standard. Fresno and Visalia sites averaged twelve days; northern sites 24 days and the County of Kings 38 days.

Modeling output provided data for both 2005 and 2014. While there is substantial emissions change projected for this period, the regional modeling evaluation does not project much change in the atmospheric ratios of directly emitted pollutants and secondary pollutants from precursor gases. This indicates that the equilibrium processes are not expected to encounter dramatic change due to limitation of reactions by scarcity of one of the reactants. This further justifies using the receptor evaluation determining the interpollutant ratio for 2009 through the year 2014 without further adjustment. If observed air quality data demonstrates a radical shift in chemistry or components during the next few years, such a change could indicate that a limiting reaction has been reached that was not projected by the model and such radical changes might require reassessment of the conclusion that the ratio should remain unchanged through 2014.

Extension by additional analysis

Regional modeling results prepared for the 2008 PM2.5 Plan were analyzed to extract fourth quarter data for all sites. The atmospheric chemistry for all counties was analyzed for consistency and variation. This analysis provided a determination that the secondary formation chemistry and component sources contributing to concentrations observed in the north fell within the range of values similarly determined for the southern four counties. Based upon examination of the components and chemistry, the northern counties would be expected to have an interpollutant ratio value less than the ratio determined for Kern County but greater than the one for Tulare County. This establishes that the interpollutant ratio determined by receptor analysis of the southern four counties provides a value that is also sufficiently protective for the north.

Strengths

Regional models provide equilibrium based evaluations of particulate formed from precursor gases and provide a regional assessment that covers the entire Valley. The projection of particulate formed in future years is more reliable than linear methods used for receptor modeling projections.

Limitations

The regional model does not provide an ability to focus on industrial organic carbon emissions separate from other carbon sources such as motor vehicles, residential wood smoke, cooking and vegetative burning. Regional modeling does not provide an assessment method for determination of sources contributing at each site or the area of influence of contributing emissions. Receptor analysis provides a more focused tool for this aspect of the evaluation.

Results and Documentation

SJVAPCD Interpollutant Ratio Results

SOx for PM ratio: 1.000 ton of SOx per ton of PM

NOx for PM ratio: 2.629 tons of NOx per ton of PM

These ratios do not include adjustments for other regulatory requirements specified in provisions of District Rule 2201.

The results of the modeling analysis developed an atmospheric interpollutant ratio for NOx to PM of 2.629 tons of NOx per ton of PM. This result was the most stringent ratio from the assessment industrial carbon emissions to secondary particulates at Kern County; with Fresno, Tulare and Kings counties having a lower ratio. The assessment of chemistry from the regional model required comparison of total carbon to secondary particulates and is therefore not directly useful to establish a ratio. However, the regional model does provide an ability to compare the general atmospheric similarity and compare changes in chemistry due to Plan reductions. Evaluation revealed that the atmospheric chemistry of San Joaquin, Stanislaus and Merced counties falls within the range of urban characteristics evaluated for the southern four counties; therefore the ratio established should be sufficiently protective of the northern four counties. Additionally, comparison of future year chemistry showed minimal change in pollutant ratio due to the projected changes in the emission inventory from implementation of the Plan. The SOx ratio as modeled indicates a value of less than one to one due to the increase in mass for conversion of SOx to a particulate by combination with other atmospheric compounds; however, the District has set guidelines that require at least one ton of an alternative pollutant for each required ton of reduction in accordance with District Rule 2201 Section 4.13.3. Therefore the SOx interpollutant ratio is established as 1.000 ton of SOx per ton of PM. These ratios do not include adjustments for other regulatory considerations, such as other provisions of District Rule 2201.

A guide to the key technical topics and the reference material relevant to that topic is found on the next page. References from the 2008 PM2.5 Plan may be obtained by requesting a copy of that document and its appendices or by downloading the document from http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm. References in Italics are spreadsheets included in the interpollutant analysis file "09 Interpollutant Ratio Final 032909.xls" which includes 36 worksheets of receptor modeling information from the 2008 PM2.5 Plan, 11 modified and additional spreadsheets for this analysis and two spreadsheets of regional model daily output. This file is generally formatted for printing with the exception of the two spreadsheets containing the regional model output "*Model-Daily Annual*" and "*Model-Daily Q4*" which are over 300 pages of raw unformatted model output files. The remainder of the file is formatted to print at approximately 100 pages. This file will be made available on request but is not currently posted for download.

Interpollutant Ratio Issues & Documentation

	TOPIC	Reference
1	**Reason for using PM2.5 for establishing the substitution relationship between direct emitted carbon PM and secondary nitrate and sulfate PM:** consistency of relationship between secondary particulates and industrial direct carbon combustion emissions.	2008 PM2.5 Plan, Sections 3.3.2 through 3.4.2
2	**Reason for using 4th Quarter analysis:** Highest PM2.5 for all sites.	*DV Qtrs*
3	**Reason for using analysis of southern SJV sites to apply to regional interpollutant ratio:** Northern site chemistry ratios are within the range of southern SJV ratios. Peak ratio will be protective for all SJV counties.	*Q4 Model Pivot, Model-site chem, Model-Daily Q4*
4	**Reason for using combined results of receptor and regional model:** Receptor model provides breakdown of different carbon sources to isolate connection between industrial emissions and secondary PM.	2008 PM2.5 Plan, Appendix F
	Regional model provides atmospheric information concerning the northern SJV not available from receptor analysis.	2008 PM2.5 Plan, Appendix G
5	**Most significant contributions of receptor evaluation:** Separation of industrial emissions from other source types. Area of influence evaluation for contributing sources.	2008 PM2.5 Plan, Appendix F
6	**Most significant contributions of regional model:** Scientific equilibrium methods for atmospheric chemistry projections for 2014. Receptor technique is limited to linear methods.	2008 PM2.5 Plan, Appendix G
7	**Common area of influence adjustments used for all receptor evaluations:** Geologic & Construction, Tire and Brake Wear, Vegetative Burning - contribution extends from more than just the urban area (L2) Mobile exhaust (primary), Organic Carbon (Industrial) primary, Unassigned - contribution extends from more than larger area, subregional (L3) Secondary particulates from carbon sources are dominated by the local area with some contribution from the surrounding area (average of L1 and L2) Marine emissions not found present in CMB modeling for this analysis.	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
8	**Variations to reflect secondary area of influence specific to location:** Fresno: Evaluation shows extremely strong urban signature (L1) for secondary sources Kern: Evaluation shows a strong urban signature mixed with emissions from the surrounding industrial areas (average L1 and L2) for both carbon and secondary sources Kings and Tulare: Prior evaluation has show a shared metropolitan contribution area (L2)	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
9	**Reasons for using 2009 Interpollutant Ratio Projection:** 2009 Interpollutant ratio is consistent with current emissions inventories	2008 PM2.5 Plan
	Regional modeling does not show a significant change in chemical relationships through 2014.	*Q4 Model Pivot*
10	**Reason for using SOx Interpollutant Ratio at 1.000:** A minimum offset ratio is established as 1.000 to 1.000 consistent with prior District policy and procedure for interpollutant offsets.	District Rule 2201 Section 4.13.3

ATTACHMENT I

Additional Supplemental Information

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES[a]
(SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	4.08 E+00	B
NO_x[c] <90% Load	8.47 E-01	B
CO[c] 90 - 105% Load	3.17 E-01	C
CO[c] <90% Load	5.57 E-01	B
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	1.47 E+00	A
Methane[g]	1.25 E+00	C
VOC[h]	1.18 E-01	C
PM10 (filterable)[i]	7.71 E-05	D
PM2.5 (filterable)[i]	7.71 E-05	D
PM Condensable[j]	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[k]	<4.00 E-05	E
1,1,2-Trichloroethane[k]	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene[k]	2.67E-04	D
1,3-Dichloropropene[k]	<2.64 E-05	E
2-Methylnaphthalene[k]	3.32 E-05	C
2,2,4-Trimethylpentane[k]	2.50 E-04	C
Acenaphthene[k]	1.25 E-06	C

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES[a]
(SCC 2-02-002-53)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	2.21 E+00	A
NO_x[c] <90% Load	2.27 E+00	C
CO[c] 90 - 105% Load	3.72 E+00	A
CO[c] <90% Load	3.51 E+00	C
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	3.58 E-01	C
Methane[g]	2.30 E-01	C
VOC[h]	2.96 E-02	C
PM10 (filterable)[i,j]	9.50 E-03	E
PM2.5 (filterable)[j]	9.50 E-03	E
PM Condensable[k]	9.91 E-03	E
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[l]	2.53 E-05	C
1,1,2-Trichloroethane[l]	<1.53 E-05	E
1,1-Dichloroethane	<1.13 E-05	E
1,2-Dichloroethane	<1.13 E-05	E
1,2-Dichloropropane	<1.30 E-05	E
1,3-Butadiene[l]	6.63 E-04	D
1,3-Dichloropropene[l]	<1.27 E-05	E
Acetaldehyde[l,m]	2.79 E-03	C
Acrolein[l,m]	2.63 E-03	C
Benzene[l]	1.58 E-03	B
Butyr/isobutyraldehyde	4.86 E-05	D
Carbon Tetrachloride[l]	<1.77 E-05	E

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%		
Type of fuel (use table above)	4	GAS
O2 correction (i.e., 3%)	15	%
Enter LB/MMBTU emission factor		
NOx	0.847	LB/MMBTU
CO	0.130	LB/MMBTU
VOC (as methane)	0.000	LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS		
NOx	229.94	ppmv
CO	57.98	ppmv
VOC (as methane)	0.00	ppmv

pV = R*T		
pressure (p)	1	atm
universal gas constant (R*)	0.7302	atm-scf/lbmole-oR
temperature (oF)	60	oF
calculated		
molar specific volume (V)	379.5	scf/lbmole
Molecular weights		
NOx	46	lb/lb-mole
CO	28	lb/lb-mole
VOC (as methane)	16	lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F			
COAL (ANTHRACITE)	10100	DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780	DSCF/MMBTU	COAL
COAL (LIGNITE)	9860	DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160	DSCF/MMBTU	OIL
GAS (NATURAL)	8710	DSCF/MMBTU	GAS
GAS (PROPANE)	8710	DSCF/MMBTU	GAS
GAS (BUTANE)	8710	DSCF/MMBTU	GAS
WOOD	9240	DSCF/MMBTU	WOOD
WOOD BARK	9600	DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570	DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710	DSCF/MMBTU	GAS

Parts Per Million Volume => Grams/Brake Horsepower - Hour

ppmv => g/Bhp-hr

Variables:		
Engine Size:	860	hp
NO_x:	230	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH_4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given:		
Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.236	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
MW (NOx):	46	as NO_2
MW (CO):	28	
MW (VOC):	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula:

$$\frac{\text{ppmv}}{1} \cdot \frac{\text{F-factor}}{1} \cdot \frac{MW_{pollutant}}{1} \cdot \frac{20.9}{(20.9 - O_2\%)} \cdot \frac{1}{\text{Conversion \#1}} \cdot \frac{1}{\text{Conversion \#2}} \cdot \frac{\text{Conversion \#3}}{1} \cdot \frac{1}{\text{Engine Eff.}} =$$

for NOx:

$$\frac{230\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{46\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{1\ \text{lb-mol}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 2.750 g/bhp-hr | 2365 g/hr | 5.21465 lbs/hr | 125 lbs/day

for CO:

$$\frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{28\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC:

$$\frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{16\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%	
Type of fuel (use table above)	4 GAS
O2 correction (i.e., 3%)	15 %
Enter LB/MMBTU emission factor	
NOx	2.270 LB/MMBTU
CO	0.130 LB/MMBTU
VOC (as methane)	0.000 LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS	
NOx	616.25 ppmv
CO	57.98 ppmv
VOC (as methane)	0.00 ppmv

pV = R*T		
pressure (p)	1	atm
universal gas constant (R*)	0.7302	atm-scf/lbmole-oR
temperature (oF)	60	oF
calculated		
molar specific volume (V)	379.5	scf/lbmole
Molecular weights		
NOx	46	lb/lb-mole
CO	28	lb/lb-mole
VOC (as methane)	16	lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F			
COAL (ANTHRACITE)	10100	DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780	DSCF/MMBTU	COAL
COAL (LIGNITE)	9860	DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160	DSCF/MMBTU	OIL
GAS (NATURAL)	8710	DSCF/MMBTU	GAS
GAS (PROPANE)	8710	DSCF/MMBTU	GAS
GAS (BUTANE)	8710	DSCF/MMBTU	GAS
WOOD	9240	DSCF/MMBTU	WOOD
WOOD BARK	9600	DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570	DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710	DSCF/MMBTU	GAS

Parts Per Million Volume -> Grams/Brake Horsepower - Hour

ppmv -> g/Bhp-hr

Variables:		
Engine Size:	860	hp
NO_x:	616	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH_4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given:		
Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.236	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
$MW_{(NO_x)}$:	46	as NO_2
$MW_{(CO)}$:	28	
$MW_{(VOC)}$:	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula:

ppmv	F-factor	$MW_{pollutant}$	20.9	1	1	Conversion #3	1	
1	1	1	(20.9 - O_2%)	Conversion #1	Conversion #2	1	Engine Eff.	=

for NOx:

616 ~~parts~~	8578 ~~dscf~~	46 ~~lb~~	20.9	~~1 lb-mol~~	~~MMBtu~~	453.59 g	1	
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	=

= 7.365 g/bhp-hr | 6334 g/hr | 13.9662 lbs/hr | 335 lbs/day

for CO:

0 ~~parts~~	8578 ~~dscf~~	28 ~~lb~~	20.9	~~lb~~	~~MMBtu~~	453.59 g	1	
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	=

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC:

0 ~~parts~~	8578 ~~dscf~~	16 ~~lb~~	20.9	~~lb~~	~~MMBtu~~	453.59 g	1	
10^6 ~~parts~~	~~MMBtu~~	~~1 lb-mol~~	20.9 - 15	379.5 ~~dscf~~	393.24 bhp-hr	~~lb~~	35%	=

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

Avenal Power Center, LLC
500 Dallas Street, Level 31
Houston, TX 77002

RECEIVED
JUL 0 3 2008
Permits Srvc
SJVAPCD

COPY

July 1, 2008

RE: Certification of Avenal Energy, owned by Avenal Power Center, LLC

I, Stuart Zisman, on behalf of Avenal Power Center, LLC, hereby certify under penalty of perjury as follows:

1. I am authorized to make this certification on behalf of Avenal Power Center, LLC.
2. This certification is made pursuant to Section 4.15.2 of Rule 2201 of the Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District.
3. To the best of the undersigned's knowledge, relative to Section 4.15.2 of District Rule 2201, Avenal Power Center, LLC. does not currently own, operate or control any Major Stationary Source or federal major modification in the State of California other than the proposed Avenal Energy Project.

Each of the statements herein is made in good faith. Accordingly, it is Avenal Power Center, LLC's understanding in submitting this certification that the SJVUAPCD shall take no action against Avenal Power Center, LLC or any of its employees based on any statement made in this certification.

Stuart Zisman
Vice President
Avenal Power Center, LLC

7/1/08
Dated

Joseph Forbes
Senior Lawyer

ATTACHMENT J

EPA Comments and District Responses

EPA Comments / District Response

The comments (from Gerardo Rios) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

EPA Comments – Letters Dated September 13, 2010

EPA Comment #1:

Applicable federal requirements include thresholds for defining a major source of criteria pollutant emissions. For those sources where emission estimates and/or emission limits are relatively close to the federal thresholds, EPA encourages the following: (a) refinement of emissions and compliance demonstration methods that would ensure the thresholds would not be exceeded, and/or (b) a 5-10% buffer between the permitted emission limits and the federal threshold.

The proposed annual NOx emission and CO emission limits are within a margin of less than 5% of the federal annual threshold limit for defining a new major stationary source under the Federal Prevention of Significant Deterioration (PSD) permit program. The threshold is 100 tons per year (tpy) each. If the limits of these pollutants are relaxed, the facility may be subject to the applicable federal requirements, such as the Federal Prevention of Significant Deterioration (PSD) permitting program (See 40 CFR Part 52.21 (r)(4)).

District's Response:

The permitted emissions from this facility are below PSD thresholds. The facility's NO_X and CO emissions limits are included as permit conditions on the PDOC. The facility is also required to maintain records to demonstrate that they do not exceed these emission limits.

In addition, emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.

EPA Comment #2:

In the "General Calculations" section (See PDOC Page 27, Section VII. C. 5), the District compares the annual emission estimates for regulated pollutants to the major source threshold to determine whether a pollutant is subject to major source requirements for NO_X, CO, VOC, PM_{10}, and SO_X emissions. However,

$PM_{2.5}$, which also is a regulated pollutant, is not included. On May 8, 2008 EPA finalized regulations to implement the NSR program for $PM_{2.5}$. A source that emits or has the potential to emit 100 tpy or more PM2.5 in a nonattainment area is defined as a major stationary source. (Reference 40 CFR Part 51, Appendix S.) We recommend the District include in its evaluation the $PM_{2.5}$ emission estimates with a comparison to the federal nonattainment major source threshold of 100 tpy (or 200,000 pounds per year).

District's Response:

The potential emissions of PM_{10} from the facility are 161,552 lb-PM_{10}/year (Calculated in the PDOC). Using the conservative assumption that all PM_{10} is $PM_{2.5}$, it is clear that the $PM_{2.5}$ emissions from this facility will not exceed the major source threshold of 100 tons/year. However, to avoid any confusion, the District will revise the PDOC to discuss the potential emissions of $PM_{2.5}$ from this operation.

EPA Comment #3:

The proposed annual emissions (calculated on a twelve consecutive month rolling basis) from the facility are 198,840 pounds per year (lb/yr) NO_X and 197,928 lb/year CO. (See PDOC Page 27, Section VII. C. 5) These annual emissions are equivalent to 99.4 tpy of NO_X emissions and 98.9 tpy of CO emissions, both of which are relatively close to the federal PSD permit program applicability threshold of 100 tpy for each ofthese pollutants. A proposed permit condition requiring that annual emissions not exceed these levels has been added to all combustion related equipment. The condition reads as follows:

> *"Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NOx (as N02) -198,840 lb/year; CO -197,928lb/year."*

In a review of the post-project potential to emit annual emission estimates in Sections VII.C.2.i through C.2.iv. (See PDOC Pages 16-26) for each piece of equipment, we noted that the combustion turbine operations contribute the majority of NOx and CO emissions.

Based on discussions with the District, we understand that in addition to the 12-month rolling facility NOx and CO emission limits that are equivalent to 99.4 tpy and 98.9, respectively, the District has made no other changes to the current FDOC permit conditions. These conditions include, but are not limited to, the following: continuous emissions monitoring of NO_X and CO; compilation of emissions on a daily, monthly, 12 consecutive month rolling average, and annual basis; quarterly reporting of excess emissions; and acid rain (40 CFR Part 75) compliance requirements.

At this time, it appears the proposed requirements provide practically and federally enforceable conditions based on our understanding of the proposed revision. However, given that the NO_X permit limit is within less than 1% of the PSD permit threshold and the CO limit is within 1.1% of the PSD permit threshold, we suggest that the District consider requiring Avenal to report more frequently emissions as the actual emissions approach or exceed 90% of the 12-consecutive month rolling average permit limit to assure the 100 tpy threshold is not exceeded.

District's Response:

Emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.

EPA Comment #4:

The District concludes on pp. 53-54 of the PDOC that the proposed project will not cause a violation of an air quality standard for NOx, and refers to Appendix G. PDOC Appendix G contains some additional detail on the air quality impact analysis for the l-hour N02 NAAQS, effective April 12, 2010, and states that "the emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS." The following are our comments specific to PDOC Appendix G:

a. SIP-Approved Rule 2201 -The District's approved SIP, in District Rule 2201, Section 4.14.1, provides that modeling used for purposes of determining whether a new or modified stationary source's emissions will cause or make worse the violation of an Ambient Air Quality Standard shall be consistent with the requirements contained in the most recent edition of EPA's "Guideline on Air Quality Models." This EPA guideline is found in 40 CFR Part 51, Appendix w. EPA recently has had occasion to review and comment on the applicant's l-hour N02 NAAQS analysis for the project in the context of the applicant's pending PSD permit application before EPA.

   We recognize that certain aspects of the project for which Avenal seeks a minor source permit vary from the project for which it seeks a PSD permit, in particular, the proposed addition of a facility-wide NOx emissions limit of the equivalent of approximately 99.4 tons per year (tpy) to the minor source permit. However, given that the equipment emitting NOx from the two projects has the same permitted hourly emission rates, many of the comments EPA made concerning consistency with 40 CFR Part 51, Appendix W in reviewing the applicant's l-hour N02 NAAQS analysis for PSD purposes may be relevant to the l-hour N02 NAAQS analysis for this minor source permit as well. We have attached for your consideration our comments dated June 15, 2010 and August 12, 2010 on the l-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes. We would be happy to discuss any issues or questions you may have concerning these comments.

b. EPA Guidance Memorandum -We also note that EPA recently issued guidance relating to modeling for the l-hour N02 NAAQS, with a cover memorandum entitled *Guidance Concerning Implementation of the 1-hour N02 NAAQS for the Prevention of Significant Deterioration Program,* dated June 29, 2010, that included two attached guidance documents, one of which was entitled *Applicability of Appendix W Modeling Guidance for the 1-hour N02 National Ambient Air Quality Standard,* dated June 28, 2010. We understand that the District is aware of this guidance, and we encourage the District to refer to this guidance for further detail on this subject.

c. Assumptions and Decision-making Process -The District's rationale in Appendix G for its conclusion that the project's emissions will not cause or contribute significantly to a violation of the l-hour N02 NAAQS is not clear from the documents provided. For example, the table addressing "Operational" scenarios on page 2 of Appendix G indicates that Tier 1 and Tier 2 impacts are each greater than the N02 NAAQS limit, while Tier III and Tier IV impacts are each below the N02 NAAQS limit. Furthermore, it is unclear how the modeling analysis meets the requirements of Appendix W (See Comment 4.a.) or whether the District intended to follow those requirements for the proposed permit revision. We recommend that the District provide a discussion of which Tier the District is relying upon to support its conclusion, the basis for selecting that Tier, and the modeling inputs, assumptions, etc. for that Tier.

<u>District's Response:</u>

a. The District has reviewed your comments dated June 15, 2010 and August 12, 2010 on the 1-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes, and has no comments at this time. We did not use Avenal Power's analysis to make determinations of NAAQS impacts, but used our own guidance to perform the NO2 modeling (please see responses below).

b. The District has reviewed the documents stated above and developed a modeling guidance to address EPA's memos that were provided to the modelers at EPA Region 9. The District is currently waiting for EPA's *response to this guidance, and is, in fact, working with EPA, ARB, and CAPCOA on developing statewide policy on how to implement our guidance, or something similar. The Avenal Power project was analyzed under this guidance, and the project was approved under Tier III of that guidance.*

c. *The District uses a tiered approach when determining compliance with any NAAQS. This approach is similar to that required by OAQPS in their memos which require that each progressively more accurate tier be used (Tier I-Complete Conversion, Tier II-NO2 Ration and Tier III-OLM) until compliance is demonstrated. This project was approved under Tier III. We believe our guidance is consistence with EPA modeling practices and direction, and as we have stated above, we are patiently awaiting EPA's input on our guidance.*

EPA Comment #5, Joint letter to District and Avenal Power Center, LLC:

Avenal Power Center, LLC (Avenal) recently applied for a minor source New Source Review (NSR) permit from the San Joaquin Valley Pollution Control District (SJVAPCD or District) for the Avenal Energy Project. This permit seeks authority to construct the project with emissions limits below the major source thresholds triggering Clean Air Act (CAA) prevention of significant deterioration (PSD) preconstruction review. On July 28, 2010, SJVAPCD's public notice announcing its Preliminary Determination of Compliance for this minor source permit application was published in the Fresno Bee, triggering a public review and comment period for the proposed permit.

Concurrently, Avenal is seeking a PSD permit from EPA Region 9 for essentially the same project, but with greater emissions exceeding the major source threshold and thereby triggering PSD preconstruction review. The applicant's simultaneous application for both a minor source permit and a major souce PSD permit for the project raises a potential concern about circumvention of PSD preconstruction requirements.

EPA guidance on this subject states:

> Parts C and D of the Clean Air Act exhibit Congress's clear intent that new major sources of air pollution be subject to preconstruction review. The purposes for these programs cannot be served without this essential element. Therefore, attempts to expedite construction by securing minor source status through receipt of operational restrictions from which the source intends to free itself shortly after operation are to be treated as circumvention of the preconstruction review requirements... If a major source or major modification permit application is filed simultaneously with or at approximately the same time as the minor source construction permit, this is strong evidence of an intent to circumvent the requirements of preconstruction review.

Guidance on Limiting Potential to Emit in New Source Permitting, Terrell E. Hunt and John S. Seitz, dated June 13, 1989, at pp. 13-14.

We recommend that the applicant carefully review the guidance quoted above and other applicable EPA guidance on this topic prior to commencing construction of the project under the minor source permit, should that permit be finalized by the SJVAPCD.

District's Response:

The District disagrees that if Avenal were to construct under a California Energy Commission license that incorporates this minor source Determination of Compliance (DOC), it would be circumvention of the PSD preconstruction review.

Circumvention might occur if a source obtained a minor source permit and soon thereafter sought a PSD permit due to a small increase in emissions, and not as a new source. In this case, Avenal has applied for a PSD permit as a new source. If they construct as a minor source and don't receive a PSD permit, they will have to continue to comply with the minor source limits. However, constructing as a minor source and then obtaining a PSD permit as a new major source and operating in accordance with that PSD permit cannot be viewed as circumvention. Therefore, the EPA process, not the District's minor source permitting process, will determine whether circumvention will occur, and circumvention will not occur if EPA requires a PSD permit if Avenal pursues a permit with emissions above the PSD triggers.

ATTACHMENT K

Green Action Comments and District Responses

Greenaction Comments / District Response

The comments (from Bradley Angel) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Greenaction Comments – Letter Dated September 11, 2010

<u>Greenaction Comment #1:</u>

The Air District failed to conduct a proper and thorough public notice and public participation process. The failure to conduct proper notice and participation processes to the mostly low-income, Latino and Spanish-speaking residents of the nearest communities (Avenal, Huron and Kettleman City) violated the Air District's own environmental justice policy. The Air District's claim that you met your agency's required notice and participation mandates is insufficient as your own environmental justice policy commits the agency to uphold environmental justice.

Failing to notify residents or their organizations, failing to hold a public hearing and failing to provide Spanish-speaking residents equal time to comment as English speakers is a violation of environmental justice and civil rights policies and laws.

We are surprised and disappointed that the Air District would only translate information into Spanish following concerns being raised by Greenaction, and after the comment period already began. On August 20, 2010, we received an email from Dave Warner of the Air District that stated:

> Bradley,
>
> The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at <u>http://www.valleyair.org/General_info/SpanishHmong_Resources.htm</u>

As this email was sent one week into the revised comment period, and as Spanish-speakers had not yet had the opportunity to read information in Spanish, this shows that there has been an unequal opportunity to comment that is improper.

The Air District's notice was inadequate for all of the affected public. No resident or organization representing residents received notice. We only learned of the original comment period from US EPA after it already had begun.

The Air District published a "Notice" in the Fresno Bee, but not in any Kings County or Spanish-language paper.

Even after meeting with the Air District on August 30, 2010 to raise all these concerns, the Air District refused to hold a public hearing, provide proper notice or provide equal opportunities to the Spanish-speaking residents who comprise a major percentage of residents of Avenal, Kettleman City and Huron.

Due to the discriminatory and disproportionate impact on low-income, Latino and Spanish-speakers of the lack of notice and full public participation notice for a project that would emit pollutants into an already over-polluted area, the Air District has violated its own environmental justice policy as well as California Government Code section 11135 and Title VI of the US Civil Rights Act of 1964.

District's Response:

The District complied with all applicable regulatory public noticing requirements with respect to the Avenal Power Center Preliminary Determination of Compliance (PDOC) and in fact took considerable actions that went far beyond statutory requirements. The District properly published notice of the proposed issuance of the PDOC in a newspaper of general circulation, in this case, the Fresno Bee whose distribution does cover the area in question. This notice was published according to our federally approved Rule 2201, which defines the timing and process of such notices. There is no additional direction on public noticing in the District's Environmental Justice Strategy document, contrary to the commenter's claims.

However, we went far beyond our required notification processes for this project, as follows:

1. *We published this notice, as we do all public notices, on the District's website, valleyair.org. This is not required by any rule or regulation, but is part of our continuing effort to make information available and accessible.*

2. *Upon hearing on August 16 of the commenter's concern that he was not notified of the District proposal to issue a DOC, we promptly, on August 18, notified him that we would extend the public noticing period for him and his clients a full additional 30 days from the date that he heard about our proposal. This was not required, since the commenter had not requested that he be informed of our actions on this project, and therefore he was not on record as an interested party. However, in the interests of providing the maximum reasonable opportunity for comment, we offered this accommodation.*

3. *Upon receiving the commenter's subsequent August 19 request for bilingual information on the project, and a public hearing, on August 20 we sent the commenter the following email, from which he quoted an excerpt above. We are providing it in full, below, as it explains our response in some additional detail that was missing from the commenter's excerpt:*

Bradley,

The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at http://www.valleyair.org/General_info/SpanishHmong_Resources.htm

We would welcome your assistance in distributing it to your Spanish-speaking clients and associates. We will also be pleased to accept comments in Spanish as we have translation capabilities here at the District. As you are aware, we have already extended the public comment period to September 13, 2010, and we believe the above steps will provide you and your Spanish speaking associates ample opportunity to provide comment on our proposal.

I just want to make sure you understand the status of this project atthis time as it pertains to the District. The District is taking public comment on a Preliminary Determination of Compliance, which is a recommendation to the California Energy Commission (CEC) that the project will comply with District regulations. We are not aware of any requirement that we hold a meeting for the purpose of receiving verbal comments.

We are not going to hold a public hearing on this project at this time. Ours is not a final permitting decision and there is no hearing process associated with it - the CEC has the sole power plant licensing authority in the state of California for power plants over 50 megawatts. They conduct any necessary public hearings associated with such a license. Our action is a certification to the CEC that, if granted, CEC's license would meet our air quality requirements. CEC is able to accept or reject our proposed conditions of approval, or can make air quality permitting decisions contrary to our determination of compliance. In addition, the CEC makes all determinations regarding power plant siting.

Finally, contrary to your contention below, the District is not required to hold a public hearing, by rule or by policy We believe the process described above will assure an efficient, fair, and productive public comment process.

Dave Warner
Director of Permit Services
San Joaquin Valley APCD

In summary, we confirmed that we would prepare a Spanish-language summary of the project and make it available to the commenter for his outreach efforts. We also confirmed our commitment to address any comments we received in Spanish, and we explained the limitations of our role in the permitting process to provide clarity to any potential commenters. None of this was required by our rules and regulations, but was intended to provide additional opportunity for community members to participate in the process.

4. *We then worked through the weekend to create a summary of the project, translate it to Spanish, and post it on the website the very next working day, Monday, August 23.*

5. *Next, on August 24 we agreed to meet with the commenter and any of his clients and community members on August 30. The commenter and other activist organization representatives attended the meeting, but, disappointingly, no independent community members. Again, this meeting was not required by any rule or regulation.*

6. *Finally, we granted another request from another employee of GreenAction that she be provided with an additional day to persuade community members of Avenal and Kettleman City to submit comments, extending the comment period to September 14, for a total public comment period of 53 days instead of the required 30 days. This provided GreenAction the opportunity to persuade community members to submit the comments summarized in the next comment section. And again, there was certainly no rule or regulation that required this accommodation.*

In summary, contrary to the assertions of the commenter, the District not only met all legal requirements but went far beyond them in providing the public opportunities to comment on the Avenal Power Center Project.

Greenaction Comment #2:

The claim by the company and the Air District that there would be substantially less emissions than were stated in the initial permit application dramatically conflicts with earlier information and needs extensive scrutiny including a full public environmental review. If there really would be dramatically lower emissions than first claimed, we wonder why the company did not state this initially, raising questions as to whether the lower, newer estimate is based solely on a desire to avoid a PSD permit requirement and protracted appeals and legal battles.

District's Response:

While no response is necessary, it should be noted that the proposal for lower annual emissions was only possible after rigorous analysis by Avenal Power of actual emissions data from other recently constructed similar power plants. In addition, it seems remarkable that there should be a complaint about a company committing to lower emissions from a facility, regardless of the purpose or intent of the proposal.

Greenaction Comment #3:

The Air District's claim that there would be "zero impact" from the proposed power plant's emissions flies in the face of reality. A huge fossil fuel power plant, no matter how much cleaner than others of its kind, still will have pollution impacts. This "zero impact" claim ignores the fact that this would be a fossil fuel power plant that would have emissions and use fuels that contribute to climate change, would emit a broad range of pollutants, and its emissions would act cumulatively in concert with the many other pollution sources in the area.

The proposed fossil fuel power plant would be close to Kettleman City, a small low-income community of color that is suffering a horrible health crisis involving a large number of birth defects and infant deaths. Even a minor increase in emissions near this community could have severe and unforeseen health impacts due to the current health vulnerability of residents. In addition, the entire San Joaquin Valley already suffers from high rates of asthma, and if built this power plant would emit asthma-triggering pollutants.

District's Response:

The District has searched the PDOC and has not been able to locate the phrase "zero impact".

However, the District has performed a Health Risk Assessment (HRA) as well as an Ambient Air Quality Analysis (AAQA) for this facility. The HRA was performed using the AERMOD model and Hot Spots Analysis and Reporting Program (HARP), and demonstrated that the acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Pursuant to the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit with a cancer risk less than one in one million, and chronic or acute hazard index less than 1.

The AAQA demonstrated that the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X. In addition, as shown in the PDOC, the calculated contribution of PM_{10} will not exceed the EPA significance level. Therefore, this project will not cause or contribute significantly to a violation of the State or National AAQS.

Greenaction Comment #4:

This proposed fossil fuel power plant is not needed. Many things have changed since the CPUC originally determined that the Avenal Power Center was needed. As California emerges from an economic recession, the energy landscape has changed. PG&E now has access to more electricity generation than it needs. Last summer, PG&E's territory operated with a 44% reserve margin during summer peak. This extraordinarily high margin is in part due to the CPUC's success at increasing energy efficiency and the demand decrease from the recession. These factors, along with delayed facility retirements and inflated population and energy export assumptions made by the CEC demonstrate that the 600 MWs that the Avenal Power Center would generate are no longer needed. Even PG&E has forecasted a decrease in need. In addition, several large solar projects are to be sited here, and other solar projects are already underway, providing truly clean and renewable energy instead of dirty fossil fuel energy.

Despite all this evidence, Avenal Power Center continues its push for this power plant. The pollution and health effects of this proposed facility are unacceptable when the new capacity is clearly not needed. Finally, allowing unneeded fossil fuel energy would also likely crowd out renewable projects.

District's Response:

The District is not able to take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission.

ATTACHMENT L

NRDC and CRPE Comments and District Responses

National Resources Defense Council (NRDC) and Center on Race, Poverty & The Environment (CRPE) Comments / District Response

The comments (from Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

NRDC and CRPE Comments – Letter Dated September 13, 2010

NRDC and CRPE Comment #1:

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year* –$1,600 per person – in the San Joaquin Valley.

District's Response:

The District has demonstrated in the PDOC that the proposed facility is in compliance with all applicable NO_X and VOC rules and regulations. It should be noted that these rules and regulations are among the strictest and most stringent in the nation and are designed to protect the health of the residents of the San Joaquin Valley.

NRDC and CRPE Comment #2:

The June, 2009 EPA Statement of Basis And Ambient Air Quality Impact Report for a prevention of significant deterioration (PSD) permit states, at page 14, that emissions of CO and NOx from the Project are expected to be 1,205,400 pounds per year and 288,600 pounds per year, respectively. The July 13, 2010 Revised Preliminary Determination of Compliance for the Project states, at page 1, that emissions of CO will now be 197,928 pounds per year and NOx 198,840 pounds per year, both to be enforced as permit limitations. Conveniently, this would bring both the CO and NOx emissions under the 100-ton limit for major sources under Title V of the Clean Air Act. This change in emission numbers was accomplished with no changes to the setup or operation of the Project itself.

In addition, this sentence occurs relating to the new CO and NOx limits:

> If the annual [CO/NOx] emissions from these units exceed this value, they will be set equal to the proposed facility wide [CO/NOx] emission limit.

Revised PDOC at pages 9 (NOx) and 10 (CO). There are two ways to read this confusing sentence. One is that the sub-100 tons limits are meaningless and will be ignored if exceeded. The other is that APCD is attempting to engage in the type of "flexible permitting" that USEPA has disapproved in Texas. In either case, the federal Clean Air Act has been violated.

District's Response:

The District agrees that the wording in the PDOC is slightly confusing. The intent of the statement was to explain that the potential annual emissions from each of the turbines was calculated based on a stated scenario that was provided by the applicant and that if the unit was not operated exactly in accordance with this scenario, there was the potential for higher NO_X and CO emissions from the unit. However, the total emissions from the facility would not be allowed to exceed the proposed facility wide NO_X and CO emissions limits.

The stated scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, the facility cannot be held to a specific operational schedule. The main point to understand is that the annual emissions from the facility will not exceed the facility wide limit that is stated as a condition on the PDOC, and therefore the impact from the facility's emissions will not be greater than that evaluated by the District.

Attached Letter Addressed to U.S. EPA - Dated October 14, 2009

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comments

The following comments were sent to U.S. EPA on October 14, 2009 from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit on behalf of El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, the Center on Race, Poverty, & the Environment, and the Natural Resources Defense Council. These comments were not sent to the District therefore, the District did not previously respond to the comments. These comments refer to the DOC performed in District project C-1080386, which analyzed the prior, higher-emitting proposal. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments (from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

<u>El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #1:</u>

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year* –$1,600 per person – in the San Joaquin Valley.

District's Response:

This is the same comment that was made in the NRDC and CRPE Letter Dated September 13, 2010 and addressed above. See above for District Response.

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #2:

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

District's Response:

The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.

In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.

The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #3:

The Project is expected to emit 80.7 tons/year of PM/PM10. *See* the June 16, 2009 EPA Statement of Basis and Ambient Air Quality Impact Report at p. 14. As we discuss below, we believe that the Project's plan to offset these PM emissions through SOx offsets is invalid under the Clean Air Act. Accordingly, ambient air quality will be impaired by the Project.

As you know, the San Joaquin Valley is in non-attainment for PM2.5. The Project proposes to meet 98% of its PM offset requirements from SOx offsets at a one-to-one ratio. *See* Final Staff Report, Air Quality Table 19. This is highly problematic for a number of reasons.

First, the one-to-one ratio ignores the very different health risks of SOx and PM. The U.S. EPA has found that particulate matter can cause or contribute to increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing, for example; decreased lung function; aggravated asthma; development of chronic bronchitis; irregular heartbeat; nonfatal heart attacks; and premature death in people with heart or lung disease.

Second, the Project applicants should not be allowed to use PM10 as a surrogate for PM2.5 emissions.

District's Response:

The facility is not using PM_{10} as a surrogate for $PM_{2.5}$. The facility has proposed to offset PM_{10} emissions with SO_X ERCs at the District evaluated interpollutant offset ratios. District Rule 2201, Section 4.13.3 allows for the use of interpollutant offsets at ratios based on air quality analysis. The SO_X for PM_{10} offset ratio used in this project is based on the best available science for determining how much PM_{10} SO_X can create. In addition, the facility is not a Major Source for $PM_{2.5}$ emissions; therefore $PM_{2.5}$ requirements will not be addressed in this project.

Attached Letter Addressed to U.S. EPA - Dated October 15, 2009

EarthJustice Comments

The following comments were sent to U.S. EPA on October 15, 2009 from Paul Cort of EarthJustice. These comments were not sent to the District therefore, the District did not respond to the comments. These comments refer to the DOC performed in District project C-1080386. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments from Paul Cort regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's response.

EarthJustice Comment #1:

Commenter's find it stunning that the proposed permit does not even mention CO2 emissions or controls. EPA is well aware that the Environmental Appeals Board ("EAB") has returned multiple PSD permits for failing to consider whether CO2 is a pollutant "subject to regulation" under the Clean Air Act. *See In re Deseret Power Elec. Coop.*, PSD Appeal No. 07 - 03 (EAB Nov. 13, 2008); *In re Northern Mich. University Ripley Heating Plant*, PSD Appeal No. 08 - 02 (EAB Feb. 18, 2009). In light of these decisions, EPA Region 9 also withdrew portions of the PSD Permit issued to Desert Rock Energy Company in order to reconsider the issue of whether CO2 is a pollutant subject to regulation. Yet EPA proposes a PSD permit for another power plant that will emit over 1.7 million tons of CO2 each year without any discussion of these contentious issues whatsoever. EPA must revise the proposed permit to explain EPA's position on BACT for CO2 so that the public can comment on the control levels selected or EPA's rationale for refusing to impose such controls.

District's Response:

This is the same comment that was made in the NRDC and CRPE Letter dated September 13, 2010 and addressed above. See above for District Response.

EarthJustice Comment #2:

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

<u>District's Response:</u>

The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.

In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.

The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.

<u>EarthJustice Comment #3:</u>

The Proposed Permit Fails to Demonstrate that the Avenal Project Will Not Cause or Contribute to Violations of National Ambient Air Quality Standards for Ozone and Fine Particulate Matter.

<u>District's Response:</u>

The facility is not a Major Source for $PM_{2.5}$; therefore $PM_{2.5}$ (fine particulate matter) requirements will not be addressed in this project.

There is no EPA approved model capable of accounting for the photochemical complexities of regional ozone formation to determine the impacts of ozone from a single site due to NOx and VOC emissions. In addition, the facility in this project does not directly emit ozone. Therefore, an analysis of nearby ozone emissions impacts was not performed in this project. Finally, we believe that our very strict standards for NOx and VOC from new sources, among the most stringent in the nation, are sufficient safeguard to prevent any single source from contributing significantly to a violation of the ozone NAAQS.

ATTACHMENT M

Rob Simpson Comments and District Responses

Public Comments / District Response

The comments (from Rob Simpson) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Rob Simpson Comments – Emailed Letters Received November 17, 2010

Simpson Comment #1 - Public Notice:

The notice was not given to me in sufficient enough time to prepare adequate comments. The newspaper notice does not provide enough information about the project to the public and was not published in Spanish.

District's Response:

On the contrary, although Mr. Simpson was not on record as being interested in receiving information regarding this specific project, we are always quite interested in providing interested parties an opportunity to provide input, and so we provided a full 30-day period for Mr. Simpson to comment, the same amount of time provided all interested parties on all permitting projects. As for the second comment, please refer to our response to GreenAction's comment #1.

Simpson Comment #2:

The revised PDOC seems to have one purpose, evasion of the Clean Air Act requirements for the Prevention of Significant Deterioration (PSD). The only change in the revised permit is a limitation on annual NOx and CO emissions but the way the permit is worded this limitation is not federally enforceable. Page 9 of the PDOC states that,

> "*The facility has proposed to limit the annual facility wide NOx emissions to 198,840 lb/year. If the annual NOx emissions from these units exceed this value, they will be set equal to the proposed facility wide NOx emission limit.*"

Page 10 of the PDOC states:

> *"The facility has proposed to limit the annual facility wide CO emissions to 197,928 lb/year. If the annual CO emissions from 'these units exceed this value, they will be set equal to the proposed facility wide CO emission limit."*

So essentially there is no change from the original permit and the Avenal Power Project still requires a PSD permit. Issuance of this permit would be a violation of the Clean Air Act and the district and the applicant would be subject to enforcement.

District's Response:

See response to NRDC and CRPE comment #2.

Simpson Comment #3 - The District is the Lead Agency for this Project:

The CEC appears to no longer be the lead agency for the project the district under CEQA, CEC or District rules. The District is now the lead agency since the purpose of the revision to the permit is merely to avoid PSD review and the CEC has no jurisdiction over PSD issues on this project. Thus the district is now the lead agency for review of this project and must conduct a complete EIR prior to issuance of an Authority to Construct for this project.

District's Response:

The District is not the lead agency for this project. Pursuant to California Public Resources Code Section 25500, the CEC "shall have the exclusive power to certify all sites (for power plants over 50 MW) and related facilities in the state". The California Public Resources Code further states that "the issuance of a certificate by the commission shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency".

Simpson Comment #4 - Is an FDOC an ATC?:

- Does the FDOC process comport with the Districts Federal permitting requirements?
- Is it the federal New Source Review (NSR) permit?
- Has the prior FDOC expired for this facility?
- Has the Applicant commenced construction or use of the prior FDOC?

District's Response:

The FDOC complies with Federal non-attainment pollutant permitting requirements, as implemented with the District's EPA-approved non-attainment NSR rule. This rule requires the District to issue a Determination of Compliance, rather than an Authority to Construct because, as noted above, the CEC has the sole licensing authority for large power plants in California. Our NSR rule does not incorporate federal attainment NSR (PSD) requirements. EPA retains the sole authority to issue PSD permits in the San Joaquin Valley.. The prior FDOC is tied to the CEC's license that has been issued, therefore it has not expired. However, the facility has not commenced construction or use of the prior FDOC. The FDOC under which construction is commenced (and only after CEC has approved any related licensing action) will determine the conditions under which the facility must operate.

Simpson Comment #5:

- I contend that the Warren Alquist Act hijacks air districts authority under the Clean Air Act in conflict with Federal law, does the District agree?.
- Does the District agree with the Brief submitted by the South Coast Air District (Exhibit 3) in the Humboldt Superior Court proceeding regarding a power plant permit that I appealed?

District's Response:

The District does not agree with either the "hijack" comment or the South Coast AQMD's brief on the subject. State law provides the CEC with sole permitting authority, but does not allow them to issue a license that violates the District's regulations. The DOC process provides the District ample opportunity to provide the appropriate guidance to the CEC prior to their licensing process. This process does not violate federal permitting requirements in any way. The federal EPA has approved the DOC process as embodied in the language of the District's NSR rule and that approval explicitly acknowledges that the process complies with federal permitting requirements.

Simpson Comment #6:

The District indicated in emails that it did not intend to issue an Authority to Construct for this project. Please provide some indication of how the permit would be enforceable without an Authority to Construct and who could enforce the State and Federal aspects of the permit. The PDOC has extensive references to an ATC.

District's Response:

Thank you for pointing out that we referred to the DOC as the ATC several times in our evaluation. We apologize for that error. The District has removed all references to the issuance of ATC's in the FDOC evaluation.

Pursuant to District Rule 2201, Section 5.8.9, the APCO shall issue a Permit to Operate to any applicant receiving a certificate from the California Energy Commission pursuant to this rule provided that the construction or modification is in compliance with all conditions of the certificate and of the Determination of Compliance, and provided that the Permit to Operate includes the conditions prescribed in Section 5.7. The District will then perform inspections of the facility to determine if it meets all requirements on their PTO.

Simpson Comment #7 - The BACT Analysis for the Permit is Defective:

The district's top down BACT analysis for NOx is defective because it fails to:

- Identify any alternative technologies or work practices which are technologically feasible for reducing NOx emissions, and
- To quantify the collateral impacts from the selection of SCR as the proposed alternative, and
- Identify combustion technologies that are effective is reducing NO_X emissions. (i.e. steam injection, dry low NO_X combustors, and catalytic combustors), and
- Analyze post-combustion controls including selective noncatalytic combustion and EM, and
- Evaluate the risk of an accident from the transport of NH_3, and
- Evaluate NH_3 as a precursor to PM2.5.

District's Response:

The District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The existing Top-Down BACT Analysis did not consider any NO_X emissions control other than the use of SCR to lower the NO_X emissions to 2.0 ppmvd @ 15% O_2, as no more efficient technology has been identified. Pursuant to the District BACT Policy, no analysis is necessary for a project in which the most effective control alternative listed in the BACT Guideline is selected. BACT Guideline 3.4.2 identifies BACT for NO_X as the use of SCR or equal to meet an emission concentration limit of 2.0 ppmvd @ 15% O_2 as the most stringent technologically feasible NO_X requirement. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.

In addition, BACT only covers operational emissions; therefore the risk from accidents during the transport of NH_3 is not evaluated and can not be evaluated under the District's NSR rule.

The evaluation of NH_3 as a precursor to $PM_{2.5}$ was not performed since the facility is not a Major Source for $PM_{2.5}$ emissions. However, it should be noted that the Valley's atmosphere does contain ammonia, largely from the Valley's considerable agricultural operations, and relatively small amounts caused by SCR systems are insignificant and are quite worth the significant NOx emissions reductions generated by the SCR. In addition, the District did analyze the health risk impacts of the NH3 emissions that are resulting from the requirement that SCR be installed, and there is no significant risk. Also see the response to comment #17, below.

Simpson Comment #8 - NO_X Emissions During Startup and Shut Down:

Emissions are greater during startups, shutdowns and combustor tuning periods than they are during steady-state operation, the BACT limits established for steady-state operations are not technically feasible during these periods. As these limits are not "achievable" during these operating modes, they are not "Best Available Control Technology" as defined in the Federal Regulations. Therefore, alternate BACT limits must be specified for these modes of operation. The discussion of Best Available Control Technologies does not include information on minimizing startup emissions or startup durations. The U.S. Environmental Protection Agency (U.S. EPA) requires that BACT apply not only during normal steady-state operations but also during transient operating periods such as startups. The District should consider conducting, as part of the BACT analysis, a review of combustion turbine and combined cycle system operational controls or design features that can shorten start up and shutdown events and optimize emission control systems.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised.

Simpson Comment #9 - BACT VOC Emission Limit:

The district has selected a VOC emission limit of 1.4 ppmvd @ 15% 02 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% 02 when it is fired with the duct burners. The BAAQMD has recently established a BACT VOC emission limit for large gas turbines for VOC's. BACT is the use of good combustion practice and abatement with an oxidation catalyst to achieve a permit limit for each gas turbine of 0.616 lb per hour or 0.00127 lb/MMBtu, which is equivalent to 1 ppm POC, 1-hr average. Since VOC emissions contribute to ozone formation and the district is in severe non attainment for the 8-hour ozone standard the district should adhere to the lower VOC emission rate or provide a top down BACT evaluation which shows that this rate is not achievable or is not cost effective.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The District Top-Down BACT Analysis did not consider any VOC emissions control other than limiting the VOC emissions to 2.0 ppmvd @ 15% O_2 when the duct burner is fired, and 1.5 ppmvd @ 15% O_2 when the duct burner is not fired.

The applicant proposed VOC emissions of 1.4 ppmvd @ 15% O_2 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O_2 when it is fired with the duct *burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O_2 did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O_2 emission factor will be determine to meet the highest ranking control option listed in the BACT. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.*

Simpson Comment #10 - BACT $PM_{2.5}$ / PM_{10} Emission Limit:

The permit proposes to allow the project to emit as much as 11.78 pounds per hour of PM-10 with the project utilizing duct firing. According to BAAQMD the projects listed in the table below all have lower PM emission limits than those proposed for this project. BACT for PM 2.5 for large combined cycle turbines with duct firing is 9 pounds per hour. The district needs to impose this limit in the FDOC.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. *District BACT Policy, Section IX.D, states that a cost effective analysis is not necessary for a project in which the most effective control alternative is selected. BACT Guideline 3.4.2 identifies BACT for PM_{10} as the use of an air inlet filter, lube oil vent coalescer and natural gas fuel. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed. In addition, it is likely that a PM10 limit of 11.78 lb/hr is substantially the same as a PM2.5 limit of 9.0 lbs/hr, as PM2.5 is a fraction of PM10.*

Simpson Comment #11 - Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether 'the operation of the proposed equipment will cause or make worse a violation of an air quality standard. For NOx the impact analysis conducted by the district in Attachment G page 2 demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the 98^{th} percentile of the annual distribution of the daily 1 hour max ppb /ug/m3 for the Visalia site which is 115.72 ug/m3. So the project does in fact violate the new federal NO2 standard and thus cannot be permitted.

District's Response:

The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour *max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.*

Simpson Comment #12:

The PDOC uses the PM-10 surrogate approach to analyze the particulate matter impacts from the project. On October 20, 2010, the USEPA issued a final rule providing modeling thresholds for evaluating impacts of PM2.5 emissions under the Prevention of Significant Deterioration (PSD) program and the Non attainment NSR program. The rule establishes Class I and Class II Increment Thresholds and Significant Impact Levels (SILs), and a Significant Monitoring Concentration (SMC) threshold. The project according to the analysis presented on page 54 exceeds both the significant impact levels for the annual PM 2.5 standard and the 24 PM 2.5 hour standard. The FDOC needs to address the compliance of the project with the new rules.

District's Response:

The project does not trigger PSD permitting and the facility is not a Major Source for $PM_{2.5}$ emissions. Therefore, the District is not required to perform modeling to evaluate impacts of $PM_{2.5}$.

Simpson Comment #13 - Federal 1 hour NO2 Standard:

The permit does not present an adequate and complete analysis for the new Federal 1 hour NO2 standard. The district failed to include information on any nearby sources which are required to be modeled with Avenal's emissions. A full impact analysis should be presented in the permit for the public to comment on using the EPA's Guideline on Air Quality Models (40 CFR Part 51 Appendix W).

District's Response:

This project does not trigger a PSD permit and therefore it is not required to follow the guideline on air quality models in 40 CFR Part 51 Appendix W. If it did trigger PSD permitting, the federal EPA would be obligated to perform such modeling, if appropriate.

Simpson Comment #14:

The revised permit should provide the input data that was used to determine compliance with the new NO2 standard. Emission factors and NO2 inventories should be presented for the public to review not just the information that is presented on page 2 Attachment G. The analysis on page 2 Attachment G demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the 98^{th} percentile of the annual distribution of the daily 1 hour max ppb / ug/m3 for the Visalia site which is 115.72 ug/m3.

District's Response:

The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.

Simpson Comment #15:

Modeling for the NO2 standard should indicate whether worst case emissions which would be the start up and shut down emissions for the project were utilized in the modeling for compliance with the standard.

District's Response:

The District performed modeling during the commissioning period and the standard operational period to determine compliance with the NO2 standard. The modeling performed by the District for these periods demonstrated compliance with the NO2 standards.

Simpson Comment #16 - The Proposed Interpollutant Trade Values Violates EPA Guidance and $PM_{2.5}$ NSR Regulations:

Based on an EPA assessment, the preferred trading ratios for SO2 to PM2.5 was set at 40:1.

District's Response:

The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.

Simpson Comment #17 - Ammonia Emissions:

Other power plant turbines have achieved a 2 ppm NO_X limit with a 5 ppm NH_3 slip limit.

The district must consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The district is not an isolated island.

District's Response:

Ammonia is an integral part of the NOx emissions control system when using SCR. The District has no regulatory basis for restricting ammonia slip to 5 ppmv. Ammonia is not a criteria air contaminant or a "precursor" as defined in District Rule 2201. The District's BACT Clearinghouse does not specify an ammonia slip rate for combustion turbines using SCR. While ammonia emissions may be restricted as part of a health risk evaluation that determines an unacceptable health risk from the ammonia to exposed populations, this is not the case with Avenal Power Center. The risk due to all toxic air contaminant emissions, including 10 ppmv ammonia, was found to be not significant.

A high ammonia slip from the turbine will not lead to increased PM_{10} formation in the atmosphere. The air basin currently has an excess of ammonia emissions; therefore lowering ammonia emissions will not reduce PM formation. This is demonstrated in the Districts $PM_{2.5}$ plan which does not not rely on ammonia reductions to reduce $PM_{2.5}$, but rather relies largely on NO_X reductions.

Generally, increased ammonia injection rates, and therefore increased ammonia slip rates, are required to maintain NOx BACT performance levels (2.0 ppmv) as the catalyst ages. Allowances for operation at the end of the economic life of a control technology and for periods of non-steady state operation (including startup and shutdown which can result in ammonia slip higher than 5 ppmv) are part of a BACT determination.

Simpson Comment #18 - Emission Reduction Credits:

ERC's used on the prior PDOC are unavailable for use on the new PDOC.

District's Response:

The ERC listed in the previous FDOC and the ones listed in the new PDOC will only be used for one of the projects. Once they are withdrawn for either project, they will no longer be available to be withdrawn for the remaining project. In addition, the applicant has provided sufficient ERC's of offset the emissions increase in either one of the projects.

Simpson Comment #19:

The PDOC indicates that the closest population center is the residential district of Avenal approximately 6 miles to the southwest. Are there people residing or working closer than that to the project? Could there be sensitive receptors closer to the site?

District's Response:

According to the application submitted by the facility, the nearest resident is 7,700 feet to the Northeast and the nearest business is 3,957 feet to the Northwest. However, our analysis of emissions and risk from those emissions is based on a theoretical long-term exposure at the point of maximum pollutant concentration. Therefore, our conclusion that there will be no significant risk from any emissions from this facility is not dependant on receptor location.

Simpson Comment #20:

It appears that there are residential structures and extensive farm land around the site. Could emissions from the facility affect crops or wildlife?

District's Response:

Such issues are addressed in the CEC's CEQA-equivalent process and are not a part of the District's analysis. However, it should be noted that the District's Health Risk Assessment (HRA) is a multipathway assessment of risk, and would include the affect on public health generated by pollutant deposition on plants and animals that are subsequently ingested by the public.

Simpson Comment #21:

- Has the District conducted and Environmental Justice analysis of the projects effects? Could farm workers be an environmental justice community that suffers a greater impact due to hard physical labor in the vicinity of the project, lack of health care, poverty and additional stressors like chemicals used in farming?
- Can farming activities cause additional air quality impacts that could contribute to a negative cumulative effect?
- Will this facility induce growth?
- Could on site Solar pre-heaters reduce Air quality impacts?
- Can this facility cause an increase of greenhouse gas emissions?
- Are there potential negative localized effects of Greenhouse gases?
- How does this plan comport with AB32?
- How does this plan comport with EXECUTIVE ORDER S-3-05?
- Has the District studied the potential air quality effects of the use of imported LNG?
- The District should study the life cycle effects of fossil fuel extraction and delivery?
- Has the District studied the effects of the facility utilizing water from the California Aqueduct?
- Will the vaporization of this water lead to negative air quality effects by increasing PM or other pollutants in the Air?

- Will the use of this water cause negative air quality effects by the diversion of water that could be utilized for farming or other uses?
- Will the pumping of this water through the Aqueduct, from its source, cause Air quality emissions?
- Is it legal to use Potable water for this Power plant use?
- As water quality changes will these effects change?
- Are there methods of minimizing these potential effects? Dry cooling for instance?

District's Response:

These questions should be directed to the CEQA lead agency for this project (CEC). Since the District is not the lead agency for this project, these comments will not be addressed at this time.

Simpson Comment #22:

How much money does the District receive if this project is approved? Denied?

District's Response:

Whether the project is approved or denied, the District receives application filing fees for all proposed equipment, and hourly engineering fees for the time spent evaluating the project. At this time, we would expect the total will be approximately $5,000. In addition, if the project is approved, the District will receive an annual permit fee to maintain the facility's permits, of approximately $26,000 per year. This latter amount would be the same whether the facility constructs under the conditions of this FDOC and a subsequent CEC approval, or under the existing FDOC which the CEC used in issuing the existing power plant license.

Comments Received from Rob Simpson in Exhibit 4:

The document provided labeled Exhibit 4 is the same document that Mr. Simpson presented as testimony for the CEC Hearings under proceeding 08-AFC-01. This exhibit was discussed at the Pre-Hearing Conference on June 30, 2009. After a review of the document, the CEC Committee overseeing the project concluded that the only information that would be allowed as testimony would be the information included in Exhibit W. A discussion of this can be found in the Pre-Hearing Conference Transcript, available at: http://www.energy.ca.gov/sitingcases/avenal/documents/2009-06-30_TRANSCRIPT.PDF. The District agrees with CEC's conclusion and will respond to the comments presented in Exhibit W. All additional comments in Exhibit 4 are documents pertaining to projects unrelated to this project, and comments that are not applicable to this project.

Simpson Comment #23:

The applicant proposes to offset the projects PM 2.5 emissions on a pound for pound basis with SOx offsets. Proposed interpollutant trading ratios are required to be scientifically justified with a site specific air quality analysis, as required by Rule 2201, Section 4.13.3. The PDOC attempts to establish an interpollutant ratio based on modeling analyses performed in the Districts 2008 PM 2.5 plan.

The EPA has finalized its regulations to implement the New Source Review (NSR) program for fine particulate matter on July 15, 2008. Their recommended ratio of SOx offsets to PM 2.5 offsets is 40 tons of SOx for each ton of PM 2.5. The applicant is proposing a ratio that is 40 times less stringent than EPA has recommended.

In addition the CEC and the air district allow the project to emit 33,521 pounds of SO2 with no mitigation despite the alleged CEC policy to offset all PM2.5 precursors. If one pound of SO2 offsets 1 pound of PM 2.5 the CEC and the Air District are allowing 33,521 pounds of SO2 to remain unmitigated. The new EPA rules on PM 2.5 require a pound for pound offset ratio for PM 2.5 precursors. If the districts assumption that one pound of SOx offsets 1 pound of PM 2.5 as allowed in the interpollutant trade the district is allowing 33,521 pounds of SOx to remain unmitigated creating 33,521 pounds of PM 2.5 in violation of CEQA and EPA NSAR rules for PM 2.5.

District's Response:

The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.

Simpson Comment #24:

The FDOC allows an ammonia slip of 10 ppm. The 5 ppm ammonia limit in combination with a 2 ppm NO limit has already been required for some CEC licensed facilities. In the alternative the District could perform a site specific analysis that demonstrates that no particulate matter will be formed locally or district wide due to the ammonia slip emissions and require mitigation if the analysis demonstrates that there is significant secondary particulate matter formation from the ammonia emissions from the LGS.

The district must also consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident.

District's Response:

This comment was addressed in the District response to Rob Simpson Comment #17 above.

Comments Received from Rob Simpson in Exhibit 5:

The document labeled Exhibit 5, submitted by Rob Simpson, discusses the California energy landscape. The District does not take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission (CEC).

ATTACHMENT Q

	NOx	SOx	PM10	CO	VOC	PM2.5	MW/hour	% of Avenal Electricity
One Digester (lbs/year)	9,166	2,268	3,970	101,636	6,370	3970	1.059	
One Digester (tons/year)	4.58	1.13	1.99	50.82	3.19	1.99		
25 Digesters (lbs/year)	229,150	56,700	99,250	2,540,900	159,250	99,250	26.475	4.41%
25 Digesters (tons/year)	114.58	28.35	49.63	1,270.45	79.63	49.63		
Avenal (lbs/year)	198,840	33,521	161,550	197,928	69,222	161550	600	
Avenal (tons/year)	99.42	16.76	80.78	98.96	34.61	80.775		
Pollution Difference Digesters vs. Avenal (tons/year)	15.16	11.59	-31.15	1,171.49	45.01	-31.15		

Source: Lakeview Dairy Biogas digester Authority to Construct Permit March 22, 2016, Post-Project Stationary Source Potential to Emit (SSPE2) at 14, 20

Source: Avenal Power Center Authority to Construct Permit No. December 17, 2010, Post-Project Stationary Source Potential to Emit (SSPE2) at 27.

ATTACHMENT R

BEFORE THE CALIFORNIA AIR RESOURCES BOARD

PETITION FOR RECONSIDERATION OF THE DENIAL OF THE PETITION FOR RULEMAKING TO EXCLUDE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LOW CARBON FUEL STANDARD PROGRAM

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percent on high PM2.5 days.[119]

The “disadvantaged communities” of California, as defined pursuant to California Senate Bill 535, are concentrated in the San Joaquin Valley.[120] Seven of the eight counties in the Valley (all except San Joaquin County) report mean income well below the 120% limit that defines low-income.[121] Every county in the San Joaquin Valley has lower household and per capita incomes, and higher poverty rates than California as a whole.[122] While median household income in California in 2019 was $75,235, countywide household median incomes for San Joaquin Valley counties ranged from $49,687 to $64,432. The highest producing dairy counties in the state and in the San Joaquin Valley, Merced and Tulare, show median household incomes at $53,672 and $49.687—both at 71 percent or below statewide median income.[123]

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[119] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS 3-2 to 3-3 (Nov. 15 2018), https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf.

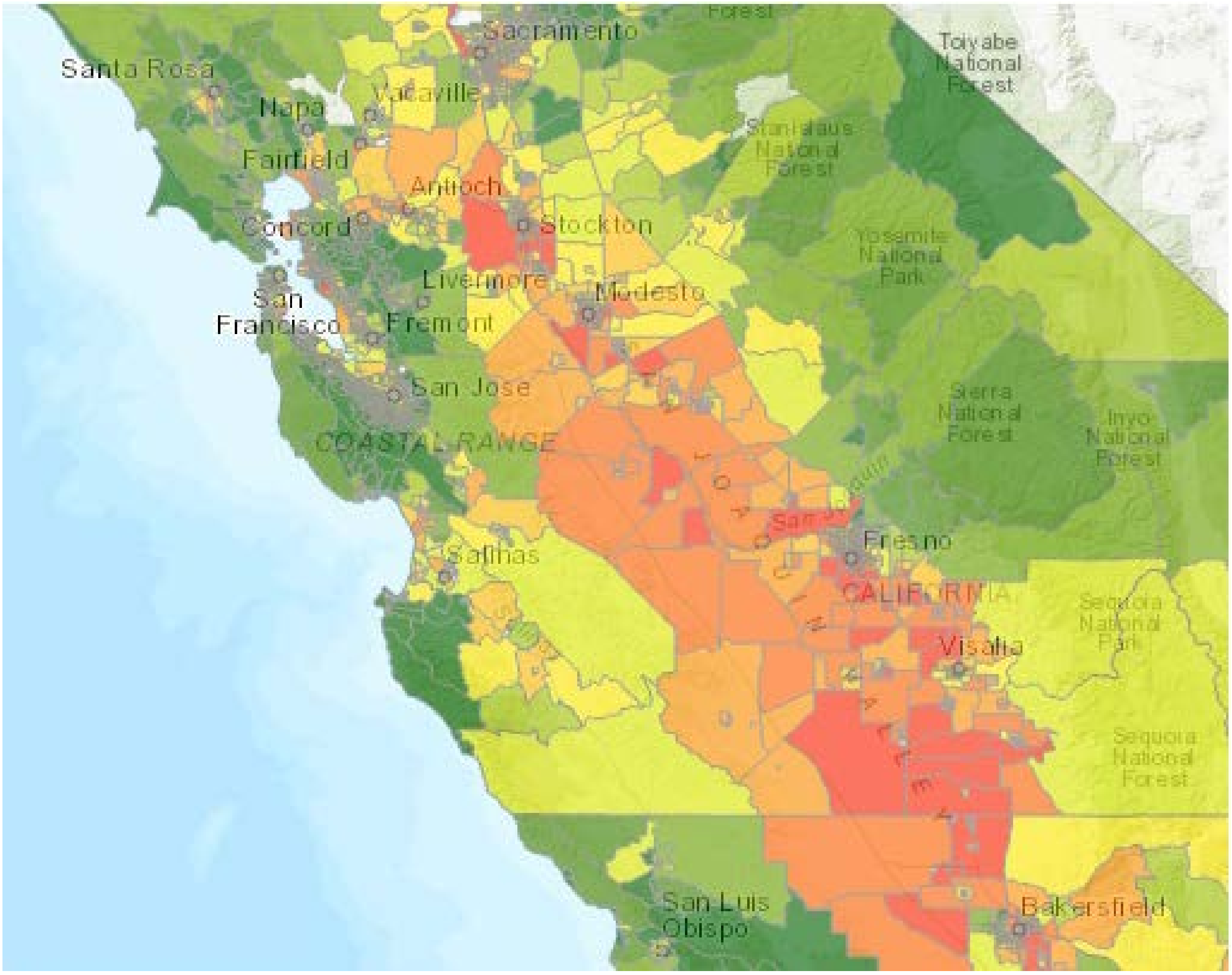
[120] CALEPA, DESIGNATION OF DISADVANTAGED COMMUNITIES PURSUANT TO SENATE BILL 535 (DE LEÓN) 1-32 (Apr. 2017), https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf. All eight counties of the San Joaquin Valley exhibit the highest scores indicating the greatest pollution burden relative to the rest of California. *See Maps & Data*, CAL. OFFICE OF ENV’T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/maps-data (last visited Mar. 25, 2022) (flagging areas of California that exhibit high to low pollution burden scores); *see also infra* page 27, San Joaquin Valley CalEviroScreen 4.0 map.

[121] Section 39711 of the Health and Safety Code sets the ceiling for low-income communities at 120% of the area median income. Additionally, Section 39711 designates communities with disproportionate environmental impacts and concentrations of low income, high unemployment, low educational attainment, and other burdensome socioeconomic factors as disadvantaged communities. Attach. 10, *Income Limits*, U.S. DEP’T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il.html#2020_data (last updated Apr. 1, 2020) (choose 30% Income Limit for ALL Areas (Excel)); Attach. 11, *FY 2020 State Income Limits* (2020), U.S. DEP’T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il/il20/State-Incomelimits-Report-FY20r.pdf.

[122] Attach. 12, *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Mar. 25, 2022).

[123] Poverty rates in every single county in the San Joaquin Valley also exceed poverty rates in California, with Merced and Tulare facing 17 and 18.9 percent poverty rates, respectively (as compared to 11.8 percent at the statewide level). *Id.*

San Joaquin Valley, CalEnviroScreen 4.0



San Joaquin Valley residents are disproportionately Latino as compared to California as a whole. All eight San Joaquin Valley Counties have higher Latino populations than the state, with populations ranging from 42 percent to 65.6 percent, as compared to the state population with 39.4 percent of residents classified as Latino. At least seven of eight San Joaquin Valley counties have a lower proportion of white residents as compared to the state as a whole.[124] Merced and Tulare counties have white, non-Latino populations of 26.5 and 27.7 percent, and Latino populations of 65.6 and 61 percent, respectively.[125] Like Merced and Tulare, Kern County also demonstrates much higher Latino populations than the rest of the state, with a Latino population of 54.6 percent.

[124] According to recent census data, 36.5 percent of the state population is classified as white, non-Latino, while 7 of the 8 counties in the San Joaquin Valley have white, non-Latino populations that range from only 26.5 to 33.2 percent. *Id.*
[125] *Id.* at 114.

i. Factory farm gas increases ammonia emissions.

Industrial dairies in the San Joaquin Valley are the largest source of ammonia.[126] Factory farm gas production adds even more ammonia to the air basin: one study documents that ammonia emissions from digestate increased 81% relative to raw manure.[127] Anaerobic digestion causes this increase in ammonia emissions, "due to an increased concentration of ammoniacal nitrogen."[128] Ammonia reacts with oxides of nitrogen to form ammonium nitrate, the most significant component of the San Joaquin Valley's PM2.5 pollution problem.[129]

CARB has analyzed the impact of ammonia emissions on ambient PM2.5 as part of the recent 2018 PM2.5 Plan for the Valley. CARB found that ammonia contributed 5.2 $\mu g/m^3$ to the ambient air and found that a 30 percent and 70 percent reduction in ammonia would result in a range of ambient reductions in PM2.5 from 0.08 to 2.3 $\mu g/m^3$.[130] For context, the 2012 annual PM2.5 standard is 12 $\mu g/m^3$.[131] The overall contribution of ammonia from current dairy activities would only increase as more anaerobic digesters cause an increase in ammoniacal nitrogen in the digestate and thus increase ammonia emitted into the air basin. This air pollution impact interferes with efforts to attain the PM2.5 24-hour and annual standards and causes a disparate impact on the basis of race and income. CARB cannot ignore this reality and must grant the Petition.

ii. Factory farm gas electricity pathways increase ozone and PM2.5 precursors.

The Petition identifies the on-site combustion of factory farm gas using internal combustion engines to power turbines for electricity generation at dairy operations as a significant air quality impact in the San Joaquin Valley Air Basin.[132] This form of factory farm gas fuel pathway to generate LCFS credits produces negative CI fuel pathways designated for electric vehicles. For example, CARB certified a pathway for such fuel generated at the Hilarides Dairy for a -758.46 CI in B016301[133] and at the Bidart-Old River Dairy for a -558.62 CI in B005901.[134] To date, Petitioners have identified eight certified pathways generating electric vehicle fuel in factory farm gas-powered engines, all located in the San Joaquin Valley, and an

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[126] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS, APPENDIX B AND APPENDIX G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf *and* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
[127] *See* Holly, et al., *supra* note 41.
[128] *Id.*
[129] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS, APPENDIX B AND APPENDIX G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf *and* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
[130] SJVAPCD, 2018 PM2.5 PLAN, APPENDIX G, 3 and tables 2 through 7 (Oct. 2018), https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
[131] *See* 78 Fed. Reg. 3086 (Jan. 15, 2013).
[132] Petition, *supra* note 1, at 30.
[133] CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B016301 (certified June 21, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0163_cover.pdf.
[134] CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B005901 (re-certified Mar. 25, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0059_cover.pdf.

additional number of similar facilities out of state.[135] Petitioners have further identified an additional three pending pathway certification applications, including one for the Lakeview Dairy.[136]

These fuel pathways represent a pollution-intensive form of fuel and one that rewards the developer with an extremely low CI value, creating an incentive to further develop this form of fuel pathway and thus even more air pollution in the Valley. To illustrate, the Lakeview Dairy Biogas project in Kern County uses two internal combustion engines to produce over 1,000 kW of electricity on-site and has applied for a fuel with a -382.98 CI value.[137] And this project, as permitted by the Air District with required pollution control technology, still emits 4.58 tons/year of NOx, 1.98 tons/year of PM2.5, and 3.18 tons/year of VOC after the imposition of Best Available Control Technology as required by the State Implementation Plan.[138] Compared to a natural gas combined cycle plant in Avenal also permitted by the Air District, the Lakeview digester project produces much higher levels of NOx, sulfur oxides (SOx), and VOC emissions per unit of electricity generated.[139] However, unlike the natural gas plant, Lakeview Dairy Biogas is not required to purchase emission reduction credits for the air pollution emitted.[140] This facility *increases* air pollution in the San Joaquin Valley.

With eight certified pathways and at least three more pending, CARB will soon be allowing the functional equivalent of the Avenal Power Center operating at about 50 percent capacity and without having offset that pollution with emission reduction credits. Another dozen electric fuel pathways powered by factory farm gas-fueled engines at Valley dairies would emit the same amount of NOx pollution as Avenal at full capacity, but only generate 4.4 percent of the electricity.[141] A similar pattern results from the emissions of VOCs.[142] This absurdity is compounded by Air District offset thresholds such that the digester engines do not buy emissions offsets and thus add more air pollution to the air basin, while in theory the Avenal Power Center would have had to purchase offsets from other sources to achieve a no net increase. This occurs in one of the most polluted air basins in the United States and classified as nonattainment for several fine particulate matter National Ambient Air Quality Standards.[143] CARB has effectively allowed the LCFS to add more air pollution to the San Joaquin Valley, call it "renewable" fuel

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[135] *See* CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APPS. B001901, B003701, B008901, B005901, B016601, B003801, B002401, and B016301.
[136] *See* CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APPS. B0104, B0105, and B0106.
[137] SJVAPCD, NOTICE OF PRELIMINARY DECISION – AUTHORITY TO CONSTRUCT (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf; CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B0104 (certified TBD), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.
[138] SJVAPCD, *supra* note 137, at 14.
[139] Attach. 13, Digester v. Avenal Comparison; Attach. 14, SJVAPCD, NOTICE OF FINAL DETERMINATION OF COMPLIANCE, AVENAL POWER CENTER, 3, 27 (Dec. 17, 2010). Producing 1.059 megawatts and emitting 4.58 tons/year of NOx, the Lakeview turbine generates 0.17 percent of the electricity while the engines powering the turbine emit 4.6 percent of the NOx pollution.
[140] Attach. 15, SJVAPCD, NOTICE OF PRELIMINARY DECISION – AUTHORITY TO CONSTRUCT 14 (Mar. 22, 2016).
[141] Digester v. Avenal Comparison, *supra* note 139. This assumes that Lakeview represents the average emissions from these factory farm gas operations.
[142] *Id*.
[143] 80 Fed. Reg. 18,528 (April 7, 2015); 81 Fed. Reg. 84,481 (November 23, 2016); 80 Fed. Reg. 2,206, 2,217 (January 15, 2015).

for electric vehicles, and then allows credits from that fuel to be sold to fossil fuel deficit holders who then may increase the pollution from their fuels sold in California. By allowing polluting factory farm gas to generate credits for "renewable" electric vehicle fuel, despite the harmful health impacts associated with emissions from the use of factory farm gas to generate that electricity, CARB ignores its statutory obligation not to "interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."[144] CARB must also grant the Petition and ensure the LCFS-related air pollution does not inflict a disparate impact on the basis of race, and must ensure that the LCFS complies with AB 32, Government Code § 11135, and Title VI of the Civil Rights Act.

d. Factory farm gas fuels consume significant energy inputs to produce which render factory farm gas much more pollution intensive than previously disclosed.

As noted above, Petitioners have submitted comments on dozens of pathway certifications and consistently have objected to the heavy redaction of information as proprietary and confidential business information. Until recently, Petitioners have not seen some of the fuel inputs for factory farm gas development as a result of this heavy-handed redaction. But recently, fuel pathway applications from Wisconsin-based factory farm gas operators shed much-needed transparency on the energy-intensive generation of factory farm gas. CARB should grant the Petition and, because such information was unavailable at the time of the Petition, also consider and disclose net energy consumption when calculating the CI values for factory farm-gas derived fuels.

First, the significance of the redactions to date have rendered meaningful public review of fuel consumption and energy inputs impossible. Below is an example of an application from a Sacramento-area factory farm gas project which claimed one of the largest negative CIs.[145]

[144] § 38562(b).

[145] SMUD, NEW HOPE DAIRY DIGESTER GREET LCFS PATHWAY TO PRODUCE ELECTRICITY TO CHARGE ELECTRIC VEHICLES IN SMUD REGION & CALIFORNIA (Dec. 4, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0166_1_report.pdf.

Sacramento 1500 Cow dairy 06/03/2021

4. Life Cycle Results for Carbon Intensity

The calculated Carbon Intensity for New Hope dairy digester system to charge electric vehicles = **-750.81 gCO_{2e}/MJ**, see table below.

[redacted]

Page | 8 New Hope Dairy Digester to EV Pathway Application No. B0166 Facility ID: F00255 Copyright © 2020

Still other pathway applications fully redact all input data and only disclose the final CI. This CI calculation from the Western Sky Dairy in Kern County illustrates this degree of redaction.[146]

Exhibit 25. Total Carbon Intensity for Dairy Manure Pathway-Western Sky Biogas LLC

Process Stage	Carbon Intensity (gCO_2e/MJ Biogas)
Diesel Consumption	[redacted]
Electricity Consumption	[redacted]
Loss/Fugitives	[redacted]
Biomethane Transmission	[redacted]
Compression of CNG	[redacted]
Tailpipe Emissions	[redacted]
Methane Avoided	[redacted]
CO_2 Diverted	[redacted]
Final CNG CI (gCO_2e/MJ)	-385.40

09/30/2021 Kern County, CA

146 CALIFORNIA BIOENERGY, LIFE-CYCLE ASSESSMENT OF DAIRY MANURE BIOGAS TO CNG (Sep. 30, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_report.pdf. Also noteworthy is the fact that Western Sky Dairy is one of the eight dairies generating reductions credited towards the DDRDP, the Aliso Canyon Mitigation Agreement, and the LCFS.

ATTACHMENT S

Ammonia: Supplemental Information for EPA in Support of 15 µg/m3 Annual PM2.5 Standard

March 2023

Table of Contents

Executive Summary

The California Air Resources Board (CARB) and San Joaquin Valley Air Pollution Control District (District) are providing this information at the request of United States Environmental Protection Agency (EPA) staff to further clarify the assessment of ammonia as a precursor to fine particulate matter (PM2.5) in the San Joaquin Valley (Valley). Specifically, this supplemental information summarizes previous information submitted to EPA and also provides new information intended to support EPA action on the Attainment Plan Revision for the 1997 Annual PM2.5 Standard (15 µg/m3 SIP Revision) submitted to EPA in 2021.

This document summarizes and reinforces the findings on ammonia as a precursor previously submitted to EPA in four documents provided between 2019 and 2021. CARB and the District continue to assert that, as documented in previous submittals, ammonia is not a significant attainment precursor for PM2.5 in the Valley for the 15 microgram per cubic meter (µg/m3) annual PM2.5 standard. PM2.5 is a complex mixture of many chemical species. Roughly 40 percent of PM2.5 is made up of ammonium nitrate particulate which is itself a combination of two precursors, ammonia and oxides of nitrogen (NOx). NOx emissions in the Valley come primarily from mobile sources while ammonia emissions come primarily from area sources. Ammonium nitrate reductions are critical for the Valley to attain the 15 ug/m3 annual PM2.5 air quality standards and provide cleaner air to residents. Ammonium nitrate formation is limited by the precursor, either ammonia or NOx, in least supply. Due to these complex reactions, when a pollutant is abundant, controlling that pollutant may not lead to PM2.5 air quality improvement. In other words, in order to reduce a secondary pollutant like ammonium nitrate PM2.5, controls need to target the pollutant that limits the chemical reaction.

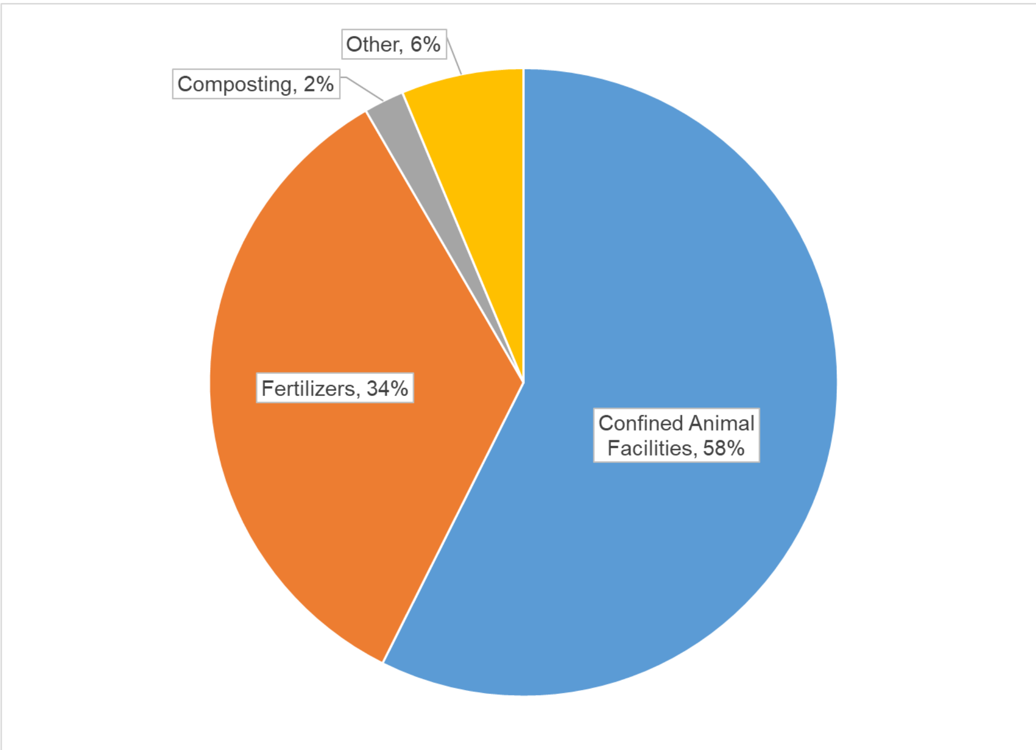
Multiple field studies in the Valley have confirmed that NOx is the limiting precursor to ammonium nitrate formation and that there is a far greater amount of ammonia in the Valley's air than is necessary to participate in the chemistry that leads to ammonium nitrate. Thus, NOx reductions are key for reducing ammonium nitrate and PM2.5 levels in the Valley. The attainment strategy recognizes this scientific finding and calls for significant NOx reductions, primarily achieved through CARB's mobile source control measures. Air quality modeling also shows that the effectiveness of ammonia controls will rapidly decrease through the 2023 timeframe as the Valley's air becomes even more NOx-limited due to dramatic and ongoing reductions in NOx from these mobile source control measures.

EPA guidance recommends modeling emissions reductions of PM2.5 precursors of between 30 and 70 percent to evaluate if precursor emissions reductions have a significant impact on PM2.5 levels, 0.25 µg/m3 for the 15.0 µg/m3 annual PM2.5 standard. At a 30 percent reduction in ammonia emissions, one site, Hanford, exceeded the 0.25 µg/m3 threshold with a value of 0.26 µg/m3. Further, nationwide, ammonia emissions are flat indicating that the sources are not being controlled significantly.

Per EPA's request, the District and CARB analyzed potential control measures to reduce ammonia emissions to evaluate whether a 30 percent reduction in emissions is feasible. Thus, negating consideration of the 70 percent precursor evaluation. For an effective control

measure evaluation, it is necessary to characterize and understand the key sources of ammonia in the Valley. The three main sources of ammonia emissions in the Valley from stationary and area sources, which account for 94 percent of the Valley's ammonia emissions as shown below in Figure ES-1, are the focus of the evaluation. These are confined animal facilities (contributing 186.5 tons per day (tpd) of ammonia emissions in 2023), agricultural fertilizers (111.2 tpd), and composting of solid and biological waste (6.7 tpd)[1].

Figure ES-1: Sources of Ammonia in the San Joaquin Valley



Specific to the confined animal facility category, the District conducted a new, extensive evaluation of potential measures to control sources of ammonia emissions for this submittal for the15 µg/m3 SIP Revision. EPA provided the list of measures to CARB and the District, and requested that the measures and studies referenced be addressed specifically for the Valley. In this evaluation, the District has identified only a few measures that have the theoretical potential to reduce additional ammonia emissions beyond the practices currently enforced through District Rule 4570 (Confined Animal Facilities). These measures are reducing crude protein content in feed for beef finishing cattle, incorporation of solid manure within 24 hours, and acidifying amendments for poultry litter and manure. Despite the technological and economic feasibility issues of these mitigation measures, the District evaluated the potential emission reductions and the impact they might have on the Valley's total ammonia emissions inventory if these measures were to be implemented. Through this

[1] 15 µg/m3 SIP Revision

evaluation, the District identified a total of 6.6 tpd of ammonia emission reductions from confined animal facilities.

For the fertilizer category, CARB has not identified effective mechanisms within its authority to regulate air emissions of ammonia from fertilizers. Furthermore, CARB and the District are unaware of any other jurisdictions with rules regulating fertilizer application. Nor has EPA staff identified any rules applicable to regulating air emissions from non-organic fertilizer application. In addition, CARB and the District did not identify feasible control measures for composting or other emissions sources. Based on this extensive evaluation, identified feasible controls, as summarized below in Table ES-1, can reduce ammonia emissions by approximately 2 percent. Therefore, CARB and the District conclude that a 30 percent reduction in ammonia emissions is not achievable.

Table ES-1. Estimated Feasible Ammonia Emission Reductions

Emissions Category	Emissions (tpd, 2023)	Identified Controls	Feasible Ammonia Reductions
Confined Animal Feeding	186.5	• Reducing crude protein content in feed for beef finishing cattle • Incorporation of solid manure within 24 hours • Acidifying amendments for poultry litter and manure	6.6 tpd
Fertilizers	111.2	No authority or feasible controls identified	0
Composting	6.7	No additional feasible controls identified at this time	0
Other sources	20.5	No feasible controls identified	0
Total Ammonia	324.9		6.6 tpd

CARB has followed EPA guidance to evaluate whether ammonia contributes significantly to PM2.5 levels that exceed the 15 µg/m3 annual standard NAAQS. While a precursor sensitivity analysis showed a small impact when ammonia was reduced by 30 percent, achieving this level of control in practice is infeasible. Thus, considering relevant contextualizing information including available controls, CARB determined that ammonia emission reductions do not improve PM2.5 levels that exceed the annual 15 µg/m3 standard in the San Joaquin Valley. Therefore, CARB has excluded ammonia as an attainment precursor and from control requirements in the SIP.

1. Background

PM2.5 is made up of many constituent particles that are either directly emitted, such as soot and dust, or formed through complex reactions of gases in the atmosphere. NOx, sulfur dioxide (SO2), volatile organic compounds (VOCs), and ammonia are gases that are precursors to PM2.5, transforming into particles through physical and chemical atmospheric processes.

Ammonium nitrate (NH4NO3) is a constituent of PM2.5, making up about 40 percent of PM2.5 mass in the Valley. Ammonium nitrate forms when nitrogen dioxide (NO2) reacts with highly oxidizing species in the atmosphere to form nitric acid (HNO3). Nitric acid then reacts with ammonia (NH3) to yield ammonium nitrate as a particle. Since ammonia reacts chemically in this way to form a particle, ammonia is a precursor to PM2.5.

Lowering PM2.5 concentrations to levels that meet the 15 µg/m3 annual PM2.5 standard will rely upon an effective control strategy for ammonium nitrate. The amount of ammonium nitrate that can form in the atmosphere is limited by whichever precursor, either NOx or ammonia, is in least supply, and research studies confirm that there are relatively fewer NOx molecules in the air in the Valley than ammonia. This implies that reducing NOx, the limiting precursor in this case, is more effective for reducing ammonium nitrate concentrations and thus improving PM2.5 air quality.

The 2018 PM2.5 Plan was developed jointly by CARB and the District to address four PM2.5 federal ambient air quality standards: the 15 µg/m3 annual, 65 µg/m3 24-hour, 35 µg/m3 24-hour, and 12 µg/m3 annual standards. For the 15 µg/m3 annual standard, the 2018 PM2.5 Plan established 2020 as the attainment date. In 2020, one air monitoring site—Bakersfield-Planz—recorded a design value over the standard despite excluding the impacts of wildfires. Since the 2020 attainment date was no longer approvable, EPA proposed, on July 22, 2021, to partially approve and partially disapprove the portions of the 2018 PM2.5 Plan pertaining to the 15 µg/m3 annual standard.[2] Specifically, EPA proposed to disapprove the following SIP elements related to the attainment demonstration for the 15 µg/m3 standard: the precursor demonstration (including for ammonia), BACM/BACT demonstration, five percent demonstration, attainment demonstration, reasonable further progress demonstration, quantitative milestone demonstration, motor vehicle emissions budgets, and contingency measure. EPA proposed to approve the 2013 base year emissions inventories.[3]

[2] 86 FR 38652. EPA's final disapproval published November 26, 2021 (86 FR 67329)

[3] The 2018 PM2.5 Plan used CEPAM 2016 version 1.05. Any new analysis in this supplemental document uses the same version of the emissions inventory.

The District and CARB quickly revised the 2018 PM2.5 SIP to address the disapproval and demonstrate attainment of the 15 μg/m3 annual PM2.5 standard as soon as possible. Accordingly, the agencies worked together to develop the Attainment Plan Revision for the 1997 Annual PM2.5 Standard (15 μg/m3 SIP Revision). The 15 μg/m3 SIP Revision amends the 2018 PM2.5 Plan to update the SIP elements associated with the disapproved attainment demonstration and demonstrates that the Valley will meet the 15 μg/m3 annual PM2.5 standard in 2023, including at the high site of Bakersfield-Planz with a 2023 design value (DV) of 14.7 μg/m3.

The 15 μg/m3 SIP Revision satisfies statutory requirements for a Clean Air Act §189(d) plan for a Serious nonattainment area SIP submission. The Valley is able to demonstrate attainment with reductions in emissions of NOx and PM2.5 coming from (1) ongoing implementation of CARB and the District's existing control strategy, (2) newly adopted CARB and District measures providing near-term reductions, and (3) a CARB aggregate emission reduction commitment made for the 15 μg/m3 SIP Revision for reductions in 2023 from measures in the 2018 PM2.5 Plan. Similar to the precursor demonstration for the 12 μg/m3 annual standard which projected attainment in 2025 and relied upon the 35 μg/m3 24-hour 2024 precursor demonstration, the 15 μg/m3 SIP Revision also relies on the EPA approved.[4] precursor demonstration associated with the 35 μg/m3 24-hour PM2.5 standard. Both are within one year of the 35 μg/m3 24-hour PM2.5 standard attainment deadline and precursor sensitivities can be assumed to be very similar to those modeled in 2024 The District Governing Board adopted the 15 μg/m3 SIP Revision on August 19, 2021, and the CARB Board adopted it on September 23, 2021. Subsequently, CARB submitted the adopted 15 μg/m3 SIP Revision to EPA as a revision to the California SIP on November 8, 2021.

CARB has provided supplemental information on ammonia to EPA on four previous occasions, as outlined below in Table 1. This supplemental document summarizes findings and information in those previous submittals, and also provides new, extensive evaluation. It is provided in support of EPA action on the 15 μg/m3 SIP Revision.

[4] See also "Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS," February 2020.

Table 1. Previous Submittals to EPA of Supplemental Information on Ammonia

Document	Date Provided to EPA	Delivery Method(s)	Key Points
Appendix G 2018 PM2.5 Plan	January 2019	The precursor analysis required for the SIP by the CAA	• Includes sensitivity analyses showing that 30% reduction of ammonia in the SIP base year of 2013 would have PM2.5 benefit, but in future years as the Valley becomes more NOx-limited, ammonia reductions would not have PM2.5 benefit • Considering relevant contextualizing information such as emissions trends, research, and available controls, CARB determined that emissions of ammonia do not contribute significantly to PM2.5 levels that exceed the PM2.5 standards in SJV, and therefore excluded ammonia from control requirements in the SIP.
Submittal letter with attachment	May 2019	Provided as attachment to letter submitting the comprehensive 2018 PM2.5 SIP to EPA	• Cites studies showing ammonia is in excess of NOx in the Valley, making NOx the limiting precursor to control for PM2.5 benefits • Indicates that the Valley will only become more NOx-limited in future years as NOx continues to decrease and ammonia levels remain stable • Highlights CARB research efforts on ammonia
Clarifying Information on Ammonia	October 2019	Emailed directly to EPA staff	• Explains that 30% ammonia reduction is infeasible, points out that fertilizer (a major ammonia source in SJV) is not within CARB's authority to control • Explains that SJVAPCD is already implementing BACT for ammonia • Summarizes ammonia-related research at CARB
Ammonia Update 2017 Data for EPA	September 2021	Emailed directly to EPA staff and published as attachment to staff report for Board item related to SJV PM2.5	• Provides new data from a 2017 study in the Valley supporting our previous findings that ammonia is not a significant precursor

2. Precursor Demonstration

EPA finalized a PM2.5 SIP Requirements Rule[5] (Rule) that identifies the four PM2.5 precursor pollutants—NOx, SO_2, VOCs, and ammonia—that "must be evaluated for potential control measures in any $PM_{2.5}$ attainment plan."[6] The Rule permits air agencies to "submit an optional precursor demonstration designed to show that for a specific PM2.5 nonattainment area, emissions of a particular precursor from sources within the nonattainment area do not or would not contribute significantly to PM2.5 levels that exceed" the National Ambient Air Quality Standards (NAAQS).[7] If the agency's demonstration is approved by EPA, the attainment plan "may exclude that precursor from certain control requirements under the Clean Air Act."[8]

In Appendix G to the 2018 PM2.5 Plan, CARB included precursor demonstrations for three PM2.5 precursors, including ammonia. Following EPA guidance, the ammonia precursor demonstration analyzed "the relationship between precursor emissions and the formation of secondary PM2.5 components"[9] using an air quality model, and take into consideration additional relevant factors.

EPA PM2.5 Precursor Demonstration Guidance

In November 2016, EPA published a draft guidance document to "assist air agencies who may wish to submit PM2.5 precursor demonstrations."[10] The document provides recommendations or guidelines, as authorized under the Clean Air Act, "that will be useful to air agencies in developing the precursor demonstrations by which the EPA can ultimately determine whether sources of a particular precursor contribute significantly to PM2.5 levels that exceed the standard in a particular nonattainment area."[11] Recommendations include modeling procedures for conducting the required analysis and contribution thresholds to determine the impact of a precursor on PM2.5 levels.[12] The guidance also describes an analytical process to perform the precursor demonstration, involving (1) a concentration-based analysis followed by (2) a sensitivity-based analysis and (3) consideration of additional information including what is achievable through controls.

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[5] 81 FR 58010 (August 24, 2016)
[6] EPA. *PM2.5 Precursor Demonstration Guidance: Draft for Public Review and Comment*. 17 Nov. 2016. Web. 3 Oct. 2017. <www.epa.gov/sites/production/files/2016-11/documents/transmittal_memo_and_draft_pm25_precursor_demo_guidance_11_17_16.pdf>. Page 7
[7] Ibid. 7
[8] Ibid. 7
[9] Ibid. 26
[10] Ibid. 7
[11] Ibid. 7-8
[12] Ibid. 9

Concentration-Based Analysis

The evaluation of precursors begins with a concentration-based analysis using ambient data to determine whether precursor emissions contribute to total PM2.5 concentrations.[13] Each precursor's impact on total $PM_{2.5}$ mass is compared to contribution thresholds. EPA recommends values for these thresholds, or air quality concentrations below which air quality impacts are not statistically significantly different from "the inherent variability in the measured atmospheric conditions," and thus do not contribute to PM2.5 concentrations that exceed the NAAQS.[14] The threshold given in the guidance document is 0.2 µg/m3 for the annual PM2.5 standard.[15] This threshold was calculated based on EPA's guidance for the 12 µg/m3 annual NAAQS. If adjusted to reflect the 15 µg/m3 annual standard, the 0.2 µg/m3 threshold for the 12 µg/m3 annual PM2.5 standard increases to 0.25 µg/m3 for the 15 µg/m3 annual PM2.5 standard. As shown below in Table 2, based on this metric, ammonia contributes to total PM2.5 mass in the Valley in amounts that exceed EPA's recommended thresholds.

Table 2. Contribution of Ammonia to Total PM2.5 Mass

Species	Precursor	Species Contribution (ug/m3) to PM2.5 Mass*	Over Threshold?
Ammonium nitrate	Ammonia	5.2	Yes

* 2015 annual average for Bakersfield

This concentration-based analysis, however, does not accurately capture the impact of reductions of precursor emissions on PM2.5 levels. Since the concentration-based analysis shows the precursors contribute to total PM2.5 mass in amounts over EPA's recommended thresholds, CARB proceeded to conduct an optional sensitivity-based analysis to demonstrate that reductions of ammonia will have a negligible impact on PM2.5.

Sensitivity-Based Analysis

The SIP Requirements Rule allows for a sensitivity-based analysis to examine the degree to which PM2.5 levels are sensitive to precursor reductions. According to the guidance:

> This modeling analysis examines the sensitivity of ambient $PM_{2.5}$ concentrations in the nonattainment area to certain amounts of decreases in the precursor emissions in the area…. Where decreases in emissions of the precursor result in negligible air quality impacts (i.e., the area is "not sensitive" to decreases), such a small degree of impact is

[13] Ibid. 8
[14] Ibid. 14, 15
[15] Ibid. 15-16

not significant and can be considered to not "contribute" to PM2.5 concentrations for the purposes of determining whether control requirements should apply.[16]

Generally, EPA recommends that the precursor demonstration "should be based on current conditions to demonstrate that precursor emissions do not contribute significantly to $PM_{2.5}$ concentrations in the nonattainment area."[17] This means evaluating emissions in a selected base year, which may be the present or a previous year.

For each existing PM2.5 monitor location in the area,[18] the first step for estimating PM2.5 impacts from ammonia in the base year is to estimate the average PM2.5 concentration on an annual basis. The second step is to calculate the annual average PM2.5 concentration at each monitor with a specified percent reduction in precursor emissions, still in the base year.[19] The difference between these two calculated PM2.5 values is the impact on PM2.5 levels from precursor emissions reductions.[20] Note that "precursor demonstrations do not examine changes in emissions *between a base year and a future year*. Instead, the calculation of relative changes in $PM_{2.5}$ concentrations occur *between a modeled case with all emissions and a modeled case with reduced precursor emissions*" (emphasis added).[21] In addition, EPA recommends modeling reductions of between 30 and 70 percent of precursor emissions.[22]

EPA guidance recommends a range of 30 to 70 percent since emission reductions need to be large enough to test the interaction of the precursor. In general, the recommended range is reasonable for NOx and SO2, this range is not reasonable for ammonia. As indicated in the EPA guidance, between 2011 and 2017, the median change in SO2 and NOx emissions was -63.6 and -31.8 percent, while the median change in ammonia was a positive 0.8 percent. The large reductions in NOx and SO2 emissions are in response to reasonable controls that are available and in practice at sources. The slight increase nationally of ammonia is indicative of the lack of controls on ammonia sources across the nation. While new types of controls are being developed for ammonia, the availability and magnitude of ammonia controls that meet EPA's requirements for submittal into the SIP along with ammonia emission reductions trends support that the 30 percent reduction may not be reasonable.

The third step in the sensitivity-based analysis is to compare the modeled impact on PM2.5 levels from a decrease in ammonia emissions to contribution thresholds for annual average PM2.5. Following the analytical process outlined in the EPA precursor demonstration guidance and summarized above, CARB has evaluated ammonia in the Valley. The results of the sensitivity-based analysis and consideration of additional information are presented below.

[16] Ibid. 25
[17] Ibid. 33
[18] Ibid. 16
[19] Ibid. 36
[20] Ibid. 36
[21] Ibid. 34
[22] Ibid. 29

CARB staff used an air quality model to estimate the PM2.5 design value for the annual standard in the base year of 2013 at each Valley monitor. Then, CARB staff applied the recommended lower bound of a 30 percent reduction to ammonia emissions and used the air quality model to estimate the PM2.5 design values. The difference between the two design values represents the modeled impact on PM2.5 levels of a 30 percent reduction in ammonia emissions in 2013. This is the value that is compared to EPA's adjusted contribution threshold for the 15 µg/m3 annual standard of 0.25 µg/m3 to establish if PM2.5 levels are sensitive to this level of ammonia reduction. For completeness, CARB staff repeated this analysis, applying instead the EPA-recommended upper bound of a 70 percent reduction to ammonia emissions in the base year. The results are shown in Table 3.

Table 3. Base Year 2013 PM2.5, 30 and 70 Percent Reduction in Ammonia Emissions

Site	2013 Baseline DV	2013 DV with 30% Ammonia Reduction	Difference	2013 DV with 70% Ammonia Reduction	Difference
Bakersfield-Planz	17.19	16.76	0.43	15.72	1.47
Madera	16.93	16.29	0.64	14.81	2.12
Hanford	16.54	15.82	0.72	14.24	2.30
Visalia	16.20	15.82	0.38	14.80	1.40
Clovis	16.12	15.80	0.32	14.95	1.17
Bakersfield-California	16.02	15.58	0.44	14.47	1.55
Fresno-Garland	14.98	14.69	0.29	13.91	1.07
Turlock	14.88	14.46	0.42	13.46	1.42
Fresno-HW	14.22	13.95	0.27	13.17	1.05
Stockton	13.14	12.84	0.30	12.10	1.04
Merced-S Coffee	13.10	12.65	0.45	11.60	1.50
Modesto	13.03	12.66	0.37	11.78	1.25
Merced-M	10.97	10.77	0.20	10.23	0.74
Manteca	10.09	9.85	0.24	9.27	0.82
Tranquility	7.72	7.33	0.39	6.46	1.26

From this analysis, the estimated air quality impact of reducing ammonia emissions by the lower bound of 30 percent in the base year exceeds EPA's adjusted annual threshold of 0.25 µg/m3 at all but two Valley monitors for the SIP base emission inventory year, 2013, 10 years ago. Reducing emissions by the upper bound of 70 percent also shows impacts above the threshold for this time period.

It is not possible, however, to conclude from this analysis that emissions of ammonia contribute significantly to PM2.5 levels. In this case, ammonia emissions have an impact above the recommended contribution threshold even at the lower bound of 30 percent emission reduction, but this does not necessarily mean the precursor contributes significantly to PM2.5 levels that exceed the NAAQS. Making the appropriate determination about the ammonia emission reduction impact requires further analysis of additional factors, such as future emission controls and potential controls on the precursors as allowed per the EPA guidance.

Consideration of Additional Information

To supplement modeling analysis, EPA guidance also allows an air agency to consider additional information, assessing the significance of a precursor "'based on the facts and circumstances of the area.'"[23] The guidance states:

> If the estimated air quality impact exceeds the recommended contribution thresholds…, this fact does not necessarily preclude approval of the precursor demonstration. There may be cases where it could be determined that precursor emissions have an impact above the recommended contribution thresholds, yet do not "significantly contribute" to levels that exceed the standard in the area.[24]

In these cases, an air agency may "provide EPA with information related to other factors they believe should be considered in determining whether the contribution of emissions of a particular precursor to levels that exceed the NAAQS is 'significant' or not."[25] Such factors may include: trends in emissions of other precursors such as NOx,[26] anticipated growth or loss of emissions sources,[27] and the consequent appropriateness of modeling impacts in a future year instead of a base year;[28] "available emissions controls,"[29] and "the severity of nonattainment at relevant monitors."[30] Other factors the agency may consider are: the amount by which a precursor's contribution exceeds the recommended contribution thresholds; source characteristics (e.g., source type, stack height, location); analyses of speciation data and precursor emission inventories; chemical tracer studies; and special

[23] Ibid. 17
[24] Ibid. 17
[25] Ibid. 17
[26] Ibid. 17
[27] Ibid. 17
[28] Ibid. 33
[29] Ibid. 29
[30] Ibid. 17

intensive measurement studies to evaluate specific atmospheric chemistry in an area. The agency may also provide other information not listed here.[31]

CARB and the District conducted additional analysis related to these factors in accordance with EPA guidance to provide information related to other factors beyond the concentration- and sensitivity-based analyses that should be considered in determining whether the contribution of ammonia emissions to levels that exceed the 15 µg/m3 annual PM2.5 is "significant" or not. These analyses are described below.

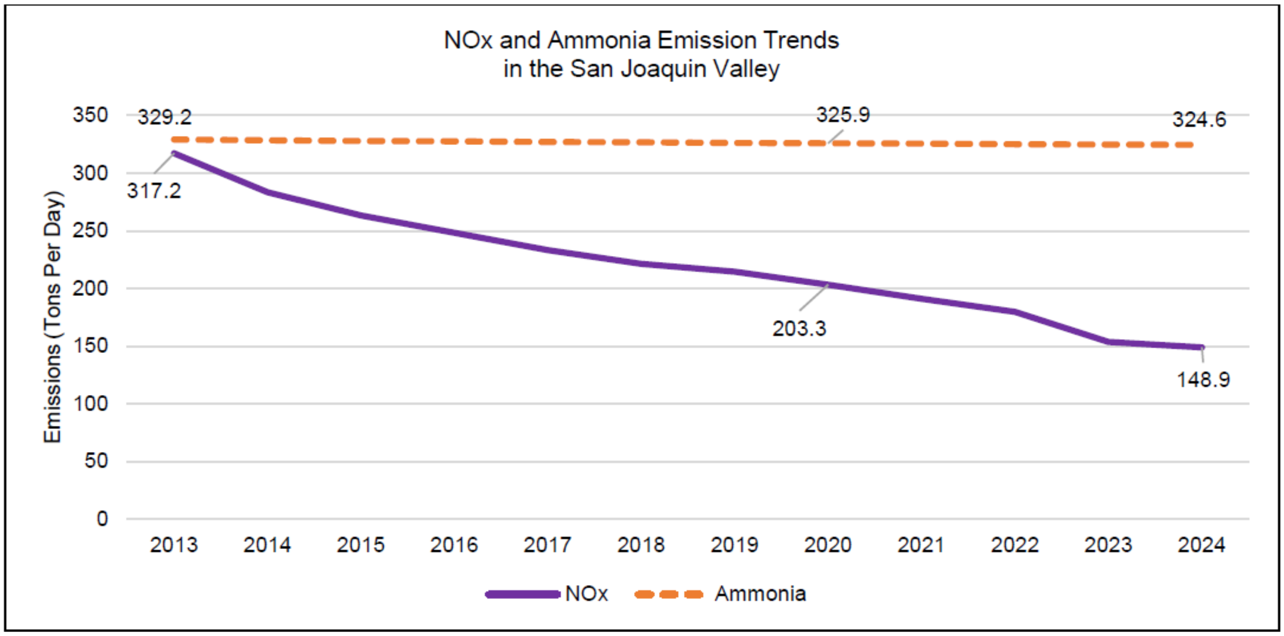
Emissions Trends and Studies

CARB has an extensive suite of measures in place to reduce NOx emissions from mobile sources that reduce ammonium nitrate. Between 2013 and 2024, total NOx emissions are projected to decline 53 percent. Meanwhile, total ammonia emissions are expected to remain flat, as shown in Figure 1. The District adopted four rules[32] between 2004 and 2011 with measures that provided ammonia emissions reductions in the Valley; however, reductions from these existing control measures are already accounted for in the inventory, prior to the 2018 PM2.5 SIP base year of 2013. In the future, emissions from the main sources of ammonia—dairies, fertilizer, and non-dairy livestock operations—are not anticipated to either increase or decrease substantially.

[31] Ibid. 17

[32] District Rule 4550: Conservation Management Practices (adopted 2004); Rule 4565: Biosolids, Animal Manure, and Poultry Litter Operations (adopted 2007); Rule 4566: Organic Material Composting Operations (adopted 2011); and Rule 4570: Confined Animal Facilities (adopted 2006, amended 2010)

Figure 1. NOx and ammonia emission trends in the San Joaquin Valley between 2013 and 2024



Source: CEPAM 2016 v 1.05

The steep downward trend of NOx emissions and the stability of ammonia emissions between 2013 and 2024 along with the time that has passed since 2013, lead CARB staff to conclude that modeling the impact of ammonia emissions reductions in the future, rather than the base year, is appropriate and more representative of the Valley's emissions conditions. EPA guidance states that, in some situations, it may be "more appropriate to model future conditions that provide a more representative sensitivity analysis."[33] This approach is applicable in the Valley. Although emissions of NOx and ammonia are of roughly similar magnitude in the base year, thereby leading to some modeled sensitivity of PM2.5 levels to a 30 percent reduction in ammonia emissions, these conditions do not persist and are not representative in the future.

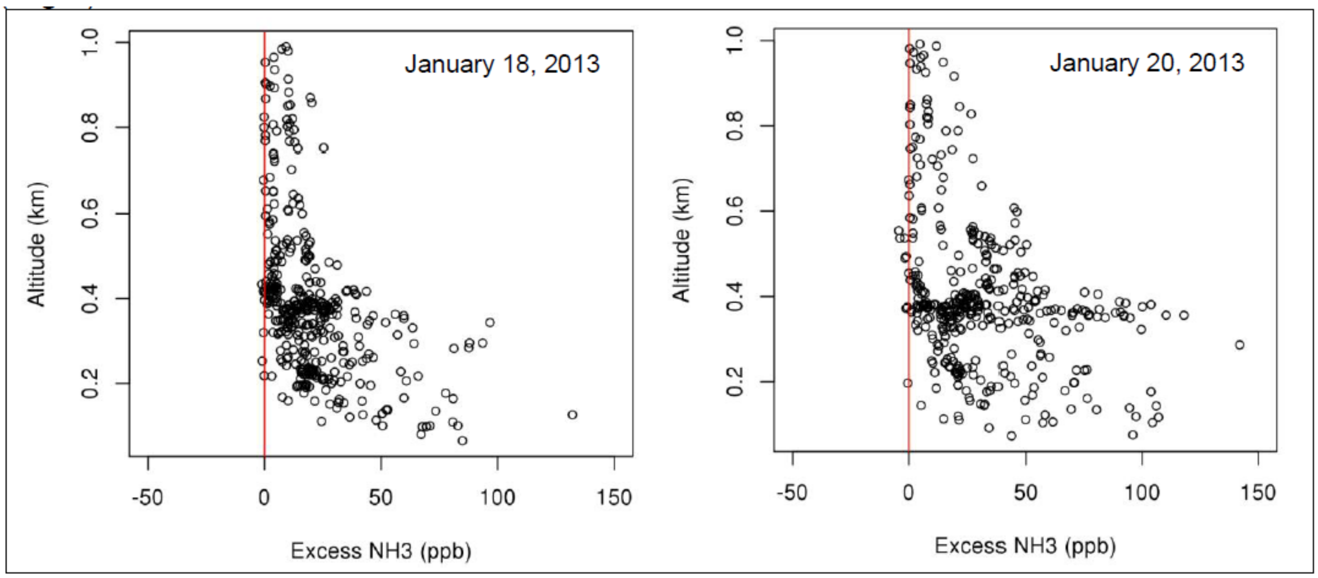
As early as the 1995 Integrated Modeling Study (IMS95), in situ measurements in the San Joaquin Valley indicated the region was ammonia-saturated, which supports NOx being the controlling precursor to ammonium nitrate formation (Kumar et al., 1998; Blanchard et al, 2000). Wintertime measurements five years later during the CRPAQS field study (December 1999 through February 2001) were consistent with the IMS95 findings, where nearly all of the measurements were ammonia-saturated (Lurmann et al., 2006). Lurmann et al. (2006) note that "[t]he consistent excess of NH3 over nitric acid levels indisputably

[33] EPA. PM2.5 Precursor Demonstration Guidance: Draft for Public Review and Comment. Page 33

shows that secondary ammonium nitrate formation is more limited by nitric acid availability than NH3 within the SJV and in the foothills."[34]

More recent measurements during the DISCOVER-AQ field campaign in January and February 2013 (Parworth et al., 2017; and Figure 2), support previous findings of an ammonia-saturated environment, where a small to moderate reduction in ammonia emissions is likely to have little to no effect on ammonium nitrate concentrations.

Figure 2. Excess ammonia (NH3) in the San Joaquin Valley on Jan 18 (Left) and Jan 20 (Right) based on NASA aircraft measurements in 2013



Since ammonium nitrate formation is limited by NOx, reducing NOx emissions is the more effective strategy for reducing ammonium nitrate and PM2.5. Other research has found that ammonia concentrations in the San Joaquin Valley have increased, further confirming that NOx reductions are the most effective path to reducing PM2.5.

A 2017 study using satellite data also aligns with this previous research. Measurements of column-integrated ammonia taken from the Infrared Atmospheric Sounding Interferometer (IASI), an instrument housed aboard the European Space Agency's MetOP-A satellite which passes over California daily, suggest that CARB's emissions inventory currently underestimates ammonia emissions in the Valley. These results suggest the 2018 PM2.5 Plan modeled sensitivity to ammonia reductions is overstated and further reinforces the efforts to develop and deploy ammonia controls would not move the Valley forward on the path to reducing PM2.5 concentrations, and that NOx emissions reductions are the most effective strategy to reduce ammonium nitrate.

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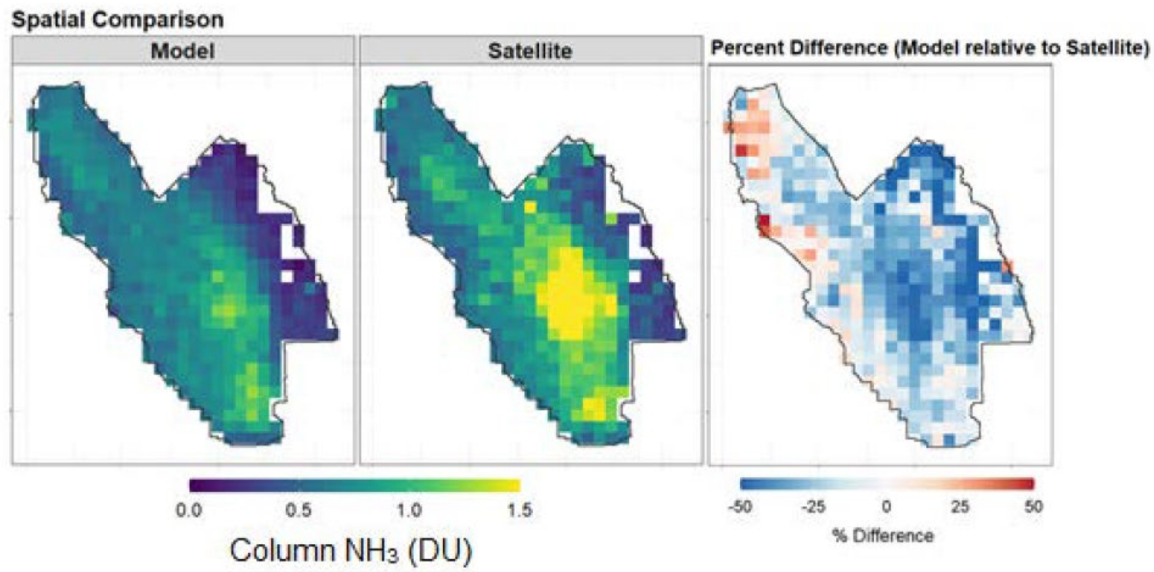
[34] Lurmann et al. "Processes influencing secondary aerosol formation in the San Joaquin Valley during winter." Journal of the Air & Waste Management Association. 2006. Web. 3 Oct. 2017. Page 1688

Figure 3 shows the annual average of column ammonia in 2017 from IASI (Satellite) and Community Multiscale Air Quality (CMAQ) (Model). The model is biased low for column ammonia in the Valley. This bias is most noticeable in Tulare County, where both the model and satellite show an ammonia hotspot, but the model shows about half as much ammonia as the satellite.

Figure 3. Maps of annual average ammonia from CMAQ (Model; left), IASI (Satellite; middle), and the percentage difference (DU, 1 DU = 2.69e16 molecules/cm2)



With these new findings from the 2017 study aligning with previous findings from IMS95, CRPAQS, and DISCOVER-AQ, CARB staff's conclusion based on the scientific analysis available continues to be that focusing on NOx emission reductions is key to improving the health of Valley residents and actions to reduce ammonia will not provide significant PM2.5 air quality improvements.

Future Year Modeling

Analysis of NOx and ammonia emissions trends, discussed above, indicated that modeling the impact of ammonia emissions reductions in the future, rather than the base year, is appropriate and more representative of the Valley's emissions conditions. In accordance with EPA guidance, CARB staff repeated the sensitivity-based analysis of ammonia for the future year of 2024.[35] Staff used an air quality model to estimate the PM2.5 design value for the annual standard in 2024 at each Valley monitor. Then, CARB staff applied a 30 percent

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[35] The attainment year for the 15 µg/m3 annual standard, as presented in the 15 µg/m3 SIP Revision, is 2023. Since 2023 is only one year before 2024, precursor sensitivities in 2023 are assumed to be very similar to those modeled in 2024. Thus, CARB's determination in the 2018 PM2.5 Plan—that emissions of ammonia do not contribute significantly to PM2.5 levels that exceed the standards in the area—remains the same in relation to the 15 µg/m3 SIP Revision, and CARB continued to exclude ammonia from control requirements in the SIP.

reduction to ammonia emissions and used the air quality model to estimate the PM2.5 design values in 2024. The difference between the two design values represents the modeled impact on PM2.5 levels of a 30 percent reduction in ammonia emissions in each attainment year. For completeness, CARB staff repeated this analysis, applying instead the EPA-recommended upper bound of a 70 percent reduction to ammonia emissions in 2024. The results are shown in Table 4.

Table 4. Future Year 2024 PM2.5, 30 and 70 Percent Reduction in Ammonia Emissions

Site	2024 Baseline DV	2024 DV with 30% Ammonia Reduction	Difference	2024 DV with 70% Ammonia Reduction	Difference
Bakersfield-Planz	12.03	11.79	0.12	11.55	0.36
Madera	11.98	11.77	0.21	11.32	0.66
Hanford	10.52	10.26	0.26	9.77	0.75
Visalia	11.09	10.97	0.12	10.71	0.38
Clovis	11.37	11.27	0.10	11.05	0.32
Bakersfield-California	11.01	10.78	0.12	10.54	0.36
Fresno-Garland	10.43	10.33	0.10	10.22	0.32
Turlock	11.14	10.95	0.16	10.53	0.61
Fresno-HW	10.02	9.92	0.10	9.68	0.34
Stockton	10.66	10.50	0.16	10.14	0.52
Merced-S Coffee	9.65	9.47	0.18	9.12	0.53
Modesto	9.97	9.79	0.18	9.41	0.56
Merced-M	8.61	8.53	0.08	8.35	0.26
Manteca	7.97	7.85	0.12	7.57	0.40
Tranquility	5.54	5.42	0.12	5.19	0.35

In 2024, the modeled air quality impact of reducing ammonia emissions by 30 percent falls under EPA's adjusted annual threshold of 0.25 µg/m3 for the 15 µg/m3 annual standard at all but one Valley monitor. The estimated air quality impact of reducing ammonia emissions by the upper bound of 70 percent in 2024 exceeds EPA's recommended thresholds for the annual standard at all sites. It is important to note that while EPA recommends a 30 percent analysis, achieving a 30 percent reduction in ammonia is not feasible.

Relevant Monitors

The impact of ammonia on PM2.5 at monitors that form the basis of the attainment finding for the Valley is the focus of this analysis. For purposes of demonstrating attainment of the PM2.5 standards, the design sites are Bakersfield and Fresno. EPA guidance permits consideration of "the severity of nonattainment at relevant monitors,"[36] and in 2024, PM2.5 levels are not sensitive to ammonia reductions at these design sites.

The Hanford site shows an impact that is 0.01 µg/m3 over the adjusted 0.25 µg/m3 threshold for the 15 µg/m3 annual PM2.5 standard. Based on CARB staff analysis, for Hanford, while the impact is over EPA's recommended significance level, achieving the level of controls needed for a 30 percent reduction of ammonia is not feasible, as discussed below.

Analysis of Available Emissions Controls

Another factor that may be considered as additional information is available emissions controls on ammonia. The availability of ammonia emissions controls is relevant to the decision-making process, influencing the extent of reasonable modeled reductions. While EPA recommends modeling emissions reductions of between 30 and 70 percent to estimate PM2.5 impacts, CARB staff, District staff, and the public process have not identified specific controls that are technologically and economically feasible to achieve reductions at the low end of the recommended sensitivity range (i.e., 30 percent), much less at the upper end of the range.

For this supplemental document, at EPA staff's request, CARB and the District have expanded on earlier analyses, assessing potential controls on ammonia sources identified by EPA to analyze the appropriateness of the 30 percent reduction threshold for the precursor analysis.

It is important to note that not all control measure concepts are appropriate to be submitted into the SIP as rules. Any rules that are submitted into the SIP must meet EPA requirements, and should:

- Include enforceable emission limitations and other control measures, means, or techniques, as well as schedules and timetables for compliance, as may be necessary to meet the requirements of the Clean Air Act [Act section 110(a)(2)(A)];
- Provide necessary assurances that the State will have adequate personnel, funding, and authority under State law to carry out such SIP (and is not prohibited by any provision of federal or state law from carrying out such SIP) [Act section 110(a)(2)(E)];

[36] EPA. PM2.5 Precursor Demonstration Guidance: Draft for Public Review and Comment. Page 17

- Be adopted by a State after reasonable notice and public hearing [Act section 110(l)]; and
- Not interfere with any applicable requirement concerning attainment and reasonable further progress, or any other applicable requirement of the Act [Act section 110(l)].

The supplemental evaluation of potential controls on ammonia sources identified by EPA is found in Section 3 below.

3. Evaluation of Potential Controls on Ammonia Emissions Sources

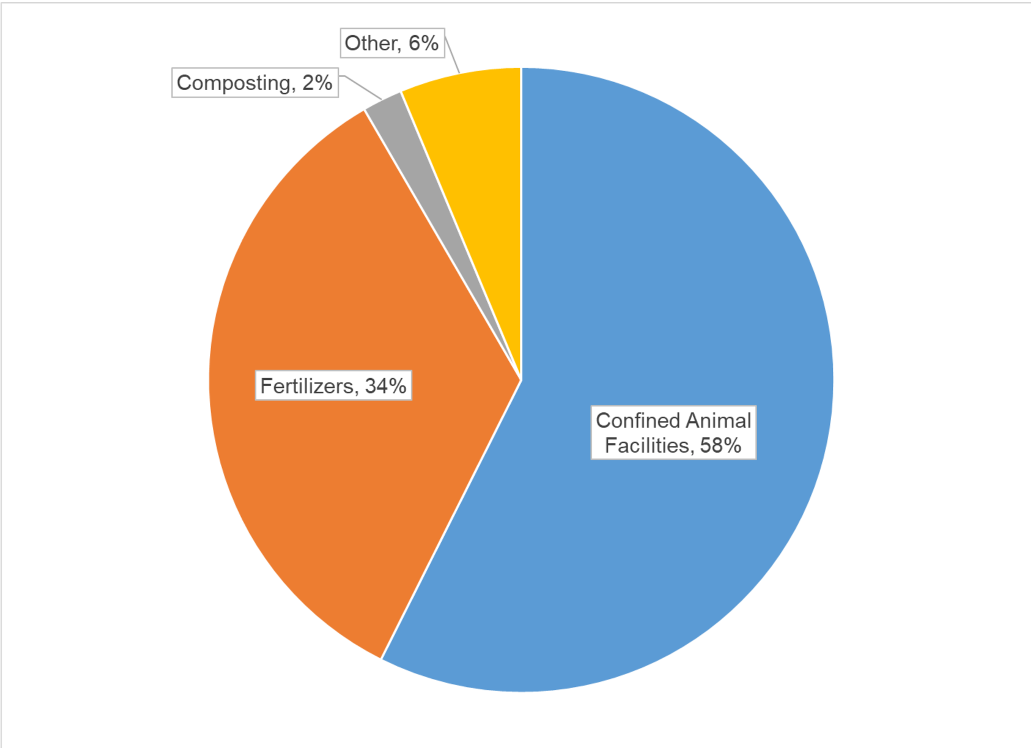
The District and CARB analyzed potential control measures to reduce ammonia emissions in order to evaluate whether a 30 percent reduction in emissions is feasible. For an effective control measure evaluation, it is necessary to characterize and understand the key sources of ammonia in the Valley.

The three main sources of ammonia emissions in the Valley from stationary and area sources, which account for 94 percent of the Valley's ammonia emissions[37], are the focus of the evaluation. Although the base year inventory for the *2018 PM2.5 Plan* is 2013, and previous ammonia technical submittals to EPA have focused on that year, the data and figures below reflect the projected ammonia inventory for 2023. The increased level of control due to the implementation of San Joaquin Valley Air Pollution Control District (District) rules and regulations is already incorporated into the projected emission inventory.

- Confined Animal Facilities (CAFs) with 186.5 tons per day (tpd);
- Agricultural Fertilizers at 111.2 tpd; and
- Composting Solid Waste Operations at 6.7 tpd.

[37] Based on CEPAM 2016 Ozone SIP v1.05 Annual Average Emissions Inventory for 2023

Figure 4: Sources of Ammonia in the San Joaquin Valley[38]



Since the primary source of ammonia emissions in the Valley are from CAFs, the District will focus its evaluation on the different types of animal operations, specifically dairies, which account for the majority of ammonia emissions.

The total ammonia emissions in the Valley in 2023 are 324.9 tons per day. As shown in Table 5 below, to reduce the total ammonia emissions by 30 percent, 50 percent, and 70 percent, emissions from CAFs would need to be further reduced by 52 percent, 87 percent, and 122 percent respectively. As shown in the evaluation below, the District has only identified a few measures that have the theoretical potential to reduce additional ammonia emissions, which may achieve a total of up to 2 percent reduction in emissions notwithstanding technological and economic feasibility considerations. These reductions are not capable of achieving the lower bound level of 30 percent reductions, and the 50 percent and 70 percent reduction levels are infeasible.

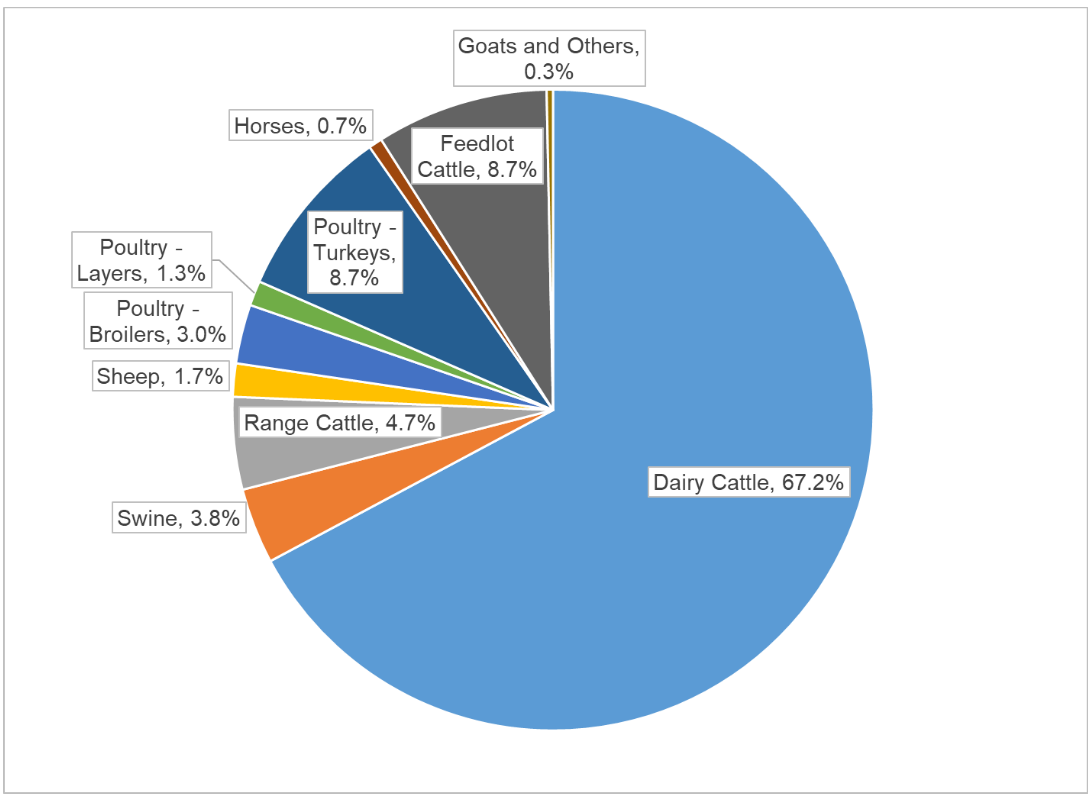
[38] Ibid. 36

Table 5: CAF Emission Reduction Analysis

	30% Reduction	50% Reduction	70% Reduction
Theoretical Ammonia Reductions (tpd)	97.5	162.4	227.4
% reduction required from CAFs	52%	87%	122%

As shown below in Figure 5, dairy cattle emissions account for 67.2 percent of ammonia emissions from CAFs.

Figure 5: Ammonia from CAFs in the San Joaquin Valley[39]



The total ammonia emissions in the Valley in 2023 are 324.9 tons per day. As shown in Table 6 below, to reduce the total ammonia emissions by 30 percent, 50 percent, and 70 percent, emissions from dairy cattle would need to be reduced by 78 percent, 130 percent, and 181 percent, respectively.

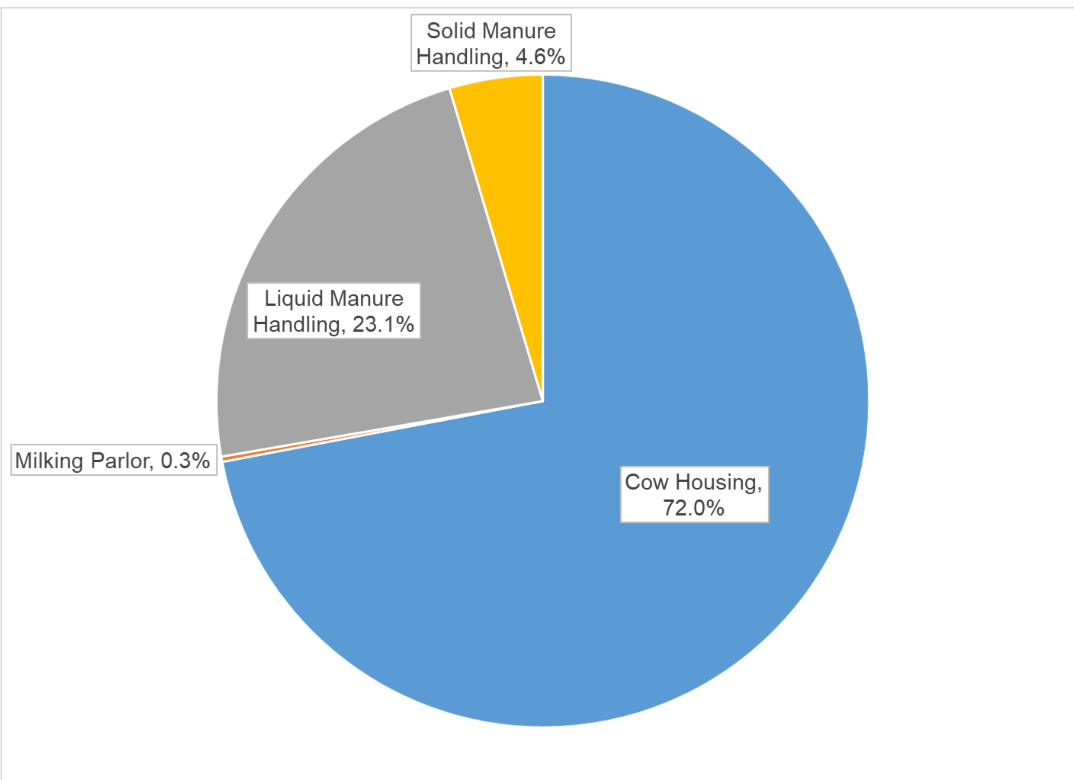
[39] Ibid. 36

Table 6: Dairy Cattle Emission Reductions Analysis

	30% Reduction	50% Reduction	70% Reduction
Theoretical Ammonia Reductions (tpd)	97.5	162.4	227.4
% reduction required of dairy cattle	78%	130%	181%

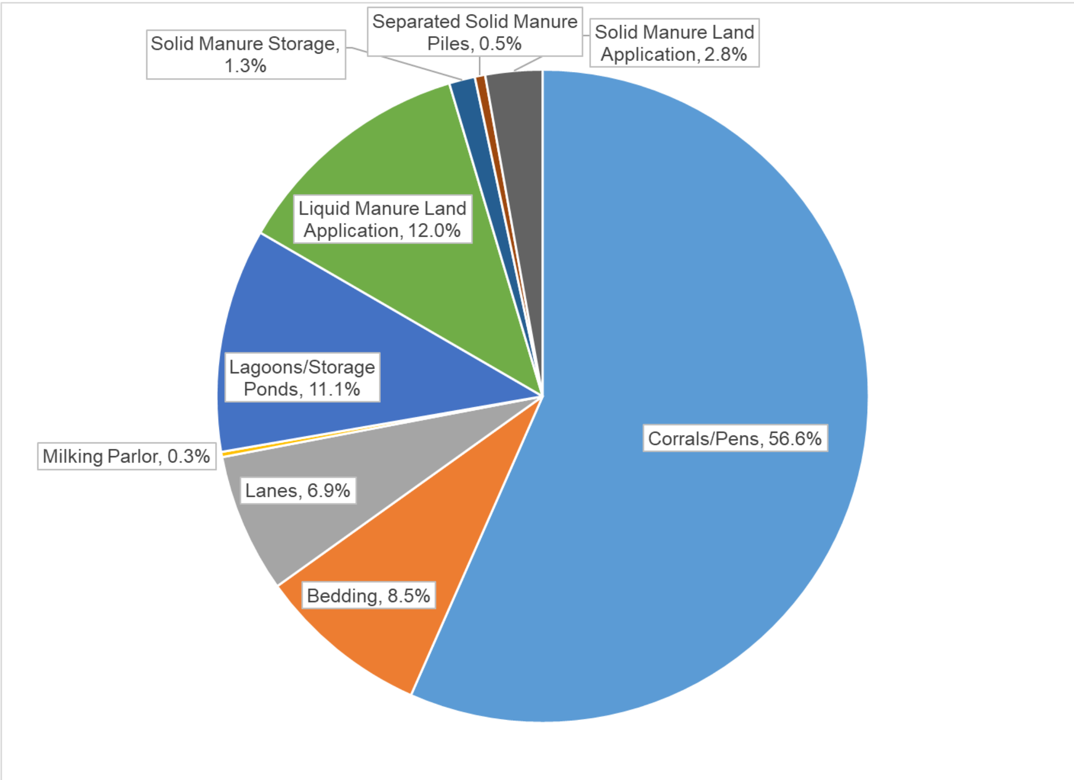
As shown in Figure 6, the primary source of ammonia emissions from dairy cattle is cow housing (72 percent). Figure 7 further evaluates ammonia emissions from dairy cattle by illustrating the different categories such as corrals/pens (56.6 percent), liquid manure land application (12 percent), and lagoons/storage ponds (11.1 percent), etc. Accordingly, the District has provided an evaluation of mitigation measures for dairy cattle focusing on housing, land application techniques, and solid and liquid manure handling.

Figure 6: Ammonia from Dairy Cattle in the San Joaquin Valley[40]



[40] Based on District ammonia emission factors for dairy cattle.

Figure 7: Ammonia from Dairy Cattle in the San Joaquin Valley (cont.)[41]



Based on the emission inventory analysis above, reducing ammonia emissions by the lower bound precursor demonstration threshold of 30 percent would require eliminating over 50 percent of ammonia emissions from CAFs, or nearly 80 percent of emissions from only dairy cattle, beyond the ammonia emission reductions already achieved by the requirements of District Rule 4570 (Confined Animal Facilities). A 70 percent reduction of ammonia emissions in the District would require the elimination of all CAFs in the District in addition to other categories that have already achieved significant ammonia reductions.

Inventory of Confined Animal Facilities in the Valley

The District reviewed current permitted facilities in the Valley. Demonstrated below in Table 7 is the count of permitted facilities by type that are subject to Rule 4570, and the controlled ammonia emissions from each type of facility.

[41] Ibid.

Table 7: Inventory of Confined Animal Facilities in the Valley

Facility Type	# of Facilities Subject to Rule 4570[42]	Ammonia Emissions from Facility Type (tpd)[43]
Dairies	865	125.3
Beef Feedlots	8	16.2
Other Cattle	77	8.7
Chicken – Broilers	47	5.6
Chicken – Layers	12	2.3
Turkeys	21	16.3
Swine	1	7.1

District Rule 4570 (Confined Animal Facilities)

Background

The largest source of ammonia in the Valley is CAFs. The District has implemented Rule 4570 to reduce emissions from this source category, and requires the most stringent requirements for reducing emissions from CAFs in the nation. Rule 4570 was originally adopted on June 15, 2006, and was again amended on October 21, 2010. District Rule 4570 applies to facilities where animals are corralled, penned, or otherwise caused to remain in restricted areas and primarily fed by a means other than grazing for at least 45 days in any twelve-month period. In addition to limiting volatile organic compound (VOC) emissions, District Rule 4570 includes measures that limit ammonia emissions from these operations.

Evaluation of District Rule 4570

District Rule 4570 includes multiple mitigation measures that control ammonia emissions from CAFs. Since these facilities generally cover a large area and have different processes, a single mitigation measure or technology is generally not sufficient to control overall emissions from the facility. Due to the varying types of operations and emissions sources at

[42] Review of District permits database (January 2023)
[43] Ibid. 36

these facilities, each CAF requires a site-specific constellation of measures to achieve overall emission reductions.

District Rule 4570 includes a large number of measures that must be implemented by each CAF and also requires additional measures to be selected from a menu of mitigation measures options to achieve additional emission reductions. The menu approach gives the facilities the flexibility to achieve the required emission reductions by selecting mitigation measures that are most practical and effective for their operation. As discussed in the staff report for the 2010 amendments to District Rule 4570,[44] the design and operation of each CAF differs depending on animal type, regional climatic conditions, business practices, and the preferences of the owners/operators. Because of this, no two CAFs are identical. In addition to air quality regulations, CAFs are subject to other regulations to protect water quality and the environment. These additional regulations often restrict how CAFs can operate.

It is not feasible for all CAFs to implement the same measures due to various factors, such as infrastructure, conditional use permits, water quality regulations, production contracts, and other limitations. The options included in District Rule 4570 provide the owners and operators of CAFs much-needed flexibility to choose the mitigation measures that make the best environmental and economic sense for their facility, while maximizing the amount of emission reductions. The required measures have reduced ammonia emissions by over 100 tpd.[45]

Other Air District Rules

The District provided an in-depth review of Rule 4570 in Appendix C of the *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards* (*2018 PM2.5 Plan*), [46] including a comprehensive analysis of Rule 4570, in which the District compared emissions limits, optional control requirements, and work practices in Rule 4570 to comparable requirements in rules from the following areas:

- South Coast Air Quality Management District (SCAQMD) Rule 223 (Emission Reduction Permits for Large Confined Animal Facilities)
- SCAQMD Rule 1127 (Emission Reductions from Livestock Waste)

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[44] SJVAPCD. *Staff Report for 2010 Amendments Rule 4570 (Confined Animal Facilities).* Available at: *http://valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2010/October/Agenda_Item_7_Oct_21_2010.pdf*

[45] Appendix F of the Staff Report for the June 2009 re-adoption of Rule 4570, starting on the 329th page of the pdf available here: *https://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2009/June/Agenda%20Item_10_June_18_2009.pdf*

[46] SJVAPCD. *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards.* Appendix C, pages C-311 – C-339. Available at: *https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf*

- Bay Area Air Quality Management District (BAAQMD) Regulation 2, Rule 10 (Large Confined Animal Facilities)
- Ventura County Air Pollution Control District (VCAPCD) Rule 23 (Exemptions from Permit)
- Sacramento Metropolitan Air Quality Management District (SMAQMD) Rule 496 (Large Confined Animal Facilities)
- Imperial County Air Pollution Control District (ICAPCD) Rule 217 (Large Confined Animal Facilities Permits Required) and Policy Number 38 (Recommended Mitigation Measures for Large Confined Animal Facilities)
- Idaho Administrative Procedure Act 58.01.01 Sections 760-764 (Rules for the Control of Ammonia from Dairy Farms)

In addition to these rules, the District's *2016 Plan for the 2008 8-hour Ozone Standard* (*2016 Ozone Plan*)[47] included a comparison of District Rule 4570 to requirements from the following:

- Butte County Air Pollution Control District (BCAQMD) Rule 450 (Large Confined Animal Facilities)
- Yakima Regional Clean Air Agency (Air Quality Management Policy and Best Management Practices for Dairy Operations)

Through the rule comparisons included in the *2018 PM2.5 Plan* and the *2016 Ozone Plan*, the District demonstrated that Rule 4570 was more stringent than the above rules in other areas, at the time of each plan's adoption. The areas mentioned above have not changed or amended their respective rules since the District's previous evaluations, except for the Yakima Regional Clean Air Agency, which rescinded their policy for dairies in 2018. The District has found no new requirements in other areas, but has reevaluated the rules above and found that Rule 4570 continues to implement the most stringent requirements for CAFs.

Federal Actions and Guidance

The evaluation of appropriate practices and measures to reduce emissions from confined animal facilities requires accurate methodologies to estimate emissions. The National Academy of Sciences identified the lack of methodologies to estimate emissions from animal feeding operations (AFOs) in 2002. In response, EPA announced an opportunity for AFOs to sign a voluntary consent agreement and final order known as the Air Compliance Agreement (2005).[48] The goal of the agreement was to develop scientifically credible methodologies for estimating emission models produced by AFOs. AFOs that chose to participate in the agreement provided the funding for the National Air Emissions Monitoring Study (NAEMS). As part of the agreement, EPA agreed not to sue participating AFOs for certain violations of

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[47] SJVAPCD. *2016 Plan for the 2008 8-hour Ozone Standard*. Available at: *http://valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/Adopted-Plan.pdf*

[48] See 70 FR 4958. (January 31, 2005). Retrieved from: *https://www.epa.gov/sites/default/files/2016-06/documents/afolagooneemreport2012draftappe.pdf*

the Clean Air Act (CAA), Compensation, and Liability Act (CERCLA), and Emergency Planning and Community Right-to-Know Act (EPCRA), provided that the AFOs comply with the agreement's conditions.

The NAEMS monitored 25 AFOs in various regions of the country to have equipment installed for ammonia, hydrogen sulfide, particulate matter, and VOC emissions monitoring. Separate draft models of swine, poultry, and dairy AFOs emissions were created using the monitoring data and input from the EPA Science Advisory Board.[49]

While data collection took place from 2007 to 2010, these draft models only became publicly available in August 2020, August 2021, and June 2022 for swine, poultry, and dairy AFOs respectively. EPA's final models to estimate emissions from AFOs are not yet available. Currently, EPA projects that finalization of all draft models will occur in late 2023.[50] Though EPA has not provided final guidance on emission estimation methodologies for CAFs, the District has reviewed information from EPA and many other sources in order to use the best information available to calculate emissions from CAFs.

District Efforts

The District first began permitting agricultural sources in 2004, and since that time District staff members have gained a great deal of experience in the evaluation of emissions from agricultural sources through collaborative efforts with other institutions, agencies, and interested stakeholders. The District has also been thoroughly involved in collaborative scientific research efforts to evaluate emissions from agricultural sources. This is particularly true of the agricultural emissions research efforts in California. The District has played an important role in coordination of these efforts through the San Joaquin Valleywide Air Pollution Study Agency (Study Agency) and the Study Agency's Agricultural Air Quality Research Committee (AgTech). The District has also been at the forefront of developing and implementing regulations to reduce emissions from CAFs.

The District will continue to track the development of rules, regulations, research/studies, and practices for CAFs to ensure the best available control measures and most stringent measures are in place in the Valley, in coordination with industry stakeholders, researchers, CARB, and other agencies.

Evaluation of Mitigation Measures for Confined Animal Facilities

In the Federal Register posting for the proposed partial approval and partial disapproval of portions of the state implementation plan revisions for the 1997 annual PM2.5 standard,[51]

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[49] Livestock and Poultry Environmental Learning Community. *NAEMS: How It Was Done and Lessons Learned*. April 20, 2022. Retrieved from: *https://lpelc.org/naems/*

[50] EPA. *National Air Emissions Monitoring Study*. Retrieved from: *https://www.epa.gov/afos-air/national-air-emissions-monitoring-study#naems-status*

[51] See 86 FR 38662. (July 22, 2021). Retrieved from: *https://www.govinfo.gov/content/pkg/FR-2021-07-22/pdf/2021-15551.pdf*

EPA indicates that further evaluation of potential control measures for ammonia sources is needed. In EPA's proposed disapproval of portions of the *2018 PM2.5 Plan* for the 2012 annual PM2.5 standard,[52] EPA refers to several studies that were cited in a Public Justice comment letter[53] that evaluate CAF mitigation measures that have the potential to achieve additional ammonia reductions. In the same proposal, EPA noted that the United States Department of Agriculture (USDA) National Resources Conservation Service (NRCS) has collaborated to develop a "Reference Guide for Poultry and Livestock Production Systems" (NRCS Reference Guide) [54] that lists 12 measures that may reduce ammonia emissions by more than 30%. EPA also cited a 2011 inventory of mitigation methods by Price et al. prepared for the UK government (UK User Guide) that identifies several ammonia mitigation methods for UK farms.[55]

Following the proposed disapprovals and several meetings with EPA Region 9 staff, the District was provided with a list of mitigation measures generated by EPA Region 9 staff for evaluation, many of which the District has already evaluated over the years. As discussed earlier, it is also important to note that EPA has been committed to addressing emission from livestock operations under a voluntary "safe harbor" consent agreement put into place by EPA in 2005. While the San Joaquin Valley has regulated emissions from livestock operations since 2005, EPA is still in the process of evaluating emissions and establishing the regulatory framework under this consent agreement, and the District will continue supporting the national effort to address emissions from these operations. This list encompassed publications that evaluated potential ammonia emission reductions for either individual mitigation measures or compilations of mitigation measures. The publications provided to the District included a wide variety of mitigation measures such as reducing crude protein content in feed, litter amendments, injection/incorporation of manure, changing land use from arable to woodland, and reducing human consumption of meat and eggs.

Though some of the suggested measures have related studies that appear to demonstrate potential feasibility, it is imperative to consider the conditions under which the studies were performed and how those conditions compare to the Valley. Several of the studies evaluated were conducted in areas outside of California, and many outside of the nation. Notably, CAFs in the Valley face unique challenges, including hot, dry summers, drought conditions,

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[52] See 87 FR 60494. (October 5, 2022). Retrieved from: *https://www.govinfo.gov/content/pkg/FR-2022-10-05/pdf/2022-21492.pdf*

[53] Public Justice, et al. (January 28, 2022). Group Comment Letter *Re: Clean Air Plans; 2012 Fine Particulate Matter Serious Nonattainment Area Requirements; San Joaquin Valley, California*; EPA-R09-OAR-2021-0884. Retrieved from: *https://www.regulations.gov/comment/EPA-R09-OAR-2021-0884-0136*

[54] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[55] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from:
https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf

and strict water regulations, which may not have been considered in some of the publications and studies that evaluated these methods. Valley dairies in particular are typically much larger than dairies in other areas. Based on information from the USDA National Agricultural Statistics Service, the average dairy in the Valley has almost 1,600 cows compared to a national average of less than 300 cows per dairy outside of California.[56, 57] The UK User Guide, which contains many of the measures evaluated in this document, indicated that the average UK dairy has 170 cows. The differences in climate, typical management practices, size of operations, and regulatory environment affect the types of mitigation measures that can be applied to each operation.

Many of the mitigation measures for consideration by EPA were not applicable to the Valley, were unreasonable or unenforceable, or were based on limited research (e.g. research conducted in other countries with drastically different operating and natural characteristics). The complete list of potential mitigation measures provided by EPA Region 9 staff can be found in Appendix A. The District's evaluation of all potential mitigation measures provided by EPA is included in the following sections.

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[56] Hanson, M. (2021) U.S. Dairy Herd Hits 27-year High. *Dairy Herd Management*. Retrieved from: *https://www.dairyherd.com/news/dairy-production/us-dairy-herd-hits-27-year-high*
[57] Latest USDA Statistics for average size of dairies excluding California, retrieved from: *https://downloads.usda.library.cornell.edu/usda-esmis/files/h989r321c/7d279w693/f7624g40c/mkpr0222.pdf* (about 270 cows per dairy outside California)

Nutrition and Feed Management (Feeding)

Table 8: Nutrition and Feed Management Measures Evaluated

Method	Measure	CAF Type	Reference
Reducing Crude Protein (Beef)	Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure	Beef	Preece[58]
	Reducing Crude Protein in Beef Cattle Diet Reduces Ammonia Emissions from Artificial Feedyard Surfaces	Beef	Todd[59]
	Reduce Dietary Crude Protein in Beef Cattle	Beef	Cole (2005)[60]
Reducing Crude Protein (Dairy)	Reducing Dietary Protein Decreased the Ammonia Emitting Potential of Manure from Commercial Dairy Farms	Dairy	Hristov[61]
Reducing Crude Protein (Swine)	Reduce Crude Protein Content from Finishing Pig Houses	Swine	Hayes[62]

[58] Preece, Sharon L.M. et al., ''Ammonia Emissions from Cattle Feeding Operations,'' Texas A&M AgriLife Extension Service, referring to Cole, N.A., R.N. Clark, R.W. Todd, C.R. Richardson, A. Gueye, L.W. Greene, and K. McBride, ''Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure,'' Journal of Animal Science 83:(3), 722 (2005)

[59] Todd, R.W., N.A. Cole, and R.N. Clark, ''Reducing Crude Protein in Beef Cattle Diet Reduces Ammonia Emissions from Artificial Feedyard Surfaces.'' Journal of Environmental Quality. 35:(2), 404–411 (2006).

[60] Cole, N., et al., Influence of dietary crude protein concentration and source on potential ammonia emissions from beef cattle manure. J. Anim. Sci. 83, 722 (2005).

[61] Hristov, A. N., Heyler, K., Schurman, E., Griswold, K., Topper, P., Hile, M., ... & Dinh, S. (2015). CASE STUDY: Reducing dietary protein decreased the ammonia emitting potential of manure from commercial dairy farms. The Professional Animal Scientist, 31(1), 68-79

[62] Hayes ET, Leek AB, Curran TP, et al. The influence of diet crude protein level on odour and ammonia emissions from finishing pig houses. Bioresource Technology, 2004

Method	Measure	CAF Type	Reference
Feed Timing	Phase, Group, and Split Sex-Feeding	Beef	Cole (2006)[63]
	Group and Phase Feeding	All	NRCS[64]
	Phase Feeding	All	Guthrie[65]
Wet Distillers Grain	Reduce Feeding of Wet Distillers Grain	Beef	Todd[66]
Grazing	Increase Grazing Time for Dairy Cattle	Dairy	Guthrie
Feed Additives	Feed Additives for Poultry	Poultry	NRCS

Reducing Crude Protein Content for Beef Cattle - ***(applies to beef cattle only)***

EPA noted that studies in 2005 and 2006 found that "*decreasing the crude protein concentration of beef cattle finishing diets based upon steam-flaked corn from 13 to 11.5 percent decreased ammonia emissions by 30 to 44 percent.*"

In the 2005 study, steers were randomly assigned to one of nine dietary treatments (three formulated dietary crude protein (CP) concentrations and three supplemental urea:cottonseed meal ratios). Steers were confined to tie stalls, and feces and urine excreted were collected and frozen after approximately 30, 75, and 120 days on feed. As protein concentration in diet increased from 11.5 to 13 percent, in vitro daily ammonia emissions

[63] Cole NA, Defoor PJ, Galyean ML, Duff GC, Gleghorn JF. "Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers", Journal of Animal Science, 2006

[64] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[65] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[66] Todd, R.W., N.A. Cole, D.B. Parker, M. Rhoades, and K. Casey. 2009. "Effect of Feeding Distillers Grains on Dietary Crude Protein and Ammonia Emissions from Beef Cattle Feedyards." In Proceedings of the Texas Animal Manure Management Issues Conference, 83–90.

increased 60 to 200 percent, due primarily to increased urinary nitrogen excretion. As days on feed increased, in vitro ammonia emissions also increased.

This study had a small sample size with 54 cattle used for nine dietary treatments (six cattle per treatment). These results are only applicable to the finishing cycle of beef cattle lives (four to six months of age), and not applicable to milk cows and support stock at dairies. There are very few finishing cycle feeder beef cattle in the Valley. Most beef cattle in California are beef calves and stockers, fed through grazing. Most of these cattle are sent outside of California for the finishing cycle.[67, 68]

Notably, beef finishing cattle make up a small part of the overall inventory of cattle in the Valley. The current feedlot cattle inventory includes all feedlot cattle; however, the lives of beef cattle are divided into different phases of production. Cow and calf pairs are raised on rangeland. Weaned yearlings/stockers may continue to be raised on rangeland or be sent to yearling/stocker feedlots until a weight of approximately 800 to 900 pounds. Finally, beef cattle are sent to other feedlots out of California for the finishing phase, in which the cattle are fed for four to six months until they reach the desired finished weight. Because of the higher cost of feeding cattle in California and the lack of sufficient beef processing capacity, most of feedlot cattle in California are yearlings/stockers for which this measure does not apply.[69]

If dietary protein concentrations are decreased to the point that animal performance is adversely affected, then total ammonia emissions could be increased because animals require more days on feed to reach market weight and condition. There was also little change in ammonia between the 13 percent and 14.5 percent CP groups.

In the 2006 study, two groups of steers were fed diets with either 11.5 or 13 percent CP and all urine and feces were collected. Manure from steers fed 11.5 percent CP diet had less urine, less urinary nitrogen, and a lesser fraction of total nitrogen in urine, compared with the 13 percent crude protein diet. Decreasing CP in beef cattle diets from 13 to 11.5 percent significantly decreased ammonia emission by 44 percent in closed chamber experiment, and decreased mean daily ammonia flux by 29 percent, 30 percent, and 52 percent in spring, summer, and autumn field trials, respectively. No difference was observed in winter.

Additionally, National Research Council (NRC) Nutrient Requirements of Beef Cattle states that decreasing the CP concentration in the diet can potentially reduce animal performance, prolonging the time necessary to reach market weight and potentially increasing ammonia

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[67] Andersen, M.A., Blank, S.C., LaMendola, T, Sexton, R.J., "California's Cattle and Beef Industry at the Crossroads", California Agriculture 56(5),152-156. Retrieved from: *https://doi.org/10.3733/ca.v056n05p152*
[68] Saitone, T.L., "Livestock and Rangeland in California", Livestock and Rangeland in California. Retrieved from: *https://s.giannini.ucop.edu/uploads/giannini_public/94/c1/94c100fd-9626-47d4-8b82-0bfdb1081a57/livestock_and_rangeland.pdf*
[69] Forero, L., Barry, S., Larson, S. (2021). Beef Cattle on California Annual Grasslands: Production Cycle and Economics. *University of California Agriculture and Natural Resources*. Retrieved from: *https://anrcatalog.ucanr.edu/pdf/8687.pdf*

emissions over the life of the cattle. Because adequate protein levels are required for optimal growth, decreasing CP levels hinder the ability to meet daily weight gain goals.

The overall effectiveness of this measure is unclear because of the small sample size and short period of the study. NRC Nutrient Requirements of Beef cattle states that decreasing the CP concentration in the diet can potentially reduce animal performance. Higher CP levels may be needed to meet daily weight gain goals.

If decreasing the CP content of the diet adversely affects performance, any short-term ammonia reductions can be negated by the longer time on feed required for animals to reach their target market weight and condition.[70] While there may be ammonia reductions in the short term, longer time on feed will result in additional ammonia emissions for the additional amount of time it takes for the animals to reach the appropriate weight. Thus, overall emissions may ultimately be the same, or possibly even increase. Due to the limited pool of data and only studying emissions for 21 days, more research is needed to show a full-cycle of emissions and full impact to the animals.

Despite the uncertainties discussed above, the District further evaluated the potential emission reductions of implementing this measure in the Valley. This analysis is provided below.

The feedlot cattle inventory in the Valley includes calves, beef stockers, yearlings, and finishing cattle. This measure is only applicable to beef finishing cattle. It will be conservatively assumed that 50 percent of the feedlot cattle in the Valley are beef finishing cattle. The ammonia emissions from young beef cattle compared to beef finishing cattle will be assumed to be proportional to their nitrogen excretion. Based on information from the American Society of Agricultural and Biological Engineers (ASABE),[71] it is estimated that the average daily nitrogen excretion for beef finishing cattle is 25.7 percent higher than young beef cattle. Therefore, the overall control efficiency for this measure can be estimated as follows:

$$30\% \times 50\% \times 1.257 = 18.9\%$$

No costs for implementation of this measure in the United States could be located. Notably, feed costs are a significant part of the overall costs of raising livestock, often representing as much as 60-70 percent of production costs,[72] and protein is often the most expensive

[70] Cole NA, Defoor PJ, Galyean ML, Duff GC, Gleghorn JF. "Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers", Journal of Animal Science, 2006.

[71] American Society of Agricultural and Biological Engineers. (March 2005). ASABE D384.2 Manure Production and Characteristics. Retrieved from: *https://elibrary.asabe.org/abstract.asp?aid=32018*

[72] Strauch, B.A., Stockton, M.C. (Sep 2013). Feed Cost Cow-Q-Lator. NebGuide. University of Nebraska–Lincoln Extension, Institute of Agriculture and Natural Resources (G2214). Retrieved from: *https://extensionpublications.unl.edu/assets/pdf/g2214.pdf*

component in livestock feed.[73] As a result, beef cattle producers will generally avoid overfeeding protein to minimize productions costs. Therefore, the actual emission reductions from this measure may be significantly lower to nothing since most beef cattle producers will already try to minimize feeding excess protein whenever feasible.

The District has concluded that the measure requires further research on both the effect on production and overall costs, and therefore is not a viable mitigation option to include in Rule 4570 at this time. The District will continue to evaluate the feasibility of this option as practices evolve and further research is conducted.

Reducing Crude Protein Content for Dairy Cattle - *(applies to dairy cattle only)*

In a compilation by Bittman[74] it was recommended that the average CP content of diets for dairy cattle should not exceed 15-16 percent of the dry matter (DM). Phase feeding can be applied in such a way that the CP content of dairy diets is gradually decreased from 16 percent of DM just before calving and in early lactation to below 14 percent in late lactation and the main part of the dry period.

A study[75] measured the effect of reducing the CP content of ammonia emitting potential of dairy manure in a controlled environment. Eleven Pennsylvania dairies with gutter-scrape, gravity-flow, or flush manure-management systems participated in the study. In the study, the CP concentration of the feed for cows that were identified as high-producing cows was decreased from an average of 16.5 to 15.4 percent for the dairies included in the study. Fecal and urine samples were collected from the dairies in the fall of 2009, spring of 2010, fall of 2010, and spring of 2011. The study indicated that laboratory ammonia emissions from reconstituted manure was on average 23 percent lower for the low CP diet versus the high CP diet. No difference was seen in milk yield and milk composition during the low CP and the high CP diet, with average milk yields of 32.2 kg/day and 32.5 kg/day. The researchers that conducted the study concluded that the ammonia emitting potential of dairy manure can be reduced by moderately decreasing dietary CP content.

Although effects of reducing the CP content of the feed for dairy cows may merit further research, there are questions related to the applicability of this study to dairy cattle in the Valley. One important question is if the milk production of the cows in the study is comparable to the milk production of cows in the Valley. The average milk production of the high-producing cows included in the study was only 32.2-32.5 kg/day. In comparison, according to information from USDA National Agricultural Statistics Service, on average, milk

[73] North Dakota State University (NDSU). (Dec 2019). Comparing Value of Feedstuffs (AS1742). Retrieved from: *https://www.ag.ndsu.edu/publications/livestock/comparing-value-of-feedstuffs*

[74] Bittman, S., Dedina, M., Howard C.M., Oenema, O., Sutton, M.A., (eds). (2014). "Options for Ammonia Mitigation: Guidance from the UNECE Task Force on Reactive Nitrogen," Centre for Ecology and Hydrology, Edinburgh, UK. Retrieved from: *http://www.vuzt.cz/svt/vuzt/publ/P2014/037.pdf*

[75] Hristov, A. N., Heyler, K., Schurman, E., Griswold, K., Topper, P., Hile, M., ... & Dinh, S. (2015). CASE STUDY: Reducing dietary protein decreased the ammonia emitting potential of manure from commercial dairy farms. The Professional Animal Scientist, 31(1), 68-79

cows in California produced approximately 36.2 kg/day of milk in 2021, [76] with high-producing cows in the Valley producing at a rate of 44 to over 50 kg/day of milk per dairy cow.[77] Therefore, although the cows in the study were identified as high-producing cows that were expected to produce greater amounts of milk, the average milk cow in California produces more milk than the cows in this study. Higher levels of milk production require higher levels of protein, so it is likely that reducing the CP content of feed will reduce milk yields of cows that produce milk.

In communications with the District, Dr. Peter Robinson, UC Davis Extension Specialist, Dairy Cattle Nutritional Management Department of Animal Science, stated that the optimal CP level for high-producing dairy cows in the Valley is around 16.8 percent, which is the level that dairy typically feed their high-producing cows. He also states that when CP levels are decreased to levels that are a little lower than required, milk production tends to be negatively impacted immediately. Dr. Robinson's recommended CP content is based on 14 large on-farm studies that he has completed in the Valley from 2005 to the present. [78] Based on the data he provided from these studies, feed with a CP content of approximately 16.9 percent resulted in maximum milk production for high-producing cows in the Valley, which was about 48.5 kg/day of milk, 50 percent more than the milk production of the high-producing cows in this study. Therefore, 50 percent more high-producing cows would be needed to produce the same amount of milk, which would negate the ammonia reductions from this measure. Another potential issue with the study is that manure samples of a specific size were used to compare the ammonia emitting potential of the manure, but it is unclear if the changes in feed composition affected manure production, which could also affect ammonia emissions.

As discussed above, California dairy operators typically feed their high-producing cows a diet that has CP content near the optimum level of 16.8 percent, and decreasing the CP content of the diet can have an adverse effect on milk production in dairy cattle. Thus, CP reductions for dairy cattle must be closely managed to avoid impacting productivity (e.g., milk yield, fat corrected yield, milk protein yield). Additionally, Dr. Robinson stated that most cows need to recoup body weight during later lactation and that lowering the CP percentage in the diet during this period could have very negative impacts on both milk yield and body weight recovery.

Because nutrient concentrations in feed and feed ingredients vary considerably, reducing CP in diets will require additional lab analyses of feed to ensure that animals receive sufficient nutrients, which will result in increased costs. Dairy operators have no incentive to overfeed

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[76] USDA, National Agricultural Statistics Service. Milk Production (February 2022). *https://downloads.usda.library.cornell.edu/usda-esmis/files/h989r321c/7d279w693/f7624g40c/mkpr0222.pdf*

[77] Data from studies of dairy cows in the San Joaquin Valley provided by Dr. Peter Robinson, UC Davis Extension Specialist, Dairy Cattle Nutritional Management Department of Animal Science. *https://animalbiology.ucdavis.edu/people/peter-robinson*

[78] A list of selected scientific publications by Peter Robinson, PhD is available on the UC Davis website at: *https://animalscience.ucdavis.edu/people/faculty/peter-robinson/Articles/Scientific-Publications*

protein since high protein feeds are usually the most expensive ingredients. The percent of CP in the diets fed that California dairy operators feed to dairy cattle has been significantly reduced from previous levels. According to Dr. Robinson, CP in the diets of dairy cows was frequently in excess of 20 percent in the 1980s and 1990s, but that has decreased to the current level of 16.8 percent today. In communication with District staff, Dr. Robert Hagevoort, Extension Dairy Specialist and Topliff Dairy Chair, New Mexico State University, [79] also confirmed similar reductions in the CP content of dairy feed for dairies in the western U.S. compared to previous levels.

In addition, reducing the CP content to the recommended levels is difficult for cattle that graze or are fed a large amount of grass because grass has higher amounts of protein. The NRCS Reference Guide indicates that reduction of CP can also cause deficiency in certain amino acids that can adversely affect animal performance, such as weight gain.

California dairies are expected to continue to try to improve feed efficiency and minimize environmental impacts. However, it is not feasible to require this measure at this time because of questions that remain about the impact on milk production, animal health, and costs on California dairies. Therefore, the District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Reducing Protein Content for Swine - ***(applies to swine only)***

Research indicates that low-protein diets may result in poorer performance in finishing pigs than conventional diets.[80] The NRCS Reference Guide indicates that changes to animal diets generally increase costs because of the time and expense of diet formulation and acquisition of new ingredients, and that the availability of additives and feedstuff fluctuates. Additionally, there are increased costs for low-protein feed due to the need to supplement with amino acids found in protein like crystalline lysine, threonine, tryptophan, methionine and valine. As previously shown, emissions from swine are a small part of the District's ammonia inventory, as there is only one permitted swine facility in the District. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Reduce Feeding of Wet Distillers Grain - ***(applies to beef cattle only)***

In another study, EPA noted that "one feedyard feeding distillers grains averaged 149 grams of ammonia-N per head per day (ammonia–N/head/day) over nine months, compared with 82 g ammonia–N/head/day at another feedyard feeding lower protein steamflaked, corn-based diets." Nominally, this would represent a 45 percent reduction in ammonia emissions from manure by going to a lower protein diet. However, the net ammonia emission reduction either from reducing crude protein levels in feed, or by providing a lower protein steam-flaked, corn-based diet rather than a distiller grain diet is unclear given the role of protein

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[79] *https://dairy.nmsu.edu/faculty-staff/robert-hagevoort.html* (accessed March 15, 2023)

[80] Hayes ET, Leek AB, Curran TP, et al. The Influence of Diet Crude Protein Level on Odour and Ammonia Emissions from Finishing Pig Houses. Bioresource Technology, 2004

intake on the time for beef cattle to reach market weight or on milk production for dairy cows.[81]

This study involved two years of near-continuous ammonia emission data collections at two feedyards. Cattle were fed either conventional feed or wet distillers grains (WDG). Ammonia emissions were 36 percent higher for cattle that were fed WDG.

This study is only applicable to WDG, a feed byproduct of ethanol production. The study notes that WDG typically contains 20 percent or more of protein. That is higher than the ideal diet protein content of 11.5-13.5 percent for beef cattle. This feed is not common in California, because WDG is sold primarily to dairies or cattle feedlots within the immediate vicinity of an ethanol plant, and California only grows 0.07 percent of the nation's corn[82], and produces 0.8 percent[83] of the nation's ethanol. Since dairies in the Valley do not feed WDG, and there is almost no means for WDG feed to be acquired by Valley dairies, this measure is already being implemented and no further emission reductions can be achieved.

<u>Phase, Group, and Split Sex-Feeding</u> - *(applies to all CAFs)*

The NRCS Reference Guide and a compilation by Guthrie, Giles, etc.[84] focus on mitigation measures for feed management including group and phase feeding, dietary formulation changes, and feed additives. Controlling the protein content of feed is a key element to lowering nitrogen content of manure. Protein naturally contains nitrogen compounds that are often broken down into simple compounds such as ammonia. Group and phase feeding allows the animal to receive the proper nutrition intake by separating animals by age or sex. This allows for a specific diet tailored to each group in order to reduce manure excretion and nitrogen content. Split sex feeding programs are already included as a mitigation option in District Rule 4570 for swine facilities.

The Reference Guide states that dietary formulation changes involve changes in feed ingredients or ration formulations to provide essential available nutrients to meet animal requirements while minimizing excess amounts of nutrients.

Because feed is one of the most significant costs for confined animal facilities, producers work with nutritionists to design diets to maximize feed efficiency and minimize excess nutrients to reduce overall costs. Confined animal facilities work to continually improve feed formulations to deliver nutrients in the amounts required to meet production goals. Overfeeding is undesirable because it will increase costs and farming operations have overall small margins of profit. Operations that overfeed would not be able to compete and would

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[81] Todd, R.W., N.A. Cole, D.B. Parker, M. Rhoades, and K. Casey. (2009). "Effect of Feeding Distillers Grains on Dietary Crude Protein and Ammonia Emissions from Beef Cattle Feedyards." In Proceedings of the Texas Animal Manure Management Issues Conference, 83–90.

[82] United States Department of Agriculture - National Agricultural Statistics Service, 2017 Census of Agriculture

[83] U.S. Energy Information Administration, State Energy Data 2020: Production

[84] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

not remain in business because they would not be able to compete with operations that formulate rations for greater efficiency.

As a result of genetic selection and improved diets, milk production per cow has increased and feed usage has decreased by 77 percent.[85] For poultry, it is estimated that genetic selection and the current feed practices have reduced nitrogen excretion by poultry by up to 55 percent.[86]

Rule 4570 includes mitigation options for feeding animals in accordance with NRC Guidelines. The NRC Guidelines establish different nutrition requirements for animals at different ages and stages of production. Nutritionists formulate diets to meet the requirements at these different ages and stages of production.

As stated above, farms already formulate diets to maximize feed efficiency and minimize excess nutrients. There are many challenges to further dietary changes[87], including:

- Nutrient concentrations in feed and feed ingredients vary considerably; therefore, changing feed formulations of diets will require additional lab analyses of feed resulting in increased costs
- Changes in dietary formulations increase feed costs due to the time and expense of diet formulation and acquisition of new ingredients
- Reduction of crude protein nitrogen can cause deficiency in certain amino acids, such as lysine, threonine, and methionine, that can adversely affect animal performance, including growth and milk production
- Crude protein reductions for dairy cattle must be closely managed to avoid impacting productivity

As discussed above, confined animal facilities already formulate diets to maximize feed efficiency and minimize excess nutrients to reduce overall costs and remain competitive. Rule 4570 includes mitigation options for feeding animals in accordance with NRC Guidelines, which includes specific nutrient requirements for different animals. Therefore, this measure is already implemented by the confined animal facilities in the Valley and any ammonia reductions from this measure are already being attained.

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[85] McCabe, C. (2021). How Dairy Milk Has Improved its Environmental and Climate Impact. Clarity and Leadership for Environmental Awareness and Research at UC Davis. Retrieved from: *https://clear.ucdavis.edu/explainers/how-dairy-milk-has-improved-its-environmental-and-climate-impact*

[86] United States Department of Agriculture - Natural Resources Conservation Service. (2020). Feed and Animal Management for Poultry. Nutrient Management Technical Note No. 190-NM-4. Retrieved from: *https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=45569.wba*

[87] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems", pp. 12-13. September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

Phase feeding and split-sex feeding have been commonly used at confined animal facilities throughout the nation for many years, particularly on larger operations,[88, 89, 90, 91] and are a standard practice for the relatively larger confined animal facilities subject to District permitting requirements in the Valley. Because of the higher cost of production in California, confined animal facilities are larger operations compared to other states to take advantage of economies of scale. The standard practice at these operations is to separate animals by phases, ages, or groups that are fed specific diets. At dairies, calves, young heifers, bred heifers, dry cows, milk cows in different stages of lactation, and sick cattle are placed in separate groups and fed rations that are specifically formulated. Beef cattle are separated into cows and calf pairs raised on rangeland, bulls, yearlings/stockers, and finishing cattle, which are fed a separate diet. Broiler chickens are typically fed three to four different diets during their grow-out period and turkeys may be fed up to six diets during their grow-out period to match the specific age or stage of production.[92] It is estimated that genetic selection and the current feed practices have reduced ammonia reduced nitrogen excretion by poultry by up to 55 percent.

Phase feeding is the standard practice in the Valley which also allows for reduction in feed costs and meet production goals. In addition, Rule 4570 includes feeding animals in accordance with NRC Guidelines. The NRC Guidelines establish different nutrition requirements for animals at different ages and stages of production. Nutritionists formulate diets to meet the requirements at these different ages and stages of production. Because phase feeding is in practice at the majority if not all of confined animal facilities in the Valley, any ammonia reductions of this practice are currently being achieved. No additional ammonia reductions are expected from the suggested mitigation measure.

[88] Carter, S., Sutton, A., Stenglein, R. (2012). Diet and Feed Management to Mitigate Airborne Emissions – Air Quality Education In Animal Agriculture. *USDA National Institute of Food and Agriculture.* Retrieved from: *https://lpelc.org/wp-content/uploads/2019/03/Dietand-Feed-FINAL.pdf*

[89] Van Heutgen, E. (2010) Growing-Finishing Swine Nutrient Recommendations and Feeding Management. Pork Information Gateway Factsheets Number PIG 07-01-09. *https://porkgateway.org/resource/growing-finishing-swine-nutrient-recommendations-and-feeding-management/*

[90] USDA Animal and Plant Health Inspection Service (APHIS). Iowa State University (2022) US Poultry Industry Manual - Broilers: brooding. Poultry FAD Preparedness & Response Series. *https://www.thepoultrysite.com/articles/fad-broilers-brooding*

[91] Miles, R.D., Jacob, J.P. (2000) Feeding the Commercial Egg-Type Laying Hen. Florida Cooperative Extension Service, Institute of Food and Agricultural Sciences, University of Florida. *https://ucanr.edu/sites/placernevadasmallfarms/files/102990.pdf*

[92] Moss A, Chrystal P, Cadogan D, Wilkinson S, Crowley T, Choct M. (2021). "Precision feeding and precision nutrition: a paradigm shift in broiler feed formulation?" *Animal Bioscience*, 2021;34(3):354-362. Retrieved from: *https://www.animbiosci.org/journal/view.php?doi=10.5713/ab.21.0034*

<u>Increase Grazing Time for Dairy Cattle</u> - *(applies to dairy cattle only)*

A compilation by Guthrie[93] states that increased grazing time could reduce ammonia from dairy operations by up to 50 percent as distributed urine can be absorbed into soil and broken down before ammonia is released. However, this practice is not feasible in the Valley, as there is not sufficient land to graze cattle and the arid climate generally requires irrigation to grow crops.

The University of California Agricultural and Natural Resources (UC ANR) publication[94] estimates that the long-term carry capacity of rangeland for grazing in Madera County is 15 or 16 acres per 1,000 lb animal unit; therefore, based on the information in this publication approximately 21-22 acres of unirrigated rangeland would be required to allow a typical 1,400 lb mature dairy cow to graze. The University of California Cooperative Extension (UCCE) publication[95] indicates that 15-18 acres of unirrigated rangeland are required to support a 1,200 lb cow in the Sierra Foothills for one year, and that one acre of irrigated pasture would produce enough forage to feed a 1,200 lb cow for six months. Based on the information in these publications, it is estimated that in the San Joaquin Valley 15-22 acres of unirrigated land would be required for each mature cow to graze for a year, one acre of irrigated pasture would be required for a mature cow to graze for six months, and two acres of irrigated pasture would be required for a mature cow to graze for one year. The enormous amount of land required to graze cattle on non-irrigated land clearly makes this infeasible. Based on information from the USDA National Agricultural Statistics Service, the average dairy in the Valley has approximately 1,600 milk and dry cows, not including heifers and calves. Therefore, it is estimated the average dairy in the Valley would require 1,600 acres of land to graze its mature cows for 6 months and 3,200 acres of land to graze its mature cows for one year. Because of the often arid conditions in the Valley, this land would need to be regularly irrigated to sustain sufficient forage for grazing. Additionally, this measure would be impossible to implement as a result of the ongoing severe drought, the Sustainable Groundwater Management Act (SGMA), and limitations on water usage pose severe challenges to the Valley.

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[93] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[94] George, M., Frost, W., and McDougald, N. (December 2020). Ecology and Management of Annual Rangelands Series Part 8: Grazing Management. University of California Agricultural and Natural Resources Publication 8547. https://anrcatalog.ucanr.edu/pdf/8547.pdf

[95] Macon, D., and Meyer, H. (June 2018). How Many Cows Can My Property Support? - Basics of Carrying Capacity, Stocking Rate, and Pasture Irrigation. University of California Cooperative Extension. *UCCE Placer/Nevada Publication 31 1005.* Retrieved from: *https://projects.sare.org/wp-content/uploads/Pub-31-1005-Carrying-Capacity-and-Stocking-Rate.pdf*

The study Survey of Dairy Housing and Manure Management Practices in California[96] reported that in 2007, the average number of milk and dry cows of dairies that responded to the survey in Tulare County was 1,800 cows and that these dairies had 524 acres on which manure was applied to grow feed. Assuming that the acreage for feed production on a dairy in the Valley is proportional to the number of mature cows, the average dairy in Valley with 1,600 mature cows is estimated to have approximately 466 acres of land used for feed production. If half of this land is maintained for feed production and the mature cows at the dairy are grazed on irrigated pasture for six months, the average dairy would require approximately 1,367 additional acres (1,600 acres – 233 acres). For grazing of mature cows on irrigated pasture for the entire year, the average dairy in the Valley with 1,600 mature cows would require approximately 2,734 additional acres (3,200 acres – 467 acres). Information from the USDA National Agricultural Statistics Service indicates that there are currently 965 dairies and 1.5 million milk and dry cows in the Valley. Therefore, 1.5 million acres of irrigated pasture would need to be available for grazing if dairy cows in the Valley graze for just six months and 3 million acres of irrigated pasture would need to be available for dairy cows in the Valley to graze for the entire year.

Because the amount of land needed is not available, this mitigation measure is not feasible in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

<u>Feed Additives for Poultry</u> - *(applies to poultry only)*

Feed additives such as minerals, antibiotics, and digestive aids are another option to mitigate emissions. These additives can allow for improved nutrient absorption and minimize nitrogen excretion. Feed additives are a mitigation option included in District Rule 4570 for poultry.

Feed additives are more commonly used with poultry than with ruminants, such as cattle, because of the differences in how the digestive system works in ruminants compared to poultry. Additives in the feed of poultry operations can be absorbed by these animals. However, feed and feed additives are pre-digested by rumen bacteria prior to being absorbed in the digestive system of ruminants, which may alter the composition of many feed additives. The use of the rumen bacteria in the digestive system of ruminants that pre-digest feed allows cattle, and other ruminants to utilize various feeds that cannot be digested by non-ruminants.

Rule 4570 requires owners/operators of a layer CAF to implement at least one of the following feed mitigation measures:

- Feed according to NRC guidelines; or
- Feed animals probiotics designed to improve digestion according to manufacturer recommendations; or

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[96] Meyer, D., Price, P.L., Rossow, H.A., Silva-del-Rio, N., Karle, B., Robinson, P.H., DePeters, E.J., and Fadel, J. (2011) Survey of dairy housing and manure management practices in California. Journal Dairy Sci. 94:4744-4750. *https://doi.org/10.3168/jds.2010-3761*

- Feed animals an amino acid supplemented diet to meet their nutrient requirements; or
- Feed animals feed additives such as amylase, xylanase, and protease, designed to maximize digestive efficiency according to manufacturer recommendations.

Feed is one of the most significant costs for confined animal facilities, therefore producers work with nutritionists to design diets that maximize feed efficiency, increase feed adsorption, and reduce costs. For poultry, it is estimated that genetic selection and the current feed practices have reduced nitrogen excretion by poultry by up to 55 percent.

There are challenges to increase usage of feed additives. Feed is one of the most significant costs of production and feed additives will increase feed costs due to the time and expense of diet formulation and feed additive acquisition. Some additives have negative effects and may increase emissions of some pollutants. The use of antibiotics as feed additives has also been subject to greater restrictions because of efforts to combat increasing bacterial resistance to antibiotics.

The Reference Guide states that many feed additives are already "regularly used to improve nutrient absorption from feed ingredients." Although the Reference Guide suggests that feed additives may improve nutrient absorption and decrease emissions of some pollutants, it does not specify which additives reduce which pollutants for different animals or the amount of each additive required.

Although the suggested measure lacks the specificity needed for a regulation, confined animal facilities already formulate diets to maximize nutrient adsorption, including the use of various feed additives. In addition, Rule 4570 includes feeding animals in accordance with NRC Guidelines, which includes specific nutrient requirements for different animals, and the option to utilize various feed additives. Therefore, because this measure is already used by the confined animal facilities in the Valley and included in Rule 4570, any ammonia reductions from this measure are already being achieved in the District.

It is critical for farmers to have the flexibility to decide the kind of mitigation measures that will work best for their specific operation by taking into consideration animal health and welfare, productivity, food safety and overall bio-security issues. The District's menu of feeding options in Rule 4570 provides farmers with this flexibility, while also requiring the most stringent measures for controlling emissions from confined animal facilities.

Animal Confinement (Housing)

Table 9: Animal Confinement Measures Evaluated

Method	Measure	CAF Type	Reference
Biofilters and Wet Scrubbers	Enclosed Barns with Biofiltration Systems	Dairy	Kresge[97]
	Biofilters	All	NRCS[98]
	Install Air-Scrubbers or Biotrickling Filters to Mechanically Ventilated Pig Housing	Swine	Price[99]
	Air Scrubbing Techniques	All	Guthrie[100]
	Wet Scrubbers	All	NRCS
Washing Floors/Lanes	Clean Lanes at Dairies	Dairy	Beene[101]
	Washing Floors and Other Soiled Areas in Livestock Facilities	All	Guthrie
	Scrape/Flush Freestall Lanes	Dairy	Mendes[102]

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[97] Kresge, L., Strochlic, R. (2007). Clearing the Air: Mitigating the Impact of Dairies on Fresno County's Air Quality and Public Health. California Institute for Rural Studies.
[98] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*
[99] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*
[100] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*
[101] Beene, M., Krauter, C., Goorahoo, D. (2005). Ammonia Fluxes from Animal Housing at a California Free Stall Dairy. California State University, Fresno. Center for Irrigation Technology and Plant Science Department. Retrieved from: *https://www3.epa.gov/ttnchie1/conference/ei15/session6/beene.pdf*
[102] Mendes, L.B., Pieters, J.G., Snoek, D., Ogink N.W.M., Brusselman, E., Demeyer, P. (2017). Reduction of Ammonia Emissions from Dairy Cattle Cubicle Houses via Improved Management or Design-Based Strategies: A Modeling Approach, In *Science of The Total Environment*, Volume 574, 2017, Pages 520-531, ISSN 0048-9697. Retrieved from: *https://www.sciencedirect.com/science/article/abs/pii/S0048969716319970?via%3Dihub*

Method	Measure	CAF Type	Reference
	Washing Down Dairy Cow Collecting Yards	Dairy	Price
Corral Management	Constantly Manage Corrals	Dairy	Card[103]
	Frequency of Corral Manure Management	Dairy	Schmidt[104]
Floor Design	Floor Design Including Slates, Grooves, V-Shaped Gutters and Sloping Floors to Collect and Contain Slurry Faster	Dairy, Swine	Guthrie
	Part-slatted Floor Design for Pig Housing	Swine	Price
	Adapt Dairy Housing	Dairy	Pinder[105]
	Separate Urine/Manure with 3% Floor Slope	Dairy	Braam[106]
Additional Straw Bedding	Additional Targeted Straw-bedding for Cattle Housing	All cattle	Price
	Straw Bedding for Cattle Housing	All cattle	Guthrie
Other Housing	Optimal Barn Acclimatization with Roof Insulation and/or Automatically Controlled Natural Ventilation	All	Guthrie
	Oil Spray/Sprinkling	Swine	NRCS

[103] Card, T. and Schmidt, C. (May 2006). Dairy Air Emissions Report: Summary of Dairy Emission Estimation Procedures. Final Report to CARB.

[104] Schmidt, C.E., T. Card, P. Gaffney, and S. Hoyt. (2005). Assessment of Reactive Organic Gases and Amines from a Northern California Dairy Using the EPA Surface Emissions Isolation Flux Chamber. Presented at the 14th Annual Emission Inventory Conference of the U.S. Environmental Protection Agency, Las Vegas, NV.

[105] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: *https://pubs.acs.org/doi/pdf/10.1021/es060379a*

[106] Braam, C., Ketelaars, J., Smits, M. (1997). Effects of floor design and floor cleaning on ammonia emission from cubicle houses for dairy cows, *Wageningen Journal of Life Sciences*. Retrieved from: *https://library.wur.nl/ojs/index.php/njas/article/view/525*

Method	Measure	CAF Type	Reference
	Convert Caged Laying Hen Housing from Deep-Pit Storage to Belt Manure Removal	Poultry	Price
	More Frequent Manure Removal from Laying Hen Housing with Belt Clean Systems	Poultry	Price
	In-House Poultry Manure Drying	Poultry	Price

Biofilters - ***(applies to all CAFs)***

A biofilter is an air filtration and odor mitigation system that channels building exhaust through a mixture of organic materials that support microbial growth. Biofilters have been identified in several publications as a potential ammonia mitigation method, including the NRCS Reference Guide. The reference guide notes many considerations that must be taken into account when implementing these systems, including that they require careful design, monitoring, and maintenance, and have very high associated costs.

Initial costs and challenges include the replacement of existing ventilation fans in order to provide the necessary airflow and the energy to overcome the added pressure drop caused by the biofilter. Biofilters require increased retention time; however increasing the retention time usually increases the system static pressure, which can compromise the ventilation system performance. It is typically not practical to treat all of the exhaust air during the summer when a large amount of ventilation flow is required to remove excessive heat from the production house. Lower ventilation airflow may also lead to heat stress in the animals.

Different types of biofilters have their own disadvantages. Flat open biofilter beds are easier to construct and generally cost less; however, they require very large footprints. Vertical biofilters are more difficult to construct and are more expensive, and biological material can settle, causing air leaks, which will reduce the performance of the system. In addition, biofilter media will need to be replaced periodically.

Biofilters require ongoing maintenance to prevent air leakage, dust accumulation, and air constriction in the media to ensure effectiveness of the system performance. Monitoring and maintenance of the filter media moisture is essential to operation of the biofilter, and sprinklers or other wetting systems may be required. Rodents and weeds have also been a problem for some biofilters.

Included in Appendix B, is a cost-effectiveness analysis that demonstrates the economic infeasibility of biofilters. District Rule 4570 does provide options for facilities to use emissions control devices such as biofilters; however, it is not feasible to require all facilities subject to Rule 4570 to install biofilters as they are not cost-effective or practical for livestock facilities in the Valley. The District has concluded that the measure discussed is not a viable mitigation measure to require in Rule 4570.

Air-Scrubbers/Wet Scrubbers - ***(applies to all CAFs)***

Several compilations of mitigation measures, including the NRCS Reference Guide and UK User Guide, list air scrubbing as a potential method of capturing ammonia from animal housing; however, there are considerable costs and challenges associated with the implementation of scrubbers at animal facilities. One such challenge is that off-the-shelf industrial scrubbers are typically not applicable to animal production systems, due to the variation and dynamic changes of such biological systems (e.g., housing structure variation, changes in ventilation airflow rate/pattern in response to the changes of air temperature, manure management practices, unique PM characteristics).

The practicality of scrubbers is limited due to their potential to compromise the ventilation airflow rate needed to control temperature in production houses to ensure animal health. There are added costs for the replacement of existing ventilation fans in order to provide the necessary airflow and the energy to overcome the added pressure drop because of the scrubber. Additionally, it is typically not practical to treat all of the exhaust air during the summer when a large amount of ventilation flow is required to remove excess heat from the production house and prevent heat stress in the animals.

Additional costs and challenges to scrubbers include the ongoing maintenance required to prevent dust accumulation and air constriction in the media to ensure effectiveness of the system performance. There are also potential dangers in transporting and handling materials such as acid used in the scrubber. Furthermore, wet scrubbers require large supplies of water and special wastewater handling systems that are not typical at animal production operations. This increased water usage is not practical in the Valley because of limited availability of water due to drought and increasing restrictions on the amount of usable groundwater, due to SGMA.

The UK User Guide identifies installing air-scrubbers as a mitigation method specifically for pig housing, however concludes that the practical application of this method is only to new purpose-built buildings. Included in Appendix B is a cost-effectiveness analysis of scrubbers for swine facilities. The District found that scrubbers are not cost effective, and are therefore not technologically or economically feasible to require in the Valley. District Rule 4570 does provide options for facilities to use emissions control devices such as scrubbers; however, it is not feasible to require all facilities subject to Rule 4570 to install scrubbers. The District has concluded that the measure discussed is not a viable mitigation measure to require in Rule 4570.

Washing Floors/Lanes - ***(applies to all CAFs)***

Several publications include the washing of floors and other soiled areas in livestock facilities as a potential mitigation method to reduce ammonia emissions. The UK User Guide includes a more specific measure involving washing down the concrete areas where dairy cows are collected prior to and after each milking even, through pressure washing or by hosing and brushing.

District Rule 4570 includes the requirement to clean the manure from the lanes, where the majority of manure is excreted, at dairies and other cattle facilities. The majority of cow holding areas at Valley dairies are equipped with sprinkler pens for washing the cows, and are periodically washed throughout the day, rather than scraped once per day.[107] Additionally, Rule 4570 requires constant washing of milking parlor floors to remove manure, which is also standard practice for California dairies. It is essential for all areas of milking parlors, including the milking parlor floors, to be the one of the cleanest parts of the dairy to ensure that the milk from the cows is clean and uncontaminated. There is a constant need for flushing and cleaning of the milking parlor because milk that is contaminated cannot be sold. Therefore, whenever practical, Rule 4570 requires cleaning of areas where the majority of manure accumulates.

Operators of dairy CAFs are required to implement several mitigation measures related to the cleaning of floors/lanes to comply with District Rule 4570, including the following:

Required Measures:

- Flush or hose milking parlor immediately prior to, immediately after, or during each milking;
- Pave feedlanes, where present, for a width of at least 8 feet along the corral side of the feedlane fence for milk and dry cows and at least 6 feet along the corral side of the feedlane for heifers; and
- Flush, scrap, or vacuum freestall flush lanes immediately prior to, immediately after, or during each milking; or flush or scrape freestall flush lanes at least 3 times per day.

Additional Measures (must select at least one of the following):

- Use non-manure-based bedding and non-separated solids based bedding for at least 90 percent of the bedding material, by weight, for freestalls;
- For a large dairy CAF, remove manure that is not dry from individual cow freestall beds or rake, harrow, scrape, or grade freestall bedding at least once every 7 days; or
- For a medium dairy CAF, remove manure that is not dry from individual cow freestall beds or rake, harrow, scrape, or grade freestall bedding at least once every 14 days.

Operators of other cattle CAFs are required to implement the following mitigation measures to comply with District Rule 4570:

- Vacuum, scrape, or flush freestalls at least once every 7 days;

[107] Chang, A., T. Harter, J. Letey, D. Meyer, R. D. Meyer, M. Campbell-Mathews, F. Mitloehner, S. Pettygrove, P. Robinson, R. Zhang (2006) Managing Dairy Manure in the Central Valley of California; University of California Committee of Experts on Dairy Manure Management Final Report to the Regional Water Quality Control Board, Region 5, Sacramento, June 2005. *https://ucanr.edu/sites/groundwater/files/136450.pdf*

- Pave feedlanes, where present, for a width of at least 6 feet along the corral side of the feedlane
- Either use non-manure-based bedding and non-separated solids based bedding for at least 90 percent of the bedding material, by weight, for freestalls; or remove manure that is not dry from individual cow freestall beds or rake, harrow, scrape, or grade bedding in freestalls at least once every seven days.

In conclusion, the District already requires mitigation measures that require CAFs to wash floors and/or lanes inside of cow housing areas. No additional ammonia reductions are expected from the suggested mitigation measure.

Corral Management - ***(applies to all cattle)***

Proper management of manure in animal housing areas will stabilize the nitrogen compounds, which will reduce the rate that these compounds are converted to ammonia that can be lost to the atmosphere. Research by Card and Schmidt (2005) supports that management of manure in corrals reduces ammonia emissions from the corrals and points out that of two dairies tested, the ammonia emissions from the dairy with constantly managed corrals had "exceptionally low ammonia emissions." Follow-up research by Card and Schmidt (2009) at one of the dairies studied indicated that ammonia emissions were significantly reduced (>80 percent reduction comparing 2008 to 2005 reported ammonia emissions) when the frequency of management of the manure in the corrals was increased.

Rule 4570 includes requirements for management of corrals to prevent excessive buildup of manure, designing or managing corrals to prevent excessive moisture, and periodic scraping and removal of manure from corrals. Under Rule 4570, dairy, beef feedlot, and other cattle facilities are required to implement four to six measures for corral management depending on facility type, as well as select one additional mitigation measure as detailed below:

Required Measures

- Pave feedlanes, where present, for a width of at least 8 feet along the corral side of the feedlane fence for milk and dry cows and at least 6 feet along the corral side of the feedlane for heifers (*dairy and other cattle*);
- Clean manure from corrals at least 4 times per year with at least 60 days between cleaning; or clean corrals at least once between April and July and at least once between September and December (*dairy*);
- Scrape corrals twice a year with at least 90 days between cleanings, excluding the removal of in-corral mounds (*beef feedlot and other cattle*);
- Scrape, vacuum or flush concrete lanes in corrals at least once every day for mature cows and every 7 days for support stock; or clean concreted lanes such that the depth of manure does not exceed 12 inches at any point or time (*dairy and other cattle*);
- Inspect water pipes and troughs and repair leaks at least once every 7 days;
- Choose one of the following:
    - Slope the surface of the corrals at least 3 percent where the available space for each animal is 400 square feet or less. Slope the surface of the corrals at least

1.5 percent where the available space for each animal is more than 400 square feet per animal;
    - Maintain corrals to ensure proper drainage preventing water from standing more than 48 hours; or
    - Harrow, rake, or scrape corrals sufficiently to maintain a dry surface.
- If the CAF has shade structures, they must choose one of the following:
    - Install shade structures such that they are constructed with a light permeable roofing material;
    - Install all shade structures uphill of any slope in the corral;
    - Clean manure from under corral shades at least once every 14 days, when weather permits access into the corral (*dairy*); or
    - Install shade structure so that the structure has a North/South orientation.

<u>Additional Measures</u>

- Manage corrals such that the manure depth in the corral does not exceed 12 inches at any time or point, except for in-corral mounding. Manure depth may exceed 12 inches when corrals become inaccessible due to rain events. The facility must resume management of the manure depth of 12 inches or lower immediately upon the corral becoming accessible.
- Knockdown fence line manure build-up prior to it exceeding a height of 12 inches at any time or point. Manure depth may exceed 12 inches when corrals become inaccessible due to rain events. The facility must resume management of the manure depth of 12 inches or lower immediately upon the corral becoming accessible.
- Use lime or a similar absorbent material in the corral according to the manufacturer's recommendation to minimize moisture in the corrals; or apply thymol to the corral soil in accordance with the manufacturer's recommendation (*dairy and other cattle*).

In conclusion, the District already requires mitigation measures that minimize emissions from corral housing areas. No additional ammonia reductions are expected from the suggested mitigation measure.

<u>Floor Design</u> - *(applies to dairy cattle and swine only)*

Several publications list different floor design types for collecting and containing slurry that may reduce ammonia emissions that include slats, grooves, v-shaped gutters, and sloping floors. The measures included in these documents are applicable to small dairies in which cows are kept in stables or cubicle-type housing that is common on small European dairies in which manure was allowed to accumulate. These measures are also applicable to manure handled as a slurry, and does not apply to the larger dairies in the Valley that are subject to District permitting, which handle very little manure as a slurry.[108] It should also be noted that

[108] Marklein, A. R., Meyer, D., Fischer, M. L., Jeong, S., Rafiq, T., Carr, M., and Hopkins, F. M. (2021) Facility-scale inventory of dairy methane emissions in California: implications for mitigation, Earth Syst. Sci. Data, 13, 1151–1166, *https://doi.org/10.5194/essd-13-1151-2021*, 2021.

most physical changes to existing dairy barns must be incorporated at the design stage, and are not practical for existing structures, resulting in significantly higher capital costs.

Valley dairies have paved lanes to facilitate manure removal, as required by Rule 4570. The lanes on the dairies are sloped to allow manure to be sent to a lagoon system. In addition, Rule 4570 requires that manure must be periodically removed from the lanes where the cattle spend the majority of their time. Therefore, Rule 4570 already incorporates control measures for specialized floor design and this is already being implemented by dairies in the Valley.

Rule 4570 requirements for dairy and other cattle facilities are as follows:

- Pave feedlanes, where present, for a width of at least 8 feet along the corral side of the feedlane fence for milk and dry cows and at least 6 feet along the corral side of the feedlane for heifers and other cattle.
- For corrals, choose one of the following:
    - Slope the surface of the corrals at least 3 percent where the available space for each animal is 400 square feet or less. Slope the surface of the corrals at least 1.5 percent where the available space for each animal is more than 400 square feet per animal;
    - Maintain corrals to ensure proper drainage preventing water from standing more than 48 hours;
    - Harrow, rake, or scrape corrals sufficiently to maintain a dry surface.

The UK User Guide includes a floor design measure specifically for swine that aims to reduce the overall emitting surface area of slurry by replacing fully slatted floors with part-slatted floors. This type of floor design is already a requirement at the only swine facility in the District. The facility has a specific permit condition that states "Permittee shall use a slatted floor system (slatted floors over deep pits or shallow flush alleys), with daily manure removal for shallow flush alleys and weekly removal from deep pits." Under Rule 4570, swine CAFs are required to implement measures for animal housing that includes the use of a similar slatted floor system, as follows:

- Use a slatted floor system (slatted floors over deep pits or shallow flush alleys), with daily manure removal for shallow flush alleys and weekly removal from deep pits.

In conclusion, the District already requires a mitigation measure for swine CAFs to minimize emissions from animal housing areas through the use of a slatted floor system. No additional ammonia reductions are expected from the suggested mitigation measure.

Separate Urine/Manure with 3 Percent Floor Slope - *(applies to dairy cattle only)*

In one study[109] completed in the Netherlands, ammonia emissions from cubicle housing with a slatted floor, used on small dairies in Europe, were compared with two different solid floor systems: a non-sloped and a 3 percent one-sided sloped floor, combined with a highly frequent or normal removal of manure by a scraper. The study results indicated that the slope of the floor had more impact on reducing ammonia emissions than increasing the scraping frequency. Solid floors with a slope decreased ammonia emissions compared to slatted floors. However, the study indicated that solid floors without a slope may not decrease ammonia emission compared with slatted floors.

Cubicle housing with slatted floors and manure pits under the housing areas are not used for dairy cattle in the Valley. The typical practice is to house cattle in barns or corrals with flushed or scraped lanes. These lanes are sloped to facilitate flushing of the manure to the lagoon system. Additionally, Rule 4570 includes requirements that corrals be sloped, which allows urine to drain away, which reduces the conversion of urea in urine to ammonia since it will have less contact with enzymes in feces that promote this transformation.

District Rule 4570 requires dairy, beef feedlot, and other cattle facilities to implement the following mitigation measure, or an equivalent measure:

- Slope the surface of the corrals at least 3 percent where the available space for each animal is 400 square feet or less. Slope the surface of the corrals at least 1.5 percent where the available space for each animal is more than 400 square feet per animal.

In conclusion, the District Rule 4570 already includes mitigation measures involving sloped floors for cattle facilities. No additional ammonia reductions are expected from the suggested mitigation measure.

Additional Targeted Straw-Bedding for Cattle Housing - *(applies to dairy and other cattle only)*

This method involves adding extra straw bedding to cattle houses, targeting the wetter and dirtier areas of the house. This measure is applicable to small dairy farms that house cattle indoors and use a solid manure handling system, such as small dairy farms in Europe; however, most dairies in the Valley handle the majority of the manure as a liquid and do not use straw bedding. One study[110] indicated that storage or treatment ponds were found on 95.9% of dairies, and another report prepared for CARB states that, "*California dairy effluent*

[109] Braam, C., Ketelaars, J., Smits, M. (1997). Effects of floor design and floor cleaning on ammonia emission from cubicle houses for dairy cows, *Wageningen Journal of Life Sciences*. Retrieved from: *https://library.wur.nl/ojs/index.php/njas/article/view/525*

[110] Meyer, D., Price, P.L., Rossow, H.A., Silva-del-Rio, N., Karle, B., Robinson, P.H., DePeters, E.J., and Fadel, J. (2011) Survey of dairy housing and manure management practices in California. Journal Dairy Sci. 94:4744-4750. *https://doi.org/10.3168/jds.2010-3761*

often runs 1% total solids."[111] These dairies also use frequent flushing to remove the manure instead of absorbing with straw, thereby reducing emissions through flushing. Beef cattle in the Valley are not housed indoors; therefore, this measure would not apply to beef cattle in the Valley.

For areas of the dairy that would benefit from this method, the use of straw, or other non-manure based bedding for cow housing is included as a menu option for cattle housed in barns, as shown below:

- Use non-manure-based bedding and non-separated solids based bedding for at least 90 percent of the bedding material, by weight, for freestalls (e.g. rubber mats, almond shells, sand, or waterbeds).

In conclusion, the District already has a mitigation measure option to minimize emissions from cow bedding. No additional ammonia reductions are expected from the suggested mitigation measure.

Optimal Barn Acclimatization with Roof Insulation and/or Automatically Controlled Natural Ventilation - *(applies to all CAFs)*

The compilation by Guthrie, et al.[112] includes ammonia mitigation measures that involve specific building design to provide optimal barn acclimatization. This measure was based on information from the United Nations Economic Commission for Europe (UNECE) compilation Framework Code for Good Agricultural Practice for Reducing Ammonia Emissions.[113] The UNECE publication stated that for cattle cubicle housing was considered the reference and that for cattle housed in cubicles with traditional slats, and claimed that this measure can moderately reduce ammonia by 20% compared to conventional cubicle housing.

Cubicle housing with traditional slats is not typically used to house cattle in the Valley; therefore, this measure is not applicable to cattle in the Valley. In cubicle housing with traditional slats, the manure that cattle excrete seeps through the slats and falls to an alley or a storage pit below the housing area. In the Valley, dairy cattle are typically housed in barns or corrals with lanes that are flushed or scraped to remove manure to a separate area for storage. In cubicle housing with traditional slats, a large amount of the ammonia emissions are from the manure stored in an alley or pit below the housing area. Therefore, this measure

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[111] Meyer, D, Heguy, J., Karle, B. and Robinson, P. (2019) Characterize Physical and Chemical Properties of Manure in California Dairy Systems to Improve Greenhouse Gas Emission Estimates. California Environmental Protection Agency, Air Resources Board. *https://ww2.arb.ca.gov/sites/default/files/classic/research/apr/past/16rd002.pdf*

[112] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[113] UNECE. 2015. United Nations Economic Commission for Europe Framework Code for Good Agricultural Practice for Reducing Ammonia Emissions. United Nations Economic Commission for Europe Convention on Long-range Transboundary Air Pollution. *https://unece.org/environment-policy/publications/framework-code-good-agricultural-practice-reducing-ammonia*

would not reduce ammonia emissions from cattle housing in the Valley because manure is stored in a different area.

In addition, these measures are not feasible for many existing buildings and must be incorporated in the initial design stage of a new build. For poultry, new houses generally incorporate insulation and controlled ventilation. However, this measure is generally not feasible for implementation at Valley dairies or other cattle facilities. Due to the warm climate in the Valley, barns used for cattle consist of a roof with open sides to allow for adequate airflow and cooling. These structures would need to be completely redesigned and reconstructed to implement this mitigation measure, and there would be substantial cost to enclose the cattle and equip the barns with ventilation systems to supply sufficient airflow for the cattle. Furthermore, the increased airflow from the fans required for ventilation may promote increased emissions from the barns rather than reduce ammonia.

In conclusion, the suggested measure is not applicable to cattle facilities in the Valley and would not result in any additional ammonia reductions.

Oil Spray/Sprinkling - *(applies to swine only)*

Sprinkling of vegetable oil in animal production areas has been demonstrated as an effective measure within swine barns for PM mitigation, with observed smaller reductions of ammonia ranging from 0-30 percent. However, results of research on the effect of this practice on ammonia emissions vary greatly.[114] This practice requires daily labor if applied by hand, and requires additional time during room washing to remove oil residue. Additionally, oil residue can cause ventilation fans to become stuck in on or off positions, preventing them from operating correctly to ensure proper ventilation and cooling of animals. As mentioned above, current research shows considerable variability in the potential ammonia emission reductions of this measure; therefore, it is currently uncertain if this measure will reduce ammonia emissions and the magnitude of any potential reductions. Furthermore, the NRCS Reference Guide indicates that this measure is applicable to swine barns, which contribute a very small amount to the District's ammonia inventory with only one permitted facility in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Convert Caged Laying Hen Housing from Deep-Pit Storage to Belt Manure Removal - *(applies to poultry only)*

This measure applies to high-rise laying hen housing with deep pit storage. In a deep-pit storage system, laying hens are kept in tiered cages and the manure from laying hens drops into a pit below the cages where it may be stored for months prior to removal. The UK User Guide identifies that replacing this system with a series of belts below each tier of cages,

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[114] Harmon, J., Hoff, S., Rieck-Hinz, A. (2014). Animal Housing – Vegetable Oil Sprinkling Overview. *Air Management Practices Assessment Tool*, Iowa State University. Retrieved from: https://store.extension.iastate.edu/product/Animal-Housing-Vegetable-Oil-Sprinkling-Overview

which remove manure from the house, could have the potential to reduce ammonia emissions.

In the United States, the overall trend for farms that produce eggs has been to shift away from high-rise laying hen housing with tiered cages to cage-free housing. In 2018, voters in California approved Proposition 12, also known as the Farm Animal Confinement Initiative.[115] Proposition 12 requires that animals held in buildings, such as laying hens, breeding sows, or veal calves, *"be housed in confinement systems that comply with specific standards for freedom of movement, cage-free design, and minimum floor space."* Implementation of the law began on January 1, 2022, and as a result all eggs produced in California must be procured only from hens in cage-free housing. High-rise hen houses in which egg-laying hens are kept in cages are no longer legal in California. There are significant questions that need to be answered regarding the practicality, cost, and overall ammonia emission reductions of implementing this measure for cage-free hen houses. Therefore, the District has concluded that this measure is not a viable mitigation option to include in Rule 4570 at this time.

More Frequent Manure Removal from Laying Hen Housing with Belt Clean Systems - *(applies to poultry only)*

This method identified in the UK User Guide increases the frequency of manure removal to twice weekly, and relies on the rapid removal of manure from the house prior to the peak rate of ammonia emission. This measure is only applicable to laying hen houses that are already equipped with belt manure removal systems, and is not feasible for the majority of existing laying hen houses in the Valley given the significant facility reconstruction costs and potential space/infrastructure limitations at existing facilities.

In addition, as explained above, all eggs produced in California must be procured only from hens in cage-free housing and there are significant questions that need to be answered regarding the practicality, cost, and overall ammonia emission reductions of implementing this measure for cage-free hen houses. Therefore, the District has concluded that this measure is not a viable mitigation option to include in Rule 4570 at this time.

In-House Poultry Manure Drying - *(applies to poultry only)*

In-house poultry manure drying, as identified in the UK User Guide, is applicable to poultry housing, and involves the installation of ventilation/drying systems that reduce the moisture content of poultry litter. The author expects implementation of this method to be low to moderate, due to the practical limitations involved with installing systems in existing buildings. Forced air drying systems are not feasible for houses in which the birds are raised on litter because the litter remains in the houses with the birds until cleaned out to prepare

[115] California Proposition 12, Animal Care Program. Retrieved from: *https://www.cdfa.ca.gov/AHFSS/AnimalCare/*

for another flock. Following BACT Guidelines 5.7.1[116] and 5.7.2[117], this practice is evaluated as a potential BACT measure for new or expanding facilities; the required mitigation measure is as follows:

- Completely enclosed mechanically ventilated layer housing with evaporative cooling pads, mixing fans, and a computer control system.

In conclusion, the District already has a mechanism to implement this mitigation measure for expanding or new poultry housing operations. No additional ammonia reductions are expected from the suggested mitigation measure.

Manure Management (Storage)

Table 10: Manure Management (Storage) Measures Evaluated

Method	Measure	CAF Type	Reference
Lagoon Management	Replace Lagoons with Deep Tanks	Dairy	Guthrie[118]
	Oxygenation of Liquid Manure Lagoons	All	NRCS[119]
Storage Bags	Storage Bags	Dairy	Guthrie
Manure Storage Covers	Liquid Manure Storage Covers	All	NRCS
		All	Marks[120]
	Solid Manure Storage Covers	All	NRCS

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[116] https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/bact/BACTID773.pdf?:linktarget=_self&:embed=yes
[117] https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/bact/BACTID774.pdf?:linktarget=_self&:embed=yes
[118] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*
[119] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*
[120] Marks, R. (2001). Cesspools of Shame: How Factory Farm Lagoons and Sprayfields Threaten Environmental and Public Health. *Natural Resources Defense Council and the Clean Water Network*. Retrieved from: *https://www.nrdc.org/sites/default/files/cesspools.pdf*

Method	Measure	CAF Type	Reference
		All	Price[121]
		All	Chadwick[122]
	Allow Cattle Slurry Stores to Develop a Natural Crust	Dairy	Price
Solid-Liquid Separation	Solid-Liquid Separation	All	NRCS
Anaerobic Digesters	Anaerobic Digesters	Dairy	NRCS
		Dairy	Marks
		Dairy	Kresge[123]
Amendments/Additives	Litter Amendments and Manure Additives	All	NRCS
	Acidifying Slurry and Shifting Chemical Balance from Ammonia to Ammonium	All	Guthrie
	Acidifying Amendments and Additives for Poultry Litter	Poultry	Price

[121] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from: https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf

[122] Chadwick, D.R. (2005). Emissions of Ammonia, Nitrous Oxide and Methane from Cattle Manure Heaps: Effect of Compaction and Covering. *Atmosphere Environment*, Vol. 39, Issue 4: 787-799. Retrieved from: https://www.sciencedirect.com/science/article/abs/pii/S135223100400994X

[123] Kresge, L., Strochlic, R. (2007). Clearing the Air: Mitigating the Impact of Dairies on Fresno County's Air Quality and Public Health. *California Institute for Rural Studies.*

Method	Measure	CAF Type	Reference
	Urease Inhibitors	All Cattle	Pinder[124]
		All Cattle	Preece[125]
Surface Cooling	Surface Cooling of Slurry Manure	All	Guthrie
pH of Manure	Lowering pH of Manure	All	Preece
On-farm Composting	Composting	All Cattle	NRCS

Replace Lagoons with Deep Tanks - ***(applies to dairy cattle only)***

A compilation[126] indicated that replacing lagoons with deep tanks can reduce ammonia emissions by 30-60 percent. The information from the compilation indicates that this measure is applicable to manure that is handled as a slurry. The reductions in ammonia emissions are a result of the smaller surface area of the manure in contact with the air from which ammonia may be emitted. Storage of manure in deep tanks is not a feasible measure for the District due to the size of dairies in the Valley and the way that manure is typically handled. As previously mentioned, the average dairy in the Valley has almost 1,600 cows compared to a national average of less than 300 cows per dairy outside of California[127, 128] and are larger than the typical European dairies for which this measure was considered. In addition, dairies in the Valley typically handle liquid manure as a dilute liquid with rather than a thick slurry.

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[124] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: *https://pubs.acs.org/doi/pdf/10.1021/es060379a*

[125] Preece, S., Cole, N., Todd, R., Auvermann, B. (2017). Ammonia Emissions from Cattle Feeding Operations. *Texas A&M AgriLife Extension Service.* Retrieved from: *http://baen.tamu.edu/wp-content/uploads/sites/24/2017/01/E-632.-Ammonia-Emissions-from-Cattle-Feeding-Operations.pdf*

[126] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[127] Hanson, M. (2021) U.S. Dairy Herd Hits 27-year High. *Dairy Herd Management.* Retrieved from: *https://www.dairyherd.com/news/dairy-production/us-dairy-herd-hits-27-year-high*

[128] Latest USDA Statistics for average size of dairies excluding California. Retrieved from: *https://downloads.usda.library.cornell.edu/usda-esmis/files/h989r321c/7d279w693/f7624g40c/mkpr0222.pdf* (about 270 cows per dairy outside California)

The dilute dairy manure typically handled in the Valley has a solids content of 2 percent or less while slurry manure has a solids content of about 10 percent. As a result, the volume of manure handled would be approximately 27 times greater than the average dairy outside of California that handles dairy manure as a slurry. It is not practical to construct tanks that would contain such large amounts of manure. Notably, the depth of lagoons and storage ponds is limited to protect groundwater because a minimum distance is required between the bottom of the lagoons and storage ponds and the groundwater.[129,130] Therefore, the tanks would need to be constructed aboveground. However, it is not practical to construct tanks aboveground because of the large amount of liquid manure that must be stored. Pumping the manure into aboveground tanks would require larger amounts of energy. Also, it is possible the release of the ammonia conserved in the manure tanks will be delayed until the manure is sent to a storage pond or applied to land. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Oxygenation of Liquid Manure Lagoons - ***(applies to all CAFs)***

The NRCS Reference guide states that large land footprint of naturally aerobic lagoons is not practical for many farms. This is particularly applicable to the large farms in the Valley. Naturally aerobic lagoons are not feasible in the Valley because the dairies in the Valley would require an extremely large footprint. The design criteria of naturally aerobic lagoons in the USDA-NRCS Practice Standard Code 359 will be used to illustrate the approximate size that would be required for naturally aerated lagoons for confined animal facilities in the Valley. USDA-NRCS Practice Standard Code 359 requires that naturally aerobic lagoons be designed to have a minimum treatment surface area as determined on the basis of daily BOD_5 loading per unit of lagoon surface. The standard specifies that the maximum loading rate of naturally aerobic lagoons shall not exceed the loading rate indicated by the USDA-NRCS Agricultural Waste Management Field Handbook (AWMFH)[131] or the maximum loading rate according to state regulatory requirements, whichever is more stringent.

According to Figure 10-30 (August 2009) of the latest version of the AWMFH, the maximum aerobic lagoon lading rate for the Valley is 45 - 55 lb-BOD_5/acre-day. Based on information from the USDA National Agricultural Statistics Service, the average dairy in the Valley has approximately 1,600 milk and dry cows. Based on a typical dairy herd composition, the average dairy in the Valley is estimated to have approximately 1,348 milk cows, 252 dry cows,

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[129] California Regional Water Quality Control Board Central Valley Region Order R5-2013-0122 – Reissued Waste Discharge Requirements General Order for Existing Milk Cow Dairies. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

[130] California Regional Water Quality Control Board Central Valley Region Order R5-2017-0058 –Waste Discharge Requirements General Order for Confined Bovine feeding Operations. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2017-0058.pdf*

[131] United States Department of Agriculture (USDA) Natural Resources Conservation Service (NRCS), Agricultural Waste Management Field Handbook (AWMFH). Retrieved from: *https://directives.sc.egov.usda.gov/viewerfs.aspx?hid=21430*

and 1,153 heifers and calves. According to Table 4-5 (March 2008) of the USDA-NRCS AWMFH, the total daily manure produced by each milk cow, dry cows, and 970 lb heifer will have an average BOD loading of 2.9 lb-BOD_5/day, 1.4 lb-BOD_5/day, and 1.2 lb-BOD_5/day, respectively. The average BOD loading of manure produced by smaller heifers and calves is estimated based on manure volatile solids excretion rates. Assuming that 80 percent of the manure will be flushed to the lagoon system, the minimum lagoon surface area required for a naturally aerobic lagoon treating manure from an average size dairy in the Valley with 1,600 milk and dry cows can be calculated as follows:

<u>BOD_5 loading (lb/day)</u>

1,348 milk cows x 2.9 lb-BOD_5/cow-day x 0.80 = 3,127 lb-BOD_5/day

252 dry cows x 1.4 lb-BOD_5/cow-day x 0.80 = 282 lb-BOD_5/day

457 heifers (15-24 months) x 1.2 lb-BOD_5/heifer-day x 0.80 = 439 lb-BOD5/day

366 heifers (7-14 months) x 0.83 lb-BOD_5/heifer-day x 0.80 = 243 lb-BOD_5/day

182 heifers (4-6 months) x 0.47 lb-BOD_5/heifer-day x 0.80 = 68 lb-BOD_5/day

148 calves (0-3 months) x 0.27 lb-BOD_5/heifer-day x 0.80 = 32 lb-BOD_5/day

Total BOD loading = 3,127 lb-BOD_5/day + 282 lb-BOD_5/day + 439 lb-BOD_5/day + 243 lb-BOD_5/day + = 68 lb-BOD_5/day + 32 lb-BOD_5/day = 4,191 lb-BOD_5/day

<u>Minimum Surface Area Required for a Naturally Aerobic Lagoon for an Average San Joaquin Valley Dairy</u>

Minimum Surface (acres) in areas with a maximum loading rate of 55 lb-BOD_5/acre-day =

4,191 lb-BOD_5/day ÷ 55 lb-BOD_5/acre-day = 76.2 acres

Minimum Surface (acres) in areas with a maximum loading rate of 45 lb-BOD_5/acre-day =

4,191 lb-BOD_5/day ÷ 45 lb-BOD_5/acre-day = 93.1 acres

As shown above the minimum surface area required for a naturally aerobic lagoon treating manure from an average size dairy in the Valley would range from approximately 76.2 – 93.1 acres. This amount of land is not typically available and would require the removal of land that is currently used to produce feed or other crops. Construction of a lagoon over 76 acres in size would be a massive project that would have numerous challenges and high costs for both design and construction. For example, the expense of lining a lagoon of this size would be extremely high. To comply with the requirements of the Central Valley Regional Water Quality Control Board, new lagoons and ponds that store dairy manure in the Valley have generally needed to comply with the Central Valley Regional Water Quality Control Board Tier 1 design standards, which require a lagoon or pond with a double liner constructed of high density polyethylene (HDPE) or material of equivalent durability with a leachate collection and removal system. The Capital Press article[132] indicated that the cost for the installation of double-liner for an existing lagoon at a dairy near Sunnyside, Washington in 2016 was roughly $500,000 for each lagoon and the lagoons averaged 78,000 square feet each. Based on this information, the cost of a double liner for a lagoon storing dairy manure is estimated to be about $7.88 per square foot and $343,253 per acre in 2022. Therefore, the cost for the liner for a lagoon only with an area of 76.2 to 93.1 acres would be $26,555,879 to $31,956,854.

In addition to construction costs, there would also be an increase in expenses for designing and maintaining lagoons of such a large size. To comply with the requirements of Regional Water Quality Control Board and Mosquito Abatement District the lagoon would need to be regularly cleared of any dead algae, vegetation, and floating debris that could create a habitat for mosquitos and other vectors that carry diseases. Therefore, as a result of the large size of the lagoons, the maintenance required to comply with these regulations would be difficult and there would also be increased costs. Finally, ammonia emissions may increase from naturally aerobic lagoons because of the large surface in contact with the atmosphere.

The NRCS Reference Guide states that the energy required at an animal production operation to introduce enough oxygen for complete aerobic treatment using mechanical aeration is very expensive and aeration of the surface of the liquid manure is more common.

The Government of Ontario publication[133] states that there are several disadvantages for on-farm use of mechanical aeration and specifically lists the following:

- High initial costs
- High energy costs
- High maintenance costs
- Effectiveness is reduced in cold weather
- The introduction of antibiotics and sanitizers can upset or destroy the required aerobic bacteria
- Nitrogen loss to the atmosphere is increased with mechanical aeration

This publication cautions that improperly designed mechanical aeration systems may contribute more odor than what is reduced through the mixing of air into the liquid, which indicates that mechanical aeration of manure can increase emissions.

The very high cost of complete mechanical aeration makes this option infeasible for farms. For complete aerobic treatment of a lagoon, sufficient oxygen must be delivered into the lagoon and the oxygen delivered must be completely mixed throughout the lagoon. A report

[132] Wheat, D. (2018). Dairy Installs Double Liner in Its Lagoon. Capital Press. Updated December 13, 2018. Retrieved from: *https://www.capitalpress.com/state/washington/dairy-installs-double-liner-in-its-lagoon/article_9ded077e-db11-5cc5-adb7-aa7ebee6e5b9.html*

[133] Government of Ontario. (2006). "Aeration of Liquid Manure". Retrieved from: *https://www.ontario.ca/page/aeration-liquid-manurehttps://www.ontario.ca/page/aeration-liquid-manure*

by the University of California (UC) Davis[134] states, "*Mixing is important to ensure uniformity of temperature and composition throughout the volume, e.g., continuous bulk turnover is needed to eliminate quiescent zones or sludge layers where anaerobic conditions persist. Also, relatively vigorous mixing (high turbulence) prevents clumping of organisms/substrate, and reduces diffusion resistance by thinning the film thickness through which dissolved oxygen must migrate (diffuse) to reach substrate particles and organisms.*" Delivery of oxygen and mixing of the oxygen throughout a lagoon requires substantial amounts of energy. The cost of electricity for complete aeration can be estimated based on the amount of oxygen that needs to be supplied and the energy required for complete mixing of oxygen throughout a lagoon. The Government of Ontario publication indicates that for complete aeration of manure, oxygen must be supplied in an amount equal to twice the BOD in the manure.

A publication[135] indicates that approximately 1.5 to 2.5 pounds of oxygen is required to digest one pound of Biological Oxygen Demand (BOD_5) with additional oxygen required for conversion of ammonia to nitrate (NO3-) (nitrification). In this publication, Dr. Ruihong Zhang of UC Davis estimated that 2.4 lbs (1.1 kg) of oxygen (O_2) per cow must be provided each day for removal of BOD and an additional 3 lbs (1.4 kg) per cow for oxidation of 70 percent of the nitrogen, which is a ratio of approximately 2.25 lb of oxygen per lb of BOD. It will be estimated that 2 lb of oxygen per 1 lb of BOD_5 is required for nitrification of ammonia.

As discussed above, the lagoons for an average size dairy in the Valley with 1,600 mature cows will have a BOD loading rate of approximately 4,191 lb-BOD_5/day. Based on the data gathered in the UC Davis report, aeration efficiencies for mechanical aerators ranged from 0.10 to 0.68 kg of oxygen provided per kW-hr of energy utilized.[136] The most efficient aerator tested installed in dairy lagoons had an aeration efficiency of 0.49 kg-O_2/kW-hr. These efficiency tests were performed in clean water. The efficiency of the aerators will be lower in liquid manure because of the higher amount of solids that it contains compared to clean water. The yearly energy requirement for a mechanically aerated lagoon treating flushed manure an average size dairy in the Valley is calculated as follows:

[134] Williams, R.B., Elmashad, H., Kaffka, S. (2020). Research and Technical Analysis to Support and Improve the Alternative Manure Management Program Quantification Methodology. *University of California, Davis, California Biomass Collaborative*, CARB Agreement No. 17TTD010. Retrieved from: *https://ww2.arb.ca.gov/sites/default/files/auction-proceeds/ucd_ammp_qm_analysis_final_april2020.pdf*

[135] San Joaquin Valley Dairy Manure Technology Feasibility Assessment Panel. (2005) An Assessment of Technologies for Management and Treatment of Dairy Manure in California's San Joaquin Valley. California Air Resources Board

[136] Zhang, R., Sun, H., Kamthunzi, W.M., Collar, C.A., Mitloehner, F.M. (2007) Aerator Performance for Wastewater Lagoon Application, ASABE. *https://elibrary.asabe.org/abstract.asp?aid=23832*

<u>Oxygen Requirement for Average Size Dairy in the Valley</u>

4,191 lb-BOD_5/day x 1 kg/2.2046 lb = 1,901 kg-BOD_5/day x 2 = 3,802 kg-BOD_5/day

<u>Electricity for High Efficiency Aerator</u>

3,802 kg-BOD_5/day ÷ (0.68 kg-O_2/kW-hr) x (365 day/year) = 2,040,779 kW-hr/year

<u>Electricity for Low Efficiency Aerator</u>

3,802 kg-BOD_5/day ÷ (0.10 kg-O_2/kW-hr) x (365 day/year) = 13,877,300 kW-hr/year

<u>Electricity for Complete Mixing of Air</u>

The UC Davis report estimates that mixing for complete aeration of a dairy lagoon would require 3,300 kW-hr per milk cow per year. The energy required for mixing for complete aeration for an average sized dairy in the Valley is calculated as follows:

1,348 milk cows x 3,300 kW-hr/milk cow-year = 4,448,400 kW-hr/year

<u>Total Electricity Required for Complete Aeration with High Efficiency Aerator</u>

2,040,779 kW-hr/year + 4,448,400 kW-hr/year = 6,489,179 kW-hr/yr

<u>Total Electricity Required for Complete Aeration with Low Efficiency Aerator</u>

13,877,300 kW-hr/year + 4,448,400 kW-hr/year = 18,325,700 kW-hr/yr

<u>Cost of Electricity for Complete Mechanical Aeration of a Lagoon Treating Manure from an Average Size Dairy in the Valley:</u>

The cost for electricity will be based upon the average price for industrial electricity in California for the year December 2021 through November 2020, as taken from the Energy Information Administration (EIA) website:

Average Cost for electricity = $0.1685/kW-hr

The electricity costs for complete aeration are calculated as follows:

<u>Low Cost Estimate (High Efficiency Aerator)</u>

6,489,179 kW-hr/year x $0.1685/kW-hr = $1,093,427/year

<u>High Cost Estimate (Low Efficiency Aerator)</u>

18,325,700 kW-hr/year x $0.1685/kW-hr = $3,087,880/year

As shown above, the estimated cost for only the electricity for a mechanically aeration to reduce ammonia emissions from an average size dairy in the Valley ranges from nearly $1.1 million per year to nearly $3.1 million per year. This cost does not include the design and construction of the mechanical aeration system or any additional operational costs. However, it is clear that the cost of electricity alone would make this system economically infeasible, especially when considering that the price of electricity is expected to continue to increase.

Although the NRCS Reference Guide states that surface aeration of manure is more common because of the difficulty and expense of complete mechanical aeration, the amount of oxygen provided by aeration of the surface of liquid manure would not be sufficient to oxidize ammonia. Any ammonia oxidized would be converted to nitrite and nitrate. Increased concentrations of nitrite and nitrate in the liquid manure may require treatment to protect water quality or increase emissions of NOx or nitrous oxide (N2O).

Although surface aeration may sometimes reduce odors of some compounds, surface aeration may actually increase ammonia emissions because it accelerates the release of carbon dioxide (CO2), an acidic gas, which increases the pH of the manure promoting increased ammonia emissions.[137, 138] Additionally, low levels of aeration will not provide sufficient oxygen for treatment, but can increase the transfer of emissions from the manure to the air because of the increased disturbance at the surface of the liquid manure.

Naturally aerated lagoons are not feasible in the Valley because of the large land requirements, fully mechanically aerated lagoons are not practical because of the high energy requirements and costs, and surface aeration is not expected to reduce ammonia emissions; therefore, this is not a feasible measure to reduce ammonia emissions from liquid manure in the Valley.

The District is unaware of any instances in which oxygenation demonstrates to be a practical technology on any farm to decrease ammonia emissions from liquid manure and has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Storage Bags - *(applies to dairy cattle only)*

Manure storage bags have primarily been used to store manure from pig farms in Europe and Canada. They have also recently started to be used to store manure on some dairy farms that are relatively small compared to the typical dairies in the Valley. The storage of manure in bags is only suitable for small dairies that handle manure as a slurry. Manure storage bags are not suitable for large dairies that handle dilute liquid manure because of the large volumes of manure that must be stored until it can be applied to cropland. The majority of dairies in the Valley are large flush dairies in which liquid manure mixed with water is stored in large earthen lagoons or ponds until it can be applied to cropland. Dairies that handle

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[137] Zhao, B., Chen, S. (2003). Ammonia Volatilization from Dairy Manure under Anaerobic and Aerated Conditions at Different Temperature. Paper number 034148, 2003 American Society of Agricultural and Biological Engineers Annual Meeting. Retrieved from: *https://elibrary.asabe.org/abstract.asp?aid=13892*

[138] Kaffka, S., Barzee, T., El-Mashad, H., Williams, R., Zicari, S., Zhang, R. (2016). Evaluation of Dairy Manure Management Practices for Greenhouse Gas Emissions Mitigation in California. Final Technical Report to the State of California Air Resources Board Contract #14-456. Retrieved from: *https://biomass.ucdavis.edu/wp-content/uploads/ARB-Report-Final-Draft-Transmittal-Feb-26-2016.pdf*

manure as a slurry without the addition of water are extremely rare in the Valley. [139] In addition, lagoons and storage ponds that hold manure are required to be lined in order to reduce the chances of manure contaminating the groundwater. Manure storage bags may not be allowed because there is a high possibility that something may puncture the bag causing manure to leak, which could degrade groundwater.

The District is unaware of any dairies in the Valley that are currently using storage bags to store manure. Manure storage bags are not suitable for the typical size dairies in the Valley and there are questions about if these bags would comply with existing California regulations, including water regulations. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Liquid Manure Storage Covers - ***(applies to all CAFs)***

The NRCS Reference Guide includes manure storage covers as a potential measure to reduce emissions from the storage of manure. Manure can be handled and stored in the form of a thick slurry, a dilute liquid, or as a solid. A study[140] notes that placing a cover over a lagoon can reduce emissions, however the different cover types have both benefits and drawbacks. Such covers include, natural or synthetic and they may be flexible or rigid, which vary in cost. The type of cover that is appropriate for each operation depends on the size and type of manure storage, environmental factors, and the goals of the farm. Manure storage covers limit emissions by slowing diffusion of gases and reducing the effects of wind on the surface of the manure. Although manure storage covers may reduce pollutants directly emitted from the manure, they do not destroy or eliminate pollutants such as ammonia. Rather, concentrations of these pollutants increase in the stored manure and additional measures would be required to prevent their release when the manure is removed from storage.

As previously mentioned, Valley dairies that handle manure as a slurry without the addition of water are extremely rare and therefore certain types of manure covers are generally not applicable. The NRCS Reference Guide notes that concrete covers cannot be used on earthen or steel manure storages and natural covers (e.g. straw, barely, cornstalks) are impractical if the surface area of the storage is very large. Dairies in the Valley primarily store liquid manure with low solids content in large earthen lagoons or ponds,[141] therefore concrete covers and natural covers cannot feasibly be used to cover liquid manure in the

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[139] Marklein, A. R., Meyer, D., Fischer, M. L., Jeong, S., Rafiq, T., Carr, M., and Hopkins, F. M. (2021) Facility-Scale Inventory of Dairy Methane Emissions in California: Implications for Mitigation, Earth Syst. Sci. Data, 13, 1151–1166, *https://doi.org/10.5194/essd-13-1151-2021*, 2021.

[140] Marks, R. (2001). Cesspools of Shame: How Factory Farm Lagoons and Sprayfields Threaten Environmental and Public Health. *Natural Resources Defense Council and the Clean Water Network*. Retrieved from: *https://www.nrdc.org/sites/default/files/cesspools.pdf*

[141] Meyer, D., Price, P.L., Rossow, H.A., Silva-del-Rio, N., Karle, B., Robinson, P.H., DePeters, E.J., and Fadel, J. (2011) Survey of Dairy Housing and Manure Management Practices in California. Journal Dairy Sci. 94:4744-4750. *https://doi.org/10.3168/jds.2010-3761*

Valley. Additionally, the Valley regulations from the Regional Water Quality Control Board[142] and mosquito abatement districts[143] generally require the removal of any materials that would form natural covers in order to decrease the chances for the proliferation of mosquitos and other vectors.

Although covers made of rigid plastic, such as HDPE, may be a potential option to cover lagoons and ponds that store liquid manure in the Valley, they would be very prohibitively expensive because of the large area that would need to be covered. As previously mentioned, the average dairy in the Valley has almost 1,600 cows compared to a national average of less than 300 cows per dairy outside of California. Since the Valley dairies are larger compared to other dairies in the nation, the lagoons and ponds that store liquid manure are also several times larger compared to the national average dairy that stores mostly undiluted slurry manure.

Moreover, manure covers do not destroy ammonia, rather they create a barrier that suppresses emissions of ammonia from the manure and air space above the manure. This leads to increased concentrations of ammonia and other air contaminants in the manure and air space above the manure, which will just delay the release of ammonia until it is sent to a different pond or applied to land. The increase concentration of ammonia in the manure will also increase the pH and subsequently increase the potential for ammonia emissions. Furthermore, because of the warm climate of the Valley, covering a lagoon with a plastic cover would turn the lagoon into an anaerobic digester. The majority of anaerobic digesters operating on dairies in the Valley are already covered lagoon digesters. The Reference Guide also states that gases will build up under impermeable covers that must be flared or utilized in another way. Flaring or combusting these gases would produce NO_X, which is the primary precursor for PM2.5 in the Valley, as well as direct PM2.5 emissions.

The District has permitted several facilities to construct and operate a covered lagoon. However, in each case, the covered lagoon was part of a digester system to capture biogas/digester-gas, and the cost of the system was funded by grants from the California Department of Food and Agriculture (CDFA) Dairy Digester Research and Development Program.

In conclusion, it is not reasonable to require covers to reduce ammonia emissions from liquid manure storage in the Valley given the high expense associated to the practice and the fact that the practice is not expected to result in any overall reductions of ammonia emissions in the Valley, but could increase emissions of other pollutants.

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[142] California Regional Water Quality Control Board Central Valley Region. Order R5-2013-0122. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

[143] The Fresno County Mosquito Control Districts. Retrieved from: *https://fresnocountymosquito.org/*

Solid Manure Storage Covers - *(applies to all CAFs)*

EPA identified Method 62 (Cover solid manure sources with sheeting) from the UK User Guide, noting that it could result in ammonia emission reductions up to 90 percent. Method 62 involves covering solid manure stores with sheeting, which provides a physical barrier preventing the release of ammonia to the air. EPA acknowledged that this method "would increase ammonium content of the slurry, potentially leading to higher ammonia emissions during storage and spreading." District Rule 4570, EPA acknowledges, contains mitigation measure options for the covering of dry manure piles, and in most cases, facilities are required to cover manure and separated solids or else remove them from the facility.[144]

Storage of solid manure/separated solids contributes a very small amount of total ammonia emissions in the Valley, by making up less than 2 percent of the total ammonia emissions from dairies. Nonetheless, covering for solid manure/separated solids during the months of October through May is included in Rule 4570 and required for most dairies during these 8 months of the year, which include the District's PM2.5 season.

Based on District permitting records covering solid manure or separated manure solids during October through May is required by 729 dairies, 84 percent of the dairies are subject to Rule 4570, and a larger percentage of the total dairy cattle since this measure is required for all dairies that are classified as large confined animal facilities under the rule.

Covers for solid manure/separated solids is not required during the summer because solid manure is primarily composed of organic material that is combustible and during the hot summers in the Valley, elevated temperatures increase the chances of spontaneous combustion of manure piles.[145] Therefore, for safety reasons manure covers cannot be required during the hotter summer months. However, through District Rule 4570, the District requires CAFs to cover solid manure/separated solids during the colder winter months, as shown below:

- Cover dry manure outside the housing with a weatherproof covering from October through May, except for times when wind events remove the covering, not to exceed 24 hours per event.
- Cover separated solids outside the housing with a weatherproof covering from October through May, except for times when wind events remove the covering, not to exceed 24 hours per event.

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[144] Chadwick, D.R. (2005). Emissions of Ammonia, Nitrous Oxide and Methane from Cattle Manure Heaps: Effect of Compaction and Covering. *Atmosphere Environment*, Vol. 39, Issue 4: 787-799. Retrieved from: *https://www.sciencedirect.com/science/article/abs/pii/S135223100400994X*

[145] Westendorf, M. L. "Animal Science Update: Spontaneous Combustion". New Jersey Farmer. August 15, 2016. Page 6. *https://plant-pest-advisory.rutgers.edu/spontaneous-combustion/*

In conclusion, the District already has a mechanism to implement this mitigation measure for solid manure/separated solid stored onsite. No additional ammonia reductions are expected from the suggested mitigation measure.

Allow Cattle Slurry Stores to Develop a Natural Crust - ***(applies to dairy cattle only)***

This measure identified in the UK User Guide involves retaining a surface crust on slurry stores, composed of fiber and bedding material present in cattle slurry, for as long as possible. This practice is applicable to thick slurry manure, which differs from the typical liquid manure stored in the Valley. The dilute liquid manure handled in the Valley is stored in ponds and lagoons much larger than storages used for slurry manure in other regions, and does not contain enough solids to form a natural crust.

Additionally, this practice is more applicable to cooler climates, while in the Valley's warm climate, floating debris on liquid manure create a habitat for mosquitos and other vectors that carry diseases, including West Nile virus, zika, dengue, chikungunya, and St. Louis encephalitis.[146] To reduce the potential for the propagation of mosquitos and other disease carrying vectors, Regional Water Quality Control Board[147] and Mosquito Abatement District regulations require the removal of any dead algae, vegetation, and floating debris, including those that would form a natural crust on the surface of a lagoon or pond.[148] Thus, this practice is not allowed in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Solid-Liquid Separation - ***(applies to all CAFs)***

The NRCS Reference Guide states that for manure streams handled as a slurry, separation of the solid and liquid portions prior to storage, additional treatment, and/or land application may reduce odor and other gaseous emissions, particularly for undersized lagoons. Various solid separation technologies are used for these purposes, including screens, rotary drums, centrifugal tanks, earthen pits, weeping walls, settling basins and screw-presses.

Dairies in the Valley primarily handle liquid manure that has been diluted with water, rather than slurry manure, and the effluent from dairies in California often has a total solids content of only 1 percent;[149] therefore this measure is not directly applicable to most dairies in the Valley. The NRCS Reference Guide indicates that solid-liquid separation does not work well for manure streams with very low or very high solids content, unless advanced technologies

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[146] The Fresno County Mosquito Control Districts. Retrieved from: *https://fresnocountymosquito.org/*

[147] California Regional Water Quality Control Board Central Valley Region. Order R5-2013-0122. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

[148] Collar, C. (2005). West Nile Virus – How Dairies Can Help 'Fight the Bite. *University of California, Davis, Cooperative Extension.* Retrieved from: *https://cemerced.ucanr.edu/newsletters/September_200523148.pdf*

[149] Meyer, D, Heguy, J., Karle, B. and Robinson, P. (2019) Characterize Physical and Chemical Properties of Manure in California Dairy Systems to Improve Greenhouse Gas Emission Estimates. California Environmental Protection Agency, Air Resources Board. Retrieved from: *https://ww2.arb.ca.gov/sites/default/files/classic/research/apr/past/16rd002.pdf*

or multiple separation stages or screen sizes are used to remove large and small solids from the manure stream separately. These technologies will have additional challenges and increased costs. Additionally, some studies indicate that the majority of ammonia nitrogen in dilute manure streams remains in the liquid portion and are not removed by solid-liquid separation. The NRCS Reference Guide indicates that some separator designs may increase emissions of gases or particles during the separation process. Dried separated solids may also increase the potential for PM emissions.

As mentioned above, this control measure is applicable to manure handled as a slurry rather than the dilute liquid manure that is typically handled on dairies in the Valley. Therefore, this practice is not directly applicable to dairies in the Valley. However, for cattle facilities that handle liquid manure, Rule 4570 does allow the facilities to choose the option to remove solids from the waste system with a solid separator system prior to the waste entering the lagoon. This option has been chosen by the vast majority cattle facilities that handle liquid manure, including over 90 percent of dairy cattle facilities subject to Rule 4570.[150] The option in Rule 4570 is as follows:

- Remove solids from the waste system with a solid separator system, prior to the waste entering the lagoon.

In conclusion, the District already has a mitigation measure option to minimize emissions from solid-liquid manure separation. No additional ammonia reductions are expected from the suggested mitigation measure.

Anaerobic Digesters - ***(applies to dairy cattle only)***

Anaerobic digesters are storage or treatment lagoons that are undergoing anaerobic reactions, primarily located at dairies. Digesters are outfitted with roofs and covers that enclose all anaerobic emissions within the system and vent to a gas collection system that eliminates undesired methane emissions. The microbes performing anaerobic reactions in lagoons convert nitrogen to form various new compounds, including ammonia. Through the implementation of its Short-Lived Climate Pollutant Strategy and SB 1383,[151] the State of California has funded the installation of over 120 dairy digester systems throughout the state to reduce methane emissions, with the majority of installations in the San Joaquin Valley. Through the generation of vehicle renewable natural gas, some dairy digester systems have the potential of reducing vehicle-related NOx, PM2.5, air toxics, and greenhouse gas (GHG) emissions.

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[150] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[151] CARB. Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target. (March 2022). Retrieved from: *https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwiayMXd4af9AhXWrmoFHYf2BNsQFnoECBAQAQ&url=https%3A%2F%2Fww2.arb.ca.gov%2Fsites%2Fdefault%2Ffiles%2F2022-03%2Ffinal-dairy-livestock-SB1383-analysis.pdf&usg=AOvVaw32GB5_r8-3GsSd57-XTnyo*

Some forms of energy conversion from biogas (e.g., burning biogas in an engine to produce electricity) may increase emissions of NOx, a precursor for PM2.5 and ozone, and direct PM2.5 emissions. These emissions can have a negative impact in the Valley, which is designated as nonattainment for PM2.5 and ozone This technology is very expensive, due to capital costs, operation, and maintenance expenses. It also requires significant addition of water, and may not be feasible in water-limited areas.

The NRCS Reference Guide includes anaerobic digesters as a measure to reduce VOCs and GHG emissions, but does not indicate that it reduces ammonia. Some of the information discussed in the NRCS Reference Guide about anaerobic digestion indicates a potential for increased ammonia emissions. The results of some studies also indicate that there is a potential for increased ammonia emissions following digestion.[152] There is limited information regarding the potential and scale of ammonia emissions impacts associated with digester, and California does not currently attribute any increased ammonia impacts from the implementation of dairy digester systems.

At this time there are significant uncertainties about the overall effect of anaerobic digesters on ammonia emissions from manure and additional research is needed to better understand this, particularly for digesters in the Valley. Because of this and the very high costs associated with installation of anaerobic digesters, they are not a feasible option to implement into Rule 4570 at this time. However, this practice would be evaluated as a potential BACT measure for any new or expanding operations; the required mitigation measure from BACT Guideline 5.8.6[153], is as follows:

- Anaerobic treatment lagoon designed according to NRCS Guideline 359.

In conclusion, the District already has a mechanism to implement this mitigation measure for expanding or new confined animal facilities. No additional ammonia reductions are expected from the suggested mitigation measure.

Manure Additives - ***(applies to all CAFs)***

Manure amendments are not practical for manure handled as a dilute liquid, which is typical for Valley dairies, because the large volume of water mixed with the manure greatly increases the amount of an amendment required to change the properties of liquid manure, such as pH. The addition of certain amendments also increases the risk of foaming in liquid manure, which can damage pumps.[154] For slurry and liquid manure, it is difficult and costly to apply a

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[152] Koirala, K., Ndegwa, P.M., Joo, H.S., Frear, C., Stockle, C.O., Harrison, J.H. (2013). Impact of Anaerobic Digestion of Liquid Dairy Manure on Ammonia Volatilization Process. *American Society of Agricultural and Biological Engineers,* Vol. 56(5): 1959-1966. Retrieved from: *https://labs.wsu.edu/ndegwa/documents/2016/09/Article-57.pdf/*

[153] CARB BACT Guidelines Tool. Retrieved from: https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/bact/BACTID781.pdf?:linktarget=_self&:embed=yes

[154] USDA NRCS/EPA (2017) Agricultural Air Quality Conservation Measures Reference Guide for Poultry and Livestock Production Systems. *https://www.nrcs.usda.gov/sites/default/files/2022-06/Ag_AQ_Conservation_Measures_Poultry_and_Livestock_September_2017.pdf*

sufficient amount of amendments to change the pH of the manure because of its natural buffering capacity, or resistance to changes in pH due to its chemical properties.

The NRCS Reference Guide states, *"It is often difficult to establish microbiological additives due to competition from naturally-occurring bacteria in manure."* The microbes in microbial additives are often out-competed by the naturally occurring microorganisms, because of the abundance of diverse microorganisms that are naturally present in manure that can multiply rapidly when favorable conditions are present. As a result, microbial additives are often ineffective or must be continually added to the manure. A study[155] conducted by Iowa State University, clearly demonstrates that many questions remain unanswered about the general effectiveness of microbial additives used to reduce emissions. The study evaluated 12 commercial microbial additives that were marketed for their ability to reduce emissions of odorous VOCs, H2S, ammonia, GHG, and odors. The results indicated that emissions from the treated manure were not statistically significant to the untreated manure for any of the 12 products tested. Thus, the ability of microbial additives to reduce emissions from manure remains unproven. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Acidifying Slurry and Shifting Chemical Balance from Ammonia to Ammonium - ***(applies to all CAFs)***

This mitigation method mentioned in the compilation by Guthrie, et al.[156] involves the use of manure amendments to minimize ammonia emissions. Manure amendments are not practical for manure handled as a dilute liquid, which is typical for Valley dairies, because the large volume of water mixed with the manure greatly increases the amount of an amendment required to change the properties of liquid manure, such as pH. The addition of certain amendments also increases the risk of foaming in liquid manure, which can damage pumps. For slurry and liquid manure, it is difficult and costly to apply a sufficient amount of amendments to change the pH of the manure because of natural buffering capacity. Notably, some additives can even increase emissions of certain pollutants and can be toxic to handle.

Moreover, any additives to the manure require approval of the Water Quality Control Board.[157] The Water Quality Control Board has determined that increased salinity is a threat

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[155] Koziel, J., Chen, B., Andersen, D., Parker, D., Bialowiec, A., Banik, C., Lee, M., O'Brien, S., Ma, H., Meiirkhanuly, Z., Wi, J., Li, P., Iowa State University. (2021). Evaluating Manure Additives for Odor Mitigation. *National Hog Farmer*. Retrieved from: *https://www.nationalhogfarmer.com/agenda/evaluating-manure-additives-odor-mitigation*

[156] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[157] California Regional Water Quality Control Board Central Valley Region. (March 2017). Resolution R5-2017-0031 (Accepting the Salt and Nitrate Management Plan). Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/resolutions/r5-2017-0031_res.pdf*

to water quality in the Valley.[158] As a result, in many cases the application of amendments and additives that use salts to change pH will not be allowed.

For reasons discussed above, manure amendments are not practical for most operations in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Acidifying Amendments and Additives for Poultry Litter - ***(applies to poultry only)***

This method involves the application of aluminum to poultry litter to reduce the pH of the litter. However, poultry operations have already reduced nitrogen excretion by 55 percent and are not a significant source of ammonia in the Valley. Use of acidifying litter amendments is more common for poultry litter however, any additives to the manure require approval of the Water Quality Control Board. The Water Quality Control Board has determined that increased salinity is a threat to water quality in the Valley.[159, 160] As a result, in many cases the application of amendments and additives that use salts to change pH will not be allowed.

Notably, some additives can increase emissions of certain pollutants and can be toxic to handle. For example, the litter in poultry houses in the Valley are drier than many other parts of the country and therefore aluminum would need to be applied as a liquid. Nevertheless, liquid aluminum is an acid that is dangerous to handle and requires a certified applicator to be hired which results in higher costs.

Despite the uncertainties above, the District further evaluated the potential emission reductions of implementing this measure in the Valley. This analysis is provided below.

Ammonia is a weak base and reducing the pH of litter binds ammonia and reduces its volatilization. Aluminum sulfate, also known as alum, is a common compound used to treat poultry litter to reduce ammonia emissions and bind phosphorous to prevent runoff. The typical recommended application rate for aluminum sulfate is 0.1 to 0.2 lb of aluminum sulfate per broiler placed.[161] The higher the aluminum sulfate application rate, the higher the ammonia control and phosphorus binding ability of aluminum sulfate. The lower recommended application rate will control ammonia emissions for about half the time as the

158 California Regional Water Quality Control Board Central Valley Region. (May 2006). Salinity in the Central Valley. Retrieved from: *https://www.waterboards.ca.gov/waterrights/water_issues/programs/bay_delta/california_waterfix/exhibits/docs/CDWA%20et%20al/SDWA_206.pdf*

159 California Regional Water Quality Control Board Central Valley Region. (May 2006). Salinity in the Central Valley. Retrieved from: *https://www.waterboards.ca.gov/waterrights/water_issues/programs/bay_delta/california_waterfix/exhibits/docs/CDWA%20et%20al/SDWA_206.pdf*

160 California Regional Water Quality Control Board Central Valley Region. (March 2017). Resolution R5-2017-0031 (Accepting the Salt and Nitrate Management Plan). Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/resolutions/r5-2017-0031_res.pdf*

161 See Moore, P. Treating Poultry Litter with Aluminum Sulfate. USDA ARS. Developed by Livestock GRACEnet. *https://www.ars.usda.gov/ARSUserFiles/np212/LivestockGRACEnet/AlumPoultryLitter.pdf*

higher recommended application rate.[162, 163] Young chicks are more vulnerable to higher ammonia concentrations in the houses; however, ammonia emissions are lower because of the lower amount of manure produced by the smaller birds. These recommended application rates are based on broilers with a finished weight of approximately four pounds. Larger birds will require correspondingly larger application rates to achieve the same control of ammonia.[164]

A study published in 2020 found that an application rate of 98 kg of aluminum sulfate per 100 square meters incorporated into litter reduced overall ammonia emissions from broilers by 35 percent.[165] In the study, the birds were placed in 2.1 m by 1.8 m pens with 50 birds per pen to evaluate different treatments. Therefore, the application rate of alum on a per bird basis was calculated as follows:

$98 \text{ kg}/100 \text{ m}^2 \times 2.1 \text{ m} \times 1.8 \text{ m} \div 50 \text{ bird} = 0.074 \text{ kg/bird}$

The application rate of 0.074 kg/bird is equivalent to an application rate 0.16 lb-aluminum sulfate per bird. Therefore, it will be assumed that this is the application rate required to reduce ammonia emissions by 35 percent. The District's current ammonia emission factor for broiler chickens is 0.0958 lb-NH3/bird-year. Thus, the ammonia emission reductions for this practice can be calculated as follows:

0.0958 lb-NH3/bird-year x 35% = 0.0335 lb-NH3/bird/year

The cost of the emission reductions is based on the cost of the purchase and application of aluminum sulfate. Because of the typically dry conditions in the Valley, liquid aluminum sulfate is preferred because moisture is required for aluminum sulfate to react with ammonia. A USDA-ARS publication[166] indicates that one ton of aluminum sulfate is equivalent to 370 gallons of liquid aluminum sulfate. Based on a web search, the price of aluminum sulfate is estimated to be $1,155 per 55 gallon drum.[167] The customer applicator rate is assumed to be

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[162] Moore, P., Watkins, S. Treating Poultry Litter with Alum. University of Arkansas (U of A) Division of Agriculture Cooperative Extension Service. *https://www.uaex.uada.edu/publications/PDF/FSA-8003.pdf*
[163] Moore, P., Miles, D., Burns, R. (March 2019). Reducing Ammonia Emissions from Poultry Litter with Alum. Livestock and Poultry Environmental Learning Community (LPELC). *https://lpelc.org/reducing-ammonia-emissions-from-poultry-litter-with-alum/*
[164] Anderson, K.; Moore, P.A., Jr.; Martin, J.; Ashworth, A.J. (2020) Effect of a New Manure Amendment on Ammonia Emissions from Poultry Litter. *Atmosphere*, *11*, 257. *https://doi.org/10.3390/atmos11030257*
[165] Penn, C., Zhang, H (April 2017) Alum-Treated Poultry Litter as a Fertilizer Source. Oklahoma State University Extension. *https://extension.okstate.edu/fact-sheets/alum-treated-poultry-litter-as-a-fertilizer-source.html#nitrogen-content-of-alum-treated-litter*
[166] See Moore, P. Treating Poultry Litter with Aluminum Sulfate. USDA ARS. Developed by Livestock GRACEnet. *https://www.ars.usda.gov/ARSUserFiles/np212/LivestockGRACEnet/AlumPoultryLitter.pdf*
[167] Alliance Chemical, Price of Aluminum Sulfate 50%. Retrieved from: *https://alliancechemical.com/product/aluminum-sulfate-50/?attribute_pa_size=55-gallon&attribute_pa_packaging-type=drum&gclid=EAIaIQobChMIurHTv9WT_QIVMRPUAR1c5QvKEAQYASABEgJ5__D_BwE*

$100 for each broiler house housing 20,000 birds. Therefore, the total cost for each application of aluminum sulfate on a per bird basis is calculated as follows:

0.16 lb-aluminum sulfate/bird x 1 ton/2,000 lb x 370 gal-aluminum sulfate/ton-aluminum sulfate x $1,155/55 gal-aluminum sulfate + $100/20,000 bird = $0.63/bird

Approximately 6.7 broiler flocks are produced each year and aluminum sulfate must be applied prior to placing each flock; therefore, the annual cost of this measure on a bird capacity basis is 6.7/year x $0.63/bird = $4.22/bird capacity-year.

The cost effectiveness of the ammonia reductions from this measure are calculated as follows:

$4.22/bird-year ÷ 0.0335 lb-NH3/bird-year x 2,000 lb/ton = $251,940/ton-NH3 reduced

As demonstrated above, the potential reductions from this measure are not cost effective, with a cost effectiveness of $251,940 per ton of ammonia reduced. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Urease Inhibitors - ***(applies to all cattle)***

A study[168] indicates that the information for this control measure was taken from AirControlNet, a software tool previously used by EPA to estimate the cost of emission reductions. The AirControlNET v.4.1 Documentation Report[169] indicates that the specific chemical additive that this measure refers to was N-(n-butyl) thiophosphoric triamide (NBPT), which was being sold under the trade name Conserve-Nr. NBPT is a type of urease inhibitor. The cost information was provided by a supplier of the chemical and appears to be an underestimate.

Urease inhibitors inhibit the action of the enzyme urease. Urease, which is present in feces and produced by soil microorganisms, converts urea into ammonia, which can then volatilize. Although there are many compounds that can inhibit urease, only a few are non-toxic, effective at low concentrations, and chemically stable. Urease inhibitors have shown promising results for reducing nitrogen emissions from urea-based fertilizers, but some studies indicate that there remain questions about their effectiveness in reducing ammonia from manure.[170]

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[168] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: *https://pubs.acs.org/doi/pdf/10.1021/es060379a*

[169] E.H. Pechan & Associates, Inc. (September 2005). AirControlNET v.4.1 Documentation Report. Retrieved from: *https://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=P1012ZYW.TXT*

[170] Lasisi, A.A., Akinremi, O.O., and Kumaragamage, D. "Ammonia emission from manures treated with different rates of urease and nitrification inhibitors," Canadian Journal of Soil Science 100(3), 198-205, (25 February 2020). Retrieved from: *https://doi.org/10.1139/cjss-2019-0128*

Urease inhibitors appear to reduce ammonia emissions for relatively short periods of time and must be reapplied, and the buildup of urea in the pen surface may require that the NBPT additions increase with time to continue to control ammonia. Because of the need to re-apply increasing amounts of urease inhibitors as manure and urea accumulate, there will be increased costs.

Additionally, there is evidence that urease inhibitors may alter plant metabolism and lead to accumulation of urea in plant tissue,[171] which can have negative effects on crops. Urea inhibitors will also increase the amount of nitrogen in the manure, and to comply with Water Quality Control Board Regulations, some farms would need to acquire additional cropland to apply the manure or identify ways to export the manure to ensure that nitrogen is not over-applied.

It appears that the treatment of animal manure with urease inhibitors has not yet been commercialized. This is likely because of the limited chemical stability of the inhibitors, the need for reapplication, the lack of efficient and automated application systems, and a subsequent increase in the cost for the farmer. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

<u>Surface Cooling of Slurry Manure</u> - *(applies to all CAFs)*

The publication by Guthrie, et al.[172] suggests this measure for CAFs with a slurry manure handling system. The measure involves lowering the temperature of the slurry in the channels by pumping a coolant (e.g., groundwater) through a series of fins floating on the slurry. This measure appears to be largely theoretical, and the District is not aware of any instances in which cooling of liquid or slurry manure has been used to reduce emissions from animal production operations. Furthermore, there are high costs for installation of piping and pumping coolant and circulation of coolant through manure, and recycling groundwater may not be permitted in some regions. For these reasons, this measure is unproven and not feasible to implement in the Valley.

<u>Feeding Strategies to Lower the pH of Manure</u> - *(applies to all CAFs)*

Livestock feeding strategies can influence the pH of manure and urine. The pH of manure can be lowered by increasing the fermentation in the large intestine. This increases the volatile fatty acids (VFA) content of the manure and causes a lower pH. The pH of urine can be lowered by lowering the electrolyte balance of the diet. Furthermore, the pH of urine can be lowered by adding acidifying components to the diet. A low pH of the manure and urine

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[171] Zanin L, Venuti S, Tomasi N, Zamboni A, De Brito Francisco RM, Varanini Z, Pinton R. (2016) Short-Term Treatment with the Urease Inhibitor N-(n-Butyl) Thiophosphoric Triamide (NBPT) Alters Urea Assimilation and Modulates Transcriptional Profiles of Genes Involved in Primary and Secondary Metabolism in Maize Seedlings. Front Plant Sci. 2016 Jun 22;7:845. doi: 10.3389/fpls.2016.00845. PMID: 27446099; PMCID: PMC4916206.
[172] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

excreted also results in a low pH of the slurry/manure during storage even after a certain storage period. This pH effect can reduce ammonia emissions from slurries during storage and also following application. This measure is primarily for non-ruminants, such as poultry and pigs and is not recommended for cattle.

The pH of freshly excreted urine mainly depends on the electrolyte content of the diet. The pH of urine will eventually rise towards alkaline values due to the hydrolysis of urea irrespective of initial pH; however, the initial pH and the pH buffering capacity of urine affect the rate of ammonia volatilization from urine immediately following urination. Lowering the pH of urine of ruminants is theoretical possible. However, it has not been demonstrated to be feasible on actual farms. Lowering the pH of cattle manure is also theoretically possible, but this might easily coincide with disturbed rumen fermentation and is therefore not recommended. Since this measure has not been demonstrated for cattle and remains theoretical, it is premature to consider it as part of any regulatory efforts.

The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Land Application of Manure

Table 11: Land Application of Manure Measures Evaluated

Method	Measure	CAF Type	Reference
Timing of Land Application	Timing of Land Application	All Cattle	NRCS[173]
	Optimal Weather Conditions for Spreading	All Cattle	Guthrie[174]
Injection	Injection	All Cattle	NRCS
	Use Slurry Injection Application Techniques	All Cattle	Price[175]
	Injector	All Cattle	Guthrie

[173] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[174] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[175] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*

Method	Measure	CAF Type	Reference
	Open-slot Injection	All Cattle	Webb[176]
	Injector	All Cattle	Eory[177]
	Injection Techniques	All Cattle	Bittman[178]
	Injection into the Soil	All Cattle	Preece[179]
Incorporation of Liquid and Solid Manure	Incorporation	All Cattle	NRCS
	Incorporate Manure into the Soil	All Cattle	Price
	Incorporation of Manure	All Cattle	Guthrie
	Incorporation of Surface-Applied Solid Manure and Slurry into Soil	All Cattle	Bittman
	Incorporation into the Soil	All Cattle	Preece
	Incorporate Manure into the Soil	All Cattle	Atia[180]

[176] Webb, J., Pain B., Bittman, S., Morgan J. The impacts of manure application methods on emissions of ammonia, nitrous oxide and on crop response—a review. Agric. Ecosyst. Environ. 137, 39–46 (2010). Retrieved from: *https://www.sciencedirect.com/science/article/abs/pii/S0167880910000046?via%3Dihub*

[177] Eory, V., Rees, B., Topp, K., Dewhurst, R., et al. ClimateXChange, "On-farm technologies for the reduction of greenhouse gas emissions in Scotland," March 2016. Retrieved from: *https://www.climatexchange.org.uk/media/1927/on-farm_technology_report.pdf*

[178] Bittman, S., Dedina, M., Howard C.M., Oenema, O., Sutton, M.A., (eds), 2014, "Options for Ammonia Mitigation: Guidance from the UNECE Task Force on Reactive Nitrogen," Centre for Ecology and Hydrology, Edinburgh, UK. Retrieved from: *http://www.vuzt.cz/svt/vuzt/publ/P2014/037.pdf*

[179] Preece, Sharon L.M. et al., ''Ammonia Emissions from Cattle Feeding Operations,'' Texas A&M AgriLife Extension Service, referring to Cole, N.A., R.N. Clark, R.W. Todd, C.R. Richardson, A. Gueye, L.W. Greene, and K. McBride, ''Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure,'' Journal of Animal Science 83:(3), 722 (2005)

[180] Atia, A. (2008). Ammonia volatilization from manure application. Alberta Agriculture, Food and Rural Development. Retrieved from: *https://open.alberta.ca/dataset/b115d4b8-982d-43d5-97a6-1d987bf8ba01/resource/863253f1-22f1-4a7b-950a-c424ef5cc9e5/download/2008-538-3.pdf*

Method	Measure	CAF Type	Reference
	Immediate Incorporation of Applied Manure	All Cattle	Pinder[181]
Band Spreading	Banding	All Cattle	NRCS
	Slurry Band Spreading Application Techniques	All Cattle	Price
	Band Spreading	All Cattle	Guthrie
	Band Spreading Slurry	All Cattle	Bittman
Other Land Application	Slurry Dilution	All Cattle	Bittman
	Transport Manure to Neighboring Farms	All Cattle	Price

Timing of Land Application - ***(applies to all cattle)***

This measure requires operators to apply the correct amount of necessary nutrients to crops when they are most in demand and in locations where they can be accessed by specific plants. Applying nutrients in spring prior to planting, when crops are ready to utilize the nitrogen, can reduce ammonia emissions compared to applying in fall. Applying at lower soil temperatures can also help to reduce near-term ammonia emissions due to reduced microbial activity in cooler soils. Split application to better time the nutrient application to crop needs can also be beneficial.

Although not specifically included in Rule 4570, the measure is already required for confined animal facilities in the Valley that apply manure to land. California Regional Water Quality Control Board regulations[182] require that manure may only be applied to land at agronomic rates in accordance with an approved nutrient management plan, and that nutrients, including nitrogen, may only be applied at times when plants can utilize these nutrients. The rate of application of manure and process wastewater for each crop in each land application area (also considering sources of nutrients other than manure or process wastewater) to meet each crop's needs without exceeding the application rates is specified in the Regional Water Quality Control Board Technical Standard.

[181] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: *https://pubs.acs.org/doi/pdf/10.1021/es060379a*

[182] California Regional Water Quality Control Board Central Valley Region. Order R5-2013-0122. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

The NRCS Reference Guide estimates that this measure will reduce ammonia emissions from land application by 65-70 percent. Because this measure is already required, as an industry standard, these reductions have already been achieved in the Valley.

Injection - ***(applies to all cattle)***

Applying manure to the soil surface without incorporation can lead to significant emissions of ammonia and other odorous gases. Several of the mitigation measure compilations evaluated by the District included injection of liquid or slurry manure as an option to reduce ammonia emissions from land application. However, this method is more applicable to slurry manure than the dilute liquid manure applied to land in the Valley. Additionally, the equipment needed to transport and inject the dilute liquid manure, which is not typically used in the Valley, would have high costs for fuel and would increase emissions of NOx and PM2.5.

Estimated ammonia emissions reductions from the injection of liquid manure are based on the assumption that surface broadcasting of liquid manure is the typical practice. Broadcasting of liquid manure results in higher emissions because of the larger amount of surface area of the liquid manure that will be in direct contact with the atmosphere. However, nearly all liquid manure in the Valley is diluted and applied via surface gravity irrigation systems, such as flood and furrow irrigation. Because of the much lower concentration of ammonia in the diluted liquid manure typically applied in the Valley, and the reduced surface area of liquid manure in furrow and flood irrigation systems compared to broadcasting, ammonia emissions from the application of liquid manure in the Valley is already much lower than traditional surface broadcasting. A report prepared by the University of California Division of Agricultural and Natural Resources Committee of Experts on Dairy Manure Management[183] indicates that in California, "nearly all" manure from lagoons is diluted with irrigation water and applied via surface gravity irrigation systems and that "during irrigations, farmers commonly dilute lagoon water with 5 to 10 parts of fresh source water." The report goes on to state that "in systems with frequent, but well diluted manure water applications, ammonia losses from the ground surface will commonly be minimal during the irrigation (10 percent or less)." The Ammonia Volatilization from Manure Application fact sheet,[184] estimates that ammonia losses from unincorporated manure to be 66 percent in the spring and early fall; this the standard practice in the Valley of applying manure by gravity flow irrigation is already estimated to reduce ammonia emissions by at least 85 percent compared to broadcasting of manure.

Furthermore, to avoid damaging growing crops, injection of liquid manure can only be performed prior to planting the crop, typically a maximum of two times per year.

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[183] Chang, A., T. Harter, J. Letey, D. Meyer, R. D. Meyer, M. Campbell-Mathews, F. Mitloehner, S. Pettygrove, P. Robinson, R. Zhang (2006) Managing Dairy Manure in the Central Valley of California; University of California Committee of Experts on Dairy Manure Management Final Report to the Regional Water Quality Control Board, Region 5, Sacramento, June 2005. *https://ucanr.edu/sites/groundwater/files/136450.pdf*

[184] Atia, A. (2008). Ammonia volatilization from manure application. Alberta Agriculture, Food and Rural Development. Retrieved from: *https://open.alberta.ca/dataset/b115d4b8-982d-43d5-97a6-1d987bf8ba01/resource/863253f1-22f1-4a7b-950a-c424ef5cc9e5/download/2008-538-3.pdf*

Additionally, the amount of nitrogen that can be applied to cropland is limited to protect water quality. Many agricultural areas in the Valley already have nitrate levels in the groundwater that are above acceptable limits, and many dairies are required to reduce the amount of nitrogen applied to land. Injection of manure reduces the amount of nitrogen emitted to the air, but the retained nitrogen is placed in the soil. Thus, injection of manure into the soil will increase the amount of nitrogen in the cropland and may not be feasible for some dairies, or will require additional land in order to comply with their nutrient management plans.

District Rule 4570 includes the requirement to minimize the amount of emissions from applying liquid manure to the soil. These mitigation measures include an option to inject liquid manure, as shown below:

- Apply liquid/slurry manure via injection with drag hose or similar apparatus

In conclusion, the District already has mitigation measures for liquid manure injection. No additional ammonia reductions are expected from the suggested mitigation measures.

<u>Incorporation of Liquid Manure</u> - *(applies to all cattle)*

Many mitigation measure compilations included incorporation of slurry and liquid manure into soil as an option to reduce ammonia emissions.[185] However, as discussed above, nearly all liquid manure in the Valley is diluted and applied via surface gravity irrigation systems, such as flood and furrow irrigation. Because of the of the much lower concentration of ammonia in the diluted liquid manure typically applied in the Valley, ammonia emissions from the application of liquid manure in the Valley is already much lower than the emissions from broadcasting slurry manure.

Slurry manure is not typically applied in the Valley and liquid manure in the Valley is diluted prior to application. However, District Rule 4570 includes a mitigation option to minimize the amount of emissions from incorporating liquid manure to the soil, as shown below:

- Allow liquid manure to stand in the fields for no more than 24 hours after irrigation.

In conclusion, the District already has mitigation measures for the incorporation of liquid manure. No additional ammonia reductions are expected from the suggested mitigation measures.

<u>Incorporation of Solid Manure</u> - *(applies to all cattle)*

The NRCS Reference Guide and UK User Guide include methods for incorporation of solid manure that involve mixing manure with surface soil to reduce the exposed surface area of the manure. The reference guide advises that incorporation should occur as soon as possible

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[185] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

after the manure is applied, or at least within 24 hours, to reduce ammonia emissions. In the Valley, solid manure land application accounts for less than 3 percent of total ammonia emissions from dairies and incorporation of solid manure within 72 hours is already required for over 80 percent of cattle facilities that apply manure to land.

To avoid damaging growing crops, incorporation of solid manure can only be performed prior to planting the crop, typically a maximum of two times per year. Almost all dairies in the Valley use a double-crop farming system for their cropland to maximize the amount of manure that can be applied and increase the amount of feed produced for the cattle, with some dairies using a triple-crop system. In the typical double-crop system used on Valley dairies, corn for silage is planted in late April through June to be harvested in September, and winter forage (e.g. wheat, oats, barley, etc.) is planted in late September to be harvested in April or May.[186,187] Because of the very short time frame available between crops, the standard practice in the Valley is to incorporate applied solid manure as soon as practical so the land can be prepared for the next crop.

Solid manure applied to cropland is often incorporated immediately after application; however, additional time may sometimes be required due to unforeseen circumstances, such as difficult weather conditions, equipment breakdowns, or the unavailability of the contractors that perform the work since they may be busy at other farms that are also preparing to plant the next crop. With this under consideration, Rule 4570 gives additional time to account for the unforeseen circumstances that may unexpectedly delay incorporation of manure into cropland within 24 hours, as shown below:

- Incorporate all solid manure within 72 hours of land application.

The District is further evaluating requiring solid manure applied to cropland to be incorporated within 24 hours. An analysis of this measure, including the control efficiency and estimated costs, is below.

The control efficiency for incorporation is estimated based on information from the Chesapeake Bay Program Watershed Model report.[188] This report includes estimations of ammonia emission reductions for low-disturbance incorporation and high-disturbance incorporation of manure. The report gives vertical tillage as an example of low-disturbance incorporation and states that for high-disturbance incorporation, chisel plowing followed by

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[186] University of California, Davis. UC Drought Management – Corn. Retrieved from: *https://ucmanagedrought.ucdavis.edu/Agriculture/Crop_Irrigation_Strategies/Corn/*

[187] Ag Proud – Progressive Dairy. 12-Month Forage Pays. Retrieved from: *https://www.agproud.com/articles/30676-12-month-forage-pays*

[188] Chesapeake Bay Phase 6.0 Manure Incorporation and Injection Expert Review Panel: Dell, C., Allen, A., Dostie, D., Meinen, R., Maguire, R (December 2016) Manure Incorporation and Injection Practices for Use in Phase 6.0 of the Chesapeake Bay Program Watershed Model. Prepared for Chesapeake Bay Program, Annapolis, MD 21403. CBP/TRS-309-16. EPA Contract No. EP-C-12-055. *https://d18lev1ok5leia.cloudfront.net/chesapeakebay/documents/Phase_6_FINAL_MII_Final_Report.pdf*

secondary tillage with a disk harrow or field cultivator is expected to be the most common practice. Information in the report indicates that with low-disturbance incorporation, ammonia emissions are reduced 34 percent when manure is incorporated within 72 hours and 50 percent when manure is incorporated within 24 hours. The report also indicates that with high-disturbance incorporation, ammonia emissions are reduced 50 percent when manure is incorporated within 72 hours and 75 percent when manure is incorporated within 24 hours. Based on this information, the ammonia (NH3) emissions from incorporation of solid manure within 72 hours and 24 hours are estimated as follows:

Low-Disturbance Incorporation of Solid Manure within 72 Hours

Control Efficiency: 34%

Percent NH3 emissions of manure that is not incorporated: 66%

Low-Disturbance Incorporation of Solid Manure within 24 Hours

Control Efficiency: 50%

Percent NH3 emissions of manure that is not incorporated: 50%

High-Disturbance Incorporation of Solid Manure within 72 Hours

Control Efficiency: 50%

Percent NH3 emissions of manure that is not incorporated: 50%

High-Disturbance Incorporation of Solid Manure within 24 Hours

Control Efficiency: 75%

Percent NH3 emissions of manure that is not incorporated: 25%

The ammonia control efficiency for incorporation of solid manure within 24 hours rather than 72 hours, compared to the ammonia emissions from solid manure that is not incorporated is estimated as follows:

Low-Disturbance Incorporation of Solid Manure within 24 Hours

66% - 50% = 16%

High-Disturbance Incorporation of Solid Manure within 24 Hours

75% - 50% = 25%

The ammonia emissions from solid manure land application are approximately 2.8 percent of the ammonia emissions from dairies and other cattle facilities; therefore, the overall control efficiency of this measure is estimated to be:

Low-Disturbance Incorporation of Solid Manure within 24 Hours

17% x 2.8% = 0.48% of total NH3 emissions from cattle

High-Disturbance Incorporation of Solid Manure within 24 Hours

25% x 2.8% = 0.7% of total NH3 emissions from cattle

The incremental ammonia control efficiency for incorporation of solid manure within 24 hours compared to incorporation of solid manure within 72 hours is calculated as follows.

Low-Disturbance Incorporation of Solid Manure within 24 Hours

1 – (50%/66%) = 24.2%

High-Disturbance Incorporation of Solid Manure within 24 Hours

1 – (50%/75%) = 33.3%

This control efficiency is just for the application of solid manure to cropland, which is a very small portion of the total emissions from cattle facilities.

The cost of more rapid incorporation varies greatly, depending whether a farm already has the required equipment available or if the farm requires an additional tractor and must contract with a custom farm service to implement this practice. For farms for which the required equipment for more rapid incorporation is available, it will be assumed that the primary cost of this measure will be the additional labor required to operate the equipment, to ensure that the manure is incorporated within the required timeframe. For other farms for which the required equipment is not available, it will be assumed that they must hire a custom farm service to ensure that manure is incorporated within the required timeframe. The labor costs for incorporation of solid manure and the costs for hiring a custom farm service will be estimated based on information from the University of California Cooperative Extension.[189, 190] The costs for labor and hiring a custom farm service for low-disturbance incorporation of solid manure are assumed to be similar to finish discing of a field, and the costs for labor and hiring a custom farm service for high-disturbance incorporation of manure are assumed to be similar to chiseling a field followed by discing.

Based on the University of California Cooperative Extension publications, the incremental cost for low-disturbance incorporation of solid manure is estimated to be approximately $2.64 per acre if only additional labor is required, and $15.37 per acre if a custom farm service must be used. At dairies in the Valley, solid manure is typically applied to land twice per year so the overall cost for low-disturbance incorporation of solid manure is as follows:

[189] University of California Cooperative Extension, Agriculture and Natural Resources, Agricultural Issues Center (2016) 2016 Sample Costs to Establish and Produce Alfalfa, Tulare County, Southern San Joaquin Valley, 300 Acre Planting. *https://coststudyfiles.ucdavis.edu/uploads/cs_public/1c/e2/1ce256d0-957e-4bd4-b17e-18fef4efcedd/16alfalfasjv300acfinal_41916.pdf*

[190] University of California Cooperative Extension, Agriculture and Natural Resources, Agricultural Issues Center (2016) 2016 Sample Costs to Establish and Produce Alfalfa, Tulare County, Southern San Joaquin Valley, 50 Acre Planting. *https://coststudyfiles.ucdavis.edu/uploads/cs_public/24/b6/24b68b4a-4c04-4853-b127-d3461e1a248f/16alfalfasjv50ac_final_4192016.pdf*

Incremental Labor Cost for Low-Disturbance Incorporation of Solid Manure within 24 Hours

$2.64/acre x 2 time/year = $5.28/acre-year.

Incremental Cost for Custom Farm Service for Low-Disturbance Incorporation of Solid Manure within 24 Hours

$15.37/acre x 2 time/year = $30.74/acre-year.

Based on the University of California Cooperative Extension publications, the incremental cost for high-disturbance incorporation of solid manure is estimated to be approximately $6.60 per acre if only additional labor is required, and $64.21 per acre if a custom farm service must be used. As mentioned above, at dairies in the Valley solid manure is typically applied to land twice per year so the overall cost for high-disturbance incorporation of solid manure is as follows:

Incremental Labor Cost for High-Disturbance Incorporation of Solid Manure within 24 Hours

$6.60/acre x 2 time/year = $13.20/acre-year.

Incremental Cost for Custom Farm Service for High-Disturbance Incorporation of Solid Manure within 24 Hours

$64.21/acre x 2 time/year = $128.42/acre-year.

Estimated ammonia emissions from unincorporated manure will be based on measurements included in the 2008 Dairy Emission Study report by Schmidt.[191] Based on measurements in this study, ammonia emissions from unincorporated solid manure are estimated to be approximately 4 lb-NH3/acre-year.

The cost effectiveness of the potential ammonia reductions for low-disturbance incorporation of solid manure with 24 hours compared to incorporation with 72 hours are estimated as follows:

NH3 Emissions for Low-Disturbance Incorporation of Solid Manure within 72 hours:

4 lb-NH3/acre-year x 66% = 2.64 lb-NH3/acre-year

NH3 Emissions for Low-Disturbance Incorporation of Solid Manure within 24 hours:

4 lb-NH3/acre-year x 50% = 2.0 lb-NH3/acre-year

Potential NH3 Emission Reductions for Low-Disturbance Incorporation within 24 hours

= 2.64 lb-NH3/acre-year - 2.0 lb-NH3/acre-year = 0.64 lb-NH3/acre-year

[191] Schmidt, C., Card, T. (August 2009) 2008 Dairy Air Emissions Report: Summary of Dairy Emission Estimation Procedures. Prepared for the San Joaquin Valleywide Air Pollution Study Agency

Cost Effectiveness if Only Additional Labor is Required

Cost of NH3 reductions: $5.28/acre-year ÷ 0.64 lb-NH3/acre-year x 2,000 lb/ton = $16,500/ton-NH3

Cost Effectiveness if Custom Farm Service is Required

Cost of NH3 reductions: $30.74/acre-year ÷ 0.64 lb-NH3/acre-year x 2,000 lb/ton = $96,063/ton-NH3

The cost effectiveness of the potential ammonia reductions for high-disturbance incorporation of solid manure with 24 hours compared to incorporation with 72 hours are estimated as follows:

NH3 Emissions for High-Disturbance Incorporation of Solid Manure within 72 hours:

4 lb-NH3/acre-year x 50% = 2.0 lb-NH3/acre-year

NH3 Emissions for High-Disturbance Incorporation of Solid Manure within 24 hours:

4 lb-NH3/acre-year x 25% = 1.0 lb-NH3/acre-year

Potential NH3 Emission Reductions for High-Disturbance Incorporation within 24 hours

= 2.0 lb-NH3/acre-year - 1.0 lb-NH3/acre-year = 1.0 lb-NH3/acre-year

Cost Effectiveness if Only Additional Labor is Required

Cost of NH3 reductions: $13.20/acre-year ÷ 1.0 lb-NH3/acre-year x 2,000 lb/ton = $26,400/ton-NH3

Cost Effectiveness if Custom Farm Service is Required

Cost of NH3 reductions: $128.42/acre-year ÷ 1.0 lb-NH3/acre-year x 2,000 lb/ton = $256,840/ton-NH3

As explained above, cattle facilities that apply solid manure to cropland incorporate the manure as quickly as possible in order to prepare for planting of the next crop; so this is already an industry standard, therefore, many cattle facilities are already attaining the potential ammonia emission reductions of this practice, except when conditions make this impractical.

In conclusion, the District already has mitigation measures for incorporation of solid manure. No additional ammonia reductions are expected from the suggested mitigation measures.

<u>Band Spreading</u> - *(applies to all cattle)*

This practice[192] reduces volatilization of ammonia by using low-pressure application near the ground. Band spreading of manure can only be done during very limited periods immediately prior to planting of a crop, a maximum of two times per year. This practice is primarily applicable to slurry manure rather than flush manure, and has limited applicability to the Valley in which most manure is applied as a liquid or a solid. Band spreading is generally a slower operation (with lower application rates), so there may be some issues with labor availability. Additionally, there are high costs due to the initial investment of new machines, as well as the costs of ongoing maintenance and fuel.

As previously discussed, nearly all liquid manure in the Valley is diluted and applied via surface gravity irrigation systems, such as flood and furrow irrigation, which allows manure to flow on the ground without using pressure to apply liquid manure. Due to the much lower concentration of ammonia in the diluted liquid manure typically applied in the Valley, and the reduced surface area of liquid manure in furrow and flood irrigation systems compared to broadcasting, ammonia emissions from the application of liquid manure in the Valley is already much lower than traditional surface broadcasting and also expected to be lower than emissions from liquid manure applied with band spreading. Moreover, trucks used for these methods would damage growing crops and directly emit NOx and PM, hindering the District's efforts to attain the PM2.5 and ozone national ambient air quality standards (NAAQS). The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

<u>Slurry Dilution</u> - *(applies to all cattle)*

This method involves the dilution of slurry with water to decrease the ammonium-N concentration, as well as increase the rate of infiltration into the soil following spreading on land. For undiluted slurry, dilution must be at least 1:1 (one part slurry to one part water) to reduce emissions by at least 30 percent.

This practice is applicable to manure handled as a slurry. The slurry manure would be diluted by 50 percent so it can be infiltrated into soil more quickly. The ammonia reductions for this measure are proportional to the extent of dilution. The majority of dairies in the Valley are large flush dairies in which liquid manure mixed with water is stored in large earthen lagoons or ponds until it can be applied to cropland. The typical practice in the Valley is to dilute manure with irrigation water when it is applied to cropland. The liquid handled on Valley dairies typically has a DM content of 2 percent or less. This manure is then commonly further diluted with 5 to 10 parts of fresh source water during irrigation. Because of this, ammonia emissions from the typical application of liquid manure can be estimated to be more than 90 percent lower than the ammonia emissions from this practice (4.5 percent DM applied,

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[192] Chang, A., T. Harter, J. Letey, D. Meyer, R. D. Meyer, M. Campbell-Mathews, F. Mitloehner, S. Pettygrove, P. Robinson, R. Zhang (2006) Managing Dairy Manure in the Central Valley of California; University of California Committee of Experts on Dairy Manure Management Final Report to the Regional Water Quality Control Board, Region 5, Sacramento, June 2005. *https://ucanr.edu/sites/groundwater/files/136450.pdf*

compared to 0.2 percent DM applied). The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Transport Manure to Neighboring Farms - ***(applies to all cattle)***

This mitigation measure does not result in overall decreases in ammonia emissions. Although ammonia emissions are reduced from the exporting farm, these emissions are transferred to the receiving farm.

Regional Water Quality Control Board regulations prohibit the over-application of nutrients from manure in the Valley and already only allow manure to be applied at agronomic rates in accordance with an approved nutrient or waste management plan. Nutrient management plans require that farms transport excess manure to other fields or identify other uses for excess manure. Transporting manure would increase emissions of NOx and PM2.5 from fuel use, and these emissions would hinder the District's efforts to attain the PM2.5 and ozone NAAQS. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Other Mitigation Measures

Table 12: Other Mitigation Measures Evaluated

Method	Measure	CAF Type	Reference
Other	Pasture and Range Management: Stocking Density	Other Cattle	NRCS[193]
	Improved Livestock Genetics	All	Price[194]
	Planting a Tree Shelter Belt	All	Guthrie[195]
	Using Plants with Improved Nitrogen Use Efficiency	All Cattle	Guthrie
	Changing Land from Arable to Woodland	All	Guthrie
	Reduced Consumption of Meat and Eggs by Humans	All	Guthrie

Pasture and Range Management: Stocking Density - ***(applies to grazing cattle only)***

The NRCS Reference Guide lists managing animal stocking density at grazing-based livestock operations as a mitigation method for ammonia emissions. However, the District does not have authority to regulate animals on pasture or rangeland, as they are not confined. This measure also does not recommend a specific stocking density; however, cattle that graze on pastureland and rangeland in California generally require low stocking densities to provide sufficient forage for cattle. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

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[193] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[194] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*

[195] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

<u>Improved Genetics</u> - *(applies to all CAFs)*

A publication prepared for use in the United Kingdom includes genetic selection of useful traits to improve animal health and fertility as a potential mitigation measure to increase the efficiency of animals and reduce environmental impacts. Farmers select animal breeds that have improved genetics that increase efficiency as feasible to reduce overall costs and increase yield. The publication notes that use of animals with improved genetics "*is generally good in the poultry, dairy and pig industries.*" Improvements in genetics and management practices to increase efficiency have already significantly reduced the environmental footprint of production from animal agriculture compared to previous years. As a result of genetic selection and improved diets, milk production per cow has increased and feed usage has decreased by 77 percent and water use has decreased by 65%.[196] GHG emissions from California dairy cattle per amount of milk produced have also decreased by over 45 percent in the 50 years from 1964 to 2014.[197] For poultry, it is estimated that genetic selection and the current feed practices have reduced nitrogen excretion by poultry by up to 55 percent, primarily due to the reduced time from egg to market age.[198]

Farmers are expected to continue to use animals with improved genetics that will increase efficiency and reduce production costs. However, there are several issues that cause this measure to be unsuitable as a requirement in a regulation. The study does not specify the genetic traits that need to be improved. The measure is largely theoretical and requires extensive research and funding to develop new breeds with the desired traits. It would take generations of each breed to evaluate the effectiveness of the breeds as it pertains to reducing ammonia emissions and any potential adverse impacts on the environment. There are also potential ethical concerns regarding if animals were to be genetically modified to accelerate selection of specific traits. Therefore, the District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

<u>Planting a Tree Shelter Belt</u> - *(applies to all CAFs)*

This measure involves planting tree shelterbelts around livestock housing and manure slurry storage facilities to disrupt airflow around these sites. The effectiveness of tree shelterbelts as a measure to reduce particulate matter from facilities depends on the shelterbelt height, canopy density, and the prevailing environmental conditions. While some evidence demonstrates effectiveness for PM2.5 emissions reductions, there is little to no evidence for

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[196] McCabe, C. (2021). How Dairy Milk Has Improved its Environmental and Climate Impact. Clarity and Leadership for Environmental Awareness and Research at UC Davis. Retrieved from: *https://clear.ucdavis.edu/explainers/how-dairy-milk-has-improved-its-environmental-and-climate-impact*

[197] Naranjo A., Johnson A., Rossow H., Kebreab E. (2020) Greenhouse Gas, Water, and Land Footprint per Unit of Production of the California Dairy Industry Over 50 years. J Dairy Sci. 2020 Apr;103(4):3760-3773. doi: *10.3168/jds.2019-16576*. Epub 2020 Feb 7. PMID: 32037166.

[198] United States Department of Agriculture - Natural Resources Conservation Service. (2020). Feed and Animal Management for Poultry. Nutrient Management Technical Note No. 190-NM-4. Retrieved from: *https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=45569.wba*

ammonia emissions reductions. Effective tree shelterbelts are expensive and difficult to establish due to the large size of the facilities, severe water limitations, soil conditions, and the number of trees needed to protect these areas.

Irrespective of the lack of available data on the potential ammonia emissions reductions, implementation of this measure requires additional consideration with respect to animal health. Cattle facilities in the Valley depend on natural airflow to cool cattle and provide them with fresh air. Disrupting natural airflow can adversely affect cattle that depend on the natural flow of air, particularly during summer months where large numbers of heat-related animal mortalities occur in the San Joaquin Valley. Tree shelterbelts also require sufficient space to be effective, thus, dairies would need either to remove crops or acquire additional land for a shelterbelt. Furthermore, a shelterbelt of sufficient height to be effective would take a number of years to establish. In many cases in the Valley, where the soil has high salinity, conditions are unsuitable for planting tree shelterbelts.

In several cases, permitted CAFs proposed to grow shelterbelts to satisfy District BACT requirements, however, the shelterbelts were not sustainable. Agronomic land surveys of the facilities confirmed the poor soil quality would not sustain the tree shelterbelts. As a result, the District eliminated this option as a BACT requirement for these specific CAFs and allowed an alternative mitigation measure to be implemented.

For the reasons listed above, it is infeasible to require planting tree shelterbelts at animal facilities; however, the trees and plants in the agricultural fields and orchards that surround Valley animal facilities already capture a portion of emissions from these facilities and remove some of the ammonia by deposition. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Using Plants with Improved Nitrogen Use Efficiency - ***(applies to all cattle)***

This measure involves developing new plant varieties with improved genetic traits for the capture of soil nitrogen, which would allow reduced fertilizer application. New plant varieties could also be developed with improved nutritional characteristics. This measure is theoretical and requires extensive research and funding to develop new plant varieties with the desired traits. Years of testing would be required to evaluate the effectiveness of new plant varieties for reducing ammonia emissions and any adverse impacts of the new plant varieties. Furthermore, capturing additional soil nitrogen would primarily benefit water quality rather than reducing ammonia emissions. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Changing Land Use from Arable to Woodland - ***(applies to all CAFs)***

This measure involves changing land use from agricultural land to permanent woodland. However, many areas in the Valley are dry and often affected by droughts, and thus not suitable for the establishment of permanent woodlands. The District does not have authority to require that agricultural land be converted to forests. Moreover, conversion of agricultural land to farmland would result in total loss of income for the farmers and an associated loss in tax revenue. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Reduced consumption of meat and eggs by humans by 63 percent - ***(applies to all CAFs)***

The District does not have authority to regulate what people eat and has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Evaluation of Potential Emissions Reductions from CAFs

As demonstrated in the evaluation above, the District has only identified a few measures that have the theoretical potential to reduce additional ammonia emissions beyond the practices currently enforced through Rule 4570. These measures are reducing CP content in feed for beef finishing cattle, incorporation of solid manure within 24 hours, and acidifying amendments for poultry litter and manure. Despite the technological and economic feasibility issues of these mitigation measures, the District evaluated the potential emission reductions and the impact they might have on the Valley's total ammonia emissions inventory if these measures were to be implemented. This was calculated as follows.

- Control efficiency of reducing CP content in feed for beef finishing cattle, applied to beef cattle emissions inventory:

  18.9% x 16.2 tpd = 3.1 tpd

- Control efficiency of incorporation of solid manure within 24 hours, applied to beef and dairy cattle emissions inventory:

  0.48% x 141.5 tpd = 0.7 tpd

- Control efficiency of acidifying amendments for poultry litter and manure, applied to broiler and layer emissions inventory:

  35% x 7.9 tpd = 2.8 tpd

The emissions reductions from the measures above total 6.6 tpd, which would be reduced from the total ammonia emissions inventory of 324.9 tpd:

6.6 tpd ÷ 324.9 tpd = 2.0%

Overall, ammonia emissions from CAFs in the Valley can only be reduced by 2 percent by implementing the mitigation measures above. This demonstrates that additional reductions in the EPA-recommended range of 30-70 percent are infeasible.

Fertilizers

Ammonia emissions from agricultural fertilizers are 111.2 tpd in 2023. Emissions growth from agricultural fertilizers are estimated by farmland acreage projection data developed by the Farmland Mapping & Monitoring Program (FMMP) of the California Department of Conservation.

The California Department of Food and Agriculture (CDFA) Feed, Fertilizer and Livestock Drugs Regulatory Services (FFLDRS) Branch primary focus is to ensure in every way possible a clean and wholesome supply of meat and milk, and to promote environmentally safe and agronomically sound use and handling of fertilizer materials. This is performed through regulating manufacturing, labeling, and use of fertilizing materials, feed and livestock drugs.

The CDFA Fertilizer Research and Education Program (FREP) funds and facilitates research to advance the environmentally safe and agronomically sound use and handling of fertilizing materials. FREP is voluntary and serves growers, agricultural supply and service professionals, extension personnel, public agencies, consultants, and other interested parties.

The Fertilizer Inspection Advisory Board (FIAB) is a statutory body that is advisory to the CDFA secretary on matters pertaining to fertilizer issues, including FREP activities. The Board consists of nine persons appointed by the secretary of agriculture, one of whom shall be a public member and eight of whom shall be licensed with CDFA to manufacture or distribute fertilizing materials, including organic inputs. The FIAB established the Technical Advisory Subcommittee (TASC) to advise the FIAB on matters related to the funding of FREP projects. The TASC serves as an expert scientific panel on matters concerning plant nutrition and on environmental effects related to fertilizing materials use. TASC assists in setting research priorities, reviews research proposals, and makes recommendations on projects for funding.

The composition of the TASC is determined by the FIAB. There should be at least nine members representing the major segments of the fertilizer industry, certified crop advisors, technical experts, farming community, public, and governmental agencies. Members have to demonstrate knowledge, technical and scientific expertise in the fields of fertilizing materials, agronomy, plant physiology, principles of experimental research, production agriculture, and environmental issues related to fertilizing materials use. One member can satisfy more than one of the criteria stated above. At minimum, one member shall be appointed from the membership of the FIAB, and one member on the TASC shall be from CDFA.

The TASC meets at least two times per year-once in spring to evaluate concept proposals and once in summer to evaluate full proposals. Additional meetings are necessary for special initiatives. Meetings typically last all day and alternate between Sacramento and other locations throughout the State. Serving on the TASC requires a time commitment in addition to participating in meetings. Members must read and critically evaluate all concept proposals (typically around 35 two-page proposals) and full proposals (typically at least ten 15-page proposals). In addition, TASC members are responsible for reviewing final research reports for FREP funded projects and may be asked to participate in conferences and special initiatives.

CARB has not found an ammonia emission reduction measure for fertilizers that meets EPA requirements for SIP submittal. CARB staff reached out to the National Association of Clean Air Agencies (NACAA) to ascertain whether other air pollution control agencies across the United States had any experience or regulations reducing ammonia emissions from fertilizers. NACAA reached out to all of their members and CARB staff did not receive any existing rules or regulations controlling ammonia emissions from fertilizers. CARB staff also reached out to

EPA Region 9 staff whether they were aware of any rules or regulations controlling ammonia emissions from fertilizers and they were not aware of any. EPA Region 9 staff did ask CARB to review some practices per Table 12.

Mitigation Measures

Table 13: Fertilizer Mitigation Measures Evaluated

Method	Measure	Reference
Fertilizer	Optimizing or minimizing use of fertilizer	Guthrie
	Adding a Urease Inhibitor	Guthrie
	Mixing and injecting fertilizer into the soil quickly	Guthrie and Eory
	Applying fertilizer during optimal weather conditions	Guthrie and Eory

<u>Optimize or minimize use of fertilizer</u>

The San Joaquin Valley is a part of Central Valley Water Board of the California Water Board, which is an expansive region extending south from the Oregon border to the northernmost portion of Los Angeles County. The California Legislature passed Senate Bill 390 in 1999, which required Water Boards to develop programs that regulate agricultural lands in accordance with the Porter-Cologne Water Quality Control Act (California Water Code Division 7). In 2003, the Central Valley Irrigated Lands Regulatory Program (ILRP) was established, regulating agricultural discharges to surface waters. The Central Valley Water Board extended the regulations in 2012 to include discharges to ground waters. With the exclusion of lands that are never-irrigated or are covered under a separate Central Valley Water Board program, all commercial irrigated lands are required to obtain regulatory coverage under the ILRP.[199] In accordance with the ILRP, growers are required to prepare farm management plans – which includes an Irrigation Nitrogen Management Plan Summary Report – that comply with the approved upon Waste Discharge Requirements (WDR). Using information from the Reports, inferences can be made about nitrogen management based on estimates that compare nitrogen applied (A) to the nitrogen removed (R) from a field: A/R ratio and A-R difference. Included in the nitrogen fraction is any nitrogen proactively added

[199] Central Valley Water Board. *Irrigated Lands Regulatory Program (ILRP) FAQs.* Available at: *https://www.waterboards.ca.gov/centralvalley/water_issues/irrigated_lands/ilrp_faq.pdf*

to a field such as organic amendments, synthetic fertilizers, manure, and irrigation water, whereas nitrogen removed refers to the nitrogen in the materials removed from the field.[200]

Though growers do not have an immediate requirement under ILRP to use nitrogen efficient strategies, growers that are deemed outliers in A/R ratio and A-R difference would be required to employ enhanced strategies to lower these estimates. CDFA FREP offers an Irrigation and Nitrogen Management training program[201] for this purpose among others. A subset of the Irrigation and Nitrogen Management training program is dedicated to nitrogen efficiency, including overviews of the "4 R's" of nitrogen management, and of efficient nitrogen practices.[202] The 4 R's principles are founded on applying the "Right source" of nitrogen at the "Right rate", "Right time", and "Right place". The right rate principle is with the identified measure, as it promotes strategies for providing nitrogen in rates that do not go beyond the crop demand for nitrogen. Examples of how this can be accomplished include adjusting the rate of application based on expected crop yield and adjusting season application rates based on soil and plant-tissue testing.

Guthrie et al. (2018) describe how minimizing the amount of fertilizer applied to an level that is optimal for crop can reduce ammonia emissions.[203] This measure and associated findings were not well described by both Guthrie et al. (2018) and the publications they referenced, nor were any specific regulations identified.[204,205,206,207] Additionally, the viewpoints of Guthrie et al. (2018) were prepared in the context of Europe and United Kingdom. There is therefore

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[200] California State Water Resources Control Board. *State of California State Water Resources Control Board, Order WQ 2018-0002.* Available at: *https://www.waterboards.ca.gov/board_decisions/adopted_orders/water_quality/2018/wqo2018_0002_with_data_fig1_2_appendix_a.pdf*

[201] CDFA. *Fertilizer Research and Education Program*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/*

[202] CDFA. *Irrigation and Nitrogen Management Training for Grower Self-Certification*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/pdfs/training/inmtp_workbook.pdf*

[203] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). Impact of ammonia emissions from agriculture on biodiversity: An evidence synthesis. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[204] UNECE. 2015. United Nations Economic Commission for Europe Framework Code for Good Agricultural Practice for Reducing Ammonia Emissions. United Nations Economic Commission for Europe Convention on Long-range Transboundary Air Pollution. *https://unece.org/environment-policy/publications/framework-code-good-agricultural-practice-reducing-ammonia*

[205] Zhang, Y., A.L. Collins, J.I. Jones, P.J. Johnes, A. Inman, J.E. Freer. (2017). The potential benefits of on-farm mitigation scenarios for reducing multiple pollutant loadings in prioritised agri-environment areas across England. Environmental Science & Policy 73, 100-114. *https://doi.org/10.1016/j.envsci.2017.04.004*

[206] Collins, A.L., Y.S. Zhang, M. Winter, A. Inman, J.I. Jones, P.J. Johnes, W. Cleasby, E. Vrain, A. Lovett, L. Noble. (2016). Tackling agricultural diffuse pollution: What might uptake of farmer-preferred measures deliver for emissions to water and air? Science of The Total Environment 547, 269-281. *https://doi.org/10.1016/j.scitotenv.2015.12.130*

[207] Dalgaard, T., J. F. Bienkowski, A. Bleeker, U. Dragosits, J. L. Drouet, P. Durand, A. Frumau, N. J. Hutchings, A. Kedziora, V. Magliulo, J. E. Olesen, M. R. Theobald, O. Maury, N. Akkal, P. Cellier. (2012). Farm nitrogen balances in six European landscapes as an indicator for nitrogen losses and basis for improved management. Biogeosciences 9, 5303–5321. *https://doi.org/10.5194/bg-9-5303-2012*

a probability that the conditions and farming practices described by Guthrie et al. (2018) are consistent with those present and employed in California. This, combined with the lack in strong evidence demonstrating the emission reduction potentials, demonstrates the need for additional research be completed under conditions consistent with those of the San Joaquin valley before this measure can be considered.

Urease Inhibitor

When combined with urease enzyme present in plants, urea present in urea-based fertilizers can be converted into ammonia, which can then volatilize. Urease inhibitors are a class of nitrogen stabilizer designed to minimize volatilization from applied nitrogen sources by inhibiting the action of the urease, thereby reducing the formation of ammonia.

Nitrogen stabilizers are regulated by federal and State regulatory agencies. At the federal level, The Federal Insecticide, Fungicide, and Rodenticide Act requires that nitrogen stabilizers sold and distributed in the United States be registered with U.S. EPA.[208] At the state level, both the California Department of Pesticide Regulations (DPR) and CDFA maintain regulatory authorities over nitrogen stabilizers. While DPR requires all nitrogen stabilizers to be registered,[209] CDFA regulates licensing, registration, labeling, tonnage reporting, and inspection of only a subset of commercial nitrogen stabilizers.[210] In coordination with 4R Nutrient Stewardship and UC Davis Land and Water Resources, CDFA FREP also encourage growers to use enhanced-efficiency sources such as Urease Inhibitors, identifying these sources as possible "Right Source" through their 4 R's principles.[211]

Although urease inhibitors have shown tremendous promise in reducing ammonia emissions, some studies indicate potential occurrences of pollution swapping through increasing of NOx emissions which must be critically considered and explored prior to further considering the measure.[212,213] Additionally, although there are numerous identified benefits associated with the use urease inhibitors, there is little existing knowledge about their potential to enter the

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[208] US EPA. *Nitrogen Stabilizer Products that Must Be Registered under FIFRA*. Available at: *https://www.epa.gov/pesticide-registration/nitrogen-stabilizer-products-must-be-registered-under-fifra*
[209] CDPR. *A Guide to Pesticide Regulation in California 2017 Update*. Available at: *https://www.cdpr.ca.gov/docs/pressrls/dprguide/dprguide.pdf*
[210] CDFA. *California Fertilizer Laws and Regulations*. Available at: *https://www.cdfa.ca.gov/is/docs/Fertilizer_Law_and_Regs.pdf*
[211] CDFA FREP. *California Crop Fertilization Guidelines.* Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/FertilizationGuidelines/Adjustments.html#h11*
[212] Drury, C.F., X. Yang, W.D. Reynolds, W. Calder, T.O. Oloya, A.L. Woodley. (2017). Combining Urease and Nitrification Inhibitors with Incorporation Reduces Ammonia and Nitrous Oxide Emissions and Increases Corn Yields. Journal of Environmental Quality 46:5, 939-949. *https://doi.org/10.2134/jeq2017.03.0106*
[213] Mirkhani, R., C. Resch, G. Weltin, L. K. Heng, J. Mitchell, R. Clare Hood-Nowotny, G. Dercon. (2023). Effect of urease inhibitor and biofertilizer on nitrous oxide emission, EGU General Assembly 2023, Vienna, Austria, 24–28 Apr 2023, EGU23-11242, *https://doi.org/10.5194/egusphere-egu23-11242*

food chain and impact food safety.[214] Further research is needed which demonstrates that there are no food safety-related issues prior to this measure being viable for consideration.

According to Guthrie et al. (2018), the addition of a urease inhibitor has the potential to reduce ammonia emissions by 40-70 percent.[215] Though this has the potential to hold remarkable mitigation potential, their estimates along with those of the original experiments, were prepared under European and United Kingdom conditions. As these findings were based outside of California where environmental and climatic conditions may differ, further research is needed that explores the reduction potentials of urease inhibitors in conditions consistent with those of the San Joaquin Valley. In addition to this, Guthrie et al. (2018) merely identified the measures but did not reference or identify any specific regulations.

Quick mixing and injecting into soil

The identified measure would involve rapid incorporation of fertilizers into soils after the fertilizers have been applied. As previously described, with the implementation of ILRP and WDRs by the Central Valley Water Board growers are required to prepare and management plans. The 4 R's of nitrogen management serve as guiding nitrogen efficiencies principles that growers are recommended to follow when developing their management plans. The identified measure is addressed through two of the four principles. The "Right time" principle refers to timed application of nitrogen to ensure availability to the plant during periods of greatest demand. The measure is also addressed through the "Right place" principle, which considers targeted application of fertilizer in the crop's effective rootzones to facilitate and enhance the uptake of nitrogen by the crop.

As described by Guthrie et al. (2018), ammonia emissions can be reduced by 50-90 percent through this measure, should the fertilizer be mixed in or injected into the soil within 4-6 hours of their application.[216] Though they do not touch on the speed of the process, Eory et al. (2016) likewise identified fertilizer injection as a candidate ammonia emission mitigation measure.[217] However, the publications referenced in Guthrie et al. (2018) and Eory et al. (2016) focus solely on manure application methods and do not provide estimates for

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[214] Byrne M.P., J.T. Tobin, P.J. Forrestal, M. Danaher, C.G. Nkwonta, K. Richards, E. Cummins, S.A. Hogan, T.F. O'Callaghan. (2020). Urease and Nitrification Inhibitors—As Mitigation Tools for Greenhouse Gas Emissions in Sustainable Dairy Systems: A Review. Sustainability 12:15, 6018. *https://doi.org/10.3390/su12156018*

[215] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). Impact of ammonia emissions from agriculture on biodiversity: An evidence synthesis. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[216] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). Impact of ammonia emissions from agriculture on biodiversity: An evidence synthesis. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[217] Eory, V., Rees, B., Topp, K., Dewhurst, R., et al. ClimateXChange, "On-farm technologies for the reduction of greenhouse gas emissions in Scotland," March 2016. Retrieved from: *https://www.climatexchange.org.uk/media/1927/on-farm_technology_report.pdf*

commercial fertilizers. [218,219] We cannot assume the mitigation potential of fertilizers to be consistent with that of manure sources. We therefore proceed with caution with the identified measure and will not be considering it at this moment. In addition to this, research from a California-context is profoundly limited,[220] resulting in uncertainty regarding the ammonia reduction potentials under California-specific conditions. Consistent with the previously mentioned fertilizer measures, Guthrie et al. (2018) and Eory et al. (2016) merely identify the measure, and do not reference any specific regulations.

Application during optimal weather conditions

Weather conditions (i.e., air temperature, precipitation, and wind speed) have a demonstrated effect on ammonia fluxes.[221] The identified measure would involve rapid incorporation of fertilizers into soils after the fertilizers have been applied. The 4 R's "Right time" principle covers the issue that this measure aims to address. The principle is based on timed nitrogen application in order to ensure the availability of nitrogen to the plant during the more nutrient demanding periods. This period is during vegetative growth in annual crops, and during early fruit and nut development in mature trees and vines.[222]

While describing the fertilizer injection measure, Eory et al. (2016) convey that additional work is needed to determine the emission benefits related to fertilizer application with respect to weather.[223] They however do not provide any additional or specific information regarding a measure or identify the reduction potential of its application. Guthrie et al. (2018) identified weather as affecting ammonia emissions by up to 5 percent and provided the recommendation that growers refrain from using urea-based fertilizers during warm, dry, and

[218] Loyon, L., C.H. Burton, T. Misselbrook, J. Webb, F.X. Philippe, M. Aguilar, M. Doreau, M. Hassouna, T. Veldkamp, J.Y. Dourmad, A. Bonmati, E. Grimm, S.G. Sommer. (2016). Best available technology for European livestock farms: Availability, effectiveness and uptake. Journal of Environmental Management 166, 1-11. *https://doi.org/10.1016/j.jenvman.2015.09.046*

[219] Webb, J., B. Pain, S. Bittman, J. Morgan. (2010). he impacts of manure application methods on emissions of ammonia, nitrous oxide and on crop response—A review. Agriculture, Ecosystems & Environment 137:1-2, 39-46. *https://doi.org/10.1016/j.agee.2010.01.001*

[220] Krauter, C., D. Goorahoo, C. Potter, S. Klooster. (2014). *Ammonia Emissions and Fertilizer Applications in California's Central Valley*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/pdfs/completedprojects/00-0515Krauter2006.pdf*

[221] Li, Q., X. Cui, X. Liu, M. Roelcke, G. Pasda, W. Zerulla, A.H. Wissemeier, X. Chen, K. Goulding, F. Zhang. (2017). A new urease-inhibiting formulation decreases ammonia volatilization and improves maize nitrogen utilization in North China Plain. Scientific Reports 7, 43853. https://doi.org/10.1038/srep43853, *https://doi.org/10.1038/srep43853*

[222] CDFA. *Irrigation and Nitrogen Management Training for Grower Self-Certification*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/pdfs/training/inmtp_workbook.pdf*

[223] Eory, V., Rees, B., Topp, K., Dewhurst, R., et al. ClimateXChange, "On-farm technologies for the reduction of greenhouse gas emissions in Scotland," March 2016. Retrieved from: *https://www.climatexchange.org.uk/media/1927/on-farm_technology_report.pdf*

windy conditions.[224] After reviewing the two publications referenced in Guthrie et al. (2018) for this measure, Zhang et al. (2017)[225] and Newell et al. (2011)[226], no information regarding concerning weather-related conditions was found. Other publications have demonstrated a link between weather conditions and ammonia emissions, though it is unclear which environmental factors are most appropriate for the various fertilizer types.[227,228] It is particularly important for further research to address the impact of weather and fertilizer application timing under conditions specific to the San Joaquin Valley. Lastly, as has been described previously, Guthrie et al. (2018) and Eory et al. (2016) do not refer to any specific regulations when identifying the measure.

Ammonia emissions from agricultural fertilizers are 111.2 tpd in 2023. Emissions growth from agricultural fertilizers are estimated by farmland acreage projection data developed by the

CARB has not identified effective mechanisms within its authority to regulate air emissions of ammonia from livestock, which overwhelmingly come from the decomposition of manure, or from fertilizers, the second largest category of emissions in the Valley. CARB's main source of authority is the California Health and Safety Code. CARB's authority is primarily over mobile sources, consumer products, and air toxics, as well as methane from livestock (see Cal. Health & Saf. Code §§ 43013, 39666, 39730.7, 41712).

Estimated feasible reductions in ammonia from this emissions source in the Valley are zero tons.

Composting and Other Sources

The District already regulates ammonia emissions from composting operations through District Rules 4565 and 4566. Based on the mitigation measures in practice at facilities

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[224] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[225] Zhang, Y., A.L. Collins, J.I. Jones, P.J. Johnes, A. Inman, J.E. Freer. (2017). The potential benefits of on-farm mitigation scenarios for reducing multiple pollutant loadings in prioritised agri-environment areas across England. Environmental Science & Policy 73, 100-114. *https://doi.org/10.1016/j.envsci.2017.04.004*

[226] Newell Price, J.P., D. Harris, M. Taylor, J.R. Williams, S.G. Anthony, D. Duethmann, R.D. Gooday, E.I. Lord, B.J. Chambers, D.R. Chadwick, T.H. Misselbrook. "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*

[227] V Venterea, R.T., A.D. Halvorson, N. Kitchen, M.A. Liebig, M.A. Cavigelli, S.J. Del Grosso, P.P. Motavalli, K.A. Nelson, K.A. Spokas, B. Pal Singh, C.E. Stewart, A. Ranaivoson, J. Strock, H. Collins. (2012). Challenges and opportunities for mitigating nitrous oxide emissions from fertilized cropping systems. Frontiers in Ecology and the Environment 10:10, 562-570. *https://doi.org/10.1890/120062*

[228] Grahmann, K., N. Verhulst, A. Buerkert, I. Ortiz-Monasterio, B. Govaerts. (2013). Nitrogen use efficiency and optimization of nitrogen fertilization in conservation agriculture. Cabi Reviews 8:053. *https://doi.org/10.1079/PAVSNNR20138053*

subject to Rule 4565 and 4566, ammonia emissions are already being reduced by 44 percent. With these controls in place, composting accounts for only 2 percent of the District's ammonia emissions; therefore, the District will not be further evaluating this source category at this time.

The other source category consists of ammonia emissions primarily from mobile sources and fuel combustion, which are heavily controlled. Therefore, the District will not be further evaluating this source at this time.

Estimated feasible reductions in ammonia from these emissions sources in the Valley are zero tons.

4. Research

CARB is working to fill knowledge gaps on feasible and effective ammonia controls. Development of effective air pollution mitigation strategies for ammonia requires additional spatiotemporal understanding of atmospheric ammonia emissions that are currently lacking as a result of limited data. CARB is conducting research, both in-house and with external partners, to characterize gaseous ammonia emissions from agricultural activities in the San Joaquin Valley. The results of these studies will help future development of CARB's ammonia emission inventory, SIP, Short-Lived Climate Pollutant Reduction Strategy, and community air protection program (AB 617). Findings from these research projects will help CARB better characterize ammonia emissions in the Valley, as a necessary prerequisite to identifying potential effective measures to achieve additional emissions reductions.

Ammonia emissions in general are not well quantified Statewide and further focused study is needed to facilitate quantification and potential further control strategies that are effective and cost-effective. As an example of the agency's work in this area, CARB's Research Division has developed a new mobile measurement platform equipped with a state-of-the-science ammonia analyzer and other advanced analytical instruments to improve the understanding of various ammonia sources in California. In September and October 2018, CARB staff collaborated with researchers from the University of California, Davis, to quantify emissions from several dairies in the Valley as part of the ongoing projects funded by the California Department of Food and Agriculture, CARB, and industry. Methane, oxides of nitrogen, and other air pollutants and meteorological parameters were measured at or near dairies in addition to ammonia. The major objective is to evaluate the effectiveness of various alternative manure management practices (AMMP) with respect to emission reductions as CARB staff will revisit these dairies after they implement the selected AMMP technologies. This effort is a direct response to Senate Bill 1383 requirements and goals. The AMMP is designed to identify air pollution sources and estimate their emission rates. Its mobility makes it ideal for field measurements that require large spatial coverage, such as mapping ammonia mixing ratios with an emphasis on determining the magnitude of emissions, characterizing spatial variability of emissions, and identifying dominant sources of emissions.

In addition, CARB is undertaking a suite of projects that address research needs. Many projects focus on emissions from dairies, while others, including those with a satellite or remote sensing component, can offer insight into ammonia emissions in the Valley from all source categories. CARB staff is also working with academic researchers and industry representatives to explore potential opportunities to reduce the emissions of ammonia and other air pollutants from dairy manure lagoons which are one of the largest contributors to ammonia in California. Preliminary experiments have been conducted, and further investigation is underway at some Valley dairies with the support from farmers. Additionally, CARB staff is planning to analyze existing satellite data to refine the spatial resolution and allocation of ammonia in California. This may also help evaluate the impact of major wildfires on surface ammonia levels in recent years, and can be used to compare with the estimation methodology in the current ammonia emission inventory associated with wildfires.

Due to research which indicates California is underestimating ammonia emissions in the air, CARB is reviewing and will reassess ammonia estimates in recognition of this research. This effort will help us update our understanding about modeled sensitivity of PM2.5 formation to changes in ammonia emissions.

5. Conclusion

While EPA guidance recommends modeling emissions reductions of PM2.5 precursors of between 30 and 70 percent to evaluate if precursor emissions reductions have a significant impact on PM2.5 levels, CARB and the District have determined that the 30 percent reduction in ammonia emissions is not achievable Moreover, CARB and the District have not identified methods within its authority to control air emissions of ammonia that achieve an overall 30 percent reduction in ammonia emissions. In practice, the District has implemented the best available control measures on livestock operations that have already achieved approximately 25 percent reduction from this source. CARB is not aware of controls that would achieve greater reductions on the order needed to achieve an overall 30 percent reduction of ammonia emissions in the Valley; nevertheless, CARB is pursuing further research specific to California and the Valley to improve our understanding of ammonia emissions from various sources as a necessary prerequisite to identifying potential effective measures to achieve additional emissions reductions.

The District and CARB analyzed potential control measures to reduce ammonia emissions from key source categories in order to evaluate whether a 30 percent reduction in emissions is feasible. Specific to the confined animal facility category, the District conducted a new, extensive evaluation of potential measures to control sources of ammonia emissions. EPA provided the list of measures to CARB and the District and requested that the measures and studies referenced be addressed specifically for the Valley. In this evaluation, the District has identified only a few measures that have the theoretical potential to reduce additional ammonia emissions beyond the practices currently enforced through District Rule 4570 (Confined Animal Facilities). These measures are reducing crude protein content in feed for beef finishing cattle, incorporation of solid manure within 24 hours, and acidifying amendments for poultry litter and manure. Despite the technological and economic feasibility issues of these mitigation measures, the District evaluated the potential emission reductions and the impact they might have on the Valley's total ammonia emissions inventory if these measures were to be implemented. Overall, ammonia emissions in the Valley can only be reduced from the confined animal facilities source category by 2 percent by implementing these mitigation measures. For the fertilizer category, CARB has not identified effective mechanisms within its authority to regulate air emissions of ammonia from livestock, which overwhelmingly come from the decomposition of manure, or from fertilizers. Furthermore, CARB and the District are unaware of any other jurisdictions with rules for the source. In addition, CARB and the District did not identify feasible control measures for composting or other emissions sources.

Based on the extensive evaluation which identified feasible reductions of only approximately 2 percent, as summarized below in Table 14, CARB and the District conclude that a 30 percent reduction in ammonia emissions is not achievable.

Table 14. Estimated Feasible Emission Reductions

Emissions Category	Emissions (tpd, 2023)	Identified Controls	Feasible Ammonia Reductions
Confined Animal Feeding	186.5	• Reducing crude protein content in feed for beef finishing cattle • Incorporation of solid manure within 24 hours • Acidifying amendments for poultry litter and manure	6.6 tpd
Fertilizers	111.2	No authority or feasible controls identified	0
Composting	6.7	No feasible controls identified	0
Other sources	20.5	No feasible controls identified	0
Total Ammonia	324.9		6.6 tpd

A 2 percent reduction is consistent with the national trend identified in EPA guidance which stated that ammonia changes ranged nationally from an increase of six percent to a decrease of nine percent.[229] Moving forward, updated national guidance on ammonia emission reductions achievable in practice is needed, as well as guidance on available and feasible control measures.

CARB has followed EPA guidance to evaluate whether ammonia contributes significantly to PM2.5 levels that exceed the 15 µg/m3 annual standard NAAQS. Considering relevant contextualizing information including available controls, CARB determined that emissions of ammonia do not contribute significantly to PM2.5 levels that exceed the annual 15 µg/m3 standard in the San Joaquin Valley. Therefore, CARB has excluded ammonia from control requirements in the SIP.

[229] EPA. *PM2.5 Precursor Demonstration Guidance*. May 2019. *https://www.epa.gov/sites/production/files/2019-05/documents/transmittal_memo_and_pm25_precursor_demo_guidance_5_30_19.pdf*

ATTACHMENT T

APPENDIX E

California Environmental Quality Act

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Functional Equivalent Document

Renewable Electricity Standard

Prepared by:

California Air Resources Board

Prepared by:

Ascent Environmental, Inc.
455 Capitol Mall, Suite 210
Sacramento, CA 95814

June 2010

Functional Equivalent Document

Renewable Electricity Standard

Prepared by:
California Air Resources Board
1001 I Street
Sacramento, CA 95812

With Assistance From:

Ascent Environmental, Inc.
455 Capitol Mall, Suite 210
Sacramento, CA 95814

Contact:

Sydney Coatsworth
Project Manager
916/930-3185

June 2010

Ascent - 10010017.01 / 06.01.10

Acknowledgement

This Functional Equivalent Document has been prepared by and under the direction of the California Air Resources Board (ARB), Energy Section. Ascent Environmental, Inc., Sacramento, California, served as the prime consultant assisting ARB. Consultants involved in the document preparation are:

Ascent Environmental, Inc.

Sydney B. Coatsworth, AICP, Project Principal
Amanda Olekszulin, Project Manager
Curtis E. Alling, AICP
Honey Walters
Linda Leeman
Kristen Stoner
Amber Giffin

Remy, Thomas, Moose, and Manley

James Moose, JD
Laura Harris
Jeannie Lee

POWER Engineers

Mike Strand

Synapse

Jeremy Fisher, Ph.D.

The Sanberg Group

Dale Schneeberger, PG, REA

Robertson-Bryan, Inc.

Michael Bryan, Ph.D.
Jeff Lafer

Applied Earthworks

M. Colleen Hamilton, RPA

Geografika Consulting

Megan Gosch

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ACRONYMS AND ABBREVIATIONS

AADT	average annual daily traffic
AB	Assembly Bill
ACEC	Area of Critical Environmental Concern
ACHP	Advisory Council on Historic Preservation
AICUZ	Department of Defense Air Installations Compatible Use Zones
ALUC	Airport Land Use Commission
amsl	above mean sea level
APE	area of potential effect
APEFZ	Alquist-Priolo Earthquake Fault Zone
ARB	California Air Resources Board
BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
BLM	U.S. Bureau of Land Management
BMPs	best management practices
bmsl	below mean sea level
BOR	U.S. Bureau of Reclamation
CAA	Clean Air Act
CAL FIRE	California, Department of Forestry and Fire Protection
Cal ISO	California Independent System Operator
CAL Recycle	State of California, Department of Resources Recycling and Recovery
Cal/EPA	California Environmental Protection Agency
Caltrans	California Department of Transportation
CBC	California Building Code
CCCT	closed circuit cooling tower
CCNM	California Coastal National Monument
CCP	comprehensive conservation plans
CCR	California Code of Regulations
CDCA	California Desert Conservation Area
CDPA	California Desert Protection Act
CEC	California Energy Commission

CEQA	California Environmental Quality Act
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFCP	California Farmland Conservancy Program
CFR	Code of Federal Regulations
CGS	California Geological Survey
CHP	combined heat and power
CI	Circulation and Infrastructure
CNEL	Community Noise Equivalent Level
CNRA	California Natural Resources Agency
CO	Conservation
CPUC	California Public Utilities Commission
CREZ	competitive renewable energy zones
CRHR	California Register of Historical Resources
CT	simple cycle cooling tower
CUPA	Certified Unified Program Agency
CVMSHCP/NCCP	Coachella Valley Multi-Species Habitat Conservation Plan/Natural Communities Conservation Plan
CVP	Central Valley Project
CWA	Clean Water Act
dB	decibel
dBA	A-weighted sound levels
Delta	Sacramento-San Joaquin Delta
DFG	Department of Fish and Game
DOGGR	California Division of Oil, Gas, and Geothermal Resources
DPR	Department of Parks and Recreation
DTSC	Department of Toxic Substances Control
DWR	California Department of Water Resources
E3	Energy and Environmental Economics, Incorporated
EDCs	endocrine disrupting compounds
EIRs	Environmental Impact Reports
EIS	environmental impact statement
EPA	U.S. Environmental Protection Agency

EPCRA	Environmental Planning and Community Right-to-Know Act
FAA	Federal Aviation Administration
FED	functionally equivalent document
FEMA	Federal Emergency Management Agency
FHA	Federal Highway Administration
FHWA	Federal Highway Administration
FLPMA	Federal Land Policy and Management Act
FMMP	Farmland Mapping and Monitoring Program
FPPA	Farmland Protection Policy Act
FRA	Federal Rail Administration
FTA	Federal Transit Administration
g	gravity
GC	Government Code
GHG	greenhouse gases
H	Housing
HCP	habitat conservation plan
HLRs	Hydrologic landscape regions
IEPR	Integrated Energy Policy Report
in/sec	inches per second
IOUs	investor owned utilities
ISEGS	Ivanpagh Solar Electric Generating Systems
kW	kilowatts
lb/MWh	pound per megawatt hour
L_{dn}	Day-Night Noise Level
LEA	local enforcement agencies
L_{eq}	Equivalent Noise Level
L_{max}	Maximum Noise Level
L_{min}	Minimum Noise Level
LOS	level of service
LU	Land Use
mg/L	milligrams per liter
Moyer program	ARB's Carl Moyer Program
MPOs	metropolitan planning organizations

MPS	modular pumped storage
MRDS	USGS Mineral Resource Data System
MRZ	Mineral Resource Zones
MUC	Multiple-Use Class
MW	megawatts
MWh	megawatt-hour
mya	million years ago
NAAQS	National Ambient Air Quality Standards
NAGPRA	Native American Graves Protection and Repatriation Act of 1990
NCAs	National Conservation Areas
NCCP	natural communities conservation plan
NCP	National Contingency Plan
NCPA	Northern California Power Agency
NECO	Northern and Eastern Colorado Desert
NEPA	National Environmental Policy Act [
NFMA	National Forest Management Act
NFS	National Forest System
NHPA	National Historic Preservation Act
NLCS	National Landscape Conservation System
NPDES	National Pollution Discharge Elimination System
NPL	National Priority List
NPS	National Park Service
NRHP	National Register of Historic Places
NRPA	Archaeological Resources Protection Act of 1979
O_2	oxygen
O&M	operation and maintenance
OAQPS	Office of Air Quality Planning and Standards
OHMVR	off-highway motor vehicle recreation
OS	Open Space
OTC	once through cooling
OWTS	onsite wastewater treatment systems
oxide	aluminum
PA	Programmatic Agreements

PCBs	polychlorinated biphenyls
PEIS	Programmatic Environmental Impact Statement
PM	Particulate matter
POUs	publicly owned utilities
ppmv	parts per million by volume
PPV	peak particle velocity
PRC	Public Resources Code
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act
REC	renewable energy credit
RES	Renewable Electricity Standard
RETI	Renewable Energy Transmission Initiative
RMPs	Resource Management Plans
RMS	root-mean-square
ROWD	Report of Waste Discharge
ROWs	right-of-ways
RPS	Renewables Portfolio Standard
RWQCB	Regional Water Quality Control Board
SARA	Superfund Amendments and Reauthorization Act
SBE	State Board of Education
SCAQMD	South Coast Air Quality Management District
Scoping Plan	AB 32 Climate Change Scoping Plan
SCPPA	Southern California Public Power Authority
SCS	Sustainable Communities Strategy”
SDAPCD	San Diego Air Pollution Control District
SDWA	Safe Drinking Water Act
SERCs/TERCs	state/tribe emergency response commissions
SIC	Standard Industrial Classification
SIP	State Implementation Policy
SJVAPCD	San Joaquin Valley Air Pollution Control District
SMARA	California Surface Mining and Reclamation Act
SMUD	Sacramento Municipal Utility District
solar DG	distributed solar generation

SVRA	State Vehicular Recreation Area
SWAMP	Surface Water Ambient Monitoring Program
SWP	State Water Project
SWPPP	Storm Water Pollution Prevention Plan
SWRCB	State Water Resources Control Board
TAC	toxic air contaminant
TDS	Total dissolved solids
TMDL	Total Maximum Daily Load
tpy	tons per year
TRI	Toxics Release Inventory
TSCA	Toxic Substances Control Act
U.S. EPA	U.S. Environmental Protection Agency
UBC	Uniform Building Code
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
UXO	unexploded ordnance
V/C	volume-to-capacity ratio
VC	Vehicle Code
VdB	vibration decibels
VOCs	volatile organic compounds
VRI	Visual Resource Inventory
VRM	Visual Resource Management
WAPA	the Western Area Power Administration
WDRs	waste discharge requirements
WECC	Western Electricity Coordinating Council
WECO	Western Colorado
WEMO	West Mojave Habitat Conservation Plan
WSA	water supply assessment

I. INTRODUCTION AND BACKGROUND

A. INTRODUCTION

The California Environmental Quality Act (CEQA) and California Air Resources Board (ARB) policy require an analysis to determine any potentially significant adverse environmental impacts of ARB's regulations. The Renewable Electricity Standard (RES) is proposed to be adopted as a regulation. If adopted, it would advance the standard for the proportion of electricity generation by eligible renewable sources from 20 percent, as established in 2002 by the California Renewables Portfolio Standard (RPS), to 33 percent. The proposed 33 percent RES would modify other provisions contained in the existing RPS, as described in Chapter II.

RES is identified as one of the measures proposed in the Climate Change Scoping Plan (Scoping Plan), which was developed for the purpose of reducing emissions of greenhouse gases (GHG) in California, as directed by the California Global Warming Solutions Act of 2006 (AB 32, Chapter 488, Statutes of 2006). One of the key elements of the Scoping Plan recommendations is "Achieving a statewide renewables energy mix of 33 percent." As described in the Scoping Plan recommendations, "increasing the 20 percent RPS to 33 percent is designed to accelerate the transformation of the electricity sector, including investment in the transmission infrastructure and system changes to allow integration of large quantities of intermittent wind and solar generation," and other eligible renewable sources.

B. THE CALIFORNIA ENVIRONMENTAL QUALITY ACT AND FUNCTIONAL EQUIVALENCY

In PRC Section 21080(a) CEQA states, "Except as otherwise provided in this division, this division shall apply to discretionary projects proposed to be carried out or approved by public agencies, including but not limited to the enactment and amendment of zoning ordinances, the issuance of zoning variances, the issuance of conditional use permits, and the approval of tentative subdivision maps, unless the project is exempt from this division. " ARB determined that adoption and implementation of the proposed 33 percent RES constitutes a "project" as defined by Public Resources Code Section 21000 et seq. The CEQA Guidelines, Section 15378, define a project as:

(a) "Project" means the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment, and that is any of the following:

  (1) An activity directly undertaken by any public agency including but not limited to public works construction and related activities clearing or grading of land, improvements to existing public structures, enactment and amendment of zoning ordinances, and the adoption and amendment of

viewsheds of State Routes 14 and 58. For wind farms that would be sited along ridgelines and open plains, the wind turbines would be more prominent and would further increase the contrast between the natural and artificial visual environment, potentially damaging the visual character of the area. Views of construction and operation activities may be visible to some viewer groups in the area, including motorists along State Routes 14 and 58, residents in nearby communities, and recreationists using the Pacific Crest Trail. Residents and recreationists would be expected to experience a longer duration of views as opposed to motorists who would be passing through the Tehachapi area at higher speeds. However, the visual impact of wind turbines and associated facilities depends on several variables, including viewing distance, angle of view, and structure placement in the landscape. Because the Tehachapi Wind Resource Area already includes wind farms, it is possible that wind energy development in this area would not substantially exacerbate scenic impacts of State Routes 14 and 58. However, because specific locations are unknown, it is possible that wind turbines could be constructed in more pristine areas, resulting in significant scenic impacts.

Out of State – Low and High Load Conditions

Under the 20 percent low and high load conditions, implementation of the same degree of wind energy resource projects in Montana, the Pacific Northwest, Utah, Southern Idaho, and Wyoming may result in significant adverse effects on scenic vistas, scenic resources, and visual character in these areas. Some of these projects may occur on federal lands, which would subject such projects to environmental review of aesthetic impacts under NEPA. In some cases, renewable energy resource projects may also occur in states where such projects would be subject to the state’s environmental review process. In any case, however, implementation of renewable energy resource projects in out-of-state locations may have significant effects primarily because such projects are typically located in areas of undeveloped, uninhabited land and would result in substantial alteration of the visual landscape. Implementation of Mitigation A-1 through A-10 would reduce scenic impacts, but it is uncertain whether mitigation would be sufficient to reduce the impact to a less than significant level.

Scenic impacts of wind energy development under the 20 percent RPS low and high load conditions would be potentially significant. This impact would be expected to occur even without adoption of the RES.

33 Percent Renewable Electricity Standard

Distributed Statewide – Low and High Load Conditions

No additional distributed wind energy is anticipated under the 33 percent RES over and above the 20 percent RPS, so no additional impact would occur from approval of the 33 percent RES.

Tehachapi – Low and High Load Conditions

Under the 33 percent RES, wind energy and transmission development in the Tehachapi area would be the same under both low and high load conditions, and the same as the high load condition under the 20 percent RPS. As such, scenic impacts of some locations, the visible changes to these scenic resources may be potentially significant.

Out of State – Low and High Load Conditions
Out-of-state scenic impacts under the 33 percent RES, high and low load, for solar thermal would be identical to the 20 percent RPS, high and low load, described above.

Scenic impacts of solar thermal and transmission line development under the 33 percent RES low and high load conditions would be significant.

Solar Photovoltaic

20 Percent Renewable Portfolio Standard

Distributed Statewide – Low and High Load Conditions
Development of solar photovoltaic energy would occur in various locations throughout the State under the 20 percent RPS low and high conditions. Construction and operation of solar photovoltaic panels, access roads, and associated facilities would introduce new elements that have the potential to substantially degrade the existing quality of sites, particularly those in undeveloped areas. While specific locations of distributed solar photovoltaic energy development are unknown, such development may occur in areas with national, state, or county designated scenic vistas, other scenic resources, and State scenic highways. Solar photovoltaic development has the potential to substantially damage scenic resources.

Tehachapi – Low and High Load Conditions
Under the 20 percent RPS solar photovoltaic energy and transmission development is expected to occur in the Tehachapi area under both low and high load conditions. High load conditions under the RPS would require approximately three times the solar photovoltaic generation from this area. Although there are no officially designated State scenic highways in the Tehachapi area, portions of State Routes 14 and 58, which intersect near the Tehachapi Mountains, are eligible for designation. Depending on the locations of solar photovoltaic development, they may extend into the viewsheds of State Routes 14 and 58. Construction of solar photovoltaic facilities would create temporary, adverse changes in the visual character of the Tehachapi area and permanent facilities have the potential to create substantial changes in the visual quality and character of the flat desert areas south of the Tehachapi Mountains. Facility elements may be visible from public vantages, particularly State Routes 14, 58, and 138, which pass directly through the area where solar photovoltaic development would occur. Residents in the community of Rosamond may be affected by construction and operation activities near State Route 14. Some recreationists in the Sierra Pelona Mountains to the south of the Tehachapi area may be affected by the change in visual character, but this would largely depend on where the recreationist is located. Because specific locations of solar photovoltaic projects are unknown, it is possible that facilities could be constructed in pristine areas, resulting in significant scenic impacts.

Out of State – Low and High Load Conditions

Under the 20 percent low and high load conditions, implementation of the same degree of solar photovoltaic energy projects in Arizona/Southern Nevada—though modest—may result in significant adverse effects on scenic resources in these areas. Projects may occur on federal lands, in which case they would be subject to environmental review of aesthetic impacts under NEPA, and projects may also be subject to state environmental policies, rules, and regulations. In any case, however, implementation of solar photovoltaic projects in out-of-state locations may have significant effects primarily because such projects are typically located in areas of undeveloped, uninhabited land. Scenic impacts of solar photovoltaic development under the 20 percent RPS low and high load conditions would be significant. This impact would be expected to occur even without adoption of the RES.

33 Percent Renewable Electricity Standard

Distributed Statewide – Low and High Load Conditions

No additional distributed solar photovoltaic energy is anticipated under the 33 percent RES over and above the 20 percent RPS, so no additional impact would occur from approval of the 33 percent RES.

Tehachapi – Low and High Load Conditions

The amount of solar photovoltaic and transmission development in the Tehachapi area under 33 percent RES low and high load conditions is expected to be the same as under the 20 percent RPS high load scenario, discussed above.

Mountain Pass – Low and High Load Conditions

As with solar thermal, the level of solar photovoltaic energy and transmission development in the Mountain Pass area is anticipated to remain the same under both the 33 percent low and high scenarios. Construction activities and introduction of new solar photovoltaic energy facilities into the desert landscape may impair scenic vistas, resources, and aesthetic character. These visual elements would be visible primarily to motorists traveling on Interstate 15, which passes through the Mountain Pass project area and is a popular route for travelers to Las Vegas, and recreationists at the Primm Valley Golf Course. While not a State-designated scenic highway, San Bernardino County has designated portions of Interstate 15 that pass through the area as having scenic character of visual importance. Motorists are considered to have a low sensitivity to change of existing visual character because of their distance, angle, and duration of views in this area. Construction and operation activities may also be visible to residents in the nearby community of Primm, Nevada, although views may be minimal because of the community's distance from the area.

Although some transmission lines already pass through the Ivanpah Valley, the solar thermal energy facilities would introduce new artificial elements that would contrast photovoltaic with the existing natural environment as well as strong spatial and scale dominance. The proposed project would result in a significant visual change in the site and its surroundings.

Riverside East – Low and High Load Conditions

As with solar thermal, a similar amount of solar photovoltaic energy and transmission development is expected to occur in the Riverside East area under the 33 percent RES low and high load conditions. Construction activities would create a temporary, adverse change in the visual character of the area due to the introduction of heavy equipment in addition to site clearing and grading activities. Operation would introduce new solar photovoltaic energy facilities into the largely undeveloped desert landscape. These visual elements would be visible primarily to motorists traveling on Interstate 10, which passes through the project area, but which is not listed as a State scenic highway. The proposed project would introduce prominent solar photovoltaic structures into the foreground of motorists and into the background of residents in the nearby City of Blythe. Some recreationists at Joshua Tree National Forest to the west of the Riverside East area may also be affected by the substantial visual change in the desert landscape. Construction and operation of solar photovoltaic development would substantially degrade the Riverside East area and its existing natural surroundings by changing the environment to an industrial landscape. This would be a significant impact.

Fairmont –Low and High Load Conditions

Under the 33 percent RES low and high load conditions, development of solar photovoltaic energy and transmission is expected to occur in the Fairmont area. Construction activities would create a temporary, adverse change in the visual character of the Fairmont area due to the introduction of heavy equipment, access roads in addition to site clearing and grading. Construction activities may also alter naturally vegetated areas. Operation of the proposed project would introduce new solar photovoltaic facilities into areas that are largely undeveloped or used for agricultural purposes. These visual elements may be visible to motorists traveling on State Route 138, and to a much lesser extent, on State Route 14 although views from State Route 14 may be indiscernible. The proposed project would introduce prominent structures with an industrial character into the foreground of motorists and into the background of some residents in the nearby cities of Palmdale and Lancaster and the community of Little Rock, As a result, construction and operation of solar photovoltaic facilities would substantially degrade the Fairmont area and its existing natural surroundings.

Out of State – Low and High Load Conditions

Out-of-state scenic impacts under the 33 percent RES, high and low load, for solar photovoltaic would be identical to the 20 percent RPS, high and low load, described above.

Scenic impacts of solar photovoltaic and transmission line development under the 33 percent RES low and high load conditions would be significant.

III.B. AIR QUALITY

This section includes a general description of existing conditions (e.g., types of sensitive land uses and sources located out-of-state), a summary of applicable regulations, and evaluation of potential short-term and long-term air quality impacts associated with the out-of-state implementation of the proposed renewable energy development scenarios. Mitigation is recommended, as necessary, to reduce significant impacts.

As described in the Project Description, the RES Calculator was used to identify out-of-state electricity generation by resource type for: 2008 conditions; 20 percent RPS in 2020 under low and high load conditions; and 33 percent RES in 2020 under low and high load conditions. Tables II-1 and II-2 illustrate comparative data for 2008 (existing conditions for purposes of analysis), RPS and RES under low and high load conditions, respectively. Tables II-3 through II-6 illustrate electricity generation by resource type, by CREZ, for each scenario. Figure II-1 illustrates CREZ locations.

It is important to note that while the RES Calculator output represents the best available data to represent the results of the proposed regulation and a reasonable set of assumptions upon which to assess impacts, the manner in which renewable energy projects would actually come on line cannot be known with certainty. The number of potential future combinations of renewable resource mix, location, and timing, and degree that would satisfy RES requirements is nearly infinite and would depend upon myriad economic, political, and environmental factors. The plausible compliance scenarios identified by ARB and modeled using the RES Calculator represent a reasonable characterization of the way in which the future could unfold; analysis of additional potential future scenarios would not meaningfully add to the body of evidence necessary for ARB to make an informed decision with regard to the proposed regulation.

In addition, as with all of the environmental effects and issue areas, the precise nature and magnitude of impacts would depend on the types of projects authorized, their locations, their aerial extent, and a variety of site-specific factors that are not known at this time but that would be addressed by environmental reviews at the project-specific level.

1. ENVIRONMENTAL SETTING

Note to Reader: The evaluation of the in-State air quality impacts resulting from the renewable energy projects necessary for compliance with the RES is provided in Chapter IX of the RES Staff Report. Based on that analysis, implementation of new in-State renewable energy projects would not generate levels of emissions that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, result in a cumulatively considerable net increase in non-attainment areas, or expose sensitive receptors to substantial pollutant concentrations or odors with mitigation (e.g., compliance with applicable regulations). Thus, in-State air quality impacts from operation of renewable energy facilities is expected to result in beneficial effects. Generally, it is important to note that renewable electricity generation produces fewer pollutants per unit of electricity output than the fossil-fuel generation it would displace and less total electricity would be generated in-State in comparison to existing conditions.

Construction of any new facilities would be subject to site-specific mitigation imposed by local and potentially federal lead agencies and local air districts. Mitigation for construction related air quality impacts is expected to be the same or similar to those detailed below in Mitigation B-1. Please refer to the RES Staff report for additional information.

The following presents an evaluation of the potential out-of-state air quality impacts that could occur with implementation of the 33 percent RES.

(a). EXISTING OUT-OF-STATE SOURCES AND SENSITIVE LAND USES

Out-of-state renewable energy resources are projected by the RES Calculator to be developed in the following general areas: Alberta, Arizona/Southern Nevada, British Columbia, Montana, New Mexico, Northwest, Reno/Dixie Valley, Utah/Southern Idaho, and Wyoming.

The existing air quality environment in the proposed out-of-state areas is influenced by stationary, area, and mobile sources. According to EPA, there are areas within those mentioned above where out-of-state renewable energy resources are projected by the RES Calculator to be developed that are currently designated as nonattainment areas for ozone (8-hour), PM_{10}, $PM_{2.5}$, CO, SO_2, and lead) (EPA 2010). Sensitive land uses in such areas may include residences (e.g., single- and multi-family), schools, hospitals, nursing homes, and other uses that may include segments of the population that are sensitive to poor air quality.

2. REGULATORY SETTING

The following provides a brief description of the Federal and State regulations that could be applicable to an out-of-state renewable energy project. Local regulations may also apply; however, because the specific siting of the renewable energy facilities is not known at this time it would be speculative to present a discussion of applicable local regulations.

Table III.B-1. Applicable Laws and Regulations for Air Quality

Regulation	Description
Federal	
40 Code of Federal Regulations (CFR) (National Environmental Policy Act [NEPA])	NEPA requires all federal agencies to consider environmental factors through a systematic interdisciplinary approach before committing to a course of action. The NEPA process is an overall framework for the environmental evaluation of federal actions.

Table III.B-1. Applicable Laws and Regulations for Air Quality	
Regulation	**Description**
Clean Air Act and 40 CFR, Part 50	The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (NAAQS) (40 CFR, Part 50) for pollutants considered harmful to public health and the environment. The Clean Air Act established two types of NAAQS. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. EPA Office of Air Quality Planning and Standards (OAQPS) has set NAAQS for six principal pollutants, which are called "criteria" pollutants.
Other Applicable Federal-Level Regulations	This includes all other applicable regulations at the federal level for portions of the project area that are outside of the U.S. (e.g., Canada).
State	
Other Applicable State-Level Regulations	This includes all other applicable regulations at the state level for portions of the project area that are outside of California (e.g., Arizona, Nevada).

3. PROJECT IMPACTS

This section describes the project's out-of-state effects on air quality for the 20 percent RPS and 33 percent RES. The discussion includes the criteria for determining the level of significance of the effects and a description of the methods and assumptions used to conduct the analysis.

As with all of the impacts, the precise magnitude and extent of the impact would depend on the type of renewable energy project authorized, its specific location, its total length and size, and a variety of site-specific factors that are not known at this time. All of these issues would be addressed through project-specific environmental reviews that would be conducted by local land use agencies (e.g., cities, counties) or other regulatory bodies at such time the projects are proposed for implementation. ARB would not be the agency responsible for conducting the project-specific environmental review because it is not the agency with authority for making land use decisions.

(a). METHODOLOGY

Potential out-of-state impacts to air quality were assessed based on the potential for the 33 percent RES to exceed the thresholds of significance identified below. The analysis that is presented below evaluates the change from existing conditions to the 33 percent RES in 2020. However, an incremental portion of these impacts would occur regardless of whether the 33 percent RES is implemented. The CPUC approved the 20 percent RPS and this regulation would be implemented by 2020. The 33 percent RES would further the renewable energy objective and would be added to the 20 percent RPS. Therefore, the analysis below describes the impacts that would occur under the 20 percent RPS, the total impacts that would occur under the 33 percent RES (i.e., existing conditions to 33 percent RES), and the incremental impacts from 20 percent RPS to 33 percent RES. For each of these alternatives, a high and low load scenario is also evaluated (see Section II, Project Description, for additional details).

For some impacts below, the same type and magnitude would occur under each scenario and each alternative. Where this occurs, a combined analysis is presented to streamline the presentation of environmental impacts to avoid unnecessary repetition.

(b). THRESHOLDS OF SIGNIFICANCE

For purposes of this analysis, the following applicable thresholds of significance were used to determine whether implementing the 33 percent RES would result in a significant air quality impacts. The project would result in a significant impact if it would:

- conflict with or obstruct implementation of the applicable air quality plan;
- violate any air quality standard or contribute substantially to an existing or projected air quality violation;
- Result in a cumulatively considerable net increase of any criteria air pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard;
- Expose sensitive receptors to substantial pollutant concentrations; or
- Create objectionable odors affecting a substantial number of people.

IMPACT B-1	**Short-Term Construction Impacts to Air Quality from Out-of-State Project-Generated Emissions of Criteria Air Pollutants and Precursors. Because the specific air quality impacts of the 33 percent RES cannot be identified with any certainty, and construction activities associated with these projects could generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas, this impact is considered *potentially significant* for all renewable energy types under the 33 percent RES (high and low load).**

All Renewable Energy Project Types

All renewable energy projects no matter their size, out-of-state location, or type would be required to seek local land use approvals prior to their implementation. Part of the land use entitlement process requires that each of these projects undergo environmental review consistent with Federal environmental review requirements (e.g., NEPA) or other applicable state requirements. The environmental review process for all renewable project types under either the 20 percent RPS or 33 percent RES would assess whether project implementation would result in short-term construction air quality impacts.

At this time, the specific location, type, and number of renewable energy projects constructed out-of-state is not known and would be dependent upon a variety of market factors that are not within the control of ARB including: economic costs, energy demands, environmental constraints, and other market constraints. Nonetheless, the analysis provided herein provides a reasonable accounting of the types of environmental impacts that would occur with implementation of the 33 percent RES plausible compliance scenarios (high or low load conditions) as discussed below for short-term construction emissions. Further, subsequent environmental review would be conducted at such time that a renewable energy project is proposed and land use entitlements are sought.

During construction of renewable energy projects out-of-state, criteria air pollutant and precursor emissions could be generated from a variety of construction activities and emission sources. These emissions would be temporary and occur intermittently depending on the intensity of construction on a given day. Site grading and excavation activities would generate fugitive PM dust emissions, which is the primary pollutant of concern during construction. Fugitive PM dust emissions (including PM_{10} and $PM_{2.5}$) vary as a function of parameters such as soil silt content and moisture, wind speed, acreage of disturbance area, and the intensity of activity performed with construction equipment. Exhaust emissions from off-road construction equipment, material delivery trips, and construction worker-commute trips could also contribute to short-term increases in PM emissions, but to a lesser extent. Exhaust emissions from construction-related mobile sources also include ROG and NO_x emissions. These emission types and associated levels fluctuate greatly depending on the particular type, number, and duration of usage for the varying equipment. Criteria air pollutants that are also associated with localized concerns (e.g., CO) are discussed under Impact B-3 below.

The site preparation phase typically generates the most substantial emission levels because of the on-site equipment and ground-disturbing activities associated with grading, compacting, and excavation. Site preparation equipment and activities typically include backhoes, bulldozers, loaders, and excavation equipment (e.g., graders and scrapers). Although detailed construction specific information is not available at this time, based on the types of renewable energy projects listed in the Section II, Project Description it would be expected that the primary sources of construction-related emissions include soil disturbance- and equipment-related activities (e.g., use of backhoes, bulldozers, excavators, and other related equipment). Based on typical emission rates and default parameters for above mentioned equipment and activities, construction of a out-of-state renewable energy project could result in hundreds of pounds of daily NO_x and PM_{10}, which may exceed general mass emissions limits depending on the exact location of generation. Thus, because the specific air quality impacts of renewable energy projects necessary to comply with the 33 percent RES cannot be identified with any certainty, and construction activities associated with these projects could generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas, this impact is considered potentially significant for all renewable energy types under the 33 percent RES (high and low load). It is important to note that there is no difference in the impacts that would occur under the 20 percent RPS versus the 33 percent RES, as, based on the modeling, the magnitude of electricity generated from new out of-state renewable projects is relatively similar (e.g., approximately 9,500 GWh versus 10,900 GWh under both low and high load scenarios). Additionally, the magnitude of this impact is influenced more by the how (e.g., size of project footprint and types of construction activities required) and the where (e.g., whether located in a nonattainment area) of the new renewable projects, more so than the total amount of electricity generated.

IMPACT B-2

Long-Term Operational Impacts to Air Quality from Out-of-State Project-Generated Emissions of Criteria Air Pollutants and Precursors. Because renewable generation produces lower levels criteria air pollutants per unit of electricity output than fossil-fuel generation it would displace and less total electricity would be generated out-of-state in comparison to existing conditions, these projects would not be anticipated to result in significant environmental impacts (e.g., generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas). This impact is considered *less than significant* for all renewable energy types under the 33 percent RES (high and low load).

All Renewable Energy Project Types

All renewable energy projects no matter their size, location out-of-state, or type would be required to seek local land use approvals prior to their implementation. Part of the land use entitlement process requires that each of these projects undergo environmental review consistent with Federal environmental review requirements (e.g., NEPA) or other applicable state requirements. The environmental review process for all renewable project types under either the 20 percent RPS or 33 percent RES would assess whether project implementation would result in long-term operational air quality impacts.

At this time, the specific location, type, and number of renewable energy projects constructed out-of-state is not known and would be dependent upon a variety of market factors that are not within the control of ARB including: economic costs, energy demands, environmental constraints, and other market constraints. Nonetheless, as discussed with regards to the in-state projects, renewable generation produces less criteria air pollutants per unit of electrical output than fossil-fuel generation it would displace with implementation of the 33 percent RES plausible compliance scenarios (high or low load conditions). Additionally, in comparison to existing conditions less total electricity would be generated out-of-state under the 33 percent RES (e.g., approximately 98,000 GWh versus 60,000 under the low load scenario and 86,000 under the high load scenario). Further, subsequent environmental review would be conducted at such time that a renewable energy project is proposed and land use entitlements are sought. Thus, project-generated long-term operational emissions of criteria air pollutants would not be anticipated to result in significant environmental impacts (e.g., generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas). It is important to note that there is no difference in the impacts that would occur under the 20 percent RPS versus the 33 percent RES (e.g., in comparison to existing conditions less total electricity would be generated out-of-state under both the low and high load scenarios). This impact is considered less than significant for all renewable energy types under the 33 percent RES (high and low load).

IMPACT B-3	**Impacts to Sensitive Receptors in the Project Area from Exposure to Substantial Pollutant Emissions (e.g., localized criteria air pollutants, toxic air contaminates) and Odors. Because the specific out-of-state air quality impacts of the 33 percent RES cannot be identified with any certainty, and these projects could potentially expose sensitive receptors to substantial localized criteria air pollutants, toxic air contaminants , or odors, this impact is considered *potentially significant* for all renewable energy types under the 33 percent RES (high and low load).**

All Renewable Energy Project Types

As discussed above under Impact B-1, all renewable energy projects no matter their size, location out-of-state, or type would be required to seek local land use approvals prior to their implementation. Part of the land use entitlement process requires that each of these projects undergo environmental review consistent with Federal environmental review requirements (e.g., NEPA) or other applicable state requirements. The environmental review process for all renewable project types under either the 20 percent RPS or 33 percent RES would assess whether project implementation would result in the exposure of sensitive receptors to air quality impacts.

At this time, the specific location, type, and number of renewable energy projects constructed out-of-state is not known and would be dependent upon a variety of market factors that are not within the control of ARB including: economic costs, energy demands, environmental constraints, and other market constraints. Nonetheless, the analysis provided herein provides a reasonable accounting of the types of environmental impacts that would occur with implementation of the 33 percent RES plausible compliance scenarios (high or low load conditions) as discussed below for the exposure of sensitive receptors to substantial emissions. Further, subsequent environmental review would be conducted at such time that a renewable energy project is proposed and land use entitlements are sought.

The primary criteria air pollutant of localized concern is CO. Local mobile-source CO emissions near roadway intersections are a direct function of motor vehicle activity, particularly during peak commute hours, including traffic volume, speed, and delay. Transport of CO is extremely limited because it disperses rapidly with distance from the source under normal meteorological conditions. Under specific meteorological conditions, CO concentrations near roadways and/or intersections may reach unhealthy levels with respect to local sensitive land uses, such as residential areas, schools, playgrounds, childcare facilities, and hospitals. Consequently, CO emissions are typically analyzed at a local rather than a regional level. Additionally, because increased CO concentrations are usually associated with roadways that are congested and with heavy traffic volume, the criteria to determine if project-generated emissions would result in the exposure of sensitive receptors to substantial pollutant concentrations is tied the project's effect on the delay times and LOS of local intersections.

As discussed in Section M, Transportation and Traffic, although detailed information is not currently available, renewable energy projects would be anticipated to result in short-term construction and long-term operational traffic from worker commute-, maintenance/operation-, and material delivery-related trips. The amount of construction activity would fluctuate depending on the particular type, number, and duration of usage for the varying equipment; and the phase of construction (e.g., demolition, construction, erection). These variations would affect the amount of project-generated traffic for both worker commute trips and material deliveries. The amount of operational traffic would also vary depending on the size and type of renewable energy project. Thus, depending on the amount of trip generation and the location of the renewable energy project, implementation could conflict with applicable programs, plans, ordinances, or policies, specifically the degradation of delay times and LOS of local intersections, which are tied as discussed above to localized CO impacts. Long-term operation of stationary sources could also result in localized CO emissions at sensitive receptors if located at close distance to new renewable energy projects.

During construction of renewable energy projects out-of-state, toxic air contaminants (TACs) could be generated from a variety of construction activities, but primarily composed of exhaust emissions from off-road construction equipment, material delivery trips, and construction worker-commute trips. Construction activities could be located in areas where naturally occurring substances are present in the soil, thatif These emission types and associated levels fluctuate greatly depending on the particular type, number, and duration of usage for the varying equipment. The amount of TAC's and associated unit risk factors from operational activities would also vary depending on the size and type of renewable energy project. Even though project implementation would be anticipated to produce less TACs overall due to the fact renewable energy production produces less TAC's per unit of electricity output than the fossil-fuel generation it would displace under the plausible compliance scenarios, the exposure of sensitive receptors is highly dependent on the their distance from the source.

With regards to both project-generated construction and operational TAC emissions, the dose to which receptors are exposed is the primary factor used to determine health risk. Dose is a function of the concentration of a substance or substances in the environment, which is positively correlated with distance from the source, and the duration of exposure to the substance. Thus, a new renewable energy project could be located in an area where sensitive receptors are currently located and no current sources exist, resulting in a net increase in exposure from project implementation.

Lastly, though the types of renewable energy projects listed in the Project Description would not be anticipated to result in any construction-related odor emissions, long-term operational activities could depending on the exact type of stationary sources on-site. Even diesel emissions at a close distance could be considered an objectionable odor source.

In summary, the specific location, type, and number of renewable energy projects constructed out-of-state is not known at this time. However, construction and operational activities could result in the generation of localized CO emissions, TACs, and odors. Thus, because the specific air quality impacts of new renewable projects needed to comply with the 33 percent RES cannot be identified with any certainty, and activities associated with these projects, depending on the exact location of the renewable energy projects in relation to existing sensitive receptors, could result in the exposure thereof to substantial pollutant concentrations or odors, this impact is considered potentially significant for all renewable energy types under the 33 percent RES (high and low load). It is important to note that there is no difference in the out-of-state impacts that would occur under the 20 percent RPS versus the 33 percent RES.

4. MITIGATION

Mitigation is required for the following significant or potentially significant impacts.

Mitigation Measure B-1

- **Proponents for the proposed renewable energy project shall coordinate with local land use agencies to seek entitlements for development of the project including completing all necessary environmental review requirements (e.g., NEPA). The local land use agency or governing body shall certify that the environmental document was prepared in compliance with applicable regulations and shall approve the project for development.**

- **Based on the results of the environmental review, proponents shall implement all mitigation identified in the environmental document to reduce or substantially lessen the environmental impacts of the project.**

- **Comply with local plans, policies, ordinances, rule, and regulations regarding air quality-related emissions and associated exposure.**

- **Apply for, secure, and comply with all appropriate air quality permits for project construction and operations from the local agencies with air** quality jurisdiction and from other applicable agencies (e.g., EPA), if appropriate, prior to construction mobilization.

- Prepare and comply with a dust abatement plan that addresses emissions of fugitive dust during construction and operation of the project.

The proponents and local land use agencies can and should be the parties responsible for the approval and implementation of the renewable energy project and its mitigation. ARB is not a land use agency and would not be responsible for ensuring that this mitigation is implemented. Implementation of the above mitigation would reduce this impact to a less-than-significant level

for all renewable energy types under the 33 percent RES plausible compliance scenarios (high and low load conditions).

Mitigation Measure B-2

- Implement Mitigation M-1 above.

The proponents and local land use agencies can and should be the parties responsible for the approval and implementation of the renewable energy project and its mitigation. ARB is not a land use agency and would not be responsible for ensuring that this mitigation is implemented.

Implementation of the above mitigation would reduce this impact to a less-than-significant level for all renewable energy types under the 33 percent RES (high and low load conditions).

ATTACHMENT U

BEFORE THE BOARD OF SUPERVISORS
COUNTY OF KINGS, STATE OF CALIFORNIA

* * * * * *

IN THE MATTER OF AMENDING THE LOCAL CEQA GUIDELINES FOR THE PREPARATION, EVALUATION AND PROCESSING OF ENVIRONMENTAL DOCUMENTS FOR THE COUNTY OF KINGS.	))))))	**RESOLUTION NO. 16-001** **RE: Local Guidelines for the Implementation of CEQA**

WHEREAS, pursuant to Section 21082 of the Public Resources Code of the State of California all public agencies are required to adopt by ordinance, resolution, rule or regulations, objectives, criteria, and procedures for the evaluation of projects, and the preparation of environmental impact reports and negative declarations under the provisions of the California Environmental Quality Act (hereinafter referred to as "CEQA", and found at Public Resources Code Section 21000 et seq; all generic "Section" references are to the Public Resources Code); and

WHEREAS, Section 21082 further requires that the objectives, criteria, and procedures adopted by a public agency shall be consistent with the provisions of CEQA and with the State CEQA Guidelines adopted by the Secretary of the Resources Agency pursuant to CEQA (as found in the California Code of Regulations, Title 14, Division 6, Chapter 3, and hereinafter referred to as the "CEQA Guidelines"); and

WHEREAS, the purpose of this Resolution is to further streamline the local CEQA process by rescinding in its entirety Resolution No. 09-001, adopted January 27, 2009, entitled "Amending the Local CEQA Guidelines for the Preparation, Evaluation and Processing of Environmental Documents for the County of Kings", and replacing it with the local guidelines for the implementation of CEQA set forth in Attachment A.

NOW, THEREFORE, BE IT RESOLVED AS FOLLOWS:

1. This action is exempt pursuant to Section 15061(b)(3) of the *Guidelines* for *California Environmental Quality Act* (*CEQA Guidelines*). This section states that a project is exempt from *CEQA* if the activity is covered by the general rule that *CEQA* applies only to projects, which have the potential for causing a significant effect on the environment. Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to *CEQA*. The CEQA Implementation procedures are technical changes concerning general policy for the implementation of CEQA and there is no possibility that adopting these procedures will have a significant effect on the environment..

2. Except as otherwise expressly provided herein, the provisions of CEQA and the CEQA Guidelines are hereby referred to, adopted and made part of this Resolution and a part of the Local Guidelines as hereinafter defined, with the same effect as if fully set forth herein, and all the provisions thereof shall apply to projects proposed to be carried out or given discretionary review and approval by the County of Kings or any organizational subdivision thereof.

3. Resolution No. 09-001 entitled "Amending the Local CEQA Guidelines for the Preparation, Evaluation and Processing of Environmental Documents for the County of Kings" is hereby rescinded in its entirety.

4. The local guidelines in Attachment A of this Resolution are hereby enacted to implement the provisions of the California Environmental Quality Act in the County of Kings (such local guidelines are herein referred to as the "Local CEQA Guidelines").

The foregoing Resolution was passed and adopted on a motion by Supervisor Fagundes, seconded by Supervisor Neves, by said Board of Supervisors at a regular meeting held on the 5th day of January, 2016, by the following vote:

AYES:	**Supervisors Fagundes, Neves, Valle, Pedersen, Verboon**
NOES:	**None**
ABSENT:	**None**

Doug Verboon

Chairman of the Board of Supervisors
County of Kings, State of California

WITNESS my hand and seal of said Board of Supervisors this 5th day of January, 2016.

Melanie Curtis

Melanie Curtis
Deputy Clerk of said Board of Supervisors

ATTACHMENT A

LOCAL GUIDELINES FOR THE PREPARATION, EVALUATION AND PROCESSING OF ENVIRONMENTAL DOCUMENTS IN THE COUNTY OF KINGS, CALIFORNIA

Section 1. Purposes.

These Local Guidelines implement the provisions of the California Environmental Quality Act (CEQA) as contained in Division 13 (commencing at Section 21000) of the Public Resources Code of the State of California and the State CEQA Guidelines, as contained in Chapter 3 (commencing at Section 15000), Division 6, Title 14 of the California Code of Regulations, as adopted by the Secretary of the Resources Agency of the State of California. These Local Guidelines do not apply to ministerial projects, or to those projects which are statutorily exempt or excluded from CEQA review requirements, as set forth in Public Resources Code sections 21080 through 21080.35, or to those projects which are categorically exempt under the provisions of Article 19 (commencing at Section 15300) of the State CEQA Guidelines, or to those projects which are emergency projects under the provisions of Section 15269 of the State CEQA Guidelines.

Section 2. Definitions.

Whenever the following words or phrases are used in these Local Guidelines, unless otherwise defined, they shall have the meaning ascribed to them in this Section. These definitions are intended to clarify but not to replace or negate the definitions used in CEQA or in the State CEQA Guidelines, beginning at Section 15350, which are included herein by reference.

a. Consultant. An individual consultant or a consulting firm with expertise in environmental sciences and the preparation of environmental documents.

b. County or County Department. County or County Department means Kings County and any organizational subdivision thereof.

c. EAC - Environmental Advisory Committee - Committee. An informal committee appointed by the Board of Supervisors to advise County boards, commissions, committee, and departments on environmental matters, associated with their individual areas of expertise, concerning the implementation of CEQA, made up of the following members:

Kings County Health Officer,
Kings County Community Development Agency Director,
Kings County Director of Public Works,
Kings County Agricultural Commissioner and Sealer of Weights and Measures,
U.C. Cooperative Extension Services Farm Advisor, and
The Manager of the Kings Mosquito Abatement District.

d. Professional Services Agreement. An agreement between the County and a consultant which specifies the work that will be performed for the preparation of environmental documents and the cost of preparing such a document.

e. Reimbursement Agreement. An agreement between the County and the project proponent to reimburse the County for the actual cost to prepare the environmental documents for the project, including the cost of the "Agreement for Professional Services" and administrative costs incurred by County staff in processing the project.

f. Indemnification Agreement. An agreement between the County and the project proponent to reimburse the County's actual cost associated with challenges to the environmental documents prepared by, or under the direction of, the County for the project and to defend and indemnify the County against any and all challenges to the County's review, consideration, processing or approval of the project application.

g. Faithful Performance/Payment Bond. A performance bond, payment bond, cash deposit, letter of credit, or other suitable financial instrument approved by the County that is convertible to cash, or any combination of the above,, provided by the applicant to ensure the faithful performance of the project proponent's obligations, and/or the payment of amounts due, under a Reimbursement Agreement and/or an Indemnification Agreement entered into between the County and the Project Proponent under the terms and provisions of these Local Guidelines.

Section 3. Kings County Environmental Advisory Committee (EAC).

a. The Kings County Environmental Advisory Committee EAC shall consist of the following six members:

   Kings County Health Officer,
   Kings County Community Development Agency Director,
   Kings County Director of Public Works,
   Kings County Agricultural Commissioner and Sealer of Weights and Measures,
   U.C. Cooperative Extension Services Farm Advisor, and
   The Manager of the Kings Mosquito Abatement District.

b. The EAC shall be advisory only and will not hold public meetings. Each EAC member may provide written comments determined by the member to appropriately reflect that member's general and specific environmental concerns related to his or her area of expertise.

c. <u>Duties of the Members of the EAC:</u> The principal duty of the members of the EAC shall be to review initial studies which are submitted by County Departments during the 20-day public review period for proposed negative declarations and the 30-day or 45-day public review period for draft EIRs required by CEQA Section 21091. Committee members may make any of the following recommendations:

   1) Recommend approval of the initial study as a negative declaration, if, based upon the initial study, the Committee member determines that the project will not have a significant effect on the environment. Failure to notify the Planning Division of the Community Development Agency within the specified review period, indicates acceptance of the initial study as submitted; or

   2) In writing, request specific changes to the draft initial study, and with those specified changes recommend that the decision maker adopt a negative declaration; or

   3) In writing, recommend the preparation of an environmental impact report if, based upon the initial study, the Committee member believes that the project will have a significant adverse effect on the environment. The committee member shall specify, in writing, what effects on the environment he or she believes will be significant and why.

d. Each EAC member shall also be responsible for recommending to the Board of Supervisors' requests for additions to, or deletions from, the list of classes or projects that are exempt from environmental review pursuant to Sections 21084 through 21086, inclusive, of CEQA.

e. <u>Limitations of Review by Environmental Advisory Committee:</u> The review of negative declarations and environmental impact reports by the members of the EAC shall be advisory in nature and shall be limited to a determination of the objectivity and adequacy of the environmental documents submitted to its members, and shall ensure that the decision maker has sufficient information about the possible impacts to the environment, in the judgment of the committee member, that the project may cause. Committee members shall not consider the value of the project itself or whether the project should be approved or denied. Such determination is solely the responsibility of the decision maker for the project.

Section 4. Ministerial Projects and Actions in Kings County

Section 21080(b)(1) of CEQA provides that the Act does not apply to ministerial projects proposed to be carried out or approved by public agencies. Section 15268 of the State CEQA Guidelines states that the determination of what is "ministerial" can most appropriately be made by the public agency involved, and that each public agency should identify or itemize those projects and actions which are deemed ministerial.

The following is a non-exclusive list of types of projects that are ministerial and therefore exempt from CEQA review requirements:

a. Sheriff-Animal Control
1. Dog Licenses

b. Agricultural Commissioner-Sealer
1. Agricultural crop moving permits

c. Building Division of the Community Development Agency
1. Plan check reviews
2. Building Permits (including Electrical, Plumbing, and Mechanical Permits)
3. Demolition Permits
4. Mobile Home Installation Permits
5. Relocation Inspections and Permits
6. Utility Service Connections and Disconnections
7. Compliance Inspections and Reports
8. Water well permits

d. County Clerk
1. Marriage Licenses

e. Fire Department
1. Fireworks Sales Permits
2. Weed Abatement Program

f. Health Department
1. Food Vendor's Permits
2. Water Supply Permits (small public water systems and state small water systems)
3. Underground Storage Tank Permits, Authority to Construct, and Authority to Abandon
4. Hazardous Materials Business Plan and Inventory approvals
5. Risk Management and Prevention Program approvals
6. Medical Waste Management Registrations
7. Limited Quantity Medical Waste Hauler Exemptions
8. Registration of businesses engaged in the cleaning of septic tanks, chemical toilets, cesspools, and seepage pits
9. Reserved.
10. Plan approval for construction, modification, or remodeling of food facilities, public swimming pools and spas, on site sewage disposal systems, small public water systems, state small water system and/or underground storage tanks (including piping)
11. Occupational health and safety consultation services
12. Body art registrations

g. Planning Division of the Community Development Agency
1. Site Plan Reviews conducted by the Zoning Administrator under the provisions of Article 16 of the Kings County Development Code.
2. Land divisions exempted by Sections 2306 and 2308.I of Article 23 of the Kings County Development Code.
3. Certificates of Compliance
4. Lot Line Adjustments
5. Annual Fire Arms Dealers Reviews
6. Code enforcement investigations and orders for abatement of nuisances and violations
7. Abandoned Vehicle Abatement Program investigations and orders for abatement
8. Certificates of Voluntary Parcel Merger
9. Temporary Use Permits

h. Public Works Department
1. Encroachment Permits
2. Moving permits
3. Traffic control activities

i. Tax Collector

1. Dance, explosive, gun, and solicitors licenses
2. Rubbish disposal operator's license

A notice of exemption shall be filed for all projects determined to be statutorily, categorically or otherwise exempt from CEQA environmental review.

Section 5. Initial Study.

The initial study process shall be conducted according to the procedures outlined in the State CEQA Guidelines, Article 5, beginning with Section 15060.

The County department initiating a public project or receiving an application for discretionary approval of a private project may prepare its own initial study, or submit a description of the project to the Planning Division of the Community Development Agency for environmental review. If a project description is submitted to the Planning Division, the Planning Division shall conduct an initial study pursuant to Section 15063 of the State CEQA Guidelines and these Local Guidelines to determine if the project may have a significant effect on the environment. The County department or the applicant shall provide any additional information the Planning Division may require in preparing the initial study. Failure to provide the requested information in a timely manner may cause the application not to be certified as complete, and delay the development of the required environmental documents.

Section 6. Time Limits for the Certification of Environmental Documents.

Pursuant to Section 21151.5 of CEQA and Article 8 of the State CEQA Guidelines, the County of Kings hereby establishes one year as the time limit for the completion and certification of environmental impact reports, and 180 days for the completion and adoption of negative declarations, for projects which require environmental review. The commencement and running of these time periods shall be governed by CEQA and the CEQA Guidelines.

<u>Extensions of Time for EIR's:</u> Extensions of time for the processing of EIR's may be approved once, for an additional period not to exceed 90 days, by the Lead Agency provided that it finds that compelling circumstances justify the extension of time and that the project applicant consents to the specified extension, pursuant to Government Code Section 65957 and State CEQA Guidelines Section 15108. Extensions exceeding 90 days may be approved where the law expressly otherwise provides for such additional extensions.

Section 7. Deposit and Accounting on Private Project.

All applications for the discretionary review of private projects by the County shall include a fee, subject to Section 21089 of CEQA, in an amount set by Ordinance of the Kings County Board of Supervisors, at the time the project application is filed with the Planning Division of the Community Development Agency to cover the cost of preparation of the initial study.

If it is determined that an EIR should be prepared, the applicant shall be required to pay the cost of preparing the EIR (see Section 2 d, e, f, and g above). The Planning Division shall ensure the EIR is prepared according to the procedures described in Article 7 (Section 15084 through 15097) of the CEQA Guidelines.

The Planning Division may prepare the required documents, with Board of Supervisors approval, by engaging the services of a consultant with expertise in preparing environmental documents, based on a detailed work plan approved by the Planning Department staff, and made a part of the "Agreement for Professional Services", shall be submitted to the project applicant who shall enter into a *Reimbursement Agreement* with the County and deposit in an interest bearing account in the County Treasury the amount of the cost shown in the detailed work plan (agreement), plus an administrative fee determined by the Community Development Agency Director to be necessary to defray the cost of administering the agreement with the consultant and the staff time necessary to process the project to its completion.

As an alternative the applicant may submit detailed information in any form, including the form of a draft EIR. The Planning Division, with Board of Supervisors approval, may engage at the expense of the applicant the services of a consultant with expertise in preparing environmental documents, to advise the County on the adequacy of the information submitted, including, but not limited to, a draft EIR, if any is submitted. Reimbursement for the costs of the County's consultant shall be the same as described above.

An accurate accounting shall be kept by the Planning Division, with assistance from the County Department of Finance, of the actual cost of preparing and administering the EIR and shall be made available to the applicant at his request. Upon the completion of the project, after the decision maker's final action, the Planning Division shall refund to the applicant any money remaining in the account, including interest that was earned and not used.

Section 7.5. Indemnification and Bonding.

In its sole and absolute discretion, the County may determine that it has exposure to potential extraordinary costs and require an applicant to provide the county indemnification against extraordinary costs associated with the review and processing of a development application. The extraordinary costs the County may incur associated with the review and processing of a development application, may include, but are not limited to, applications for development entitlements requiring preparation of environmental impact reports, specific plans, and major general plan amendments, large urban development projects, project decisions that are appealed or challenged through law suits, etc. In addition, if it is determined that an Indemnification Agreement is required, the applicant will be required to provide a bond in an amount sufficient to ensure that the applicant's indemnification of the County is sufficient to protect the public interest in case of challenges to the process or action of the County related to the project, or failure of the applicant to provide the County with required reimbursements for the cost of the application review and processing under the terms of the Reimbursement Agreement. In its sole and absolute discretion, the County may determine that the Reimbursement Agreement and the Indemnification Agreement be combined as one document. The form, nature and amount of the bond and/or bonds or other suitable financial instrument, required under the terms of these Local Guidelines and in the light of any risks associated with a particular project shall be in the sole and absolute discretion of the County.

Section 8. Action by the Decision-Maker.

(a) When a proposed negative declaration has been forwarded to the decision-maker, the decision-maker shall, prior to making a decision on the project, either approve the negative declaration based upon a finding that the project will not have a significant effect on the environment, or shall refer the matter to the Planning Division of the Community Development Agency for preparation of an EIR, or mitigated negative declaration, based upon a finding that the project may have a significant effect on the environment. If the matter is referred for additional review, the decision maker shall take no further action on the project until a final EIR, or mitigated negative declaration, has been prepared as required by law.

(b) When a final EIR has been prepared and processed according to Article 7, beginning with Section 15080 of the State CEQA Guidelines, the decision-maker shall, prior to making a decision on the project, certify that the final EIR has been completed in compliance with CEQA and the State CEQA Guidelines, and shall review and consider the information contained in the final EIR. Based upon information contained in the final EIR, when the decision-maker finds that the project will have a significant effect on the environment, the decision-maker shall state in writing reasons to support its decision to approve or carry out the project based upon information contained in the final EIR or other information contained in the record.

Section 9. Mitigation Reporting and Monitoring Program.

When approving projects for which mitigation measures are required and adopted, the decision maker shall adopt as part of the approval action a "Mitigation Reporting and Monitoring Program", pursuant to Section 21081.6 of CEQA and Section 15097 of the State CEQA Guidelines, for the changes to the project. The "Mitigation Reporting and Monitoring Program", then becomes a condition of approval to mitigate or avoid significant effects on the environment. Failure of the project applicant to comply with the reporting requirements and mitigation measures are grounds for permit revocation or correcting the effects on the environment at the project applicant's cost.

The decision maker may require the applicant to deposit an amount of money estimated to offset the cost of monitoring the development and operation of the project into an interest bearing account in the Kings County

Treasury. Upon completion of the monitoring program any unused money in the account shall be returned to the applicant.

Section 10. Notice of Determination.

After making a decision on a project, the decision-maker shall cause to be filed a Notice of Determination, pursuant to Section 21080.4 of CEQA and 15094 of the State CEQA Guidelines. Such notice shall include a brief description of the project, the decision of the decision-maker to approve (carry out) or disapprove (not carry out) the project, the determination of the decision-maker whether the project will or will not have a significant effect on the environment, and a statement whether an environmental impact report has been prepared. The Planning Division of the Community Development Agency shall ensure that such notices are filed.

Section 11. Duties of the County Clerk.

All notices submitted to the County Clerk pursuant to CEQA shall posted by the County Clerk at the place designated by the County Clerk for the posting of all official notices. Members of the general public requesting copies of said notices shall be charged for the actual cost of reproducing that copy. The County Clerk shall prepare and maintain a list of the names and mailing addresses of all persons requesting review of a particular notice.

Section 12. Severability.

If any provision of these Local Guidelines or the application thereof to any person or circumstances is held invalid, such invalidity shall not affect other provisions or applications of these Local Guidelines which can be given effect without the invalid provision of application thereof, and to this end the provisions of these Local Guidelines are severable.

END OF GUIDELINES

ATTACHMENT V

Notice of Exemption

TO: ☐ Office of Planning and Research

For U.S. Mail
P.O Box 3044, Room 113
Sacramento, CA 95812-3044

Street Address
1400 Tenth St.
Sacramento, CA 95814

☒ County Clerk
County of Kings
Kings County Government Center
Hanford, California 93230

FROM: Kings County Community Development Agency
Kings County Government Center
Hanford, CA 93230

ORIGINAL FILED
DEC 07 2023
KRISTINE LEE
KINGS COUNTY CLERK

PROJECT TITLE:
Site Plan Review No. 23-14 (Felicita Dairy)

PROJECT APPLICANT:
4-Creeks, Cole Martin, 324 S. Santa Fe St., Visalia, CA 93292
(559) 802-3052

PROJECT LOCATION - Specific:
22154 4th Ave.

PROJECT LOCATION - City
Hanford

PROJECT LOCATION - County:
Kings

DESCRIPTION OF PROJECT:
The applicant is proposing to construct a new anaerobic digester and ancillary equipment at the existing Felicita Dairy, located at 22154 4th Ave., Hanford, Assessor's Parcel Number 028-280-011. The proposed application includes the installation of a 360' L x 175' W x 25' D anaerobic digester and ancillary equipment. The biogas produced by the digester is proposed to be transported through a low-pressure pipeline to an onsite biogas conditioning pad for cooling and compression prior to entering the biogas collection line. It will then be transported to a centralized biogas upgrading facility, located on Assessor's Parcel Number 228-090-009 in Tulare County (Tulare County Special Use Permit No. PSP 18-015), for conditioning and electrical generation.

NAME OF PUBLIC AGENCY APPROVING PROJECT:
Kings County Community Development Agency, 1400 W. Lacey Blvd., Building 6, Hanford, CA 93230, (559) 852-2670

NAME OF PERSON OR AGENCY CARRYING OUT PROJECT:
Gerrit DeJong, Felicita Dairy, 22154 4th Ave., Hanford, CA 93230, (559) 992-3272

EXEMPT STATUS: *(check one)*

☒ Ministerial (Section 21080(b)(1); 15268);
☐ Declared Emergency (Section 21080(b)(4); 15269(a));
☐ Emergency Project (Section 21080(b)(4); 15269(b)(c));
☐ Categorical Exemption. State type and section number: ______________________
☐ Statutory Exemptions. State code number: ______________________

REASONS WHY PROJECT IS EXEMPT:
Section 4.G.1. of the *Kings County Local Guidelines to Implement CEQA* lists Site Plan Review as a Ministerial Project pursuant to Section 15268 of the *Guidelines for California Environmental Quality Act.*

CONTACT PERSON:
Noelle Tomlinson

TELEPHONE NUMBER:
(559) 852-2697

Signature: Noelle Tomlinson
Title: Planner
Date: 12/7/23

Clerk/Recorder,, Kristine Lee

Date: 12/07/2023 09:09 AM

Kings County

Receipt Detail

Receipt Information

Receipt Time:	12/7/2023 9:08:18 AM	**Receipt #:**	19471		
Location:	MAIN OFFICE	**Department:**	REAL ESTATE	**Device:**	VIRGINIA DENKER
Effective Date:		**User:**	R069		
Customer:	4-CREEKS COLE MARTIN				
Address1:					
Address2:					
City:		**State:**		**Zip:**	
Phone:		**Email Address:**			
Remarks:					
Change Issued:	$0.00	**Refund:**	$0.00	**Surplus:**	$0.00
Cash Total:	$0.00	**Check Total:**	$70.00	**Escrow Total:**	$0.00
VoucherTotal:	$0.00	**Credit Card Total:**	$0.00	**Legalease Total:**	$0.00

Revenue Information

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Payment Information

#	Type	Payment ID #	Amount	NSF
1	CHECK	5001	$70.00	

Revenue Detail Information

Seq #	GL Seq	Revenue Account #	Amount	Payment #	Payment Type	Amount Paid	Amount Remaining
1	1	DFW CLERK FILING FEE	$70.00	1	CHECK		

Account Transaction Information

Account #	Revenue #	GL Seq	Amount	Transaction Type	Reference #	Transaction Time

ATTACHMENT W

Notice of Exemption

TO: ☐ Office of Planning and Research

For U.S. Mail	*Street Address*
P.O Box 3044, Room 113	1400 Tenth St.
Sacramento, CA 95812-3044	Sacramento, CA 95814

☒ County Clerk
County of Kings
Kings County Government Center
Hanford, California 93230

FROM: Kings County Community Development Agency
Kings County Government Center
Hanford, CA 93230

ORIGINAL FILED
MAY 15 2023
KRISTINE LEE
KINGS COUNTY CLERK

PROJECT TITLE:
Site Plan Review No. 22-16 (Countryside Dairy)

PROJECT APPLICANT:
Lauren Duggan, 2711 Meadow View Dr. suite 100 Redding CA 96002

PROJECT LOCATION - Specific:
21256 4th Ave

PROJECT LOCATION - City
Corcoran

PROJECT LOCATION - County:
Kings

DESCRIPTION OF PROJECT:
The applicant is proposing to establish a covered anaerobic digester and ancillary biogas cleanup equipment incidental to an existing dairy facility, Countryside Dairy, located at 21256 4th Ave, Corcoran Assessor's Parcel Number 028-280-018. There are two proposed options for the cleanup equipment – Option A (Trucking Biogas) and Option B (Piping Biogas).

NAME OF PUBLIC AGENCY APPROVING PROJECT:
Kings County Community Development Agency

NAME OF PERSON OR AGENCY CARRYING OUT PROJECT:
David & Arlene Bakker, Lauren Duggan, Maas Energy, 2711 Meadow View Dr. suite 100 Redding CA 96002 (530) 710-8545

EXEMPT STATUS: (*check one*)

☒ Ministerial (Section 21080(b)(1); 15268);
☐ Declared Emergency (Section 21080(b)(4); 15269(a));
☐ Emergency Project (Section 21080(b)(4); 15269(b)(c));
☐ Categorical Exemption. State type and section number: ____________
☐ Statutory Exemptions. State code number: ____________

REASONS WHY PROJECT IS EXEMPT:
Section 4.G.1. of the *Kings County Local Guidelines to Implement CEQA* lists Site Plan Review as a Ministerial Project pursuant to Section 15268 of the *Guidelines for California Environmental Quality Act.*

CONTACT PERSON:
Alex Hernandez

TELEPHONE NUMBER:
(559) 852-2679

Alex Hernandez

Signature: Alex Hernandez
Title: Deputy Director - Planning
Date: 05/15/23

KINGS COUNTY CLERK-RECORDER
1400 W. LACEY BLVD.
HANFORD, CA 93230
(559) 582-3211 X2470

Receipt Time: 05/15/2023 12:26:35 PM   Receipt #: 8153
Issued To: LAUREN DUGGAN

Documents

#	Type	# Pages	Quantity	Reference #	Book / Page	Amount
1	NOTICE OF EXEMPTION	1	1	NA-15413505		$65.00
					Total :	$65.00

Payments

#	Type	Payment #		Amount	NSF
1	CHECK	11123		$65.00	
			Total Payments:	$65.00	

SITE PLAN REVIEW NO. 22-16 (COUNTRYSIDE DAIRY)

THANK YOU!
R066

Clerk-Recorder,, Kristine Lee
Kings County
Receipt Detail

Date: 05/15/2023 12:36 PM

Receipt Information

Receipt Time:	5/15/2023 12:26:35 PM	**Receipt #:**	8153		
Location:	MAIN OFFICE	**Department:**	REAL ESTATE	**Device:**	ALEJANDRA ESPINOZA
Effective Date:		**User:**	R066		
Customer:	LAUREN DUGGAN				
Address1:	2711 MEADOW VIEW DR				
Address2:	SUITE 100				
City:	REDDING	**State:**	CA	**Zip:**	96002
Phone:		**Email Address:**			
Remarks:	SITE PLAN REVIEW NO. 22-16 (COUNTRYSIDE DAIRY)				
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VoucherTotal:	$0.00	**Credit Card Total:**	$0.00	**Legalease Total:**	$0.00

Revenue Information

Seq #	No Fee	Voucher	Reference #	Transaction Type	# Pages	Amount	SubSystem Id
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Payment Information

#	Type	Payment ID #	Amount	NSF
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Revenue Detail Information

Seq #	GL Seq	Revenue Account #	Amount	Payment #	Payment Type	Amount Paid	Amount Remaining
1	1	DFW CLERK FILING FEE	$65.00	1	CHECK		

Account Transaction Information

Account #	Revenue #	GL Seq	Amount	Transaction Type	Reference #	Transaction Time

ATTACHMENT X

So. Tulare Biogas Gathering Line

Summary

SCH Number
2020080277

Public Agency
Tulare County

Document Title
So. Tulare Biogas Gathering Line

Document Type
NOE - Notice of Exemption

Received
8/18/2020

Posted
8/18/2020

Document Description
CalBioGas South Tulare LLC proposes to construct 8.8 miles of a pressurized underground gas pipeline within portions of the County of Tulare rights-of-way of Roads 96, 128, 132 and 152; Avenues I84, 192 and 208; and Spacer Drive D 134), south of the City of Tulare. The intent of the project is to transport dairy biogas from participating dairies to a Southern California Gas Company mainline tie-in facility. The scope of the project consists of the installation of HDPE PE4710 SDR 11 gas pipeline and concomitant safety equipment along the 8.8-mile alignment. On August 18, 2020, the Tulare County Board of Supervisors approved an indemnification agreement to allow some segments of the underground pipeline to utilize County rights-of-way within easements along or across public roadways. All of Tulare County will benefit as the Project would recover manure methane at dairies and using the methane as a renewable source of natural gas thereby reducing greenhouse gas emissions.

Contact Information

Name
Hector Guerra

Agency Name
Tulare County Resource Management Agency

Contact Types
Lead/Public Agency

Address

5961 South Mooney Blvd
Visalia, CA 93277

Phone

(559) 624-7000

Email

hguerra@co.tulare.ca.us

Name

Agency Name

CalBioGas South Tulare LLC

Contact Types

Project Applicant

Location

Counties

Tulare

Township

21,20S

Range

24,25E

Section

multi

Other Location Info

Section Various, Township 21 and 20 S, Range 24 and 25 E of the Lake View School, Tipton, Tulare, and Cairn's Corner USGS 7 ½ minute quadrangles

Notice of Exemption

Exempt Status

Categorical Exemption

Type, Section or Code

Sec. 15301, Class 1, and Sec. 15303, Class 3

Reasons for Exemption

The Project will not involve any new developments or changes to existing land uses, nor are any proposed, there will be no additional vehicular trips generated as a result of the proposed Activity/Project. The Activity/Project will result in no adverse impact to the environment including aesthetics, air quality, agriculture, biology, cultural, greenhouse gases, hazards/hazardous materials, land use/planning, noise, public services, traffic, or utilities/service systems. Furthermore, the proposed Project site will be required to comply with applicable San Joaquin Valley Unified Air District rules and regulations, including but not limited to, Rule 2010 (Permits Required), Rule 2201 (New and Modified Stationary Source Review), and Rule

9510 (indirect Source Review). The Activity/Project will result in reduction of methane-related GHG by using methane gas emissions from the dairies as an alternative/renewable fuel source, is consistent with draft Tulare County Dairy Climate Action Plan (which incorporates strategies to promote the use of renewable energy sources, including digesters for energy-production), and is also consistent with and implements the California Environmental Protection Agency Air Resources Board's Short-Lived Climate Pollutant Reduction Strategy March 2017; Methane Emissions Reductions from Dairy Manure. As the equipment modification will occur at an existing site and pipelines for this Activity/Project will remain within County of Tulare Rights-of-Way, this action is consistent with 14 Cal. Code Regs. Section 15301 (b) Existing facilities or both investor and public owned utilities used to provide electric power, natural gas, sewerage, or other public utility services and; 14 Cal. Code Regs. Section 15303(d) Water main, sewage, electrical gas, and other utility extensions, including street improvements, or reasonable length to serve such construction. Therefore, the use of CEQA Guidelines Sections 1530l (b) and 15303 (d), as noted above, are applicable and appropriate for this Activity/Project.

Attachments

Notice of Exemption

NOE_S Tulare Biogas Gathering Line_ocr PDF 464 K

ATTACHMENT Y

SB 535 Disadvantaged Communities

CalEnviroScreen Training Videos
SB 535 Disadvantaged Communities

California Climate Investments to Benefit Disadvantaged Communities

Disadvantaged communities in California are specifically targeted for investment of proceeds from the state's Cap-and-Trade Program. These investments are aimed at improving public health, quality of life and economic opportunity in California's most burdened communities, and at the same time, reducing pollution that causes climate change. The investments are authorized by the California Global Warming Solutions Act of 2006 (Assembly Bill 32, Nunez, 2016).

In 2012, Senate Bill (SB) 535 (De León, Chapter 830, Statutes of 2012) established initial requirements for minimum funding levels to "Disadvantaged Communities" (DACs). The legislation also gives CalEPA the responsibility for identifying those communities, stating that CalEPA's designation of disadvantaged communities must be based on "geographic, socioeconomic, public health, and environmental hazard criteria".

In 2016, Assembly Bill (AB) 1550 (Gomez, Chapter 369, Statutes of 2016) directed CalEPA to identify DACs and also established the currently applicable minimum funding levels:

- At least 25 percent of funds must be allocated toward DACs
- At least 5 percent must be allocated toward projects within low-income communities or benefiting low-income households
- At least 5 percent must be allocated toward projects within and benefiting low-income communities, or low-income households, that are outside of a CalEPA-defined DAC but within ½ mile of a disadvantaged community.

Final Designation of Disadvantaged Communities (May 2022)

English | En Español

After receiving public input at workshops and in written comments, in May 2022, CalEPA released its updated designation of disadvantages communities for the purpose of SB 535. In this designation, CalEPA formally designated four categories of geographic areas as disadvantaged:

1. Census tracts receiving the highest 25 percent of overall scores in CalEnviroScreen 4.0 (1,984 tracts).
2. Census tracts lacking overall scores in CalEnviroScreen 4.0 due to data gaps, but receiving the highest 5 percent of CalEnviroScreen 4.0 cumulative pollution burden scores (19 tracts).
3. Census tracts identified in the 2017 DAC designation as disadvantaged, regardless of their scores in CalEnviroScreen 4.0 (307 tracts).
4. Lands under the control of federally recognized Tribes. For purposes of this designation, a Tribe may establish that a particular area of land is under its control even if not represented as such on CalEPA's DAC map and therefore should be considered a DAC by requesting a

consultation with the CalEPA Deputy Secretary for Environmental Justice, Tribal Affairs and Border Relations at TribalAffairs@calepa.ca.gov.

The designation takes into account the latest and best available data and considers factors related to data unavailability. This designation will go into effect on July 1, 2022, at which point programs funded through California Climate Investments will use the designation in making funding decisions.

Disadvantaged Communities Map

Click to open this map in a new window

CalEPA California Environmental Protection Agency SB 535 Disadva CalEPA... CalEnv... A... m

State's Cap-and-Trade Program specifically targeted for investment in disadvantaged communities in California. These funds must be used for programs that further reduce emissions of greenhouse gases.

Senate Bill 535 (De León, Statutes of 2012) directed that at least a quarter of the proceeds go to projects that provide a benefit to disadvantaged communities and at least 10 percent of the funds go to projects located within those communities. The legislation gives CalEPA the responsibility for identifying those communities.

How to use this map

- Use your mouse or touchpad to pan around.
- Zoom in/out with a mouse wheel or the +/- icons.
- Search by location or census tract number with the **search icon**.
- Click on a census tract to view additional information in the pop-up window.
- Dock the pop-up window to the side of the screen by clicking the **dock** icon.
- Export a map view that includes the legend and popup using the **screenshot** widget.
- Click the links in the header to view additional resources related to SB 535 Disadvantaged Communities.

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SB 535 Disadvantaged Communities 2022 (Census Tracts and Tribal Areas)

E Powerec

Download SB 535 CalEnviroScreen Data

In addition to the interactive map above, SB 535 disadvantaged communities data is available for download in other formats:

- SB 535 Excel Spreadsheet and data dictionary (May 2022). There are two files in this zipped folder. 1) a spreadsheet showing the list of census tracts identified as disadvantaged communities, a list of the Federally recognized tribal areas identified as disadvantaged communities, and the raw data and calculated percentiles for individual indicators and combined CalEnviroScreen scores for census tracts identified as disadvantaged communities. 2) a pdf document including the data dictionary.
- SB 535 ArcGIS Geodatabase (May 2022): A zipped file which can be unzipped, then opened using ArcGIS software to view the results. (ArcGIS is a paid subscription)

Service URL: ArcGIS feature service:
https://services1.arcgis.com/PCHfdHz4GlDNAhBb/arcgis/rest/services/SB_535_

Additional information as well as the previous identification of disadvantaged communities from 2017 using CalEnviroScreen 3.0 is available on the CalEPA page.

For questions, please contact CalEnviroScreen@oehha.ca.gov or (916) 324-7572.

Documents

- SB 535 List of Disadvantaged Communities (2022) Spreadsheet and Data Dictionary
- SB 535 List of Disadvantaged Communities (2022) Geodatabase

Cal EPA

- Air Resources Board
- Cal Recycle
- Department of Pesticide Regulation
- Department of Toxic Substances Control
- State Water Resources Control Board

Alerts

- Amber Alert
- Cal Alerts
- My Hazards

About

- Governor
- Lt. Governor
- California Data

Campaigns

- Register to Vote
- Save Our Water
- Flex Alert

Select Language ▼

Gavin Newsom
California Governor
Website

Yana Garcia
Secretary for Environmental Protection
Website

Lauren Zeise
Director
Website

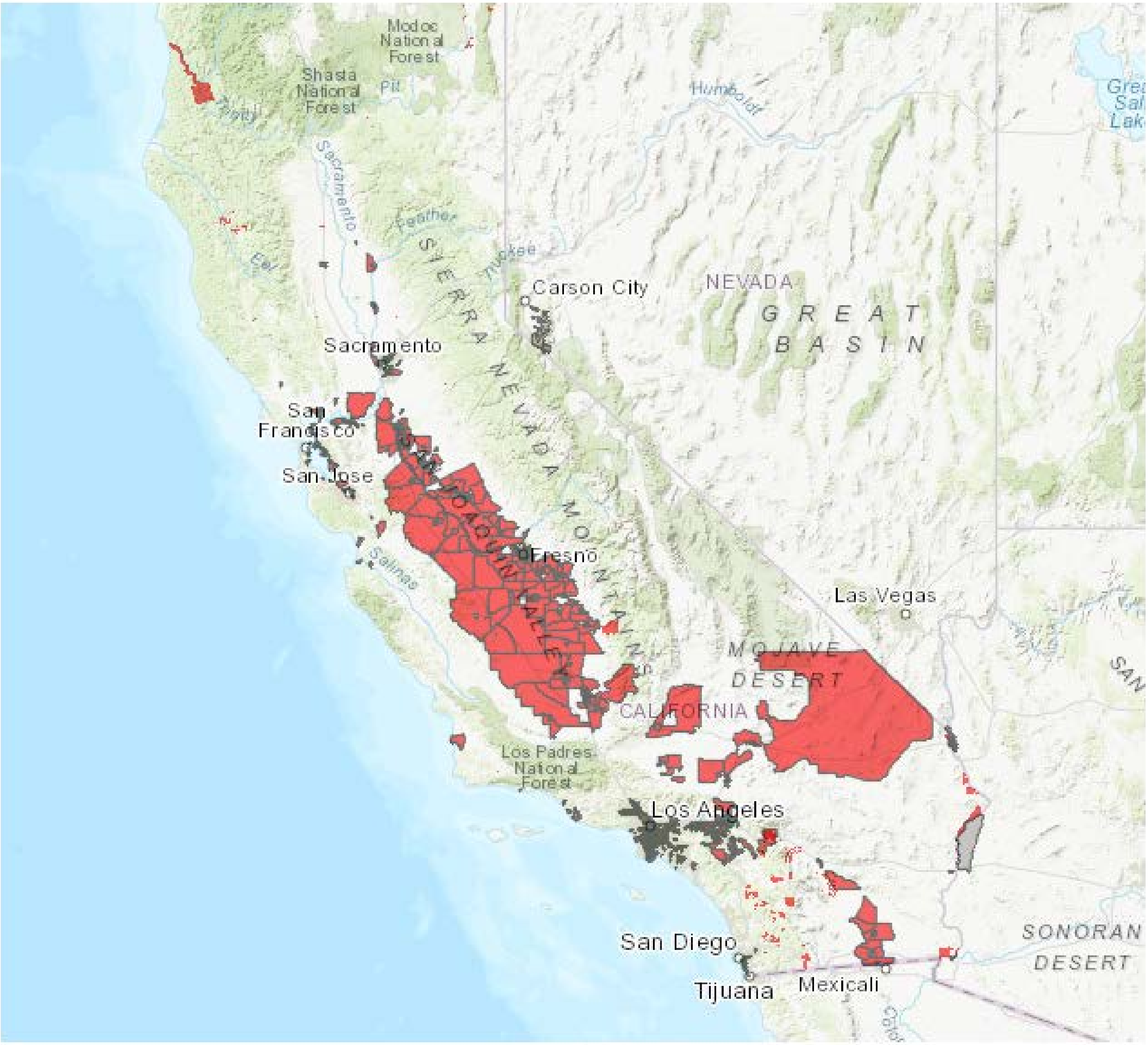
Conditions of Use/Privacy Policy

Accessibility

Help

Site Map

SB 535 Map



SB 535 Disadvantaged Communities 2022 (Census Tracts and Tribal Areas)

ATTACHMENT Z

Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target

Final

March 2022

CALIFORNIA AIR RESOURCES BOARD

Table of Contents

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Executive Summary

California took a major step toward reducing greenhouse gas (GHG) emissions and combatting climate change when the Legislature enacted Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), which requires the State to reduce GHG emissions to 1990 levels by 2020. California achieved this target in 2016, four years earlier than mandated. To achieve deeper reductions, the Legislature enacted Senate Bill (SB) 32 (Pavley, Chapter 249, Statutes of 2016), which requires the State to further reduce GHG emissions to 40 percent below 1990 levels by 2030. In the same year, the Legislature enacted SB 1383 (Lara, Chapter 395, Statutes of 2016), which recognizes the immediate climate benefits of reducing short-lived climate pollutants (SLCP). In the 2017 Scoping Plan Update, the plan for achieving GHGs reductions in the State, the California Air Resources Board) CARB describes that short lived climate pollutant (SLCP) reductions account for about one-third of the cumulative GHG emissions reductions the State is relying on to achieve the statewide 2030 GHG emissions target established under SB 32.

Short-lived climate pollutants, including methane, are powerful climate forcers that have a relatively short atmospheric lifetime, but a high global warming potential compared to other GHGs such as carbon dioxide. SB 1383 establishes SLCP reduction targets and requires CARB to implement a Short-Lived Climate Pollutant Reduction Strategy (Strategy) to achieve these targets. The law sets a 2030 methane emissions reductions target for the dairy and livestock sector (2030 target), which produces more than half of the State's methane emissions. This target is a reduction of 40 percent below 2013 levels, or a reduction of 9 million metric tons carbon dioxide equivalent ($MMTCO_2e$)[1] by 2030. SB 1383 also requires CARB, in consultation with the California Department of Food and Agriculture (CDFA), to analyze the progress that the sector has made toward achieving the 2030 reduction target and achieving the goals identified in the SLCP Strategy, including progress made in overcoming technical and market barriers to implementing methane emissions reductions measures identified in the Strategy. This Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target (Analysis) is responsive to that mandate.

Dairy and livestock methane emissions originate from two primary sources, manure management and enteric fermentation. Manure methane emissions can be reduced through two primary methods—installation of an anaerobic digester and alternative

[1] This emissions reduction estimate is calculated using the 100-year global warming potential (GWP) for methane (IPCC, 2007: Climate Change 2007: Synthesis Report; Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, Pachauri, R.K and Reisinger, A. (eds.)]; IPCC, Geneva, Switzerland, 104 pp (AR4)). The Short-Lived Climate Pollutant Reduction Strategy estimated emissions using the 20-year GWP (AR4).

manure management practices. Anaerobic digesters capture methane-rich biogas for beneficial uses, including in electricity generation and fossil natural gas displacement. Alternative manure management practices reduce manure methane emissions in ways that do not involve an anaerobic digester. Examples include solid separation, conversion to dry scrape, and pasture-based management. Both digester and alternative manure management practices reduce GHG emissions and can improve water quality and nutrient management. Enteric methane emissions can be reduced through genetic selection, diet modification, and feed additives.

This Analysis shows that the dairy and livestock sector is projected to achieve just over half of the annual methane emissions reductions necessary to achieve the target by 2030 through modifications to manure management systems—primarily using anaerobic digesters—and additional reductions through decreases in animal populations. Figure ES-1 shows significant emissions reductions through 2030 absent additional funding after fiscal year 2019-20.[2]

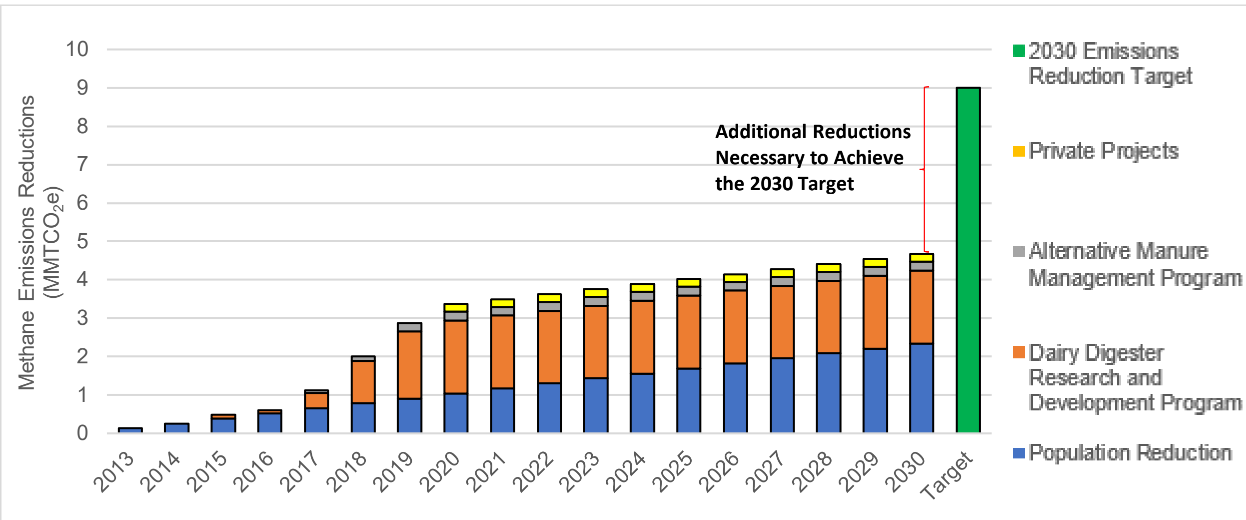

Figure ES-1. Projected Annual Methane Emissions Reductions through 2030 without Additional Funding beyond FY 2020-21

To meet the 2030 target, the dairy and livestock sector will need to achieve considerable emissions reductions from additional manure management projects, proven enteric mitigation strategies, or a combination of both over the next few years.

To understand what level of resources are needed to achieve the target, CARB staff looked at existing dairy methane emissions reduction efforts, including both grant

[2] This does not include $32 million in FY 2021-22 appropriations because it is uncertain how these appropriations will be allocated.

programs that fund the initial capital costs and market-based programs that incentivize GHG emissions reductions or low carbon fuel production.

Over the past six years, California Climate Investments (CCI)—the program that utilizes the State's Cap-and-Trade Program auction proceeds to facilitate GHG emissions reductions—has offset some capital costs through two CDFA grant programs to reduce manure methane emissions: the Dairy Digester Research and Development Program and the Alternative Manure Management Program. An approximate appropriation of $289 million in CCI funds has facilitated the construction of 233 dairy and livestock GHG emissions reduction projects. Many of these manure methane reduction projects are also generating environmental credits through CARB's Cap-and-Trade Program, Low Carbon Fuel Standard (LCFS) Program, and the federal Renewable Fuel Standard (RFS) Program. These projects, cumulatively funded through FY 2019-20, are expected to deliver the 2.0 $MMTCO_2e$ in annual methane emissions reductions noted above from manure management systems by 2030, or about 22 percent of the reductions necessary to achieve the 2030 target.

New or expanded local, State, or federal incentives or funding mechanisms could potentially accelerate the capture and beneficial use of California biomethane, provide additional revenue necessary to ensure that California's dairy manure methane emissions are captured, and direct the biogas to difficult-to-decarbonize sectors. Replacing fossil natural gas with upgraded dairy biogas (biomethane) or other alternatives is important for California's near and longer-term climate goals, but the cost to procure biomethane can be six to ten times more expensive than fossil natural gas. This cost disparity is almost entirely associated with the cost of bringing biomethane to market and will likely persist into the future. This is one of the primary reasons incentives are needed for California's dairy and livestock sector to adopt methane reduction strategies that also support the transition away from fossil natural gas supplies. Additional funding could also accelerate the adoption of alternative manure management projects. These projects provide climate benefits through avoided methane production and environmental co-benefits including water quality improvements and conservation, reduction of synthetic fertilizer usage and improvement of nutrient management, as well as groundwater protection.

Through coordinated State, industry, and utility efforts, the dairy and livestock sector has made meaningful progress in overcoming technical barriers to digester projects, interconnecting to utility electrical grids and pipeline networks, and meeting biomethane pipeline injection standards. Improved environmental credit certainty has also reduced the most considerable market barriers to digester projects by helping project developers obtain funding and financing. Challenging sector economics, insufficient availability of public funds, and underdeveloped markets for value-added manure products are persistent market barriers for both digester and alternative manure management projects. There has been limited progress in overcoming technical barriers to alternative manure management practices because emissions reductions vary based on site-specific factors. There has also been limited progress in overcoming both technical and market barriers to enteric reductions. Enteric methane-reducing feed additives may achieve considerable near-term emissions reductions. There are two commercially available products that were developed for enteric methane mitigation, with potential emissions reductions up to 10-20 percent. Additional feed additives are under development that may provide larger enteric methane emissions reductions.

Despite progress in overcoming barriers, there is more to do to ensure that the State meets the 2030 target. Remaining barriers may be overcome through multiple reasonable efforts, including allocation of additional local, State, or federal funding or incentives. If the remaining reductions needed to achieve the 2030 target are met through a mix of California dairy projects in which half are dairy digesters and half are alternative manure management projects, then at least 420 additional projects may be necessary. This approach would cost an amount between $0.8 and $3.7 billion, which could be supported by local, State, and federal funding, or other financial mechanisms, such as the pilot financial mechanism outlined in SB 1383.[3] If, going forward, only digester projects were developed to achieve the target, approximately 230 additional digesters may be needed, at a cost between $0.7 and $3.9 billion depending on the types of technologies selected. For example, prioritizing deploying digesters with internal combustion engines is the lowest-cost option ($0.7 billion) to achieve the 2030 target, but this would result in on-site criteria pollutant emissions. Alternatively, deployment of digesters that utilize fuel cell technology may avoid these emissions, but at a significantly higher cost ($3.9 billion). Finding 1-6 of this Analysis describes project types, technologies, and cost ranges. With respect to alternative manure management practices, based on currently funded projects and reduction trends observed to date, staff's analysis indicates that the State would be unable to achieve the 2030 dairy and livestock sector target through deployment of alternative manure management practices alone. A combination of dairy digesters, alternative manure management, enteric strategies, and dairy herd size population decreases will be needed to meet the 2030 target.

[3] On February 24, 2022, the California Public Utilities Commission approved Decision 22-02-025 adopting biomethane procurement standards pursuant to SB 1440 (Hueso, Chapter 739, Statutes of 2018), including procurement of biomethane from the California dairy and livestock sector.

Regardless of the project and technology mix used, the most important factors for achieving the 2030 target are ongoing capital funding for new methane emissions reduction projects, continued revenue streams that incentivize dairy biogas capture and beneficial use, and an available and accepted means of reducing enteric methane emissions. Even with considerable progress toward achieving the target since the enactment of SB 1383, the statute requires CARB to adopt a regulation to meet the target, provided that certain conditions are met. Further, CARB is only authorized to implement regulations to meet the 2030 target after January 1, 2024, provided that CARB, in consultation with CDFA, determine the regulations are technologically and economically feasible, cost-effective, include provisions to minimize and mitigate potential leakage, and include an evaluation of the achievements made by incentive-based programs. In designing a regulation for methane emission reductions, CARB staff will consider reasonable strategies to support the sector in meeting the 2030 target, which may include strategies that further support biogas capture and end-uses needed to advance the State's carbon neutrality efforts.

While the California dairy and livestock sector has made significant progress, it must still achieve considerable methane emissions reductions to meet the 2030 target. This will require implementation of additional methane emissions reductions strategies, and continued collaboration among agencies and other stakeholders. In addition, CDFA plans to convene a working group to address market development barriers for facilitate value-added manure products. CARB will continue to track progress of methane emission reductions project funding and outcomes, manure management and enteric methane reduction options, and will evaluate progress in the 2022 Scoping Plan Update.

Introduction

California has long championed environmental protection, and the State has made significant investments and efforts to decarbonize its economy. In 2006, the Legislature passed and the Governor signed the California Global Warming Solutions Act. Assembly Bill (AB) 32 (Núñez, Chapter 488, Statutes of 2006) requires the State to reduce greenhouse gas (GHG) emissions to 1990 levels by 2020. It also tasked the California Air Resources Board (CARB or Board) with developing a climate change scoping plan that details how the State will achieve its climate target and requires CARB to periodically update the plan. The Board adopted the first Climate Change Scoping Plan in December 2008 and updated this plan in 2013 and 2017.

Through aggressive pursuit of regulatory and voluntary GHG emissions reduction measures across economic sectors, California GHG emissions fell below 1990 levels in 2016, 2017, 2018, and 2019. Acknowledging the need to make deeper GHG emissions reductions to help slow climate change, the Legislature passed Senate Bill (SB) 32 (Pavley, Chapter 249, Statutes of 2016), which requires the State to reduce GHG emissions to 40 percent below 1990 levels by 2030. Figure 1 shows these GHG emissions reduction targets as well as the State's additional goal to reduce GHG emissions by 80 percent below 1990 levels by 2050.[4] Meeting these emissions reduction targets will be critical as California strives to achieve another goal – reaching carbon neutrality by 2045.[5] The Intergovernmental Panel on Climate Change (IPCC) has acknowledged carbon neutrality as necessary to limit global warming to 1.5 degree Celsius or less, the goal set by the international Paris Agreement on climate.

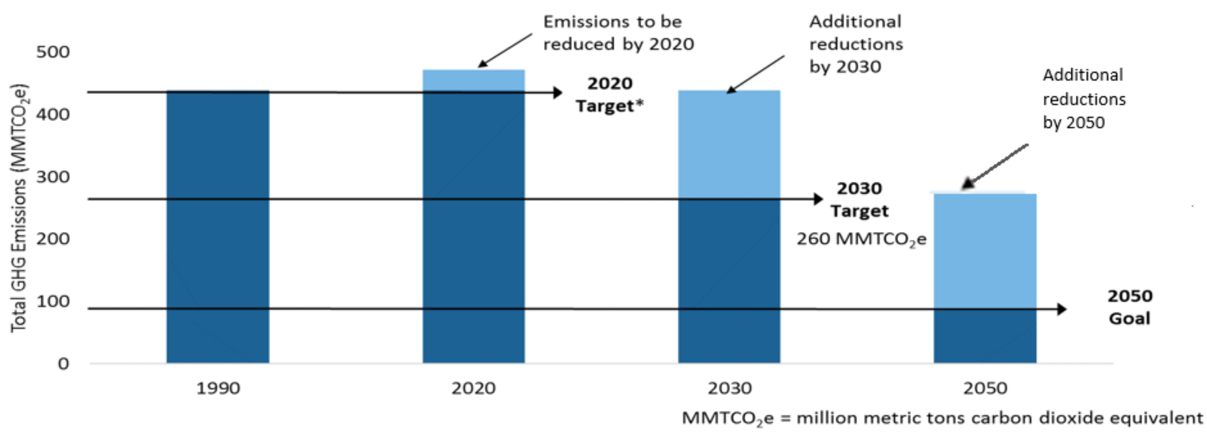

Figure 1. California GHG Emissions Reduction Targets and Goal through 2050

[4] Executive Order S-3-05.
[5] Executive Order B-55-18.

The Legislature also took action to limit emissions of short-lived climate pollutants (SLCP), which are powerful climate forcers that have relatively short atmospheric lifetimes but high global warming potentials (GWP). As a result, SLCP emissions reductions achieved now can have an immediate beneficial impact on climate change. Methane, a powerful SLCP, stays in the atmosphere for approximately a decade before being converted to carbon dioxide.[6] The effect of methane on climate change is 25 times stronger than that of carbon dioxide using the 100-year GWP (GWP 100), and 75 times stronger than carbon dioxide using the 20-year GWP (GWP 20).

CARB uses GWP 100 to quantify statewide methane emissions for inventory and regulatory purposes. GWP 100 is the standard for inventory development and aligns with IPCC and US Environmental Protection Agency (EPA) methods, allowing for comparison of the state inventory with other sub-national and international inventories through common methodologies and requirements for accuracy.

In 2014, the Legislature passed SB 605 (Lara, Chapter 523, Statutes of 2014), which requires CARB to develop a strategy to reduce SLCP emissions in the State. In response, staff developed and the Board approved a comprehensive Short-Lived Climate Pollutant Reduction Strategy (Strategy). In 2016, the Legislature passed SB 1383 (Lara, Chapter 395, Statutes of 2016), which requires CARB to approve and begin implementing the Strategy, and establishes a requirement, among others, for different SLCPs[7] to meet methane emissions reduction targets. More specifically, SB 1383 requires the California dairy and livestock sector to reduce methane emissions from enteric fermentation and manure management to 40 percent below 2013 levels by 2030. It also requires CARB, in consultation with the California Department of Food and Agriculture (CDFA), to adopt regulations to achieve this mandate if certain conditions are met. Specifically, SB 1383 intends to prioritize the use of voluntary and incentive-based measures to achieve those reductions before regulations are implemented. To achieve that end, the law calls for several specific efforts to incentivize reductions, including requiring CARB to work with stakeholders to identify and address technical, market, regulatory, and other challenges and barriers to development of dairy methane emissions reduction projects. Further, CARB is only

[6] While methane itself is not considered a toxic air contaminant, it is a large component of biogas, which may contain a mixture of gases including some toxic air contaminants like hydrogen sulfide. Removing these toxic air contaminants can reduce potential health impacts associated with the processing, transportation, and use of biogas streams.

[7] SB 1383 requires the reduction in the statewide emissions of methane by 40 percent, hydrofluorocarbon gases by 40 percent, and anthropogenic black carbon by 50 percent below 2013 levels by 2030. Additionally, the bill requires a 50 percent and 75 percent reduction in the level of the statewide disposal of organic waste from the 2014 level by 2020 and 2025, respectively. SB 1383 also sets a goal that not less than 20 percent of edible food that is currently disposed of is recovered for human consumption by 2025.

authorized to implement the regulations to meet the 2030 target after January 1, 2024, provided that CARB and CDFA determine the regulations are technologically and economically feasible, cost-effective, include provisions to minimize and mitigate potential leakage, and include an evaluation of the achievements made by incentive-based programs.

The Strategy put forward a path to achieve the SLCP emissions reduction goals established in SB 1383 in a way that provides both environmental and economic benefits to the State. Using the latest scientific and emissions information on SLCPs, it outlines the emissions reduction progress for specific SLCPs, potential options for additional reductions of these SLCPs, and strategies to achieve the respective emissions reduction targets. SLCP reductions are necessary to achieve the State's 2030 GHG emissions target, as described in the 2017 Scoping Plan Update, as well as the mid-century carbon neutrality goal. Notably, while some State programs incentivize dairy and livestock methane emissions reductions, no existing California programs directly require them or incentivize a sector-wide implementation of reduction measures. For example, CARB's Low Carbon Fuel Standard (LCFS) program provides some incentive for dairy operations to develop digesters and receive credits for biomethane production. However, on its own this program does not require operators to develop projects and through its credit system may not support statewide implementation of anaerobic digesters at dairies, and thus these emissions will not decrease without additional targeted programs or other interventions. In contrast, for the electricity and transportation sectors, the Cap-and-Trade Program acts as a backstop to ensure that GHG emissions reductions are achieved.

The Strategy describes a variety of manure management options that can provide the greatest methane emissions reduction potential, recognizing that not every option is feasible for each facility. The Strategy also recommends additional research to evaluate potential enteric methane emissions reduction options as well as the acceleration of early project development through incentives and market development. Prior to implementing regulations, incentives like California Climate Investments (CCI) allocations using Cap-and-Trade Program auction proceeds will encourage voluntary methane emissions reductions at dairies. The Strategy recognizes that implementing a variety of mitigation measures is necessary to achieve the 2030 target and will deliver significant reductions from the dairy and livestock sector while providing a variety of environmental and economic benefits.

Upon adoption of the Strategy and in compliance with SB 1383, CARB convened an interagency Dairy and Livestock Greenhouse Gas Emissions Working Group (Working Group) consisting of CARB, CDFA, California Energy Commission (CEC), and California

Public Utilities Commission (CPUC) principals. At the initial meeting in May of 2017, the Working Group convened three stakeholder subgroups composed of representatives and subject matter experts from State agencies, industry, academia, and the environmental justice community. The objective of these subgroups was to comply with SB 1383's requirement for CARB to work with stakeholders to identify and address barriers to dairy and livestock methane emissions reductions projects, and to develop actionable recommendations that State agencies could implement to help overcome these barriers.

Subgroup 1 provided recommendations to the Working Group to overcome barriers to non-digester manure management practices that focused on available and potential incentives, and developing value-added manure product markets. Subgroup 2 provided recommendations to the Working Group to overcome barriers to implementing livestock digester projects in California, along with a dairy digester emissions matrix that shows potential GHG and criteria pollutant emissions from dairy biogas use. Subgroup 3 focused on research needs related to dairy and livestock methane emissions reductions including enteric fermentation, and published a comprehensive Dairy Research Prospectus to Achieve California's SB 1383 Climate Goals, which outlines research concepts and needs to guide future funding of research projects in California. Over 18 months, the subgroups developed a set of Final Recommendations to the Dairy and Livestock Greenhouse Gas Reduction Working Group and presented them to the Working Group in December 2018. These recommendations outline potential solutions to overcome barriers to methane emissions reduction projects at California dairy and livestock operations and highlight innovative research on methane emissions reductions.

SB 1383 includes additional requirements on CARB to help provide market and environmental credit certainty to biogas-capturing anaerobic digester projects. These requirements, which CARB staff have fulfilled, include developing a white paper describing a potential pilot financial mechanism that, if implemented, could improve market stability for environmental credits from dairy digester projects. CARB, CDFA, and CPUC collaborated in selecting six dairy biomethane pipeline injection pilot projects to receive rate-recoverable infrastructure funding. Evaluating the factors that affect the cost and technical feasibility of these projects will help the State better understand and refine future incentives and regulatory measures. CARB staff also developed a frequently asked questions document discussing the potential impact that a dairy and livestock methane emissions reduction regulation would have on environmental credits generated under the LCFS Program and Cap-and-Trade Program.

Finally, SB 1383 requires CARB, in consultation CDFA, to analyze the progress that the sector has made toward achieving the 2030 target. This Analysis discusses the expected methane emissions reductions through 2022 and the estimated number of additional projects necessary to achieve the 2030 target. It also explores progress made in overcoming the technical and market barriers to implementing dairy and livestock methane emissions reductions projects.

Dairy and Livestock Sector Methane Emissions

In 2013, methane accounted for 40 million metric tons carbon dioxide equivalent ($MMTCO_2e$),[8] or approximately nine percent[9] of the State's GHG emissions (Figure 2). The dairy and livestock sector has been and continues to be the largest source of methane emissions in California, producing approximately 22 $MMTCO_2e$, or about 55 percent, of statewide methane emissions (Figure 3). Eighty percent of these emissions are from manure management and enteric fermentation at more than 1,300 dairies throughout the State. These dairies house more than 1.7 million milking cows and a similar number of replacement stock.[10]

Methane emissions at dairy and livestock operations come from two main sources—the animals themselves through enteric fermentation and manure management operations, especially at dairies. Enteric and manure emissions are both functions of cattle population, meaning that that more head of cattle there are, the higher the methane emissions. As a result, market dynamics such as changes in cost, revenue, or product demand can lead to fluctuations in methane emissions.

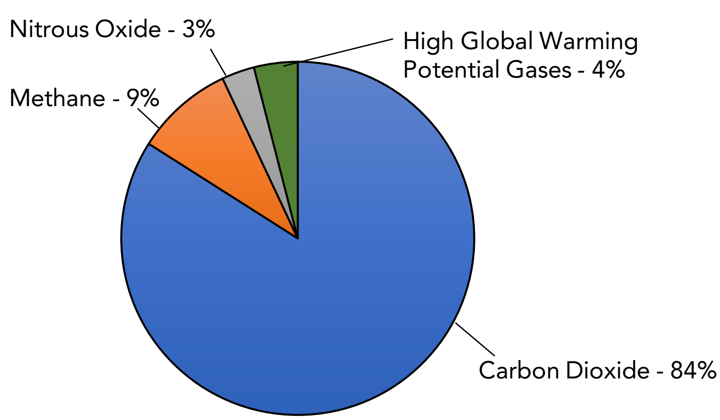

Figure 2. 2013 California GHG Emissions by Gas (Total 2013 Emissions~460 $MMTCO_2e$)

[8] 100-year GWP from IPCC AR4.
[9] California Greenhouse Gas Emissions for 2000 to 2017.
[10] California Agricultural Statistics Review 2018 to 2019.

The dairy and livestock sector has the potential to achieve significant methane emissions reduction from manure management operations at relatively low cost compared to other CCI-funded programs. Projects average $29 and $70 per $MMTCO_2e$ including both public and private funding for dairy digester and alternative manure management projects, respectively.[11,12] Enteric methane mitigation strategies also have important methane mitigation potential, but there is limited cost information available since only a few products are scientifically proven and commercially available.

Enteric fermentation is a natural digestive process that occurs within the digestive tract of ruminant animals such as cattle, sheep, and goats. In 2013, enteric fermentation emissions represented about 30 percent of California's total methane emissions (Figure 3), with two-thirds from dairy cows and the remaining one-third from other animal types. During the digestive process, microbes in the rumen decompose and ferment plant matter, which produces methane that ruminants subsequently emit, mostly through eructation (burping). A variety of factors influence enteric fermentation emissions including breed, diet, and the presence of feed additives, with the latter offering significant potential methane emissions reductions. In general, methane emissions from enteric fermentation can potentially be reduced through selective breeding, dietary modifications that improve milk production efficiency, and the introduction of methane-reducing feed additives.

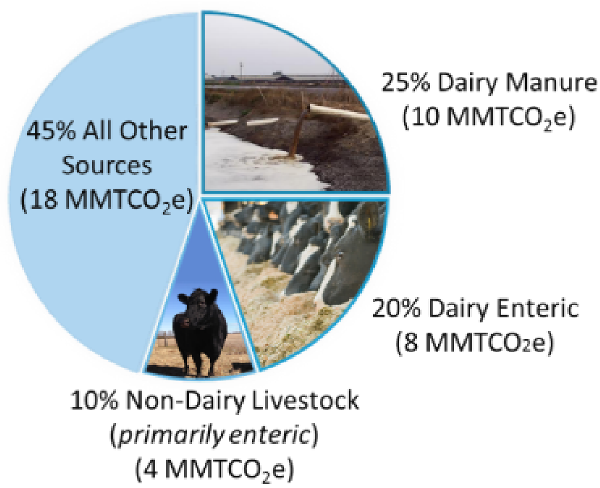

Figure 3. 2013 California Methane Emissions by Source

Anaerobic manure management and storage comprise the other main source of methane emissions at California dairy and livestock operations, accounting for about 25 percent of California's total methane emissions. Manure management systems that

[11] Dairy Digester Research and Development Report of Funded Project from 2015 to 2019.
[12] Alternative Manure Management Program Webpage.

treat or store manure under anaerobic conditions (i.e., those common to liquid manure management lagoons) are a large source of methane emissions. Anoxic manure treatment and storage conditions, common in manure settling basins and storage lagoons, are conducive to methanogenic bacteria producing methane from volatile solids. Methane emissions from anaerobic manure management can be mitigated through capture and destruction, or through avoidance of production.

Two types of projects—dairy digesters and alternative manure management projects—effectively reduce a significant amount of methane emissions from dairy and livestock operations. Dairy digesters involve installation of an anaerobic digester to capture biomethane produced from dairy waste for beneficial end-uses including but not limited to onsite electricity generation to offset facility needs, or delivery to the electrical grid. Upgraded biomethane that meets utility pipeline specifications set by the California Public Utilities Commission (CPUC) can also be injected into the natural gas pipeline network to offset use of fossil natural gas in multiple sectors. Use of upgraded biomethane in vehicles in place of diesel also provides the additional co-benefit of reducing nitrogen oxides (NOx) emissions. Dairy biomethane can also be used as a heat source in industrial application, or as a feedstock for low carbon fuels including renewable hydrogen and dimethyl ether. The biomethane produced is eligible for credits in CARB's LCFS program, the Federal Renewable Fuels Standard, or CARB's Cap-and-Trade offsets program, which act as an ongoing revenue stream for facilities to help offset the initial high capital costs of development as well as support the ongoing operational costs of the digester.

Alternative manure management practices reduce the amount of manure (and volatile manure solids) managed or stored under anaerobic conditions; the goal of these practices is to limit methane production and emissions. Examples of effective alternative manure management practices include conversion to "solid," "dry," or "scrape" manure management; installation of a compost-bedded pack barn; increase in the time animals spend on pasture; or implementation of solid-liquid separation technology into flush manure management systems (e.g., various types of mechanical separators and weeping walls). Other alternative manure management strategies that may result in methane emissions reductions include but are not limited to acidification, which involves the application of acid(s) to animal manure to reduce emissions; vermifiltration, which is an aerobic decomposition process that produces worm castings; and chemical flocculation, which involves using polymers to increase the solid separation rate from animal manure streams. A more detailed overview of these and other alternative manure management practices is available in the Newtrient technology catalog—a source of information on manure management practices that can reduce environmental impacts.[13]

These practices can also provide important environmental co-benefits including improved water quality and nutrient management, and more easily exportable manure solids. For example, dairies can contribute to groundwater pollution through nitrate and salt leaching when overapplying manure to cropland, however, these components may replace synthetic fertilizer or improve soil health in other regions. Exporting excess nutrients and solids may also help dairy and livestock operations comply with water quality requirements. In California, dairy manure is largely managed in liquid form, making it difficult and cost-prohibitive to export without solid-liquid separation. Certain alternative manure management practices can remove manure solids, nitrogen, and salt from the manure stream and concentrate them in the solids that can be more readily exported as organic fertilizer or converted them into environmentally benign end products such as nitrogen gas. Manure solids may be further processed into value-added manure products like compost or soil amendments that can provide additional revenue, though market development remains a barrier. Alternative manure management strategies also provide flexibility to operations seeking to reduce methane emissions where a digester may be infeasible.

Through the strategies described above, the dairy and livestock sector can make considerable progress toward achieving the target of reducing methane emissions to 40 percent below 2013 levels by 2030. This Analysis describes progress the sector has already made toward achieving the target through manure methane emissions reduction projects. It also assesses progress that may occur based on various funding scenarios, reductions in animal populations, or commercial availability of a methane-reducing feed additive. Additionally, it discusses technical and market barriers to methane emissions reductions strategies that must be overcome to achieve the 2030 target.

[13] Newtrient provides information about manure management strategies and associated environmental impacts to dairy producers through an online technology catalog. Newtrient participated in CARB's Dairy and Livestock GHG Emissions Workgroup but does not have a formal relationship to CARB. Reference to that material does not constitute an endorsement of that catalog, or any associated strategies, technologies, etc., included therein.

Analysis and Findings

Analysis Item 1: California's Dairy and Livestock Methane Emissions Reduction Progress and Projected Annual Emissions Reductions through 2030

Finding 1-1: The Sector Has Made Significant Progress, But Will Not Meet the 2030 Target without Almost a Doubling of Emissions Reductions Projects

The California dairy and livestock sector has predominantly relied on manure management strategies to achieve the methane emissions reductions directed by the Legislature. Even with limited enteric methane mitigation options, the sector is on course to achieve significant emissions reductions. Through private investments and public incentive funding programs, approximately 278 manure methane emissions reduction projects have been completed or are under construction at California's dairy farms. Of these, CCI funded 233 projects through CDFA's Dairy Digester Research and Development Program (DDRDP) and Alternative Manure Management Program (AMMP), which have been instrumental in driving manure methane emissions reduction projects at California dairy operations. DDRDP provides up to half of the capital cost of construction, and AMMP encourages private matching funds. Both programs are consistently over-subscribed, with requested funds usually about twice the amount available.

As of December 2020, 22 DDRDP and 61 AMMP projects were complete and operational. An additional 96 DDRDP and 54 AMMP projects are under construction, with expected completion by the end of 2022. The latest round of CCI funding in fiscal year (FY) 2019-20 funded 12 DDRDP and 13 AMMP projects; all are expected to be operational by the end of 2022. Aggregating the emissions reductions expected from all 233 CCI projects yields an estimated annual methane emissions reduction of 2.0 $MMTCO_2e$[14] by the end of 2022.[15] The emissions reductions counted toward the 2030 target represent over 20 percent of the 9 $MMTCO_2e$ required to achieve that target. Stated differently, CCI funded dairy and livestock projects are expected to

[14] Emissions reduction estimates are in 100-year GWP (AR4). Estimated emissions reductions using 20-year GWPs can be calculated by multiplying 100-year GWP figures in this Analysis by 2.88.

[15] These estimates do not include the anaerobic digestion projects receiving Aliso Canyon Mitigation Settlement funds, which will result in an estimated additional 0.3 $MMTCO_2e$ in annual methane emissions reductions. Since these projects count toward natural gas sector mitigation, they do not count toward the 2030 target.

reduce total methane emissions from the sector to about 9 percent below 2013 levels by the end of 2022.

CARB, in collaboration with air districts and dairy and livestock industry groups, identified as many as 45 additional manure management projects implemented or under development using only private funding throughout the State since January 1, 2013. Of these, 40 involve installation of a solid-liquid separation system, and the remaining five involve installation of an anaerobic digester. Solid separation systems reduce the amount of volatile solids that are managed anaerobically by diverting a fraction of these solids to a dry management system to produce compost, soil amendment, and bedding, preventing them from producing significant methane emissions. To estimate reductions from these projects, CARB staff used average methane emissions reductions for DDRDP and AMMP projects, respectively. The combined annual methane emissions reductions amount to 0.2 $MMTCO_2e$ from these projects, with 0.1 $MMTCO_2e$ each from digester and alternative manure management projects.

Changes in animal populations are an additional driver of methane emissions reductions, caused by factors including reduced product demand, increased costs, insufficient revenue, greater out-of-State competition, and land use changes. For example, consumer preferences may change, reducing the demand for animal-based products. Increased out-of-State competition and decreased national and international demand may also result in oversupply of products and animal population reductions. Increases in production costs for commodities like animal feed, electricity, and fuel can also have significant impacts on the financial viability of animal operations, especially when coupled with low commodity prices. In other cases, competing land uses like conversion to high-value crops or urban encroachment may lead to facility closures and animal population reductions.

Every five years, the U.S. Department of Agriculture (USDA) conducts a Census of Agriculture (Ag Census), which provides the most consistent and reliable population data available in absence of state-level activity data. As part of the Ag Census, USDA reports the number of animals by type on each farm in the U.S., allowing for state-specific population tracking, including for California's GHG Emission Inventory. USDA's two most recent Ag Census reports, from 2012 and 2017, cover dairy and livestock population changes between 2008 and 2017, and provide a basis for estimating methane emissions reductions from average annual population changes. The 2012 Ag Census also provides a reasonable 2013 baseline because it quantifies dairy and livestock populations in California by animal type as of December 31, 2012. Based on the 2012 and 2017 Ag Census reports, CARB staff calculated an average annual decline of 0.5 percent in animal populations from the sector between 2008 and 2017. Assuming that this population change trend will remain constant, methane emissions reduction attributable to sector population decreases will be ~0.13 $MMTCO_2e$ annually or 1.3 $MMTCO_2e$ total through 2022.

Adding methane emissions reductions expected from State- and privately funded manure management projects with those from expected animal population decreases yields a total methane emissions reduction in 2022 relative to 2013 of ~3.5 $MMTCO_2e$, as shown in

Table 1 below.[16] Assuming that the animal population will continue to decrease at approximately 0.13 $MMTCO_2e$ annually,[17] and not taking into account any additional funding that may be available for manure methane reduction projects beyond FY 2019-20, the total estimated 2030 methane emissions reductions would be approximately 4.6 $MMTCO_2e$. This would be just over half of the 9 $MMTCO_2e$ emissions reductions needed to meet the 2030 target – with about 4.4 $MMTCO_2e$ reductions remaining (Figure 4).

[16] Due to the time required to construct dairy methane emissions reductions projects—especially anaerobic digesters pipeline injecting biomethane (between 18 and 24 months)—a limited number of projects have been completed to date.

[17] Starting in March of 2020, California enacted shelter-in-place orders and temporary closures of public and private gathering spaces due to the global pandemic. Resulting closures of schools and restaurants likely exacerbated dairy sector economic challenges and may have lasting impacts, including accelerated facility closures and decreases in animal population. However, due to uncertainty about net long term impacts the pandemic may have on the dairy and livestock sector, this Analysis assumes that recent trends in animal population trends observed in USDA's 2012 and 2017 Ag Census change will remain consistent through 2030.

Table 1. Estimated California Dairy and Livestock Methane Emissions Reduction by the End of 2022

Reduction Type		Number of Projects Funded through FY 2019-20	Expected Emissions Reductions Through 2022 ($MMTCO_2e$)
Population Change		Not Applicable	1.3
Anaerobic Digester	State-funded (DDRDP)	118	1.8
	Privately funded	5	0.1
Alternative Manure Management Practices	State-funded (AMMP)	115	0.2
	Privately funded	40	0.1
Total		**278**	**3.5**

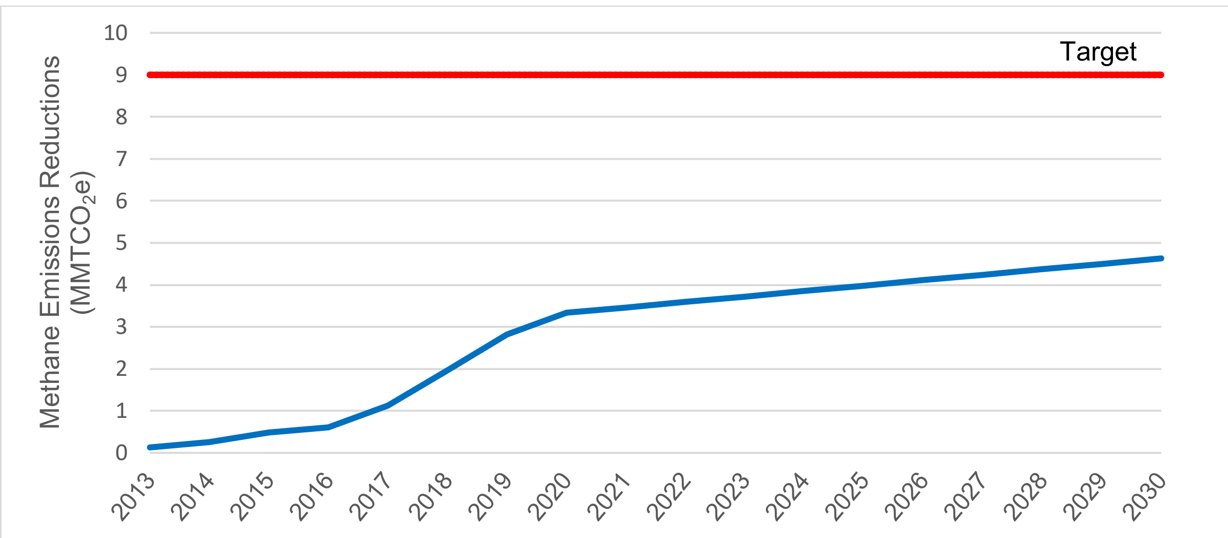

Figure 4. Projected Annual Methane Emissions Reductions through 2030 without Additional CCI Funding beyond FY 2020-21

The remaining 4.4 $MMTCO_2e$ in emissions reductions are expected to be achieved through manure management strategies but may be advanced by widespread adoption of effective enteric methane mitigation strategies. To estimate additional manure methane emissions reductions projects needed to reach the target, CARB staff used average reductions from DDRDP and AMMP projects. Staff calculated average project-level methane emissions reductions by program using figures reported by CDFA through DDRDP and AMMP. Based on the average emissions reductions, staff determined the number of additional projects necessary to achieve the 2030 target. This assumes that distribution of project types will remain roughly equal between digesters and alternative manure management projects, consistent with past practice. Based on this approach, at least 210 anaerobic digestion and 210 alternative manure management projects are necessary to achieve the remaining 4.4 $MMTCO_2e$ in methane emissions reductions. However, future project types may vary dependent upon available incentives and operator preference. If only dairy digester projects were implemented—which are about ten times as effective at reducing emissions than alternative manure management projects—over 230 projects would be necessary to achieve this level of emissions reductions. With respect to alternative manure management practices, based on currently funded projects and reduction trends observed to date, staff's analysis indicates that the State would be unable to achieve the 2030 dairy and livestock sector target through deployment of alternative manure management practices alone. A combination of dairy digesters, alternative manure management, enteric strategies, and dairy herd size population decreases will be needed to meet the 2030 target.

Finding 1-2: Public and Private Funding Support Methane Emissions Reduction Projects

Significant allocations of CCI funding have enabled the sector to make progress toward the 2030 target. From 2014 through 2020, the Legislature appropriated approximately $289 million in CCI funds for dairy methane emissions reduction projects. These funds, administered through CDFA's DDRDP and AMMP, have been effective in leveraging private capital investment and achieving cost-effective methane emissions reductions. With local, State, and federal funding, the dairy and livestock sector will be able to implement additional projects to help meet the 2030 target. Table 2 (below) shows that dairy methane projects constructed using CCI funds through the DDRDP and AMMP have successfully leveraged over $1.60 in match funding for each CCI dollar invested.[18]

[18] DDRDP eligibility requirements include a mandatory private match contribution of at least 50 percent of initial project cost estimates. AMMP does not require private match contributions.

Table 2. Private Funding Contributions per CCI Dollar Invested

Funding Sources	Programs		Total Funding
	AMMP	DDRDP	
CCI ($ million)	$67.8	$195.5	$263.3
Private Match ($ million)	$9.9	$413.1	$423.0
Private Match per CCI Dollar Invested ($)	$0.15	$2.11	-

In addition to DDRDP and AMMP, additional State programs, including the Cap-and-Trade Program, the LCFS Program, CPUC's Bioenergy Market Adjusting Tariff (BioMAT), CPUC's Renewable Gas Pipeline Interconnection Incentive Program and CPUC's SB 1383 Biomethane Pipeline Injection Pilot Project Program, have supported dairy and livestock methane emissions reduction projects through credit generation and grants, and other bioenergy and biofuel incentives. To date, more than $1 billion in combined public and private funding has supported approximately 280 anaerobic digester and alternative manure management projects. Additionally, public funds have supported rate-recoverable programs for biomethane pipeline interconnection infrastructure, which help deliver biomethane to end users.

The Strategy recommended a minimum funding amount[19] of at least $100 million per year for five years as necessary to accelerate significantly project development by offsetting capital costs and economic risks for manure management methane emissions reduction projects. CARB and CDFA, working with industry stakeholders and project developers during public development of the Strategy, estimated that $500 million would greatly increase the deployment rate of manure management projects within the State, though that amount was not estimated to be sufficient to achieve the 2030 target. To date, CDFA's DDRDP has awarded approximately $200 million in CCI funds for 118 dairy digesters, nearly an eightfold increase over the number of digesters operating prior to the availability of CCI funds. Similarly, CDFA's AMMP has awarded approximately $68 million for 115 alternative manure management projects and has greatly accelerated adoption of those practices. CARB staff estimates an additional $600 million in privately matched CCI funds, or similar public incentives, is necessary to achieve the emissions reductions still needed to meet the 2030 target through dairy digester projects. Despite considerable State investment and private match funding, incentives have not been sufficient to achieve

[19] In the Strategy, CDFA estimated that at least $100 million in the form of grants, loans, or other incentives would be needed for five years to support the development of necessary methane emissions reducing manure management projects including digesters and alternative manure management projects, as well as associated infrastructure.

the 2030 target. The FY 2019-20 CCI allocation of $34 million was considerably lower than the $99 million available in FY 2017-18 and FY 2018-19, falling $66 million short of annual funding needs. The proposed FY 2020-21 appropriation of $20 million did not materialize because of State budget cuts. The FY 2021-22 budget includes an appropriation of $32 million for CDFA's livestock methane reduction program, with priority given to AMMP.

CDFA's DDRDP projects have been the primary driver of GHG emissions reductions in the dairy and livestock sector since FY 2014-15. Prior to the availability of CCI funds, about 15 digesters were operating in California—far short of the 799 candidate dairies identified by the USDA AgSTAR program and 543 dairies identified in the Strategy[20] as necessary to achieve the 2030 target.[21] Most of the digesters installed prior to the start of CCI (2006-2013) relied heavily on public funding from CEC's Dairy Power Production Program. Emissions reductions resulting from these projects are not counted towards the target because they were online prior to the 2013 baseline year. Figure 5 below shows the number of digesters in place prior to the baseline year, the number of digesters resulting from CCI funding, and the number of additional digester projects necessary to achieve the 2030 target.

[20] The Strategy was adopted prior to the opening of the Alternative Manure Management Program and assumed that most of the necessary methane emissions reductions would result from digester installations.

[21] Noted in Table 17: Sector-wide implementation assumptions, and upfront capital costs of the Strategy.

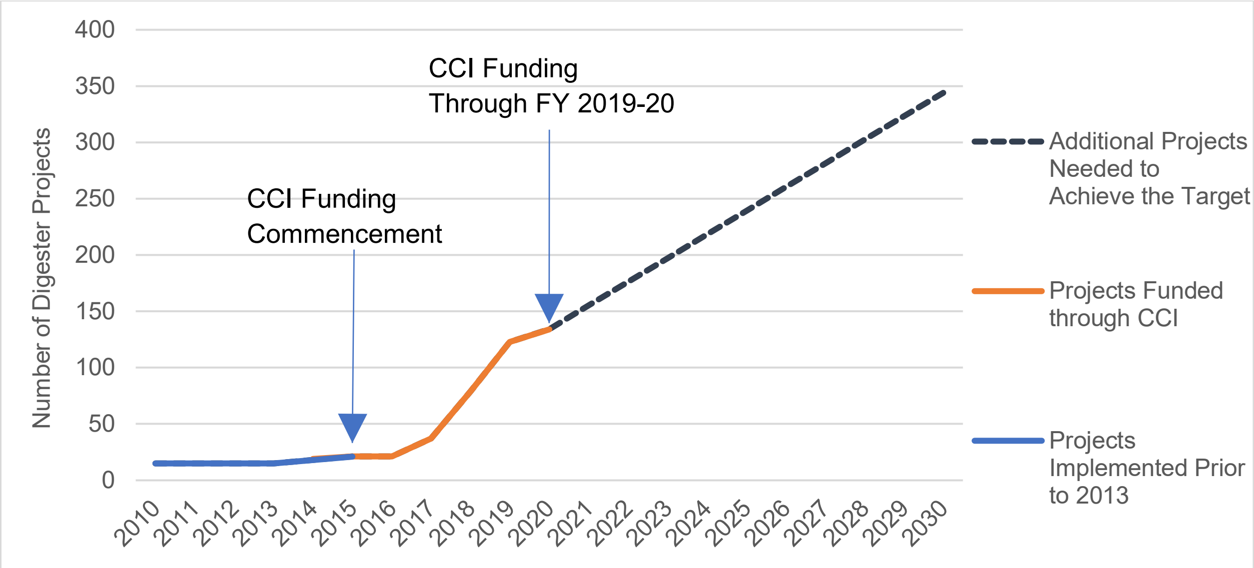

Figure 5. Number of Dairy Digesters in California[22]

Similarly, CDFA's AMMP is a primary source of funds for alternative manure management projects, which also rely heavily on public funds. Project developers are generally smaller dairies that are often not well suited to a digester because of limited financial resources, insufficient herd sizes, or other operational characteristics. While less expensive than a digester, alternative manure management projects on average cost about $600,000 per project. Unlike a digester project, alternative manure management projects do not produce bioenergy or biofuels and are not eligible to generate revenue from environmental credits. Some project developers realize cost savings from bedding purchases or sales of value-added manure products, while others—especially smaller pasture-based operations—are unable to capture any savings or revenue at all.

Infrastructure costs for digester systems producing onsite electricity from biogas including the cost to construct and install an anaerobic digester, construct conditioning facilities to upgrade biogas to necessary specifications, and either convert it to electricity using a reciprocating engine, a microturbine, or a fuel cell. These costs range from approximately $3 million to $17 million depending on the configuration and biomethane utilization option chosen, with average costs between $4 million and $7 million. Infrastructure costs to produce onsite electricity at the lower end assume that a project uses a reciprocating engine generator to produce onsite electricity, while upper end costs (~$17 million) assume the use of a solid oxide fuel cell. Infrastructure costs for digester systems that produce biomethane for pipeline

[22] Numbers shown in Figure 5 do not include the five privately funded dairy digester projects implemented since 2013.

injection (or trucking to injection point or fueling station) including the cost to install an anaerobic digester and a biogas upgrading facility. These costs range from $3 million to $16 million. Project variables include distance to the pipeline and whether the project is on a single dairy or part of a cluster of dairies.

According to CCI reports published to date, DDRDP and AMMP have delivered some of the most cost-effective GHG emissions reductions on a per-metric ton CO_2e basis compared to other CCI funded programs. Table 3 details State, private, and total investments into dairy manure methane emissions reduction projects.

Table 3. Estimated Cost Effectiveness of California Dairy and Livestock Methane Emissions Reductions through 2022

Program	State Investment ($/MTCO₂e)	Private Investment ($/MTCO₂e)	Total Investment ($/MTCO₂e)
DDRDP	$9	$20	$29
AMMP	$61	$9	$70

Alternative manure management projects can be further subdivided into three project types, including compost bedded pack barns, flush-to-scrape conversions, and solid-liquid separation systems. Methane emissions reduction potential and cost-effectiveness varies across these project types. Table 4 shows the average methane emissions reductions and cost-effectiveness of these alternative manure management project types. According to the table, solid-liquid separation projects have the highest per-project average methane emissions reductions and the lowest implementation costs among these alternative manure management practices. Importantly, site-specific conditions affect methane reductions potential and cost-effectiveness across all project types.

Table 4. Estimated Methane Emissions Reduction Potential and Cost-Effectiveness of Alternative Manure Management Projects through 2022

AMMP Practices	Reduction per Project ($MTCO_2e$)	Cost-effectiveness ($/$MTCO_2e$)	
		State Investment	Total Investment
Compost Bedded Pack Barn	1,880	$73	$91
Flush-to-Scrape Conversion	1,420	$78	$88
Solid-Liquid Separation	2,120	$54	$58

In addition to public funding of digester construction costs, incentive funds and other mechanisms are available to provide ongoing support to project developers. This includes the BioMAT, the Cap-and-Trade Program, and the LCFS Program. The Cap-and-Trade Program allows dairy digester developers to quantify the methane emissions reductions resulting from the installation of a digester using the CARB Compliance Offset Protocol for Livestock Projects. These methane emissions reductions can generate carbon offset credits that developers can sell to capped entities. The Cap-and-Trade Program is designed to encourage capped entities to reduce their GHG emissions while providing flexibility in how those reductions are achieved. The LCFS Program is designed to reduce the average carbon intensity of transportation fuels[23] in California by incentivizing the production and use of low carbon fuels. Alternative fuels like biomethane generate credits in the LCFS program that can be sold to entities generating deficits for supplying high carbon fuels for sale in California.

Dairy digester projects are increasingly participating in the LCFS credit market,[24] where credit prices averaged $192 in 2019.[25] A hypothetical 3,000 milking cow dairy supplying transportation fuel could generate approximately $3.5 million in annual LCFS credit value.[26] Equivalent emissions reductions from the same dairy project might generate $250,000 in annual compliance offset credit value through the Cap-and-Trade Program, using the weighted average price for livestock offset credit transfers.[27,28] However, these potential credit revenue values do not include project-specific variations in additional revenue streams or costs, which may be considerable, even among projects with similar sizes and designs. While dairy digesters offer significant and cost-effective methane emissions reductions, without large-scale public incentives, the rate of adoption would likely decrease greatly. Incentives such as the

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[23] Information on current fuel pathways can be obtained through the CARB Current Fuel Pathways Spreadsheet, which is searchable and sortable, by feedstock, fuel, classification, and/or facility name. Accessed in December 2020.

[24] Anaerobic digester projects cannot simultaneously generate both LCFS and Cap-and-Trade credits.

[25] Monthly LCFS Credit Transfer Activity Reports. Accessed in August 2020.

[26] The LCFS credit value represents potential gross revenue from sale of LCFS credits in 2020; this does not include revenues from the sale of fuel, nor the potential revenue from sale of Renewable Identification Numbers (RIN) under the federal EPA Renewable Fuel Standard (RFS). Project development costs are not included in these estimates due to significant variability; costs may include but are not limited to project feasibility, design, and interconnection studies, digester and gas upgrading equipment and installation, and pipeline interconnection infrastructure construction.

[27] Cap-and-Trade Compliance Offset Credits from livestock projects were valued at $13.67 on average per metric ton for transactions occurring in 2019. Summary of Market Transfers Completed in 2019.

[28] Offset credit revenue from livestock projects may vary considerably, even across similarly sized and designed projects resulting from variations in project costs, location, and additional revenue streams. The gross revenue values provided in this Analysis are intended to illustrate potential offset credit revenue for programmatic comparison but may not accurately describe actual net project revenues.

Cap-and-Trade Program, LCFS Program, or RFS Program significantly improve the attractiveness of investment in digester projects.

Finding 1-3: The 'Social Cost of Methane' Metric Cannot be Used to Determine the Net Societal Benefits or Disbenefits of Methane Emissions Reduction Projects Comprehensively; Methane Reduction Benefits or Disbenefits Vary by Project Type

In addition to mandating SLCP emissions reductions, the Legislature passed AB 197 (Garcia, Chapter 250, Statutes of 2016), which directs CARB to consider the social costs associated with GHG emissions mitigation rules and regulations. The social cost of methane is a measure of the long-term damages caused by emitting one ton of methane in a given year. Using the methodology developed in 2009 by a federal interagency working group convened by the U.S. Council of Economic Advisors and the Office of Management and Budget, CARB staff estimated the potential range in the social cost of methane emissions from 2015 through 2030 in the 2017 Climate Change Scoping Plan.[29] The current analysis focuses on the social costs of methane emissions in 2030 using different discount rates[30] in 2020 dollars[31]—or the value today of preventing environmental damages in the future (Table 5).

The social cost of methane is a metric that can contribute to understanding the societal benefits or disbenefits that accrue from reducing methane emissions. The social cost of methane accounts for damages that occur from the release of methane, including damages due to changes in human health, changes in net agricultural productivity, property damages from increased flood risk, changes in energy system costs, non-market amenities (based on outdoor recreation), and changes to human settlements and ecosystems. Importantly, the models used to estimate the social cost of methane emissions cannot assess the monetary value of all physical, ecological, or economic impacts of climate change. As such, actual societal benefits or disbenefits could differ considerably from the calculated values used in this analysis.

Furthermore, when conducting a complete cost benefit analysis, net societal benefits from a specific project may accrue despite an estimated project disbenefit (negative values shown in Table 5) associated solely with the social value of reducing methane

[29] More information is available in Table 8 in the 2017 Climate Change Scoping Plan.

[30] Discount rate is the rate at which society is willing to trade present benefits for future benefits. Discount rate affects decision making parameters including net present value, cost-effectiveness ratio, internal rate of return, return on investment.

[31] All social cost values have been adjusted to 2020 dollars using the U.S. Bureau of Labor Statistics Historical Consumer Price Index for All Urban Consumers. Accessed in December 2020.

emissions. A methane emissions reduction project may yield a social disbenefit when only accounting for methane emission reductions but may result in substantial improvements to air quality and water quality that are not quantified or monetized by only looking at the social cost of methane. For example, for the dairy and livestock sector, manure management projects such as anaerobic digesters have been successful at reducing methane emissions. The captured methane from digesters can be converted to an energy product, such as renewable electricity produced through fuel cells and internal combustion engine generators, resulting in potential net societal benefits or disbenefits associated with methane emissions reductions before considering other environmental and socioeconomic co-benefits.

Staff used the social costs of methane in Table 5 to estimate the societal benefits and disbenefits of various methane mitigation projects, including fuel cells and internal combustion engine generators at discount rates of 2.5, 3.0, and 5.0 percent. Subtracting the project investment costs from the social cost of methane estimates the net societal benefits or disbenefits of reducing methane emissions by investing in specific manure methane emissions reduction projects, solely from a methane mitigation perspective.[32] Depending on project types, societal benefits or disbenefits from reducing one metric ton of methane vary, ranging from a societal disbenefit of $2,806 to a societal benefit of $1,878. However, as previously noted, this methodology does not fully assess the monetary value of all environmental and socioeconomic co-benefits that may result from establishing these projects, nor does it fully assess any additional societal disbenefits that may arise from non-methane emissions. For example, implementing such strategies may offer improved nutrient management to farms through more precise application of manure solids to crop lands at agronomic rates and potential reductions in synthetic fertilizer use. Conversely, adoption of other methane emissions reductions strategies such as converting biogas to electricity using internal combustion engine generators may increase NOx and other air pollutant emissions, resulting in societal disbenefits. Given that most California dairies are in or near disadvantaged communities that may be disproportionately exposed to air quality impacts, ensuring air quality and other environmental benefits in these communities to the extent feasible is important, independent of the limitations to current social cost of methane estimates.

[32] The overall societal value of a project maybe positive even if a methane emissions reduction project has a social cost of methane disbenefit. Without conducting a comprehensive cost analysis of all environmental and socioeconomic factors, actual net societal benefits of a project remain unknown.

Table 5. Social Cost and Societal Benefits or Disbenefits of Reducing One Metric Ton of Methane Emissions in 2030

Discount Rate	Social Cost of Methane ($/MT CH_4)	Methane Emissions Reduction Cost ($/MT CH_4)		Net Societal Disbenefits (-) or Benefits (+)‡ ($/MT CH_4 Reduced)
		Fuel Cell	IC Engine	
5.0%	$949	$3,755	$773	$-2,806 to $176
3.0%	$1,997	$3,145	$648	$-1,148 to $1,349
2.5%	$2,496	$3,002	$618	$-506 to $1,878

Methane emission reduction scenarios shown in Table 5 assume methane is captured using a dairy digester and destroyed using either fuel cell or an internal combustion engine. These examples provide upper and lower bound estimates for net social benefits and disbenefits. (While pipeline injection projects are the most frequently implemented project types, they are not shown here because costs are highly variable based on project site. However, they would fall within the range shown.)

‡Net societal benefits or disbenefits of reducing one metric ton of methane emissions do not account for all environmental and socioeconomic co-benefits resulting from that reduction.

Finding 1-4: Feed and Manure Additive Methane Mitigation Strategies Could be Scaled to Help Achieve the 2030 Target

In addition to the manure management practices described above, additional strategies are under development to achieve further reductions from the sector. For example, certain markets have begun using additives that reduce methane emissions from enteric fermentation in ruminants, though use in North America is limited due to pending regulatory approval. Additives to reduce methane emissions from manure management are also under development. Such additives may potentially achieve important, cost-effective methane emissions reductions from dairy and livestock operations while offering increased flexibility and avoiding the significant upfront capital investment associated with installing a digester or implementing an alternative manure management practice.

Animal Feed Additives

Methane emissions from enteric fermentation in dairy and livestock account for about 30 percent of statewide methane emissions, or approximately 12 $MMTCO_2e$ annually. This presents an opportunity to achieve significant methane emissions reductions, potentially at a cost of approximately $50 per metric ton on a carbon dioxide equivalent basis.[33] Potential strategies to reduce emissions from the digestion process

[33] Assumes use of a product with a ten percent enteric methane emissions reduction effectiveness at an annual cost of approximately $48 per ton ($0.05 per cow per day) on a carbon dioxide equivalent basis.

include diet modifications, feed additives, feed efficiency improvements, and selective breeding of low methane producing animals. Of these, feed additives offer the greatest potential for sector-wide methane emissions reductions because they potentially deliver considerable methane emissions reductions shortly after adoption. In comparison, strategies like diet modifications, feed efficiency improvements, and selective breeding require a relatively long time to achieve significant emissions reductions. Unlike the manure management strategies described above, these strategies can be implemented at existing operations with minimal need to modify facility design and without significant upfront capital requirements. This makes these strategies potentially attractive for dairy and livestock operations, especially rented or leased operations.

Research suggests that certain feed additives may have promising methane emissions reduction potential. For example, 3-Nitrooxypropanol (3-NOP under the commercial name of Bovaer®),[34] has shown an emissions reduction potential between 20 and 40 percent across multiple ruminant species under various testing conditions.[35,36,37] The additive 3-NOP has undergone both laboratory-scale and on-farm testing for effectiveness in reducing methane emissions safely, and for potential impacts on animal health, reproduction, and productivity. It is a chemical product that is currently undergoing US Food and Drug Administration (FDA) approval and may become available within the next few years.[38] Nitrate is another feed additive that has shown an

[34] Mention of trade names or commercial products does not constitute or imply CARB endorsement or recommendation.

[35] Kim, S., Lee, C., Pechtl, H. A., Hettick, J. A., Campler, M. R., Pairis-Garcia, M. D. Beauchemin, K. A., Celi, P., Duval, S. M. (2019). Effects of 3-nitrooxypropanol on enteric methane production, rumen fermentation, and feeding behavior in beef cattle fed a high-forage or high-grain diet. *Journal of Animal Science*, 97(7), 2687–2699.

[36] Gonzalo, M., Stephane, D., Kindermann, M., Schirra, H, J., Denman, S. E., McSweeney C. S. (2018). 3-NOP vs. Halogenated Compound: Methane Production, Ruminal Fermentation and Microbial Community Response in Forage Fed Cattle. *Frontiers in Microbiology*, 9, 1582.

[37] Van Wesemael, D., Vandaele, L., Ampe, B., Cattrysse, H., Duval, S., Kindermann, M., Fievez, V., De Campeneere, S., Peiren, N. (2019). Reducing Enteric Methane Emissions from Dairy Cattle: Two Ways to Supplement 3-Nitrooxypropanol. *Journal of Dairy Science*, 102(2), 1780-1787.

[38] Mitloehner, F. M., Kebreab, E., Tricarico, J., Wallace, J., Gooch, C., Gibbs, C. (2020). Dairy Feed Additives to Reduce Enteric Methane Emissions. Newtrient.

emissions reduction potential between 10 and 20 percent.[39,40,41,42,43] However, existing research is insufficient to conclude that microbes in the rumen will acclimate to increased nitrate without causing adverse animal health impacts. Agolin® Ruminant,[44] an essential oil mix, has shown methane reduction potential between 10 and 20 percent for dairy cows without impacting milk yield and composition. Mootrol® Ruminant, a pelleted product made from garlic and orange extract, has also shown methane mitigation potential in both *in vitro* and *in vivo studies* [45,46] and researchers are currently investigating its long-term effectiveness in beef cattle. Both Agolin® Ruminant and Mootral® Ruminant are commercially available and are Generally Regarded As Safe (GRAS)[47] by the FDA. Novel additives, such as lemongrass and seaweed[48] have also shown emissions reduction potential but lack sufficient *in vivo* (animal) studies to demonstrate long-term effectiveness and potential impacts on

[39] Alemu, A. W., Romero-Pérez, A., Araujo, R. C., Beauchemin, K. A. (2019). Effect of Encapsulated Nitrate and Microencapsulated Blend of Essential Oils on Growth Performance and Methane Emissions from Beef Steers Fed Backgrounding Diets. *Animals (Basel)*, 9(1), 21.

[40] Klop, G., Hatew, B., Bannink, A., Dijkstra, J. (2016). Feeding nitrate and docosahexaenoic acid affects enteric methane production and milk fatty acid composition in lactating dairy cows. *Journal of Dairy Science*, 99(2), 1161-1172.

[41] Raleng, A. O. (2008). The Potential of Feeding Nitrate to Reduce Enteric Methane Production in Ruminants.

[42] Meller, R. A., Wenner, B. A., Ashworth, J., Gehman, A. M., Lakritz, J., Firkins, J. L. (2019). Potential roles of nitrate and live yeast culture in suppressing methane emission and influencing ruminal fermentation, digestibility, and milk production in lactating Jersey cows. *Journal of Dairy Science*, 102(7), 6144-6156.

[43] Zijderveld, S. V., Gerrits, W., Dijkstra, J., Newbold, J., Hulshof, R., & Perdok, H. B. (2011). Persistency of methane mitigation by dietary nitrate supplementation in dairy cows. *Journal of dairy science*, 94(8), 4028-38.

[44] Carrazco, A. V., Peterson, C. B., Zhao, Y., Pan, Y., McGlone, J. J., DePeters, E. J., Mitloehner, F. M. (2020). The Impact of Essential Oil Feed Supplementation on Enteric Gas Emissions and Production Parameters from Dairy Cattle. Sustainability, 12(24), 10347

[45] Eger, M., Graz, M., Riede, S., Breves, G. (2018). Application of Mootral™ reduces methane production by altering the Archaea community in the rumen simulation technique. Frontier in microbiol, 9, 2094. doi: 10.3389/fmicb.2018.02094

[46] Roque, B. M., Van Lingen, H. J., Vrancken, H., Kebreab, E. (2019). Effect of Mootral—a garlic- and citrus-extract-based feed additive—on enteric methane emissions in feedlot cattle. Translational Animal Science, 3(4), 1383–1388

[47] "GRAS" is an acronym for the phrase Generally Recognized As Safe by the FDA. Under sections 201(s) and 409 of the Federal Food, Drug, and Cosmetic Act (the Act), any substance intentionally added to food is a food additive, that is subject to premarket review and approval by FDA, unless the substance is generally recognized, among qualified experts, as having been adequately shown to be safe under the conditions of its intended use, or unless the use of the substance is otherwise excepted from the definition of a food additive (https://www.fda.gov/food/food-ingredients-packaging/generally-recognized-safe-gras).

[48] Abbott, D. W., Aasen, I. M., Beauchemin, K. A., Grondahl, F., Gruninger, R., Hayes, M., Huws, S., Kenny, D. A., Krizsan, S. J., Kirwan, S. F., Lind, V., Meyer, U., Ramin, M., Theodoridou, K., von Soosten, D., Walsh, P. J., Waters, S., Xing, X. (2020). Seaweed and Seaweed Bioactives for Mitigation of Enteric Methane: Challenges and Opportunities. *Animals*, *10*, 2432.

productivity and human or animal health.

To better understand the potential contribution of feed additives in achieving the 2030 target, staff evaluated six potential enteric methane emissions reduction scenarios that focused on the use of feed additives. These scenarios shown in Figure 6 (below) illustrate potential annual methane emissions reductions resulting from the use of feed additives with methane mitigation effectiveness of 10, 30, and 50 percent,[49] representing the low, medium, and high potential of different feed additives, at adoption rates of 50 and 75 percent. The 2030 target is shown as a red dotted line at the top of the graph. At the bottom of the graph, a solid red line shows the methane emissions reductions attributed to dairy and livestock population change and manure methane emissions reduction projects already completed or under construction. It assumes that no additional projects will be implemented.[50] As the figure shows, if solely enteric feed additives are utilized beyond 2022 and no additional manure methane projects are implemented, a feed additive with a methane emissions reduction effectiveness of at least 50 percent would need to be adopted by at least 75 percent of ruminants in the sector to achieve the 2030 target.

[49] These values represent the enteric methane mitigation effectiveness of various feed additives. Ten percent represents a conservative estimate of mitigation effectiveness for currently available products; thirty percent represents a median estimated effectiveness for 3-NOP, which shows mitigation potential between 20-40 percent, and is expected to become commercially available in the near future; fifty percent represents a conservative estimate for the most effective emerging approaches, such as seaweed.

[50] Additional manure methane emissions reduction projects are expected to be developed but have been omitted from Figure 6 to illustrate the potential of feed additive-based enteric methane emissions reductions.

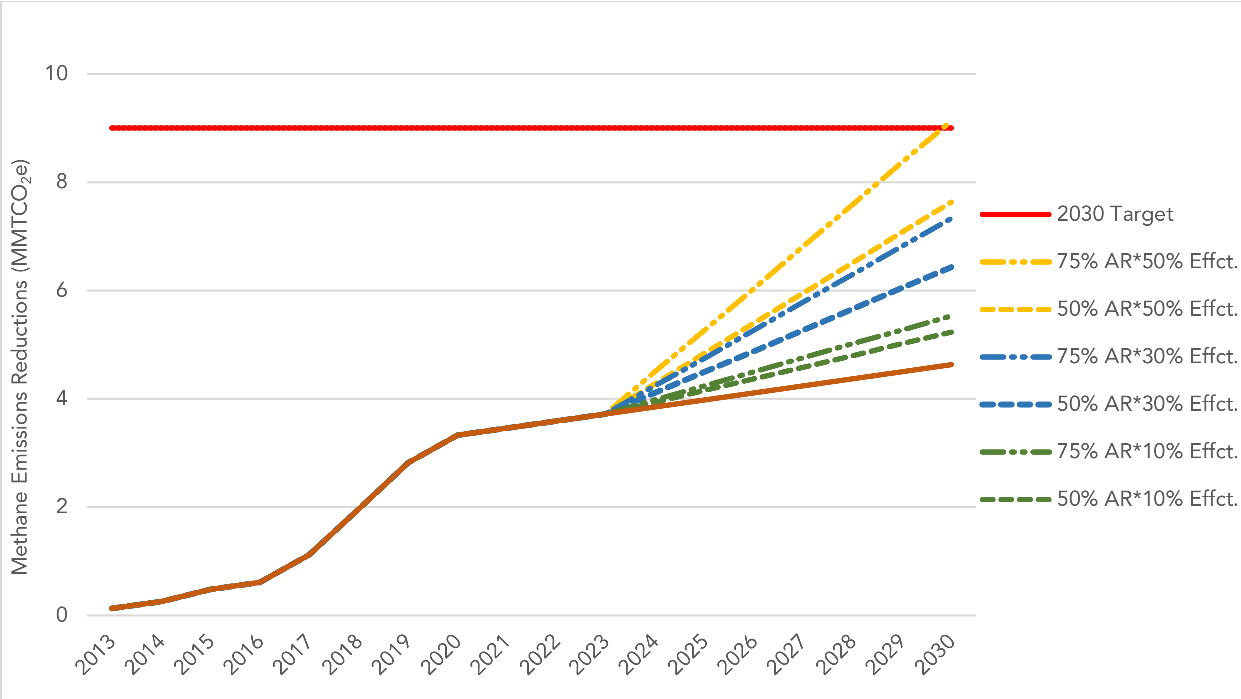

Figure 6. Projected Annual California Dairy and Livestock Sector Enteric Methane Emissions Reductions through 2030 Under Various Feed Additive Adoption Rates (AR) and Methane Mitigation Effectiveness (Effct.)

Manure Additives to Reduce Methane Emissions

Most of California's manure methane emissions originate from anaerobic manure treatment and storage lagoons. Manure additives can potentially modify environmental conditions in manure treatment and storage facilities, including but not limited to pH, redox potential, and microbial composition, to levels that are less conducive to methane production. Examples of potential manure additives include incorporation of biochar or proprietary lagoon additives, as well as the use of manure acidification. However, these strategies require additional investigation of their methane emissions mitigation effectiveness, applicability to California dairy and livestock manure management systems, and potential unintended impacts to air or water quality. For example, biochar has been shown to reduce methane emissions through incorporation into manure slurry; however, it may not be practical or effective in liquid manure management systems that are predominant on California dairy operations. Similarly, acidification of manure slurry may be effective at reducing methane emissions but may be impractical for California operations due to the need for large acid volumes that require special handling and safety equipment. CARB will continue tracking developments in manure additives as they become available, especially those with long-term studies that detail potential methane emissions mitigation effectiveness and environmental co-benefits.

Finding 1-5: Dairy and Livestock Sector May Fall Short of the 2030 Target absent an Enteric Strategy and Sufficient Public Funds[51]

To estimate potential emissions reductions from manure management projects under various public funding scenarios, CARB staff developed scenarios to extrapolate funding outcomes through 2030. These projections are based on project development costs and emission reductions described above, and do not account for environmental credit values on project costs. The impact of LCFS and RFS environmental credit prices on project economics is discussed in the following section. Figure 7 (below) illustrates potential methane emissions reductions achievable through the combination of an available enteric strategy, changes in animal populations, and from manure management projects at different levels of CCI funding assumptions.52 The 2030 target is shown as a red dotted line at the top of the graph. Potential methane emissions reductions from average animal population changes (discussed in Finding 1-1) are shown as a dark blue dashed line at the bottom of the graph.

[51] Trends discussed in this section are based on publicly available data wherever possible. In instances where available information was incomplete or insufficient, CARB staff used reasonable and conservative assumptions based on existing trends and available information.

[52] Funding projections assume that DDRDP and AMMP will fund an approximately equal number of projects, consistent with past practice.

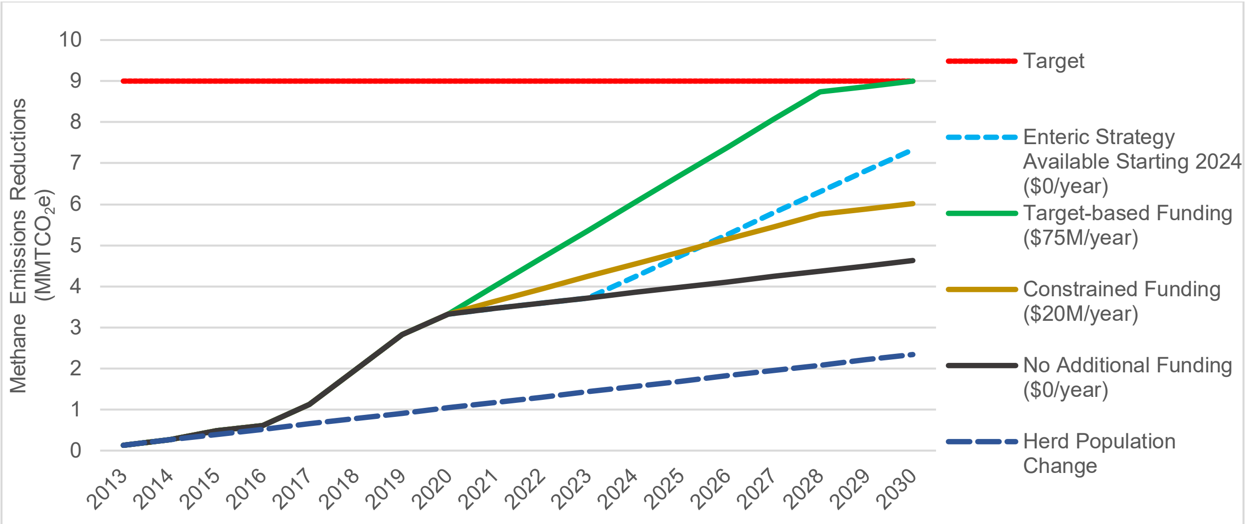

Figure 7. Projected Annual California Dairy and Livestock Sector Methane Emissions Reductions through 2030[53][54]

Additionally, Figure 7 shows methane emissions reductions expected under three different funding scenarios from FY 2020-21 through FY 2027-28 (green, brown, and dark gray solid lines).[55] It also shows potential emissions reductions from herd population changes and a potential enteric strategy (dark and light blue dashed lines, respectively). The funding scenarios assume that the observed decline in animal populations will continue at a constant rate through 2030. While emissions reductions attributable to a potential enteric strategy are shown in the figure, those emissions reductions are not accounted for in any of the funding scenarios above.

Each scenario includes emissions reductions expected from changes in population through 2030 as well as reductions expected from DDRDP and AMMP projects funded through FY 2019-20.

Incentive Funding Scenario 1: No Additional Funding

This scenario assumes that no additional appropriations of local, state, and federal funds are available for DDRDP and AMMP beyond FY 2019-20. Methane emissions reductions expected under Scenario 1 are shown in Figure 7 by the gray line labeled "No Additional Funding." This scenario assumes that funding is the limiting factor in new projects coming online. The y-axis difference between this line and the population

[53] Funding levels identified in Figure 7 do not reflect potential revenue from the generation of Cap-and-Trade, LCFS, or RFS RIN credits.
[54]Funding levels identified in Figure 7 do not reflect potential revenue from the generation of Cap-and-Trade, LCFS, or RFS RIN credits.
[55] Funding levels do not reflect private match funding that is required for DDRDP projects.

change line represents emissions reductions attributed mostly to State funds, emphasizing their importance in achieving the methane emissions reductions through 2022. Staff estimates this scenario will achieve 4.6 $MMTCO_2e$ of methane emissions reductions by 2030, falling 4.4 $MMTCO_2e$ short of the 2030 target.

Incentive Funding Scenario 2: Constrained Funding

This scenario assumes that consistent annual appropriations of $20 million for DDRDP and AMMP from FY 2020-21 through FY 2027-28. Methane emissions reductions expected under Scenario 2 are shown by the yellow line in Figure 7. This scenario assumes that allocations between DDRDP and AMMP will fund an approximately equal number of projects, consistent with past practice. With constrained funding through FY 2027-28, all funded projects will likely be operational by 2030. Staff estimates this scenario will achieve 6.0 $MMTCO_2e$ of methane emissions reductions by 2030, falling 3.0 $MMTCO_2e$ short of the 2030 target.

Incentive Funding Scenario 3: Target-Based Funding

This scenario assumes annual appropriations of $75 million for DDRDP and AMMP beyond FY 2019-20 through FY 2027-28—a level sufficient to achieve the 2030 target through manure emissions mitigation projects. This scenario accounts for a 20 percent project cost increase over current levels due to projects with smaller cattle populations and increased distances to the nearest natural gas pipeline with sufficient capacity. Methane emissions reductions expected under Scenario 3 are shown by the green line in Figure 7. Staff estimate that this scenario will achieve the 2030 target of 9.0 $MMTCO_2e$.

Enteric Strategy Scenario

Staff also estimated that a scientifically proven, cost-effective, safe, and consumer-accepted enteric methane mitigation strategy may be commercially available within the next three to five years to help achieve the 2030 target, shown by the light blue dashed line near the top of Figure 7. This assumes adoption of a feed additive with 30 percent enteric methane mitigation potential across ruminant species in California starting in 2024, and a linear annual adoption rate of approximately 11 percent through 2030, totaling 75 percent of the ruminant population.

For simplicity, the target-based funding scenario assumes that no enteric strategy will be available before 2030. Similarly, the enteric strategy scenario described below assumes that no public funding will be available beyond FY 2019-20. While both scenarios are based on reasonable estimates and are illustrative of potentially achievable methane emissions reductions, actual methane emissions reductions may vary.

While these scenarios focus on the outcomes of public investments and required private match funding to meet the 2030 target, revenue available through the California Cap-and-Trade Program and LCFS Program, as well as the federal RFS Program, can substantially reduce or eliminate the need for public funding of these projects. These revenue streams have become strong drivers of anaerobic digestion projects, helping ensure their long-term operation and financial stability.

Alternative Manure Management Practice Scenarios

Staff also evaluated the potential for different adoption rates of alternative manure management practices at California dairies to help achieve the 2030 target. As above, staff used average methane emissions reduction values to calculate potential reductions from various numbers of additional projects at California dairies. Staff also assumed that the approximately 280 dairy operations that had already implemented a manure methane strategy would not incorporate additional manure or implement enteric methane reduction strategies, leaving approximately one thousand dairies available for project implementation. Staff evaluated potential annual methane emission reductions resulting from alternative manure management project adoption under three different scenarios with 250, 500, and 750 additional dairies.

The estimated annual emissions reductions for each scenario are shown in Figure 8 (below). The 2030 target is shown as a red dotted line at the top of the graph. At the bottom of the graph, a solid red line shows the methane emissions reductions attributed to dairy and livestock population change and manure methane emissions reduction projects already completed or under construction. It assumes that no additional digesters projects and no enteric methane reduction strategies are implemented, showing the potential impact of alternative manure management projects on progress towards the 2030 target. The blue, yellow, and gray lines show expected annual emissions reductions from implementing new alternative manure management practices on 250, 500, and 750 additional dairies, respectively. On their own, none of these scenarios are estimated to provide sufficient methane emissions reduction to achieve the 2030 target.

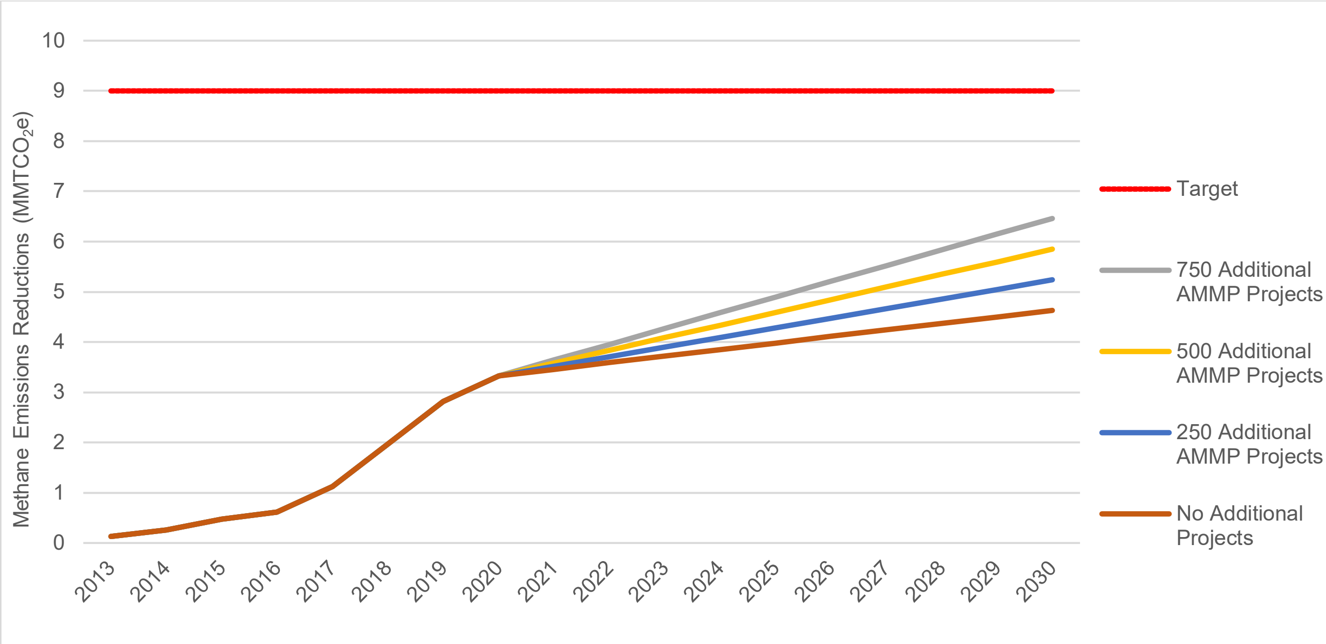

Figure 8. Projected Annual California Dairy and Livestock Sector Methane Emissions Reductions through 2030 Resulting from Implementing Additional Alternative Manure Management Projects

However, alternative manure management practices are important strategies that may provide significant additional environmental co-benefits. First, these practices may be more broadly implemented across the sector, including at small- and medium-sized dairies due to reduced upfront capital and maintenance costs compared to digesters. They may also provide flexibility to dairies with configurations that make digester implementation infeasible. Second, implementing certain alternative manure management practices alone or in combination with practices incentivized by other programs such as State Water Efficiency and Enhancement Program may provide additional water conservation and GHG benefits. These practices include conversion to scrape manure management, use of sub-surface drip irrigation, or pasture dairy conversion. Third, alternative manure management practices may improve solids and nutrient management, reduce nitrate leaching and improve water quality, reduce chemical fertilizer use, increase crop yield, and provide cost savings to dairy and livestock operations.

In addition to solid-liquid separation, compost bedded pack barns, conversion to scrape manure management, and pasture dairy conversion, stakeholders have proposed eligibility for other alternative manure management practices. These practices include but are not limited to manure acidification, vermifiltration, advanced chemical flocculation, and dissolved air flotation. Given the emergent nature of these strategies, additional research or observation at California dairy and livestock operations is necessary to evaluate methane reduction potential, long-term effectiveness, and potential unintended environmental impacts. Staff will continue monitoring deployment of these and other promising alternative manure management practices as they become available.

In some cases, alternative manure management practices can be combined with digesters to achieve greater emissions reductions than either strategy might on its own. Solid-liquid separators are commonly installed in conjunction with covered lagoon digesters to remove coarse solids, potentially reducing digester maintenance needs. These separated solids can be used for animal bedding, providing cost savings to the farmer. These same solids and nutrients can also be further processed into compost or soil amendment for onsite land application or export offsite, potentially generating additional revenue or cost savings while reducing chemical fertilizer needs. Stricter control of solids and nutrients can also help minimize water quality impacts by reducing nutrient leaching to groundwater.

Finding 1-6: Dairy Digester Development Will Need Significant Policy and Incentive Support, Providing Additional Methane Emissions Reduction Potential and Biomethane Supply

Generating environmental credits through the California Cap-and-Trade Program, LCFS Program, and federal RFS Programs can provide important revenue streams to dairy operators and project developers. As a result, these credit values are likely to drive additional dairy digester project development, methane emissions reductions, and increases in-State biomethane supply.

To estimate statewide dairy biomethane supply and production cost, staff reviewed existing literature and reports[56,57,58] as well as recent dairy population data from Regional Water Quality Control Board permits and annual reports. As part of that evaluation, and to refine supply estimates, staff adjusted underlying datasets to reflect facilities that had implemented an alternative manure management practice[59] or had closed. Staff assume that the remaining dairies can implement a digester project and

[56] Jaffe, A. M. (2016). Final Draft Report on The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute.

[57] Jaffe, A. M., Dominguez-Faus, R., Ogden, J., Parker, N. C., Scheitrum, D., McDonald, Z., Fan, Y., Durbin, T., Karavalakis, G., Wilcock, G., Miller, M., Yang, C. (2017). The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology.

[58] Parker, N., Williams, R., Dominguez-Faus, R., & Scheitrum, D. (2017). Renewable natural gas in California: An assessment of the technical and economic potential. *Energy Policy*, *111*, 235-245.

[59] Facilities with alternative manure management practices implementation are less likely to divert animal waste to anaerobic digesters for biomethane production.

estimate that at least an additional 210 digester projects are necessary to achieve the target (in addition to 210 alternative manure management projects).

The six project technology options below describe potential pathways to use methane captured in a digester. These options include onsite electricity production using a reciprocating engine, a microturbine, or a solid oxide fuel cell, as well as direct injection into a natural gas pipeline from a single dairy, cluster of dairies, or through trucking to an existing interconnection point where it can displace fossil natural gas. While these technology options may result in similar methane emissions reductions, criteria pollutant performance, potential carbon intensities, project costs, and project revenues may vary considerably. Staff assume that project developers will select the digester technology option that is most suitable for their facility.

Anaerobic Digestion Technology Option 1: Reciprocating Engine Generator for Electricity Generation

This technology option involves using a reciprocating engine generator to generate electricity on site using biogas and offset fossil fuel-derived electricity for a variety of end uses, including but not limited to electric vehicle charging.[60] However, reciprocating engine generators also result in new sources of air pollutant emissions that adversely impact regional air quality, attainment of ambient air quality standards, and public health outcomes. For example, the San Joaquin Valley is home to the majority of the State's dairy and livestock operations, it has among the worst air quality in the country and is home to many of the State's most disadvantaged and low-income communities. Given the potential for further impacts, utilizing even the cleanest reciprocating engine generator is the least desirable option.

Anaerobic Digestion Technology Option 2: Microturbine for Electricity Generation

This technology option involves using a microturbine certified under the CARB Distributed Generation (DG) Certification Program to generate electricity using biogas. The DG Certification Program requires manufacturers of electrical generation technologies that are exempt from air district permit requirements to certify their technologies to specific criteria pollutant emission standards before selling products in California. Common DG technologies certified under this program include fuel cells and microturbines. Microturbines have higher costs compared to reciprocating engine generators but produce fewer air pollutant emissions, and therefore have fewer associated impacts on regional air quality and public health. As with all onsite

[60] The LCFS Program includes three California dairies projects that use reciprocating engine generators, one of which received a -630.92 g/MJ carbon intensity score, the lowest LCFS carbon intensity score to date.

electricity generation projects, microturbines do not require pipeline interconnection, improving their locational flexibility compared to pipeline projects.

Anaerobic Digestion Technology Option 3: Fuel Cell for Electricity Generation

This technology option involves using a fuel cell to generate onsite electricity using biogas to support electric vehicle charging.[61] Fuel cells generate onsite electricity with very low air pollutant emissions, especially when compared to emissions associated with reciprocating engine generators. These projects provide electricity using biogas that avoids up to 90 percent of the NOx and up to 80 percent of the particulate matter emissions resulting from other combined heat and power technologies on a life-cycle basis.[62] Fuel cells installed at dairies have the potential to be certified for ultra-low carbon intensity scores, and the potential LCFS credit revenue may make them competitive in the long-term. As with all onsite electricity generation projects, fuel cells do not require pipeline interconnection, improving their locational flexibility compared to pipeline projects.

Anaerobic Digestion Technology Options 4a & 4b: Onsite Injection of Biomethane into a Natural Gas Pipeline

These technology options include either single dairy or cluster pipeline interconnection projects. These are the most common options and involve biogas capture, upgrading to pipeline biomethane specifications, and injection into a natural gas pipeline. These projects reduce GHG emissions further when they replace fossil natural gas. They also avoid onsite combustion for electricity generation and the associated onsite air pollutant emissions and public health impacts. As a result, these projects are preferable to onsite combustion projects but may not be feasible due to factors including distance to the nearest natural gas pipeline with enough capacity, and whether the facility is part of a cluster. Project cost between these two categories differ notably, with single dairy projects costing considerably more compared to cluster projects due to lack of ability to share upgrading facility and pipeline extension costs.

Anaerobic Digestion Technology Option 5: Trucking Biomethane to an Existing Interconnection Point for Injection into Natural Gas Pipeline

This technology option involves trucking biomethane to the closet injection point or natural gas vehicle refueling station. This option assumes that biomethane is

[61] Two DDRDP projects use Bloom Energy solid oxide fuel cells.
[62] An Assessment of Energy Technologies and Research Opportunities: Chapter 4: Advancing Clean Electric Power Technologies September 2015.

transported by a zero-emissions electric or natural gas heavy duty truck with few criteria pollutant (including oxides of nitrogen) and particulate matter emissions compared to a diesel heavy-duty truck. Using natural gas or electric heavy-duty trucks reduces criteria pollutant emissions and avoids emissions of harmful diesel particulate matter from biomethane transport, with negligible impact on project cost compared to using a diesel truck. Trucking biogas, referred to as a "virtual pipeline," may reduce project costs and provide flexibility compared to construction of dedicated pipelines. It also mitigates the risk of stranded infrastructure in the event of reduced demand from a site-specific large downstream consumer (e.g., milk processing operation). Trucking biomethane to existing injection points may be a cost-effective delivery option that results in fewer emissions than reciprocating engine generator and microturbine projects. However, it will also increase vehicle miles traveled, likely in disadvantaged communities, so incentives or regulatory approaches should encourage facilities to reduce reliance on trucking where feasible and use of zero emission vehicles or natural gas heavy-duty trucks when necessary.

Potential Biomethane Supply from Anaerobic Digestion

The preceding anaerobic digestion technology options describe potential pathways to deliver biomethane to market through electricity generation or pipeline injection. This section illustrates the potential biomethane supplied to market and associated costs under each of these options in a baseline scenario, and under various environmental credit price scenarios. Figure 9 below shows potential biomethane supply and market delivery cost under a baseline scenario, which is absent any State or federal financial incentives. The dashed red line shows expected biomethane supply by 2022, approximately 4.7 trillion British thermal units (Btu). The dashed black line indicates the estimated amount of biomethane supply (~13.5 trillion Btu) needed to achieve the 2030 target. Without State or federal financial incentives like the State's LCFS Program or the federal RFS Program, none of the technology options described above (Figure 9) are financially viable.

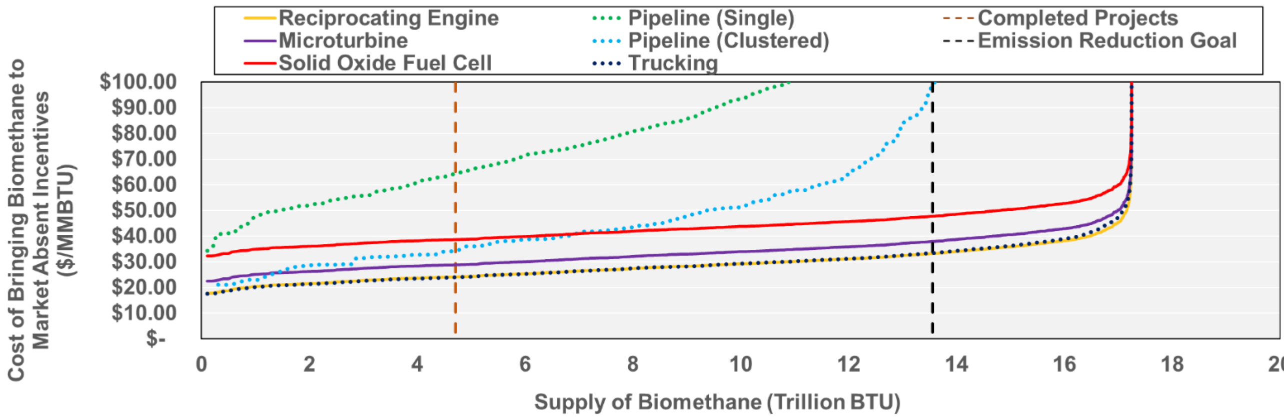

Figure 9. Biomethane Supply and Market Delivery Cost under Different Technology Options absent Federal and State Incentives

Figure 9 illustrates the cost of bringing biomethane to market under each technology option absent any public incentives (e.g., CCI funds, Cap-and Trade Program compliance offset credits, LCFS credits, RFS RIN credits). The costs portrayed for this curve and the subsequent supply curves in Figures 10 through 12 show levelized cost, and therefore includes financing assumptions for the digester projects as well as the additional capital and operating expenses associated with the technology that uses the dairy gas produced through anaerobic digestion. For instance, the levelized cost of pipeline projects is inclusive of the covered lagoon and anaerobic digestion system, upgrading the gas, building the pipeline, and injecting the gas into the pipeline. For the other technologies, the costs include any upgrading costs, as well as any additional equipment costs (e.g., solid oxide fuel cell) required to bring the gas to market.

In general, the supply curves for pipeline-based technologies have a substantially greater upward slope. Pipeline interconnection distances vary for each facility, and facilities that are further away from pipelines will have higher costs to build the network relative to facilities that are closer to pipeline interconnection points. Additionally, facilities that produce more biomethane (i.e., larger facilities) will be able to recoup fixed pipeline costs by distributing these costs over larger quantities of produced biomethane over time. As such, the lowest cost pipeline projects will generally be for large facilities that are closer to pipeline interconnections. The other technologies largely scale linearly with the size of the facility. As such, the slope for non-pipeline technologies is generally more gradual.

The cost to deliver biomethane to market may be as low as $30 per MMBtu if trucked to an existing pipeline interconnection or used to produce onsite electricity using a reciprocating engine generator. In contrast, delivering biomethane to market may cost as much as $100 per MMBtu for pipeline injection at a cluster of dairies—the costliest option with sufficient capacity to achieve the 2030 target. For comparison, in October 2020 wholesale fossil natural gas prices on Henry hub were approximately $3 per MMBtu, but has increased to approximately $5 per MMBtu in October 2021. Given that the price of fossil natural gas is approximately one tenth to one sixth that of biomethane, it is uneconomic to utilize biomethane without incentives beyond sale price.

Staff used biomethane delivery costs and volumes from Figure 9 to estimate potential costs for implementing at least 210 additional digester projects necessary to achieve the 2030 target. To be conservative, staff developed estimates using expected biomethane delivery costs from the 2030 target line to reduce potential underestimation of the total cost to achieve the target for feasible scenarios. Project costs on this line are expected to be the highest over time and assumes that more financially feasible projects have already been implemented.

To bound the potential total cost of achieving the 2030 target, staff used the solid oxide fuel cell scenario costs as an upper bound and costs associated with trucking biomethane to an existing interconnection point and producing onsite electricity using a reciprocating engine generator as the lower bound value. Though cluster pipeline projects may also potentially deliver sufficient biomethane to meet the 2030 target, this scenario is unlikely to be implemented at enough facilities to achieve the target. The costs associated with constructing additional pipelines to supply enough biomethane to achieve the target make it increasingly unlikely that the more costly projects would be implemented. Instead, it is more likely that these facilities will choose the lower cost options of generating onsite electricity or trucking biomethane to an existing interconnection point. As such, it is inappropriate to use direct pipeline injection as an upper cost bound.

Staff also assumed, as previously discussed in Finding 1-1, that at least 210 alternative manure management projects may be implemented at an assumed per project cost of $0.6 million, resulting in a total cost of $0.1 billion. Staff added this $0.1 billion to the total costs associated with the lower and upper bound cost of implementing the additional 210 digester projects. Based on these assumptions, the estimated total cost to achieve the 2030 target range from $0.8 to $3.7 billion absent any public incentives. The 2030 target may also be achieved solely through implementation of as few as 230 additional digester projects costing between $0.7 and $3.9 billion.

With public incentives like LCFS credits and RFS RINs, the need for upfront public investment in digester projects[63] may be reduced or even eliminated, assuming project developers will have access to debt financing for upfront project construction cost. These incentives can be sufficient to offset project development, operational, and financing costs in some cases depending on the level of incentive available, providing a positive project revenue stream and making the project financially viable.

Staff evaluated the same methane emissions reduction technology options used in the baseline scenario above to estimate biomethane supply and cost under various combinations of LCFS and RFS RIN credit prices.[64,65,66] These credit value scenarios range from $150-$200 per credit for LCFS and $0-$2 per RIN. Table 6 shows potential credit values from delivering one MMBtu of biomethane to market at these price ranges under different technology options. Potential credit values at such levels may make these projects competitive with fossil natural gas and with other sources of biomethane.

Table 6. Potential Environmental Credit Value ($) from Producing One MMBtu of Biomethane under Different Technology Options at Various LCFS and RIN Credit Prices[67]

Biomethane Delivery Option	LCFS $150			LCFS $200		
	RIN $0	RIN $1	RIN $2	RIN $0	RIN $1	RIN $2
Reciprocating Engine	$41	$41	$41	$55	$55	$55
Microturbine	$55	$55	$55	$74	$74	$74
Solid Oxide Fuel Cell	$64	$64	$64	$85	$85	$85
Pipeline (Single or Cluster)	$49	$62	$75	$66	$79	$92
Trucking	$44	$57	$70	$59	$72	$85

[63] Alternative manure management projects are not eligible for State and federal biomethane incentive programs because, while they do reduce dairy methane emissions, they do not produce biomethane.
[64] Assumes D3 cellulosic RIN
[65] Electricity generation projects are not currently able to generate RFS RIN credits and have been assigned a $0.00 RIN price across all evaluated credit price scenarios.
[66] Offset credits are not evaluated because the LCFS credits value is considerably more than the Cap-and-Trade program.
[67] The assumed carbon intensities, energy efficiency rating (EER), and percent efficiency rating for the identified biomethane delivery options are as follows:

- Reciprocating Engine: -490 grams per mega Joule (g/MJ), 3.4 EER, 32% efficiency
- Microturbine: -490 g/MJ, 3.4 EER, 44% efficiency
- Solid Oxide Fuel Cell: -400 g/MJ, 3.4 EER, 57% efficiency
- Pipeline (Single or Cluster): -230 g/MJ, 0.9 EER, 100% efficiency
- Trucking: -230 g/MJ, 0.9 EER, 100% efficiency

Figure 10 through Figure 12 below illustrate the potential biomethane supply and market delivery cost under three different combinations of LCFS and RIN credit prices. These scenarios illustrate a potential lower bound, a potential upper bound, and a scenario with medium credit values. They are described in greater detail below. Values below $0.00 on the y-axis provide positive revenue to projects making them financially viable because revenues exceed project costs. Conversely, values above $0.00 indicate that revenues are insufficient to offset project costs, making the projects infeasible because supply costs are too high.

Environmental Credit Price Scenario 1: $150 LCFS and $0 RIN

This scenario estimates biomethane supply and production cost assuming values of $150 for LCFS credits and $0 for RIN credits (Figure 10). Under this scenario, single dairy pipeline projects can supply approximately 1 trillion Btu of biomethane to the market, falling far short of the required volume to meet the 2030 target. Previously funded projects exceeded this capacity, which suggests that future single pipeline injection projects are not viable at these prices.

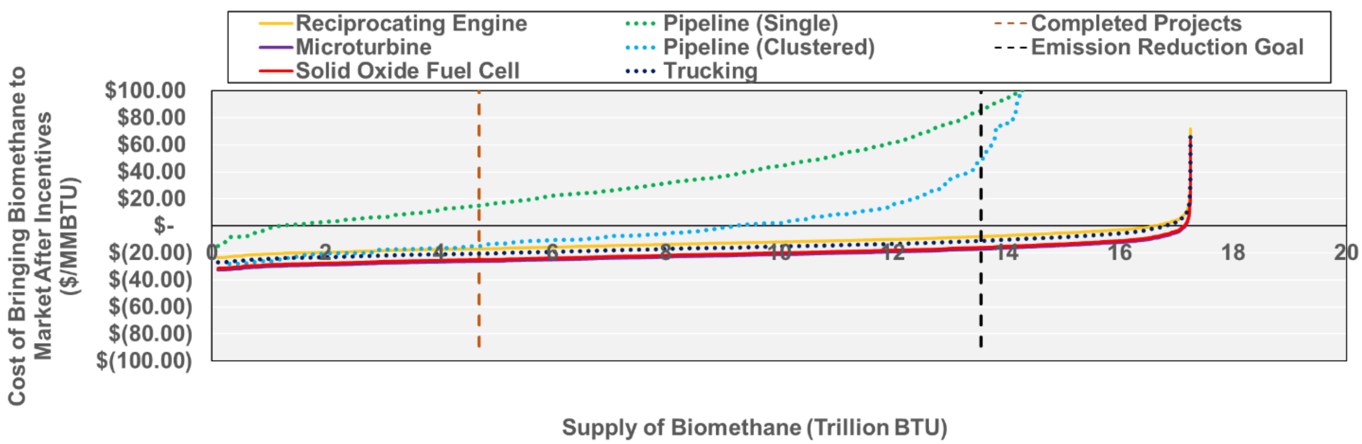

Figure 10. Biomethane Supply and Market Delivery Cost at LCFS and RIN Credit Prices of $150 and $0, Respectively

For comparison, clustered pipeline projects can supply approximately 9 trillion Btu. While a significant increase over the single pipeline projects, this still falls short of the volume required to meet the target. Under Scenario 1, both the single and cluster pipeline injection options are unable to bring sufficient dairy biomethane to market to meet the target without additional incentives.

However, biomethane-to-electricity projects and trucking biomethane to existing interconnection points may provide enough biomethane volume to the market to meet the 2030 target. In this scenario, the solid oxide fuel cell technology option generates the highest revenue with an LCFS environmental credit value of $64 per

MMBtu. Biogas-to-electricity projects that use reciprocating engines and microturbines result in less revenue but cost less than solid oxide fuel cell projects.

Environmental Credit Price Scenario 2: $200 LCFS and $1 RIN

This scenario estimates biomethane supply and production cost assuming values of $200 for LCFS and $1 for RIN (Figure 11). Under this scenario, single-dairy pipeline projects can cost-effectively supply approximately 8 trillion Btu of biomethane to the market, which is a considerable increase over Scenario 1, but still more than 5 trillion Btu short of the 2030 target. Cluster pipeline injection projects will not be able to cost-effectively supply sufficient biomethane to achieve the target either, falling short by approximately 1 trillion Btu. Consistent with Scenario 1, biogas-to-electricity, solid oxide fuel cell projects, and biomethane trucking projects can supply sufficient biomethane to achieve the 2030 target, with the latter two offering the considerably higher credit revenue. Under this scenario, only dairy pipeline injection projects would require additional incentives to achieve the target.

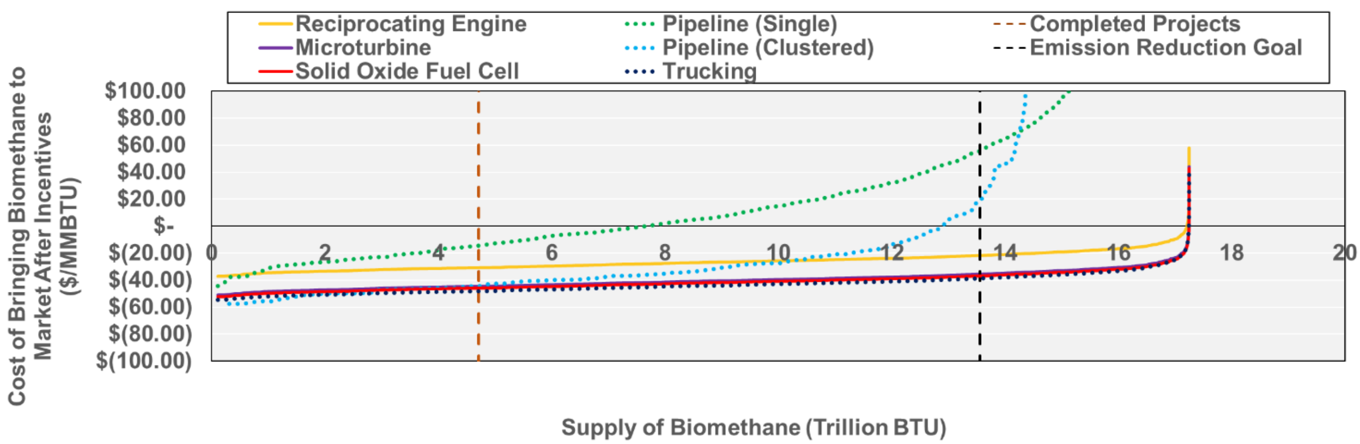

Figure 11. Biomethane Supply and Market Delivery Cost at LCFS and RIN Credit Prices of $200 and $1, Respectively

Environmental Credit Price Scenario 3: $200 LCFS and $2 RIN

This scenario estimates biomethane supply and production cost assuming values of $200 for LCFS and $2 for RIN (Figure 12). In this scenario, single-dairy pipeline injection projects can cost-effectively bring about 10 trillion Btu of biomethane to market, the highest volume across scenarios but still fall short of the target by 3 trillion Btu. Cluster pipeline injection projects can cost-effectively bring over 13 trillion Btu of biomethane to market, nearly achieving the target. Trucking projects are the most cost-effective overall resulting from credit revenue available and relatively low project development costs. Solid oxide fuel cell projects are another cost-effective option given the estimated credit value. Under this scenario, all but pipeline injection projects can cost effectively bring enough biomethane to market without the need for additional incentives.

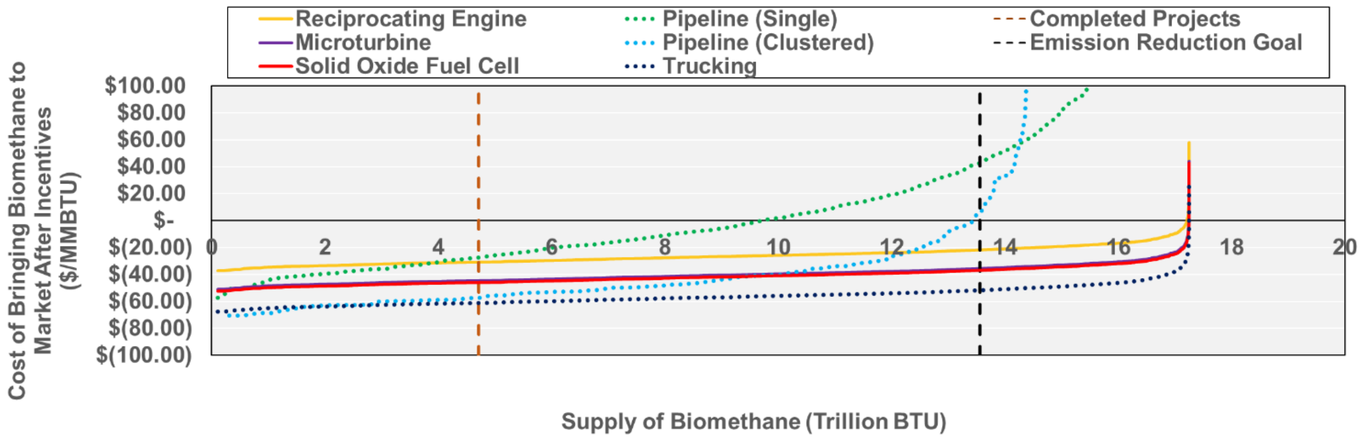

Figure 12. Biomethane Supply and Market Delivery Cost at LCFS and RIN Credits Prices of $200 and $2, Respectively

Current Federal and State Environmental Credits, Combined with Project Development Incentives, May Be Sufficient to Support Dairy Biomethane Projects

As the scenarios above illustrate, LCFS and RFS RIN credit prices are significant drivers of economic feasibility for anaerobic digestion projects at California dairy and livestock operations. This is especially true for projects that do not receive public funding. It is also clear that, given sufficient and sustained credit prices, most of these project types can cost-effectively supply sufficient biomethane to achieve the 2030 target with no additional public incentive funding, potentially reducing the need for those resources.

While each of these anaerobic digestion scenarios can potentially generate revenue or even profits to support construction and operation of digester projects, LCFS and RFS credit markets may be perceived as relatively uncertain as compared to conventional project financing options. Developers unable to obtain debt financing will need additional equity, assets, or public funding like that available through CCI to avoid delays in project implementation, or foregoing projects altogether. In these cases, local, state, and federal funding can ensure that projects will continue to move forward.

State law requires DDRDP expenditures funded by CCI to prioritize projects based on criteria pollutant emissions reduction benefits. While environmental credit prices may be sufficient to drive and sustain projects without additional public funds, the absence of these incentives may result in less desirable projects. For example, projects that use a reciprocating engine generator to produce electricity from biogas are often lower cost than other options but result in criteria pollutant impacts, potentially in some of California's most disadvantaged communities.

Similarly, trucking of biomethane to existing interconnection points may be a lower-cost option but may result in increased criteria pollutant emissions and vehicle miles traveled throughout the State. Reducing or eliminating CCI or other public funding for dairy and livestock methane emissions reduction projects may eliminate prioritization of projects that deliver important environmental and public health co-benefits.

Alternative Manure Management Projects Are Unlikely to be Implemented Without Incentives

Alternative manure management practice projects are not eligible to generate environmental credits because it is difficult to quantify methane emissions reductions relative to facility baseline emissions. This results from site-specific project variations that influence methane emissions mitigation. Variability in outcomes is a barrier to develop an offset quantification protocol for alternative manure management practices, so these projects are currently ineligible to generate carbon offset credits under CARB's Cap-and-Trade Program. As a result, financial viability is dependent on public funding, cost savings, and potential sales of value-added manure products like soil amendments and compost. In many cases, these combined savings and revenues are insufficient to offset project development costs, so public investments are critical. Without them, it is unlikely that a large number of projects will be implemented, which may impede the sector's ability to maximize its contribution to the target. These projects also provide important environmental and economic co-benefits through production of high-quality soil amendments, destruction of pathogens, reduction in nitrates and salts that threaten water quality, and production of a product that can be cost effectively transported to replace chemical fertilizer across the State.

Additional State Policies and Incentives Can Support Dairy Biomethane Projects

Long-term policies and incentives can play critical roles in supporting ongoing capture and use of biomethane from the dairy sector to achieve the 2030 target and the State's broader carbon neutrality goals. For example, a funding mechanism that incentivizes the capture of biomethane in California could expand to advance the production and use of biomethane and could provide market certainty to help project developers obtain project financing. While dairy biomethane is currently directed to the transportation fuel market through the LCFS Program, other market-based programs could play a role in directing the biomethane to alternative end uses, including towards industries that are difficult to electrify and otherwise decarbonize.

As described in the 2017 Scoping Plan Update, California must prioritize electrification wherever possible to in order to achieve its GHG emissions reduction goals. The State's electricity sector has already made considerable progress in moving toward zero- or low-GHG emissions generation, but other sectors including transportation, residential, and commercial still offer significant potential to decarbonize using electricity from sources like wind and solar. Some sectors, however, are difficult to electrify so directing dairy and livestock biomethane to these sectors can help decarbonize them, contributing to State carbon neutrality goals. The Scoping Plan Update will discuss additional policies to diversify dairy biomethane use and ensure long-term success of these projects to contribute to State's climate targets.

Analysis Item 2: Progress Made in Overcoming Technical and Market Barriers to Dairy and Livestock Methane Emissions Reductions Projects

The Strategy identifies barriers to methane emissions reductions measures that the dairy and livestock sector must overcome to achieve the 2030 target. These include technical barriers that impede project development based on various factors including technology limitations, incomplete development, or lack of standardized information. Market barriers impede project development based on factors including cost, availability of financing, environmental credit uncertainty, consumer acceptance, cost-effectiveness, and sector economics. This section will provide a short summary description of how to understand the technical and market barriers in this sector, followed by findings regarding the identified technical barriers and market barriers. Ultimately, the findings support that investment by the State and successful collaborations between agencies, developers, and stakeholders have largely overcome previously significant barriers.

Technical Barriers

Technical barriers impede both manure management methane emissions reduction projects and enteric mitigation strategy development. Specific to manure management, technical barriers impact both anaerobic digestion and alternative manure management projects. As described in the Strategy, technical barriers to anaerobic digestion include difficulties interconnecting with utility electrical grids and natural gas pipeline networks.

Technical barriers to alternative manure management projects result from inconsistent methane emissions reductions across project types and the resultant difficulty with accurately quantifying methane emissions reductions. In some cases, technical barriers may reinforce market barriers, making them even harder to overcome. For example, challenges in quantifying alternative manure management projects impedes the development of offset protocols or other market mechanisms that could improve their financial viability.

Market Barriers

Like the technical barriers discussed above, market barriers also impede both anaerobic digestion and alternative manure management projects. As detailed in the Final Recommendations to the Dairy and Livestock Greenhouse Gas Reduction Working Group, existing market barriers for manure methane reduction projects include project development costs, perceived lack of environmental credit certainty, out-of-State RNG competition, and underdeveloped markets for manure-based products. In addition to competition from out-of-State RNG, electricity and biofuels from California dairy waste faces competition from other sources of in-State renewable electricity such as solar and wind electricity, and competition from other sources of biomethane like landfills. As a result, dairy project developers rely on incentive funding or environmental credit revenues to make projects feasible. However, demand for incentives has consistently outpaced supply, especially for grant funding. Table 7 summarizes the status of progress for each technical and market barrier discussed in this section.

Table 7. Technical and Market Barriers to Implementing Manure Management and Enteric Fermentation Methane Emissions Reductions Projects

	Technical Barriers	Market Barriers
Manure Management	Alternative manure management projects ✗ Inconsistent reductions ✗ Difficulty quantifying reductions Anaerobic Digesters ✓ Grid and pipeline interconnection ✓ Biomethane quality standards	✓ Project development costs and financing ✓ Environmental credit certainty ✗ Sector economics ✗ Insufficient public funds ✗ Undeveloped markets for value-added manure products
Enteric Fermentation	✗ Transient effect/rumen adaptation ✗ Potential animal health impacts Limited availability ✓ Limited products with commercial availability ✗ Seasonal products	? Consumer acceptance ? Cost-effectiveness

✓ = Progress made ✗ = Persistent barrier? = Limited information available

Finding 2-1: Technical Barriers: Progress Has Been Made on Grid and Pipeline Interconnection and Biomethane Quality Standards, but Other Technical Barriers Remain

Technical Barriers to Anaerobic Digestion Projects

The dairy and livestock sector has made progress in overcoming certain technical barriers of manure methane emissions reductions projects, including access to pipeline networks and utility electrical grids. Project developers and utilities collaborated to understand technological and cost requirements for pipeline and electricity grid interconnection to reduce project development timelines.

Specific to pipeline injection projects, state agencies, utilities, project developers, and suppliers of biomethane upgrading equipment collaborated to identify technology immediately available for dairy operations to upgrade biomethane onsite.[68] Raw biogas from dairy and livestock facilities is mostly comprised of methane and carbon dioxide, with traces of many other constituents including oxygen, nitrogen, hydrogen sulfide, and water. To be injected into the utility pipeline, it must be upgraded, conditioned, and compressed to required pressures. Since the adoption of the Strategy, in Proceeding R.13-02-008, CPUC lowered the minimum heating value required for biomethane injected into natural gas pipelines. Prior to this change, achieving minimum heating value standards was a significant technical challenge and cost barrier for biomethane injection projects. This change resulted in decreased upgrading costs and removed the technical barrier without endangering public health or pipeline integrity.

In 2008, Pacific Gas and Electric Company (PG&E) interconnected the first dairy biomethane pipeline injection project, the first of its kind in California. PG&E continues to allow biomethane producers like dairy and livestock operations to interconnect to the natural gas pipeline system within their coverage area where sufficient capacity and downstream demand within the local pipeline exists. Interconnecting to the PG&E natural gas pipeline network consists of three steps. The first step involves an interconnection screening study which PG&E uses to determine the closest pipeline that can accept a producer's pipeline quality biomethane supply. Step two involves a preliminary engineering study where PG&E reviews the safest, most efficient interconnection route before developing a preliminary cost estimate for the

[68] Online Article. Xebec Enters California Dairy RNG Market with Maas Energy Works. Accessed on December 05, 2019.

interconnection. The final step consists of a detailed engineering study followed by construction of the interconnection.

In 2015, Southern California Gas Company (SoCalGas) began offering the Biogas Conditioning/Upgrading Services Tariff to allow the utility to plan, design, procure, construct, own, operate, and maintain biogas conditioning and upgrading equipment on customer premises. This optional fee service can further assist customers in their coverage area to overcome technical difficulties associated with interconnecting to the natural gas pipeline system. These potential biogas upgrading options help facilities achieve biomethane quality standards necessary for pipeline injection.

PG&E and SoCalGas are also working with dairy biomethane producers to engineer and construct pipeline infrastructure for six dairy biomethane pilot projects pursuant to SB 1383. These projects will help producers, utilities, and the State better understand the technical and economic factors affecting biomethane injection while ensuring and demonstrating successful biomethane delivery into the pipeline network. Additionally, three in-State projects that currently inject biomethane to the utility pipeline system have consistently met SoCalGas biomethane delivery specifications. In 2019, one of these projects completed construction of a digester cluster in Pixley, California and began delivering biomethane to the SoCalGas natural gas pipeline network. While costly, achieving pipeline quality specifications is technically feasible and no longer considered a technical barrier. In fact, in response to CARB's May 2020 webinar on this Analysis, SoCalGas submitted comments clarifying that the utility no longer views achieving pipeline quality specifications for biomethane injection a significant technical barrier.

Project developers and electric utilities have also overcome financial and technical barriers to accessing utility electrical grids. Interconnecting to utility electrical grids requires initial feasibility studies, which can cost several hundred thousand dollars, to outline site-specific technology requirements. Equipment and installation costs for system upgrades can be up to $1 million or more. While the costs and timelines associated with interconnections have not decreased considerably, experience from initial projects has helped to improve understanding of the processes and technical requirements and increased the deployment rate of electricity generation at dairy facilities. Three in-State dairy operations currently have certified LCFS pathways to deliver renewable electricity to the grid for electric vehicle charging with additional facilities—including two solid oxide fuel cell projects under development—that will pursue similar electric vehicle charging pathways to capitalize on potential LCFS credit revenue.

Technical Barriers to Alternative Manure Management Projects

Methane emissions reductions from alternative manure management practices vary substantially based not only on the technology chosen, but also on project-specific implementation variables. For example, a properly operated single stage slope screen solid-liquid separation system might reduce total and volatile solids sent to anaerobic storage by 17 percent. That same separation system operating in exceedance of its throughput capacity may process the same manure stream but with a reduced separation efficiency, allowing manure solids to bypass separation and proceed directly to anaerobic storage, eliminating the benefits intended by the system. Similarly, the composition of manure streams may affect the solid-liquid separation efficiency of the system with some manure streams being more readily separated than others. Such factors can cause considerable variability in solids removal and overall methane emissions reduction effectiveness, making it difficult to quantify reductions accurately and with certainty. In conclusion, alternative manure management practices have great methane emissions reduction potential, but many operational factors can affect their efficiencies, resulting in difficulties to quantify with appropriate certainty the methane emissions reductions benefits. CDFA and CARB have invested in the following research projects consistent with Dairy and Livestock Subgroup 1 Recommendations to better understand the methane emissions reduction potential of various alternative manure management practices:

- **Evaluation of Dairy Manure Management Practices for Greenhouse Gas Emissions Mitigation in California**
  In 2015, CDFA funded this University of California (UC), Davis study to measure the efficiency of various solid-liquid separation technologies. Results showed high variability across technologies resulting from factors including project design, operational capacity, and material throughput, and the associated report recommended additional research, particularly on weeping walls. This study also included an economic analysis to evaluate the cost-effectiveness of methane mitigation strategies on California dairy farms.

- **Characterize Physical and Chemical Properties of Manure in California Dairy Systems to Improve Greenhouse Gas Emission Estimates**
  In 2016, CARB funded this UC Davis research to characterize the physical and chemical properties of manure in California dairy systems.

- **Research and Technical Analysis to Support and Improve the Alternative Manure Management Program Quantification Methodology**
  In 2017, CARB funded this UC Davis literature review to assess methane emissions reduction potential of various alternative manure management practices, including solid-liquid separation and weeping walls. Results found all studied technologies had variable performance and the associated report recommended additional research on factors affecting performance of these systems.

- **Benchmarking of Pre- and Post-Alternative Manure Management Program Dairy Emissions and Prediction of Related Long-Term Airshed Effect**
  Between 2016 and 2018, CARB and CDFA collaborated to fund these complementary studies to monitor GHG and air pollutant emissions before and after implementation of various alternative manure management practices at six AMMP-funded dairies. In a separate but complementary effort, CARB installed flux towers to measure methane emissions on three of the six AMMP-funded dairies.

- **Development of the California Dairy Emissions Model**
  In 2019, CARB funded UC Davis to develop a California dairy emissions model to evaluate the effectiveness of potential mitigation strategies and to estimate GHG and other air pollutant emissions from California dairies.

Technical Barriers to Enteric Methane Mitigation Strategies

Enteric strategies, especially feed additives, hold considerable methane mitigation potential from all ruminant species. However, limited commercial availability and seasonal availability of effective feed additives, a lack of long-term effectiveness, and the potential for adverse impacts on animal health for certain products remain persistent technical barriers.

A few methane reducing feed additives with proven long-term effectiveness and no adverse impacts on animal or human health have become commercially available, indicating progress towards overcoming that barrier. However, limited availability of proven strategies remains a barrier for enteric mitigation strategies. For example, the most well-studied potential feed additive, 3-NOP, is expected to become commercially available in the United States in 2024.[69] There is a significant body of evidence to support the effectiveness of 3-NOP in reducing enteric methane emissions by approximately 30 percent. 3-NOP is currently undergoing long-term trials as part of

[69] Mitloehner, F., Kebreab, E., Tricarico, J., Wallace, J., Gooch, C., Gibbs, C. (2020). Dairy Feed Additives to Reduce Enteric Methane Emissions. Newtrient.

the FDA evaluation and approval process before final approval for commercial distribution.

Grape pomace is another additive that may reduce emissions and may not require FDA approval. However, it is only available in late summer and early fall during grape harvest, limiting its feasibility for year-round emissions reductions. Some novel additives such as seaweed also show methane emissions mitigation potential, but with limited *in vivo* (animal) studies to evaluate their long-term effectiveness and potential impacts on animal health, productivity, and product safety. For example, *Asparagopsis,* a special species of seaweed, shows mitigation potential of up to 90 percent during *in vitro* (non-animal studies using rumen simulation technologies) studies,[70] while *in vivo* studies show a mitigation potential of approximately 50 percent during enteric fermentation.[71] However, this additive is still under development, with many unaddressed technical barriers including the potential risk of elevated bromide residues in milk (a food safety concern), palatability concerns causing decreased feed intake and milk production, and low availability and high cost for the product.

Another persistent technical barrier for enteric methane mitigation strategies is limited long-term information about product effectiveness for most available or emerging options. There are a variety of products in various stages of commercial development that face barriers mentioned above. For example, some additives may impact animal health and productivity. Others may have limited long-term effectiveness due to rumen adaptation leading to rapid additive breakdown.[72] While some additives show great mitigation potential, their long-term impacts on animal health, availability, and cost-effectiveness are not well known. In short, feed additives offer promising potential as a mitigation strategy, but require further research and development before being required for use as part of any CARB regulation. SB 1383 requires that only incentive-based mechanisms are authorized for enteric emissions reductions until CARB, in consultation with CDFA, determines that another mechanism is cost-effective, considering the impact on animal productivity and must be scientifically proven to reduce enteric methane emissions, and that adoption of the enteric

[70] Machado, L., Magnusson, M., Paul, N., Kinley, R., de Nys, R., Tomkins, N. (2015). Dose-response effects of Asparagopsis taxiformis and Oedogonium sp. on in vitro fermentation and methane production. *Journal of Applied Phycology*, 28(2).

[71] Roque, B. M., Salwen, J. K., Kinley, R., Kebreab, E., (2019). Inclusion of Asparagopsis armata in lactating dairy cows' diet reduces enteric methane emission by over 50 percent. *Journal of Cleaner Production*, 234: 132-138.

[72] Hook, S.E., André -Denis G.W., McBride, B.W. (2010). Methanogens: Methane Producers of the Rumen and Mitigation Strategies. Archaea, 11 pages.

emissions reduction method would not damage animal health, public health, or consumer acceptance.

Additional Research to Address Technical Barriers

The California legislature appropriated $5 million for research grants for FY 2021-22 to measure and verify emissions reductions associated with dairy livestock methane emissions reduction projects. Specifically, the Legislature requires additional research in the following areas:

- Assessment of the cost-effectiveness of various dairy and livestock methane mitigation strategies on a per ton basis including a comparison of projects funded under AMMP and DDRDP
- Assessment of the cost-effectiveness of enteric methane mitigation strategies
- Additional research on value-added manure-based products development
- Measurement of greenhouse gases and criteria pollutants before and after livestock methane reduction projects are implemented

These research projects will further the State's understanding of the effectiveness of anaerobic digestion and alternative manure management projects at achieving methane emissions reductions and environmental co-benefits. In addition, these studies will allow further investigation of the efficacy and cost-effectiveness of enteric strategies, should additional strategies become available.

Finding 2-2: Market Barriers: The State and Federal Incentive Programs Have Helped Achieve Progress with Project Funding and Incentives

Similar to the technical barriers detailed above, the State, along with others, have made considerable progress in overcoming market barriers to implementing methane emissions reductions projects. Improved understanding of project development costs and significant allocations of CCI funding for manure methane emissions reduction projects have contributed to progress in overcoming barriers related to project funding (Table 8).

Table 8. State Investment in Manure Methane Emissions Reduction Projects

State Investment Program	Investment ($ million)
DDRDP	$196
AMMP	$68
Pilot pipeline construction	$319
Renewable Gas Pipeline Incentive Program	$40
Total	**$623**

This Analysis has already discussed the critical role that market-based programs like Cap-and-Trade and LCFS, RFS, and grant programs like DDRDP and AMMP, have played in driving manure management project development. In addition to those programs, with year-over-year funding to support project development, the Legislature also enacted other initiatives to reduce market barriers for anaerobic digestion projects. Through SB 1383, the Legislature directed CPUC, along with CARB and CDFA, to select six pilot projects to demonstrate biomethane injection into the common carrier pipeline network. This pilot program committed $319 million in rate-recoverable funding to 45 dairies for pipeline infrastructure and operational expenses over 20 years with no private match funding requirement.[73] These projects will provide valuable information on pipeline interconnection processes and the associated costs.

CPUC also administers BioMAT, which provides long-term power purchase agreements with a guaranteed price to projects that generate onsite electricity from certain biogenic feedstock and deliver that electricity to the grid. This market program allows three utilities (Pacific Gas and Electric Co., San Diego Gas & Electric Co., and Southern California Edison) to offer favorable rates to onsite generation projects using a market adjusting mechanism that periodically increases the rate until there are enough market participants. BioMAT has funded two projects for a cumulative total of $8 million, with eight additional projects pending. To date, dairy electricity generation projects have filled nearly 19 megawatts (MW) of the 90 MW available. Another program administered by CPUC is the Renewable Gas Pipeline Interconnection Incentive Program, which provides cost share for dairy biomethane pipeline injection projects. The Legislature appropriated $40 million for pipeline interconnection projects, with up to $3 million in infrastructure cost share available for single-dairy projects, and up to $5 million for dairy cluster projects. Although these programs predate SB 1383, both have seen increased interest since it was enacted.

These incentive programs have been critical to funding the upfront costs of anaerobic digesters, and have also been consistently oversubscribed, which shows an unmet need for additional local, state, and federal investment. However, the availability of incentives coupled with environmental credit revenue has led to increased private investment. Private equity firms and companies have invested in anaerobic digesters, creating additional opportunities for project developers and financers. Increased private funding may result in projects that are financially solvent without upfront incentives, but these funding sources are limited. Sustained environmental credit

[73] California Public Utilities Commission. (December 3, 2018). CPUC, CARB, and Department of Food and Agriculture Select Dairy Biomethane Projects to Demonstrate Connection to Gas Pipelines.

revenue can further reduce risk to lenders and deliver quicker returns on investments, making these projects increasingly attractive to private capital.

One important consideration about the role of public funding is its ability to prioritize multiple benefits. For instance, private capital will pursue biomethane or electricity options that minimize costs and maximize revenue available through environmental credits. In contrast, the State can require funded projects to meet multiple goals. For example, CDFA prioritizes DDRDP projects that minimize environmental impacts including NOx and air pollutants and maximize the environmental co-benefits and community benefits as required by the Legislature when it passed SB 859 (Chapter 368, Statutes of 2016). Implementation of SB 859 has resulted in widespread implementation of pipeline injection projects due to their lower air quality impact compared to relatively lower-cost onsite combustion or trucking projects.

Alternative manure management practices and enteric methane mitigation strategies have not seen similar progress in project funding; without additional local, State, and federal funding, these project types are unlikely to move forward.

Finding 2-3: Market Barrier: Clarity from the State Has Improved Environmental Credit Certainty

California's Cap-and-Trade Program and LCFS Program, and the federal RFS Program, are the primary policy and programmatic mechanisms that provide environmental credit revenue for dairy digesters. To improve market certainty of the Cap-and-Trade Program and LCFS Program for dairy digesters, CARB developed the following two documents:

- Credit Generation for Reduction of Methane Emissions from Manure Management Operations helps project developers better understand potential impact to environmental credit generation that a methane emissions reduction regulation may have, to provide greater market certainty.

- The SB 1383 Pilot Financial Mechanism Paper describes a potential pilot financial mechanism that, if implemented, could improve stability and certainty around LCFS credits generated from anaerobic digestion at dairy operations. The white paper describes two potential approaches—put options and contracts for differences—to ensure that participating facilities can receive a set minimum LCFS credit price. Increasing revenue certainty helps project developers access private financing, potentially reducing or eliminating the need for long-term public support. For the mechanism to be implemented, however, it would need an administrator and initial funding. The white paper notes that CARB should not administer this program because of a conflict of interest as the LCFS Program administrator.

Finding 2-4: Market Barriers Remain for Value-Added Manure Products, Alternative Manure Management Projects, and Enteric Methane Mitigation Strategies

Despite progress, persistent market barriers for alternative manure management projects and enteric methane mitigation strategies create an enduring need for funding to support these methane emissions reduction strategies.

Market Barriers for Value-Added Manure Products

Underdeveloped markets for value-added manure products is a persistent market barrier that, if addressed, could improve the financial viability of manure management projects and provide a variety of environmental co-benefits. Most alternative manure management practices produce compost that could be further commodified to provide an additional revenue stream for dairy operators. Improved markets for such products may also drive additional upstream or downstream GHG emissions reductions. For example, manure compost typically contains fewer contaminants and has higher nutrient content than municipal green waste. Similarly, dairy-based organic fertilizers avoid the upstream GHG emissions resulting from manufacture and distribution of synthetic, fossil-based fertilizers. As a result, value-added manure products can potentially provide an important revenue stream to dairy and livestock operations that could reduce reliance on public funding.

Additionally, these products can provide important environmental co-benefits, including soil health, water retention, and potential displacement of petrochemical fertilizers. Market maturation would offer more opportunity to export nutrient-rich manure solids and reduce potential for water quality impacts from land application of manure. These benefits may be especially important in the San Joaquin Valley, where representative groundwater monitoring shows widespread water quality impacts.[74]

Despite considerable potential benefit to producers and consumers, there is limited information available about the demand for value-added manure products or the quantity that can be cost effectively delivered to the market. To help overcome market barriers and facilitate value-added manure products market development, CDFA is

[74] Shrestha, A. & Luo, W. (2017). An assessment of groundwater contamination in Central Valley aquifer, California using geodetector method. *Annals of GIS*, 23(3), 149-166.

planning to convene a focused working group to address these obstacles and improve financial viability of alternative manure management projects.

Market Barriers to Alternative Manure Management Projects

In many cases, adopting alternative manure management practices at dairies may not be cost-effective due to the lack of revenue streams to generate attractive rates of return to farmers and developers. Additionally, many of the dairies that implement these practices may not have the have the resources to diversify their operations to take advantage of new or expanded market opportunities. In the absence of public funding, these operations—often smaller and less able to capitalize on economies of scale—will need to rely on cost savings and revenue from the sale of value-added manure products (e.g., compost and soil amendment). However, the limited financial benefits of these projects are often insufficient to offset project costs. Additionally, ineligibility for environmental credits and underdeveloped markets for value-added manure products present additional market barriers. As a result, the availability of debt financing is limited.

Market Barriers to Enteric Methane Mitigation Strategies

Limited information is available for a comprehensive analysis of market barriers for enteric mitigation strategies, though market barriers may arise as options become available. However, to be viable, the market requires potential products to gain consumer acceptance and be cost-effective. SB 1383 requires cost-effectiveness of products, among other requirements, prior to requiring their use. Additives that fail to meet these requirements are unlikely to be adopted as effective enteric methane mitigation strategies.

Next Steps

Moving forward, the dairy and livestock sector must still achieve considerable methane emissions reductions to meet the 2030 target. Achieving the target will require careful consideration of potential methane emissions reductions strategies and coordination with other agencies, the dairy and livestock sector, and the public, including environmental justice and disadvantaged communities. Implemented strategies must not only reduce methane emissions from the sector sufficient to achieve the 2030 target but should also be consistent (to the extent feasible) with other State objectives. These objectives include reduced impacts to air and water quality, improved soil health, reduced impacts to environmental justice communities, and maximized GHG emissions reductions while minimizing emissions leakage. This will require coordinated action between the State and the dairy and livestock sector to overcome barriers to implementing proven methane emissions reduction projects and emerging mitigation options, especially for enteric fermentation. Improved accuracy in tracking and quantifying methane emissions reductions achieved by operational manure management projects or expected from future projects—especially alternative manure management projects and emerging enteric methane reducing feed additives—is also critical to evaluating progress toward the 2030 target. These improvements will help identify effective incentives and policies in the near-term and will aid in the design of potential regulations should that be necessary for achieving the 2030 target. The 2022 Scoping Plan Update will further assess and describe the role that the dairy and livestock sector can play to help achieve carbon neutrality.

CARB staff will continue to monitor the dairy and livestock sector's methane emissions reductions progress and refine its understanding of emissions sources, emissions reduction potential, and the achievements of incentives. CARB will continue to research additional technology options and management practices that can achieve methane emissions reductions, as well as research the effectiveness of practices used today. CARB will consider potential options to improve quantification of methane emissions reductions from manure management projects as well as ways to refine GHG emissions accounting for the sector. In order to comply with the statutory direction, CARB will consider regulation development to ensure that the 2030 target is achieved, assuming the conditions outlined in the statute are met. These next steps are described in greater detail below.

Continue Tracking Progress of Methane Emissions Reduction Projects and Funding

The State's appropriation of $289 million in CCI funds for manure methane emissions reductions to date has resulted in 233 dairy manure management projects that will achieve an estimated 2.0 $MMTCO_2e$ in annual reductions by 2022. This funding delivers some of the most cost-effective SLCP emissions reductions to date. CARB staff will continue to track the availability of local, State, and federal incentive funding, the progress of existing projects, and future projects implemented using both public and private funds. Additionally, CARB staff will continue to monitor market developments for value added manure products, and CDFA will convene a working group to reduce market barriers and improve the financial viability of alternative manure management projects.

Continue Tracking Manure Management Methane Emissions Reduction Options

CARB staff will track advancements in manure methane emissions reductions. Specifically, staff will continue to monitor the results of ongoing research including the monitoring emissions at AMMP project sites pre- and post-implementation, CPUC pilot pipeline infrastructure projects, methane emissions flux monitoring, literature reviews, and the development of a dairy emissions model to better understand changes from manure management methane emissions reduction projects. CARB, in collaboration with CDFA, will also continue to evaluate the potential for additional alternative manure management practices.

Continue Tracking Enteric Methane Emissions Reduction Options

There are limited commercially available animal feed for mitigating enteric methane emissions reductions additives in the United States. Some regions, including Brazil, Chile, and Europe have recently approved the use of 3-NOP.[75,76] CARB staff will continue to track the progress of these enteric methane emissions mitigation strategies, analyze their cost-effectiveness, and assess consumer acceptance.

Address GHG Emission Inventory Challenges

In addition to tracking enteric and manure methane emissions reductions options, CARB staff is evaluating options to improve the accuracy of the annual GHG Emission Inventory. Gathering operational or "activity data"[77] from facilities within the sector is an important first step to refining inventory models and associated assumptions to be more California-specific. These refinements would improve GHG Emission Inventory accuracy and inform incentive planning and regulatory development efforts.

Detailed facility activity data on the parameters that affect methane emissions should be collected annually. Specific data may include animal breed, population, production stage, diet composition, animal housing type, and the manure collection rate, storage conditions and length, treatment methods, and land application rates of manure. A more accurate accounting of these parameters can help assess methane mitigation strategies and calibrate emission models.

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[75] https://www.bloomberg.com/news/articles/2021-09-09/world-s-top-beef-supplier-approves-methane-busting-cow-feed

[76] https://www.dsm.com/corporate/news/news-archive/2022/dsm-receives-eu-approval-Bovaer.html

[77] Activity data refers to important factors that can impact emissions from dairy and livestock operations. Some example factors include animal population size, breed, age, lactation status, diet, and type of manure management.

CARB recommends a collaborative effort including public agencies and industry to gather activity data from dairy and livestock operations. Specifically, it may evaluate leveraging or modifying existing reporting structures like annual water quality reports to gather additional activity data from the sector. This approach may increase the likelihood of a high response rate, reduce resources needed to develop a new reporting structure, and reduce the reporting burdens to dairy and livestock operations. A voluntary survey of the sector could also provide useful activity data if a new or modified reporting structure is infeasible.

If these efforts are infeasible or are unsuccessful, a recordkeeping and reporting regulation developed pursuant to SB 1383[78] could provide a mechanism to obtain the necessary activity data. Reported information would be used to improve inventory accuracy, evaluate methane emissions reduction progress, and inform design of potential emissions reduction regulations, should that be necessary.

[78] Section 39730.7(h).

ATTACHMENT AA

CALIFORNIA
AIR RESOURCES BOARD

December 2022

2022 Scoping Plan for Achieving Carbon Neutrality

CARB's mission is to promote and protect public health, welfare, and ecological resources through effective reduction of air pollutants while recognizing and considering effects on the economy. CARB is the lead agency for climate change programs and oversees all air pollution control efforts in California to attain and maintain health-based air quality standards.

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Abbreviations

°F	Fahrenheit
°C	Celsius
AB	Assembly Bill
AQMD	Air Quality Management District
AR5	IPCC Fifth Assessment Report
BECCS	bioenergy with carbon capture and storage
CAISO	California Independent System Operator
CalEPA	California Environmental Protection Agency
CalGEM	California Geologic Energy Management Division
CalSTA	California State Transportation Agency
CAP	climate action plan
CARB	California Air Resources Board
CCR	California Code of Regulations
CCS	carbon capture and sequestration
CCUS	carbon capture, utilization, and storage
CDFA	California Department of Food and Agriculture
CDPH	California Department of Public Health
CDR	carbon dioxide removal
CE	common era
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CES	CalEnviroScreen
CH_4	methane
CMAQ	Community Multiscale Air Quality
CNRA	California Natural Resources Agency
CO_2	carbon dioxide
COPD	chronic obstructive pulmonary disease

CORE	Clean Off-Road Equipment
CPUC	California Public Utilities Commission
CVM	Climate Vulnerability Metric
DAC	direct air capture
DPR	Department of Pesticide Regulation
Draft EA	Draft Environmental Analysis for this Scoping Plan
EA	Environmental Analysis
ED	emergency department
EIA	U.S. Energy Information Administration
EJ	environmental justice
EJ Advisory Committee	Environmental Justice Advisory Committee
EO	executive order
EV	electric vehicle
F-gas	fluorinated gas
FCEV	fuel cell electric vehicle
GCF	Governors' Climate and Forests Task Force
GDP	gross domestic product
GHG	greenhouse gas
GSP	gross state product
GW	gigawatt
GWh	gigawatt-hour
GWP	global warming potential
HDV	heavy-duty vehicle
HD ZEV	heavy-duty zero-emission vehicle
HFC	hydrofluorocarbon
IBank	Infrastructure and Economic Development Bank
ICE	internal combustion engine
IPCC	Intergovernmental Panel on Climate Change

IPT	incidence-per-ton
IWG	Interagency Working Group
LCFS	low-carbon fuel standard
LDV	light-duty vehicle
MDV	medium-duty vehicle
MMT	million metric tons
$MMTCO_2e$	million metric tons of carbon dioxide equivalent
MOU	memorandum of understanding
MRR	Mandatory Reporting of GHG Emissions
$MTCO_2e$	metric tons of carbon dioxide equivalent
MW	megawatt
N_2O	nitrous oxide
NEMS	National Energy Systems Model
NF_3	nitrogen trifluoride
NOAA	National Oceanic and Atmospheric Administration
NOx	nitrogen oxides
NRDC	National Resources Defense Council
NWL	Natural and Working Lands
OEHHA	Office of Environmental Health Hazard Assessment
OGV	Ocean-Going Vessel
OPR	Governor’s Office of Planning and Research
OTC	once-through cooled
PFC	perfluorocarbon
PHMSA	Pipelines and Hazardous Materials Safety Administration
PM	particulate matter
$PM_{2.5}$	fine particulate matter
PPP	public-private partnership
RFS	renewable fuel standard

ROG	reactive organic gases
RPS	Renewables Portfolio Standard
SB	Senate Bill
SC-CH_4	social cost of methane
SC-CO_2	social cost of carbon
SC-GHG	social cost of greenhouse gases
SC-N_2O	social cost of nitrous oxide
SF_6	sulfur hexafluoride
SGIP	Self-Generation Incentive Program
SLCP	short-lived climate pollutant
TSD	Technical Support Document
UC	University of California
UCLA	University of California, Los Angeles
UNFCCC	United Nations Framework Convention on Climate Change
U.S. EPA	United States Environmental Protection Agency
VMT	vehicle miles traveled
WUI	wildland-urban interface
ZEV	zero-emission vehicle

Executive Summary

This Scoping Plan lays out the sector-by-sector roadmap for California, the world's fifth[1] largest economy, to achieve carbon neutrality by 2045 or earlier, outlining a technologically feasible, cost-effective, and equity-focused path to achieve the state's climate target. This is a challenging but necessary goal to minimize the impacts of climate change. There have been three previous Scoping Plans. Previous plans have focused on specific greenhouse gas (GHG) reduction targets for our industrial, energy, and transportation sectors—first to meet 1990 levels by 2020, then to meet the more aggressive target of 40 percent below 1990 levels by 2030. This plan, addressing recent legislation and direction from Governor Newsom, extends and expands upon these earlier plans with a target of reducing anthropogenic emissions to 85 percent below 1990 levels by 2045. This plan also takes the unprecedented step of adding carbon neutrality as a science-based guide and touchstone for California's climate work. The plan outlines how carbon neutrality can be achieved by taking bold steps to reduce GHGs to meet the anthropogenic emissions target and by expanding actions to capture and store carbon through the state's natural and working lands and using a variety of mechanical approaches.

What this means for California is an ambitious and aggressive approach to decarbonize every sector of the economy, setting us on course for a more equitable and sustainable future in the face of humanity's greatest existential threat, and ensuring that those who benefit from this transformation include communities hardest hit by climate impacts and the ongoing pollution from the use of fossil fuels. The combustion of fossil fuels has polluted our air—particularly in low-income communities and communities of color—for far too long and is the root cause of climate change. This Scoping Plan helps us chart the path to a future where race and class are no longer predictors of disproportionate burdens from harmful air pollution and climate impacts.

The major element of this unprecedented transformation is the aggressive reduction of fossil fuels wherever they are currently used in California, building on and accelerating carbon reduction programs that have been in place for a decade and a half. That means rapidly moving to zero-emission transportation; electrifying the cars, buses, trains, and trucks that now constitute California's single largest source of planet-warming pollution. It also means phasing out the use of fossil gas used for heating our homes and buildings. It means clamping down on chemicals and refrigerants that are thousands of times more powerful at trapping heat than carbon dioxide (CO_2). It means providing our communities with sustainable options for walking, biking, and public transit to reduce reliance on cars and their associated expenses. It means continuing to build out the solar arrays, wind turbine capacity, and other resources that provide clean, renewable energy to displace fossil-fuel fired electrical generation. It also means scaling up new options such as renewable hydrogen for hard-to-electrify end uses and biomethane where needed. Successfully achieving the outcomes called for in this Scoping Plan would reduce demand for liquid petroleum by 94 percent

1 In October 2022, California was poised to become the world's fourth largest economy.

and total fossil fuel by 86 percent in 2045 relative to 2022.[2] Despite these world-leading efforts, some amount of residual emissions will remain from hard-to-abate industries such as cement, internal combustion vehicles still on the road, and other sources of GHGs, including high global warming chemicals used as refrigerants.

The plan addresses these remaining emissions by re-envisioning our natural and working lands—forests, shrublands/chaparral, croplands, wetlands, and other lands—to ensure they play as robust a role as possible in incorporating and storing more carbon in the trees, plants, soil, and wetlands that cover 90 percent of the state's 105 million acres while also thriving as a healthy ecosystem. Modeling indicates that natural and working lands will not, on their own, provide enough sequestration and storage to address the residual emissions. For that reason, it is necessary to research, develop, and deploy additional methods of capturing CO_2 that include pulling it from the smokestacks of facilities, or drawing it out of the atmosphere itself and then safely and permanently utilizing and storing it, as called for in recent legislation. Carbon removal also will be necessary to achieve net negative emissions to address historical GHGs already in the atmosphere.

This is a plan that aims to shatter the carbon status quo and take action to achieve a vision of California with a cleaner, more sustainable environment and thriving economy for our children. This ambitious plan will serve as a model for other partners around the world as they consider how to make their transition. As we have so often in the past, California can continue to serve as a leader in innovation that has produced not only the fifth largest economy on the planet, but ultimately one of the most energy-efficient economies, with a track record of demonstrating the ability to decouple economic growth from carbon pollution. This plan also builds upon current and previous environmental justice efforts to integrate environmental justice directly into the plan, to ensure that all communities can reap the benefits of this transformational plan. Specifically, this plan identifies a path to keep California on track to meet its SB 32 GHG reduction target of at least 40 percent below 1990 emissions by 2030.

2 See *CARB's energy demand reductions*.

- Identifies a technologically feasible, cost-effective path to achieve carbon neutrality by 2045 and a reduction in anthropogenic emissions by 85 percent below 1990 levels.
- Focuses on strategies for reducing California's dependency on petroleum to provide consumers with clean energy options that address climate change, improve air quality, and support economic growth and clean sector jobs.
- Integrates equity and protecting California's most impacted communities as driving principles throughout the document.
- Incorporates the contribution of natural and working lands (NWL) to the state's GHG emissions, as well as their role in achieving carbon neutrality.
- Relies on the most up-to-date science, including the need to deploy all viable tools to address the existential threat that climate change presents, including carbon capture and sequestration, as well as direct air capture.
- Evaluates the substantial health and economic benefits of taking action.
- Identifies key implementation actions to ensure success.

The path forward is informed by robust science. The recent Sixth Assessment Report (AR6) of the Intergovernmental Panel on Climate Change (IPCC) summarizes the latest scientific consensus on climate change. It finds that atmospheric concentrations of CO_2 have increased by 50 percent since the industrial revolution and continue to increase at a rate of two parts per million each year.[3] By the 2030s, and no later than 2040, the world will exceed 1.5°C warming unless there is drastic action. While every tenth of a degree matters—every incremental increase in warming brings additional negative impacts—climate-related risks to human health, livelihoods, and biodiversity are projected to increase further under 2°C warming, compared to 1.5°C.[4] For example, at 1.5°C of global warming, we would experience increasing heat waves, longer warm seasons, and shorter cold seasons, but at 2°C of global warming, heat extremes would more often reach critical tolerance thresholds for human health and agriculture.[5] We are already seeing unprecedented climate change impacts, such as continued sea level rise, that are "irreversible" for centuries to millennia, and we are dangerously close to hitting 1.5°C in the near term.[6] To avoid climate catastrophe and remain below 1.5°C with limited or no overshoot of that threshold, global net anthropogenic CO_2 emissions need to reach net zero by 2050.

3 *IPCC. 2021. Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. [Masson-Delmotte, V., P. Zhai, A. Pirani, S. L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M. I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J. B. R. Matthews, T. K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press. In Press.*

4 *IPCC. 2018. Global Warming of 1.5°C. World Meteorological Organization. Geneva, Switzerland. 32 pp.*

5 *IPCC. 2021. Climate change widespread, rapid, and intensifying – IPCC. August.*

6 *United Nations. 2021. IPCC report: 'Code red' for human driven global heating, warns UN chief. August 9.*

It has been 16 years since the Global Warming Solutions Act of 2006 was passed and signed into law. In 2017, the second update to the Assembly Bill (AB) 32 Climate Change Scoping Plan[7] (2017 Scoping Plan) laid out a cost-effective and technologically feasible path to achieve the 2030 GHG reduction target. At the time, many characterized the plan and the AB 32 target as unachievable, citing that it would lead to massive business and job loss, and excessive costs. Those predictions proved to be incorrect as California achieved its AB 32 target years ahead of schedule, all the while growing our economy, with the state distinguishing itself as a hub for green technology investment. This Scoping Plan draws on a decade and a half of proven successes and additional new approaches to provide a balanced and aggressive course of effective actions to achieve carbon neutrality in 2045, if not before, in addition to the 2030 goal.

California's economy is projected to grow vigorously in the coming years and decades. In 2045, under a Reference Scenario, the gross state product would be $5.1 trillion, nearly $2 trillion more than in 2021, and allow growth that would add hundreds of thousands of jobs. Under the Scoping Plan scenario, impacts to economic and job growth would be negligible in both 2035 and 2045, while delivering $199 billion of benefits in the form of reduced hospitalizations, asthma cases, and lost work and school days due to the cleaner air supported by this plan. This should come as no surprise given the tremendous growth of California's economy since the Great Recession of 2007–2009, even as the state has taken drastic measures to lower emissions. As noted, the savings associated with ambitious climate action are extensive, both in terms of avoided climate impacts and health costs. As described in Chapter 1, the health costs of climate and air pollution in the U.S. are well over $800 billion today and will continue to grow in the coming years[8] without robust action. Similarly, the costs of delayed or insufficient climate action could cost the U.S. upwards of $14.5 trillion over the next 50 years.[9] We can either take action now or pay the cost of inaction, both now and later.

Grows CA's economy
to $5.1 trillion by 2045

New jobs
↑ 4 million

Health costs
↓ $200 billion

We cannot take on this unprecedented challenge alone. Collaboration with the federal government, other U.S. states, and other jurisdictions around the world will continue to be fundamental for California to succeed in achieving its climate targets, especially as the pace of our efforts increases in the coming years. We believe this collaboration and coordination also creates a race to the top, encouraging and enabling other jurisdictions to achieve climate and air quality goals as well, and often providing lessons for national action.

One example of fruitful collaboration is California's longstanding vehicle emissions standards programs, which have repeatedly been freely adopted by other states, consistent with the federal Clean Air Act. California's programs frequently pioneer more rigorous standards or new technologies—such as the now-standard catalytic converter and the rules that led directly to the nation-leading numbers of zero-emission vehicles on our roads today. From initial standards for cars

7 *CARB. 2017. California's 2017 Climate Change Scoping Plan.*

8 *Alwis, D. D., and V. S. Limaye. No date. The Costs of Inaction: The Economic Burden of Fossil Fuels and Climate Change on Health in the United States. NRDC, The Medical Society Consortium on Climate and Health, and WHPCA.*

9 *Deloitte. 2022. The Turning Point: A New Economic Climate in the United States.*

and trucks decades ago to the world-leading Advanced Clean Trucks program currently helping to electrify heavy-duty vehicles, this partnership continues to offer regulatory options and spread innovative technologies. A major example of future work is the Advanced Clean Cars II program, which lays out California's legally binding path to achieving 100 percent zero emission vehicle (ZEV) sales in 2035.[10] The California Air Resources Board (CARB) continues to work closely with many other states that also see zero-emission vehicles as critical to their climate and public health goals and expects many states to choose to adopt this regulation as well. This partnership with other states also creates market certainty for automakers, which in turn helps to ensure that California consumers have access to a variety of ZEVs at multiple price points.

The Scoping Plan Process

Four scenarios were extensively modeled to develop this Scoping Plan, with the objective of informing the most viable path to remain on track to achieve our 2030 GHG reduction target: a reduction in anthropogenic emissions by 85% below 1990 levels and carbon neutrality by 2045. All four have their merits and are informed by stakeholder input. The scenario ultimately chosen as the basis of this Scoping Plan is the alternative that most closely aligns with existing statute and Executive Orders. It was selected because it best achieves the balance of cost-effectiveness, health benefits, and technological feasibility.

For the first time, this Scoping Plan includes modeling and quantification of GHG emissions and carbon sequestration in natural and working lands (NWL). To date, the focus has been only on reducing the emissions of GHGs from our transportation, energy, and industrial sectors. The state's 2020 and 2030 GHG reductions targets only include these sources, as they are the primary drivers of climate change and disproportionate harmful air pollution in our vulnerable communities. This Scoping Plan, through the lens of carbon neutrality, expands the scope to more meaningfully consider how our NWL contribute to our long-term climate goals. For the first time, new and cutting-edge modeling tools allow us to estimate the quantitative ability of our forests and other landscapes to remove and store carbon under different scenarios. These cutting-edge tools were developed through a stakeholder process and in coordination with other agencies for the purpose of this update and will continue to be refined over time and made available to others seeking to do similar work.

10 *Executive Department. State of California. Executive Order N-79-20.*

As recent data and Scoping Plan modeling shows, our NWL also can act as a source of emissions, principally in the form of wildfires. California's forests are experiencing a deadly combination of drought and heat combined with a century of misguided fire suppression management. Scoping Plan modeling shows that, at this time and until our forests reach a balance through appropriate treatments, California's NWL will act as a net source of emissions, not a sink. As such, the Scoping Plan includes policy direction and actions intended to quickly move the sector toward being a net sink and a more natural state, where wildfires will continue to be an important part of the healthy forest cycle but not at the intensity and frequency observed in recent years.

Development of this Scoping Plan also includes careful consideration of, and coordination with, other state agencies, consistent with Governor Gavin Newsom's whole-of-government approach to tackling climate change. State agency plans and regulations, including the SB 100 Joint Agency Report,[11] State Implementation Plan, Climate Action Plan for Transportation Infrastructure,[12] AB 74 Studies on Vehicle Emissions and Fuel Demand and Supply,[13,14,15] Short-Lived Climate Pollutant Strategy (SLCP Strategy),[16] CARB's Achieving Carbon Neutrality Report,[17] Climate Smart Lands Strategy,[18] Natural Working Land Implementation Plan,[19] and the California Climate Insurance Report: Protecting Communities, Preserving Nature, and Building Resiliency,[20] among others, provided critical inputs and data points for this plan. This Scoping Plan is the product of work by multiple agencies across the Administration, including dozens of public workshops and years of rigorous analysis and economic modeling by California's leading institutions. This cooperation on planning lays the foundation for even closer coordination among and between state agencies to put the plan into effect.

The plan is also the product of tireless efforts of, and recommendations from, the AB 32 Environmental Justice Advisory Committee (EJ Advisory Committee). The EJ Advisory Committee, created by statute, plays a critical role to inform the development of each Scoping Plan and helps to ensure environmental justice is integrated throughout the plan. CARB reconvened the EJ Advisory Committee in early 2021 to advise on the development of this Scoping Plan. In their advisory role, the EJ Advisory Committee has worked together to provide inputs to CARB to inform the development of scenarios and the associated modeling. And in April 2022, the EJ Advisory Committee provided draft preliminary recommendations in advance of the Draft 2022 Scoping Plan to help ensure the draft plan meaningfully addresses environmental justice. The CARB Board and EJ Advisory Committee held a joint board hearing on September 1, 2022, where the EJ Advisory Committee presented their final recommendations on the Scoping Plan. Over five dozen of the recommendations are reflected in the Scoping Plan. Going forward, as this plan is ultimately acted on by the Board, ongoing input from the EJ Advisory Committee will be essential to address environmental justice and achieve the ambitious vision outlined in the plan throughout its implementation in the coming years.

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11 *California Public Utilities Commission (CPUC), California Energy Commission (CEC), and CARB. 2021. SB 100 Joint Agency Report.*

12 *California State Transportation Agency (CalSTA). 2021. Climate Action Plan for Transportation Infrastructure.*

13 *California Environmental Protection Agency (CalEPA). 2021. Carbon Neutrality Studies.*

14 *Brown, A. L., et. al. 2021. Driving California's Transportation Emissions to Zero. University of California Institute of Transportation Studies.*

15 *Deschenes, O. 2021. Enhancing equity while eliminating emissions in California's supply of transportation fuels. University of California Santa Barbara.*

16 *CARB. Short-Lived Climate Pollutants.*

17 *Energy and Environmental Economics, Inc. 2020. Achieving Carbon Neutrality in California: PATHWAYS Scenarios Developed for the California Air Resources Board. October.*

18 *California Natural Resources Agency (CNRA). 2021. Draft Climate Smart Lands Strategy.*

19 *CARB. 2019. Draft California 2030 Natural and Working Lands Climate Change Implementation Plan.*

20 *California Department of Insurance. 2021. Protecting Communities, Preserving Nature, and Building Resiliency.*

Importantly, per legislative direction, the Scoping Plan development includes modeling and analyses of emissions, economics, air quality, health, jobs, and public health. This work is important to inform the discussion around trade-offs and how to balance the various legislative direction in identifying a path to achieve the state's climate goals. The technical work serves as a backdrop to what this means to Californian's daily lives—to how they will work, play, and live as we act to eliminate fossil fuel combustion and achieve the many public health and environmental benefits that will result from that action.

Ensuring Equity and Affordability

The state has a long history of public health and environmental protection. However racist and discriminatory practices such as redlining have resulted in low-income communities and communities of color being disproportionately exposed to health hazards and pollution burdens.[21] These communities are often located adjacent to major roadways and large stationary sources that not only emit GHGs, but also harmful localized air pollution. The plan delivers on the promise to transform the way we move, live, and work by nearly eliminating our dependence on fossil fuels. It includes effective actions to move with all possible speed to clean energy, zero-emission cars and trucks, energy-efficient homes, sustainable agriculture, and resilient NWL. And it prioritizes working with the communities most impacted to ensure that these strategies address their needs.

An important part of our equity consideration is ensuring the transition to a zero-emission economy is affordable and accessible, and that it uplifts disadvantaged, low-income communities and communities of color. Some aspects of the transition will have associated costs (e.g., escalating efforts to retrofit existing homes and businesses to support electric appliances and vehicles and increased costs of insurance). The state must ensure that these costs do not disproportionately burden consumers. In addition, the state has an important role to play in providing financial incentives, especially to low-income consumers, to allow for uptake of clean technologies. The Department of Community Services and Development's Low Income Weatherization Program is a prime example of this approach, enabling low-income Californians to be part of the zero-emission transition, all while lowering energy bills. The program provides low-income households with solar

21 *CalEPA. 2021. Pollution and Prejudice: Redlining and Environmental Injustice in California. August 16.*

photovoltaic systems and energy efficiency upgrades at no cost to residents, helping cushion the impact of climate change on vulnerable communities.

With this Scoping Plan, the state also adds another tool to help identify and close climate change impact gaps that will emerge over time. As California invests in climate mitigation and adaptation, it is essential to understand the relative impact of climate change across the state's diverse communities. We know not all communities are equally resilient in the face of climate impacts due to persisting health and opportunity gaps. We also know that a global metric such as the Social Cost of Carbon cannot adequately capture the incremental additional impact faced by overly burdened communities. The Climate Vulnerability Metric (CVM) is specifically focused on quantifying the community-level impacts of a warming climate on human welfare.

Energy and Technology Transitions

To support the transformation needed, we must build the clean energy production and distribution infrastructure for a carbon-neutral future. The solution will have to include transitioning existing energy production and transmission infrastructure to produce zero-carbon electricity and hydrogen, and utilizing biogas resulting from wildfire management or landfill and dairy operations, among other substitutes. In almost all sectors, electrification will play an important role. That means that the grid will need to grow at unprecedented rates and ensure reliability, affordability, and resiliency through the next two decades and beyond. It also means we need to keep all options on the table, as it will take time to fully grow the electricity grid to be the backbone for a decarbonized economy. We also know that electrification is not possible in all situations. As such, this plan systematically evaluates and identifies feasible clean energy and technology options that will bring both near-term air quality benefits and deliver on longer-term climate goals.

4x
solar & wind generation

1,700x
renewable hydrogen

100%
ZEV sales by 2035

This transition will not happen overnight. It will take time and planning to ensure a smooth transition of existing energy infrastructure and deployment of new clean technology. And while this Scoping Plan has the longest planning horizon of any Scoping Plan to date, this 25-year horizon is still relatively short in terms of transforming California's economy. We must avoid making choices that will lead to stranded assets and incorporate new technologies that emerge over time. Importantly, given the pace at which we must transition away from fossil fuels, we absolutely must identify and address market and implementation barriers to be successful. The scale of transition includes adding four times the solar and wind capacity by 2045 and about 1,700 times the amount of current hydrogen supply.

As we transition our energy systems, we must also rapidly deploy the clean technologies that rely on a decarbonized grid. As called for in Executive Order N-79-20, all new passenger vehicles sold in California will be zero-emission by 2035, and all other fleets will have transitioned to zero-emission as fully possible by 2045. This means the percentage of fossil fuel combustion vehicles will continue to rapidly decrease, becoming a fading vision of the past. Successful implementation of this Executive

Order (EO) and other zero-emission priorities will have to be attractive to consumers. As an example, electric and hydrogen transportation refueling must be readily accessible, and active transportation and clean transit options must be cheaper and more convenient than driving.

Cost-Effective Solutions Available Today

Ultimately, to achieve our climate goals, urgent efforts are needed to slash GHG emissions. Fortunately, cost-effective solutions are available to do so in many cases. In short, this plan relies on existing technologies — it does not require major technological breakthroughs that are highly uncertain.

For example, targeted action to reduce methane emissions can be achieved at low or negative cost, and with significant near-term climate and public health benefits. In many cases, renewable energy and energy storage are cheaper than polluting alternatives, and are already firmly part of our business-as-usual approach; modeling related to the most recent integrated resource planning process at the California Public Utilities Commission (CPUC) has shown that scenarios associated with the best emissions outcomes had the lowest average rates. As another example, research from Energy Innovation shows that the U.S. can achieve 100 percent zero-carbon power by 2035 without increasing customer costs.[22]

The same is either already true, or soon to be true, for zero-emission vehicles as well. Myriad studies show cost parity for light-duty and heavy-duty ZEVs being achieved by mid-decade or shortly thereafter. A carbon neutrality study conducted by the University of California (UC) Institute of Transportation Studies and funded by the California Environmental Protection Agency (CalEPA) shows that achieving carbon neutrality in the transportation sector will save Californians $167 billion through 2045.[23] Similar research from the Goldman School of Public Policy at UC Berkeley finds that achieving 100 percent light-duty ZEV sales nationwide would save consumers $2.7 trillion through 2050; equivalent to $1,000 per household, per year, for 30 years.[24]

22 *Phadke, A. et al. 2020. "Illustrative Pathways to 100 Percent Zero Carbon Power by 2035 Without Increasing Customer Costs, Energy Innovation." September.*

23 *Brown, A. L., et al. 2021. Driving California's Transportation Emissions.*

24 *Goldman School of Public Policy. 2021. 2035: The Report: Transportation. UC Berkeley. April.*

Many of these outcomes are a direct result of California's vision and policy development to advance clean energy and climate solutions, including through the Renewables Portfolio Standard, Advanced Clean Cars II regulations, SLCP Reduction Strategy, and others. While the world collectively has not yet fully deployed clean energy and climate solutions at the scale needed to adequately address climate change, California has made tremendous progress—even since the last Scoping Plan update in 2017. Continued ambition, leadership, and climate policy development from California will help the state achieve the scale of emissions reductions needed from technologies and strategies that are already cost-effective or close to it today, and will move additional technologies and strategies to that point in the near future. Achieving those outcomes and reducing costs for the entire array of climate solutions needed to achieve carbon neutrality and then maintain net-negative emissions will prove the true measure of California's success. This will enable California to not just meet our own climate targets, but to ultimately develop the replicable solutions that can scale globally to address global warming.

Continue with a Portfolio Approach

Over the past decade and a half, the state has undertaken a successful three-pronged approach to reducing GHGs: incentives, regulations, and carbon pricing. The 2017 Scoping Plan leveraged existing programs such as the Renewables Portfolio Standard, Advanced Clean Cars, Low Carbon Fuel Standard, Short-lived Climate Pollutant Strategy, mobile source measures to achieve federal air quality targets, and a Cap-and-Trade Program, among others, to lay out a technologically feasible and cost-effective path to achieve the 2030 GHG reduction target. When looking toward the 2045 climate goals and the deeper GHG reductions needed across the AB 32 GHG Inventory sectors, all of the existing programs must be evaluated and, as necessary, strengthened to support the rapid production and deployment of clean technology and energy, as well as the increased pace and scale of actions on our natural and working lands.

The challenge before us requires us to keep all tools on the table. Given the climate mitigation co-benefits, critical actions to deliver near-term air quality benefits, such as those included in the State Implementation Plan to achieve the federal air quality standards, are incorporated into this Scoping Plan, as are new legislative mandates to decarbonize the electricity and cement sectors. And, if additional gaps are identified, new programs and policies must be developed and implemented to ensure all sectors are on track to reduce emissions. Opportunities to leverage these programs to address ongoing air quality disparities must also be considered, along with targeted environmental justice policies such as the AB 617 Community Air Protection Program and the investments made possible through the California Climate Investments Program.

Conclusion

California has never undertaken such a comprehensive, far-reaching, and transformative approach to fighting climate change as that called for in this plan. Once implemented, it will place every aspect of how we live, work, play, and travel in California on a more sustainable footing, with a focus on directly benefitting those communities already most burdened by pollution. This comprehensive approach reflects how climate change is already changing life in California. We have all experienced the impacts of devastating wildfires, extreme heat, and drought. Despite much progress, California still has some of the worst air pollution in the nation, especially in the San Joaquin Valley and the Los Angeles Basin, which is driven by the continued use of fossil fuel-powered trucks and cars.

This Scoping Plan provides a solution; a way forward and a vision of a California where we can and will address those impacts. This plan is fundamentally based on hope. It is a hope grounded in experience and science that we can fundamentally improve the California we leave to future generations. The plan is built on the legacy of effective actions and on the conviction that we can effectively marshal the combined capabilities of California—from state, regional, tribal, and local governments to industry to our research institutions, and most importantly, to the nearly 40 million Californians who will benefit from the actions laid out in the plan. It addresses the challenge of our generation by laying out a pathway and guideposts for action across three decades. But the Scoping Plan is only that: a plan. The hard work—and hopeful work—is putting its recommendations into action. And there is no time to waste.

Post-adoption of the Scoping Plan

As with previous Scoping Plans, CARB Board approval is the beginning of the next phase of climate action. Specifically, approval of this plan catalyzes a number of efforts, including the development of new regulations as well as amendments to strengthen regulations and programs already in place, not just at CARB but across state agencies. The unprecedented rate of transition will also require the identification and removal of market and implementation barriers to the production and deployment of clean technology and energy. All of these actions and more will be needed if we are to achieve our climate goals.

Chapter 1: Introduction

"The debate is over around climate change. Just come to the state of California. Observe it with your own eyes."

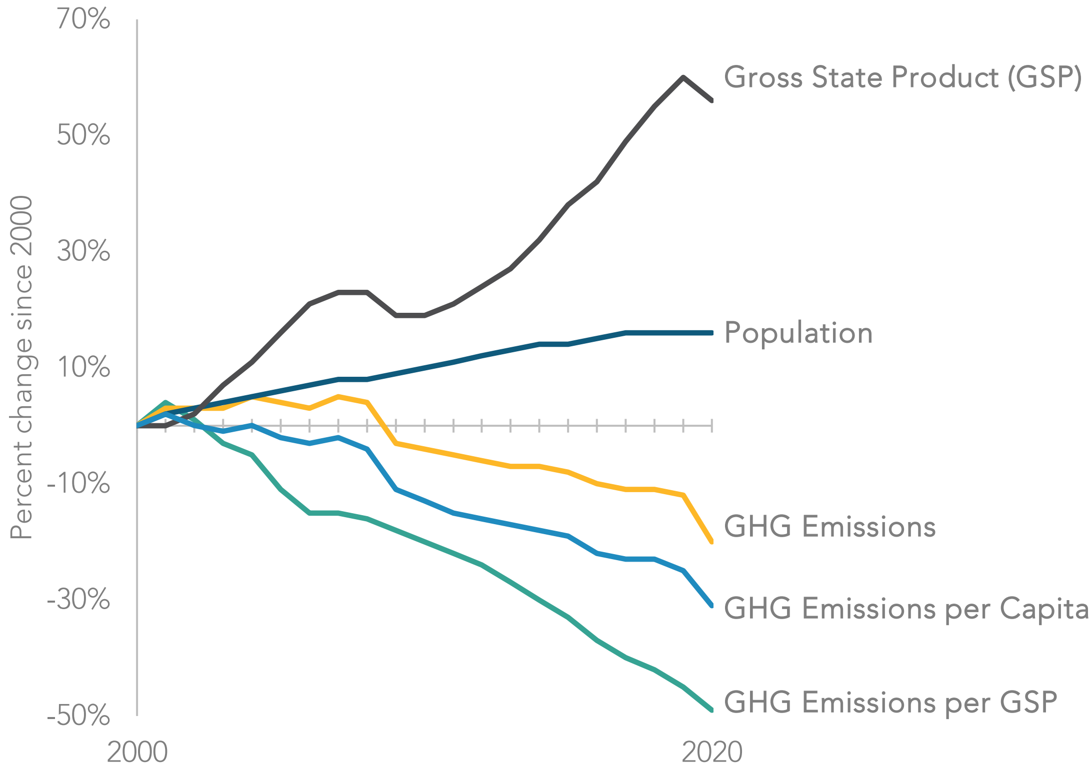
- California Governor Gavin Newsom in September 2020 after surveying the devastation caused by catastrophic wildfires

The impacts of climate change are no longer a distant threat on the horizon—they are right here, right now, with a growing intensity that is adversely affecting our communities and our environment, here in California and across the globe. The science that, decades ago, predicted the impacts we are currently experiencing is even stronger today and unambiguously tells us what we must do to limit irreversible damage: we must act with renewed commitment and focus to do more and do it sooner. That science is indisputable. Unless we increase ambition, we will be faced with more fire, more drought, more temperature extremes, and deadly, choking air pollution. The future of our state—our communities, economy, and ecosystems—is inextricably tied to the way we respond in this decade and the partnerships we forge along the way.

The impacts of climate change fall most heavily on frontline communities that bear the brunt of extreme heat, drought, wildfires, and other effects. Low-income communities and communities of color are also disproportionately impacted by fossil fuel combustion-related air pollution and related health problems. The continued phaseout of fossil fuel combustion will advance both climate and air quality goals and will deliver the greatest health benefits to the most impacted communities.

As it has responded to this climate crisis, California has established itself as a global leader in science-based, public health-focused climate change mitigation and air quality control. The California Legislature has worked with both Republican and Democratic governors to advance action on public health and environmental protections—and California has made progress on addressing climate change during periods of both Republican and Democratic federal administrations. Since the passage of Assembly Bill 32 (AB 32) (Núñez and Pavley, Chapter 488, Statutes of 2006), California has developed bold, creative, and durable policy solutions to protect our environment and public health, all while growing our economy. In fact, California met the target established in AB 32—a return of greenhouse gas (GHG) emissions to 1990 levels by 2020—years ahead of schedule, even as the state established itself as the one of the largest economies in the world. As Figure 1-1 below shows, California's emissions and economic growth have continued to decouple, and California is now the fifth largest economy in the world.

Figure 1-1: California total and per capita GHG emissions[25]



Recognizing both California's early successes in achieving GHG emissions reductions while growing the economy, as well as the worsening impacts of climate change, our governors and legislators have continued to enact ambitious goals. California's unwavering commitment to address climate change is based on indisputable science and data. This commitment is also informed by our collective efforts to address environmental justice and advance racial equity, such that race will no longer be a predictor for disproportionate environmental burdens faced by low-income communities and communities of color. As the Office of Environmental Health Hazard Assessment's

[25] Due to the global pandemic, 2020 is an outlier year and should not be considered indicative of a trend; emissions are likely to increase as economies recover from the impacts of the pandemic.

(OEHHA's) recent analysis of race/ethnicity and air pollution vulnerability and CalEnviroScreen 4.0 scores demonstrate, much work remains to be done.[26]

Many of California's environmental policies have served as models for similar policies in other U.S. states, and at national and international levels. Moving forward, California will continue its pursuit of collaborations and advocacy for action to address climate change at all levels of government. While California is responsible for just one percent of global GHG emissions, and we must do our part, we also play an important role in exporting both political will and technical solutions to address the climate crisis globally.

Today, we have a chance to re-envision California's future and set the state on a path to be carbon neutral no later than 2045 while advancing equity, addressing environmental justice, and continuing to grow our economy. This Scoping Plan provides a roadmap outlining key policies we can implement to achieve our climate goals while improving the health and welfare of Californians and addressing disparities in health outcomes to create a more equitable future. It will enable us to turn the corner in our efforts to protect and preserve our critical natural and public resources, all while providing unparalleled opportunities for clean, pollution-free economic growth.

Severity of Climate Change Impacts

With the increasing severity and frequency of drought, wildfire, extreme heat, and other impacts, Californians just have to look out their windows to know that climate change is real and rapidly getting worse. The impacts we thought we would see in the decades to come are happening now. We must act decisively to both reduce our GHG emissions and build resilience to these impacts for ourselves, future generations, and our iconic landscapes.

Wildfires

Of the twenty largest wildfires ever recorded in California, nine occurred in 2020 and 2021. The worst wildfire season in California's recorded history was in 2018, with over 24,226 structures damaged or destroyed and over 100 lives lost. The largest wildfire season ever recorded in state history was in 2020, where more than 4.3 million acres burned, albeit at different intensity and with varying ecological impacts, and over 112 million metric tons of

[26] OEHHA and CalEPA. 2021. Analysis of Race/Ethnicity and CalEnviroScreen 4.0 Scores. https://oehha.ca.gov/media/downloads/calenviroscreen/document/calenviroscreen40raceanalysisf2021.pdf.

carbon dioxide (CO_2) emitted into the atmosphere.[27] The economic damage of these fires was estimated to be over $10 billion in property damage and over $2 billion in fire suppression costs.[28] The Camp Fire, which destroyed much of Paradise, California, was the world's costliest natural disaster in 2018, with overall damages of $16.5 billion.[29] It was also the deadliest fire in California history, with 85 civilian fatalities. Wildfires have always been part of California's natural ecology and will continue to be. However, changes to the state's climate and precipitation expands the footprint of wildfire threat, severity, and intensity, with one quarter of California—more than 25 million acres—now classified as being under very high or extreme fire threat.[30]

The impacts of wildfire smoke have been linked to respiratory infections, cardiac arrests, low birth weight, mental health conditions, and exacerbated asthma and chronic obstructive pulmonary disease.[31] In 2020, with all of California covered by wildfire smoke for over 45 days—and 36 counties for at least 90 days—maximum fine particulate ($PM_{2.5}$) levels persisted in the "hazardous" range of the Air Quality Index for weeks in several areas of the state.[32,33]

Catastrophic wildfire damages extend beyond human health and the economy. The Castle Fire in 2020 and the KNP Complex and Windy Fires in 2021 led to the loss of an unprecedented number of giant sequoias: an estimated 13 to 19 percent of the giant

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[27] CARB. 2020. Public Comment Draft Greenhouse Gas Emissions of Contemporary Wildfire, Prescribed Fire, and Forest Management Activities. https://ww3.arb.ca.gov/cc/inventory/pubs/ca_ghg_wildfire_forestmanagement.pdf.

[28] News18. 2021. San Francisco Bay Area Receives its First Wildfire Warning of 2021, After California Concludes its Driest Year. https://www.news18.com/news/buzz/san-francisco-bay-area-receives-its-first-wildfire-warning-of-2021-after-california-concludes-its-driest-year-3722897.html.

[29] Munich RE. 2019. Extreme Storms, Wildfires and Droughts Cause Heavy Nat Cat Losses In 2018. https://www.munichre.com/en/company/media-relations/media-information-and-corporate-news/media-information/2019/2019-01-08-extreme-storms-wildfires-and-droughts-cause-heavy-nat-cat-losses-in-2018.html#-1808457171.

[30] CARB. No date. Wildfires. https://ww2.arb.ca.gov/our-work/programs/wildfires/about.

[31] Reid, C. E., M. Brauer, F. H. Johnston, M. Jerrett, J. R. Balmes, and C. T. Elliott. 2016. "Critical Review of Health Impacts of Wildfire Smoke Exposure." *Environmental Health Perspectives* http://dx.doi.org/10.1289/ehp.1409277.

[32] Vargo J. A. 2020 (updated in 2021 using the NOAA Hazard Mapping System). "Time Series of Potential US Wildland Fire Smoke Exposures." *Frontiers in Public Health* https://doi.org/10.3389/fpubh.2020.00126.

[33] CalFire. 2020 *Fire Siege Report.* https://www.fire.ca.gov/media/hsviuuv3/cal-fire-2020-fire-siege.pdf.

sequoia population in the Sierra Nevada. An iconic species, giant sequoias are the largest trees on earth, with exceptional longevity outside of climate extremes.[34,35]

It is clear that we must take drastic measures to prepare for future wildfires, which is why California invested $2.7 billion in wildfire resilience from fiscal years 2020 to 2023. The exponential increase in funding launched more than 552 wildfire resilience projects in less than a year, and CAL FIRE met its 2025 goal of treating 100,000 acres a full three years ahead of schedule. Since Fiscal Year 2019–20, treatment work has significantly increased, and CAL FIRE has averaged 100,000 acres treated each fiscal year.

Although we are making progress, we have a lot more work to do in order to achieve our goal of treating one million acres annually by 2025. The Governor's Wildfire and Forest Resilience Strategy details 99 actions needed to address the key drivers of catastrophic wildfires, ramp up the pace and scale of forest management, and make threatened communities more resilient to catastrophic fires. It is also important to note that natural wildfire cycles are a part of a sustainable forest ecosystem and will continue to play a role in a healthy forests' future. We should not expect wildfires to cease, but we must manage our lands to address catastrophic wildfires that result from buildup of carbon stocks due to our interventions to suppress wildfires and from climate change resulting from fossil fuel combustion.

Drought

Drought is a recurring feature of the California climate that has been intensified by increasingly warmer average temperatures. Anthropogenic climate trends have exacerbated drought conditions; human-caused climate change accounts for 19 percent of drought severity and 42 percent of the soil moisture deficit in this region since 2000. The governor declared a drought state of emergency in October 2021, and as of September 2022, 94 percent of California was in severe drought, and 99.8 percent[36] of the state was in at least moderate drought. The first three months of 2022 were the driest January, February, and March on record in California.[37] The harsh drought conditions affecting California are part of a larger megadrought—a drought lasting more than two

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[34] Shive, K., C. Brigham, T. Caprio, and P. Hardwick. 2021. 2021 Fire Season Impacts to Giant Sequoias. The Nature Conservancy and National Park Service. https://www.nps.gov/articles/000/2021-fire-season-impacts-to-giant-sequoias.htm.

[35] Shive, K. L., A. Wuenschel, L. J. Hardlund, S. Morris, M. D. Meyer, and S. M. Hood. 2022. "Ancient Trees and Modern Wildfires: Declining Resilience to Wildfire in the Highly Fire-adapted Giant Sequoia." *Forest Ecology and Management* 511, 120110. https://doi.org/10.1016/j.foreco.2022.120110.

[36] Drought.gov. California. National Oceanic and Atmospheric Administration (NOAA) and the National Integrated Drought Information System. https://www.drought.gov/states/california.

[37] Drought.ca.gov. September 26, 2022. California Drought Update. https://drought.ca.gov/media/2022/09/Weekly-CA-Drought-Update-09262022-FINAL.pdf.

decades—that has been ongoing in the Southwestern region of North America since 2000. The past 22 years have been the region's driest period since at least 800 CE.[38]

While large urban water districts with diversified sources of water supply have maintained water deliveries to customers through the drought, hundreds of individual well owners and some small water systems have suffered disruption. The state is providing funding for water system consolidation and modernization projects in small communities, emergency repairs and replacements for dry wells, and bottled and hauled water deliveries. A 2021 law requires small suppliers to create drought contingency plans. During the drought of the last three years the state has delivered emergency drinking water assistance to nearly 10,000 households and 150 water systems.

California agriculture is responsible for more than half of all U.S. domestic fruit and vegetable production, and in 2021 drought resulted in the fallowing of nearly 400,000 acres of fields.[39] Direct crop revenue losses were approximately $962 million, and total economic impacts were more than $1.7 billion, with over 14,000 full- and part-time job losses.[40] During the 2011–2017 drought, California's agricultural industry suffered at least $5 billion in losses.[41] The 2022–23 budget includes $100 million to support agricultural water conservation practices, provide on-farm technical assistance, and provide direct relief to small farm operators.

Though native California species are adapted to drought, human engineering has altered most streams and wetlands in the state, making drought increasingly stressful to fish and wildlife. The state has conducted hundreds of fish and amphibian rescues in this drought to move creatures from diminished habitat, upgraded hatcheries, and boosted hatchery production, and has hauled millions of young hatchery salmon to San Francisco Bay to avoid adverse river conditions. State biologists monitor dozens of streams statewide and have negotiated voluntary agreements with landowners and water users to improve stream flows and temperatures.

California has started to implement major policies to build resilience to combat drought—such as the Sustainable Groundwater Management Act of 2014, the governor's Water Resilience Portfolio (2020), the governor's Water and Supply Strategy (August 2022), and

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[38] Williams, A. P., B. I. Cook, and J. E. Smerdon. 2022. "Rapid Intensification of The Emerging Southwestern North American Megadrought in 2020–2021." *Nature Climate Change* https://doi.org/10.1038/s41558-022-01290-z.

[39] Medellín-Azuara, J. 2022. *Economic Impacts of the 2021 Drought on California Agriculture.* University of California Merced. https://wsm.ucmerced.edu/wp-content/uploads/2022/02/2021-Drought-Impact-Assessment_20210224.pdf.

[40] Medellín-Azuara. *Economic Impacts of the 2021 Drought*.

[41] National Resources Defense Council (NRDC). 2019. Climate Change and Health in California. Issue Brief. https://www.nrdc.org/sites/default/files/climate-change-health-impacts-california-ib.pdf.

new standards for indoor, outdoor, and industrial water use. However, it is crucial that we take further actions to minimize the impacts of drought in the years to come.

Extreme Heat

California's hottest summer on record was 2021.[42] Death Valley recorded the world's highest reliably measured temperature (130°F) in July 2021, breaking its own record (129°F) from summer 2020.[43] Meanwhile, Fresno also broke one of its own records, with 64 days over 100°F in 2021.[44] This is part of a trend: the daily maximum average temperature, an indicator of extreme temperature shifts, is expected to rise 4.4°F–5.8°F by 2050 and 5.6°F–8.8°F by 2100.[45] Heat waves that result in public health impacts are also projected to worsen throughout the state. By 2050, these heat-related health events are projected to last two weeks longer in the Central Valley and occur four to ten times more often in the Northern Sierra region.[46]

Heat ranks among the deadliest of all climate hazards in California, and heat waves in cities are projected to cause two to three times more heat-related deaths by mid-century.[47] Climate vulnerable communities[48] will experience the worst of these effects, as heat risk is associated and correlated with physical, social, political, and economic factors. Aging populations, infants and children, pregnant people, and people with chronic illness are especially sensitive to heat exposure.[49,50] Combining these characteristics and existing health inequities with additional factors such as poverty, linguistic isolation,

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[42] NOAA. 2022. Climate at a Glance. *https://www.ncdc.noaa.gov/cag/statewide/time-series/4/tavg/3/8/1895-2021?base_prd=true&firstbaseyear=1901&lastbaseyear=2000*.

[43] Masters, J. 2021. Death Valley, California, breaks the all-time world heat record for the second year in a row. Yale Climate Connections. *https://yaleclimateconnections.org/2021/07/death-valley-california-breaks-the-all-time-world-heat-record-for-the-second-year-in-a-row/*.

[44] NOAA. Climate Data Online Search. Accessed on 16 March 2022. *https://www.ncdc.noaa.gov/cdo-web/search*.

[45] Governor's Office of Planning and Research (OPR), CEC, and CNRA. 2018. *California's Fourth Climate Change Assessment*. Page 23. *https://www.energy.ca.gov/sites/default/files/2019-11/Statewide_Reports-SUM-CCCA4-2018-013_Statewide_Summary_Report_ADA.pdf*.

[46] OPR, CEC, and CNRA. *California's Fourth Climate Change Assessment - Statewide Summary Report.* *https://www.energy.ca.gov/sites/default/files/2019-11/Statewide_Reports-SUM-CCCA4-2018-013_Statewide_Summary_Report_ADA.pdf*.

[47] Ostro, B., S. Rauch, and S. Green. 2011. "Quantifying the health impacts of future changes in temperature in California." National Library of Medicine. *https://pubmed.ncbi.nlm.nih.gov/21975126/*.

[48] CARB. Priority Populations. California Climate Investments. *https://www.caclimateinvestments.ca.gov/priority-populations*.

[49] Basu, R. 2009. "High Ambient Temperature and Mortality: A Review of Epidemiologic Studies from 2001 to 2008." National Library of Medicine. *https://pubmed.ncbi.nlm.nih.gov/19758453/*.

[50] Basu, R., and B. Malig. 2011. "High Ambient Temperature and Mortality in California: Exploring the Roles of Age, Disease, and Mortality Displacement." National Library of Medicine. *https://pubmed.ncbi.nlm.nih.gov/21981982/*.

housing insecurity, and the legacy of racist redlining practices, can put individuals at a disproportionately high risk of heat-related illness and death.[51,52] Rising temperatures will also speed up smog-forming chemical reactions, leading to worse asthma, reduced lung function, cardiac arrest, and cognitive decline. African American, American Indian/Alaskan Native, and Puerto Rican Californians are particularly sensitive to smog, as they are between 28.6 and 132.5 percent more likely to be diagnosed with asthma than white Californians.[53]

In addition to the dangers to public health, California's September 2022 heat wave is particularly illustrative of how more frequent extreme heat strains the state's infrastructure we depend on to adapt to a changing climate. For example, as all-time high temperature records were broken in Sacramento, San Jose, Santa Rosa and Fairfield, electricity demand for air conditioning threatened to overwhelm the state power supply.[54]

California has taken major steps to protect communities from the impacts of extreme heat. Our recent budgets invest $800 million to cool our schools and neighborhoods, including projects to reduce urban overheating. The Extreme Heat Action Plan, released in April 2022, outlines the all-of-government approach California is taking to reduce urgent risks and build long-term resilience to the impacts of extreme heat. In September 2022, Governor Newsom signed multiple bills addressing extreme heat, including AB 2238 (Rivas, Chapter 264, Statutes of 2022), which will create the nation's first extreme heat advance warning and ranking system to better prepare communities ahead of heat waves. The Administration is committed to addressing extreme heat, but we still have a lot of work to do.

Wildfires, drought, and extreme heat are some of the most pronounced climate impacts California is experiencing, but they are not the only ones. Sea level rise, rising ocean temperatures, ocean acidification, and inland flooding are also already having devastating impacts on our communities, ecosystems, and economy, and will continue to do so in the years and decades to come. The decisions and actions that we take today will determine how strongly we will feel the impacts of climate change in the future.

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[51] Hoffman, J. S., V. Shandas, and N. Pendleton. 2020. "The Effects of Historical Housing Policies on Resident Exposure to Intra-Urban Heat: A Study of 108 US Urban Areas." MDPI. *https://www.mdpi.com/2225-1154/8/1/12/htm*.

[52] U.S. Climate Resilience Toolkit. No date. Heat and Social Inequity in the United States. *https://toolkit.climate.gov/tool/heat-and-social-inequity-united-states*.

[53] NRDC. 2019. Climate Change and Health. Issue Brief. *https://www.nrdc.org/sites/default/files/climate-change-health-impacts-california-ib.pdf*.

[54] Samenow, Jason. 2022. No September on record in the West has seen a heat wave like this. *The Washington Post.* September 9. *https://www.washingtonpost.com/climate-environment/2022/09/08/western-heatwave-records-california-climate/*.

Imperative To Act

Consequences of Further Warming

The Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6) found that it will not be possible to keep global warming within the threshold of 1.5°C to avoid the most severe impacts of climate change unless we make immediate and large-scale reductions in GHG emissions. It finds that atmospheric concentrations of CO_2 have increased by 50 percent since the industrial revolution, and that they continue to increase at a rate of two parts per million each year.[55] Without immediate action, the world will exceed 1.5°C (or 2.7°F) warming by the 2030s, and no later than 2040.

While every tenth of a degree matters—every incremental increase in warming brings additional negative impacts—climate-related risks to human health, livelihoods, and biodiversity are projected to increase further under 2°C (or 3.6°F) warming, compared to 1.5°C.[56] To remain below 1.5°C with limited or no overshoot of that threshold, global net anthropogenic CO_2 emissions need to be cut by about half by 2030 and reach net-zero by 2050.

If we fail to make rapid changes, we may not be able to limit global warming to 2°C,[57] and the consequences of inaction would be catastrophic. Our planet is already 1.2°C warmer than pre-industrial times due to human-induced warming, and many impacts we are already experiencing, such as sea level rise, are "irreversible" for centuries to millennia.[58] Californians with the fewest resources, who are disproportionately low-income communities and communities of color, are the most vulnerable to the impacts of climate change. While the human costs associated with health impacts can never be fully monetized, a recent report finds that the health costs of climate and air pollution in the U.S. are well over $800 billion today and will continue to grow in the coming years.[59]

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[55] IPCC. 2021. *Climate Change 2021: The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.

[56] IPCC. 2018. *Special Report: Global Warming of 1.5°C.* World Meteorological Organization. https://www.ipcc.ch/sr15/.

[57] IPCC. 2021. Summary for Policymakers. In: *Climate Change 2021: The Physical Science Basis.* Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S. L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M. I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J. B. R. Matthews, T. K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. In Press. https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_SPM_final.pdf.

[58] United Nations. 2021. IPCC report: 'Code red.' https://news.un.org/en/story/2021/08/1097362#:~:text=%27Code%20red%20for%20humanity%27&text=We%20are%20at%20imminent%20risk,%2C%20to%20keep%201.5%20alive.%22.

[59] Alwis, D. D., and V. S. Limaye. No date. *The Costs of Inaction*. https://www.nrdc.org/sites/default/files/costs-inaction-burden-health-report.pdf.

Any delays in action or insufficient action are a threat to public health and the environment. The impacts to our economy would be devastating as well. While not specific to California, a 2022 report from Deloitte Economics Institute finds that failing to take sufficient action to reduce emissions could result in economic losses to the U.S. of more than $14.5 trillion over the next 50 years.[60] On a hopeful note, however, the report finds that if the country invests now and in the coming years in a net-zero economy, $3 trillion could be added to the economy over the next 50 years. The U.S. annual gross domestic product (GDP) would be 2.5 percent higher in 2070 in this fast-action scenario than in the delayed action scenario. The lessons for California from these analyses are clear: invest now or pay the price later. As shown in Figure 1-2, inaction can lead to negative consequences for individuals, communities, the economy, and society as a whole. As discussed later, Governor Newsom and the Legislature have accepted this imperative and made significant investments in climate action. This Scoping Plan combined with the historic investments and policy direction from the governor and Legislature, will result in unprecedented action to address the climate crisis.

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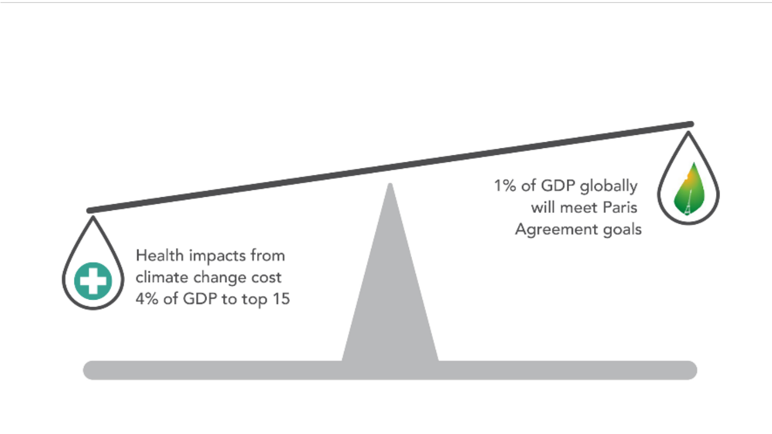
[60] Deloitte. 2022. *The Turning Point.* https://www2.deloitte.com/content/dam/Deloitte/us/Documents/about-deloitte/us-the-turning-point-a-new-economic-climate-in-the-united-states-january-2022.pdf?id=us:2el:3dp:wsjspon:awa:WSJSBJ:2021:WSJFY22.

Figure 1-2: The real costs of inaction[61]

Costs of Inaction Outweigh Costs of Action for World's Largest 15 GHG Emitters



Exposure to air pollution causes 7 million deaths worldwide every year and costs an estimated US$5.11 trillion in welfare losses globally. In the 15 countries that emit the most greenhouse gas emissions, the health impacts of air pollution are estimated to cost more than 4% of their GDP. Fossil fuel combustion contributes to both air pollution and climate change. Actions to meet the Paris goals would cost about 1% of global GDP.

Scoping Plan Overview

Previous Scoping Plans

The Scoping Plan is a strategy the California Air Resources Board (CARB) develops and updates at least one every five years, as required by AB 32. It lays out the transformations needed across our society and economy to reduce emissions and reach our climate targets. This Scoping Plan is the third update to the original plan that was adopted in 2008. The initial Scoping Plan laid out a path to achieve the AB 32 2020 limit of returning to 1990 levels of GHG emissions, a reduction of approximately 15 percent below business as usual.[62] The 2008 Scoping Plan included a mix of incentives, regulations, and carbon pricing, laying out the portfolio approach to addressing climate change and clearly making the case for using multiple tools to meet California's GHG targets. The 2013 Scoping Plan assessed progress toward achieving the 2020 limit and made the case for addressing

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[61] Katowice, P. 2018. *Health benefits far outweigh the costs of meeting climate change goals.* WHO. https://www.who.int/news/item/05-12-2018-health-benefits-far-outweigh-the-costs-of-meeting-climate-change-goals.

[62] CARB. 2008. *Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/document/adopted_scoping_plan.pdf.

short-lived climate pollutants (SLCPs).[63] The most recent update, the 2017 Scoping Plan,[64] also assessed the progress toward achieving the 2020 limit and provided a technologically feasible and cost-effective path to achieving the Senate Bill 32 (SB 32, Pavley, Chapter 249, Statutes of 2016) target of reducing GHGs by at least 40 percent below 1990 levels by 2030.

Overview of this Scoping Plan

It is paramount that we continue to build on California's success by taking effective actions and doubling down on implementation of the strategies outlined here. As such, this Scoping Plan builds on and integrates efforts already underway to reduce the state's GHG, criteria pollutant, and toxic air contaminant emissions by identifying the clean technologies and fuels that should be phased in as the state transitions away from combustion of fossil fuels. By selecting and pursuing a sustainable and clean economic path, the state will continue to successfully execute existing programs, work to eliminate air pollution inequities, demonstrate the coupling of economic growth and environmental progress, and enhance new opportunities for engagement within the state to address and prepare for climate change.

The 2022 Scoping Plan for Achieving Carbon Neutrality (Scoping Plan) is the most comprehensive and far-reaching Scoping Plan developed to date. It identifies a technologically feasible and cost-effective path to achieve carbon neutrality by 2045 while also assessing the progress California is making toward reducing its GHG emissions by at least 40 percent below 1990 levels by 2030, as called for in SB 32 and laid out in the 2017 Scoping Plan.[65] The 2030 target is an interim but important stepping stone along the critical path to the broader goal of deep decarbonization by 2045. Modeling for this Scoping Plan shows that this decade must be one of transformation on a scale never seen before to set us up for success in 2045.

The relatively longer path assessed in this Scoping Plan incorporates, coordinates, and leverages many existing and ongoing efforts to reduce GHGs and air pollution, while identifying new clean technologies and energy. Given the focus on carbon neutrality, this Scoping Plan also includes discussion for the first time of the Natural and Working Lands (NWL) sectors as both sources of emissions and carbon sinks. Chapter 2 of this document

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[63] CARB. 2014. *First Update to the Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

[64] CARB. 2017. *California's 2017 Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/scoping_plan_2017.pdf.

[65] CARB. 2017. *California's 2017 Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/scoping_plan_2017.pdf.

includes a description of a suite of specific actions to drastically reduce GHGs across all sectors. Chapter 3 provides the air quality and economic evaluations of the actions. Chapter 4 provides a broader description of the many actions needed across all sectors to achieve carbon neutrality. Chapter 5 provides an overview of the next steps and partnerships needed to implement this Scoping Plan. Guided by legislative direction, the actions identified in this Scoping Plan reduce overall GHG emissions in California and deliver policy signals that will continue to drive investment and certainty in a low carbon economy. This Scoping Plan builds upon the successful framework established by the Initial Scoping Plan and subsequent updates while identifying new, technologically feasible, and cost-effective strategies.

Principles That Inform Our Approach to Addressing the Climate Challenge

California has decades of experience addressing the climate challenge. Through this experience, and based on extensive engagement with stakeholders through our regulatory and program development processes, we have developed a set of principles to inform our approach.

Unprecedented Investments in a Sustainable Future

The scale of transformation needed over this decade to avoid the worst impacts of climate change and meet our ambitious climate goals is extraordinary. This is why Governor Newsom and the Legislature invested over $15 billion in climate action through the 2021–2022 California Comeback Plan, and why the 2022–2023 budget marks the beginning of the California Climate Commitment—the governor's multi-year plan to invest $54 billion in climate action. The enacted budgets (Figure 1-3) and the California Climate Commitment represent investments of a historic scale and will advance precisely the type of all-of-government approaches necessary to create the whole-of-society changes described in this Scoping Plan that will enable us to avert the worst impacts of climate change.

Figure 1-3: Comprehensive California climate change investments

The *California Climate Commitment* includes the following game-changing elements:

- $10 billion for zero-emission vehicles (ZEVs), including $1.5 billion for electric school buses to protect students' health and $3 billion to build an accessible charging network. ZEV investments will particularly focus on programs such as heavy-duty vehicle and port electrification that will reduce emissions and protect public health in low-income communities.
- $2.1 billion for clean energy investments, such as long duration storage, offshore wind, green hydrogen,[66] and industrial decarbonization.
- $13.8 billion for programs that reduce emissions from the transportation sector, such as improving public transportation while also funding walking, biking, and adaptation projects.
- Over $720 million for California's higher education institutions and research that will support the next generation of climate innovations.

[66] For the purposes of this Scoping Plan, "renewable hydrogen" and "green hydrogen" are interchangeable and are not limited to only electrolytic hydrogen produced from renewables.

- Nearly $1 billion to build sustainable, affordable housing and over $1 billion to help low-income Californians realize energy cost savings through building decarbonization.
- Nearly $9 billion for wildfire risk reduction, drought mitigation, extreme heat resilience, and nature-based solutions.

These investments are incredibly important in the context of this Scoping Plan in that they accompany and help support implementation of the many policies and regulations that will continue to be necessary to achieve our 2030 and carbon neutrality targets. In addition, these incentive programs jump-start emission reduction strategies for priority sectors, sources, and technologies, leveraging private-sector investment and building sustainable, growing markets for clean and efficient technologies. Many of California's incentive programs work in concert with federal and other state programs to drive emission reductions. As an example, as California pushes to move to 100% sales of new zero emission-vehicles, including plug-in hybrid vehicles, the Newsom Administration continues to invest heavily in incentive programs that allow families, communities, and businesses to choose zero-emission vehicles. This is done while simultaneously working with the federal government, other states, and jurisdictions around the world to align policies, regulations, and incentives, creating market certainty for the automakers that serve our markets.

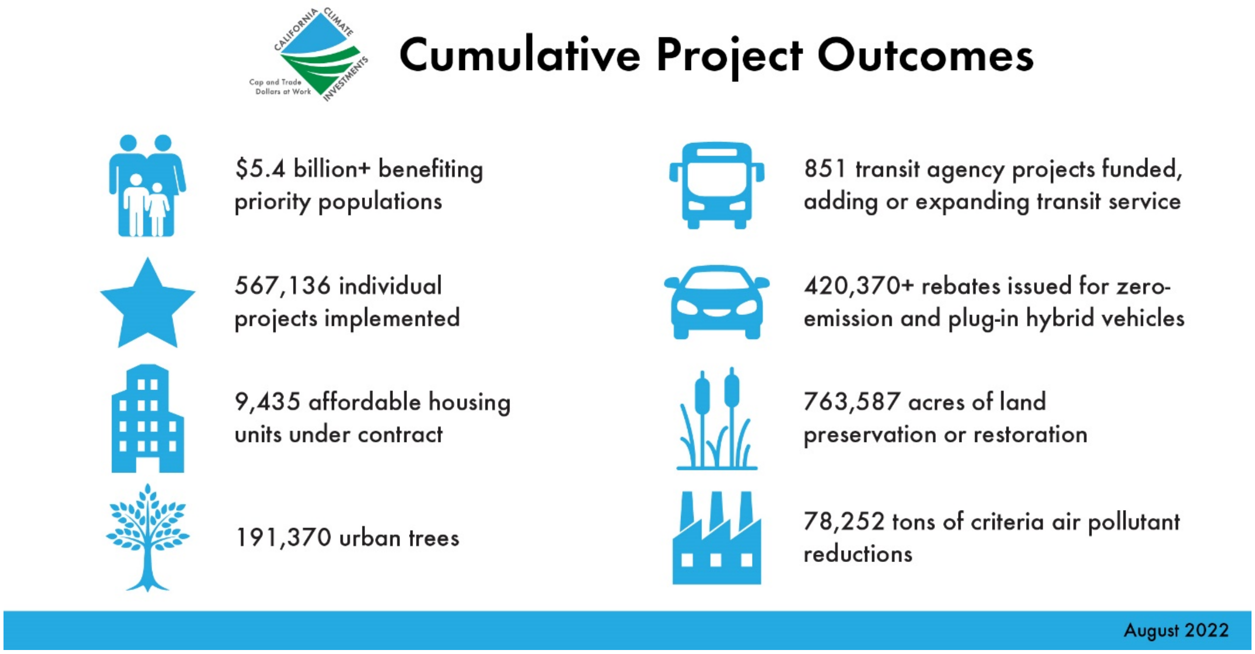
Centering Equity

Prioritizing equity is just as important as the magnitude of the climate investments California is making. Addressing climate change and advancing our equity and economic opportunity goals cannot be decoupled. In line with the governor's Executive Order[67] to take additional actions to embed equity analysis and considerations, this plan works to center equity by addressing disparities for historically underserved and marginalized communities. California strives to ensure that our climate and air research, regulations, investments, and plans include provisions that specifically address and advance equity. This includes reducing and eliminating air pollution disparities, removing barriers that can prevent frontline communities from accessing benefits, lowering costs for low-income Californians, and promoting high-quality jobs. CARB's incentive programs regularly surpass their mandated equity targets, and CARB has incorporated equity-focused provisions in our research, planning, and regulatory efforts. For instance, statute requires that a minimum of 35 percent of California Climate Investments benefit low-income households along with disadvantaged and low-income communities (referred to as *priority*

[67] Executive Department. State of California. 2022. Executive Order N-16-22. GSS_9320_2-20220912152941 (ca.gov).

populations). However, 48 percent—over $5.4 billion—of implemented California Climate Investments project funding is benefiting priority populations, greatly exceeding the statutory minimums (see Figure 1-4). Senate Bill 535 (De León, Chapter 830, Statutes of 2012) and AB 1550 (Gomez, Chapter 369, Statutes of 2016) direct state and local agencies to make significant investments using auction proceeds to assist California's most vulnerable communities. Under these laws, a minimum of 25 percent of the total investments are required to be located within and provide benefits to disadvantaged communities, and at least 10 percent of the total investments must benefit low-income communities and households. Moving forward, the state will continue to devote a greater share of incentive funding to priority populations, with the light-duty vehicle incentive program as just one example. We can simultaneously confront the climate crisis and build a more resilient, just, and equitable future for all communities.

Figure 1-4: California climate investments cumulative outcomes[68,69]



Role of the Environmental Justice Advisory Committee

To inform the development of the Scoping Plan, AB 32 calls for the convening of an Environmental Justice Advisory Committee (EJ Advisory Committee) to advise CARB in developing the Scoping Plan, and any other pertinent matter in implementing AB 32. It requires that the Committee be comprised of representatives from communities with the most significant exposure to air pollution, including communities with minority populations and/or low-income populations. On January 25, 2007, CARB appointed the first

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[68] CARB. 2022. California Climate Investments program implements $10.5 billion in greenhouse gas-reducing programs, expected to reduce 76 million metric tons of emissions. April 11. https://ww2.arb.ca.gov/news/california-climate-investments-program-implements-105-billion-greenhouse-gas-reducing-projects.

[69] SB 535 and AB 1550 require investments located in and benefiting low-income communities and households, which are termed *priority populations. Disadvantaged communities* are currently defined by CalEPA as the top 25 percent of communities experiencing disproportionate amounts of pollution, environmental degradation, and socioeconomic and public health conditions according to the Office of Environmental Health Hazard Assessment's *CalEnviroScreen tool,* plus certain additional communities including federally recognized Tribal Lands. Low-income communities and households are defined by statute as those with incomes either at or below 80 percent of the statewide median or below a threshold designated as low-income by the Department of Housing and Community Development.

Environmental Justice Advisory Committee to advise it on the Initial Scoping Plan and other climate change programs.

For this Scoping Plan, CARB reconvened the EJ Advisory Committee in May 2021. The committee is currently comprised of 14 environmental justice and disadvantaged community representatives, including the EJ Advisory Committee's first tribal representative, who was appointed in February 2022. In October 2021, the EJ Advisory Committee formally created eight workgroups. These workgroups are a space for EJ Advisory Committee members to better understand specific sectors of the Scoping Plan and to assist the EJ Advisory Committee in the development of recommendations on this Scoping Plan. In December 2021, the EJ Advisory Committee provided scenario input responses to help shape the modeling for this Scoping Plan. In February 2022, San Joaquin Valley EJ Advisory Committee members hosted their first community workshop, with over 100 attendees. In March 2022, the CARB Board held a joint public meeting with the EJ Advisory Committee to discuss their draft preliminary recommendations for this Scoping Plan. In June 2022, over 165 attendees participated in a statewide community workshop held by EJ Advisory Committee members. The full schedule of EJ Advisory Committee Meetings and meeting materials are available on CARB's website.[70] This Scoping Plan includes references where EJ Advisory Committee Final Recommendations[71] are included in the document. The final recommendations were discussed at a joint CARB and EJ Advisory Committee Hearing on September 1, 2022.

The integration of environmental justice is critical to ensure that certain communities are not left behind. The AB 32 EJ Advisory Committee provided recommendations on September 30 in advance of the final Scoping Plan. There are footnotes to indicate where there is alignment between the AB 32 EJ Advisory Committee's recommendations and this Scoping Plan. While the language in the text may not fully incorporate the specific EJ Advisory Committee's recommendation, the footnotes do acknowledge the places in the text where there is general alignment with the spirit of the EJ Advisory Committee's recommendation.

Partnering with Tribes

[70] CARB. Environmental Justice Advisory Committee Meetings and Events. https://ww2.arb.ca.gov/environmental-justice-advisory-committee-meetings-and-events.

[71] Environmental Justice Advisory Committee. September 30, 2022. 2022 Scoping Plan Recommendations. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/090122/finalejacrecs.pdf.

There are 109 federally recognized tribes and over 60 non-federally recognized tribes in California. [72] In 2011, Governor Brown issued Executive Order B-10-11, recognizing and reaffirming the inherent right of tribes to exercise sovereign authority over their members and territory and directing state agencies to engage in government-to-government consultation with tribe and to work to develop partnerships and consensus.[73] In 2019, Governor Newsom issued Executive Order N-15-19, which acknowledges and apologizes on behalf of the state for the historical "violence, exploitation, dispossession and the attempted destruction of tribal communities."[74] Establishing partnerships with tribal leaders to incorporate their priorities, traditional expertise, and knowledge will be important to achieving California's climate goals. The Scoping Plan includes actions that tribal partners can voluntarily implement for sources under their jurisdiction (e.g., transitioning to zero emission fleets, installing infrastructure and control technologies, conducting climate smart land management). The Scoping Plan also uplifts the importance of having our tribal partners help guide actions that may impact tribal cultural resources and of benefitting from tribal input.

We also need alignment between state and local partners and tribes on actions related to land-use decisions. This means respecting and reinforcing tribal sovereignty and self-determination. As tribes do not always draw clear lines between the "natural" and "cultural" resources of a place, taking a holistic perspective will result in positive impacts in ability to address the complex issues of land management and regulatory undertakings.

Tribes have an intimate and historical knowledge of places and should be engaged early on to inform planning and future management related to activities that may impact tribal resources and areas including potential funding opportunities, technical assistance, and capacity building, where appropriate. Additionally, tribes should be involved in the identification of their own significant resources and areas of use. As decisions are made related to Scoping Plan undertakings, agencies should recognize and appropriately consider cultural resources and management from the beginning, not as an afterthought; and consider how the project could impact tribes.

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[72] These numbers are subject to change depending on determinations made by the Bureau of Indian Affairs (BIA) and the Native American Heritage Commission (NAHC). Please consult the most current Federal Register for a list of federally recognized tribes and the NAHC for a list of non-federally recognized tribes in California. As of the date of the Scoping Plan, the current list for federally recognized tribes is located at 87 Fed. Reg. 4636 (Jan. 28, 2022).

[73] Executive Order B-10-11. https://www.ca.gov/archive/gov39/2011/09/19/news17223/index.html#:~:text=EXECUTIVE%20ORDER%20B-10-11%20Published%3A%20Sep%2019%2C%202011%20WHEREAS,and%20affirmed%20in%20state%20and%20federal%20law%3B%20and.

[74] Executive Order N-15-19. https://tribalaffairs.ca.gov/wp-content/uploads/sites/10/2020/02/Executive-Order-N-15-19.pdf.

Finally, to the extent allowed by law, traditional ecological knowledge and culturally sensitive information should be protected, as this is information that may not be common knowledge and may not be known outside the tribe, as each tribe is unique and influenced by its local environment and cultural practices. Protection of this information will help foster productive relationships with tribes and should be included as part of the process. CARB and other agencies should continue to foster relationships with tribal partners.

Maximizing Air Quality and Health Benefits

The state has over 50 years of experience successfully cleaning the air in California by addressing criteria pollutants and toxic air contaminants from mobile and stationary sources. CARB has been a leader in measuring, evaluating, and reducing sources of air pollution that impact public health. Its air pollution programs have been adapted for national programs and emulated in other countries. Significant progress has been made in reducing diesel particulate matter (PM), which is a designated toxic air contaminant, and many other hazardous air pollutants. CARB partners with local air districts to address stationary source emissions and adopts and implements state-level regulations to address sources of criteria and toxic air pollution, including mobile sources. CARB also collaborates with federal agencies to address air pollution from sources primarily under federal jurisdiction. In many instances, actions to reduce fossil fuel combustion and achieve federal air quality standards also help to reduce GHG emissions.

However, air pollution disparities still exist, and more must be done to ensure the most vulnerable populations have safe air to breathe. California must continue to evaluate opportunities to harmonize our climate and air quality programs through innovative policymaking and by building on existing programs like the Low Carbon Fuel Standard (LCFS) and Community Air Protection Program. The LCFS includes a provision that allows electric utilities to opt-in and generate residential electric vehicle (EV) charging credits, where some of the revenues are invested back into rebate programs that address air quality and climate pollution.[75] The Community Air Protection Program[76] is the first of its kind in the country and brings together diverse stakeholders, including CARB, local air districts, and residents of environmental justice communities to increase local air monitoring and develop community-led plans to improve air quality in the communities most impacted by air pollution.

This Scoping Plan identifies actions that will deliver near-term air quality benefits to communities with the highest exposures and provide long-term GHG benefits. Many of the actions in this Scoping Plan are key elements of the 2022 State Strategy for the State

[75] CARB. LCFS Utility Rebate Programs. https://ww2.arb.ca.gov/resources/documents/lcfs-utility-rebate-programs.

[76] CARB. Community Air Protection Program. https://ww2.arb.ca.gov/capp.

Implementation Plan to meet federal air quality standards,[77] which has a primary focus of reducing harmful air pollution and achieving federal air quality targets. California's approach of leveraging air quality and GHG policies together has yielded results. A 2022 report by the Office of Environmental Health and Hazard Assessment (OEHHA)[78] that evaluated GHG and harmful air pollution emissions from the heavy-duty vehicle (HDV) and large stationary source sectors found declines in emissions in both sectors, with the greatest declines in disadvantaged communities. Both sectors are subject to state GHG and air quality policies, in addition to federal and local rules on harmful air pollution. Because of historically racist and discriminatory practices such as redlining, both types of sources are disproportionately located adjacent to vulnerable communities, which are predominantly communities of color.[79] The key findings from the OEHHA report are as follows:

- Both HDVs and facilities subject to the Cap-and-Trade Program have reduced emissions of co-pollutants, with HDVs showing a clearer downward trend when compared to stationary sources. These emission reductions have major health benefits, including a reduction in premature pollution-related deaths.
- The greatest beneficiaries of reduced emissions from both HDVs and facilities subject to the Cap-and-Trade Program have been in communities of color and in disadvantaged communities in California, as identified by CalEnviroScreen (CES). This has reduced the emission gap between disadvantaged and non-disadvantaged communities, but a wide gap still remains.
- The transition to zero-emission HDVs will expedite further emissions reductions.
- While the progress observed is encouraging, inequities persist, and federal, state, and local climate and air quality programs must do more to reduce emissions of GHGs and co-pollutants to reduce the burden of emissions on disadvantaged communities and communities of color.

It will take all tools at all levels of government, with robust enforcement, to ensure that vulnerable communities continue to see improvements in air quality until no disparities exist in air pollution across the state.

[77] CARB. 2022 State Strategy for the State Implementation Plan. https://ww2.arb.ca.gov/resources/documents/2022-state-strategy-state-implementation-plan-2022-state-sip-strategy.

[78] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits within Disadvantaged Communities: Progress Toward Reducing Inequities.* https://oehha.ca.gov/environmental-justice/report/ab32-benefits.

[79] CalEPA. 2021. Pollution and Prejudice. https://storymaps.arcgis.com/stories/f167b251809c43778a2f9f040f43d2f5.

Economic Resilience

The state's efforts to tackle the climate crisis will create economic and workforce development opportunities in the clean energy economy in communities across the state. Transitioning existing skills and expanding workforce training opportunities in climate-related fields are critical for reducing harmful emissions and supporting workers in transitioning to new, high-quality jobs. The Administration's recent budgets acknowledge the challenges facing workers in industries most affected by the state's response to climate change—especially those in the fossil fuel industry. It will invest $1 billion in regional partnerships and economic diversification to create new jobs and support a local tax base and workforce transition and development once opportunities are identified. It also will invest in safety nets to protect, and support impacted communities as part of the transition to a carbon neutral economy. Specifically, the Community Economic Resilience Fund Program[80] (CERF) supports communities and regional groups in producing regional roadmaps for economic recovery and transition that prioritize the creation of accessible, high-quality jobs in sustainable industries. The budget investments create the opportunity to future-proof and increase economic resilience in the face of more frequent climate impacts and shifting economic conditions. For these investments and implementation of the Scoping Plan to be successful in supporting the transition to a carbon neutral economy, workers and affected communities must be included in ongoing dialogue to ensure a high-road transition for regional economies.

That state also recognizes it can play a more direct role in supporting a sustainable work force through its incentive programs. In 2021, Assembly Bill 680 (AB 680) (Burke, Chapter 746, Statutes of 2021) was signed into law, requiring CARB to work with the California Labor and Workforce Development Agency to update the Funding Guidelines to include new workforce standards. CARB's Funding Guidelines currently include requirements for administering agencies to, wherever possible, foster job creation within California, provide employment opportunities or job training tied to employment, and target these opportunities to priority populations. The Funding Guidelines also recommend administering agencies prioritize investments in projects that directly support jobs or a job training and placement program, and that they report the estimated employment benefits and employment outcomes for projects that meet specified criteria. These new requirements apply to agencies administering certain California Climate Investments

[80] Office of Planning and Research. Community Economic Resilience Fund. https://opr.ca.gov/economic-development/cerf/.

programs that receive continuous appropriations from the Greenhouse Gas Reduction Fund and fall into the following six categories of standards:

- fair and responsible employer standards,
- inclusive procurement policies,
- prevailing wage for construction work,
- community workforce agreements for construction projects over one million dollars,
- preference for projects with educational institutions or training programs, and
- creation of high-quality jobs. CARB will be updating the Funding Guidelines through a public process over the next year to operationalize these new requirements.

Partnering Across Government

The Scoping Plan is an actionable plan to identify and align programs and policies to achieve California's climate targets. To realize the outcomes and deliver results in any Scoping Plan, action is critical. For this Scoping Plan, there are also actions that rely on our federal partners to take on sources primarily under their jurisdiction (such as aviation, and federally owned/managed lands) while they also continue to develop national programs for GHG reductions. The federal government is already taking major steps to advance these types of programs. The Inflation Reduction Act of 2022[81] includes $369 billion for domestic energy production and manufacturing and is expected to lead to U.S. GHG emission reductions of roughly 40 percent by 2030. Direct incentives will include those for clean vehicles and ENERGY STAR appliances, as well as improving transportation and clean energy in underserved communities.

We also need our local partners to align on actions related to land-use decisions that support sustainable, resilient, low-carbon communities and permitting for clean energy production facilities and infrastructure; diversion of organics from landfills; and other climate-related projects. State agencies also should use the Scoping Plan to review and update their own programs and policies to support the actions identified in this Scoping Plan. Importantly, the Scoping Plan also can serve as a resource as the Legislature considers new legislative direction and funding to support the state's path to carbon neutrality and continue action to address near-term air pollution disparities.

Partnering with the Private Sector

Government cannot achieve our climate targets alone. The scale of investment needed requires both private-sector investment and partnerships with philanthropies. Public

[81] Pub.L. No. 117-169 (August 16, 2022).

sector dollars, accompanied by strong and steady policy signals, must be a catalyst for deeper and broader investments by the private sector in both reducing emissions and building the resilience of our communities. Governor Newsom is committed to working collaboratively with businesses, including small businesses, to deploy the technologies, capital, and ingenuity that are hallmarks of the private sector.

California structures our climate policies and regulations to create market signals and certainty that spur private sector investment. For example, the Governor's Executive Order on Zero-Emission Vehicles[82] set 2035 as the target year for 100 percent zero-emission vehicle sales, creating a time horizon that allows automakers to scale up zero-emission fleets and sending a clear signal to the companies and utilities that would deploy charging infrastructure. The Executive Order has been followed by development and adoption of the Advanced Clean Cars II regulation. CARB convened auto manufacturers, environmental justice groups, labor organizations, and many other stakeholders to provide input into development of the regulation in a robust and transparent manner; again, with the aim of providing certainty for producers and consumers.

California also pursues public-private partnerships (PPP) as a mechanism to advance our collective climate goals. We know these vehicles can be effective at increasing the impact of public sector dollars and helpful in moving markets in a direction aligned with state policy. A new PPP the Administration is advancing is the Climate Catalyst Revolving Loan Fund, housed at the state's Infrastructure and Economic Development Bank (IBank). The fund offers a range of financial instruments—including flexible credit and credit support—to help bridge financing gaps currently preventing advanced climate solutions from scaling in the marketplace. The Catalyst Fund's initial areas of investment include forest biomass management and utilization (unlocking innovation to reduce wildfire threats), climate-smart agriculture, and clean energy transmission. The fund leverages public sector investments by mobilizing private finance for shovel-ready projects that are stuck in the deployment phase. As such, IBank is ideally positioned as the state's all-purpose "Green Bank," with increasing connection to federal financing programs such as US DOE's Loan Programs Office and the United States Environmental Protection Agency's (U.S. EPA) Greenhouse Gas Reduction Fund.

The Catalyst Fund builds from existing IBank financing programs that are themselves increasingly focused on the climate imperative. The IBank's Infrastructure State Revolving Fund provides supportive capital to climate-aligned projects promoted by local governments and certain nonprofit entities, and will be refining its criteria and market outreach strategies to increase its level of service. IBank's bonds program has supported

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[82] Executive Department. State of California. Executive Order N-79-20. *https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf*.

multiple large environmental projects, including more than $2 billion in "green bonds," and is poised to help expand access to the state's deep and liquid bond capital market. Within IBank's Small Business Finance Center, the new Climate Tech Loan Guarantee program encourages commercial banks to back climate-focused small businesses, leveraging federal capital to insure a portion of the private bank's loan. And through IBank's Expanding Venture Capital Access Fund program, the state is promoting greater diversity in the venture capital community, including climate equity and climate justice.

All of these financing programs exist to leverage private capital in support of the state's climate goals, and to partner with state policy agencies driving the transition. IBank will also continue to collaborate closely with the State Treasurer's Office in its provision of capital support to climate solutions, ensuring that funding flows to programs best positioned to deliver success. This partnership of public and private capital, responsive to and in communication with the climate policy community, will ensure that California gets the maximum possible benefit from its allocation of scarce resources.

Supporting Innovation

Reaching our ambitious, deep decarbonization goals will require continued technological innovation. Investment in research, development, and deployment of clean technologies has never been more critical. Sending clear and sustained market and policy signals will encourage large and small companies alike to pursue innovation that can be scaled up and deployed here and beyond our borders. The full suite of AB 32 policies[83] has touched nearly every sector of California's economy and spurred technology innovation in the state, including the growth of technology developers, manufacturers, processors, and assemblers in many areas. Specifically, AB 32 policies and programs support both the supply side and the demand side to build new markets in California. On the supply side, AB 32 policies support businesses to demonstrate and refine technologies, and to help establish critical supply chains. On the demand side, AB 32 policies and programs provide outreach, education, and incentives—as well as disincentives—to motivate everyone from consumers to institutional purchasers to utility planners to adopt new, climate smart technologies. Innovations resulting directly from the state's climate policies include the following:

- In the past 10 years, a growing market for heavy-duty zero-emission vehicles (HD ZEVs) was established in California, and this market now represents the largest single share of North American supply and demand for HD ZEVs. Vehicle

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[83] CARB. Climate Change Programs. *https://ww2.arb.ca.gov/our-work/topics/climate-change*.

and component manufacturers are making long-term investments to develop and produce HD ZEVs within California.

- Total consumption of renewable diesel in the California LCFS market has skyrocketed from approximately 1.8 million gallons in 2011 to nearly 589 million gallons in 2020. The LCFS is a key driver of market development for renewable diesel and its coproducts. While the federal renewable fuel standard (RFS) and blenders tax credit also benefit producers, an analysis of their respective contributions to market development, and interviews with industry representatives and independent experts, point to LCFS as a more important factor in market development, at least in recent years.
- In the past five years, a market for small-scale energy storage in California was created where none previously existed. As of 2020, 185 megawatts (MW) of small-scale energy storage projects have been interconnected to the grid. The significant increase in deployment in the last five years is a result of the Self-Generation Incentive Program (SGIP), which significantly reduces the upfront costs to purchase and install small-scale energy storage devices, and of growing customer interest in disaster resiliency in the face of increasing risk from wildfire and related utility outages. These systems have already provided disaster resiliency benefits for residential and non-residential customers.

We have seen how quickly market barriers can be overcome in response to strong policy signals, as occurred in the solar panel and electric vehicle battery space. Government-stated priorities have a significant role in guiding private and public research, development, and deployment. This Scoping Plan unequivocally puts the marker down on the need for innovation to continue in non-combustion technologies, clean energy, CO_2 removal options, and alternatives for SLCPs. The five-year update to the Scoping Plan allows for a periodic evaluation of new tools to add to the state's toolkit.

Engagement with Partners to Develop, Coordinate, and Export Policies

California works closely with other states, tribal governments, the federal government, and international jurisdictions to identify the most effective strategies and methods to reduce GHGs, manage GHG control programs, and facilitate the development of integrated and cost-effective regional, national, and international GHG reduction programs. For example, the state's Cap-and-Trade Program has been linked with Québec's since 2014, and CARB staff regularly engage with jurisdictions throughout the world on the design features of our Cap-and-Trade Program through memoranda of understanding (MOUs) and venues such as the International Climate Action

Partnership.[84] Low carbon fuel mandates similar to California's LCFS have been adopted by the U.S. EPA and by other jurisdictions, including Oregon, Washington, British Columbia, the European Union, and the United Kingdom. Many other jurisdictions from Japan to New Zealand, Australia, and the European Commission also continue to seek information and technical experience on our LCFS. California has and will continue to share information and encourage ambitious emissions reductions with interested jurisdictions, with a focus on China, India, Mexico, Canada, and the European Union. California's early action to reduce super-pollutants such as methane and other SLCPs was reaffirmed by the 2021 Global Methane Pledge signed by the U.S. and over 100 other countries at the 26th Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC).[85]

In addition, under the Clean Air Act, the federal government is authorized to allow California to set more stringent vehicle emissions regulations than federal standards. California's goals and regulations to transition to 100 percent sales of new zero-emission passenger vehicles by 2035 (including plug-in hybrid vehicles), to drayage trucks by 2035, and other trucks and buses where feasible by 2045 are being emulated by partner states across the U.S. and in jurisdictions around the world. CARB's Advanced Clean Cars II regulation, [86] which codifies these targets, was approved in August 2022, and already at least four other states have announced their plans to adopt this regulation. Earlier in June 2020 CARB adopted the Advanced Clean Truck regulation, which requires truck manufacturers to meet increasing sale targets of zero-emission trucks in California through 2035. Since adoption, at least five other states—20 percent of the U.S. truck market—have adopted this regulation. These kinds of coordinated policies help signal to vehicle manufacturers a widespread and growing demand for zero-emissions technology, which in turn helps scale production and lower costs for consumers.

With the Mexican Secretariat for Environment and Natural Resources (SEMARNAT), California has engaged in a technical exchange on clean vehicle policies and helped to establish Mexico's Emissions Trading System (being piloted in 2022). A 2019 MOU signed between California and Environment and Climate Change Canada enables in-depth collaboration on policies and programs to decarbonize vehicles, engines, and fuels. This partnership has led to tangible emissions reductions, from aligning vehicle emissions targets and policies to collaborating on emissions testing and research critical to enforcing

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[84] International Carbon Action Partnership (ICAP). Homepage. https://icapcarbonaction.com/en?msclkid=dac30cb7b4f511ec94ccd0f1ae323e98.

[85] Global Methane Pledge. Homepage. https://www.globalmethanepledge.org/.

[86] Cal. Code Regs., tit. 13, §§ 1900,1961.2, 1961.3, 1962.2, 1962.3, 1962.4, 1962.5, 1962.6, 1962.7, 1962.8, 1965, 1968.2, 1969, 1976, 1978, 2037, 2038, 2112, 2139, 2140, 2147, and 2903; and Test Procedures located here: https://ww2.arb.ca.gov/rulemaking/2022/advanced-clean-cars-ii.

emissions limits for vehicle manufactures. At the national level, China has looked to California for cutting-edge requirements for car diagnostics and policies that promote zero-emissions vehicles. At a local level, Beijing has adopted California's vehicle emissions standards and several other progressive environmental regulations. California will continue and renew such efforts across China, including through a 2022 MOU signed with China's Ministry of Ecology and Environment.

Between 2021 and 2023, California also will serve as president of the Transport Decarbonisation Alliance, a global network of countries, regions, cities, and companies that come together to share experiences and technical expertise, and to increase the ambition and accelerate the deployment of targeted transportation decarbonization policies across freight, electric vehicle infrastructure, and active mobility. Throughout its presidency, California will focus its leadership on decarbonizing the cross-jurisdiction network of medium- and heavy-duty vehicles, both to ensure cleaner air in freight-adjacent communities and to stem the effects of climate change.

Over the years, California has also asserted the importance of and supported the ongoing efforts of state and local clean air and climate leadership. Through our participation in the Pacific Coast Collaborative alongside British Columbia, Washington, and Oregon,[87] the Under2 Coalition,[88] the U.S. Climate Alliance,[89] the International ZEV Alliance,[90] the Transportation Decarbonisation Alliance, and many more organizations, California has and will continue to build climate partnerships with state and local governments.

California also recognized the need to address the substantial emissions caused by the deforestation and degradation of tropical and other forests, and continues its work alongside other subnational governments as part of the Governors' Climate and Forests Task Force (GCF).[91] Founded in 2008, there are currently 39 GCF members, including states and provinces in Brazil, Colombia, Ecuador, Indonesia, Ivory Coast, Mexico, Nigeria, Peru, Spain, and the United States—all of whom are considering or operating programs to reduce emissions from deforestation, land-use, and rural development, and to benefit local and indigenous communities. CARB's California Tropical Forest Standard provides a rigorous methodology to assess jurisdiction-scale programs that reduce deforestation and to incentivize responsible action and investment.[92] The standard

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[87] Pacific Coast Collaborative. Homepage. *https://pacificcoastcollaborative.org/*.
[88] Under2 Coalition. Homepage. *https://www.theclimategroup.org/under2-coalition*.
[89] United States Climate Alliance (USCA). Homepage. *https://www.usclimatealliance.org/*.
[90] ZEV Alliance. Homepage. Accelerating the Adoption of Zero-Emission Vehicles. *https://zevalliance.org/*.
[91] Governors' Climate and Forests Task Force. University of Colorado Boulder: Colorado Law. *https://www.gcftf.org/*.
[92] CARB. California Tropical Forest Standard. *https://ww2.arb.ca.gov/our-work/programs/california-tropical-forest-standard*.

provides a strong signal to value the preservation of tropical forests over continued destructive activities such as oil exploration and extraction and ensures rigorous social and environmental safeguards for indigenous peoples and local communities.

Working Toward Carbon Neutrality

To date, California and many other regions have focused on reducing GHG emissions from the industrial, energy, and transportation sectors. As defined in statute, the state's 2020 and 2030 targets include all in-state sources of GHG emissions—and those emissions associated with imported power that is consumed in the state. By moving to a framework of carbon neutrality, the scope for accounting is expanded to include all sources and sinks. As such, carbon neutrality is achieved when the GHG fluxes are at equilibrium—when sources equal sinks. Figure 1-5 depicts the sources included in the AB 32 GHG Inventory and the new sources and sinks added in this Scoping Plan under the framework of carbon neutrality. Natural and working lands are able to sequester carbon and therefore play an increasingly important role in this framework. However, modeling for this plan shows that carbon sequestration in our natural and working lands alone will be insufficient to achieve carbon neutrality no later than 2045. Therefore, this plan also considers the role of carbon capture and sequestration, as well as biological and mechanical carbon sequestration processes that are included in the IPCC Sixth Assessment Report,[93] as necessary tools for climate change mitigation.

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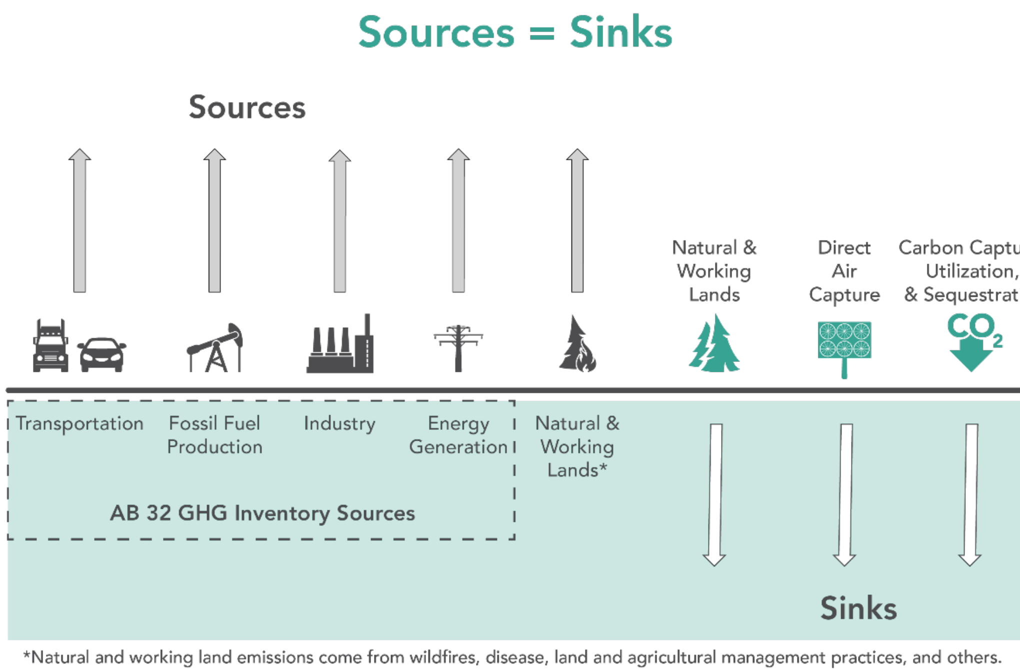
[93] IPCC. 2021. *Climate Change 2021: The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.

Figure 1-5: Carbon neutrality: Balancing the net flux of GHG emissions from all sources and sinks



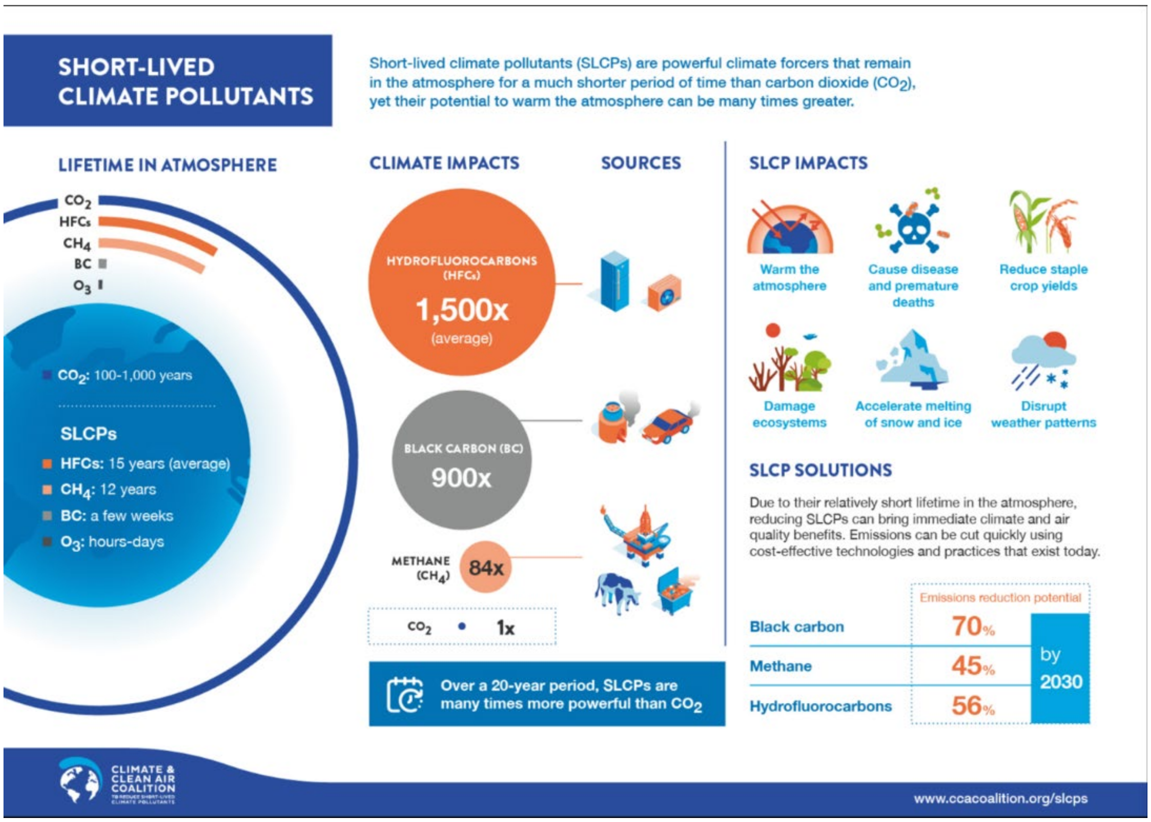
Supporting Healthy and Resilient Lands

Our natural and working lands are an important piece in California's fight to achieve carbon neutrality and build resilience to the impacts of climate change. Healthy land can sequester and store atmospheric carbon dioxide in forests, grasslands, soils, and wetlands. Healthy lands can also reduce emissions of powerful short-lived climate pollutants, limit the release of future GHG emissions, protect people and nature from the impacts of climate change, and build our resilience to future climate risks. Unhealthy lands have the opposite effect—they release more GHGs than they store and are more vulnerable to future climate change impacts. Through climate smart land management that focuses on supporting healthy living systems, we can support our carbon neutrality goals, reduce emissions, advance sequestration, and support healthy and more climate-resilient lands.

Maintaining the Focus on Methane and Short-Lived Climate Pollutants

Given the urgency of climate change, the often-disproportional impacts already being felt by underserved populations across California and the world, and the need to rapidly decarbonize and avoid climate tipping points as identified in the most recent IPCC assessment, efforts to reduce short-lived climate pollutants are especially important. SLCPs include methane (CH_4), black carbon (soot), and fluorinated gases (F-gases, including hydrofluorocarbons, or HFCs), and they are among the most harmful pollutants to both human health and the global climate. SLCPs are more potent than CO_2 in terms of their impact on climate change (and subsequently, global warming) and have a much shorter lifetime in the atmosphere than CO_2 does. That means they have an outsized impact on climate change in the near term—they are responsible for up to 45 percent of current climate forcing. It also means that targeted efforts to reduce short-lived climate pollutant emissions can provide outsized climate and health benefits, within weeks to about a decade (see Figure 1-6).

Figure 1-6: Short-lived climate pollutant impacts[94]



California has been a leader in addressing SLCP emissions. As part of the 2014 Scoping Plan,[95] CARB committed to developing a dedicated strategy to reduce SLCP emissions.

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[94] Climate and Clean Air Coalition. Short-Lived Climate Pollutants (SLCPs). https://www.ccacoalition.org/en/content/short-lived-climate-pollutants-slcps.
[95] CARB. 2014. *First Update.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

The resulting SLCP Reduction Strategy,[96] adopted by CARB in 2017, implements targets codified in SB 1383 (Lara, Chapter 395, Statutes of 2016) to reduce methane and HFC emissions by 40 percent by 2030 and anthropogenic black carbon emissions by 50 percent. California worked with several other states through the U.S. Climate Alliance to establish a similar goal to reduce SLCP emissions in line with the requirements of the Paris Agreement,[97] identifying the potential to reduce SCLPs by 40 to 50 percent by 2030 across the U.S. Climate Alliance.[98]

Process for Developing the Scoping Plan

This Scoping Plan was developed in coordination with the Governor's Office and state agencies, in accordance with direction from the Chair and Members of CARB, through engagement with the Legislature, with advice from the EJ Advisory Committee, in consultation with tribes, and with open and transparent opportunities for stakeholders and the public to engage in workshops and other meetings. Appendix A (Public Process) includes details of the public workshops, and Chapter 5 includes details of the EJ Advisory Committee's role in the Scoping Plan update process.

Guidance from the Administration and Legislature

This Scoping Plan reflects existing and recent direction in the Governor's Executive Orders and Statutes. Table 1-1 provides a summary of major climate legislation and executive orders issued since the adoption of the 2017 Scoping Plan.

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[96] CARB. 2017. *Short-Lived Climate Pollutant Reduction Strategy.* *https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf*.

[97] UNFCCC. 2015. Paris Agreement. *https://unfccc.int/sites/default/files/english_paris_agreement.pdf*.

[98] USCA. 2018. *From SLCP Challenge to Action: A Roadmap for Reducing Short-Lived Climate Pollutants to Meet the Goals of the Paris Agreement.* http://www.usclimatealliance.org/slcp-challenge-to-action.

Table 1-1: Major climate legislation and executive orders enacted since the 2017 Scoping Plan

Bill/Executive Order	Summary
Assembly Bill 1279 (AB 1279) (Muratsuchi, Chapter 337, Statutes of 2022) *The California Climate Crisis Act*	AB 1279 establishes the policy of the state to achieve carbon neutrality as soon as possible, but no later than 2045; to maintain net negative GHG emissions thereafter; and to ensure that by 2045 statewide anthropogenic GHG emissions are reduced at least 85 percent below 1990 levels. The bill requires CARB to ensure that Scoping Plan updates identify and recommend measures to achieve carbon neutrality, and to identify and implement policies and strategies that enable CO_2 removal solutions and carbon capture, utilization, and storage (CCUS) technologies. This bill is reflected directly in this Scoping Plan.
Senate Bill 905 (SB 905) (Caballero, Chapter 359, Statutes of 2022) *Carbon Capture, Removal, Utilization, and Storage Program*	SB 905 requires CARB to create the Carbon Capture, Removal, Utilization, and Storage Program to evaluate, demonstrate, and regulate CCUS and carbon dioxide removal (CDR) projects and technology. The bill requires CARB, on or before January 1, 2025, to adopt regulations creating a unified state permitting application for approval of CCUS and CDR projects. The bill also requires the Secretary of the Natural Resources Agency to publish a framework for governing agreements for two or more tracts of land overlying the same geologic storage reservoir for the purposes of a carbon sequestration project. The Scoping Plan modeling reflects both CCUS and CDR contributions to achieve carbon neutrality.
Senate Bill 846 (SB 846) (Dodd, Chapter 239, Statutes of 2022) *Diablo Canyon Powerplant: Extension of Operations*	SB 846 extends the Diablo Canyon Power Plant’s sunset date by up to five additional years for each of its two units and seeks to make the nuclear power plant eligible for federal loans. The bill requires that the California Public Utilities Commission (CPUC) not include and disallow a load-serving entity from including in their adopted resource plan, the energy, capacity, or any attribute from the Diablo Canyon power plant. The Scoping Plan explains the emissions impact of this legislation.
Senate Bill 1020 (SB 1020) (Laird,	SB 1020 adds interim renewable energy and zero carbon energy retail sales of electricity targets to California end-use customers set at 90 percent in 2035 and 95 percent in 2040.

Chapter 361, Statutes of 2022) *Clean Energy, Jobs, and Affordability Act of 2022*	It accelerates the timeline required to have 100 percent renewable energy and zero carbon energy procured to serve state agencies from the original target year of 2045 to 2035. This bill requires each state agency to individually achieve the 100 percent goal by 2035 with specified requirements. This bill requires the CPUC, California Energy Commission (CEC), and CARB, on or before December 1, 2023, and annually thereafter, to issue a joint reliability progress report that reviews system and local reliability. The bill also modifies the requirement for CARB to hold a portion of its Scoping Plan workshops in regions of the state with the most significant exposure to air pollutants by further specifying that this includes communities with minority populations or low-income communities in areas designated as being in extreme federal non-attainment. The Scoping Plan describes the implications of this legislation on emissions.
Senate Bill 1137 (SB 1137) (Gonzales, Chapter 365, Statutes of 2022) *Oil & Gas Operations: Location Restrictions: Notice of Intention: Health protection zone: Sensitive receptors*	SB 1137 prohibits the development of new oil and gas wells or infrastructure in health protection zones, as defined, except for purposes of public health and safety or other limited exceptions. The bill requires operators of existing oil and gas wells or infrastructure within health protection zones to undertake specified monitoring, public notice, and nuisance requirements. The bill requires CARB to consult and concur with the California Geologic Energy Management Division (CalGEM) on leak detection and repair plans for these facilities, adopt regulations as necessary to implement emission detection system standards, and collaborate with CalGEM on public access to emissions detection data.
Senate Bill 1075 (SB 1075) (Skinner, Chapter 363, Statutes of 2022) *Hydrogen: Green Hydrogen: Emissions of Greenhouse Gases*	SB 1075 requires CARB, by June 1, 2024, to prepare an evaluation that includes: policy recommendations regarding the use of hydrogen, and specifically the use of green hydrogen, in California; a description of strategies supporting hydrogen infrastructure, including identifying policies that promote the reduction of GHGs and short-lived climate pollutants; a description of other forms of hydrogen to achieve emission reductions; an analysis of curtailed electricity; an estimate of GHG and emission reductions that could be achieved through deployment of green hydrogen through a variety of scenarios; an analysis of the potential for opportunities to integrate hydrogen production and applications with drinking water supply treatment needs; policy recommendations for regulatory and permitting processes

	associated with transmitting and distributing hydrogen from production sites to end uses; an analysis of the life-cycle GHG emissions from various forms of hydrogen production; and an analysis of air pollution and other environmental impacts from hydrogen distribution and end uses. This bill would inform the production of hydrogen at the scale called for in this Scoping Plan.
Assembly Bill 1757 (AB 1757) (Garcia, Chapter 341, Statutes of 2022) *California Global Warming Solutions Act of 2006: Climate Goal: Natural and Working Lands*	AB 1757 requires the California Natural Resources Agency (CNRA), in collaboration with CARB, other state agencies, and an expert advisory committee, to determine a range of targets for natural carbon sequestration, and for nature-based climate solutions, that reduce GHG emissions in 2030, 2038, and 2045 by January 1, 2024. These targets must support state goals to achieve carbon neutrality and foster climate adaptation and resilience. This bill also requires CARB to develop standard methods for state agencies to consistently track GHG emissions and reductions, carbon sequestration, and additional benefits from natural and working lands over time. These methods will account for GHG emissions reductions of CO_2, methane, and nitrous oxide related to natural and working lands and the potential impacts of climate change on the ability to reduce GHG emissions and sequester carbon from natural and working lands, where feasible. This Scoping Plan describes the next steps and implications of this legislation for the natural and working lands sector.
Senate Bill 1206 (SB 1206) (Skinner, Chapter 884, Statutes of 2022) *Hydrofluorocarbon gases: sale or distribution*	SB 1206 mandates a stepped sales prohibition on newly produced high- global warming potential (GWP) HFCs to transition California's economy toward recycled and reclaimed HFCs for servicing existing HFC-based equipment. Additionally, SB 1206 also requires CARB to develop regulations to increase the adoption of very low-, i.e., GWP < 10, and no-GWP technologies in sectors that currently rely on higher-GWP HFCs.
Senate Bill 27 (SB 27) (Skinner, Chapter 237, Statutes of 2021)	SB 27 requires CNRA, in coordination with other state agencies, to establish the Natural and Working Lands Climate Smart Strategy by July 1, 2023. This bill also requires CARB to establish specified CO_2 removal targets for 2030 and beyond as part of its Scoping Plan. Under SB 27, CNRA is to establish and maintain a registry to identify projects in the state

Carbon Sequestration: State Goals: Natural and Working Lands: Registry of Projects	that drive climate action on natural and working lands and are seeking funding. CNRA also must track carbon removal and GHG emission reduction benefits derived from projects funded through the registry. This bill is reflected directly in this Scoping Plan as CO_2 removal targets for 2030 and 2045 in support of carbon neutrality.
Senate Bill 596 (SB 596) (Becker, Chapter 246, Statutes of 2021) *Greenhouse Gases: Cement Sector: Net-zero Emissions Strategy*	SB 596 requires CARB, by July 1, 2023, to develop a comprehensive strategy for the state's cement sector to achieve net-zero-emissions of GHGs associated with cement used within the state as soon as possible, but no later than December 31, 2045. The bill establishes an interim target of 40 percent below the 2019 average GHG intensity of cement by December 31, 2035. Under SB 596, CARB must: • Define a metric for GHG intensity and establish a baseline from which to measure GHG intensity reductions. • Evaluate the feasibility of the 2035 interim target (40 percent reduction in GHG intensity) by July 1, 2028. • Coordinate and consult with other state agencies. • Prioritize actions that leverage state and federal incentives. • Evaluate measures to support market demand and financial incentives to encourage the production and use of cement with low GHG intensity. The Scoping Plan modeling is designed to achieve these outcomes.
Executive Order N-82-20	Governor Newsom signed Executive Order N-82-20 in October 2020 to combat the climate and biodiversity crises by setting a statewide goal to conserve at least 30 percent of California's land and coastal waters by 2030. The Executive Order also instructed the CNRA, in consultation with other state agencies, to develop a Natural and Working Lands Climate Smart Strategy that serves as a framework to advance the state's carbon neutrality goal and build climate resilience. In addition to setting a statewide conservation goal, the Executive Order directed CARB to update the target for natural and working lands in support of carbon neutrality as part of this Scoping Plan, and to take into consideration the NWL Climate Smart Strategy.

	Executive Order N-82-20 also calls on the CNRA, in consultation with other state agencies, to establish the California Biodiversity Collaborative (Collaborative). The Collaborative shall be made up of governmental partners, California Native American tribes, experts, business and community leaders, and other stakeholders from across the state. State agencies will consult the Collaborative on efforts to: • Establish a baseline assessment of California's biodiversity that builds upon existing data and can be updated over time. • Analyze and project the impact of climate change and other stressors in California's biodiversity. • Inventory current biodiversity efforts across all sectors and highlight opportunities for additional action to preserve and enhance biodiversity. CNRA also is tasked with advancing efforts to conserve biodiversity through various actions, such as streamlining the state's process to approve and facilitate projects related to environmental restoration and land management. The California Department of Food and Agriculture (CDFA) is directed to advance efforts to conserve biodiversity through measures such as reinvigorating populations of pollinator insects, which restore biodiversity and improve agricultural production. The Natural and Working Lands Climate Smart Strategy informs this Scoping Plan.
Executive Order N-79-20	Governor Newsom signed Executive Order N-79-20 in September 2020 to establish targets for the transportation sector to support the state in its goal to achieve carbon neutrality by 2045. The targets established in this Executive Order are: • 100 percent of in-state sales of new passenger cars and trucks will be zero-emission by 2035. • 100 percent of medium- and heavy-duty vehicles will be zero-emission by 2045 for all operations where feasible, and by 2035 for drayage trucks. • 100 percent of off-road vehicles and equipment will be zero-emission by 2035 where feasible. The Executive Order also tasked CARB to develop and propose regulations that require increasing volumes of zero-electric passenger vehicles, medium- and heavy-duty

	vehicles, drayage trucks, and off-road vehicles toward their corresponding targets of 100 percent zero-emission by 2035 or 2045, as listed above. The Scoping Plan modeling reflects achieving these targets.
Executive Order N-19-19	Governor Newsom signed Executive Order N-19-19 in September 2019 to direct state government to redouble its efforts to reduce GHG emissions and mitigate the impacts of climate change while building a sustainable, inclusive economy. This Executive Order instructs the Department of Finance to create a Climate Investment Framework that: • Includes a proactive strategy for the state's pension funds that reflects the increased risks to the economy and physical environment due to climate change. • Provides a timeline and criteria to shift investments to companies and industry sectors with greater growth potential based on their focus of reducing carbon emissions and adapting to the impacts of climate change. • Aligns with the fiduciary responsibilities of the California Public Employees' Retirement System, California State Teachers' Retirement System, and the University of California Retirement Program. Executive Order N-19-19 directs the State Transportation Agency to leverage more than $5 billion in annual state transportation spending to help reverse the trend of increased fuel consumption and reduce GHG emissions associated with the transportation sector. It also calls on the Department of General Services to leverage its management and ownership of the state's 19 million square feet in managed buildings, 51,000 vehicles, and other physical assets and goods to minimize state government's carbon footprint. Finally, it tasks CARB with accelerating progress toward California's goal of five million ZEV sales by 2030 by: • Developing new criteria for clean vehicle incentive programs to encourage manufacturers to produce clean, affordable cars. • Proposing new strategies to increase demand in the primary and secondary markets for ZEVs. • Considering strengthening existing regulations or adopting new ones to achieve the necessary GHG reductions from within the transportation sector.

	The Scoping Plan modeling reflects efforts to accelerate ZEV deployment.
Senate Bill 576 (SB 576) (Umberg, Chapter 374, Statutes of 2019) *Coastal Resources: Climate Ready Program and Coastal Climate Change Adaptation, Infrastructure and Readiness Program*	Sea level rise, combined with storm-driven waves, poses a direct risk to the state's coastal resources, including public and private real property and infrastructure. Rising marine waters threaten sensitive coastal areas, habitats, the survival of threatened and endangered species, beaches, other recreation areas, and urban waterfronts. SB 576 mandates that the Ocean Protection Council develop and implement a coastal climate adaptation, infrastructure, and readiness program to improve the climate change resiliency of California's coastal communities, infrastructure, and habitat. This bill also instructs the State Coastal Conservancy to administer the Climate Ready Program, which addresses the impacts and potential impacts of climate change on resources within the conservancy's jurisdiction.
Assembly Bill 65 (AB 65) (Petrie-Norris, Chapter 347, Statutes of 2019) *Coastal Protection: Climate Adaption: Project Prioritization: Natural Infrastructure: Local General Plans*	This bill requires the State Coastal Conservancy, when it allocates any funding appropriated pursuant to the California Drought, Water, Parks, Climate, Coastal Protection, and Outdoor Access For All Act of 2018, to prioritize projects that use natural infrastructure in coastal communities to help adapt to climate change. The bill requires the conservancy to provide information to the Office of Planning and Research on any projects funded pursuant to the above provision to be considered for inclusion into the clearinghouse for climate adaption information. The bill authorizes the conservancy to provide technical assistance to coastal communities to better assist them with their projects that use natural infrastructure.
Executive Order B-55-18	Governor Brown signed Executive Order B-55-18 in September 2018 to establish a statewide goal to achieve carbon neutrality as soon as possible, and no later than 2045, and to achieve and maintain net negative emissions thereafter. Policies and programs undertaken to achieve this goal shall: • Seek to improve air quality and support the health and economic resiliency of urban and rural communities, particularly low-income and disadvantaged communities. • Be implemented in a manner that supports climate adaptation and biodiversity, including protection of the state's water supply, water quality, and native plants and animals.

	This Executive Order also calls for CARB to: • Develop a framework for implementation and accounting that tracks progress toward this goal. • Ensure future Scoping Plans identify and recommend measures to achieve the carbon neutrality goal. This Scoping Plan is designed to achieve carbon neutrality no later than 2045 and the modeling includes technology and fuel transitions to achieve that outcome.
Senate Bill 100 (SB 100) (De León, Chapter 312, Statutes of 2018) *California Renewables Portfolio Standard Program: emissions of greenhouse gases*	SB 100 mandates that the CPUC, CEC, and CARB plan for 100 percent of total retail sales of electricity in California to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045. This bill also updates the state's Renewables Portfolio Standard (RPS) to include the following interim targets: • 44% of retail sales procured from eligible renewable sources by December 31, 2024. • 52% of retail sales procured from eligible renewable sources by December 31, 2027. • 60% of retail sales procured from eligible renewable sources by December 31, 2030. Under SB 100, the CPUC, CEC, and CARB shall use programs under existing laws to achieve 100 percent clean electricity. The statute requires these agencies to issue a joint policy report on SB 100 every four years. The first of these reports was issued in 2021. This Scoping Plan reflects the SB 100 Core Scenario resource mix with a few minor updates.
Assembly Bill 2127 (AB 2127) (Ting, Chapter 365, Statutes of 2018) *Electric Vehicle Charging Infrastructure: Assessment*	This bill requires the CEC, working with CARB and the CPUC, to prepare and biennially update a statewide assessment of the electric vehicle charging infrastructure needed to support the levels of electric vehicle adoption required for the state to meet its goals of putting at least 5 million zero-emission vehicles on California roads by 2030 and of reducing emissions of GHGs to 40% below 1990 levels by 2030. The bill requires the CEC to regularly seek data and input from stakeholders relating to electric vehicle charging infrastructure. This bill supports the deployment of ZEVs as modeled in this Scoping Plan.

Senate Bill 30 (SB 30) (Lara, Chapter 614, Statutes of 2018) *Insurance: Climate Change*	This bill requires the Insurance Commissioner to convene a working group to identify, assess, and recommend risk transfer market mechanisms that, among other things, promote investment in natural infrastructure to reduce the risks of climate change related to catastrophic events, create incentives for investment in natural infrastructure to reduce risks to communities, and provide mitigation incentives for private investment in natural lands to lessen exposure and reduce climate risks to public safety, property, utilities, and infrastructure. The bill requires the policies recommended to address specified questions.
Assembly Bill 2061 (AB 2061) (Frazier, Chapter 580, Statutes of 2018) *Near-zero-emission and Zero-emission Vehicles*	Existing state and federal law sets specified limits on the total gross weight imposed on the highway by a vehicle with any group of two or more consecutive axles. Under existing federal law, the maximum gross vehicle weight of that vehicle may not exceed 82,000 pounds. AB 2061 authorizes a near-zero-emission vehicle or a zero-emission vehicle to exceed the weight limits on the power unit by up to 2,000 pounds. This bill supports the deployment of cleaner trucks as modeled in this Scoping Plan.

Consideration of Relevant State Plans and Regulations

Development of this Scoping Plan also included careful consideration of, and coordination with, other state agency plans and regulations, including the SB 100 Joint Agency Report,[99] the 2022 State Strategy for the State Implementation Plan,[100] Climate Action Plan for Transportation Infrastructure,[101] AB 74 Studies on Vehicle Emissions and Fuel Demand and Supply,[102,103,104] Short-Lived Climate Pollutant Strategy (SLCP Strategy),[105]

[99] CPUC, CEC, and CARB. 2021. *SB 100 Joint Agency Report.* https://www.energy.ca.gov/sb100.
[100] CARB. January 31, 2022. Draft 2022 State Strategy for the State Implementation Plan. https://ww2.arb.ca.gov/sites/default/files/2022-01/Draft_2022_State_SIP_Strategy.pdf.
[101] CalSTA. 2021. *Climate Action Plan.* https://calsta.ca.gov/subject-areas/climate-action-plan.
[102] CalEPA. 2021. Carbon Neutrality Studies. https://calepa.ca.gov/climate/carbon-neutrality-studies/.
[103] Brown, A. L., et. al. 2021. *Driving California's Transportation Emissions.* https://escholarship.org/uc/item/3np3p2t0.
[104] Deschenes, O. 2021. *Enhancing equity*. https://zenodo.org/record/4707966#.YKPiaKhKi73.
[105] CARB. Short-Lived Climate Pollutants. https://ww2.arb.ca.gov/our-work/programs/slcp.

CARB's Achieving Carbon Neutrality Report,[106] Climate Smart Strategy,[107] and draft Natural and Working Lands Implementation Plan,[108] among others.

Input from Partners and Stakeholders

CARB also collaborated with other state agencies, held consultations with tribes, and solicited comments and feedback from affected stakeholders, including labor organizations and the public. The process to update the Scoping Plan began with kickoff workshops in early June 2021,[109] followed by over a dozen public workshops, including engagement with tribes,[110] and featured a series of EJ Advisory Committee and environmental justice community meetings.[111] The June 2021 workshop and several others were a joint agency effort, as there are many agencies with direct authority or jurisdiction over different sectors of the economy. Consultation with agencies also included bi-weekly, monthly, and weekly meetings.

During the summer of 2022 CARB held three community listening sessions, hosted by the CARB Chair and Board, in communities around the state, along with one virtual community listening session and one tribal listening session specifically for tribes. Many tribes provided written feedback, which was incorporated into this Scoping Plan. In addition, CARB respects tribal sovereignty and also engaged in a consultation campaign with tribes, which resulted in government-to-government consultations, and this Scoping Plan is reflective of this process.[112]

Emissions Data That Inform the Scoping Plan

Greenhouse Gas Emissions

AB 32 includes which GHGs are to be regulated, reduced, and included in the state's targets and goals. That list includes seven GHGs: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs),

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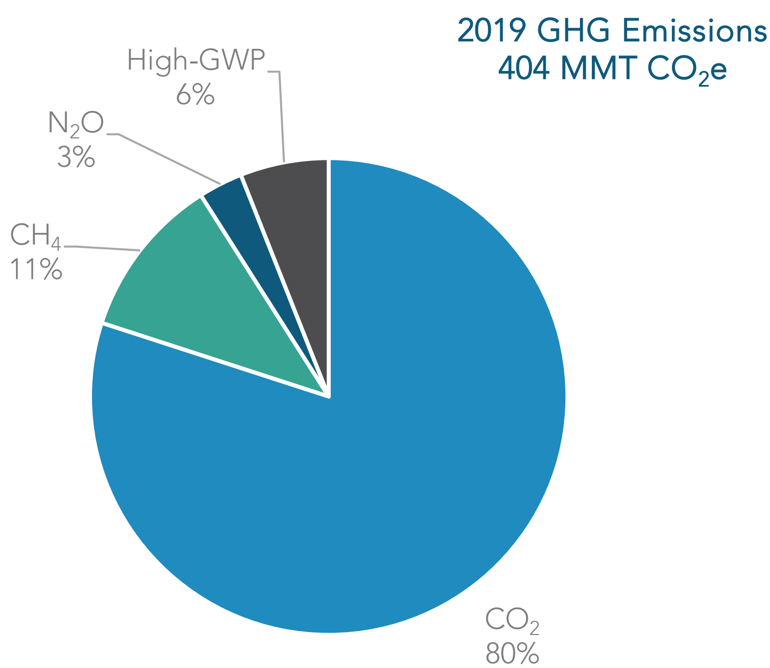
[106] Energy and Environmental Economics, Inc. 2020. *Achieving Carbon Neutrality.* https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf.
[107] CNRA. 2022. Natural and Working Lands Climate Smart Strategy. https://resources.ca.gov/Initiatives/Expanding-Nature-Based-Solutions.
[108] CARB. 2019. *Draft California 2030 Natural and Working Lands Climate Change Implementation Plan.* https://ww2.arb.ca.gov/resources/documents/nwl-implementation-draft.
[109] Appendix A (Public Process).
[110] CARB. Scoping Plan Meetings & Workshops. https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/scoping-plan-meetings-workshops.
[111] CARB. Environmental Justice Advisory Committee Meetings and Events. https://ww2.arb.ca.gov/environmental-justice-advisory-committee-meetings-and-events.
[112] CARB. 2018. Tribal Consultation Policy. October. https://www.arb.ca.gov/regact/nonreg/2018/california_air_resources_board_tribal_consultation_policy.pdf.

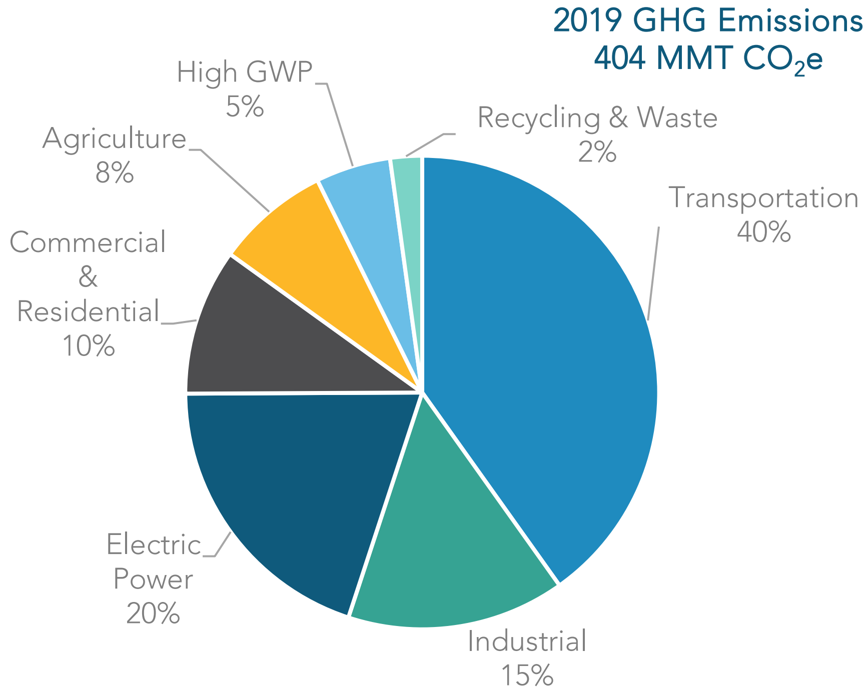
perfluorocarbons (PFCs), and nitrogen trifluoride (NF_3). Carbon dioxide is the primary GHG emitted in California, accounting for 83 percent of the total GHG emissions in 2019, as shown in Figure 1-7 below. Figure 1-8 illustrates that transportation (primarily on-road travel) is the single largest source of CO_2 emissions in the state. Upstream transportation emissions from the refinery and oil and gas sectors are categorized as CO_2 emissions from industrial sources and constitute about 50 percent of the industrial source emissions. When including these emissions, the transportation sector accounts for approximately half of statewide GHG emissions. Other significant sources of CO_2 include electricity production, industrial sources like refineries and cement plants, and residential sources like fossil gas. Figures 1-7 and 1-8 show state GHG emission contributions by GHG and sector based on the 2020 Greenhouse Gas Emission Inventory; GHG emissions for 2019 are shown because 2020 was an outlier due to the global pandemic. Emissions in Figure 1-8 are depicted by Scoping Plan sector, which includes separate categories for high-global warming potential (GWP) and recycling/waste emissions that are otherwise typically included within other economic sectors.

Figure 1-7: 2019 State GHG emission contributions by GHG[113]



[113] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020: Trends of Emissions and Other Indicators.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

Figure 1-8: 2019 State GHG emission contributions by Scoping Plan sector[114]



The scope of the AB 32 GHG Inventory encompasses emission sources within the state's borders, as well as imported electricity consumed in the state. This construct for the inventory is consistent with IPCC practices to allow for comparison of statewide GHG emissions with those at the national level and with other international GHG inventories. Statewide GHG emissions calculations use many data sources, including data from other state and federal agencies. However, a significant source of data comes from reports submitted to CARB through the Regulation for the Mandatory Reporting of GHG Emissions (MRR). The MRR requires facilities and entities with more than 10,000 metric tons of carbon dioxide equivalent ($MTCO_2e$) of combustion and process emissions, all facilities belonging to certain industries, and all electric power entities to submit an annual GHG emissions data report directly to CARB. Furthermore, this regulation requires that reports from entities that emit more than 25,000 $MTCO_2e$ be verified by a CARB-

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[114] The High GWP sector includes high global warming potential gas emissions from releases of ozone depleting substance (ODS) substitutes, SF_6 emissions from the electricity transmission and distribution system, and gases that are emitted in the semiconductor manufacturing process. ODS substitutes, which are primarily HFCs, are used in refrigeration and air conditioning equipment, solvent cleaning, foam production, fire retardants, and aerosols.

accredited third-party verification body. More information on MRR emissions reports can be found at CARB's Mandatory Greenhouse Gas Emissions Reporting website.[115]

All data sources used to develop the GHG Emission Inventory are listed in CARB's inventory supporting documentation.[116]

Natural and Working Lands

For natural and working lands, the 2018 ecosystem carbon inventory (NWL Inventory)[117] shows there are approximately 5,340 million metric tons (MMT) of carbon in the carbon pools[118] (reservoirs of carbon that have the ability to both take in and release carbon) that CARB has quantified (see Figure 1-9). For purposes of comparison, 5,340 MMT of ecosystem carbon stock is equivalent to 19,600 MMT of atmospheric CO_2. Forests and shrublands contain the majority of California's carbon stock because they cover the majority of California's landscape and have the highest carbon density of any land cover type. All other land categories combined comprise over 35 percent of California's total acreage, but only 15 percent of carbon stocks. Roughly half of the 5,340 MMT of carbon resides in soils and half in plant biomass.

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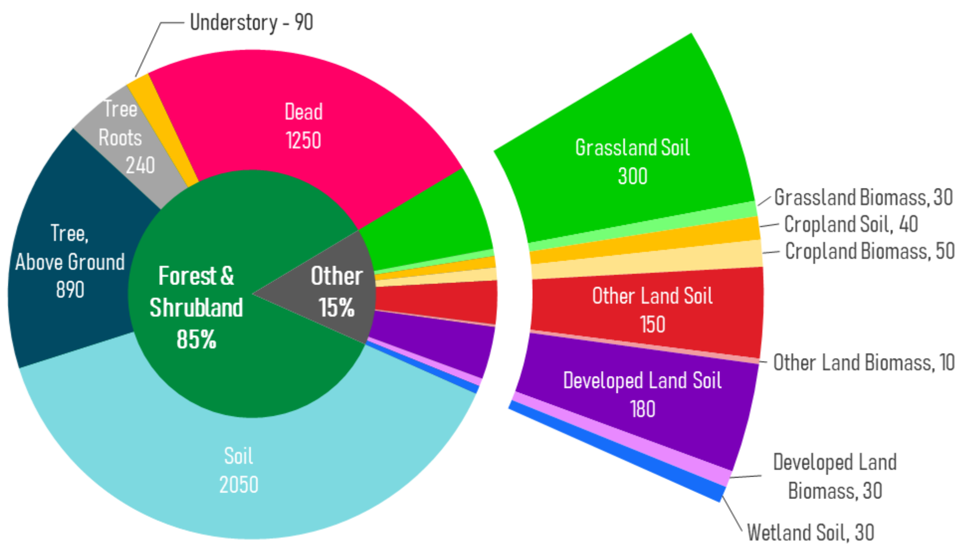
[115] CARB. Mandatory Greenhouse Gas Emissions Reporting. https://ww2.arb.ca.gov/our-work/programs/mandatory-greenhouse-gas-emissions-reporting.

[116] CARB. Current California GHG Emission Inventory Data. www.arb.ca.gov/cc/inventory/data/data.htm.

[117] CARB. 2018. *An Inventory of Ecosystem Carbon in California's Natural and Working Lands.* https://ww3.arb.ca.gov/cc/inventory/pubs/nwl_inventory.pdf.

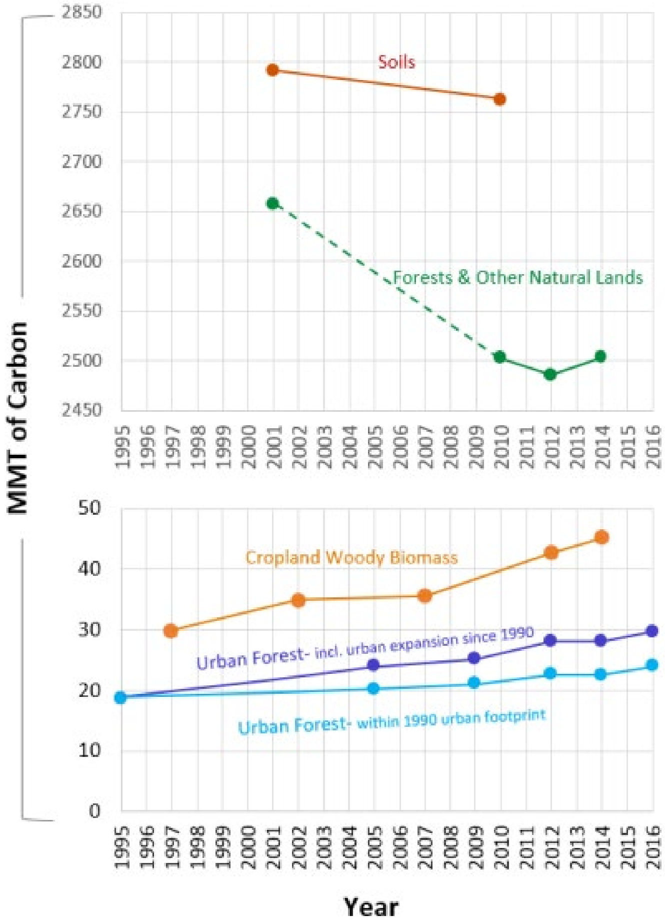
[118] "Carbon pools" are Above-Ground Live Biomass (boles, stems, and foliage in shrubs, trees, grasses, and herbaceous vegetation), Below-Ground Live Biomass (roots in shrubs, trees, grasses, and herbaceous vegetation), Dead Organic Matter (standing or downed dead wood and litter), Harvested Wood Products (all wood and bark material that leaves harvest sites regardless of whether it is eventually incorporated into merchandisable products), and Soil Organic Matter (organic carbon in the top 30 centimeters of soil).

Figure 1-9: Carbon stocks in natural and working lands (MMT carbon)



In addition to providing an estimate of the ecosystem carbon that exists on California's landscape, the NWL Inventory also shows how those carbon stocks are changing (see Figure 1-10). The inventory attributes stock change to human activity, such as land use change, or to disturbances, such as wildfire. CARB's inventory shows these lands were a source of GHG emissions from 2001 to 2011, releasing more carbon than they stored, and then they returned to be a slight carbon sink from 2012 to 2014. These trends highlight the interannual and interdecadal variability of lands and their ability to be both a source and a sink of carbon.

Figure 1-10: Changes in carbon stock by landscape type



For natural and working lands, California's inventory is also based on IPCC methods for tracking ecosystem carbon over time, providing for comparability with other national and subnational inventories and carbon accounting. As such, the NWL Inventory is an important tool for tracking both carbon stock changes in California over time and the impacts that interventions such as those identified in this Scoping Plan, actions identified in the Climate Smart Land Strategy, and others have on NWL carbon stocks.

All data sources used to develop the NWL Inventory are listed in the technical support documentation at CARB's California Natural & Working Lands Inventory website.[119]

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[119] CARB. California Natural & Working Lands Inventory. https://ww2.arb.ca.gov/nwl-inventory.

Black Carbon

In addition, CARB has developed a statewide emission inventory for black carbon in support of the SLCP Strategy. The inventory is reported in two categories: non-forestry (anthropogenic) sources and forestry sources.[120] The black carbon inventory is calculated using existing $PM_{2.5}$ emission inventories combined with speciation profiles that define the fraction of $PM_{2.5}$ that is black carbon. The black carbon inventory helps support implementation of the SLCP Strategy, but it is not part of California's GHG Inventory that tracks progress toward the state's climate targets under AB 32 or SB 32. The state's major anthropogenic sources of black carbon include off-road transportation, on-road transportation, residential wood burning, fuel combustion, and industrial processes. CARB estimated 2017 black carbon emissions to be approximately 8 $MTCO_2e$.[121] The majority of anthropogenic sources come from transportation—specifically, heavy-duty vehicles. The share of black carbon emissions from transportation is dropping rapidly and is expected to continue to do so between now and 2030 as a result of California's air quality programs. The remaining black carbon emissions will come largely from woodstoves/fireplaces, off-road applications, and industrial/commercial combustion. The forestry category includes non-agricultural prescribed burning and wildfire emissions.

Tracking Life-Cycle and Out-of-State Emissions

In recent years there has been increased interest in the embedded carbon in products, also known as *life-cycle emissions.* A life-cycle accounting framework refers to all of the GHG emissions generated from the sourcing, production, and transportation of products to an endpoint. In doing such assessments for a product, emissions may be associated with sourced materials and production activity outside a jurisdiction's borders. While life-cycle emissions can provide a more comprehensive picture of the emissions associated with the goods we consume and ongoing demand, life-cycle inventories are inconsistent with IPCC standards, as they would result in double counting of emissions across jurisdictions. Other countries and regions do produce their own inventory reports consistent with IPCC methods and are taking action to reduce emissions within their jurisdictions. In addition, jurisdictions often lack legal authority to regulate sources outside of their borders. Finally, it is difficult to obtain accurate data for sources and production activities outside of a region's border that would impact the accuracy of such an inventory. For these reasons, the inventory used in the Scoping Plan does not use a life-cycle

[120] SB 1383. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.
[121] This is a preliminary estimate developed for this Scoping Plan. Official Black Carbon emissions estimates are provided in the SLCP inventory here: https://ww2.arb.ca.gov/ghg-slcp-inventory.

approach and remains consistent with international accounting standards and consistent with how other countries and regions track emissions within their jurisdictions.

However, GHG mitigation action may cross geographic borders as part of subnational and international collaboration, or as a natural result of implementation of regional policies. In addition to the state's existing GHG inventory, CARB will develop an accounting framework that reflects the benefits of our policies accruing outside of the state. This accounting framework will be important to better understand the true impact of the state's policies on what is emitted into the atmosphere. For example, the LCFS incentivizes GHG reductions along the entire supply chain for the production and delivery of transportation fuel imported for use in the state. However, our inventory only captures the change in emissions from the tailpipe of when that fuel is used in California and does not capture any GHG reductions that occur in the production process if the fuel is produced out of state.

Natural and working lands forestry actions are another example, where California's policies are inspiring forest management actions in other states that result in increased permanent carbon sequestration. California's NWL inventory does not capture the increased carbon stocks resulting from forestry projects happening outside of California, and the CO_2 removals resulting from these projects are not applied in either CARB's NWL inventory or CARB's AB 32 GHG Emissions Inventory. For GHG reductions outside of the state to be attributed to our programs, those reductions must be real, quantifiable, verifiable, and permanent.

It also will be important to avoid any double counting (including claims to those reductions by other jurisdictions) and to transparently indicate whether any extra-jurisdictional emissions reductions might be included in another region's inventory. CARB is collaborating with other jurisdictions to ensure GHG accounting rules are consistent with international best practices, as robust accounting rules instill confidence in the reductions claimed and maintain support for joint action across jurisdictions. The policy goals of consistency and transparency are critical as we work together with other jurisdictions on our parallel paths to achieve our GHG targets with real benefits to the atmosphere.

Tracking Progress

Historically, the AB 32 GHG Inventory has been the primary metric to track progress toward achieving climate targets.[122] However, we must now deploy clean technology at unprecedented rates. The emissions modeling underpinning this Scoping Plan and

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[122] Starting with the 2022 Edition of the AB 32 GHG inventory, the inventory development now relies more directly on the annually reported and third-party verified emissions from the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

targets for clean technology in statute can serve as leading indicators across the economy on how our actions compare to the pace of action needed to be on track to achieve carbon neutrality. The California Climate Dashboard[123] was launched in 2022 and provides high-level metrics for clean energy production and technology deployment. Statistics such as the deployment of zero emission vehicles and clean electricity generation are just some of the examples of metrics across the economy that can be tracked, in addition to GHG emissions, to understand if the state is on track to meet its climate goals. A key indicator to track will be building of new energy infrastructure and deployment of clean technology as evaluated in the uncertainty analysis in Chapter 2. CARB will coordinate with state agencies to establish and make public similar metrics across all economic sectors to help provide transparency on the state's progress in deploying clean technology at the pace and scale needed to achieve carbon neutrality no later than 2045.

[123] CalEPA. California Climate Dashboard. https://calepa.ca.gov/climate-dashboard/.

Chapter 2: The Scoping Plan Scenario

This chapter describes the Scoping Plan Scenario, which for the first time includes sources in both the AB 32 GHG Inventory and Natural and Working Lands (NWL). It begins with a short description of the alternatives evaluated. Four scenarios for the AB 32 GHG Inventory and NWL were considered separately and helped to inform the Scoping Plan Scenario. Each of the alternatives were considered in terms of the important criteria and priorities that the state's comprehensive climate action must deliver, including the need for GHG reductions that are not only technologically feasible and cost-effective, but also can deliver health and economic benefits for the state. All the scenarios were set against what is called the *Reference Scenario*—that is, what the GHG emissions would look like if we did nothing at all beyond the existing policies that are required and already in place to achieve the 2030 target of at least 40 percent below 1990 levels, or those expected with no new actions in the NWL sector. For this Scoping Plan, two sets of modeling tools were used to evaluate the AB 32 GHG Inventory and NWL sectors because no single model can assess both AB 32 sectors and NWL together. As a result, two different sets of scenarios were developed for each sector type. While this chapter breaks out discussion separately for the two sector types, the Scoping Plan Scenario reflects the combined actions across both sectors by choosing an alternative from each sector type. The modeling provides point estimates; however, that does not imply precision. As discussed in the uncertainty section, several types of uncertainties are associated with any outcomes projected by the modeling results. There will be ranges of estimates associated with each point that are not shown in the graphs or results.

Scenarios for the AB 32 GHG Inventory Sectors

The Reference Scenario for the AB 32 GHG Inventory sectors shows continuing but modest GHG reductions beyond 2030 that level off toward mid-century. The comprehensive analysis of all four alternatives indicates that the Scoping Plan Scenario is the best choice to achieve California's climate and clean air goals while balancing the legislative direction on prioritizing direct emissions reductions, reducing anthropogenic emissions by at least 85 percent by 2045, being technologically feasible, and being cost-effective. It also protects public health, provides a solid foundation for continued economic growth, and drastically reduces the state's dependence on fossil fuel combustion and does not disproportionately impact disadvantaged communities. Each of the alternative scenarios was the product of a process of development informed by public input, the governor,[124] CARB, legislative direction, and input by the EJ Advisory Committee.[125,126] Future updates to the Scoping Plan may consider new clean technologies and fuels beyond those included in this Scoping Plan.

The four scenarios evaluated shared many similarities. They each embodied the following characteristics:

- Drastic reduction in fossil fuel dependence, with some remaining in-state demand for fossil fuels for aviation, marine, and locomotion applications, and for fossil gas for buildings and industry
- Ambitious deployment of efficient non-combustion technologies such as zero emission vehicles and heat pumps
- Rapid growth in the production and distribution of clean energy such as zero carbon electricity and hydrogen
- Progressive phasedown of fossil fuel production and distribution activities as part of the transition to clean energy
- Remaining emissions of fugitive SLCPs such as refrigerants and fugitive methane
- Strong consumer adoption of clean technology and fuel options
- Removal of remaining CO_2 emissions to achieve carbon neutrality
- Some reliance on carbon capture and sequestration (CCS)

While the four scenarios had a lot in common, they also had some differences:

- Year in which carbon neutrality is achieved (2035 or 2045)
- Rate of deployment of clean technology and production and distribution of zero carbon energy
- Remaining amount of demand for fossil energy in the year carbon neutrality is achieved
- Constraints on technology and fuels deployed in certain sectors
- Consumer adoption rates of clean technologies and fuels
- Degree of reliance on CO_2 removal
- Degree of reliance on CCS

[124] Newsom, Gavin. July 22, 2022. Letter from Governor Newsom to CARB Chair Liane Randolph. Retrieved from https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf.

[125] EJ Advisory Committee. December 2, 2021. EJ Advisory Committee Responses for the CARB Scenario Inputs. https://ww2.arb.ca.gov/sites/default/files/2021-12/EJAC%20Final%20Responses%20to%20CARB%20Scenario%20Inputs_12_2_21.pdf.

[126] CARB. January 25, 2022. Update on PATHWAYS Scenario Modeling Assumptions. https://ww2.arb.ca.gov/sites/default/files/2022-01/Scenario%20Slides%20for%20Jan25%20EJAC%20Mtg_01242022.pdf.

The summary below provides an overview of the alternatives designed and considered for the energy and industrial sectors in this update. Full details of each scenario considered can be found in the *Draft 2022 Scoping Plan Update*

Scoping Plan Scenario (modeling scenario Alternative 3 from the Draft): carbon neutrality by 2045, deploy a broad portfolio of existing and emerging fossil fuel alternatives and clean technologies, and align with statutes, Executive Orders, Board direction, and direction from the governor

Alternative 1: carbon neutrality by 2035, nearly complete phaseout of all combustion, limited reliance on carbon capture and sequestration and engineered carbon removal, and restricted applications for biomass-derived fuels

Alternative 2: carbon neutrality by 2035 and aggressive deployment of a full suite of technology and energy options, including engineered carbon removal

Alternative 4: carbon neutrality by 2045, deployment of a broad portfolio of existing and emerging fossil fuel alternatives, slower deployment and adoption rates than the Scoping Plan Scenario, and a higher reliance on CO_2 removal

Other considerations for the AB 32 GHG Inventory sectors include the following:

- To what extent does an alternative meet the statewide targets and any sector targets, and also deliver clean air benefits (especially in the near term) to address ongoing healthy air disparities, prioritize reductions for mobile and large stationary sources, and emphasize continued investment in disadvantaged communities?
- Does an alternative support California in building on efforts to collaborate with other jurisdictions and include exportable policies based on robust science?
- Does an alternative provide for compliance options and a cost-effective approach to reduce GHG emissions?
- Does the alternative present a realistic and ambitious path forward consistent with statute and science, and support economic opportunities, particularly in anticipated growth sectors?

Scenarios for Natural and Working Lands

For the natural and working lands sector, the Reference Scenario shows that NWL will continue to emit GHGs and lose carbon stocks into the future as the combined effects of past unhealthy management practices and climate change impact our lands. Relative to the Reference Scenario, the four NWL scenarios represent different scales of land management on seven landscapes (forests, shrublands/chaparral, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands) to support carbon neutrality.

The analysis of the four NWL scenarios shows that the Scoping Plan Scenario is the preferred choice because it prioritizes sustainable land management to sequester carbon over the long term, GHG and air pollution reductions, ecosystem health and resilience, and implementation and technological feasibility and cost-effectiveness. The Scoping Plan Scenario reduces catastrophic wildfire risk to the state; increases the health and resilience of California's forests, shrublands, and grasslands; increases soil health; and protects, restores, and enhances California's natural and working lands for future generations. The Scoping Plan Scenario takes into consideration the priority landscapes and nature-based strategies identified in California's Climate Smart Strategy[127] and reflects the state's priorities to manage lands in ways that support the multiple benefits they provide. The Scoping Plan Scenario, as well as each of the alternative NWL scenarios, were informed by input from other agencies, the public, and the EJ Advisory Committee. Additional landscapes and land management activities will be added and evaluated in future Scoping Plan updates and in response to AB 1757.

Each of the NWL scenarios have several similarities, including the following:

- Prioritizing NWL management actions on forests, shrublands, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands. These actions can reduce GHG emissions from these lands, protect ecosystems against future climate change, protect communities, and enhance the ecosystem benefits they provide to nature and society.
- Exploring the potential impacts of different levels of NWL management actions that are designed to achieve the objective associated with each scenario.
- Analyzing the carbon impacts of land management actions, climate change, wildfire, and water use on California's diverse natural and working lands through 2045.

There are also differences across the four NWL scenarios. These include:

- The level of NWL management actions taken on each landscape, such as varying the acres of healthy soils practices for croplands.
- The types of NWL management actions taken on each landscape, such as prescribed burning or thinning for forests, grasslands, and shrublands.

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[127] CNRA. 2022. Natural and Working Lands Climate Smart Strategy. https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/CNRA-Report-2022---Final_Accessible_Compressed.pdf.

The summary below provides an overview of the alternatives designed and considered for the NWL sectors in this Scoping Plan. Full details of each scenario considered can be found in the *Draft 2022 Scoping Plan Update*.

> **Scoping Plan Scenario (NWL Alternative 3 from the Draft):** land management activities that prioritize restoration and enhancement of ecosystem functions to improve resilience to climate change impacts, including more stable carbon stocks
>
> **NWL Alternative 1:** land management activities that prioritize short term carbon stocks in our forests and through increased climate smart agricultural practices on croplands
>
> **NWL Alternative 2:** land management activities representative of California's current commitments and plans
>
> **NWL Alternative 4:** land management activities that prioritize reducing catastrophic wildfires in forests, shrublands, and grasslands

Evaluation of Scoping Plan Alternatives

CARB staff solicited feedback from topical experts, affected stakeholders, and the EJ Advisory Committee, including a tribal representative, at public meetings to assemble input assumptions for four carbon neutrality scenarios to model using PATHWAYS. Revisions to the Draft Scoping Plan were informed by direction in statute, the Governor's Executive Orders, public comments, and the recommendations of the EJ Advisory Committee. The three alternative scenarios were designed to explore the potential speed, magnitude, and impacts of transitioning California's energy demand away from fossil fuels. The modeling assumptions listed below identify the primary fossil fuel alternative that is commercially available and technically feasible for widespread use by 2045 for each sector. CARB assumes that any energy demand that remains after the alternative technology or fuel is applied—such as on-road internal combustion engines, industrial processes, and gas use in existing buildings that have not yet decarbonized—will continue to be met by fossil fuels, resulting in residual GHG emissions.

NWL Scoping Plan Alternatives

For the NWL sectors, staff significantly expanded the scale of the scientific analysis for NWL from previous Scoping Plan efforts. CARB staff utilized modeling tools for this expanded analysis to assess both the carbon and other ecological, public health, and economic outcomes of management actions on forests, shrublands, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands. CARB staff aligned the scenarios with both the landscape types and actions identified in other efforts called for in Governor Newsom's Executive Order N-82-20 (e.g., California's Climate Smart Strategy and Pathways to 30x30). As part of this Scoping Plan, CARB staff modeled as many of the management actions identified in the Natural and Working Lands Climate

Smart Strategy as were feasible. The management actions that were included in the model were selected because of the State of California's previous work to quantify these actions' impacts. It was not feasible to model every land management strategy for NWL, and so it is possible that larger volumes of sequestration (e.g., in soils or in oceans) could result from additional non-modeled activities. California's Natural and Working Lands Climate Smart Strategy includes a more comprehensive listing of priority nature-based solutions and management actions. It is important to note that the absence of a particular management action or its climate benefit in the modeling is not an indication of its importance or potential contributions toward meeting the target or toward supporting the carbon neutrality target for California.

Forests: Management strategies were modeled for forests: biological/chemical/herbaceous treatments (e.g., herbicide application), clearcut, various timber harvests (e.g., variable retention, seed tree / shelterwood, selection harvesting), mastication, other mechanical treatments (e.g., piling of dead material, understory thinning), prescribed burning, and thinning. Avoided land conversion to another land use was also included in the modeling. Wildfire was modeled and is responsive to management strategies and climate conditions.

Shrublands and chaparral: Management strategies were modeled for shrublands and chaparral: biological/chemical/herbaceous treatments, prescribed burning, mechanical treatment (e.g., mastication, crushing, mowing, piling), and avoided conversion from shrubland to another land use. Wildfire was modeled and is responsive to management strategies and climate conditions.

Grasslands: Management strategies were modeled for grasslands: biological/chemical/herbaceous treatments, prescribed burning, and avoided land conversion from grasslands to another land use. Wildfire was modeled and is responsive to management strategies and climate conditions.

Croplands: Management strategies were modeled for row crops: cover cropping, no till, reduced till, compost amendment, transition to organic[128] farming, avoided conversion of annual crop agricultural land through easements, establishing riparian forest buffers, alley cropping, establishing windbreaks/shelterbelts, establishing tree and shrubs in croplands, and establishing hedgerows. For perennial crops, windbreaks/shelterbelts, hedgerows, conversion from annual crops to perennial crops, and avoided conversion to other land uses were modeled.

[128] Note: N_2O reductions from decreases in synthetic fertilizer application in organic farming were not modeled.

Developed lands: Management strategies were modeled for developed lands: Increasing tree canopy cover through planting trees and improved management of existing trees, and removing vegetation surrounding structures in accordance with the CAL FIRE Defensible Space PRC 4291.

Wetlands: Management strategies were modeled for wetlands: Restoring wetlands through submerging cultivated land in the Sacramento-San Joaquin Delta and avoided land conversion in the Sacramento-San Joaquin Delta.

Sparsely vegetated lands: Management strategies were modeled for sparsely vegetated lands: Avoided conversion of sparsely vegetated lands to another land use.

Scoping Plan Scenario

The Scoping Plan Scenario achieves GHG emission reductions that exceed the levels expected based on existing policies represented in the Reference Scenario, keeping California on track to achieve the SB 32 GHG reduction target for 2030 and become carbon neutral no later than 2045. Actions that reduce GHG emissions and transition AB 32 GHG Inventory sources away from fossil fuel combustion affect each economic sector. Actions that lead to improved carbon stocks affect each landscape.

AB 32 GHG Inventory Sectors

The AB 32 GHG Inventory Sector Reference scenario is the forecasted statewide GHG emissions through mid-century, with existing policies and programs but without any further action to reduce GHGs beyond those needed to achieve the 2030 limit. The Reference Scenario was developed based on other projections of business-as-usual conditions. Sources of data and policies included are:

- California Energy Demand Forecast[129]
- The two transportation carbon neutrality studies required by AB 74[130]
- The Mobile Source Strategy[131]
- SB 100 60 percent Renewables Portfolio Standard
- A Low Carbon Fuel Standard carbon intensity reduction target of 20 percent

Policies that are under study or design, such the Advanced Clean Fleets regulation, are not included. The Reference Scenario reflects current trends and expected performance of policies identified in the 2017 Scoping Plan—some of which are performing better (such as the RPS and LCFS) and others that may not meet expectations (such as vehicle miles traveled [VMT] reductions and methane capture). Figure 2-1 provides the modeling results for a Reference Scenario for the AB 32 GHG Inventory sectors compared to the Scoping Plan Scenario.

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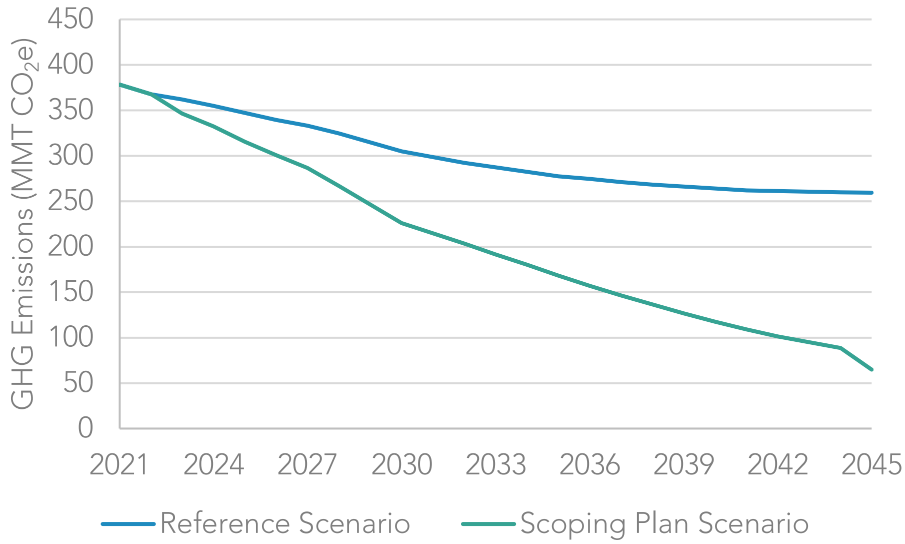
[129] California Energy Commission (CEC). 2020. *2019 Integrated Energy Policy Report.* https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report.

[130] Brown et al. 2021. *Driving California's Transportation Emissions.* https://escholarship.org/uc/item/3np3p2t0 and Deschenes et al. 2021. *Enhancing equity.* https://zenodo.org/record/4707966#.YI72RNrMKUn.

[131] CARB. 2021. 2020 *Mobile Source Strategy.* https://ww2.arb.ca.gov/sites/default/files/2021-12/2020_Mobile_Source_Strategy.pdf.

Figure 2-1: Reference and Scoping Plan Scenario GHG emissions[132]



The Scoping Plan Scenario is summarized in Table 2-1. The table shows the types of technologies and energy needed to drastically reduce GHG emissions from the AB 32 Inventory sectors. It also includes references to relevant statutes and Executive Orders, although it is not comprehensive of all existing new authorities for directing or supporting the actions described. Each action is expected to both reduce GHGs and help improve air quality, primarily by transitioning away from combustion of fossil fuels. The Scoping Plan Scenario achieves the AB 1279 target of 85 percent below 1990 levels by 2045 and identifies a need to accelerate the 2030 target to 48 percent below 1990 levels.

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[132] The drop in emissions in 2045 reflects both the need to achieve an 85% reduction below 1990 levels in anthropogenic emissions per AB 1279 and Governor Newsom's request for a 100 MMT CO2e carbon removal and capture target in 2045. This was modeled by extending CCS to electric sector emissions.

Table 2-1: Actions for the Scoping Plan Scenario: AB 32 GHG Inventory sectors

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
GHG Emissions Reductions Relative to the SB 32 Target[133]	40% below 1990 levels by 2030	SB 32: Reduce statewide GHG emissions. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Smart Growth / Vehicle Miles Traveled (VMT)	VMT per capita reduced 25% below 2019 levels by 2030, and 30% below 2019 levels by 2045	SB 375: Reduce demand for fossil transportation fuels and GHGs, and improve air quality. In response to Board direction and EJ Advisory Committee recommendations
Light-duty Vehicle (LDV) Zero Emission Vehicles (ZEVs)	100% of LDV sales are ZEV by 2035	EO N-79-20: Reduce demand for fossil transportation fuels and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory 2035 target aligns with the EJ Advisory Committee recommendation.

[133] While the SB 32 GHG emissions reduction target is not an Action that is analyzed independently, it is included in this table for reference.

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Truck ZEVs	100% of medium-duty (MDV)/HDV sales are ZEV by 2040 (AB 74 University of California Institute of Transportation Studies [ITS] report)	EO N-79-20: Reduce demand for fossil transportation fuels and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Aviation	20% of aviation fuel demand is met by electricity (batteries) or hydrogen (fuel cells) in 2045. Sustainable aviation fuel meets most or the rest of the aviation fuel demand that has not already transitioned to hydrogen or batteries.	Reduce demand for petroleum aviation fuel and reduce GHGs. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory In response to Governor Newsom's July 2022 letter to CARB Chair Liane Randolph
Ocean-going Vessels (OGV)	2020 OGV At-Berth regulation fully implemented, with most OGVs utilizing shore power by 2027. 25% of OGVs utilize hydrogen fuel cell electric technology by 2045.	Reduce demand for petroleum fuels and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Port Operations	100% of cargo handling equipment is zero-emission by 2037. 100% of drayage trucks are zero emission by 2035.	Executive Order N-79-20: Reduce demand for petroleum fuels and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Freight and Passenger Rail	100% of passenger and other locomotive sales are ZEV by 2030. 100% of line haul locomotive sales are ZEV by 2035. Line haul and passenger rail rely primarily on hydrogen fuel cell technology, and others primarily utilize electricity.	Reduce demand for petroleum fuels and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Oil and Gas Extraction	Reduce oil and gas extraction operations in line with petroleum demand by 2045.	Reduce GHGs and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Petroleum Refining	CCS on majority of operations by 2030, beginning in 2028 Production reduced in line with petroleum demand.	Reduce GHGs and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Electricity Generation	Sector GHG target of 38 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) in 2030 and 30 $MMTCO_2e$ in 2035 Retail sales load coverage[134] 20 gigawatts (GW) of offshore wind by 2045 Meet increased demand for electrification without new fossil gas-fired resources.	SB 350 and SB 100: Reduce GHGs and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory In response to Governor Newsom's July 2022 letter, Board direction, and EJ Advisory Committee recommendation
New Residential and Commercial Buildings	All electric appliances beginning 2026 (residential) and 2029 (commercial), contributing to 6 million heat pumps installed statewide by 2030	Reduce demand for fossil gas and GHGs, and improve ambient and indoor air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory In response to Governor Newsom's July 2022 letter

[134] SB 100 speaks only to retail sales and state agency procurement of electricity. The *2021 SB 100 Joint Agency Report* reflects the agency authors' understanding that other loads—wholesale or non-retail sales and losses from storage and transmission and distribution lines—are not subject to the law.

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Existing Residential Buildings	80% of appliance sales are electric by 2030 and 100% of appliance sales are electric by 2035. Appliances are replaced at end of life such that by 2030 there are 3 million all-electric and electric-ready homes—and by 2035, 7 million homes—as well as contributing to 6 million heat pumps installed statewide by 2030.	Reduce demand for fossil gas and GHGs, and improve ambient and indoor air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory In response to Governor Newsom's July 2022 letter
Existing Commercial Buildings	80% of appliance sales are electric by 2030, and 100% of appliance sales are electric by 2045. Appliances are replaced at end of life, contributing to 6 million heat pumps installed statewide by 2030.	Reduce demand for fossil gas and GHGs, and improve ambient and indoor air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory In response to Governor Newsom's July 2022 letter
Food Products	7.5% of energy demand electrified directly and/or indirectly by 2030; 75% by 2045	Reduce demand for fossil gas and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Construction Equipment	25% of energy demand electrified by 2030 and 75% electrified by 2045	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Chemicals and Allied Products; Pulp and Paper	Electrify 0% of boilers by 2030 and 100% of boilers by 2045. Hydrogen for 25% of process heat by 2035 and 100% by 2045 Electrify 100% of other energy demand by 2045.	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Stone, Clay, Glass, and Cement	CCS on 40% of operations by 2035 and on all facilities by 2045 Process emissions reduced through alternative materials and CCS	SB 596: Reduce demand for fossil energy, process emissions, and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Other Industrial Manufacturing	0% energy demand electrified by 2030 and 50% by 2045	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Combined Heat and Power	Facilities retire by 2040.	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Agriculture Energy Use	25% energy demand electrified by 2030 and 75% by 2045	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions
Low Carbon Fuels for Transportation	Biomass supply is used to produce conventional and advanced biofuels, as well as hydrogen.	Reduce demand for petroleum fuel and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Low Carbon Fuels for Buildings and Industry	In 2030s biomethane[135] blended in pipeline Renewable hydrogen blended in fossil gas pipeline at 7% energy (~20% by volume), ramping up between 2030 and 2040 In 2030s, dedicated hydrogen pipelines constructed to serve certain industrial clusters	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory

[135] *Biomethane* is also known as renewable natural gas (RNG).

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Non-combustion Methane Emissions	Increase landfill and dairy digester methane capture. Some alternative manure management deployed for smaller dairies Moderate adoption of enteric strategies by 2030 Divert 75% of organic waste from landfills by 2025. Oil and gas fugitive methane emissions reduced 50% by 2030 and further reductions as infrastructure components retire in line with reduced fossil gas demand	SB 1383: Reduce short-lived climate pollutants.
High GWP Potential Emissions	Low GWP refrigerants introduced as building electrification increases, mitigating HFC emissions	SB 1383: Reduce short-lived climate pollutants.

Natural and Working Lands

The Reference Scenario for NWL represents the amount of land management that occurred between 2001 and 2014, and projects the outcomes from maintaining the 2001–2014 levels of land management until 2045. The management and land use practices that occur within the Reference Scenario were derived from empirical data used by staff. For forests, shrublands/chaparral, and grasslands, the Reference Scenario constitutes approximately 250,000 acres of annual statewide treatments. For croplands, the Reference Scenario represents no healthy soil practices because during this period the healthy soil program did not yet exist. For land use change within all land types that consider land use change, historical rates of land conversion from 2001–2014 also were taken from empirical data and modeled into the future for the Reference Scenario.

Table 2-2 summarizes the Scoping Plan Scenario. The table also includes references to relevant statutes and Executive Orders where available.

Table 2-2: Actions for the Scoping Plan Scenario: NWL sectors

Sector	Action	Statutes, Executive Orders, Outcome
Natural and Working Lands	Conserve 30% of the state's NWL and coastal waters by 2030. Implement near- and long-term actions to accelerate natural removal of carbon and build climate resilience in our forests, wetlands, urban greenspaces, agricultural soils, and land conservation activities in ways that serve all communities—and in particular low-income, disadvantaged, and vulnerable communities.	EO N-82-20 and SB 27: CARB to include an NWL target in the Scoping Plan. AB 1757: Establish targets for carbon sequestration and nature-based climate solutions. SB 1386: NWL are an important strategy in meeting GHG reduction goals.

Sector	Action	Statutes, Executive Orders, Outcome
Forests and Shrublands	At least 2.3 million acres[136] treated statewide annually in forests, shrublands/chaparral, and grasslands, comprised of regionally specific management strategies that include prescribed fire, thinning, harvesting, and other management actions. No land conversion of forests, shrublands/chaparral, or grasslands.	Restore health and resilience to overstocked forests and prevent carbon losses from severe wildfire, disease, and pests. Improve air quality and reduce health costs related to wildfire emissions. Improve water quantity and quality and improve rural economies. Provide forest biomass for resource utilization. EO B-52-18: CARB to increase the opportunity for using prescribed fire. AB 1504 (Skinner, Chapter 534, Statutes of 2010): CARB to recognize the role forests play in carbon sequestration and climate mitigation.

[136] The 2.3 million acre target is what the Scoping Plan modeling shows would be needed to realize the carbon stock target called for in this Scoping Plan by 2045.

Sector	Action	Statutes, Executive Orders, Outcome
Grasslands	At least 2.3 million acres[137] treated includes increased management of grasslands interspersed in forests to reduce fuels surrounding communities using management strategies appropriate for grasslands. No land conversion of forests, shrublands/chaparral, or grasslands.	Help to achieve climate targets, improve air quality, and reduce health costs.
Croplands	Implement climate smart practices for annual and perennial crops on ~80,000 acres annually. Land easements/ conservation on annual crops at ~5,500 acres annually. Increase organic agriculture to 20% of all cultivated acres by 2045 (~65,000 acres annually).	Reduce short-lived climate pollutants. Increase soil water holding capacity. Increase organic farming and reduce pesticide use. SB 859: Recognizes the ability of healthy soils practices to reduce GHG emissions from agricultural lands. Target increased in response to Governor Newsom's direction to prioritize sustainable land management.

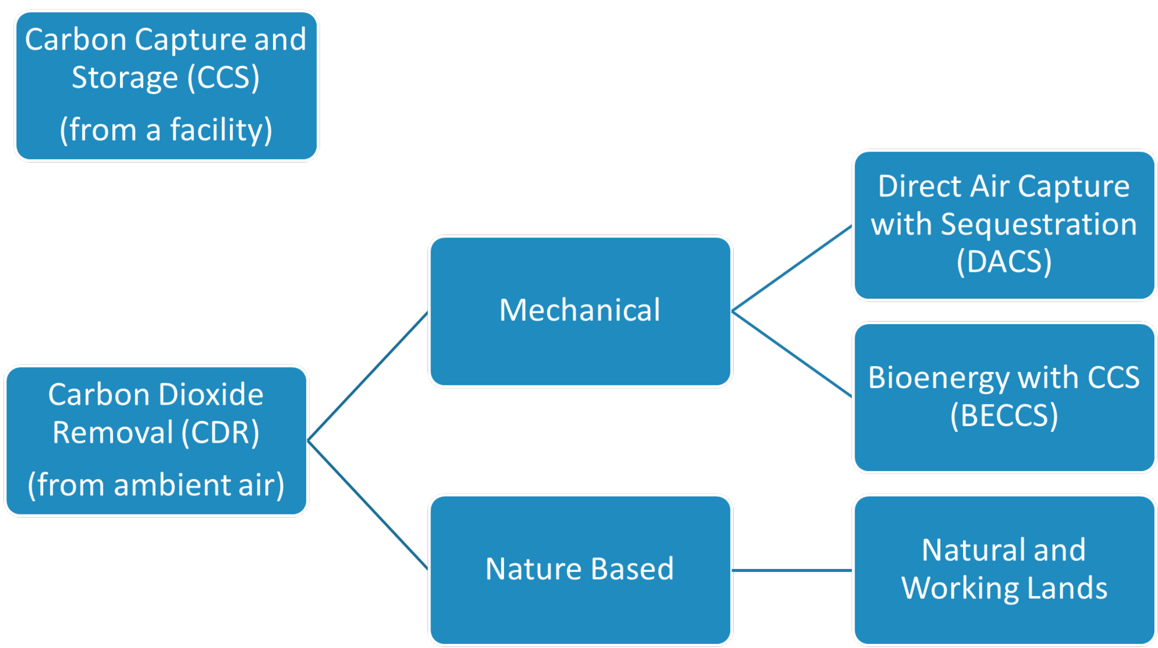
[137] The 2.3 million acre target is what the Scoping Plan modeling shows would be needed to realize the carbon stock target called for in this Scoping Plan by 2045.

Sector	Action	Statutes, Executive Orders, Outcome
Developed Lands	Increase urban forestry investment by 200% above current levels and utilize tree watering that is 30% less sensitive to drought. Establish defensible space that accounts for property boundaries.	Increase urban tree canopy and shade cover. Reduce heat island effects and support water infrastructure. Reduce fire risk via defensible space. AB 2251 (Calderon, Chapter 186, Statutes of 2022): Increase urban tree canopy 10% by 2035. Target increased in response to AB 2251 and Governor Newsom's direction on CO_2 removal targets in his July 2022 letter.
Wetlands	Restore 60,000 acres of Delta wetlands.	Increase carbon sequestration and reduce short-lived climate pollutants. Helps to reverse land subsidence while improving flood protection and providing critical habitat.
Sparsely Vegetated Lands	Land conversion at 50% of the Reference Scenario land conversion rate.	Reduce the rate of land conversion to more GHG-intensive land uses.

Strategies for Carbon Removal and Sequestration

To achieve carbon neutrality, any remaining emissions must be compensated for using carbon removal and sequestration tools. The following discussion presents more detail on the options available to capture and sequester carbon. Carbon removal and sequestration will be an essential tool to achieve carbon neutrality, and the modeling clearly shows there is no path to carbon neutrality without carbon removal and sequestration. Governor Newsom also recognized the importance of CO_2 removal strategies and directed CARB to establish CO_2 removal and carbon capture targets of 20 $MMTCO_2$ and 100 $MMTCO_2$ by 2030 and 2045, respectively, as well as signing 2022 legislation on carbon removal and sequestration, including: AB 1279, SB 905, SB 1137, and AB 1757. Carbon removal and sequestration can take different forms. Figure 2-2 illustrates the types of carbon removal and sequestration included in this Scoping Plan. There are numerous other carbon removal options undergoing research, development, and pilot deployment. As these options mature and new approaches emerge, they can be considered in future Scoping Plan updates.

Figure 2-2: Forms of carbon removal and sequestration considered in this Scoping Plan



The Role of Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) will be a necessary tool to reduce GHG emissions and mitigate climate change while minimizing leakage and minimizing emissions where no technological alternatives may exist. CCS is a process by which large amounts of CO_2 are captured, compressed, transported, and sequestered. CCS projects are paired with a source of emissions, as the CCS project captures CO_2 as it leaves a facility's smokestack. CCS projects are often paired with large GHG-emitting facilities such as energy, manufacturing, or fuel production facilities. The sequestration component of CCS includes CO_2 injection into geologic formations (such as depleted oil and gas reservoirs and saline formations), as well as use in industrial materials (e.g., concrete). CCS is distinct from biological sequestration, which is typically accomplished through NWL management and conservation practices that enhance the storage of carbon or reduce CO_2 emissions with nature-based approaches. CCS is also distinct from mechanical CO_2 removal technologies, where CO_2 is removed directly from the atmosphere using mechanical and/or chemical processes.

CARB adopted a CCS Protocol in 2018 as part of amendments to the Low Carbon Fuel Standard.[138] At this time, no CCS projects have been implemented or have generated any credits under that protocol. However, CCS projects have been implemented elsewhere since the 1970s, largely on coal-fired power plants, with over two dozen projects operational around the world. Over 100 are at the stages of advanced or early development and are expanding beyond coal-fired plants to fossil gas, fuel production, and electricity generation facilities.[139] CCS projects are in development for addressing emissions from fuel, gas, energy production, and chemical production. As of November 2019, more than half of global large-scale CCS facilities (representing approximately 22 $MMTCO_2$/yr in capacity[140]) were in the U.S., mostly as a result of sustained governmental support for these technologies.[141] This support includes the federal 45Q tax credit for CCS[142,143] and research and deployment grants from federal agencies.[144,145] California's deep sedimentary rock formations in the Central Valley represent world-class

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[138] CARB. 2022. Carbon Capture & Sequestration. https://ww2.arb.ca.gov/our-work/programs/carbon-capture-sequestration.

[139] Global CCS Institute. 2021. *Global Status of CCS 2021.* https://www.globalccsinstitute.com/wp-content/uploads/2021/11/Global-Status-of-CCS-2021-Global-CCS-Institute-1121.pdf.

[140] IHS Markit. August 2021. Carbon Removal Potential: An Overview. https://ww2.arb.ca.gov/sites/default/files/2021-08/ihsmarkit_presentation_sp_engineeredcarbonremoval_august2021.pdf.

[141] Beck, Lee. 2019. *Carbon capture and storage in the USA: The role of US innovation leadership in climate-technology commercialization.* https://academic.oup.com/ce/article/4/1/2/5686277.

[142] Congressional Research Service. 2021. Carbon Storage Requirements in the 45Q Tax Credit. IF11639. https://crsreports.congress.gov/product/pdf/IF/IF11639.

[143] The Inflation Reduction Act of August 2022 expands and enhances the 45 Q tax credit for CCS. Pub.L. No. 117-169 (August 16, 2022).

[144] U.S. Department of Energy. 2020. U.S. Department of Energy Announces $131 Million for CCUS Technologies. https://www.energy.gov/articles/us-department-energy-announces-131-million-ccus-technologies.

[145] U.S. Department of Energy. 2021. Funding Opportunity Announcement 2515, Carbon Capture R&D for Natural Gas and Industrial Point Sources, and Front-End Engineering Design Studies for Carbon Capture Systems at Industrial Facilities and Natural Gas Plants. https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial.

CO_2 storage sites that would meet the highest standards, with storage capacities of at least 17 billion tons of CO_2.[146, 147]

In this Scoping Plan, CCS is included to address emissions from limited sectors, including electricity generation, cement production facilities, and refineries, to ensure anthropogenic emissions are reduced by at least 85 percent below 1990 levels in 2045, as directed in AB 1279. While the modeling outputs show CCS not being applied to the electricity sector until 2045, CCS could be implemented earlier on the electricity sector with a similar ramp up over time as that for refineries and cement plants. An earlier application of CCS in the electricity sector would yield additional reductions in years prior to 2045. In addition, CCS can support hydrogen production until such time as there is sufficient renewable power for electrolysis and an abundant water source.

Cement plants have emissions associated with combustion and process-related activities. Combustion emissions account for approximately 40 percent of the total emissions at cement plants. The remaining emissions are related to process-related activities. Due to the high heat content needed to produce cement, there is currently no technically feasible alternative to combustion. SB 596 calls for a 40 percent reduction in GHG intensity in cement emissions from 2019 levels by 2035, and then net zero emissions by 2045. To meet in-state demand, the state relies on cement both produced in state and imported. There are seven cement plants operating in California.[148] To minimize emissions leakage and address emissions from cement plants, the Scoping Plan Scenario includes CCS for cement plants. Additional reductions will need to be pursued and considered as part of implementation of SB 596, which calls for CARB to develop a comprehensive strategy by July 1, 2023, for the state's cement sector to achieve net-zero emissions of GHGs associated with cement used within the state as soon as possible, but no later than December 31, 2045. This effort began in the summer of 2022 and included sector specific workshops.

Even with implementation of EO N-79-20, and despite all of the ambitious efforts in the Scoping Plan Scenario, there will remain some demand for petroleum fuels for legacy vehicles on road applications, and in aviation, rail, and marine applications. Petroleum refineries will need to implement technology to decarbonize their operations and reduce their emissions. This Scoping Plan also assumes CCS at petroleum refineries as one of those potential strategies. Currently, there are seventeen petroleum refineries operating

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[146] For comparison purposes, California's emitted 418.2 million metric tons of CO_2e in 2019.
[147] Lawrence Livermore National Laboratory. 2020. *Getting to Neutral: Options for Negative Carbon Emissions in California.* Revision 1. https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf.
[148] CARB. Mandatory GHG Reporting – Reported Emissions. https://ww2.arb.ca.gov/mrr-data

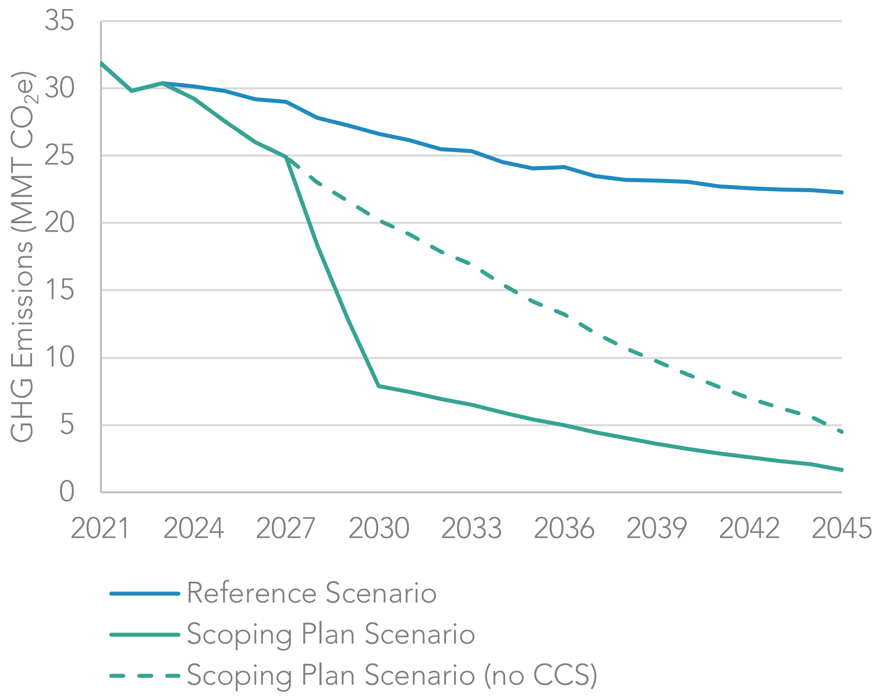
in the state.[149] On the supply side, the modeling assumes all in-state demand is met through some very limited refining activities in California. Figure 2-3 shows the emissions from the refining sector with and without CCS. If CCS is not deployed, the emissions would be directly emitted into the atmosphere, and CO_2 removal by NWL or direct air capture would need to increase to compensate for the sector's emissions.

Refineries can have a variety of point sources that emit CO_2—such as steam methane reformers for producing hydrogen, combined heat and power units, and catalytic crackers—that are best suited for CCS. Each configuration of a refinery can be unique to its footprint, onsite operations, and the types of crude oils processed. There are newer technologies with smaller footprints[150] that can be deployed in modular configurations to capture CO_2 in space-constrained and multiple-point-source facilities such as refineries. CCS can provide a path to reducing GHG emissions from these facilities to meet petroleum demand while avoiding leakage and until such time as some refineries can be transitioned to produce clean energy to support the transition away from fossil fuels.

While the Scoping Plan modeled deployment of CCS on refineries and identifies significant emissions reductions that can be achieved, the refineries in California are large and complex. The actual deployment of CCS at these facilities as modeled in the Scoping Plan is uncertain. It will be important to closely monitor the evolution of CCS deployment in the refinery sector and, in the next Scoping Plan update, to evaluate the progress toward use in this sector to determine whether the projected reductions will be achieved.

[149] CARB. Mandatory GHG Reporting. https://ww2.arb.ca.gov/mrr-data.
[150] Carbon Clean. Modular Carbon Capture Systems for Industry. https://www.carbonclean.com/modular-systems?hsLang=en.

Figure 2-3: Petroleum refining emissions with and without carbon capture and sequestration



This Scoping Plan also calls for accelerating the transition from combustion of fossil fuels to hydrogen. Hydrogen can be produced through electrolysis with renewable electricity or through steam methane reformation of biomethane. There is a high degree of uncertainty around the availability of solar to support both electrification of existing sectors and the production of hydrogen through electrolysis. Producing hydrogen required under the Scoping Plan Scenario with electrolysis would require about 10 gigawatts (GW)[151] of additional solar capacity. If steam methane reformation is paired with CCS, the hydrogen produced could potentially be low carbon. Additionally, the biomethane used to generate hydrogen could be sourced from gasification of forest or agricultural waste resulting from forest management and other NWL management practices, which could also lead to net negative carbon outcomes. Steam methane reformation paired with CCS can thus ensure a rapid transition to hydrogen and increase hydrogen availability until such time as

[151] The Draft Scoping Plan included an estimate for solar capacity (40 GW) to support only electrolysis to produce all hydrogen in the Proposed Scenario. The Scoping Plan now includes steam methane reformation of biomethane and biomass gasification with CCS to produce hydrogen, along with electrolysis from off-grid solar. See Appendix H (AB 32 GHG Inventory Sector Modeling) for additional details.

electrolysis with renewables can meet the ongoing need, assuming there is also sufficient water supply. Additional background and next steps for CCS can be found in Chapter 4.

The EJ Advisory Committee has raised multiple concerns related to the inclusion of CCS and mechanical CDR in the Scoping Plan. Concerns range from potential negative health and air quality impacts in communities from operation of facilities utilizing CCS that continue to emit other emissions, to safety concerns related to potential leaks, to the viability of the current technology. Additionally, the EJ Advisory Committee has policy concerns about the strategy and wants to ensure that engineered carbon removal is not used as a substitute for strategies to achieve emissions reductions onsite and that it does not result in delays in phasing out fossil fuel use. Given these and other concerns and the importance of building public awareness, CARB recognizes the need for a multi-stakeholder process including other state, federal, and local agencies; tribes; independent experts; and community residents to further understand and address community concerns related to CCS. CARB hosted a CCS Symposium with U.S. EPA Region 9 and the Stanford Doerr School of Sustainability to discuss some of these critical issues with community members and other participants. As CARB begins the process of implementing SB 905 in 2023, that will provide an opportunity for further engagement.

In the context of CCS deployment, the Council of Environmental Quality (CEQ) also highlighted the need to further assess and quantify potential impacts on local criteria air pollutants and other emissions resulting from carbon capture retrofits at industrial facilities in response to concerns regarding potential cumulative emissions from single and/or multiple sources.[152] An October 2020 Stanford report[153] discussed how the potential post-combustion capture for CO_2 could also reduce emissions of criteria air pollutant emissions from certain facilities. Exploring these potential outcomes will be important to ensure deployment of CCS does not exacerbate air pollution impacts in communities and maximizes any air pollution benefits. The need for these types of evaluations is also included in SB 905.

The Role of Natural and Working Lands Emissions and Sequestration

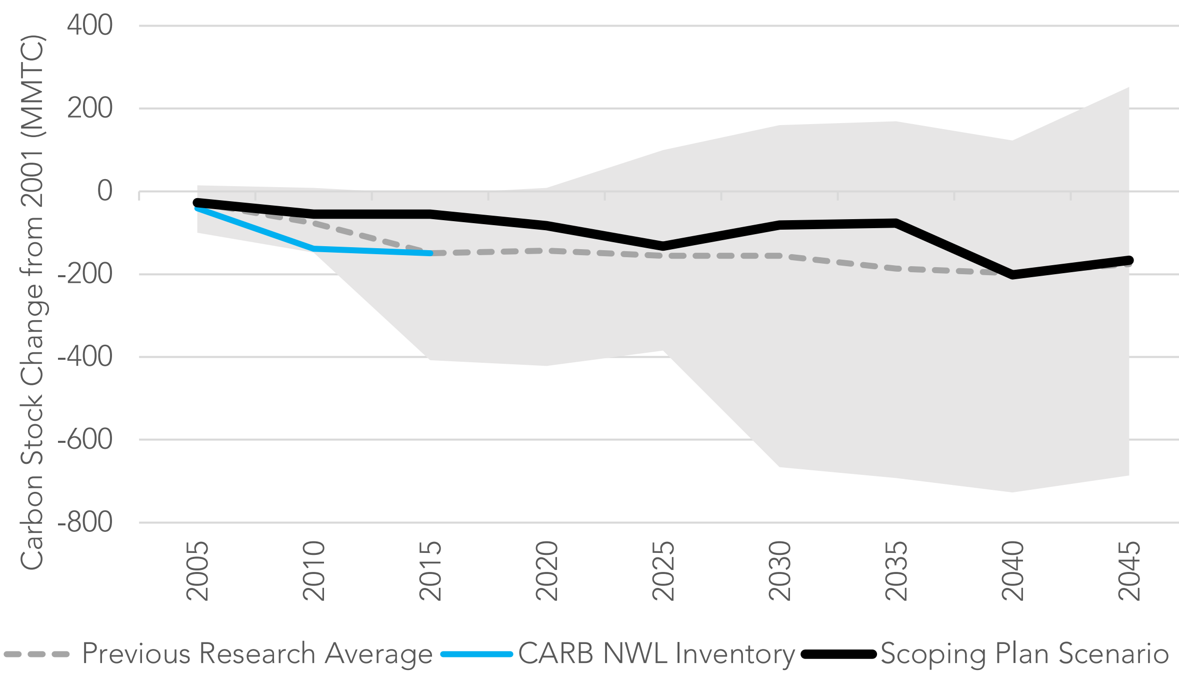
California's NWL assessments highlight the importance of increasing the pace and scale of NWL actions to ensure that our ecosystems are better equipped to withstand future climate change so they continue to provide the benefits that nature and society depend

[152] Carbon Capture, Utilization, and Sequestration Guidance. 87 Fed. Reg. 8808 (Feb. 16, 2022), 2022-03205.pdf (govinfo.gov).

[153] Stanford Center for Carbon Storage. 2020. *An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions.* October. https://sccs.stanford.edu/ccs-in-ca/full-report-form?msclkid=6f9177f6c57811ecbebc473e75203b21.

upon for survival. As climate change increases the likelihood of extreme wildfires, drought, heat, and other impacts, carbon stocks in California's NWL will face increased risks and impacts. We know from previous climate change and Scoping Plan work[154] that lands can be a net source of GHG emissions or a net sink, and that the magnitude of carbon stock changes and GHG emissions and sequestration from NWL are dependent on the effects of climate change and land management. The expanded modeling conducted for this Scoping Plan shows that NWL are projected to be a net source of emissions through 2045 and indicates a probable decrease of carbon stocks into the future. This projection is further corroborated by previous, independent research that has reached the same conclusion, showing a range of varying levels of carbon stock loss. Figure 2-4 shows the modeling results of the Scoping Plan Scenario overlaid with the NWL inventory and findings from independent research.

Figure 2-4: Comparison of the Scoping Plan Scenario (NWL) with existing research



The modeling indicates that immediate and aggressive climate action can reduce the environmental impacts that would occur in the absence of this action. The results of the modeling demonstrate that regular NWL management over the next two decades can

[154] CARB. 2019. January 2019. *Draft California 2030 Natural and Working Lands Climate Change Implementation Plan*. https://ww2.arb.ca.gov/sites/default/files/2020-10/draft-nwl-ip-040419.pdf.

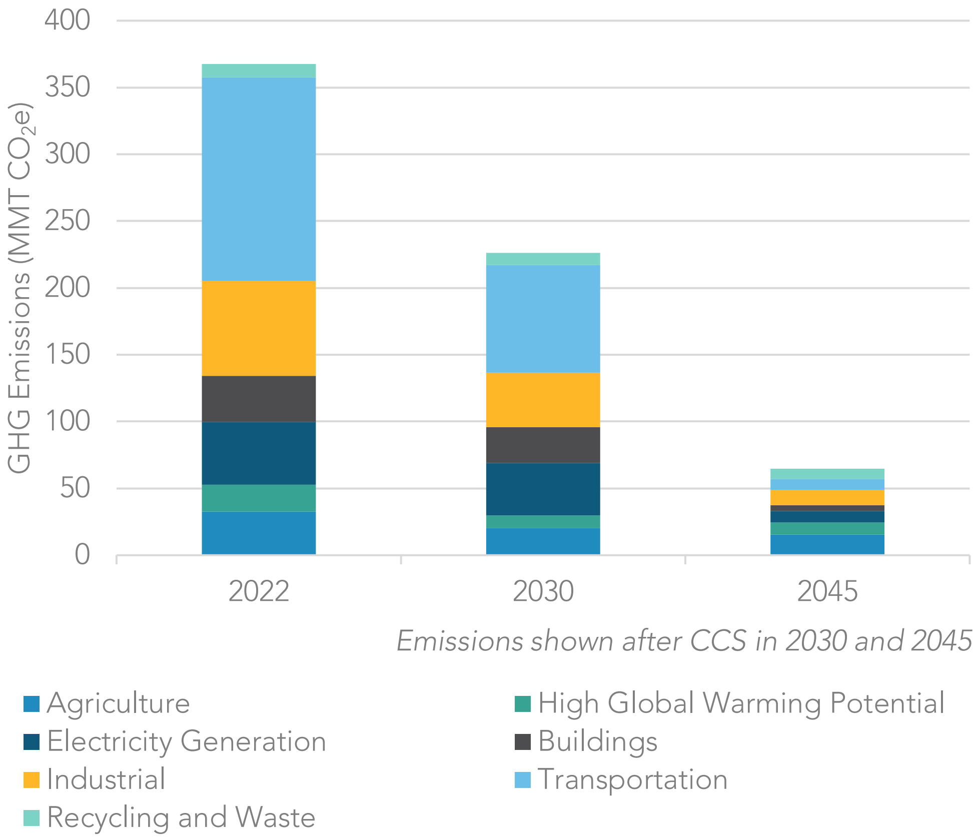
increase carbon stocks from the Reference Scenario trajectory, reduce GHG emissions from lands, and improve ecosystem and public health. This effort is the most comprehensive scientific effort taken by any government to include NWL within its overall climate strategy. Even so, we know that uncertainty exists about future climate and economic forces and the impacts they may have on our ecosystems, so it is important that the state take decisive and aggressive action to improve and diversify ecosystem structures and management.

The effects of climate change, including increased drought, wildfire, and extreme heat, play a significant role in determining the future of California's carbon stocks. And while management actions will help to reduce the impact that climate change will have on California, it is clear from the analysis that NWL sinks and sources are highly variable from year to year, and short time frames do not adequately demonstrate the impact that climate and management are having on ecosystems. For the purposes of climate planning, therefore, it is best to focus on carbon stock changes over longer periods rather than focusing on sequestration or emissions on shorter time frames. The Scoping Plan Scenario is estimated to result in additional NWL emissions of 7 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) annually from 2025–2045. The Reference Scenario is estimated to result in annual emissions of 9 $MMTCO_2e$ over the same time period, and so the Scoping Plan Scenario slows the rate of emissions and provides an approximate 2 $MMTCO_2e$ in additional annual sequestration relative to the Reference Scenario. Because NWL are projected to be a net emissions source, the annual NWL emissions of approximately 7 $MMTCO_2e$ from the Scoping Plan Scenario will need to be compensated by additional CO_2 removal approaches to ensure California can achieve carbon neutrality by 2045.

The Role for Carbon Dioxide Removal (Direct Air Capture)

Even if anthropogenic emissions are reduced to at least 85 percent below 1990 levels by 2045 as called for by AB 1279, there will still be residual emissions in the AB 32 GHG Inventory sectors in 2045 that must be addressed in order to achieve the California's carbon neutrality target. Figure 2-5 includes the emissions by sector for the AB 32 GHG Inventory Sectors in 2022, 2030, and 2045 for the Scoping Plan Scenario.

Figure 2-5: Residual emissions in 2022, 2030, and 2045 for the Scoping Plan Scenario[155]



To achieve carbon neutrality, mechanical CDR will therefore need to be deployed. Because NWL management is not estimated to be a significant carbon removal path in the near term, additional CDR options will be needed. *Mechanical CDR* refers to a range of technologies that capture and concentrate ambient CO_2. Direct air capture (DAC) is one available option that is under development today and could be widely deployed. Note that, unlike CCS, DAC technologies are not designed to be attached to a specific source or smokestack. These technologies include chemical scrubbing processes that capture CO_2 through absorption or adsorption separation processes. Another carbon removal

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[155] The High GWP sector includes high global warming potential gas emissions from releases of ozone depleting substance (ODS) substitutes, SF_6 emissions from the electricity transmission and distribution system, and gases that are emitted in the semiconductor manufacturing process. ODS substitutes, which are primarily hydrofluorocarbons (HFCs), are used in refrigeration and air conditioning equipment, solvent cleaning, foam production, fire retardants, and aerosols.

option that involves rapid mineralization of CO_2 at the Earth's surface is called *mineral carbonation.*[156] As is the case with CCS, mechanical CDR technologies will need governmental or other incentive support to overcome technology and market barriers. In the United States, the U.S. Department of Energy announced financing specifically for DAC in March 2020[157] and March 2021.[158] Additionally, almost $9 billion in CCS support was included in the $ 1 trillion Infrastructure Investment and Jobs Act of 2021.[159] This includes funding to establish four DAC hubs. The Inflation Reduction Act of 2022[160] increases the value of the 45Q tax credit to USD 85 per metric ton of CO_2 captured and stored in geologic formations from some industrial applications and USD 180 per metric ton for DAC with storage in geologic formations. In 2021, there were approximately 19 DAC facilities globally.[161]

Ultimately, the role for mechanical CDR will depend on the success of reducing emissions directly at the source in the AB 32 GHG Inventory sectors and the ability of the NWL to sequester carbon. However, mechanical CDR also provides an opportunity to not just achieve carbon neutrality, but also remove legacy GHG emissions from the atmosphere. As such, increased deployment of DAC can help achieve net negative emissions. This would further help avoid the most damaging impacts of climate change. While the federal incentives for DAC provide some support for this technology, the only California program that recognizes this technology is the LCFS program. Permitting must also happen across different levels of government and across multiple state agencies. Energy availability must also be addressed if DAC is to be implemented in remote areas. Additional information and next steps on DAC can be found in Chapter 4.

[156] The National Academies Press. 2018. Direct Air Capture and Mineral Carbonation Approaches for Carbon Dioxide Removal and Reliable Sequestration: Proceedings of a Workshop–in Brief. https://nap.nationalacademies.org/catalog/25132/direct-air-capture-and-mineral-carbonation-approaches-for-carbon-dioxide-removal-and-reliable-sequestration#:~:text=National%20Academies%20of%20Sciences%2C%20Engineering%2C%20and%20Medicine%3B%20Division,concentrate%20carbon%20dioxide%20%28CO%202%29%20from%20ambient%20air.

[157] U.S. Department of Energy. 2020. Department of Energy to Provide $22 Million for Research on Capturing Carbon Dioxide from Air. https://www.energy.gov/articles/department-energy-provide-22-million-research-capturing-carbon-dioxide-air.

[158] U.S. Department of Energy. 2021. DOE Invests $24 Million to Advance Transformational Air Pollution Capture. https://www.energy.gov/articles/doe-invests-24-million-advance-transformational-air-pollution-capture.

[159] Pub.L. No. 117-58 (November 15, 2021). https://www.congress.gov/bill/117th-congress/house-bill/3684/text.

[160] Pub.L. No. 117-169 (August 16, 2022). https://www.congress.gov/bill/117th-congress/house-bill/5376/text.

[161] International Energy Agency (IEA). 2022. Direct Air Capture – Analysis. https://www.iea.org/reports/direct-air-capture.

Carbon Dioxide Removal and Capture Targets for 2030 and 2045

Recognizing the importance of CO_2 removal, Governor Newsom and the Legislature identified the need for targets to send policy and regulatory signals to pilot, deploy, and scale action for those efforts. Governor Newsom requested that CARB set a CO_2 removal and capture target of 20 MMT for 2030 and 100 MMT for 2045, first prioritizing sequestration in NWL. And while this Scoping Plan prioritizes and recommends significant increased climate-smart action on all NWL to support carbon neutrality and healthy and resilient lands, the modeling indicates that, across all NWL, lands will be a net source of emissions when accounting for both carbon sequestration and GHG (CO_2, CH_4, and N_2O) emissions from lands.

Some landscapes, however, are projected to have a net increase in carbon stocks under the Scoping Plan Scenario between 2025 and 2045 relative to the reference case, indicating that NWL actions can help California achieve Governor Newsom's CO_2 removal targets. Carbon stocks in urban forests and grasslands are projected to increase relative to historical levels from implementation of the 2022 Scoping Plan. To support the governor's CO_2 removal targets, CARB estimates that lands would contribute an average of 1.5 MMT of CO_2 removals each year between 2025 and 2045. Any carbon sequestration contributions from lands need to reflect both long-term storage and an overall net increase in carbon stocks over time to ensure these NWL actions are contributing toward California's achievement and maintenance of carbon neutrality over time.

CARB will work to update and revise these estimates as part of implementation of AB 1757, which was signed by the governor in September 2022 and requires that CARB and the California Natural Resources Agency (CNRA) work with an expert advisory committee to determine an ambitious range of carbon sequestration targets by January 1, 2024, for the years 2030, 2038, and 2045.

For the AB 32 GHG Inventory sectors, the Scoping Plan Scenario modeling indicates that the scenario would meet or exceed the 2030 SB 32 target through GHG reduction policies without the need for CDR. CDR will, however, be necessary to increase ambition for an accelerated 2030 target and in increasing amounts over the following decades to achieve carbon neutrality by 2045.[162] Given the likelihood of NWL to be a net source of emissions, and the need for CDR to compensate for residual emissions to achieve carbon neutrality

[162] The modeled scenarios assume that residual emissions will be compensated using DAC technologies by including the direct cost in terms of dollars per ton CO_2 removed. The energy source for DAC is not modeled, but renewable electricity and/or hydrogen produced from electrolysis are zero carbon options consistent with the carbon neutrality targets in this Scoping Plan.

by 2045, California will need increasing deployment of mechanical CDR over the coming decades. In the immediate future, scaling nature-based CDR approaches also can help to provide some CO_2 removal quickly while mechanical CDR is scaled up between now and 2045. Table 2-3 provides estimates of CO_2 removal and capture needed in 2030[163] and 2045.

[163] As identified in Chapter 1, SB 27 (Skinner, Chapter 237, Statues of 2021) directed CARB to “establish carbon dioxide removal targets for 2030 and beyond” as part of this Scoping Plan. CARB is establishing these targets to satisfy both the requirements of SB 27 and the directive from Governor Newsom to establish CO_2 removal targets for 2030 and 2045.

Table 2-3: GHG emissions and removals needed to achieve carbon neutrality and meet the 20 $MMTCO_2$ removal and capture target in 2030 and the 100 $MMTCO_2$ removal and capture target in 2045.[164]

	2030 ($MMTCO_2e$)	2045 ($MMTCO_2e$)
GHG Emissions	233	72
AB 32 GHG Inventory Sector Emissions	226	65
Net NWL GHG Emissions Across All Landscapes (annual average from 2025–2045)	7	7
Carbon Capture and Sequestration (CCS): Avoided GHG Emissions from Industry and Electric Sectors	(13)	(25)
Carbon Dioxide Removal (CDR) including natural and working lands carbon sequestration,[165] Direct Air Capture, and Bioenergy with CCS (BECCS).	(7)	(75)
Net Emissions (GHG Emissions + CDR)	226	(3)

In 2030, the CO_2 removal and capture target is 20 MMT, but because the SB 32 target only encompasses the AB 32 GHG Inventory sectors, only CCS that reduces GHG emissions on AB 32 sources count toward achieving more ambitious GHG emission reductions in 2030. In 2045, the CO_2 removal and capture must compensate for any residual emissions from the AB 32 Inventory sectors and NWL emissions to support achieving carbon neutrality while also totaling at least 100 MMT. It is important to note that NWL, particularly forests, need a natural wildfire cycle to remain healthy. While the modeling projected wildfires, and implementing the Scoping Plan will result in a reduction in future wildfire emissions, getting to zero wildfires in the sector is not the goal, nor the

[164] Modeled estimates from the Scoping Plan Scenario indicate the relative quantity of emissions and removals to achieve carbon neutrality and meet carbon removal and capture targets. These estimates are not intended to imply precision, as the required policies are yet to be implemented and all models have some uncertainty in their forecasts.

[165] For the purposes of quantifying how to achieve the governor's 20 MMT and 100 MMT CO_2 removal and capture target, CARB included 1.5 $MMTCO_2e$ sequestration from NWL, which is the sequestration from urban forests. This is included as CO_2 removal because it is this sequestration that CARB can consider as having some permanence. Permanence is necessary for incorporating NWL into carbon neutrality. The net NWL emissions of 7 $MMTCO_2e$, identified in the second row of Table 2-3, includes *all* emissions and sinks from all NWL landscapes, which is inclusive of the 1.5 $MMTCO_2e$ sequestration. CARB will develop an accounting framework to accommodate NWL carbon stocks.

right approach to a sustainable forestry sector. In contrast in 2045, the reductions from programs and policies are estimated to reduce emissions by 169 $MMTCO_2e$ from business as usual.

The 2030 target for engineered CDR also provides a near term milestone for California and can serve as an important marker for progress in deploying CDR to support California's carbon neutrality goal. Preliminary estimates indicate that, globally, capacity from already announced projects will range from about 2 million metric tons per year ($MMTCO_2/y$) to 8 $MMTCO_2/y$ from bioenergy paired with CCS, and from about 2,000 metric tons per year ($MTCO_2/y$) to 1 $MMTCO_2/y$ from DACs by 2027,[166] which indicates that California's 2030 target is an ambitious, but achievable, goal.

Scenario Uncertainty

Greenhouse Gas Emissions Modeling

Several types of uncertainty are important to understand in both forecasting future emissions and estimating the benefits of emission reduction actions. In developing this Scoping Plan we forecasted a reference scenario and estimated the GHG emissions outcome of the AB 32 GHG Inventory sectors using the PATHWAYS[167] model. Inherent in the reference scenario modeling is the expectation that many of the existing programs will continue in their current form, and that the expected drivers for GHG emissions, such as energy demand, population growth, and economic growth, will match our current projections.

However, there is also the expectation that each of the policies included and implemented to achieve the 2030 target in the 2017 Scoping Plan will deliver their exact outcomes. It is unlikely the future will precisely match our projections, and this will lead to uncertainty in the forecast. For example, we never could have foreseen and forecasted economic and emissions impacts related to the extended disruptions from the COVID-19 pandemic. Thus, the single "reference" or "forecast" line should be understood to represent one possible future in a range of possible predictions. For this Scoping Plan, PATHWAYS utilized inputs that reflect technically feasible levels of deployment or adoption of low- or zero-carbon fuels and technologies. Each of the input assumptions provided to PATHWAYS has some uncertainty, which also contributes to uncertainty in the resulting reference scenario.

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[166] IHS Markit. August 2021. Carbon Removal Potential. *https://ww2.arb.ca.gov/sites/default/files/2021-08/ihsmarkit_presentation_sp_engineeredcarbonremoval_august2021.pdf*.
[167] See Appendix H (AB 32 GHG Inventory Sector Modeling).

Similarly, for the NWL modeling, CARB used a mix of individual modeling tools[168] to estimate the carbon and other ecological, public health, and economic outcomes. The Reference scenario assumes that the level of land management actions that occurred between 2001 and 2014 for forests, shrublands, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands continues into the future. Alternative scenarios assessed the effect of increasing levels of management actions from the reference scenario beginning in 2025. There is a great deal of uncertainty about exactly how lands are currently managed, and a larger uncertainty about how they may be managed in the future. For NWL, it is unlikely that the future will precisely match the carbon stock outcomes CARB has projected, particularly given the uncertainties around current and future land management and the effects climate change will have on our lands. For any modeling exercise these uncertainties exist; however, this modeling effort brings together the best available science, data, and models to quantify the impact our actions may have on the landscape under an unknown future.

Implementation

As this Scoping Plan is designed to chart a path to achieving carbon neutrality, additional work will be required to fully design and implement any policies and actions identified in this plan. During the subsequent development of policies, the Legislature, CARB, and other state agencies will learn more about the technologies and their costs, as well as how each industry works, as a more comprehensive evaluation is conducted in coordination with stakeholders, including community engagement. Significant areas of uncertainty include permitting wait times[169] and local ordinances that might limit or slow the build-out of utility scale renewables.[170,171] In another example, times to reach commercial operations for solar projects after securing an interconnection agreement also have increased in recent years, to 3.5 to 5.5 years.[172]

The level of natural and working lands climate action identified in this Scoping Plan is ambitious. Achieving the level of action needed to result in the quantified carbon,

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[168] See Appendix I (Natural and Working Lands Technical Support Document).

[169] CEC. 2021. *SB 100 Joint Agency Report.* https://www.energy.ca.gov/sb100#anchor_report.

[170] Roth, Sammy. 2019. "California's San Bernardino County slams the brakes on big solar projects." *Los Angeles Times.* https://www.latimes.com/business/la-fi-san-bernardino-solar-renewable-energy-20190228-story.html?fbclid=IwAR2qHGq3bahHme6SFErLsnyFi9UPIfBHIhvnOh3dU3OM7kUTMcEqYfN3pQA.

[171] Chediak, Mark. 2021. "California NIMBYs Threaten Biden's Clean Energy Goals." *BNN Bloomberg.* https://www.bnnbloomberg.ca/california-nimbys-threaten-biden-s-clean-energy-goals-1.1634351?msclkid=668c9ae9c11311ec92e34035ea157ad4.

[172] Rand, Joseph, et al. 2022. Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2021. Power Point Presentation. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf.

emissions, health, and economic outcomes within this Scoping Plan requires coordination, investment, and partnerships across all levels of government and sectors of the economy. It is possible that not all of the actions at the identified level will begin in 2025. This uncertainty will result in diminished levels of beneficial outcomes quantified in the Scoping Plan Scenario. The levels of NWL action identified in this Scoping Plan represent CARB's assessment of the pace and scale of action needed to achieve the carbon stock targets and CO_2 removal targets identified in this Scoping Plan.

The Scoping Plan Scenario identifies that 2.3 million acres of forests, shrubland, and grassland management annually would achieve substantial levels of fire emissions reductions and the concomitant health and economics benefits. Currently, 1 million acres of forest treatment annually is the joint federal and state government goal (500,000 acres each). This target of one million acres annually by 2025 is for the purposes of increasing forest health and wildfire resilience in the near term, whereas the 2.3 million acre target is what the Scoping Plan modeling shows would be needed to realize the carbon stock target called for in this Scoping Plan by 2045. By identifying 2.3 million acres of climate action annually in forests, shrublands, and grasslands, this Scoping Plan emphasizes the importance of that 1 million acre annual goal as a milestone on the way to even more action and improved fire and air quality outcomes. The modeling indicates that substantial improvements to statewide fire emissions will occur at levels of action greater than 1 million acres per year. If these levels of action do not occur starting in 2025, the Scoping Plan has quantified climate benefits that will still occur, but to a lesser extent. In terms of fire emissions, compared to the Reference Scenario, 2.3 million acres of forest, shrubland and grassland management will result in a 10% reduction in wildfire emissions. At 1 million acres per year, this decreases to a 2.5% reduction. If 1 million acres per year is also not accomplished, then the emissions and health benefits are even lower.

Climate action in other NWL sectors also generates many co-benefits. Climate action identified in this Scoping Plan is aimed at not only fighting climate change but also improving air quality and public health. The climate action identified in the agricultural sector, for example, should result in decreased pesticide and synthetic fertilizer use. This decrease of synthetic chemical use in agriculture across California also should result in improved public health, especially for communities that work and live in and around agricultural lands. However, as with the forestry sector, the benefits of climate action in agricultural lands and in any other land are dependent on how much implementation takes place. Ramping up increased healthy soils practices and increasing organic agriculture in California will require continued and sustained implementation by private industry and public agencies. For example, achieving the carbon stock outcomes for the annual crops called for in this Scoping Plan would require deployment and maintenance of healthy soils practices on 80,000 additional acres of croplands in California every year between 2025 and 2045. For context, CDFA's Healthy Soils Program, which is an incentive program supporting healthy soils practices, took almost four years of sustained funding to achieve approximately 50,000 acres total under healthy soils practices.[173]

Given the uncertainty around the modeling assumptions, and performance uncertainty as specific policies are fully designed and implemented, estimates associated with the Scoping Plan Scenario are certain to be different than what is ultimately implemented. One way to mitigate for this is to develop policies that can adapt and increase certainty in GHG emissions reductions. Periodic reviews of progress toward achieving the 2030 target and longer term deeper decarbonization, as well as performance of specific policies, also provide opportunities for the state to consider any changes to ensure we remain on course to achieve the 2030 target and carbon neutrality. The need for this periodic review process was anticipated in AB 32, as it calls for updates to the Scoping Plan at least once every five years. For this Scoping Plan, the metrics provided on the rate of deployment of clean fuels and technologies, along with the annual AB 32 GHG Inventory, provide additional information that can be used to assess progress on sectors and aggregate emissions. This is also true of CARB's NWL carbon inventory. An uncertainty analysis for achieving an accelerated 2030 target is provided toward the end of this chapter.

Targeted Evaluations for the Scoping Plan: Oil and Gas Extraction and Refining

To achieve California's air quality and climate goals, we must end our dependence on petroleum. This will not happen overnight. There are about 28 million combustion engine heavy- and light-duty trucks and passenger vehicles in California, and these are almost always replaced at their end of life. The ZEV Executive Order (EO N-79-20) calls for 100 percent new ZEV car sales beginning in 2035 and a 100 percent ZEV medium- and heavy-duty fleet sales by 2045 where feasible. The result is an ongoing, albeit shrinking, pool of vehicles that will continue to require petroleum fuels. To avoid leakage, as called for in AB 32, and to meet that remaining demand for petroleum fuel, a complete phaseout of oil and gas extraction and refining is not possible by 2045. This Scoping Plan assumes a phasedown in both oil and gas extraction as well as petroleum refining in line with the reduction in demand for in-state on-road petroleum fuel demand. Since the transportation sector is the largest source of GHG emissions and harmful local air pollution, we must continue to research and invest in efforts to deploy zero emissions technologies and clean fuels, and to reduce VMT. An assessment of ongoing progress and efforts to reduce

[173] California Department of Food and Agriculture. 2021. *Incentives Program 2017–2020 Summary by the Numbers.* https://www.cdfa.ca.gov/oefi/healthysoils/docs/HSP_Incentives_program_level_data_funded_projects.pdf.

demand for petroleum fuels and of opportunities to phase down oil and gas extraction and refining will be included in the next Scoping Plan update.

In addition to supplying in-state demand, California is a net exporter of gasoline, diesel, and jet fuel. California pipelines supply the Nevada and Arizona regions[174] with approximately 87 million barrels gasoline equivalent of refined products annually.[175] California pipelines deliver approximately 85% of Nevada's and 40% of Arizona's refined product. Most finished fuels flowing from California to Nevada and Arizona are currently produced by California refineries. To manage the phasedown of oil and gas extraction and petroleum refining in California, exports of finished fuels must be considered and factored into that process, in addition to the declining in-state demand. The authorities and considerations related to supply and demand of petroleum fuels span federal, state, and local agencies. If supply of fossil fuels is to decline along with demand, a multi-agency discussion is needed to systematically evaluate and plan for the transition to ensure that it is equitable.

This inter-agency work should also consider related topics, such as the following:

- Direct and indirect job and economic impacts
- Demand for other liquid fuel types such as renewable fuels, and expected volumes
- Legal considerations
- Public health benefits
- Demand and supply strategies for petroleum fuels, including how to avoid short term supply constraints that may impact low-income consumers

Some of these topics were also discussed as part of two studies[176] supported by the California Environmental Protection Agency, which can serve as a starting point for a working group to analyze these questions and develop policy recommendations.

Oil and Gas Extraction

On April 23, 2021,[177] Governor Newsom directed CARB to evaluate the phaseout of oil and gas extraction no later than 2045 as part of this Scoping Plan. As noted above, this Scoping Plan still has some California demand for finished fossil fuels (gasoline, diesel,

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[174] CEC. August 2021. A Primer on California's Pipeline Infrastructure. *Petroleum Watch.* https://www.energy.ca.gov/sites/default/files/2021-08/August_Petroleum_Watch_ADA.pdf.

[175] CEC. March 2020. *Petroleum Watch.* https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.

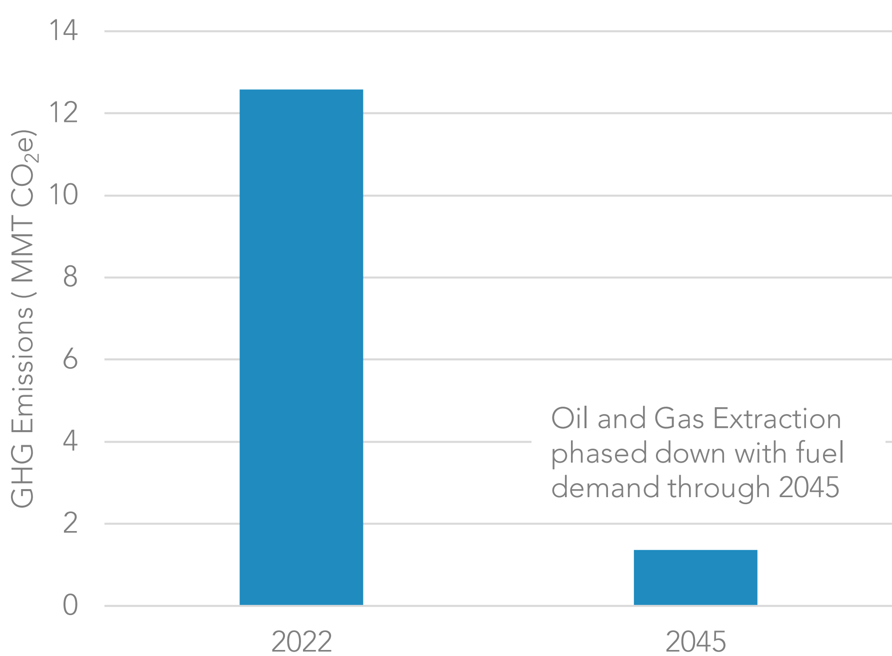
[176] CalEPA. 2021. Carbon Neutrality Studies: https://calepa.ca.gov/climate/carbon-neutrality-studies/.

[177] Governor Newsom. April 23, 2021. Governor Newsom Takes Action to Phase Out Oil Extraction in California. Press Release. https://www.gov.ca.gov/2021/04/23/governor-newsom-takes-action-to-phase-out-oil-extraction-in-california/.

and jet fuel) in 2045. This demand is primarily for transportation, including for sectors that are directly regulated by the state and some that are subject to federal jurisdiction, such as interstate locomotives, marine, and aviation. As discussed more fully below, while significant GHG reductions from oil and gas extraction could be achieved as demand for fossil fuels is reduced due to strategies in this Scoping Plan, it is not feasible to phase out oil and gas production fully by 2045 given this remaining demand.

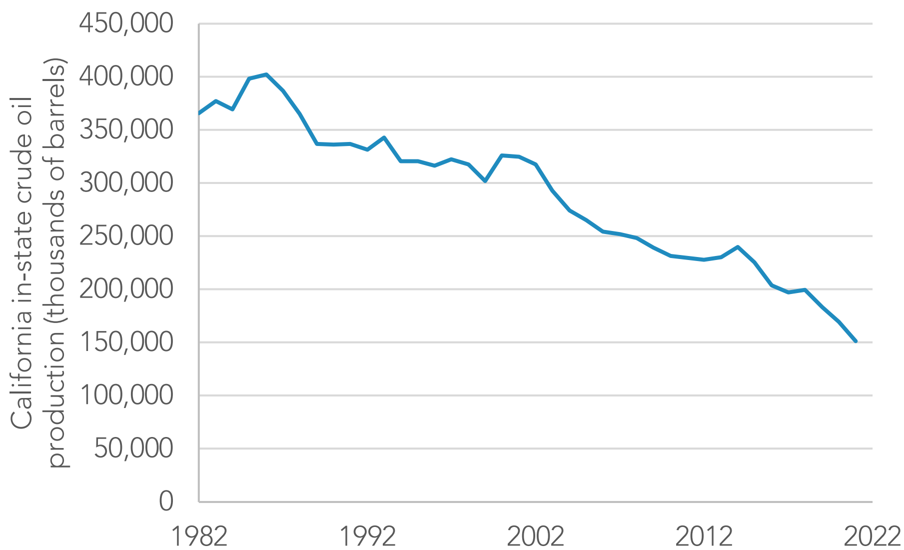
In the Scoping Plan Scenario, with successful deployment of zero carbon fuels and non-combustion technology to phase down petroleum demand, GHG emissions from oil and gas extraction could be reduced by approximately 89 percent in 2045 from 2022 levels if extraction decreases in line with in-state finished fuel demand. If in-state extraction were to be phased out fully, the future petroleum demand by in-state refineries would be met through increased crude imports to the state relative to the Scoping Plan Scenario. AB 32 defines leakage as, “a reduction in emissions in greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state.” AB 32 also requires any actions undertaken to reduce GHGs to “minimize leakage.” Increases in imported crude could result in increased activity outside California to extract and transport crude into California. Therefore, our analysis indicates that a full phaseout of in-state extraction could result in GHG emissions leakage and in-state impacts to crude oil imported into the state. Figure 2-6 compares the 2022 emissions from this sector with the modeled results when the sector is phased down with in-state petroleum demand.

Figure 2-6: Oil and gas extraction sector GHG emissions in 2022 and 2045 when activity is phased down with in-state fuel demand



According to California Energy Commission (CEC) data used in Figure 2-7, the total oil extracted in California peaked at 402 million barrels in 1986. Since then, California crude oil production has decreased by an average of 6 million barrels per year, to about 200 million barrels in 2020. This steadily decreasing production of crude in California is expected to continue as the state's oil fields deplete.

Figure 2-7: California in-state crude oil production[178]



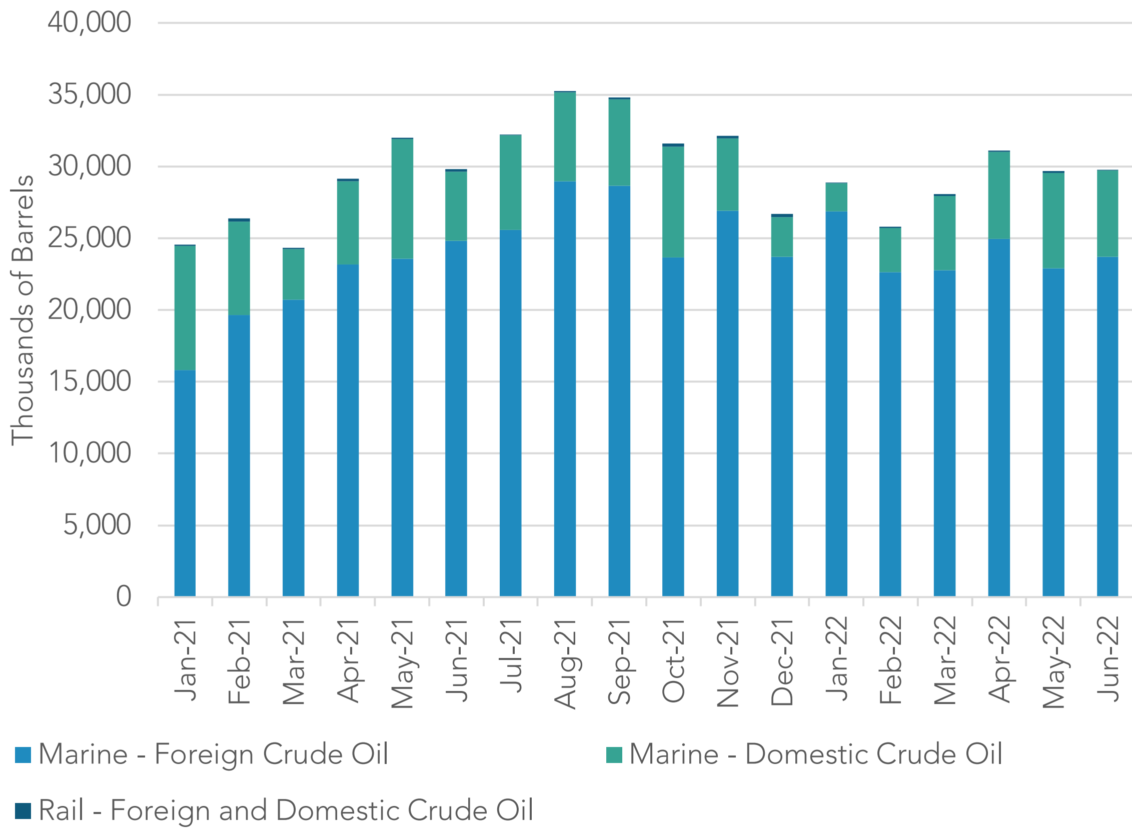
A UC Santa Barbara report estimated that, under business-as-usual conditions, California oil field production would decrease to 97 million barrels in 2045.[179] The business-as-usual model assumed no additional regulations limiting oil extraction in California.

Any crude oil demand by California refineries not met by California crude oil will be met by marine imports of Alaskan and foreign crude.[180] As shown in Figure 2-8, approximately 99 percent of crude imports into California are delivered by marine transportation. The

[178] CEC. No date. Oil Supply Sources to California Refineries. Accessed April 21, 2022. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/oil-supply-sources-california-refineries.
[179] University of California, Santa Barbara. 2021. Enhancing Equity While Eliminating Emissions in California's Supply of Transportation Fuels.
[180] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf, and CEC. 2020. *Petroleum Watch: What Types of Crude Oil Do California Refineries Process?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.

remaining imports occur by rail.[181] There are no pipelines that bring crude oil into California from out of state.[182]

Figure 2-8: Crude oil imports by transportation type[183]



Crude oil delivered by marine tankers is delivered to onshore storage tanks and subsequently to refineries via pipeline. Most crude oil produced in California is delivered to California refineries by pipeline. Using historical trends, any increases in imported crude above historic levels would result in increased deliveries through the marine ports. This increased activity could require more infrastructure to store and move larger volumes of crude to the refineries in state.

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[181] CEC. June 2021. Crude Oil Imports by Transportation Type. Accessed March 16, 2022. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/crude-oil-imports-source.
[182] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.
[183] CEC. June 2021. Crude Oil Imports. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/crude-oil-imports-source.

California refineries import a variety of crude oils to meet refinery needs. California petroleum refineries are generally designed to process relatively heavy crude relative to other U.S. refineries. In 2018, crude inputs to California refineries had an average American Petroleum Institute (API) gravity of 26.18 and an average sulfur content of 1.64 percent. Processing significantly lighter or heavier crude blends would require significant changes to a refinery.[184] Most crude imported from Alaska and the Middle East is relatively light (API gravity > 30) compared to California crude (API gravity < 20).[185] If California crude production is insufficient to meet the demand at California refineries, then California refineries will need access to a similarly heavy source of crude so that the average API gravity of crude remains within their established operating window. South American crude oil imports into California are the heaviest relative to other regions, and therefore they may be the most likely to replace decreased California crude oil supply.[186]

In summary, the modeling indicates that demand for petroleum will persist due to legacy fleets that will not be replaced until end of life. The modeling also shows what the GHG emissions reductions would be if oil and gas extraction activities were phased down in line with the reduction of in-state petroleum demand. Trend data shows that oil and gas extraction already has been on the decline and will continue to decline. It is possible to anticipate the likely regions and types of crude that would be imported to meet in-state petroleum demand if in-state extraction was fully phased out by 2045. Importantly, activity at the ports would increase, and new infrastructure would be needed to store and deliver crude to in-state refineries. And while GHG emissions from this sector would go to zero in our AB 32 GHG Inventory with a full phaseout, emissions related to the production and transport of crude to California might increase elsewhere, resulting in emissions leakage.

As the state continues to reduce demand for petroleum, efforts to protect public health for communities located near oil and gas extraction sites must also continue. In October 2021, Governor Newsom directed action to prevent new oil drilling near communities and

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[184] CEC. 2020. *Petroleum Watch: What Types of Crude?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.

[185] CEC. 2020. *Petroleum Watch: What Types of Crude?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.

[186] CEC. 2020. *Petroleum Watch: What Types of Crude?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.

expand health protections.[187,188] In 2022, the Legislature passed, and the governor signed, SB 1137 to protect communities from existing and any new oil and gas extraction activities through 3,200 foot setbacks.

Petroleum Refining

In the Scoping Plan Scenario CARB modeled a phasedown of refining activity in line with petroleum demand. Meeting petroleum demand means sufficient availability of finished fuel (gasoline, diesel, and jet fuel). Crude is processed at in-state refineries to produce finished fuel. In response to stakeholder requests,[189] this evaluation focuses on the Scoping Plan Scenario, but with an evaluation of a complete phasedown of refinery operations in state.

The Scoping Plan Scenario results in California petroleum refining emissions of 4.5 $MMTCO_2e$ in 2045; a reduction of approximately 85 percent relative to 2022 levels, which is in line with the decline in in-state finished fuel demand.[190] Emissions from refining can be reduced further through the application of CCS technology, as shown in Figure 2-9. If in-state refining is phased down to zero and the demand for the finished fuels produced by that refining persists, imported finished fuels may be needed to meet the remaining in-state demand.[191] The current data shows unmet demand for liquid petroleum transportation fuels would most likely be met by marine imports. A CEC report notes, "The only way for California to receive large amounts of crude and refined products is by marine."[192]

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[187] Office of Governor Gavin Newsom. 2021. California Moves to Prevent New Oil Drilling Near Communities, Expand Health Protections. https://www.gov.ca.gov/2021/10/21/california-moves-to-prevent-new-oil-drilling-near-communities-expand-health-protections-2/?msclkid=6c0da86bc58e11ecb81cf596d4d8a735.

[188] California Department of Conservation Geologic Energy Management Division. October 2021. Draft Rule for Protection of Communities and Workers from Health and Safety Impacts from Oil and Gas Production Operations. https://www.conservation.ca.gov/calgem/Pages/Public-Health.aspx?msclkid=45660232cf2511ecb1c56119097e3b0c.

[189] California Environmental Justice Alliance. October 22, 2021. Comment on 2022 Scoping Plan Update - Scenario Inputs Technical Workshop. https://www.arb.ca.gov/lists/com-attach/68-sp22-inputs-ws-WzhdPlI5AjACW1Qx.pdf.

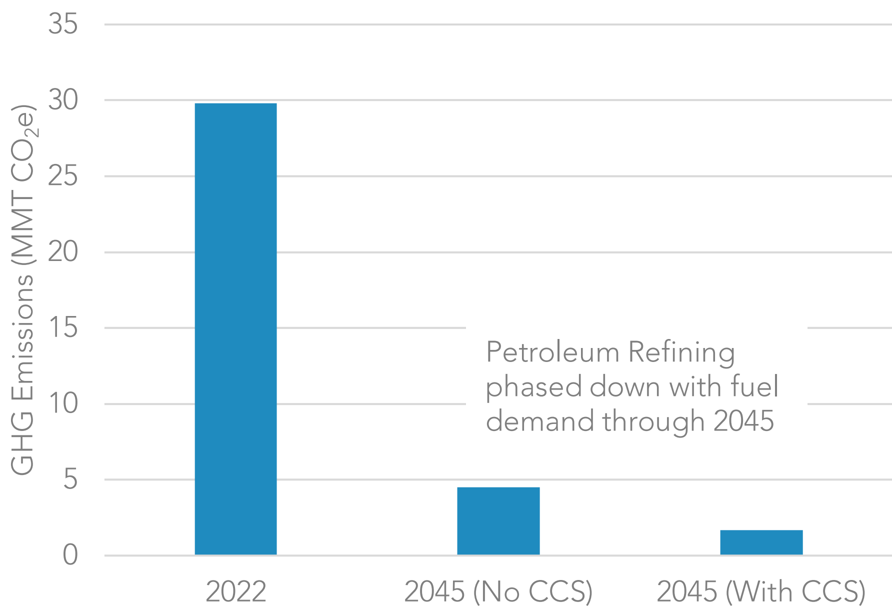
[190] This reduction in demand does not assume any need for ongoing operations to support exports to neighboring states.

[191] If demand assumes an ongoing need to support exports to neighboring states, the residual demand would require a five-fold increase in finished fuel imports.

[192] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.

There are currently no pipelines capable of bringing refined products to the state, and rail imports of refined products have historically made up less than 1 percent of all imports.[193] Significant increases in marine imports would likely require significant reconfiguring, retrofitting, or replacement of crude pipelines and storage tanks at current marine terminals, and possible reconfiguring of existing finished fuel infrastructure to account for changes in volumes and locations of supply points.

Figure 2-9: Petroleum refining sector GHG emissions in 2022 and 2045 (with and without CCS) when activity is phased down with fuel demand



If California's finished fuel demand is not met by continued refining activity in California, the state would need to import finished fuels to meet the ongoing demand. This would likely result in a two- to five-fold increase in the number of finished fuel ship deliveries to marine terminals. Marine tankers delivering refined products are often much smaller than crude oil tankers, so changes in fuel use and emissions cannot be easily estimated from the change in both the type and the number of ship deliveries.[194]

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[193] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.

[194] Personal communication with CEC staff, March 2022; U.S EIA. 2017. *World Oil Transit Chokepoints*. 3. https://www.eia.gov/beta/international/regions-topics.php?RegionTopicID=WOTC.

If refining ceased in California, the rail and marine deliveries currently needed to support both refining processes and the export of waste products, such as petroleum coke, would cease.

In summary, the modeling indicates that demand for petroleum will persist through 2045. The modeling also shows what the GHG emissions reductions would be if refining activities were phased down in line with the reduction in in-state petroleum demand. CCS can further reduce emissions for this sector. Importantly, activity at the ports would increase, and new infrastructure would be needed to store and deliver finished fuel across the state, if in-state refining were fully phased down by 2045. And while GHG emissions from this sector would go to zero in our AB 32 GHG Inventory with a full phaseout, emissions related to the refining and transport of finished fuel to California might increase elsewhere, resulting in emissions leakage.

Progress Toward Achieving the Accelerated 2030 Target

The 2017 Scoping Plan laid out a path to achieving the SB 32 target of at least a 40 percent reduction of GHG emissions below 1990 levels by 2030 that focused on reducing emissions in the state and was technologically feasible and cost-effective, reflecting statutory direction. Many of the programs to achieve the 2030 target increased in stringency beginning January 1, 2021. However, the 2030 target must be increased to help achieve the deeper reductions needed to meet the state's statutory carbon neutrality target specified in AB 1279 and Executive Order B-55-18.

Starting in 2020 and extending into 2022, the COVID-19 pandemic impacts reverberated across the globe in a multitude of ways, including the devastating loss of millions of lives. The pandemic also had a significant impact on GHG emissions by virtue of its impact on global economies and lifestyle changes for Californians, with extended work and school disruptions. Thus, assessing our progress toward meeting our SB 32 target is confounded by the unprecedented nature of the pandemic. Nevertheless, an assessment of progress toward the 2030 target is critical, in particular the accelerated 2030 target called for in this Scoping Plan, since achieving the accelerated 2030 target would make the state well positioned to achieve its carbon neutrality goals and bring critical near-term air quality benefits to address historical and ongoing disparities in access to healthy air. Because there is only one year of data available for this decade, the analysis takes a prospective look using projected emissions over the remainder of this decade.

Estimating GHG emissions in 2030 requires projecting the effect of policies or measures that are currently deployed and undergoing implementation. Table 2-4 shows three distinct estimates of GHG emissions in 2030 that were created at different times and used different modeling approaches.

Table 2-4: Estimates of 2030 GHG emissions

Scenario Description	2030 GHG Emissions ($MMTCO_2e$)
2017 Scoping Plan: the projected outcome from implementing policies identified in the 2017 Scoping Plan that was approved by the CARB Board in December 2017.	320
Reference Scenario: the assessment of current trends and expected performance of policies identified in the 2017 Scoping Plan, as of February 2022, using the PATHWAYS model (E3).	305
Reference Scenario (Rhodium): the analysis of projected emissions from 2021 to 2030 from state and federal policies implemented as of July 2022, including the estimated impact of the Inflation Reduction Act and Advanced Clean Cars II using RHG-NEMS and other Rhodium Taking Stock 2022 methods (https://rhg.com/wp-content/uploads/2022/07/Taking-Stock-2022_US-Emissions-Outlook.pdf).	324

These three estimates of 2030 GHG emissions differ, which is expected. The estimates reflect different outcomes of the current and future impact of policies and measures. They also vary due to fundamental differences in the way these models work. For example, PATHWAYS is an economy-wide, scenario-based GHG accounting tool that tracks energy demands and supplies in line with scenario assumptions and is benchmarked to historical values. RHG-NEMS optimizes both the supply and demand sides of the energy system while factoring in consumer constraints and dynamic economic and energy systemwide feedback. Importantly, while these point estimates give the appearance of certainty and accuracy, there is significant uncertainty in future emissions projections that is documented thoroughly in each of the three emissions scenarios described above. No model can predict the future given unforeseen factors such as notable economic swings and implementation delays for programs. However, the range of emissions estimates provides a useful indication of possible outcomes from successful implementation of policies and measures.

An important source of uncertainty is the impact of delayed implementation of policy measures and market actions. The successful rate of deployment of clean technology and fuels—including consumer adoption patterns, economic recovery from the pandemic, and the permitting and build-out of necessary new assets and reuse of existing assets to produce and deliver clean energy—is essential to reach GHG emission reduction targets. Any delays will only increase GHG emissions in 2030.

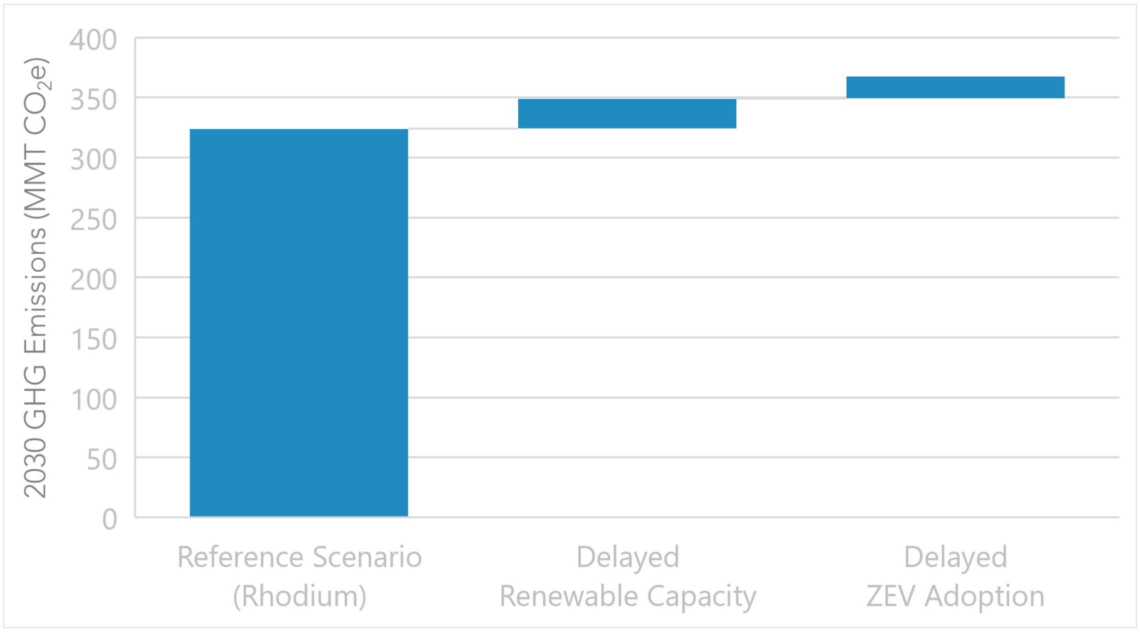
It is important to note that incentives, carbon pricing, and regulations all can result in similar types of responses including, but not limited to:

- Build-out of clean energy and infrastructure
- Deployment of clean technology
- Reduced demand for fossil energy
- Efficiency improvements

As such, the uncertainty analysis discussion focuses on implementation (technology and infrastructure deployment), and not any specific programs or policies. It is successful implementation that must ultimately happen for emissions reductions to be realized.

The uncertainty analysis described in Appendix J (Uncertainty Analysis) quantifies the impact of delayed permitting and building of renewable generation and transmission in the power sector and delayed adoption of ZEVs across all vehicle fleets in the transportation sector. The Reference Scenario (Rhodium) estimates emissions in 2030 to be 324 MMTCO2e. A five-year delay in renewable capacity would increase emissions by 8 percent in 2030 (25 MMTCO2e) relative to the Reference Scenario. If similar delays in clean energy production and deployment occur in other sectors, a larger increase in emissions relative to the reference scenario would be expected, jeopardizing the state's ability to achieve the 2030 target. Similarly, a delay in consumer adoption of zero emission vehicles (LDV, MDV, HDV) would increase emissions by 6 percent in 2030 (19 MMTCO2e) relative to the Reference Scenario. Delays in transitioning to electric equipment and appliances in homes and businesses would also lead to increased emissions in 2030. Figure 2-10 illustrates the impact on projected emissions in 2030 associated with delayed renewable capacity and delayed transportation vehicle electrification.

Figure 2-10: Impact of delayed implementation on 2030 GHG emissions[195]



Appendix J (Uncertainty Analysis) includes additional details on the assumptions and model used for the uncertainty analysis and the risks to achieve the emissions reductions from 2022 to 2030 that are anticipated in the Scoping Plan Reference Scenario. While the analysis focuses on renewable capacity and transportation, the analysis identifies a common set of themes that can impact emissions reductions across economic sectors, including permitting, technology availability, and consumer adoption. The impact of delayed emissions reductions will vary by sector and by the specific policy at risk of delay.

We give these quantitative examples of the impact implementation delays can have on GHG reductions, but almost every economic sector will have the need for permitting to enable at least a 40 percent reduction below 1990 levels. If we consider the increased ambition of the Scoping Plan Scenario, which identifies an accelerated 2030 target, the same types of uncertainty manifest themselves in successful implementation of the Scoping Plan Scenario, with the added need for CCS and CDR and a need to grow other energy sectors such as hydrogen.

[195] The implementation delay scenarios were modeled separately and do not necessarily reflect the combined impact of delayed renewable capacity and transportation vehicle electrification.

Cap-and-Trade Program Update

Since the adoption of the first Scoping Plan in 2008, carbon pricing in the form of a Cap-and-Trade Program has been part of the portfolio to achieve the state's GHG reduction targets, and it will remain critical as we work toward carbon neutrality. This section provides an update on the program and its role in achieving the 2030 target.

The Cap-and-Trade Program first came into effect in 2012, under AB 32, and included declining allowance caps through 2020. In 2017, AB 398[196] was passed by a supermajority in the Legislature and included prescriptive direction on the design of the program from 2021 through 2030. The AB 398 Cap-and-Trade Program came into effect on January 1, 2021, and it included the following changes:

- Doubling of stringency with an annual cap decline of 4 percent per year from 2021–2030
- AB 398 price ceiling
- AB 398 redesigned allowance price containment reserve with two tiers
- AB 398 100 percent leakage assistance factor for industry
- AB 398 lower offset limits: Usage limit cut from 8 percent to 4 percent, and half of offsets must provide direct benefits to California

The reduction in the role of offsets in the program was in recognition of ongoing concerns raised by environmental justice advocates regarding the ability of companies to use offsets for compliance instead of investing in actions on site to reduce GHG emissions that could also potentially reduce criteria or toxic emissions.[197,198] Note that data show the relationship between facility emissions of GHGs and co-pollutants is highly variable by sector and pollutant.[199] Changes to the allowance price containment reserve and the addition of the price ceiling were included to ensure protections against price spikes in the program, while the changes to the leakage assistance factors were to ensure the maximum protection against leakage in the program. The original design of the program included an auction floor price that increases by 5 percent plus inflation each year, and

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[196] Assembly Bill 398 (Garcia, Chapter 135, Stats. of 2017). California Global Warming Solutions Act of 2006: market-based compliance mechanisms: fire prevention fees: sales and use tax manufacturing exemption. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398.

[197] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits Within Disadvantaged Communities*. https://oehha.ca.gov/media/downloads/environmental-justice/impactsofghgpoliciesreport020322.pdf.

[198] The OEHHA report also found that companies that use the most offsets often own the facilities that contribute to local $PM_{2.5}$ exposure. However, there was no causal relationship found to indicate that implementation of the Cap-and-Trade Program was contributing to increases in local air pollution. Also see: CARB. FAQ Cap-and-Trade Program. https://ww2.arb.ca.gov/resources/documents/faq-cap-and-trade-program.

[199] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits Within Disadvantaged Communities*. https://oehha.ca.gov/media/downloads/environmental-justice/impactsofghgpoliciesreport020322.pdf.

that escalation factor is retained in the post-2020 program and is also applied to the allowance price containment reserve and price ceiling. These features, combined with the self-ratcheting mechanism for unsold allowances at auctions,[200] help to ensure the program is able to handle periods of high and low demand for allowances while continuing to ensure a steadily increasing price signal for regulated entities to invest in GHG reduction technologies.

As a result of achieving the 2020 target several years earlier than mandated by law, there are unused allowances in circulation. CARB estimated the amount to be approximately 310 million allowances after the conclusion of the third compliance period (2018–2020).[201] AB 398 had also called for a similar analysis, which was completed in 2018.[202] This bank represents approximately 5 percent of the total number of vintage 2013–2030 allowances issued within the joint market. This bank of allowances can only remain banked if year-over-year the covered emissions are declining by 14 MMT. If the annual decline in actual emissions is less than 14 MMT, regulated entities will need to use the banked allowances to cover their compliance obligations. It is likely that the existing bank of 310 million allowances will be needed over the early part of this decade and will be exhausted by the end of the decade. During the same period, prices for allowances will continue to increase at least 5 percent plus inflation year-over-year, sending a steadily increasing price signal to spur investment in onsite reductions for covered entities.

With the passage of AB 1279, the state has a statutory target to achieve carbon neutrality no later than 2045. This Scoping Plan demonstrates that planning on a longer time frame for the new carbon neutrality target means we must accelerate our near-term ambition for 2030 in order to be on track to achieve our longer-term target. CARB will use the modeling for this Scoping Plan to assess what changes may be warranted to the Cap-and-Trade or other programs to ensure we are on track to achieve an accelerated 2030 target. Since the original adoption of the Cap-and-Trade regulation, the program has been amended eight times through a robust public process. Moreover, then-California Environmental Protection Agency Secretary Jared Blumenfeld testified at a Senate hearing in 2022 that CARB will report back to the Legislature by the end of 2023 on the status of the allowance supply with any suggestions on legislative changes to ensure the number of allowances

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[200] The self-ratcheting mechanism temporarily removes unsold allowances from the market until either sufficient demand manifests for two consecutive auctions and they are incrementally reintroduced at future auctions, or they are permanently removed from general circulation if demand remains low.
[201] CARB. 2022. BR 18-51 Cap-and-Trade Allowance Report. Attachment A. *https://ww2.arb.ca.gov/sites/default/files/cap-and-trade/Allowance%20Report_Reso18_51.pdf*.
[202] CARB. 2018. Staff Report: Initial Statement of Reasons: Proposed Amendments to the Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation. September 4. *https://www.arb.ca.gov/regact/2018/capandtrade18/ct18398.pdf?_ga=2.134288305.1735610122.1664813952-1100516233.1657841496*.

is appropriate to help the state achieve its 2030 target of at least 40% below 1990 levels. As part of that status update, CARB will also provide information on any potential program changes that may be needed to allowance supply to help achieve an accelerated target for 2030 identified in this Scoping Plan as necessary to achieve carbon neutrality no later than 2045. Engaging in this process in 2023 will allow for the consideration of this Scoping Plan, inclusion of additional data points for the second year of operation of the AB 398-designed program (which only came into force in January 2021), and an opportunity to hold public workshops.

It is also worth noting that the COVID-19 pandemic had significant impacts on economic activity in California and elsewhere.[203] Emissions were significantly lower in 2020 due to the impacts of the global pandemic. There is an expectation that emissions will increase as the economy recovers and behaviors continue to shift from the impacts of the ongoing pandemic. As a result, 2020 should be regarded as an outlier in the emissions trends. This scenario of increasing emissions is similar to what happened in the first compliance period for Cap-and-Trade, where the state economy was recovering from the Great Recession and does not correlate to a problem with the structure of this program or other programs that cover emissions related to the manufacturing or transportation sectors. In any assessment of this and other programs, it is essential to consider external factors such as economic activity and availability of zero carbon energy such as hydropower, among others.

To better understand the role of the Cap-and-Trade Program in achieving the 2030 target, Table 2-5 compares the 2030 GHG emissions estimates from the three reference scenarios described in Table 2-4. The 2017 Scoping Plan projection is from the PATHWAYS model for the Scoping Plan Scenario approved by the Board in late 2017. It excludes the contribution of the Cap-and-Trade Program, without any consideration of uncertainty factors (i.e., a characterization of the uncertainty that a given GHG reduction measure included in the 2017 Scoping Plan will actually achieve the GHG reductions it is projected to deliver). The Reference Scenario represents what GHG emissions would look like if we did nothing beyond the existing policies that are required and already in place to achieve the 2030 target; this scenario is based on the recent PATHWAYS modeling, excluding the contribution of the Cap-and-Trade Program, and without any consideration of uncertainty factors. It indicates that GHG emissions will be lower over this decade than originally projected when the 2017 Scoping Plan was approved. The

[203] CARB. November 4, 2021. Mandatory Greenhouse Gas Reporting - 2020 Emissions Year Frequently Asked Questions. https://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/2020mrrfaqs.pdf?_ga=2.264251343.1760432228.1650736660-1644197524.1577749754.

Reference Scenario (Rhodium) which also does not include uncertainty bounds, is the modeling used for the uncertainty analysis above.

Importantly, PATHWAYS is not able to explicitly model a carbon pricing policy, and therefore the Cap-and-Trade Program is not represented in the 2017 Scoping Plan or the Reference Scenario. Carbon pricing is included in RHG-NEMS, which reflects state and federal policies included in the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2022 and the National Energy Systems Model (NEMS), which is the basis for RHG-NEMS.[204]

As detailed in EIA's documentation, California's Cap-and-Trade Program is represented through increased energy prices, which flow across economic sectors.[205] However, many of the emissions covered by the California Cap-and-Trade Program are not energy- and fuel-related emissions. Given that, the energy systems model RHG-NEMS was used to model the impact of California Cap-and-Trade on the energy system. However, RHG-NEMS does not explicitly model the entire program, which includes non-energy related emissions from the industrial, agricultural, waste, and transportation sectors.

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[204] U.S. EIA. 2022. *Summary of Legislation and Regulations Included in the Annual Energy Outlook 2022.* March. https://www.eia.gov/outlooks/aeo/assumptions/pdf/summary.pdf.

[205] U.S. EIA. 2022. Electricity Market Module. https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

Table 2-5: Comparison of 2017 Scoping Plan and two Reference Scenarios

	2030 GHG Emissions ($MMTCO_2e$) (2017 Scoping Plan)	2030 GHG Emissions ($MMTCO_2e$) (Reference Scenario)	2030 GHG Emissions ($MMTCO_2e$) (Reference Scenario-Rhodium)
Reference Scenarios	320	305	324
Gap to Accelerated 2030 Target under the Scoping Plan Scenario (226)[206]	94	79	98

Under the Scoping Plan Scenario, in 2030 California emissions are anticipated to be 48% below 1990 levels. This represents an acceleration of the current SB 32 target of a 40% reduction below 1990 levels. Table 2-5 includes the gap between the different reference scenarios and the accelerated 2030 target achieved under the Scoping Plan Scenario. It also shows that depending on the modeling, there are a range of potential emissions levels in 2030 prior to accounting for the full impact of the Cap-and-Trade Program on emissions. That range is from 305 to 324 $MMTCO_2e$ in 2030. That represents a 19 $MMTCO_2e$ spread, or about 8.4 percent of the accelerated 2030 target of 226 $MMTCO_2e$. Importantly, none of these scenarios includes all of the actions identified in the Scoping Plan Scenario for this Scoping Plan; many of those actions, such as SB 596, CCS, and a more stringent LCFS program, will only begin to happen in this decade, and their contributions toward meeting the accelerated 2030 target are therefore not included in the reference scenarios. The actual emissions for the remainder of this decade will therefore likely be lower than in each of the scenarios in Table 2-5 once policies and regulations are in place to support an accelerated 2030 target. However, the degree of this difference between actual and projected emissions will differ across the modeled reference scenarios.

[206] Table 3 from the 2017 Scoping Plan included a range of 34 to 79 $MMTCO_2e$ for reductions needed from the Cap-and-Trade Program to achieve a 2030 target of 40 percent below 1990 levels.

Regardless of the uncertainty and differences in the models, it is clear additional GHG reductions must happen over this decade to achieve an accelerated 2030 target. This will require an evaluation of all major programs to assess the need to increase their stringency between now and 2030. As the actual reductions from non-Cap-and-Trade Program measures increase, California will be less reliant on the Cap-and-Trade Program to “fill the gap” to meet an accelerated 2030 reduction target. For example, CARB is developing a proposal to increase the stringency of the LCFS program for 2030, the recently adopted Advanced Clean Cars II regulation is more stringent than modeled for the 2030 40 percent target in the 2017 Scoping Plan, and SB 596 requires specific reductions in the cement sector over this decade and beyond. However, we also know we are not on track to achieve the VMT reduction called for in the 2017 Scoping Plan and will need to double down to achieve the even more ambitious target called for in the Scoping Plan Scenario. Also, we will need additional actions over the coming years to reduce short-lived climate pollutants to meet the emission reductions called for in SB 1383.

Collectively, any additional legislation or prescriptive policies for sectors, delays in successful implementation of non-Cap-and-Trade programs and policies, increases in incentive program funding, and delays in economic recovery from the pandemic will continue to affect the role the Cap-and-Trade Program will need to play over this decade to meet the state’s GHG reduction obligations. In summary, the Cap-and-Trade Program must continue to be able to scale across a range of possibilities. With passage of AB 1279 and the need to accelerate the 2030 target, CARB will initiate a public process to utilize the modeling results from this Scoping Plan, specifically the Scoping Plan Scenario, to evaluate and potentially propose changes to the design of the Program, including the annual caps. This process will ensure that the Program supports an increased ambition for 2030 while retaining the ability to scale as other factors, such as changing economic conditions and implementation of non Cap-and-Trade programs, impact the actual emissions at the sources covered by the Program. Any changes to the Program must continue to support a well-designed system that continues to send a steadily increasing price signal, minimizes for leakage, reduces emissions in the covered sectors toward the state’s targets, is cost-effective and technologically feasible, and avoids energy rate spikes. Importantly, the Program should support air quality benefits, especially in overly burdened communities, and not exacerbate existing air quality disparities.

Chapter 3: Economic and Health Evaluations

This chapter provides two approaches for quantifying the economic and health outcomes of the Scoping Plan Scenario. One approach is to consider the combined impact of all measures[207] in a scenario. The other approach is required by AB 197, where each measure within a scenario is evaluated independently. In addition to these two evaluation approaches, this chapter also includes a discussion of the Public Health implications for the Scoping Plan Scenario, an overview of the Climate Vulnerability Metric, and the Environmental Analysis conducted in accord with the California Environmental Quality Act (CEQA).

It is important to note that all of the analyses in this chapter use a variety of data sources, but because the modeling is economy-wide at the state level, none of them produce community specific detail outputs. The AB 32 GHG Inventory Sector analysis relies on PATHWAYS data at the state level that is proportionally applied across all regions of the state to translate changes in state level fuel combustion to local level changes. The NWL analysis similarly utilizes a variety of data sources and a suite of models that produce data that are scaled up to the statewide level. All of the models, except the Wildland Urban Interface (WUI) defensible space model, which is conducted at the county level, create aspatial projections that are not applicable at the community level.

Economic Analysis

As part of the process to develop this Scoping Plan, alternative scenarios that transition energy needs away from fossil fuels and achieve carbon neutrality no later than 2045 were developed. Alternative scenarios that assess the impact of different land management strategies on carbon stocks in NWL were also developed. These alternatives are described in Appendix C (AB 197 Measure Analysis). The following sections describe the Scoping Plan Scenario in terms of direct cost, the economy, employment, and health outcomes.[208]

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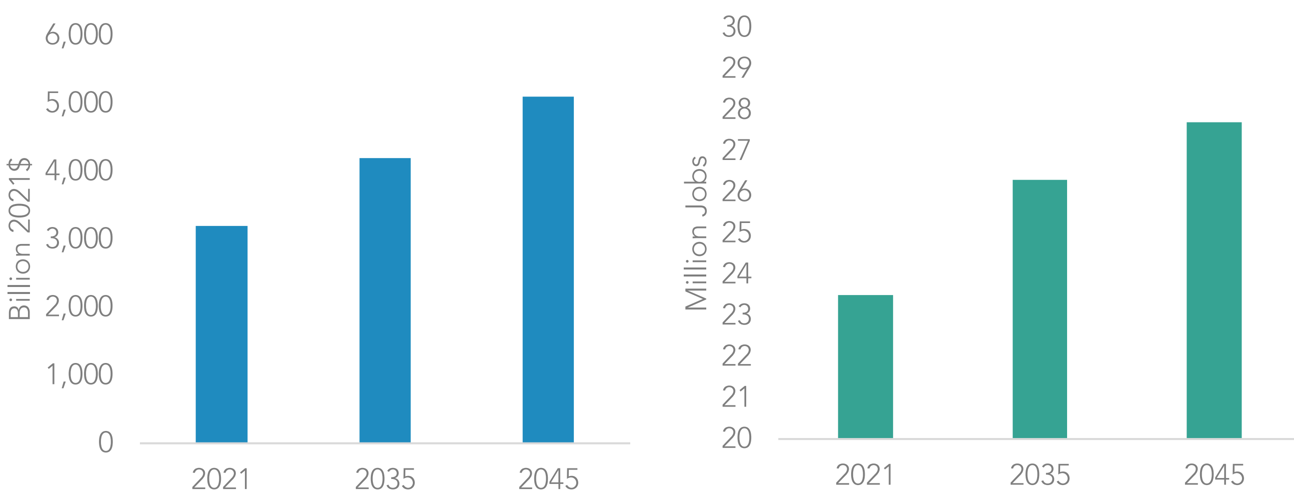
[207] AB 197 calls for the evaluation of "measures." This Scoping Plan treats each action and its variants on stringency as measures for the purposes of this chapter. Appendix C (AB 197 Measure Analysis) lists the measures and corresponding modeling assumptions for each alternative and the Scoping Plan Scenario. The modeling assumptions for the Scoping Plan Scenario are summarized in Table 2-1.

[208] For the Draft 2022 Scoping Plan Update, achieving carbon neutrality in 2035 and 2045 was evaluated. The AB 32 GHG Inventory sector direct cost, the economy, employment, and health outcomes were assessed in those years. Similarly, the Scoping Plan Scenario assessments that are presented in this chapter were made for years 2035 and 2045.

The California economy is growing, and it is projected to continue to grow about 2 percent each year, from $3.2 trillion in 2021 to $5.1 trillion in 2045, as shown in Figure 3-1. Similarly, employment in California is anticipated to grow 0.7 percent per year, from 23.5 million jobs in 2021 to 27.7 million jobs in 2045. It is in this context, termed the *Reference Scenario,* that CARB evaluates the Scoping Plan Scenario in terms of its impact on economic growth and employment. The projections shown in Figure 3-1 were produced by CARB to evaluate the incremental impact of regulations.

Figure 3-1: Projected California gross state product (left) and employment growth (right) from 2021 to 2035 and 2045



Source: California Air Resources Board

Transitioning away from fossil fuels to alternatives and increasing action on NWL will affect employment opportunities, household spending, businesses, and other economic aspects of our lives. Sectors expected to see growth include renewable electricity and hydrogen production, while other sectors may shrink. The deployment of clean technology may require higher upfront costs for things like heat pumps and induction stoves, but those could be offset by energy efficiency savings. Employment and economic development in NWL-related industries and sectors are expected to increase as land management actions increase, especially for the Forestry sector (in which a significant increase is called for under the Scoping Plan Scenario). The net impact of these actions on employment and jobs is presented in this chapter.

Estimated Direct Costs

One key metric is the direct cost, or net investment, reflecting any savings that result from actions. Similar approaches were used to estimate direct costs for the AB 32 GHG Inventory sectors and for the NWL, as described in this section.

AB 32 GHG Inventory Sectors

Transitioning away from fossil fuels requires investment in new equipment and infrastructure throughout the economy. It involves developing the capacity to produce fuels and electricity from renewable sources rather than producing fossil energy. This transition also takes time. One approach is to eliminate combustion of fossil fuels by replacing all equipment in a specified year. Another approach is to establish a future point at which all sales of new equipment rely on alternative energy sources and allow the transition to occur over time as equipment is replaced upon its end of life.

To evaluate the investment required through 2045, the PATHWAYS model was used to represent equipment stock and its turnover to non-fossil fuel alternatives over time. The annualized, incremental cost of infrastructure in excess of the annualized cost of the Reference Scenario[209] was computed for each year from 2022 through 2045. These costs were computed by first taking the absolute cost in each year—which includes both new equipment investment and also expenditures on energy, operations, and maintenance in each year—and then levelizing the costs (in the same way car or house payments are annualized or spread out over time) to arrive at an annualized cost. Fuel savings, and resulting cost savings, associated with changing energy demand—from gasoline to electricity for vehicles, for example—are included as a result of this methodology. Carbon dioxide removal includes DAC technology powered primarily by off-grid solar, BECCS to produce hydrogen or other fuels, and NWL sequestration, as discussed in Chapter 2.[210]

Figure 3-2 shows the stock investment cost, fuel/efficiency savings, and CDR cost. The Scoping Plan Scenario allows end-of-life transition of equipment. The cost of investing in new equipment is partially offset by savings associated with efficiency gains and reduced demand for fuels like gasoline. This is particularly relevant in the transportation sector, which leads to the majority of savings in 2045 in the Scoping Plan Scenario, which models near complete electrification of transport relying only on end-of-life replacement of vehicles. Appendix H (AB 32 GHG Inventory Sector Modeling) includes additional detail on direct costs in each sector and how costs change over time.

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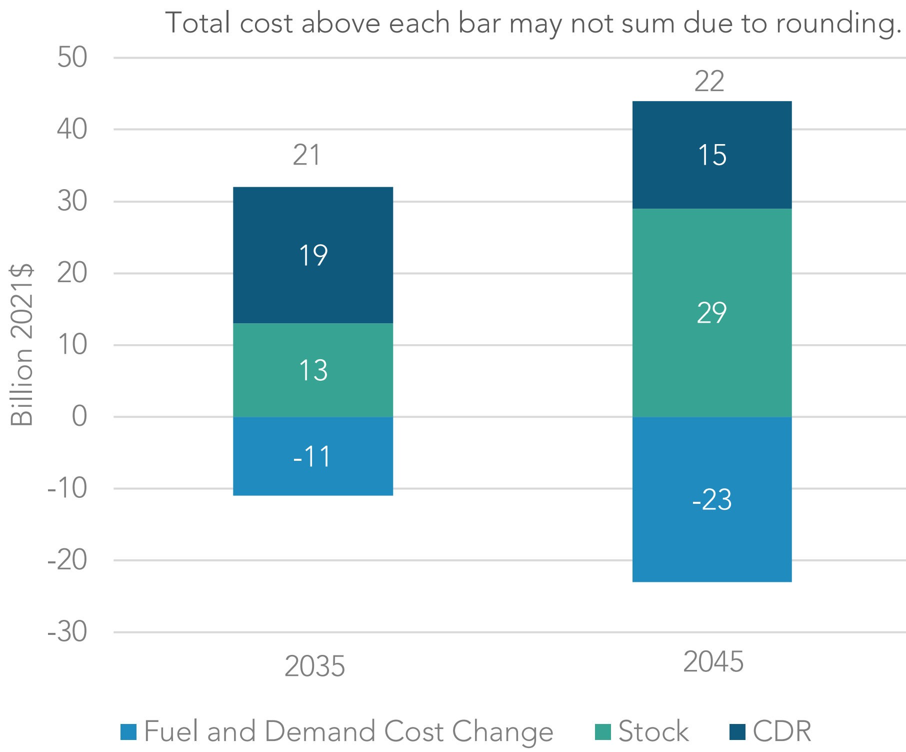
[209] The Reference Scenario described in Chapter 2 and in Appendix H (AB 32 GHG Inventory Sector Modeling) was the basis for the direct cost comparison.

[210] The energy source for DAC is not modeled, but renewable electricity and/or hydrogen produced from electrolysis are zero-carbon options consistent with the carbon neutrality targets in this Scoping Plan. The economic analysis associated the investment in DAC with the solar industry for consistency with the carbon neutrality targets.

Figure 3-2: Cost and savings relative to the growing California economy for the Scoping Plan Scenario in 2035 and 2045 (AB 32 GHG Inventory sectors)



Natural and Working Lands

For NWL, the direct costs of each management strategy were estimated using available academic literature, monitoring and reporting data, survey data, and cost data from existing subsidy programs on the per acre cost of implementing the management strategy. These cost data, in combination with the acreage of each management strategy under the scenarios, provided estimates of the overall direct cost to either the government or the private sector. The direct costs are independent of the policy lever used to implement the action and do not include many important benefits and externalities of the actions. They are assumed to be constant for each scenario and into the future. Avoided or secondary costs, such as those from reductions in wildfire suppression expenses, are not included. Appendix I (NWL Technical Support Document) includes additional direct cost details.

Table 3-1 includes the direct cost estimates for the Scoping Plan Scenario compared to the Reference Scenario.[211] Direct costs for the NWL sector are expected to be significant due to the ambitious level of action for each land type.

Table 3-1: Cost and savings relative to a growing California economy for the Scoping Plan Scenario (NWL)

Measure	Scoping Plan Scenario: Average Direct Annual Cost, 2025–2045 (millions $/year)
Forests / Shrublands / Grasslands	1,780
Annual Croplands	284
Perennial Croplands	4
Urban Forest	4,230
Wildland Urban Interface (WUI)	114
Wetlands	28
Sparsely Vegetated Lands	4
Totals	6,460
Note: Table values may not add to total due to rounding.	

CARB estimates that all jurisdictions, including private landowners, currently spend approximately $4 billion dollars annually on planting, maintenance, sidewalk repair, tree removal, and other expenses related to urban forests, and that reaching the theoretical maximum tree cover would require increasing that spending by a factor of 20. The cost of the Scoping Plan Scenario is predominantly a mix of urban forests and forests, shrubland, and grasslands spending.

[211] The Reference Scenario described in Chapter 2 and in Appendix I (NWL Technical Support Document) was the basis for the direct cost comparison.

Economy and Employment

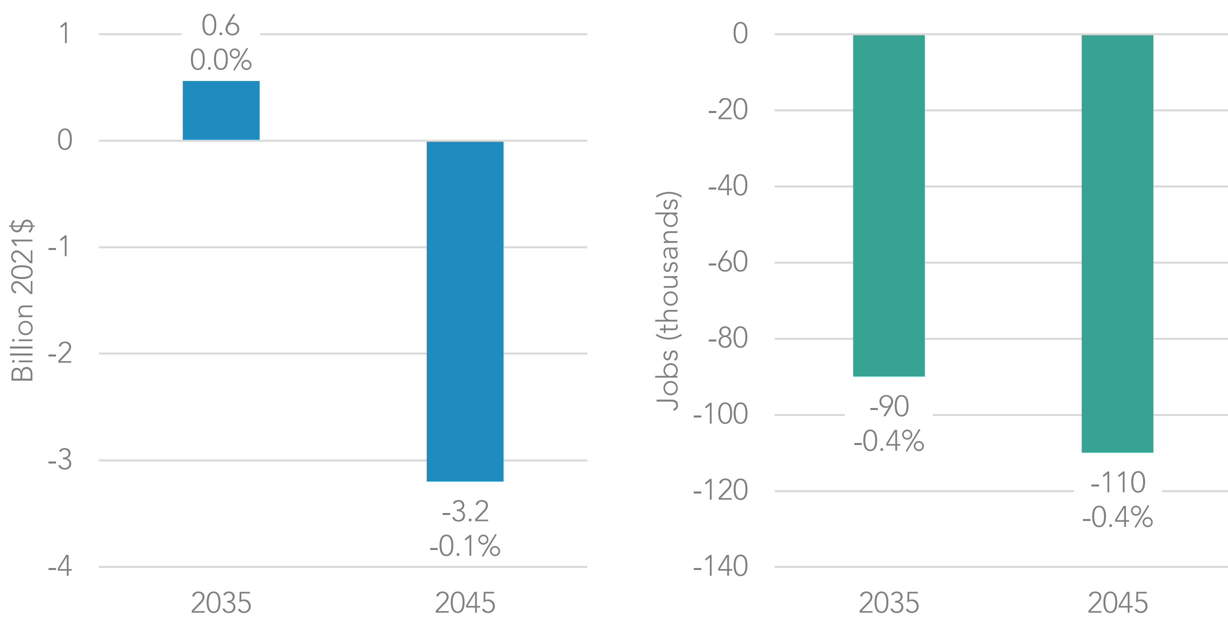
Two different models were used to estimate the overall impact that investing in a transition away from fossil fuels and in our NWL may have on the growing California economy. The transition away from fossil fuels was evaluated using the IMPLAN economic analysis model. The NWL investments were evaluated using the REMI PI+ economic model. These models provide similar outputs relative to the same economic and employment forecasts used to develop a Reference Scenario for use in each model.

AB 32 GHG Inventory Sectors

To estimate the overall impact that investing in a transition away from fossil fuels may have on the California economy, CARB used the IMPLAN model. Additional detail regarding the model, assumptions, and methodology are included in Appendix H (AB 32 GHG Inventory Sector Modeling). The IMPLAN model is a multisector representation of private industries in the U.S. economy that maps economic relationships across industries, households, and governments. This model translates direct costs and savings associated with transitioning away from fossil fuels with indirect effects such as wages, purchases of goods and services, business tax impacts, and supply chain effects. In addition, the induced effects of household purchases, local and import purchases, wages paid, and household tax impacts are estimated. This comprehensive assessment of the interactions between capital investment in fossil fuel alternatives and household purchases provides an indication of the response of the California economy to the Scoping Plan Scenario.

The Scoping Plan Scenario results in a small impact on the Gross State Product (GSP) and employment relative to the Reference Scenario, as shown in Figure 3-3. Economic growth is largely unaffected by the Scoping Plan Scenario in 2035 and slowed by 0.1 percent in 2045. Employment growth is also slowed a small amount, 0.4 percent in 2035 and in 2045, and employment still grows. Assuming annual growth rates of 0.7 percent means there would be more than 193,000 additional jobs in 2045.

Figure 3-3: Gross state product (left) and employment (right) relative to a growing California economy for the Scoping Plan Scenario in 2035 and 2045 (AB 32 GHG Inventory sectors)



California households will see increased costs from the purchase of new capital stock and savings from reduced spending on fuel, as shown in Figure 3-2. Households also will face increased costs associated with CDR, costs associated with energy efficiency measures, and commercial stock purchases—all of which are assumed to be passed directly to consumers. The impact to California households, however, is not limited to these direct costs, as changes in relative prices, employment, and wages can affect household well-being. Personal income, which captures the direct, indirect, and induced impacts, is a metric commonly used to evaluate the impact of policies on households.

Personal income in California is projected to grow from $2.7 trillion in 2021 to $3.6 trillion in 2035 and $4.4 trillion in 2045. Household projections are based on California Department of Finance population projections, which estimate the state's population to grow an average of 0.3 percent each year from 2021 to 2045.[212] California households are projected to increase from 13.3 million in 2020 to 14.6 million in 2035 and 15.0 million in 2045.

[212] California Department of Finance. Population Projections (Baseline 2019). https://dof.ca.gov/forecasting/demographics/projections/.

While the transition away from combustion of fossil fuels will improve air quality for all Californians (and even, more so in overly burdened communities), the economic impacts of the Scoping Plan Scenario are unlikely to be equal among Californians. Table 3-2 presents the change in income by household income group relative to the Reference Scenario in 2035 and 2045. While in 2035 there is a net decrease in personal income of $600 million, total income for households that make less than $100,000 per year is estimated to decline by $4.1 billion dollars, and the total income for households that make more than $100,000 per year will increase by $3.5 billion under the Scoping Plan Scenario. In 2045, although there is no net change in personal income across all California households, results vary by income level. Total income for households that make less than $100,000 per year are estimated to decline by $5.3 billion dollars, while the total income for households that make more than $100,000 per year will increase by $5.3 billion under the Scoping Plan Scenario.

Table 3-2: Income Impacts by California household income group in 2035 and 2045 for the Scoping Plan Scenario (AB 32 GHG Inventory Sectors)

Household Income Group ($2021)	Percentage of 2021 California Households[213]	Change in Income (Billion $2021)	
		2035	2045
Less than $50,000	30	-2.9	-3.9
$50,000 to $100,000	27	-1.2	-1.4
$100,000 to $200,000	28	2.5	4.0
More than $200,000	15	1.0	1.3
Total	100	-0.6	0.0

[213] U.S. Census Bureau. 2021. Household Income. California. https://data.census.gov/cedsci/table?q=california%20income.

In addition to income level, there is likely to be an impact to California personal income that varies based on race/ethnicity.[214] Table 3-3 shows the percentage of households within each income group based on eight race/ethnicity categories identified in the American Community Survey 2021. As shown in Table 3-2, households in lower income groups are anticipated to see negative impacts, while households in higher income groups are anticipated to see positive impacts from the Scoping Plan Scenario in both 2035 and 2045. Because more than 60% of households in the race/ethnicity categories of Hispanic, Black alone, Native Hawaiian (HI) or Pacific Islander, American Indian or Alaskan Native, Other, and Two or More make less than $100,000 per year, these populations generally are likely to experience reduced income. White and Asian households will generally experience both increased and decreased income because these households are distributed more evenly across all four income groups.

The state recognizes the need to ensure that accessibility to clean technology and energy do not further exacerbate health and opportunity gaps for low-income households and communities of color. The Climate Change Investments program exceeds the statutory minimums to invest in projects to benefit disadvantaged communities.[215] Utilities implement programs for reduced energy bills for qualifying low-income customers.[216] There are also resources for waste and water bills that leverage federal funds.[217] CARB also coordinated with the CPUC to ensure that the Climate Credit[218] funded from the sale of Cap-and-Trade allowances provided to utilities on behalf of ratepayers is credited equally to households and not based on how much energy is used. These are just a few examples of how the state is designing and implementing programs to avoid increasing existing disparities. The state must continue to find ways to relieve economic burdens on low-income households.

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[214] The number of households in each bracket and the race/ethnicity categories are from American Community Survey 2021 results. Population changes through 2035 and 2045 are not forecast. U.S. Census Bureau. 2021. Household Income. California. https://data.census.gov/cedsci/table?q=california%20income.

[215] CARB. Priority Populations — California Climate Investments. https://www.caclimateinvestments.ca.gov/priority-populations.

[216] CPUC. CARE/FERA Program. https://www.cpuc.ca.gov/lowincomerates/.

[217] California Department of Community Services and Development. Low Income Household Water Assistance Program. https:/www.csd.ca.gov/lihwap.

[218] CPUC. California Climate Credit - FAQ. https://www.cpuc.ca.gov/industries-and-topics/natural-gas/greenhouse-gas-cap-and-trade-program/california-climate-credit/california-climate-credit---faq.

Table 3-3: Percentage of households in each race/ethnicity category by household income group

Household Income Group ($2021)	Households in Income Group (%)							
	White Not Hispanic	Hispanic	Black Alone	Asian Alone	Native HI or Pacific Islander	American Indian or Alaskan Native	Other	Two or More
Less than $50,000	26	35	45	25	30	35	37	32
$50,000 to $100,000	25	32	27	21	31	33	33	30
$100,000 to $200,000	29	25	21	30	30	26	24	27
More than $200,000	19	7	7	24	9	7	5	11

Natural and Working Lands

The macroeconomic impact of the NWL scenario was evaluated separately in the REMI PI+ model. For the Scoping Plan Scenario, the macroeconomic impact was modeled by assuming that economic activity in the relevant industries grows in proportion to the proposed implementation spending in that industry. All funds for implementing the actions were assumed to be sourced from within the state. For urban forests, the funds were modeled as being sourced from a combination of state government and private property owners in proportion to the current estimated private/public spending ratio. For all other actions, funds were assumed to be sourced from the state government. In each modeled scenario, government spending and income to property owners were reduced relative to the Reference Scenario in proportion to the annual costs of implementation. None of the proposed spending was modeled as being sourced from increased taxes. Additional details on the methodology for evaluating macroeconomic impacts are in Appendix I (NWL Technical Support Document).

While the macroeconomic model does count the increased economic activity in the affected industries as part of GSP, it does not quantify many of the important economic, health, and environmental benefits that would occur if these actions were implemented. While these benefits—like the reduced use of pesticides, value of urban trees, and increased recreational opportunities—would be very significant, they are outside the scope of the macroeconomic model.

The macroeconomic model also makes projections about the total level of employment in the state. The model forecasts that the Scoping Plan Scenario, which greatly increases the level of NWL management actions, channels economic activity toward related industries and would lead to a slight increase in total employment. (Table 3-4). While the model does aim to accurately represent many labor market dynamics, including adjustments of wages and migration rates, it does not account for many costs that might be associated with dramatically scaling up employment in a particular industry, such as the cost of job training.

Table 3-4: Gross state product and employment relative to a growing California economy for the Scoping Plan Scenario in 2035 / 2045 (NWL)

	Scoping Plan Scenario (%)
Gross State Product	0.00 / 0.01
Employment	0.12 / 0.10
Personal Income	-0.04 / -0.04
Personal Income per Capita	-0.04 / -0.14

Health Analysis

Air quality is affected by pollutant emissions from various processes associated with energy systems, including the combustion of fossil fuels, as well as the combustion of vegetation biomass from NWL during wildfires. Pollutants that are important contributors to degraded air quality in California include nitrogen oxides (NO_x), particulate matter (PM), reactive organic gases (ROG), and others. Further, in the atmosphere these pollutants are transported away from the locations of the emissions by wind and other phenomena, and undergo chemical reactions that result in the formation of new pollutants such as ground-level ozone and fine particulate matter ($PM_{2.5}$). Both primary (emitted) and secondary (formed) pollutants are important from a public health standpoint and contribute to the incidence of air pollution-related mortality and disease within California populations. Measures focused on GHGs do not incorporate specific targets to reduce emissions of $PM_{2.5}$ or air toxics like benzene. These co-pollutants, which are emitted from many of the same pollution sources as GHGs, affect local air quality and pose known risks to public health, such as the risk of asthma and cardiovascular disease. Generally, for stationary sources, certain harmful pollutants are regulated via local rules and regulations that are reflected in permits for stationary sources and are enforced by local air districts, with CARB also regulating air toxics contaminants from stationary sources with the air districts.

AB 32 GHG Inventory Sectors

To assess health impacts for the AB 32 GHG Inventory sectors, an integrated modeling approach was used to quantify and value the air pollution-related public health benefits of the Scoping Plan Scenario relative to the Reference Scenario. Additional details about the models, assumptions, and methodology are included in Appendix H (AB 32 GHG Inventory Sector Modeling). Using output from the PATHWAYS model, projections of pollutant emissions to 2045 were developed for stationary, area, and mobile source emissions using a detailed base year CARB pollutant emissions inventory. Further, the emissions are processed, including for where and when they occur in California, using the Sparse Matrix Operator Kernels Emissions (SMOKE) model. For example, on-road vehicle emissions were allocated along existing roadways, and refining emissions were assigned to the locations of existing refineries. It should be noted that the emissions projections represent statewide average reductions associated with high-level assumptions about alternative fuels and technologies. For example, emissions occurring from refineries to produce liquid fuels are reduced in line with petroleum demand. This reduction is applied equally to all refineries in the Scoping Plan Scenario and does not specify individual facility responses to changing demand. Similarly, the Scoping Plan Scenario does not specify which refineries transition to biofuel production or where new electricity generation facilities are built.

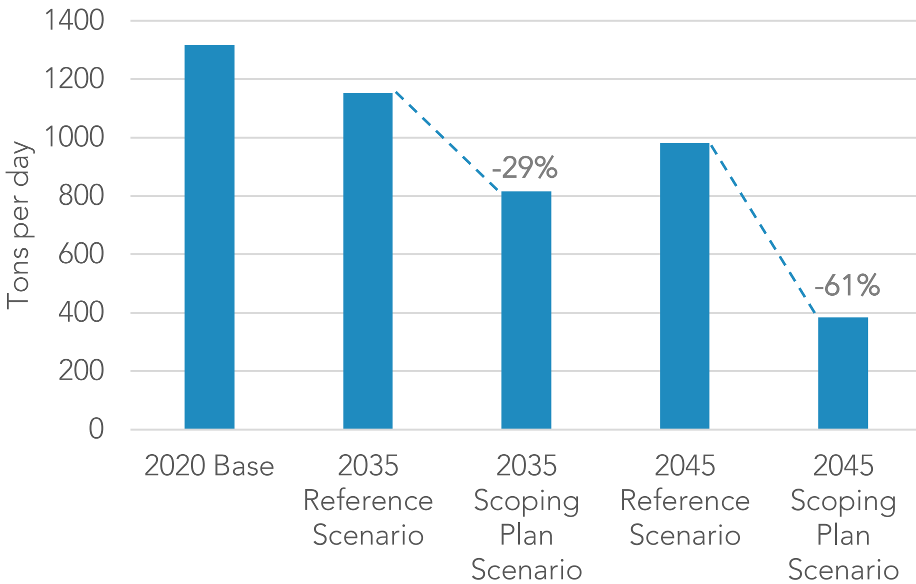
Next, emission changes were translated into impacts on atmospheric pollution levels, including ground-level ozone and $PM_{2.5}$, via an advanced photochemical air quality model called the Community Multiscale Air Quality (CMAQ) model, which accounts for atmospheric chemistry and transport. A comprehensive assessment of how pollutant concentrations are impacted throughout the year was achieved by simulating all months in 2035 and 2045 for the Scoping Plan Scenario.[219] Health benefits were estimated using the U.S. EPA's environmental Benefits Mapping and Analysis Program (BenMAP) model to translate pollutant changes into avoided incidence of mortality, hospital admissions, emergency room visits, and other outcomes as a result of reduced exposure to ozone and $PM_{2.5}$. These outcomes are associated with an economic value in order to aggregate health impacts.

The Scoping Plan Scenario shows a substantial reduction in pollutant emissions relative to the Reference Scenario, including NO_x, $PM_{2.5}$, and ROG. Reductions in NO_x are shown in Figure 3-4. Even under a business-as-usual trajectory, emissions are reduced from present levels by 26 percent in 2045 in the Reference Scenario, demonstrating the impact of current regulations and trends in energy sectors. The Scoping Plan Scenario further reduces NO_x

[219] This annual approach differs from the episodic modeling approach applied to the Proposed Scenario and Alternatives in the Draft 2022 Scoping Plan Update. Appendix H (AB 32 GHG Inventory Sector Modeling) describes both approaches.

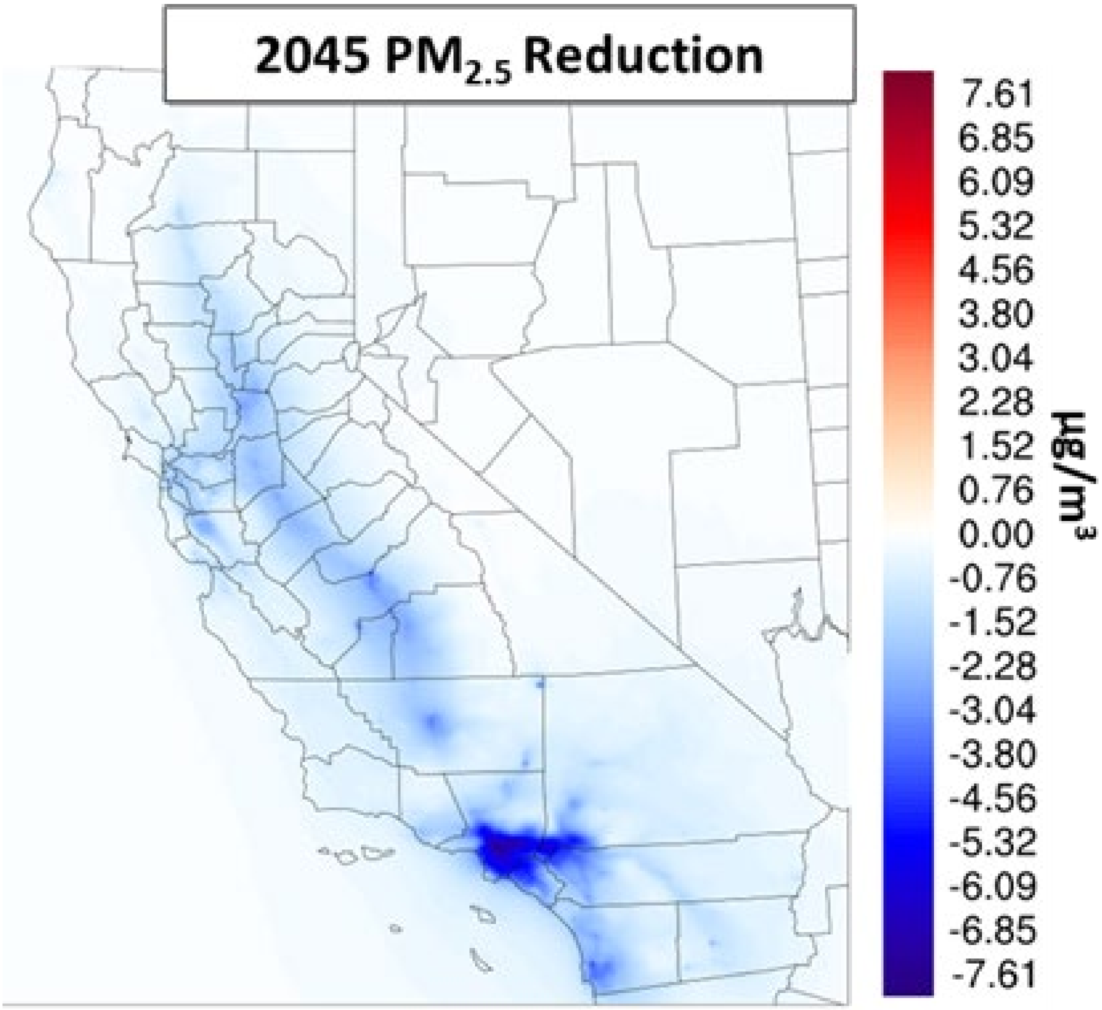
emissions from the Reference Scenario by 29% in 2035 and 61% in 2045. Emission reductions occur throughout the state with particular prominence in urban areas, including the South Coast Air Basin, due to the large presence and activity of emission sources. Appendix H (AB 32 GHG Inventory Sector Modeling) contains additional information about the pollutant emissions modeling and results.

Figure 3-4: Illustration of NOx emission reductions from current levels for the Reference Scenario and the Scoping Plan Scenario (AB 32 GHG Inventory sectors)



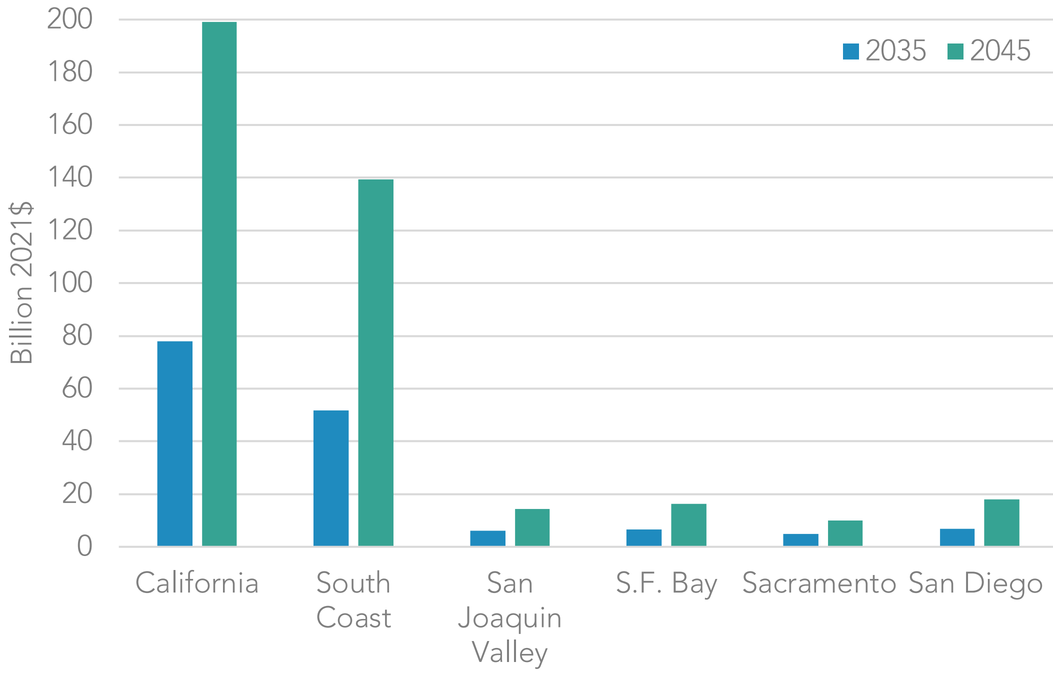
The emission reductions achieve important improvements in air quality throughout California, including reductions in the levels of ozone and $PM_{2.5}$. Reductions in annual $PM_{2.5}$ levels are shown in Figure 3-5. The greatest reductions are evident in Southern California, the San Joaquin Valley, the San Francisco Bay area, and the Greater Sacramento area due to the large presence and activity of emission sources, meteorology, topography, and others. To highlight the extent of the air quality improvements: reductions reach nearly 8 micrograms per cubic meter (μg/m^3) in 2045 and lead to 76% fewer exceedances of the health-based National Ambient Air Quality $PM_{2.5}$ standard of 12 μg/m^3. Similarly, ozone improvements reach 19 parts per billion (ppb) and yield 62% fewer exceedance events. Furthermore, the locations of improvements carry important implications for human health as these areas support large urban populations and generally experience the most degraded ozone and $PM_{2.5}$ pollution. Appendix H (AB 32 GHG Inventory Sector Modeling) provides details regarding the atmospheric modeling and results, including differences in ozone and $PM_{2.5}$.

Figure 3-5: Difference in annual average $PM_{2.5}$ ($\mu g/m^3$) in the Scoping Plan scenario relative to the Reference scenario in 2045 (AB 32 GHG Inventory sectors)



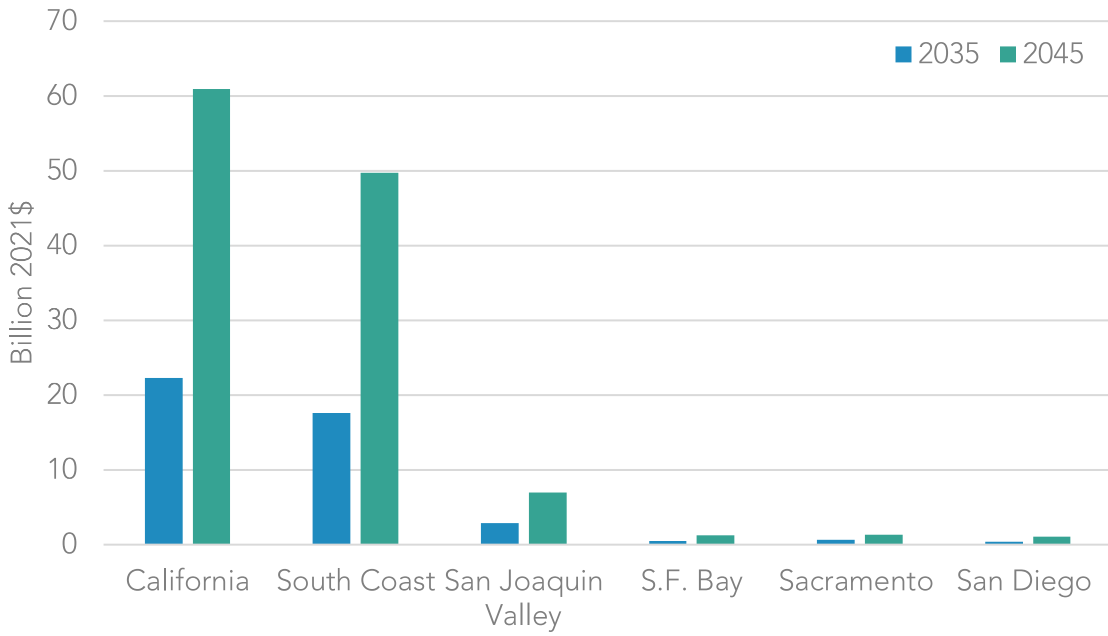
Notable health benefits representing the economic value of the avoided incidence of health effects are associated with the Scoping Plan Scenario. In total, the benefits reach $78 billion in 2035 and $199 billion in 2045, as shown in Figure 3-6. Populations in Southern California benefit the most due to preexisting air quality challenges, significant emission sources and activity, and the presence of a large, dense urban population. Additional details regarding the health impact assessment are provided in Appendix H (AB 32 GHG Inventory Sector Modeling).

Figure 3-6: Total health benefits estimated from air quality improvements in the Scoping Plan Scenario (AB 32 GHG Inventory sectors)



Furthermore, these benefits accrue within socially and economically disadvantaged communities identified by CalEnviroScreen, where they are most needed. Total health benefits within census tracts identified as disadvantaged communities using CalEnviroScreen 4.0 reach $22 billion in 2035 and $61 billion in 2045, as shown in Figure 3-7. Similarly to the statewide health benefits, the largest share of benefits occurs within disadvantaged communities in Southern California. Additional information on the health benefits within disadvantaged communities can be found in Appendix H (AB 32 GHG Inventory Sector Modeling).

Figure 3-7: Disadvantaged community health benefits relative to the Reference Scenario for the Scoping Plan Scenario (AB 32 GHG Inventory sectors)

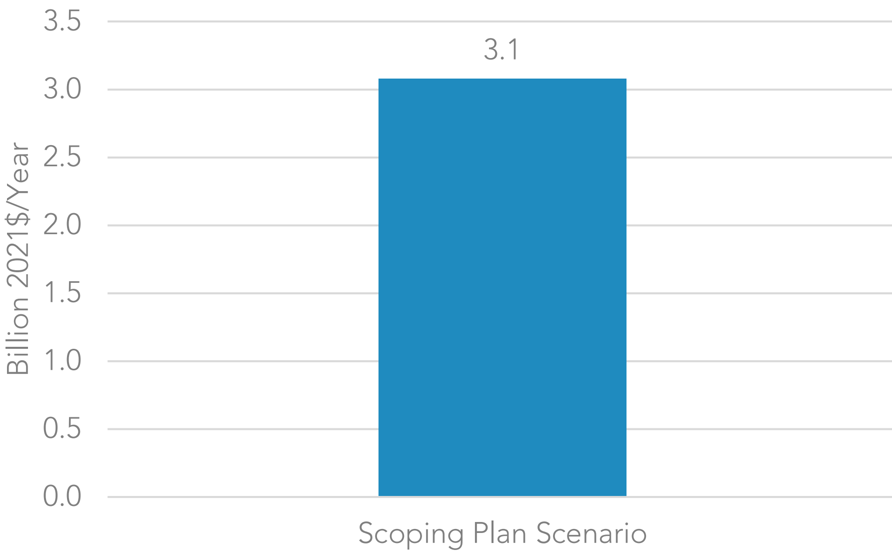


Natural and Working Lands

For NWL, health benefits were evaluated based on projected $PM_{2.5}$ wildfire emissions on forests, shrublands, and grasslands, discussed in the AB 197 Measure Analysis section of the chapter that follows.[220] The health endpoints for the Scoping Plan Scenario and in Appendix I (NWL Technical Support Document) for the alternative scenarios were the basis for the estimated health benefits shown in Figure 3-8. Health benefits were derived from the preliminary University of California, Los Angeles (UCLA) study that estimated annual health impacts and associated costs from California's wildfires from 2008–2018. Additional details are included in Appendix I (NWL Technical Support Document). These costs were applied to the health endpoints discussed in the AB 197 Measure Analysis section of the chapter.

[220] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11, N14. *finalejacrecs.pdf (arb.ca.gov)*.

Figure 3-8: Total average annual health benefits relative to the Reference Scenario for the Scoping Plan Scenario (NWL)



As health impacts analyzed here are driven by wildfire emissions, the health benefits for the Scoping Plan Scenario are directly related to the amount of forest, shrubland, and grassland management action. These management actions reduce vegetation fuels and, as a result, wildfire activity. The Scoping Plan Scenario increases the amount of these management actions, reducing wildfire emissions and avoiding incidence of emission-related health effects. The health benefits, or economic value of the avoided incidence of health effects, correspondingly increase with an increasing management implementation rate. Additional details are included in Appendix I (NWL Technical Support Document).

Estimated health benefits do not include the direct impact of wildfires on injuries, deaths, or mental health, nor the indirect costs of lost ecosystem benefits to wildfire. Additional direct health costs may result from wildfire that would likely increase the health benefits from increased forest, shrubland, and grassland management to reduce wildfire activity. Nonetheless, the conservative health benefits under the Scoping Plan Scenario are estimated to be $3.1 billion per year relative to the Reference Scenario for all NWL actions identified in the Scoping Plan Scenario.

AB 197 Measure Analysis

This section provides estimates for information associated with GHG emissions reduction measures evaluated in this Scoping Plan.[221] These estimates, which were developed as part of the process for meeting the requirements of AB 197 (E. Garcia, Chapter 250, Statutes of 2016), provide information on the relative impacts of the evaluated measures when compared to each other. To support the design of a suite of policies that result in GHG reductions, air quality co-benefits, and cost-effective measures, it is important to understand if a measure will increase or reduce criteria pollutants or toxic air contaminant emissions, or if increasing stringency at additional costs yields few additional GHG reductions. To this end, AB 197 requires the following for each potential emissions reduction measure evaluated in any Scoping Plan update:

- The range of projected GHG emissions reductions that result from the measure;
- The range of projected criteria pollutant emission reductions that result from the measure; and
- The cost-effectiveness, including avoided social costs, of the measure.

The following sections describe the evaluation of measures for the AB 32 GHG Inventory sectors and NWL. For the purposes of this Scoping Plan, the identified emissions reduction measures for the analysis required by AB 197 are actions grouped by sectors where several policies and programs are expected to overlap. This approach reflects the most granular feasible analysis given the modeling tools available,[222] the overlap and interaction effects among policies and incentive programs, the longer planning horizon used for this Scoping Plan compared to previous efforts, and the scale of transition needed to achieve carbon neutrality. To implement this Scoping Plan, dozens of individual regulations, policies, and incentive programs are anticipated that work together to drive down emissions across all economic sectors and support actions. Every specific policy or incentive program that could contribute to the deployment of clean technology and energy called for in this plan may overlap in ways that make it infeasible to tease out those policies and programs' individual effects with any reasonable degree of certainty. For example, in the transportation sector, deploying ZEVs and reducing driving demand may be achieved through a combination of the implementation of new or existing regulations, fuels programs, incentive programs, and VMT reduction initiatives that can each contribute to reductions in emissions for the sector. It is not feasible to isolate each sub action from each other at this time in terms of the share of contribution to total reductions. The estimated emission

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[221] AB 197 calls for the evaluation of "emission reduction measures." This Scoping Plan treats each action and its variants on stringency as emission reduction measures for the purposes of this chapter. Appendix C (AB 197 Measure Analysis) lists the measures and corresponding modeling assumptions for each alternative.

[222] See Appendix H (AB 32 GHG Inventory Sector Modeling and Appendix I (NWL Technical Support Document).

reductions, health endpoints, and costs by measure for the Scoping Plan Scenario are presented in this chapter, and the corresponding estimates for the Proposed Scenario and Alternatives 1, 2, and 4 are included in Appendix C (AB 197 Measure Analysis).

Because many of the measures and underlying assumptions interact with each other, isolating the GHG emission reductions, corresponding changes to fuel combustion, and associated cost of an individual measure is analytically challenging. Each measure is evaluated by examining the change in fuel combustion, cost, and emissions associated with just that measure using the PATHWAYS model. The difference between the Scoping Plan Scenario and the Reference Scenario is estimated for each measure. Starting from the Scoping Plan Scenario, the modeling assumptions for an individual measure are reverted to the Reference Scenario values, resulting in GHG reductions, changes to fuel combustion, and costs (or savings). This approach does not reflect interactions between sectors in PATHWAYS that influence the results for each complete alternative, presented earlier. As such, the values associated with each measure should not be added to obtain an overall scenario estimate.

To arrive at the 2045 target for NWL, CARB modeled the ecological impact that climate smart land-based management strategies (suites of on-the-ground actions, or *treatments,* that are used across the landscape to manipulate an ecosystem) will have on ecosystem carbon; and whenever possible, additional co-benefits from those actions. The Scoping Plan Scenario incorporates a set of land management actions at varying scales of implementation for each land type to achieve the GHG emission reductions. Each land type, and its associated management actions, was considered a measure for this analysis. For modeling individual landscapes and management actions, CARB used a suite of models. The complexity of these models varies by land type, depending on the existing science, data, and availability of existing models to use. Appendix I (NWL Technical Support Document) provides detailed modeling assumptions for each NWL type. The estimated emission reductions, health endpoints, and costs by measure under the Scoping Plan Scenario for each NWL type are presented in this chapter, and the corresponding estimates for the Proposed Scenario and NWL Alternatives 1, 2, and 4 are included in Appendix C (AB 197 Measure Analysis).

Estimated Emissions Reductions

Both GHG emissions reductions and emissions of criteria air pollutants were evaluated for the AB 32 GHG Inventory sectors and for NWL. The methods and results are described in this section.

AB 32 GHG Inventory Sectors

In the absence of having direct modeling results for criteria pollutant estimates from PATHWAYS, CARB estimated criteria pollutant emissions impacts by using changes in fuel combustion in units of exajoules from PATHWAYS and emission factors in units of tons per exajoule to estimate the change in emissions in tons per year. Emission factors from a variety of sources for each sector were utilized, including but not limited to CARB's mobile source emissions models,[223] U.S. EPA's AP 42 Emissions Factors,[224] and the South Coast Air Quality Management District's (AQMD's) District Rules.[225] These emission factors were applied to fuel burn change by fuel type, sector, equipment type, and process, where applicable. Statewide annual average emissions were estimated for three criteria pollutants: NO_x, $PM_{2.5}$, and ROG.

Table 3-5 provides the estimated GHG and criteria pollutant emission reductions for the measures in the Scoping Plan Scenario in 2035 and 2045. The other alternatives are presented in Appendix C (AB 197 Measure Analysis). Based on the estimates below, these measures are expected to provide air quality benefits. The estimates provided in this chapter and Appendix C (AB 197 Measure Analysis) are appropriate for comparing across alternatives considered for the development of this Scoping Plan, but they are not precise estimates.

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[223] CARB. MSEI - Modeling Tools. https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/msei-modeling-tools.
[224] U.S EPA. AP-42: Compilation of Air Emissions Factors. https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors.
[225] South Coast AQMD. South Coast AQMD Rule Book. https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book.

Table 3-5: Estimated GHG and criteria pollutant emission reductions relative to the Reference Scenario for the Scoping Plan Scenario in 2035/2045 (AB 32 GHG Inventory sectors)

Measure	GHG Reductions ($MMTCO_2$)	NOx Reductions (Short Tons/Year)	$PM_{2.5}$ Reductions (Short Tons/ Year)	ROG Reductions (Short Tons/Year)
Deploy ZEVs and reduce driving demand	-46 / -84	-51,620 / -122,806	-2,008 / -6,506	-18,967 / -30,410
Coordinate supply of liquid fossil fuels with declining California fuel demand	-25 / -30	-1,601 / -2,707	-978 / -1,705	-747 / -1,323
Generate clean electricity	-8 / -31	-92 / -1,555	-177 / -1,382	-41 / -425
Measure	**GHG Reductions ($MMTCO_2$)**	**NOx Reductions (Short Tons/Year)**	**$PM_{2.5}$ Reductions (Short Tons/ Year)**	**ROG Reductions (Short Tons/Year)**
Decarbonize industrial energy supply	-9 / -22	-21,172 / -34,876	-1,188 / -2,527	-3,710 / -6,298
Decarbonize buildings	-14 / -35	-8,105 / -94,455	-826 / -6,877	-1,093 / -8,109
Reduce non-combustion emissions[a]	-0.41 / -0.52 ($MMTCH_4$)	N/A	N/A	N/A
Compensate for remaining emissions	-25 / -64	N/A	N/A	N/A

[a] Methane emissions reductions are reported for this measure.

The measures related to reducing non-combustion emissions and compensating for the remaining emissions do not include changes to fuel combustion, and therefore are not associated with changes to air pollutants. Biomethane combustion is captured in measures that reduce combustion of fossil gas, such as decarbonizing industrial energy supply and buildings.

Natural and Working Lands

NWL ecosystems naturally vary between being a source and a sink for carbon over time. The NWL ecosystem carbon stock changes projected through mid-century by the suite of models were used to estimate net emissions or emissions reductions relative to the Reference Scenario. These changes in carbon stocks were affected by projected climate change, the implementation of management actions under the various scenarios, land conversion, and (for forests, shrublands, grasslands) wildfire. Each NWL type was evaluated, and an overview of all NWL is presented in Table 3-6. More detailed results for each NWL type can be found in Appendix C (AB 197 Measure Analysis).

Table 3-6: Estimated average annual GHG and criteria pollutant emission reductions relative to the Reference Scenario for the Scoping Plan Scenario from 2025–2045 (NWL)

Measure	GHG Reductions ($MMTCO_2e$/year)	$PM_{2.5}$ Reductions (MT/Year)
Forests/Shrublands/Grasslands	-0.12	-17,500
Annual Croplands	-0.25	N/A
Perennial Croplands	-0.01	N/A
Urban Forest	-1.29	N/A
Wildland Urban Interface (WUI)	0.75	N/A
Wetlands	-0.43	N/A
Sparsely Vegetated Lands	<-0.01	N/A

Fine particulate wildfire emissions were evaluated for forests, shrublands, and grasslands only. Wildfire emissions decreased under the Scoping Plan Scenario compared to the Reference Scenario. The Scoping Plan Scenario's higher level of management actions that reduce tree or shrub densities, protect large trees, reintroduce fire to the landscape, and diversify species and structures result in greater reductions in wildfire emissions.

Estimated Health Endpoints

Climate change mitigation will result in both environmental and health benefits. This section provides information about the potential health benefits of the Scoping Plan Scenario. Health benefits are primarily the result of reduced $PM_{2.5}$ pollution, both from stationary and mobile sources, as well as wildfire in forests, shrublands, and chaparral.

AB 32 GHG Inventory Sectors

CARB used the criteria pollutant emissions in Table 3-5 to understand potential health impacts. Similar to the air quality estimates, this information should be used to understand the relative health benefits of the various measures and should not be taken as absolute estimates of health outcomes. CARB used the incidence-per-ton (IPT) methodology to quantify the health benefits of emission reductions. The IPT methodology is based on a methodology developed by the U.S.

EPA.[226,227,228,229] Under the IPT methodology, changes in emissions are approximately proportional to the resulting changes in health outcomes. IPT factors are derived by calculating the number of health outcomes associated with exposure to $PM_{2.5}$ for a baseline scenario using measured ambient concentrations and dividing that number by the emissions of $PM_{2.5}$ or a precursor. To estimate the reduction in health outcomes, the emission reductions are multiplied by the IPT factor. For future years, the number of outcomes is adjusted to account for population growth. IPT factors were computed for the two types of $PM_{2.5}$: primary $PM_{2.5}$ and secondary $PM_{2.5}$ of ammonium nitrate aerosol formed from precursors.

For this AB 197 analysis, CARB calculated the health benefits associated with the five key measures that are represented by changes to fuel combustion. The health benefits associated with emission reductions for the Scoping Plan Scenario were estimated for each air basin and then aggregated for the entire state of California. CARB assumed that the statewide emission reductions distribution among the air basins is proportional to the baseline emissions in that air basin.

Calculated health endpoints include premature mortality, cardiovascular emergency department (ED) visits, acute myocardial infarction, respiratory ED visits, lung cancer incidence, asthma onset, asthma symptoms, work loss days, hospitalizations due to cardiopulmonary illnesses, hospitalizations due to respiratory illnesses, hospital admissions for Alzheimer's disease, and hospital admissions for Parkinson's disease.[230,231,232] These health endpoints were calculated using the IPT method for estimated emission reductions. Table 3-7 compares the health benefits of emission reductions associated with each measure for the Scoping Plan Scenario in the year

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[226] CARB. CARB's Methodology for Estimating the Health Effects of Air Pollution. Retrieved February 9, 2021. https://ww2.arb.ca.gov/resources/documents/carbs-methodology-estimating-health-effects-air-pollution.
[227] Fann, N., C. M. Fulcher, and B. J. Hubbell. 2019. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution." *Air Quality, Atmosphere & Health* 2:169–176. https://www.ncbi.nlm.nih.gov/pmc/articles/PMC2770129/.
[228] Fann, N., K. R. Baker, and C. M. Fulcher. 2012. "Characterizing the $PM_{2.5}$-related health benefits of emission reductions for 17 industrial, area and mobile emission sectors across the U.S." *Environ Int*. 49:141–51. November 15. https://www.sciencedirect.com/science/article/pii/S0160412012001985.
[229] Fann, N., K. Baker, E. Chan, A. Eyth, A. Macpherson, E. Miller, and J. Snyder. 2018. "Assessing Human Health $PM_{2.5}$ and Ozone Impacts from U.S. Oil and Natural Gas Sector Emissions in 2025." *Environ. Sci. Technol.* 52 (15), 8095–8103. https://pubs.acs.org/doi/abs/10.1021/acs.est.8b02050.
[230] CARB. CARB's Methodology. https://ww2.arb.ca.gov/resources/documents/carbs-methodology-estimating-health-effects-air-pollution.
[231] CARB. 2022. Updated Health Endpoints in CARB's Health Benefits Methodology. *Evaluating New Health Endpoints for Use in CARB's Health Analyses*.
[232] Cardio-pulmonary mortality, hospitalizations due to cardiopulmonary illnesses, and hospital admissions due to respiratory illnesses endpoints utilize studies documented in CARB's methodology document. For future assessments, CARB will use more recent studies to estimate cardiovascular hospital admissions and respiratory hospital admissions, as documented in CARB's updated health endpoints memo.

specified (2035 or 2045). The other alternatives are presented in Appendix C (AB 197 Measure Analysis).

Table 3-7: Estimated avoided incidence of mortality, cardiovascular and respiratory disease onset, work loss days and hospital admissions relative to the Reference Scenario for the Scoping Plan Scenario (AB 32 GHG Inventory sectors)

Measure	Mortality	Cardiovascular ED Visits	Acute Myocardial Infarction	Respiratory ED Visits	Lung Cancer Incidence	Asthma Onset	Asthma Symptoms	Work Loss Days	Hospital Admissions, Cardiovascular	Hospital Admissions, Respiratory	Hospital Admissions, Alzheimer's Disease	Hospital Admissions, Parkinson's Disease
Deploy ZEVs and reduce driving demand in 2035	635	170	70	400	45	1,475	128,930	92,510	95	115	245	40
Deploy ZEVs and reduce driving demand in 2045	1,820	475	200	1,115	135	3,995	343,095	255,800	295	350	745	125
Coordinate supply of liquid fossil fuels with declining CA fuel demand in 2035	115	30	15	70	10	275	23,530	16,880	20	20	50	10

Measure	Mortality	Cardiovascular ED Visits	Acute Myocardial Infarction	Respiratory ED Visits	Lung Cancer Incidence	Asthma Onset	Asthma Symptoms	Work Loss Days	Hospital Admissions, Cardiovascular	Hospital Admissions, Respiratory	Hospital Admissions, Alzheimer's Disease	Hospital Admissions, Parkinson's Disease
Coordinate supply of liquid fossil fuels with declining CA fuel demand in 2045	215	55	25	130	15	490	40,860	30,445	35	40	95	15
Generate clean electricity in 2035	20	5	0	10	0	45	3,930	2,820	5	5	10	0
Generate clean electricity in 2045	170	45	20	105	15	385	32,065	23,890	25	30	75	10
Decarbonize industrial energy supply in 2035	300	80	35	190	20	695	60,660	43,520	45	55	115	20
Decarbonize industrial energy supply in 2045	595	155	65	365	45	1,310	111,925	83,435	95	115	245	40

Measure	Mortality	Cardiovascular ED Visits	Acute Myocardial Infarction	Respiratory ED Visits	Lung Cancer Incidence	Asthma Onset	Asthma Symptoms	Work Loss Days	Hospital Admissions, Cardiovascular	Hospital Admissions, Respiratory	Hospital Admissions, Alzheimer's Disease	Hospital Admissions, Parkinson's Disease
Decarbonize buildings in 2035	155	40	15	95	10	360	31,130	22,335	25	30	60	10
Decarbonize buildings in 2045	1,610	420	175	985	120	3,550	303,830	226,500	260	310	665	115

Note: All values are rounded to the nearest 0 or 5.

The measures related to reducing non-combustion emissions and compensating for remaining emissions do not include changes to fuel combustion and therefore are not associated with changes to air pollutants or health endpoints. Biomethane combustion is captured in measures that reduce combustion of fossil gas, such as decarbonizing industrial energy supply and buildings.

Although the estimated health outcomes presented are based on a well-established methodology, they are subject to uncertainty. For instance, future population estimates are subject to increasing uncertainty as they are projected further into the future, and baseline incidence rates can experience year-to-year variation. Also, the relationship between changes in pollutant concentrations and changes in pollutant or precursor emissions is assumed to be approximately proportional.

In addition, emissions are reported at an air basin level and do not capture local variations. These estimates also do not account for impacts from global climate change, such as temperature rise, and are only based on the scenarios in this Scoping Plan.

The fuel changes for each AB 197 measure are estimated based on the impact of each measure compared to the Reference Scenario for the years 2035 and 2045. Therefore, aggregating the effect of each measure would overestimate the impacts of the Scoping Plan Scenario because the implementation of each measure would affect the level of benefits of the other measures. This measure-by-measure analysis uses a different methodology for calculating health endpoints than does the health analysis for the complete Scoping Plan Scenario provided earlier.

Natural and Working Lands

Implementation of NWL management strategies to mitigate and adapt to climate change will result in both environmental and health benefits. This section provides information about the potential health benefits of measures evaluated for the Scoping Plan Scenario. For this analysis, health benefit estimates were focused on increases or decreases to $PM_{2.5}$ resulting from wildfire emissions on forests, shrublands, and grasslands.[233] Other health benefits resulting from NWL management actions in the Scoping Plan Scenario are not quantified here but are important for all Californians. This includes, but is not limited to, reductions in exposure to synthetic pesticides when switching to organic agricultural systems, improvements in shade availability and mental health with increasing urban forest cover, improved mental health from opportunities for recreation in resilient and healthy environments, and protection from floods and rising sea levels.

[233] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11, N14. finalejacrecs.pdf (arb.ca.gov).

These examples are by no means exhaustive, as our natural and working lands provide immense health benefits to everyone.

For this analysis, CARB used the $PM_{2.5}$ emissions in Table 3-6 to understand potential health impacts. This information should be used to understand the relative health endpoints of the various measures and should not be taken as absolute estimates of health outcomes of this Scoping Plan statewide or within a specific community. The IPT methodology was used to calculate health endpoints, similar to the AB 32 GHG Inventory Sector analysis. CARB calculated the annual health endpoints associated with the wildfire emissions changes resulting from the implementation of management strategies on forests, shrublands, and grasslands under each alternative. The annual health endpoints associated with emission reductions for the Scoping Plan Scenario were estimated for the entire state. Calculated health endpoints include emissions-caused mortality, hospital admittance, and emergency room visits from asthma; hospital admittance from chronic obstructive pulmonary disease; and emergency room visits from respiratory and cardiovascular outcomes. Table 3-8 compares the average annual health endpoints of wildfire emission reductions associated with the Scoping Plan Scenario over the period 2025–2045. The other alternatives are presented in Appendix C (AB 197 Measure Analysis).

Table 3-8: Estimated average annual avoided incidence of hospital admissions, emergency room visits, and mortality relative to the Reference Scenario for the Scoping Plan Scenario resulting from forest, shrubland, and grassland wildfire emissions (NWL)

Health Endpoints from Forest, Shrubland, and Grassland Wildfire Emissions	Average Annual Avoided Incidence
Hospital admissions from asthma	22
Hospital admissions from chronic obstructive pulmonary disease without asthma	19
Hospital admissions from all respiratory outcomes	63
Emergency room visits from asthma	155
Emergency room visits from all respiratory outcomes	419
Emergency room visits from all cardiovascular outcomes	156
All causes of mortality	394

Estimated Social Cost

Social costs are generally defined as the cost of an action on people, the environment, or society and are widely used to understand the impact of regulatory actions. One tool, the social cost of greenhouse gases (SC-GHG), is an estimate of the present value of the costs associated with the emission of GHGs in future years. It combines climate science and economics to help understand the benefits of reducing GHG emissions. The estimates of the social cost of carbon (SC-CO_2) and social cost of methane (SC-CH_4), two types of SC-GHGs presented here, estimate the value of the net harm to society associated with adding GHGs to the atmosphere in a given year; they do not represent the cost of actions taken to reduce GHG emissions (known as the *cost of abatement*) nor the cost of GHG emissions reductions. In principle, the SC-GHG includes the value of climate change impacts, including but not limited to, changes in net agricultural productivity, human health effects, property damage from increased flood risk and other natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. It reflects the societal value of reducing emissions of the gas in question by one metric ton.[234] Many of these damages from GHG emissions today will affect economic outcomes throughout the next several centuries.

In 2008, federal agencies began incorporating SC-CO_2 estimates into the analysis of their regulatory actions. U.S. EPA has used various models and discount rates to determine the value of future impacts. Generally, these models begin with assumptions to predict economic activity over time, along with projected GHG emissions. The modeled emissions are input into a model of the global climate system, which then translates into estimates of surface temperature, sea level rise, and other impacts. These outputs are used to estimate economic damages per ton of GHG emitted in a given year in the future. Since the models are calculating the present value of future damages, a discount rate is applied. For example, the SC-CO_2 for the year 2045 represents the value of climate change damages from a release of CO_2 in 2045 discounted back to today. The present value is significantly affected by the discount rate used; a higher discount rate results in a lower present value. For example, in 2021 dollars the SC-CO_2 in 2045 is $31 using a 5 percent discount rate, $88 using a 3 percent discount rate, and $122 using a 2.5 percent discount rate. Additional detail is included in Appendix C (AB 197 Measure Analysis).

The 2017 Scoping Plan utilized SC-CO_2 and SC-CH_4 Obama Administration-era values developed by the Council of Economic Advisors and the Office of Management and Budget-convened Interagency Working Group on the Social Cost of Greenhouse Gases (IWG)[235] to consider the social costs of actions to reduce GHG emissions. The Biden Administration reinstated these values in February 2021,[236] after they had been rescinded and significantly revised by the Trump Administration. The reinstatement was considered an interim step, and the Biden Administration also reconvened the IWG to continue its work to evaluate and incorporate the latest climate science and economic research and

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[234] U.S. Government. Interagency Working Group on Social Cost of Greenhouse Gases. February 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide – Interim Estimates under Executive Order 13990. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[235] Originally titled the "Interagency Working Group on the Social Cost of Carbon," the IWG was renamed in 2016. 82 Fed. Reg. 16093, 16095-96 (Mar. 28, 2017). https://www.govinfo.gov/content/pkg/FR-2017-03-31/pdf/2017-06576.pdf.

[236] Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, Executive Order 13990 (Jan. 20, 2021), 86 Fed. Reg. 7037 (Jan. 25, 2021). https://www.energy.gov/sites/default/files/2021/02/f83/eo-13990-protecting-public-health-environment-restoring.pdf. IWG, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990 (February 2021), https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf See also, The White House. 2021. A Return to Science: Evidence-Based Estimates of the Benefits of Reducing Climate Pollution. https://www.whitehouse.gov/cea/written-materials/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/.

respond to the National Academies' recommendations from 2017 as it develops a more complete revision of the estimates.

It is important to note that the models used to produce SC-GHG estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate literature. There are additional costs to society, including the costs associated with changes in co-pollutants and costs that cannot be included due to modeling and data limitations. The IWG has stated that the range of the interim SC-GHG estimates likely underestimates societal damages from GHG emissions.[237] The revised estimates were originally slated to be released in early 2022 but were stalled.[238] CARB staff is applying the interim values presented in the IWG February 2021 Technical Support Document (TSD), which reflect the best available science in the estimation of the socioeconomic impacts of GHGs.[239] This Scoping Plan utilizes the TSD standardized range of discount rates, from 2.5 to 5 percent, to represent varying valuation of future damages.

AB 32 GHG Inventory Sectors

Table 3-9 presents the estimated social cost, in terms of avoided economic damages, for each measure of the Scoping Plan Scenario. For each measure, Table 3-9 includes the range of the SC-CO_2 and SC-CH_4 that results from the GHG emissions reductions in 2035 and 2045 at 2.5 and 5 percent discount rates. Additional background on the SC-GHG and methodology for calculating the SC-CO_2 and SC-CH_4 estimates in this Scoping Plan, as well as estimates for the alternatives, are provided in Appendix C (AB 197 Measure Analysis).

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[237] Interagency Working Group on Social Cost of Greenhouse Gases. 2021. Technical Support Document. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[238] See *Louisiana v. Biden* (W.D. La. 2022) 585 F.Supp.3d 840, stayed pending review (5th Cir. Mar. 16, 2022) 2022 WL 866282. A federal district court ruling issued in early February 2022 had granted a preliminary injunction blocking the Biden Administration from using the interim IWG SC-GHG estimates. However, a federal appeals court overturned the lower court's preliminary injunction in March 2022, which allows the Biden Administration to continue using the policy as legal proceedings continue. CARB will continue to monitor the litigation. However, the federal action does not prohibit CARB from using social cost of carbon and CARB will use the best available science regardless of politics. A separate federal appeals court upheld the Biden administration's use of the IWG SC-GHG estimates in October 2022. *Missouri v. Biden* (8th Cir. 2022) ____ F.4th ____.

[239] Interagency Working Group on Social Cost of Greenhouse Gases. 2021. Technical Support Document. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

Table 3-9: Estimated social cost (avoided economic damages) of measures considered in the Scoping Plan Scenario (AB 32 GHG Inventory sectors)

Measure	Social Cost of Carbon in 2035, 5%–2.5% Discount Rate Billion USD (2021 dollars)	Social Cost of Carbon in 2045, 5%–2.5% Discount Rate Billion USD (2021 dollars)
Deploy ZEVs and reduce driving demand	1.12–4.87	2.64–10.23
Coordinate supply of liquid fossil fuels with declining California fuel demand	0.61–2.63	0.95–3.67
Generate clean electricity	0.20-0.88	0.97–3.75
Decarbonize industrial energy supply	0.23–1.01	0.69–2.67
Decarbonize buildings	0.35–1.52	1.11–4.32
Reduce non-combustion emissions	0.51–1.29 (SC-CH_4)	0.86–2.01 (SC-CH_4)
Compensate for remaining emissions	0.61–2.66	2.03–7.84
Scoping Plan Scenario SC-CO_2 **Scoping Plan Scenario SC-CH_4** **Scoping Plan Scenario (Total)[a]**	2.4–10.4 0.51–1.3 2.9–11.7	5.6–21.9 0.86–2.0 6.5–23.9

[a] CARB staff could not precisely separate some CO_2 and CH_4 from other GHGs from PATHWAYS outputs, but the contribution is believed to be small for purposes of calculating the social cost of carbon. The approach used to estimate GHG emissions reductions for individual measures in PATHWAYS does not reflect cross-sector interactions. Therefore, the GHG values for each measure do not sum to the overall scenario total. The total GHG emissions reduction used in this calculation is 97 $MMTCO_2e$ in 2035 and 180 $MMTCO_2e$ in 2045.

Natural and Working Lands

The SC-CO_2 estimates for the NWL measures shown in Table 3-10, in terms of avoided economic damages, reflect 2021 IWG interim values, updated for inflation, similar to the AB 32 GHG Inventory Sector analysis. This analysis utilizes the 2.5 percent and 5 percent discount rate and the average annual emissions reductions from each NWL type from 2025–2045. Estimates for all alternatives are included in Appendix C (AB 197 Measure Analysis).

Table 3-10: Estimated social cost (avoided economic damages) of measures considered in the Scoping Plan Scenario (NWL)

Measure	Social Cost of Carbon in 2035, 5%–2.5% Discount Rate Billion USD (2021 dollars)	Social Cost of Carbon in 2045, 5%–2.5% Discount Rate Billion USD (2021 dollars)
Forests/Shrublands/Grasslands	0.003–0.012	0.004–0.014
Annual Croplands	0.006–0.027	0.008–0.031
Perennial Croplands	<0.001–0.001	0.000–0.001
Urban Forest	0.032–0.138	0.041–0.157
Wildland Urban Interface (WUI)	(0.018) – (0.080)[a]	(0.023) – (0.090)
Wetlands	0.011–0.046	0.014–0.053
Sparsely Vegetated Lands	<0.001	<0.001

[a] Parentheses indicate an increase in estimated social cost, i.e., an increase in economic damages. This is only the case for WUI measures where emissions are increased, shown in Table 3-6. The estimated social cost does not account for the decrease in wildfire risk or decrease in wildfire damages resulting from the WUI measures.

Social Costs of GHGs in Relation to Cost-Effectiveness

AB 32 includes a requirement that rules and regulations "achieve the maximum technologically feasible and cost-effective" greenhouse gas emissions reductions.[240] Under AB 32, *cost-effectiveness* means the relative cost per metric ton of various GHG reduction strategies,[241] which is the traditional cost metric associated with emission control. In contrast, the SC-CO_2, SC-CH_4, and social cost of nitrous oxide (SC-N_2O), because they are estimates of the cost to society of additional GHG emissions, can be used to estimate of the economic benefits of reducing emissions, but do not take into account the cost of the actions that must be taken to achieve those GHG emissions reductions.

There may be technologies or policies that do not appear to be cost-effective when compared to the SC-CO_2, SC-CH_4, and SC-N_2O associated with GHG reductions. However, these technologies or policies may result in other benefits that are not reflected in the IWG social costs. Examples include the evaluation of social diversification of the portfolio of transportation fuels (a goal outlined in the Low Carbon Fuel Standard) and reductions in criteria pollutant emissions from power plants (as in the Renewables Portfolio Standard). Additionally, costs for new technology may be higher early on in a technology's development cycle and may drop over time as use of the technology is scaled up.

Estimated Cost per Metric Ton

AB 197 requires an estimation of the cost-effectiveness of the measures evaluated for this Scoping Plan. The cost (or savings)[242] per metric ton of CO_2e reduced for each measure is one metric for comparing the performance of the measures. Additional factors beyond the cost per metric ton that could be considered include continuity with existing laws and policies, implementation feasibility, contribution to fuel diversity and technology transformation goals, and health and other benefits to California. These considerations are not reflected in the cost per metric ton estimates presented below. It is important to understand the relative cost-effectiveness of individual measures as presented in this section. However, the economic analysis presented earlier in this chapter, in Appendix H

[240] AB 32 Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006. (AB 32, Nuñez, Chapter 488, Statutes of 2006). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.

[241] Health & Saf. Code § 38505(d).

[242] Similarly, to the direct costs reported earlier, the cost per metric ton of a measure reflects the stock costs and any fuel or efficiency savings associated with a measure divided by the GHG emission reduction achieved by the measure. Costs are reported as positive values, and savings are reported as negative values.

(AB 32 GHG Inventory Sector Modeling), and in Appendix I (NWL Technical Support Document) provides a more comprehensive analysis of how the Scoping Plan Scenario and alternative scenarios affect the state's economy and jobs.

AB 32 GHG Inventory Sectors

The cost per metric ton for the AB 32 GHG Inventory sectors was computed for each measure independently relative to the Reference Scenario using the sensitivity calculations based on PATHWAYS and RESOLVE outputs. The difference in the annualized cost between the Scoping Plan Scenario and the Reference Scenario was computed for each measure in 2035 and in 2045. The incremental cost was divided by the incremental GHG emissions impact to calculate the cost per metric ton in each year. To capture the fuel and GHG impacts of investments made from 2022 through 2035, or from 2022 through 2045, CARB computed an average annual cost per metric ton. The incremental cost in each year was averaged over the period. This value is divided by the corresponding annual, incremental GHG impact averaged over the same period.

The cost metric includes the annualized incremental cost of energy infrastructure, such as zero-emission vehicles, electric appliances, and required revenue to support all electric assets. A residual value for equipment such as vehicles or appliances that are retired early is included. The annual fuel cost or avoided fuel cost that results from efficiency improvements or changes to demand for fuels associated with transitioning to alternative fuels is included. Not included in this cost metric are costs that represent transfers within the state, such as incentive payments for early retirement of equipment.

It is important to note that this cost per metric ton does not represent an expected market price value for carbon mitigation associated with these measures. In addition, the values do not capture fuel savings or GHG reductions associated with the full economic lifetime of measures that have been implemented by the target date of 2035 or 2045 but whose impacts extend beyond the target date.

Table 3-11 includes the cost per metric ton and annual average cost per metric ton estimates for the Scoping Plan Scenario. The other alternatives are presented in Appendix C (AB 197 Measure Analysis). Measures that are relatively less costly in 2035 or 2045 are also less costly over the extended period. As noted earlier, incremental costs of new vehicles are generally offset by gains in efficiency and avoided fuel consumption resulting in negative cost per metric ton.

Table 3-11: Estimated cost per metric ton of reduced CO_2e relative to the Reference Scenario for measures considered in the Scoping Plan Scenario (AB 32 GHG Inventory sectors)

Measure	Annual Cost, 2035 ($/ton)	Average Annual Cost, 2022–2035 ($/ton)	Annual Cost, 2045 ($/ton)	Average Annual Cost, 2022–2045 ($/ton)
Deploy ZEVs and reduce driving demand	-171	-99	-103	-122
Coordinate supply of liquid fossil fuels with declining CA fuel demand	60	109	-50	39
Generate clean electricity[a]	101	156	145	161
Decarbonize industrial energy supply	290	217	257	274
Decarbonize buildings	235	230	112	213
Reduce non-combustion emissions	93	94	106	99
Compensate for remaining emissions	745	823	236	485

[a] Note: The denominator of this calculation (2045) does not include GHG reductions occurring outside of California resulting from SB 100. If these reductions were included, this number would be lower.

Natural and Working Lands

The cost per metric ton for NWL measures were computed for the Scoping Plan Scenario relative to the Reference Scenario using the projected carbon stock/sequestration data from the NWL modeling and the direct cost estimates for each management action, described earlier. Direct costs represent the cost of implementing a certain management action. The projected emissions reductions take into account the loss of carbon that results from the management action, such as fuels reduction treatments in forests, as well as climate change effects on growth. The direct cost for each NWL measure was divided by the average annual emission reductions presented in Table 3-6 to produce the cost per metric ton. The increasing effect of climate change on diminished future growth reduces the ability of the land to sequester or store carbon, driving up the cost per ton.

It is important to note that this cost per metric ton does not represent an expected market price value for carbon mitigation associated with these measures. In addition, emissions benefits of NWL management actions often take longer time periods to accrue, and these values only capture GHG reductions up to 2045.

Table 3-12 includes the average cost per metric ton estimates for the average annual CO_2e reductions from 2025 through 2045 for the Scoping Plan Scenario. The other alternatives are presented in Appendix C (AB 197 Measure Analysis).

Table 3-12: Estimated average cost per metric ton of reduced CO_2e relative to the Reference Scenario for measures considered in the Scoping Plan Scenario (NWL)

Measure	Average Cost per Reduced Ton CO_2e (\$/Ton)
Forests/Shrublands/Grasslands	15,500
Annual Croplands	1,100
Perennial Croplands	412
Urban Forest	3,270
Wildland Urban Interface (WUI)	N/A
Wetlands	64
Sparsely Vegetated Lands	451,000

Climate Vulnerability Metric

As California invests in climate mitigation and adaptation, it is essential to understand that the relative impact of climate change will vary across the state's communities. Due to persisting health and opportunity gaps, not all communities are equally resilient in the face of climate impacts. A global metric such as the Social Cost of Carbon cannot adequately capture the incremental additional economic impact faced by overly burdened communities. The Climate Vulnerability Metric (CVM) is specifically focused on quantifying the community-level impacts of a warming climate on human welfare and the additional costs. Additional details and results are included in Appendix K (Climate Vulnerability Metric).

The CVM aggregates the impacts of climate change that can be quantified at the census tract level using robust and currently available research. The CVM includes the projected impacts of climate change on human welfare across four categories (hours worked, household energy costs, human mortality, and flood-related property damage) through midcentury. The CVM identifies nine components of the four climate impacts as shown in Figure 3-9 and aggregates the data to generate a total CVM result for each census tract. To ensure that the CVM represents the diversity of California communities, it is reported as the aggregate monetized impact of climate change as a percentage of census tract-specific incomes.[243] For example, a CVM value of 3 implies that by 2050, a census tract is projected to experience human welfare impacts of climate change that amount to 3% of annual income in that tract.

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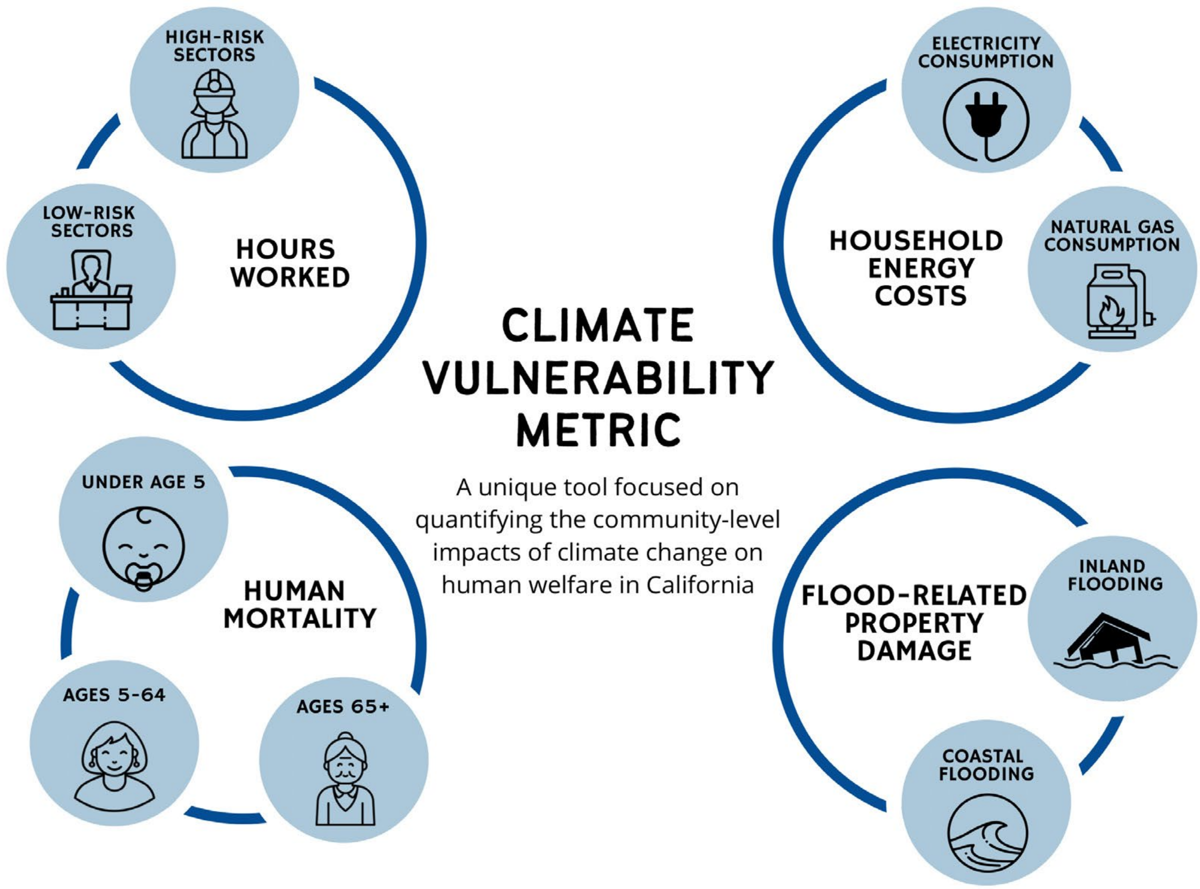
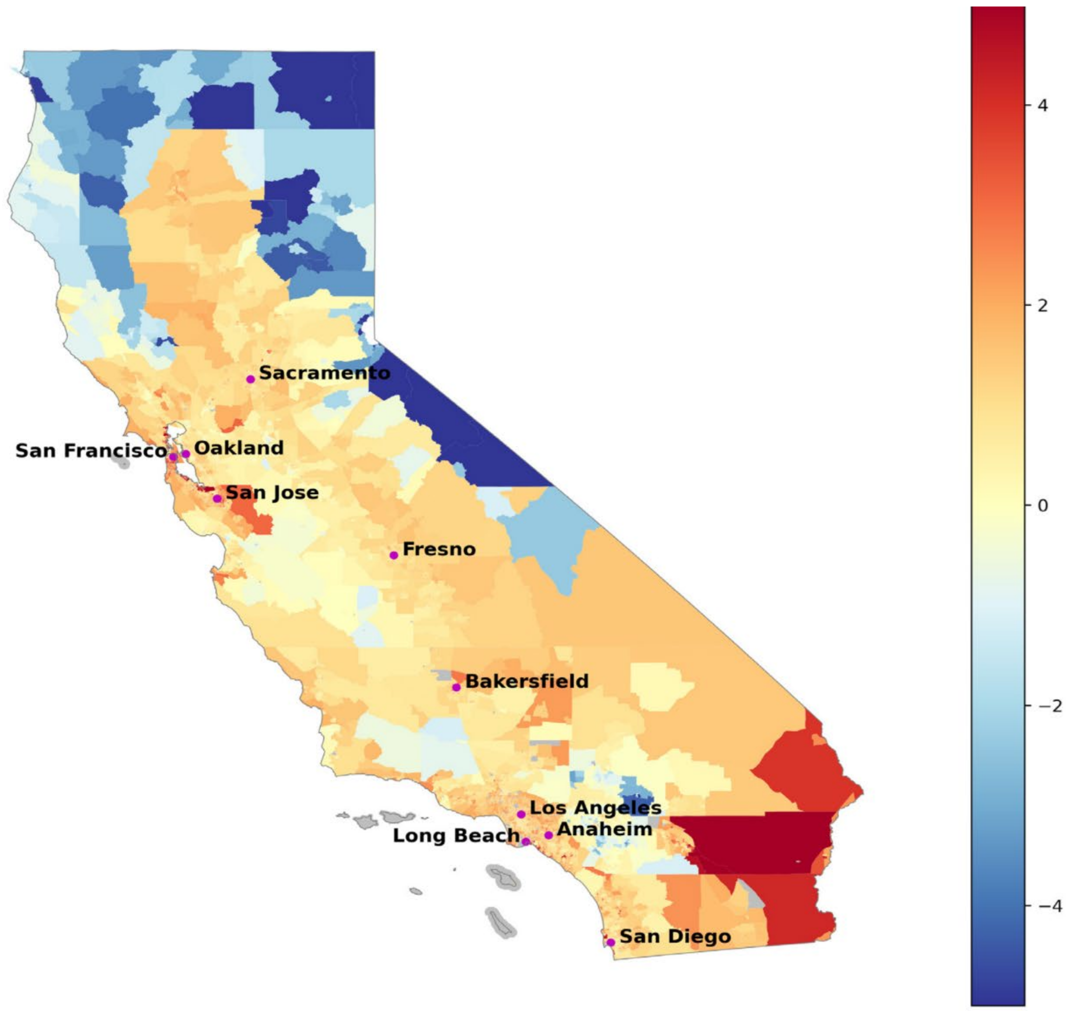
[243] Per capita income in 2019 for census tracts across California ranges from $633 to $176,388, with a median of $32,181 ($2019). Source: American Community Survey.

Figure 3-9: Categories of climate change impacts on human welfare included in the Climate Vulnerability Metric.



The CVM shows that climate change will have highly unequal impacts across California. While some southeastern regions of California are estimated to suffer damages that exceed 5% of annual income, other high-elevation northeastern regions of California are estimated to see benefits of up to 10%. Some low-lying urban areas, such as the San Francisco Bay Area, are estimated to be particularly vulnerable, while much of the Central Valley is estimated to suffer at least moderate economic damages relative to the rest of the state. It is important to note that the CVM does not set a threshold for vulnerability. Instead, it shows relative impacts across census tracts. The CVM is limited to the impacts that can currently be quantified at the census tract level.

Figure 3-10: Combined impacts of climate change in 2050 under a moderate emissions scenario; damages as share of 2019 tract income (%)



The map shows combined impacts of climate change in 2050 under a moderate emissions scenario (RCP 4.5), reported as a share of 2019 census tract income. For example, a CVM value of 3 implies that by 2050, a census tract is projected to experience human welfare impacts of climate change that amount to 3% of annual income. Impacts are combined across the categories shown in Figure 3-9. The higher the CVM for a given census tract, the more damaging the projected impacts of climate change on human welfare. Census tracts with high CVMs are represented by positive percentages in orange and red. A lower CVM is associated with lower projected impacts of climate change, shown in yellow, while a negative CVM value represents a projected beneficial impact of climate change (e.g., through reductions in deaths caused by extremely cold winter weather). Negative CVMs are represented by negative percentages in blue.

By providing information about how climate vulnerability varies across California (Figure 3-10), the CVM results can be used to direct resources to enhance resiliency in the state's most vulnerable communities based on the specific impacts, such as heat or flooding, they are experiencing. The CVM may be used in combination with existing screening tools, such as CalEnviroScreen 4.0, to identify communities that face environmental and health hazards that contribute to disproportionate economic impacts in addition to climate vulnerability. The CVM can become an essential source of information to implement this Scoping Plan and build a more resilient, just, and equitable future for all communities.

Public Health

Health Analysis Overview

This section focuses on a broader evaluation of public health and climate change. Science demonstrates that taking action to address climate change presents one of the most significant opportunities to improve public health outcomes.[244] Transitioning to clean energy and technology and improving land and ecosystem management will lead to a much healthier future. Many actions to reduce GHG emissions also have health co-benefits that can improve the health and well-being of populations across the state, as well as address climate change. This section and the accompanying Appendix G (Public Health) provide a qualitative analysis of health benefits to accompany the quantitative health analysis included in this chapter, in Appendix C (AB 197 Measure Analysis), and in Appendix H (AB 32 GHG Inventory Sector Modeling). Together the qualitative and quantitative analyses of benefits are demonstrating the many ways that climate action and health improvements go hand in hand.

Climate change can lead to a wide range of direct health impacts such as increased heat-related illnesses (i.e., heat exhaustion and heat stroke), and injuries and deaths from extreme weather events or disasters (e.g., severe storms, flooding, wildfires). Indirect impacts include:

- more air pollution-related exacerbations of cardiovascular and respiratory diseases (e.g., due to increased smog, wildfire smoke)
- increased vector-borne and fungal diseases due to changes in the distribution and geographic range of disease-carrying species (e.g., mosquitoes, ticks, fungi in dust)
- negative nutritional consequences related to decreases in agricultural food yields
- stress and mental trauma due to extreme weather-related catastrophes
- anxiety, depression, and other mental health impacts associated with gradual changes in the climate (e.g., prolonged drought or temperature shifts affecting jobs and industries) that result in unemployment and income loss

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[244] Watts, N., W. N. Adger, P. Agnolucci, et al. 2015. "Health and climate change: Policy responses to protect public health." *Lancet* 386, 1861–1914.

- residential displacement and home loss (e.g., sea level rise impacting coastal communities)

Wildfires and wildfire smoke are one area where we have already seen and expect to see even further drastic impacts on the health of Californians. According to CalFire, since 1932 the top eight largest wildfires in California have occurred in the past five years (2017–2022), with 151 deaths due directly to fires during that period.[245] Researchers estimate that wildfire smoke during fall 2020 may have led to as many as 3,000 excess deaths, with at least 95% of Californians suffering unhealthy levels of particle pollution due to wildfires in 2020.[246] Continued climate change is projected to further increase smoke exposure from wildfires through the end of the century.[247] Wildfires also create a high-risk environment for outdoor workers, including agricultural workers. While the direct medical and physical health impacts are often most noticeable, the psychological impacts can develop and persist well after the event. Estimates indicate that 20%–65% of survivors of extreme weather events have mental health issues following the event.[248]

Extreme heat, drought, and associated worsened air quality impacts are among the most serious climate-related exposures affecting the health of Californians. Numerous studies find a wide range of adverse health effects accompanying extreme heat, including heat stroke and adverse birth outcomes, and find that extreme heat can harm most body systems. Climate change exacerbates air pollution problems that cause difficulty breathing and can lead to serious illness and death in many parts of California. Increasing temperatures cause increases in ozone and other pollution concentrations, including for California's most polluted regions, and heighten health risks for the vulnerable and marginalized populations living in these areas.[249] In 2020, there were 157 ozone polluted days across Los Angeles, Orange, Riverside, and San Bernardino Counties—the most days since 1997. In addition, particulate matter exposure is a heightened problem during

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[245] California Department of Forestry and Fire Protection (CAL FIRE). "Stats and Events." *Cal Fire Department of Forestry and Fire Protection*, https://www.fire.ca.gov/stats-events/.
[246] G-FEED. 2020. Indirect mortality from recent wildfires in CA. *http://www.g-feed.com/2020/09/indirect-mortality-from-recent.html*.
[247] M. D. Hurteau, A. L. Westerling, C. Wiedinmyer, and B. P. Bryant. 2014. "Projected effects of climate and development on California wildfire emissions through 2100." *Environ. Sci. Technol.* 48, 2298–2304.
[248] American Public Health Association. 2019. Addressing the Impacts of Climate Change on Mental Health and Well-Being. Policy No: 20196. *https://www.apha.org/policies-and-advocacy/public-health-policy-statements/policy-database/2020/01/13/addressing-the-impacts-of-climate-change-on-mental-health-and-well-being*.
[249] American Lung Association. State of the Air 2021. *https://www.lung.org/research/sota*.

droughts, which are expected to increase over this century.[250,251] Worse air quality leads to illnesses, emergency room visits, and hospitalizations for chronic health conditions, including chronic obstructive pulmonary disease (COPD), asthma, chronic bronchitis, and other respiratory and cardiovascular conditions, as well as increased risk for respiratory infections, which all result in greater health costs to the state.[252,253,254] These and other climate-related health impacts are discussed in more detail in Appendix G (Public Health).

Health Analysis Components

This Scoping Plan health analysis focuses on the contrast between a California that is still dependent on a fossil fuel-based economy and a California that is transitioned to a carbon-neutral, clean energy future. This qualitative analysis evaluates and demonstrates the broad range of benefits of a dramatic reduction in fossil fuels by 2045 combined with healthier ecosystem management, comparing health outcomes for a "no-action" scenario (Reference) to a "take-action" decarbonization scenario. As this is a qualitative analysis, it looks more broadly at the public health benefits of a drastic reduction in fossil fuel combustion. While this analysis provides scientific evidence for Scoping Plan benefits based on achieving carbon neutrality by 2045, it does not analyze a specific scenario.

The key areas of focus for the analysis are: heat impacts, children's health and development, economic security, food security, mobility and physical activity, urban greening, wildfires and smoke impacts, and housing affordability. For each area of focus, the analysis covers the scientific evidence and compares expected health effects between the Reference and decarbonization scenarios. This analysis looks at the major health outcomes, provides directional effects for each health outcome, and where possible provides information on the strength and scale of health impacts. Some areas include quantitative information where tools are available to measure health outcomes. While the analysis is focused on health outcomes statewide, it also includes discussion

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[250] Cvijanovic, I., B. D. Santer, C. Bonfils, et al. 2017. "Future Loss of Arctic Sea-ice Cover Could Drive a Substantial Decrease in California's Rainfall." 8 *Nat. Commun.* 1947. https://doi.org/10.1038/s41467-017-01907-4.

[251] Williams, A. P., R. Seager, J. T. Abatzoglou, B. I. Cook, J. E. Smerdon, and E. R. Cook. 2015. "Contribution of anthropogenic warming to California drought during 2012–2014." *Geophysical Research Letters* 42(16), 6819–6828.

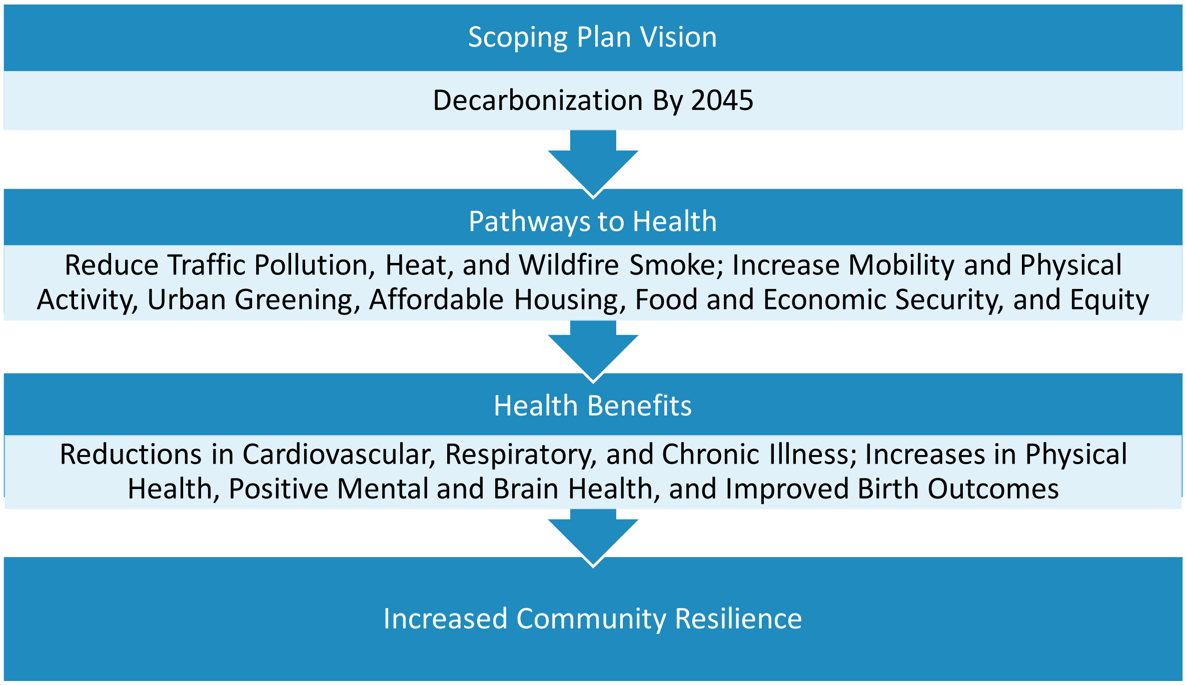
[252] Romley, J. A., A. Hackbarth, and D. P. Goldman. 2010. Cost and Health Consequences of Air Pollution in California. Santa Monica, California. RAND Corp. https://www.rand.org/pubs/research_briefs/RB9501.html.

[253] Wang, M., C. P. Aaron, J. Madrigano, E. A. Hoffman, E. Angelini, J. Yang, A. Laine, et al. 2019. "Association between long-term exposure to ambient air pollution and change in quantitatively assessed emphysema and lung function." *JAMA* 322(6), 546–556.

[254] Inserro, A. 2018. "Air Pollution Linked to Lung Infections, Especially in Young Children." *Am. J. Managed Care* (May 6). https://www.ajmc.com/view/air-pollution-linked-to-lung-infections-especially-in-young-children.

of benefits to community health and climate resilience, as well as potential inequities experienced at a community level. Figure 3-11 shows the co-benefit areas covered in this Scoping Plan and the path to health improvements and increased community resilience.

Figure 3-11: Scoping Plan outcome and the path to health improvements



Social and Environmental Determinants of Health Inequities

Communities across the state do not experience exposure to pollution sources and the resulting effects equally. Low-income communities and communities of color (including Black, Latino and Indigenous communities) consistently experience significantly higher rates of pollution and adverse health conditions than others due to factors including historic marginalization rooted in systemic racism. As shown in Figure 3-12, the most impacted neighborhoods according to CalEnviroScreen (CES) are home to very high percentages of people of color while the least impacted neighborhoods are predominantly white. Recent findings show that Black Californians have 19% higher $PM_{2.5}$ exposure from vehicle emissions than the state average, and the census tracts with the highest $PM_{2.5}$ pollution burden from vehicle emissions have a high proportion of people of color.[255] Air pollutant emissions from mobile sources have disproportionate impacts on low-income communities and communities of color due to their proximity.[256] Diesel-fueled vehicles traveling on California's freeways and major roads expose nearby residents to pollution that is linked to lung cancer, hospitalizations and emergency department visits for chronic heart and lung disease, and premature death.[257,258] A combination of historical and social inequities are evident in communities of color disproportionately living close to freeways and other major sources of vehicle pollution. Environmental exposures and contaminants are one component of a broader set of social, economic, and environmental factors that can amplify health conditions, and the combination of all these factors can compound the health effects of individual exposures. This broader set of community factors can be referred to as "cumulative impacts." In addition, specific populations are more sensitive to pollution and face greater susceptibility. This includes young children, older adults, and individuals with existing health conditions.

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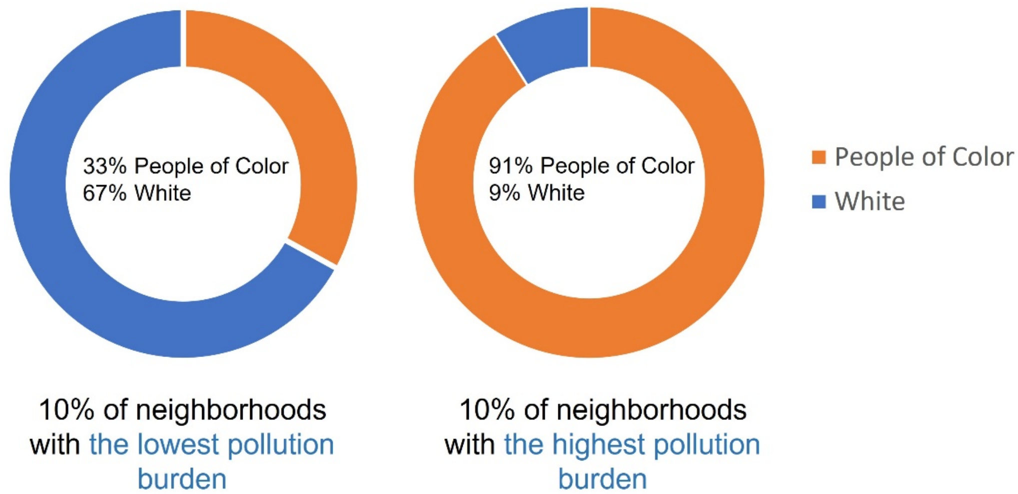
[255] Reichmuth, D. 2019. *Inequitable exposure to air pollution from vehicles in California.* https://www.ucsusa.org/resources/inequitable-exposure-air-pollution-vehicles-california-2019.

[256] CARB. 2017. *California's 2017 climate change scoping plan.* https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf.

[257] CARB. 2020. Overview: Diesel exhaust & health. https://ww2.arb.ca.gov/resources/overview-diesel-exhaust-and-health.

[258] Kagawa, J. 2002. "Health effects of diesel exhaust emissions—a mixture of air pollutants of worldwide concern." *Toxicology* 181–182:349–353.

Figure 3-12: Least and most impacted neighborhoods from CalEnviroScreen[259]



Social Determinants of Health Inequities

The physical and mental health of individuals and communities is shaped, to a great extent, by the social, economic, and environmental circumstances in which people live, work, play, and learn. According to the World Health Organization, these same circumstances—or social determinants of health—are “mostly responsible for health inequities: the unfair and avoidable differences in health status seen within and between countries.” In fact, a strong body of research demonstrates that more than 50 percent of long-term health outcomes are the result of social determinants affecting an individual.[260] Race/ethnicity and socioeconomic status, for example, have been found to amplify impacts from long- and short-term environmental exposures for several health outcomes,

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[259] The figure represents the top and bottom decile scoring of CalEnviroScreen census tracts for pollution burden. This chart is modified from Figure 2. Race in the Least and Most Impacted Census Tracts of CalEnviroScreen 4.0 in the Office of Environmental Health Hazard Assessment, California Environmental Protection Agency. Analysis of Race/Ethnicity and CalEnviroScreen 4.0 Scores. 2021. https://oehha.ca.gov/media/downloads/calenviroscreen/document/calenviroscreen40raceanalysisf2021.pdf.

[260] California Department of Public Health (CDPH). 2015. *The Portrait of Promise: The California Statewide Plan to Promote Health and Mental Health Equity.* A Report to the Legislature and the People of California by the Office of Health Equity. Sacramento, California. California Department of Public Health, Office of Health Equity.

such as mortality and birth outcomes.[261,262,263,264] Social factors combine in low-income communities and communities of color to create levels of toxic chronic stress and limit opportunities for healthy food and healthy lifestyles. Social factors also can cause health disparities through psychosocial pathways such as discrimination and social exclusion.[265] While the importance of social determinants is well known, measuring the specific and cumulative impacts of social determinants is challenging.

There are several important tools to evaluate and map cumulative impacts and factors contributing to the results of historical practices such as redlining, and these tools have been used for air quality and climate planning, community protection, and investments. CalEnviroScreen is a tool that maps cumulative pollution burdens and vulnerabilities on a statewide basis and ranks census tracts based on environmental, exposure, population, and socioeconomic indicators. An analysis using CES shows a direct, persistent relationship between exposure to environmental burdens and socioeconomic and health vulnerabilities affecting communities of color and historical redlining practices. OEHHA has evaluated health impacts of certain climate change policies on disadvantaged communities and communities of color utilizing CES rankings.[266] The Healthy Places Index (HPI) maps indicators that affect life expectancy on a statewide basis. In the future, these and other tools can be helpful to prioritizing investments and informing implementation efforts for GHG emission reductions policies.

Environmental Determinants of Health Inequities

Communities with large percentages of Black and other socially vulnerable and marginalized groups are disproportionately located near pollution sources, such as traffic

[261] O'Neill, M. S., M. Jerrett, I. Kawachi, J. I. Levy, A. J. Cohen, N. Gouveia, et al. 2003. "Health, wealth, and air pollution: Advancing theory and methods." *Environ Health Perspect.* 111 (16): 1861–70.
[262] Ponce, N. A., K. J. Hoggatt, M. Wilhelm, and B. Ritz. 2005. "Preterm birth: The interaction of traffic-related air pollution with economic hardship in Los Angeles neighborhoods." *Am J Epidemiol.* 162 (2): 140–8.
[263] Morello-Frosch, R., B. Jesdale, J. Sadd, and M. Pastor. 2010. "Ambient air pollution exposure and full-term birth weight in California." *Environ Health.* 9: 44.
[264] Finkelstein, M. M., M. Jerrett, P. DeLuca, N. Finkelstein, D. K. Verma, K. Chapman, et al. 2003. "Relation between income, air pollution, and mortality: A cohort study." *CMAJ.* 169 (5): 397–402.
[265] Clougherty, J., and L. Kubzansky. 2009. "A framework for examining social stress and susceptibility in air pollution and respiratory health." *Environ Health Perspect.* 117 (9): 1351–8.
[266] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits Within Disadvantaged Communities.* https://oehha.ca.gov/media/downloads/environmental-justice//impactsofghgpoliciesreport020322.pdf.

and freight facilities, industrial facilities, and hazardous waste sites.[267,268,269,270] Research shows large disparities in exposure to pollution between white and non-white populations in California, and between low-income and communities of color (Figure 3-13). The research also shows Black and Latino populations experience significantly greater air pollution impacts than white populations in California.[271] Additionally, Native Americans are disproportionately impacted by air pollution with high rates of exposure to industrial, diesel, and residential pollution sources and higher rates of diseases linked to air pollution.[272, 273]

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[267] Mohai. P., P. M. Lanz, J. Morenoff, J. S. House, and R. P. Mero. 2009. "Racial and socioeconomic disparities in residential proximity to polluting industrial facilities: Evidence from the Americans' Changing Lives Study." *Am J Public Health.* 99 (Suppl 3): S649–56.

[268] Mohai, P., and R. Saha. 2007. "Racial inequality in the distribution of hazardous waste: A national-level reassessment." *Soc Probl.* 54 (3): 343–70.

[269] Morello-Frosch, R., M. Pastor, C. Porras, and J. Sadd. 2002. "Environmental justice and regional inequality in southern California: Implications for future research." *Environ Health Perspect.* 110 (Suppl 2): 149–54.

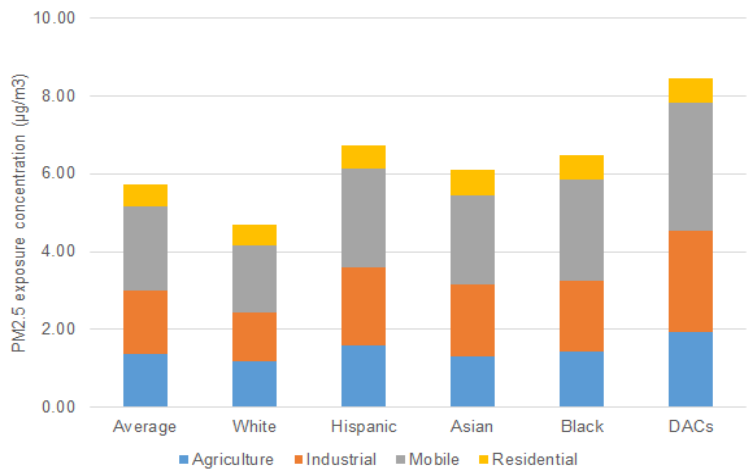
[270] Gunier, R. B., A. Hertz, J. von Behren, and P. Reynolds. 2003. "Traffic density in California: Socioeconomic and ethnic differences among potentially exposed children. *J Expo Anal Environ Epidemiol.* 13 (3): 240–6.

[271] Apte, J. S., S. E. Chambliss, C. W. Tessum, and J. D. Marshall. 2019. *A Method to Prioritize Sources for Reducing High $PM_{2.5}$ Exposures in Environmental Justice Communities in California.* CARB Research Contract Number 17RD006.

[272] Indigenous People and Air Pollution in the United States. A Report from the National Tribal Air Association and Moms Clean Air Force. 2021. https://7vv611.a2cdn1.secureserver.net/wp-content/uploads/2021/04/indigenousairpollution_041421.pdf

[273] National Tribal Air Association. 2022. Status of Tribal Air Report. Pg. 66. https://7vv611.a2cdn1.secureserver.net/wp-content/uploads/2022/10/2022-NTAA-Status-of-Tribal-Air-Report.pdf.

Figure 3-13: Top sources of $PM_{2.5}$ and their contribution to $PM_{2.5}$ exposures by race and in disadvantaged communities



These disparities in exposure to pollution sources generate health inequities. Communities located near major roadways are at increased risk of asthma attacks and other respiratory and cardiac effects. Studies consistently show that mobile source pollution exposure near major roadways or freight sources contributes to and exacerbates asthma, impairs lung function, and increases cardiovascular mortality.[274] The exposure to mixtures of gaseous and particulate pollutants in mobile sources (including PM, NO_x, and benzene) is associated with higher rates of heart attacks, strokes, lung cancer, autism, and dementia.[275]

Environmental hazards found in communities also can include exposures to toxic substances and emissions, as well as occupational exposures. Due to historical inequities, under-resourced communities and communities of color are often located close to sources of toxic pollution, including chrome platers; metal recycling facilities; oil and gas operations; agricultural burning; railyards; facilities transporting, managing, or disposing of hazardous waste; and areas impacted by pesticides, among others. Some populations may be at increased risk of exposure to pollutants, both at work and home.

Children are more susceptible to environmental pollutants for many reasons, including the ongoing development of their nervous, immune, digestive, and other bodily systems. Moreover, children eat more food, drink more fluids, and breathe more air relative to their

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[274] U.S. Environmental Protection Agency website. How Mobile Source Pollution Effects Your Health. https://www.epa.gov/mobile-source-pollution/how-mobile-source-pollution-affects-your-health.
[275] USC Environmental Health Centers. 2018. Living Near Busy Roads or Traffic Pollution. https://envhealthcenters.usc.edu/wp-content/uploads/2016/10/living-near-bus_19696172.pdf.

body weight, as compared to adults.[276] Exposure to high levels of air pollutants, including indoor air pollutants, increases the risk of respiratory infections, heart disease, and asthma.[277] Children living in low-income communities near industrial operations, rail yards, and heavily trafficked freeways and streets in urban areas are at especially high risk of chronic respiratory conditions. Black children are four times more likely to be hospitalized for asthma compared with white children, and urban Black and Latino children are two to six times more likely to die from asthma than white children.[278] Native American children also experience more impacts from asthma and Native American children, along with Black children, have the highest prevalence of asthma.[279]

For older adults, increased vulnerability is linked to respiratory, cardiovascular, and immune systems weakened by aging.[280] Preexisting health conditions interact with environmental pollutants to enhance risks of adverse health outcomes.[281,282] The recent COVID-19 pandemic has highlighted the heightened vulnerability of older adults as well as communities of color to respiratory disease, as hospital admissions and mortality data linked to COVID-19 cases for these groups have been higher than other groups. Research has also underscored the important link between COVID-19 mortality and morbidity and air pollution, demonstrating significantly higher mortality and morbidity for COVID-19 in areas of elevated $PM_{2.5}$ pollution.

Climate Vulnerabilities

Climate change is expected to exacerbate the existing disparities of health conditions and worsen climate vulnerability, which is the degree to which natural systems and people or

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[276] Blaisdell, R. J. Air Toxics Hot Spots Program Risk Assessment Guidelines. 2012. Technical Support Document for Exposure Assessment and Stochastic Analysis. Oakland, California: California Environmental Protection Agency, Office of Environmental Health Hazard Assessment. August.
[277] Woodruff, T. J., D. A. Axelrad, A. D. Kyle, O. Nweke, and G. G. Miller. 2003. *America's Children and the Environment: Measures of Contaminants, Body Burdens, and Illness.* 2nd ed. Washington, D.C.: United States Environmental Protection Agency. February.
[278] California Department of Public Health. Asthma Inequities in California Children. 2021. https://www.cdph.ca.gov/Programs/CCDPHP/DEODC/EHIB/CPE/CDPH%20Document%20Library/CA_Asthma_Inequities_Children_2021-Infographic.pdf.
[279] Meng, Y., S. H. Babey, T. A. Hastert, and E. Brown. 2007. California's Racial and Ethnic Minorities More Adversely Affected by Asthma. UCLA: Center for Health Policy Research. Retrieved from https://escholarship.org/uc/item/4k45v3xt.
[280] Sandström, T., A. J. Frew, M. Svartengren, and G. Viegi. 2003. "The need for a focus on air pollution research in the elderly." *Eur Respir J Suppl.* 40: 92s–5s.
[281] Zanobetti, A., and J. Schwartz. 2001. "Are diabetics more susceptible to the health effects of airborne particles?" *Am J Respir Crit Care Med.* 164 (5): 831–3. https://www.atsjournals.org/doi/pdf/10.1164/ajrccm.164.5.2012039.
[282] Zanobetti, A., J. Schwartz, and D. Gold. 2000. "Are there sensitive subgroups for the effects of airborne particles?" *Environ Health Perspect.* 108 (9): 841–5.

communities are at risk of experiencing the negative impacts of climate change.[283] A report from the California Climate Change Center warned that the impacts of climate change will likely create especially heavy burdens on low-income and other vulnerable populations: "*Without proactive policies to address these equity concerns, climate change will likely reinforce and amplify current as well as future socioeconomic disparities, leaving low-income, minority, and politically marginalized groups with fewer economic opportunities and more environmental and health burdens*."[284]

In the U.S. Environmental Protection Agency's "Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts,"[285] investigators analyzed risks of six primary climate change impacts disproportionately affecting communities across income, educational attainment, race/ethnicity, and age groups. Four socially vulnerable populations—low income, communities of color, no high school diploma, and age 65 and older—were identified as having a higher likelihood of experiencing the greatest impacts of a changing climate (according to the projected 2°C of global warming or 50 centimeters of global sea level rise). Disproportionate impacts were projected for climate events, including air quality, extreme temperature, coastal flooding, and other impacts, leading to increased risk of health and other adverse outcomes. The study projected significant health impacts for low-income communities, certain racial and ethnic subgroups, and those with lower educational attainment.

Several climate vulnerability tools have been developed or are under development to better understand and map areas at higher risk of climate impacts. The Climate Change and Health Vulnerability Indicators (CCHVIs) for California helps state and local health officials prepare for and reduce adverse health impacts due to a changing climate.[286] For example, Los Angeles County shows higher than state average climate vulnerability overall, particularly for those who are linguistically isolated (more than twice the state average).

In summary, there are many environmental, social, individual, and economic factors affecting health and equity in California and contributing to worsening health outcomes from climate change impacts. This section and Appendix G (Public Health) reference a substantial and growing body of research documenting the different social and

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[283] OPR. 2018. Defining Vulnerable Communities in the Context of Climate Adaptation. https://opr.ca.gov/docs/20180723-Vulnerable_Communities.pdf.

[284] Shonkoff, S., R. Morello-Frosch, M. Pastor, and J. Sadd. 2011. "The climate gap: environmental health and equity implications of climate change and mitigation policies in California—A review of the literature." *Climatic Change* 109 (Suppl 1): S485–S503.

[285] U.S. EPA. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency. EPA 430-R-21-003.

[286] CDPH. 2022. Climate Change and Health Vulnerability Indicators for California. California Department of Public Health. https://www.cdph.ca.gov/Programs/OHE/Pages/CC-Health-Vulnerability-Indicators.aspx.

environmental factors affecting health outcomes and the many groups that are vulnerable to increased effects or that experience health inequities in California (see Table 3-13).

Table 3-13: Examples of vulnerable groups due to socioeconomic, environmental, developmental, and climate change factors

Examples of Vulnerable Groups Due to Socioeconomic, Environmental, Developmental, and Climate Change Factors		
Older People	People with Existing Chronic Illness	People Impacted Due to Working Conditions
Tribal Groups	Infants and Children	Low-Income People
People with Disabilities	People Experiencing Homelessness	Pregnant People
Communities of Color	Marginalized People	Immigrants/Refugees
People with Less Educational Options	Linguistically Isolated Households	People Impacted Due to Poor Housing Conditions

Summary of the Qualitative Health Analysis

CARB has developed a detailed health analysis that covers eight social and environmental co-benefit areas that impact public health (listed below). These co-benefit areas were selected due to ongoing research in these areas as well as discussion in a public workshop on climate change and health impacts held in summer 2018. For each social and environmental area, the analysis includes:

- a discussion of health impacts and disparities,
- key health metrics or epidemiological research on this topic,
- a discussion of how these areas would be affected by “no-action” (i.e., Reference) scenario compared to a “take-action” (i.e., Scoping Plan) scenario
- a discussion of where there are actions to consider for further success, and
- the types of mitigation actions that can help reduce or eliminate disparities and promote greater health equity and resilience.

All co-benefit areas are interconnected, and pursuing benefits in all areas has the potential to multiply positive results and further support building community resilience. *Community resilience* is the ability of a community to reduce harm and maintain an acceptable quality of life in the face of climate-induced stresses, which vary depending on that community’s circumstances and location. Below is a brief description of the areas evaluated for public health co-benefits. The specific health outcomes impacted by each area, as well as the directional health benefits, are included in the Summary of Health Benefits section of the chapter and covered in more detail in Appendix G (Public Health).

Heat Impacts

Globally, increased GHG concentrations in the atmosphere are causing a continuing increase of the planet's average temperature. California temperatures have risen since records began in 1895, and the rate of increase is accelerating. Recent heat waves have broken heat records and caused serious illness across the state, and these events are becoming more frequent. Heat waves have a particularly high impact in Southern California, where they have become more intense and longer lasting. In the past two years, Los Angeles recorded 121°F, and the Coachella Valley had its hottest year ever, with temperatures reaching 123°F. Heat island effects in urbanized areas can elevate heat effects and disproportionately affect low-income communities and communities of color. Heat events exacerbate respiratory and cardiac illness and cause emergency room visits to soar. Strategies that reduce the impacts of heat exposure promote improved health outcomes.

Wildfires and Smoke

California's NWL cover more than 90 percent of California and include rangeland, forests, woodlands, grasslands, and urban green space. They provide biodiversity and ecosystem benefits, including their ability to sequester carbon from the atmosphere. Protecting and managing California's forests and other natural lands and maintaining their ecosystem health are key practices for maximizing GHG benefits and minimizing negative climate change impacts. Vegetation plays an important role in storing carbon; however, it can also release CO_2 back into the atmosphere when it dies or is burned by fires. California's wildfires are getting worse with increased fire risks, higher frequency of occurrence, larger burn areas, more costly damage, and a longer fire season due to climate change. Strategies that promote healthy ecosystem management of natural and working lands and increased urban greening promote improved health outcomes. Healthy ecosystems provide many health and environmental benefits and can maximize carbon sequestration.

Children's Health and Development

There are a wide range of interconnected environmental, social, biological, and community factors associated with climate change that are adversely affecting children's health. This section focuses on air pollution and near-roadway or traffic pollution as environmental impacts that have a profound effect on children's health. Children's bodies and lungs are still developing, and they take in more air per body weight than adults do. Many low-income communities and communities of color in California experience disproportionately high levels of air pollution, as well as high levels of traffic and freight that impact children. This excess exposure harms children's development and predisposes them to increased risk of illness throughout their lives. Strategies that reduce air pollution and traffic emissions promote improved health outcomes for children.

Economic Security

Climate change is expected to result in serious adverse socioeconomic effects across many sectors. Economic factors, such as income inequality (among geographic regions), poverty, wealth, debt, unemployment rate, and job security are among the strongest determinants of health. Along the entire income spectrum, higher income is associated with increased life expectancy and improved health outcomes in the United States. Additionally, economic insecurity and negative health impacts are more pronounced in low-income communities and communities of color. Economic strategies, such as the promotion of clean energy and other green jobs and investments in low-income communities and communities of color, and promoting a transition to high road jobs in economic sectors tied to the current fossil fuel economy, can promote improved health outcomes.[287]

Food Security

The food system is under pressure from numerous factors, and climate change is a key concern. Climate change can affect food production and agricultural yield, impact culturally significant plants and animals for Native American tribes, and exacerbate factors that limit food availability, such as supply chain disruption. Food security is defined as stable access to affordable, sufficient food for an active, healthy life. Many Californians routinely experience food insecurity, and while that impacts Californians of all races and groups, low-income communities and communities of color and children are disproportionately affected by food insecurity. Many Native Americans depend on resources from the land, such as animals and plants for consumption and cultural practices. Strategies that promote sustainable agriculture, access to healthy foods, and reduced organic food waste promote improved health outcomes.

Mobility and Physical Activity

Physical activity is one of the most important factors for a healthy lifestyle, and lack of activity increases the risk of chronic illness and premature death. Research shows that regular physical activity improves health in people of all ages by improving heart and lung

[287] According to the California Labor and Workforce Development Agency's High Road Training Partnership program, high road jobs are considered "Quality jobs [that] provide family-sustaining wages, health benefits, a pension, worker advancement opportunities, and collective worker input and are stable, predictable, safe and free of discrimination." https://cwdb.ca.gov/wp-content/uploads/sites/43/2020/08/OneSheet_Job-Quality_ACCESSIBLE.pdf.

function, muscle fitness, mental health and brain function, and sleep quality. A sedentary lifestyle contributes to chronic illnesses, including obesity, heart disease, and Type 2 diabetes among other chronic illnesses. Promoting community design that supports sustainable patterns of land use and transportation enables active transportation choices like walking, biking, and public transit over driving, and can significantly increase physical activity, leading to many valuable health benefits.

Affordable Housing

Housing is an important social determinant of health. The stability of housing, housing quality, conditions inside and outside the home, the cost of housing, and the environmental and social characteristics of the places people live all affect health (including energy efficiency and insulation, cooler building material, tree canopy, home size). Housing affordability is a key factor, and this section highlights how housing affordability supports not only improved health but also more sustainable land use and transportation patterns. A lack of affordable housing is increasing commute distances for low-income renters and creating health burdens. Strategies that support sustainable transportation and housing patterns, together with increased housing affordability, promote improved health outcomes.

Urban Greening

Urban Greening is well recognized as an important amenity, but the inherent health benefits are not always well understood. Under-resourced and vulnerable areas consistently show a lack of urban greening and higher percentages of concrete, asphalt, and impervious surfaces. Under-resourced communities have a greater proportion of concrete and heat-trapping surfaces and a lower amount of tree cover in the neighborhoods in which they live. Areas with reduced urban greening have the potential to create areas of higher temperatures as heat is reflected from pavements and buildings. By contrast, increasing urban greening can provide air pollution buffers and promote physical activity. Strategies that preserve and create urban parks, green space, natural infrastructure, and sustainable agricultural practices support improved physical and mental health outcomes.

No Action Scenario (Reference)

In a no-action scenario, California would remain dependent on fossil fuels and other GHG emitting technologies. Fossil-fuel powered mobile sources including cars, trucks, trains, tractors, and a myriad of other on-road and off-road vehicles and equipment are the largest source of criteria pollutants and toxic air contaminants that directly affect community health and contribute the largest portion of GHG emissions.[288] Other key GHG emission sources include buildings, natural and working lands, and power production and industry. The no-action scenario reflects a continued reliance on fossil fuels in mobile and stationary sectors, including buildings. The continued production and use of fossil fuels; ongoing dependence on gasoline and diesel cars, trucks, buses, and equipment; continued releases of short-lived climate pollutants; and decreased emphasis on forest and ecosystem health will impact communities by reducing climate resilience and health benefits. Green space will likely remain at the same levels or degrade, and urban heat islands will likely increase. With continued growth of vehicle miles traveled, physical activity and the accompanying health benefits will not increase.

Exposure to wildfire smoke will increase, and air quality is expected to worsen as rising temperatures will increase levels of harmful air pollution. Jobs and economic security will be affected by the continuing potential for price spikes in fossil fuels, impacts to the economy from climate change, and fewer job opportunities in green technologies such as solar and electric vehicles. Food security in California will decrease due to the effects of accelerating climate impacts to agriculture; and without increased recovery of organic waste, including food products, food security will continue to decline under a no action scenario. All these impacts can be linked to worse health outcomes. Adverse health impacts are often most felt by Black, Latino, Native American, and other people of color and in low-income communities. These groups are affected more intensely by the physical stress of environmental pollution, social inequities, and the psychological stress of extreme weather events and food and economic insecurity.

Take Action Scenario

In the Take Action scenario, California will drastically reduce reliance on fossil fuels for motor vehicles, freight, buildings, electricity, or other sectors. This scenario is not a specific scenario within this Scoping Plan but examines the broad outcomes of actions to achieve carbon neutrality in 2045. Implementation of this Scoping Plan would achieve a transition to ZEVs, with 100% sales of light-duty ZEVs by 2035 and 100% sales of zero emission trucks by 2040, along with 30% VMT reductions below 2019 levels by 2045. State and local action that supports sustainable land use and transportation patterns and enables more transit and active transportation will lead to substantial health benefits from physical activity, including reduced illness and deaths.

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[288] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

The economic benefits of improved health through active transportation can be modeled using the Healthy Mobility Options Tool (HMOT).[289] In order to demonstrate the important health and economic benefits of VMT reduction, CARB and CDPH used the HMOT to analyze an illustrative trip reduction scenario for 2050 from the California Transportation Plan (CTP). The CTP has a goal of increasing active modes of travel and transit from the current level of 13 percent to a level of 23 percent of all travel trips. While the CTP goal of 23 percent for active modes of travel is not a VMT reduction target, the scenario increases active transportation through a mix of changes in land use planning for increased transportation options, including increases in biking, walking, and transit use, and it helps to show the health benefits of increased active transportation. By achieving the CTP 2050 goals, nearly 8,000 deaths would be avoided in 2050 alone (see Figure 3-14), along with significant reductions in chronic diseases. Achieving this would rank among the top public health accomplishments (see Appendix G [Public Health] for additional modeling results and detailed discussion).

The dramatic reduction in fossil fuel combustion, combined with reductions in VMT and freight and traffic emissions projected in this Scoping Plan will significantly reduce air pollution and its associated health impacts on a statewide basis and in communities near freight sources. Coordinated action strategies will emphasize natural and working lands management changes, including healthy forests, increased vegetative cover, and increased organic farming. Wildfire smoke exposure will reduce significantly with healthy ecosystem management strategies. Since many communities in California are disproportionately impacted by high levels of traffic pollution, the reduction in petroleum fueled vehicles will reduce the additional impacts of living or going to school near historically highly polluting sources. Indoor air quality is also likely to improve through a shift to non-fossil fuel appliances. Concerted state and local action to support sustainable land use and transportation patterns can enable more active transportation with health benefits from physical activity.

[289] ITHIM California. 2020. Transportation Planning for Health, Equity, and Climate Change. https://skylab.cdph.ca.gov/HealthyMobilityOptionTool-ITHIM/.

Figure 3-14: Quantified health benefits of active transportation from increased physical activity

*Calculated by the Healthy Mobility Options Tool, active transportation (including walking, rolling, cycling, and taking public transit) from the California Transportation Plan 2050 compared to business as usual for 2050.

Overall community resilience is expected to increase as physical activity and green space increases—potentially decreasing urban heat islands. Efforts to support VMT reduction will include coordination across state agencies on affordable housing measures. Reduced fossil fuel dependence will reduce economic pressure from wildfires, droughts, and price spikes in fossil fuels, especially as more jurisdictions implement plans with similar actions. Investment in sustainable agriculture, healthy forests, urban greening, and clean energy technologies will add sustainable jobs and further promote economic security. More sustainable agriculture and food recovery efforts will add to food security. All these impacts can be linked to wide ranging health benefits, including positive respiratory and cardiovascular effects, healthier birth and brain outcomes, improved mental health indicators, improved life expectancy, reductions in chronic illness and cancers, improved children's health and development, reduced depression, and other benefits. The magnitude of the possible co-benefits is extremely large, especially in areas that are currently the most affected.

Summary of Health Benefits

Below, Tables 3-14 and 3-15 show overall summaries of the directional benefits by co-benefit area estimated for this Scoping Plan. The supporting epidemiological studies used for qualitative or quantitative analysis of each co-benefit area are included in Appendix G (Public Health). Another section of Chapter 3, together with Appendix C (AB 197 Measure Analysis) and Appendix H (AB 32 GHG Inventory Sector Modeling), also includes the quantitative analysis of air pollution related health impacts, including recently added health endpoints for CARB's ongoing analysis.

Table 3-14: Scoping Plan directional benefits for health co-benefit areas (heat, affordable housing, food security, economic security, and urban greening)

	Health Co-benefit Areas*				
Quantitative vs. Qualitative	**Reduced Heat Impacts**	**Increased Affordable Housing**	**Increased Food Security**	**Increased Economic Security**	**Increased Urban Greening**
Research was used for Qualitative Analysis	↓ Mortality ↓ Emergency Room Visits for cardiovascular and respiratory causes and intestinal infections ↓Hospitalization for cardiovascular, respiratory causes ↓ Preterm Birth ↓ Mental Illness	↓ Infectious Disease ↓ Chronic Illness ↓ Asthma ↓ Injuries ↓ Mental Illness ↑ Children's Performance in Schools ↑ Children's Health ↓ Children's Behavioral Problems	↓ Mental Illness ↓ Iron Deficiency ↓ Chronic Diseases ↑ Life Expectancy ↓ Children's Mental Illness ↓ Children's Cognitive Problems ↓ Children's Behavioral Health Problems ↓ Children's Iron Deficiency ↓ Children's Oral Health Problems	↑ Life Expectancy ↑ Health Status ↑ Mental Health	↓ Mortality ↓ Asthma Prevalence ↓ Depression ↓ Adverse Birth Outcomes including low birth weight and small for gestational age ↑ Life Expectancy

*See Appendix G (Public Health) for a table with references to research for each health outcome listed.

Table 3-15: Scoping Plan directional benefits for health co-benefit areas (traffic pollution, wildfire, and active transportation)

Health Co-benefit Areas*			
Quantitative vs. Qualitative	**Reduced Traffic Pollution**	**Reduced Wildfire Smoke**	**Increased Active Transportation**
Research was used for Quantitative Analysis	↓ Children's Respiratory Outcomes, Hospital Admissions ↓ Children's Respiratory Outcomes, Emergency Room Visits ↓ Children's Asthma Onset ↓ Children's Asthma Symptoms	↓ All-Cause Mortality ↓ Asthma, Hospital Admissions ↓ COPD, Hospital Admissions ↓ All Respiratory Outcomes, Hospital Admissions ↓ Asthma, Emergency Room Visits ↓ All Respiratory Outcomes, Emergency Room Visits ↓ All Cardiac Outcomes, Emergency Room Visits	↓ Cardiovascular Diseases ↓ Colon Cancer ↓ Breast Cancer ↓ Diabetes ↓ Dementia ↓ Lung Cancer ↓ Respiratory Disease ↓ Depression ↑ Traffic Accidents
Research was used for Qualitative Analysis	↑ Children's Lung Function Growth ↓ Children's Bronchitic Symptoms ↓ Children's Impaired Cognitive Development ↓ Children's Adverse Birth Outcomes, including low birth weight and preterm birth		

*See Appendix G (Public Health) for a table with references to research for each health outcome listed.

In summary, the qualitative health analysis of the No-Action versus Take-Action scenarios for this Scoping Plan shows an overwhelming benefit for the state by taking action to move forward to carbon neutrality while continuing efforts to increase health equity and resilience in individual communities. Taking action can improve physical and mental health for adults and children, reduce a range of chronic illnesses, and promote improvements in life expectancy. Development and implementation of actions to achieve the outcomes called for in this Scoping Plan should consider how to engage affected communities in implementation, address the existing health and opportunity gaps, and pursue equitable implementation statewide and locally. This Scoping Plan deployment of clean technology and fuels, together with improved land management, will reduce GHGs and air pollution and create more resilient communities that are better able to prepare for and recover from extreme climate events.

Environmental Analysis

In May 2022, CARB, as the lead agency for the Scoping Plan, released for public review the Draft Environmental Analysis (Draft EA) for this Scoping Plan; it assessed the potential environmental impacts of implementing the Scoping Plan. CARB circulated the Draft EA for public review and comment for a period of 45 days that began on May 10, 2022, and ended on June 24, 2022. CARB held a public hearing on June 23, 2022 to provide the opportunity for public comment. During the review period, written and oral comments were received on the Draft EA. CARB reviewed the comments to identify environmental topics and began preparation of responses to those comments.

After the end of the Draft EA public review period, CARB identified potential revisions to certain aspects of this Scoping Plan that merit revisions to the project description. This new information results from, among other things, revisions to the project description regarding energy sector goals (including offshore wind), revised carbon removal targets, and additional strategies for natural and working lands. CARB released a Recirculated Draft EA for a written public comment period that started September 9, 2022, and ended on October 24, 2022. See Chapter 2 of the Recirculated Draft EA[290] for further information regarding the changes. The Recirculated Draft EA assesses the potential for significant adverse and beneficial environmental impacts associated with all proposed actions in this Scoping Plan, and provides a programmatic environmental analysis of the reasonably foreseeable compliance responses that could result from implementation of the Scoping

[290] CARB. 2022. Recirculated Draft EA. https://ww2.arb.ca.gov/sites/default/files/2022-09/2022-draft-sp-appendix-b-draft-ea-recirc.pdf.

Plan.[291] The Recirculated Draft EA concluded implementation of this Scoping Plan could result in the following:

- Beneficial impacts to: air quality (long-term operational-related) and GHG emissions (short-term construction-related and long-term operational-related)
- Less than significant impacts to: energy demand, mineral resources, population and housing, public services, recreation (short-term construction-related), and wildfire (short-term construction-related)
- Potentially significant and unavoidable adverse impacts to: aesthetics, agriculture and forest resources, air quality (construction-related and operational odors), biological resources, cultural resources, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, noise, recreation (long-term operational-related), transportation and traffic, tribal cultural resources, utilities and service systems, and wildfire (long-term operational-related

Before the public meeting at which the Board will consider this Scoping Plan Update, CARB will publish the Final EA as Appendix B (Final Environmental Analysis) to this Scoping Plan, along with written responses to timely submitted comments raising significant environmental issues received on the Draft EA and the Recirculated Draft EA, which will be presented to the Board for consideration.

[291] The Recirculated Draft EA is available at *https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents*.

Chapter 4: Key Sectors

Chapter 4 provides an overview of the major energy sources and technology in use today, and of alternative clean technology and fuels to support decarbonization based on the latest information available. Every sector of the economy will need to begin to transition in this decade to meet our GHG reduction goals and achieve carbon neutrality no later than 2045. AB 32 requires climate change mitigation policies to be considered in the context of the sector's contribution to the state's total GHG emissions. The transportation, electricity (in-state and imported), and industrial sectors are the largest contributors of GHGs in the state and present the largest opportunities for GHG reductions. Actions to reduce fossil fuel combustion in these sectors also can provide critical air pollution reductions in low-income communities and communities of color, which are often located adjacent to these sources. A carbon neutrality framework also elevates the role of CO_2 removal through natural and working lands and mechanical capture and storage. Actions that support energy efficiency, reduced VMT, alternative fuels, and renewable power also can provide benefits by reducing both criteria and toxic air pollutants.

What sets this plan apart from previous Scoping Plans is the focus on the accelerated rate of deployment of clean technology and energy within every sector. As a result, specific actions, including accelerated rates of deployment of clean technology and fuels identified within this Scoping Plan, will need to be translated into both new and amended regulations, policies, and incentive programs. State agencies will need to evaluate current authority to align existing policies or develop new ones to achieve outcomes called for in this Scoping Plan. Legislative support may be needed in some cases to ensure authority and funding is sufficient to ensure this Scoping Plan is translatable to action on the ground. Most regulations, or change to existing regulations, ultimately considered by the Board or other state agencies for adoption will be subject to administrative procedure requirements. Accordingly, they must rely on specific subsequent supporting analysis and extensive public processes and consultations with interested tribes to develop and identify appropriate proposals for effective implementation. For example, any proposal to strengthen the LCFS regulations through amendments increasing the stringency of the carbon intensity (CI) targets would be considered on the basis of a public process, including workshops, and focused environmental, economic, and public health analyses.

Policies that ensure economy-wide investment or program decisions that incorporate consideration of GHG emissions are particularly important. As we pursue GHG reduction targets, we must acknowledge the manner in which built and natural environments are connected, how changes in one may impact the other, and how policy choices in one sector can and do impact other sectors. For example, fostering more compact, transportation-efficient development in infill areas and increasing transportation choices with the goal of reducing VMT not only reduces demand for transportation fuel but also requires less energy for buildings and helps to conserve natural and working lands that sequester carbon. Therefore, the multiple and often interwoven actions that reduce VMT both reduce emissions from the transportation sector and support reductions needed in other sectors.

Legislation, such as SB 350[292] (De León and Leno, Chapter 457, Statutes of 2015), has recognized the need for CARB, the CEC, and the CPUC to work together to ensure the state's energy and climate goals are integrated in procurement decisions by load serving entities as part of Integrated Resource Plans. Moving forward, it is especially critical that similar approaches are adopted to break down silos across state agencies to ensure policies and programs are aligned with multiple state priorities outlined in this plan. Finally, supportive legislative direction, such as SB 905 that requires CARB to create the Carbon Capture, Removal, Utilization, and Storage Program, may also benefit emerging areas of policy to provide express agency authority and roles for these nascent efforts, including streamlining of permitting, while ensuring that protections for communities are in place.

Unlike previous Scoping Plans that separated out individual economic sectors, this Scoping Plan approaches decarbonization from two perspectives: (1) managing a phasedown of existing energy sources and technology and (2) ramping up, developing, and deploying alternative clean energy sources and technology over time. This approach supports a more comprehensive consideration of our energy infrastructure, the ability to repurpose existing assets, and the need to build new assets. It also provides multiple metrics beyond just the annual AB 32 GHG Inventory to better enable tracking progress. For example, it clearly demonstrates the production and distribution rates of specific types of clean energy, such as adding 4.3 GW of utility solar and 2.5 GW of storage year-over-year between now and 2035 to be on track to achieve carbon neutrality no later than 2045, and does the same for technology deployment, such as 11 million ZEVs in 2035.

The sections below include key actions to support success in the necessary transition away from fossil combustion, which is an overriding goal of this plan. The wide array of complementary and supporting actions being contemplated or to be undertaken across state government are detailed here. The broad view of actions described in this chapter thus provides context for the specific deployment of clean technology and fuels identified in the Scoping Plan Scenario described in Chapter 2. Actions identified in this Scoping Plan are based on currently known options and the latest science. As part of future Scoping Plan updates, additional clean technology and fuels may be identified and added to the mix of needed tools to continue to reduce the state's GHG emissions, support air quality co-benefits, and remove carbon from the atmosphere.

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[292] California Air Resources Board. SB 350 Electricity Sector Greenhouse Gas Planning Targets. https://ww2.arb.ca.gov/our-work/programs/sb350.

Transportation Sustainability

The transportation sector has long relied on liquid petroleum fuels as the primary energy source for internal combustion engine (ICE) vehicles, including cars, trucks, locomotives, marine equipment, and aircraft. Combustion of fossil fuels in vehicles emits significant amounts of GHGs, criteria pollutants, and toxic air contaminants. In 2019,[293] the transportation sector accounted for approximately 50 percent of statewide GHG emissions[294] and thus was by far the single largest source of carbon pollution in the state. In addition, the transportation sector accounted for over 80 percent of statewide NOx emissions and 30% of fine particulate matter emissions, including toxic diesel particulate matter.[295]

Communities adjacent to congested roadways, including ports and distribution centers, are exposed to the highest concentration of toxic pollutants from vehicles and equipment consuming fossil fuels, leading to a number of demonstrated health impacts such as respiratory illnesses, higher likelihood of cancer development, and premature death. In addition, communities located near oil extraction operations or crude oil refineries often experience higher exposure to poor air quality. While CARB's programs, along with local action, have made substantial progress over the past few decades, it is clear that California must transition away from fossil fuels to zero-emission technologies with all possible speed and pursue policies that result in less driving, in order to meet our GHG and air quality targets.

The transportation sector can be divided into three general categories: Technology, Fuels, and Vehicle Miles Traveled.

- *Technology* refers to the vehicles themselves, as well as the associated refueling infrastructure for those vehicles.
- *Fuels* refers to the energy source used to power vehicles and the facilities that produce them.
- Vehicle travel is measured as *vehicle miles traveled* (VMT), and is a product of development patterns and available transportation options.

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[293] In 2020 the state experienced shelter-in-place orders in response to the COVID-19 pandemic. The orders, and the effects of the pandemic, led to a significant year-over-year decline in transportation emissions in 2020. This means 2019 is likely a more representative year for overall transportation emissions and 2020 a likely outlier in the historical transportation emissions trend data.
[294] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf. This includes upstream oil extraction and refining emissions.
[295] CARB. California Greenhouse Gas Emission Inventory Program. https://ww2.arb.ca.gov/our-work/programs/ghg-inventory-program.

Sector Transition

Technology

Vehicles must transition to zero emission technology to decarbonize the transportation sector. Executive Order N-79-20[296] reflects the urgency of transitioning to zero emission vehicles (ZEVs) by establishing target dates for reaching 100 percent ZEV sales or fleet transitions to ZEV technology. The primary ZEV technologies available today are battery-electric and hydrogen fuel cell electric vehicles (FCEVs), both of which emit zero tailpipe GHGs, criteria pollutants, and toxic air contaminants, as they do not burn fuel. These vehicles are rapidly growing in performance, affordability, and popularity.[297] Plug-in hybrid electric vehicles also offer a limited but increasing range of zero emission operation and will play a role in the transition to ZEVs.

Light-duty passenger vehicles consume the majority of gasoline in the state—12.9 billion gallons in 2019[298]—and are well-suited for transitioning to ZEVs. EO N-79-20 calls for 100 percent ZEV sales of new light-duty vehicles by 2035, and this target is reflected in this Scoping Plan.[299] The Advanced Clean Cars II regulation fulfills the goal in the Executive Order and serves as the primary mechanism to help deploy ZEVs. A number of existing incentive programs also support this transition, including the Clean Cars 4 All Program.[300] Heavy-duty trucks are the largest source of diesel particulate matter, a toxic air contaminant that is directly linked to a number of adverse health impacts, and EO N-79-20 also sets targets for transitioning the medium- and heavy-duty fleet to zero emissions: by 2035 for drayage trucks and by 2045 for buses and heavy-duty long-haul trucks where feasible. Replacing heavy-duty vehicles with ZEV technology will significantly reduce GHG emissions and diesel PM emissions in low-income communities and communities of color adjacent to ports, distribution centers, and highways. The existing Advanced Clean Trucks regulation, paired with the proposed Advanced Clean Fleets regulation, are designed to transition a significant amount of the

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[296] Executive Department. State of California. Executive Order N-79-20. https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf.

[297] CARB. 2021. Public Workshop for Advanced Clean Cars II. May 6. https://ww2.arb.ca.gov/sites/default/files/2021-05/acc2_workshop_slides_may062021_ac.pdf.

[298] CARB. 2022. *Fuel Activity for California's Greenhouse Gas Inventory by Sector and Activity.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/fuel_activity_inventory_by_sector_all_00-20.xlsx.

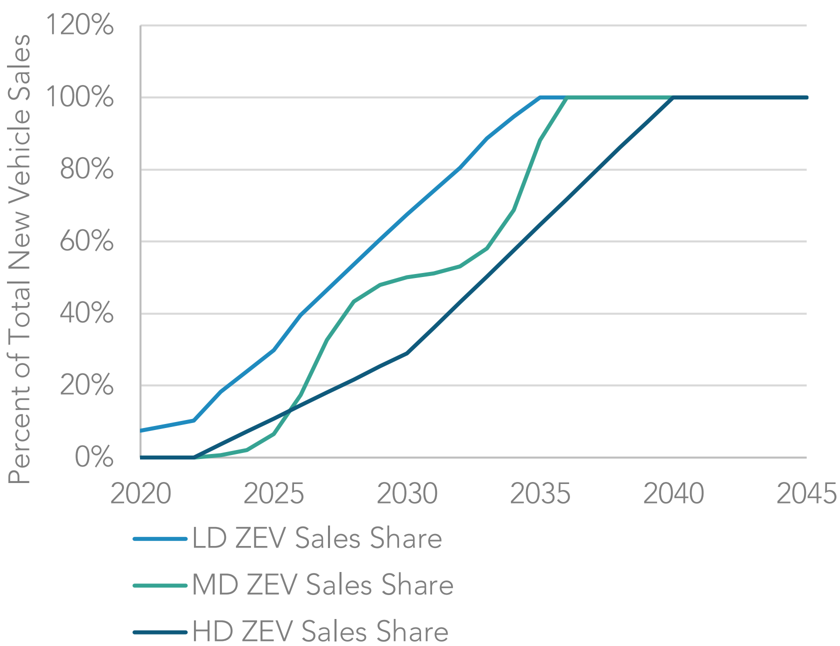
[299] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1A, with reference to the date at which all new vehicle sales are ZEVs. finalejacrecs.pdf (arb.ca.gov).

[300] CARB. Clean Cars 4 All. https://ww2.arb.ca.gov/our-work/programs/clean-cars-4-all. The Clean Vehicle Rebate Project (CVRP) also supports the transition to ZEVs. https://cleanvehiclerebate.org/en.

California truck fleet to ZEV technology. As with the LDV sector, a number of incentive programs support this transition, such as the Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP).[301]

Figure 4-1 below illustrates the pace of transition in vehicle technology needed to drastically reduce GHG emissions from vehicles. All vehicle classes reach 100 percent ZEV sales before 2045, with some achieving this well before. The ZEV technology across the vehicle classes is assumed to be primarily battery electric and hydrogen fuel cell (reflecting the primary ZEV technologies available today).[302]

Figure 4-1: Transition of on-road vehicle sales to ZEV technology in the Scoping Plan Scenario



Today, off-road vehicles also rely heavily on ICE technology. Executive Order N-79-20 sets an off-road equipment target of transitioning the entire fleet to ZEV technology by 2035, where feasible. There is a great need for both investment and innovation in the off-road space in order to develop and commercialize zero emission equipment types that meet or exceed the performance of existing equipment. A number of funding sources currently support this transition, including programs such as FARMER, Carl Moyer, and

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[301] California HVIP. Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project. https://californiahvip.org/?msclkid=efaf65f2c26f11eca6bdd08ecc323864.

[302] The light-duty fleet includes more than 11 million battery electric and hydrogen fuel cell vehicles in 2035 and over 23 million battery electric and hydrogen fuel cell vehicles in 2045.

the Community Air Protection Incentives—as well as Low Carbon Transportation Incentives, including the Clean Off-Road Equipment (CORE) program. In addition, the 2021–22 California budget provided record-high allocations for funding ZEVs, including off-road equipment, and the 2022–23 budget is similarly ambitious.[303] Several regulations focused on transitioning to zero emission off-road equipment have recently been adopted or are in the works, and apply to locomotives,[304] forklifts, ocean-going vessels at berth,[305] commercial harbor craft,[306] small off-road engines,[307] and more.

Intrastate aviation relies on ICE technology today, but battery-electric and hydrogen fuel cell aviation applications are in development, along with sustainable aviation fuel. The Scoping Plan Scenario includes a transition of 20% of aviation fuel demand to ZEV technologies by 2045 and sustainable aviation fuel for the rest.

Refueling infrastructure is a crucial component of transforming transportation technology. Electric vehicle chargers and hydrogen refueling stations must become easily accessible for all drivers to support a wholesale transition to ZEV technology. Deployment of ZEV refueling infrastructure is currently supported by a number of existing local and state public funding mechanisms, the new National Electric Vehicle Infrastructure (NEVI) federal funding mechanism, California's electric utilities, the Electrify America initiative that was established in response the Volkswagen ZEV commitment, and by numerous companies, such as EVgo, ChargePoint, Tesla, Ford, FirstElement Fuel, Chevron, Shell, and Iwatani, who are investing substantial private resources into developing these networks. Private investment in reliable, affordable and ubiquitous refueling infrastructure must drive the transition as the business case for ZEVs continues to strengthen.

Strategies for Achieving Success

- Achieve 100 percent ZEV sales of light-duty vehicles by 2035[308] and medium-heavy-duty vehicles by 2040.
- Achieve a 20% zero emission target for the aviation sector.

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303 AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1C. CARB and the Administration are committed to increasing focus on transportation equity investment as was reflected in the governor's 2022–23 budget. *finalejacrecs.pdf (arb.ca.gov)*.

304 CARB. Reducing Rail Emissions in California. *https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california.*

305 CARB. Ocean-Going Vessels At Berth Regulation. *https://ww2.arb.ca.gov/our-work/programs/ocean-going-vessels-berth-regulation*.

306 CARB. CARB passes amendments to commercial harbor craft regulation. *https://ww2.arb.ca.gov/news/carb-passes-amendments-commercial-harbor-craft-regulation*.

307 CARB. Small Off-Road Engines (SORE). *https://ww2.arb.ca.gov/our-work/programs/small-off-road-engines-sore*.

308 AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1A. *finalejacrecs.pdf (arb.ca.gov)*.

- Develop a rapid and robust network of ZEV refueling infrastructure to support the needed transition to ZEVs.
- Ensure that the transition to ZEV technology is affordable for low-income households and communities of color, and meets the needs of communities and small businesses.[309]
- Prioritize incentive funding for heavy-duty ZEV technology deployment in regions of the state with the highest concentrations of harmful criteria and toxic air contaminant emissions.[310]
- Promote private investment in the transition to ZEV technology, undergirded by regulatory certainty such as infrastructure credits in the Low Carbon Fuel Standard for hydrogen and electricity[311] and hydrogen station grants from the CEC's Clean Transportation Program[312] pursuant to Executive Order B-48-18.[313]
- Evaluate and continue to offer incentives similar to those through FARMER,[314] Carl Moyer,[315] the Clean Fuel Reward Program,[316] the Community Air Protection Program,[317] and Low Carbon Transportation,[318] including CORE.[319] Where feasible, prioritize and increase funding for clean transportation equity programs.[320]
- Continue and accelerate funding support for zero emission vehicles and refueling infrastructure through 2030 to ensure the rapid transformation of the transportation sector.

[309] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF6, in the context of communities. finalejacrecs.pdf (arb.ca.gov).
[310] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF7. finalejacrecs.pdf (arb.ca.gov).
[311] CARB. LCFS ZEV Infrastructure Crediting. https://ww2.arb.ca.gov/resources/documents/lcfs-zev-infrastructure-crediting.
[312] CEC. Clean Transportation Program. https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program.
[313] EO B-48-18 calls for 200 hydrogen refueling stations by 2025. https://www.library.ca.gov/wp-content/uploads/GovernmentPublications/executive-order-proclamation/39-B-48-18.pdf.
[314] CARB. FARMER program. https://ww2.arb.ca.gov/our-work/programs/farmer-program.
[315] CARB. Carl Moyer program. https://ww2.arb.ca.gov/our-work/programs/carl-moyer-memorial-air-quality-standards-attainment-program.
[316] California Clean Fuel Reward Program. https://cleanfuelreward.com/.
[317] CARB. Community Air Protection Program. https://ww2.arb.ca.gov/capp.
[318] CARB. Low Carbon Transportation Investments and Air Quality Improvement Program. https://ww2.arb.ca.gov/our-work/programs/low-carbon-transportation-investments-and-air-quality-improvement-program.
[319] Clean Off-Road Equipment (CORE) Voucher Incentive Program. https://californiacore.org/.
[320] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1C. finalejacrecs.pdf (arb.ca.gov).

- Evaluate and align with this Scoping Plan relevant CARB policies such as Advanced Clean Cars II,[321] Innovative Clean Transit,[322] Zero Emission Airport Shuttle,[323] California Phase 2 GHG Standards,[324] Advanced Clean Trucks, Advanced Clean Fleets, Zero Emission Forklifts,[325] In-use Locomotives,[326] the Off-Road Zero-Emission Targeted Manufacturer rule, Clean Off-Road Fleet Recognition Program, In-use Off-Road Diesel-Fueled Fleets Regulation,[327] Commercial Harbor Craft,[328] Off-Road Zero-Emission Targeted Manufacturer rule, Clean Off-Road Fleet Recognition Program, Amendments to the In-use Off-Road Diesel-Fueled Fleets Regulation,[329] carbon pricing through the Cap-and-Trade Program,[330] and the Low Carbon Fuel Standard.[331]
- Identify and address permitting and market barriers to successful rapid ZEV technology deployment while protecting public health and the environment.

Fuels

Transitioning away from conventional ICE vehicles is part of the solution, but we must ensure that an adequate supply of zero-carbon alternative fuel and distribution is available to power these vehicles. Electricity and hydrogen are currently the primary fuels for ZEVs,

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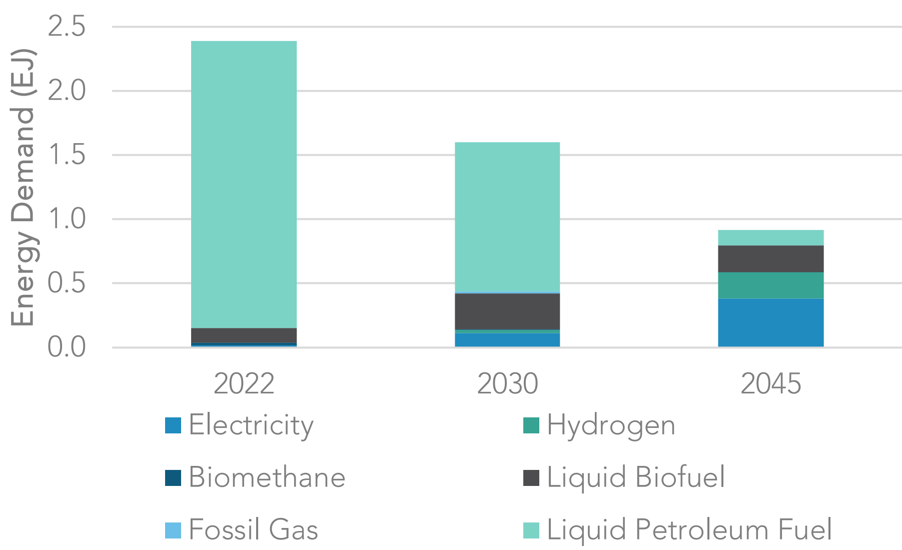
[321] CARB. Advanced Clean Cars Program. https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program. Cal. Code Regs., tit. 13, §§ 1900, 1961.2, 1961.3, 1961.4, 1962.2, 1962.3, 1962.4, 1962.5, 1962.6, 1962.7, 1962.8, 1965, 1968.2, 1969, 1976, 1978, 2037, 2038, 2112, 2139, 2140, 2147, 2317, 2903.
[322] CARB. Innovative Clean Transit. https://ww2.arb.ca.gov/our-work/programs/innovative-clean-transit. Cal. Code Regs., tit. 13, §§ 2023—2023.11.
[323] CARB. Zero-Emission Airport Shuttle. https://ww2.arb.ca.gov/our-work/programs/zero-emission-airport-shuttle. Cal. Code Regs., tit. 17, §§ 95690.1—95690.8.
[324] CARB. California Phase 2 Greenhouse Gas Standards. https://ww2.arb.ca.gov/our-work/programs/greenhouse-gas-standards-medium-and-heavy-duty-engines-and-vehicles/phase2. Cal. Code Regs., tit. 13, §§ 1956.8 and 2036; and Cal. Code Regs., tit. 17, §§ 95301, 95302, 95303, and 95663.
[325] CARB. Zero-Emission Forklifts. https://ww2.arb.ca.gov/our-work/programs/zero-emission-forklifts. Cal. Code Regs., tit. 17, §§ 95690.1—95690.8.
[326] CARB. Reducing Rail Emissions. https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california. Proposed Cal. Code Regs., tit. 13, §§ 2478—2478.16.
[327] CARB. In-use Off-Road Diesel-Fueled Fleets Regulation. https://ww2.arb.ca.gov/our-work/programs/use-road-diesel-fueled-fleets-regulation. Cal. Code Regs., tit. 13, §§ 2449, 2449.1, 2449.2.
[328] CARB. Commercial Harbor Craft. https://ww2.arb.ca.gov/our-work/programs/commercial-harbor-craft. Cal. Code Regs., tit. 13, § 2299.5.
[329] CARB. In-use Off-Road Diesel-Fueled Fleets Regulation. https://ww2.arb.ca.gov/our-work/programs/use-road-diesel-fueled-fleets-regulation.
[330] CARB. Cap-and-Trade Program. https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program. Cal. Code Regs., tit. 17, §§ 95801 et seq.
[331] CARB. Low Carbon Fuel Standard. https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard. Cal. Code Regs., tit. 17, §§ 95480 et seq.

and both fuels must be produced using low-carbon technology and feedstocks to minimize upstream emissions.

The transition to complete ZEV technology will not happen overnight. Conventional ICE vehicles from legacy fleets will remain on the road for some time, even after all new vehicle sales have transitioned to ZEV technology. In addition, some equipment types are only now in the initial stages of development of ZEV technology for propulsion, such as commercial aircraft or ocean-going vessels. In addition to building the production and distribution infrastructure for zero-carbon fuels, the state must continue to support low-carbon liquid fuels during this period of transition and for much harder sectors for ZEV technology such as aviation, locomotives, and marine applications. Biomethane currently displaces fossil fuels in transportation and will largely be needed for hard-to-decarbonize sectors but will likely continue to play a targeted role in some fleets while the transportation sector transitions to ZEVs. Figure 4-2 provides the detail on fuels used in 2020 and the fuel mix under the Scoping Plan Scenario for 2035 and 2045.

Figure 4-2: Transportation fuel mix in 2022, 2030, and 2045 in the Scoping Plan Scenario[332]



Private investment in alternative fuels will play a key role in diversifying the transportation fuel supply away from fossil fuels. The Low Carbon Fuel Standard is the primary mechanism for transforming California's transportation fuel pool with low-carbon

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332 See https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx for transportation fuels by year.

alternatives and has fostered a growing alternative fuel market. Partially as a result of the powerful market signals from the LCFS, fuels like renewable diesel, sustainable aviation fuel, biomethane, and electricity have all gained significant market shares and continue to displace gasoline and diesel in both on- and off-road vehicles. In addition, Executive Order N-79-20 calls on state agencies to support the transition of existing fuel production facilities away from fossil fuels and directs that this transition also protect and support workers, public health, safety, and the environment. In line with this direction, existing refineries could be repurposed to produce sustainable aviation fuel, renewable diesel, and hydrogen. This trend has already begun, and continuing to develop fuel production capacity in-state to support the energy transition while making the most efficient use of existing assets is critical to avoiding emissions leakage. If fuel demand persists after fuel production facilities have ceased operations, fuel demand will have to be met through imports.

As we transition or build new energy production facilities and infrastructure, it will be important to ensure low-income communities, tribes, and communities of color do not experience increases in existing air pollution disparities and continue to experience a reduction in the air pollution disparities that exist today. California must use the best available science to ensure that raw materials used to produce transportation fuels do not incentivize feedstocks with little to no GHG reductions from a life cycle perspective. A dramatic increase in alternative fuel production must not come at the expense of global deforestation, unsustainable land conversion, or adverse food supply impacts, to name a few examples. CARB will continue to monitor scientific findings on these topics to ensure that California policies, such as the LCFS, send the appropriate market signals and do not result in unintended consequences.[333]

Strategies for Achieving Success

- Accelerate the reduction and replacement of fossil fuel production and consumption in California.[334]
- Incentivize private investment in new zero-carbon fuel production in California.
- Incentivize the transition of existing fuel production and distribution assets to support deployment of low- and zero-carbon fuels while protecting public health and the environment.
- Invest in the infrastructure to support reliable refueling for transportation such as electricity and hydrogen refueling.

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[333] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1E. finalejacrecs.pdf (arb.ca.gov).

[334] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F3. finalejacrecs.pdf (arb.ca.gov).

- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Initiate a public process focused on options to increase the stringency and scope of the LCFS:
  - Evaluate and propose accelerated carbon intensity targets pre-2030 for LCFS.
  - Evaluate and propose further declines in LCFS post-2030 carbon intensity targets to align with this 2022 Scoping Plan.
  - Consider integrating opt-in sectors into the program.
  - Provide capacity credits for hydrogen and electricity for heavy-duty fueling.
- Monitor for and ensure that raw materials used to produce low-carbon fuels or technologies do not result in unintended consequences.[335]

Vehicle Miles Traveled

Transforming the transportation sector goes beyond phasing out combustion technology and producing cleaner fuels. Managing total demand for transportation energy by reducing the miles people need to drive on a daily basis is also critical as the state aims for a sustainable transportation sector in a carbon neutral economy. Though GHG emissions are declining due to cleaner vehicles and fuels, rising VMT can offset the effective benefits of adopted regulations.

Even under full implementation of Executive Order N-79-20 and CARB's Advanced Clean Cars II Regulations, with 100 percent ZEV sales in the light-duty vehicle sector by 2035, a significant portion of passenger vehicles will still rely on ICE technology, as demonstrated in Figure 4-2 above. Accordingly, VMT reductions will play an indispensable role in reducing overall transportation energy demand and achieving the state's climate, air quality, and equity goals. After a significant pandemic-induced reduction in VMT during 2020, passenger VMT has steadily climbed back up and is now closing in on pre-pandemic levels.[336] Driving alone with no passengers remains the primary mode of travel in California, amounting to 75 percent of the mode share for daily commute trips. Conversely, the transit industry, which was significantly impacted during

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[335] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1E. finalejacrecs.pdf (arb.ca.gov).

[336] U.S. Department of Transportation. 2021. December 2021 Traffic Volume Trends. Figure 3 - Seasonally Adjusted Vehicle Miles Traveled by Month. https://www.fhwa.dot.gov/policyinformation/travel_monitoring/21dectvt/figure3.cfm.

the lockdown months, and has struggled to recover; ridership only averages two-thirds of pre-pandemic levels,[337] [338] and service levels also lag behind.

Sustained VMT reductions have been difficult to achieve for much of the past decade, in large part due to entrenched transportation, land use, and housing policies and practices. Specifically, historic decision-making favoring single-occupancy vehicle travel has shaped development patterns and transportation policy, generating further growth in driving (and making transit, biking and walking less viable alternatives). These policies have also reinforced long-standing racial and economic injustices that leave people with little choice but to spend significant time and money commuting long distances, placing a disproportionate burden on low-income Californians, who pay the highest proportion of their wages on housing and transportation. While CARB has included VMT reduction targets and strategies in the Scoping Plan and appendices, these targets are not regulatory requirements, but would inform future planning processes. CARB is not setting regulatory limits on VMT in the 2022 Scoping Plan; the authority to reduce VMT largely lies with state, regional, and local transportation, land use, and housing agencies, along with the Legislature and its budgeting choices.

Appendix E (Sustainable and Equitable Communities) elaborates on reasons for reducing VMT and identifies a series of policies that, if implemented by various responsible authorities, could help to achieve the recommended VMT reduction trajectory included in this Scoping Plan (and related mode share increases for transit and active transportation). These policies aim to advance four strategic objectives:

1. Align current and future funding for transportation infrastructure with the state's climate goals, preventing new state-funded projects from inducing significant VMT growth and supporting an ambitious expansion of transit service and other multimodal alternatives.
2. Move funding for transportation beyond the gasoline and diesel taxes and implement fuel-agnostic pricing strategies that accomplish more productive uses of the roadway network and generate revenues to further improve transit and other multimodal alternatives.
3. Deploy autonomous vehicles, ride-hailing services, and other new mobility options toward high passenger-occupancy and low VMT-impact service models that complement transit and ensure equitable access for priority populations.
4. Encourage future housing production and multi-use development in infill locations and other areas in ways that make future trip origins and destinations

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[337] U.S. Government Accountability Office. January 25, 2022. During COVID-19, Road Fatalities Increased and Transit Ridership Dipped. https://www.gao.gov/blog/during-covid-19-road-fatalities-increased-and-transit-ridership-dipped.
[338] American Public Transportation Association. APTA - Ridership Trends. https://transitapp.com/APTA.

closer together and create more viable environments for transit, walking, and biking.

The pace of change to reduce VMT must be accelerated. Certainly, structural reform will be challenging, but California has demonstrated time and again that it possesses the collective leadership and commitment to break away from ideas that no longer represent Californians' values and their aspirations for the many generations to come.

Strategies for Achieving Success

- Achieve a per capita VMT reduction of at least 25 percent below 2019 levels by 2030 and 30 percent below 2019 levels by 2045. [339]
- Reimagine new roadway projects that decrease VMT in a way that meets community needs and reduces the need to drive.
- Invest in making public transit a viable alternative to driving by increasing affordability, reliability, coverage, service frequency, and consumer experience.[340]
- Implement equitable roadway pricing strategies based on local context and need, reallocating revenues to improve transit, bicycling, and other sustainable transportation choices.[341]
- Expand and complete planned networks of high-quality active transportation infrastructure.[342]
- Channel the deployment of autonomous vehicles, ride-hailing services, and other new mobility options toward high passenger-occupancy and low VMT-impact service models that complement transit and ensure equitable access for priority populations.
- Streamline access to public transportation through programs such as the California Integrated Travel Project.
- Ensure alignment of land use, housing, transportation, and conservation planning in adopted regional plans, such as regional transportation plans (RTP)/ sustainable communities strategies (SCS), regional housing needs assessments (RHNA), and local plans (e.g., general plans, zoning, and local transportation plans), and develop tools to support implementation of these plans.

[339] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1D. *finalejacrecs.pdf (arb.ca.gov)*.
[340] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1D. *finalejacrecs.pdf (arb.ca.gov)*.
[341] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1D. *finalejacrecs.pdf (arb.ca.gov)*.
[342] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1F. *finalejacrecs.pdf (arb.ca.gov)*.

- Accelerate infill development and housing production at all affordability levels in transportation-efficient places, with a focus on housing for lower-income residents.

Clean Electricity Grid

Much of the state's success to date in reducing GHGs is due to decarbonization of the electricity sector as a result of the RPS, SB 100 implementation, and the Cap-and-Trade Program. Moving forward, a clean, affordable, and reliable electricity grid will serve as a backbone to support deep decarbonization across California's economy. Under this Scoping Plan, the role of electricity in powering the economy will grow in almost every sector.

In 2021, 70 percent of California electricity demand was served by in-state power plants totaling about 82 GW, with the rest coming from out-of-state imports.[343] Additionally, approximately 8 GW of customer solar photovoltaic capacity has been installed to date to help with in-state demand.[344] Figure 4-3 shows the breakdown of in-state and imported sources of electricity.

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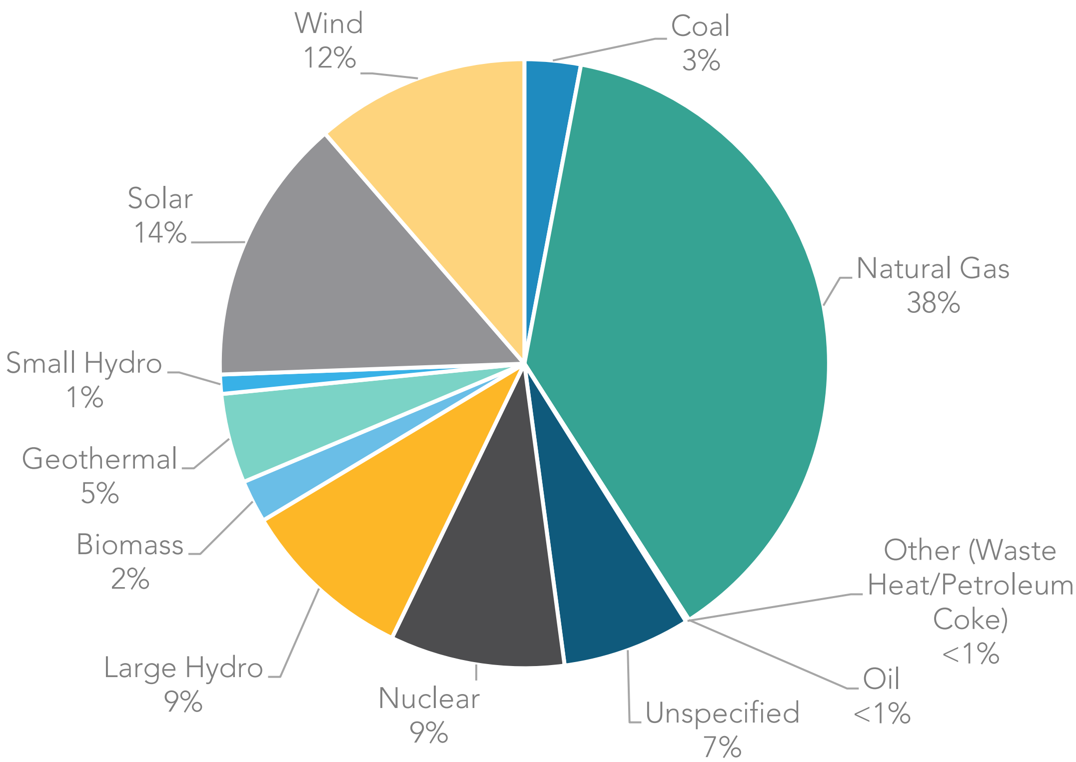
[343] CEC. 2021. Electric Generation Capacity and Energy. Data available at: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy and CEC. 2021. Total System Electric Generation. Data available at: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation. Capacity values are nameplate capacity from sources 1 MW and larger.

[344] CEC. 2021. *SB 100 Joint Agency Report Summary: Achieving 100% Clean Electricity in California, An Initial Assessment.* 10. https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity.

Figure 4-3: 2021 total system electric generation (based on GWh)[345]



Note: Imports contributing to total system generation are comprised of 58% zero-carbon energy and 42% non-renewable and unspecified energy. Percentages do not add to exactly 100 due to rounding.

In 2021, about 48 percent of electricity generation serving California came from non-renewable and unspecified[346] resources, while 52 percent came from renewable and zero-carbon resources. The state's Strategic Reliability Reserve, established in AB 205 to provide additional reliability insurance during extreme events, may make three of the fossil gas-fired OTC plants planned for retirement available to support the grid on a limited basis after 2023. The state also adopted legislation to facilitate extension of the Diablo Canyon Nuclear Power Plant for five years beyond its 2025 planned closure.[347] At the

[345] *Total system generation* is the sum of all utility-scale, in-state generation, plus net electricity imports. CEC. 2021 Total System Electricity Generation. https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation.

[346] *Unspecified power* refers to electricity that is not traceable to a specific generating facility, such as electricity traded through open market transactions. It typically consists of a mix of resources and may include renewables.

[347] In accordance with SB 846 (Dodd, Chapter 239, Statutes of 2022).

same time, the state continues to rapidly expand deployment of clean energy generation and storage resources and plan for increased electrification.[348] This is critical to reducing GHG emissions and addressing the long-term impacts of climate change.

Climate change is causing unprecedented stress on California's energy system—driving high demand and constraining supply. Heat, drought, and wildfires can both reduce electricity supply from reductions in hydropower generation and impacts on generation and transmission performance, and increase demand, especially in the evening hours when solar generation is declining.

California has experienced three straight years of energy reliability challenges, including a multi-day extreme heat event across the western United States with temperatures up to 20 degrees above normal in California, resulting in rotating outages in August 2020. In 2021, heat waves in June prompted a Grid Warning and the onset of emergency conditions, and the Bootleg Fire caused the loss of one transmission line, reducing import capability by 3,000 megawatts into the California Independent System Operator (CAISO) balancing authority area. And from August 31–September 9, 2022, a 10-day extreme heat event resulted in an unprecedented, sustained period of high peak loads in the CAISO system, averaging 47,000 MW and maxing at an all-time record of over 52,000 MW on September 6. The Western region also hit its record peak load on September 6, at 167.5 GW.

Reliable electricity service was maintained throughout the 10-day September 2022 heat wave in spite of the record breaking load levels. Factors that contributed to this outcome include the installation of over 3,500 MW of lithium-ion battery storage since summer 2020, enhanced coordination and communication within and outside of California, engagement with customer groups and other stakeholders, state actions to reduce load during critical times, and the additional capacity provided through the Strategic Reliability Reserve and other new state programs authorized in the 2022 Budget to provide load reduction and support the grid in extreme events. CEC, CPUC, CAISO, and the California Department of Water Resources will continue to build out strategies to enhance reliability in light of the increasing and compounding impacts of climate change on the electricity system.

[348] In June 2021, the CPUC adopted D.21-06-035 directing procurement of 11,500 MW of new capacity between 2023 and 2026 to ensure systemwide electric reliability as Diablo Canyon and several OTC facilities retire. It requires that, out of the 11,500 MW, 2,500 MW must be from zero-emission resources. Additionally, 2,000 MW must be long lead-time resources, with at least 1,000 MW of long-duration storage and 1,000 MW of firm capacity with zero on-site emissions or that qualifies under the RPS eligibility requirements.

While the electricity sector is using less fossil fuel due to increasing amounts of renewables,[349] existing fossil gas generation will continue to play a critical role in grid reliability until other clean, dispatchable alternatives can be deployed at scale. The integration of greater amounts of variable renewable generation resources[350] is changing power system planning and operations, and system operators need resources with flexible attributes to balance shifting supply and demand.

High levels of solar generation can lead to instances of oversupply during the middle of the day, when the sun is brightest.[351] In the evening hours, as the sun is setting, solar generation declines to zero and customers with solar generation shift back to the electric grid. In hot weather, customer demand remains high well into the summer evening period to power air conditioning, which can lead to reliability challenges.[352]

Figure 4-4 shows the energy sources used throughout one summer day in July. Renewable energy is consistent during the middle of the day, but it cannot meet all of the evening demand in the gray area. As illustrated in the figure, fossil gas generation is currently a resource that is typically ramped up to meet this evening demand as solar production begins to drop and electrical loads increase To help address this challenge, resource installations that pair solar with batteries, as well as a greater amount of battery build-out, are coming online currently and over the next five years. Nevertheless, the state's electricity grid is expected to be stressed further in the coming years by heat waves, drought, wildfires, and the growing intermittent power supply from renewables. California must accelerate deployment of diverse clean energy resources to maintain reliability and affordability in the face of climate change.

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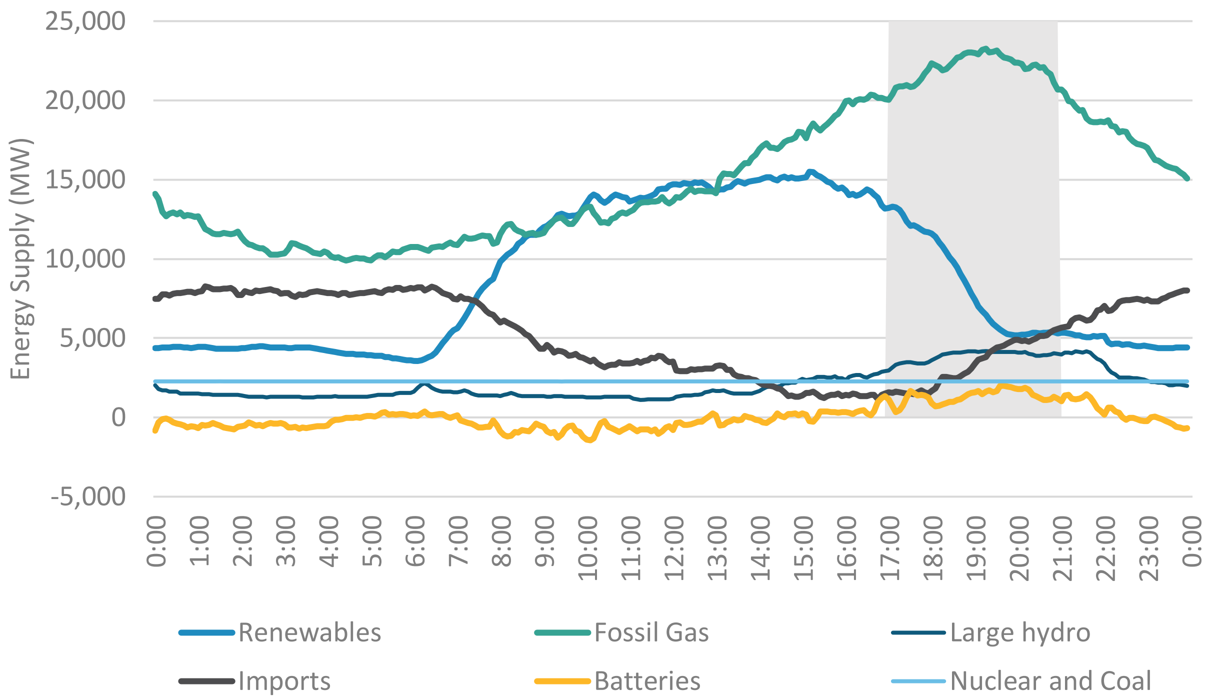
[349] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

[350] A *variable renewable generation resource* is a renewable source of electricity that is non-dispatchable due to its fluctuating nature and only produces electricity when weather conditions are right, such as when the sun is shining or the wind is blowing. Renewable resources that can be controlled and are dispatchable include geothermal, biomass, and dam-based hydroelectric power.

[351] *Brightness* is used colloquially here; solar energy depends on insolation (e.g., sun-hours), which is the measurement of cumulative solar energy that reaches an area over a period of time.

[352] CAISO, CPUC, and CEC. 2021. *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave.* http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

Figure 4-4: Electricity supply trend by resource for a California summer day, July 2022



Sector Transition

Decarbonizing the electricity sector is a crucial pillar of this Scoping Plan. It depends on both using energy more efficiently and replacing fossil-fueled generation with renewable and zero carbon resources, including solar, wind, energy storage,[353] geothermal, biomass, and hydroelectric power. The RPS Program[354] and the Cap-and-Trade Program continue to incentivize dispatch of renewables over fossil generation to serve state demand. SB 100 increased RPS stringency to require 60 percent renewables by 2030 and for California to provide 100 percent of its retail sales[355] of electricity from renewable and zero-carbon resources by 2045. Furthermore, SB 1020 has added interim targets to

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[353] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF1, NF2. finalejacrecs.pdf (arb.ca.gov).

[354] The CEC estimates that 36 percent of California's 2019 retail electricity sales was served by RPS-eligible renewable resources (see CPUC. 2021. CPUC Perspectives on Electric Sector Decarbonization. https://ww2.arb.ca.gov/sites/default/files/2021-11/CPUC-sp22-electricity-ws-11-02-21.pdf).

[355] SB 100 speaks only to retail sales and state agency procurement of electricity. The *2021 SB 100 Joint Agency Report* interprets this to mean that other loads—wholesale or non-retail sales and losses from storage and transmission and distribution lines—are not subject to the law.

SB 100's policy framework to require renewable and zero-carbon resources to supply 90 percent of all retail electricity sales by 2035 and 95 percent of all electricity retail sales by 2040; the governor has asked the CEC to establish a planning goal of at least 20 GW of offshore wind by 2045; and the governor directed that state agencies plan for an energy transition that avoids the need for new fossil gas capacity to meet California's long-term energy goals.[356] In addition to grid-level resources, state efforts have supported rapid growth of the distributed solar industry through key actions like the California Solar Initiative (SB 1, Murray, Chapter 132, Statues of 2006).[357] Steps to commercialize microgrids powered by clean resources[358] are also being examined as part of SB 1339 (Stern, Chapter 566, Statutes of 2018).[359]

California also continues to advance its appliance and building energy efficiency standards to reduce growth in electricity consumption and meet the SB 350 goal to double statewide energy efficiency savings in electricity and fossil gas end uses[360] by 2030. In 2018, the CEC adopted a building energy efficiency code requiring most new homes to have solar photovoltaic systems[361] (or be powered by a solar array nearby) starting January 1, 2020. In 2019, California reached the milestone of 1 million solar rooftop installations.

Increased transportation and building electrification and continued policy commitment to behind-the-meter solar and storage will continue to drive growth of microgrids and other distributed energy resources (DER).[362] The CPUC's High-DER proceeding is examining how to prepare the electric grid for a high DER future by determining how to integrate

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[356] Newsom, Gavin. July 22, 2022. Letter from Governor Newsom to CARB Chair Liane Randolph. *https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf*.

[357] More information on the program, which closed in 2016, can be found on the CPUC website, including annual program assessment reports, at: *https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/california-solar-initiative*.

[358] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, In part (NF2, NF13). *finalejacrecs.pdf (arb.ca.gov)*.

[359] CPUC. Resiliency and Microgrids. *https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/resiliency-and-microgrids*.

[360] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF1, ES1. *finalejacrecs.pdf (arb.ca.gov)*.

[361] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF2. *finalejacrecs.pdf (arb.ca.gov)*.

[362] Distributed energy resources include rooftop solar and other distributed renewable generation resources, energy storage, electric vehicles, time variant and dynamic electric rates, flexible load management, demand response, and energy efficiency technologies.

millions of DERs within the distribution grid to maximize societal and ratepayer benefits from DERs while ensuring grid reliability and affordable rates.[363]

SB 350 also aims to connect long-term planning for electricity needs with the state's climate targets. This is primarily accomplished through CARB's establishment of 2030 GHG emissions targets for the electricity sector in general and for each electricity provider, which inform the CPUC and publicly owned utilities' integrated resource planning. A GHG planning target range of 30 to 53 $MMTCO_2e$—informed by the 2017 Scoping Plan—was originally developed and adopted by CARB in 2018. In its 2021 IRP planning cycle, the CPUC adopted a 38 MMT GHG target for the electricity sector in 2030, which drops to 35 MMT in 2032.[364]

The Scoping Plan Scenario incorporates SB 350's energy efficiency doubling goal, aligns with the CPUC's IRP 2030 GHG target and latest GHG emissions benchmarks through 2035,[365] the governor's 20 GW offshore wind and no new gas generation[366] goals, and SB 100's 2030 RPS and 2045 zero-carbon retail sales targets to reduce dependence on fossil fuels in the electricity sector by transitioning substantial energy demand to renewable and zero-carbon resources.[367] As described in Chapter 2, CCS is applied in limited sectors, including on 16.7 MMT of CO_2 from existing fossil gas electricity generation in 2045, to ensure the state achieves the 85 percent reduction in anthropogenic emissions required by AB 1279. Continued transition to renewable and

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[363] The High-DER proceeding is one of four "anchor" proceedings in the CPUC's DER Action Plan 2.0 and is within the Action Plan's infrastructure track. Information on the High-DER proceeding is available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning. The Action Plan can be accessed at: https://www.cpuc.ca.gov/about-cpuc/divisions/energy-division/der-action-plan.

[364] The February 10, 2022, Decision 22-02-004 by the CPUC adopts the 2021 Preferred System Plan, completing the 2019–21 IRP cycle. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF. The Decision requires load serving entities to submit plans in the next IRP cycle detailing how they will meet their proportionate share of a 30 MMT electric sector target, as well as a 38 MMT GHG target.

[365] June 15, 2022, Administrative Law Judge's Ruling for 2022 integrated resource plan filings specifies the need for GHG targets to plan for in 2035 to continue progress toward the 2045 goal. The ruling proposes a straight-line projection from the GHG planning target for 2030. Corresponding to the adopted Preferred System Plan in D.22-02-004, 38 MMT in 2030 leads to a target of 30 MMT in 2035. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M485/K625/485625915.PDF.

[366] The governor's July 22, 2022, letter specifies no new gas generation but does not place any constraints on existing gas resources. Therefore, for purposes of RESOLVE electricity sector modeling, existing gas capacity is an available resource that is able to be reduced over time based on announced retirements or if selected for retirement by the model.

[367] CARB. 2021. PATHWAYS Scenario Modeling: 2022 Scoping Plan Update – Attachment B: Generation Technologies to be included in Modeling. https://ww2.arb.ca.gov/sites/default/files/2021-12/Revised_2022SP_ScenarioAssumptions_15Dec.pdf.

zero-carbon electricity resources will enable electricity to become a zero-carbon substitute for fossil fuels across the economy.

Figure 4-5 shows the modeled resource capacity to meet the SB 100 retail sales target.[368] Energy efficiency moderates some of the need for additional electricity generation. However, that is quickly surpassed by growing electricity demand of 26 percent by 2030 and 76 percent by 2045 compared to today (2022) from increased population and electrification of other sectors, as shown in Figure 4-6. The estimated resource build needed to meet this level of demand amounts to approximately 72 GW of utility solar[369] and 37 GW of battery storage by 2045. Annual build rates (over the 2022–2035 period) for the Scoping Plan Scenario will need to increase by about 60 percent and over 700 percent for utility solar and battery storage, respectively, compared to historic maximum rates.[370] To reach the 2045 target, the state will need to quadruple its current level of wind and solar capacity. This does not include capacity associated with hydrogen production nor mechanical CDR, which was modeled off-grid; assuming hydrogen production via electrolysis, this would roughly be equivalent to an additional 10 GW[371] of solar generation needed in 2045, and an additional 64 GW of solar generation for direct air capture in 2045. The scale of solar and battery build rates needed could be reduced through the commercialization of new zero-carbon technologies.

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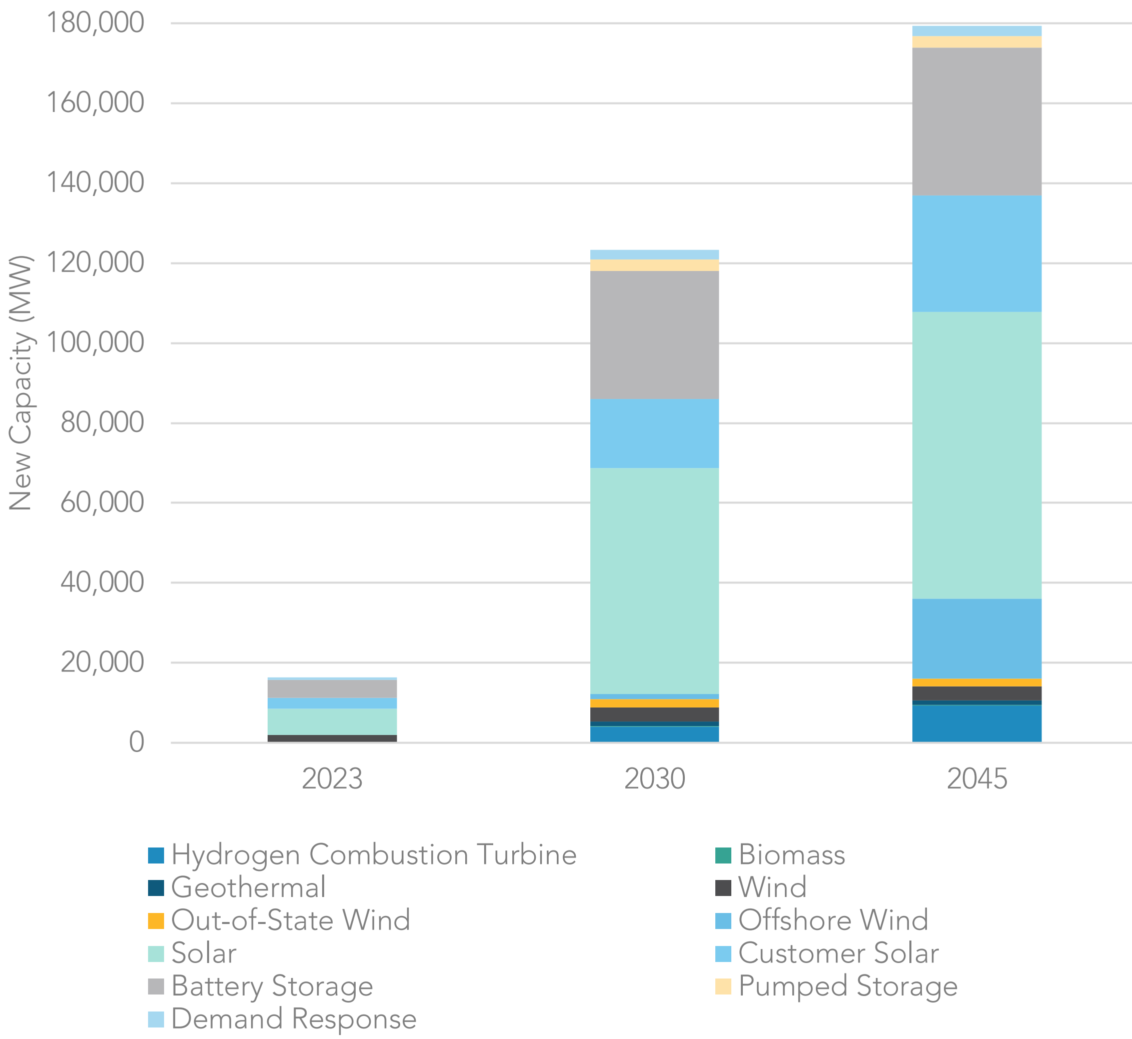
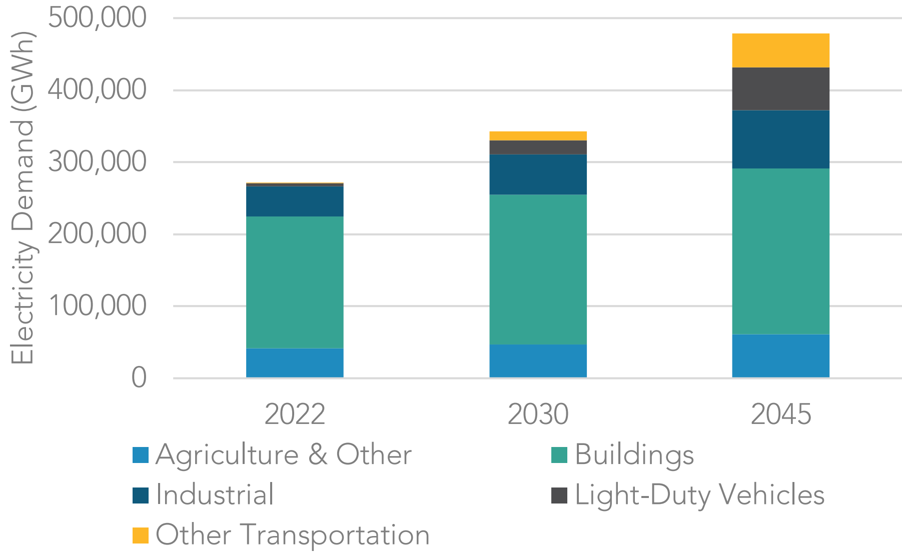
[368] SB 846 requires that load-serving entities exclude energy, capacity, or any attribute from the Diablo Canyon power plant in their resource plans. The Scoping Plan Scenario excludes energy, capacity, or any attribute from the Diablo Canyon power plant after the prior planned retirement date of 2025.
[369] The amount of additional customer solar included in the Scoping Plan Scenario is 29,208 MW by 2045.
[370] E3. 2022. CARB Scoping Plan: AB32 Source Emissions Final Modeling Results. PowerPoint. *https://ww2.arb.ca.gov/sites/default/files/2022-11/SP22-MODELING-RESULTS-E3-PPT.pdf*. Build rates are from EIA data historical builds in the 2011–2021 time frame.
[371] The estimate does not include hydrogen production assumed to be produced with bioenergy with carbon capture and storage (BECCS) and steam methane reforming (SMR).

Figure 4-5: Projected new electricity resources needed by 2045 in the Scoping Plan Scenario[372]



[372] See *https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx* for the capacity build-out by resource type.

Figure 4-6: Electric loads in 2022, 2030 and 2045 for the Scoping Plan Scenario[373]



This transformation will drive investments in a large fleet of generation and storage resources but will also require significant transmission to accommodate these new capacity additions. Transmission needs include high-voltage lines to access out-of-state resources and major in-state generation pockets. In consideration of typical 8- to 10-year lead times for many projects, the CAISO published its first 20-Year Transmission Outlook to inform transmission planning focused on meeting the needs identified through the 2021 SB 100 Joint Agency Report process. The outlook calls for significant transmission development to access offshore wind and out-of-state wind and reinforce the existing CAISO footprint at an estimated cost of $30.5 billion.[374]

Presently, fossil gas power plants provide about 75 percent of the flexible capacity for grid reliability as more renewable power enters the system. Moving forward, other resources such as storage and demand-side management are essential to maintain reliability with high concentrations of renewables. Hydrogen produced from renewable resources and renewable feedstocks can serve a dual role as a low-carbon fuel for existing combustion turbines or fuel cells, and as energy storage for later use. Reliability

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[373] *Other Transportation* includes all non-light-duty vehicles and reflects electrification of modes like passenger and freight rail, aviation, and ocean-going vessels.
[374] CAISO. 2022. *20 Year Transmission Outlook.* http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf.

also can be supported through increased coordination and markets in the interconnected western power grid; this is already helping to better integrate renewables.[375]

Strategies for Achieving Success

- Use long-term planning processes (Integrated Energy Policy Report, IRP, CAISO Transmission Planning Process, AB 32 Climate Change Scoping Plan) to support grid reliability and expansion of renewable and zero-carbon resource and infrastructure deployment.
- Complete systemwide and local reliability assessments across CAISO and other balancing authority areas, using realistic assumptions for land use, build rates, statewide and distribution system level constraints, and energy needs. Such assessments should be completed before state agencies update their electricity sector GHG targets.
- Prioritize actions to mitigate impacts to electricity reliability and affordability and provide sufficient flexibility in the state's decarbonization roadmap for adjustments as may be needed.
- Facilitate long lead-time resource development through the IRP and the SB 100 interagency process and through technology development and demonstration funding[376] that includes resources such as long-duration energy storage and hydrogen production.
- Continue coordination between energy agencies and energy proceedings to maximize opportunities for demand response.
- Continue to explore the benefits of regional markets to enhance decarbonization, reliability, and affordability.
- Address resource build-out challenges, including permitting, interconnection, and transmission network upgrades.
- Explore new financing mechanisms and rate designs to address affordability.[377]
- Per SB 350, double statewide energy efficiency savings in electricity and fossil gas end uses by 2030, through a combination of energy efficiency and fuel substitution actions.[378]
- Per SB 100 and SB 1020, achieve 90 percent, 95 percent, and 100 percent

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[375] CEC. 2021. *2021 SB 100 Joint Agency Report – Achieving 100 Percent Clean Electricity in California: An Initial Assessment.* Publication Number: CEC-200-2021-001.

[376] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, ES2. The committee recommendation speaks specifically to offshore wind production. *finalejacrecs.pdf (arb.ca.gov)*.

[377] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF30. *finalejacrecs.pdf (arb.ca.gov)*.

[378] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF1, NF2. *finalejacrecs.pdf (arb.ca.gov)*.

renewable and zero-carbon retail sales by 2035, 2040, and 2045, respectively.

- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Target programs and incentives to support and improve access to renewable and zero-carbon energy projects (e.g., rooftop solar, community owned or controlled solar or wind, battery storage, and microgrids) for communities most at need, including frontline, low-income, rural, and indigenous communities.[379]
- Prioritize public investments in zero-carbon energy projects to first benefit the most overly burdened communities affected by pollution, climate impacts, and poverty.[380]

Sustainable Manufacturing and Buildings

Fossil gas is the primary gaseous fossil fuel used to produce heat at industrial facilities, as well as in residential and commercial buildings. In buildings, space and water heating, cooking, and clothes drying all rely on gaseous fuels today. Industrial processes that require heat for conventional boilers and other processes also rely on gaseous fuels. Refineries rely on fossil gas and other gaseous fossil fuels, like liquefied petroleum gas and refinery fuel gas, and fossil gas is also used to generate electricity, as discussed earlier.

Gaseous fossil fuel use can be displaced by four primary alternatives: zero-carbon electricity, solar thermal heat, hydrogen, and biogas/biomethane. Displacing gaseous fossil fuel use can yield indoor air quality benefits, protect public health and property from unexpected fossil gas leaks, and reduce short-lived climate pollutants, which are many times more potent in affecting climate change than CO_2. The Scoping Plan Scenario reduces dependence on fossil gas in the industrial and building sectors by transitioning substantial energy demand to alternative fuels. Reducing fossil gas combustion also will help toward achieving our air quality and equity goals by reducing pollution in neighboring areas and communities. In addition, reduced dependence on gasoline and diesel in the transportation sector diminishes the need for gaseous fossil fuels to support oil and gas production and petroleum refining operations as those are phased down relative to the demand.

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[379] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF2, NF9, NF11, NF12, NF13. *finalejacrecs.pdf (arb.ca.gov)*.

[380] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF14. *finalejacrecs.pdf (arb.ca.gov)*.

Sector Transition

Industry

California's industrial sector contributes significantly to the state's economy, with a total output from manufacturing in 2019 of $324 billion (10.4 percent of the state total)[381] and employment of 1,222,000 manufacturing jobs (7.6 percent of the total state workforce).[382] California industry includes a diverse range of facilities, including cement plants, refineries, glass manufacturers, oil and gas producers, paper manufacturers, mining operations, metal processors, and food processors. Combustion of fossil gas, other gaseous fossil fuels, and solid fossil fuels provide energy to meet three broad industry needs: electricity, steam, and process heat. Non-combustion emissions result from fugitive emissions and from the chemical transformations inherent to some manufacturing processes. About 20 percent of the GHG emissions from the industrial sector are non-combustion emissions.

Decarbonizing industrial facilities depends upon displacing fossil fuel use with a mix of electrification, solar thermal heat, biomethane, low- or zero-carbon hydrogen, and other low-carbon fuels to provide energy for heat and reduce combustion emissions. Emissions also can be reduced by implementing energy efficiency measures and using substitute raw materials that can reduce energy demand and some process emissions. Some remaining combustion emissions and some non-combustion CO_2 emissions can be captured and sequestered. The strategy employed will depend on the industrial subsector and the specific processes utilized in production. The left side of Figure 4-7 illustrates the fuels used to meet industrial manufacturing energy demand in 2020. Industrial manufacturing energy demand needs to transition to the fuel mix shown for 2035 and 2045. The right side of Figure 4-7 illustrates the fuel mix needed to meet the energy demand of oil and gas extraction and petroleum refining operations for the same years. Energy demand in this portion of the industrial sector declines along with decreased demand for gasoline and diesel in the transportation sector. In both figures there is a continuing demand for fossil gas due to lack of non-combustion technologically feasible or cost-effective alternatives for certain industrial sectors. Policies that support decarbonization strategies like electrification, use of renewable energy, and transition to alternative fuels are needed.

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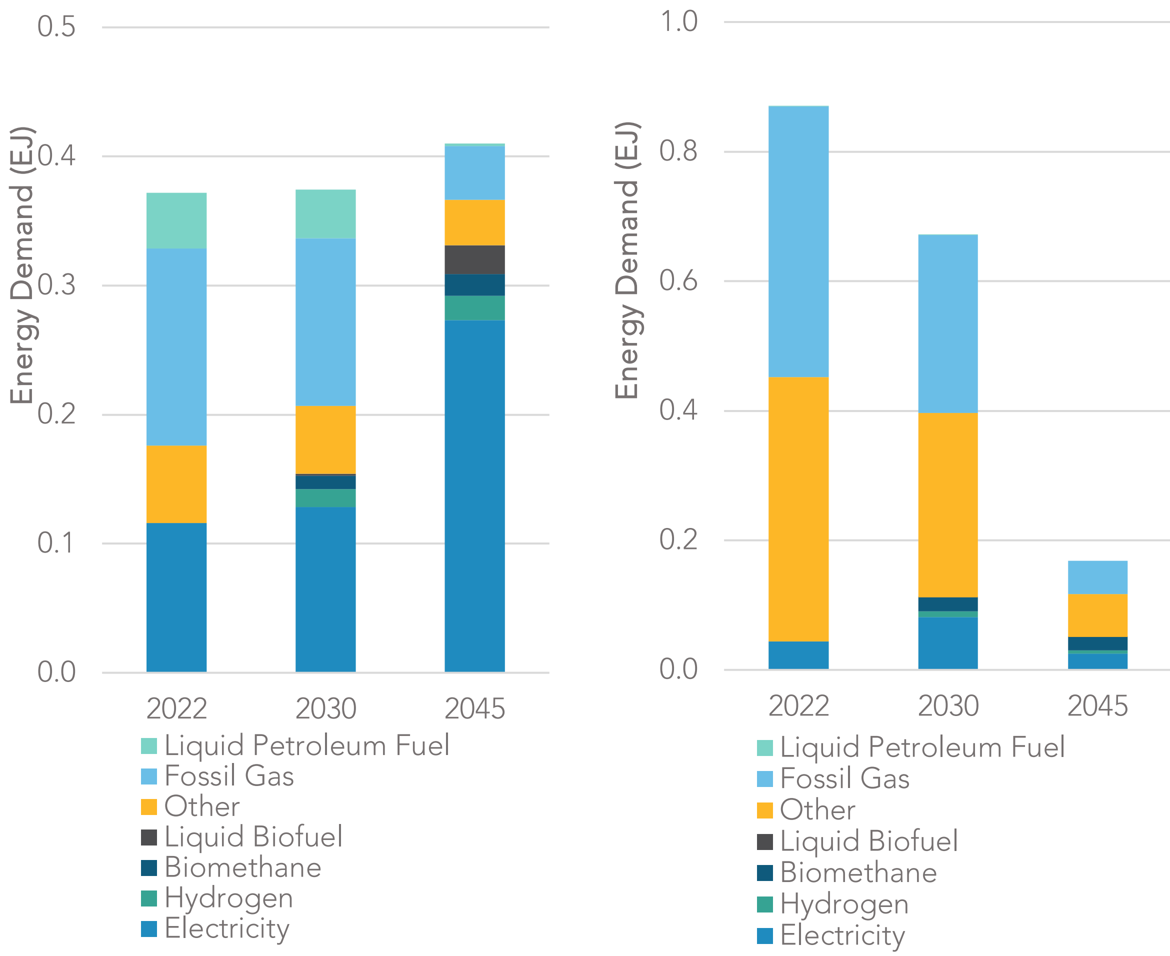
[381] National Association of Manufacturers (NAM). 2021 California Manufacturing Facts. https://www.nam.org/state-manufacturing-data/2021-california-manufacturing-facts/.
[382] NAM. 2021 California Manufacturing Facts. https://www.nam.org/state-manufacturing-data/2021-california-manufacturing-facts/.

Figure 4-7: Final energy demand in industrial manufacturing (left) and in oil and gas extraction and petroleum refining (right) in 2022, 2030, and 2045 in the Scoping Plan Scenario[383]



Electrification and solar thermal heat are best-suited to industrial processes that have relatively low heat requirements, such as food processors, paper mills, and industries that use low-pressure steam in their processes. Approaches could include replacing fossil gas boilers with electric boilers, process heaters with industrial electric heat pumps, steel forging furnaces with induction heaters, and implementing other sector-specific process electrification. Under current rate structures for industrial electricity and fossil gas in

[383] *Other* fuel in the industrial manufacturing sector is primarily coke and coal for cement production. *Other* fuel in the petroleum refining sector is primarily fossil gas associated with refining petroleum products.

California, most projects to electrify a fossil gas-powered industrial process will face operating cost barriers and potential reliability concerns. Microgrids powered by renewable resources and with battery storage are emerging as a key enabler of electrification and decarbonization at industrial facilities.

There are fewer commercially available and economically viable electrification options to replace industrial processes that require higher-temperature heat. For these processes, onsite combustion may continue to be needed, and decarbonization will require fuel substitution to hydrogen,[384] biomethane, or other low-carbon fuels. Fuel substitution and continued combustion will require monitoring and mitigation of any potential air quality impacts, especially in low-income and communities of color which already face disproportionate air pollution burdens. Industries in California with high heat needs include steel forging, glass manufacturing, and industries with calcination processes, such as manufacturing lime and cement.

Onsite emissions from cement manufacturing derive from two main sources: (1) fuel combustion to heat the kiln to a very high temperature and (2) process CO_2 emissions from the chemical transformation of limestone. Over 60 percent of emissions from the sector are process emissions unrelated to fuel use, and most emissions related to fuel use are from coal and petroleum coke combustion. Process emissions from cement manufacturing are significant and will continue even if the sector were to operate using only zero-carbon fuels; thus carbon capture and use/sequestration will be a likely component of any strategy to fully decarbonize cement manufacturing. There are additional opportunities to reduce GHG emissions from cement manufacturing via the combination of fuel-switching to low-carbon fuels (e.g., biomethane, municipal solid waste, biochar), increased blending of non-clinker materials, and efficiency improvements. High technological and economic barriers exist to electrifying kiln process heat at cement plants, as clinker production requires temperatures in excess of 1,500°C. There are potential decarbonization opportunities throughout the value chain of cement use, including in cement manufacturing, concrete mixing, and construction practices.[385] SB 596 (Becker, Chapter 246, Statutes of 2021), which was signed by Governor Newsom in September 2021, requires CARB to develop a comprehensive strategy for cement use in California to achieve a GHG intensity 40 percent below 2019 levels by 2035, and net-zero emissions by 2045.

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384 Griffiths, Steve, Benjamin K. Sovacool, Jinsoo Kim, Morgan Bazilian, and Joao M. Uratani. 2021. "Industrial decarbonization via hydrogen: A critical and systematic review of developments, socio-technical systems and policy options." *Energy Research & Social Science* 80. 102208, ISSN 2214-6296. https://doi.org/10.1016/j.erss.2021.102208.

385 California Nevada Cement Association. Achieving Carbon Neutrality in the California Cement Industry. https://cncement.org/attaining-carbon-neutrality.

Oil and gas extraction and refining make up over half of California's industrial GHG emissions. Reduced demand for transportation fossil fuels corresponds to reduced supply of fossil gas and other gaseous fossil fuels for refineries to produce these fuels. Some refining operations will continue to operate to produce fossil fuel for the remaining transportation energy demands, along with renewable diesel and sustainable aviation fuel, as discussed in the Transportation Sustainability section of this chapter.

Across industrial subsectors and processes, California facilities also could realize significant reductions in GHG emissions and energy-related costs by implementing advanced energy efficiency projects and tools.[386] While enhanced operation and maintenance practices are typical at industrial facilities, additional strategic energy management practices offer greater efficiency gains by focusing on setting goals, tracking progress, and reporting results.

Strategies for Achieving Success

- Maximize air quality benefits using the best available control technologies for stationary sources in communities most in need, including frontline, low-income, disadvantaged, rural, and tribal communities.[387]
- Prioritize alternative fuel transitions first in communities most in need, including frontline, low-income, disadvantaged, rural, and tribal communities.[388]
- Invest in research and development and pilot projects to identify options to reduce materials and process emissions along with energy emissions in California's industrial manufacturing facilities, leveraging programs like the CEC's Electric Program Investment Charge (EPIC).[389]
- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Support electrification with changes to industrial rate structures.
- Develop infrastructure for CCS and hydrogen production to reduce GHG emissions where cost-effective and technologically feasible non-combustion alternatives are not available.
- Implement SB 905.

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[386] Therkelsen, Peter, Aimee McKane, Ridah Sabouini, and Tracy Evans. 2013. *Assessing the Costs and Benefits of the Superior Energy Performance Program.* U.S Department of Energy. https://www.osti.gov/servlets/purl/1165470.

[387] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT14. *finalejacrecs.pdf (arb.ca.gov)*.

[388] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT15. *finalejacrecs.pdf (arb.ca.gov)*.

[389] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, M20. *finalejacrecs.pdf (arb.ca.gov)*.

- Establish markets for low-carbon products and recycled materials using Buy Clean California Act and other mechanisms relying on robust data
- Develop a net-zero cement strategy to meet SB 596 targets for the GHG intensity of cement use in California.
- Continue to leverage energy-efficiency programs, including the U.S. DOE's ENERGY STAR program,[390] U.S. DOE's Superior Energy Performance program,[391] and ISO 50001.[392]
- Evaluate and continue to offer incentives to install energy efficiency and renewable energy technologies through programs such as CPUC decisions as part of rulemaking R.19-09-009[393] and the CEC's Food Production Investment Program (FPIP) and EPIC programs.[394]
- Leverage low-carbon hydrogen programs, including the Bipartisan Infrastructure Law, for regional hydrogen hubs, hydrogen electrolysis, and hydrogen manufacturing and recycling.
- Evaluate the role of hydrogen in meeting GHG emission reductions, including policy recommendations regarding the use of hydrogen in California as required by SB 1075.
- Address cost barriers to promote low-carbon fuels for hard-to-electrify industrial applications.

Buildings

Buildings have cross-sector interactions that influence our public health and well-being and affect land use and transportation patterns, energy use, water use, and indoor and outdoor environments.[395] There are about 14 million existing homes and over 7.5 billion square feet of existing commercial buildings[396] in California. Fossil gas supplies about half of the energy consumed by end uses in these buildings. In addition to GHG emissions, fossil gas usage in buildings also produces CO_2, NOx, $PM_{2.5}$, and

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390 ENERGY STAR. ENERGY STAR Guidelines for Energy Management. https://www.energystar.gov/buildings/tools-and-resources/energy-star-guidelines-energy-management.
391 Energy.gov. Superior Energy Performance 50001. https://www.energy.gov/eere/amo/superior-energy-performance.
392 ISO. ISO 50001 Energy Management. https://www.iso.org/iso-50001-energy-management.html.
393 CPUC. January 14, 2021. CPUC Adopts Strategies to Help Facilitate Commercialization of Microgrids Statewide. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M360/K370/360370887.PDF.
394 Bailey, Stephanie, David Erne, and Michael Gravely. 2021. *Final 2020 Integrated Energy Policy Report Update, Volume II: The Role of Microgrids in California's Clean and Resilient Energy Future, Lessons Learned From the California Energy Commission's Research.* California Energy Commission. Publication Number: CEC-100-2020-001-V2-CMF.
395 See Appendix F (Building Decarbonization).
396 CEC. 2021. California Building Decarbonization Assessment. https://efiling.energy.ca.gov/GetDocument.aspx?tn=239311&DocumentContentId=72767.

formaldehyde.[397] Each year, about 120,000 new homes[398] and more than 100 million-square feet[399] of commercial buildings are newly constructed across California. These new buildings will represent between a third to half of the total building stock by mid-century.

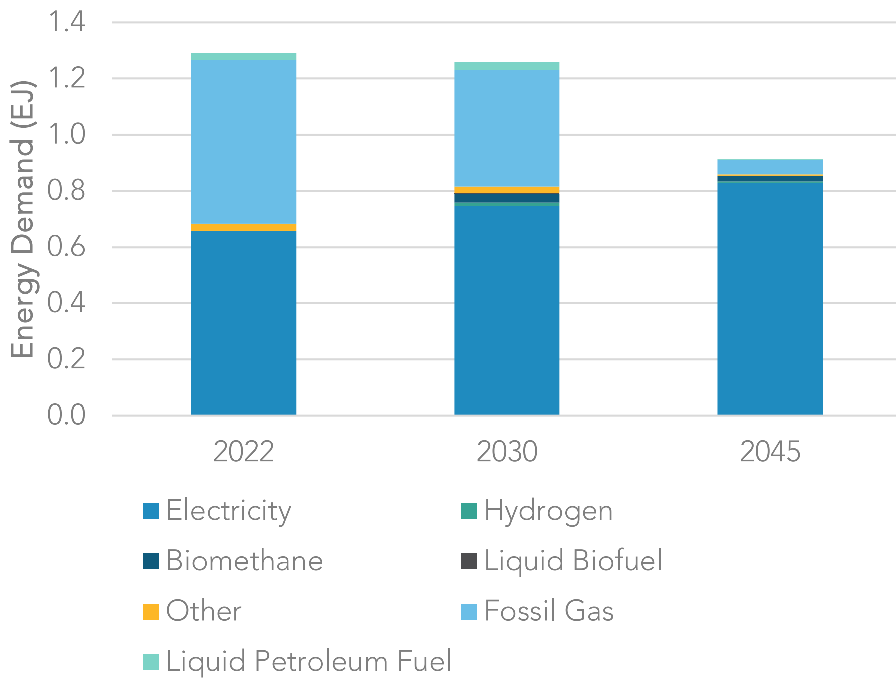
Achieving carbon neutrality must include transitioning away from fossil gas in residential and commercial buildings, and will rely primarily on advancing energy efficiency while replacing gas appliances with non-combustion alternatives. This transition must include the goal of trimming back the existing gas infrastructure so pockets of gas-fueled residential and commercial buildings do not require ongoing maintenance of the entire limb for gas delivery. Blending low-carbon fuels such as hydrogen and biomethane into the pipeline further displaces fossil gas. Pipeline safety and reliability must be evaluated to accommodate low-carbon fuels. Figure 4-8 illustrates the energy Californians use in buildings at present compared with the Scoping Plan Scenario, which introduces alternatives to fossil gas. In that scenario almost 90 percent of energy demand is electrified by 2045, and the remaining energy demand is met with combustion of hydrogen, biomethane, and fossil gas.

[397] Zhu, Yifang, et al. 2020. *Effects of Residential Gas Appliances on Indoor and Outdoor Air Quality and Public Health in California.* UCLA Fielding School of Public Health Department of Environmental Health Sciences.

[398] Construction Industry Research Board. 2018. Annual Building Permit Summary. http://www.cirbreport.org.

[399] Delforge, Pierre. August 11, 2021. California Forging Ahead on Zero Emission Buildings. Blog. NRDC. https://www.nrdc.org/experts/pierre-delforge/california-forging-ahead-zero-emission-buildings.

Figure 4-8: Final energy demand in buildings in 2022, 2030, and 2045 in the Scoping Plan Scenario[400]



This transition is achieved when all new buildings constructed include non-combustion appliances, and appliances in existing buildings are replaced at the end of their useful life with non-combustion alternatives. Currently, electric alternatives, combined with the decarbonizing of California's grid, are the most effective alternatives, and the Scoping Plan Scenario modeled these alternatives. The Scoping Plan Scenario assumes three million all-electric and electric-ready homes by 2030 and seven million by 2035. Figure 4-9 illustrates the pace at which electric space heating appliance sales increase and gas space heating appliance sales decrease in residences in the Scoping Plan Scenario, such that by 2035 100 percent of residential home appliance sales are electric. By 2030 over six million electric heat pumps are installed statewide. The residential electric space heating appliance sales increases rapidly in the near term as new all-electric buildings are constructed and as existing buildings are renovated to utilize electric appliances. A similar transition is envisioned for other home appliances. Commercial buildings also will undergo a transition away from gas appliances to electric appliances, achieving 80 percent sales of all-electric appliances by 2035 and 100 percent by 2045. Appendix F (Building Decarbonization) describes a holistic policy approach to rapidly grow the

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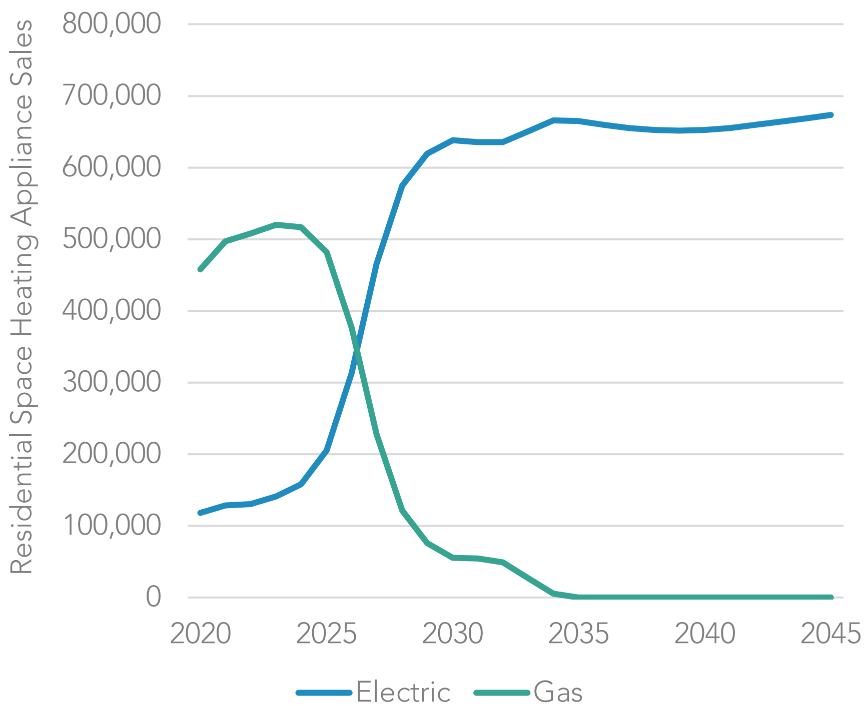
[400] *Other* fuel in the buildings sector is primarily liquid petroleum gas and waste heat.

number of zero emission appliances and buildings, to surmount the market barriers, and to prioritize an equitable transition for vulnerable communities.

Figure 4-9: Residential space heating appliance sales in the Scoping Plan Scenario



Strategies for Achieving Success

- Prioritize California's most vulnerable residents with the majority of funds in the new $922 million Equitable Building Decarbonization program, created through the 2022–2023 state budget. This would include residents in frontline, low-income, disadvantaged, rural, and tribal communities. This program is dedicated to a statewide direct-install building retrofit program for low-income households to replace fossil fuel appliances with electric appliances, energy-efficient lighting, and building insulation and sealing while also coordinating reductions in gas infrastructure in specific geographic areas.
- Achieve three million all-electric and electric-ready homes by 2030 and seven million by 2035 with six million heat pumps installed statewide by 2030.
- Expand incentive programs to support the holistic retrofit of existing buildings, especially for vulnerable communities.
- Ensure that incentive programs prioritize energy affordability and tenant protections, promote affordable and low-income household retrofits that improve habitability and reduce expenses, protect and empower small landlords and homeowners, address overlooked consumer groups, and pair decarbonization

with other critically needed renovation efforts to ensure that buildings support human health and are climate- and weather-resistant.[401]

- End fossil gas infrastructure expansion for newly constructed buildings.[402]
- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Strengthen California's building standards to support zero-emission new construction.
- Develop building performance standards for existing buildings.
- Adopt a zero-emission standard for new space and water heaters sold in California beginning in 2030, as specified in the 2022 State Strategy for the State Implementation Plan.
- Expand use of low-GWP refrigerants within buildings.
- Support electrification with changes to utility rate structures and by promoting load management programs.
- Increase funding for incentive programs and expand financing assistance programs focused on existing buildings and appliance replacements.
- Expand consumer education efforts to raise awareness and stimulate the adoption of decarbonized buildings and appliances, especially in vulnerable communities.
- Implement biomethane procurement targets for investor-owned utilities as specified in SB 1440 (Hueso, Chapter 739, Statutes of 2018) to reduce GHG emissions in remaining pipeline gas and reduce methane emissions from organic waste.

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[401] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF23, NF24, NF25, NF26, NF28. *finalejacrecs.pdf (arb.ca.gov)*.

[402] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF22. *finalejacrecs.pdf (arb.ca.gov)*.

Carbon Dioxide Removal and Capture

Climate Change 2022: Mitigation of Climate Change,[403] a report by the IPCC released in early 2022, states "The deployment of CDR to counterbalance hard-to-abate residual emissions is unavoidable if net zero CO_2 or GHG emissions are to be achieved. The scale and timing of deployment will depend on the trajectories of gross emission reductions in different sectors. Upscaling the deployment of CDR depends on developing effective approaches to address feasibility and sustainability constraints especially at large scales." In line with that report, this Scoping Plan considers CDR as a complement to technologically feasible and cost-effective GHG emissions mitigation, and the size of its role will depend on the degree of success in reducing GHG emissions at the source across the economy. [404] The modeling shows that emissions from the AB 32 GHG Inventory sources will continue to persist even if all fossil related combustion emissions are phased out. These residual emissions must be compensated for to achieve carbon neutrality. Options for CDR include both sequestration in natural and working lands and mechanical approaches like direct air capture. Chapter 2 provides estimates on how much CO_2 removal is possible by our natural and working lands and how much must be removed by mechanical CDR.

CCS, which is carbon capture from anthropogenic point sources, is described in Chapter 2 and involves capturing carbon from a smokestack of an emitting facility. Direct air capture, on the other hand, captures carbon directly from the atmosphere. Direct air capture technologies, unlike CCS, are not associated with any particular point source.

For this section, *carbon management* refers to the capture, movement, and sequestration of CO_2 through mechanical solutions for both capture at point sources and direct removal from the atmosphere through direct air capture.[405] Enabling policies and regulations across each of these steps are necessary for individual projects, and on a broader scale, for delivering reductions in support of the state's carbon neutrality and long-term carbon-negative goals. Figure 4-10 provides a graphic of the typical carbon management infrastructure.

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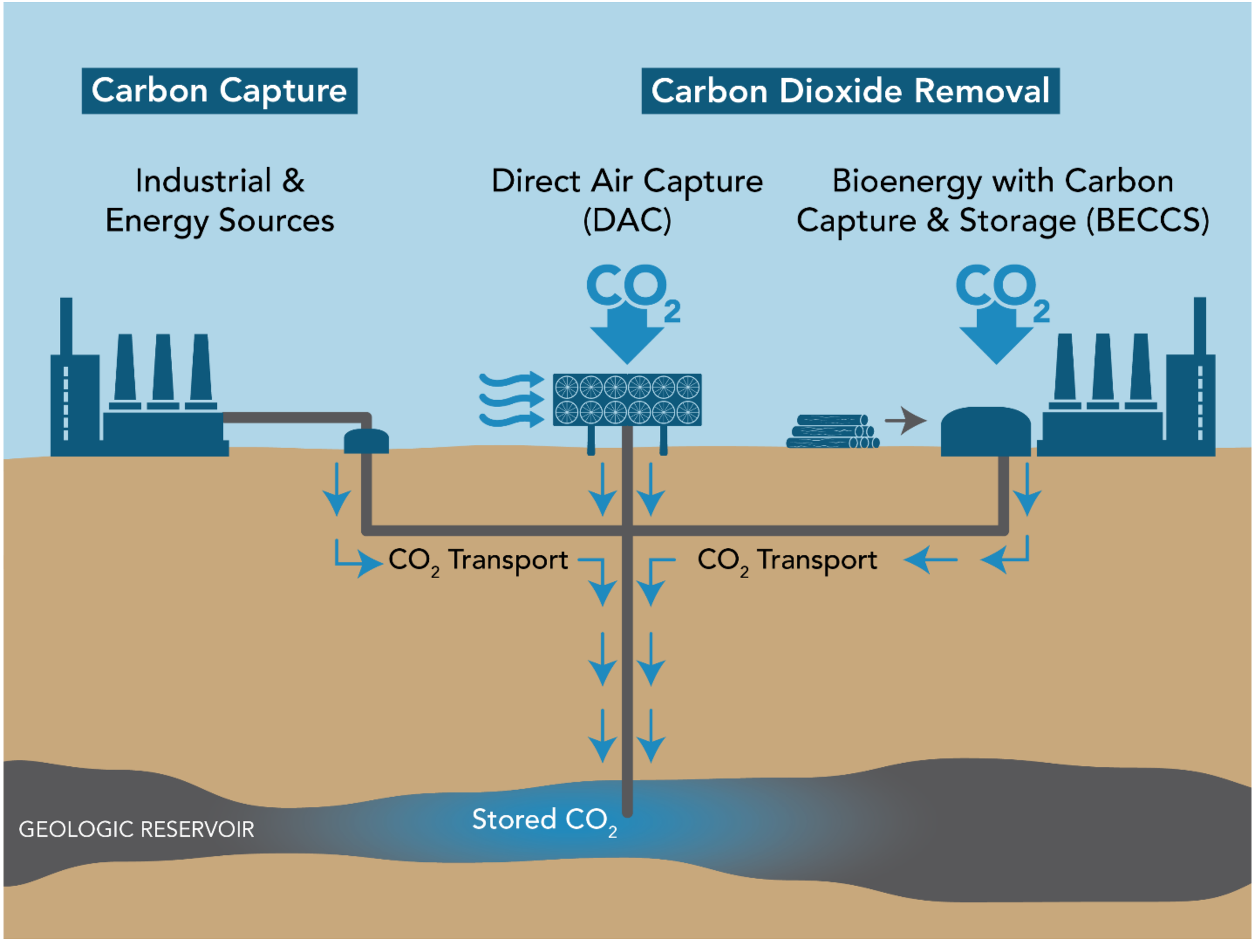
[403] IPCC. 2022. *Climate Change 2022: Mitigation of Climate Change.* https://www.ipcc.ch/report/sixth-assessment-report-working-group-3/.

[404] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.7. *finalejacrecs.pdf (arb.ca.gov)*.

[405] CDR through natural and working lands is discussed in Chapter 2 and later in this chapter.

Figure 4-10: Carbon management infrastructure



Carbon dioxide removal directly from the atmosphere itself refers to a suite of carbon negative technologies that can be used to draw down ongoing and historical carbon emissions already in the atmosphere. Some CO_2 removal technologies leverage the abilities of both natural photosynthesis and mechanical removal by using biomass wastes as inputs to make low- or zero-carbon energy or fuels, all while capturing and storing produced CO_2.

Captured CO_2 from point sources or from the atmosphere is permanently stored in specialized geologic formations, typically half a mile or more underground. A recent Stanford University study estimated the state's commercial storage potential is nearly 70,000 million metric tons of CO_2, even when excluding oil and gas reservoirs.[406] California is well-positioned because few other places on the West Coast are suitable for

[406] Stanford Center for Carbon Storage. Opportunities and Challenges for CCS in California. https://sccs.stanford.edu/california-projects/opportunities-and-challenges-for-CCS-in-California.

geologic storage at scale. To inform discussion around CO_2 removal, CARB held two full-day workshops exploring the types of options for carbon capture and geologic storage and utilization in products.[407,408,409]

The modeling results provided in Chapter 2 demonstrate the targeted need for CCS on large facilities such as refineries and cement. The CCS numbers do not include the potential additional applications for producing hydrogen with biomethane, other manufacturing, electricity, or other bioenergy. If CCS is not deployed, those emissions would be released directly into the atmosphere and instead need to be addressed through CDR to achieve carbon neutrality. Although a study finds California has 76 existing electricity and industrial facilities that are suitable candidates for CCS retrofit,[410] this Scoping Plan proposes a targeted role for this technology such that it would only be used to address sectors where non-combustion options are not technologically feasible or cost-effective at this time, to the extent needed to achieve the 85 percent reduction in anthropogenic emissions as called for in AB 1279. In future updates to the Scoping Plan, there may be additional options for technologically feasible or cost-effective technologies that may be deployed, which would further reduce the need for CCS and CDR except in situations to address historical GHG emissions.

Recognizing the need for carbon capture and utilization sequestration and removal, the Legislature passed, and the governor signed, SB 905. It includes several key requirements in the development of the state's Carbon Capture Removal, Utilization, and Storage Program. The following is a summary of the work to be completed to establish and administer this program. Many of these steps will address the need to evaluate the safety and efficacy of actions to support carbon removal, sequestration, and transfer via pipelines. Note that not all of these actions are under CARB's authority.

- Review technology to evaluate efficacy, safety, viability of CCUS/CDR methodologies.
- Develop monitoring and reporting requirements and schedules.
- Develop a unified permit application.
- Develop financial responsibility requirements.
- Develop a centralized public database for project status.

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407 CARB. December 11, 2019. Carbon Neutrality Meetings & Workshops. *https://ww2.arb.ca.gov/our-work/programs/carbon-neutrality/carbon-neutrality-meetings-workshops*.
408 CARB. August 2, 2021 Scoping Plan Meetings & Workshops. *https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/scoping-plan-meetings-workshops*.
409 *Carbon utilization* refers to the use of captured carbon to produce products such as plastics and concrete.
410 Glenwright, Kara. 2020. *Roadmap for carbon capture and storage in California.* Precourt Institute for Energy. *https://earth.stanford.edu/news/roadmap-carbon-capture-and-storage-california#gs.ysj78q.*

- Consult with CNRA on pore space requirements as CNRA develops a framework for pore space governing agreements.
- Establish a Geologic Carbon Sequestration Group to identify suitable injection well locations, subsurface monitoring, and potential hazards that may require suspension of injection.

SB 905 also has requirements for project developers such as to develop monitoring plans and to avoid any adverse health and environmental impacts at the carbon capture location—or mitigation of unavoidable impacts as required under existing requirements. For the site of injection, there are requirements for site stability, monitoring, and reporting plans. SB 905 also bans CCS with enhanced oil recovery in California and prohibits the transfer of CO_2 via pipeline until the U.S. Department of Transportation's Pipelines and Hazardous Materials Safety Administration (PHMSA) completes its current rulemaking to update existing CO_2 pipeline safety requirements.

An often-cited example of pipeline concerns involves a CO_2 pipeline in Mississippi. On February 22, 2020, a CO_2 pipeline operated by Denbury Gulf Coast Pipelines LLC (Denbury) ruptured in proximity to the community of Satartia, Mississippi. The rupture followed heavy rains that resulted in a landslide, creating excessive axial strain on a pipeline weld (DOT 2022). The combination of weather and topography resulted in a slower dissipation of the gas. The pipeline was also carrying hydrogen sulfide, a flammable and toxic gas. The pipeline failed on a steep embankment, which had recently subsided. Heavy rains are believed to have led to a landslide, which created axial strain on the pipeline and resulted in a full circumferential girth weld failure. The PHMSA investigation also revealed several contributing factors to the accident, including but not limited to: Denbury not addressing the risks of geohazards in its plans and procedures, underestimating the potential affected areas that could be impacted by a release in its CO_2 dispersion model, and not notifying local responders to advise them of a potential failure.

As the Satartia example highlights, appropriate pipeline safety and environmental standards in California are critical to minimize any risks from CO_2 transport in the future. As such, SB 905 also tasks CNRA, in consultation with the Public Utilities Commission, to, no later than February 1, 2023, provide a proposal to the Legislature to establish a state framework and standards for the design, operation, siting, and maintenance of intrastate pipelines carrying CO_2 fluids of varying composition and phase to minimize the risk posed to public and environmental health and safety. The recommended framework shall be designed to minimize risk to public health and environmental health and safety, to the extent feasible. Because SB 905 prohibits the transfer of CO_2 via pipeline until the PHMSA completes its current rulemaking to update existing CO_2 pipeline safety requirements, CCS or CDR projects that would require a pipeline to transfer CO_2 are not feasible at this time within California.

Ultimately, and in accordance with SB 905, the merits of each CCS or CDR project must be evaluated on a case-by-case basis.[411] Deployment of CCS and CDR could support skilled jobs and workforces, including those in traditional fossil energy communities. Other co-benefits could include criteria air pollutant reductions and water production. It will be important to design projects that do not exacerbate community health impacts, include early and ongoing community engagement, and are in compliance with local, state, and federal public health and environmental protection laws. It also should be noted that, as these types of projects are an emerging area of governance, additional coordination and discussion will be needed among the various levels of authorities involved. SB 905 has already initiated this process by assigning specific agencies with tasks related to their expertise and authority.

Chapter 2 includes a more detailed discussion about the proposed role of CO_2 removal in this Scoping Plan.

Sector Transition

State,[412] national,[413,414] and global decarbonization analyses[415] indicate a significant role for carbon management infrastructure, yet relatively few projects are operational. Around the world, about two dozen large CCS projects are capturing tens of millions of metric tons of CO_2 each year, with about a dozen operating in the United States.[416] The vast majority of capacity is at industrial facilities, such as ethanol and fertilizer plants, that would otherwise vent nearly pure CO_2 into the atmosphere as a by-product of normal, non-combustion processes. Future research, development, and demonstration projects must refine and commercialize capture systems for more complex applications, especially

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411 AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.5. finalejacrecs.pdf (arb.ca.gov).

412 E3. October 2020. Achieving Carbon Neutrality in California Report: Final Presentation. https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_presentation_oct2020_2.pdf.

413 World Resources Institute. January 31, 2020. CarbonShot: Federal Policy Options for Carbon Removal in the United States. Working paper. https://www.wri.org/research/carbonshot-federal-policy-options-carbon-removal-united-states.

414 C2ES. No date. Getting to Zero: A U.S. Climate Agenda — Center for Climate and Energy Solutions. https://www.c2es.org/getting-to-zero-a-u-s-climate-agenda-report/.

415 IPCC. Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development. Chapter 2. https://www.ipcc.ch/sr15/chapter/chapter-2/. All analyzed pathways limiting warming to 1.5°C with no or limited overshoot use CDR to some extent to neutralize emissions from sources for which no mitigation measures have been identified and, in most cases, also to achieve net negative emissions to return global warming to 1.5°C following a peak (high confidence). The longer the delay in reducing CO_2 emissions toward zero, the larger the likelihood of exceeding 1.5°C, and the heavier the implied reliance on net negative emissions after mid-century to return warming to 1.5°C (high confidence).

416 Congressional Research Service. 2021. Carbon Capture and Sequestration (CCS) in the United States. R44902. https://crsreports.congress.gov/product/pdf/R/R44902?msclkid=e45e0012c25911ec8085ca575cb61e82.

for those with limited decarbonization options. It has only been in the last few years that attention has seriously turned to mechanical CDR. As new information and modeling on climate change have been made available, the science has become clearer that avoiding the most catastrophic impacts of climate change requires both reducing emissions and deploying mechanical CDR.

California is paving a path forward on a science-based carbon management infrastructure policy that can serve as an example for other jurisdictions. The LCFS, which reduces the carbon intensity of transportation fuels, includes a protocol for select carbon management projects to become certified and generate LCFS credits.[417] CCS is not a new concept or technology. Twenty years of CCS testing show it is a safe and reliable tool.[418] As mentioned in Chapter 2, while no new CCS projects have been implemented or generated any credits under the CARB CCS protocol, CCS projects have been implemented elsewhere since the 1970s. Moreover, there has been a U.S. Department of Energy CCS research program underway for more than two decades. These all form a foundation of information for future efforts. Certified projects must successfully demonstrate adherence to rigorous pre-construction, operational, and site closure standards designed to strengthen environmental performance, as described in CARB's CCS Protocol. The protocol is designed to layer on top of existing federal carbon sequestration regulations designed to protect the environment. The protocol would need to be reevaluated if CCS were to be more broadly applied across sectors beyond transportation fuel production.

Direct air capture and carbon mineralization have high potential capacity for removing carbon, but direct air capture is currently limited by high cost. Carbon mineralization may also have high potential for removing carbon from the atmosphere, but understanding of the technology is still limited.[419] Direct air capture could also be deployed at higher rates to remove legacy GHG emissions from the atmosphere. Chapter 2 contains additional information on the current status of CCS and mechanical CDR projects globally, as well as federal support of such technologies.

Strategies for Achieving Success

- Implement SB 905.

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[417] CARB. 2018. Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard. August 13. https://ww2.arb.ca.gov/sites/default/files/2020-03/CCS_Protocol_Under_LCFS_8-13-18_ada.pdf.

[418] National Energy Technology Laboratory. Permanence and Safety of CCS. https://netl.doe.gov/coal/carbon-storage/faqs/permanence-safety.

[419] Aines, Roger. No date. Options for Removing CO_2 from California's Air. Lawrence Livermore National Laboratory. https://ww2.arb.ca.gov/sites/default/files/2021-08/llnl_presentation_sp_engineeredcarbonremoval_august2021.pdf.

- Convene a multi-agency Carbon Capture and Sequestration Group comprised of federal, state, and local agencies to engage with environmental justice advocates, tribes, academics, researchers, and community representatives to identify the current status, concerns, and outstanding questions concerning CCS, and develop a process to engage with communities to understand specific concerns and consider guardrails to ensure safe and effective deployment of CCS.[420]
- Iteratively update the CARB CCS Protocol with the best available science and implementation experience.
- Incorporate CCS into other sectors and programs beyond transportation where cost-effective and technologically feasible options are not currently available and to achieve the 85 percent reduction in anthropogenic sources below 1990 levels as called for in AB 1279.
- Evaluate and propose, as appropriate, financing mechanisms and incentives to address market barriers for CCS and CDR.
- Evaluate and propose, as appropriate, the role for CCS in cement decarbonization (SB 596) and as part of hydrogen production pathways (SB 1075).
- Support carbon management infrastructure projects through core CEC research, development, and demonstration (RD&D) programs.
- Continue to explore carbon capture applications for producing or leveraging zero-carbon power for reliability needs as part of SB 100.
- Consider carbon capture infrastructure when developing hydrogen roadmaps and strategy, especially for non-electrolysis hydrogen production.
- Evaluate and streamline permitting barriers to project implementation while protecting public health and the environment.
- Explore options for how local air quality benefits can be achieved when CCS is deployed.
- Explore opportunities for CCS and CDR developers to leverage existing infrastructure, including subsurface infrastructure.
- Explore permitting options to allow for scaling the number of sources at carbon sequestration hubs.

Short-Lived Climate Pollutants (Non-Combustion Gases)

Short-lived climate pollutants (SLCPs) include black carbon (soot), methane (CH_4), and fluorinated gases (F-gases, including hydrofluorocarbons [HFCs]). They are powerful climate forcers and harmful air pollutants that have an outsized impact on climate change

[420] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.9. finalejacrecs.pdf (arb.ca.gov).

in the near term, compared to longer-lived GHGs, such as CO_2. According to the IPCC's *Climate Change 2021: The Physical Science Basis,* in the near-term (i.e., 10- to 20-year time scale) the warming influence of all SLCPs combined will be at least as large as that of CO_2.[421] The United Nations Environment Programme's Global Methane Assessment[422] advises that achieving the least-cost pathways to limit warming to 1.5°C requires global methane emission reductions of 40–45 percent by 2030 alongside substantial simultaneous reductions of all climate forcers, including CO_2 and SLCPs. Action to reduce these powerful emissions sources today will provide immediate benefits—both to human health locally and to reduce warming globally—as the effects of our policies to transition to low carbon energy systems and achieve carbon neutrality further unfold.

In 2017, the Board approved the comprehensive Short-Lived Climate Pollutant Reduction Strategy (Strategy).[423] This strategy explained how the state would meet the following SB 1383-established targets:

- 40 percent reduction in total methane emissions[424] (including a separate 40 percent reduction in dairy and livestock emissions)
- 40 percent reduction in hydrofluorocarbon gas emissions
- 50 percent reduction in anthropogenic black carbon emissions
- 50 percent reduction of organic waste disposal from 2014 levels by 2020, and 75 percent by 2025, including recovery of at least 20 percent of edible food for human consumption

The state is expected to achieve roughly half of the SB 1383 targeted emissions reductions by 2030 through strategies currently in place (See Figure 4-11). As directed by the Legislature under SB 1383, state agencies focused on voluntary, incentive-based mechanisms to reduce SLCP emissions in the early years of implementation to overcome technical and market barriers. Under this "carrot-then-stick" strategy, incentives are replaced with requirements as the solutions become increasingly feasible and cost-effective. To meet legislated targets, more aggressive action is needed.

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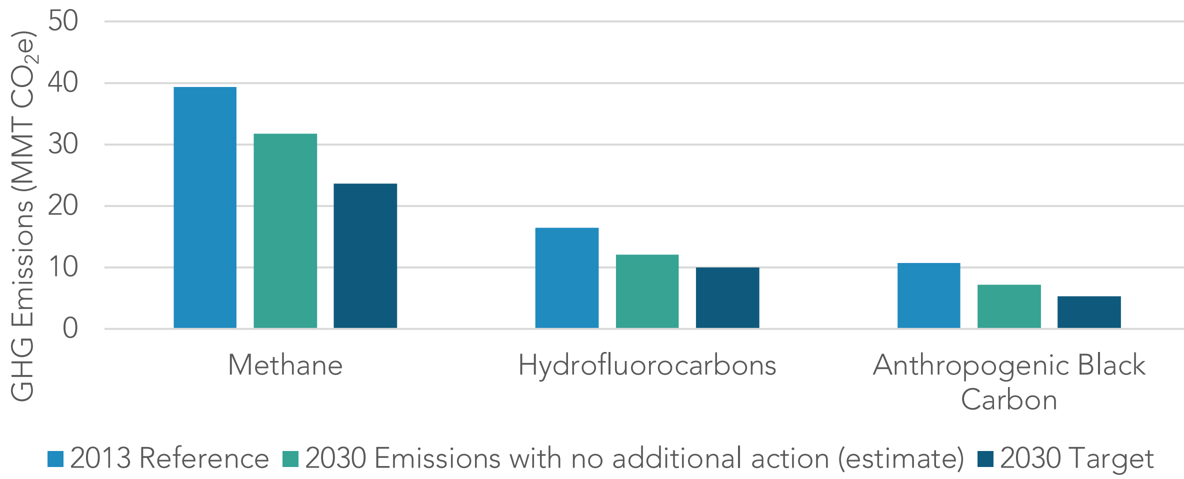
[421] IPCC. 2021. *Climate Change 2021:The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.
[422] United Nations. Global Methane Assessment. Summary for Policymakers. https://wedocs.unep.org/bitstream/handle/20.500.11822/35917/GMA_ES.pdf.
[423] CARB. 2017. Short-Lived Climate Pollution Reduction Strategy. https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.
[424] All SB 1383 emissions reductions are mandated to be realized by 2030 and are relative to 2013 levels.

Figure 4-11: Expected progress toward SB 1383 targeted emissions reductions by 2030 through strategies currently in place



While the state's overall GHG emissions have declined by 9 percent over the past decade, SLCP emissions reductions have not kept pace with broader progress toward decarbonization. After growing steadily in the preceding decade, methane emissions have remained relatively flat since 2013.

HFCs are the fastest growing source of GHG emissions, primarily driven by their use to replace ozone-depleting substances and an increased demand for cooling and refrigeration.[425] Since 2005, statewide HFC emissions have more than doubled. While the rate of increase has slowed in recent years due to the state's measures, HFC emissions are still on the rise in California, and have grown by over 50 percent since 2010.[426] Globally, as temperatures rise, adoption of cooling technologies (and refrigerants) is increasing rapidly. If no measures are taken, it is estimated that HFCs will account for 9 to 19 percent of the total global GHG emissions by 2050.[427]

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[425] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020: Trends of Emissions and Other Indicators.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

[426] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

[427] Velders, G. J., D. W. Fahey, J. S. Daniel, M. McFarland, and S. O. Andersen. 2009. "The large contribution of projected HFC emissions to future climate forcing." *Proceedings of the National Academy of Sciences* 106(27), 10949–10954.

Methane

Human sources of methane emissions are estimated to be responsible for up to 25 percent of current warming.[428] Fortunately, methane's short atmospheric lifetime of ~12 years[429] means that emissions reductions will rapidly reduce concentrations in the atmosphere, slowing the pace of temperature rise in this decade. Further, a substantial portion of the targeted reductions can be achieved at low cost and will provide significant human health benefits. For example, the UN's *Global Methane Assessment* (2021)[430] found that over half of the available targeted measures have mitigation costs below \$21/MTCO_2e, and that each million metric tons of methane reduced would prevent 1,430 premature deaths annually due to ozone pollution caused by methane.

Following the Twenty Sixth Conference of Parties (COP26) (the United Nations Convention on Climate Change in 2021), over 110 nations have signed onto the Global Methane Pledge (Pledge)[431] to limit methane emissions by 30 percent relative to 2020 levels. The Pledge covers countries that emit nearly half of all methane and make up 70 percent of global GDP. The UN's Global Methane Assessment[432] shows that human-caused methane emissions can be reduced by up to 45 percent this decade, which would avoid nearly 0.3°C of global warming by 2045.

As shown in Figure 4-12, the three largest sources of California's methane emissions are the dairy and livestock industry, landfills, and oil and gas systems.

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428 IPCC. 2021. *Climate Change 2021:The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.

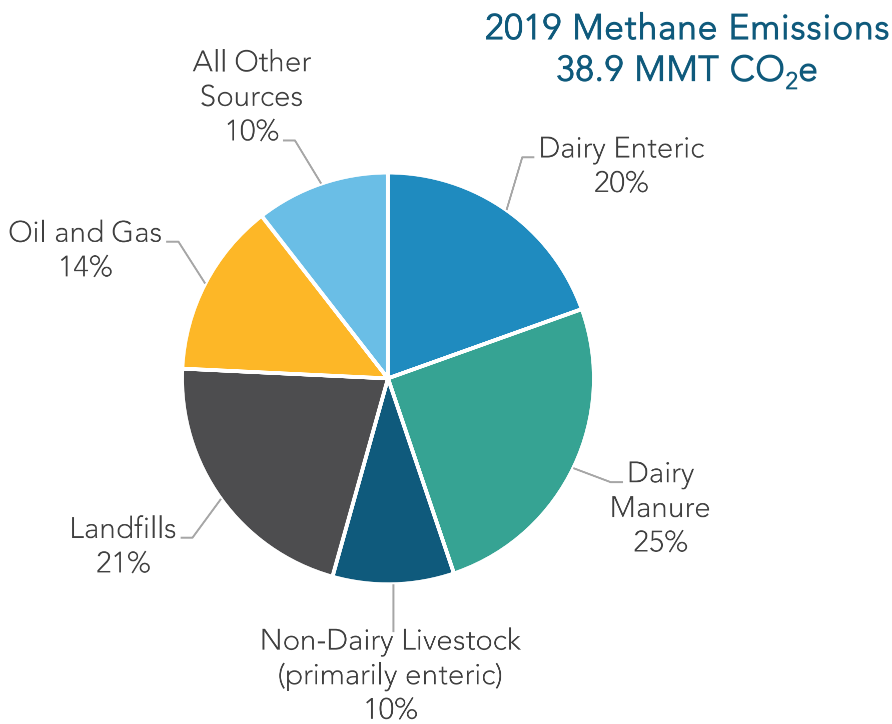
429 In contrast, the lifetime of CO_2 is hundreds of years. The IPCC Third Assessment Report concluded that no single lifetime can be defined for CO_2 because of the different rates of uptake by different removal processes. According to IPCC Fourth Assessment Report, the majority of an increase in CO_2 will be removed from the atmosphere within decades to a few centuries, while the remaining 20 percent may stay in the atmosphere for many thousands of years.

430 United Nations. 2021. Global Methane Assessment. https://wedocs.unep.org/bitstream/handle/20.500.11822/35917/GMA_ES.pdf.

431 Global Methane Pledge. https://www.globalmethanepledge.org/.

432 United Nations Environment Programme. 2021. Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions. https://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane-emissions?msclkid=00661370c85811eca078eb8fdbd603d1.

Figure 4-12: Sources of California methane emissions (2019)



Emissions from dairy and livestock operations come from two main sources: (1) enteric fermentation and (2) manure management operations, especially at dairies that employ open anaerobic lagoons that allow methane to escape into the atmosphere. Landfills, the second largest source of methane emissions, produce methane from the decomposition of organic waste. Although approximately 95 percent of all the waste that has been disposed of in the state has been deposited in a landfill that is equipped with a gas collection and control system, as required by California's Landfill Methane Regulation,[433] a portion of the methane still escapes into the atmosphere. Fugitive methane emissions can be intermittent and highly variable, both seasonally and spatially, particularly at landfills. Research has shown that landfills are complex systems and a wide range of conditions (e.g., atmospheric, operational, biological, chemical, and physical) may contribute to variability in rates of organic waste degradation, methane generation, and capture efficiency, so reducing the amount of organics deposited in landfills is critical to reducing overall landfill methane emissions. And despite the variability in individual landfill emissions, landfill gas collection and control systems remain the most effective strategy

[433] CARB. Landfill Methane Regulation. https://ww2.arb.ca.gov/our-work/programs/landfill-methane-regulation.

for reducing methane emissions from waste once it is placed in a landfill. Non-combustion methane emissions from the oil and gas sector are the third largest source of methane emissions in California. Almost three-quarters of the methane emissions from this sector come from leaks and venting from fossil gas transmission and distribution pipelines and equipment.

Hydrofluorocarbons

HFCs are synthetic GHGs that are powerful climate forcers. They are used mainly as refrigerants or heat transfer fluids in refrigeration, space conditioning, and heat pump equipment. Refrigerants are ubiquitous and are used everywhere from supermarkets, convenience stores, cold storage warehouses and wineries, to vending machines and residential and motor vehicle air-conditioners. Additionally, HFCs are also used as foam-blowing agents, solvents, aerosol-propellants, and fire suppressants. While HFCs remain in the atmosphere for a much shorter time than CO_2, the relative global warming potential (GWP) values of HFCs can be hundreds to thousands of times greater than CO_2. The mix of HFCs currently in use in California, weighted by usage (tonnage), have an average 100-year GWP of 1,700.[434] The average atmospheric lifetime of the mix of HFCs in use is 15 years.[435] Given the short average lifetimes, rapid reductions in HFC emissions can translate into near-term reductions in climate change effects.

As the global temperatures increase, the demand for cooling and refrigerants will continue to grow, as will the use of electric heat pumps to replace conventional fossil gas heating options. Unless addressed, continued use of high-GWP HFCs will perpetuate a feedback loop, where the cooling agents themselves cause additional warming.

In 2016, representatives from 197 nations signed the Kigali Amendment, which amended the existing Montreal Protocol (to reduce ozone-depleting substance production and consumption) to include a global phasedown in the production and consumption of HFCs beginning in 2019.[436] As of September 2022, 137 nations have either accepted, approved, or ratified the Kigali Amendment. On September 21, 2022, the U.S. Senate approved ratification of the Kigali Amendment, and it is expected that the United States

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[434] CARB. 2020. *Initial Statement of Reasons: Public Hearing to Consider the Proposed Amendments to the Prohibitions on Use of Certain Hydrofluorocarbons in Stationary Refrigeration, Chillers, Aerosols-Propellants, and Foam End-Uses Regulation.* October 20. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2020/hfc2020/isor.pdf?_ga=2.164659835.592460318.1646664679-912670513.1542398285.

[435] Zhongming, Z., et al. 2011. *HFCs: A Critical Link in Protecting Climate and the Ozone Layer: A UNEP Synthesis Report.*

[436] United Nations Treaty Collection. Chapter XXVII, Amendment to the Montreal Protocol on Substances that Deplete the Ozone Layer. https://treaties.un.org/Pages/ViewDetails.aspx?src=IND&mtdsg_no=XXVII-2-f&chapter=27&clang=_en.

will soon join the 137 nations that have already ratified.[437] In the United States, Congress enacted the federal *American Innovation and Manufacturing (AIM) Act* in December 2020.[438] The AIM Act authorizes the U.S. EPA to address HFCs in several ways, including a national HFC phasedown that nearly mirrors the schedule of the global phasedown under the Kigali amendment.[439]

Nearly 90 percent of HFC emissions in California come from their use as refrigerants in the commercial, industrial, residential, and transportation sectors. The timescales over which the HFC emissions occur vary, depending on the type of application. Thus, strategies to reduce HFC emissions must be tailored by equipment type. CARB has several measures in place to tackle HFC emissions from the various sources shown in Figure 4-13 below. This includes the Refrigerant Management Program[440] that tracks and manages emissions from large commercial, industrial, and cold storage refrigeration facilities in the state. CARB has adopted regulations to reduce HFC emissions from consumer product aerosol propellants, semiconductor manufacturing, and small cans of automotive refrigerant.[441]

In 2018, California adopted HFC prohibitions via regulation and legislation for several sectors, including stationary refrigeration and foam end uses to backstop the partially vacated federal Significant New Alternatives Policy (SNAP) program.[442] Most recently, in 2020, CARB adopted additional measures that place GWP limits on refrigerants used in refrigeration and air conditioning equipment, which are the largest sources of HFC emissions, and are commonly used in residential, commercial, and industrial buildings. Additionally, CARB adopted a unique pilot program requiring the use of reclaimed refrigerant: the Refrigerant Recovery, Reclaim, and Reuse (R4) Program. The newly adopted HFC rules for the refrigeration and air conditioning sectors are the first of their kind in the nation.

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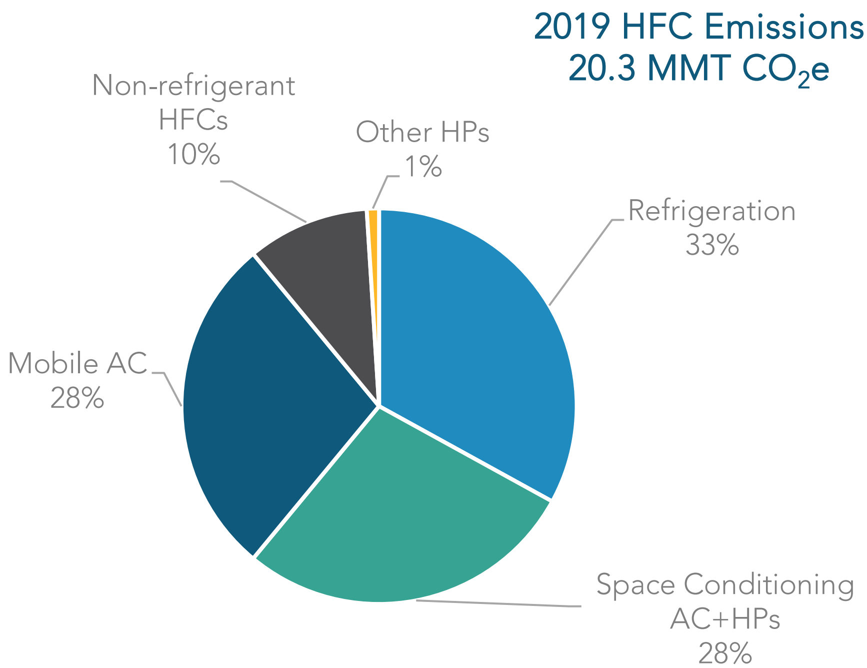
[437] U.S. Ratification of the Kigali Amendment - United States Department of State. https://www.state.gov/u-s-ratification-of-the-kigali-amendment/.
[438] 42 U.S.C § 7675, Pub. L. 116-260, § 103. https://www.epa.gov/sites/default/files/2021-03/documents/aim_act_section_103_of_h.r._133_consolidated_appropriations_act_2021.pdf.
[439] 42 U.S.C § 7675, Pub. L. 116-260, § 103.
[440] Cal. Code of Regs., tit. 17, §§ 95380, et seq.
[441] Contained in various sections, commencing with Cal. Code of Regs., tit. 13, §§ 1900 et seq.
[442] Cal. Code of Regs., tit. 17, §§ 95371, et seq.; California Cooling Act, Senate Bill 1013 (Lara, Stats. of 2018, Ch. 375, Health & Saf. Code § 39764).

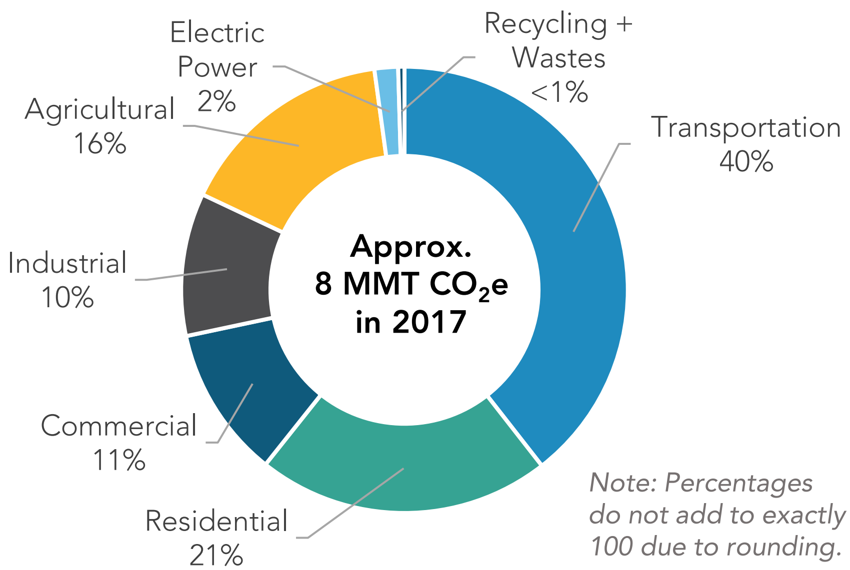
Figure 4-13: Sources of hydrofluorocarbon (HFC) emissions (2019)



Anthropogenic Black Carbon

Black carbon is not included in AB 32 or the state's AB 32 GHG inventory that tracks progress toward the state's climate targets; however, it has been identified as a powerful climate forcer and is included California's Short-Lived Climate Pollutant Reduction Strategy. The majority of anthropogenic black carbon emissions come from transportation, specifically heavy-duty vehicles, and they have decreased since 2013 due to engine certification standards and in-use rules for on-road and off-road fleets, along with clean fuel requirements and incentives, including California Climate Investments and LCFS credits. Additionally, fuel combustion for residential, commercial, and industrial applications contribute significantly to overall black carbon emissions. Approximately 95 percent of residential black carbon emissions are due to wood combustion; these emissions are being reduced through programs like the Woodsmoke Reduction Program established by SB 563 (Lara, Chapter 671, Statutes of 2017). Alternatives to agricultural burning and policies that phase out agricultural burning will also result in agricultural black carbon emissions reductions. In 2021 CARB provided a preliminary estimate of 2017 black carbon emissions (Figure 4-14).[443] This estimate will be finalized as part of a future update to the Short-Lived Climate Pollutant Inventory.

Figure 4-14: Sources of anthropogenic black carbon (preliminary 2017 estimates; AR5 100-yr GWP 900)



Sector Transition

California has long recognized the importance of mitigating non-combustion SLCPs and took several early action measures as part of a comprehensive, ongoing program to reduce in-state GHG emissions under AB 32. The early action measures included CARB's Landfill Methane Regulation,[444] Refrigerant Management Program,[445] and Oil and Gas Methane Regulation.[446]

Methane

The methane abatement strategies currently in place are projected to achieve half of the methane emissions needed to meet the overall methane reduction target of SB 1383 (40 percent reduction by 2030). The reduction target translates to a limit of less than 24 $MMTCO_2e$ in 2030 (Figure 4-15). It is anticipated that, since some sectors have fewer

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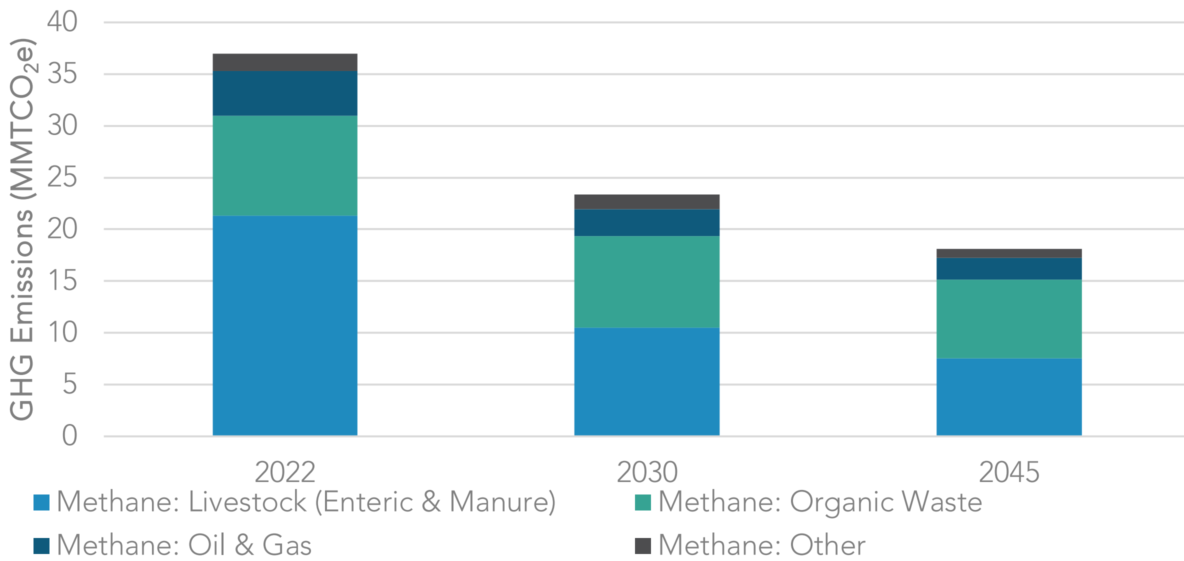
[443] CARB. 2021. 2022 Scoping Plan Update – Short-Lived Climate Pollutants Workshop Presentation, September 8. https://ww2.arb.ca.gov/sites/default/files/2021-09/carb_presentation_sp_slcp_september2021_1.pdf.
[444] Cal. Code of Regs., tit. 17, §§ 95460, et seq.
[445] Cal. Code of Regs., tit. 17, §§ 95380, et seq.
[446] Cal. Code of Regs., tit. 17, §§ 95665–77.

strategies that can be implemented to reduce methane in the near-term, other sectors will need to go beyond the 40 percent reduction to meet the target.

Figure 4-15: Methane emissions in 2022, 2030, and 2045 in the Scoping Plan Scenario[447]



Dairy and Livestock Methane

California is the largest dairy-producing state, home to one in five U.S. dairy cows. To date, methane emissions reductions from the dairy and livestock sector have mainly been driven by a decreasing animal population and the growing adoption of manure management strategies, including anaerobic digesters and conversion to dry manure systems and pasture systems. CARB recently completed a detailed analysis of the emission reductions expected by 2030 and the estimated additional investment needed to reach the dairy and livestock sector methane reduction target. [448]

Assuming no adoption of additional manure management and enteric mitigations strategies beyond the projects that have committed funding, and a continued annual animal population decrease of 0.5 percent per year through 2030, further reductions of approximately 4.4 $MMTCO_2e$ will be needed to achieve the 2030 methane emissions reduction target for the sector set by SB 1383. If the remaining reductions are met through

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[447] The *Organic Waste* category includes methane from landfills, wastewater treatment, and compost facilities.

[448] CARB. 2021. Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target. June. https://ww2.arb.ca.gov/sites/default/files/2021-06/draft-2030-dairy-livestock-ch4-analysis.pdf.

a mix of dairy projects in which half are dairy digesters and half are alternative manure management projects, then it is estimated that at least 420 additional projects will be necessary. Additional emissions reductions beyond this level will likely be necessary to ensure that the overall state methane emissions reduction targets are met.

Despite the considerable methane emissions mitigation potential of enteric strategies like feed additives, little progress has been made, as few products with proven mitigation potential have become commercially available, and unlike manure management strategies, there is a lack of financial incentives for their adoption.

Market conditions favoring farm consolidation and improved production efficiencies have driven reductions in the California and U.S. dairy population over the past decade. [449] These efficiency gains have allowed California to maintain production levels despite the decreasing population. If demand for dairy and beef products remains steady or increases, continued improvements in production efficiency and adoption of effective manure management and enteric mitigation strategies will be important to support dairy and livestock methane emission reductions.

Strategies for Achieving Success

- Install state of the art anaerobic digesters that maximize air and water quality protection, maximize biomethane capture, and direct biomethane to sectors that are hard to decarbonize or as a feedstock for energy.
- Increase alternative manure management projects, including but not limited to conversion to "solid," "dry," or "scrape" manure management; installation of a compost-bedded pack barn; an increase in the time animals spend on pasture; and implementation of solid-liquid separation technology into flush manure management systems.
- Implement enteric fermentation strategies that are cost-effective, scientifically proven, safe for animal and human health, and acceptable to consumers, and that do not impact animal productivity. Provide financial incentives for these strategies as needed.
- Accelerate demand for dairy and livestock product substitutes such as plant-based or cell-cultured dairy and livestock products to achieve reductions in animal populations.
- In consideration of pace of deployment of methane mitigation strategies and the scale of complimentary incentives, consider regulation development to ensure that the 2030 target is achieved, assuming the conditions outlined in SB 1383 are met.

[449] MacDonald, James M., Jonathan Law, and Roberto Mosheim. 2020. *Consolidation in U.S. Dairy Farming.* ERR-274. July. https://www.ers.usda.gov/webdocs/publications/98901/err-274.pdf.

Landfill Methane

Achieving the 75 percent organic waste disposal reduction target[450] of SB 1383, and maintaining that level of disposal in subsequent years, would bring annual landfill emissions in 2030 to just below the 2013 baseline. Annual methane emissions will be higher through 2030 than originally anticipated by the SLCP Strategy because the state did not achieve the anticipated reductions in organic waste disposal of 50 percent below 2014 levels by 2020. SB 1383 prohibited the organic disposal regulations from taking effect until 2022,[451] and, as a result, emissions have continued to increase.

Due to the multidecadal time frame required to break down landfilled organic material, the emissions reductions from diverting organic material in one year are realized over the course of several decades. For example, one year of waste diversion in 2030 is expected to avoid 8 $MMTCO_2e$ of landfill emissions, cumulatively, over the lifetime of that waste's decomposition.[452] Near-term diversion efforts are critical to avoid locking in future landfill methane emissions.

CalRecycle's 2020 report, *Analysis of the Progress Toward the SB 1383 Waste Reduction Goals,*[453] estimated that 8 million short tons of composting and anerobic digestion capacity will be needed to manage organic wastes, above the existing and new capacity expected to be available by 2025. The 2019 report, *Co-Digestion Capacity in California,*[454] from the State Water Resources Control Board estimated that at least 2.4 million tons of digester capacity is available at urban wastewater treatment plants if sufficient incentives or funding for collection, receiving, and processing operations are provided to enable utilization of this capacity. The CPUC approved a decision in February 2022 implementing the biomethane procurement program, which will require investor-owned utilities by 2025 to procure 17.6 billion cubic feet (BCF) of biomethane produced from organic wastes to support the landfill disposal reduction and SLCP target and reduce fossil gas reliance for

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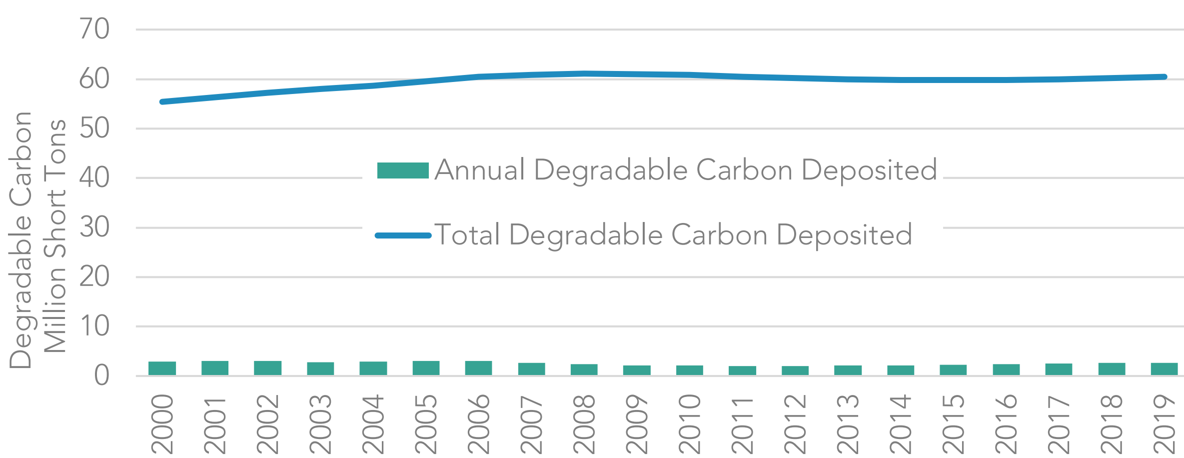
[450] The target is from 2014 levels by 2025.
Public Resources Code, § 42652.5. CalRecycle approved the SLCP: Organic Waste Reductions regulations (*https://calrecycle.ca.gov/organics/slcp/*) in 2020 and began implementing them in January 2022. These regulations are designed to achieve the 2025 disposal reduction and edible food recovery targets.
[452] The life cycle emissions reduction is based on anticipated diversion of 27 million short tons of organic waste from CalRecycle (2020) Analysis of the Progress Toward the SB 1383 Organic Waste Reduction Goals (*https://www2.calrecycle.ca.gov/Publications/Details/1693*). Under CalRecycle's SLCP regulations, an alternative to landfill disposal must achieve a life cycle GHG reduction of 0.3 $MTCO_2e$ per short ton of waste diverted.
[453] CalRecycle. 2020. *Analysis of the Progress Toward the SB 1383 Waste Reduction Goals.* *https://www2.calrecycle.ca.gov/Publications/Details/1693*.
[454] State Water Resources Control Board. 2019. *Co-Digestion Capacity in California.* *https://www.waterboards.ca.gov/water_issues/programs/climate/docs/co_digestion/final_co_digestion_capacity_in_california_report_only.pdf*.

residential and commercial customers.[455] Additionally, the organic waste stream includes more than one million tons of edible food that could be recovered before it enters the waste stream through food rescue programs that combat hunger in communities throughout California.

While reducing organic waste disposal is the most effective means of achieving reductions in waste sector methane, strategies to reduce emissions from waste already in place in landfills also will play a role in achieving near-term reductions. As Figure 4-16 shows, the total degradable carbon (a measure of the amount of waste with potential to generate methane) that is accumulated from waste deposited in previous years is over 20 times greater than the amount added each year. This illustrates that even if we were able to entirely phase out landfilling of organic waste today, the existing waste in place at landfills would continue to generate methane for decades into the future.

Through a combination of improvements in operational practices, use of lower permeability covers, advanced landfill gas collection systems, and increased monitoring to detect and repair leaks, it is estimated that a direct emission reduction of 10 percent is achievable across the state's landfills by 2030. Technologies to utilize landfill gas efficiently can contribute further emission reductions in the energy sector.

Figure 4-16: Degradable carbon deposited in landfills



Strategies for Achieving Success

- Maximize existing infrastructure and expand it to reduce landfill disposal, with strategies including composting, anaerobic digestion, co-digestion at wastewater treatment plants, and other non-combustion conversion technologies.

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[455] CPUC. 2022. Decision 22-02-025.

- Expand markets for products made from organic waste, including through recognition of the co-benefits of compost, biochar, and other products.[456]
- Recover edible food to combat food insecurity.
- Invest in the infrastructure needed to support growth in organic recycling capacity.
- Utilize existing digesters at wastewater treatment facilities to rapidly expand food waste digestion capacity.
- Direct biomethane captured from landfills and organic waste digesters to sectors that are hard to decarbonize.
- Implement improved technologies and best management practices at composting and digestion operations.
- Reduce emissions from landfills through improvements in operational practices, lower permeability covers, advanced collection systems, and technologies to utilize landfill gas.
- Leverage advances in remote sensing capabilities to quickly pinpoint large methane sources and mitigate leaks, improve understanding of the factors that lead to better capture efficiency, and explore new technologies and practices that can reliably improve methane control at landfills.

Upstream Oil and Gas Methane Reduction

For oil and gas production, processing, and storage, California is currently on track to achieve a 41 percent reduction in methane emissions by 2025 relative to 2013. The additional reductions needed to meet the 2030 target may be achieved by implementing additional regulatory requirements to further reduce intentional venting of fossil gas from equipment. If necessary, additional reductions from transmission and distribution facilities may be achieved by requiring the utilities to increase inspection and repair activities or further reduce emissions from pipeline blowdowns by implementing methods such as using portable compressors, using plugs to isolate sections of pipelines, flaring vented gas, routing gas to fuel gas systems, and installing static seals on compressor rods. Advances in methane detection technologies (e.g., satellites equipped to detect large methane sources) may also help to identify and mitigate methane emissions quickly across the oil and gas sector.

As California transitions away from fossil fuels, in-state oil and gas production will likely decline. This could result in an increase over time in the number of long-term idle and orphan wells (idle wells lacking a financially solvent, responsible owner) in the state. While California has regulations aimed at helping ensure operators manage their idle wells,

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[456] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.4. finalejacrecs.pdf (arb.ca.gov).

there could likely be an increase in California's orphan well population. Plugging all orphan wells, of which there are currently over 5,000, could take decades due to the limited resources California has for orphan well plugging. The benefits from plugging wells include methane emission reductions and job creation; employment gains from well plugging and site remediation activities could help temporarily offset job losses from the oil and gas industry. The California Council on Science and Technology's 2018 report on orphan wells, *Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells,*[457] found that the potential cost to the state of plugging current orphan wells could be approximately $500 million, and the cost of plugging all active and idle wells could total over $9.1 billion. As oil and gas production in California declines due to reduced demand for fossil fuels, additional funding will likely be needed to cover the costs of plugging wells that have no viable operator.

Strategies for Achieving Success

- Mitigate emissions from leaks by regular leak detection and repair (LDAR) surveys at all facilities.
- Replace high emitting equipment with zero emission alternatives wherever feasible.[458]
- Have CARB and CalGEM lead a Task Force to identify and address methane leaks from oil infrastructure near communities.
- Pursuant to SB 1137, develop leak detection and repair plans for facilities in health protection zones, implement emission detection system standards, and provide public access to emissions data.
- Minimize emissions from equipment that must vent fossil gas by design (e.g., fossil gas powered compressors).
- Install vapor collection systems on high emitting equipment.
- Phase out venting and routine flaring of associated gas (gas produced as a by-product during oil production).
- Continuous ambient monitoring at fossil gas underground storage facilities to quickly detect large methane sources.
- Reduce pipeline and compressor blowdown emissions.

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[457] The California Council on Science and Technology. 2018. *Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells.* https://ccst.us/wp-content/uploads/CCST-Orphan-Wells-in-California-An-Initial-Assessment.pdf.

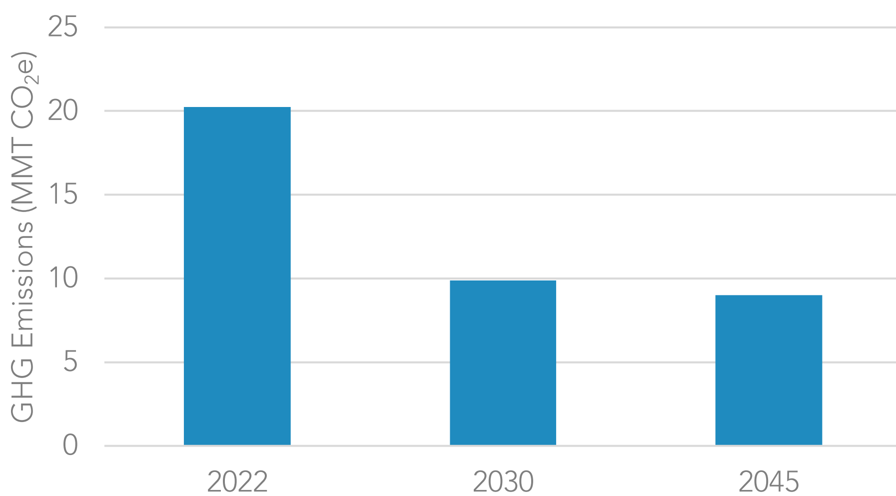
[458] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, P5. finalejacrecs.pdf (arb.ca.gov).

- Leverage advances in remote sensing capabilities to quickly pinpoint large methane sources and mitigate leaks.[459]

Hydrofluorocarbons

In California, all the HFC measures currently in place will help achieve more than 70 percent of the reductions needed to achieve the 2030 HFC goal and provide very significant emissions reductions by 2045 and beyond. However, new targeted measures will be needed to maintain the pace of reductions, as demand for technologies that currently predominantly use high-GWP refrigerants is anticipated to grow. Despite decarbonization efforts, high-GWP HFCs are expected to be among the last remaining persistent GHG emission sources, as shown in Figure 4-17.[460]

Figure 4-17: Hydrofluorocarbon emissions in 2022, 2030, and 2045 in the Scoping Plan Scenario



HFC emissions from new and existing sources should be addressed in tandem with building decarbonization efforts to maximize reductions.[461] As buildings are electrified in an effort to decarbonize them, the use of heat pumps for space conditioning, water heaters, and clothes dryers is expected to increase significantly. Heat pumps, while using

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[459] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, CC17. finalejacrecs.pdf (arb.ca.gov).

[460] Energy and Environmental Economics, Inc. 2020. *Achieving Carbon Neutrality.* https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf.

[461] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF26. finalejacrecs.pdf (arb.ca.gov).

electricity, not fossil gas, currently rely predominantly on high-GWP refrigerants. Very low- or no-GWP technologies and solutions are either available or emerging for various heat pump technologies, and likely to develop further as international efforts to mitigate HFCs continue. However, most of these technologies are still nascent in the United States. In addition, some of the alternatives cannot be used until California building codes are updated, which is currently expected at the earliest in mid-2024 for some technologies based on the recently adopted provisions in AB 209[462] requiring the California Building Standards Commission to adopt the latest safety standards for refrigerant containing equipment into California's building codes. The current updates to the building codes will allow the use of many refrigerants with lower GWPs than HFCs currently in use. However, additional building code updates are needed to expand the choices of ultra-low-GWP alternatives, and that will need to happen in the next few years. The adoption of low-GWP refrigerants must occur in parallel with building decarbonization efforts; without such efforts, the vast GHG benefits of the latter will be partially offset, and the proportion of HFC emissions from buildings will continue to grow.

Leaks from existing air conditioning and refrigeration equipment are a major source of statewide and global HFC emissions. Once installed, refrigeration and air conditioning equipment can stay in place for decades, while leaking refrigerants into the atmosphere. This makes it very important that new installed equipment use refrigerants with a GWP as low as possible. The refrigerants inside existing equipment are sometimes collectively referred to as the *installed base* or *banks* of potential HFC emissions. If released spontaneously, the existing HFC banks would equal 60 percent of all annual statewide GHG emissions in California, as illustrated in Figure 4-18.[463]

The sales prohibitions on newly produced refrigerants set forth in SB 1206 (2022) and the national/international HFC phasedown will help in reducing HFC emissions from existing equipment by restricting the supply of and increasing the value of existing high-GWP HFCs, thus enabling a circular economy. In the 2022–2023 state budget, CARB received $45 million in incentive funding for climate-friendly refrigerant technologies; this funding will be critical in shifting the market toward the best available refrigerant technologies in various sectors.

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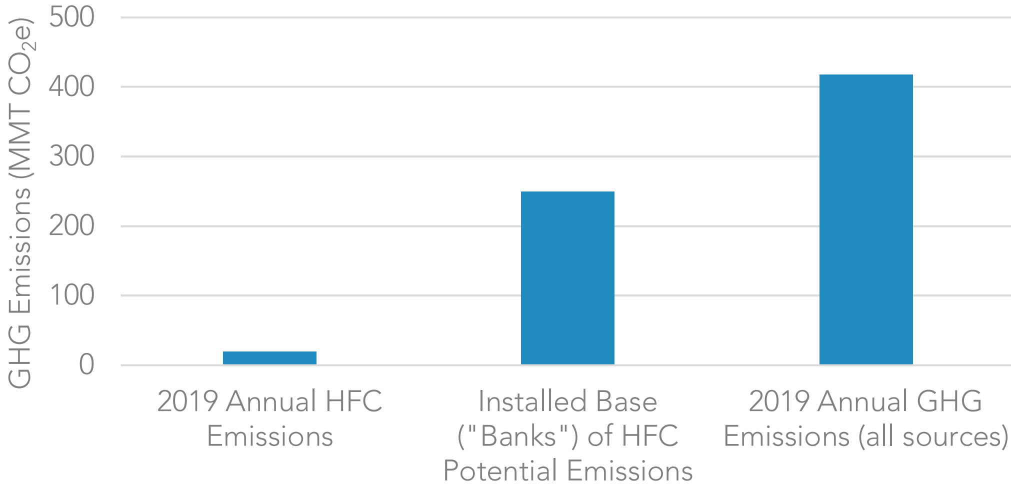
[462] AB 209: Energy and climate change. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB209.

[463] CARB. 2021. 2022 Scoping Plan Update – Short-Lived Climate Pollutants Workshop Presentation. September 8. https://ww2.arb.ca.gov/sites/default/files/2021-09/carb_presentation_sp_slcp_september2021_1.pdf.

Figure 4-18: Potential emissions from refrigerants in existing equipment



Strategies for Achieving Success

- Expand the use of very low- or no-GWP technologies in all HFC end-use sectors, including emerging sectors, like heat pumps for applications other than space conditioning, to maximize the benefits of building decarbonization.[464]
- Convert large HFC emitters such as existing refrigeration systems to the lowest practical GWP technologies.[465]
- Prioritize small-scale and independent grocers serving priority populations in addressing existing "banks" of high-GWP refrigerants.[466]
- Improve recovery, reclamation, and reuse of refrigerants by limiting sales of new or virgin high-GWP refrigerants and requiring the use of reclaimed refrigerants where appropriate.[467]
- Assist low-income and disadvantaged communities in obtaining low-GWP space conditioning units to protect vulnerable communities from heat stress and wildfire smoke.[468]

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[464] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF26. *finalejacrecs.pdf (arb.ca.gov)*.
[465] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF22. *finalejacrecs.pdf (arb.ca.gov)*.
[466] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT5 and JT6. *finalejacrecs.pdf (arb.ca.gov)*.
[467] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT1. *finalejacrecs.pdf (arb.ca.gov)*.
[468] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF28, JT5, and JT6. *finalejacrecs.pdf (arb.ca.gov)*.

- Accelerate technology transitions in California and the U.S. overall by collaborating with international partners committed to taking action on HFCs under the Kigali Amendment to the Montreal Protocol; this includes addressing barriers to adoption of very low- or no-GWP refrigerant technologies such as high upfront costs, shortage of trained technicians, and lag in updating safety standards and building codes.

Anthropogenic Black Carbon

Significant progress has been made since 2013 to reduce anthropogenic black carbon emissions, primarily from decreased combustion of distillate fuels in the agricultural sector, as well as improvements to provide cleaner, on-road combustion technologies. Under current strategies, anthropogenic black carbon from transportation is expected to be reduced by over 60 percent in 2030. Continued reductions in combustion emissions across all sectors from both the state's climate and air quality programs will also help reduce anthropogenic black carbon emissions going forward.

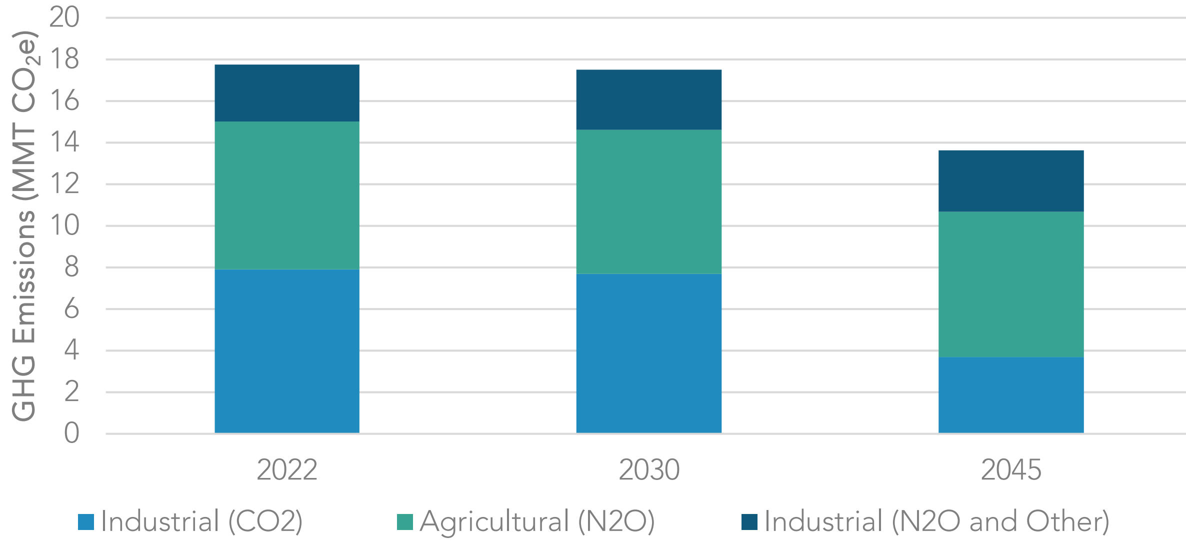
Strategies for Achieving Success

- Reduce fuel combustion commensurate with state's climate and air quality programs, particularly from reductions in transportation emissions and agricultural equipment emissions.[469]
- Invest in residential woodsmoke reduction.

In addition to SLCP emissions, some remaining non-combustion emissions are anticipated to persist in the coming decades, as shown in Figure 4-19. These include CO_2 from industrial processes such as cement manufacturing, oil and gas extraction, and geothermal electric power; N_2O from wastewater treatment, fertilizers, and livestock manure applied to agricultural soils; and other industrial, non-HFC GHG emissions.

[469] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1A and Appendix A (Table Summary of Direct Emission Reduction Strategies). "Emissions reductions from energy consumed by California's agricultural sector, including post-harvest processing, use of tractors and other farm equipment, and water import and irrigation." *finalejacrecs.pdf (arb.ca.gov)*.

Figure 4-19: Remaining non-combustion emissions in 2022, 2030, and 2045 in the Scoping Plan Scenario



Natural and Working Lands

California's natural and working lands (NWL) cover approximately 90 percent of the state's 105 million acres,[470] and include forests, grasslands, shrublands and chaparral, croplands, wetlands, sparsely vegetated lands, and the green spaces in urban and built environments. These lands include California Native American tribes' ancestral and cultural lands, parks and green spaces in our cities and communities, and the waters and the iconic landscapes we know and love. The diverse landscapes and biodiversity found throughout California's NWL provide a multitude of benefits to the people of California, including clean water, clean air, biodiversity, food, economic prosperity, recreational opportunities, continuation of traditional tribal ways of life, mental health benefits, and many others.

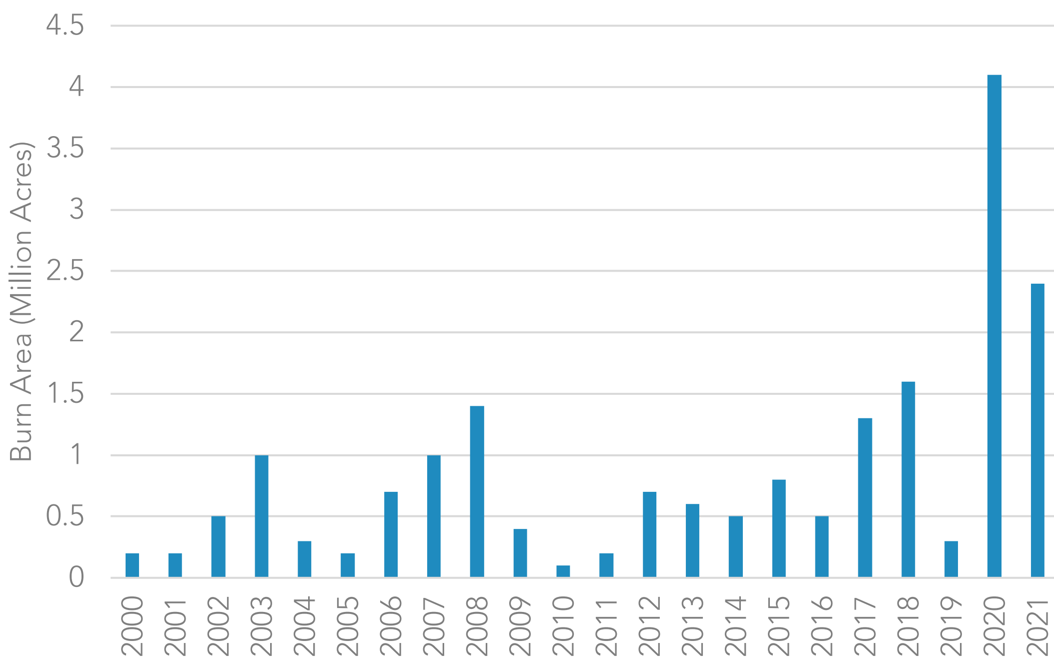
Our lands are a critical sector in California's fight to achieve carbon neutrality and build resilience to the impacts of climate change. Healthy land can sequester and store atmospheric CO_2. Healthy lands also can reduce emissions of powerful SLCPs, limit the release of future GHG emissions, protect people and nature from the impacts of climate change, and build our resilience to future climate risks. Creation of healthy lands through

[470] CNRA. 2022. Natural and Working Lands Climate Smart Strategy. https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/CNRA-Report-2022---Final_Accessible_Compressed.pdf.

multi-benefit and mitigation measures can also support tribal and local traditional lifeways. Unhealthy lands have the opposite effect—they release more GHGs than they store and are more vulnerable to future climate change impacts.

Climate change impacts have become more apparent in recent years and are having significant effects on communities throughout the state. One of these impacts is the much more frequent occurrence of unusually large, high-severity wildfires, which are being driven by climate change and by a recent history of fire-exclusion and land management practices that have resulted in forests with high levels of biomass. These recent large and high-severity wildfires have resulted in a significant amount of burned acreage and emissions in California (Figure 4-20).[471]

Figure 4-20: Acreage of burned wildland vegetation area



These wildfires deviate from the lower-severity fires that previously occurred at frequent intervals, around which California's forests evolved. As climate change accelerates, these large, uncharacteristic wildfires are likely to become more common and impact more of our landscapes. Climate change is also expected to have other significant effects on our lands, including more extreme droughts, floods, extreme heat, and the spread of invasive aquatic and terrestrial species, pests, diseases, and parasites. These impacts can lead

[471] CARB. 2022. Wildfire Emission Estimates for 2021. https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/Wildfire%20Emission%20Estimates%202000-2021.pdf.

to negative feedback loops on human and ecological health; for example, increasing the spread of invasive species can lead to increases in pesticide use, if not managed through regulation or mitigation, which can pose risks to human health and the environment.

California's approach to climate action in the NWL sector is not solely focused on maximizing carbon stocks but instead on supporting carbon management that holistically fosters ecosystem health, resilience, provision of overall climate function, and other co-benefits.

Natural systems operate on a longer timescale than the energy and industrial sectors, and benefits from climate action on our lands can take decades to accrue. Scaling climate smart land management in California requires taking action now and playing the "long game" by establishing and maintaining consistent, patient approaches and programs.

Landscapes

For the first time, this Scoping Plan includes modeling for the NWL sector. The focus of the initial modeling is limited to seven land types that align with the those in the NWL Climate Smart Strategy.[472] Work will continue to incorporate more landscapes and management practices into the modeling over time. The initial landscapes included in the modeling for this Scoping Plan are:

- Forests
- Shrublands and Chapparal
- Grasslands
- Croplands
- Wetlands
- Developed Lands
- Sparsely Vegetated Lands

Each of these land types are a key component to the state's approach to increasing climate action in the NWL sector, as called for in Executive Order N-82-20 and AB 1757.[473] The Executive Order directs CARB to update the target for this sector in support of carbon neutrality by 2045 as part of this Scoping Plan, and to take into consideration the NWL Climate Smart Strategy. AB 1757 calls for the development of an

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472 CNRA. 2022. *Natural and Working Lands Climate Smart Strategy. Appendix B.* *https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/Appendix-B_04132022_ada.pdf*.

473 AB 1757 California Global Warming Solutions Act of 2006: Climate Goal: Natural and Working Lands. *https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB1757*.

ambitious range of targets for the NWL sector to be integrated into the Scoping Plan and other state policies. It directs CARB and CNRA to work closely together to update the NWL Climate Smart Strategy, and establish an expert advisory committee to inform and advise on NWL modeling, targets, and implementation strategies.[474] Additionally, in 2021, the governor signed SB 27[475] (Skinner, Chapter 237, Statutes of 2021) into law. It directed CARB to establish CO_2 removal targets for 2030 and beyond and take into consideration the NWL Climate Smart Strategy. The governor's Executive Order, AB 1757, and SB 27 go beyond previous direction from the Legislature and past administrations. These directives emphasize the importance of quantifying land-based carbon both statewide,[476] and in programs and policies,[477] setting targets[478] for NWL to support the state's climate objectives, and advancing land management actions[479] that support the health and resiliency of these lands.

Blue carbon (also known as carbon captured and held in coastal vegetation and soils, such as seagrasses, seaweeds, and wetlands)—is also important to consider as we look at long-term climate goals. While this landscape is not currently covered by IPCC inventory guidelines or included in California's NWL Inventory, the United States was the first nation to include blue carbon in its national GHG emissions inventory. California's Ocean Protection Council and San Francisco Estuary Institute are partnering to create a new coastal wetlands, beaches, and watersheds inventory. CARB staff will utilize information from this effort and assess other available data to evaluate how this landscape may be integrated into our efforts in the future as more data become available.[480]

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[474] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N20. [finalejacrecs.pdf (arb.ca.gov)].

[475] SB 27 Carbon sequestration: state goals: natural and working lands: registry of projects. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220SB27.

[476] SB 859 Public resources: greenhouse gas emissions and biomass (SB 859, Committee on Budget and Fiscal Review, Chapter 368, Statutes of 2016). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB859.

[477] SB 1386. Resource conservation: working and natural lands. (SB 1386, Chapter 545, Statutes of 2016). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1386.

[478] CARB. 2017. 2017 Climate Change Scoping Plan Update. Board Resolution 17-46. https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2017/res17-46.pdf.

[479] Executive Department. State of California. EO B-52-18. https://www.ca.gov/archive/gov39/wp-content/uploads/2018/05/5.10.18-Forest-EO.pdf.

[480] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N2. [finalejacrecs.pdf (arb.ca.gov)].

Trends of Carbon on Landscapes

CARB currently tracks the carbon stock changes though the Inventory of Ecosystem Carbon in California's Lands[481] (NWL Inventory), which is summarized in Chapter 1. The NWL Inventory is a key tool for tracking changes in carbon stocks across the state, and it will serve as the inventory of record for this sector, tracking sector-wide progress toward the target. The NWL Inventory provides a retrospective snapshot of the status of California's lands, and captures the gains or losses of carbon stocks that occur over time. In addition to tracking carbon stock changes, the NWL Inventory is an important tool for understanding the impacts of our efforts to increase climate action in this sector (such as those identified in this Scoping Plan and the NWL Climate Smart Strategy) on NWL carbon stocks. The inventory is also used as the foundation for Scoping Plan scenario modeling and target setting.

CARB's inventory shows that carbon stocks decreased in NWL lands from 2001 to 2011, releasing more carbon than they were storing, and then increased slightly from 2012 to 2014.[482] These trends highlight the interannual and interdecadal variability of lands and their ability to be both a source and a sink of carbon, and the importance of looking at NWL data and trends over multiyear and multidecadal time periods, as opposed to looking only at annual changes. This movement is part of the Earth's carbon cycle, where carbon transfers between the land, ocean, and atmosphere. As part of the carbon cycle, over decades or centuries, fire and plant respiration and decomposition move carbon from the land to the atmosphere, while plant growth and other processes move carbon from the atmosphere to the land. Emissions from fossil-fuel combustion are contributing to putting this cycle out of balance.

Additionally, some historic land management practices that have resulted in the loss of carbon from the soil are also contributing to the atmospheric rise of CO_2 while simultaneously exacerbating the imbalance of the water cycle, which is influenced by and linked to the carbon cycle. These emissions are also contributing to a feedback loop for California's lands: as CO_2 emissions accumulate in the atmosphere—and California experiences more warming, extreme heat events, and droughts—the risk and intensity of carbon losses also increases, which in turn transfers more carbon from the land to the atmosphere. And because forests and shrublands comprise approximately 85 percent of the carbon stocks in California, management strategies and disturbances in forest and

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[481] CARB. *An Inventory of Ecosystem Carbon in California's Natural & Working Lands.* 2018 Edition. *nwl_inventory.pdf (ca.gov).* Accessed 3/2/2022.

[482] These trends are consistent estimates in the most recent AB 1504 reporting period.

shrubland carbon play an important role in determining whether California's lands are providing either net carbon sequestration or net emissions on an annual basis.

The gains and losses of carbon on our lands will fluctuate in the future; what is important is to restore carbon in places where it has been lost and reduce large carbon losses on our NWL through active, attentive, and adaptive management. For additional details on the nexus between NWL and GHGs, see pages 5–6 of the NWL Climate Smart Strategy.

Goals and Accelerating Nature-Based Solutions

The state's climate mitigation targets are traditionally identified by individual years, (i.e., tons of GHG emissions in 2020 or 2030). However, because NWL processes fluctuate year to year and because it can sometimes take decades for climate action to fully impact carbon in NWL, it is important to consider the statewide, long-term trends of carbon stock change when identifying how this sector contributes to California's pathway to achieving carbon neutrality. Tracking carbon stock change over a multi-decadal period is the best way to assess the full direct impact climate action has on carbon storage. Such an approach filters out fluctuations from year-to-year weather variations and multi-year natural climate cycles, such as El Niño patterns.

Current data sources and methods allow us to track only certain carbon stocks that exist on NWL. For target tracking to be successful, each carbon pool must be inventoried using a methodology that can detect changes due to management and climate change. Certain carbon pools lack the scientific data and methodologies necessary for target-setting and tracking. For example, soils in forests, shrublands, and grasslands are not included in the Scoping Plan carbon stock target because, currently, there is no way to track statewide soil carbon through time in a way that would capture the effects of increased climate action and climate change.

When considering how NWL contribute to the state's goal of carbon neutrality, all lands' carbon stock gains and losses must be considered, and the Scoping Plan target is set in these terms. It is not sufficient to aggregate climate benefits only within areas where projects, management, or climate action occur. Much of the state does not receive active or quantifiable management, but these areas still contribute to the state's overall carbon stock change and GHG emissions. To incorporate the entire carbon balance toward true carbon neutrality, the Scoping Plan target is set in terms of carbon stock change across the entire state. This incorporates all lands that both receive and do not receive active management, and includes the end result of all sequestration, emissions, and other changes to carbon on the landscape.

However, carbon stock change is not equivalent to emissions. Currently, the data and emission quantification science is not sufficient to enable inventories to comprehensively track all NWL emissions in a way that would enable us to set an NWL target in terms of statewide emissions and sequestration. There is a great need, across the entire NWL sector statewide, for more empirical data, science, and tools to track all carbon stocks across each carbon pool, and to begin to track emission and sequestration rates. As California implements AB 1757, there is an opportunity to update the data, science, and tools to enable this level of tracking and target setting in the future.

As outlined in Chapter 2, California is projected to lose carbon stocks over the coming decades, but this Scoping Plan analysis also shows that increasing the pace and scale of climate smart land management in California will reduce the carbon stock losses and GHG emissions from the NWL sector. In response to EO N-82-20 and AB 1757, the proposed target for NWL is shown in Table 4-1.

Table 4-1: Scoping Plan modeled target for NWL, based on increasing action on NWL

	Total Carbon Stock % Change from 2014
2045	-4

Achieving this target will require significant expansion of the pace and scale of climate action on California's NWL, including the following:

- Increasing climate smart forest, shrubland, and grassland management to at least 2.3 million acres a year—an approximate 10x increase in management from current levels.
- Increasing climate smart agricultural practices by at least 78,000 acres adopted a year, annually conserving at least 8,000 acres a year of croplands, and increasing organic agriculture to comprise at least 20 percent of cultivated acres in California by 2045—an approximate 7.5x increase in healthy soils practices from previous levels and a 2x increase in total acres of organic agriculture.
- Increasing annual investment in urban trees in developed lands by at least 200 percent above historic levels and establishing defensible space on all parcels by 2045.
- Restoring at least 60,000 acres, or approximately 15 percent of all Sacramento–San Joaquin River Delta (Delta) wetlands, by 2045.
- Cutting land conversion of deserts and sparsely vegetated landscapes by at least 50 percent annually from current levels, starting in 2025.

If the carbon stock target above is met, and the management actions above are implemented, the modeling for NWL indicates that California's lands will be a net source of emissions, producing approximately 7 $MMTCO_2e$ of average annual emissions.

Additional climate smart management practices and additional landscapes, such as those included in the Climate Smart Strategy and discussed below in Additional Management Strategies, have the potential to increase carbon stocks and reduce GHG emissions from NWL beyond the levels modeled for this Scoping Plan.

The purpose of the NWL target and the above estimated outcomes is to provide a numerical guide that can support the state's efforts to accelerate both near-term and long-term climate action on California's lands, prioritizing durable solutions that deliver multiple outcomes. Taking these actions over the coming decades will reduce the potential carbon losses from NWL, reduce GHG emissions from some landscape types (such as croplands and Delta wetlands), and support sequestration of GHGs from NWL between 2025 and 2045. These actions will also deliver significant benefits to Californians beyond advancing our climate goals, such as reducing wildfire emissions and their associated health impacts, increasing habitat for biodiversity, reducing urban heat island effects, reducing harmful pesticide exposure, expanding economic opportunities, and others. Additional information on several economic and health outcomes from the Scoping Plan Scenario is included in Chapters 2 and 3.

Statewide planning and target setting for the NWL sector will only create meaningful change if followed by effective on-the-ground implementation. State government cannot accomplish this implementation alone. Effective large scale climate action is dependent on partnerships among tribal, federal, state, regional, and local partners, and across governmental, private, nonprofit, and commercial sectors. The NWL sector of the Scoping Plan sets a carbon target with climate action recommendations that can be used to achieve the quantified carbon, health, and economic outcomes. Implementation of these actions must be led by local or regional partnerships that plan and execute projects appropriate to the specific conditions. The technical expertise and local knowledge of land managers and stewards in all sectors must be elevated to ensure relevant, efficient, and effective climate action.

Implementation of climate action should contribute to state targets, maximize local benefits, and alleviate environmental injustices and other social inequities. On-the-ground action is largely executed and managed by local and regional actors, but state government agencies must support communities across the state in implementing nature-based climate solutions that address statewide objectives, such as the Scoping Plan carbon target. This includes providing resources and developing frameworks, while greatly increasing capacity and technical assistance to assist and empower local partners. Examples of how this can be done are the Regional Forest and Fire Capacity Program within the forestry sector, the UC Cooperative Extension in the agricultural and forestry sectors—as well as the work of the state's 10 regional Conservancies. These programs provide strong examples to emulate as they facilitate statewide coordination, and information and resource transfer from the state to the regional and local levels. The Regional Forest and Fire Capacity Program provides funding for local and regional groups to build their organizational capacity to plan and implement wildfire and forest management projects that are informed by their own local expertise. The UC Cooperative Extension is an example of how the state provides technical assistance to local landowners and community organizations, helping them apply the latest science-based management strategies to their lands. California's regional Conservancies play a pivotal role in implementing regional conservation, restoration, and land management efforts through activities such as grant funding, science generation, and planning assistance.

The state also has identified the need to incorporate and elevate traditional indigenous knowledge into climate action on the regional and local scales. Accomplishing this requires close partnerships with tribes for mutual knowledge and resource sharing, while protecting culturally sensitive knowledge and resources. As Tribes are sovereign nations with specialized cultural knowledge and experience in managing lands, climate action on these lands that contribute to the State of California's climate targets can only be accomplished with the full participation and under the leadership of the Tribes that govern those lands.

Strategies for Achieving Success: Crosscutting Items for all NWL

- Implement AB 1757 and SB 27.
- Implement the Climate Smart Strategy.
- Accelerate the pace and scale of climate smart action, consistent with the management levels identified above, as part of a collective effort between federal, state, private, nonprofit, and individual land managers.
- Prioritize and practice equity, including through meaningful community engagement and prioritizing implementation of nature-based solutions that benefit the communities most vulnerable to climate change.[483]
- Advance multi-benefit, collaborative, landscape-level approaches that engage communities and landowners, and incorporate adaptive managements.
- Consult and partner with California Native American tribes to increase co-management and tribal management authority; restore, protect, and enhance natural cultural resources, traditional foods, and cultural landscapes; respect tribal sovereignty; and support tribes' implementation of tribal expertise and Traditional Ecological Knowledge and cultural easements.[484]

[483] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N8. *finalejacrecs.pdf (arb.ca.gov)*.

[484] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N1, N6, N16, N17, N18. *finalejacrecs.pdf (arb.ca.gov)*.

- Leverage existing innovative financial and market mechanisms, and explore new ones, between the public, private, and philanthropic sectors to secure funding of climate smart land management.
- In partnership with communities, tribes, and the private sector, expand and develop new infrastructure for manufacturing and processing of climate smart agricultural and biomass products.
- Leverage and support technical assistance providers: such as the UC Cooperative Extension and California's 98 Resource Conservation Districts, that have track records of providing technical assistance to local landowners and implementing agriculture, forestry, natural resource management, and restoration projects across the state.
- Establish and expand mechanisms that ensure NWL are protected from land conversion and parcelization (e.g., conservation easements or Williamson Act), in line with the strategies outlined in CNRA's Pathways to 30x30 California.[485,486] Pair land conservation projects with management plans that increase carbon sequestration, where feasible.
- Increase opportunities for private and philanthropic investments in nature-based climate solutions, utilizing existing voluntary and compliance carbon markets, existing state and local programs, and the California Carbon Sequestration and Climate Resiliency Project Registry established pursuant to SB 27.
- Expand monitoring and tracking of management actions and outcomes consistent with the tracking and monitoring recommendations of the Climate Smart Strategy.

Forests, Shrublands, and Chaparral

At roughly 29 million acres, forests cover 27 percent of California. Shrublands and chaparral cover 31 percent of the state; roughly 33 million acres. Both types are distinct, with their own ecological dynamics and management strategies, and are modeled within a single model that is calibrated to treat them uniquely.

Together, forests, shrublands, and chaparral support a high biodiversity of plants and animals, in addition to high levels of carbon stocks. They provide important air and water quality benefits to all Californians, as well as recreational opportunities and, for forests, harvested wood products for the state. These landscapes are fire-adapted, and historical tribal management of these lands has fostered ecosystem health and resilience. Over the past century, these lands have been impacted severely by fire exclusion, including

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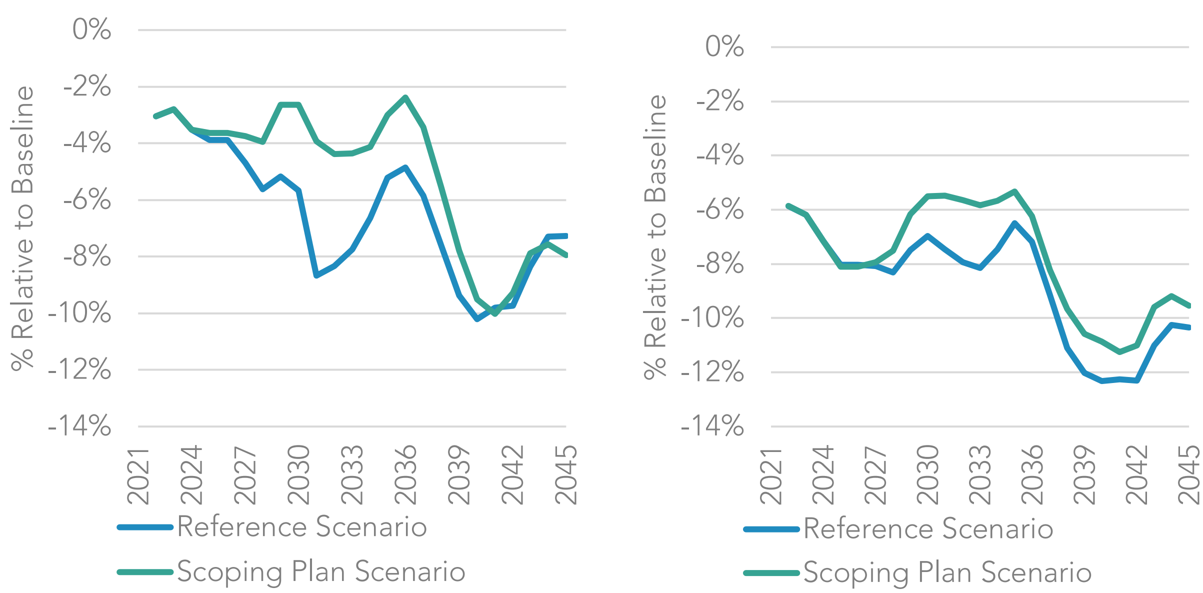
[485] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N5, N26, N27. *finalejacrecs.pdf (arb.ca.gov)*.

[486] CNRA. 2022. *Pathways to 30x30 California*. https://www.californianature.ca.gov/pages/30x30.

exclusion of indigenous people's management and past management practices, which has resulted in less resilient ecosystems and communities and more destructive wildfires today. This, along with drought induced stress and mortality, has changed these landscapes from a carbon sink to a carbon source. Climate smart management can help make forests more resilient to climate change and less prone to catastrophic wildfire. Climate-smart management in shrublands and chaparral face additional challenges and uncertainty, but can still provide protection for threatened communities and natural resources. This management, if conducted on a regular basis to maintain forest health, can help reduce emissions from forests, shrublands, and chaparral, and help strengthen and maintain the co-benefits that Californians experience from them.

Under all management levels, forests and shrublands are expected to lose carbon over the next two decades due to climate change and wildfire (Figure 4-21).

Figure 4-21: Forest (left) and shrubland (right) carbon stocks by 2045[487,488]



While this decrease in carbon stocks may be inevitable, forest management under the Scoping Plan Scenario can help direct where and how carbon loss occurs. By proactively managing forests and shrublands, the loss of carbon from wildfire can be lessened as the risk of high severity fire is decreased, with the removed biomass going toward a more

[487] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N13. *finalejacrecs.pdf (arb.ca.gov)*.
[488] This analysis is the aggregation of all forests and shrublands from all ownerships across the entire state of California.

useful purpose such as harvested wood products, bioenergy, and engineered carbon removal. Managing for a diverse and resilient forest landscape also can help forests recover more quickly so that when climate change and wildfire impacts occur, forests will be less affected and can continue to thrive and sequester carbon. Additional details on the climate benefit potential of forests and shrublands/chapparal can be found in Section 2 of the NWL Climate Smart Strategy.

Strategies for Achieving Success

- Accelerate the pace and scale of climate smart forest management to at least 2.3 million acres annually by 2025, in line with the climate smart management strategies identified in this Scoping Plan, the NWL Climate Smart Strategy, and the Wildfire and Forest Resilience Action Plan.[489]
- Establish and expand mechanisms that ensure forests, shrublands, and grasslands are protected from land conversion and that support ongoing, rather than one-time, management actions.
- In collaboration with state and local agencies, accelerate the deployment of long-term carbon storage from waste woody biomass residues resulting from climate smart management, including storage in durable wood products, underground reservoirs, soil amendments, and other mediums.
- Expand infrastructure to facilitate processing of biomass resulting from climate smart management.
- Expand permit streamlining in collaboration with state and local agencies to accelerate implementation of climate smart forest management while protecting natural resources.

Grasslands

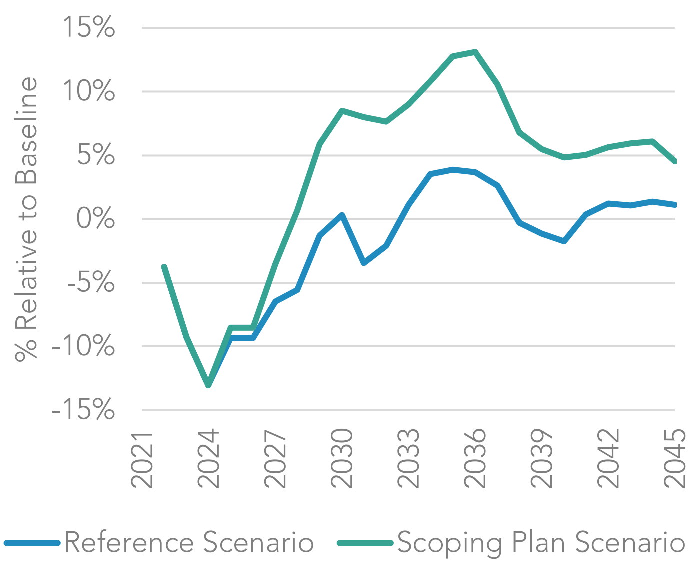
Grasslands cover 9 percent of California, roughly 10 million acres, and are found throughout the state in various landscapes, with concentrations in the foothills surrounding the Sacramento and San Joaquin Valleys. In addition to carbon storage (primarily in the soil), grasslands provide open space, wild habitat, grazing land, and important water filtration and recharge benefits. The protection of grasslands provides an opportunity to reduce sprawl and complement VMT reduction strategies. As grasslands are susceptible to invasive species, climate smart strategies can increase grassland

[489] Forest Management Task Force. 2021. *California's Wildfire and Forest Resilience Action Plan: Recommendations of the Governor's Forest Management Task Force.* https://www.fire.ca.gov/media/ps4p2vck/californiawildfireandforestresilienceactionplan.pdf.

resilience to climate change by improving species diversity and maintaining or increasing soil carbon stocks.

Modeling results show that increased fuels treatments and avoided land conversion can increase carbon stocks on grasslands by 2045, but sequestration rates fluctuate annually. Grasslands are capable of high carbon sequestration rates but are susceptible to carbon losses from wildfire and land conversion. Soil carbon is the major carbon pool on these lands, and continued future improvement of the monitoring and modeling of soil carbon is needed. Similar to forests and shrubland/chaparral, modeling alternatives that include fuels treatments resulted in greater carbon stocks compared to no management, and had lower wildfire emissions. Unlike forests and shrubland/chaparral, which have a general declining carbon stocks trend, the modeling results (Figure 4-22) show grasslands can maintain or increase carbon stocks with active management. Details on the climate benefit potential of grasslands can be found in Section 2 of the NWL Climate Smart Strategy.

Figure 4-22: Grassland carbon stocks by 2045



Strategies for Achieving Success

- Establish and expand mechanisms that ensure grasslands are protected from land conversion/parcelization and that support ongoing, rather than one-time, management actions that improve carbon sequestration.
- Deploy grassland management strategies, like prescribed grazing, compost application, and other regenerative practices, to support soil carbon sequestration, biodiversity, and other ecological improvements.

- Increase adoption of compost production on farms and application of compost in appropriate grassland settings for improved vegetation and carbon storage, and to deliver waste diversion goals through nature-based solutions.

Croplands

Croplands cover 9 percent of the state, roughly 9.5 million acres. This land is some of the most productive agricultural land in the world, and enables California to be a global leader in agriculture. Aside from developed lands, croplands are the most intensively managed landscapes in the state, and are closely tied to society through the food they produce and the constant, direct contact that people have with croplands through the course of management. In addition to food security, croplands provide considerable carbon storage in the soil and, in perennial croplands, in aboveground biomass. Climate smart practices can improve public health; for example, by reducing synthetic fertilizer and pesticide use. They also help to maintain or increase the climate resilience of cropland productivity through improved soil conditions and increased pollinator habitat.

There is also significant potential to transform this sector to increase soil carbon storage, reduce GHG emissions (Figure 4-23), and reduce pesticide exposure and health impacts. Moving to an agricultural system that improves soil health and water holding capacity reduces over-application of nitrogen, reduces the use of pesticides and fumigants, and increases biodiversity and pollinator habitat, supporting California's pathway to carbon neutrality while simultaneously improving the lives of those who live and work in the agricultural community. Croplands are intricately tied to people, communities, and their health, and through climate smart practices and cropland conservation, these lands have the potential to contribute more to society than just food.[490] The implementation of climate smart agricultural practices and diversified organic agriculture can help California achieve social and environmental benefits, like improving water use efficiency, increasing pollinator habitat, and reducing synthetic fertilizer and pesticide use.[491] Additional details on the climate benefit potential of croplands can be found in Section 2 of the NWL Climate Smart Strategy.

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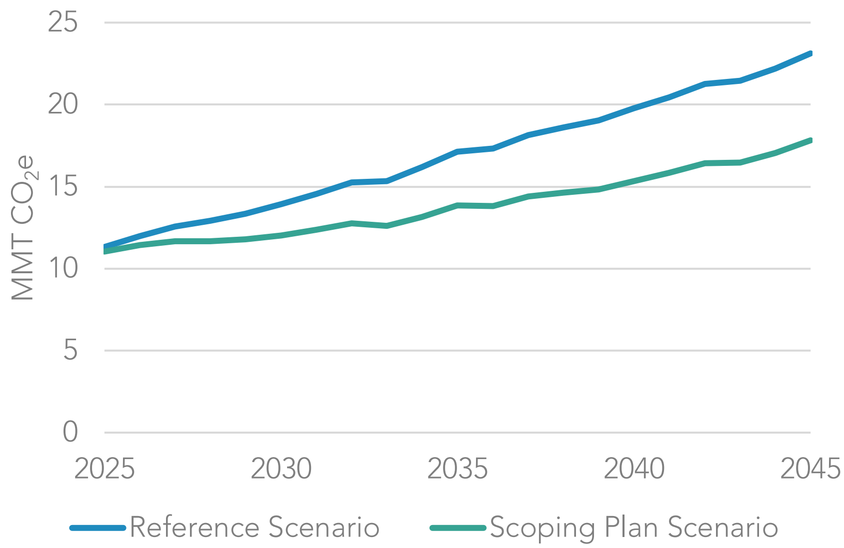
[490] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations In-part (N3, N4, N22), N5, N21. finalejacrecs.pdf (arb.ca.gov).
[491] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11. finalejacrecs.pdf (arb.ca.gov).

Figure 4-23: Cumulative CO_2e emissions from annual croplands in 2045[492]



CARB recognizes the complex nature of croplands, cross-sector relationships, and the need to build on this analysis to further our understanding of cropland dynamics. Many more aspects of cropland management need to be explored for potential climate benefits, such as water and nutrient use management, pest control methods, crop rotations, and other management practices. The impacts of climate change on water availability, annual/perennial crop growth, and future carbon sequestration trends are uncertain, and recent policies such as the Sustainable Groundwater Management Act may also influence cropland management in unforeseen ways. Nonetheless, it is clear that greater climate smart practice implementation can prepare California for the future and yield tangible benefits for the state.

Strategies for Achieving Success

- Accelerate the pace and scale of healthy soils practices to 80,000 acres annually by 2025, conserve at least 8,000 acres of annual crops annually, and increase organic agriculture to 20 percent of all cultivated acres by 2045.

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[492] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11. *finalejacrecs.pdf (arb.ca.gov)*.

- Utilize the recommendations included in CDFA's Farmer and Rancher-Led Climate Change Solutions[493] report to accelerate deployment of healthy soils practices, organic farming, and climate smart agriculture practices.
- Establish or expand financial mechanisms that support ongoing deployment of healthy soils practices and organic agriculture.[494]
- Support strategies that achieve co-benefits of safer, more sustainable pest management practices and the health and preservation of ecosystems, such as implementing the California Department of Pesticide Regulation's (DPR's) Sustainable Pest Management Work Group recommendations.[495]
- Conduct research on the intersection of pesticides, soil health, GHGs, and pest resiliency via a multi-agency effort with DPR, CDFA, and CARB.[496]
- Conduct outreach and education to develop and facilitate the increased adoption of safer, more sustainable pest management practices and tools; reduce the use of harmful pesticides; promote healthy soils; improve water and air quality; and reduce public health impacts.
- In collaboration with state and local agencies, accelerate the deployment of alternatives to agricultural burning that increase long-term carbon storage from waste agricultural biomass, including storage in durable wood products, underground reservoirs, soil amendments, and other mediums.
- Work across state agencies to reduce regulatory and permitting barriers around some healthy soils practices (e.g., composting), where appropriate.
- Utilize innovative agriculture energy use and carbon monitoring and planning tools to reduce on-farm GHG emissions from energy and fertilizer application or to increase carbon storage, as well as to promote on-farm energy production opportunities.

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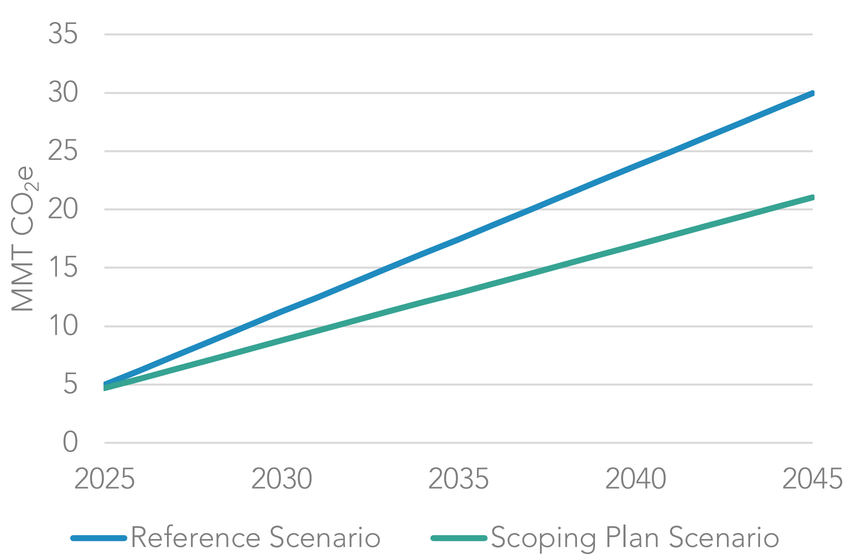
[493] California Department of Food and Agriculture. 2021. Farmer and Rancher Led Climate Change Solutions. https://www.cdfa.ca.gov/oefi/climate/docs/cdfa_farmer_and_rancher-led_climate_solutions_meetings_summary.pdf.
[494] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N5, N7. finalejacrecs.pdf (arb.ca.gov).
[495] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations N3, N4, N5, N7, N22. finalejacrecs.pdf (arb.ca.gov).
[496] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11. finalejacrecs.pdf (arb.ca.gov).

Wetlands

Wetlands cover 2 percent of the state (roughly 1.7 million acres) and include inland and coastal wetlands, such as vernal pools, peatlands, mountain meadows, salt marshes, and mudflats. These lands are essential to California's communities as they serve as hotspots for biodiversity, contain considerable carbon in the soil, are critical to the state's water supply, and protect upland areas from flooding due to sea level rise and storms. Wetlands have been severely degraded through reclamation, diking, draining, and dredging practices in the past, resulting in the emissions of the carbon stored in the soils and the loss of ecosystem benefits. Climate smart strategies to restore and protect all the types of wetlands can reduce emissions while simultaneously improving the climate resilience of surrounding areas and improving the water quality and yield for the state. Restored wetlands also can reduce pressure on California's aging water infrastructure. These benefits beyond emissions reductions will help in the future, as climate change is predicted to negatively affect water supply.

Avoided conversion and restoration of Delta wetlands reduces CO_2 and methane emissions from wetlands, with GHG reductions scaling with implementation rates (Figure 4-24). Expansion of conservation and restoration efforts will generate benefits such as the conservation of biodiversity, improved water quality and supply, and reduced flood risk. Additional details on the climate benefit potential of wetlands can be found in Section 2 of the NWL Climate Smart Strategy.

Figure 4-24: Cumulative CO_2e emissions from Delta wetlands by 2045



Strategies for Achieving Success

- Restore 60,000 acres of Delta wetlands annually by 2045 to reduce methane emissions from wetlands and reverse the resulting subsidence.

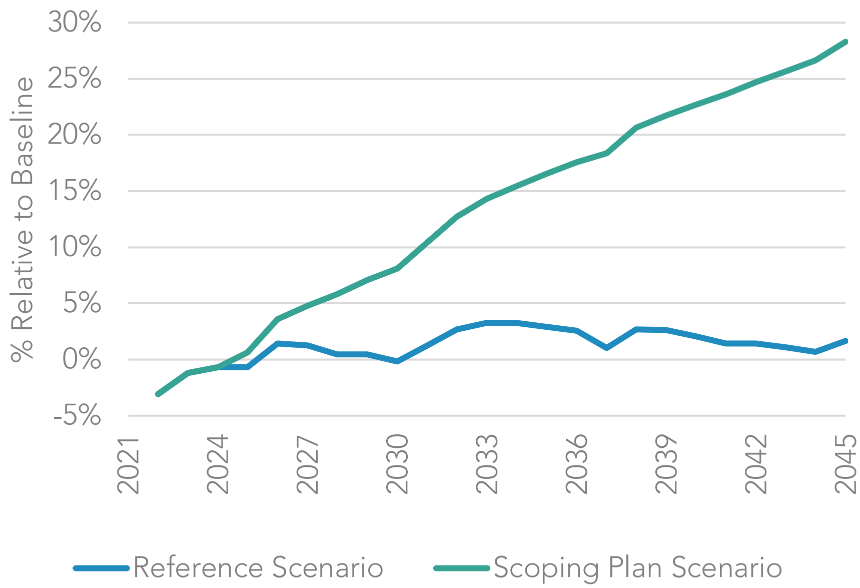
- Identify and prioritize wetland restoration efforts around climate vulnerable communities.
- Leverage other funding and institutions to support wetland restoration projects, including land trusts, local funding (e.g., San Francisco Measure AA), federal funding, and private and philanthropic funding to support wetlands restoration projects.
- Work across state agencies to reduce regulatory and permitting barriers around wetland restoration projects, where appropriate.

Developed Lands

Developed lands cover 6 percent of the state (roughly 6.8 million acres) and include urban, suburban, and rural areas, as well as transportation and supporting infrastructure throughout California. This area encapsulates the land on which the vast majority of Californians reside and call home. The vegetation within cities and communities, and along infrastructure, are all part of developed lands. This vegetation provides numerous benefits to surrounding areas, including carbon storage, air and water filtration, reduced urban heat island effect, and access to nature, aesthetics, and mental health, among others. These areas are susceptible to climate change as well, and climate smart strategies to protect and expand the urban forests, landscaping, green spaces, parks, and associated vegetation can increase their climate resilience and the benefits Californians derive from them. These strategies also have a significant opportunity to benefit disadvantaged communities, who may not have equitable access to these practices or the benefits they provide. Additional details on the climate and equity benefit potential of developed lands can be found in Section 2 and the Introduction of the NWL Climate Smart Strategy.

Urban forests have a significant potential to sequester carbon (Figure 4-25). They are vastly different from wildland forests, as they require investments to maintain and irrigate. This results in the need for a significant increase in investment to increase urban forest carbon. As urban forests become denser and management difficulty increases, the carbon stock returns on investment diminish, making it expensive to maximize carbon in urban forests. Water availability and irrigation efficiency are also an important consideration for increasing urban forest cover. As water becomes scarcer, the prioritization of irrigating trees over lawns or gardens may be required to achieve increases in urban forest carbon.

Figure 4-25: Carbon stocks in urban forests by 2045



Within wildland-urban interface (WUI) areas, defensible space can protect urban and rural communities from wildfire. Analysis results show that 48 percent of parcels are currently fully compliant with defensible space requirements. This highlights how much work needs to be done to protect communities and homes. Defensible space results in a decrease in carbon stocks, as expected when reducing fuels for wildfire.

Strategies for Achieving Success

- Increase urban forestry investment annually by 200 percent, relative to business as usual.
- Increase public awareness of urban forest benefits and, where appropriate, prioritizing irrigation of trees over lawns.
- Provide technical assistance and resources to disadvantaged communities to implement community urban greening projects to provide equitable access to the benefits of urban greening projects.[497]
- Work with state and local agencies to expand technical assistance for and enforcement of the defensible space requirements of PRC 4291 to reduce wildfire risk to homes and structures.

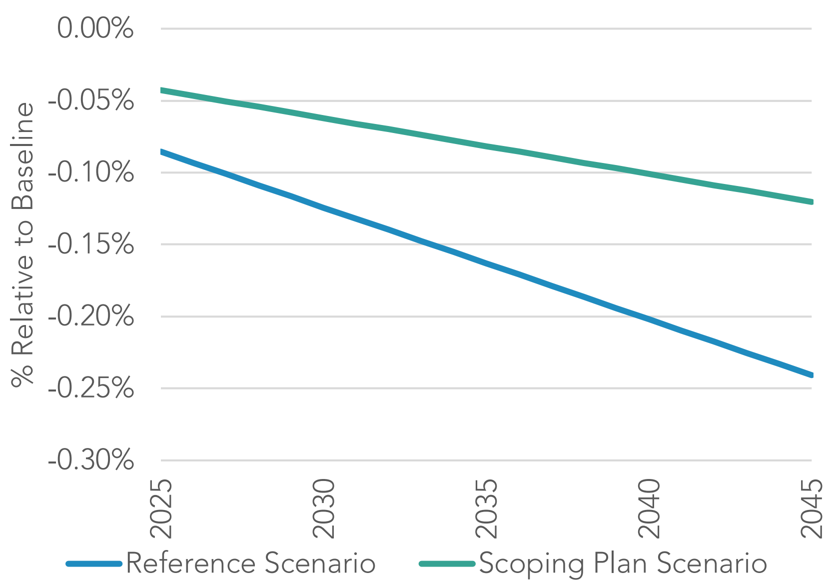
[497] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N8. *finalejacrecs.pdf (arb.ca.gov)*.

Sparsely Vegetated Lands

Sparsely vegetated lands cover 10 percent of the state, roughly 10.2 million acres, primarily in the east and southern parts of California. These lands include deserts, beaches, dunes, bare rock, and areas covered in ice and snow (e.g., higher mountain elevations). The limited carbon storage of these lands varies from bare rock and mineral soil to more vegetated areas, though severe climate limits the amount of biomass. Nonetheless, sparsely vegetated lands are important for open space and provide rare and unique habitats for endemic species and a diversity of wildlife. These lands present important recreational opportunities for Californians and serve as important protective buffers in coastal and low-lying areas. Land use change threatens these lands, and conservation efforts are important for protecting these unique areas of California.[498]

Avoided conversion of sparsely vegetated lands reduces the organic carbon lost from the soil, which is the major carbon pool in this land type (Figure 4-26). In identifying the outcomes for sparsely vegetated lands, CARB modeled avoided land conversion to another land use.

Figure 4-26: Carbon stocks in sparsely vegetated lands by 2045



Strategies for Achieving Success

- Establish and expand mechanisms that ensure sparsely vegetated lands are

[498] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N26. finalejacrecs.pdf (arb.ca.gov).

protected from land conversion, prioritizing those areas most vulnerable to climate change and loss.

Additional Management Strategies

Additional nature-based climate solutions beyond those management strategies modeled for this Scoping Plan are available for implementation, but either cannot currently be modeled and/or affect carbon and the landscape in ways that cannot currently be tracked. Nevertheless, it is important to take action even where these technical gaps exist. Some of these actions, such as cultural burning and indigenous farming practices, have been used on large scales for decades or even centuries, while others are relatively new concepts. The state nevertheless recommends implementing the additional solutions listed here to achieve potential additional climate benefits, as well as other co-benefits. These additional solutions were drawn from the NWL Climate Smart Strategy and stakeholder, tribal government, and interagency feedback.[499]

Considerations

Although these practices are recommended, because of the lack of in-depth modeling and analysis available, several considerations must be addressed when implementing them. These considerations also apply to the management strategies included in the Scoping Plan Scenario.

- Future climate change impacts are uncertain: The negative impact that climate change can have on the ability of these practices to maintain expected climate benefits is uncertain and may significantly change in the future. Climate change is expected to further diminish the already constricting growing conditions in California, with increasing droughts, more extreme weather events, and expanding disturbances from fire, insects, and disease. It is estimated that suitable habitat for many native plant and animal species could shift, creating novel ecosystems without historical precedent. Close monitoring of all practices, including no management, across our NWL will be critical to understand if and how future climate change affects outcomes and how to adapt management to meet the needs of the system under climate change.[500]

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[499] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N24. *finalejacrecs.pdf (arb.ca.gov)*.
[500] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N15. *finalejacrecs.pdf (arb.ca.gov)*.

- Local conditions: Not every practice is applicable, feasible, or even desirable in every location across California. Implementation of these practices should account for local conditions and needs that may affect the appropriateness of that practice.
- Long-term carbon storage: The ability to sequester additional carbon into NWL is only beneficial to the climate if that carbon stays out of the atmosphere. Many of the additional practices listed here may require continual incentives or interventions to ensure permanence of carbon storage in the soil and biomass. For example, in croplands, it is difficult to estimate how much of the carbon stored by no-tillage can be released by a single subsequent tillage, but a return to conventional tillage would usually be expected to erase most gains.[501,502]
- Scaling actions: There are uncertainties on how these practices may impact both the environment and communities when significantly expanded. For this reason, it is best to take a cautious and measured approach to ramping up actions to a larger scale.
- Infrastructure and operational needs: Scaling up the implementation of some of these practices demands transformational change in the supporting infrastructure and operational frameworks. For example, increasing forest management to the degree included in the Scoping Plan Scenario will require significant changes to wood-processing infrastructure, workforce capacity, permitting processes, technical assistance, and other operational constraints. The increased application of compost to croplands, and potentially to rangelands, will require a significant increase in organic waste and dairy manure collection to increase compost supply, in line with SB 1383. This will also require additional compost production facilities as well as compost/organic waste transportation and application methods.
- Co-benefits: Many co-benefits from these practices exist beyond the climate benefits. These co-benefits include improved public and worker health; improved microbial, insect, and wildlife habitat; enhanced biodiversity; greater labor demand in the nature-based economy; and improved climate resilience.
- Labor and Economics: Many of these practices require additional labor, and an evaluation of how many more jobs are needed to carry out many of these practices

[501] Muñoz-Romero, V., R. J. Lopez-Bellido, P. Fernandez-Garcia, R. Redondo, S. Murillo, and L. Lopez-Bellido. 2017. "Effects of tillage, crop rotation and N application rate on labile and recalcitrant soil carbon in a Mediterranean Vertisol." *Soil Tillage Res.* 169, 118–123.
[502] Mitchell, J. P., A. Shrestha, W. R. Horwath, R. J. Southard, N. Madden, J. Veenstra, and D. S. Munk. 2015. "Tillage and cover cropping affect crop yields and soil carbon in the San Joaquin Valley." *California. Agron. J.* 107, 588–596.

is currently unknown. There will also be the need to explore the costs and economic benefits of implementing these additional practices.

- Retreatments: All of these practices have limits on how long they can enhance carbon sequestration. Many of these practices need to be periodically repeated, followed by complementary practices, or maintained through time. This increases costs and requires diligence and long-term stewardship.

Additional NWL Actions and Strategies

Below is a set of additional actions that should be taken on California's natural and working lands. Again, these practices were not modeled for this Scoping Plan, and all of the considerations listed above should be taken into account before implementing the following actions.

- Conservation of all NWL types (in line with the NWL Climate Smart Strategy and CNRA's Pathways to 30x30 California) is critical to ensuring continued carbon sequestration and provision of co-benefits from these lands for all Californians.[503]
- Reforestation following disturbance, using appropriate species, is an impactful practice that can help prevent conversion away from forestland and establish new trees to sequester carbon. The number of acres that may need reforestation following high severity wildfires is estimated to continue to increase into the future.
- Restoration of shrublands, chaparral, riparian zones, and oak woodlands across California includes a variety of practices to alter their structure and return endemic species to the areas. These unique habitats provide multiple co-benefits to the state, such as clean water, reduced wildfire risk, and biodiverse habitats for flora and fauna.
- Conservation and restoration of wetlands, beyond the Delta wetlands included in the NWL modeling, can protect these unique habitats and the climate benefits they provide. These wetland types can include but are not limited to coastal wetlands, mountain meadows, vernal pool complexes, alkali sinks and meadows, and floodplains.
- Conservation and restoration of seagrasses and seaweeds provide a number of benefits, including carbon storage and sequestration, habitat provision for many culturally and commercially important species of fishes and invertebrates, shoreline protection, and tourism opportunities.[504]

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[503] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N26, N27. *finalejacrecs.pdf (arb.ca.gov)*.

[504] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N2. *finalejacrecs.pdf (arb.ca.gov)*.

- Prescribed herbivory utilizes various livestock to consume vegetation to reduce fuel loads across an area. This fuel management practice can be used in forests, grasslands, and shrublands as an effective alternative to herbicide use, and should be considered wherever local conditions allow.
- Urban and community greening efforts such as green schoolyards, urban farms, rain gardens, community gardens, community composting, and many more provide numerous health benefits to communities.
- Additional Healthy Soils Program practices on annual croplands such as conservation cover and crop rotation, biomass planting for borders, wind barriers, riparian areas, and improved nutrient management can improve soil health, water retention, and increase carbon stocks.
- Healthy Soils Program practices on perennial croplands and rangelands, such as compost application and alley cropping/cover cropping to improve soil health, water retention, erosion control, and biomass growth.[505]
- Stacking of these Healthy Soils Program practices, where appropriate, in perennial and annual systems, can synergistically improve soil health and provide multiple benefits.
- Mulching adds high carbon materials to croplands or fallowed lands to reduce competing vegetation and retain moisture. This practice can support other benefits such as reduced water use and reduced synthetic pesticide and fertilizer use, as well as provide a use for suitable forest and agricultural waste biomass.
- Reductions in the use of synthetic fertilizers in cropland management, generally supported by the implementation of new management tools or technologies, can lead to reductions in GHG emissions from the production and application of fertilizers. This benefit is in addition to the co-benefits of reduced chemical runoff into waterways and reduced exposure of human populations to their harmful effects.

[505] Various types of organic amendments are being researched for application to particular landscape types. For example, compost application to rangelands is a relatively new practice that has been shown to improve soil health and increase carbon sequestration in the short term, though the science on the long-term impacts of this practice is still developing and the supply of available compost may be limiting.

Chapter 5: Challenge Accepted

This chapter provides an overview of the next steps and partnerships that will be needed to successfully implement this Scoping Plan. The path forward is not dependent on one agency, one state, or even one country. It will take action on a global level to address the threat climate change poses. But, the work begins at home.[506] The state can lead by engaging Californians and demonstrating how action at the state, regional, and local levels of government, as well as action at community and individual levels, can contribute to addressing the challenge before us. We must build partnerships with academic institutions, private industry, and others to support and accelerate the transition to carbon neutrality. Ultimately, the success of this Scoping Plan will be measured by our ability to implement the actions modeled in the Scoping Plan Scenario at all levels of government and society. This will depend on a mix of legislative action, regulatory program development, incentives, institutional support, workforce and business development, education and outreach, community engagement, and research and development and deployment. Optimizing this mix will help to ensure that clean energy and other climate mitigation strategies are clear, winning alternatives in the marketplace and in communities—to promote equity, drive innovation, and encourage consumer adoption. Bold institutional action will catalyze continued research and push private investment to create jobs and bring innovative ideas to reality.

State-level Action

Achieving the targets described in this Scoping Plan will require continued commitment to and successful implementation of existing policies and programs and identification of new policy tools and technical solutions to go further, faster. California's Legislature and state agencies will continue to collaborate to achieve the state's climate, clean air, equity, and broader economic and environmental protection goals. It will be necessary to maintain and strengthen this collaborative effort, and to draw upon the assistance of the federal government, regional and local governments, tribes, communities, academic institutions, and the private sector to achieve the state's near-term and longer-term emission reduction goals and a more equitable future for all Californians.

[506] This "polycentric" approach to climate challenges, engaging many levels of government, was articulated in leading papers by Nobel laureate Elinor Ostrom. See, for example, Ostrom, E. 2014. "A Polycentric Approach to Coping with Climate Change." *Annals of Economics and Finance* 15-1, 97–134.

Regulations and Programmatic Development

Meeting the AB 32 2020 GHG emissions reduction target several years earlier than mandated demonstrated that developing mitigation strategies through a public process, where all stakeholders have a voice, leads to effective actions that address climate change and yields a series of additional economic and environmental co-benefits to the state. Following adoption of this Scoping Plan, state agencies will continue to update and implement new and existing programs to align with the outcomes in the plan. Community, tribal, and stakeholder engagement will be a critical part of this work. Several state agencies, including CARB, the CEC, the California State Transportation Agency (CalSTA), the CPUC, and others will need to be part of various subsequent rulemaking processes. Each of these agencies' leadership and technical staff will engage with the public through public meetings, written and oral comment, and other methods of engagement. This work will be informed by evaluations of the health, air quality, environmental, equity, and economic benefits and impacts of regulations, including an assessment of the societal cost of carbon, as required under AB 197.

Incentive Programs

As described in Chapter 1, incentive programs are one of the most important tools the state has in advancing our low carbon future, especially for climate vulnerable communities. The programs ensure clean technology and energy are accessible and are critical to closing ongoing opportunity gaps. These programs also leverage private-sector investment and build sustainable, growing markets for clean and efficient technologies, and they are particularly necessary to support GHG emission reduction strategies for priority sectors, sources, and technologies. Clean technologies are often already the best and lowest cost option over their lifetimes but incentive funding is critical to ensure that they are broadly available, especially in climate vulnerable communities. Incentives also build on California's long track record of driving innovative technology developments, and creating new industries, with targeted investment. The Inflation Reduction Act also provides a new source of funding and tax incentives that must be leveraged to help achieve the state's climate goals.

Many state funding programs are designed to achieve multiple objectives simultaneously: reduce emissions from GHGs, criteria pollutants, and toxic air contaminants; manage natural and working lands for carbon sequestration; and address health and opportunity gaps in disadvantaged communities. California's incentive programs focused on jump-starting the transition to a zero emission transportation future are a good example of this "stacked" approach. The state is investing billions of dollars through programs such as the On-Road Heavy-Duty Voucher Incentive Program and Clean Cars 4 All in order to replace the light- and heavy-duty vehicles most responsible for the state's GHG emissions and poor air quality, all while bolstering the nascent ZEV market. Further strategies aid in developing new technologies, in ramping up access for all, and in shifting to cleaner modes of transport; for instance, by supporting investments in walkable, bikeable communities and transit, as well as in vehicles. This funding strategy is, of course, paired with the regulatory approach described above.

Local Action

Local action by cities can support and amplify efforts to reduce GHGs. For example, the City of Oakland requires all new construction to be all-electric and is currently working on electrifying existing buildings.[507] In addition, starting in 2023, the City of Sacramento will require all new buildings under three stories to be all-electric, and it extends the mandate to all new construction by 2026 with some limited exemptions. The City of Sacramento also requires levels of EV charging infrastructure in new construction starting in 2023, higher than the minimum state requirements, and provides parking incentives for zero-emission carsharing and EV charging.[508] Local governments asserting this type of leadership are critical partners in supporting state-level measures to contain the growth of GHG emissions associated with the transportation system and the built environment.

California must accommodate population and economic growth in a far more sustainable and equitable manner than in the past. Good climate policy can and should create affordable and pleasant places to live, with effective transport and clean air for all—a future in which local governments and communities are central partners. Local governments have the primary authority to plan, zone, approve, and permit how and where land is developed to accommodate population growth, economic growth, and the changing needs of their jurisdictions. They also make critical decisions on how and when to deploy transportation infrastructure, and can choose to support transit, walking, bicycling, and neighborhoods that do not force people into cars. Local governments also have the option to adopt building ordinances that exceed statewide building code requirements, and play a critical role in facilitating the rollout of ZEV infrastructure. As a result, local government decisions play a critical role in supporting state-level measures to contain the growth of GHG emissions associated with the transportation system and the built environment—the two largest GHG emissions sectors over which local governments have authority.

Local governments are also frequently the source of innovative and practical climate solutions that can be replicated in other areas. Their efforts to reduce GHG emissions within their jurisdictions are vital to achieving the state's near-term air quality and long-term climate goals. Local governments must continue to take action that affirmatively

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[507] City of Oakland. Building Electrification. *https://www.oaklandca.gov/projects/building-electrification*.
[508] City of Sacramento. Electrification of New Construction. *http://www.cityofsacramento.org/SacElectrificationOrdinance*.

builds the projects and expend the funds needed to further the state's collective path toward equitable emissions reductions. As such, aligning local jurisdiction action with state-level priorities to tackle climate change and the outcomes called for in this Scoping Plan is critical to achieving the statutory targets for 2030 and 2045. Local governments can implement climate strategies that can effectively engage residents by addressing local conditions and issues that also deliver local economic benefits.

Local Climate Action Planning and Permitting

California encourages local jurisdictions to take ambitious, coordinated climate action at the community scale; action that is consistent with and supportive of the state's climate goals.[509] As discussed in more detail in Appendix D (Local Actions), local jurisdictions can do much to enable statewide priorities, such as taking local action to help the state develop the housing, transport systems, and other tools we all need. Indeed, state tools—such as the Cap-and-Trade Program or zero-emission vehicle programs—do not substitute for these local efforts. Multiple legal tools are open to local jurisdictions to support this approach, including development of a climate action plan (CAP), sustainability plan, or inclusion of a plan for reduction of GHG emissions and climate actions within a jurisdiction's general plan. Any of these can help to align zoning, permitting, and other local tools with climate action.

Once adopted, the GHG emissions reductions plans detailed in CAPs can provide local governments with a valuable tool for coordinated climate planning in their community. When a local CAP complies with CEQA requirements, individual projects that comply with the CAP are allowed to streamline the project-specific GHG analysis.[510,511] Effectively, local governments that adopt a CEQA-compliant CAP enable project developers to use this streamlined approach. This saves time and resources and provides more consistent expectations for how GHG reduction measures are applied across projects in the jurisdiction. While the state encourages local governments to follow this approach, we acknowledge not all jurisdictions have the resources to develop a CAP that meets the CEQA requirements.

In addition to being required for a local CAP to comply with CEQA, local GHG reduction targets have long been recommended as part of the process of developing a climate

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[509] This plan provides more detailed guidance and tools to local governments in Appendix D (Local Actions).

[510] Cal. Code of Regs., tit. 14, § 15183.5.

[511] California Governor's Office of Planning and Research. n.d. "General Plan Guidelines - Chapter 8 Climate Change."

action plan.[512] One challenge local jurisdictions have faced is how to evaluate and adopt quantitative, locally appropriate goals that align with statewide goals. An effective response to this challenge is to focus on goals that can help implement overall state priorities—enabling the key transformations California needs.

There are many ways that local governments can make key contributions to this transformation, depending on the characteristics of their jurisdiction and community. For example, some jurisdictions will inherently have more land capacity to remove and store carbon, whether through natural and working lands or by other means. Other jurisdictions will be host to GHG-emitting facilities that serve necessary functions and will take time to transition to clean technology (e.g., municipal wastewater treatment plants, landfills, and energy generation and transmission facilities). It is important to recognize that we will need to build new energy production and distribution infrastructure, and repurpose existing ones, for clean technology and energy before we are able to phase down existing fossil sources. There also will be a need to handle the significant amount of biomass resulting from sustainable forest management for catastrophic wildfire prevention, agricultural waste, and landfill diversion.

Regional efforts can support change too: energy and transportation systems that serve Californians do not stop at jurisdictional boundaries, and some local decisions can have ramifications for other communities. For instance, Metropolitan Planning Organizations (MPOs) can help to integrate local efforts by planning consistent with the Scoping Plan and Climate Action Plan for Transportation Infrastructure, including by removing polluting roadway capacity expansions from project pipelines and instead focusing on climate-friendly solutions. These varied capabilities and needs should be taken into account in setting targets for local climate plans. For instance, although net zero targets can often be valuable and achievable, and mitigation is important, targets should be considered in the larger context of these goals. This all means any GHG targets on a local scale should take into consideration the actions and outcomes included in this Scoping Plan. Jurisdictions considering "net zero" targets should carefully consider the implications such targets may have on emissions in neighboring communities and the ability of the state to meet our collective targets.

Jurisdictions without formal CAPs also have important opportunities within this context. These jurisdictions can still take actions that effectively translate key state plans, goals, and targets, including those articulated in this Scoping Plan for local action. For instance, state ZEV targets can advance local efforts to promote broad and equitable access to charging and fueling. Similarly, local jurisdictions can enable reduced dependence on

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[512] Climate Smart Communities. 2014. Climate Action Planning Guide. https://cdrpc.org/wp-content/uploads/2015/05/CAP-Guide_MAR-2014_FINAL.pdf.

single-occupancy vehicles by supporting dense infill housing and transit, among other actions. Such actions can be reflected in particular project plans, in general plans, or through other local policies. Regional partnerships among these jurisdictions can also help tap resources and provide for more effective overall action.

Unlocking CEQA Mitigation for Local Success

The California Environmental Quality Act also provides important tools for lead agencies to support the achievement of the state's GHG and VMT reduction goals. Although many climate-friendly local government actions already fall into categories that may not require a full CEQA analysis, thanks to streamlining or other tools, and although certain product types (such as affordable infill housing) are generally clearly consistent with state climate goals, CEQA analyses may still sometimes be required. CEQA can be a powerful and useful tool to engage the public, identify additional opportunities to support climate efforts, and localize change. It is important that lead agencies look for ways to use CEQA to support these core purposes, ensuring that these processes do not become sources of delay but instead unlock more opportunities. The uncertainty analysis in Chapter 2 evaluates how project implementation delays can lead to missed state climate targets and continued dependence on fossil energy. Mitigation measures applied in the communities affected by projects subject to CEQA have the added benefit of improving health, social, and economic resiliency as climate impacts worsen.

Appendix D (Local Actions) explores the role of local government action and CEQA in detail. As discussed there, an important CEQA-related tool is mitigation—which can be used to further drive local action consistent with state climate goals. When a lead agency determines that a proposed project would result in potentially significant GHG impacts due to its GHG emissions or a conflict with state climate goals, the lead agency must impose feasible mitigation measures to minimize the impact. Appendix D (Local Actions) provides suggestions for prioritizing the various types of mitigation, starting with on-site GHG-reducing design features[513] and mitigation measures, such as methods to reduce VMT and support building decarbonization, access to shared mobility services or transit, and EV charging. After exhausting all the on-site GHG mitigation measures, CARB recommends prioritizing local, off-site GHG mitigation measures, including both direct investment and voluntary GHG reduction or sequestration projects, in the neighborhoods impacted by the project. This could include, for example, development of a neighborhood green space, investment in street trees, or expansion of transit services. Implementing GHG mitigation measures in the project's vicinity would allow the project proponent and the lead agency to work directly with the affected community to identify and prioritize the

[513] Cal. Code of Regs., tit. 14, § 15126.4(c)(2) and (3).

mitigation measures that meet their needs while minimizing multiple environmental and societal impacts.

Once all potential on-site and local off-site GHG mitigation measures have been incorporated to the extent feasible, Appendix D (Local Actions) provides further suggestions for prioritizing other mitigation types, including non-local off-site mitigation, and voluntary offsets issued by a recognized and reputable voluntary carbon registry (as listed on CARB's website[514]) may be appropriate. Additional in-state mitigation also may be available in the upcoming SB 27[515] (Skinner, Chapter 237, Statues of 2021) registry, which will serve as a database of projects in the state that drive climate action on natural and working lands. Lead agencies should use substantial evidence to demonstrate that the project proponent explored and prioritized investments in feasible, local mitigation prior to moving mitigation to a geography located farther away from the project.

Communities and Environmental Justice

As noted in Board Resolution 20-33,[516] it is incumbent on CARB to function as an agent of responsible social change, especially when it is clear that environmental injustices continue to persist for low-income communities, tribes, and communities of color.

State law defines *environmental justice* as the fair treatment of all people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies.[517] Government Alliance for Race and Equity (GARE)[518] defines *racial equity* as when race can no longer be used to predict life outcomes and outcomes for all groups are improved.

For this Scoping Plan to be successful, it must address environmental justice and advance racial equity. Implementation of the plan needs to address the needs of those communities that are disproportionately burdened by climate impacts and continue to face significant health and opportunity gaps. Now, we need to ensure our actions allow these communities to not only have a seat at the table, but also inform and shape the policies

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[514] CARB. 2022. Offset Project Registries. https://ww2.arb.ca.gov/our-work/programs/compliance-offset-program/offset-project-registries.

[515] SB 27. Carbon sequestration: state goals: natural and working lands: registry of projects. (SB 27, Skinner, Chapter 237, Statutes of 2021).
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220SB27.

[516] CARB. 2020. Resolution 20-33: A Commitment to Racial Equity and Social Justice. October 22.
https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2020/res20-33.pdf.

[517] Gov. Code, § 65040.12, subd. (e).

[518] Local and Regional Government Alliance on Race and Equity. 2015. *Advancing Racial Equity and Transforming Government: A Resource Guide to Put Ideas into Action.* Page 9.
https://racialequityalliance.org/wp-content/uploads/2015/02/GARE-Resource_Guide.pdf.

to ensure their communities thrive. With this Scoping Plan, the state also adds a new tool to identify which communities will be the least resilient in the face of selected climate impacts and will see disproportionate economic impacts as a result. As described in Chapter 3, the CVM will enable the state to target programs and policies to build resiliency in the specific regions that will feel climate impacts more acutely due to existing health and opportunity disparities leading to disproportionate economic impacts. This tool will be critical in the state's efforts to address climate impacts while accounting for environmental injustices and racial inequities. CARB will incorporate the CVM into its work as it moves forward and will share this new tool with other agencies to align our efforts. The goal is to keep expanding the CVM to incorporate additional climate impacts to better identify disproportionate economic impacts as community level data becomes available.

AB 617 is another important tool for both Air Districts and CARB to bring resources to communities that have long been disproportionately burdened by poor air quality. While AB 617 does not require local agencies to participate in the Community Air Protection Program, several AB 617 communities are finding ways to bring local land use agencies to the table to respond to community priorities. We look forward to more opportunities to foster relationships with local authorities and continued collaboration between state and air district programs.

In alignment with AB 32, and to ensure environmental justice and racial equity were integrated into this Scoping Plan, CARB reconvened the AB 32 Environmental Justice Advisory Committee (EJ Advisory Committee) to advise CARB on the development of this Scoping Plan. Since reconvening in May 2021, the EJ Advisory Committee has engaged in the following activities:

- In October 2021, the EJ Advisory Committee sent a letter to the governor requesting a timeline extension for the Scoping Plan process. In response to the EJ Advisory Committee's letter, CARB modified this Scoping Plan process[519] and committed to an active engagement with the EJ Advisory Committee following the approval of this Scoping Plan. The EJ Advisory Committee also presented to the CARB Board[520] at its October 2021 Board meeting, reiterating its request for a timeline extension, as well as sharing additional concerns about process.

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[519] Randolph, L. M. 2021. LMR October 19 response to Environmental Justice Advisory Committee Letter. https://ww2.arb.ca.gov/sites/default/files/2021-10/LMR%20October%2019%20response%20to%20EJAC%20Letter%20Final.pdf.

[520] Argüello, M. D., K. Hamilton, S. Taylor, and P. Torres. 2021. EJ Advisory Committee Co-Chair Informational Presentation to CARB Board. October 28. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2021/102821/21-11-4pres.pdf.

- In December 2021, the EJ Advisory Committee shared its responses to Scenario Input Questions,[521] as well as a narrative document outlining their concerns[522] around the process, the need for evaluation, and the need for a tribal representative. In response to the EJ Advisory Committee Scenario Input Questions, CARB incorporated the EJ Advisory Committee responses into the Scenario Assumptions document,[523] and modeled results from PATHWAYS.[524] In response to the EJ Advisory Committee's concerns, CARB worked diligently to appoint a tribal representative[525] in February 2022, and to outline additional opportunities for the EJ Advisory Committee to engage in the Scoping Plan process.[526]
- In March 2022, the EJ Advisory Committee presented at the joint EJ Advisory Committee / CARB Board meeting[527] and walked through their preliminary draft recommendations to inform this Scoping Plan. In April, the EJ Advisory Committee shared its revised preliminary draft recommendations[528] to inform this Scoping Plan.
- In September 2022, the EJ Advisory Committee presented at the joint EJ Advisory Committee / CARB Board meeting[529] and engaged in discussion about priority items as they relate to incorporating environmental justice into the Scoping Plan. By the end of September, the EJ Advisory Committee shared its final

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[521] EJ Advisory Committee. 2021. EJ Advisory Committee Final Responses to CARB Scenario Inputs. December 2. https://ww2.arb.ca.gov/sites/default/files/2021-12/EJAC%20Final%20Responses%20to%20CARB%20Scenario%20Inputs_12_2_21.pdf.

[522] EJ Advisory Committee. 2021. EJ Advisory Committee Responses to Scenario Input Questions. EJ Advisory Committee narrative document regarding scenario input recommendations. December 1. https://ww2.arb.ca.gov/sites/default/files/2021-12/EJAC%20Narrative%20Document%20re%20Scenario%20Input%20Recommendations%2012_1_2021.pdf.

[523] CARB. 2021. PATHWAYS Scenario Modeling. https://ww2.arb.ca.gov/sites/default/files/2021-12/Revised_2022SP_ScenarioAssumptions_15Dec.pdf.

[524] E3. 2022. CARB Draft Scoping Plan AB32 Source Emissions Initial Modeling Results. March 15. https://ww2.arb.ca.gov/sites/default/files/2022-03/SP22-Model-Results-E3-ppt.pdf.

[525] CARB. AB32 EJ Advisory Committee Meeting, February 28, 2022 CARB Update. https://ww2.arb.ca.gov/sites/default/files/2022-02/CARB%20EJAC022822presentation.pdf.

[526] Fletcher, C. 2021. CARB Response to EJ Advisory Committee Narrative. CARB. December 15. https://ww2.arb.ca.gov/sites/default/files/2021-12/CARB%20response%20to%20EJAC%20Narrative.pdf.

[527] EJ Advisory Committee. 2022. EJ Advisory Committee Presentation: Preliminary Draft Recommendations. March 10. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/031022/ejacpres.pdf.

[528] AB 32 EJ Advisory Committee. Draft Recommendations. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/031022/ejacrecsrevised.pdf.

[529] EJ Advisory Committee. 2022. EJAC Presentation. September 1. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/090122/ejacpres.pdf

recommendations[530] to inform this Scoping Plan. To the extent possible, CARB has incorporated and cited these recommendations through this Scoping Plan.

In addition to the activities listed above, Central Valley EJ Advisory Committee members hosted a successful community engagement workshop[531] in San Joaquin Valley in February 2022 with over 100 attendees. Members of EJ Advisory Committee hosted a statewide community engagement workshop[532] in June 2022 with more than 165 attendees. Throughout the EJ Advisory Committee's process, members of the Committee continued to work with their communities to ground truth their recommendations to inform the development of the Scoping Plan. The EJ Advisory Committee worked hard to ensure the voices of those communities most burdened by climate impacts were reflected in the plan. The EJ Advisory Committee will continue to play an ongoing role in the implementation of this Scoping Plan to ensure environmental justice and racial equity are prioritized in our effort to address the climate challenge before us.

To the extent possible, the EJ Advisory Committee's recommendations were integrated throughout the plan. This plan directly cites instances where there is alignment between the plan and the EJ Advisory Committee recommendations. This approach seeks to ensure there is more transparency and identify consensus that exists, as well as relevant ways equity and environmental justice are addressed in this plan and in the planning for future related implementation activities. CARB is dedicated to its efforts to ensure this plan does not leave communities behind.

As this Scoping Plan moves into the implementation phase, there will be a need to better understand how to address EJ Advisory Committee recommendations on the following topics:

- Actions under the jurisdiction of other agencies: there are certain EJ Advisory Committee recommendations that are outside of CARB's jurisdiction. As the EJ Advisory Committee continues to convene, it would be helpful to understand the

[530] EJ Advisory Committee. 2022. EJAC 2022 Scoping Plan Recommendations. September 30. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/090122/finalejacrecs.pdf

[531] San Joaquin Valley Climate Justice & the Scoping Plan. 2022. https://ww2.arb.ca.gov/sites/default/files/2022-07/SJV%20Climate%20Justice%20%26%20the%20Scoping%20Plan%20Workshop%20Report%20out%20%26%20Recommendations_5.2022.pdf

[532] EJAC. 2022. *EJAC/Community Engagement Synthesis Report '22.* https://ww2.arb.ca.gov/sites/default/files/2022-07/EJAC-CommunityEngagement-SynthesisReport-2022-English%26Spanish.pdf.

role that CARB can play as it relates to the EJ Advisory Committee's recommendations for actions outside CARB's jurisdiction and coordinates with sister agencies.

- Actions that require legislative direction: there are certain EJ Advisory Committee recommendations that would require legislative action. As the EJ Advisory Committee continues to convene, it will be helpful to understand how CARB can work with the EJ Advisory Committee to share these recommendations with the appropriate members of the Legislature.
- Actions directly tied to implementation activities: This Scoping Plan is not an implementation document; it is a plan to chart a course to continue to reduce GHG emissions and achieve carbon neutrality. Once the Scoping Plan is approved, there will be follow-up action at CARB, as well as at other agencies. In these follow-up efforts, there will be a role for ongoing EJ Advisory Committee engagement.
- Actions to implement recent legislation, such as SB 905.

CARB proposes to continue to work with the EJ Advisory Committee to better understand how to move forward on EJ Advisory Committee recommendations that fall into the topics listed above and any other recommendations that were not included in this plan. It is also important to note that there are numerous recommendations where CARB shares the goals of the EJ Advisory Committee and can assist in implementation steps. Examples include the following:

- CARB shares the goal of prioritizing non-fossil energy generation and supports non-fossil projects and opportunities to locate behind-the-meter clean resources in communities of concern in programs such as the Solar on Multifamily Affordable Housing program.
- CARB will engage with agencies and academic institutions to further workforce development.
- Many other recommendations related to financial support for various energy projects, such as microgrids, are within the purview of the CPUC or local publicly owned utilities. Similarly, utility scale projects are within the jurisdiction of other agencies. However, CARB supports strategies identified in the recommendations such as offshore wind to reduce the reliance on fossil fuel generation.
- CARB is supportive of rooftop solar, although it is not within CARB's jurisdiction to determine how incentives for those projects are structured.
- CARB is supportive of strong energy decarbonization goals, recognizing that increased reliance on electrification in transportation and other sectors will create significant demand for electricity, and therefore ensuring reliability of a decarbonized grid is a critical need for the state.
- In the transportation sector, CARB is supportive of the EJ Advisory Committee's recommendations to maintain aggressive zero emission vehicle goals consistent

with its statutory mandate to ensure regulations are technologically feasible and in alignment with Governor Newsom's ZEV Executive Order (EO N-79-20). CARB looks forward to continued engagement on rulemakings that will implement these goals.

- As noted elsewhere in this plan, CARB is supportive of the Caltrans California Transportation Plan 2050 and the California Climate Action Plan for Transportation Infrastructure.
- CARB is supportive of additional public support for transit. CARB is supportive of locating EV charging in low-income communities and communities of color.
- CARB is supportive of prioritizing funding incentives for transit and heavy- and medium-duty vehicles, although CARB does believe there is an important role for incentives that support adoption of light-duty vehicles for the time being. CARB will also be opening a rulemaking on the Low Carbon Fuel Standard to ensure it continues to support clean fuels that will displace petroleum fuels and will consider the EJ Advisory Committee recommendations on this program.
- In the industrial sector, in addition to the strategies discussed more fully in this Scoping Plan, CARB continues to work with the Legislature, local agencies, and air districts to support, implement, and enforce effective reductions in emissions of GHGs and air pollutants in stationary sources. The air districts have the authority to directly issue permits addressing a facility's criteria pollutant and toxics emissions levels. These levels are set after careful permit review, under district regulation and statute. However, AB 617 directs and authorizes CARB to take several actions to improve data reporting from facilities, air quality monitoring, and pollution reduction planning for communities affected by a high cumulative exposure burden. CARB will continue to implement AB 617 and look for ways to strengthen the Community Air Protection Program.
- Considerations around the phaseout of oil and gas extraction and refining, and the role of carbon capture are discussed more thoroughly in Chapter 2.

As CARB continues to engage with the EJ Advisory Committee—in addition to the EJ Advisory recommendations that have been integrated throughout this plan—below are the following commitments that CARB is making to ensure that environmental justice is integrated in this plan and its implementation:

- Building decarbonization is a pillar of this Scoping Plan and CARB commits to working closely with state and local agencies to implement the EJ Advisory Committee recommendations that call for prioritization for residents in low-income communities and communities of color in this transition.
- CARB commits to sharing the EJ Advisory Committee's recommendations with the CEC, CPUC, and other agencies administering funds to support building

decarbonization, and to work closely with those agencies as they engage in public processes to further building decarbonization.

- CARB has committed to review the Cap-and-Trade program and determine what potential legislative or regulatory amendments could be necessary to ensure the program continues to deliver GHG reductions needed to achieve the statutory climate goals. In that process, CARB will consider the recommendations of the EJ Advisory Committee[533] and Independent Emissions Market Advisory Committee,[534] as well as others.

Critically, the EJ Advisory Committee makes numerous recommendations centered around tracking progress of the various strategies in this Scoping Plan. Currently, progress is tracked and reported in numerous ways, including the annual GHG inventory and reports to the Legislature. Part of the ongoing work of implementation, however, will include consideration of ways to provide more data and information to the public, such as rates of deployment of clean energy and technology as described in Chapter 1. CARB will also continue to collaborate with CDPH and OEHHA on health metrics to track cumulative benefits of air pollution and climate programs, especially in low-income communities and communities of color.

As noted earlier in this document, the EJ Advisory Committee will continue to play a vital role in the Scoping Plan and its implementation to ensure environmental justice and racial equity are prioritized in our effort to address the climate challenge before us. This includes ongoing EJ Advisory Committee engagement to advise CARB on the development of the Scoping Plan and any other pertinent matters in implementing AB 32. The ongoing EJ Advisory Committee will help to ensure integration of environmental justice in implementation efforts as it relates to AB 32, and also help CARB as we work toward a future where race is no longer a predictor for life outcomes.

Academic Institutions and the Private Sector

Academic institutions produce and present the latest science on both the impacts of, and actions to reduce, climate change damages. They are also leading the way by

[533] California Legislative Information. Bill Text – AB 32. Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006. (AB 32, Nuñez, Chapter 488, Statutes of 2006). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.

[534] California Legislative Information. Bill Text – AB 398. California Global Warming Solutions Act of 2006: market-based compliance mechanisms: fire prevention fees: sales and use tax manufacturing exemption. (AB 398). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398.

establishing their own climate goals and GHG emissions reductions targets.[535, 536, 537] They are incubators for innovation and knowledge in clean energy and technology and play an important role in adding to the wealth of robust information to inform policies and programs. Academic institutions have the ability to fill knowledge gaps and push us toward new frontiers. As we move forward, we will continue to see these institutions as partners and resources that can help CARB look for ways to accelerate and introduce actions to reduce GHG emissions and remove and store carbon.

As such, it will be important to maintain and enhance relationships with academic institutions, including community colleges. Community colleges are more likely to have a large proportion of first generation students or students that come from low-income communities or communities of color. The perspective of this diverse student body will be critical to inform discussions on climate change damages and mitigation efforts. This student body is also a future workforce, and courses to teach the skills for a sustainable economy are a chance to close historical opportunity gaps. Importantly, many of the students at community colleges are local residents and community members. This engagement provides another way to invest in communities across our state. The Foundation for California Community Colleges is already leading the way through innovate programs such as their Good Jobs Challenge - California Resilient Careers in Forestry.[538] These types of programs could be replicated across other sectors. CARB will evaluate how to leverage the requirements in AB 680 on workforce development in the California Climate Investments programs with the work at the Foundation for California Community Colleges.

As noted in Chapter 1, public and private partnerships will be important as we move forward in the great energy transition. But the private sector is also important in the context of research and development and deployment. Many of these companies have the resources and expertise to build and produce the clean technology and energy we will need. It was through the efforts of several private companies (Bell, Exxon, Telecom

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[535] University of California. Our Commitment. *https://www.universityofcalifornia.edu/initiative/carbon-neutrality-initiative/our-commitment*.

[536] California State University. Energy, Sustainability, & Transportation. *https://www.calstate.edu/csu-system/doing-business-with-the-csu/capital-planning-design-construction/operations-center/Pages/energy-sustainability.aspx*.

[537] California Community Colleges Chancellor's Office. Climate Action and Sustainability. *https://www.cccco.edu/About-Us/Chancellors-Office/Divisions/College-Finance-and-Facilities-Planning/Facilities-Planning/Climate-Action-and-Sustainability?msclkid=4a72350ec4f511ecaf292c6b14ac9a4f*.

[538] Foundation for California Community Colleges. 2022. Good Jobs Challenge. Developing Resilient Careers in Forestry for Californians. *https://foundationccc.org/What-We-Do/Workforce-Development/Good-Jobs-Challenge*.

Australia) that the photovoltaic solar panels in use today were developed.[539] Similarly, it was companies such as General Electric and Texas Instruments that contributed to the development of hydrogen fuel cells.[540] This Scoping Plan includes the known and emerging clean technologies and fuels available today. The private sector spirit of invention, improvement, and innovation must continue to deliver new tools in the fight against climate change.

Individuals

This Scoping Plan not only projects ambitious availability of clean technology and energy, but also includes aggressive assumptions about consumer adoption of ZEVs, heat pumps, and other energy efficiency practices, among others. When it comes to climate change mitigation, the sum of the parts matters. Only when we add up the impacts of the choices we make do we understand the true impact on GHG emissions. Today, many Californians have opportunities to choose between driving a car, taking a bus, biking, or walking. Many can choose to install a heat pump or buy an electric cooktop. Together, we can increase these opportunities and pick the future we want. We can start or transform businesses that create clean jobs, innovate new technologies, or introduce new systems. We can engage with fellow workers to support durable paths for labor in a clean economy. And we can choose to engage with our community, tribes, and our governments to advocate for change, call out challenges, and propose solutions. Our choices will help determine California's climate future. Down one path is a future of climate impacts that will continue to worsen and further increase disparities across communities. Down the other is a future that avoids the worst impacts of climate change, improves air quality—especially for the most burdened communities—and fosters new economic and job opportunities to support a sustainable economy.

Importantly, we must acknowledge that historical decisions have resulted in health and opportunity gaps for residents in low-income communities and communities of color. Not everyone has the resources or access to make these choices—to buy a ZEV, install a heat pump, or use public transit to get to work. It is here that government can help. Government, at multiple levels, can fund programs and structure policies to provide consumers with more choice and to support them in adopting cleaner technology options. Whether through affordable energy rates or assistance in purchasing zero emission vehicles and appliances, we can use the transition to a carbon neutral economy as an opportunity to close some of these persisting opportunity gaps. By acting now, we can

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[539] Californiasolarcenter.org. Passive Solar History. *http://californiasolarcenter.org/old-pages-with-inbound-links/history-pv/*.
[540] Fuel Cell Store. History of Fuel Cells. *https://www.fuelcellstore.com/blog-section/history-of-fuel-cells?msclkid=04a19450c50211ec8d20f2afff4039fe*.

change our planet’s fate and build a more resilient, healthier, and equitable future for all Californians.

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Comment 300 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Nicole
Last Name	Looney
Email Address	nicole.looney@smud.org
Affiliation	SMUD
Subject	SMUD's Comments on the Proposed Amendments to the Low Car
Comment	SMUD's Comments on the Proposed Amendments to the Low Carbon Fuel Standard.
Attachment	www.arb.ca.gov/lists/com-attach/6970-lcfs2024-AXJROgRwBTIKU1Ix.pdf
Original File Name	SMUD Comments Re LCFS - LEG 2024-0023.pdf
Date and Time Comment Was Submitted	2024-02-20 16:29:13

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Chair Liane Randolph and Members of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

February 20, 2024
LEG 2024-0023

Re: Sacramento Municipal Utility District's Comments on the Proposed Amendments to the Low Carbon Fuel Standard

The Sacramento Municipal Utility District (SMUD) appreciates the opportunity to provide comments on the California Air Resources Board's (CARB or Board) proposed amendments to the Low Carbon Fuel Standard (LCFS), issued on December 19, 2023 (Proposed Amendments). Transportation electrification is a key component in achieving the goals of SMUD's 2030 Zero Carbon Plan and the state's carbon neutrality goals, and the LCFS serves as a critical policy tool to complement and support SMUD and others in the effort to eliminate emissions from the transportation sector.

While SMUD is overall supportive of the Proposed Amendments, SMUD files these comments to recommend several areas where additional clarification or revision is needed. SMUD's comments on the Proposed Amendments cover the following:

291.1 1. The Proposed Amendments represent a significant improvement and address many needed revisions to the LCFS regulations.

291.2 2. CARB should clarify that the equity holdback requirements for local publicly owned utilities (POUs) will remain at 50% of total holdback credit proceeds.

3. The Proposed Amendments introduce several new and amended equity
291.3 holdback project categories that, with minor clarifications, will allow investment in needed programs and projects.

4. CARB should clarify the intent for removing the equity holdback project
291.4 category for multilingual marketing, education, and outreach (ME&O). SMUD supports retaining a more focused version of this category that would enable targeted outreach to underserved communities.

5. While some verification of transaction data and calculations may be necessary,
291.5 CARB should remove the site visit requirement for all covered electrical chargers or, if retained, clarify the Less Intensive Verification option.

Beyond these comments, SMUD also supports comments submitted by
291.6 the California Municipal Utilities Association (CMUA) and the California Electric Transportation Coalition (CalETC), both filed on February 20.

1. The Proposed Amendments represent a significant improvement and address many needed revisions to the LCFS regulations.

291.1 cont. SMUD commends CARB staff for their collaborative approach to updating the LCFS
regulation and believes that the Proposed Amendments represent a significant
291.7 improvement and clarification of the LCFS. Increasing the stringency of the program
to 18.75% in 2025 and to 30% by 2030, at minimum, is a necessary step to support
a healthy market for LCFS credits. Likewise, the implementation of the auto-
291.8 acceleration mechanism will help to ensure technology advancements that lower the
carbon intensity of fuels do not result in an oversupply of LCFS credits. These
necessary market improvements will help drive investments in electric mobility
options, charging infrastructure and programs necessary to reach the state's
decarbonization goals. SMUD supports CARB's efforts and supports consideration
of further increases in stringency.

291.9 SMUD strongly supports the Proposed Amendments continuing the allocation of
base credits to electric distribution utilities (EDUs) to develop and administer projects
and programs that advance transportation electrification (TE). POUs are well
positioned to design and implement programs that meet the needs of the
communities they serve. SMUD also appreciates CARB's efforts to clarify and
291.10 expand examples of holdback and equity holdback project categories, even where
we recommend further clarification below.

291.11 SMUD further appreciates CARB's recognition that there is a growing need to
support the market and infrastructure for medium- and heavy-duty (MHD) electric
vehicles (EVs); refocusing the California Clean Fuel Rewards (CCFR) program is an
appropriate change. Additionally, right-sizing EDU contributions to the CCFR
291.12 program will both ensure that the statewide program is appropriately scaled to the
smaller MHD market, as well as enable EDUs to devote more funding toward
holdback programs focused on transportation electrification.

291.2 cont. **2. CARB should clarify that the equity holdback requirements for local POUs will remain at 50% of total holdback credit proceeds.**

CARB should revise the Proposed Amendments to clarify that the equity holdback requirement for POUs remains at 50% of total holdback credit proceeds. The text of the Proposed Amendments changes the equity holdback credit requirements for all electric distribution utilities and does not distinguish between investor-owned utilities (IOUs) or POUs.[1] However, CARB's supporting documents indicate that these changes were necessary in order to align CARB's equity contribution requirements with similar requirements from the California Public Utilities Commission (CPUC);

[1] 94583(c)(1)(A)5.a. (all references to regulatory sections are to the Proposed Amendments, unless otherwise noted).

291.2 cont. such requirements apply only to IOUs.[2] Further, Appendix E specifically notes that the "holdback equity requirement for Publicly Owned Utilities would remain at 50%."[3] Since this revision was merely intended to align CARB and CPUC requirements, the regulatory language in Section 94583 should be updated to reflect this intent.

In addition, for many POUs like SMUD, LCFS is the primary source of funding for transportation electrification programs. There remains a significant need for investment in transportation electrification programs and infrastructure in communities across our region. When coupled with the increase in holdback credits, maintaining the 50% spending requirement will allow SMUD to accelerate its investments in projects benefiting equity communities while continuing to offer our critically needed portfolio of transportation electrification programs.

Furthermore, POUs should a have somewhat greater flexibility in how to spend holdback credit proceeds. First, POUs are not-for-profit entities that are ultimately responsible to their communities. This structure requires POUs to prioritize community needs and often means that POUs are best positioned to develop programs and direct investments to the areas of greatest need. Additionally, POUs come in different sizes but are generally much smaller than IOUs. As a result, there is significant variation between POUs regarding the demographics, income levels, and unique challenges facing their local community. If POUs had to devote a substantially higher percentage of their holdback proceeds to a limited set of projects, this would impair POUs' ability to put proceeds toward their best use in each POU service area. SMUD appreciates that CARB staff recognized this need and requests that CARB update the regulatory text consistent with this understanding. SMUD supports CalETC's proposed revisions to Section 95483(c)(1)(A)5.a.

291.3 cont.

3. **The Proposed Amendments introduce several new and amended equity holdback project categories that, with minor clarifications, will allow investment in needed programs and projects.**

The Proposed Amendments provide a revised list of qualified equity holdback projects, which overall demonstrates a substantial improvement. Several new and important categories were included and will allow EDU investment in high-impact programs. However, there are project categories that require some clarification and revision in order to enable utilization. These categories include: investments in electric and clean mobility solutions, re-skilling and workforce development, investments in grid-side distribution infrastructure for MHD EV charging, and the explicit inclusion of panel upgrades for low-income residential customers.

[2] See *Staff Report: Initial Statement of Reasons* (December 19, 2023) at 36, 67 (hereinafter "Staff Report"); *Appendix E: Purpose and Rationale of Proposed Amendments for the Low Carbon Fuel Standard Requirements* at 14, 15 (hereinafter "Appendix E").
[3] Appendix E at 15.

291.3 cont. *A. There are two categories addressing electric mobility that may be clarified by substituting with a single encompassing category.*

The Proposed Amendments include an existing equity project category focused on electric mobility solutions, and introduce a new, similar category focused on public transit and other clean mobility solutions:

> iii. Investment in electric mobility solutions, such as EV sharing and ride hailing programs.
>
> …
>
> v. Promoting use and additional incentives for use of public transit and other clean mobility solutions, via charging equipment or infrastructure for the following categories:
>
> > I. EV sharing and ride hailing programs,
> >
> > II. Electrification of public transit and school buses, including battery swap programs, and
> >
> > III. Use or ownership of neighborhood electric vehicles, eBikes, eScooters, eMotorcycles, and other micromobility solutions.[4]

These are important categories to include in the equity holdback project list and SMUD appreciates their inclusion in the Proposed Amendments. SMUD's work with local community-based organizations (CBOs), local agencies, and residents has revealed that there is substantial need for a variety of electric mobility solutions within many equity communities.

SMUD coordinated with three other local agencies[5] in the development of the Sacramento Area Zero Emission Vehicle (ZEV) Deployment Strategy (Strategy).[6] The Strategy is a regional approach to improving air quality, reducing greenhouse gas emissions, and promoting efficient mobility. Equity is a key component of each of the four program areas, which include electrifying the public transit fleet, eMobility hubs, MHD charging plazas, and training a clean energy workforce. Each of the Strategy's program areas have a clear nexus with project categories included on CARB's proposed equity holdback project list.

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[4] 94583(c)(1)(A)5.a.

[5] Coordinating entities included Sacramento Regional Transit, the Sacramento Metropolitan Air Quality Management District, and the Sacramento Council of Governments.

[6] The Sacramento Area ZEV Deployment Strategy is accessible at: https://www.sacog.org/planning/transportation/transit-strategies/zero-emissions-vehicle-planning.

291.3 cont. Particularly relevant for this equity project category, the Strategy is planning for 600 transit buses with zero emission fuels and five strategically located charging facilities throughout the region. Additionally, the Strategy identifies the need for 27 eMobility hubs within Sacramento County and an additional 25 hubs throughout the region. These eMobility hubs will provide shared electric cars, battery storage, and microgrid capabilities. A necessary part of this effort is SMUD's Sustainable Communities program that leads engagement efforts in coordination with CBOs and residents to understand priorities for under resourced communities regarding electric mobility access and associated charging.

SMUD commends CARB's inclusion of the new eMobility project category, but requests clarification about how the existing and proposed categories should be understood. First, both categories include "EV sharing and ride hailing programs." This introduces confusion regarding whether these categories overlap or are aimed at different programs and projects. Second, Section 94583(c)(1)(A)5.a.v. could be read to limit investments to only charging equipment or infrastructure for subcategories I. through III. SMUD opposes this apparent limit, if intended, because it is unnecessarily restrictive. Investments in public transit and eMobility solutions involve many expenses, particularly in under resourced communities, beyond just charging and infrastructure. For example, eMobility hubs include the development and identification of suitable locations, community outreach, coordination with other local agencies and CBOs, designing tools to make the hubs useful to residents, staffing and technical assistance for users of the hubs, and often incentives towards the purchase of mobility solutions. Conversely, if it was not intended as a limit, it is unclear how to reconcile the language limiting spending to charging and infrastructure with language in the subcategories referring to ownership of micromobility solutions (e.g., "use or ownership of neighborhood electric vehicles…"). Since these current categories lead to confusion over scope and application, SMUD supports CalETC's proposed revision, which both combines and simplifies these project categories.

CalETC's proposed amendment is as follows:

~~iii. Investment in electric mobility solutions, such as EV sharing and ride hailing programs.~~

v. Investing in, or promoting the ~~Promoting~~ use of, ~~and additional incentives foruse of~~ public transit and other clean mobility solutions~~, via~~ ~~charging equipment or infrastructure for the following categories~~ such as:

I. EV sharing and ride hailing programs,

II. Electrification of public transit and school buses, including battery swapprograms, and

III. Use or ownership of neighborhood electric vehicles, 291.3 cont. eBikes, eScooters, eMotorcycles, and other micromobility solutions.

IV. Charging equipment or infrastructure for any of the above.

291.13 *B. The addition of a re-skilling and workforce development equity holdback category is a significant improvement, with minor clarifications needed.*

Section 94583(c)(1)(A)5.a.vi. provides the following:

vi. Re-skilling and workforce development for transportation electrification and electric vehicle infrastructure applications, developed in coordination with the California Workforce Development Board or local workforce development agencies.[7]

SMUD appreciates the inclusion of this proposed subsection, which promises more streamlined investment of equity holdback proceeds in re-skilling and workforce development programs. Under the existing regulations, SMUD received Executive Officer approval for a workforce development program, but the process took over a year. The inclusion of this category will remove this additional administrative hurdle and help to promote development of these programs.

CARB should broaden the scope of entities that EDUs are permitted to coordinate with in order to make these investments. The ZEV Deployment Strategy specifically acknowledges the need to partner with other key entities, including educational institutions, trade organizations, CBOs, and others.[8] Additionally, SMUD's EO approved program was developed in coordination with local CBOs but was not developed in coordination with state or local workforce development agencies. SMUD understands that this project is consistent with the intent of this new proposed equity project category.

SMUD continues developing plans and strategies for TE workforce development focused on its local community. SMUD is uniquely positioned to address these workforce needs given its coordination on the ZEV Deployment Strategy, ongoing experience with workforce development, and knowledge of EV charging needs and infrastructure within its service area. Requiring EDUs to specifically coordinate with state or local workforce development agencies, which may or may not be familiar with TE needs, is largely unnecessary and may slow development of these programs.

SMUD supports CalETC's proposal that provides more flexibility for coordinating entities:

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[7] 94583(c)(1)(A)5.a.vi.
[8] See ZEV Deployment Strategy at footnote 6.

291.13 cont. vi. Re-skilling and workforce development for transportation electrification and electric vehicle infrastructure applications, developed in coordination with the California Workforce Development Board, ~~or~~ local workforce development agencies, a community-based organization, a California Community College, or a workforce strategy adopted by the Board of a POU.

291.14 *C. SMUD supports the inclusion of MHD EV charging infrastructure investments, and requests that CARB clarify that these investments are not geographically restricted.*

SMUD appreciates the inclusion of the MHD EV charging infrastructure category in the equity holdback project list.[9] Inclusion of this category will enable investment in this needed and costly infrastructure and is complementary to the shift of the statewide CFR program to incentivize MHD EV purchases. In 2022, SMUD conducted a study on the impact of MHD charging on SMUD's distribution system. Based on this study and ongoing analysis, SMUD estimates that, through 2041, SMUD would need to invest between hundreds of millions to over a billion dollars in grid upgrades, depending on the role of managed charging, in order to support growth in light, medium, and heavy-duty EVs in our region. LCFS funding can play a critical role in readying the grid for widespread MHD vehicle charging while mitigating the impacts of these investments on ratepayers.

CARB should clarify that MHD EV charging infrastructure benefits equity communities regardless of the location of these projects. Many equity projects implicitly contain a locational requirement in that they must primarily benefit or serve equity communities.[10] Such a restriction for MHD EV infrastructure would significantly limit the number of locations where these investments could be made, and investments may be needed in areas that do not overlap with equity communities. Instead, CARB should clarify that MHD EV infrastructure investments will primarily benefit and serve equity communities regardless of location or proximity to such communities, since equity communities often bear a disproportionate share of pollution associated with major transportation corridors. Since MHD EV infrastructure projects will help to reduce emissions within these corridors, the location of these projects within or near equity communities should not be required.

291.15 *D. SMUD supports the explicit inclusion of residential panel and service upgrades in the equity holdback project list.*

Proposed Section 94583(c)(1)(A)5.a.iv. permits rebates and incentives for low-income individuals to obtain an EV and for installing EV charging infrastructure

[9] 94583(c)(1)(A)5.a.vii.
[10] See 94583(c)(1)(A)5.a.

291.15 cont. in residences. SMUD appreciates the retention of this equity holdback project category, but requests that CARB specifically list panel and service upgrades as permitted expenses. While this category allows “installing EV charging infrastructure in residences”, it could be read narrowly to only permit installation of EV chargers or more broadly to permit upgrades for all needed electrical improvements to enable EV charging. Specifically including panel and service upgrades in this category will provide more confidence that these types of investments are consistent with CARB’s intent.

291.4 cont. **4. CARB should clarify the intent for removing the equity holdback project category for multilingual marketing, education, and outreach. SMUD supports retaining a more focused version of this category that would enable targeted outreach to underserved communities.**

SMUD is concerned by the elimination of the multilingual ME&O equity project category. The Proposed Amendments fully eliminate the multilingual ME&O category, but no justification was provided in the Staff Report. Appendix E does address the multilingual ME&O category but merely states that “[s]taff is also proposing the removal of holdback credit proceeds for Marketing, Education, & Outreach for electric vehicles.”[11]

First, CARB should clarify the statement in Appendix E. While the change in the proposed regulatory text appears limited to eliminating the multilingual ME&O category, Appendix E could be read to prevent investments in ME&O from non-equity holdback credit proceeds as well as project-specific ME&O for equity holdback projects. CARB should clarify that both non-equity holdback ME&O spending and project-specific ME&O associated with equity projects are still permitted.

Further, equity-focused education and outreach projects provide substantial value that should be recognized in the equity project list. SMUD regularly conducts direct community outreach events specifically targeted at underserved communities. These events are different from general marketing or broad-based advertising campaigns and allow customers to directly ask questions, experience EV operation, and understand EV benefits. SMUD has also used equity funding to support needs assessments, conducted in partnership with CBOs, and other pre-project work, like community listening sessions and neighborhood canvasing in under-resourced communities.[12] This targeted work must be done to facilitate programs and projects that fit the needs of specific communities because needs vary throughout SMUD’s service area. Eliminating such pre-project work risks less informed and under-utilized equity projects.

[11] Appendix E at 15.
[12] See e.g., ZEV Deployment Strategy at footnote 6.

291.4 cont. SMUD encourages CARB to clarify that EDUs are still permitted to spend equity proceeds on project-specific ME&O expenses and utilize non-equity holdback credit proceeds on ME&O more generally. Additionally, SMUD urges CARB to reconsider full elimination of the multilingual ME&O category and revise this category to preserve direct customer outreach and education to identify and tailor programs to successfully meet community needs.

SMUD supports CalETC's proposed revision to the multilingual ME&O category:

v. Multilingual ~~marketing, education, and outreach~~ community education events located within communities listed in 95483(c)(1)(A) designed to increase awareness and adoption of EVs and clean mobility options, and outreach in coordination with community-based organizations, including but not limited to neighborhood canvassing, community listening sessions, and needs assessments, focused in communities listed in 95483(c)(1)(A) to inform the development of projects and programs tailored to community needs. ~~including information about: the environmental, economic, and health benefits of EV transportation; basic maintenance and charging of EVs; electric rates designed to encourage EV use; and local, state, and federal incentives available for purchase of EVs.~~ Education and outreach do not include general marketing or advertising campaigns.

291.5 cont. **5. While some verification of transaction data and calculations may be necessary, CARB should remove the site visit requirement for all covered electrical chargers or, if retained, clarify the Less Intensive Verification option.**

Section 95500(c)(1)(E)1. introduces a new verification requirement applicable to metered residential and non-residential EV charging but exempting nonmetered residential EV charging.[13] SMUD agrees with CARB staff[14] that the growth in the number of LCFS credits generated by EV charging justifies additional assurance that data and calculations reported to CARB are accurate. However, electricity transactions are substantially different from other fuel pathway types, and due to this difference, CARB should consider a different level and scope of verification for these transactions.

As currently drafted, the Proposed Amendments would require site visits to all covered electric charger facilities, only excluding non-metered residential EV

[13] See 95500(c)(1)(E)1. (specifically exempting EV charging under 95491(d)(3)(A), which includes "Non-Metered Residential EV Charging"; 95491(d)(3)(B) covers metered residential charging, and subsection (C) covers non-residential EV charging).
[14] Appendix E at 117-118 (explaining that the data assurance needs have increased due to the growth and projected growth of transportation electrification).

291.5 cont. charging but still including all metered residential and non-residential EV charging.[15] While there may be benefit in performing desktop reviews of electricity transaction data and calculations, CARB should not require verification bodies to perform site visits for EV charging sites. First, site visits would likely only verify the existence of the equipment, which is already accomplished when chargers are submitted to CARB for fuel supply equipment (FSE) registrations. These site visits would at best only confirm the accuracy of the charging equipment and would not provide data regarding charger reliability, inventory, or utilization, which are beyond the current scope of the LCFS program. Since EV charging equipment is standardized and charging data can be collected without a site visit, it is unclear what benefit would be provided from conducting these site visits. Second, these sites vary in size, some include few chargers per site, and many are dispersed throughout broad service areas. The impracticality of annually visiting each covered charger facility throughout the state may be exacerbated if there is an insufficient number of third-party verifiers to conduct site visits. This potentially constrained supply of verifiers and the numerous (and growing) number of chargers is likely to lead to substantial costs. Additionally, accessing covered sites may be particularly difficult since the Proposed Amendments require site visits for any metered residential EV charging and many non-residential charging sites are located on private property.[16] Third, this increased cost may hinder the ability of utilities and others receiving EV charging credits to scale EV charging deployment and solutions. Recognizing the pace and scale of the need for EV charging, CARB should acknowledge that increased costs may disincentivize deployment. SMUD encourages CARB to remove site visit requirements for electricity transactions listed in Section 95500(c)(1)(E)1. since this requirement will not provide meaningful improvement for data accuracy for the LCFS program, may have several practical implementation challenges, and may substantially increase costs that will hinder deployment.

If CARB chooses not to remove the site visit requirements, CARB should clarify the "Less Intensive Verification" requirements.[17] The Proposed Amendments state that fuel reporting entities "only reporting electricity transactions" identified in 95500(c)(1)(E) are eligible for the Less Intensive Verification.[18] Section 95500(c)(1)(E)1. specifically exempts nonmetered residential EV charging from the definition. This would seemingly make all EDUs receiving credits associated with nonmetered residential EV charging (i.e., base credits) ineligible for Less Intensive Verification, since these entities would be reporting electricity transactions not covered by that section. Additionally, as written, fuel reporting entities receiving credits from sources other than EV charging, despite these other sources also being separately subject to verification, would be ineligible for Less Intensive Verification

[15] See 95501 (stating that "services must meet the following requirements"), 95501(b) (stating "[v]erification services must include, but are not limited to, the following:"), 95501(b)(3) (requiring site visits).
[16] See footnote 13 (explaining that only non-metered residential EV charging is exempted under 95500(c)(1)(E)1.).
[17] 95501(h).
[18] *Id.*

291.5 cont. for the portion of their data associated with verification of their electricity transactions. For example, a fuel reporting entity reporting hydrogen fuel cell vehicle fueling[19] that also reported covered electricity transactions would seemingly be completely ineligible for Less Intensive Verification, despite these hydrogen transactions requiring separate verification. Instead, CARB should clarify that fuel reporting entities are eligible for the Less Intensive Verification for any verification required by 95500(c)(1)(E) and this verification option is only available for electricity-based transactions, but reporting other transaction types does not revoke eligibility.

Finally, if CARB chooses not to remove site visit requirements entirely, CARB should consider providing clearer guidelines on when site visits may be required for electricity transactions. Currently, the Proposed Amendments give the verification body the discretion to conduct site visits where "deemed necessary" to achieve reasonable assurance.[20] Vesting this discretion with the verification body may create an incentive to conduct site visits where unnecessary or call into question the fairness and objectivity of verification results, given the Less Intensive Verification section does not provide any meaningful review or standards for making this determination.

6. Conclusion

Thank you for the opportunity to provide feedback on the Proposed Amendments. SMUD looks forward to working with CARB and stakeholders to develop proposed regulatory changes that strengthen the LCFS regulation and promote widespread transportation electrification.

/s/

JOSHUA STOOPS
Government Affairs Representative
Sacramento Municipal Utility District
P.O. Box 15830, MS B404
Sacramento, CA 95852-0830

[19] See 95500(c)(1)(D) and (F).
[20] 95500(h)(5).

/s/

KATHARINE LARSON
Regulatory Program Manager
Sacramento Municipal Utility District
P.O. Box 15830, MS B404
Sacramento, CA 95852-0830

/s/

JOY MASTACHE
Senior Attorney
Sacramento Municipal Utility District
P.O. Box 15830, MS B406
Sacramento, CA 95852-0830

cc: Corporate Files (LEG 2024-0023)

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Comment 301 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Noah
Last Name	Garcia
Email Address	noah.garcia@evgo.com
Affiliation	EVgo
Subject	EVgo Comments on Proposed LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6971-lcfs2024-VjBUO10yUWMFb1UK.pdf
Original File Name	Final ISOR Comments February 20.pdf
Date and Time Comment Was Submitted	2024-02-20 16:34:58

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Honorable Chair Liane Randolph and Honorable Board Members
Low Carbon Fuel Standard Program
California Air Resources Board
1001 I St., Sacramento, CA 95814

Sent via email to LCFSworkshop@arb.ca.gov

Re: Proposed Low Carbon Fuel Standard Amendments

Chair Randolph and Members of the Board:

EVgo appreciates the opportunity to comment on the California Air Resources Board's (CARB) amendments to the Low Carbon Fuel Standard (LCFS) proposed in the agency's Initial Statement of Reasons (ISOR). Headquartered in Los Angeles, EVgo is one of the nation's largest public fast charging providers for electric vehicles (EVs) with a mission to expedite the mass adoption of EVs by creating a convenient, reliable, and affordable EV charging network that delivers fast charging to all drivers.

The LCFS is one of California's most effective decarbonization tools. It supports critical investments in EV charging infrastructure needed to meet Advanced Clean Cars (ACC) II and other CARB zero-emission vehicle (ZEV) regulations. Unlike other California policies that incentivize EV charger deployment through one-time capex support, the LCFS provides critical ongoing support for EV charger operations, including maintenance, in a manner that enhances the EV charging experience for all drivers.

It is imperative that CARB strengthen the LCFS in this rulemaking to further accelerate ZEV adoption and drive investment in clean fuels. EVgo appreciates the measures CARB has proposed to raise the ambition of the program and recommends CARB take additional action to ensure that the LCFS continues to bolster the deployment of EV charging across the state, as summarized below:

292.1
1. EVgo supports the increased stringency of the annual carbon intensity (CI) targets and the introduction of the auto-acceleration mechanism (AAM) to deliver more greenhouse gas (GHG) emissions reductions in line with state climate goals.

292.2
2. CARB can reduce the risk of excess credits and support greater GHG emissions reductions through an increase in the stringency of the 2025 CI step down by at least seven percentage points.

292.3 3. CARB can support greater GHG emissions reductions by allowing the AAM to be triggered in 2026 with an effective date in 2027.

292.4 4. CARB can strengthen the light-duty fast charging infrastructure (FCI) credit provisions to support the deployment of public fast charging infrastructure necessary to meet state climate and equity goals.

292.5 5. CARB should consider overlapping existing California Department of Food and Agriculture (CDFA) Division of Measurement Standards (DMS) weights & measures regulations before the adoption of new verification requirements for electric fuels in the LCFS.

292.1 cont. **1. EVgo supports the increased stringency of the annual CI targets and the introduction of the AAM to deliver more GHG emissions reductions in line with state climate goals.**

EVgo directionally supports the more ambitious near-term annual CI targets proposed in the ISOR, including the revised 30% CI target in 2030. As CARB plainly stated in its November 2022 Workshop preceding this rulemaking, the LCFS is overperforming.[1] Increasing the stringency of near-term CI targets is one important step CARB can take to improve the health of the program and account for the current pace of low carbon fuel adoption.

Additionally, EVgo supports the adoption of the AAM to reduce the risk that the LCFS will continue to overperform in future years. The AAM will ensure that the program continues to send a clear investment signal to low carbon fuel providers and ensure that the LCFS accommodates unforeseen advances in the decarbonization of California's transportation fuel pool. Furthermore, the AAM can set a helpful precedent for other jurisdictions seeking to adopt and implement successful clean fuel standards that support climate, air quality, and economic development goals.

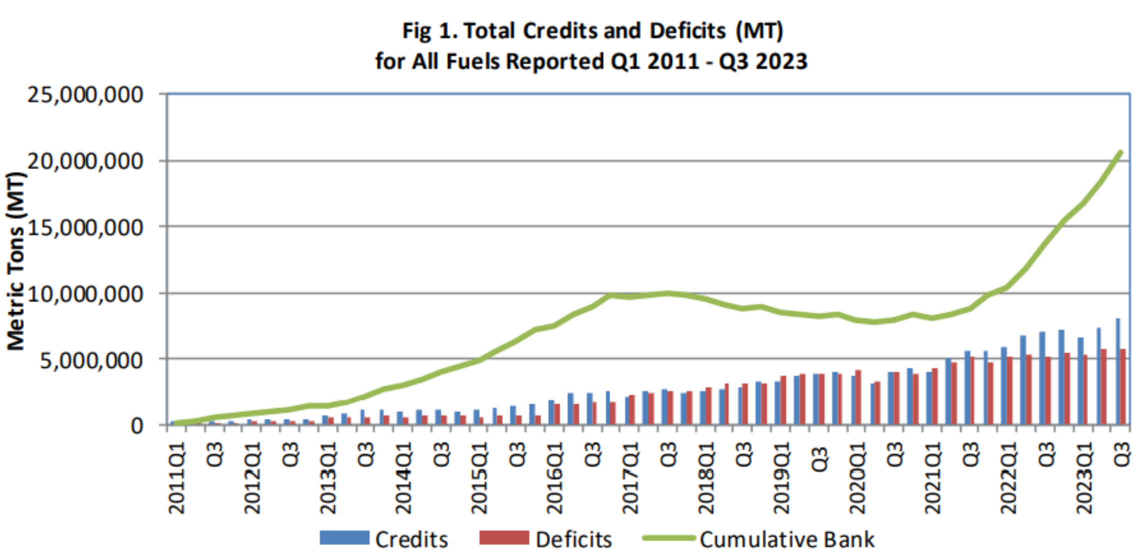
292.2 cont. **2. CARB can reduce the risk of excess credits and support greater GHG emissions reductions through an increase in the stringency of the 2025 CI step down by at least seven percentage points.**

While EVgo directionally supports the 2025 CI step down as a critical measure to stabilize the LCFS credit market, EVgo asserts that CARB can feasibly support a more ambitious step down of at least seven percentage points – leading to a 2025 CI target of at least 20.75% below base year CI target.[2]

[1] https://ww2.arb.ca.gov/sites/default/files/2022-11/LCFSPresentation.pdf
[2] Sheehy and Yan, *Analyzing Future Low Carbon Fuel Targets in California*, released February 2024, available at: https://static1.squarespace.com/static/5b57ab49f407b4a7ffa44ffa/t/65cd3c74d1a72f445cdc7a7e/1707949173143/ICFReport2024.pdf

The ISOR clearly demonstrates that production of low carbon fuels has far exceeded CARB's estimates in 2018 when the current annual CI targets were established.[3] CARB's most recent quarterly data summary for Q3 2023 illustrates that the LCFS credit bank exceeded 20 million credits for the first time – growing unabated as decarbonization of California's transportation fuel pool outpaces the ambition of the program.[4] Increasing the stringency of near-term CI targets is vital for correcting program overperformance and providing greater stability to the credit bank.

Moreover, CARB has revised the baseline CI value for ultra low sulfur diesel (ULSD) upward from 100.45 gCO2e/MJ to 105.76 gCO2e/MJ in Appendix A-1 of the Proposed Regulation Order (PRO).[5] This adjustment would partially offset the benefit of CARB's proposed five percent CI step down in 2025 by lowering the stringency of the program and increasing the risk that the credit bank continues to grow – primarily from credits generated by renewable diesel. If CARB proposes to make this adjustment to the baseline ULSD CI value, raising the ambition of the 2025 CI step-down by at least seven percentage points will help avoid the risk of sustained overperformance and better align with California's climate policy objectives.



[3] ISOR at 22-23.

[4] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/dashboard/quarterlysummary/Q3%202023%20Data%20Summary_013124.pdf

[5] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appa1.pdf

292.3 cont. **3. CARB can support greater GHG emissions reductions by allowing the AAM to be triggered in 2026 with an effective date in 2027.**

EVgo asserts that CARB can further support the ambition of California's decarbonization goals by allowing the AAM to be triggered in 2026 with a potential earliest effective date in 2027 as opposed to the currently proposed 2027 trigger year and effective date in 2028. CARB has taken care to develop a transparent, easily understandable mechanism to address one of the central challenges of the LCFS today and into the foreseeable future: "market overperformance."[6] It is not apparent why CARB would purposefully delay the implementation of this conditional market mechanism at a time when the LCFS credit bank continues to reach unprecedented levels and when the transportation sector remains the largest contributor to California GHG and criteria pollutant emissions. Allowing the AAM to trigger earlier will support more ambitious, achievable, and near-term emissions reductions and send a clear market signal to invest further in clean fuels.

292.4 cont. **4. CARB can strengthen the light-duty FCI credit provisions to support the deployment of public fast charging infrastructure necessary to meet state climate and equity goals.**

While EVgo appreciates several of the amendments made to strengthen the light-duty FCI provisions in the LCFS, including the minimum 150 kW charger capacity requirement and a revised FCI cap formula, EVgo respectfully encourages CARB to modify the proposed FCI provisions to ensure they are aligned with the trajectory of California's EV goals. As noted by Earthjustice[7], the Natural Resources Defense Council[8], CalETC and the Electric Vehicle Charging Association[9], and CARB itself[10], it is imperative that the LCFS support California's climate policy goals by supporting the adoption zero-emission vehicles wherever feasible. The light-duty passenger vehicle market is one sector that is primed for rapid growth in coming years driven by ACC II requirements, and EVgo provides the following recommendations to ensure FCI continues to play a complementary role in EV market development:

292.6 a. *Preserve the existing pool of light-duty FCI credits at 2.5% of prior quarter deficits starting in 2026 instead of reducing the available pool of credits to 0.5% of prior quarter deficits.* Updated modeling from California Energy Commission's (CEC) AB 2127 state EV

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[6] ISOR at 22.

[7] Earthjustice Comments on May 31 Community Workshop at 7, available at: https://ww2.arb.ca.gov/system/files/webform/public_comments/4041/20230614-Earthjustice%20-%20LCFS%20Community%20Meeting%20Comments.pdf

[8] NRDC Recommendations for Updates to the Low Carbon Fuel Standard at 12, available at: https://ww2.arb.ca.gov/system/files/webform/public_comments/4036/NRDC%20Letter%20to%20CARB%20on%20LCFS%20Updates_061423_final.pdf

[9] CalETC and EVCA Comments on Feb 22, 2023 workshop at 2. Available at: https://www.arb.ca.gov/lists/com-attach/86-lcfs-wkshp-feb23-ws-AGMHYFA9V2FVJwJh.pdf

[10] ISOR at 22.

charger demand assessment plainly demonstrates that substantial near-term deployment of direct current fast charging (DCFC) infrastructure is needed to support 2030 charging needs established by ACC II.[11] The benefits of FCI are not limited disadvantaged, low-income, or rural communities: given that California needs over 37,000 fast chargers across the state by 2030 to meet ACC II goals, EV charging developers seek to deploy charging ahead of demand and may rely on short-term FCI credits when charger utilization at a site is initially low.

FCI credits are also critically important for supporting ongoing operating costs for fast chargers that enhance reliability and customers' charging experience. With charging experience issues gaining traction as a state[12] and national[13] priority necessary for bolstering consumer confidence in EV adoption, now is not the time to pull back on this critical source of funding for ongoing O&M costs.[14] Regrettably, reducing the size of the available FCI credit pool may ultimately deter investment in DCFC infrastructure where expected charger utilization may not be sufficiently robust – including low-income, disadvantaged, and rural communities.

292.7 b. *Adopt the U.S. Treasury Department (TD) and Internal Revenue Service (IRS) definition of "non-urban census tracts" to establish LD-FCI eligibility for public DCFC sites in rural California communities in lieu of the current 10-mile threshold definition proposed by Staff.* In January 2024, TD and IRS released guidance on charging station location requirements to be eligible for the 30C alternative fuel vehicle refueling property credit, which was amended in the Inflation Reduction Act to encourage greater EV charging infrastructure deployment in rural and low-income communities.[15] Maps were also released to clearly illustrate which rural areas would be eligible for the 30C tax credit resulting from this guidance through 2030.[16] While California has clear definitions for disadvantaged and low-income communities that can readily be used to determine FCI eligibility, CARB Staff's proposal to define rural eligibility as 10 miles from the nearest public DCFC[17] is arbitrary and challenging to implement because charging developers are

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[11] Alexander, Matt, Noel Crisostomo, Wendell Krell, Jeffrey Lu, and Raja Ramesh. July 2021. Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment: Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030 — Commission Report. California Energy Commission. Publication Number: CEC-600-2021-001-CMR. Available at https://www.energy.ca.gov/programs-and-topics/programs/electric-vehicle-charging-infrastructureassessment-ab-2127.

[12] https://efiling.energy.ca.gov/GetDocument.aspx?tn=252434&DocumentContentId=87440

[13] https://driveelectric.gov/chargex-consortium

[14] The CEC is expected to finalize its EVSE reliability regulations pursuant to AB 2061 in 2024. EVgo recommends that CARB coordinate closely with the CEC to assess how the implementation of these regulations would affect charging stations that participate in the LCFS.

[15] https://www.irs.gov/pub/irs-drop/n-24-20.pdf

[16] https://experience.arcgis.com/experience/3f67d5e82dc64d1589714d5499196d4f/page/Page/

[17] Appendix A-1 at 105.

constantly adding new chargers across the state. To improve clarity, provide stability, align with federal policy guidance, and encourage greater investment in public DCFC outside of California's major metro areas, EVgo recommends that CARB replace the proposed rural eligibility criteria with TD and IRS's definition of non-urban census tracts.

292.8 c. *Expand the size of eligible FCI sites beyond four chargers and 1,000 kW nameplate capacity to align with guidance from the National Electric Vehicle Infrastructure (NEVI) program minimum standards, California state agency activities, EV market trends, and an enhanced customer experience.* CARB Staff proposed limiting FCI eligibility to up to four chargers per site and a nameplate capacity of no greater than 1,000 kW to provide FCI to more charging stations across the state.[18] EVgo appreciates the intent of these policy provisions but asserts that limiting eligible FCI per site to four chargers and 1,000 kW is misaligned with federal, state, and market guidance. CARB references NEVI program minimum standards when justifying its proposal to increase minimum charger nameplate capacity eligibility to 150 kW[19], and the NEVI guidance also plainly specifies that four ports and 150 kW charging is the *minimum* required for NEVI-eligible stations – not the maximum. CEC and Caltrans have incorporated this guidance into their first round NEVI solicitation, which encourages applicants to build charging stations well in excess of the four-port minimum on key corridors such as I-5 and I-15.[20]

Finally, larger sites are critical to an enhanced customer experience and will be increasingly so as EV penetration continues. The growth in EV sales necessitates larger sites with faster, more convenient charging; smaller sites are more likely to lead to queuing, or customers needing to wait in line – contrary to state goals for an enhanced customer experience. It is not uncommon for new public DCFC sites to include more six or more DCFC stalls, exceeding a cumulative 1,000 kW nameplate capacity as part of network providers' ongoing efforts to elevate the customer experience. It is vital that CARB consider EV drivers' charging experience when establishing FCI guidelines and EVgo recommends that CARB remove the FCI charger limit per site and preserve the existing 2,500 kW cap on FCI-eligible DCFC sites.[21]

292.5 cont. **5. CARB should consider overlapping CDFA DMS weights & measures regulations before the adoption of new verification requirements for electric fuels in the LCFS.**

CARB has proposed to require third-party verification for reporting of electricity from EV charging, including non-residential charging. EVgo supports timely, accurate reporting of fuel

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[18] Appendix E at 37-38. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appe.pdf
[19] *Id.* at 34.
[20] See slide 18-19 for more details on specific corridor charging requirements in CEC/Caltrans first round NEVI solicitation. https://efiling.energy.ca.gov/GetDocument.aspx?tn=253051&DocumentContentId=88250
[21] Appendix A-1 at 99. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appa1.pdf

292.5 cont. transactions to maintain the integrity of the LCFS. However, CARB's proposed regulations appear to duplicate existing CDFA DMS regulations[22] that require EV chargers to meet stringent accuracy tolerances and require county weights & measures offices to regularly test EV charging equipment.

Specifically, DMS adopted regulations in January 2020 that require commercially available EV chargers to meet stringent accuracy standards – as well as other consumer protection requirements – which conform to the National Institute of Standards and Technology Handbook 44 technical standards for charging equipment.[23] These requirements, which include a +/- 5% maintenance tolerance for DC electricity as vehicle fuel, are aligned with CARB's proposed §95491.2(a)(1)(B) which would require all meters to achieve accuracy levels of +/- 5%.[24] Furthermore, many county weights & measures officials are beginning to enforce compliance with these regulations by testing EV chargers in the field; if a charger is not performing within the accuracy tolerances prescribed by DMS regulation, counties can require a charger to enter maintenance until the charger's accuracy tolerance is corrected.[25] Finally, EV charging providers already support continued implementation and enforcement of weights & measures regulations by paying annual device registration fees to counties where the devices are in operation.[26] In sum, EVgo respectfully encourages CARB to consider these existing CDFA regulations before establishing new, overlapping verification requirements for EV chargers in the LCFS.

Conclusion

EVgo commends CARB's ZEV leadership and its continued refinement of the LCFS in confronting California's most pressing transportation decarbonization challenges. The LCFS is one of California's signature climate policies, and CARB is well-positioned to strengthen the ambition of the program while ensuring that it remains aligned with the agency's core ZEV regulations and CEC's charging infrastructure goals. EVgo looks forward to continued engagement on these topics and further development of a robust, convenient, and reliable EV charging network that benefits all Californians.

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[22] https://www.cdfa.ca.gov/dms/regulations.html

[23] https://govt.westlaw.com/calregs/Document/IA5650EF3543B11ECAE2D000D3A7C4BC3?viewType=FullText&originationContext=documenttoc&transitionType=CategoryPageItem&contextData=(sc.Default))

[24] Appendix A-2 at 18. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appa-2.pdf

[25] https://www.cdfa.ca.gov/dms/docs/publications/2023/2023_Combined_BPC.pdf

[26] *Id*.

Respectfully submitted this 20th Day of February,

Noah Garcia
Manager, Market Development and Public Policy
EVgo Services, LLC
11835 W. Olympic Blvd., Suite 900E
Los Angeles, CA 90064
Tel: 310.954.2900
E-mail: noah.garcia@evgo.com

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Comment 302 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Julian
Last Name	Lake
Email Address	jlake@bayareacouncil.org
Affiliation	Bay Area Council
Subject	Low Carbon Fuel Standard Updates

Comment

February 20, 2024

Rajinder Sahota
Deputy Executive Officer
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Low Carbon Fuel Standard Updates

Dear Deputy Executive Officer Sahota,

On behalf of the Bay Area Council and our partners, we respectful request the California Air Resources Board (CARB) consider specif actions in the Low Carbon Fuel Standard (LCFS) update to advance the production of Sustainable Aviation Fuels (SAF) in furtherance of California's 2045 climate goals. Specifically, we ask that CAR cap carbon intensity ratings for new Sustainable Aviation Fuel (SAF) production facilities; provide equal access expansion of boo and claim accounting to SAF; leverage LCFS provisions to realize additional SAF air quality benefits beyond GhG emissions; and tha CARB reconsider its proposal to regulate fossil jet fuel for intrastate flights.

The CARB 2022 Scoping Plan establishes the goal of using SAF to meet 80 percent of all aviation fuel demand by 2045, up from less than one percent today. Meeting this ambitious goal will require unprecedented investments in new infrastructure and the processin of many thousands of tons of feedstock. SAF refineries are large infrastructure projects requiring substantial financing, and the inclusion of CARB's renewable fuel refinery CI performance thresholds in commercial contracts is an increasingly important tool for making these projects pencil. Models used for the generation of price support mechanisms such as the Low Carbon Fue Standard (LCFS) credit and the Blenders Tax Credit (BTC) rely on as a key metric for credit valuation and generation. However, und current rules, CARB may change the official CI for SAF projects a any time, undermining the value of the BTC and the LCFS credit th underpins project feasibility. This uncertainty acts as a disincentive to investors and is an obstacle to achieving the state's SAF production goals and broader emissions targets.

To address this challenge, CARB should consider opening a 10-year window during which time SAF refinery projects would be allowed tc keep, for a period of 20 years, the CI determination made by CARB using the GREET methodology at the time of the project's Final Investment Decision (FID). To ensure the baseline CI determined at FID is continuously met, producers should agree to re-testing on a regular bi-annual cadence. By better aligning CI incentives with asset lifespans, CARB would provide the predictability necessary for securing the large-scale financing needed to jump-start this important new industry.

We commend CARB's current policy supporting book and claim accounting for low-CI electricity and RNG inputs for low-CI hydrogen production, as well as their initiative to expand access through power purchase agreements (PPAs). Nevertheless, we advocat for equal access expansion to Sustainable Aviation Fuel (SAF). Bot low-CI hydrogen and SAF play pivotal roles in displacing hard-to-electrify

sectors like aviation, as outlined in the 2022 CARB Scoping Plan. However, existing LCFS rules tend to disadvantage SAF in compariso to hydrogen due to limited access to emissions reductions from process energy, such as low-CI electricity and RNG. This incongruity undermines state objectives for SAF uptake and aviatic decarbonization, necessitating CARB's intervention to ensure equitable treatment between these future fuels.

Furthermore, we underscore the critical importance of encouraging the long-term adoption of SAF by leveraging LCFS provisions to realize additional air quality and climate benefits. Notably, whil light and medium/heavy-duty transportation are expected to electrify within decades, aviation's transition to decarbonizatior will be more prolonged, with SAF anticipated as the primary lever CARB must recognize and account for the substantial positive externalities associated with SAF substitution for fossil jet fuel and devise mechanisms within the LCFS to drive SAF adoption. Additionally, considerations such as the air quality benefits of SAF, particularly in reducing fine particulate matter, must be addressed. Equally significant are the environmental justice concerns raised by communities living near airports, urging CARB's support for SAF as a means to mitigate the disproportionate health impacts of fossil jet fuel combustion. It is only through actual SAF adoption that these air quality benefits might be realized. Given these multifaceted benefits unique to SAF, we urge CARB to prioritize its utilization and explore innovative measures, such a credit multipliers or CO2 equivalent metrics, to appropriately incentivize its adoption and address its distinctive contributions to climate mitigation.

In addition, The Bay Area Council also expresses serious concern with a new proposal by the California Air Resources Board (CARB) t regulate "fossil jet fuel used for intrastate flights" as an obligated fuel under the LCFS Program. We do not believe this proposed change would result in increased SAF production, availability, or use in California, but it would lead to higher je fuel prices. The primary barrier to increased SAF production and availability in California remains the higher cost of SAF for producers and buyers relative to conventional jet fuel and renewable diesel. The CARB proposal would not address this fundamental challenge or otherwise meaningfully increase SAF suppl or use. Instead, the Bay Area Council suggests CARB consider alternative incentive structures that can help close the price gap between SAF and Conventional Jet-A, alongside SAF-specific economi development programs and investments via GoBiz as previously encouraged by SB1383 and the SAF Coalition.

Additionally, the intra-state flight proposal seeks to regulate je fuel and reduce emissions from aviation, both of which are pre-empted under federal law - a fact that CARB recognized when it exempted jet fuel in 2018. Aviation has unique demands for reliability and consistency with approved fuel specifications for the safe operation and maintenance of aircraft. Accordingly, while the EPA is the primary federal regulator for on-highway, non-road, and marine fuels, under 42 U.S.C. § 7545, the FAA has authority to establish standards for composition and chemical or physical properties of jet fuel or to eliminate aircraft emissions (49 U.S.C. § 44714). The FAA retains federal jurisdiction over suc fuels even if used for intrastate flights. These statutory authorities establish clear and broad federal authority for regulating jet fuel and aircraft engine emissions that pre-empts California from regulating fossil jet fuel under the LCFS program We ask that CARB reconsider this aspect of the proposed regulatior and maintain the exemption for jet fuel from regulation under the

LCFS program.

The Bay Area Council represents 350 of the Bay Area's largest employers across all sectors of the economy. For many of these companies, air travel represents the vast majority of Scope 3 emissions. Unlike other sectors, aviation has no realistic net-zer alternative over the next 20 years, making state efforts to scale SAF all the more important. By better aligning current incentives with asset life cycles, California can become a world leader in SA production and come that much closer to achieving its broader climate goals. We stand ready to offer any assistance necessary to transform these goals into a tangible reality.

Thank you for your leadership, and for considering our views.

Sincerely,

Adrian Covert
Senior Vice President, Public Policy
Bay Area Council

Adam Klauber
VP Sustainability and Digital Supply Chain
World Energy

Jared Asch
Managing Partner
Capstone Government Affairs

Attachment	www.arb.ca.gov/lists/com-attach/6972-lcfs2024-BzdWYgQrVTQGMANc.docx
Original File Name	02.20_LCFS.1.docx
Date and Time Comment Was Submitted	2024-02-20 16:30:56

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Rajinder Sahota
Deputy Executive Officer
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Low Carbon Fuel Standard Updates

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On behalf of the Bay Area Council and our partners, we respectfully request the California Air Resources Board (CARB) consider specific actions in the Low Carbon Fuel Standard (LCFS) update to advance the production of Sustainable Aviation Fuels (SAF) in furtherance of California's 2045 climate goals. Specifically, we ask that CARB cap carbon intensity ratings for new Sustainable Aviation Fuel (SAF) production facilities; provide equal access expansion of book and claim accounting to SAF; leverage LCFS provisions to realize additional SAF air quality benefits beyond GhG emissions; and that CARB reconsider its proposal to regulate fossil jet fuel for intrastate flights.

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293.1 refinery projects would be allowed to keep, for a period of 20 years, the CI determination made by CARB using the GREET methodology at the time of the project's Final Investment Decision (FID). To ensure the baseline CI determined at FID is continuously met, producers should agree to re-testing on a regular bi-annual cadence. By better aligning CI incentives with asset lifespans, CARB would provide the predictability necessary for securing the large-scale financing needed to jump-start this important new industry.

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producers and buyers relative to conventional jet fuel and renewable diesel. The CARB proposal would
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Thank you for your leadership, and for considering our views.

Sincerely,

Adrian Covert
Senior Vice President, Public Policy
Bay Area Council

Adam Klauber
VP Sustainability and Digital Supply Chain
World Energy

Jared Asch
Managing Partner
Capstone Government Affairs

Comment Log Display

Here is the comment you selected to display.

Comment 303 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jane
Last Name	Sadler
Email Address	jsadler@rmi.org
Affiliation	RMI
Subject	Applicability of Book and Claim for Low CI Electricity
Comment	Please see attached document for comments.
Attachment	www.arb.ca.gov/lists/com-attach/6973-lcfs2024-nVDdlXf1yACVYm0D.pdf
Original File Name	RMI_LCFS 2024 Comments.pdf
Date and Time Comment Was Submitted	2024-02-20 16:27:11

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

2490 Junction Place, Suite 200, Boulder, CO 80301

California Air Resources Board
1001 I Street
Sacramento, CA 95815

RE: Proposed 2024 Low Carbon Fuel Standard Amendments

Dear California Air Resources Board,

Thank you for the opportunity to provide input regarding the 2024 California Low Carbon Fuel Standard (LCFS) Amendments. RMI is a global non-profit organization that focuses on deep decarbonization of the world's most polluting sectors, leading sustainability programs across four geographies: the U.S., India, China, and the Global South. RMI has a 40-year history of advancing low and zero-carbon transportation solutions and transforming global power systems to support modern, low-carbon economies.

These comments will address the proposed rules on page 149 of Appendix A-1, in section 95488.8(i)(1) that focus on the applicability of book-and-claim accounting for low-carbon intensity (CI) electricity for hydrogen production. As the proposed rules stand, hydrogen that is used as a feedstock in the production of e-fuels would not be eligible to use book-and-claim accounting to certify its CI score under California's LCFS. This will limit such projects to relying on on-site, "behind the meter" clean electricity to certify their CI score; as grid electricity used to make hydrogen without the option of a well-regulated book-and-claim option will not result in clean hydrogen. E-fuels, including sustainable aviation fuel, maritime fuels such as methanol or ammonia, and renewable diesel, are made using low-emission hydrogen and biogenic or atmospheric CO_2 sourced from carbon dioxide removal facilities.

294.1 Limiting the end uses for hydrogen that is produced using grid-connected electrolysis would limit the amount of hydrogen produced in California, impede effective decarbonization of heavy transportation, and undermine the state's decarbonization goals as stated in the 2022 Scoping Plan.

We urge CARB to continue to allow book-and-claim accounting of low-CI electricity in the production of hydrogen feedstock for low-carbon transportation fuels. Below we have outlined why the current proposed rulemaking would be counter to the stated goals of the LCFS and the 2022 Scoping Plan.

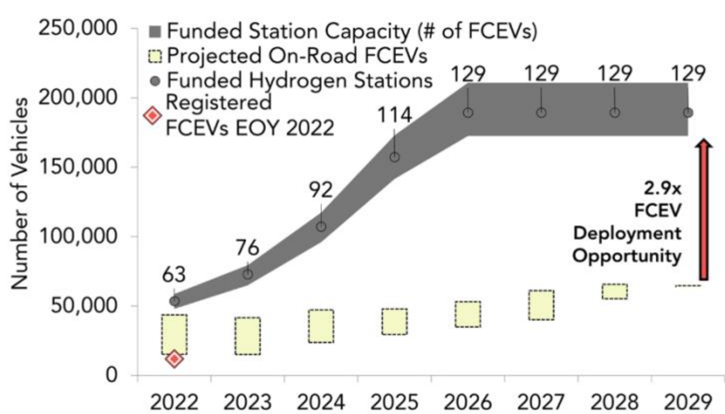
294.1 cont. **1. Hydrogen has the greatest decarbonization potential in sectors that are difficult or uneconomic to electrify. For transportation, this often means being used as a feedstock in e-fuels.**

Hydrogen can be used to directly power fuel cell electric vehicles (FCEVs) but RMI analysis shows that direct electrification of light duty vehicles results in 0.41 kg CO_2e/kWh *more* reduction than using zero emissions hydrogen. As such, hydrogen should be directed to transportation end uses that cannot be electrified, like aviation, maritime fuel, and even diesel replacement in some long-haul trucking routes. For these applications, hydrogen will be most commonly used to produce e-fuels rather than as a direct fuel in a FCEV.

In many cases, hydrogen's highest and best use for decarbonization is as a feedstock into these fuels, rather than as a direct fuel itself. E-fuels should therefore benefit from book-and-claim accounting option in the same way that hydrogen as a direct fuel does.

2. Light-duty FCEVs are not a large enough offtake market for the planned amount of electrolytic hydrogen production in California.

FIGURE 22: COMPARISON OF PROJECTED VEHICLE DEPLOYMENT AND NETWORK RATED CAPACITY



Source: California Air Resources Board, Annual Evaluation of Fuel Cell Electric Vehicle Deployment

In addition to not being the most effective end use for hydrogen as a decarbonization tool, FCEVs alone will not generate enough demand to offtake hydrogen produced in California. According to CARB's 2023 Annual Evaluation of Fuel Cell Electric Vehicle Deployment, just under 13,000 FCEVs are currently on the roads (making up 1.1% of all zero emission cars in California). In the same report, CARB estimated that "the projected hydrogen fueling network capacity growth is expected to stay well ahead of demand through the end of the decade. By 2029, the statewide hydrogen fueling network will have rated capacity at full availability sufficient for nearly three times the number of expected FCEVs on the road." In

294.1 cont. an analysis that used the network capacity at recent levels of availability (as opposed to rated capacity) station capacity would still be at least double the projected demand.

It is clear that light-duty FCEVs will not constitute a large enough offtake sector to support electrolytic hydrogen plans in California. Allowing electrolytic hydrogen used as a feedstock to use book-and-claim electricity would afford hydrogen producers flexibility in finding offtakers while still benefiting from LCFS and decarbonizing priority offtake sectors.

3. **The proposed addition of intrastate jet fuel to the LCFS will require access to hydrogen as a feedstock for sustainable aviation fuel.**

In the Proposed 2024 LCFS Amendments, CARB suggests eliminating the exemption for intrastate fossil jet fuel. We applaud this expansion of the program and suggested it as a lesson for other LCFS states to learn from in a recent policy memo. However, adding restrictions to electrolytic hydrogen as a feedstock in the same rulemaking is counterproductive to this action.

While most sustainable aviation fuel (SAF) that is currently on the California market is made from lipids and biofeedstocks, it is unlikely that this pathway will be able to scale to meet the sector's low carbon fuel needs. SAF made from biofeedstocks faces steep competition for those feedstocks (e.g. corn and soy) from other biofuels, biogenic carbon removal, bioenergy, and other end uses. Additionally, the scaling of these crop-based fuels comes with its own problems, including inefficient land use, increased food prices, and the undermining of the sustainability of the eventual fuel. In part due to these problems, SAF made from biofeedstocks is only expected to reach a global high of 8.9 billion gallons by mid-century, contributing to slightly less than 10% of the global aviation fuels market at that time. It is increasingly clear that biogenic SAF will not be able to scale to the level needed to meet decarbonization goal.

At the same time, the technology required for battery electric or hydrogen fuel cell-powered aircraft is still more than a decade away. Current battery densities for flight are less than 200 Wh/kg — acceptable for short haul flights but inefficient for longer hauls. Long haul electrification would require densities in excess of 350 Wh/kg, which may not be available until 2040. Hydrogen fuel cell technologies face similar challenges.

This leaves hydrogen-derived SAF as the best option for aviation decarbonization right now. Hydrogen-derived SAF is an emerging fuel, but the technology is well-understood and will be scalable as feedstock supply chains mature. It is imperative that SAF producers can access low-CI hydrogen--specifically electrolytic hydrogen that does not depend on biofeedstocks--to create the fuel necessary to participate in LCFS.

294.1 cont. **4. This rule will reduce IRA dollars flowing into the state.**

The Inflation Reduction Act (IRA) offers multiple credits that will support the production of hydrogen and hydrogen-derived fuels; by limiting the eligible offtakers for grid-connected electrolytic hydrogen, this proposed rule will likely reduce the amount of hydrogen produced and therefore the amount of federal funding that California companies can unlock through the 45V tax credit and other federal funding opportunities. 45V is a tech-neutral credit which evaluates all production pathways with the same set of emissions standards, including grid-connected and behind the meter electrolytic hydrogen, and non-electrolytic hydrogen that meets CI requirements. Furthermore, there has been intense debate and research into how grid connected electrolytic hydrogen may certify its CI score to qualify for 45V. We believe that CARB should align its book-and-claim system (for all hydrogen, regardless of its end use) to the federal standards. In this way it can reduce regulatory strain on California companies and draw tax credits to the state.

By limiting the production of hydrogen-based SAF, this rule will also reduce the amount of 40B/45Z credits for the production of SAF that California companies may pursue. All together, this could severely limit the growing hydrogen and SAF industries as well as industries up and down their supply chains.

We urge the Air Resources Board to reconsider this small but consequential element of the proposed 2024 amendments to the Low Carbon Fuel Standard. To accomplish its decarbonization goals and to successfully support the growing hydrogen industry, the LCFS must allow book-and-claim accounting of low-CI electricity supplied for hydrogen production through electrolysis for use in production of a transportation fuel.

Sincerely,

Kyle Clark-Sutton
Manager, US Program
kclarksutton@rmi.org

Comment Log Display

Here is the comment you selected to display.

Comment 304 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Oscar
Last Name	Garcia
Email Address	oscar.garcia@neste.com
Affiliation	Neste
Subject	Neste Comments on Dec 19th Proposed LCFS Regulation
Comment	Neste is please to submit these comments on the December 19th, 202 Proposed LCFS Regulation. Thank you.
Attachment	www.arb.ca.gov/lists/com-attach/6974-lcfs2024-B2lUN1YkACcLaARb.pdf
Original File Name	Neste_December 19 LCFS Proposed Regulation Comments_Feb 20 2024.pd
Date and Time Comment Was Submitted	2024-02-20 16:36:42

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

VIA ELECTRONIC FILING

Ms. Rajinder Sahota
Deputy Executive Officer - Climate Change & Research
California Air Resources Board
1001 I Street
Sacramento, Ca 95814

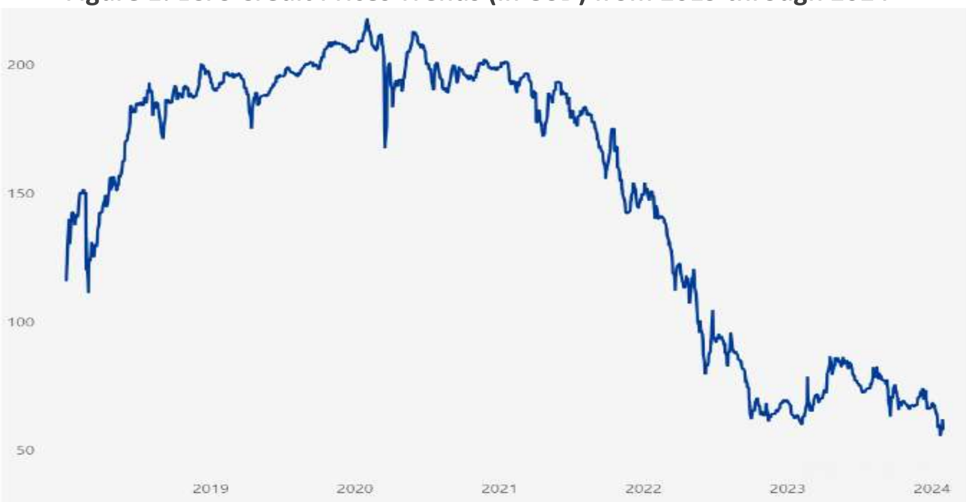
Re: Neste Comments on Proposed Low Carbon Fuel Standard (LCFS) Regulation Published on December 19, 2023

Dear Ms. Sahota:

Neste appreciates the opportunity to provide these comments to the California Air Resources Board (CARB) regarding the proposed LCFS regulation published on December 19, 2023. Neste is the world's largest producer of renewable diesel (RD) and sustainable aviation fuel (SAF), over 90% of which are produced from waste and residues. During the past ten years, Neste's transformation journey has taken it from a local oil refiner to a global leader in renewable and circular solutions. Neste's goal is to achieve carbon neutral production by 2035 and supply California with products that will enable the state to be carbon neutral by 2045. We are in the business of combating climate change by producing effective climate solutions, and our vision is to create a healthier planet for our children.

295.1 Neste believes that finalizing this rulemaking quickly is the highest priority. The LCFS credit market continues to be unstable due to the record amount of renewable energy generating significantly more credits than are required to offset deficits created by the currently outdated CI targets. As shown below in Figure 1, the LCFS credit prices continue to go down because the CI reduction goals are not strict enough, and delays in this rulemaking have made the problem worse. The market had expected CARB to complete this rulemaking to be complete in late 2023, but it only officially started in January 2024. Thus, the instability of the credit market continues to get worse as shown in Figure 1 and it will take that much longer to recover. This continued uncertainty about credit prices makes it difficult for the industry to make its investment decisions and thus essential emissions reductions are on pause. Other LCFS programs, such as Oregon's Clean Fuels Program, have essential program upgrades on pause as well because most believed California's LCFS rulemaking would be complete by now. We urge CARB to prioritize this rulemaking and ensure it is completed by **2nd quarter 2024**.

Figure 1: LCFS Credit Prices Trends (in USD) from 2019 through 2024



February 20, 2024

Neste recommends the following as part of the LCFS rulemaking:

295.1 reference
- Ensure the regulatory updates go into effect in 2024 to avoid further unrealized emissions reductions due to overperformance of the credit market;

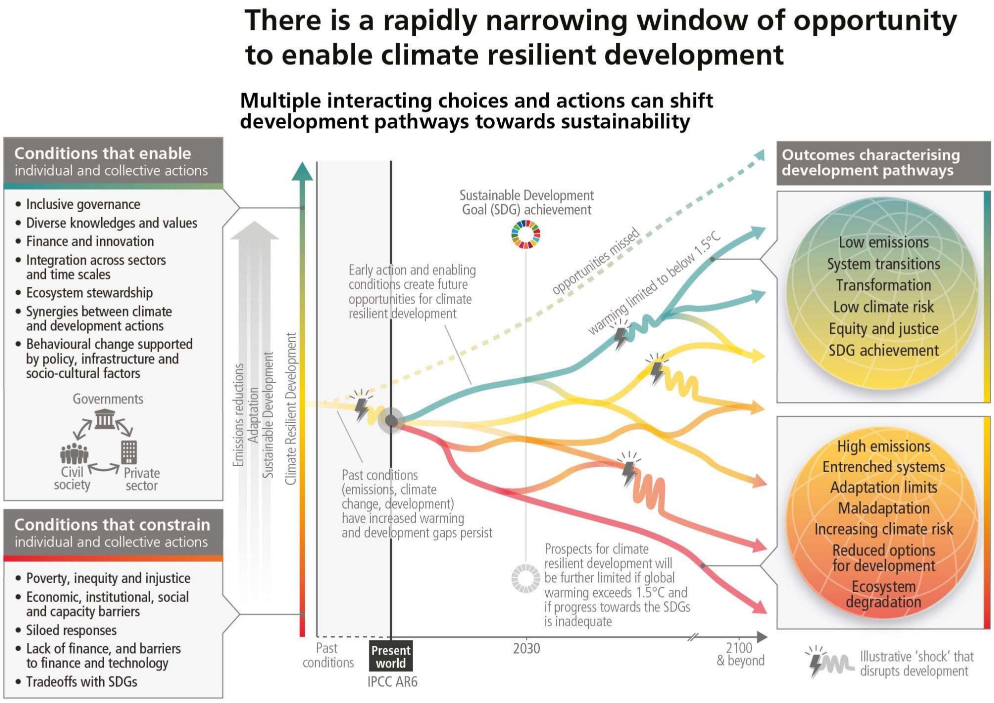
295.2
- Apply an immediate CI step-down of **12%** (and not the proposed 5%) in 2025 to adequately address the large credit bank and to account for the adjustment to the fossil diesel baseline that effectively cancels out the proposed 5% step down for diesel;

295.3
- Start applying the CI Automatic Acceleration Mechanism (AAM) proposed by CARB in 2026 (using 2025 data) and not wait until 2027 to address overperformance in the LCFS credit market should it persist;

295.4
- Avoid an arbitrary cap on feedstocks used to produce renewable diesel and SAF. Such a cap will have the unintended consequences of extending dependence on fossil fuels, exacerbating air quality challenges, and compromising the ability to decarbonize the aviation and maritime sectors.

It is very important that CARB pursue the most aggressive carbon intensity (CI) reduction goals. The IPCC has stated in 2023 that, "There is a rapidly closing window of opportunity to secure a liveable and sustainable future for all (very high confidence);" and, "The choices and actions implemented in this decade will have impacts now and for thousands of years (high confidence)" as shown in Figure 2 below[1]. The time for action is **now**, and the future of our planet is counting on CARB's leadership to address climate change. Modeling work being conducted by the Low Carbon Fuels Coalition (LCFC) shows that CARB can be
295.1 referenced aggressive without jeopardizing the stability of the LCFS. As such, we recommend that CARB pursue aggressive action on this rulemaking, as any hesitance will only favor fossil fuels and delay emission reductions.

Figure 2: IPCC Data on Rapidly Narrowing Window to Address Climate Change



Neste is proud of being an early supplier of renewable diesel in California. We started selling renewable diesel in the state in 2012 when many questioned the viability of the LCFS program, and are glad to see that over **6.5 billion** (with a "b") gallons of fossil diesel have been displaced with renewable diesel over the life of the LCFS program. That is more than twice the diesel California consumes in one year. This equates to

[1] https://www.ipcc.ch/report/ar6/syr/downloads/report/IPCC_AR6_SYR_SPM.pdf , pg 25

about 45 million metric tons of GHG emissions reduced by renewable diesel, the equivalent of what 15 or so large refineries emit in one year. This was all possible due to the leadership CARB showed when it enacted the LCFS program, and Neste encourages CARB to demonstrate that same leadership today to continue setting ambitious carbon reduction goals.

Neste congratulates CARB for creating effective policies and market signals that have resulted in the California diesel market becoming **61%** renewable as of 3rd quarter 2023. What is more impressive is that consumers saw a drop in diesel prices during more recent increases in renewable diesel consumption, showing that phasing out fossil fuels can actually protect the consumer. As noted by CARB staff in the LCFS Rulemaking Standardized Regulatory Impact Assessment (SRIA)[2] and Initial Statement of Reasons (ISOR)[3] stronger action in the LCFS rulemaking can speed up the phaseout of fossil fuels and result in billions of dollars worth of health benefits to Californians.

With this rulemaking, CARB has an opportunity to implement Governor Newsom's July 2022 directive[4] to speed the transition away from petroleum and CARB can do so by maximizing the stringency of the LCFS regulation. Hesitation to be ambitious at this point will only delay critical progress toward meeting the state's carbon emission goals. Neste urges CARB to make every effort to maximize the carbon reductions that will occur under this LCFS rulemaking. Our planet and our children are counting on your leadership.

Below is a summary of some key benefits of the California LCFS to the California consumer as well as detailed discussion of policy recommendations for the Proposed LCFS Regulation. Neste also supports the comments from the Low Carbon Fuels Coalition and ICF on this rulemaking. We appreciate your consideration.

Overview of the Benefits of the California LCFS Program

The LCFS Continues to Drive Use of Renewable Energy While Protecting California Consumers

Per the US Department of Energy Alternative Fuels Data Center,[5] renewable diesel is now competitive in price with conventional diesel in California. This is largely due to the incentives and stable renewable fuels market created by the California LCFS program, and Neste agrees with CARB that, "LCFS credit prices have not shown any historical correlation with retail gasoline prices" (See page 83 of the ISOR). In other words, there is no data showing that the LCFS is directly contributing to price spikes at the fuel pumps and studies have shown there is no such correlation[6]. In fact, CARB estimates that consumers will see an annual savings of **$20 billion** in lower transportation costs in 2045 when compared to 2021 costs, and all from using alternative fuels (See page 82 of the ISOR).

The price of petroleum crude, however, continues to be the main driver for spikes in the diesel and gasoline markets, and California consumers will continue to be impacted by these spikes as long as California continues to depend on fossil fuels. As shown below in Figures 3 and 4, diesel and gasoline prices (orange lines) follow the price of crude (black lines) and consumers saw price spikes when crude prices peaked. On the other hand, there are no obvious diesel or gasoline price increases (orange lines) due to increases in renewable fuels blending or LCFS credit prices (area/pillars in gold). The LCFS program provides the certainty needed to establish thriving renewable fuels markets, while protecting consumers at the pump.

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[2] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appc-1.pdf
[3] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf
[4] https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf
[5] https://afdc.energy.gov/fuels/prices.html
[6] https://www.bateswhite.com/newsroom-insight-Low-carbon-fuels-standards-Cain-2022.html

February 20, 2024

Figure 3: Price Trends of US Crude, Diesel and RD Share of CA Diesel

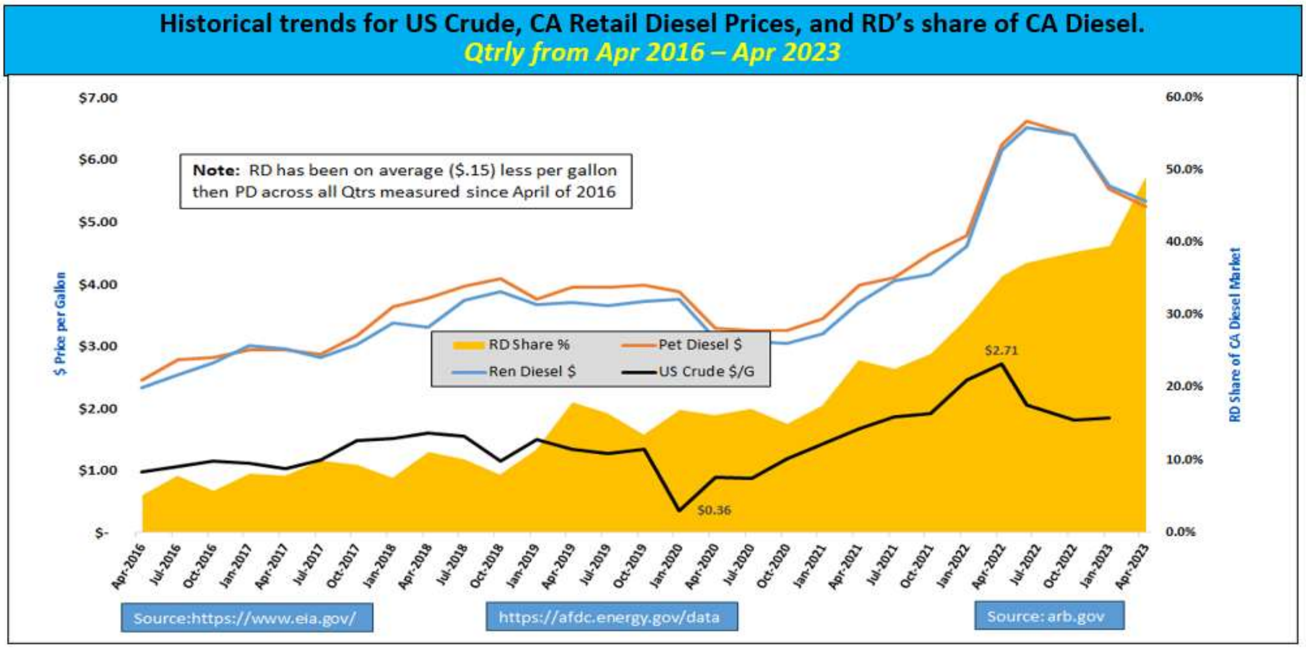
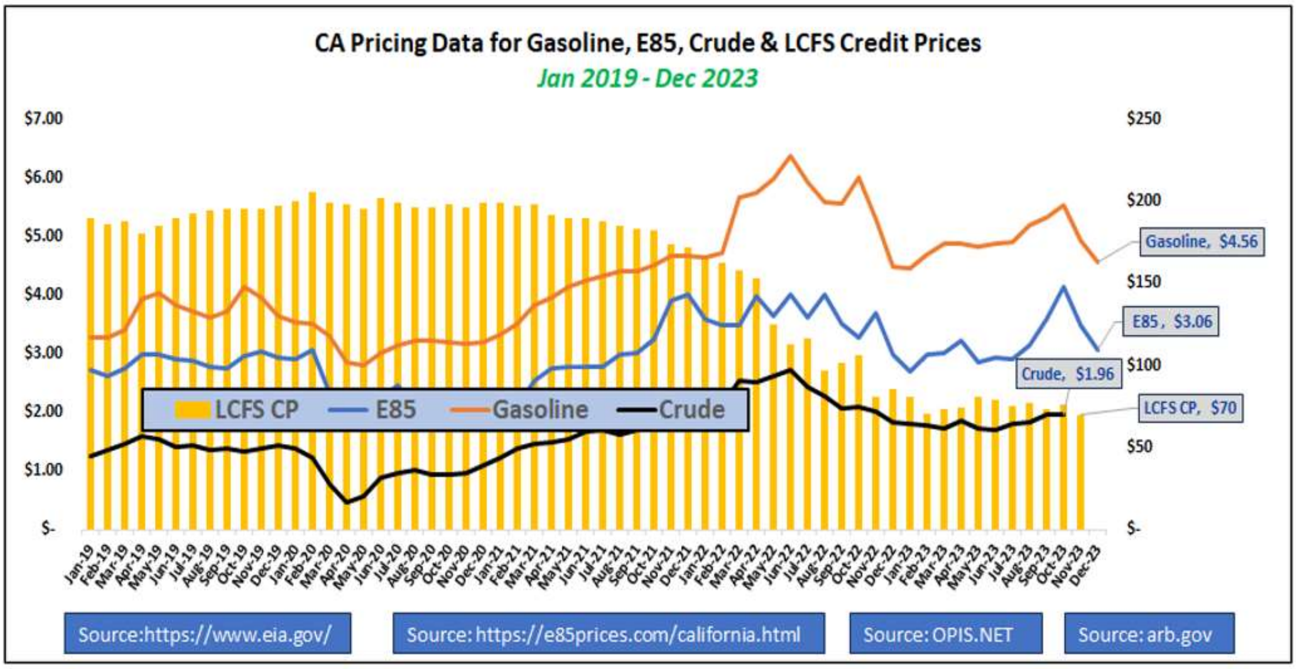


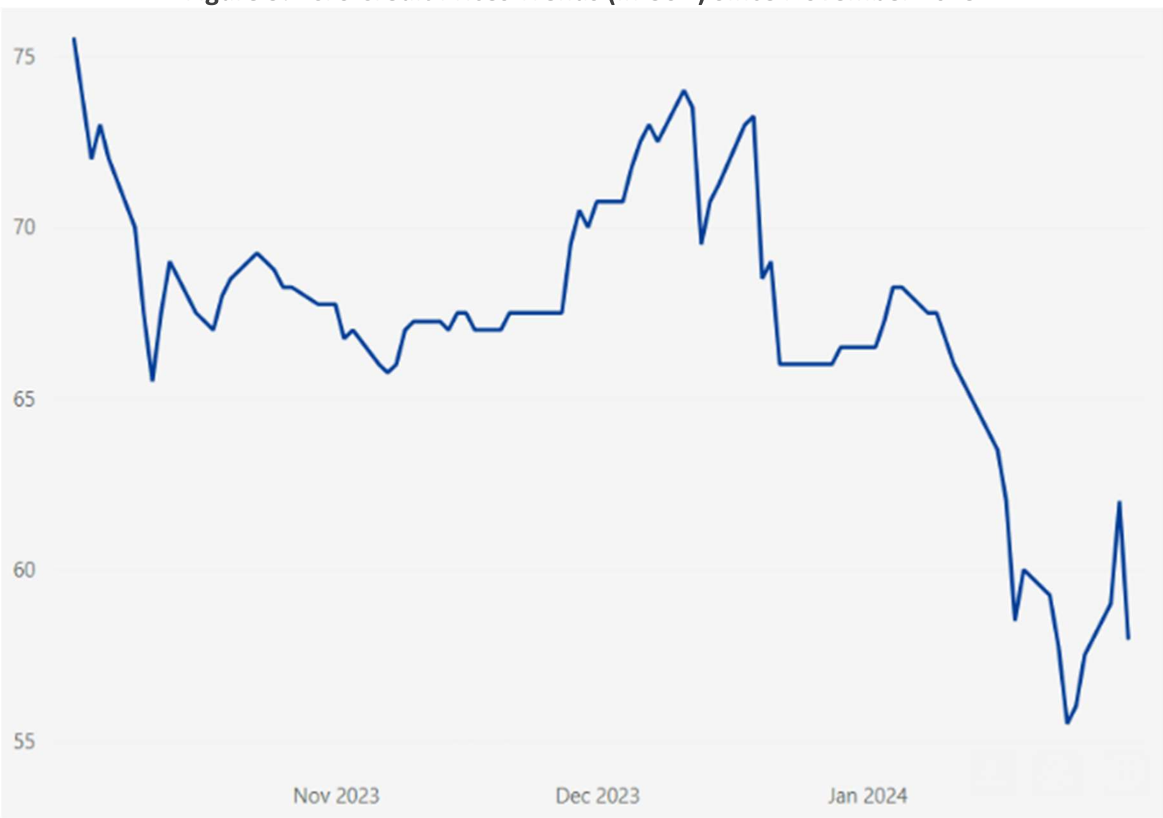
Figure 4: Price Trends of US Crude, Gasoline, Ethanol and California LCFS Credits



The LCFS Continues to Drive Economic Growth in California

One of the major successes of the California LCFS program is the billions of dollars invested in the state to meet the renewable fuels demand created by the LCFS program. Per Bloomberg, renewable energy is the fastest growing business in the state, and has greatly contributed to the GDP growth in California[7]. It in fact helped California surpass Germany as the 4th largest economy in the world. The LCFS is not only advancing the state's climate goals, it is generating economic growth, job creation and tax revenue growth that is helping drive the California economy. As seen in Figure 5 below, LCFS credit prices continue to tumble since the proposed LCFS regulation was published in December 2023, signaling that the market likely believes that CARB can be more aggressive in this rulemaking. This further makes the case for CARB to take aggressive action by updating the LCFS incentives for renewable fuels so that California remains the center of renewable fuels investments in the nation.

Figure 5: LCFS Credit Prices Trends (in USD) Since November 2023



Per the 2022 Scoping Plan, the "LCFS is a key driver of market development for renewable diesel and its coproducts. While the federal renewable fuel standard (RFS) and blenders tax credit also benefit producers, an analysis of their respective contributions to market development, and interviews with industry representatives and independent experts, point to LCFS as a more important factor in market development, at least in recent years" (see page 38 of the 2022 Scoping Plan)[8]. The ISOR for this rulemaking similarly states on page 7 that, "Private investments, policy signals such as a more stringent LCFS, and federal incentives will all need to be leveraged to realize the outcomes in the 2022 Scoping Plan Update". On Page 53 the ISOR states "Cumulatively, from 2024 through 2046, the proposed amendments are estimated to increase total revenue for credit generating businesses as compared to the baseline scenario by **$149**

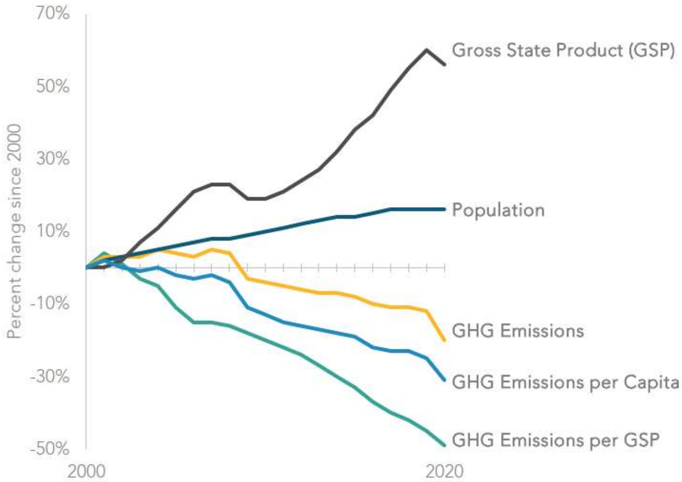
[7] https://www.bloomberg.com/opinion/articles/2022-10-24/california-poised-to-overtake-germany-as-world-s-no-4-economy

[8] https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

billion, of which approximately $128 billion is estimated to accrue to California businesses." In other words, the LCFS rulemaking is expected to drive significant value to California business.

Figure 1-1 in the 2022 Scoping Plan shows that California has been able to reduce its carbon footprint while having strong GDP growth (see below). This is largely due to the success of the LCFS program. In fact, per the US Bureau of Economic Activity (BEA), California has had stronger GDP growth than neighboring states with no LCFS programs.[9]

Figure 1-1: California total and per capita GHG emissions[25]



The California LCFS Program Has Delivered Significant GHG and Criteria Emissions Reductions:

CARB should clearly state its commitment to the LCFS program given the significant GHG emissions reductions it has delivered thus far. It has been highly successful in driving emissions reductions in the transportation sector thus far. Below is an overview of some of the successes of the LCFS program through 3rd quarter 2023[10].

- ***145.8 million tons of CO_2***, the equivalent of removing carbon emissions from 14% of gasoline vehicles in the US in 2022[11]
- Displaced the equivalent of ***29.4 billion gallons*** of conventional gasoline, diesel and jet fuels since its inception in 2011. This is the equivalent of 21% of total annual US gasoline consumption as of 2022[12].
- Renewable diesel capacity has grown substantially and far exceeds what was previously modeled in 2018 when the current CI benchmarks were established (page 22 of the ISOR)

In addition to delivering GHG emissions reductions, the LCFS has also been instrumental in driving reductions in criteria pollutants from vehicles across the state, including in disadvantaged communities that are disproportionately impacted by air emissions from the transportation sector. As part of this LCFS rulemaking, CARB estimated that the LCFS would reduce annual emissions as shown below in Table 1, and that toxic air contaminant (TAC) emissions would similarly go down.

[9] https://www.bea.gov/data/gdp/gdp-state
[10] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries
[11]https://www.eia.gov/tools/faqs/faq.php?id=307&t=10#:~:text=EIA%20estimates%20that%20in%202022,1%2C488%20MMmt%20of%20CO2
[12] https://www.eia.gov/tools/faqs/faq.php?id=23&t=10

Table 1: Emissions Reductions Expected from this LCFS Rulemaking from 2024 through 2046[13]

Pollutant	Reduction
GHGs	558 million MT
PM2.5	4,281 tons
NOx	25,586 tons

Per page 8 of the ISOR for this rulemaking, "The LCFS also supports other existing State GHG reduction efforts; notably, the Short-Lived Climate Pollutant (SLCP) Reduction Strategy, Advanced Clean Cars II (ACC II) regulations, Advanced Clean Fleets (ACF) regulation, Clean Truck Partnership, Advanced Clean Trucks (ACT) regulation, 2020 Mobile Source Strategy, Sustainable Freight Action Plan (SFAP), Commercial Harbor Craft (CHC) regulation, In-Use Locomotive regulation, Innovative Clean Transit (ICT) regulation, and Renewable Portfolio Standard (RPS)." In other words, all of these regulations depend on the LCFS regulation to drive further emissions reductions in each of these emissions sources, thus making the LCFS the cornerstone of emissions reductions in the state of California.

Renewable Diesel Has Delivered Significant Emissions Reductions:

Renewable diesel is now the single ***largest carbon reducer*** over the life of the LCFS program, and has resulted in **31%** of the GHG reductions achieved by the LCFS program[14]. Combined with newer heavy duty diesel engine technologies delivering near-zero NOx and PM emissions, studies have shown that increased use of renewable diesel and biodiesel can achieve three times the GHG reductions possible in the next 10 years versus accelerated electrification[15]. If liquid renewable fuels were further incentivized by the LCFS, California would see dramatic decreases in GHG, criteria and toxic pollutant emissions more quickly because liquid renewable fuels are widely available TODAY.

In addition to generating lower GHG emissions, renewable diesel burns much cleaner than conventional diesel. This leads to improvements in the air quality of regions with high diesel truck traffic, which tends to impact disadvantaged communities. Below are some examples of renewable diesel's co-benefits documented by CARB. In other words, renewable diesel use has resulted in significant NOx and PM reductions across the state, including in disadvantaged communities, and by far the largest reductions among all fuels in the LCFS program. This further highlights the need for CARB to continue making the LCFS a top priority and to prioritize currently available technologies such as renewable diesel so that local communities can benefit from reduced emissions immediately.

- As part of the Alternative Diesel Fuels (ADF) Regulation, CARB determined that renewable diesel reduced **NOx by 10%** relative to conventional diesel[16]
    - CARB also found that PM, benzene, ethyl benzene, and toluene emissions from renewable diesel were significantly lower than from conventional diesel combustion.
- As part of the Commercial Harbor Craft Regulation, CARB determined that renewable diesel reduced **NOx by 11.8%** and **PM by 26.6%** when compared to conventional diesel[17]

[13] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf (pages 56 and 58)
[14] https://ww2.arb.ca.gov/sites/default/files/2023-01/quarterlysummary_013123.xlsx
[15] https://dieselforum.org/news-posts/posts/10-years-of-opportunity-cutting-emissions-from-medium-and-heavy-duty-vehicles-in-the-northeast
[16] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2015/adf2015/adf15isor.pdf
[17] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2021/chc2021/appe.pdf

  - CARB noted that the cleaner combustion of renewable diesel is driven by the superior cetane rating (consistently above 70) which leads to maintenance benefits for truck owners
- Renewable diesel does not contain sulfur, eliminating all SOx emissions

Table 2 below summarizes the significant GHG and criteria emissions reductions achieved when switching from conventional diesel to renewable diesel.

Table 2: Renewable Diesel Emissions Reductions When Compared to Conventional Diesel

Pollutant	% Reduction
GHGs	80%
PM	26.6%
NOx	10-11.8%
SOx	100%

Considering that California diesel trucks now run on 54% renewable diesel as of 3rd quarter 2023[18], a large percentage of the emissions reductions shown in Table 2 are being realized today. Additional emissions reductions are possible if CARB further prioritizes the use of renewable diesel by going beyond the 30% CI reduction as noted in the ISOR. Local communities are benefiting TODAY from significant emissions reductions due to the cleaner burning fuels incentivized by the LCFS program, and CARB should work towards maximizing these emissions reductions generated by renewable fuels.

Renewable Diesel Driving Economic, Climate and Air Quality Benefits Locally TODAY

As noted above, RD has delivered significant economic and environmental benefits across the state. It is also important to note that Neste's focus on circular solutions - where waste and residue can be collected, processed and repurposed for energy – works on a community level. Through our acquisition of Mahoney Mahoney Environmental®, Neste has helped foodservice establishments turn used cooking oil (UCO) and other waste products into useful products like renewable fuels. Mahoney manages the entire recycling process — from equipment set-up to collection and processing. Mahoney shares the benefit of the UCO and passes that added value onto restaurant operators.

Mahoney is a licensed EPA recycler, and all facilities recycle nearly 100% of the materials processed. Mahoney's goal is to be the premier back-of-the-house service provider to foodservice operators — from national and regional chains to independent restaurants to airports – throughout the United States.

Mahoney services about 80,000 foodservice facilities nationwide, and about 13,400 in California. In California, Mahoney collects about 66,980,000 pounds of UCO and recycles it. The environmental impact from recycling the UCO collected in California is equivalent to:

- 73,452 Tons of Waste Diverted from a Landfills and/or waterways
- 11,300,328 Trees Planted
- 12,830 Cars Made Zero Emission

Mahoney is proud to employ over **100 employees** in California and that makes an economic impact with job creation across the state. Mahoney also does business with hundreds of restaurants, including small

[18] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

and minority owned businesses. The goal is to make kitchens and the environment safer for future generations.

As part of our circular approach to fueling, Neste has partnered with the City of Oakland to collect used cooking oil locally and convert it into renewable diesel for use in the city's fleet. By making waste more valuable and supporting jobs that collect and treat it, this concept helps the local economy in the city while the cleaner-burning Neste MY Renewable Diesel improves the lives of its residents by reducing local emissions from the city's fleet.

By simply switching to Neste MY Renewable Diesel, the city of Oakland's fleet has been able to reduce the following emissions when compared to fossil diesel:

- GHG emissions by 74 percent
- Fine particulates by 33 percent
- Carbon monoxide emissions by 24 percent
- Nitrogen oxide emissions by 9 percent

This concept creates a win-win-win for the city, its businesses and its residents. It helps the local economy in and around Oakland, improves air quality in the city, and, of course, ensures that used cooking oil does not end up as waste. Neste hopes that CARB continues to incentivize these circular solutions that are having real impacts in local communities TODAY.

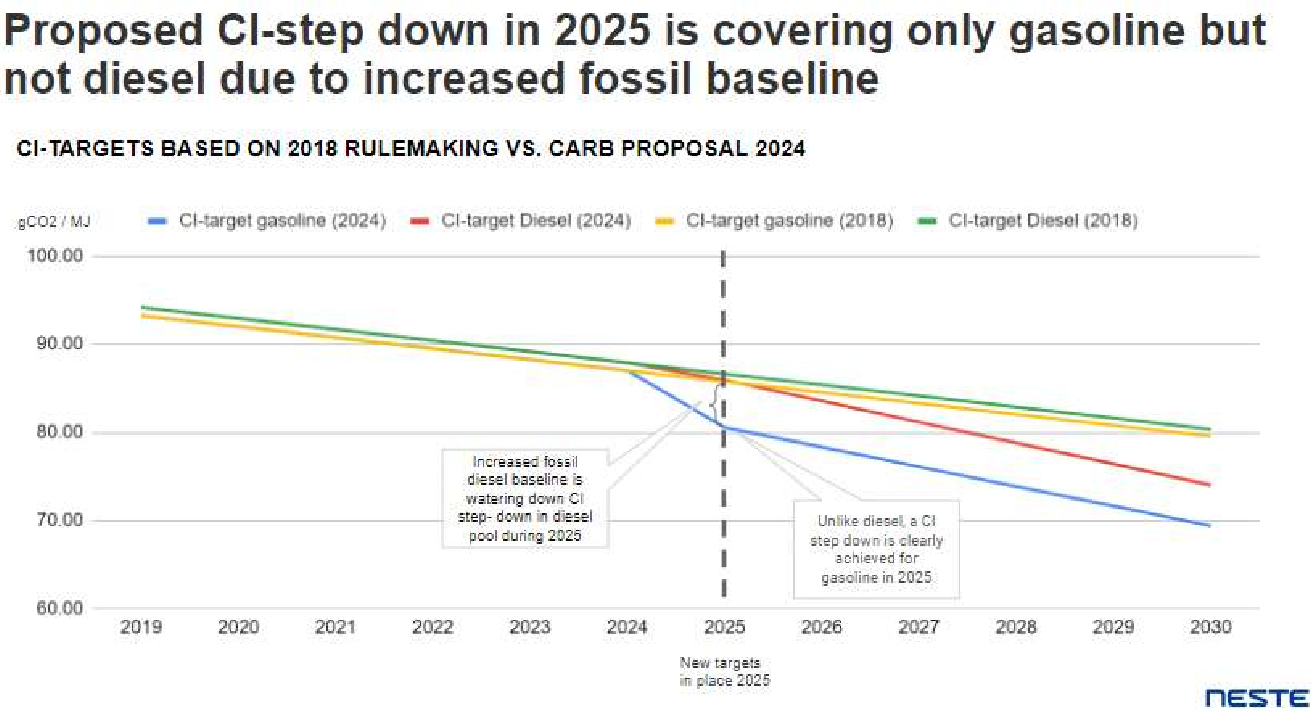
Overview of the Comments on the Proposed LCFS Regulation

Step Down CI Reduction Is Needed Immediately to Stabilize the LCFS Carbon Market:

295.2 reference

Neste sees an immediate step down in the CI as integral to quickly addressing the overperformance of the LCFS program and the depressed credit prices. This could also provide visibility to the industry that could bolster investments in future alternative energy projects. Overperformance is a lost opportunity for GHG reductions, and the longer the market overperforms, the longer California passes up significant reductions in GHGs and harmful air pollutant emissions. Neste supports a CI step down in the range of 12% for 2025 as modeled by ICF in the "ISOR Case", versus the 5% proposed by CARB. ICF found that a CI reduction of 25% in 2025 is needed to "ensure that the credit bank reverses and that the bank is drawn down to a level that is in line with a credit bank of only two quarters' worth of deficits". As part of this rulemaking, CARB also updated the fossil diesel baseline from 100.45 gCO_2/MJ to 105.76 gCO_2/MJ, a 5% CI increase that essentially canceled out the 5% CI step down that CARB proposed for diesel. Neste plotted the CI reduction targets proposed by CARB in Tables 1 and 2 of the Proposed LCFS Regulation in Figure 6 below, showing that the CI step down is nonexistent for diesel. To truly balance the LCFS credit market, **a 12% CI step down must be made in 2025**. This step down is needed before the AAM can be effectively implemented, otherwise the AAM could be triggered excessively and overperformance will persist.

Figure 6: Fossil Diesel Baseline Increase Effect on CARB Diesel Annual CI Reduction Targets



Automatic Acceleration Mechanism (AAM) Should Start in 2026 (using 2025 data):

In the current environment, where the credit price is at 2015 lows and the credit bank is at a record 20.6 million credits[19], it is important that adjustments to the CI reduction targets are made through a
295.3 predictable process and send credible, long-term signals to the market. Neste therefore appreciates that
reference CARB is proposing an AAM that will move up the CI standard by one year (and subsequent years) when triggered, resulting in a predictable impact on the longer-term fuel market.

Given the significant credit bank and the expected record growth in renewable energy consumption in California, Neste recommends that the AAM first be activated in **2026** (using 2025 data) and not wait until 2027. It is essential that CARB have this mechanism in place should overperformance persist, and to balance out the credit market more quickly so that renewable fuel producers can feel more confident investing in new production.

Neste also supports ICF's recommendation that the AAM triggers be reevaluated to ensure a smoother reduction of the credit bank. By lowering the "Credit Bank to Average Quarterly Deficit Ratio" AAM trigger from 3 to 2.5, CARB can provide an even more predictable credit market.

19 https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/dashboard/quarterlysummary/Q3%202023%20Data%20Summary_013124.pdf

Feedstock Sustainability Certifications Are More Effective at Phasing Out Fossil Fuels

A Cap on Lipid Feedstocks Only Favors Fossil Fuels

295.4 reference

Neste supports the sustainability requirements proposed by CARB in this rulemaking, and is strongly opposed to any caps on feedstocks used to produce liquid renewable fuels. Calls for caps on feedstocks as a means to balance the LCFS credit market are in reality calls to pause emissions reductions, and fossil fuels would be further used over renewable energy. Neste agrees with CARB that more aggressive emissions reductions will more quickly balance out the credit market and not pauses on emissions reductions. Arbitrary caps will likely lead to increases in GHG and criteria pollutant emissions, and will undermine California's ability to address difficult to decarbonize sectors such as the aviation and maritime sectors. Neste agrees with CARB that a cap on feedstocks will have the following negative impacts on California's most vulnerable residents:

- Increased dependence on fossil fuels (pg 102 of SRIA)
- Exacerbates existing air quality challenges due to higher NOx and PM (pg 102 of SRIA and pgs 118 and 124 of the ISOR)
- Will lead to worst health outcome among all scenarios modeled by CARB (pg 124 of ISOR)

Neste agrees with CARB that, "The inclusion of land use change emissions in LCFS life cycle methodologies result in stronger incentives for waste-and-residue-based feedstocks, which are not associated with land use change impacts, relative to crops. As a result, the majority of biomass-based diesel in the LCFS has historically come from waste feedstocks like used cooking oil, animal fat and inedible distiller's corn oil" as stated on page 35 of the ISOR. Waste and residues continue to be the dominant feedstock used to produce California's liquid renewable energy, and create a true circular solution while eliminating a major environmental hazard. In fact, per the World Economic Forum "Clean Skies for Tomorrow" report prepared by McKinsey and Co[20], waste and residue volume worldwide is estimated to be 40 MT/yr (see Figure 11 on page 27) a figure that is 10 times larger than what CARB estimates in its modeling. As noted on page 116 of the ISOR, a cap on lipid feedstocks will "result in higher volumes of fossil diesel being used than any of the other scenarios evaluated" and resulting in "credit prices immediately reaching the maximum credit price in 2025 and remaining at the maximum levels for every year analyzed." A cap only favors fossil fuels and undermines CARB's goal to be carbon neutral by 2045, and therefore should be rejected.

There is simply no data supporting the need for a cap on crop-based feedstocks. The Advanced Biofuels Association (ABFA) conducted a study that concluded, "To 2030, feedstock supplies available for use in the U.S. are more than enough to meet our forecast demand—after accounting for food[21]." In fact, data is showing that meat prices are dropping due to the production of renewable energy because more animal feed is being produced[22]. As part of the July 7th LCFS Workshop, CARB received compelling data showing that the Indirect Land Use Change (ILUC) factors are helping prevent deforestation and other land use issues. The ILUC factors also reduce credit generation from diesel produced from these feedstocks, something proponents of a cap are seeking. Neste therefore strongly opposes a cap, and strongly recommends that vegetable oils derived from newer crops and farming technologies should be accounted for in the LCFS. There is no data showing that crop-based feedstocks are affecting food prices, availability and overall land use.

[20] https://www3.weforum.org/docs/WEF_Clean_Skies_Tomorrow_SAF_Analytics_2020.pdf

[21] http://advancebioprod.wpengine.com/wp-content/uploads/2021/12/LMC-Lipid-Feedstocks-Outlook-SUMMARY-SLIDES-Nov-2021.pdf

[22] https://www.bloomberg.com/news/articles/2024-01-28/why-us-chicken-pork-prices-will-fall-when-soy-based-renewable-diesel-ramps-up

Highlight of Comments submitted to CARB as part of July 7th, 2022 LCFS Workshop:

- Technology advancements have resulted in significant increases in production yields per acre and thus crop production is increasing while land use remains stable
  - A cap could actually eliminate investments in newer farming practices that could lead to even lower CI fuels
- Liquid biofuels have achieved about 75% of the GHG reductions since the inception of the LCFS program
- Liquid biofuels burn much cleaner and lead to immediate air quality benefits, especially to communities of color that are disproportionately affected by the air pollution of the transportation sector

A cap will likely also deter what could be one of the greatest environmentally positive changes to date in farming methodology. CARB has a great opportunity to acknowledge through incentives that not all farming is the same. Methodologies utilizing low to zero till, reduced fertilizer, cover cropping, and other climate smart agriculture (CSA) practices could change farming practices for the better to the point that it reshapes an industry to make the planet a healthier place for our children. Renewable fuel companies are also making major investments on future low-CI technologies such as green hydrogen, algae and Power to X. Renewable fuel producers often use existing feedstocks to produce newer generation biofuels, and concurrently phase out older generation feedstocks. This means announcements for new renewable energy are often tied to repurposing of existing feedstocks. By prematurely restricting the production of liquid renewable fuels today, CARB will delay essential GHG reductions, improvements in air quality in disadvantaged communities, and the production of next generation renewable fuels.

Recommendations for the Sustainability Requirements for Crop-Based and Forest-Based Feedstocks

Neste agrees that requiring additional sustainability requirements are more appropriate at addressing concerns with the growth of crop-based and forest-based feedstocks than arbitrary caps on feedstocks. Currently, all of Neste's feedstocks are subject to sustainability due diligence and we ensure sustainability of most of our renewable fuel production chain through certifications like ISCC EU, ISCC Plus, RedCERT2 and national verification schemes[23]. All of our Neste operated refineries also hold ISCC certificates. In the United States, our renewable fuel sustainability is approved by the Environmental Protection Agency (EPA). Neste also supports the comments submitted by the LCFS Coalition on CSA and the need to recognize CSA in the LCFS, and we look forward to working with CARB staff to establish detailed guidance on the sustainability requirements so that industry is clear on how they will apply.

Neste believes it is essential that approved certification systems be posted and available to the public within 3 months of submission of a complete application. The logistics of a certification will be very complex, and maximum amounts of time will be required to ensure feedstocks are certified by January 2028. Lastly, we recommend that CARB provide a 3 year grace period for certification systems that are revoked or suspended, to ensure that there is sufficient time to get certified under a new system.

Climate Smart Ag Recommendations

Instead of pursuing a cap on crop-based feedstocks that could hamper investment on CSA, CARB should instead incentivize these new technologies by recognizing that CSA can result in fuels with lower CI values.
295.5 Climate change is already happening, and CARB should start working on creating these science based ILUC factors and CA-GREET model that account for the lower emissions from CSA such as regenerative cultivation methods and cover crops to drive the development of the low CI fuels of tomorrow.

[23] https://www.neste.com/sustainability/supply-chain/raw-material-sourcing

Intrastate Jet Fuel Exemption:

295.6 In analyzing CARB's proposal to eliminate the exemption for intrastate jet fuel, in combination with other measures already discussed in these comments, it is likely to help bring stability to the credit market and help correct the current imbalance. Neste believes that the proposal will also drive continued growth in SAF demand and production, as well as potentially for other renewable fuels. We see such proposals as important to continue driving investments in the production of SAF, and enhancing its viability as an alternative to fossil jet fuel to provide significant GHG and air pollution reduction benefits. We agree with CARB that SAF is the only viable way to decarbonize emissions on a large scale from the hard-to-carbonize aviation sector. The current proposal allows for multiple options for obligated parties to comply. These options can be in addition to, in combination with, or even instead of using SAF.

Neste recognizes that the aviation sector has concerns with the proposal. Since this is the first proposal of its kind, we encourage CARB and all stakeholders to continue working to identify enhancements, additional options for implementation, or alternative approaches to advance the publicly stated emissions reductions goals of the aviation sector.

Low-CI Hydrogen Recommendations:

295.7 Neste appreciates CARB's proposing to create greater incentives for the production and use of low-CI hydrogen, especially as noted in Section 95488.8 (i)(3) "Book-and-Claim Accounting for Pipeline-Injected low-CI Hydrogen Used in FCV and Alternative Fuel Production." Neste recommends that all renewable facilities that use low-CI hydrogen be allowed to generate CI benefits from using low-CI hydrogen and not just facilities connected to a California hydrogen pipeline. Globally, Neste is investing millions in the development of low-CI hydrogen to produce even lower CI versions of drop-in fuels like renewable diesel and SAF.[24] We hope to eventually expand the use of low-CI hydrogen at all our facilities and have the option to bring those lower CI fuels to California. The California hydrogen pipeline requirement creates unnecessary barriers and should be deleted.

In Section 95488.8 (i)(3), Neste also recommends the elimination of the December 22, 2022 facility startup date for facilities to be eligible for the low-CI hydrogen CI benefits. As the lone renewable fuel company with a production footprint on 3 continents, allowing low-CI hydrogen from any of our facilities could help increase supply of lower CI fuels to California.

General Recommendations:

Neste also has the following general comments that apply to more administrative requirements in the LCFS regulation:

295.8
1. **Transition to CA-GREET 4.0:** Given that the LCFS rulemaking is delayed, a 2024 start date for using CA-GREET 4.0 will not be feasible. The start date for using it should be 2025 or later, and for credit transactions it should be required in 2027 or later to give all stakeholders enough time to apply for new CARB fuel pathways. This should be reflected throughout the Proposed Regulation as it appears that a 2024 startup date was assumed.

295.9
2. **Temporary Fuel Pathways:** Per Section 95488.9(b), the Temporary Pathways are increasing by an average of 5 gCO2e/MJ for all fuels. Neste could not confirm the exact reason for this, and recommends that CARB provide the data and calculations associated with these significant CI increases.

[24] https://www.neste.com/news/neste-moves-forward-in-its-renewable-hydrogen-project-in-porvoo-finland

295.10 3. **Incentives to Be Below Certified CI:** In Section 95488.10, lists that CARB is willing to issue credits for those pathway holders with a verified CI that is below the certified CI. To further incentivize CI reductions, CARB should also have a multiplier when below the certified CI just as imposed when the verified CI is above the certified CI. This will incentivize investments in emissions reductions more quickly.

295.11 4. **Low-CI Hydrogen:** CARB is introducing the concept of Low-CI hydrogen throughout the Proposed Regulation. We recommend clarification on how this is different from Renewable Hydrogen. If different, Neste requests a definition for Low-CI Hydrogen be added into the Proposed Regulation.

295.12 5. **Clarify Section 95488.8(i)(1):** Low-CI/renewable hydrogen can be used to produce liquid renewable fuels such as renewable diesel. Can CARB please clarify that 95488.8(i)(1) also applies to low-CI electricity used to produce hydrogen that is then used to produce liquid renewable fuels. It is Neste's understanding that this is CARB's intention, but Section 95488.8(i)(1) should be modified to state "or Used to Produce Hydrogen as a transportation fuel or for alternative fuel production."

295.13 6. **The Tier 1 Calculator for HEFA:** The "Pathway Summary '' tab has automatic column and row hiding that is difficult to manage and Neste requests that it be removed.

295.14 7. **Ocean Going Vessels (OGVs):** Facing increasing CI reduction targets proposed by the International Maritime Organization (IMO), shipping companies are looking to renewable fuels as a way to reduce their emissions. CARB should consider including fuel used in those ocean going vessels within the LCFS to support and accelerate the decarbonization of large container ships, tankers, and other OGVs.

295.15 8. **Severability:** Given the significant number of updates that will occur as part of this rulemaking, Neste recommends that CARB make the following updates to the Severability language in Section 95497.

§ 95497. Severability.

Each provision of this subarticle shall be deemed severable, and in the event that any provision, or part thereof, in this subarticle is held to be invalid~~,~~ or temporarily unenforceable, the remainder of this subarticle shall continue in effect.

Neste looks forward to continued participation in the LCFS rulemaking, and leading in the fight against climate change.

Please feel free to contact me if you want additional information or have questions regarding our submission.

We appreciate your consideration.

Oscar G

Oscar Garcia

West Coast Regulatory Affairs Manager
Neste US, Inc.

Comment Log Display

Here is the comment you selected to display.

Comment 305 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Megan
Last Name	Mekelburg
Email Address	megan@caleec.com
Affiliation	Electric Vehicle Charging Association
Subject	EVCA Comments on LCFS - Multifamily Credits
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6975-lcfs2024-UTRXJ1U3ADIFLgZp.pdf
Original File Name	EVCA-only letter LCFS .pdf
Date and Time Comment Was Submitted	2024-02-20 16:39:24

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

ELECTRIC VEHICLE CHARGING ASSOCIATION

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: SUPPORT Proposed Amendments to the Low Carbon Fuel Standard Regulation

EVCA is a not-for-profit trade organization of 22 leading EV charging industry member companies and two zero-emission autonomous fleet operators. The association was established in 2015 to comprehensively represent the entire EV charging value chain and provide a collective industry voice for decision-makers in California.

The Low Carbon Fuel Standard (LCFS) has been instrumental in supporting California's transition to low-carbon fuels, and we applaud the effort by the California Air Resources Board (CARB) to make modifications to the regulation to adapt to the changing needs of the market. While EVCA is broadly supportive of the proposed modifications to LCFS and has separately submitted joint comments on various elements of the Proposed Regulation, this letter focuses on the issue of LCFS credits claimable by multi-family properties.

SUPPORT: LCFS credits for non-residential chargers at multi-family properties.

EVCA supports the amendment proposal to expand eligibility for LCFS credits to non-residential charging stations at multi-family residences. The ability to
296.1 claim credits will encourage multi-family properties to deploy chargers and create new financing opportunities that reduce the cost of charger deployment for property owners. This proposal presents a powerful new tool to offer the convenience of home charging for residents of multi-family housing and address the gap in charger access for these residents compared to Californians living in single-family homes.

RECOMMENDATION: Allow multi-family residences with dedicated parking arrangements to claim LCFS credits.

While EVCA is supportive of the proposal to expand eligibility for multi-family residences to claim LCFS credits, we find the proposal stops short because it is not inclusive of chargers serving dedicated parking spaces. Restricting credits based on parking arrangements would be challenging to track and implement. Further, multi-family residences with dedicated parking arrangements face the same underlying barriers to charger deployment as properties with unassigned parking. Expanding LCFS credit eligibility to all non-residential station owners will alleviate the following challenges across the segment:

- **Station ownership.** Charging equipment serving dedicated spaces is often purchased, installed, and maintained by the property owner or by a 3rd party owner-operator charging network, as a service for residents. Though chargers serving dedicated spaces may serve a single household, the responsibilities and costs of managing and maintaining these chargers ultimately falls to the property owner or 3rd party owner-operator charging network. When the station owner and the station user are not the same entity, LCFS credits should be allowed to be claimed by the station owner-operator, to defray the costs of such an investment in the multi-family context.
- **Shared infrastructure.** Residents of multi-family housing struggle to install their own dedicated chargers due to the shared nature of electrical infrastructure. It is often infeasible for a single dedicated space in a separated parking area to install a charger without significant construction and electrical work, which may include adding new electrical service, conduit, trenching, and upgrading a panel. Shared electric infrastructure, even when it serves dedicated charging spaces, raises costs beyond what a single resident may be willing to pay. This circumstance creates a need for a single entity - the property owner or 3rd party owner-operator charging network- to make the investment to own and operate stations on behalf of residents, justifying broader eligibility for LCFS.
- **Split decision-making authority.** Regardless of the parking arrangement, the shared nature of electric service upgrades for multifamily residences splits decision-making responsibilities across many stakeholders. Eligibility for LCFS would encourage investment in

stations on behalf of residents to circumvent these challenges; decision-making is simplified if costs are reduced and a single entity is willing to make an investment on behalf of the group.

EVCA believes CARB's intention is to empower more multi-family residences to invest in charger access for use by residents. To better support the goal, EVCA respectfully urges CARB to amend the Proposed Regulation to allow all non-residential chargers at multi-family residences to directly claim credits from the LCFS program, regardless of parking arrangement.

We appreciate the opportunity to submit comments on this matter. Thank you for your consideration.

Sincerely,

Reed Addis
Governmental Affairs
Electric Vehicle Charging Association

Comment Log Display

Here is the comment you selected to display.

Comment 306 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jan
Last Name	Warren
Email Address	jxwarren1947@yahoo.com
Affiliation	Interfaith Climate Action Network of Con
Subject	December 19, 2023 LCFS comments
Comment	Thanks for the opportunity to give additional comments on the dra Dec. 19, 2023 LCFS document. I've attached my letter. Please let me know if you have any troub receiving. the letter. Jan Warren jxwarren1947@yahoo.com
Attachment	www.arb.ca.gov/lists/com-attach/6976-lcfs2024-BmVcNVQ4V2IQMwdp.docx
Original File Name	COMMENTS ON LCSF PROPOSED DRAFTS FROM DECEMBER.docx
Date and Time Comment Was Submitted	2024-02-20 16:12:46

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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COMMENTS ON LCSF PROPOSED DRAFTS FROM DECEMBER 19, 2023 – February 20, 2024

To Whom it might concern,

297.1 I appreciate the auto acceleration to increase the CI stringency and support no Board approval for consecutive auto acceleration events unless they are further strengthened.

297.2 Electrification needs to be the focus. Regarding equity measures in impacted communities, the credits should first be directed to providing clean electric public buses and school buses, along with the necessary charging infrastructure. Impacted communities should have a say in where the equity dollars are spent.

297.3 There has been an explosion of logistic facilities (warehouses) especially in communities that already are impacted by pollution and often currently don't meet the Clean Air Standards. Please encourage our State legislators to pass moratoriums on these centers until some priority system is established for who gets the funding, i.e., trucks at ports.

297.4 There has been an explosion of increasing sizes of dairies into industry size numbers and negative community health impacts. We must move away more quickly from combustion period. There should be a cap on the number and location of dairies in relationship to where people live. There needs to be better measurement of leakage and methods moved away from a wet to a dry process for manure.

297.5 I'd like to have access to the amount of methane leaking from landfills in our communities. We have a closed landfill in our county that still leaks and receives violations and fines.

297.5a Just as we need to move away from corporate one-crop farming, we need to move away from consolidation of dairy cows just to make it more economical to purchase expensive bio-digestors to capture methane, which it looks like will be with us for a long time. First this report stated that biomethane will be used for injection into our natural gas pipeline system. Let's call it what it is – FOSSIL GAS. Then you want to use the FOSSIL GAS for hydrogen. With 80% of credits going to a combustion source in one way or the other, there is harm to health regardless of the name.

From past experience I've known real estate developers who buy land for a development and hold it for 20 years and then say the project can build using the old regulations. Look at CAL GEM. Petroleum/Energy companies take out permits on extraction projects and sit with the permits. Any time there is an announcement of no more permits as of (pick a date), the numbers of permits skyrockets.

297.6 This "Phase Out" of methane crediting needs a major rollback on the proposed deadlines and extensions. After all, ethanol was first introduced as an additive in automobiles in 1910, and it's still with us. The credits have lasted for years.

297.7 It's a good idea to discontinue the credits for forklifts and move those funds to something else that needs electrification.

297.8 I support verification requirements for electricity credits that all participants generating credits from EV go through annual independent verifications.

297.9 As originally proposed hydrogen still needs more pilot programs and strict safety requirements from federal and State laws. Hydrogen should be focused only on hard to decarb industries. The only hydrogen used should be "green" electrolytic, not blue, or some other way to reuse fossil fuels.

In the original LCFS bill the leg analysis states, “Create air monitoring and mitigation plan. Avoid any
297.10 significant impact on residents in communities affected by high-cumulative exposure burden.” This
applies to biodigesters. Refining biofuels, and hydrogen projects, et al.

Remember to calculate the use of energy needed to create the outcomes. Pipes leak whether above the ground, underground, or under water.

While I appreciate the stated no palm oil use for biofuels, guardrails and caps need to be put in place. I
297.11 have a cousin living in Iowa and I hear about the pushback from farmer’s pressured by imminent domain
to be bought out because of these credits for biofuels.

We need healthy soil and incentives in the Federal Farm Bill to protect smaller farmer and encourage
farmers to stay in business to feed America. Food prices have increased faster than incomes and many
297.12 people are only feeding their families with Food Banks, school meals, and SNAP programs.

There needs to be more awareness around the harm of viruses from birds and animals too closely habituated and fed grains.

297.13 I appreciate that CARB works with Natural Resources and Transportations and hope there is a holistic approach also with Water, since so many of these energy producing facilities negatively impact our water supplies.

297.14 I support the elimination exemption for Intrastate FF jet fuel.

I don’t support allowing hydrogen production facilities directly to the refineries to implement eligible
297.15 GHG reduction projects as it is written in the draft LCFS. We know that hydrogen is a secondary source
of energy. Most hydrogen today is by steam reforming natural gas (Methane, fossil gas). There are already enough dangers at our local refineries. I think there needs to be more specificity in the draft proposal. There has been excessive flaring at Chevron in Richmond since they installed the new hydrogen plant in 2012.

I have attended the last 4 CARB workshops on LCFS. I have listened to the public, EJAC. Presenters, and members of CARB Board and staff. I think the allocation of the different pieces used to meet the Statewide goals needs to be looked at. At the August 25 meeting I heard 380 more digesters were
297.16 needed to meet the LCFS goals. The current dairy digester method shouldn’t be increased when the
amount we already have is causing such harm in our communities.

297.17 We should honestly be looking to promote consuming less beef and dairy products. If not, we need to move incentives to smaller farms with natural land and diverse products. Less close habitation reduces viruses that wipe out large numbers of animals, similar to the chickens that had to be killed in large numbers recently. It reduces trucking products long distances.

Great strides are being made in insulating electrical wires with lighter material that do not weigh down
297.18 power lines and contribute to more fires, and allow more electrical transmissions on the same existing
lines and infrastructure. Just because LCFS as it was created 15 years ago does not mean it has to last until 2045. Let’s look at a clean air economy through holistic eyes. Who benefits and who is harmed from each of these programs.

Jan Warren at 3202 Primrose Lane, Walnut Creek, CA 94598 – 925.818.6530

Comment Log Display

Here is the comment you selected to display.

Comment 307 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Julio
Last Name	Friedmann
Email Address	jfriedmann@carbon-direct.com
Affiliation	Carbon Direct

Subject	Comment regarding DAC emissions matching requirements

Comment

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This comment focuses on the requirements for low-carbon heat and
power for CO2 removal using direct air capture and storage (DACS)

It includes discussions around reporting options, technical and
commercial readiness of some kinds or low-carbon energy, and the
need to consider methodologies for emissions avoided and removed.

These recommendations may provide precedent and guidance for other
low-carbon pathways involving significant electric and heat inputs
such as green hydrogen and e-fuels.
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Attachment	www.arb.ca.gov/lists/com-attach/6977-lcfs2024-AF9WM109AiNQNFIN.pdf
Original File Name	CARB_CDR-DAC-Emissionality_Comments-final_CarbonDirect-2024.pdf

Date and Time Comment Was Submitted	2024-02-20 16:39:26

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Carbon Direct

17 State Street
New York, NY 10004

February 20, 2024

To the California Air Resources Board and associated staff:

We support the CARB's direction to further progress direct air capture (DAC) as a technology option to abate the greenhouse gas emissions of California fuels under the Low Carbon Fuel Standard (LCFS). This flexibility as a compliance option may reduce compliance costs, stimulate innovation and investment in climate technology, and position California as a global leader in reaching economy-wide, net-zero emissions targets. We welcome the opportunity to add our perspective to CARB's ongoing development related to DAC.

298.1

Direct air capture with storage (DACS) is a critical carbon removal technology for a net-zero world. This is recognized and substantiated in a large number of studies and deep decarbonization roadmaps, such as the IPCC's Sixth Assessment Report, the recent Lawrence Livermore National Laboratory's "Roads to Removal" report, and the European Union's communication of their 2040 climate target as well as their proposed path to climate neutrality by 2050.

Because DAC is in its early stages of operational and scale-up development, it is essential for the technology to mature and be available at the anticipated scale for later, deeper decarbonization. *Learning, knowledge sharing, data collection, and reporting are the immediate necessary steps before sound commercial and environmental regulation can be made*. Real data from operational pilots and facilities are essential. This is, in part, a key outcome of the US Department of Energy's Direct Air Capture Hub program, which includes pilot and small demonstration projects in California. In this context, CARB's decisions may prove precedent-setting not only for DAC in the US, but for other critical reduction and removal technologies and associated regulatory policies around the globe.

Carbon Direct agrees with most scholars and experts in the field: to provide material removal of CO_2 from the air and oceans, DAC facilities must operate on a net basis,

17 State Street
New York, NY 10004

with high removal efficiencies, and with deduction of input energy emissions in their full product value chain. These must be substantiated by the use of low-carbon-intensity energy (heat and power) on a life-cycle basis. One proposed approach is “book and claim” power matching. This is where the annually averaged power used by DAC plants is matched with additional, location-based, renewable power. We are involved in ongoing discussions on the carbon credentials and impacts of these approaches, on both the power- and carbon-systems levels.

We would like to offer an addition or alternative to power matching as a way to substantiate carbon matching and integrity. Specifically, we hold that the current wish for “24/7” hourly matched power is not, at this time, technically nor commercially available at the quantity or quality needed for DAC matching loads. Additionally, quarterly power matching can be severely constrained or unavailable with the seasonal and episodic limits of variable renewable power (i.e., wind and solar, with or without batteries).

- To achieve true atmospheric neutrality, overall carbon neutrality of heat and power supply is a critical quality specification for DAC projects. However, time-matching of low-carbon generation and power demand (e.g. hourly power matching) is not the only way to demonstrate this and in some cases it may not be sufficient. Another approach is true carbon reduction accounting or "emissionality." This is the quantified, avoided emissions from the electricity generated by the low-carbon power supply minus the induced emissions from the electricity consumed by the facility, based on the respective hourly marginal emissions. This methodology can be applied regardless of the source of low-carbon electricity (nuclear, renewable, biopower, geothermal).
- The use of emissionality reporting[1] may provide the necessary confidence to market participants surrounding the carbon matching of electricity supply. Carbon matching of electricity could be used for DAC and other power-intensive projects, like green hydrogen production. This would provide time-shifted carbon matching which may be separate from hourly power matching.[2] Time-shifted matching can be location-based, with a wider or more narrow temporal and geographic definition. True carbon neutrality can be met with annual power averaging if the carbon avoided matches the carbon

[1] See the Resurety white paper, WattTime insight brief, and the report on UtilityDive for more information on emissonality.
[2] Though emissionality does not directly contribute to the development of firm, dispatchable, low-carbon power, it can catalyse their development as they can be included as “hourly” low-carbon power supplies, and with increasing renewables the amount of avoided emissions will decrease.

induced, and this is substantiated and quantified. Quarterly power matching would not improve emissions integrity further.

- *DAC facility operators could provide emissionality reporting to CARB through a transparent mechanism* (e.g., an annual book and claim methodology). Because emissionality is a maturing methodology, it would not be appropriate to include annual carbon matching as a requirement for DAC facilities until emissionality techniques are mature and this information is widely available. The lack of access to reliable, marginal emissions information for specific DAC plant technologies and low-carbon power generator locations remains a concern, and mandatory annual reporting would help.

Carbon Direct fully supports the development of firm, dispatchable, low-carbon power and power storage on the pathway toward a genuine 24/7, year-round, low-carbon power supply at capacity. Emissionality can be a "bridge" approach to catalyzing development and, as grids decarbonize further, may deliver more avoided emissions.

Thank you for the opportunity to provide feedback and your consideration.

Carbon Direct Inc. (Carbon Direct), helps organizations go from climate goal to climate action. Carbon Direct is a science-first organization that combines technology with deep expertise in climate science, data, and policy. We deliver actionable climate strategies and high-quality carbon dioxide removal (CDR) to decarbonize the global economy.

Carbon Direct has built a reputation as a trusted arbiter of high-quality strategy for carbon reduction, removal, and utilization throughout value chains, working with leading organizations. Our team of over 40 scientists includes thought leaders who actively contribute to the science of climate mitigation with novel assessment methodologies, providing public resources to facilitate action. Carbon Direct has applied its expertise to the completion of:

- Over 600 engineered, hybrid, and nature-based carbon credit project assessments, deep diligences for multi-year off-take agreements, and project co-design engagements;
- Over 150 unique emerging technology diligence reviews; and
- Deep technical diligence and de-risking engagements in improved forest management, reforestation, BECCS, and DAC, with commercial strategy support in collaboration with carbon credit developers to ensure that their products are best-in-class.

Comment Log Display

Here is the comment you selected to display.

Comment 308 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Kevin
Last Name	Welsh
Email Address	kwelsh@airlines.org
Affiliation	Airlines for America
Subject	Airlines for America Input on the 2024 Proposed Low Carbon Fuel Standard Amendments
Comment	Airlines for America (A4A), the principal trade and service organization of the U.S. airline industry, appreciates the opportunity to provide comments to the California Air Resources Board (CARB) on the Proposed Low Carbon Fuel Standard (LCFS) Amendments. Our comments are provided in the attached document.
Attachment	www.arb.ca.gov/lists/com-attach/6978-lcfs2024-VTQFNwdnU18Kb1U6.pdf
Original File Name	A4A Comments on Proposed LCFS Program Changes-2024-Final 02-20-2024.pdf
Date and Time Comment Was Submitted	2024-02-20 16:39:26

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Airlines for America®
We Connect the World

February 20, 2024

Submitted electronically at:
https://ww2.arb.ca.gov/lispub/comm/bclist.php

Clerks' Office
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: Airlines for America® Input on the 2024 Proposed Low Carbon Fuel Standard Amendments

Dear Chair Randolph:

I. Introduction

Airlines for America® (A4A), the principal trade and service organization of the U.S. airline industry,[1] appreciates the opportunity to provide comments to the California Air Resources Board (CARB) on the Proposed Low Carbon Fuel Standard (LCFS) Amendments.[2]

The U.S. airline industry is committed to reducing its climate impact and achieving net zero carbon emissions by 2050. Transitioning to Sustainable Aviation Fuels (SAF), also referred to as Alternative Jet Fuel (AJF) by CARB, is core to this commitment, and we have pledged to work with governments and other stakeholders to make three billion gallons of SAF available in the United States by 2030. Achieving these goals requires new and additional policy incentives, streamlined permitting processes, and close collaboration among airlines, the fuels industry, manufacturers, environmental organizations and governments, among others.

With respect to SAF, California has established itself as an early leader in attracting investment, production, and use of SAF through the existing Low Carbon Fuels Standard (LCFS) Program, which provides an opt-in credit for SAF that helps reduce the price difference between SAF and conventional jet fuel. We look forward to working with CARB on measures that will rapidly expand availability and deployment of SAF in California.

Aviation accounts for 2.6% of the U.S. greenhouse gas emissions but 5% of U.S. Gross Domestic Product (GDP) and 4.1% of California's GDP, thus having an outsized economic impact relative to its share of emissions. There are more than 380,000 employees of U.S.

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[1] A4A's members are: Alaska Airlines, Inc.; American Airlines Group Inc.; Atlas Air, Inc.; Delta Air Lines, Inc.; Federal Express Corporation; Hawaiian Airlines, Inc.; JetBlue Airways Corp.; Southwest Airlines Co.; United Airlines Holdings, Inc.; and United Parcel Service Co. Air Canada, Inc. is an associate member.

[2] These comments supplement and incorporate A4A's comments on the LCFS submitted on January 7, 2022, August 8, 2022, and March 15, 2023, as well as the comments previously submitted during the 2018 LCFS referenced in footnote 10 *infra*.

commercial aviation firms based in California, with an overall economic impact of $194 billion[3]. Aviation is critical to driving California's economy and its rank as the fifth largest economy in the world, enabling $114 billion in annual trade flows and underpinning many of the rest of California's biggest economic drivers such as agriculture, tourism, manufacturing, banking, technology and small business. Ensuring a healthy and vibrant aviation industry is essential to California's future, and leveraging CARB's early leadership on SAF can enable California leadership in the emerging SAF production industry, creating new jobs and economic development opportunities.

299.1 With this context, we express our serious concern with the proposal by CARB to regulate jet fuel used for flights within California as an obligated fuel under the LCFS Program. This proposal to obligate jet fuel would be unlikely to result in increased SAF production, availability, or use in California, but would lead to higher jet fuel prices and slow down rather than accelerate efforts to increase SAF production and use in California. The primary impediment to increased SAF production and availability in California and elsewhere remains the higher cost of SAF for producers and buyers relative to conventional jet fuel and renewable diesel. In addition, the long permitting processes for constructing SAF production facilities is a major impediment to growing overall production capacity in California, a necessary step to achieve California's goals. 299.2 The CARB proposal would not address these fundamental challenges or otherwise meaningfully increase SAF supply or use. And because the proposal will not meaningfully increase SAF supply, the local air quality benefits attributed to increased SAF use as a result of eliminating the intrastate jet fuel exemption are overstated.

299.3 In addition to not being an effective policy tool to increase SAF production, the CARB proposal to regulate jet fuel is pre-empted by federal law, a fact that CARB recognized when it exempted jet fuel from the LCFS in 2018.[4] It is critically important that uniform federal rules apply to aviation and aviation fuels, under the Supremacy Clause of the U.S. Constitution. The CARB proposal seeks to regulate jet fuel and reduce emissions from aviation through such regulation, both of which are pre-empted under federal law, as described in further detail below. In light of the clear and broad federal authority for regulating jet fuel and aircraft engine emissions, California is pre-empted from regulating jet fuel under the LCFS.

299.4 We urge CARB to reconsider and withdraw the proposal to remove the exemption for jet fuel for intrastate flights and instead preserve the existing opt-in approach for SAF and partner with the aviation sector and stakeholders across the emerging SAF ecosystem on new policies and approaches to address the underlying challenges which could rapidly increase the availability and use of SAF in California. We encourage further dialog on this point to find a mutually acceptable path forward.

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[3] The Economic Impact of Civil Aviation on the U.S. Economy, State Supplement, US Department of Transportation, November 2020

[4] CARB stated that "[s]ubjecting aircraft fuels to annual carbon intensity standards would raise federal preemption issues" available at https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/isor.pdf?_ga=2.259407882.120243749 0.1641231788-253234234.1573227006

II. Discussion

1. The proposal to remove the exemption for conventional jet fuel is unlikely to lead to increased SAF production, availability, or use

299.1 reference

The proposal to remove the exemption for conventional jet fuel for flights within California is unlikely to result in increased SAF production, availability, or use in California, but is likely lead to higher jet fuel prices. Given the higher cost of SAF compared to other regulated fuels, such as renewable diesel, producers and importers are most likely to buy credits generated from other fuels, rather than produce SAF to address the deficits generated by conventional fuels used on flights within California. Fuel producers will continue to prioritize renewable diesel production instead of SAF. As a result, the removal of the exemption for conventional jet fuel is unlikely to materially change the SAF production relative to the status quo. In fact, the deficits created by intrastate jet fuel likely will be retired primarily by renewable diesel and other road transport related credits. Obligating jet fuel will lead to the increased price of jet fuel, diverting resources that might have gone for SAF purchase and use towards renewable diesel production instead.

The relationship between deficit generation and credit generation is unchanged by the CARB proposal. Under the structure of the LCFS program, deficits are created for fuel producers from specific conventional fuels delivered into California as identified and defined by the program. These deficits form a common pool that can be retired with credits from any type of eligible fuel. But there is no requirement for a relationship between the type of fuel that created the deficit and the type of credit that retires that deficit. To illustrate this situation, one must only look at which fuels generate deficits in the current program, and which alternative fuels receive the credit benefits. In the current program, CARBOB (gasoline) generates 85% of the deficits, but gasoline alternatives (i.e. ethanol and EV related credits) receive only 40% of the credits. Diesel, on the other hand, generates only 14% of the deficits, but receives 44% of the credits.

Share of LCFS Program deficits and credits by fuel type for 2022 calendar year[5]

	CARBOB (Gasoline)	Diesel	Jet
Share of Total Deficits by Source	85%	14%	0%
Share of Credits by Fuel Alternative	40% (24% Electric, 16% ethanol)	44% (36% Renewable Diesel, 8% Biodiesel)	<1% (Alternative Jet Fuel)

Very few (<1%) AJF credits are generated because of the relatively higher cost of AJF compared to renewable diesel, not because of the absence of conventional jet fuel deficits. The relative cost of the fuels that can generate credits will be unchanged by the CARB proposal and therefore the relative supply and demand for renewable diesel and AJF credits is also unlikely to change. The LCFS proposal is likely to undermine the critical need to rapidly scale up

[5] A4A analysis of LCFS Program Quarterly Data Spreadsheet, available at https://ww2.arb.ca.gov/sites/default/files/2023-10/quarterlysummary_Q22023.xlsx

production and use of SAF in order to meet ambitious government and aviation sector climate goals, including California's own ambitions for aviation within the state.

Also, regarding implementation, the proposal identifies producers as the First Fuel Reporting Entity for jet fuel but does not provide any information for how Reporting Entities would determine the volume of jet fuel used for flights within California. Data on jet fuel usage for flights within California is not currently collected or readily available and reporting entities would not be able to accurately measure and report on jet fuel used for intrastate flights across all types of operators – commercial, business, and general aviation. CARB's proposal is therefore completely unworkable and cannot be complied with in its current form.

2. The air quality benefits attributed to the intrastate jet fuel obligation are inaccurate and overstated.

299.2 referenced

A4A and its members concur with CARB's assessment that SAF has the potential to provide local air quality (LAQ) benefits (compared to conventional jet fuel) near airports. Significant academic and industry research has been conducted, including full scale static engine tests and flight tests have demonstrated lower Sulphur Oxides (SOx) and Particulate Matter (PM) emissions from SAF compared to conventional fossil jet fuel. However, we disagree with CARB's analysis and presentation of future LAQ levels that implies reductions in jet fuel related LAQ emissions resulting from the proposed intrastate jet fuel obligation. In addition, we recommend CARB review its model for jet fuel LAQ emissions as it does not appear to reflect the current scientific consensus. This analysis is so fundamental to CARB's proposal that it deserves an accurate and more robust study of the available facts.

As described in earlier sections of this document, the proposal to remove the jet fuel exemption is unlikely to stimulate additional SAF production, with producers most likely using credits generated by other fuels to satisfy the jet fuel obligation. Further, whatever increases in SAF production occur over the forecast time period will be the result of all economic levers: federal incentives[6], LCFS incentives, LCFS deficit generation, and operator contributions. Attributing all SAF increase to only LCFS deficit generation is a misattribution of benefit of the proposed obligation. Therefore, claims of PM and NOx reduction from SAF use as a result of the intrastate jet fuel proposal are greatly overstated. LAQ emissions reduction will only occur when and where SAF is actually used in significant quantities.

In addition, we note that CARB's analysis of the benefits of LAQ emissions resulting from the use of SAF is based on a single series of tests conducted by NASA in 2009 and reported on in 2011[7]. CARB's interpretation of the results from this test identified that "Alternative jet fuel emits 87.4% the NOx and 55% the PM2.5 that fossil jet fuel emits." Additional research has been conducted since 2009 and the scientific consensus differs significantly from what CARB has modeled. The Airport Cooperative Research Program analyzed the body of research available in 2018 and concluded that SAF minimally reduces or has no effect on NOx. The body of research and summary analysis does verify that potential reductions in SOx and PM emissions are significant, similar to CARB's assumptions, and generally proportional to the SAF blend

[6] See ISOR p. 55, IRA tax credits are included in baseline scenario
[7] See ISOR Appendix C-1, Sec VI, p. B-6

percentage as combusted in the engine.[8] We recommend CARB review its Methodology for Estimating Changes in Criteria Pollutant Emissions from Use of Alternative Jet Fuel for AJF emissions and update to current scientific consensus.

3. The proposal to remove the exemption for jet fuel used on flights within California is pre-empted by Federal Law.

CARB's Previous Recognition of Federal Preemption

299.3 reference

Conventional Jet Fuel (CJF), which is defined in section 95481(a)(33) of the LCFS regulation, is currently exempt from the LCFS Program through section 95482(c)(2). When CARB proposed and then finalized this exemption as part of the 2018 LCFS rulemaking, CARB stated, correctly, that "[s]ubjecting aircraft fuels to annual carbon intensity standards would raise federal preemption issues."[9] CARB then pointed out that it "has the authority to amend the LCFS regulations to create incentives to promote the use of low carbon fuels in aircraft by allowing credit for such fuels. Importantly, by promoting the voluntary production and use of alternative jet fuel, CARB would not be regulating aircraft fuels, but rather would simply be creating opportunities for airlines to better support California's GHG objectives."[10] A4A fully supported CARB's continuation of the non-deficit generating status of CJF (which was originally set forth in section 95480.1(d)(1) of the LCFS regulation before being moved to section 95482(d)(4)) and its inclusion of AJF as a credit-generating fuel under the LCFS Program on a voluntary, opt-in basis.[11]

The exemption in section 95482(c)(2) is expansive and encompasses all CJF, whether used in intrastate flights or any other flights taking off from California airports. Nothing has changed since the 2018 LCFS rulemaking, meaning California, like every other state in the country, continues to be federally preempted from regulating jet fuel irrespective of a flight's destination. Put another way, CARB remains subject to federal law that clearly preempts any authority other than the Federal Aviation Administration (FAA) from regulating aviation fuel, and CARB is compelled to maintain the scope of 95482(c)(2) to include CJF used for intrastate flights.

Preemption Under the Clean Air Act and the Federal Aviation Act

Federal law has for many decades made clear that the FAA has exclusive jurisdiction over jet fuel and that states are expressly preempted from adopting and enforcing fuel standards for aircraft:

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[8] See
https://nap.nationalacademies.org/download/25095
https://onlinepubs.trb.org/onlinepubs/acrp/acrp_wod_41Factsheet.pdf

[9] *See* Staff Report on Public Hearing on Proposed Amendments to LCFS, CARB at III-30 (Mar. 6, 2018) https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/isor.pdf?_ga=2.259407882.1202437490.1641231788-253234234.1573227006 at III-30.

[10] *Id*.

[11] We incorporate by reference the comments we filed during the 2018 LCFS rulemaking, "Comments on the 2018 Amendments to the Low Carbon Fuel Standard" (April 23, 2018), and "Airlines for America's Comments on Proposed Modifications to the Proposed Revisions to the Low Carbon Fuel Standard (LCFS) Regulation" (July 5, 2018).

> The Administrator of the [FAA] shall prescribe-
>
> (1) standards for the composition or chemical or physical properties of an aircraft fuel or fuel additive to control or eliminate aircraft emissions the Administrator of the Environmental Protection Agency decides under section 231 of the Clean Air Act (42 U.S.C. 7571) endanger the public health or welfare; and
>
> (2) regulations providing for carrying out and enforcing those standards.[12]

Congress added this provision to the Federal Aviation Act of 1958 in conjunction with its adoption of Sections 231-234 of the Clean Air Amendments of 1970. Taken together, those complementary legislative enactments manifested an express Congressional intent that federal regulation alone was govern the regulation of aircraft emissions.[13]

That express intent with respect to the aircraft fuel and emissions must be read in the broader context of federal preemption of the field of aircraft regulation that has been legislated by Congress and embraced by the courts. As the Supreme Court has held, it is well-settled that the Federal Aviation Act of 1958 creates a "uniform and exclusive system of federal regulation" of aircraft that preempts state and local regulation.[14] This recognizes the critical importance of ensuring aircraft operations are not subject to a patchwork of state and local laws. It also recognizes the critical importance that maintaining the integrity of aviation fuel has to maintaining the safety of aircraft operations. Quite simply, Congress recognized the need to ensure the FAA had sole and exclusive authority to regulate aviation fuels.

As a corollary of the federal government's express and exclusive authority with respect to the regulation of aviation fuel, Section 233 of the Clean Air Act explicitly preempts states and their political subdivisions from "adopt[ing] or attempt[ing] to enforce any standard respecting emissions from any aircraft or engine thereof unless such standard is identical to a standard" established under section 231,[15] which requires that the FAA be consulted on any aircraft *engine* emission standards proposed by the U.S. Environmental Protection Agency (EPA).[16]

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[12] *See* 49 U.S.C. § 44714 ("Aviation fuel standards").

[13] *See* Conf. Rep. No. 1783, 91st Cong. 2nd Session (1970) ("The states were preempted from adopting or enforcing any emissions control standard with respect to aircraft or aircraft engines to which federal standards would apply").

[14] *See Burbank v. Lockheed Air Terminal, Inc.*, 411 U.S. 624, 639 (1973); see also *American Airlines v. Department of Transp.*, 202 F.3d 788, 801 (5th Cir. 2000) (aviation regulation is an area where "[f]ederal control is intensive and exclusive") (quoting *Northwest Airlines, Inc. v. Minnesota*, 322 U.S. 292, 303 (1944)).

[15] *See* 42 U.S.C. § 7573; 40 C.F.R. § 87.3(d).

[16] 40 C.F.R. § 87.3(a) (EPA emission standards "apply to engines on all aircraft that are required to be certificated by FAA"). Aircraft and engine certification is the exclusive domain of the FAA. Thus, any state

EPA, for its part, has openly acknowledged that FAA has exclusive authority over aviation fuel. In a 2012 response to a rulemaking petition requesting that EPA address the lead content of fuel used in piston-engine general aviation aircraft, EPA explained as follows:

> EPA has no direct authority on setting . . . aviation fuel specifications by regulation. Rather, FAA has authority to prescribe standards for the composition or chemical or physical properties of aircraft fuels to control or eliminate aircraft emissions. 49 U.S.C. § 44714. However, under current practice, these specifications are not set directly by government regulation. Rather, FAA indirectly regulates aircraft fuel by specifying that fuel meeting specifications identified by the aircraft engine manufacturer as part [of] the engine type certificate . . . must be used by the operator as a condition of operating the aircraft under its type certificate. Thus, while EPA has an interest in environmentally compatible fuels, our direct role here is limited to setting an engine emission standard under [Clean Air Act] section 231 that can be met, within appropriate leadtime, with the development and application of requisite technology, giving appropriate consideration to the cost of compliance and to safety and noise factors.[17]

In accordance with the legislative directives of CAA Section 231 (requiring the EPA Administrator to issue regulations for aircraft engine emissions) and Section 232(a) (granting

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regulation that interferes with EPA's emissions standards for aircraft engines also interferes with FAA's authority.

[17] *See* EPA, *Memorandum in Response to Petition Regarding Lead Emissions from General Aviation Aircraft Piston-Engines*, at 16 (July 18, 2012) (footnote omitted) (emphasis added), available at https://www.epa.gov/sites/default/files/2016-09/documents/ltr-response-av-ld-petition.pdf; *see also* 75 Fed. Reg. 22440, 22441 (Apr. 28, 2010) ("Under the [Clean Air Act], if, in the Administrator's judgment, lead emissions from the use of leaded avgas cause or contribute to air pollution which may reasonably be anticipated to endanger public health or welfare, then EPA would be required under our statutory authority to prescribe standards to control the emissions of lead from piston-engine aircraft. In promulgating such standards, the EPA would be required to consult with the [FAA], and could not change standards if doing so would significantly increase noise and adversely affect safety. FAA would then be required, after consultation with EPA, to prescribe regulations to [e]nsure compliance with any standards to control the emissions of lead from piston-engine aircraft. ***Under 49 U.S.C. 44714, FAA would also be required to prescribe standards for the composition or chemical or physical properties of piston-engine fuel or fuel additives to control or eliminate aircraft lead emissions***.) (emphasis added); *id.* at 22445-46 ("**fuels used exclusively in aircraft engines are to be regulated by the FAA**") (emphasis added); National Academies of Sciences, Engineering, and Medicine, *State and Federal Regulations That May Affect Initiatives to Reduce Airports' GHG Emissions*, at 15 (2012) (footnote omitted) ("EPA's authority to establish [aircraft emission standards] under the [Clean Air Act] does not extend to the regulation of jet fuel. Rather, FAA has exclusive authority to prescribe 'standards for the composition or chemical or physical properties of an aircraft fuel or fuel additive to control or eliminate aircraft emissions' for pollutants EPA has found endanger the public health and welfare"), available at https://www.nap.edu/cart/download.cgi?record_id=22671.

the Secretary of Transportation authority to enforce standards issued under Section 7571) both EPA and FAA have issued regulations exercising their exclusive authorities in this space.[18] There is no language in those regulations suggesting an exemption that would allow California or any other state to regulate fuel content, nor has any court decision recognized the same.

For aviation fuel, 14 CFR § 34.3 sets forth the uniform "General Requirements" for that fuel. As explained above, that regulation contemplates FAA setting standards in consultation with EPA as the federal agency with expertise in this area. States, however, are not involved, reflecting the legislative intent for uniform federal regulation. Further, the LCFS is not identical to any fuel standard that has been adopted by EPA and FAA under the auspices of Sections 231 and 233 of the CAA and the Federal Aviation Act. Extending its reach to aviation fuel is therefore not excused from preemption.

<u>The Federal Aviation Act Preempts State Regulation of Aircraft Operations</u>

Extending the reach of the LCFS to jet fuel would impose a regulatory mandate of aircraft operations. California is both expressly precluded from regulating aircraft fuels, and the Federal Aviation Act more broadly preempts the field of aviation regulation so as to preclude applying the LCFS to aircraft operations. *See City of Burbank*, 411 U.S. at 634 (explaining that the *pervasive* nature of federal regulation evidences Congress' preemptive intent). Congress recognized that the airline industry is a uniquely complex, interconnected system in which even the slightest disruption can have ripple effects that disrupt the functioning of the National Airspace System and interstate commerce.

Indeed, with respect to operational mandates there is no "minor" encroachment in the aviation industry—any state interference with airlines' operations has the potential to cause chaos at a national or international level. *Northwest Airlines v. State of Minnesota*, 322 U.S. 292, 303 (1944) ("Planes do not wander about in the sky like vagrant clouds. They move only by federal permission, subject to federal inspection, in the hands of federally certified personnel and under an intricate system of federal commands. The moment a ship taxies onto a runway it is caught up in an elaborate and detailed system of controls. It takes off only by instruction from the control tower, it travels on prescribed beams, it may be diverted from its intended landing, and it obeys signals and orders. Its privileges, rights, and protection, so far as transit is concerned, it owes to the Federal Government alone and not to any state government").

This concern prompted Congress to vest FAA with sole, exclusive authority to regulate airline *operations*. As the court explained in *Arapahoe County Public Airport Authority v. Federal Aviation Administration*, 242 F.3d 1213, 1221 (10th Cir. 2001), it is "difficult to visualize a more comprehensive scheme of combined regulation, subsidization, and operational participation than that which Congress has provided in the field of aviation") (citations omitted). ("Congress' clear intent to occupy the field with respect to the airline industry "tilts the balance toward the application of supremacy principles to protect against state courts trumping the federal interests and concerns") *Id.*; *see also English v. General Electric Co.*, 496 U.S. 72, 79 (1990) ("in the absence of explicit statutory language, state law is pre-empted where it regulates conduct in a field that Congress intended the Federal Government to occupy exclusively").

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[18] See notes 14 and 15, supra. FAA has issued regulations under 49 U.S.C. § 44714, set forth at 14 CFR Part 34.

Extending the LCFS to Aviation Fuels Would be Preempted by the Airline Deregulation Act

California's proposal would interfere with airlines' prices, routes, and services, and is therefore preempted under the Airline Deregulation Act (ADA). Under the ADA, states are expressly forbidden from interfering with airlines' prices, routes, and services. The ADA provides that "[a] State, political subdivision of a State, or political authority of at least 2 States may not enact or enforce a law, regulation, or other provision having the force and effect of law related to a price, route, or service of an air carrier." 49 U.S.C. § 41713(b).

This is an expansive prohibition and federal courts have consistently struck down laws that even minimally encroach on the aviation industry. *Rowe v. New Hampshire Motor Transport Association*, 552 U.S. 364 (2008). Congress' goal in passing the ADA was to avoid inefficient regulation of the airline industry and to allow market demands to drive airlines' competitive decisions. *Federal Express Corp. v. California Public Utilities Commission*, 936 F.2d 1075, 1075, 1079 (9th Cir. 1991) (explaining that Congress preempted state regulation of the airline industry to create a "sound regulatory environment" and to "facilitate adaptation of the air transportation system to the present and future needs of the domestic and foreign commerce of the United States). By including these specific statutory preemption provisions, Congress sought to ensure the ADA purposes and avoid the effect of a balkanized system of local laws and a patchwork of regulatory regimes at odds with a national objective of deregulating air commerce. *Ventress v. Japan Airlines*, 747 F.3d 716 (9th Cir. 2014).

California's proposed LCFS expansion would cause disruptions that would impermissibly interfere with airlines' operations, including but not limited to:

- Forcing airlines to alter their methods of tracking fuel supply sources and uses.
- Forcing airlines to potentially alter the amount of fuel carried by planes involved in intrastate trips.
- Forcing airlines to restructure their supply chain based on California's regulatory CI metric, rather than based on the demands of the marketplace.

All of these effects will have impacts on airlines' prices, routes, and services. They are all far more disruptive to airlines' methods of service than other state regulations that have been struck down, such as the signature requirement for packages at issue in *Rowe*. 552 U.S. 364. They will also affect airlines' prices because disruptions to the supply chain and the larger market will raise costs for airlines, and those costs will inevitably be passed on to consumers.[19]

Any argument that the economic impact from the rule will be felt by fuel producers, not airlines themselves, is also misplaced. Higher costs for fuel producers will be passed on to the airlines and it is beyond dispute that higher costs translate into higher prices. "It is freshman-year economics that higher prices mean lower demand, and that consumers are sensitive to the full price that they must pay, not just the portion of the price that will stay in the seller's coffers."

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[19] While the ADA does not prevent a state that owns or operates an airport from carrying out its proprietary powers and rights (49 U.S.C. § 41713(b)(3)), the regulation of jet fuel does not fall within said powers, and 49 U.S.C. § 44714 recognizes no exception to its express preemptive language. *see also Arapahoe* County, 242 F.3d at 1221-22 (explaining the interactions of FAA's preemptive authority and the "proprietary powers" exception).

Sanchez, 590 F.3d 1027 at 1030 (citing *Buck v. Am. Airlines, Inc.*, 476 F.3d 29, 36 (1st Cir. 2007)).

CARB's Program in its Current Form Would Violate the Commerce Clause

CARB's Program also is not in conformity with the Dormant Commerce Clause. Courts have refused to enforce state regulations with the type of burdens that are proposed here on instrumentalities of interstate transportation—trucks, trains, and the like. *See, e.g., Bibb v. Navajo Freight Lines, Inc.*, 359 U. S. 520, 523–530 (1959) (concerning a state law specifying certain mud flaps for trucks and trailers); *Southern Pacific Co. v. Arizona ex rel. Sullivan*, 325 U.S. 761, 763–782 (1945) (addressing a state law regarding the length of trains).[20]

These cases support a prohibition on state regulations that impose improper or discriminatory extraterritorial burden, and apply a balancing of legitimate interests which has not been undertaken here. At a minimum, these cases condemning state laws that "although neutral on their face . . . were enacted at the instance of, and primarily benefit," in-state interests. *Raymond Motor Transp., Inc. v. Rice*, 434 U. S. 429, 447 (1978). These concerns predominate where preemption also applies state regulation of the entire field of aviation operations and fuels, and where a lack of national uniformity would impede the flow of interstate goods.

4. Concerns about the proposed guardrails on crop and forestry-based fuels through supply chain traceability and certification

299.5 During CARB's workshops held in 2022 and 2023 and the CARB Board Meeting held on September 28, 2023, CARB Staff and Board members expressed desire to establish "guardrails" for crop-based feedstocks. A4A and its members concur with CARB that "biofuel production must not come at the expense of deforestation or food production" and towards that end urge CARB to continue relying on its robust carbon intensity methodology for assessing land use change,[21] including a quantification of the indirect effects associated with crop-based biofuels. The analytical, science-based methodologies used by CARB provide the necessary controls on feedstocks and fuels to ensure environmental integrity. As the available science continues to evolve, these models can be and are updated.

The proposal to establish supply chain traceability requiring certification through third party Sustainability Certification Systems (SCS) raises several concerns. First, this concept was not shared during workshops and thus does not have the benefit of stakeholder consideration and feedback. Stakeholder consultation would be needed to discover additional detail process requirements and definition necessary for implementation. As a result, the SCS certification program, as envisioned by CARB, may take longer to develop and implement than has been allocated by CARB.

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[20] See generally *National Pork Producers Council et al. v. Ross*, 598 U.S. 356, 373 (May 11, 2023); *see also id.*at, 389 n.4 (dormant Commerce Clause protects the instrumentalities of transportation from state regulation).

[21] *See* 17 CCR § 95488.3.

Second, there are only two established third-party SCSs generally relevant to biofuels and both have been developed through Europe-based organizations. Both SCSs have requirements that have limited experience in being applied to U.S. agricultural feedstocks and supply chains. The proposal should instead rely on an existing U.S. government standard, such as controls incorporated into the EPA Renewable Fuel Standard.

Third, the existing SCSs are struggling with capacity constraints in providing certifications under already established voluntary certification programs, EU RED, and ICAO CORSIA. Burdening the existing SCSs with an additional requirement for the CARB LCFS program could create an administrative bottleneck on qualifying feedstocks and supply chains for the LCFS program that would otherwise be qualified. This would have the adverse impact of slowing down supply growth, which for the still emerging SAF market is a constraint that must be avoided.

We urge CARB to reconsider the necessity of and timeline for this proposed requirement at this time. CARB should consider other options which may accomplish the same intent of providing reasonable assurance that biofuel production credited under the LCFS program does not come at the expense of deforestation or food production without creating undue administrative impediments to the availability of SAF supply that would otherwise meet sustainability requirements.

5. Concerns about SAF producer's ability to source low-carbon intensity electricity and hydrogen produced from low-carbon intensity electricity through indirect accounting

299.6

Under the existing LCFS Regulation, indirect accounting (aka book-and-claim accounting) is authorized for low-CI electricity supplied as a transportation fuel or to produce hydrogen through electrolysis if that hydrogen is used either as a transportation fuel or in the production of another transportation fuel (e.g., SAF). Through these provisions, SAF production facilities are explicitly authorized to source low-CI electricity from the grid to produce hydrogen that is used in the production of transportation fuels. Under the existing LCFS provisions, low-CI electricity can be sourced flexibly through the use of Renewable Energy Certificates (RECs) or via a qualifying Green Tariff program.

The proposed LCFS program revisions would dramatically narrow the power-sourcing landscape for SAF producers and limit the use of "Indirect Accounting" for "low-CI Electricity" to produce "Hydrogen as a transportation fuel." The proposed amendments would revoke the current authorization to source low-CI electricity for electrolysis through the REC mechanism when used for SAF production.

CARB's proposal will particularly and severely inhibit the growth of Power to Liquid (PtL) SAF production, availability and use in California. PtL is a promising fuels pathway that has the potential to provide very low CI SAF. Other jurisdictions (e.g. European Union and United Kingdom) have policies in place to attract PtL SAF, and CARB's proposal will encourage PtL SAF producers that utilize indirect accounting for the sourcing of low-CI electricity in their production to sell their fuels into those jurisdictions. Other types of biomass based SAF utilizing indirect accounting for use of low-CI electricity in their SAF production will have their CI scores lowered accordingly, which may make markets in other jurisdictions more attractive.

We recommend CARB preserve its existing policy allowing use of indirect accounting mechanisms for low-CI electricity that is used for hydrogen production in the production of a transportation fuel. We also recommend that CARB expand the use of its existing indirect accounting mechanisms to extend the use of book-and-claim RECs to facilities sourcing power to produce SAF, PtL and other alternative fuels.

CONCLUSION

A4A supports the existing opt-in crediting model under the LCFS, combined with U.S. federal incentives, as an effective approach for increasing SAF production, use and availability in California. With further collaboration and partnership, we see the potential to dramatically increase the production and use of SAF in California and other jurisdictions and are interested in identifying new opportunities to work together. A4A offers its technical and operational expertise to work together with CARB and other stakeholders in better understanding the challenges and opportunities for promoting the availability of SAF to achieve CARB's objectives of a sustainable and workable reduction of carbon emissions in the transportation sector. The proposal to remove the exemption for jet fuel used on flights within California, however, will not be an effective tool for stimulating SAF production, and instead would divert resources and attention away from SAF objectives shared by California and the aviation industry. In addition, CARB is federally pre-empted from removing the exemption for jet fuel and obligating conventional jet fuel as a deficit-generating fuel. We urge CARB to reconsider and withdraw the proposal to eliminate the exemption for jet fuel used on flights within California.

* * *

Thank you for your consideration of our comments. Please do not hesitate to contact us if you have any questions.

Sincerely,

Kevin Welsh
Vice President, Environmental Affairs and Chief Sustainability Officer
kwelsh@airlines.org

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Comment 309 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Gary
Last Name	Grimes
Email Address	ggrimes@worldenergy.net
Affiliation	World Energy
Subject	World Energy's Comments on the Proposed Amendments to the LCFS
Comment	Attached, please find World Energy's comments on the proposed amendments to the LCFS. Thank you for the opportunity to provide these comments.
Attachment	www.arb.ca.gov/lists/com-attach/6980-lcfs2024-UDxcLlUmV1sELwJd.pdf
Original File Name	Ltr - World Energy’s Comments on the Proposed Amendments to the Low Carbon Fuel Standard 02.20.24 Executed.pdf
Date and Time Comment Was Submitted	2024-02-20 16:17:55

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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CONTACT
WORLD ENERGY HEADQUARTERS
225 Franklin Street Suite 2330
Boston, MA 02110
p: 617.889.7300 (main)
e: info@worldenergy.net

February 20, 2024

Chair Liane Randolph and the Members of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: World Energy's Comments on the Proposed Amendments to the Low Carbon Fuel Standard

Dear Chair Randolph and Members of the Board,

World Energy values the opportunity to provide comments on the proposed amendments to the Low Carbon Fuel Standard (LCFS). We also wish to thank your staff for their hard work in updating the regulations in a timely manner. The LCFS continues to play a significant role in helping California transition to cleaner transportation and remains a model policy for other jurisdictions hoping to achieve similar emission reductions.

World Energy is one of the largest and longest-serving advanced clean energy suppliers in North America. We were the world's first producer of sustainable aviation fuel (SAF) and remain leaders in the field of renewable fuels. Our facility in Paramount, CA is in the final stages of conversion from a petroleum refinery to a 100% renewable fuels bio-refinery. When completed, World Energy's Paramount facility is projected to increase production capacity to approximately 350 million gallons of low carbon fuels per year.

We have made significant investments in continuously reducing the carbon intensity of our fuels and producing very-low carbon fuels for the California market. We have fuel pathways providing up to an 85% reduction in carbon intensity. Our fuels have helped the LCFS program meet and exceed its targets, and our Paramount plant is a premiere example of the clean energy future. World Energy continues our commitment to reduce transportation emissions including investing $4 billion in scaled manufacturing and new technologies to achieve our goal of supplying 1 billion gallons of sustainable aviation fuel annually by 2030.

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CONTACT
WORLD ENERGY HEADQUARTERS
225 Franklin Street Suite 2330
Boston, MA 02110
p: 617.889.7300 (main)
e: info@worldenergy.net

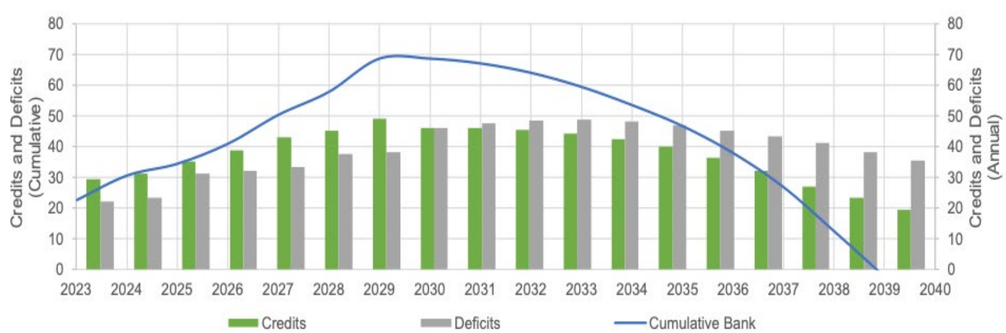
World Energy wishes to provide the following comments in response to the proposed amendments to the LCFS:

2030 Target

300.1 Increasing the 2030 target to 30% reduction is a step in the right direction, however, we urge CARB to consider a more ambitious target. As we see the market reacts to the large balance in the credit bank, weighed against a 30% reduction target, the corresponding drop in market prices makes it clear that more carbon reductions are possible.

Along with other stakeholders, World Energy has been working with ICF to model the LCFS targets. The recent ICF modeling relative to the ISOR[1] highlights that 30% CI by 2030 is still conservative and will leave an estimated 70 million in excess credits in 2029 (Figure 2). With such a large credit bank, program investors will have a low incentive to further invest in the newest technologies and innovations in carbon reduction. The ICF "Central Case" modeling shows more aggressive 2030 CI targets of 41-44% are readily achievable given the anticipated fuel volumes and CI reductions across various fuel pathways.

Figure 2. Credit-Deficit Balance in the ICF ISOR Case



In addition to increasing the 2030 targets, we recommend CARB consider changes to the proposed step-down and Auto Acceleration Mechanism (AAM).

Step Down

300.2 Increasing the step-down by at least 2% (for a total step-down of at least 7%) will right-size the current credit to deficit ratio and allow for the current robust credit bank to be utilized. This could potentially abate an immediate trigger of the Auto Acceleration Mechanism in its first eligible year.

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[1] https://static1.squarespace.com/static/5b57ab49f407b4a7ffa44ffa/t/65cd3c74d1a72f445cdc7a7e/1707949173143/ICFReport2024.pdf

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225 Franklin Street Suite 2330
Boston, MA 02110
p: 617.889.7300 (main)
e: info@worldenergy.net

Auto Acceleration Mechanism

300.3 The proposed Auto Acceleration Mechanism is an important new concept for credit generators in the LCFS. World Energy is very supportive of this proposal. The initial staff proposal is strong, but World Energy has a couple of suggestions for the proposed design. First and most important, our modeling suggests that the proposed 2030 target and 5% step-down will only serve to increase the credit bank and dampen investment in low carbon fuels. Moving the first eligible date of the AAM forward may be necessary to allow for the AAM to "catch" any near-term adjustments needed. In the current proposed amendments, the Executive Officer will announce whether the AAM has been triggered starting in May 2027, with an effective date in January 2028. Instead, a first eligible trigger announcement in 2026 for a 2027 effective date would be more appropriate. While the staff proposal is likely giving the market time to "adjust" to the new 2030 targets after a 2025 implementation, our experience is that the market reacts in real time. As of February 2024, the market has already modeled, reacted to, and priced the proposed 2030 targets, and the result has been a *decrease* in credit price. The current credit price reflects the market's belief that the package of design details is insufficient to draw down the credit bank precipitously. In that instance, the AAM is needed as soon as possible to help with a large oversupply of credits. With the current pace of the market and size of the credit bank, the AAM will be needed as soon as possible to recalibrate the program and account for the many GHG emissions that would go unaddressed if the AAM is delayed.

Alternative Jet Fuel (AJF) / Sustainable Aviation Fuel (SAF)

300.4 World Energy sees alignment between the staff proposal to include intrastate jet fuel under the provisions of the LCFS and the goals of the program, which are to abate climate impacts from the state's transportation sector. As AJF continues to develop and grow in the state, including incentives within the LCFS will only serve as encouragement for increasing production of AJF. World Energy is hopeful that it will foster additional growth in the use of AJF as a low-CI alternative for aviation in California.

Book-and-Claim

<u>Hydrogen</u>

300.5 World Energy would also like to express our support for the extension of book-and-claim to additional fuels like hydrogen. Book-and-claim is essential in maintaining and promoting the success of the LCFS program. It has enabled many GHG emission reductions and encourages more low-CI fuels to enter the California market. In part, World Energy believes that book-and-claim plays an important role for carbon reductions to happen wherever possible, without necessitating an unnecessary (and carbon intensive) shipment of products to disparate locations.

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WORLD ENERGY HEADQUARTERS
225 Franklin Street Suite 2330
Boston, MA 02110
p: 617.889.7300 (main)
e: info@worldenergy.net

As CARB proposes including book-and-claim for hydrogen, we support the addition as it will aid in the deployment of renewable hydrogen in the state, a crucial component to transitioning California's hard-to-decarbonize transportation and other technologies.

One key area for improvement in the book-and-claim proposal is extending the provisions outside California, consistent with other LCFS provisions. The current proposal calls for a California pipeline connection in §95488.8(i)(3)(A). The requirement as written favors only in-state hydrogen pipelines and does not provide incentives for renewable fuel production outside California. Absent this allowance, CARB is implicitly providing no incentive for low carbon hydrogen over fossil-based hydrogen for fuels produced in other states. In order to advantage low CI hydrogen across the country, allowing book-and-claim for interconnected regional hydrogen pipelines will be necessary to overcome traditional hydrogen's cost advantages. As such, World Energy recommends modifying §95488.8(i)(3)(A) as follows:

Low-CI hydrogen is injected into a dedicated hydrogen pipeline physically connected to <u>a distribution system or a production facility that provides transportation fuel to California.</u>

<u>Electricity</u>

300.6

World Energy appreciates the introduction of power sourcing flexibility as proposed under the draft regulation in §95488.8(i)(1). This is important for facilities like our Paramount plant, which is in a dense urban area. Our plant's location will require us to site more remote new renewable energy projects, like the Mojave Desert, which will be within the same balancing authority but may not have a direct, dedicated connection. We believe in further reducing the CI of the fuels we produce at our plants but look to CARB for an investment signal in the value of this lower carbon electricity. To this end, there are key restrictions within the proposal that may not serve to advance the market.

Specifically, the proposal under §95488.8(i)(1)(C) should be broadened to apply to other renewable fuel / project types, including SAF. This will provide incentives for World Energy and other producers to further lower the CI of the electricity used to produce our renewable fuels, beyond what is available from the grid. We urge CARB to consider that biorefinery locations will frequently be near other industrial and distribution infrastructure, whereas new renewable energy generation will necessarily be sited in more remote areas of the state. Writing the regulation with respect to these land use realities will help World Energy and future renewable fuel production within the state's boundaries.

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@World Energy LLC
@officialworldenergy
World Energy

CONTACT
WORLD ENERGY HEADQUARTERS
225 Franklin Street Suite 2330
Boston, MA 02110
p: 617.889.7300 (main)
e: info@worldenergy.net

Sustainability Criteria and Soil Carbon Accumulation

300.7 We encourage CARB to recognize the low carbon regenerative agriculture practices used in the production of low carbon biofuels that minimize negative impacts of agriculture and encourage the environmental benefits (soil carbon restoration and GHG impacts) of bio-based fuels. EU RED now recognizes soil carbon accumulation in their lifecycle carbon assessments as described in Annex V – "Methodology for Determining the Emission Savings from Soil Carbon Accumulation Via Improved Agricultural Management" and there are new procedures through the Geneva based sustainability organization, RSB, to implement these practices.[1,1]

We encourage CARB to study and adopt current research from the EU which recognizes the use of biochar as a carbon negative soil amendment, a practice that has significant potential to reduce atmospheric CO2 and simultaneously sequester and restore healthy soil carbon through agricultural practices.

Ocean-going and Marine Vessels

300.8 Given the addition of intrastate fossil jet as a deficit generator in the LCFS proposed amendments, World Energy requests CARB to consider adding ocean-going and marine vessels to the program. Like aviation, ocean-going and marine vessels are hard-to-decarbonize and represent more than 150% of the GHG emissions from aviation. Similar to the other success stories of the LCFS, including ocean-going and marine vessels can signal for long-term investment in finding low-CI solutions. While this may not be an issue that staff can incorporate in this rulemaking period, we encourage staff to begin the learning process now for a future program update. One early example is biodiesel testing (B100) on Canada Steamship Lines in their Great Lakes / St Lawrence Seaway fleet.[1]

On January 1, 2024, the EU added maritime fuels into their ETS carbon trading system[1] and the International Maritime Organization (IMO) is following the lead of the International Civil Aviation Organization in their commitment to reduce GHG emissions similar to the commercial aviation industry.[1] Similar to California's lower carbon aviation fuel goals, California can encourage lower carbon maritime fuels through the LCFS program.

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[2]https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32022R09

[3]https://rsb.org/2024/01/16/rsb-receives-positive-assessment-to-implementing-regulation-under-eu-red/

[4]https://cslships.com/news/csl-successfully-completes-worlds-largest-b100-biofuel-tests/
[5]https://climate.ec.europa.eu/eu-action/transport/reducing-emissions-shipping-sector_en
[6]https://www.imo.org/en/MediaCentre/PressBriefings/pages/Revised-GHG-reduction-strategy-for-global- shipping-adopted-.aspx

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@officialworldenergy

World Energy

CONTACT

WORLD ENERGY HEADQUARTERS

225 Franklin Street Suite 2330

Boston, MA 02110

p: 617.889.7300 (main)

e: info@worldenergy.net

We appreciate CARB staff's work on this important regulation and the opportunity to provide these comments.

Sincerely,

Scott Lewis

Scott Lewis
President, World Energy Supply Zero, LLC
225 Franklin Street, Suite: 2330
Boston, MA 02110
Telephone: +19053306997
Email: Slewis@worldenergy.net
ICE. slewis14

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Comment 309 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Gary
Last Name	Grimes
Email Address	ggrimes@worldenergy.net
Affiliation	World Energy

Subject	World Energy's Comments on the Proposed Amendments to the LCFS
Comment	Attached, please find World Energy's comments on the proposed amendments to the LCFS. Thank you for the opportunity to provide these comments.
Attachment	www.arb.ca.gov/lists/com-attach/6980-lcfs2024-UDxcLlUmV1sELwJd.pdf
Original File Name	Ltr - World Energy’s Comments on the Proposed Amendments to the Low Carbon Fuel Standard 02.20.24 Executed.pdf
Date and Time Comment Was Submitted	2024-02-20 16:17:55

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p: 617.889.7300 (main)
e: info@worldenergy.net

February 20, 2024

Chair Liane Randolph and the Members of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: World Energy's Comments on the Proposed Amendments to the Low Carbon Fuel Standard

Dear Chair Randolph and Members of the Board,

World Energy values the opportunity to provide comments on the proposed amendments to the Low Carbon Fuel Standard (LCFS). We also wish to thank your staff for their hard work in updating the regulations in a timely manner. The LCFS continues to play a significant role in helping California transition to cleaner transportation and remains a model policy for other jurisdictions hoping to achieve similar emission reductions.

World Energy is one of the largest and longest-serving advanced clean energy suppliers in North America. We were the world's first producer of sustainable aviation fuel (SAF) and remain leaders in the field of renewable fuels. Our facility in Paramount, CA is in the final stages of conversion from a petroleum refinery to a 100% renewable fuels bio-refinery. When completed, World Energy's Paramount facility is projected to increase production capacity to approximately 350 million gallons of low carbon fuels per year.

We have made significant investments in continuously reducing the carbon intensity of our fuels and producing very-low carbon fuels for the California market. We have fuel pathways providing up to an 85% reduction in carbon intensity. Our fuels have helped the LCFS program meet and exceed its targets, and our Paramount plant is a premiere example of the clean energy future. World Energy continues our commitment to reduce transportation emissions including investing $4 billion in scaled manufacturing and new technologies to achieve our goal of supplying 1 billion gallons of sustainable aviation fuel annually by 2030.

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CONTACT
WORLD ENERGY HEADQUARTERS
225 Franklin Street Suite 2330
Boston, MA 02110
p: 617.889.7300 (main)
e: info@worldenergy.net

World Energy wishes to provide the following comments in response to the proposed amendments to the LCFS:

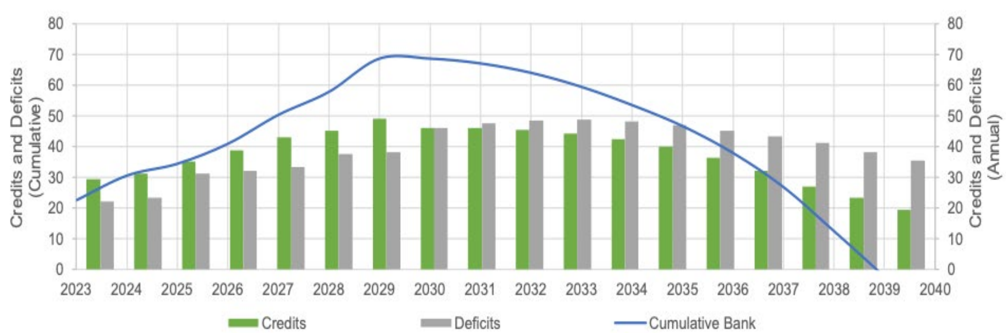
300.1

2030 Target

Increasing the 2030 target to 30% reduction is a step in the right direction, however, we urge CARB to consider a more ambitious target. As we see the market reacts to the large balance in the credit bank, weighed against a 30% reduction target, the corresponding drop in market prices makes it clear that more carbon reductions are possible.

Along with other stakeholders, World Energy has been working with ICF to model the LCFS targets. The recent ICF modeling relative to the ISOR[1] highlights that 30% CI by 2030 is still conservative and will leave an estimated 70 million in excess credits in 2029 (Figure 2). With such a large credit bank, program investors will have a low incentive to further invest in the newest technologies and innovations in carbon reduction. The ICF "Central Case" modeling shows more aggressive 2030 CI targets of 41-44% are readily achievable given the anticipated fuel volumes and CI reductions across various fuel pathways.

Figure 2. Credit-Deficit Balance in the ICF ISOR Case



In addition to increasing the 2030 targets, we recommend CARB consider changes to the proposed step-down and Auto Acceleration Mechanism (AAM).

Step Down

300.2 Increasing the step-down by at least 2% (for a total step-down of at least 7%) will right-size the current credit to deficit ratio and allow for the current robust credit bank to be utilized. This could potentially abate an immediate trigger of the Auto Acceleration Mechanism in its first eligible year.

[1] https://static1.squarespace.com/static/5b57ab49f407b4a7ffa44ffa/t/65cd3c74d1a72f445cdc7a7e/1707949173143/ICFReport2024.pdf

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225 Franklin Street Suite 2330
Boston, MA 02110
p: 617.889.7300 (main)
e: info@worldenergy.net

Auto Acceleration Mechanism

300.3 The proposed Auto Acceleration Mechanism is an important new concept for credit generators in the LCFS. World Energy is very supportive of this proposal. The initial staff proposal is strong, but World Energy has a couple of suggestions for the proposed design. First and most important, our modeling suggests that the proposed 2030 target and 5% step-down will only serve to increase the credit bank and dampen investment in low carbon fuels. Moving the first eligible date of the AAM forward may be necessary to allow for the AAM to "catch" any near-term adjustments needed. In the current proposed amendments, the Executive Officer will announce whether the AAM has been triggered starting in May 2027, with an effective date in January 2028. Instead, a first eligible trigger announcement in 2026 for a 2027 effective date would be more appropriate. While the staff proposal is likely giving the market time to "adjust" to the new 2030 targets after a 2025 implementation, our experience is that the market reacts in real time. As of February 2024, the market has already modeled, reacted to, and priced the proposed 2030 targets, and the result has been a *decrease* in credit price. The current credit price reflects the market's belief that the package of design details is insufficient to draw down the credit bank precipitously. In that instance, the AAM is needed as soon as possible to help with a large oversupply of credits. With the current pace of the market and size of the credit bank, the AAM will be needed as soon as possible to recalibrate the program and account for the many GHG emissions that would go unaddressed if the AAM is delayed.

Alternative Jet Fuel (AJF) / Sustainable Aviation Fuel (SAF)

300.4 World Energy sees alignment between the staff proposal to include intrastate jet fuel under the provisions of the LCFS and the goals of the program, which are to abate climate impacts from the state's transportation sector. As AJF continues to develop and grow in the state, including incentives within the LCFS will only serve as encouragement for increasing production of AJF. World Energy is hopeful that it will foster additional growth in the use of AJF as a low-CI alternative for aviation in California.

Book-and-Claim

<u>Hydrogen</u>

300.5 World Energy would also like to express our support for the extension of book-and-claim to additional fuels like hydrogen. Book-and-claim is essential in maintaining and promoting the success of the LCFS program. It has enabled many GHG emission reductions and encourages more low-CI fuels to enter the California market. In part, World Energy believes that book-and-claim plays an important role for carbon reductions to happen wherever possible, without necessitating an unnecessary (and carbon intensive) shipment of products to disparate locations.

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World Energy

CONTACT
WORLD ENERGY HEADQUARTERS
225 Franklin Street Suite 2330
Boston, MA 02110
p: 617.889.7300 (main)
e: info@worldenergy.net

As CARB proposes including book-and-claim for hydrogen, we support the addition as it will aid in the deployment of renewable hydrogen in the state, a crucial component to transitioning California's hard-to-decarbonize transportation and other technologies.

One key area for improvement in the book-and-claim proposal is extending the provisions outside California, consistent with other LCFS provisions. The current proposal calls for a California pipeline connection in §95488.8(i)(3)(A). The requirement as written favors only in-state hydrogen pipelines and does not provide incentives for renewable fuel production outside California. Absent this allowance, CARB is implicitly providing no incentive for low carbon hydrogen over fossil-based hydrogen for fuels produced in other states. In order to advantage low CI hydrogen across the country, allowing book-and-claim for interconnected regional hydrogen pipelines will be necessary to overcome traditional hydrogen's cost advantages. As such, World Energy recommends modifying §95488.8(i)(3)(A) as follows:

Low-CI hydrogen is injected into a dedicated hydrogen pipeline physically connected to <u>a distribution system or a production facility that provides transportation fuel to California.</u>

<u>Electricity</u>

300.6 World Energy appreciates the introduction of power sourcing flexibility as proposed under the draft regulation in §95488.8(i)(1). This is important for facilities like our Paramount plant, which is in a dense urban area. Our plant's location will require us to site more remote new renewable energy projects, like the Mojave Desert, which will be within the same balancing authority but may not have a direct, dedicated connection. We believe in further reducing the CI of the fuels we produce at our plants but look to CARB for an investment signal in the value of this lower carbon electricity. To this end, there are key restrictions within the proposal that may not serve to advance the market.

Specifically, the proposal under §95488.8(i)(1)(C) should be broadened to apply to other renewable fuel / project types, including SAF. This will provide incentives for World Energy and other producers to further lower the CI of the electricity used to produce our renewable fuels, beyond what is available from the grid. We urge CARB to consider that biorefinery locations will frequently be near other industrial and distribution infrastructure, whereas new renewable energy generation will necessarily be sited in more remote areas of the state. Writing the regulation with respect to these land use realities will help World Energy and future renewable fuel production within the state's boundaries.

COMPANY

World Energy

www.worldenergy.net

@WorldEnergy

@NewsWorldEnergy

@World Energy LLC

@officialworldenergy

World Energy

CONTACT

WORLD ENERGY HEADQUARTERS

225 Franklin Street Suite 2330

Boston, MA 02110

p: 617.889.7300 (main)

e: info@worldenergy.net

Sustainability Criteria and Soil Carbon Accumulation

300.7 We encourage CARB to recognize the low carbon regenerative agriculture practices used in the production of low carbon biofuels that minimize negative impacts of agriculture and encourage the environmental benefits (soil carbon restoration and GHG impacts) of bio-based fuels. EU RED now recognizes soil carbon accumulation in their lifecycle carbon assessments as described in Annex V – "Methodology for Determining the Emission Savings from Soil Carbon Accumulation Via Improved Agricultural Management" and there are new procedures through the Geneva based sustainability organization, RSB, to implement these practices.[1,1]

We encourage CARB to study and adopt current research from the EU which recognizes the use of biochar as a carbon negative soil amendment, a practice that has significant potential to reduce atmospheric CO2 and simultaneously sequester and restore healthy soil carbon through agricultural practices.

Ocean-going and Marine Vessels

300.8 Given the addition of intrastate fossil jet as a deficit generator in the LCFS proposed amendments, World Energy requests CARB to consider adding ocean-going and marine vessels to the program. Like aviation, ocean-going and marine vessels are hard-to-decarbonize and represent more than 150% of the GHG emissions from aviation. Similar to the other success stories of the LCFS, including ocean-going and marine vessels can signal for long-term investment in finding low-CI solutions. While this may not be an issue that staff can incorporate in this rulemaking period, we encourage staff to begin the learning process now for a future program update. One early example is biodiesel testing (B100) on Canada Steamship Lines in their Great Lakes / St Lawrence Seaway fleet.[1]

On January 1, 2024, the EU added maritime fuels into their ETS carbon trading system[1] and the International Maritime Organization (IMO) is following the lead of the International Civil Aviation Organization in their commitment to reduce GHG emissions similar to the commercial aviation industry.[1] Similar to California's lower carbon aviation fuel goals, California can encourage lower carbon maritime fuels through the LCFS program.

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[2]https://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32022R09

[3]https://rsb.org/2024/01/16/rsb-receives-positive-assessment-to-implementing-regulation-under-eu-red/

[4]https://cslships.com/news/csl-successfully-completes-worlds-largest-b100-biofuel-tests/
[5]https://climate.ec.europa.eu/eu-action/transport/reducing-emissions-shipping-sector_en
[6]https://www.imo.org/en/MediaCentre/PressBriefings/pages/Revised-GHG-reduction-strategy-for-global- shipping-adopted-.aspx

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World Energy

CONTACT
WORLD ENERGY HEADQUARTERS
225 Franklin Street Suite 2330
Boston, MA 02110
p: 617.889.7300 (main)
e: info@worldenergy.net

We appreciate CARB staff's work on this important regulation and the opportunity to provide these comments.

Sincerely,

Scott Lewis

Scott Lewis
President, World Energy Supply Zero, LLC
225 Franklin Street, Suite: 2330
Boston, MA 02110
Telephone: +19053306997
Email: Slewis@worldenergy.net
ICE. slewis14

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Comment 310 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jennifer
Last Name	Bingham
Email Address	jbingham@westcoastadvisors.com
Affiliation	Dairy Cares
Subject	Dairy Cares Comments on Proposed Low Carbon Fuel Standard Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6981-lcfs2024-VjIAZ1I6UXBWKQVa.pdf
Original File Name	Dairy Cares_Comments on the Proposed LCFS Amendments.pdf
Date and Time Comment Was Submitted	2024-02-20 16:47:12

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Dairy Cares Policy Comments on the Proposed
Low Carbon Fuel Standard Amendments

February 20, 2024

Dairy Cares[1], appreciates the opportunity to provide these comments on the California Air Resources Board's (CARB) proposed, Low Carbon Fuel Standard (LCFS) amendments. Dairy Cares represents the California dairy sector, including dairy producer organizations, leading cooperatives, and major dairy processors.

Introduction

While the comments following are designed to provide a complete overview of California's comprehensive and highly successful efforts to reduce dairy methane in the state, two foundational conclusions remain indisputable:

301.1

1. California cannot achieve the 40% target in livestock methane reduction by 2030 without the continued implementation of dairy digesters which capture enormous quantities of methane on dairy farms in the state.
2. The continued implementation of dairy digesters in California hinges on the incentives provided by continued avoided methane crediting in the LCFS program.

Put simply, without appropriate avoided methane crediting and continued participation in the LCFS, California cannot successfully achieve 40% reductions in dairy and other livestock emissions by 2030 and will fail to achieve the state's overall short-lived climate pollutant (SLCP) targets as sought under SB 1383 and will fail to achieve the state's overall 48% targeted reduction in carbon by 2030.

These conclusions are consistent with any credible analysis of the state's climate strategies and policies, including the CARB 2022 Scoping Plan Update, as well as other CARB analysis[2], and those by UC Davis researchers.[3, 4]

Moreover, continued avoided methane crediting by digesters under the LCFS is fully consistent with CARB's stated goals as outlined in the Initial Statement of Reasons (ISoR) as follows:

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[1] For more information about Dairy Cares, visit www.dairycares.com

[2] CARB Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target

[3] Analysis by UC Davis researchers: Meeting the Call: How California is Pioneering a Pathway to Significant Dairy Sector Methane Reduction

[4] Analysis by UC Davis researchers published in CABI Reviews: The path to climate neutrality for California dairies

4. “Supporting methane emission reductions and deploying biomethane for best uses across transportation.”

Discussion

Livestock’s essential role

California nation-leading dairy sector plays a vital role in providing essential nutrition and supporting the livelihoods and resilience of countless families and communities in rural California. California dairy farms are the most productive and important agricultural commodity in the state and directly and indirectly account for over 180,000 well-paying, year-round, and benefited jobs, most of which are in the eight county San Joaquin Valley.

California dairy farms also play an integral role in California sustainable food systems. Dairy cattle upcycle agricultural and food waste from other agricultural commodities, food and wine processing, and urban food waste. Approximately 40% of California’s dairy feed is from agricultural and food waste, representing 5.5 million tons of feed that has zero additional carbon footprint, and would otherwise need to be landfilled or disposed, leading to significant additional methane and carbon avoidance. Upcycling agricultural and food waste also dramatically reduces land use, water use, use of fossil fuels, pesticides and synthetic fertilizer, as well as resulting in less energy needed to produce traditional feed crops. From 1964 to 2014 the increased use of agricultural byproducts and food waste, as well as improved animal nutrition and animal welfare, contributed to California’s rapidly rising milk product production efficiency, resulting in 89% less land, 88% less water, 45% less greenhouse gases, including reduced methane emissions and fewer fossil fuels used.

California’s dairy farms also provide a critical source of organic fertilizer that dramatically reduces the need for synthetic fertilizer production and use. Manure from California’s dairy farms is a tremendous source of crop nutrients for the state’s growing organic and regenerative farm practices and the advancement of healthy soils, a leading state priority.

When managed properly, dairy farms can reduce their footprint on the planet. California’s dairy farms play a vital role in developing sustainable food systems, a healthier environment, enhanced nutrition, and a better quality of life for all.

California’s comprehensive dairy methane reduction approach

The emission intensity, as well as emission sources of dairy production varies significantly across dairy livestock management practices, and even across regions in California. “Organic pasture-based” operations on California’s North Coast produce more enteric emissions than conventional “free-stall” farming operations in the San Joaquin Valley, while conventional operations in the San Joaquin Valley generally produce more manure methane emissions. “Dry-lot” farming operations generally found in the Chino basin and on older dairies in the San Joaquin Valley also tend to likely produce more enteric than manure methane. Each of these production systems possess unique characteristics, cost/benefits, interactions, and trade-offs. The size of dairy farm operations, while all owned by families, also varies greatly from a few hundred cows to several thousand cows. Recognizing these unique characteristics, CARB and CDFA have correctly recognized that there is no universal one-size-fits-all solution to lowering methane emissions from California’s dairy sector. CARB and CDFA also have correctly recognized that California is not building new dairies. California’s comprehensive approach has appropriately been tailored and designed to work with California’s unique and existing mix of pasture-based, dry-lot and conventional free-stall-barn dairy operations. California's comprehensive approach also recognizes that the effectiveness of intervention options depends on factors such as location, access to services, farmers' willingness to implement interventions, economic considerations, and uncertainty surrounding the efficacy of certain measures.

CARB and CDFA have designed a comprehensive five-part strategy to reduce dairy and other livestock sector methane. CARB and CDFA did not arrive at this comprehensive strategy alone. The strategy was developed with significant input from stakeholders representing broad and diverse interests, including the dairy and other livestock sectors, environmental and environmental justice NGOs, air and water quality regulators, leading scientists and academics, and other state agencies. Multiple stakeholder group meetings were conducted and followed by several public hearings held throughout California, as required by Senate Bill 1383.

The comprehensive approach that has emerged correctly recognizes the broad adoption of sustainable best management practices across California's diverse dairy and livestock farming systems and is crucial to delivering lower emissions and mitigating the environmental impact of dairy and other livestock systems. The approach also correctly recognizes that dairy methane comes from both manure (back end) and enteric (front end) sources and solutions for both are distinct, but necessary since both contribute significantly to the state's methane inventory. In fact, enteric methane counts for slightly more overall methane from the combined California livestock sectors (12 million metric tons) versus methane from livestock manure management (10 million metric tons).

<u>California's Dairy Cow Population Continues to Decline</u>
Fact: no new dairies in California of any significance have been built in the past 7 to 8 years and the state's cow population continues to steadily decline.

California's milk cow population peaked at 1.880 million cows in 2008 and since that time has declined by over 10% to 1.688 milk cows in 2022, according to the USDA's recently published Census of Agriculture (2017-2022). This significant decline is expected to continue and accelerate in the future due in large part to the lack of available water supplies[5] resulting from surface water curtailments and implementation of the Sustainable Groundwater Management Act (SGMA). Increased regulation, high feed costs, skyrocketing energy costs and rapidly rising cost of labor, coupled with historically low milk prices will further accelerate the decline.

The decline in California's milk cow population has already resulted in an estimated 2 million metric tons (MMT) reduction as each fewer milk cow represents an average reduction of about 10 metric tons of CO_2e reduction in the state's annual inventory[6]. Continued reductions in the

[5] Economic Impacts of SGMA on San Joaquin Valley Dairies and Beef Cattle – analysis by ERA Economics
[6] Analysis by UC Davis researchers: Meeting the Call: How California is Pioneering a Pathway to Significant Dairy Sector Methane Reduction

milk cow herd in California, similar to the 2017, 2022 reductions, which averaged approximately 13,000 cows per year, will lead to an estimated additional 100,000 cow attrition over the next eight years. (2023-2030). This continued reduction in cow herd will add another 1 MMT of CO2e reduction in California's inventory or more than 3 MMT of CO2e since 2008. These reductions will be higher if accelerated attrition occurs as no new dairies are expected to be built in the state and the number of operating dairies in the state continues to steadily decline. This latter trend is evidenced by the latest USDA Census of Agriculture, which showed the number of operating dairies in California declined by over 500 dairies from 2017 to 2022.

CDFA's Grant programs

These comments focus primarily on manure methane emissions, due to the important role played by the LCFS in incentivizing sustainable manure methane practices. As part of the comprehensive strategy, CARB and CDFA have designed two primary programs to address manure methane. These programs can broadly be characterized as methane avoidance and methane capture and beneficial use mitigation programs.

CDFA's Alternative Manure Management Program or AMMP has historically provided grants up to 100% of project cost to incentivize farmer adoption. AMMP projects are designed to work on dairies of all sizes and encourage adoption of alternative practices that avoid methane production on dairy farms. Practices include solid-liquid separation systems, conversion from flush to scrape or vacuum systems, conversion to pasture-based systems, or the adoption of compost pack barns. All of these practices avoid manure methane creation by limiting manure in anaerobic conditions where methane production increases. CDFA, with significant financial support from USDA ($85 million), has also recently deployed the Dairy-Plus Program which is designed to maximize methane avoidance on dairy farms. To date, CDFA has funded more than 185 AMMP (170), or Dairy-Plus (15) projects on California dairies. It should be noted, the incentives and funding for these alternative methane avoidance projects has grown substantially, and the number of grants awarded each year now exceeds both the number and dollars awarded under the Dairy Digester Research and Development Program. While AMMP methane avoidance projects are highly cost-effective compared to other programs funded by the state's climate investments, they currently only account for about 10% of the state's manure methane reductions. CDFA's implementation of the Dairy-Plus Program and funding more alternative projects each year will increase the contribution of AMMP projects in overall methane reduction efforts.

DDRDP – Methane Capture and Utilization

CDFA's Dairy Digester Research and Development Program (DDRDP) provides grants to dairy digester projects in California that are designed to buy down the capital cost of the technology. The program only funds a small portion (generally 25% or less) of the overall cost of a typical project. Total project costs can easily exceed $8 - $10 million per dairy farm or more. Additional revenue streams associated with the beneficial use of the captured methane, such as the LCFS, federal Renewable Fuel Standard, as well as the CPUC Biomat and RNG procurement programs, are also needed to incentivize investment.

The LCFS has become the primary program to fully incentivize the development of dairy digesters in the state. This investment has paid significant dividends in California, leading to an estimated 2.4 MMT of CO2e annually in dairy methane reductions from the 140 projects funded to date. These reductions represent about 90% of the total dairy methane reduction from projects funded by the state. These significant reductions are critical to the state's dairy methane reduction efforts, and without these reductions, the state's overall 40% SLCP and 48% GHG reduction targets cannot be met by 2030. The state's DDRDP is also highly cost-effective, returning 1 MT of CO_2e reduction for each $9 invested by the state. The return on investment is greatly magnified by the fact that the reductions are methane emissions and more valuable in short-term efforts to limit additional global warming. As a result, the state's DDRDP is widely regarded as the most cost-effective program. Equally important, the DDRDP is by far the most effective in achieving overall emissions reductions. According to the most recent California Climate Investments 2023 Annual Report produced by the state, the DDRDP accounts for 23% of GHG reductions from all climate programs invested in by the state with just 1.6% of total funds awarded. Moreover, the report highlights that 68% of funds expended on dairy digesters are benefiting priority populations, including disadvantaged communities.

Without participation in the LCFS, these projects are simply not economically feasible and will not be financed in California. Preclusion from participation in the LCFS, or the loss of avoided methane crediting would not only jeopardize existing dairy digester projects but would foreclose the ability to finance the additional 100 or so projects that will be necessary to achieve the state's methane reduction and climate targets.

Direct Regulation Will Prevent Achievement of Targets

While direct regulation of dairy methane reductions is outside the scope of this proceeding, we offer the following comments in response to repeated efforts by environmental justice organizations to directly regulate the dairy industry.

SB 1383 only authorizes CARB to implement regulation of the dairy and livestock sectors after January 1, 2024, and only after key conditions and considerations are met. These conditions and considerations include the determination by CARB and CDFA that any proposed regulations are technologically and economically feasible, cost-effective, and mitigate and minimize (prevent) leakage. SB 1383 also mandates an evaluation of progress made by incentive-based programs.

While none of these mandated considerations have been undertaken and the conditions cannot be met at this time, any effort to impose direct regulation will simply delay further progress toward the goals and ensure they will not be met. Efforts to develop regulations will take years, face significant legal challenges, and only ensure the state's methane reduction targets are not met. Efforts to directly regulate the dairy and beef cattle sectors only in California will also lead to massive methane leakage to other states, which is contrary to SB 1383 and California's leadership role in climate policy. Moreover, the existing comprehensive incentive-based program is clearly achieving the targeted reductions. Throwing out a successful program in search of a new, unproven direct regulatory scheme would be foolish and would ensure the state's climate policies are not followed by jurisdictions.

Conclusion

California's comprehensive approach to reducing methane from dairy operations is widely recognized as an effective model and fully consistent with national efforts being implemented by USDA and other federal agencies. The state's dairy methane reduction strategies are designed to provide cost-effective options and incentives for the state's diverse array of dairy farms. Continuation of these programs and efforts are critical to achieving the state's methane reduction and overall climate goals by 2030. In December 2022, a UC Davis report, *Meeting the*

Call: How California is pioneering a pathway to significant dairy sector methane reduction[7], summed it up as follows:

"Our analysis shows that continued implementation and commitment to the incentive-based climate-smart solutions that are currently driving voluntary dairy methane reduction in California should by 2030 achieve the full 40% reduction in dairy methane sought by the state's regulators without the need for direct regulation."

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[7] Analysis by UC Davis researchers: Meeting the Call: How California is Pioneering a Pathway to Significant Dairy Sector Methane Reduction

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First Name	Mikhael
Last Name	Skvarla
Email Address	mik@calobby.com
Affiliation	
Subject	H2 Collaboration - 45-day
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6982-lcfs2024-UDhUYABeB3kAWQFt.pdf
Original File Name	H2 - LCFS 45-day Comments_02202024.pdf
Date and Time Comment Was Submitted	2024-02-20 16:47:09

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

California Hydrogen Coalition

CALIFORNIA HYDROGEN BUSINESS COUNCIL

Hydrogen Means Business in California!

GREEN HYDROGEN COALITION

February 20, 2024

Ms. Liane Randolph
Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95864

Re: Proposed Low Carbon Fuel Standard Regulation

On behalf of the undersigned organizations and companies, we are pleased to submit the following comments for consideration as the California Air Resources Board (CARB) deliberates the proposed updates to the Low Carbon Fuel Standard (LCFS). We would like to express our gratitude for the diligent efforts undertaken to shape the low-carbon fuel standard to address the role of hydrogen. This supports the vision in the Scoping Plan and is crucial to recognize the comprehensive strides made in addressing the essential components of this transformative pathway for achieving carbon neutrality. While acknowledging the inclusion of significant policy components, we must underscore the importance of nuanced adjustments to ensure the success of hydrogen – a success that is also vital for achieving the standards set forth in Advanced Clean Fleets (ACF), Advanced Clean Trucks (ACT), Innovative Clean Transit (ICT), and Advanced Clean Cars 2 (ACC2) regulations. Our comments are largely focused on very specific intricacies that improve the operability of the initial proposal and we look forward to continuing to work closely with the Board and staff to finalize this regulation.

Ambition and Market Stability – *Near Term Proposal*
The regulatory aspirations of California's LCFS have had significant influence in California and beyond – with states like Oregon, Washington, and Minnesota carefully watching this proceeding. The rapid expansion of low carbon fuel alternatives has been remarkable. However, accompanying this progress is a pressing near-term challenge that demands attention to ensure market stability.

302.1 Upon thorough market modeling analysis, we express reservations regarding the proposed one-time 5%[1] stringency step-down. We contend that this increment is insufficient for market stabilization. Consequently, we advocate for the implementation of a one-time 9% increase in stringency, set to commence in 2025. This adjustment is anticipated to yield a substantial 22.75% Carbon Intensity (CI) reduction, a notable enhancement from the initially proposed 18.75%. Moreover, we support a linear progression in stringency, reaching 30% from 2026 through 2030 after the initial 9% increase.

[1] The one-time 5% stringency step-down is essentially cancelled out by the 5% Diesel baseline CI increase noted in Table 7-1 – accordingly a more aggressive CI increase of 9% is needed.

Table 7-1[2] delineates the CI adjustment for the Diesel baseline. The proposed 5% increase elevates the CI benchmark for Diesel from 100.45 to 105.76, inadvertently augmenting the number of credits in the market. This unintended consequence is particularly pertinent due to the outsized impact of biodiesel and renewable diesel on the credit bank. Addressing this, we recommend a 9% increase in CI, effective from 2025, to align with CARB's objectives and stabilize the market.

302.2 Acknowledging CARB's ambition to manage the market's "potential overperformance," it becomes imperative to recognize the cumulative impact on the credit bank through 2030 by adjusting the Diesel baseline CI. As a precautionary measure, we advocate for CARB to incorporate an annual program review of the credit bank, encompassing both deficits and credits, along with a forecast of anticipated fuel demand and production. If the annual review validates the program's feasibility, we propose triggering the Automatic Acceleration Mechanism (AAM) in 2025, rather than waiting until 2027. The earliest market impact of the AAM would be felt in 2026, contingent on meeting market conditions.

While endorsing CARB's endeavors to manage the swift progress in fuel decarbonization, we underscore the urgency to make timely adjustments that will effectively influence the market in this regard. The immediacy of these adjustments is crucial to ensuring the continued success of the LCFS program.

Capacity Crediting

Light and Medium Duty Station Capacity

302.3 To optimize the effectiveness of the Low Carbon Fuel Standard (LCFS) program, a strategic focus on enhancing Light-duty (LD) Hydrogen Refueling Infrastructure (HRI) capacity is imperative. This is particularly crucial to accommodate the unique needs of medium-duty (MD) vehicles, given their co-mingling with LD fleets. The alignment of LCFS capacity credits with market behavior is paramount for station crediting.

In light of this, incentivizing 600kg stations should be reconsidered in the context of California's near- and long-term vehicle and fleet deployment goals. MD vehicles typically require larger stations, and their integration with LD fleets, as opposed to heavy-duty (HD), underscores the importance of incentivizing larger stations. Larger stations, proven to be more reliable, better align with California's policy goals and the current market dynamics.

Maintaining the existing 1200kg credit is recommended, considering its success in driving private sector investment without relying on state grants. This credit has proven effective in supporting the existing HRI, and its continuation is aligned with the ongoing success of the infrastructure.

The US Auto Manufacturers' letter to CEC[3] underscores the industry's perspective on MD vehicles and their operational needs. Specifically, we believe that these stations and the HRI credits supporting them should contemplate high-flow refills at 10 or more kilograms per session of vehicles that have a gross vehicle weight rating of 26,000 lbs or lower, often referred to as class 6.

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[2] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appa1.pdf

[3] *Necessity for H_2 Refueling Stations for Medium-Duty Fuel Cell Electric Vehicles in the U.S.*, United States Council for Automotive Research, August 23, 2023

Limitations on Locations

To enhance the viability of hydrogen refueling station, flexibility in locations for both HD and LD is paramount. The current absence of a comprehensive station network argues against stringent geographic limitations. These limitations have the immediate consequence of limiting decarbonization

302.4 and air quality impacts of transitioning from fossil fuels, especially in the overburdened communities along these statewide transportation corridors.

While the implementation of the screenings within the CalEnviroScreen tool and the definitions in regulations provide some flexibility there is still a greater need for adaptability in station placement. Additionally, the impact of inflation and LCFS pricing on GFO 19-602 station buildout necessitates a reassessment of location constraints. The proposed restriction on HD locations are particularly limiting as the SR-60 corridor is not eligible. For example, an existing site supporting the refueling of heavy-duty trucks and wants to add H2 or charging for that matter but isn't technically located in "the right location", will not be eligible for capacity credits even if they are proximate to or there is a nexus to supporting trucks that go into disadvantaged communities. We believe additional discretion should be provided to the Executive Order (EO) on station location crucial to accommodate the evolving landscape.

HyCap Modeling and Multi-Modal Stations

The complexity in modeling multi-modal stations for capacity crediting necessitates ongoing

302.5 collaboration with CARB staff and the National Renewable Energy Laboratory (NREL) to refine the HyCap model. The model must evolve to consider diverse weight classes refueling at the same location. These refinements and functionality are essential and should progress concurrently with the adoption of the LCFS. We will work diligently with CARB staff and NREL to refine and test the model to reflect real world practices and fueling profiles.

Inequity in Capacity Crediting Standards

The imposition of an 80% renewable content requirement exclusively for HRI raises pertinent questions,

302.6 particularly in comparison to Fast-Charging Infrastructure (FCI). This requirement places hydrogen at a competitive disadvantage against other energy sources, which benefit from substantial federal, state, and ratepayer subsidies not extended to hydrogen. The absence of a pathway to generate Hydrogen-Renewable Identification Numbers (H-RINs) in the federal Renewable Fuel Standard (RFS) further disadvantages hydrogen compared to Renewable Natural Gas (RNG) and electricity.

Moreover, the 80% renewable content mandate introduces cost implications. While our industry strives for a high renewable content aligns with market goals, the exclusive application of this requirement to hydrogen is deemed discriminatory. Both the LCFS and HRI send robust signals that have prompted hydrogen station operators to provide decarbonized and renewable hydrogen. However, given the thin market supply and the exclusive application of this requirement to hydrogen, it is crucial to reassess the fairness and practicality of this stipulation.

We suggest that this additional requirement should be eliminated as it is unnecessary and counter to the carbon intensity focus and technology neutral principles that have driven innovation and investment in the LCFS program to date. Existing requirements to state funded projects could be grandfathered but is unnecessary as the LCFS sets the standard and drives commercial decisions that favor lower carbon products. Going forward, the requirement is discriminatory, will reduce available supply, increase the cost of H2 thereby hindering adoption and achievement of the state's zero carbon goals.>

Crediting Window

The shift from a 15-year to a 10-year timeframe for capacity credits has a significant impact on station financing and economics.

302.7

Notably, this change introduces a new challenge for HD stations, which are both larger and more capital-intensive. The shorter 10-year timeframe contrasts with the previously longer capacity crediting period, creating a misalignment with the capital costs associated with HD infrastructure. The substantial capital investment demands a longer-term perspective to ensure the economic viability and sustainability of HD stations. Reevaluating the timeframe in consideration of the unique characteristics and financial requirements of HD infrastructure is crucial for fostering a conducive environment for hydrogen development in this sector.

Capacity Credits for Private Depots

As a principle we believe that public programs should support only publicly available infrastructure. The crediting of private refueling locations under HRI should be grounded in several considerations.

302.8

This approach fails to expand the availability and optionality of hydrogen/fuel cells in the current-year or near-term obligations. The reduced number of publicly available stations limits the options for fleets complying with ACF, particularly impacting the adoption of fuel cell electric trucks.

Private depots should not be overbuilt and capacity crediting for private fleets is counterproductive to the purpose and intent of HRI. It hinders effective utilization of resources and undermines the efficiency of the infrastructure. Private depots carry no risk, they control their own demand. The purpose of the HD HRI program is to eliminate the risk of underutilization and promote the installation of HD H2 stations absent adequate bilateral contracts that would secure offtake and return on capital invested. Private transit facilities incur no such risk.

The HD HRI is intended to eliminate the chicken and the egg problem, by promoting deployment of stations in anticipation of zero-emission vehicle fleet growth. If HD HRS development is dependent on bilateral contracts, it will take a lot longer to deploy and penetration of HD FCETs into the market will take much longer.

Timing and Approvals

302.9 The stipulated 24-month timeline from HRI approval to bringing the Hydrogen Refueling Station (HRS) online raises concerns due to permitting and supply chain delays that have been common to date. The retraction of an approved HRI award has a substantial impact on the viability of a project. We propose granting the Executive Officer the discretion to extend this timeline, provided tangible progress is evident, similar to the flexibility afforded in ACF regulations.

Moving to the approval process for HRI applications, while we agree with the imperative to expedite approvals, the suggestion of tying approvals to a calendar quarter seems overly rigid. Instead, we advocate for a more streamlined 90-day approval period, maintaining efficiency without compromising the thorough evaluation of applications.

Lastly, the current practice of requiring Original Equipment Manufacturer (OEM) certification for a station before operations appears antiquated in the current landscape. It is pertinent to reconsider and potentially eliminate this requirement, aligning with industry advancements and ensuring regulatory practices remain synchronized with technological progress.

In essence, these proposed adjustments aim to strike a balance between expeditious progress and a comprehensive evaluation, fostering an environment conducive to the dynamic and evolving nature of hydrogen infrastructure development.

Reporting

302.10 The introduction of a new quarterly reporting requirement (Appendix A-1, §95491(d)(4)(D)) for hydrogen (H2) fuel sold through pathways utilizing book-and-claim accounting poses notable challenges, particularly for fuel retailers with mixed product inventories supplied from multiple sources.

Comparatively, electricity, utilized for charging does not face a similar reporting burden and gets to maintain a three-quarter temporal requirement and no additionality requirements. This creates an inequitable disparity in policy standards between hydrogen and electricity, placing hydrogen at a distinct disadvantage. The differential treatment risks compromising the equitable evolution of both energy sources within the ZEV landscape, warranting a reassessment of reporting requirements to ensure consistency and fairness.

Tier 1 Calculator

302.11 The liquification energy needs appear to be higher than experienced by actual operation, prompting a need for further evaluation and adjustments to align with realistic energy requirements.

We urge consideration of broadening eligibility criteria by including "process energy" for book and claim in the Tier 1 calculator. The exclusion of process energy is highlighted through a sample calculation, raising the possibility of necessitating Tier 2 pathway submissions solely for process energy credits. This approach is deemed burdensome for all parties involved and merits reconsideration.

Tier 1 Hydrogen Pathway Summary

FOR APPLICANT ONLY - CONTAINS CONFIDENTIAL BUSINESS INFORMATION - DO NOT DISTRIBUTE

Applicant Information	
Application #	
Company Name	
Company ID	
Facility ID	
Pathway Type	Steam Methane Reformation
H2 Production Data	Default Values
Operational Data Period	

Hydrogen Production Quantities		Unit	Total	Gaseous Hydrogen (GH2)	
Total Hydrogen Produced		kg	90,000	90,000	
		MJ, LHV	10,800,000	10,800,000	
H2 for LCFS Pathway(s)	Produced	kg	90,000	90,000	
	T&D Loss Factor	%	1.0%	1.7%	
	Dispensed	kg	88,479	88,479	
	(Calculated)	MJ, LHV	10,617,531	10,617,531	
				Without B&C	With B&C RNG
Maximum Matchable B&C		MMBtu , HHV	12,142		12,142
Hydrogen Reportable by Pathway		kg	90,000	0	90,000
Delivered H2 for CI Calculations		MJ, LHV	10,617,531	0	10,617,531

Carbon Intensity (CI) Calculations								
Fuel Pathway Inputs				Emission Factors		Emissions	GH2 CI (gCO_2e/MJ, LHV)	
Category	Name	Value	Unit	Value	Unit	gCO_2e	Without B&C	With B&C RNG
Feedstock	North American Natural Gas	9,243	MMBtu, LHV	75,496	gCO_2e/MMBtu, LHV	697,776,824	65.72	
Process Energy	North American Natural Gas	3,945	MMBtu, LHV	75,496	gCO_2e/MMBtu, LHV	297,800,042	28.05	28.05
	GH2 Compression	171,000	kWh		gCO_2e/kWh			
	Balance of Low-CI Electricity	1,354	kWh		gCO_2e/kWh			
	Balance of Grid Electricity	21,825	kWh		gCO_2e/kWh			
Book-and-Claim	RNG Matched to GH2	12,142	MMBtu, HHV	57,662	gCO_2e/MMBtu, HHV	700,120,753		65.94
Transportation and Distribution	GH2 Tube Trailer Truck	9,000,000	kg-miles	12.01	gCO_2e/kg-mile	108,094,529	10.18	10.18
	GH2 Fueling	10,617,531	MJ GH2, LHV	3.25	gCO_2e/MJ H_2, LHV	34,532,267	3.25	3.25
Fuel Pathway CI (gCO_2e/MJ H_2, LHV)							107.20	107.42
Margin of Safety (entered by applicant)								
Fuel Pathway CI with Margin of Safety							**107.20**	**107.42**

These suggestions aim to refine the Tier 1 Calculator, ensuring accuracy in energy needs and streamlining the credit allocation process for process energy without imposing undue administrative complexities.

Developing the Hydrogen Economy

To stimulate robust demand for hydrogen, crucial for the rapid expansion of distributed Low-Carbon
302.12 Intensity (CI) hydrogen production, we propose reinstating CARB's prior eligibility provision for LCFS electricity book-and-claim. Previously, this provision encompassed "hydrogen used in the production of a transportation fuel."

While we appreciate CARB's recent decision to extend eligibility to Low-CI hydrogen derived from sources meeting the criteria outlined in §95488.8(i)(3), we express concern over the LCFS Proposal's restrictive stance on how hydrogen can be used as a fuel. Specifically, the proposal limits book-and-claim eligibility to "hydrogen used as a transportation fuel," deviating from existing regulations that include hydrogen used in the production of a transportation fuel.

CARB's rationale for this restriction is grounded in concerns about the limited availability of Low-CI power in California and the constraints on power supply expansion. Although we acknowledge these concerns and the intent to ensure sufficient Low-CI power for Zero Emission Vehicles (ZEVs), we assert that limiting the use of Low-CI book-and-claim to neat/unblended hydrogen for Fuel Cell Electric Vehicles (FCEVs) impedes the substantial growth of hydrogen supply essential to achieving CARB's ambitious 1,700x growth target by 2045.

Our market-based concern stems from the limitation's impact on the addressable hydrogen market demand, constraining it from small to infinitesimal. To develop multiple facilities in California, hydrogen project developers require substantial capital, and investors seek a clear return on investment (ROI). Arbitrary limitations on electrolytic hydrogen contradict state policies and market conditions.

Book-and-Claim

We respectfully propose that CARB modifies the LCFS amendments to make book-and-claim available for hydrogen used to produce transportation/alternative fuels. Specifically, hydrogen used for transportation
302.13 fuels would adhere to the Strict Power Purchase Agreement (PPA) book-and-claim power sourcing regime. To align with CARB's goal of maximizing Low-CI power for FCEVs, we recommend reinstating hydrogen used as a fuel in FCEVs to the flexible Renewable Energy Certificate (REC) power sourcing regime outlined in the LCFS Proposal for Low-CI electricity supplied to Battery Electric Vehicles (BEVs) under §95488.8(i)(1)(A)-(B). This approach restores parity between BEVs and FCEVs in book-and-claim power sourcing flexibility.

Recognizing the priority given to ZEVs in the Scoping Plan, hydrogen used neat in FCEVs would be subject to the Flexible REC Book-and-Claim, while hydrogen used to produce transportation fuel (e.g., power-to-liquids, sustainable aviation fuel, or renewable diesel) would adhere to the Strict PPA Tier requirements. This two-tier system accelerates hydrogen supply growth while aligning with the Scoping Plan's emphasis on ZEVs over internal combustion engines.

Conclusion

We appreciate CARB staff's work on the development of the proposed rule and their commitment to improving the LCFS. Successful adoption of battery and fuel cell electric vehicle technologies requires changes in LCFS to reinforce market pricing, parity in policy, and encourage deployment of fueling and charging infrastructure for zero-emission fleets. The undersigned associations and companies will continue to develop the vehicles and infrastructure as well as low-carbon, zero-carbon and renewable hydrogen needed to build this market and reduce emissions. We look forward to continuing to work with CARB staff on the necessary details to achieve consensus for the upcoming workshop and rulemaking proceeding.

Thank you,

Teresa Cooke	Katrina Fritz	Janice Lin
Executive Director	President and CEO	Founder and President
California Hydrogen Coalition	California Hydrogen Business Council	Green Hydrogen Coalition

cc: Rajinder Sahota, Deputy Executive Officer
Matt Botill, Division Chief
Jordan Ramalingam, Manager

Comment Log Display

Here is the comment you selected to display.

Comment 312 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Emily
Last Name	Lemei
Email Address	emily.lemei@ncpa.com
Affiliation	Northern California Power Agency
Subject	NCPA's Comments on Proposed Amendments to the LCFS
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6983-lcfs2024-UT9XMlljUGIBWAJh.pdf
Original File Name	NCPA Comments on LCFS Amendments_022024F.pdf
Date and Time Comment Was Submitted	2024-02-20 16:52:14

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

Honorable Chair Liane Randolph
California Air Resources Board
1001 I Street
P.O. Box 2815
Sacramento, CA 95812

Re: Northern California Power Agency's Comments on Proposed Amendments to the Low Carbon Fuel Standard Regulation

The Northern California Power Agency ("NCPA") respectfully submits these comments to the California Air Resources Board ("CARB") regarding amendments to the Low Carbon Fuel Standard ("LCFS") regulation as drafted in the Proposed Regulation Order posted on December 19, 2023.

NCPA was established in 1968 to construct and operate renewable and low-emitting generating facilities and assist in meeting the wholesale energy needs of its 16 members: the Cities of Alameda, Biggs, Gridley, Healdsburg, Lodi, Lompoc, Palo Alto, Redding, Roseville, Santa Clara, Shasta Lake, and Ukiah, Plumas-Sierra Rural Electric Cooperative, Port of Oakland, San Francisco Bay Area Rapid Transit District, and Truckee Donner Public Utility District – collectively serving nearly 700,000 electric consumers in Central and Northern California.

NCPA supports the LCFS program as an essential and effective strategy for diversifying California's transportation fuels and significantly reducing greenhouse gas ("GHG") emissions from the transportation sector to further the state's climate change goals. POUs are uniquely positioned to complement the state's transportation electrification efforts by tailoring programs to the specific needs of the communities they serve. As POUs have no shareholders or profit motivations and are directly accountable to their customers through locally elected public officials, they serve as their customers' caretakers of LCFS credits. LCFS credit revenue is a critical funding source for transportation electrification incentive programs, and LCFS funds are directed back into the community.

303.1 With regards to the Proposed Regulation Order, NCPA supports an increase in the carbon intensity targets and the inclusion of the automatic acceleration mechanism to address current and future imbalances in the credit market. However, NCPA requests the following specific changes to the Proposed Order:

I. THIRD-PARTY VERIFICATION OF ELECTRICITY CREDITS

The proposed order expands the applicability of Verification of Quarterly Fuel Transactions Reports in section 95000(c) to include all types of electricity credits except for base credits. While some verification of electricity credits may be warranted, the Proposed Order does not adequately recognize fundamental differences between electricity and other fuel types. This change will disproportionately impact small fleets, non-profits, and small and rural cities.

A. Low-Volume Charging Should Be Exempt from Verification Requirements

303.2 The deferment of verification for entities generating fewer than 6,000 credits doesn't go far enough to protect entities from the high costs of verification, as even verification every three years may lead to costs that exceed the proceeds from credits generated during that period. Entities generating a low number of credits, perhaps under 2,000 credits per year, should continue to be exempt from the verification requirements to ensure that we aren't inadvertently causing barriers to entry for smaller entities. These barriers exist for entities generating a low volume of electricity credits as well as entities dispensing low volumes of low-carbon liquid fuels like compressed natural gas.

Many NCPA members own and operate a small number of EV chargers within their territories as a public service for their communities and to ensure charger availability. This service is especially critical in remote areas, underserved areas, and areas with lower EV adoption, as it may not yet be profitable for larger charger companies to invest in infrastructure in such locations. However, if Cities and Utilities are not generating enough LCFS credits to cover the cost of verification, they will be less likely to participate in the LCFS, expand charger availability, and invest credit proceeds into their communities.

Based on our experience, costs for annual verification services could easily exceed the proceeds generated NCPA, NCPA Members, and customers with small fleets. It's also unclear whether there are enough accredited verifiers available to support verification of every entity participating in the LCFS, which may cause costs to increase further. Expanding the existing verification requirements may cause the cost of LCFS to be far greater than the benefits provided to small entities looking to invest in lower-carbon fuels.

NCPA itself, as a public agency with a small fleet, has invested in charging infrastructure at its headquarters, and its participation in the LCFS allows the aggregation and sale of credits on behalf of NCPA Members. The proposed verification requirements would likely cause NCPA to drop out of the LCFS, making it more difficult for our small utility Members to participate as well.

B. Site Visits Should Be Based on an Assessment of Risk

303.3 The specific process for third-party verification is set forth in section 95501 and is essentially unchanged by the amendments, despite the expansion to various types of electricity credits.

The regulatory requirements for site visits are drafted inflexibly and do not differentiate between fuel pathways and quarterly fuel reports. For example, the regulations require the same verification steps for a hydrogen facility as a single EV charger reporting 1 MWh of charging per month. EV charging stations are largely standardized pieces of equipment with existing accuracy regulations. Requiring site visits will yield very little data of value and will instead be wasteful of time and resources.

The regulation should be amended so that site visits are not required for quarterly fuel reports for electricity credits; instead, desktop reviews should be relied on whenever possible. The language in 95501 (b)(3) *Site Visits* should be amended to recognize that the verifier should only conduct site visits if warranted after assessing risk. Residential charging, in particular, must be exempt from site visits, as a requirement to visit hundreds of thousands of homes would be disruptive and, frankly, alarming to residents. CARB should also consider additional methods for reducing the burden of verification, such as data sampling.

C. The Less Intensive Verification Process Should Be Allowed for Entities with Deferred Verification

303.4 While the regulation does incorporate a new process allowing for "less intensive verifications" for certain entities only reporting electricity transactions, the mechanism also appears to require annual verifications, thereby undoing any good achieved by the deferment for entities under 6,000 credits. The provisions in section 95501 should remove the word "annual."

II. REQUIREMENTS FOR UTILITY HOLDBACK CREDITS

303.5 The amended section 95483(c)(1)(A)(6) of the Proposed Regulation Order makes several changes to the use of proceeds from residential base credits issued to electrical distribution utilities ("EDUs"). NCPA supports the revisions to the percentage allocation of base credits to holdback credits as it will further transportation electrification programs tailored to community needs and invested in hard-to-reach communities, including disadvantaged and low-income communities.

However, the requirements for holdback credits must recognize that program needs will vary based on territory and population being served, and should not establish barriers to participation that keep out utilities with a need for funding to support transportation electrification programs.

A. Caps for administrative costs for equity programs should remain at 10%

303.6 The costs associated with the development and implementation of equity programs are vital to the success of such programs, and reducing the current cap from 10% to 5% is unrealistic and inconsistent with the needs for administering such programs. Smaller utilities, in particular, have higher administrative costs and fewer resources to administer programs that support the adoption of EV technology and deployment of EV infrastructure in equity communities.

Administrative costs contain a number of fixed costs that cannot be simply cut in half due to a change in the regulation, and those fixed costs may naturally require a higher percentage of program costs for smaller utilities. Furthermore, programs run by small utilities will never benefit from the economies of scale that a larger program like the Clean Fuel Reward will experience.

CARB should maintain the current cap of 10% for administrative costs and its current guidance detailing what costs are included. If CARB finds it necessary to amend its definition of administrative costs or its cap, it should include a distinction between large EDUs and small and medium EDUs.

B. The definition of "Rural" should be updated to reflect a change in U.S. Census Data

303.7 NCPA supports the continued inclusion of "rural areas" as eligible for equity project funding; rural communities face unique challenges that require additional assistance and support to ensure the adoption of zero-emission vehicle technologies. However, the definition of "rural" needs to be updated as the U.S. Census Bureau no longer reports rural percentages for census tract population.

The Census Bureau now defines rural as "all population, housing, and territory not included within an urban area." NCPA recommends amending the definition of "rural" within the LCFS to align with the U.S. Census Bureau's use of "non-urban" for rural census tracts:

"Rural Area" means a census tract ~~with at least 75 percent of its population~~ identified as ~~rural~~ non-urban by the latest US Census data.

C. The Equity Requirement for POUs should Remain at 50%

303.8 In alignment with the posted "Purpose and Rationale for Low Carbon Fuel Standards Amendments," the equity requirements for POUs should remain at 50%. POUs represent specific and limited territories within the State, with a wide variety of populations, EV densities, and community needs. Designing and implementing effective transportation electrification programs for low-income and/or disadvantaged communities can be challenging, and the uptake and timing of projects is difficult to predict. There will be natural fluctuations in program spending year-to-year, and an annual requirement of 50% allows for better planning to maximize the impact of equity spending.

The current regulatory structure successfully prioritizes transportation electrification support for equity communities, and the continuation of flexibility in annual program spend is needed to ensure the design of successful and meaningful programs in POU territories. In addition to the POUs' equity programs, POUs are investing in transportation electrification in a myriad of ways that benefit their communities as a whole, such as grid modernization and public charging infrastructure.

D. The LCFS should not require specific rate structures as a barrier to accessing base credits

303.9 The requirement in section 95483 (c) for EDUs to specifically provide rate options is inappropriate and will potentially have negative consequences for transportation electrification programs in areas with low EV adoption. Rates are adopted by POU Governing Boards through a public process and developed to balance system needs and system costs. The five largest utilities in the state already offer rate options to encourage off-peak charging, as do most medium-sized POUs. However, there are POUs that are either 1) unable to adopt such a rate option due to current limitations in metering infrastructure, or 2) do not yet have a need for such a rate option.

Adopting rate options to encourage off-peak charging is an ongoing consideration for all utilities as the deployment of transportation and building electrification increases. It can take years to develop and approve new rate structures. In the meantime, such POUs can encourage off-peak charging through non-rate mechanisms. Requiring a rate option as an eligibility requirement to access base credits could potentially cause POUs to drop out of the LCFS program and, therefore, cease funding for transportation electrification programs in those territories.

Therefore, NCPA recommends striking the following from 95483 (c)(1)(A):

~~*(1) EDUs seeking eligibility to generate base credits must provide rate options that encourage off-peak charging and minimize adverse impacts to the electrical grid;*~~

E. Additional support is needed to jumpstart transportation electrification in Small POU territories

303.10 Approximately 20 small electric distribution utilities (EDUs) in California have not yet opted into the LCFS, often due to limited staff resources and lower EV penetration. The LCFS allocates base credits based on the percentage of EVs in every utility territory, and allocates those credits directly to utilities participating in the LCFS so they can invest in programs that further transportation electrification adoption in their respective territories. Utilities that have not yet joined the LCFS program are unable to receive their allocated base credits, and without base credits they often do not have enough funding available to launch transportation electrification programs, further exacerbating inequities in the deployment of EV charging infrastructure and adoption.

Pursuant to section 95483(c)(1)(A), unallocated base credits are deposited into the joint Clean Fuel Reward (CFR) account but are tracked separately by the CFR program administrator. These accumulated credit proceeds could potentially be reallocated to the state's smallest utilities to help provide the additional funding needed for start-up costs involved in designing and launching transportation electrification programs.

NCPA recommends including regulatory language that allows the CFR Steering Committee to work with the Executive Officer to design one-time transfers to qualifying small EDUs:

Proceeds from non-opt-in EDU base credits that were allocated to the Large EDUs beginning with the deposit of Q2 2019 credits through the deposit of Q2 2024 credits and then transferred to the Clean Fuel Reward program pursuant to section 95483 (c)(1)(A) may be transferred by the Clean Fuel Reward Program Administrator to small EDUs opted in to the LCFS program by March 31, 2025. Any base credit proceeds reallocated in this manner must be spent by the recipient small EDU in accordance with section 95491 (e)(5). The Executive Officer must approve the Clean Fuel Reward Program Administrator's plan for distribution of previously unallocated base credit proceeds prior to any transfers.

F. The list of Holdback Programs should be reorganized and clarified

303.11 NCPA supports the California Electric Transportation Coalition's (CalETC) proposed revisions to the list of holdback programs in section 95483 as detailed in its comment letter, which includes the following improvements:

- There should be one pre-approved list of programs, rather than maintaining different program lists for equity and non-equity. Many program types may contain an equity and non-equity component, and the current reporting structure already requires documentation to account for the portion directly benefitting equity communities. Maintaining two separate lists causes confusion and delays in program design.
- NCPA supports including projects for medium- and heavy-duty (MHD) electrification as an "equity" project, but believes the regulations should clarify that any such project should qualify as equity without consideration to location. Pollutants from MHD vehicles disproportionately impact low-income and disadvantaged communities due to their traffic patterns, regardless of where they may be domiciled or refueled.
- The list of agencies that POUs may consult in the creation of workforce development projects should be expanded to include other pertinent entities, such as California Community Colleges, community-based organizations, and POU Governing Boards.
- Education and outreach projects pertaining to transportation electrification technologies and focused on equity communities are still important tools for increased adoption in equity communities, and should be included on the project list.
- Panel upgrades should be explicitly included in the project list, as they are an important component of the infrastructure needed for transportation electrification, particularly in older buildings.
- The project list should consolidate and clarify the eligibility of projects related to clean mobility solutions.

III. CLEAN FUEL REWARD PROGRAM

303.12 NCPA supports the revisions to the California Clean Fuel Reward program to prioritize electrification of MHD vehicles and to update the required transfer percentages for utilities. The regulatory language should be amended to clarify that both new and used MHD vehicles are eligible for funding, to provide flexibility for future funding needs for the MHD market. Additionally, the Proposed Order's 5% cap of CFR admin costs should be rejected, and the cap should instead revert to 10% on allowable combined administrative and ME&O costs for the Clean Fuel Reward program, as authorized in the current version of the LCFS Regulation and CPUC Resolutions.

IV. FIXED GUIDEWAY CREDITS

303.13 NCPA encourages CARB to revisit the credit mechanisms for fixed guideway systems to ensure that transit systems generate the credits warranted for their role in transitioning Californians to transportation electrification. It is unreasonable for pre-2011 fixed guideway systems to receive a fraction of the LCFS credits that post-2010 fixed guideway systems receive, considering there is no efficiency difference recorded in the actual operation of newer vs. older railway systems. Systems like the Bay Area Rapid Transit (BART) provide public transit services that are essential to California's climate goals, and the inequitable treatment of fixed guideway credits should be rectified in the current rulemaking to help ensure that transit agencies can continue to provide services.

V. CONCLUSION

We appreciate the Board's consideration of these comments, and would like to recognize CARB staff for the robust public process they have managed over the past months to develop the Proposed Regulation Order. We look forward to continuing our collaboration with CARB and other stakeholders to advance transportation electrification and reduce GHG emissions from California's transportation sector.

Respectfully submitted,

Emily Lemei

Emily Lemei
Customer Programs Manager
Northern California Power Agency
651 Commerce Drive
Roseville, CA 95678
emily.lemei@ncpa.com

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Comment 313 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Amelia
Last Name	Keyes
Email Address	amelia@cbecal.org
Affiliation	Communities for a Better Environment
Subject	CBE Comments on the Proposed 2024 LCFS Regulation
Comment	Please see comments attached.
Attachment	www.arb.ca.gov/lists/com-attach/6984-lcfs2024-VTZRNVYyAg5QOgRn.pdf
Original File Name	CBE LCFS Comments.pdf
Date and Time Comment Was Submitted	2024-02-20 16:56:22

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

COMMUNITIES FOR A BETTER ENVIRONMENT
established 1978

February 20, 2024

Via electronic submittal

Chair Liane Randolph and
Members of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814
cotb@arb.ca.gov

Re: CBE Comments on the Proposed 2024 Low Carbon Fuel Standard Regulation

Dear Chair Randolph and Members of the Board:

Communities for a Better Environment ("CBE") writes in opposition to the Proposed 2024 Low Carbon Fuel Standard ("LCFS") Regulation. CBE is an Environmental Justice ("EJ") organization, representing East Oakland, Wilmington, Richmond, Southeast Los Angeles, and surrounding communities, heavily impacted by fossil fuel pollution from mobile sources, oil refineries and drilling operations, power plants, and many other sources.

304.20 CBE supports the recommendations provided to CARB by the Environmental Justice Advisory Committee.[1] CBE has also submitted comments alongside other EJ organizations titled "Climate and Environmental Justice Organizations Recommendations for the LCFS," and we support the full set of demands included in that letter. This comment focuses on a more specific set of issues that are highly important for California communities living alongside oil refineries and other fossil fuel infrastructure.

The Low Carbon Fuel Standard, one of the most consequential regulations serving California's climate targets, must follow the requirements and principles of California's climate laws. AB 32 instructs CARB to design greenhouse gas emission reduction measures "in a manner that is equitable [and] seeks to minimize costs and maximize the total benefits to California,"[2] and ensure that these measures "do not disproportionately impact low-income communities"[3] or interfere with "efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."[4]

Unfortunately, the proposal described in the Initial Statement of Reasons ("ISOR") does not follow these statutory requirements. This comment provides detail on the following reasons why CARB must make critical changes to the proposal:

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[1] *Assembly Bill 32 Environmental Justice Advisory Committee Recommendations to the California Air Resources Board on the Low Carbon Fuel Standard Regulation Updates* (Aug. 28, 2023), https://ww2.arb.ca.gov/sites/default/files/2023-08/EJAC%20DRAFT%20Low%20Carbon%20Fuel%20Standard%20Recommendations%20Version%202%20082823.pdf.
[2] CAL. HEALTH & SAFETY CODE § 38562(b)(1).
[3] CAL. HEALTH & SAFETY CODE § 38562(b)(2).
[4] CAL. HEALTH & SAFETY CODE § 38562(b)(4).

304.1 • The proposal's incentives for biofuel consumption, particularly renewable diesel, will interfere with efforts to reduce pollution in oil refinery communities and will create new health and safety risks in those communities.

304.2 • The ISOR's analysis of the proposal and regulatory alternatives overlooks important evidence that would result in lower estimated climate and health benefits from biofuels. Including this evidence would likely increase the estimated benefits of a cap on crop-based biofuels.

304.3 • A cap on crop-based biofuels would also better achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions.

304.4 • The proposed guardrails for biofuels will not address the most important land use change risks from biofuels, and CARB needs better analysis to measure the land use change effects of internationally sourced feedstocks.

304.5 • Without a rapid phaseout of avoided methane crediting and biomethane combustion crediting for livestock manure, these credits will increase pollution in communities already deeply burdened by fossil fuel pollution.

304.6 • Credits for carbon capture and sequestration projects at oil refineries have no economic or technological justification and will worsen air pollution and safety risks.

304.7 • CARB's choice to increase program stringency rather than restrict supply of combustion fuels will disproportionately harm low-income communities due to higher program costs and missed opportunities to expand access to zero emission transportation options.

304.8 • Additionally, CARB's CEQA analysis is inadequate and must be corrected before CARB finalizes the regulation.

We request that the Board direct CARB staff to substantially revise the proposal and its accompanying CEQA documents. Additionally, in consideration of the fact that the proposal includes significant changes from what was presented at public workshops and at the September 2023 Board meeting, CBE requests that the CARB Board hold an additional, non-voting meeting to discuss the LCFS proposal, prior to the final vote.

Below, we provide detailed comments on the problems in this proposal and explain how CARB should correct the proposal to align with the requirements of AB 32.

I. THE PROPOSAL'S INCENTIVES FOR BIOFUELS VIOLATE STATUTORY REQUIREMENTS AND ARE BASED ON INACCURATE ANALYSIS.

304.1 reference

The proposal violates sections 38560, 38562(b), and 38562(d) of the California Health & Safety Code because it fails to achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions, fails to design the LCFS in a manner that is equitable, fails to ensure that compliance activities complement efforts to attain air quality standards and do not disproportionately impact low-income communities, and fails to achieve real greenhouse gas emission reductions that are in addition to those otherwise required by law.

First, the proposal will disproportionately impact low-income communities and interfere with efforts to attain air quality standards by incentivizing production of biofuels with serious health impacts in environmental justice communities. The proposal will encourage renewable diesel to become the most important fuel in the LCFS, and it does not adequately address the major climate and health risks of this fuel. Renewable diesel is already dominating the program: in the first three quarters of 2023, renewable diesel alone earned nearly 40% of the total program credits, and it earned 1.6 times more credits than electricity.[5] Production of renewable diesel and other biofuels is largely taking place in refinery communities and interfering with much-needed efforts to achieve air pollution improvements in these environmental justice communities. Further increases in renewable diesel consumption under this proposal will extend and deepen refinery pollution burdens.

304.2, 304.10 reference

Second, the analysis in the ISOR has several important omissions that cause CARB to overestimate the climate and air quality benefits of biofuels and thus overestimate the overall benefits of the proposal. Specifically, CARB did not consider the effects of biofuel reshuffling under the federal Renewable Fuel Standard. This omission results in inaccurate emission estimates, and it also conflicts with CARB's duty to ensure that emission reductions are real and in addition to those otherwise required by law. Additionally, CARB overlooked a federal Environmental Protection Agency study and other evidence that raise uncertainty about the climate intensity benefits of soybean-based diesel, and it failed to consider a study that it commissioned about the air pollution impacts of biomass-based diesel combustion. CARB should remedy these omissions and reassess the proposal as well as the regulatory alternatives that were rejected.

304.3 reference

Third, CARB should take a step toward addressing biofuels' climate and health problems by putting a cap on credits for crop-based biofuels at 2020 energy levels and conducting a risk assessment of biofuel feedstocks. This measure will better serve CARB's statutory mandate of achieving maximally technologically feasible and cost-effective emission reductions by boosting incentives for truly clean, scalable technologies including electrification. It is also critical for addressing the harms of biofuel refining as well as its global deforestation and food security risks.

304.4 reference

Fourth, in addition to placing a cap on crop-based biofuels, CARB should take further steps to protect against high-risk biofuel feedstocks. The "guardrails" included in the proposal will not address the risks of indirect land use change from crop-based biofuels. One basic step CARB should take is to calculate land use change effects for each region that provides imported crop-based feedstocks in the program.

Addressing these serious problems in the proposal will make the LCFS more sustainable, equitable, and aligned with the requirements of AB 32.

A. The lack of meaningful safeguards on biofuels disproportionately burdens low-income communities of color and interferes with efforts to attain air quality standards.

[5] CAL. AIR RESOURCES BD., 2023 LCFS REPORTING TOOL (LRT) QUARTERLY DATA SUMMARY REPORT NO. 1 (2024).

AB 32 requires that CARB, in adopting regulations to achieve greenhouse gas emission reductions, design the regulation "in a manner that is equitable"[6] and ensure that activities undertaken to comply with those regulations "do not disproportionately impact low-income communities."[7] CARB must also ensure that compliance activities "complement, and do not interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."[8] By incentivizing the continued, unrestricted growth of biofuel production and consumption, the proposal fails to follow these legislative mandates.

304.1 reference

1. <u>LCFS biofuel incentives are extending pollution burdens in oil refinery communities.</u>

The LCFS is undermining much-needed cleanup of pollution in refinery communities. LCFS biofuel incentives are driving rapid increases in California renewable diesel production, and the most significant expansions in renewable diesel production capacity are occurring at oil refineries.[9] Renewable diesel production is expected to accelerate under CARB's proposal, and additional refinery conversions are likely. In CARB's 2022 Scoping Plan, it began planning for a phasedown in oil and gas refining by 2045.[10] This phasedown would create major pollution relief in overburdened communities via direct reductions in refinery emissions and associated reductions in truck, rail, and marine pollution; however, this desperately needed relief is unlikely to come if oil refineries are instead revamped to produce biofuels.

Oil refineries are generally located in areas with higher pollution burdens that are largely comprised of low-income households and people of color, due in part to a history of racist housing discrimination. Three refinery biofuels conversions—Phillips 66 Rodeo, Marathon Martinez, and Altair Paramount—provide illustrative examples. The first two are within the San Francisco Bay Area Air Basin, which is out of attainment with state standards for particulate matter (PM10), fine particulate matter (PM2.5), and ozone.[11] The cities of Rodeo and Martinez contain environmental justice communities where residents are disproportionately burdened by pollution and vulnerable to health risks. According to CalEnviroScreen, residents in the census tract closest to the Phillips 66 refinery experience a pollution burden greater than 86 percent of census tracts in the state.[12] For the census tracts nearest the Marathon refinery, their pollution burden is greater than 82–91 percent of state census tracts.[13] Communities near these refineries

[6] CAL. HEALTH & SAFETY CODE § 38562(b)(1).
[7] CAL. HEALTH & SAFETY CODE § 38562(b)(2).
[8] CAL. HEALTH & SAFETY CODE § 38562(b)(4).
[9] Jeremy Martin, *Everything You Wanted to Know About Biodiesel and Renewable Diesel. Charts and Graphs Included*, THE EQUATION (Jan. 10, 2024), https://blog.ucsusa.org/jeremy-martin/all-about-biodiesel-and-renewable-diesel/.
[10] *California's 2022 Climate Change Scoping Plan Fact Sheet*, California Air Resources Board (Jun. 16, 2022), https://ww2.arb.ca.gov/resources/fact-sheets/californias-2022-climate-change-scoping-plan-fact-sheet#:~:text=The%20Draft%202022%20Scoping%20Plan,and%20gas%20extraction%2C%20and%20refining.
[11] *Air Quality Standards and Attainment Status*, BAY AREA AIR QUALITY MGMT. DIST., https://www.baaqmd.gov/about-air-quality/research-and-data/air-quality-standards-and-attainment-status (last visited Feb. 9, 2024).
[12] CalEnviroScreen 4.0, CAL. OFF. ENV'T HEALTH HAZARD ASSESSMENT, https://experience.arcgis.com/experience/11d2f52282a54ceebcac7428e6184203/page/CalEnviroScreen-4_0/?org=OEH (last visited Feb. 9, 2024) (search for census tract 6013358000).
[13] *Id.* (last visited Feb. 9, 2024) (search for census tracts 6013320001, 6013320004, and 6013315000).

experience increased rates of asthma and cardiovascular disease, and newborns born near the refineries have increased risk of low birthweight.[14] Both the Rodeo and Martinez refinery communities are designated as "disadvantaged communities" by the California Environmental Protection Agency under SB 535.[15]

Encouraging major oil refineries to produce large volumes of renewable diesel conflicts with CARB's statutory requirement to complement efforts to attain air quality standards and its duty to avoid disparate harms in low-income communities and communities of color. The experiences at Phillips 66 Rodeo, Marathon Martinez, and AltAir Paramount refineries provide examples of how biofuel refining extends existing pollution and creates new harms in disadvantaged communities.

Marathon Martinez and Phillips 66 Rodeo together account for a major share of the new renewable diesel capacity coming online in 2023 and 2024.[16] The Marathon Martinez oil refinery suspended operations in 2020 and was shut for several years before it reopened as a biofuel refinery. In the Environmental Impact Report for the conversion project, the county estimated that the biofuel refinery would require 180 diesel truck trips through the area per day, 63 railcars per day (an increase compared to the oil refinery due to the transport of biofuel feedstocks), and 400 marine vessels per year (also an increase compared to the oil refinery).[17] Looking at cumulative impacts on air pollution, the county found that the conversion would have a significant and unavoidable impact on PM2.5 exposure for residents and workers in the area.[18] Similarly, the Phillips 66 Rodeo refinery conversion is estimated to have significant impacts on pollution-causing activities. The refinery is now one of the largest biofuel refineries in the world. The Environmental Impact Report for the conversion found that the refinery's increased need for delivery of feedstocks would cause marine and rail traffic to increase substantially compared to when the refinery processed oil: rail car unloads per day would increase from 4.7 to 16, and tanker vessel and barge calls per year would more than double.[19] The refinery requires approximately 16,000 diesel truck trips per year.[20]

While Phillips 66 Rodeo and Marathon Martinez are two of the biggest biofuel producers in the state, they are hardly the only facilities creating biofuel pollution in oil refinery communities. In another stark example of environmental injustice, the Paramount refinery in

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[14] *Id.*
[15] *SB 535 Disadvantaged Communities*, CAL. OFF. ENV'T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/sb535 (last visited Feb. 9, 2024) (see "Disadvantaged Communities Map" and search for census tracts 6013358000, 6013320001, 6013320004, and 6013315000).
[16] Phillips 66 Rodeo and Marathon Martinez have nameplate capacities of 680 and 480 million gallons per year, respectively, making them two of the largest renewable diesel producers in the state. Maria Gerveni & Scott Irwin, *Overview of the Production Capacity of U.S. Renewable Diesel Plants for 2023 and Beyond*, FARMDOCDAILY (Mar. 29, 2023), https://farmdocdaily.illinois.edu/2023/03/overview-of-the-production-capacity-of-u-s-renewable-diesel-plants-for-2023-and-beyond.html.
[17] Contra Costa Cnty. Dep't of Conservation and Dev., *Draft Environmental Impact Report Vol. I (County File# CDLP20-02046)*, at 2-36–38 (Oct. 2021), https://www.contracosta.ca.gov/DocumentCenter/View/72957/Martinez-Refinery-Renewable-Fuels-DEIR-Vol-1-Complete-DEIR.
[18] *Id.* at 3.3-40.
[19] Verified Petition for Writ of Mandate at 13, *Communities for a Better Environment v. County of Contra Costa*, Contra Costa County Superior Court, Case No. N22-1091 (2023).
[20] *Id.*

Paramount, California took small steps toward producing biofuels in 2013, after it had ceased processing crude oil and gone idle in 2011.[21] In 2018, the refinery proposed a plan to substantially expand its operations to 25,000 barrels per day of biofuel feedstock throughput (up from 3,500 barrels per day). The City of Paramount is majority people-of-color and is considered an environmental justice community, where residents are exposed to a range of industrial pollutants, including the highest levels of hexavalent chromium (a cancer-causing air toxin) in Los Angeles County.[22] Paramount is in the South Coast Air Basin, which is in "extreme" non-attainment of many federal air quality standards, including ground-level ozone.[23] The Environmental Impact Report for the expansion project estimated that the expanded refinery would release 1,743 pounds of VOCs and 2,133 pounds of NOx emissions per day, and it would require 50 rail car unloads per day and 540 diesel truck trips.[24] The Paramount refinery demonstrates how biofuel incentives can encourage previously shuttered oil refineries to expand refining operations, even when they are located within environmental justice communities that already face air pollution levels far beyond what is considered safe for human health.

These refinery conversions make it clear that, contrary to CARB's assertions in the LCFS proposal, biofuels are not delivering the air quality improvements needed in heavily polluted environmental justice communities. Without serious safeguards to limit the growth of biofuel production in California, communities living near refineries—often in areas that are already severely out of attainment with state and federal air quality standards—will be stuck with refinery pollution for decades longer.

2. <u>The proposal fails to recognize evidence of new health and safety risks associated with biofuel refining.</u>

The existing biofuel conversions have also demonstrated that biofuel refining creates new
304.9 health and safety risks for local communities, which CARB does not recognize in the proposal. Biofuel refining may require more intensive use of hydrogen compared to fossil fuels, which can cause more frequent flaring hazards.[25] This is supported by site-specific evidence: since the Marathon Martinez facility reopened as a biofuel refinery in late 2022, there have been over 46 flaring incidents reported by the refinery.[26]

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[21] Verified Petition for Writ of Mandate and Complaint for Declaratory and Injunctive Relief at 11, *Communities for a Better Environment v. City of Paramount*, Los Angeles County Central District Superior Court, available at https://climatecasechart.com/wp-content/uploads/case-documents/2022/20220516_docket-na_petition-for-writ-of-mandate.pdf.

[22] *Id.* at 8.

[23] *Id.* at 8.

[24] *Id.* at 12–13.

[25] *Phillips 66 Rodeo Renewed Project (File No. LP20-2040) – comment concerning draft environmental impact report* at 38, submitted by Communities for a Better Environment and other environmental organizations (Dec. 17, 2021), available at https://www.nrdc.org/sites/default/files/rodeo_renewed_deir_comment.pdf; *see also* Katie Lauer, *Biofuel is poised to usurp crude oil refining in the Bay Area. But are their 'renewable' fuels a green solution or 'greenwashing'?*, EAST BAY TIMES (Feb. 4, 2024), https://eastbaytimes.com/2024/02/04/biofuel-is-poised-to-usurp-crude-oil-refining-in-the-bay-area-but-are-their-renewable-fuels-a-green-solution-or-greenwashing/.

[26] *Health officials conduct surprise inspection at Martinez refinery after recent incidents*, ABC7 NEWS (Dec. 26, 2023), https://abc7news.com/martinez-refining-company-surprise-inspection-refinery-flaring-air-quality/14228185/.

The Martinez refinery has also had an alarming number of health and safety emergencies. In a 2022 incident that the refinery failed to report, it released 20 to 24 tons of spent catalyst chemicals into the community, where residents found dust containing heavy metals settled onto front yards and vehicles.[27] In November 2023, the refinery had two major fires that refinery officials described as "facility-wide emergencies;" one of these fires resulted in life-threatening injuries for a refinery worker and released over 200,000 pounds of renewable diesel fuel.[28] These incidents have triggered a federal investigation by the U.S. Chemical Safety Board and led the Contra Costa Health department and Bay Area Air Quality Management District to conduct a surprise inspection at the facility, and local health officials have publicly expressed concerns about the frequency of safety incidents at the refinery since reopening.[29]

Despite this clear evidence that producing biofuels at oil refineries can create serious, under-studied health and safety risks, CARB's proposal has not acknowledged these risks nor accounted for them in its analyses of the proposal and the regulatory alternatives.

B. The proposal, and CARB's rejection of the regulatory alternatives, relies on incomplete analysis that overstates the climate and air quality benefits of biomass-based diesel.

CARB overestimates the benefits of the proposal by disregarding evidence that would
304.2 reference lower the calculated benefits of biomass-based diesel. First, the proposal does not consider the reshuffling of biofuel consumption into California under the federal Renewable Fuel Standard, and a fairer accounting of emissions reductions attributable to the LCFS would result in fewer climate benefits. Second, CARB has not considered evidence that land use change effects of crop-based biofuels are likely greater than what CARB's modeling estimates. Third, the proposal overlooks a recent study, commissioned by CARB, that suggests biomass-based diesel has fewer air quality benefits than previously estimated.

A more thorough analysis of the climate and air quality impacts of biomass-based diesel would likely affect the comparison of regulatory alternatives. CARB compares the proposal to "Alternative 1," a scenario with lower carbon intensity stringency and a cap on crop-based biofuels, and to the "Comprehensive Environmental Justice Scenario," which involves a cap on crop-based biofuels and limits on livestock biogas. CARB concludes that the proposal performs better than these two alternatives in part because the proposal displaces more fossil diesel with biomass-based diesel, which creates improvements in greenhouse gas emissions and air pollution. Given that CARB's dismissal of these regulatory alternatives relies heavily on the climate and air quality benefits of biomass-based diesel, CARB must update its analysis of the proposal and the comparison to regulatory alternatives.

[27] *Id.*

[28] Ted Goldberg, *Federal Agency Probes Marathon's Martinez Refinery After Two Large Fires Last Month*, KQED (Dec. 5, 2023), https://www.kqed.org/news/11968786/recent-fires-at-marathons-martinez-refinery-spark-major-safety-concerns.

[29] *Id.*; ABC7 NEWS, *supra* note 26.

1. <u>The proposal overlooks the effects of biofuel reshuffling under the federal Renewable Fuel Standard, in violation of CARB's duty to ensure emission reductions are additional.</u>

CARB's analysis of the greenhouse gas emissions reductions associated with increasing biomass-based diesel consumption takes credit for reductions that should be attributed to the federal Renewable Fuel Standard ("RFS"). The LCFS is not the only law that incentivizes production of biofuels. The federal RFS mandates production of increasing volumes of biomass-based diesel; it also allows for credit trading across regions, wherein overcompliance in one
304.10 region can be used to offset undercompliance in another region. The interaction between the LCFS and federal RFS encourages biofuel producers to concentrate consumption in California because they can take advantage of the added LCFS incentives here.[30] This has led to California consuming an increasingly large share of the country's biodiesel and renewable diesel, and in 2022 California consumed half of all the biomass-based diesel consumed in the U.S.[31] Meanwhile, consumption outside California is declining.[32] This dynamic means that a share of the biomass-based diesel consumption that CARB attributes to the LCFS is actually reshuffled from other states, where it would be consumed anyway due to the federal RFS.

CARB avoided this double counting problem in previous rulemakings by conducting an attribution analysis, but it provides no explanation why it removed the attribution analysis in this proposal. In the 2018 LCFS rulemaking, CARB calculated the greenhouse gas emissions reductions attributable to the LCFS in order to count only reductions where "complying with the LCFS can be argued to be the primary reason for the action."[33] For biomass-based diesel, CARB only gave attribution to the LCFS for products with a carbon intensity below what the federal RFS required. Under this attribution analysis, CARB rightly took credit only for the emissions reductions that were additional to what the federal RFS required; consequently, the emissions reductions associated with biomass-based diesel were reduced. In the current proposal, CARB provides no attribution analysis and does not account for the LCFS program's interaction with the federal RFS. The result of CARB's backsliding is that emission reductions associated with biomass-based diesel appear larger than they should.

This faulty analysis not only overestimates the benefits of the proposal; it also conflicts with CARB's statutory requirement to ensure that emission reductions are additional. CARB must ensure that any greenhouse gas emission reductions achieved are "real"[34] and are "*in addition to* any greenhouse gas emission reduction otherwise required by law or regulation, and

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[30] Jeremy Martin, *A Cap on Vegetable Oil-Based Fuels Will Stabilize and Strengthen California's Low Carbon Fuel Standard*, THE EQUATION (Jan. 30, 2024), https://blog.ucsusa.org/jeremy-martin/a-cap-on-vegetable-oil-based-fuels-will-stabilize-and-strengthen-californias-low-carbon-fuel-standard/.
[31] *Id.*
[32] Martin, *supra* note 9 ("Rising California consumption has come partly at the expense of biodiesel consumption elsewhere in the US, which fell 28% percent in 2022 compared to its peak in 2016.").
[33] CAL. AIR RES. BD., *Appendix F to Initial Statement of Reasons: Methodologies for Estimating Potential GHG and Criteria Pollutant Emissions Changes Due to the Proposed LCFS Amendments*, F-13 (Mar. 6, 2018), https://www.arb.ca.gov/regact/2018/lcfs18/appf.pdf?_ga=2.136358512.1729481274.1707759900-1149230758.1693940701.
[34] CARB must ensure that "[t]he greenhouse gas emission reductions achieved are real, permanent, quantifiable, verifiable, and enforceable." CAL. HEALTH & SAFETY CODE § 38562(d)(1).

any other greenhouse gas emission reduction that otherwise would occur."[35] By removing its attribution analysis for reductions associated with biomass-based diesel consumption, CARB has provided inflated emission reduction estimates. It takes credit for emission reductions that, without the LCFS, would occur anyway in other states due to the federal RFS production requirements. This constitutes a failure to ensure emission reductions are real and additional to reductions that are already required by law and would otherwise occur.

2. <u>The proposal underestimates the risks of land use change effects from increased production and import of biofuel feedstocks.</u>

304.11

CARB underestimates the climate harm of crop-based fuels and thereby over-incentivizes biofuels. The asserted climate benefits of the proposal are based in part on the carbon intensity advantages that biomass-based diesel has over fossil diesel; however, CARB's analysis is rooted in an incomplete evaluation of the climate impacts of biomass-based diesel. These climate impacts are highly dependent on a) the feedstocks used to produce biomass-based diesel and b) where those feedstocks come from. Biomass-based diesel in California is increasingly produced from virgin vegetable oil, primarily soybean oil,[36] and producers are starting to import soybean oil from South America.[37] These crop-based feedstocks have numerous harmful effects, including climate impacts from deforestation, loss of indigenous lands, and increased food insecurity. The proposal, which allows crop-based biofuels to grow unchecked, will accelerate these effects. It is therefore especially important for CARB to accurately estimate the land use change effects of crop-based feedstocks.

The proposal overlooks evidence suggesting that the land use change impacts of crop-based feedstocks are greater than CARB estimates. CARB estimates land use change effects using the Global Trade Analysis Project ("GTAP") model, but this is just one of several global economic and land use models available. The federal Environmental Protection Agency ("EPA") recently published a "Model Comparison Exercise," which evaluates the climate impacts of an increase in soybean oil-based biodiesel using three different models, including GTAP.[38] Only the GTAP model found that displacing fossil diesel with soybean diesel led to lower greenhouse gas emissions, and the other two models found that soybean biodiesel could emit *more* greenhouse gas than fossil diesel due to deforestation.[39] This EPA publication suggests, at the very least, that the GTAP model may be seriously underestimating the land use change effects of crop-based feedstocks.

The proposal also appears to calculate land use change effects based on feedstock production shocks occurring in the U.S., which does not reflect land use change effects of imported feedstocks. CARB has already approved fuel pathways for a major biofuel producer,

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[35] Emphasis added. CAL. HEALTH & SAFETY CODE § 38562(d)(2).
[36] *Initial Statement of Reasons* 32 ("the use of crop-derived, biomass-based diesel has increased in recent years"); *see also* Martin, *supra* note 30.
[37] *See* Martin, *supra* note 30.
[38] U.S. ENV'T PROTECTION AGENCY, MODEL COMPARISON EXERCISE TECHNICAL DOCUMENT (2023), https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf.
[39] Dan Lashof, *EPA's New Renewable Fuel Standard Will Increase Global Carbon Emissions – Not Lower Them*, WORLD RESOURCES INST. (Jul. 3, 2023), https://www.wri.org/insights/us-renewable-fuel-standards-emissions-impact.

Phillips 66, to produce biofuels from soybean oil imported from Argentina,[40] and imports from South America are likely to accelerate under the proposal. Land use change effects vary by region due to specific domestic economic factors and trade dynamics, and South American soybean oil presents particularly strong deforestation risks.[41] One study that looked at soybean oil cultivation in Brazil found that its direct and indirect land use change impacts could outweigh the carbon benefits of replacing fossil diesel.[42] By focusing its land use change analysis on U.S. feedstock production shocks, CARB is underestimating the carbon intensity of the feedstocks that this proposal will incentivize. Given that CARB provides credits to biofuels sourced from imported crop-based feedstocks, the proposal's failure to thoroughly evaluate land use changes by region produces indefensibly inaccurate carbon intensity estimates.[43]

Underestimation of the land use change effects of biofuels can have catastrophic consequences. In South America, deforestation linked to soybean farming is destroying critical tropical forests like the Gran Chaco Forest in Argentina and Paraguay, which is one of the biggest carbon sinks in the world, provides a critical habitat for thousands of plant and animal species, and is an ancestral home to many Indigenous communities. The proposal's incentives for soybean oil cultivation will do permanent damage to these critical natural and cultural resources.

3. The proposal does not consider recent evidence that air quality impacts from biomass-based diesel are higher than previously estimated.

304.12 By overlooking recent evidence about biomass-based diesel combustion emissions, the proposal overestimates the air quality benefits of biomass-based diesel. A 2021 study prepared for CARB evaluated the NOx and PM emissions from biomass-based diesel used in legacy and new technology diesel engines.[44] It found that the air quality benefits of using renewable diesel in legacy engines did not occur in new technology diesel engines.[45] Given that CARB has taken steps to require use of new technology diesel engines, this study shows that the emissions benefits of using biomass-based diesel in on-road fleets are uncertain and likely overestimated. CARB must account for this study in its evaluation of the proposal and the regulatory alternatives.

4. The emission factors used for biofuel production are likely not characteristic of biofuel production in California.

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[40] Low Carbon Fuel Standard Tier 2 Pathway Application No. B0520, Phillips 66 Rodeo (certified Dec. 26, 2023), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0520_cover.pdf.

[41] *Comments on Tier 2 Pathway Application No. B0520*, submitted by Communities for a Better Environment (Dec. 13, 2023), available at https://ww2.arb.ca.gov/public-comments/lcfs-fuel-pathways-public-comments/webform/submission/7151.

[42] David M. Lapola et al., *Indirect land-use changes can overcome carbon savings from biofuels in Brazil*, 107 PNAS 3388 (2010), http://www.pnas.org/content/107/8/3388.full.pdf+html.

[43] *See Comments on Tier 2 Pathway Application No.* B0520 at 2–3, submitted by University of California, Davis Policy Institute for Energy, Environment, and the Economy (Dec. 13, 2023), available at https://ww2.arb.ca.gov/public-comments/lcfs-fuel-pathways-public-comments/webform/submission/7161 (hereinafter "*U.C. Davis Comments*").

[44] CAL. AIR RESOURCES BD., LOW EMISSION DIESEL (LED) STUDY: BIODIESEL AND RENEWABLE DIESEL EMISSIONS IN LEGACY AND NEW TECHNOLOGY DIESEL ENGINES (2021).

[45] *Id.* at 53–54.

The proposal appears to calculate the air pollution impacts of renewable diesel, renewable gasoline, and alternative jet fuel using emissions factors from a simple oil refinery – specifically, Kern Oil & Refining Co.[46] This refinery is not characteristic of many refineries in California that are producing biofuels.

304.13 Because the Kern refinery is not a complex refinery, its emissions profile is likely very different from other biofuel-producing refineries. The Kern refinery includes a distillation process, a hydrotreater, and a small amount of reforming. Most biofuels in California are produced at refineries that are far complex. Complex refineries include distillation, catalytic cracking, hydrocracking, alkylation, reforming, desulfurization, sulfur recovery, hydrogen production, coking, in addition to hundreds of thousands of seals for valves, flanges, pumps, and compressors, major storage tank farms, and more, all of which can produce emissions. To produce a more accurate estimate of air pollution from biofuel production, CARB should conduct a more thorough analysis of the refineries that will foreseeably produce biofuels and generate emissions factors that are more characteristic of those from the foreseeable set of biofuel refineries.

In sum, CARB's emissions assumptions are inaccurate and inadequate to support its adoption of the proposal. CARB's failure to assess federal renewable fuels requirements backslides from prior LCFS analyses and violates the additionality requirements. CARB's narrow assumptions about crop-based biofuels render the proposal's land use change analysis arbitrary and capricious. Complete information about emissions impacts from the transition to combustion of biofuels shows lower air quality gains, and CARB's omission of this relevant information is arbitrary and capricious. Finally, CARB must conduct a more thorough analysis of the refineries that will foreseeably produce biofuels before it can rely on any emissions factors for biofuel refineries. Given that CARB's dismissal of the regulatory alternatives relies heavily on the climate and air quality benefits of biomass-based diesel, CARB must update its analysis of the proposal and the comparison to regulatory alternatives.

C. A cap on credits for crop-based biofuels would better achieve the maximum technologically feasible and cost-effective emission reductions.

304.3 reference A cap on crop-based biofuels at 2020 energy levels is an important step toward addressing the local and global environmental harms of biofuels; it also better serves CARB's statutory objectives. Under AB 32, CARB's primary regulatory objective is to "achieve the maximum technologically feasible and cost-effective reductions in greenhouse gas emissions. . . in furtherance of achieving the statewide greenhouse gas emissions limit."[47] The proposal, which encourages unchecked increases in crop-based biofuels, does not maximize technologically feasible and cost-effective reductions. Capping crop-based biofuels would open up room in the LCFS to prioritize investments in scalable technologies that are truly clean and drive us toward our goal of carbon neutrality by 2045.

Biofuels, produced in the volumes contemplated in the proposal, will not provide cost-effective emission reductions. The lion's share of the program's biofuel credits will not go to

[46] *Standardized Regulatory Impact Assessment* B-2.
[47] CAL. HEALTH & SAFETY CODE §§ 38560, 38560.5(c).

strategic advanced fuels that require investment to scale up; rather, they will go to expensive fuels that offset the regulatory burden for fossil fuel producers. Analysis by the International Council on Clean Transportation and the Union of Concerned Scientists shows that biomass-based diesel will likely only be economical to produce when it is subsidized, because the costs of producing vegetable oils are regularly higher than the costs of wholesale diesel (without even considering the costs of producing diesel from vegetable oils).[48] It is unlikely that subsidies from the LCFS will help achieve improvements in production costs, given that vegetable oil production is already a mature global industry.[49] Further, many of the new renewable diesel production facilities are oil refineries. For these refineries, part of the benefit of converting to biofuels is the opportunity to offset their compliance burden and delay a costly facility closure process.[50] LCFS incentives will thus be used to enshrine the oil giants' impacts to local communities despite a transition away from fossil fuels.

The glut of credits for renewable diesel will also undermine LCFS incentives for electrification and other scalable clean transportation technologies. Setting a cap on biofuels would help stabilize credit prices and focus credit money on electrification.[51] In the proposal, CARB recognizes that achieving carbon neutrality will require a massive shift towards electric vehicles, and that this transition is technologically feasible. Yet the proposal delays progress toward this transition by allowing biofuel credits to crowd out opportunities for regulated parties to invest in electrification.

D. The proposed guardrails do not address the problems with crop-based biofuels.

304.4 reference

The proposal recognizes some of the harmful effects of crop-based biofuels and includes guardrails it posits will address these effects. The guardrails, called "Crop-Based Biofuels Sustainability Criteria" include point-of-origin tracking, independent certification, and a ban on palm oil. The guardrails will not, however, address biofuels' harmful effects in any meaningful way. The proposal does not thoroughly explain what point-of-origin tracking and independent certification would achieve, but they are unlikely to significantly reduce the direct land use change effects of biofuel feedstock cultivation, and they do not seem to address indirect land use change effects at all. And the ban on palm-derived fuels does not address the real risks of palm oil-associated deforestation in the LCFS. The real palm oil deforestation problem comes from consumer substitution between palm oil and other vegetable oils, wherein increased demand for biofuel feedstocks like soybean oil drives up the price of soybean oil and food consumers respond to higher soy prices by substituting with palm oil.[52] The LCFS' continued crediting of biofuels derived from soybean oil will indirectly cause tropical deforestation via increased palm oil production for food, and the palm oil crediting ban will do nothing to address it.

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[48] JANE O'MALLEY ET AL., SETTING A LIPIDS CAP UNDER THE CALIFORNIA LOW CARBON FUEL STANDARD 4 fig. 2 (2022), https://theicct.org/wpcontent/uploads/2022/08/lipids-cap-ca-lcfs-aug22.pdf.
[49] *Id.*
[50] Martin, *supra* note 9.
[51] Martin, *supra* note 30.
[52] For more details about fungibility between soybean oil and palm oil, and the environmental and climate externalities of palm oil production, see *NRDC Recommendations for Updates to the Low Carbon Fuel Standard*, submitted by Natural Resources Defense Council (Jun. 14, 2023), available at https://ww2.arb.ca.gov/system/files/webform/public_comments/4036/NRDC%20Letter%20to%20CARB%20on%20LCFS%20Updates_061423_final.pdf. *See also* JANE O'MALLEY ET AL., *supra* note 48.

E. CARB should require region-specific analysis of land use change effects for fuel pathways that involve imported feedstocks.

304.14 One basic way CARB should address land use change risks is by providing more thorough analysis for fuel pathway applications. As Sections I.B.2 and I.D of this comment explain, crop-based biofuels present serious, likely underestimated, direct and indirect land use change risks, and CARB's proposed guardrails will not reduce these risks. One of the most important reasons to accurately estimate land use change effects is that these estimates are used in Tier 2 fuel pathway applications to calculate carbon intensity values for crediting biofuels. In this context, underestimating a land use change value results in over-crediting a biofuel project.

CARB should provide a region-specific direct and indirect land use change analysis for fuel pathway applications that rely on imported crop-based feedstocks. CARB's current land use change analysis models U.S. crop production shocks,[53] but pathway applicants have been permitted to use this analysis for imported feedstock pathways.[54] If CARB provided modeling analysis that reflected a region-specific production shock, it would more accurately account for domestic economic factors and trade dynamics to arrive at a carbon intensity estimate that better aligns with the true climate impacts of the feedstock.[55]

II. THE PROPOSAL'S SUPPORT FOR PATHWAYS THAT PERPETUATE FOSSIL FUEL EMISSIONS BURDENS LOW-INCOME REFINERY COMMUNITIES AND INTERFERES WITH ATTAINMENT OF AIR QUALITY STANDARDS.

304.15 In addition to the biofuel incentives, the proposal supports several other technology pathways that will be used by the fossil fuel industry, including at oil refineries, and will extend air pollution from fossil fuels. These include incentives for fossil-based hydrogen production, pathways for avoided methane crediting from livestock manure, delayed phaseout of petroleum project crediting, and incentives for carbon capture and sequestration (CCS) and direct air capture (DAC). To the extent that these incentives delay the phase down of oil refining in California, they violate AB 32's requirements to ensure emission reductions do not disproportionately burden low-income communities and do not interfere with efforts to achieve air quality standards.[56]

Most of California's oil refineries are in the San Francisco Bay area, Los Angeles area, and San Joaquin Valley, none of which are in attainment of state and federal air quality standards. Oil refineries are predominantly concentrated near communities of color and low-income communities due to decades of racist housing and land use policies. One important example of an area experiencing extreme environmental injustices due to the oil industry is the Carson/Wilmington/Long Beach area, which has five oil refineries that account for over a third

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[53] *See* CALIFORNIA AIR RESOURCES BOARD, DETAILED ANALYSIS FOR INDIRECT LAND USE CHANGE I-20–21 (2015), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/iluc_assessment/iluc_analysis.pdf.

[54] For example, in December 2023 CARB approved two Tier 2 fuel pathway applications by Phillips 66 Company that involve import of soybean oil feedstocks from Argentina. The applicant's analysis relied upon the land use change impact value for soy biodiesel that is listed in Table 6 of the LCFS regulation.

[55] *See U.C. Davis Comments*, *supra* note 43, at 2–3.

[56] CAL. HEALTH & SAFETY CODE § 38562(b)(2) & (4).

of the state's overall refining capacity.[57] Carson/Wilmington/Long Beach residents also deal with pollution from a large oilfield, two major ports, nine rail yards, four major freeways, and multiple chemical facilities.[58] Most of the residents living in this area are people of color. Air pollution levels in this area regularly exceed federal and state standards, and oil refineries are one of the area's largest industrial sources of criteria pollution and toxic pollution. To reduce the pollution burden of communities in Carson/Wilmington/Long Beach, along with all other California refinery communities, the LCFS cannot continue to support the oil industry's false climate solutions.

A. CARB should end avoided methane crediting and biomethane combustion crediting for livestock manure.

To start, CARB should rapidly phase out pathways that provide avoided methane crediting and biomethane combustion crediting for livestock manure, including pathways that are linked with hydrogen production. The proposal would extend these pathways through 2040, and through 2045 for projects linked to hydrogen production. In addition to incentivizing livestock pollution management practices that pollute the air and water of agricultural communities, these pathways harm refinery communities. The credits encourage oil refiners and other hydrogen producers to produce fossil fuel-based hydrogen, because they can make fossil-based hydrogen look carbon negative by purchasing avoided methane credits from dairy digesters that may not even operate in California. They also enable oil refiners to offset their compliance burdens using lavish biomethane combustion credits.

304.5 reference

CARB has already approved many fuel pathways in which hydrogen producers earn highly valuable credits by matching fossil-based hydrogen with avoided methane credits. For example, Shell Energy has two certified pathways for production of fossil-based hydrogen (produced from natural gas via steam methane reformation) at facilities in Wilmington and Carson (as explained above, these are areas with already exceptionally high fossil fuel pollution).[59] Shell uses book-and-claim accounting to claim the environmental attributes of biomethane derived from manure digesters in Minnesota; Minnesota biomethane does not have to actually reach California. Under this scheme, CARB has certified Shell to earn LCFS credits using carbon intensity values of -147 and -152 gCO2e/MJ—these low carbon intensity values make the pathway more valuable than most electric vehicle pathways.[60] Shell is thus earning highly valuable LCFS credits to produce fossil-based hydrogen in deeply burdened environmental justice communities.

[57] *California Oil Refinery Locations and Capacities*, CAL. ENERGY COMM. (Sep. 1, 2023), https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/californias-oil-refineries
[58] Erica Yee & Hannah Getahun, *A hot spot for polluted air: By the numbers*, CALMATTERS (Feb. 1, 2022), https://calmatters.org/environment/2022/02/california-environmental-justice-by-the-numbers/.
[59] Low Carbon Fuel Standard Tier 2 Pathway Application No. B0348, Shell Energy (certified Sep. 29, 2022), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0348_cover.pdf; Low Carbon Fuel Standard Tier 2 Pathway Application No. B0349, Shell Energy (certified Sep. 29, 2022), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0349_cover.pdf (hereinafter "Shell Hydrogen Pathway Applications").
[60] *See LCFS Pathway Certified Carbon Intensities*, CAL. AIR RESOURCES BD., https://ww2.arb.ca.gov/resources/documents/lcfs-pathway-certified-carbon-intensities (last visited Feb. 20, 2024).

In addition to subsidizing production of fossil-based fuels in environmental justice communities, avoided methane crediting for livestock manure also fails to produce real, additional greenhouse gas emissions reductions as AB 32 requires.[61] First, many of the digesters that produce avoided methane credits were funded by other state and federal programs, which means that the LCFS is claiming credit for reductions that would have occurred anyway. Second, CARB has a legislative mandate in AB 1383 to adopt regulations to directly regulate methane emissions from livestock manure, yet it relies on its failure to act on that mandate as justification for these avoided methane credits. Rather than achieving real emission reductions by requiring reductions from livestock operations (as CARB has clear authority to do under AB 1383), the avoided methane credits function as a convoluted offset program that perversely encourages livestock operations to produce more methane to earn more credits. Third, CARB has a concerning lack of data about livestock operations and the effectiveness of digesters at capturing methane, and research from Food & Water Watch suggests that California digesters receiving LCFS credits allow significant volumes of methane to escape.[62] CARB must carefully analyze the effectiveness of digesters to ensure that the emission reductions it is claiming are real.

B. CARB should rapidly phase out crediting for petroleum projects, including for CCS projects.

304.6 reference

CARB should end crediting for projects that directly subsidize oil refineries. The proposal would not phase out these petroleum project credits until 2040, and it would not phase out credits at all for CCS projects. The LCFS already gives fossil fuel producers incentives to reduce the carbon intensity of their products via deficit generation; it is unnecessary to subsidize projects that may entrench fossil fuel operations further into the future.

Importantly, CARB should remove crediting for CCS at refineries. CARB's justification for keeping these credits in the program is that the 2022 Scoping Plan identified CCS projects as an important strategy for meeting AB 1279 targets. However, CBE and the California Environmental Justice Alliance provided comments to CARB during the Scoping Plan process showing that CCS for oil refineries is an unproven technology that has major implementation barriers and creates health and safety hazards.[63] Specifically, the comments explained that CCS for oil refineries requires specialized design and has limited applicability to a small number of CO_2-emitting combustion units.[64] They also provided evidence that widespread CCS units at

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[61] CARB must ensure that any greenhouse gas emission reductions achieved are "real" and are "in addition to any greenhouse gas emission reduction otherwise required by law or regulation, and any other greenhouse gas emission reduction that otherwise would occur." CAL. HEALTH & SAFETY CODE § 38562(d)(1) & (2).

[62] FOOD & WATER WATCH, THE PROOF IS IN THE PLUMING: FACTORY FARM BIOGAS HAS NO PLACE IN THE LOW CARBON FUEL STANDARD (2024), https://www.foodandwaterwatch.org/2024/02/01/new-analysis-identifies-significant-methane-releases-at-california-mega-dairies/#:~:text=A%20new%20Food%20%26%20Water%20Watch,signature%20Low%20Carbon%20Fuel%20Standard.

[63] *CBE Comments on the Draft Recirculated Environmental Assessment (REA) for the 2022 Scoping Plan* at 6 (Oct 24, 2022), available at https://www.arb.ca.gov/lists/com-attach/41-sp22-recirc-ea-ws-B2RRNVUxAw8BZFU6.pdf (hereinafter "*CBE Scoping Plan Comments*"); *CEJA Draft Scoping Plan Sector-Specific Comments* at 20–27 (Jun. 24, 2022), available at https://www.arb.ca.gov/lists/com-attach/4459-scopingplan2022-UDMAY1Y9V2VQCQBk.pdf (hereinafter "*CEJA Scoping Plan Comments*").

[64] *CBE Scoping Plan Comments*, *supra* note 63, at 6.

refineries would increase safety risks from refinery fires and explosions.[65] Given the barriers and risks associated with deployment of CCS at oil refineries, this LCFS proposal should not rely on it as a climate solution.

C. CARB should not allow indirect accounting for fossil-based hydrogen.

304.16 The LCFS should only incentivize green hydrogen produced in a manner consistent with Environmental Justice Equity Principles.[66] Unfortunately, the proposal expands the program's support for non-green hydrogen projects by adding book-and-claim crediting for hydrogen produced outside California. Particularly concerning is CARB's proposal to add book-and-claim eligibility for fossil-based hydrogen that uses CCS or book-and-claim biomethane. This would allow out-of-state producers to create hydrogen from fossil fuels and earn LCFS credits by using CCS or purchasing book-and-claim biomethane credits. As a result, California drivers will subsidize the out-of-state production of fossil-based hydrogen.

III. CARB'S CHOICE TO INCREASE PROGRAM STRINGENCY RATHER THAN LIMIT CREDIT SUPPLY FOR COMBUSTION FUELS DISPROPORTIONATELY HARMS LOW-INCOME DRIVERS.

304.7 reference The proposal reflects a choice by CARB to ramp up the stringency of carbon intensity targets instead of meaningfully restricting the supply of credits for combustion fuels through limits on biofuel and biomethane crediting. This decision will increase program costs without prioritizing much-needed incentives to expand access to zero emission transportation options. In the 2023 Standardized Regulatory Impact Assessment ("SRIA"), CARB projects that the proposal will pass through significant costs to gas prices. The ISOR instead focuses on the proposal's minimal impacts on the average cost per mile for all fuels including clean fuels; however, this analysis fails to discuss that zero-emission vehicles are not equitably distributed in California. So far, affluent, white communities have been the main benefactors of government investment in zero-emission vehicles. Electric vehicles are still rare in low-income and rural communities and communities with the largest percentages of Black and Latinx residents.[67] CARB should prioritize increasing investment and reducing access barriers to ensure low-income communities receive benefits from the LCFS and do not disproportionately bear its costs.

By prioritizing expansion of combustion fuels like biofuels and biomethane, the proposal misses opportunities to accelerate equitable access to zero-emission vehicles and other zero-emission transportation options. Limiting the supply of these combustion fuels would increase credit incentives for electrification, and it would reduce the need to ramp up stringency of carbon intensity targets. Moreover, CARB should expand crediting opportunities that facilitate electrification. The proposal's extension of incentives for light-duty vehicle refueling is a solid

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[65] *CEJA Scoping Plan Comments*, *supra* note 63, at 26.

[66] *Equity Principles for Hydrogen: Environmental Justice Position on Green Hydrogen in California*, COMMUNITIES FOR A BETTER ENV'T (Oct. 10, 2023), https://www.cbecal.org/wp-content/uploads/2023/10/Equity-Hydrogen-Initiative-Shared-Hydrogen-Position-1.pdf.

[67] Nadia Lopez & Erica Yee, *Who buys electric cars in California — and who doesn't?*, CALMATTERS (Mar. 22, 2023), https://calmatters.org/environment/2023/03/california-electric-cars-demographics/#:~:text=Communities%20with%20high%20concentrations%20of,faces%20electrifying%20the%20entire%20fleet.

start, but CARB can take further action. For example, CARB should add a credit multiplier for zero-emission mass transit vehicles, including transit buses and school buses. These changes are critical to ensure that the program lifts up low-income communities rather than leaving them stuck in combustion vehicles paying the program's costs.

IV. THE DRAFT ENVIRONMENTAL IMPACT ANALYSIS DOES NOT SATISFY CEQA REQUIREMENTS.

304.8 reference

CARB has been authorized to implement its own certified regulatory program under the California Environmental Quality Act ("CEQA"), and failure to comply with that regulatory program violates CEQA.[68] The Draft Environmental Impact Analysis ("EIA") for the proposal violates CEQA in several respects. First, the set of alternatives CARB chose is not sufficient to evaluate feasible alternatives that could lessen significant environmental impacts. Specifically, CARB should include alternatives that involve a cap on biofuels. Second, CARB concludes that impacts on air quality are unavoidable without considering feasible mitigation options that are within its authority. Third, CARB's conclusion that odor impacts are less-than-significant overlooks relevant information. Finally, CARB's suggestion that land use and permitting authorities can adequately mitigate the indirect land use impacts of biofuel feedstocks is not consistent with the experience at existing biofuel refineries, and its conclusion flatly contradicts both records evidence and reality.

A. The EIA should include alternative scenarios that cap credits for crop-based biofuels.

CARB's certified regulatory program requires CARB to produce a staff report that analyzes whether any feasible alternatives are available that would substantially lessen any significant environmental impacts.[69] The alternatives "should focus on reducing or avoiding significant environmental impacts associated with the project as proposed."[70]

The alternatives that CARB identifies in the Draft EIA are not effective in helping to evaluate feasible alternatives that could substantially lessen the proposal's significant environmental impacts. Many of the proposal's significant environmental impacts stem from the high supply of credits for combustion fuels including biofuels and biomethane. But the alternatives included in the Draft EIA (specifically Alternatives 1, 3, and 4) primarily modify the stringency of the carbon intensity targets and provide only minor variations in the supply of different types of credits. These alternatives cannot be expected to significantly change the environmental impacts identified in the proposal.

An adequate alternatives analysis must include alternatives that cap crop-based biofuels. There are several reasons why the lack of an alternative with a biofuels cap in the Draft EIA prevents CARB and the public from fully evaluating the range of regulatory options and their environmental impacts.

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[68] *POET, LLC v. State Air Resources Bd.*, 218 Cal.App.4th 681, 270 (2013).
[69] CAL. CODE REGS. Tit. 17, § 60004.2(c)(2).
[70] *Draft Environmental Impact Analysis* 172.

First, CARB is clearly considering a regulatory option that includes a cap on biofuels. "Alternative 1" in the ISOR's "Evaluation of Regulatory Alternatives" is a scenario with lower carbon intensity stringency and a cap on virgin crop-based biofuels. However, the EIA does not include a comparable scenario. Including a biofuels cap scenario in the EIA would enable consideration of a variety of environmental resource impacts that are not studied in the ISOR. By excluding a biofuels cap scenario from its CEQA analysis, CARB fails to evaluate an alternative that it has already demonstrated is feasible and under consideration in the ISOR.

Second, the analysis of "Alternative 1" in the ISOR does not satisfy CARB's CEQA requirements. The ISOR's analysis of regulatory alternatives allows CARB to compare scenarios across specific factors including costs, overall climate benefits, and overall air quality benefits. The Draft EIA's analysis of feasible alternatives considers a broader range of significant environmental impacts from the proposal. For example, the Draft EIA determines that the proposal will have a significant impact on land use related to feedstock production; agricultural and forest resources due to feedstock cultivation; and biological and cultural resources, in part due to increased use of biofuel feedstocks. Analyzing a biofuel cap alternative in the EIA would enable CARB to evaluate whether a reduced supply of biofuel credits could reduce the significant impacts identified in the proposal.

Third, CARB omitted a biofuel cap from the "Focused Crediting Scenario," and provides no reason for leaving out this component of the Comprehensive EJ Scenario requested by the EJAC and a variety of stakeholders. CARB previously committed to evaluating the Comprehensive EJ Scenario, which includes a cap on crop-based biofuels, a rapid phaseout of avoided methane crediting, and other environmental justice priorities. It is unclear why the version of this scenario evaluated in the Draft EIA leaves out a biofuel cap. In its current form, the "Focused Crediting Scenario" is unresponsive to the EJAC's request.

CARB should therefore include a scenario comparable to "Alternative 1" in the ISOR, and it should modify the "Focused Crediting Scenario" to include a biofuel cap, making it comparable to the requested EJAC scenario.

B. CARB has feasible options, within its authority, to mitigate significant air quality impacts.

CEQA requires CARB to identify feasible mitigation measures that would "substantially lessen the significant environmental effects" of the proposal.[71] "Feasible" mitigation means
304.17 measures "capable of being accomplished in a successful manner within a reasonable period of time, taking into account economic, environmental, social, and technological factors."[72] Contrary to what the Draft EIA concludes, CARB has feasible options to mitigate the air quality impacts of the proposal.

The Draft EIA correctly concludes that Short-Term Construction-Related and Long-Term Operational-Related Impacts on Air Quality are significant, although it does not thoroughly

[71] CAL. PUB. RESOURCES CODE § 21002.1; CEQA GUIDELINES § 15126(a); CAL. CODE REGS. Tit. 17, § 60004.2(c)(2).
[72] CAL. PUB. RESOURCES CODE § 21061.1.

discuss the potential causes of local emissions increases. CARB estimates that "localized increases in emissions" could occur near biofuel production facilities, routes for biofuel feedstock, and routes for finished fuel transportation.[73] CARB should also consider potential local increases in emissions around facilities that produce fossil-based hydrogen matched with biomethane credits (for example, at the Shell Energy natural gas-based hydrogen facilities in Carson and Wilmington).[74]

The Draft EIA's conclusion that air quality impacts are unavoidable is not correct. CARB argues that there are no feasible mitigation options because CARB does not have authority to require implementation of mitigation for projects that are under control of local and state land use and permitting authorities. However, there are many feasible mitigation options that are squarely within CARB's authority.

First, CARB can require, as a condition for earning LCFS credits, that trucks carrying feedstocks and finished fuels to and from biofuel, hydrogen, and biomethane facilities are zero-emissions vehicles. CARB has authority to place conditions on pathway holders (for example, the proposal would impose sustainability certification conditions on pathway holders for crop-based biofuels). CARB also has authority, which it deploys in the Advanced Clean Fleets Rule, to require fleets to phase in zero-emission vehicles. And thanks in part to CARB's groundbreaking vehicle emissions regulations, the use of zero-emission trucks is a feasible technology option to use for mitigation.

Second, CARB can prohibit or invalidate approval of pathways at facilities that are out of compliance with state and federal air quality regulations. This is a common-sense, necessary measure to ensure that the LCFS does not continue incentivizing unlawful releases of air pollution. For example, in 2021 CARB approved three pathways for Phillips 66 Rodeo to produce renewable diesel, despite receiving notice via the pathway application comments that the facility was under investigation by the Bay Area Air Quality Management District for operating an unpermitted renewable diesel hydroprocessing unit.[75] CARB has clear authority to prevent these situations, as CARB's Executive Officer can "restrict, suspend, or invalidate credits" that are "generated... in violation of other laws, statutes, or regulations."[76] This option is also plainly feasible, because it merely requires compliance with existing air quality regulations.

Third, CARB can prohibit approval of pathways that produce significant air pollution in areas out of attainment with air quality standards, and/or in environmental justice communities. This would be highly effective in mitigating localized air pollution impacts, and it fits squarely within CARB's authority to decide which fuel pathways are eligible to receive credits under the program.

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[73] *Draft Environmental Impact Analysis* 62.
[74] *See, e.g.*, Shell Hydrogen Pathway Applications, *supra* note 59.
[75] *Comments on Phillips 66 – Application No. B0241 for Three Low-Carbon Fuel Standard Tier 2 Fuel Pathways*, submitted by Communities for a Better Environment & Natural Resources Defense Council (Dec. 17, 2021), available at https://www.arb.ca.gov/lists/com-attach/905-tier2lcfspathways-ws-BXVdbVRjBAhWPABj.pdf?_ga=2.161580924.1729481274.1707759900-1149230758.1693940701.
[76] CAL. CODE REGS. Tit. 17, § 95495(a).

These are just three examples of feasible mitigation options that CARB should consider before concluding that air quality impacts are unavoidable.

C. CARB's finding that odor impacts are less than significant is likely incorrect.

304.18 The Draft EIA's finding that long-term operational impacts from odors are less than significant is likely incorrect because it overlooks odor impacts at biofuel refineries. In both the Phillips 66 Rodeo and Marathon Martinez refinery conversions, the Environmental Impact Reports for both conversion projects found that odor impacts could be significant without mitigation measures.[77] Although the elimination of petroleum refining has beneficial impacts on refinery odors, the use of animal-based feedstocks can create odors similar to those from animal and food processing facilities.[78] The risks of these odor impacts led Contra Costa County to require odor mitigation measures at both biofuel refineries. Given these findings of significant odor impacts from specific biofuel refinery facilities, CARB should reconsider its finding of less-than-significant odor impacts.

D. CARB's conclusion that significant land use impacts from biofuels are "unavoidable" leaves no real opportunities for mitigation.

304.19 The Draft EIA finds that biofuels cause numerous significant environmental impacts related to indirect land use change, but it does not acknowledge that there are few realistic ways to ensure that those impacts are analyzed and mitigated. Increased demand for biofuel feedstocks can lead to indirect land use changes by diverting food crops to produce biofuels. This has significant global impacts on agriculture and forest resources, biological resources, cultural resources, and geology and soils. For each of these resource areas, CARB concludes that significant impacts are unavoidable because CARB does not have authority to require mitigation that would be implemented by local authorities, and CARB provides a list of "recognized practices" that are "routinely required" by other authorities that are likely to minimize such impacts.

In practice, communities are left in a catch-22 in which no state or local authority in California will evaluate the indirect land use impacts of biofuel feedstocks and consider mitigation options. The Phillips 66 Rodeo biofuel refinery provides an instructive example of this problem. During CEQA review of the refinery conversion, communities asked Contra Costa County to analyze the project's indirect land use change effects, but the County refused to conduct this analysis on the grounds that these effects were too speculative because the specific mix of feedstocks used at the refinery could not be predicted.[79] The Contra Costa County Superior Court agreed, holding that the mix of feedstocks used at the facility could not be

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[77] *Communities for a Better Environment v. County of Contra Costa*, Contra Costa County Superior Court Case No. N22-1080, at 17 (Jul. 21, 2023); *Communities for a Better Environment v. County of Contra Costa*, Contra Costa County Superior Court Case No. N22-1091, at 14 (Jul. 21, 2023).

[78] Contra Costa Cnty. Dep't of Conservation and Dev., *Draft Environmental Impact Report (County File# CDLP20-02040)*, at 4.3-79 (Oct. 2021), https://www.contracosta.ca.gov/DocumentCenter/View/72880/Rodeo-Renewed-Project-DEIR-October-2021-PDF.

[79] *See Communities for a Better Environment v. County of Contra Costa*, Contra Costa County Superior Court Case No. N22-1080, at 21 (Jul. 21, 2023).

accurately predicted to support an indirect land use change analysis.[80] The local permitting process thus provided no opportunity to evaluate indirect land use change effects and consider mitigation options, despite the fact that throughout this CEQA process, Phillips 66 was already receiving credits from CARB for fuel pathways based on specific feedstocks.

This experience shows that although fuel producers are able to provide CARB with sufficient information about their feedstocks to enable analysis of land use change effects, this information is unlikely to be used in CEQA analyses for biofuel projects. This casts doubt on CARB's conclusion that land use change impacts could be reduced to less-than-significant levels with mitigation from land use agencies and permitting agencies. It also exposes the lack of realistic options for evaluating and addressing the proposal's land use change impacts.

CBE appreciates the opportunity to provide comments on this proposal, and we urge the Board to direct CARB staff to make critical changes that will align the LCFS with AB 32 requirements and the needs of environmental justice communities.

Sincerely,

Amelia Keyes
CBE Attorney & Legal Fellow

[80] *Id.*

Comment Log Display

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Comment 314 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Bernard
Last Name	Fenner
Email Address	bernard.fenner@ductor.com
Affiliation	Ductor Americas
Subject	Letter of Comment on Proposed Tier 1 Calculators
Comment	Ductor Corporation is pleased to submit comments on the Proposed LCFS Amendments and updated Tier 1 calculators. We believe minor adjustments can significantly improve their effectiveness in promoting alternative fuels. Detailed feedback is provided in the attached letter. Thank you fo the opportunity to provide comment, and your consideration of thi letter.
Attachment	www.arb.ca.gov/lists/com-attach/6985-lcfs2024-BWFdLIQ2AiVWP1Mh.pdf
Original File Name	Ductor_LCFS Amendments_Calculators.pdf
Date and Time Comment Was Submitted	2024-02-20 16:49:28

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Board Comments Home

DUCTOR®

February 20, 2024

Matthew Botill
California Air Resources Board
1011 I Street
Sacramento, CA 95814

Subject: Comments on the Proposed Low Carbon Fuel Standard Tier 1 Calculators

Dear Mr. Botill:

Thank you for the opportunity to comment on the Proposed Low Carbon Fuel Standard (LCFS) Amendments and updated Life Cycle Analysis (LCA) and Documentation.

Ductor was founded in 2009 with the ambitious aim of creating a solution that would help solving today's environmental challenges in the energy and agricultural sectors. Today we build, own, and operate turnkey microbiological facilities that turn organic resources from the agricultural sector into sustainable fertilizers and biogas. We are focused on building and operating anaerobic digestion facilities throughout the United States, including in California, that will reduce agricultural emissions.

We recommend the following minor changes to the proposed Tier 1 calculators. We believe our insights can help refine the calculators to better serve a broad range of fuel developers and accelerate the growth of alternative fuels in California.

Our specific comments and recommendations are summarized below.

Recommendation for Tier 1 Organic Waste (OW) Calculator: Recognize Diversity and Address N_2O Emissions in all Waste Treatments

305.1 California has seen an increase in composted materials since the implementation of SB1383. However, the Tier 1 Organic Waste (OW) calculator has not been updated to reflect these changes in waste management. We suggest:

- Introducing options to indicate the percentage of Other Organic Waste (OOW) diverted from composting, in addition to landfilling.
- Incorporating user inputs for site-specific baseline CH_4 emissions.
- Including user inputs for site-specific baseline N_2O emissions.

Recommendation: Align Tier 1 Calculators with CA GREET4.0 Livestock Categories

In the CA GREET4.0 RNG tab, livestock categories include Beef, Dairy Cow, Dairy Heifer, Swine, Layer, and Broiler and Turkey. However, the Tier 1 calculator for animal manure (tier 1 DSM) presently covers only dairy cow, heifer, and swine categories. We suggest minor changes to align the tier 1 DSM with CA GREET4.0: CARB should incorporate poultry manure categories into the DSM, using corresponding baseline manure management emissions described
305.2 in CAGREET4.0 (Figure 1). To reflect these changes, we propose renaming the Tier 1 Dairy and Swine Manure Calculator to the Tier 1 Livestock Manure calculator.

	Beef Feedlots [2]		Layer Operation		Broiler and Turkey Operation	
	Dry Lot	Liquid/Slurry	Anaerobic La	Poultry w/o	Pasture	Poultry w/o Litter
Manure Region Management System Usage (MS%)						
U.S. Average	100.0%	0.7%	12.9%	87.1%	1.0%	99.0%
Manure Management System MCFs						
U.S. Average	1.2%	30.4%	71.5%	1.5%	1.2%	1.5%
Direct N2O Emission Factors (kg N2O N/kg N)	0.02	0.005	0	0.001	0	0.001
N Loss Factors through Volatilization of NH3	23%	26%	54%	34%	0%	34%

Figure 1. Snapshot of CA GREET4.0 Waste Tab showing manure management system baseline MCF values.

We also note that livestock manures, and especially poultry manure, emit significant amounts of N_2O under traditional management systems. These emissions are amplified by the increasing concentration of modern livestock and poultry operations. This concentration leads to an overabundance of nutrients, exceeding the capacity of nearby crops to absorb them. Without effective manure management solutions to distribute these excess nutrients, they accumulate in concentrated areas, creating hotspots with devastating environmental consequences. These consequences include, but are not limited to, the eutrophication of water bodies and the proliferation of harmful algal blooms[1].

Ductor's technology transforms nitrogen-rich organic resources from agriculture, aquaculture, and other organic sources into energy and fertilizers. We specialize in feedstock that cannot be used directly in conventional anaerobic digestion and biogas facilities. This feedstock is fed into the Ductor pre-process, where an IP-protected consortium of microorganisms and the IP-protected Ductor process converts them via fermentation and subsequent ammonia recovery into organic and sustainable liquid nitrogen fertilizer. The digestate is further processed into additional fertilizing and soil-improving products. Ductor's liquid fertilizer and soil-improving products can be delivered to markets requiring nutrients, easing the effects of concentrated livestock operations on our soils and watersheds.

We urge CARB to consider including avoided N_2O emissions in all manure-to-RNG pathways and the associated Tier 1 calculator. The state can enable significant reductions in agricultural N_2O emissions and mitigate the effects of concentrated livestock operations by accounting for avoided N_2O emissions in LCFS pathways.

[1] Bryant, Ray B., et al. "Poultry manureshed management: Opportunities and challenges for a vertically integrated industry." Journal of Environmental Quality 50.4 (2021): 1201-1213. https://doi.org/10.1002/jeq2.20273

Conclusion

Biogas and RNG offer immediate solutions for reducing emissions in the waste, agricultural, and livestock sectors. We believe that the changes to the Tier 1 calculators suggested above will facilitate these reductions.
Thank you for your consideration of these comments, and please do not hesitate to reach out with any questions.

Sincerely,

Bernard C. Fenner
CEO Ductor Corporation, President Ductor Americas, LLC

Ductor Americas, Inc
1200 18th Street NW
Suite 700
Washington, District of Columbia
20036

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Comment 315 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Stefan
Last Name	Unnasch
Email Address	unnasch@lifecycleassociates.com
Affiliation	Life Cycle Associates
Subject	Credit Adjustment and Margin of Safety
Comment	See attached comment letter on Credit Adjustment and Margin of Safety.
Attachment	www.arb.ca.gov/lists/com-attach/6986-lcfs2024-BWIUMQNjU18GYwV3.pdf
Original File Name	LCA_Credit Adjustment and Margin of Safety_LCFS Comments Feb 20 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 16:20:55

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Stefan Unnasch
1.650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

February 20, 2024

Liane M. Randolph
Chair, California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject**:** Letter of Comment on Credit Adjustment and Margin of Safety for Proposed Amendments to the LCFS, posted December 19, 2023

Dear Chair Randolph:

Life Cycle Associates would like to take this opportunity to provide our comments on the Proposed Amendments to the Low Carbon Fuel Standard Regulation, posted on December 19, 2023. This letter is focused on two key components of the proposed amendments: Credit Adjustment and Margin of Safety.

Proposed Credit Adjustment
The following is an excerpt from the proposed regulation:

"Credit True Up after Annual Verification. Beginning with the 2025 annual Fuel Pathway Report data reporting year, the Executive Officer may perform credit true up for a fuel pathway that has a lower verified operational CI upon receiving a positive or qualified positive verification statement for the associated annual fuel pathway report and quarterly fuel transactions reports, notwithstanding the prohibition on retroactive credit generation in section 95486(a)(2). To implement this true up, the Executive Officer will calculate an equivalent number of credits representing the difference between the reported CI and the verified operational CI from annual Fuel Pathway Reports for each fuel pathway code reported with non-liquid transaction types and with the following liquid fuel transaction types "Production in California," "Production for Import," and "Import" during a compliance year, and place those credits in the account of each appropriate fuel reporting entity after August 31 for the prior compliance year. The credits will be calculated according to the following equation:"

Expected Impact of Proposed Credit Adjustment

- If a fuel pathway holder's operational CI exceeds their certified CI, 4.0× credits are taken away per § 95486.1. (g).
- The clarity of this penalty eliminates uncertainty associated with non-compliance
306.1 but does not include any consideration of specific conditions leading to non-compliance.
- If the operational CI is below the certified CI, the under-generated credits may be returned to the fuel pathway holder.
- Pathway holders now have an artificial incentive for an inflated margin of safety (MOS). The expected outcome is election of highly inflated margin of safety to avoid any CI non-compliance risk while still (retroactively) generating all of the credits associated with the operational CI improvement. This measure also

Stefan Unnasch
1.650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

provides an incentive for deferring the generation of credits and prevents reporting the benefits of the LCFS program as timely and accurately as possible.

Rationale

306.1 cont
- CI exceedances are often out of the control of fuel producers, often arising from black swan events outside the scope of a facility's operational control. Black swan examples include extreme weather events or global/regional supply chain disruptions due to the war in Ukraine or COVID-19. These events can create a discrepancy between the certified CI and operational CI for many fuel pathway holders, unrelated to their operation.
- In such situations, fuel producers should not receive high penalties for exceedances that they are unable to mitigate.
- High margins of safety results in skewing of credit reporting and deferred cash flow.

Recommendations:
Application of a Margin of Safety

306.2
- Oregon CFP has adopted a quantitative variability approach to determine a margin of safety for their fuel pathways, requiring pathway holders to submit their quantitative variability analysis to support the margin of safety election.
- We find that the quantitative approach under the Oregon CFP may be an appropriate framework for calculating the conservative margin of safety "of a magnitude determined by the applicant", within California's LCFS.
- We recommend inclusion of a similar provision to prevent election of overly conservative MOS as a way to entirely avoid CI non-conformance while creating a significantly large true-up accounting burden on CARB.

Reduced True-up factor for Communicating CI Exceedance in Advance

306.3
- We recommend inclusion of a provision that allows for reduced penalty consideration for specific cases:
  - If a fuel producer informs CARB well in advance, in writing, of projected CI exceedance and retains a matching credit balance in their LCFS Reporting Tool (LRT) account at the end of the reporting year, CARB may reduce the CI exceedance factor from 4.0 to 2.0.
- Such a relief should be strongly considered for CI exceedances arising from black swan events.

Thank you for your consideration in reviewing our comments and incorporating them into the final regulation. If you have any questions, please reach out to me directly.

Sincerely,

Stefan Unnasch
Managing Director
Life Cycle Associates, LLC

Love Goyal
Sustainability Project Manager
Life Cycle Associates, LLC

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Here is the comment you selected to display.

Comment 316 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Steven
Last Name	Berry
Email Address	steven.berry@yale.edu
Affiliation	Yale University
Subject	GTAP Model in CARB

Comment

I am submitting the attached co-authored report evaluating the economic foundations of the GTAP model. This model is used by CARB to estimate emissions from indirect land use change ILUC for the Low Carbon Fuel Standard. It results in far lower estimates than biophysical models would estimate of the land use costs of converting land to produce the quantity of crops that are incorporated into a mega joule of each biofuel.

Our report is based on on-going research sponsored by the Tobin Center for Economic Policy at Yale. The report finds that the GTAP model lacks an economic basis and is particularly unable to project changes in land use. Our report also finds that both unsupported structural features and parameters systematically lead to these low ILUC estimates. Accordingly, GTAP does not
307.1 provide a reasonable scientific basis on which to estimate ILUC nor to support a conclusion that crop-based biofuels reduce greenhouse gas emissions when replacing gasoline or diesel. For this reason, it would be inappropriate to make regulatory changes designed to reduce greenhouse gas emissions that incentive any increased use, or even continued use, of these biofuels.

The inability of GTAP to provide an economically grounded estimate of ILUC does not mean that the use of land to produce biofuels should be considered carbon-free. One reasonable alternative approach is to factor in the carbon opportunity cost of using for biofuels. It this land would be equally appropriate to use a biophysical model to estimate what the average carbon losses have been to produce the cropland that in turn generates the crops used for biofuels (amortized according to CARB policy over 30 years). Either approach is likely to conclude that using crop-based biofuels substantially increases greenhouse gas emissions relative to the use of fossil fuels.

Attachment www.arb.ca.gov/lists/com-attach/6987-lcfs2024-AXVUPQNgUWsDa1AP.pdf

Original File Name Tobin Center Report on the Economic Foundations of the GTAP Model (Berry, Searchinger & Yang February 2024.pdf

Date and Time Comment Was Submitted	2024-02-20 16:57:15

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Evaluating the Economic Basis for GTAP and Its Use for Modeling Biofuel Land Use

Steven Berry, Timothy Searchinger, and Anton Yang
(February 20, 2024)[1]

Increased biofuel use requires crops, producing crops requires cropland, and producing cropland causes losses of carbon from vegetation and soils. In a typical lifecycle context for products other than biofuels, carbon accounting attributes to each product the emissions from inputs, including fixed inputs if they are significant, so some of the emissions from each fixed input are assigned to each output. For example, some of the emissions of producing a car factory are assigned to each car. Following this approach, the carbon emissions of biofuels are high: as discussed below, the emissions to generate a hectare of cropland greatly exceed the reduced emissions from gasoline or diesel by substituting 30 years of biofuel production on that hectare.

In determining the emissions from the use of cropland for biofuels, the convention has been instead to use an economic analysis to determine how much carbon land conversion will occur to replace crops diverted lost from land conversion as a result of the consumption of specific biofuels. There are sound economic and biophysical reasons to believe that economic responses will not be substantially less than those associated with the average loss of carbon in the past to create the requisite quantity of cropland.

Global cropland for annual crops is expanding at an increasing rate: according to a recent, high-quality satellite-based study at a net rate of 10 million hectares per year (and a gross rate of roughly twice that) (Potapov et al. 2021), roughly equal to the annual harvested cropland area of Iowa. Although data limitations impede analysis of net changes in pasture area, satellites show that expansion of pasture is an even larger direct source of deforestation than cropland (Weisse and Goldman 2021). Sound econometric studies have shown that shocks to agricultural supply translate into prices for crops around the world (Roberts and Schlenker 2013). This connection means that increases in demand for biofuels in one region will cause similar price increases in different parts of the world and thereby stimulate cropland expansion wherever it is cheapest to do so. And where robust econometric studies are available, they

[1] The research on which this report is based is ongoing. Comments welcome to sberry@yale.edu, and some further improvements are likely. Berry: Yale University Department of Economics and Tobin Center. Searchinger: Princeton University and Tobin Center. Yang: Yale University and Tobin Center.

have found that cropland expansion is highly sensitive to crop prices in carbon-rich parts of the world, such as Brazil and the Amazon, particularly over any period longer than short-term (Souza-Rodrigues 2019) (Sant'Anna 2024). These same rigorous studies have found that yield effects are an extremely small fraction of the estimated area effects, which implies that cropland expansion is the dominant way the market replaces crops.

To estimate these effects, however, governments have sometimes relied on models that seek to predict how biofuel demand will reallocate world land use through global market pricing mechanisms, sometimes including interactions with the entire global economy. The resulting emissions are known as emissions from indirect land use change or "ILUC." GTAP is one model used to estimate ILUC, with one version used by the California Air Resources Board (CARB) and changed versions used as inputs to the GREET model at the U.S. Department of Energy. In both versions, estimated ILUC carbon losses from a gallon of corn ethanol and soybean biodiesel are extremely low, meaning there is little carbon cost for diverting even prime farmland to biofuel production.

To serve this function, the GTAP model must be scientifically credible. This memo evaluates GTAP's scientific foundation. We find that GTAP lacks any appropriate economic foundation. It is particularly unable to evaluate land use changes.

- Of thousands of economic parameters, only a small number claim to have any direct, empirical basis. Of these, few of the cited empirical studies make any use of credible techniques for distinguishing correlation from causation and, most fundamentally, supply from demand. Regardless, these parameters are all or nearly all misapplied to data, regions, and functional forms that differ fundamentally from the original empirical results. In effect, these parameters are claimed to predict changes in supply and demand they do not.

- We also find that functional forms of the GTAP model, to which parameters are misapplied, lead to findings of low ILUC. In multiple ways the purely assumed structural form leads to extremely limited conversion of forests. As one example, the functional form leads GTAP to select a single, average parameter from the one study relied upon for estimating the likelihood of land use change, which explicitly underestimates the level of cropland expansion and greatly overestimates the economic resistance of forests to this conversion. These features also also causes forests to instantly reappear in new areas. In some cases, the structural form leads to bizarre results.

- GTAP's basic economic structure is particularly unsuited to the analysis of land use change because it does not reallocate land among different uses but instead destroys or creates large quantities of physical land. This land must then be arbitrarily "adjusted back" to respect the actual finite quantity of land. These adjustments radically reduce the ILUC results and further shrink the share of land use change from GTAP's proxy for forests.

- The model's structural form also cannot allow conversion of unmanaged land, which is much of the world's carbon rich land. It also contains no notion of a standing forest that can exist for multiple reasons – there is only land that exists to produce wood. These assumptions, required by the structural form, not only forces the model to ignore a major direct source of potential land use change but works backward to limit the model's conversion of this proxy for managed forests and even of grasslands.

- GTAP uses an outdated trade model that is designed to capture patterns of trade in manufactured goods. Applying this model to agricultural products artificially limits the predicted effects of US policy on world land use.

- We also review how additional, empirically unsupported decisions added to the model since the first version used for CARB have further reduced the estimated ILUC. These include unjustified pure assumptions that ensure that to the extent the model claims the need for more cropping area, it does not actually result in additional land conversion.

Benchmarking ILUC

To determine a useful benchmark for ILUC, we can ask on average how much carbon has been lost from vegetation and soils to produce the crops that go into one gallon (or one mega joule) of each biofuel. Following both national and California policy, we can then amortize this carbon loss over 30 years of biofuel production. This calculation generates an ILUC if the crop, such as corn diverted to biofuels, is replaced by the same quantity of corn on new cropland with the average global yield and with the average carbon losses that occurred from previous cropland expansion for corn This is the same general approach taken for inputs in lifecycle analyses, including for other inputs used for corn.

As shown in Table 1 (and estimated in (Timothy D. Searchinger et al. 2018), this theoretical ILUC is 200 gCO_2/MJ for corn ethanol and 330 gCO_2/MJ of biodiesel. That number, which excludes the production emissions from use of fertilizer and fossil fuels, is roughly 3-4.5 times the direct fossil fuel savings from the use of the biofuel. By this benchmark, the GTAP ILUC estimate used by CARB is only around 10% of these average emissions in generating cropland to produce corn and soybeans. That estimated ILUC is also only around 25% of the carbon that could be sequestered by allowing U.S. corn land to grow forest (assuming 3tC/ha/year). (See Table 1). The GTAP versions incorporated into the GREET model are even lower. Implicitly, they are claiming that all the cropland in Iowa can be diverted to biofuel production -- or to any other use -- with almost no effect on global land use elsewhere or climate consequences.

The GTAP estimates are also far below estimates of some other recent economic model estimates. In (Lark et al. 2022), the authors found that ILUC emissions in the U.S. alone were 39 grams CO_2/MJ without counting international ILUC emissions. In (Merfort et al. 2023), the authors estimated an ILUC of 92 grams CO_2/MJ for ethanol from high-yielding energy crops.

Table 1: Comparison of GTAP ILUC Estimates with Biophysical Carbon Costs

	Average global carbon loss to produce crop	Land use cost of not reforesting land at 3tC/hectare at U.S. yields	GTAP California ILUC estimate	GTAP-BIO ILUC estimate used by GREET	Exhaust pipe emissions from gasoline or diesel
Grams CO_2/mega joule					74
Corn ethanol	200	83	22	7.8 – 14.3	
Soybean biodiesel	330	179	27	9.1-12.1	

Biofuel figures are "land use cost" figures measured by the different methods excluding production emissions and excluding the portion of land attributable to co-products. Sources: Column 1 (Searchinger et al. 2018), column 2, author's calculations, column 3, CARB emissions estimates, column 4, GTAP results incorporated into GREET model outputs.

An economic model might estimate these much lower carbon costs than the average carbon cost of producing the biofuel crop for one or a combination of three reasons, all of which contribute to GTAP's low ILUC estimates.

- First, a model may estimate that much of the food diverted to biofuels is not replaced because higher food prices depress consumption. New cropland is not therefore needed to replace much of the food. In the original GTAP estimates of ILUC from corn ethanol for CARB, roughly half of the food calories are not replaced. (Hertel et al. 2010)(T.D. Searchinger et al. 2015).

- Second, a model may claim that higher prices may induce farmers to increase output per acre on existing agricultural land: This can occur by increasing crop yields, by intensifying pasture, or by increasing double-cropping or other forms of "cropping intensity. These effects also play a major role in GTAP (Malins, Plevin, and Edwards 2020) (Hertel et al. 2010) (T.D. Searchinger et al. 2015). In recent modeling, for example, the model predicts that 80% or more of additional cropping area in most regions is supplied not by new cropland but by growing crops on existing cropland more frequently. (Malins, Plevin, and Edwards 2020).

- Third, the model may claim that converting land for new cropland releases little carbon. In recent GTAP runs for corn ethanol, 89% of the new cropland comes from grassland, with only 11% from forests (Table 1) (Farzad Taheripour, Zhao, and Tyner 2017) (Table 1). As discussed in Malins et al. (2020), some new versions of GTAP used for GREET also claim that converting much of this pasture to cropland gains soil carbon.

These functions may interact. In GTAP, for reasons discussed below, farmers directly convert mostly grassland rather than forest, and in turn, livestock producers do not then significantly convert forests to replace grazing land either because of reduced meat consumption or because of livestock intensification.

The ILUC calculation depends in essence on the ratio of three different responses to increased prices: agricultural land expansion, intensification, and food demand reductions. This means that all three responses must be soundly estimated to produce a scientifically useful ILUC estimate.

Specific recent GTAP modifications that lead to a low ILUC

GTAP was originally used by the California Air Resources Board to establish an ILUC in 2010 but has undergone subsequent revisions. This section discusses specific parameter decisions made regarding GTAP, critiqued in (Malins, Plevin, and Edwards 2020), and to which some GTAP modelers responded in (F. Taheripour, Mueller, and Kwon 2021). These decisions by themselves will generate extremely low ILUC estimates in three ways:

- By increasing the "intensification" effect of cropland, so new cropland is not needed to replace crops;
- By increasing the intensification effect on pasture, so if pasture is converted to cropland, conversion of forest to pasture is not needed to replace the meat or milk;
- Through adjustments to ensure that even more cropland expansion comes out of grassland not forest, plus related changes to the estimated carbon effects of converting much of this grassland to cropland. Both changes reduce the carbon losses from expanding cropland.

Although the major contribution of this paper is to focus on the underlying model, we discuss first the issues raised by these recent changes because of their ability to greatly lower ILUC and because they help illustrate how a model can generate low ILUC estimates. We agree with the critiques in Malins et al., and we add some relevant additional observations.

1. Double cropping or other increases in cropping intensity

A major feature introduced into the model is an elasticity that ensures that 80% of the increase in cropping area in most regions, including the U.S., results not from expansion into native lands but from cropping the same cropland more frequently. (Malins, Plevin, and Edwards 2020). Such a change is modeled as an increase in "cropping intensity." This can occur, for example, by increasing the acres that produce two crops in a year, known as "double cropping." Because doing so reduces the need for new cropland; an 80% increase in cropping intensity reduces ILUC by 80% (relative to the estimate without this effect).

As discussed in Malins et al., the GTAP authors have neither conducted nor cited any economic analysis that estimates that increased demand causes increases in double cropping or otherwise increases cropping intensity. What the authors appear to have done is simply adopt elasticities tailored by region, which they feel matches recent cropland trends in these regions. Even if there were a trend toward increased cropping intensity, that does not mean that increased demand for crops drives this trend, let alone by how much if it contributes at all.

One way to highlight the flaw in this analysis is to compare the author's claim that 80% of U.S. cropping will be provided by increases in cropping intensity with the contrary evidence of what has happened. Although there appeared to be a small increase in double-cropping in the U.S. in the first years of the renewable fuel standard mandate, there has since been a significant decline. Double cropping over the last five years was roughly 40% lower than between 2007-2011 and among the lowest levels ever recorded in USDA data. For overall cropping intensity, which also factors in how often land is left fallow or crops fail, there has been no discernible U.S. trend for decades. (USDA data available at https://www.ers.usda.gov/data-products/major-land-uses/major-land-uses/#Cropland). (For the remainder of the world, poor data makes it impossible to determine even what the true trends really are.[2]) If nothing else, this data calls the authors' assumptions into question.

But this change also helps illustrate the improper economic data-analysis methods that are frequently used in designing the GTAP model. The "method" here is to treat short-run observed changes in double-cropping as reflecting a large, long-run causal effect of crop prices on double-cropping. Having now seen the recent data on double-cropping, if they followed their own method, the GTAP modelers would make adjustments and remove this double-cropping effect for the U.S. But of course, the original decision was not based on any serious attempt to distinguish causal relationships in the data. In fact, none of this data tells us about the real effect of prices on double-cropping in either direction. We discuss these issues more broadly below.

More broadly, these kinds of ad hoc adjustments turn modeling into mathematical forms of storytelling. But any number of stories could be told from the same snippets of information. For double-cropping, alternative potential stories include that the original increase in double-cropping was driven by non-price factors. Alternatively, increases in cropping intensity could be explained as a short-term response to increased demand before cropland area expanded to meet demand at a lower cost. The large number of potential and contradictory story lines are why economics requires rigorous methods to tease out the effects of changes in demand or supply.

[2] As Malins et al. correctly observe, the data from the FAO that estimates a country's area of cropland and that estimates its area harvested come from different sources using different methods. The limitations in our understanding of cropping intensity are discussed in (T. Searchinger et al. 2019), which provides examples of how FAO statistics can conflict with results from satellite studies.

2. Demand-induced yield gains of cropland and pasture

The GTAP modelers have similarly incorporated a substantial price-induced yield effect. This was originally based on a claimed set of U.S. papers for corn and then applied that to every crop and to every country in the world. The lead author here reviewed these papers for the California Air Resources Board and determined that the papers relied upon actually as a whole found no yield intensification effect after the 1960's (ST Berry 2011). In fact, as discussed in Malins et al., corn yields in the U.S. follow an intensely linear trend independent of price. Furthermore, applying this intensification effect to other crops and to other regions lacks any foundation at all as the physical and economic factors that determine the ratio between land expansion and intensification will vary greatly by country.

In revisions to the model, as discussed in Malins et al., a large intensification effect has also been applied to pasture. As a result, when cropland expands into pasture, little pasture expands into forest to replace the meat or milk. As quoted in Malins et al. (2020), the GTAP authors conceded that this estimate does "'not have an empirical basis.'"

We add that this is a particularly significant, pure assumption. Expansion of pasture into forest is the main direct source of global deforestation (Weisse and Goldman 2021). Although lacking economic rigor, several papers have found statistical associations in Brazil between conversion of pasture to cropland and knock-on expansion of pasture into forest. (Lapola et al. 2013)(Lapola et al. 2010) (Arima et al. 2011). A rigorous, econometric study has shown that increases in beef prices have a strong effect on deforestation in the Brazilian Amazon (Araujo, Costa, and Sant' Anna 2020), which implies a significant knock-on effect if pasture is converted to cropland elsewhere. Other unjustified model features, discussed below, lead GTAP to project hat cropland will expand into pasture. This pure assumption therefore has the effect of additionally assuming away much ILUC.

3. Cropland pasture

The introduction of a category of land called cropland pasture was one of the model features that leads the model to project even more conversion of pasture rather than forest. Cropland pasture is land that is occasionally cropped but is used for pasture, and it became the dominant modeled source of new cropland in both the U.S. and Brazil. This was not based on any kind of economic analysis but on an observation that as U.S. biofuel production rose, USDA was reporting a continuing decline in a land use category called cropland pasture. The primary effect of this change, given the GTAP structure, is to make it even more likely that cropland will expand into pasture rather than forest. (GTAP assumes that cropland will more likely switch from one crop use to another than expand into new non-crop uses.) As Malins et al. observe, the GTAP-GREET versions of the model then further assume that this conversion increases soil carbon, contrary to virtually all other estimates of the effect of pasture conversion. One effect of this assumption is that the cropland pasture assumption, as well as other elements of the model that lead cropland to expand into pasture rather than forest, cause even larger reductions in ILUC.

As discussed in both Malins et al. (2020) and Lark et al. (2022), this trend in cropland pasture is as likely based on definition changes and measurement inconsistencies as real changes, as USDA has cautioned. Malins et al. also observe that the GTAP authors employed no economic estimates to differentiate any changes in cropland pasture due to biofuels from trend line changes. And they observe that there is no international category of cropland pasture. [3] We agree with these critiques and add two observations.

First, the GTAP authors claim that the FAO category of "temporary pastures and meadows" is the global equivalent of cropland pasture, so they can apply it in Brazil (F. Taheripour, Mueller, and Kwon 2021). Even if this were true, in Brazil this category of land use has had a steady increase during the rise of biofuels, increasing in area by 20% from the average of 2003-05 average to the of 2019-2021.

Second, the claim that converting cropland pasture to cropland increases soil carbon is not merely empirically unsupported but flawed conceptually because it is based on a failure to distinguish fluctuations in price from a structural shift in demand. This claim assumes that cropland pasture is marginal cropland that rotates in and out of cropping, which depresses its carbon stock relative to land used consistently as pasture (F. Taheripour, Mueller, and Kwon 2021). However, due to fluctuations in price, there will always be "frictional" cropland, i.e., land that is cropped in some years and not others. Even at a higher level of demand for crops due to the growth of ethanol, there will continue to be fluctuations in prices, so there will continue to be land cropped only in some years. There could be other structural economic changes that alter cropland pasture area, but there is no conceptual reason to believe, let alone econometrically established relationship, that the quantity of frictional cropland will decrease due to the rise of biofuels or other increases in demand.

GTAP'S Economic Foundation

This section goes beyond the specific, recent modeling choices discussed in *Malins et al.* to evaluate the GTAP model more generally. This part first explores the parameters and

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[3] In (F. Taheripour, Mueller, and Kwon 2021), the GTAP authors claim that the decline in cropland pasture was based on USDA data and large enough to accommodate increased land for biofuels even assuming losses to alternative uses. But this claim does not address the critiques. The GTAP authors did not perform an economic analysis to determine if increased demand leads to a decrease in cropland pastures. Moreover, if the data on cropland pasture is fundamentally flawed, it could not be be used for economic analysis. There might be some trend in behavior, but not knowing the true quantity of cropland pasture, it would not be possible even to try to determine its causal factors. As stated in Lark et al. 2022: "[T]he source of cropland-pasture data in the United States is the 5-year interval Census of Agriculture, where the category is a subjectively interpreted aggregate variable that has undergone significant definition changes (Bigelow and Borchers 2017) and measurement inconsistencies (USDA 2019; 2002) across time, further rendering it inappropriate for LUC assessment."

economic structure of the model. It finds that these lack an economic foundation. We then focus on the specific modeling of land use. We find that ILUC is reduced both by the general structure of the model and by the specifics of land use in the model.

In both parts of this discussion, we show some results from running the 2010 version of GTAP-BIO. This is the only reasonably well-documented version of GTAP-BIO and it is the version applied, with some adjustments, to generate the ILUC estimates for crop-based biofuels originally incorporated into regulations by CARB. Among our findings, we find that the basic structure of the model, by itself, can lead to odd and hard-to-explain results. One such flaw is that the economic equations in GTAP lead the model to destroy or create large quantities of land, which the model handles via a bolted-on adjustment factor that brings total land area back to its original level. In doing so, the model greatly reduces ILUC and the role played by deforestation.

This "hand of God" nonprice adjustment also contradicts the core rationale for using GTAP to study ILUC. The GTAP community often argues that one needs some global equilibrium price model to evaluate ILUC. Both the climate benefits and costs of biofuels, including ILUC, are indeed driven entirely by the mechanisms of price changes. But GTAP's behavioral responses to price changes do not allocate actual physical land. The resulting ad hoc nonprice adjustments contradict the entire rational for using GTAP in the first place. Whatever its other qualities, GTAP is therefore particularly inappropriate for estimating land effects.

1. **Basic Structure of Model**

At its essence, GTAP is a model for estimating shifts in supply and demand. For demand, it estimates how much changes in price for one good, whether corn, electricity, or various services, cause shifts in its consumption. (In economics, this is known as an "own-price" effect, often expressed as an "own-price elasticity."). GTAP also estimates how this change affects the consumption of other goods. For example, if the price of corn increases, and its consumption for food and feed declines, GTAP estimates what (and to what degree) other crops or foods replace those losses. (These are known as "cross-price" effects, often expressed as a "cross-price elasticity.") Prices changes can affect consumption and production in a multitude of ways. For example, if corn prices increase, not only may livestock producers shift to other feeds, but the price of livestock products will increase, causing food consumers to shift to other foods and potentially to reduce their consumption of food overall, buying more of other goods. GTAP purports to predict all these effects.

The same adjustments occur on the supply side as producers of goods shift from one input to another. For example, if the demand for one form of energy increases, producers may not only shift to another form of energy but also reduce their energy consumption overall and shift a little to alternative inputs. GTAP purports to measure both the decline in consumption of each input whose prices increase and the shift to other inputs. GTAP purports to project these shifts, which are the core of the model, in a highly disaggregated ways: by country or groups of countries, by multiple agroecological zones (AEZs) within countries, and by product.

To do this, GTAP creates a hierarchical "tree" structure of layers, or "nests" of equations. Lower level nests results in aggregate products that are inputs to higher level nests. For example, a lower nest has the cropland used for different crop types, which compete with each other for use of cropland. The aggregate of these different uses of cropland generate a total cropland area, which is included in a higher level nest. At this higher level, cropland overall competes for the uses of total land with other uses of land, particularly grassland used for livestock and wood-producing land (GTAP's proxy for forests). Throughout the model, GTAP modelers group goods and inputs based on an intuition of which are likely to compete more directly with each other.

Within each nest, responses to price changes are based on two factors. First, there is a "substitution parameter", a single number, which is supposed to determine in general how likely it is that the quantity of goods produced, or the inputs used increase or decrease as a result changes in price. We call this the "nest parameter."[4] However, this parameter by itself does not determine the sensitivity of change, i.e., the elasticity of supply or demand. Instead, as discussed more below, this elasticity depends both on that parameter and on a product's share of the total revenue of all products, or all inputs, within that nest. For example, the elasticity of cropland area within each agroecological zone, i.e., the extent to which the area of cropland varies with a 1% change in price, depends on both the nest parameter and on the share of total rent from all land uses supplied by cropland.[5] As discussed more below, the revenue share is also the sole factor determining how much other inputs or outputs in the nest change as substitutes when the supply or demand for one product increases or decreases.

As a result, all supply and demand elasticities are determined by a single nest parameter for all products within a nest, and by the share of revenue or cost of each product within that nest.[6] This formula is chosen for its computational tractability not for its empirical reality. (As discussed below, it actually contradicts the limited economic analyses cited by the modelers to justify their choice of nest parameters.) This choice is understandable as a research strategy, but it does not produce a model that can be treated seriously as a policy tool.

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[4] In the literature, in ways that vary across the components of the model, this parameter might be called the "CES substitution parameter" or the "CET transformation parameter" or the "elasticity" parameter. The terms CES and CET refer to the restrictive functional forms of the model. The CES is somewhat modified in the consumer demand portions of the model, adding some additional flexibility, especially with respect to income.

[5] As discussed more in Appendix B, the precise formula is the nest parameter, which uses the Greek letter sigma, multiplied by 1 minus the revenue share. For example, if the sigma is .2 and the cropland has 60% of the total revenue, then the elasticity will be .2 * (1-.4) = .12 This means that a 100% increase in price will cause a 12% change in cropland area.

[6] A parameter on an upper-level nest will then determine the percentage changes in the upper-level nests. Cost/expenditure/revenue shares play a similar role at the upper levels, interacting with the nest parameter to produce a set of computationally convenient results. At the upper level, the relevant price is a price index for the composite commodity.

2. **Absence of economically estimated parameters**

The first problem is that even if the overall formula were empirically grounded, its legitimacy still depends on thousands of necessary nest parameters. GTAP only even claims to base a handful of these parameters directly on *any* empirical economic analysis.

For the parameters that are claimed to have an empirical basis, none appear to be derived using modern econometrics. There is a very large literature on how to properly estimate demand and supply elasticities, including cross-price effects. It is the strong consensus of the economics profession that such estimates require changes in demand conditions ("instruments") to estimate supply, and vice-versa. For a famous application to biofuels, see Roberts and Schlenker (2013). For the consensus around this broad idea, see papers ranging from Wright (1928) to Berry and Haile (2021). To our knowledge, none of the thousands of parameters in GTAP is based on a high-quality application of consensus econometrics.

For others, although some reference may be made for an elasticity parameter, this nearly always based on a particular product in a particular location. GTAP's approach is to apply the same parameters often to quite different products or inputs and in multiple or all regions. In some cases, whole categories of parameters are set to a fixed fraction (such as one-half) of some other set of parameters.[7]

The land use nest parameters illustrate these problems. To estimate the elasticity of cropland area, and therefore cropland expansion, the GTAP authors originally relied on a single study, which we call *Lubowski,*[8] focused exclusively on changes in the United States. The use of the *Lubowski* results is a "best case" for GTAP, because this is a respectable, although still imperfect, empirical study. This solely US-focused study generated highly different estimates for different land use transitions in different locations. GTAP boiled down these different elasticities down to a single nest parameter for all transitions in all locations and applied this parameter to each type of land transition, in each agroecological zone, and in each of multiple countries or regions (F. Taheripour, Mueller, and Kwon 2021) (Hertel et al. 2010).

In reality, the relationship between cropland expansion and price will depend on widely different physical conditions in different locations, such as soil qualities, rainfall and slope, as

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[7]As examples, the elasticity of substitution in value-added-energy sub-production for many goods is the same for every region. The elasticity of substitution between domestic and imported goods is the same for firms and households, although it is not clear why demand and supply parameters should be equal. The relationship between sources of inputs and the domestic/imported allocation follows the so-called "rule of two." For example, the so-called Armington CES for regional allocation of imports of gasoline is 4.2 and the domestic/imported allocation is one half of that. The CES elasticity of import demand for oil across sources is 10.4, and the CES elasticity between domestic and imported goods is one half of that, and so forth. .

[8] Versions of roughly the same empirical study design were published in several versions with different policy applications including (R. Lubowski 2002), (R. N. Lubowski, Plantinga, and Stavins 2006) (R. N. Lubowski, Plantinga, and Stavins 2008)

well as economic factors such transportation costs, energy costs, property rights, and differential access to capital. *Lubowksi* modeled detailed *plot-level* transitions, factoring in such variables as soil quality and prior land use. Not surprisingly, *Lubowski* found wide differences in the elasticities that should apply to different plots of land (as well as different types of shift in land uses as discussed below).

The land use nest parameter chosen by GTAP was intended to be an average of these different elasticities in the U.S. Given both the vast physical differences around the world, and the different economics of different land uses in different parts of the world, it would be an extraordinary coincidence if this US-derived parameter could be validly applied to multiple regions and multiple countries.

This is not a correct way to do global analysis. It *is* economically consistent to use globally estimated parameters from global datasets to predict global responses. The biofuel analyses of Roberts and Schlenker (2013) illustrate how this can be done. GTAP-Bio 2010 instead uses local estimates from one country to distill a single parameter that is then applied to many different agroecological zones in many different regions where the parameter interacts with land use data from that zone and region. Doing so is virtually guaranteed to create invalid results as well as a spurious implication of specificity and precision where none is warranted.

Interestingly, the principal GTAP modelers decided in 2013 that applying the *Lubowski* parameter to the whole world was not justified, and they purported to "tune" this elasticity parameter to different regions. But they did not provide any economic analysis for any other country or region. Instead, they appeared to still use the U.S. parameter as a kind of global, middle benchmark, although it was not. Then, after surveying regions with more or less cropland expansion, the authors subjectively raised or lowered their nest parameter from this benchmark in different regions. They did so without the use of any standard econometric method, most particularly without any attempt to determine if observed land transitions are caused by price changes as opposed to changes in any other determinants of demand and supply. The lack of economic basis is so extreme that the modelers informally chose price elasticity parameters without making use of any systematic data on prices.

Among the resulting alterations, it appears that the GTAP modelers lowered the cropland expansion parameter and therefore elasticity in the U.S. to 10% of the value ascribed to *Lubowski*. Although this U.S.-derived parameter remains the *only* land use change parameter for which the GTAP authors claim to have *any* econometric support, they picked a new U.S. value that contradicted that basis.

Model parameters matter. The lack of empirical support for GTAP is therefore disqualifying all on its own.

In a recent commentary, some GTAP authors claimed that without econometrically derived parameters, it is appropriate to "use a calibration/tuning process to proxy the missing parameters" (F. Taheripour, Mueller, and Kwon 2021). If there is strong econometric support for a model and its key parameters, it might be appropriate to use a sensitivity analysis to test an unknown parameter. But this model lacks virtually any parameters that are derived from appropriate econometric method applied to appropriate data variation. In this case, appropriate data would include variation in prices, quantities, and in demand side factors that shift demand curves, tracing out land supply. In contrast, the authors are not even using any combination of statistics and data to even roughly "fit" a price-quantity relationship– itself an inappropriate technique. As in the case of double cropping, they appear to be picking parameters to fit a narrative.

3. **The role of revenue shares, which leads to misapplication of these parameters, and contradiction with their underlying economic analyses**

Even if some or all the parameters used in the model had some empirical basis, GTAP changes their meaning by misusing them to project wildly different relationships. That is because, as discussed, all the demand and supply elasticities in GTAP, which in govern the supply and demand changes, are governed also by the share of costs or revenues each product or input has within each "nest." This feature was presumably selected because this cost share data is relatively easily available, which may be fine as a research project, but not in a serious policy realm. Its use to determine elasticities, which has large consequences, both lacks an empirical basis and contradicts the limited economics cited by the modelers.

A cake recipe can help illustrate both how a revenue share formula works and why it cannot in general be used to replace empirical estimates of how demand or supply for specific products or inputs varies with price. Baking a cake may require flour, milk, butter, eggs, granulated sugar, powdered sugar, chocolate or vanilla, salt, sprinkles, and baking powder Increased use of some of these ingredients may be able to partially compensate if others increase in price, but that will depend not only on the price of each but on the physical role each plays. For example, a baker might be reasonably willing to substitute powdered sugar for granulated sugar. But given the special need for baking powder, it is unlikely that increasing its cost would cause bakers to use less per cake baked. That is particularly true given the modest contribution to the total costs of a cake of a tablespoon or two or baking powder. With a high enough price increase, it is conceivable that a baker might substitute more egg white to generate the rising effect, but other ingredients probably cannot be substituted at all.

As this example illustrates, demand and supply responses in general depend on a variety of functional attributes and consumer preferences that are specific to those products, inputs, and various alternatives. Consumers will more readily substitute green beans for broccoli than lard. Producers will more readily substitute internet-based news for a newspaper than a massage, although all may be characterized as services. In none of these examples is the overall share of the cost necessarily a single factor let alone a determinative factor in determining these substitutions.

However, under the basic structure of the GTAP model, if the ingredients for a cake are put into the same nest, and the price of baking powder rises, the percentage share of each other cake ingredient will determine what is substituted. As a result, if the price of baking powder rises, GTAP would predict that consumption of baking powder will decline and will be replaced by at least some of *all* the other ingredients. Moreover, the ratios of quantities of the other ingredients replacing baking powder will be based solely on their cost share. As a result, milk, butter, and chocolate would likely be the largest replacements, in proportion to their cost shares, even though their functional roles are distinct.[9]

Cakes are not specifically in GTAP, but this revenue-share (or cost-share) function is what determines the elasticity of demand or supply of all products and all inputs. For example, if demand for cropland and therefore its price increases, the quantity of cropland expansion will depend on a nest parameter, but also on its revenue share. And in general, substitute inputs (the diversion ratios) will depend exclusively on their relative revenue shares.

Appendix C uses the energy sector to illustrate how this structure leads to non-credible, results. For example, as modeled, the ethanol mandate leads to a large price increase for gasoline, producing a decline in the aggregate consumption of gasoline and ethanol. It also causes substantial declines in household electricity use, and consumption of natural gas, coal and oil for uses other than for transportation. As explained in the Appendix, these results, which lack an empirical basis and do not seem to have actually occurred, are driven by the structural form of the model. In particular, this result is driven by the expenditure share assumption together with the multi-level tree structure of the nests.

This theory that revenue or expenditure shares determine elasticities also *contradicts* the few economic analyses cited to generate inputs, and results in invalid use of their parameters. Again, GTAP claims that the elasticities governing shifts between cropland, pasture and forest – the prices at which land shifts from one use to another --- are based on each land use's share of the total revenue of all land uses within each agroecological zone. To provide parameters for these shifts, the authors rely exclusively on *Lubowski*. However, that study found that elasticities vary with soil and prior land use, <u>not</u> with AEZ level revenue shares.

An analogy helps to explain the nature of the error. Consider a careful, data-based study of a health treatment that finds success varies with weight. The results might imply that the treatment should only be applied to higher weight people. Now consider a new researcher who has constructed a model that, without evidence, varies treatment success with height. This researcher could (but should not) fit an average treatment effect to people of all heights that matches the average effect found for people of all weights. This researcher could then say "my model uses the results of the earlier treatment/weight study," but that would be misleading. The interactions with height were purely invented. This new model could not validly be used to advise people to obtain treatment based on their heights.

[9] The formal way to discuss these "patterns of substitution" is as a "diversion ratio," as in the land "diverted" from alternative uses to corn land when the return to corn land increases. See Conlon and Mortimer (2021). In the CES/CET functions of GTAP, within-nest diversion ratios do not depend at all on any parameter, but only on revenue/expenditure shares.

As described more precisely in Appendix B, the GTAP modelers have engaged in this kind of statistically invalid effort to convert elasticities found using one kind of relationship to project changes based on entirely different relationships, i.e., changes based on revenue share. This is true for shifts among land but also true for all, or nearly all, other statistical relationships in the model.

How the Model Structure and Assumptions Lead to Physical Impossible Economic Projections and Low ILUC Estimates

This section focuses specifically on the effects of this model structure and choice of parameters on the land functions in GTAP. This function plays a key role in determining how much cropland expands and whether that expansion occurs into pasture or forest.

1. GTAP economic functions commonly destroy or create land, and GTAP then uses an artificial constraint to adjust land area in ways that greatly reduce ILUC and further lower conversion of forests.

Because land area is fixed, a land use model needs to be able to determine if cropland expands and how much of this land area comes from alternative land uses, such as pasture and forest. GTAP, however, does not actually base its economic function for allocating land on physical land areas and as a result it can (and will) create or destroy land.

The reason is that the competition between different land uses, such as cropland, grasslands, and managed forest, is represented by their share of their combined revenue within an agroecological zone. When there is a shock to the system, such as more demand for cropland for biofuels, roughly speaking, not the physical areas but the revenue from changes in pasture and managed forest need to match the revenue increase from cropland. Because each hectare has a different rent, the physical areas do not match. Depending on the different price changes and other characteristics in different agroecological zones, the model "creates" physical land or "destroys" it. As shown in Appendix A, this features results in vast discrepancies, with changes in total land area several times larger than the projected changes in cropland area.

One fundamental problem with GTAP is therefore that a viable economic model of land use change cannot create or destroy total land. If the economics claim that land is created, the economics are incorrect.

The second problem is how the remainder of the model responds to these economic claims. To deal with this problem of fictionally created or destroyed land, GTAP modelers have added a pure adjustment factor, which reduces the area of pasture and forest automatically to match the area. Such an arbitrary adjustment does not make the model economically valid. If a model claims that individual incomes increase in total vastly more than the total national income increases, it is not a sign of a valid model that the model then reduces individual incomes proportionately to match the national income.

In addition, the adjustment factor applied by GTAP generates results that are inconsistent with its economics and result in less forest conversion and a lower ILUC. In Appendix A, we show the results before and after final adjustment of the GTAP model for the U.S. using the 2010 model version of GTAP-BIO for corn ethanol.

- As shown in Table A3, the economic projections in the model are for a total of 7,952 million tons of CO_2 emissions from land use change, but these shrink to 536 million tons with the adjustment (7% of the originally estimated ILUC).
- While the economic portion of the model projects that 54% of the non-cropland converted to cropland comes from forest, Table A2 shows this share shrinks to 34% after the adjustment. In other words, the adjustment does not just reduce total ILUC area, but it also sharply reduces the contribution of forests to land use change.
- In several agroecological zones, including AEZ7, which has the largest quantity of cropland expansion, the model shifts the forestry results and transforms a large decline in forestry area into an increase.

To summarize, the structure of the economics of the model produces physically impossible results. Even if the economics were reliable, the imposed adjustment factor generates an inconsistent result and lower ILUC.

2. GTAP cannot allow conversion of unmanaged land, and thereby forces intensification and demand reduction versus agricultural land expansion.

Previous commentary on GTAP has noted that it cannot model and does not allow conversion of unmanaged land. Unmanaged land can be a large part of a country's agricultural region, and its conversion is a major focus of global agricultural land expansion. Making it available for conversion would roughly double the potential area of forest conversion in GTAP (Plevin et al. 2022). It is difficult to imagine how a model that does not allow conversion of unmanaged land can be used to calculate ILUC. Not surprisingly, using a different model, modelers have found that incorporating unmanaged land leads to a substantially larger ILUC (Plevin et al. 2022).

The significance of this gap in GTAP will even more depress ILUC because the lack of unmanaged land also leads to more limited conversion of grassland and managed forest. In effect, grasslands and managed forest exist in GTAP only to supply livestock or wood products. Yet under GTAP, if increased crop prices were to encourage cropland conversion of these lands, livestock products and wood products cannot be alternatively supplied by expansion into unmanaged land. If cropland begins to expand into grassland, the only options are: (a) for livestock production to be intensified to replace the meat produced; (b) for meat consumption to decline, or (c) for pasture to replace "wood-producing land" not unmanaged land. In turn, for wood-producing lands, the only options are (a) intensification, which the model does not count as causing emissions, (b) a decline in wood consumption, or (c) for wood-producing lands to replace pasture elsewhere. Of these six options, five cannot cause ILUC emissions and one reduces ILUC emissions.

In effect, because the model does not allow people to bring more land into human use, the model will structurally favor cropland responses that do not cause ILUC. Then, because of the inability of wood production or livestock production to expand into more unmanaged land, the model will project price increases in livestock and wood products that lead to increase the profitability of grassland and wood-producing land. These price increases will further push back against cropland expansion according to essentially the same formula that causes cropland to expand. None of this is based on economic analysis but flows from the unwarranted assumption that only land with a rent can be converted, and that its conversion depends on its revenue share.

In short, the model structure both makes it impossible for cropland to expand into unmanaged land, which is much of the concern with land use change, and artificially reduces the conversion of grassland and wood-producing land, GTAP's concept of forest.

3. The revenue share formula requires parameter choices that reduce conversion of forest and conflict with the sole economic source of this parameter.

The *Lubowski* study, which is the sole, claimed economic basis for land conversion elasticities in GTAP, not surprisingly found that increases in cropland profitability had a far larger effect on conversion of noncropland than increases in the profitability of forest had on conversion of cropland to forest. In fact, the study found that even a doubling of the profitability of forest caused only "extremely small" changes in forest area (R. Lubowski 2002). (This can be seen visibly in Appendix B.) The reason is intuitive. Wood production and therefore rents are much lower than cropland rents (R. Lubowski 2002), so it would take large percentage increases in the profitability of forestry to outcome any cropland. As a result, any viable model, and specifically any model based on the results of *Lubowski*, should have a lower response of managed forest area to changes in the profitability of forest than of changes in cropland area to the profitability of crops.

But GTAP requires that the same nest parameter that is used to estimate how much cropland expands into other lands with a change in price of cropland also controls how much other land expands into cropland with a change in its price. To provide this single parameter, the GTAP authors chose a parameter that averages the elasticities of the different land uses. (Appendix B provides a more specific description.) As a result, GTAP deliberately chose a parameter that simultaneously understates the elasticity of conversion of cropland and overstates the conversion of cropland to forestry multifold. This means that relative to the findings of Lubowski, cropland will not expand as much in GTAP. It also means that GTAP will overestimate the rebound effect that curtails cropland expansion by overestimating the effect rising wood prices have on resisting cropland expansion.

In short, the functional form causes GTAP to fundamentally misuse the results in *Lubowski* leading to far less forest conversion than the *Lubowski* results imply and thereby to a misleadingly low ILUC.

4. Additional, incorrect assumptions about managed forests work together with the revenue-share structure to cause forests to instantly reappear elsewhere and to reduce net forest conversion*.*

Both the inability to convert unmanaged land to other uses, including wood production, and the misuse of *Lubowski*'s parameters lead to a strong need to preserve the existing area of managed forest to maintain wood production. Adding to this is the assumption that wood production lost due to conversion of managed forests cannot be replaced just by cheaply harvesting more wood from existing managed forests, resulting in carbon losses. In the real world, managed forests are growing, in significant part due to higher carbon dioxide fertilization and other aspects of climate change itself (Harris et al. 2021)(Pan et al. 2011)(Ruehr et al. 2023). They have abundant more wood that can be harvested, which means that they can supply more wood – with a carbon cost not counted in GTAP – to replace managed forests.

These limitations of the GTAP structure work together lead not only to resist forest conversion but also to a "rebound" of agricultural land to forests. In other words, if some forests are converted to agriculture in one agroecological zone, new managed forests can reappear at the expense of agricultural land in another US zone. This is not based on any actual economic estimates – and is contradicted by the estimates in the *Lubowski* analysis that even a doubling of the profitability of forest has "extremely small" effects on forest area (R. Lubowski 2002).

5. How inappropriate modeling of international trade limits GTAP's projection of U.S. biofuel consumption on world land use.

In Appendix D, we discuss the GTAP trade model. This model is based on a late 1960s idea that trade patterns in manufactured goods can best be explained by a "home bias" for domestic products. GTAP applies such a model to world agricultural trade. As explained in the appendix, this goes against a large high-quality empirical literature that there is a well-integrated world market for homogeneous agriculture products, without home bias, limited only by transportation costs. An implication of this literature is that cross-country prices differences for core agricultural commodities are severely limited by cross-country arbitrage, constrained only by (relatively low) transportation costs. GTAP does not impose this arbitrage constraint, instead allowing the modeled "home bias" to limit trade.

The empirically contradicted GTAP trade model forces much of the adjustment to U.S. biofuel policy to remain in the US. The model predicts very large changes in U.S. crop prices that are not matched by changes in other countries. This then forces much of the equilibrium adjustment onto predicted U.S. consumption and U.S. livestock intensification. A realistic model of world trade could easily predict that much more of the adjustment would take place outside of the US, particularly along active forest/crop boundaries, as in the well-measured empirical papers cited in the introduction.

Summary

In summary, we find that GTAP lacks an economic basis, is peculiarly unsuited to estimate changes in land use, and systematically and without economic foundation leads to low ILUC estimates:

- Of thousands of parameters, only a few are claimed to have any credible economic foundation. Even these parameters that are referenced by the model are misapplied. Most importantly, they are claimed to project economic changes based on revenue or cost shares, which has large consequences, even though the original empirical studies made no such projections.

- The structure causes the model not to allocate land but to create or destroy large quantities of land relative to changes in cropland, which makes it not credible for analyzing land use change. A subsequent "hand-of-God" readjustment to conserve physical land area. This adjustment both greatly reduces ILUC estimates, and in particular, reduces the role of deforestation – and therefore its high emissions - in contributing to additional cropland.

- The structure of the model, including its unsupported use of revenue and cost-shares, leads to low ILUC.

    - The structure prevents GTAP from allowing conversion of unmanaged land, which includes roughly half of all forests and is a major focus of global land use change. The inability to convert unmanaged land in turn leads the model to project increased profitability of managed forest and pasture profitability that limits their own conversion to cropland.
    - The structure requires GTAP to select a single parameter, which resulted in a parameter that understates the expansion of cropland in response to price increases and vastly overstates the role that increased profitability of forestry has in resisting conversion to cropland or pasture.
    - The structure does not model standing forests and so requires an assumption that all "forestry land" is currently fully engaged in the production of wood. If forestry land is converted to cropland in one zone, this creates pressure to create forestry land in other zones, to meet the continuing demand for wood. In the model, these new "forests" do not even need to grow and mature, rather they instantly appear.

- The trade model, borrowed from non-agricultural markets and without econometric support, underestimates the role that trade in agricultural goods similar changes in crop prices across countries and thereby leads to large underestimates of the global land use change from U.S. changes in biofuels.

- More recent changes to the model, also without economic support, further lower ILUC in a variety of ways. One assumes without economic support, and in contradiction to experience in the U.S., that most of the new cropping area is supplied by increases in double cropping or other cropping intensity. Another assumes a large, unjustified response of pasture-intensification to grassland conversion, which greatly reduces the need for pasture to expand into forest to maintain meat and milk production. A third greatly reduces the carbon losses associated with conversion of grassland.

Many of these unjustified effects work together to generate an extremely low ILUC. Several effects cause the economic component of the model to select conversion of pasture rather than pasture. The ad hoc adjustment at the end then further reduces the role of forest conversion relative to grassland. The pasture intensification function avoids the pressure to clear forest to replace pasture converted to cropland. After these factors combine to limit forest conversion, the claim that much of the grassland conversion to cropland increases soil carbon makes the remaining conversions carbon "cheap."

In Taheripour et. al. (2021), the GTAP modelers do not claim to have significant econometric support but contend, in effect, that it is appropriate to assume a model structure and most of the parameters and then adjust it to data. That is incorrect. Across the sciences, particularly those that cannot use direct experiments, there has been widespread attention to statistical abuses. Economics went through a credibility revolution in which even otherwise valid regressions were shown to be improper because they did not use "instruments" to separate correlations from causal effects (Angrist and Pischke 2010). But the calibration exercise the GTAP modelers are employing – many that involve ad hoc adjustments to parameters -- are not even making statistical errors because they are not using statistics to try to explain the effects of changed prices. They are at best assuming some stories to explain what is happening in the world and then altering parameters to fit their assumed stories. This effort is illegitimate: it is always possible to use different stories to explain the data, with different implications for the role of biofuels or any other source of increased demand.

Economics requires more. As shown, GTAP is generating results that project the lost carbon from land to supply additional future crops is only a very small fraction of the average carbon lost to generate the crop that supplies biofuel crops today. As shown in Table 1, this average would indicate that crop-based biofuels do not come close to reducing greenhouse gas emissions from transportation over 30 years. This average from experience should not be disregarded absent sound economic evidence to the contrary.

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Appendix A: GTAP-Bio's Projections of Changed U.S. Land Use and ILUC Projections With and Without Adjustments

This appendix shows results from the GTAP-BIO 2010 ethanol expansion policy experiment. The columns are U.S. agroecological zones (AEZs). The columns labeled "With Adjument … " are the reported land use changes. These are given in percentage terms in Table A1 and in physical terms in Table A2. The U.S. does not have the full set of AEZ, so while GTAP produces "percentage changes" for these zones, they correspond to no physical change in land. The three columns labeled "economic predictions" are the values net of the ad-hoc adjustment. These are not equilibrium outcomes as defined in the model, but they are the "economic output" of the model, to which the adjustment is applied. In Table A1, we see that forestry and livestock land are arbitrary reduced by the same number of percentage points. The cells in red represent cells where the adjustment causes projections of forest area decline by the economic model to turn into forest area increases after the adjustment. The table further shows how the model does not allow changes in unmanaged land.

Table A1.

Non-Market Ad-hoc Adjustment vs Economic Predictions in the GTAP-BIO Model (in % Change)

	With Adjustment in the Model				Economic Predictions				% Adjustment (Differences)			
	Forestry	Livestock	Crops	Unmnngland	Forestry	Livestock	Crops	Unmnngland	Forestry	Livestock	Crops	Unmnngland
AEZ1	-0.50	-1.13	1.66	0.00	-2.37	-2.99	1.09	0.00	1.86	1.85	0.57	0.00
AEZ2	-0.50	-1.13	1.66	0.00	-2.37	-2.99	1.09	0.00	1.86	1.85	0.57	0.00
AEZ3	-0.50	-1.13	1.66	0.00	-2.37	-2.99	1.09	0.00	1.86	1.85	0.57	0.00
AEZ4	-0.50	-1.13	1.66	0.00	-2.37	-2.99	1.09	0.00	1.86	1.85	0.57	0.00
AEZ5	-0.50	-1.13	1.66	0.00	-2.37	-2.99	1.09	0.00	1.86	1.85	0.57	0.00
AEZ6	-0.50	-1.13	1.66	0.00	-2.37	-2.99	1.09	0.00	1.86	1.85	0.57	0.00
AEZ7	0.34	-0.30	1.15	0.00	-2.39	-3.00	1.38	0.00	2.72	2.70	-0.23	0.00
AEZ8	0.16	-0.48	0.56	0.00	-3.23	-3.84	0.53	0.00	3.38	3.36	0.03	0.00
AEZ9	-0.05	-0.69	0.30	0.00	-4.51	-5.12	0.23	0.00	4.46	4.43	0.07	0.00
AEZ10	-0.41	-1.04	0.86	0.00	-5.01	-5.61	0.67	0.00	4.60	4.57	0.18	0.00
AEZ11	-0.39	-1.02	0.85	0.00	-4.35	-4.95	0.75	0.00	3.96	3.93	0.10	0.00
AEZ12	-0.25	-0.88	1.34	0.00	-1.93	-2.55	1.46	0.00	1.69	1.68	-0.12	0.00
AEZ13	0.15	-0.49	0.75	0.00	-1.19	-1.82	0.98	0.00	1.34	1.33	-0.23	0.00
AEZ14	0.01	-0.62	1.86	0.00	-1.34	-1.96	2.15	0.00	1.35	1.34	-0.29	0.00
AEZ15	0.00	-0.63	2.60	0.00	-1.34	-1.97	1.70	0.00	1.34	1.33	0.90	0.00
AEZ16	-0.00	-0.64	2.74	0.00	-0.10	-0.73	3.20	0.00	0.10	0.10	-0.46	0.00
AEZ17	-0.50	-1.13	1.66	0.00	-2.37	-2.99	1.09	0.00	1.86	1.85	0.57	0.00
AEZ18	-0.50	-1.13	1.66	0.00	-2.37	-2.99	1.09	0.00	1.86	1.85	0.57	0.00

Note: The values in the table are presented in percentage terms.

The results in Table A3 (on the next page) applies the GTAP land change CO_2 to the physical land changes in Table A2. These changes are dramatic. The "hand of God" adjustment turns large CO_2 emissions from forestry land destruction into small positive or negative changes in $C0_2$. For U.S. ILUC, the arbitrary adjustment factor has a huge effects on the predicted results.

Table A2

Non-Market Ad-hoc Adjustment vs Economic Predictions in the GTAP-BIO Model (Level Changes from Baseline)

	With Adjustment in the Model				Economic Predictions				Adjustment in Levels			
	Forestry	Livestock	Crops	Unmngland	Forestry	Livestock	Crops	Unmngland	Forestry	Livestock	Crops	Unmngland
AEZ1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ7	0.03	-0.43	0.41	0.00	-0.19	-4.33	0.49	0.00	0.21	3.90	-0.08	0.00
AEZ8	0.02	-0.18	0.15	0.00	-0.49	-1.42	0.15	0.00	0.52	1.24	0.01	0.00
AEZ9	0.00	-0.04	0.04	0.00	-0.44	-0.28	0.03	0.00	0.43	0.24	0.01	0.00
AEZ10	-0.26	-0.17	0.43	0.00	-3.14	-0.94	0.34	0.00	2.89	0.76	0.09	0.00
AEZ11	-0.20	-0.12	0.32	0.00	-2.25	-0.58	0.28	0.00	2.05	0.46	0.04	0.00
AEZ12	-0.16	-0.06	0.22	0.00	-1.23	-0.18	0.24	0.00	1.07	0.12	-0.02	0.00
AEZ13	0.02	-0.04	0.01	0.00	-0.19	-0.14	0.02	0.00	0.21	0.10	0.00	0.00
AEZ14	0.01	-0.01	0.01	0.00	-0.75	-0.04	0.01	0.00	0.76	0.03	0.00	0.00
AEZ15	0.00	0.00	0.00	0.00	-0.68	0.00	0.00	0.00	0.68	0.00	0.00	0.00
AEZ16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	-0.54	-1.05	1.59	0.00	-9.35	-7.91	1.55	0.00	8.81	6.85	0.04	0.00

Note: The values in the table are presented in million hectares.

Table A3

Non-Market Ad-hoc Adjustment vs Economic Predictions in the GTAP-BIO Model (in CO2 Emissions)

	With Adjustment in the Model				Economic Predictions				Adjustment in Levels			
	Forestry	Livestock	Crops	Unmngland	Forestry	Livestock	Crops	Unmngland	Forestry	Livestock	Crops	Unmngland
AEZ1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ3	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ4	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ7	-5.74	45.96	-7.33	0.00	141.61	459.07	-8.78	0.00	-147.35	-413.10	1.45	0.00
AEZ8	-5.22	18.79	-2.76	0.00	375.99	150.35	-2.62	0.00	-381.21	-131.57	-0.14	0.00
AEZ9	3.77	3.99	-0.77	0.00	331.58	29.77	-0.59	0.00	-327.81	-25.78	-0.18	0.00
AEZ10	194.05	18.38	-7.72	0.00	2386.75	99.31	-6.08	0.00	-2192.71	-80.92	-1.64	0.00
AEZ11	154.42	12.68	-5.81	0.00	1708.66	61.31	-5.13	0.00	-1554.24	-48.63	-0.68	0.00
AEZ12	118.33	6.57	-3.92	0.00	931.92	19.10	-4.28	0.00	-813.59	-12.53	0.36	0.00
AEZ13	-4.96	3.89	-0.25	0.00	141.43	14.45	-0.33	0.00	-146.40	-10.56	0.08	0.00
AEZ14	-1.54	1.39	-0.11	0.00	571.93	4.39	-0.13	0.00	-573.47	-3.00	0.02	0.00
AEZ15	-0.06	0.09	-0.01	0.00	514.30	0.29	-0.01	0.00	-514.36	-0.20	0.00	0.00
AEZ16	0.02	0.00	0.00	0.00	3.61	0.00	0.00	0.00	-3.58	0.00	0.00	0.00
AEZ17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
AEZ18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	453.07	111.74	-28.68	0.00	7107.79	838.04	-27.94	0.00	-6654.72	-726.29	-0.74	0.00

Note: The values in the table are presented in million Mg CO2 Emissions.

Appendix B: How GTAP Transforms Lubowski Land Use Transformation Elasticites to GTAP Parameters and the Resulting Inconsistencies

The ways in which GTAP uses the estimated elasticities from Lubowski (2002) can be seen in the following graphs taken from the GTAP working paper (Ahmed, Hertel, and Lubowski 2009), which are reproduced below. Lubwoski (2002) actually used a functional form that estimated different elasticities over different years, in other words, it estimated that land use conversions would occur more over time. The GTAP authors decided to use the estimated elasticity after 5 years. As can be seen in what the Ahmed paper labeled Figure 2, the percentage change in the area of forest in response to changes in forestry's own profitability is extremely small. By contrast, the response of cropland area to a percentage change in the price of cropland is multiple times larger. In other words, for the same percentage change in their own profitability, cropland should expand by a much larger percentage than forestry.

Figure 3 shows how GTAP translated this "own price" elasticity into the very different transformation elasticities used in GTAP, which we have called "nest parameters," and which the GTAP authors call CET values. These "nest parameters" (CET values) are not themselves elasticities in GTAP, which depends both on the nest parameter and on the share of revenue each land use type has in each agroecological zone in each country. The formula for the ultimate elasticity is this nest parameter (for which they use the Greek letter sigma) multiplied by one minus the revenue share of that land use. For example, if the sigma is 0.2 and cropland in an AEZ has 60% of the revenue, the elasticity would be 0.2 * (1-.6), which equals 0.08. Running GTAP for the U.S., the authors determined the average CET's for each of the three different land uses (cropland, pasture/range and managed forest) that results in the relevant elasticity predicted by Lubowski. Figure 3 shows that matching nest parameters are very different for the different land uses, particularly between managed forestry and pasture or cropland. The authors chose a roughly average parameter of the three different land use types at the period of 5 years, or 0.2. They did so because the GTAP function requires the same parameter be used for all items, such as all land uses, in the same nest.

As discussed in text, this approach has two fundamental flaws that both ensure the predictions of GTAP will not actually match those implied by Lubowski (2002), the claimed source, and that it will result in far less conversion of forest. One flaw is simply that the resulting CET value will result in wildly different elasticities for different land uses and in different agroecological zones and countries based on their different revenue shares. Yet Lubowski (2002) did not find that elasticities vary by revenue share. The GTAP function is therefore not just inconsistent but contradicts the findings in Lubowski even as it purports to base the model on Lubowski.

The second flaw is that this approach both underestimates the (own price) elasticity of cropland and overestimates the elasticity of managed forest. Both contribute to an underestimate of cropland expansion and a particularly strong underestimate of conversion of forest. The reason an excessive forestry elasticity also reduces cropland expansion is that the model predicts increases in the price of managed forest due to some loss of forest area, and then, as forestry prices increases, this excessive elasticity will cause the model to over-resist net conversion of forest to cropland. As discussed in text, this excessive own price forest elasticity far beyond that found in Lubowski will also cause forests to expand in other agroecological zones at the expense of cropland.

Figure B1 – Figures taken from Ahmed et al. (2008) showing how GTAP derived its transformation parmaters from Lubowski (2002)

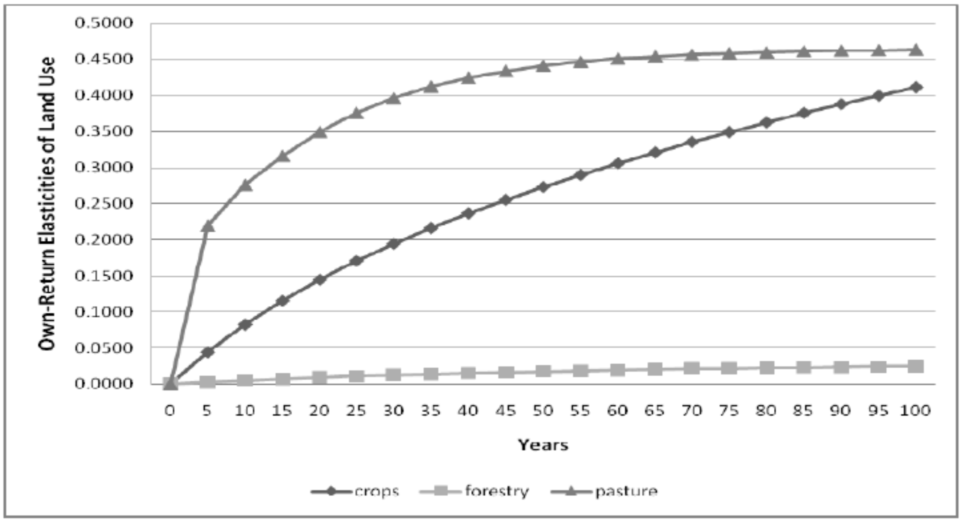


Figure 2: Own-Return Elasticities of Land USe at *t* for Use *i*
Source: Authors' Simulations

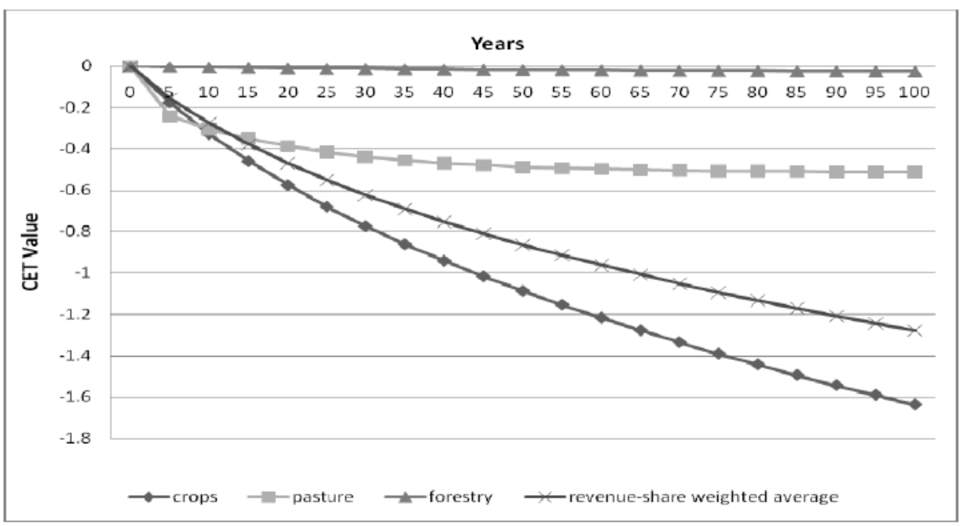


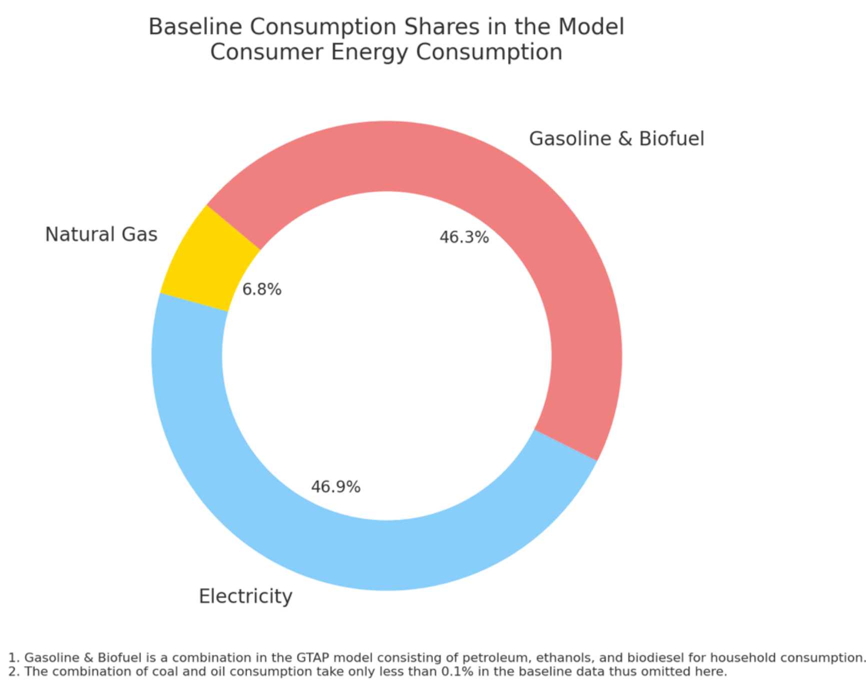
Figure 3: CET Calibration Estimates by Land Use at time *t*, for t=5 to t=100
Source: Authors' Simulations

Appendix C: Example and Discussion: Household Energy Consumption and the Counterintuitive Effects of the GTAP Model Structure

It is useful to look at the GTAP household energy consumption nests. This serves as a pedagogical exercise to understand the structure of GTAP and it also serves to indicate why that structure tends to generate odd and counterintuitive results that likely bear little resemblance to reality. In particular, we describe how the GTAP structure artificially causes household electricity consumption to fall as ethanol policy causes a large increase in the price of gasoline. The only reason for this substantial decline in electricity consumption is the choice of nesting structure for household energy nest, a choice that is very hard for policy makers to see and understand.

The following figure displays the GTAP-bio (2010) data on baseline household energy expenditure shares in the in base year of the model.[10] "Gasoline and Biofuel" is an aggregate created by a lower-level nest from a combination of gasoline-biofuels. As noted, quantities and types of energy substituted are determined by these expenditure shares, and do not even depend on the nest parameter. This result means that the very structure of the model will create a large substitution effect if a policy changes the consumption of the gasoline-biofuel bundle.

Figure C1.



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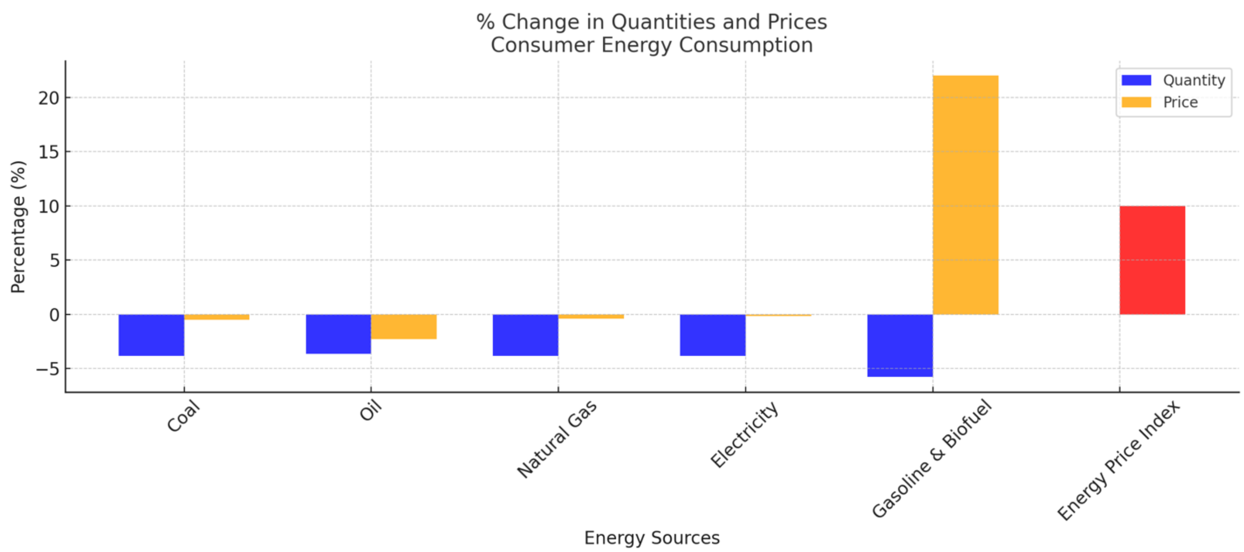
[10] We frequently rely on the 2010 version of GTAP-bio because it is by far the best documented version of the model. We have verified that most key features remain in place in a later CARB version of the model, although some components of the overall model are further elaborated by CARB.

The result of the GTAP ethanol policy simulation exercise is shown in the following figure. (It reveals market prices before taxes.)

Figure C3.



Gasoline & Biofuel is a combination in the GTAP model consisting of petroleum, ethanols, and biodiesel for household consumption.

We see that the price of the gasoline-biofuel bundle is predicted to increase by over 20%. This causes the use of the combination of gasoline and biofuel to drop by more than 5%. Surprisingly, though, the consumption of household electricity and natural gas falls by more than half as much in percentage terms. One can see in the graph that these startling effects are not caused by a raising price for non-gasoline energy. We know of no attempt in the GTAP modeling community to validate their predictions that ethanol policy will cause the consumption of natural gas, fuel oil and electricity to decline without any corresponding price increase.

It turns out that these odd results are caused by a combination of (1) the simplified way that GTAP models ethanol policy and (2) the use of a particular price index to model overall household energy consumption. The second effect, the use of special nest price indices, has important effects throughout the GTAP model.

On the first point, the modelers assume a target level of corn ethanol use (a more than 750% increase over pre-policy levels) and assume that this will be achieved via a consumption subsidy to corn ethanol. In the model, the subsidy is paid for via a tax on gasoline.[11] This is contrary to reality, but the modelers can only do simple policy exercises. They require that

---

[11] The choice of how to simplify a policy (and other exogenous factors) inside of GTAP is called the “closure” of the model. Discussion of model predictions are rarely related back to the decisions made about the closure, even though the choice of the closure can have large effects on policy outcomes.

government policy is budget-balanced and so the subsidy has to be offset by some tax. In the GTAP computation, the required taxes and subsidies are very large.

This artificial policy then interacts with the very structure of the model to create the odd (and very likely incorrect) results. In GTAP, a higher-level nest determines consumer expenditure on dollar-valued “household energy bundle.” The consumption of this bundle is driven by a single price index. The percentage change in this price index is calculated as a weighted average of the percentage price changes across all the products in the nest. The weights are the fixed base-year expenditure shares displayed in the prior chart.

Since gasoline is a large part of the energy bundle, the predicted increased price of gasoline drives up this price index, as shown in the red bar of the last chart. One can see that the overall “price of energy” is now 10% higher. In the GTAP structure, this price increase causes a decrease in the fictional “energy composite,” which drives down the consumption of energy. That sounds reasonable, but the GTAP structure simply distributes this declining energy consumption across all the energy products, even those whose price does not increase. The change is distributed using the product-level price changes but relies heavily on the base-year expenditure shares.

Appendix D. The GTAP Trade Model

As noted elsewhere in our report, there is strong empirical evidence of a moving cropland frontier in some places in the world. Given world trade in agricultural products, this means that diverting corn production to ethanol in the US will likely result in land use changes along these more active non-US land use frontiers. The GTAP model was originally built as a trade model and it contains a complex model of these effects.

Over decades, the GTAP approach to trade has been rendered obsolete in the academic literature. New trade models (e.g. Eaton and Kortum (2002) and Adao, Costinot and Donaldson (2017)) are explicitly motivated by a desire to avoid the problems of models with thousands of poorly justified parameters. These new trade models feature product differentiation, imperfect competition and, above all, a key role for the effects of distance and market size (the empirically impressive “gravity” model of trade). This is very different from GTAP.

GTAP has parameters that reflect a strong “home bias” in consumption. This reflects, for example, the traditional tendency of French consumers to buy French cars while German consumers buy German, but not French, cars. The home bias effect is motivated by trade in manufactured goods and certain kinds of services. However, there is an important literature that rejects the idea of a large home bias for agricultural products. Shipping distance may still have a strong effect on fresh goods (although these are often shipped very long distances) but likely has much lower effects for non-branded bulk products like grain or food oil. It is difficult to believe that many consumers care intensely about the country-of-origin of the grain or food oil in processed foods.

In contrast to GTAP, Roberts and Schlenker (2013), published in the prestigious American Economic Review with 581 citations, uses rigorous econometric tests to show that Brazilian crop price responses to US corn yield shocks are statistically indistinguishable from US responses to US shocks. This indicates a high degree of world market integration, consistent with the existence of large international companies who are in the business of agricultural commodity arbitrate. This empirical finding conflicts with the GTAP “home bias” assumption that restricts trade in agricultural commodities. Roberts and Schlenker also cite Fackler and Tastan (2008), who develop statistical procedures to test for market integration. They consider the market for soybeans, which they say is well-understood to be integrated. Their statistical tests confirm that "the United States/Brazil/Rotterdam markets appear to be fully integrated" in soybeans.

Berquist et al (2022) argues persuasively that credible policy analysis in agricultural policy cannot rely on GTAP style models (which are a subset of the more general traditional “CGE models”.) That paper criticizes GTAP-style models that “largely abstract from modeling the granular economic geography of farm production, consumption and trade costs” that are key to policy analysis. The paper properly distinguishes trade in manufacturing costs, for which variations in products create loyalties that slow shifts in trade, from trade in homogenous goods like commodity crops. The paper showed how trade is still influenced by transportation costs that vary with distance, but once cross-location price differences are enough to overcome the transportation cost, new and expanded trade links can be created very quickly.

In (Villoria and Hertel 2011), the authors conceptually defend the GTAP trade model through analysis claiming that data does not prove an integrated world model of prices. Their analysis, which conflicts with papers cited above, is not convincing:

- It does not use any kind of exogenous shock ("instrument") to test market integration. The paper therefore of necessity confuses different supply and demand effects and cannot produce credible empirical results (Angrist and Pischke 2010); (Berry and Haile 2021), (Pearl 2009). By contrast, Roberts and Schlenker (2013) do make use of such shocks, which makes their results showing close price integration are far more credible.
- The paper does not reference any modern trade literature.
- Although the paper rejects a theory of one global price, that does not justify use of the GTAP model, which just imposes a restriction for unknown reasons on the degree of shift in trade in response to prices. The alternative to account for differential prices is to factor the effect on prices of real, measured, transportation costs, which is an approach consistent with modern trade theory. The two approaches reach different results. A transportation cost model, with otherwise homogeneous goods such as soybeans, would impose maximum price differences between two points (with the difference being the transport cost). GTAP does not impose these maximum differences, which can result in unrealistic trade barriers because it allows US prices to rise tremendously more than European or Brazilian prices.

Overall, there is a lack of evidence to support the GTAP approach to agricultural trade and a large well-cited literature that advocates very different approaches. These are critical. By artificially restraining trade effects in agriculture, GTAP is artificially restricting the effects of biofuel policy to the US. Because the crop/forest frontier is more settled in the US than elsewhere, and because quickly expanding trade links are plausible, this trade feature will underestimate the world-wide effects of land use change.

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Comment 317 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ellison
Last Name	Folk
Email Address	folk@smwlaw.com
Affiliation	Shute, Mihaly & Weinberger LLP
Subject	League for Accountability and Justice Comments on Proposed LCFS Amendments
Comment	Please see the attached comments from Ellison Folk, on behalf of The League for Justice and Accountability, regarding the Proposed Amendments to the Low Carbon Fuel Standard. Thank you.
Attachment	www.arb.ca.gov/lists/com-attach/6988-lcfs2024-UzAAaQdrAjxVNgJs.pdf
Original File Name	Comments on LCFS Amendments 2-20-24.pdf
Date and Time Comment Was Submitted	2024-02-20 16:48:23

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

SHUTE, MIHALY
& WEINBERGER LLP

396 HAYES STREET, SAN FRANCISCO, CA 94102
T: (415) 552-7272 F: (415) 552-5816
www.smwlaw.com

ELLISON FOLK
Attorney
Folk@smwlaw.com

February 20, 2024

<u>Via Electronic Submittal</u>

Clerk of the Board
California Air Resources Board
1001 I. Street
Sacramento, CA 95814

Re: <u>Comments on the Proposed Amendments to the Low Carbon Fuel Standard</u>

Dear Honorable Members of the California Air Resources Board:

This firm represents the Leadership Counsel for Justice and Accountability ("Leadership Counsel") in matters relating to the California Air Resources Board's ("CARB") Proposed Amendments to the Low Carbon Fuel Standard Regulation ("Proposed Amendments" or "Project"). Central Valley Defenders of Clean Water & Air, Animal Legal Defense Fund, and Food & Water Watch have informed us that they also join in this letter. CARB's adoption of the Proposed Amendments is subject to the California Environmental Quality Act ("CEQA").[1] CARB's Draft Environmental Impact Analysis ("Draft EIA") must therefore: evaluate all reasonably foreseeable impacts of the Proposed Amendments in sufficient detail; adopt all feasible mitigation measures to lessen the severity of the Proposed Amendments' environmental impacts; and consider all feasible alternatives that would achieve the goals of the Proposed Amendments while lessening the severity of the Proposed Amendments' environmental impacts. Public Res. Code §§ 21002.1; 21100. The Draft EIA fails to comply with each of these obligations.

[1] CARB acts pursuant to a certified regulatory program which exempts the agency from preparing an Environmental Impact Report ("EIR") because the environmental analysis CARB is required to undertake is deemed the functional equivalent of an EIR. 17 Cal. Code. Regs. §§ 60000-60007; *POET, LLC v. State Air Resources Bd.* (2013) 218 Cal.App.4th 681, 710 CARB's actions are subject to all other applicable provisions of CEQA. 14 Cal. Code Regs. § 15250; *POET, LLC*, 218 Cal.App.4th at 710.

As discussed in more detail below, the Proposed Amendments will increase the already significant incentive concentrated animal feeding operations ("factory farms") have to create more Low Carbon Fuel Standard-eligible fuels and expand their operations to increase fuel production. Despite this inevitable effect of the Proposed Amendments, CARB's Draft EIA fails to mention—let alone analyze—the environmental impacts associated with factory farm expansions or anaerobic digestion-related fuel production. The Draft EIA acknowledges that the installation of anaerobic digesters, which are necessary to generate LCF-eligible fuel from manure methane emissions, will have significant environmental impacts. However, the Draft EIA fails to adequately discuss and analyze these impacts, which include impacts to air quality and water quality and adverse public health impacts on communities living in close proximity to factory farms.

In addition, the Draft EIA fails to propose adequate mitigation measures to address the project's impacts and fails to adequately analyze alternatives to the project. These inadequacies require that the Draft EIA be revised and recirculated so that the public and decision-makers are provided with a proper analysis of the project's significant environmental impacts and feasible mitigation for those impacts. See CEQA Guidelines § 15002(a)(1) (listing as one of the "basic purposes" of CEQA to "[i]nform governmental decision makers and the public about the potential, significant environmental effects of proposed activities").

This letter is submitted along with comments prepared by: Silvia Secchi, Ph.D., Professor, Department of Geographical and Sustainability Sciences, University of Iowa, Attachment A ("Secchi Comments"); and Paul Rosenfeld, Ph.D., Principal Environmental Chemist, Soil Water Air Protection Enterprise ("SWAPE"), Attachment B.

I. The Proposed Amendments incentivize factory far expansion and the installation of anaerobic digesters.

The Proposed Amendments will greatly increase the incentive that already exists under the Low Carbon Fuel Standard ("LCFS") for factory farm expansion and digester installation.

This is evidenced in the stated Project objectives, which specify the following objectives:

- Increase credit prices by increasing the carbon intensity benchmarks (Objectives 1-4, Draft EIA at 13)
- Incentivize more digesters to achieve the Senate Bill 1383, Senate Bill 32, and Assembly Bill 1279 GHG reduction targets (Objective 5, Draft EIA at 13).

- Use the LCFS to build out and then transition biomethane infrastructure from supplying transportation fuels to supplying hydrogen fuels for stationary sources (Objective 5, Draft EIA at 13).

Therefore, CARB has designed the Proposed Amendments to increase carbon intensity targets, which in turn, will increase demand for credits and increase credit prices. Currently, biomethane accounts for approximately 20 percent of credits generated but only 1 percent of energy used for transportation.[2] The quantity and growth of biomethane credits in the LCFS has contributed to a glut of credits at low prices and diminished incentive for biogas investors to expand their investments.[3] The Proposed Amendments would increase the value of LCFS credits and incentivize investors to build more digesters and generate more credits. The Proposed Amendments incentivize fuel production practices that will, in fact, increase GHG emissions and result in significant environmental impacts.

The Proposed Amendments include three distinct changes to the LCFS that will increase the incentives factory farms have to expand their operations and install anaerobic digesters: (1) strengthening the carbon intensity benchmark, thereby increasing the price of credits for eligible fuel pathways, including electricity, natural gas, and hydrogen generated from factory farm manure methane emissions; (2) limiting biomethane pathways eligible for LCFS credits with deliverability requirements, which will also increase the price of credits for eligible fuel pathways; and (3) restricting new compressed natural gas and hydrogen fuel pathways that qualify for 35 years of avoided methane crediting to those that CARB certifies or that break ground by December 31, 2029.

By strengthening the carbon intensity benchmark from a 20% reduction in carbon intensity by 2030 to 30% by 2030 and establishing a new 90% carbon intensity reduction benchmark by 2045, CARB will increase demand for LCFS credits in the near-term, especially with the “step down” in 2025.[4] The intended and inevitable effect of this change will be to increase the demand of LCFS credits available for purchase, thereby increasing credit prices. Thus, those fuel pathways that qualify for credits after the amendments go into effect—including electricity, natural gas, and hydrogen derived from

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[2] Aaron Smith, 2024.01.22 article https://asmith.ucdavis.edu/news/cow-poop-now-big-part-california-fuel-policy attached as Attachment C.
[3] Id.
[4] CARB Staff Report: Initial Statement of Reasons, at 22-26 (December 19, 2023) (“ISOR”).

factory farm manure—will receive more money per credit sold. The Proposed Amendments will therefore incentivize factory farms to increase their herds to maximize manure methane production (credit generation). This proposed change will also provide incentives for the installation of digesters at factory farms, and thus result in GHG and air pollutant emissions.

Additionally, the amendments include new deliverability requirements that will limit the biomethane eligible for LCFS crediting to biomethane "carried through common carrier pipelines that physically flow within California or toward end use in California."[5] Currently, all factory farms across the nation can qualify for LCFS credits on the same basis as factory farms in California. As with the carbon intensity benchmark change, these deliverability requirements will further limit the supply of LCFS credits, thereby increasing the amount of money eligible fuel producers receive per credit. Also, by limiting eligibility to those factory farms that have a connection to California, these deliverability requirements will further incentivize factory farm expansion specifically in California along with the installation of digesters at livestock facilities in California.

Lastly, the Proposed Amendments draw a bright line between factory farm fuel pathways that are certified before, and after, January 1, 2030, with respect to avoided methane crediting.[6] If a factory farm fuel pathway is certified before January 1, 2030, that pathway is eligible to be renewed for up to three consecutive 10-year crediting periods. However, fuel pathways for bio-CNG, bio-LNG, and bio L-CNG from projects that break ground after December 31, 2029 can only generate avoided methane credits through December 31, 2040. Similarly, fuel pathways for hydrogen from projects that break ground after December 31, 2029 can only generate avoided methane credits through December 31, 2045. The Proposed Amendments therefore provide a significant incentive for factory farms to expand their herds and install digesters before December 31, 2029.

The Proposed Amendments' incentives to expand CAFO herds and install polluting anaerobic digesters by increasing the monetization of manure methane will have significant impacts on the environment which the Draft EIA fails to adequately analyze and fails to require feasible mitigation or project alternative, as described below.

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[5] ISOR, at 30-31.
[6] ISOR, at 31.

II. The Draft EIA's Environmental Impacts analysis violates CEQA.

A. The Draft EIA fails to analyze the Proposed Amendments' environmental impacts.

1. Expansion of factory farm herds is a reasonable expected result in response to the Proposed Amendments.

CEQA requires lead agencies to analyze all reasonably foreseeable environmental impacts caused by a project they are proposing to approve. *Laurel Heights Improvement Assn. v. Regents of University of California* (1988) 47 Cal.3d 376, 396-98; *Ebbets Pass Forest Watch v. Cal. Dept. of Forestry & Fire Protection* (2008) 43 Cal.4th 936, 954-55. A public agency can only omit analysis of its project's impact if it is "speculative." *Santa Rita Union School District v. City of Salinas* (2023) 94 Cal.App.5th 298, 334-36. An agency's conclusion that a particular environmental impact is too speculative to be adequately analyzed must be supported by substantial evidence. *Id* at 335. To support such a conclusion, the CEQA Guidelines require lead agencies to conduct a "thorough investigation" and "note its conclusion" that the impact is too speculative to be considered. 14 Cal. Code Regs. § 15145; *County of Butte v. Dept. of Water Resources* (2023) 90 Cal.App.5th 147, 161; *Citizens' Committee to Complete the Refuge v. City of Newark* (2021) 74 Cal.App.5th 460, 479.

The Draft EIA's analysis is "based on reasonably foreseeable compliance responses that are based on a set of reasonable assumptions" and purportedly "includes actions that could likely occur under a broad range of the potential scenarios."[7] As explained in Section I, *supra*, the Proposed Amendments include three distinct changes that increase factory farms' incentive to generate more LCFS-eligible fuel by expanding existing herds and installing digesters. The Draft EIA considers the installation of anaerobic digesters a reasonable compliance response because the Proposed Amendments would "incentivize the collection and use of biomethane gas from dairies."[8]

The same elements of the Proposed Amendments that incentivize collecting existing biomethane at factory farms also incentivize increasing the volume of biomethane at factory farms. This incentive to produce more methane necessarily includes expanding factory farm herds to generate more manure. However, the Draft EIA ignores this potential impact entirely. The Draft EIA fails to provide any evidence, let

[7] ISOR, at 39.
[8] Draft EIA, at 64.

alone substantial evidence, supporting its omission of factory farm expansion as a reasonable compliance response.

As explained in Dr. Secchi's comments, the analysis of Project-related impacts related to resulting factory farm expansion fails for two reasons. First, the "ISOR offers no monitoring data showing whether the LCFS has caused, or the proposed amendments will cause, herd expansions at dairies or hog facilities located in California or outside of California."[9] Without such data, the Draft EIA has no evidence to support an assumption that the use of digesters at factory farms results in a reduction of methane emissions overall.

Second, the evidence demonstrates that since the adoption of the low carbon fuel standard and Federal subsidy programs encouraging use of digesters, factory farms have expanded both inside and outside of California.[10] Dr. Secchi posits that, in reality, the incentives created by the Proposed Amendments are likely to result in significant expansion of factory farms that will, in turn, increase the amount of methane produced.[11] Recent deregulation of biodigesters in Iowa is correlated with dairy expansions in that state.[12] As explained above, by increasing the carbon intensity benchmark and the value of credits, the Proposed Amendments will incentivize increased expansion and concentration of dairy operations leading to increased adverse environmental impacts (as discussed further below). The aforementioned is a reasonably foreseeable compliance response that is not accounted for in the ISOR or the Draft EIA.

Recent data from the USDA Ag Census further demonstrates that during the period that CARB has implemented its avoided methane crediting policy (since the 2018 LCFS amendments), the number of milk cows at large, California dairies have increased while the number of milk cows at smaller dairies have decreased, showing that the California dairy herd is consolidating into larger dairies that produce and store sufficient quantities of manure to finance and generate revenues from captured methane. The data show that for dairies with 2,500 or more milk cows, the milk cow herd increased from 808,503 milk cows in 2017 to 1,025,716 milk cows in 2022, or an increase of 28.6 percent. In contrast, the data show that for dairies with less than 1,000 cows, the milk cow herd *decreased* from 303,746 milk cows in 2017 to 144,472 milk cows in 2022, or a

[9] Attachment A, Secchi Comments, at 1.
[10] Id. at 5 and 6.
[11] Id.
[12] Id. at 3.

decrease of 52.4 percent.[13] While correlation does not establish causation, the data strongly suggest that the LCFS has had a substantial effect on the increase in milk cows at the largest dairies which are most likely to install digesters and monetize their manure.[14]

2. The Draft EIA fails to adequately analyze nitrogen-based emissions from digesters that contribute to PM2.5 nonattainment and climate change.

Having failed to properly analyze the foreseeable expansion of factory farms as a result of the Project, the Draft EIA fails to analyze the Project's related impacts. It is well-established that "industrial dairies in the San Joaquin Valley are a major source of local air and water pollution, nuisance odors, groundwater overdraft, and greenhouse gas emissions."[15] Specifically, dairies are the largest source of volatile organic compounds, in the San Joaquin Valley. Oxides of nitrogen result from combustion of fuels, including biogas fuels from anaerobic digesters. Volatile organic compounds and NOx are precursors to ozone formation, which can cause a variety of respiratory illnesses, especially in children and for people who have asthma.[16] Factory farms and the resulting digestate are also a significant source of ammonia, which impacts nearby residents as a toxic gas and also reacts to form ammonium nitrate, a form of fine particulate matter for which the EPA has classified the valley as nonattainment with the federal health-based National Ambient Air Quality Standard.[17]

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[13] The data also show that for dairies with more than 1,000 cows, the milk cow herd increased from 1,446,583 milk cows in 2017 to 1,543,730 milk cows in 2022, an increase of 6.9 percent.

[14] U.S. Department of Agriculture Census, attached as Attachment D.

[15] *See*, Briefing paper: Factory Farm Dairies, Biogas, and the Dangerous Path California is On, Leadership Counsel for Justice and Accountability, 2023, Attached as Attachment E.

[16] U.S. Environmental Protection Agency, "Health Effects of Ozone Pollution", attached as Attachment F and available at https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution#:~:text=Depending%20on%20the%20level%20of%20exposure%2C%20ozone%20can%3A,diseases%20such%20as%20asthma%2C%20emphysema%2C%20and%20chronic%20bronchitis.

[17] *See* 87 Fed. Reg. 60494 (Oct. 5, 2022) (proposed disapproval of plan to attain the 2012 annual PM2.5 standard), attached as Attachment G.

In addition, contaminated runoff can result in water pollution in both surface and ground water; the intensive water use required by factory farms results in overdraft of groundwater supplies; and caustic ammonia emissions can result in illness and odors. As discussed below, the Draft EIA's failure to analyze the impacts of the Proposed Amendments, both resulting in significant expansion of factory farms and due to increased use of digesters, implicates the EIA's analysis of all of the aforementioned environmental impacts. Even where the Draft EIA did purport to evaluate impacts, the analysis is perfunctory.

(a) Ammonia Emissions

Ammonia, a toxic, odorous gas, causes respiratory issues; irritation to the throat, lungs, and eyes; and lung damage if exposure to elevated ammonia levels is prolonged.[18] In addition to the health risks imposed by increased local emissions, ammonia also reacts with nitrogen oxides (e.g., NOx) in winter and contributes to the formation of ammonium nitrate, a fine particulate matter ("PM2.5").[19] In the United States, ammonia from agriculture accounts for the formation of almost one third of $PM_{2.5}$.[20] Exposure to PM 2.5 is linked to premature deaths in people with heart or lung disease, heart attacks, irregular heartbeat, aggravated asthma, decreased lung function and long-term lung conditions including cancer.[21] Yet, the Draft EIA's analysis of the Project's public health and safety impacts is cursory at best.

(b) Greenhouse Gases

The Draft EIA analysis omits a full accounting of greenhouse gas emissions resulting from both a foreseeable expansion of factory farms and increased use of digesters.[22] For example, as the Rosenfeld Comments explain, during biogas combustion in the anaerobic digestion process, ammonia is oxidized into nitrous oxides. Furthermore,

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[18] Attachment B, Rosenfeld comments, at 2.
[19] Johns Hopkins Center for a Livable Future comments on LCFS Amendments dated February 20, 2024.
[20] Id.
[21] USEPA, "Health and Environmental Effects of Particulate Matter", attached as Attachment H and available at https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing .
[22] Attachment A, Secchi Comments, at 6.

digestate solids emit significant nitrous oxide emissions that negate methane captured by the digester. According to the EPA, nitrous oxide ("N2O") has a Global Warming Potential that is 273 times that of carbon dioxide ("CO2") for a 100-year timescale.[23] Therefore, N2O emitted today remains in the atmosphere for more than 100 years, on average.[24] Yet, the Draft EIA omits any evaluation impacts from Project-related increases of N2O.

In another example, NOx emissions react with volatile organic compounds in the presence of sunlight to form ozone, which also contributes to climate change. Ozone (O3) is the third most important anthropogenic greenhouse gas after carbon dioxide (CO2) and methane.[25] NOx also reacts with ammonia to form ammonium nitrate, a form of PM2.5. The San Joaquin Valley of California, where most factory farms and biodigesters are located, is a nonattainment area for both ozone and PM2.5National Ambient Air Quality Standards. However, the Draft EIA provides only a cursory—and internally inconsistent—discussion of the potential impacts related to ozone and PM2.5 formation. On the one hand, the Draft EIA states the Proposed Amendments "*could* result in an overall decrease in long-term operational NOx and PM2.5 emissions…in all state-designated ozone non-attainment areas from 2024 through 2046," (emphasis added) with a corresponding reduction in health impacts.[26] But the Draft EIA then pivots to conclude that long-term impacts from NOx and PM 2.5 emissions "could be potentially significant and unavoidable."[27]

The Draft EIA's conclusion that the Proposed Amendments could reduce NOx and PM2.5 emissions fails to account for emissions resulting both from the increased use of digesters and the expansion of factory farms. To the extent the Draft EIA makes any attempt to acknowledge the potentially significant impacts of increased NOx and PM2.5, it does not provide any of the information required by CEQA to explain the extent and severity of these impacts. The Draft EIA's failure to provide meaningful information about the significance of these impacts violates CEQA. *Cleveland Nat'l Forest Foundation v. San Diego Assn. of Governments* (2017) 3 Cal.5th 497, 514 ("an EIR's designation of a particular adverse environmental effect as 'significant' does not excuse

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[23] U.S. EPA, Understanding Global Warming Potentials", attached as Attachment I and available at
[24] Id.
[25] Aura Science: Greenhouse effect of tropospheric ozone, NASA, attached as Attachment J and available at https://aura.gsfc.nasa.gov/science/feature-20110403.html
[26] Draft EIA, at 57.
[27] Draft EIA, at 62.

the EIR's failure to reasonably describe the nature and magnitude of the adverse effect"); *Berkeley Keep Jets Over the Bay Com. v. Board of Port Cmrs.* (2001) 91 Cal.App.4th 1344, 1371 ("simply labeling the effect 'significant' without accompanying analysis of the project's impacts … is inadequate to meet the environmental assessment requirements of CEQA").

3. The Draft EIA Fails to Adequately Analyze NOx emissions from Flaring.

The Draft EIA refers to the air quality analysis in the Standard Regulatory Impact Assessment ("SRIA") as the basis for its estimates of criteria pollutants.[28] In the SRIA, CARB estimated emissions from flaring at digesters. The Draft EIA states that "[S]taff assumed that about 10% of methane produced is flared. Hence, flaring is the only source of local emissions used in estimating emissions from dairy biomethane."[29] Ammonia in flared biogas causes increased NOx emissions.[30] However, the SRIA only used air district emission factors for flares.[31] Thus, the EIA fails to adequately analyze NOx emissions from flaring biogas. A revised EIA should recalculate digester flare emissions using flared biogas.

4. The Draft EIA Fails to Adequately Analyze NOx emissions from Biomethane Electric Fuel Pathways.

In its evaluation of Project-impacts related to biomethane electric vehicle fuel pathways, the Draft EIA indicates that "[T]he LCFS modeling assumes use of fuel cells to generate this electricity, which do not rely on combustion."[32] Thus, staff calculate near zero NOx from electricity production of biomethane using an emission factor of 0.00085 tons/GWh.[33] However, this assumption underlying the analysis is questionable for multiple reasons. First, to date, CARB has certified only one biomethane electric vehicle fuel pathway that relies on Bloom fuel cells at a dairy to produce electricity, and that is at

[28] Draft EIA, at 58.
[29] SRIA, Appendix C-1 at B-2 Table 49.
[30] Attachment B, Rosenfeld Comments at 4.
[31] SRIA, Appendix C-1 at B-2.
[32] Draft EIA, at 27; SRIA, Appendix C-1 at B-3, (citing a dead link Bloom Energy (2002). *The Bloom Energy Server 5 Data Sheet*. https://www.bloomenergy.com/wp-content/uploads/es5-300kw-datasheet-2022.pdf)] .
[33] Id.

Bar 20, one of the largest dairies in California. By contrast, CARB has certified 19 biomethane electric vehicle fuel pathways that rely on internal combustion engines[34] .

Second, Bloom fuel cells are more expensive to purchase and maintain than internal combustion engines, and the San Joaquin Valley Unified Air Pollution Control District has declined to find that fuel cells are cost-effective and thus Best Available Control Technology ("BACT"). Instead, the District has issued Authority to Construct Permits and found that internal combustion engines represented BACT. Therefore, CARB lacks substantial evidence to support its unfounded assumption Bloom fuel cells will be used for electric vehicle fuel pathways. And while Bar 20 has permits for and operates fuel cells, there is no record on the Air District public notice log of *any* BACT determination for fuel cells at Bar 20.[35]

Furthermore, the most recent internal combustion engine Authority To Construct Permit from the San Joaquin Valley Air District found that fuel cells were not cost-effective and not BACT. Instead, the Air District required internal combustion engines as BACT.[36] This approach is inconsistent – on the one hand, the Air District does not consider fuel cells as BACTs or cost effective and does not require fuel cells as BACT; on the other hand, CARB's analysis of impacts from digester projects that generate electric vehicle fuel contends that all such fuel pathways will rely on fuel cells to emit near-zero NOx.

NOx emissions from digester-related internal combustion engine used for electric vehicle fuel pathways are significant. For example, the Lakeview Dairy Biogas project in Kern County uses two internal combustion engines to produce over 1,000 kW of electricity on-site.[37] And this project, as permitted by the Air District with required internal combustion engines, still emits 4.58 tons/year of NOx, 1.98 tons/year of PM2.5,

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[34] CARB: Total Number of Applications or Pathways (excel spreadsheet), February 9, 2024, attached as Attachment K.
[35] SJVAPCD Bar 20 Bloom Energy Permits, attached as Attachment L.
[36] *See* Attachment M - 2020.04.20 Notice of Final Action – Authority to Construct, ATC Lone Oak Energy; 2020.02.21 Notice of Preliminary Decision – Authority to Construct Lone Oak Energy at 13, Appendix C.
[37] SJVAPCD, Notice of Preliminary Decision – Authority to Construct (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf, attached as Attachment N; CalEPA & Cal. Air Res. Bd., LCFS Tier 2 Pathway App. B0104 (certified TBD), attached as Attachment O and available at https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.

and 3.18 tons/year of VOC *after* the imposition of BACTs as required by the State Implementation Plan.[38] Compared to a natural gas combined cycle power plant in Avenal, also permitted by the Air District, the Lakeview digester project produces much higher levels of NOx, sulfur oxides (SOx), and VOC emissions per unit of electricity generated.[39] However, unlike the natural gas plant, Lakeview Dairy Biogas is not required to purchase emission reduction credits for the air pollution emitted. This facility, and others like it with internal combustion engines, emit significant levels of NOx even after Clean Air Act-required controls.[40] Therefore, the Draft EIA wrongfully omitted analysis NOx emissions from these facilities and fuel pathways.[41]

In summary, given that (a) the Proposed Amendments increase carbon intensity benchmarks, and thus credit prices, and will incentivize more pathways for electricity from internal combustion engines, (b) CARB does not require fuel cells as mitigation, and (c) the San Joaquin Valley Unified Air Pollution Control District does not consider fuel cells as BACT, it is reasonably foreseeable that more digesters with IC engines will apply for such pathway certifications. For these reasons, the Draft EIA must be revised to correct this error and to evaluate NOx impacts from biomethane electric vehicle fuel pathways that rely on IC engines.

5. The Draft EIA Fails to Adequately Analyze NOx emissions after 2039.

The Draft EIA fails to analyze NOx emissions from biomethane fuel pathways after 2039, despite authorizing crediting for biomethane fuel pathways well beyond 2039. The Draft EIA's PM2.5 and NOx emissions analysis explicitly relied on the Standardized Regulatory Impact Assessment ("SRIA"), including Tables 47-59.[42] Table 47 of the SRIA assumes no hydrogen or electricity will be produced from dairy biomethane after 2039.[43] However, as discussed in Section I, the Proposed Amendments explicitly

[38] SJVAPCD, *supra* note 137, at 14.
[39] SJVAPCD, Notice of Final Determination of Compliance, (December 17, 2010) Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01), attached as Attachment P.
[40] Id.; Attachment Q Comparison of Digester vs. Avenal; and Rosenfeld Comments at _.
[41] Johns Hopkins, Center for a Livable Future comments LCFS Amendments; Petition for Reconsideration at 28-30, attached as Attachment R.
[42] Draft EIA, at 58.
[43] CARB Staff Report: Initial Statement of Reasons for Proposed Amendments to the Low Carbon Fuel Standards, Appendix C-1: Standardized Regulatory Impact Assessment, at B-3 (September 9, 2023) ("SRIA").

authorize CARB to certify electricity and hydrogen fuel pathways well beyond 2039. The Draft EIA's analysis of NOx emissions is grounded on an inaccurate assumption. The Draft EIA must evaluate the impacts of NOx emissions over the time period during which these emissions will occur. 14 Cal. Code Regs. § 15126 ("[a]ll phases of a project must be considered when evaluating its impact on the environment"); *Make UC a Good Neighbor v. Regents of University of California* (2023) 88 Cal.App.5th 656, 667; *In re Bay-Delta etc.* (2008) 43 Cal.4th 1143, 1169.

6. The Draft EIA fails to adequately analyze Project-related ammonia emissions associated with digestate.

Aside from omitting analysis of the impacts resulting from factory farm expansion and use of anaerobic digesters described above, the Draft EIA presents an incomplete analysis of the project's ammonia impacts because it fails to evaluate the impacts from production and application of substantial increases of anaerobic digestate.[44] Apart from the size of the herd, the production and application of digestate to agriculture land is much more polluting and more hazardous to public health compared to raw manure.[45] CEQA requires an analysis of these impacts.

The Draft EIA's conclusion that the Project may have significant air quality impacts—without consideration of the extent and severity of those impacts—cannot cure this deficiency. Merely stating that an impact will occur is insufficient; an EIR must also provide "information about how adverse the adverse impact will be." *Cleveland Nat'l Forest Foundation*, 3 Cal.5th at 514; *Berkeley Keep Jets Over the Bay Com.*, 91 Cal.App.4th at 1371. This information, of course, must be accurate and consist of more than mere conclusions or speculation. *Id*. The Draft EIA's analysis of air quality impacts fails to fulfill this mandate in several instances.

(a) Air pollution

Anaerobic digestate results in higher emissions in part because anaerobic digestion decomposes the waste into smaller molecules, which allows it to more easily volatilize into the atmosphere.[46] In this way, digestate results in significant releases of higher

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[44] Draft EIA at 56-62 (concludes impacts to air quality are significant); at 64-65 (concludes impacts from odor are not significant); Attachment B, Rosenfeld comments, at 2 and 3.
[45] Johns Hopkins Center for a Livable Future comments on LCFS Amendments at 2.
[46] Attachment B, Rosenfeld comments, at 3.

amounts of ammonia, a toxic gas, and NOx emissions than unprocessed manure.[47] The Draft EIA concludes that long-term operational air quality impacts related to PM2.5 and NOx would be significant and unavoidable.[48] We do not disagree that the Project's emissions would be significant. However, the DEIR fails to disclose the extent and severity of this impact.[49] A revised analysis must provide more details about the impacts and must account for increased application of digestate on agricultural land. *Cleveland Nat'l Forest Foundation*, 3 Cal.5th at 514; *Berkeley Keep Jets Over the Bay Com.*, 91 Cal.App.4th at 1371.

Furthermore, the Draft EIA's conclusion that odor impacts from ammonia emissions would not be significant is unsupported. As explained in the Rosenfeld Comments, ammonia emits a strong odor that is easily detectable at low concentrations and contributes to irritation such as immediate burning of the nose and respiratory tract.[50] In addition, anaerobic digestion significantly increases the amount of ammonia emissions compared to a dairy without an anaerobic digester.[51]

As discussed above, ammonia also contributes to the formation of $PM_{2.5}$ (e.g., formation of ammonium nitrate), exposure to which is linked to a variety of serious health problems).[52] CARB's own ammonia data show that ammonia contributes to PM2.5 formation.[53] Therefore, CARB must include a full evaluation of ammonia emissions.

(b) Public Health and Safety

Health and safety effects, including adverse health impacts from air pollutants, may constitute significant environmental impacts for the purposes of CEQA. See, e.g., *Sierra Club v. County of Fresno* (2018) 6 Cal.5th 502, 517-22; *Bakersfield Citizens for*

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[47] Id.
[48] Draft EIA at 62.
[49] Draft EIA at 56-62.
[50] Rosenfeld Comments at 2.
[51] *Id*. at 3-4.
[52] Johns Hopkins Center for a Livable Future comments on LCFS Amendments comments at 3; See Attachment H https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing .
[53] 2023 CARB Ammonia Demonstration re 1997 PM2.5 plan standard SJV at 3, attached as Attachment S.

Local Control v. City of Bakersfield (2004) 124 Cal.App.4th 1184,1219-21. 14 CCR § 15126.2(a). Here, as discussed above, in the anaerobic digestion process substantial amounts of ammonia are produced as a byproduct.

In addition to the health risks imposed by increased local emissions, emissions and impacts on nearby communities, ammonia also contributes to the formation of $PM_{2.5}$.[54] In the United States, ammonia from agriculture accounts for the formation of almost one third of $PM_{2.5}$.[55] Exposure to PM 2.5 is linked to premature deaths in people with heart or lung disease, heart attacks, irregular heartbeat, aggravated asthma, decreased lung function and long-term lung conditions including cancer.[56] Yet, the Draft EIA's analysis of the Project's public health and safety impacts is cursory.[57] While the Draft EIA discloses that an increase in emissions of criteria pollutants associated with production of biofuels is possible, it falls short of actually evaluating the potential health impacts of these emissions.[58] Instead, once again the Draft EIA concludes that impacts would be significant, but then fails to describe the severity of those impacts.

Harmful emissions from expanded use of anaerobic digesters disproportionately affect communities in close proximity to dairies, which are often comprised of lower-income residents. Lower-income residents are often more vulnerable to the adverse effects of these emissions due to various factors, such as lack of resources, inadequate infrastructure, and the concentration of anaerobic digester facilities near these populations.

(c) Impacts Outside of California

The Draft EIA fails to analyze the Proposed Amendments' impacts outside of California. CEQA requires public agencies to analyze the potentially significant impacts of a proposed project that may occur in "the area which will be affected by [the] proposed project." 14 Cal. Code. Regs. § 15360; Public. Res. Code § 21060.5. CARB itself acknowledged its obligation to analyze out-of-state impacts in conducting its CEQA

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[54] Id.
[55] Id.
[56] See Attachment H; https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing.
[57] Draft EIA, at 61 and 62.
[58] Id.

review for the Renewable Electricity Standard in 2010.[59] Factory farms across the nation are eligible for LCFS credits, and are thus incentivized by the Proposed Amendments to install anaerobic digesters and expand existing herds, just as in-state factory farms are. The Proposed Amendments will therefore have adverse environmental impacts out-of-state. CARB's refusal to analyze such impacts is clear legal error.

7. The Draft EIA fails to adequately analyze Project-related discharges to groundwater associated with digestate.

The Draft EIA's analysis of increased digestate on groundwater is equally flawed. As explained in the Rosenfeld Comments, anaerobic digestion breaks down waste into a digestate of smaller molecules that makes digestate more susceptible to leaching into the groundwater.[60] Anaerobic digestion also leads to higher concentrations of ammonia in digestate, which can subsequently convert to nitrate.[61]

"[N]itrate pollution leading to groundwater contamination is much more likely to occur with anaerobically digested digestate, as the ammonia is more readily available for conversion into nitrate, which can then leach into groundwater."[62] Nitrate contamination in drinking water and food can lead to severe illness in infants, such as the onset of blue baby syndrome, also known as methemoglobinemia.[63] Yet, the Draft EIA fails to include any analysis of these potential impacts.

Although the Draft EIA concludes that the Project's long-term operational impacts to water quality are significant and unavoidable, the document lacks a thorough analysis of these impacts. As the Rosenfeld Comments explain, increased amounts of digestate have the potential to result in groundwater nitrate contamination, excessive accumulation of soil phosphorus, and eutrophication of surface waters from anaerobic digesters.[64] These impacts to water quality and public health must be evaluated in a revised EIA.

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[59] California Air Resources Board, Functional Equivalent Document for the Renewable Electricity Standard, at E-77, E-82, E-83, E-105, E-107, E-108 (June 2010), attached as Attachment T and available at https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2010/res2010/res10e.pdf.
[60] Attachment B at 5.
[61] Id.
[62] Attachment B at 5 and 6.
[63] Id.
[64] Id. at 7.

In summary, the Draft EIA fails to grapple with an analysis of all of the foreseeable, significant, direct and indirect environmental impacts of implementing the Proposed Amendments. As discussed above and in several comment letters from other stakeholders, these impacts include, but are not limited significant air quality, climate change, water quality, and public health impacts. Furthermore, as discussed below, the Draft EIA fails to identify feasible mitigation measures to minimize acknowledged significant impacts resulting from the project. A revised EIA must correct these deficiencies in order for the public and decision-makers to fully understand the Project's impacts.

III. The Draft EIA fails to identify any enforceable mitigation measures to lessen the severity of the Proposed Amendments' significant impacts.

If, as here, a lead agency determines its project will have one or more significant environmental effects, CEQA requires that agency to adopt all feasible mitigation measures to reduce the severity of those impacts. Public. Res. Code § 21002; *Sacramento Old City Assn. v. City Council* (1991) 229 Cal.App.3d 1011, 1027; *POET, LLC*, 218 Cal.App.4th at 734-35. Mitigation can take many forms, including avoiding the impact altogether by not taking a certain action or parts of an action and minimizing impacts by limiting the degree or magnitude of the action and its implementation. 14 Cal. Code Regs., § 15370. Mitigation measures are only legally valid if they are fully enforceable. Public Res. Code § 21081.6(b); *Assn. of Irritated Residents v. Kern County Bd of Supervisors* (2017) 17 Cal.App.5th 708, 752.

The Draft EIA's approach to mitigation measures is woefully deficient. CARB has not proposed *any* enforceable mitigation measures to be incorporated as part of the Proposed Amendments. The Draft EIA's reasoning for doing so is based on a fundamental legal error. Because CARB has no authority over the projects and actions that will be undertaken in response to the Proposed Amendments, the Draft EIA asserts that CARB has no obligation to incorporate feasible mitigation measures into the Proposed Amendments themselves. CARB does have jurisdiction over the Proposed Amendments, and it must include measures that will reduce or eliminate the reasonable foreseeable impacts of the Amendments. 14 Cal. Code Regs. § 15126.4.

The Draft EIA's illogical reasoning is compounded by its unsupported assumption that the projects it identifies as reasonably compliance responses will be subject to future CEQA review. Factory farm expansions and digester installations are commonly considered exempt from CEQA review by the local agencies in Central Valley that routinely approve such projects. The Leadership Counsel proposes numerous feasible mitigation measures CARB can, and must, incorporate into the Proposed Amendments to lessen the severity of its significant impacts associated with digester installation and factory farm expansion.

1. The Draft EIA's approach to mitigation measures is legally erroneous.

CARB has not proposed *any* enforceable mitigation measures, despite the Draft EIA concluding that the Proposed Amendments will have numerous significant environmental impacts. According to the Draft EIA, CARB—one of the most powerful regulators in the State—has no ability or authority to mitigate the impacts associated with the Proposed Amendments. In attempting to off-load its obligation to impose feasible mitigation measures, CARB confuses the project before it—the Proposed Amendments—with the projects (e.g. anaerobic digesters, factory farm expansions) that will be undertaken *as a result* of the Proposed Amendments. Because CARB does not have authority over these projects, the Draft EIA asserts CARB has no ability to incorporate feasible mitigation measures within the Proposed Amendments.

However, CEQA requires CARB to determine whether changes or additions can be made to the *Proposed Amendments themselves* that will reduce the severity of their significant environmental impacts. 14 Cal. Code Regs. § 15126.4(a)(2) ("[i]n the case of the adoption of a plan, policy, regulation, or other public project, mitigation measures can be incorporated into the plan, policy, regulation, or project design"). CARB clearly has the authority to make changes or additions to its own Proposed Amendments, which will lessen the severity of their environmental impacts. Its failure to even consider doing so constitutes grave legal error.

2. CARB's EIA process is likely the last opportunity for environmental review and mitigation of the impacts of factory farm expansion and digester installation.

CARB's faulty reasoning is compounded by its unsupported assumption that the projects which will be undertaken as a result of the Proposed Amendments will be subject to future CEQA review and, thus, the obligation to mitigate significant impacts. However, in the Central Valley, where factory farms are predominately located, the installation of anaerobic digesters and the expansion of factory farms are commonly considered by local agencies to be exempt from CEQA review on the grounds that the projects are ministerial or qualify for a categorical exemption. Therefore, with respect to these projects, the Draft EIA process is likely the last stop for both detailed environmental review and the imposition of meaningful mitigation measures.

For example, Kings County has adopted local guidelines that inform its implementation of CEQA.[65] Included in these guidelines are a list of categories of projects that are exempt from CEQA review because they are subject to ministerial review. These ministerial projects include "Site Plan Reviews." In 2023 alone, Kings County approved two anaerobic digester projects, exempting them from CEQA review on the grounds they were subject to ministerial review.[66] Kings County thus had no obligation under CEQA to analyze and mitigate the adverse impacts associated with either of these projects.

Other jurisdictions have exempted digester projects from CEQA review—and the obligation to mitigate significant impacts—on the grounds that these projects qualify for a Categorical Exemption. For example, Tulare County issued a Notice of Exemption in 2020 for a pipeline construction project intended to transport dairy biogas on the grounds the project qualified for the Class 1 (minor alterations to existing facilities) and Class 3 (new construction of small structures) Categorical Exemptions.[67] Tulare County also filed a Notice of Exemption to expand an existing biogas pipeline to connect an additional dairy digester to existing infrastructure. Other jurisdictions where similar projects have been exempted from CEQA review recently include Merced, Stanislaus, and Kern.

Tulare County also filed multiple Notices of Exemption in 2022 for factory farm herd consolidation projects, including a project that increased an existing herd size by

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[65] Kings County, *Local Guidelines for the Implementation of CEQA*, (January 5, 2016), attached as Attachment U and available at https://www.countyofkings.com/home/showpublisheddocument/12485/635919879294330000.

[66] Kings County Notice of Exemption for Felicita Dairy Anaerobic Digester Project (December 7, 2023), attached as Attachment V and available at https://files.ceqanet.opr.ca.gov/293555-1/attachment/CDzMvjy1XpNztMTMZYB397RSlELw_rWgq8tiJxKcc3SF7-nLFEgELbQwM06hiwOeTZEiJUhU6gqHLBNx0; Kings County Notice of Exemption for Countryside Dairy Anaerobic Digester Project (May 15, 2023), attached as Attachment W and available at https://files.ceqanet.opr.ca.gov/287881-1/attachment/q5K_P65aU7RUja-BYGe9-uDeE-Fz0Az_DAbus84Q28vqdXyG1cceIHq937esHc4jb7WmtPLcv9qGvzOn0.

[67] Tulare County Notice of Exemption for Tulare Biogas Gathering Line (August 18, 2020), attached as Attachment X and available at https://files.ceqanet.opr.ca.gov/264014-2/attachment/ZQ976ZUWit1klndpB1s5MYMKZJQBpo6c-8VIweVKasCVOsmAyGVogK05MqqmSLuQk994sssNab-A3-7Q0.

almost 3,000 animal units.[68] Kings County filed a Notice of Exemption for a project that expanded the herd size of an existing calf ranch in 2023 on the grounds that the underlying approval was ministerial.

CARB's attempt to justify its refusal to adopt any enforceable mitigation measures on the grounds that the projects incentivized by the Proposed Amendments will be subject to future CEQA review fails. CARB's discretionary approval of the Proposed Amendments is likely the last chance to rigorously analyze and mitigate the significant impacts associated with many future factory farm expansions and digester development projects. CARB must use its authority as the regulatory agency tasked with crafting the LCFS to ensure all identified significant impacts are mitigated to the extent feasible.

3. CARB must adopt feasible mitigation measures that will lessen the severity of the Proposed Amendments' impacts on factory farm expansion and digester installation.

CEQA explicitly acknowledges that feasible mitigation measures can include changes that are incorporated into the regulation itself. 14 Cal. Code Regs. § 15126.4(a)(2). Each of the following mitigation measures is feasible and within CARB's authority to incorporate within the Proposed Amendments; CARB's failure to do so would constitute a clear violation of CEQA:

- Limit the generation of credits for fuel pathway holders for biogas derived from livestock manure to the volume of feedstock at each associated dairy or livestock operation on January 1, 2017, or on the date the pathway was certified, whichever is earlier.

- Restrict the generation of credits for fuel pathway holders for biogas derived from livestock manure located in Disadvantaged Communities as designation by the Office of Environmental Health Hazard Assessment pursuant to Senate Bull 535.[69]

- When calculating the carbon intensity of fuel derived from livestock manure, include all emissions of greenhouse gases generated from the production of the

[68] Cows, pigs, and other animals raised in factory farms and dairies are not "units," but are sentient beings, each of which has its own unique personality.
[69] An interactive map delineating the Disadvantaged Communities throughout the State is available at https://oehha.ca.gov/calenviroscreen/sb535. A copy of the state-wide map is attached as Attachment Y.

fuel and all emissions of greenhouse gases generated from the production of the feedstock. Update the carbon intensity of each pathway for fuel derived from livestock manure after making this calculation. These emissions include, but are not limited to,

- o Enteric emissions;
- o Emissions from production and storage of feed, transport of feedstock, or fuel;
- o Emissions resulting from digestate handling, composting, or treatment; and
- o Emissions resulting from land application of manure or digestate.

- Disapprove any application for a fuel pathway that includes the use of biogas derived from livestock manure which does not provide all information and calculations used to determine carbon intensity, including but not limited to:
  - o Herd size;
  - o Volume of feedstock produced or used;
  - o Volume of biogas produced.
- Make publicly available on CARB's website all information and calculations used to determine carbon intensity.

IV. The Draft EIA fails to analyze all reasonable alternatives by which the State can achieve its methane reduction goals.

As a preliminary matter, the Draft EIA's failure to disclose the extent and severity of the Project's broad-ranging impacts necessarily distorts the document's analysis of Project alternatives. As a result, the alternatives are evaluated against an inaccurate representation of the Project's impacts. Proper identification and analysis of alternatives is impossible until Project impacts are fully disclosed.

CEQA requires CARB's Draft EIA to describe a range of "reasonable alternatives to the project," which would "attain most of the basic objectives of the project but would avoid or substantially lessen any of the significant effect of the project," and evaluate the "comparative merits" of the alternatives. 14 Cal. Code. Regs. § 15126.6. The discussion of mitigation and alternatives is "the core" of CEQA analysis. *Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal.3d 553, 564.

The Draft EIA's alternatives analysis presents a series of false choices, that rests on the assumption that the only method by which the State can achieve its methane emissions reduction goals is through the LCFS's indirect, incentive-based regulation. Each alternative scenario is simply a version of the LCFS with different requirements than the Proposed Amendments. The Draft EIA fails to analyze a scenario where CARB uses its regulatory authority to directly regulate methane emissions from factory farms, as required by Health & Safety Code §§ 38562.5, 39730.7(b)(1), thereby achieving the State's methane reduction goals while reducing the incentive for factory farms to expand their environmentally damaging operations.

The Draft EIA must be amended to include analysis of an alternative scenario with the following components: (1) elimination of LCFS credits for fuel derived from manure methane emissions; (2) implementation of direct regulation of factory farms to achieve the same level of methane reduction CARB currently contemplates will be achieved through the LCFS; and (3) decrease the stringency of the LCFS' carbon intensity requirement, to ensure the elimination of credits for fuel derived from manure methane emissions does not affect credit prices negatively and risk the State failing to achieve its fuel decarbonization goals.

The State Legislature has granted CARB the regulatory authority to directly regulate the major sources of methane emissions within the State, including the dairy and livestock industry, landfills, and the oil and gas system. To date, CARB has taken action to directly regulate landfills (the Landfill Methane Regulation, Cal. Code of Regs., tit. 17 §§ 95460, et seq.) and the oil and gas system (the Oil and Gas Methane Regulation, Cal. Code of Regs., tit. 17, §§ 95665-77). However, CARB has yet to directly regulate the dairy and livestock industry—the largest source of methane emissions within the State.

The State Legislature, through Senate Bill 1383, mandated that CARB adopt regulations and mandated that CARB implement such regulations beginning in January of 2024 provided that CARB make certain findings. As CARB itself has stated, the agency shall adopt regulations and has authority to implement the regulations, "provided that CARB, in consultation with CDFA, determine the regulations are technologically and economically feasible, cost-effective, include provisions to minimize and mitigate potential leakage, and include an evaluation of the achievements made by incentive-based programs."[70]

CARB itself acknowledged in its 2022 Scoping Plan that direct regulation of the sources of methane emissions is integral to the State's methane emissions reduction strategy.[71] CARB's stated strategy for reducing the emissions of short-lived climate pollutants, most notably methane, is a "carrot-then-stick" approach.[72] This approach begins with the incentive-based, indirect regulations, such as the LCFS (the "carrot"), and then transitions into direct regulation, similar to those that have been promulgated for the landfill and oil and gas systems (the "stick"). The 2022 Scoping Plan ultimately recommends the carrot and stick approach for manure methane.[73] CARB acknowledged that the dairy and livestock industry must "achieve considerable methane emissions reductions to meet the 2030 target," which will "require implementation of additional methane emissions reductions strategies."[74]

Despite having the mandatory duty and authority to directly regulate methane emissions from the dairy and livestock industry, and explicitly stating that such regulation is integral to the State's emissions reduction strategy, CARB fails to analyze an alternative scenario where this direct regulatory authority is applied. The only alternatives CARB considers are those where the LCFS is the primary, if not sole, mechanism for achieving methane emissions reductions from the dairy and livestock industry. CARB has the authority to simultaneously reduce the methane emissions and adverse environmental impacts from factory farms, while not risking the State's fuel decarbonization goals. CARB's failure to consider such a scenario constitutes clear legal error.

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[70] California Air Resources Board, Analysis of Progress Toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target, at ES-4 (March 2022), attached as Attachment Z and available at https://ww2.arb.ca.gov/sites/default/files/2022-03/final-dairy-livestock-SB1383-analysis.pdf.
[71] California Air Resources Board, 2022 Scoping Plan, at 222-25 (2022), attached as Attachment AA and available at https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.
[72] *Id*. at 223.
[73] *Id*. at 232.
[74] CARB, Analysis of Progress Toward Achieving 2030 Methane Emissions Target, at ES-6.

V. Conclusion

Due to the foregoing and numerous adverse environmental impacts not fully disclosed and properly analyzed in the Draft EIA, the Leadership Counsel opposes the Project as proposed. Additional alternatives and mitigation measures are essential to avoid the Project's significant adverse impacts. The Leadership Counsel respectfully urges the Air Resources Board to delay further consideration of this Project until the agency recirculates a revised Draft EIA that fully complies with CEQA and the CEQA Guidelines.

Very truly yours,

SHUTE, MIHALY & WEINBERGER LLP

Ellison Folk

Attachments:

Attachment A: Comments of Silvia Secchi, Ph.D., Professor, Department of Geographical and Sustainability Sciences, University of Iowa

Attachment B: Comments of Paul Rosenfeld, Ph.D., Principal Environmental Chemist, Soil Water Air Protection Enterprise

Attachment C: Aaron Smith, "Cow poop is now a big part of California Fuel Policy", UC Davis, Jan. 22, 2024.

Attachment D: U.S. Department of Agriculture, 2017 Census of Agriculture – State Data, Table 17. Milk Cow Herd Size by Inventory and Sales: 2017 and Table 17. Milk Cow Herd Size by Inventory and Sales: 2022

Attachment E: Briefing paper: Factory Farm Dairies, Biogas, and the Dangerous Path California is On, Leadership Counsel for Justice and Accountability, 2023.

Attachment F: U.S. EPA, "Health Effects of Ozone Pollution"; https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution#:~:text=Depending%20on%20the%20level%20of%20exposure%2C%20ozone%20can%3A,diseases%20such%20as%20asthma%2C%20emphysema%2C%20and%20chronic%20bronchitis.

Attachment G: 87 Fed. Reg. 60494 (Oct. 5, 2022) (proposed disapproval of plan to attain the 2012 annual PM2.5 standard).

Attachment H: U.S. EPA, Health and Environmental Effects of Particulate Matter, https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm#:~:text=Numerous%20scientific%20studies%20have%20linked%20particle%20pollution%20exposure,irritation%20of%20the%20airways%2C%20coughing%20or%20difficulty%20breathing

Attachment I: U.S. EPA, Understanding Global Warming Potentials; https://www.epa.gov/ghgemissions/understanding-global-warming-potentials

Attachment J: Aura Science: Greenhouse effect of tropospheric ozone, NASA, https://aura.gsfc.nasa.gov/science/feature-20110403.html

Attachment K: CARB: Total Number of Applications or Pathways (excel spreadsheet), February 9, 2024.

Attachment L: SJVAPCD Bar 20 Bloom Energy Permits

Attachment M: Notice of Final Action – Authority to Construct, ATC Lone Oak Energy; 2020.02.21 Notice of Preliminary Decision – Authority to Construct Lone Oak Energy

Attachment N: SJVAPCD, Notice of Preliminary Decision – Authority to Construct Lakeview Dairy Biogas (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf.

Attachment O: CalEPA & Cal. Air Res. Bd., LCFS Tier 2 Pathway App. B0104 Lakeview Dairy Biogas(certified TBD), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf

Attachment P: Notice of Final Determination of Compliance, Avenal Power Center, at 3, 27 (Dec. 17, 2010)

Attachment Q: Digester v. Avenal Comparison

Attachment R: Excerpt from Petition for Reconsideration Of The Denial Of The Petition For Rulemaking To Exclude All Fuels Derived From Biomethane From Dairy And Swine Manure From The Low Carbon Fuel Standard Program

Attachment S: 2023 CARB Ammonia Demonstration re 1997 PM2.5 plan standard SJV.

Attachment T: Excerpts of CARB Functional Equivalent Document for Renewable Electricity Standard, June 2010.
https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2010/res2010/res10e.pdf

Attachment U: Kings County, *Local Guidelines for the Implementation of CEQA*, January 5, 2016.

Attachment V: Kings County Notice of Exemption for Felicita Dairy Anaerobic Digester Project, December 7, 2023.

Attachment W: Kings County Notice of Exemption for Countryside Dairy Anaerobic Digester Project, May 15, 2023.

Attachment X: Tulare County Notice of Exemption for Tulare Biogas Gathering Line, August 18, 2020.

Attachment Y: OEHHA SB 535 Disadvantaged Communities Map, https://oehha.ca.gov/calenviroscreen/sb535.

Attachment Z: California Air Resources Board, Analysis of Progress Toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target (March 2022), https://ww2.arb.ca.gov/sites/default/files/2022-03/final-dairy-livestock-SB1383-analysis.pdf.

Attachment AA: California Air Resources Board, 2022 Scoping Plan https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

ATTACHMENT A

Comments on the Amendments to Low Carbon Fuel Standard

Silvia Secchi

My name is Silvia Secchi and I am a professor in the Department of Geographical and Sustainability Sciences at the University of Iowa. I have a Ph.D. in economics from Iowa State University and have been studying the environmental impacts of Midwestern agriculture for over a quarter of a century, my google scholar profile shows see my record of peer reviewed publications[1]. I have reviewed the Initial Statement of Reasons of the Proposed Amendments to California's Low Carbon Fuel Standard and associated Appendices. Based on my my professional expertise as an agricultural economist, I have several concerns about CARB's failure to adequately address the potential for changes in the Standard to encourage the development of concentrated animal feeding operations, both through the establishment of new dairies and the concentration of existing operations.

First, the ISOR offers no monitoring data showing whether the LCFS has caused, or the proposed amendments will cause, herd expansions at dairies or hog facilities located in California or outside of California. As a result, CARB cannot in good faith assert that the capturing of manure from CAFO is actually reducing methane emissions from dairy and/or hog operations, and that the LCFS will not result in rebound effect or Jevon's paradox: the technological improvement (in this case the biodigesters) change the behavior of consumers and producers so that the efficiency gains actually result in increased production and the net effects are not reductions but increases in resource use and – in this case – methane emissions. There is extensive evidence of this type of phenomenon in the agricultural sector[2].

CARB's lack of jurisdiction outside state borders exacerbates this problem by causing a "race to the bottom" in jurisdictions that build digesters as a way to attract new operations or allow existing operations to expand along with digester installation. Race to the bottom has been found to be a significant factor in determining location of Confined Animal Feeding Operations (CAFOs) for both dairy and hog operations[3].

Here I detail recent trends in dairy production in Iowa and the increase in biodigesters, to show that the LCFS is already having an impact. The data I present here are the result of several hours of search on the Iowa Department of Natural Resources (DNR) website. I conducted this research in the course of a project in which I am examining the effects of lax environmental regulations in the expansion of CAFOs, in particular in association with "climate smart" policies. This data is important because the EPA Agstar database[4] that experts like Prof. Aaron Smith at UC Davis have been using severely underreports the number of biodigesters compared to the Iowa DNR site. As a result, national level analyses are extremely likely to underestimate the rebound effect. This is likely to be compounded by the fact that the deployment of biodigesters and the expansion do not always occur in the same year, as evidenced in two cases reported in

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[1] https://scholar.google.com/citations?user=rXte6MIAAAAJ&hl=en&oi=ao

[2] Paul, C., Techen, A. K., Robinson, J. S., & Helming, K. (2019). Rebound effects in agricultural land and soil management: Review and analytical framework. Journal of cleaner production, 227, 1054-1067.

[3] Herath, D., Weersink, A., & Carpentier, C. L. (2005). Spatial Dynamics of the Livestock Sector in the United States: Do Environmental Regulations Matter? Journal of Agricultural and Resource Economics, 30(1), 45-68.

[4] https://www.epa.gov/agstar

Table 1. In these cases, the impacts of the biodigesters on expansion will easily be underestimated.

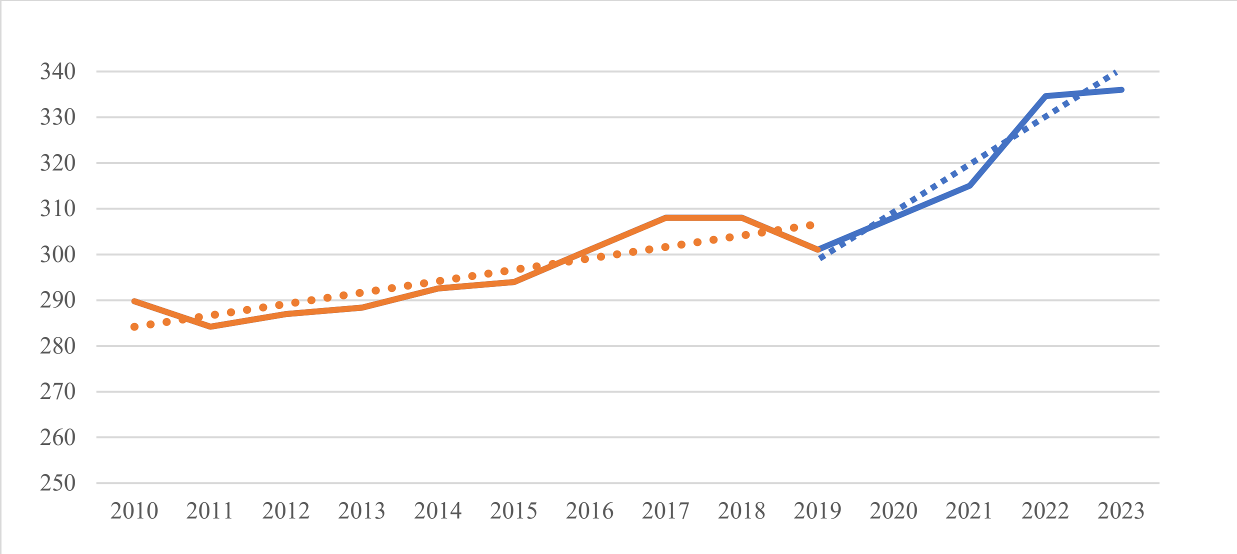
As Table 1 shows, there have been 15 digesters built in Iowa dairies since 2019. **The AgStar database only includes 4 of them.** These 15 digesters are associated with an increase of over 17,000 Animal Units (AUs). This corresponds to an increase of almost 20% in AUs. Milk production in Iowa had been growing, but it was doing so at a much slower pace before 2019 (Figure 1). Though it is not possible to formally attribute causality, it is notable that Iowa's dairy cows AUs increased by 35,000 between 2019 and 2023. **This means that a large portion of the increase in milk cows in the state is associated with biodigesters.**

Table 1 – Recent biodigesters installed in Iowa and associated capacity expansion

	Facility location	General Location	ID	Year	Initial size (AUs)	Final size (AUs)
Black Soil Dairy	Granville	North West	60565	2021	4,500	4,500
Geno	Blairstown	East Central	61209	2022	6,280	7,512
Kirkman Farms	Kirkman	West Central	64174	2021	8,500	11,900
Legacy Dairy	Sanborn	North West	60531	2022	3,920	6,160
Maassen	Maurice	North West	57177	2022	3,200	3,995
Marshall Ridge Farms	State Center	Central	60101	2020 digester 2023 expansion	8,499	11,425
Meadowvale Dairy North	Rock Valley	North West	62015	2021	20,300	20,300
Rock River Jerseys-Inwood Dairy	Doon	North West	66387	2019 digester 2022 expansion	8,499	14,000
Roorda Dairy	Paullina	North West	64981	2021	5,880	5,880
Salix Farms	Salix	North West	64623	2023	3,500	3,500
Sioux Jerseys	Salix	North West	62420	2023	6,300	6,300
Van Ess Dairy	Sanborn	North West	65143	2021	7,599	8,499
Winding Meadows Dairy	Rock Valley	North West	60218	2021	2,884	3,360

Source: Iowa DNR Animal Feeding Operation online application https://programs.iowadnr.gov/afoemmp/

Figure 1 – Iowa milk cow AUs (1,000s)



Source: USDA NASS Milk production reports
https://usda.library.cornell.edu/concern/publications/h989r321c?locale=en#release-items

Again, it is not possible to demonstrate unequivocally that this growth in dairy operations is directly linked to the expanded use of biodigesters. But two laws deregulating biodigesters were recently passed in Iowa. In 2019 SF 534[5] repealed the statutory requirement for rulemaking for all waste control technology facilities, including biodigesters, and in 2021, HF 522[6] allowed large dairies (over 8,500 AUs) to exceed confinement capacity if they install an anaerobic digester to treat all manure. There is a strong correlation between the deployment of biodigesters and the dairy expansions. As Table 1 shows, there were 3 such operations that expanded as they deployed biodigesters. In my professional opinion, this very strongly suggests that the increasing availability and decreasing regulation of biodigesters is contributing to dairy expansion and concentration.

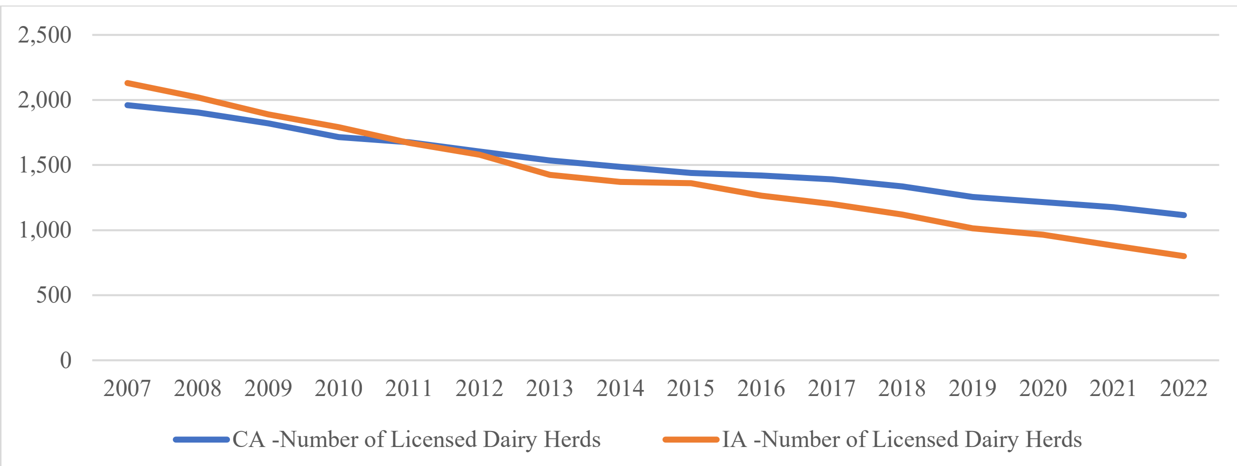
And while the dairies in Table 1 are not currently associated with approved pathways, biogas companies have already indicated their intent to avail themselves of the LCFS to generate credits at several of these facilities. Specifically, Gevo has announced that BP Canada Energy Marketing Corp. and BP Products North America Inc. will market Iowa-produced natural gas in California on its behalf[7]. Gevo is contracting with three of the dairies in Table 1, Meadowvale, Rock River Jerseys and Winding Meadows, two of which have expanded[8]. Another of the dairies

[5] https://www.legis.iowa.gov/docs/publications/LGE/88/SF534.pdf
[6] https://www.legis.iowa.gov/docs/publications/SOL/1224327.pdf#HF522
[7] https://investors.gevo.com/news-releases/news-release-details/gevos-northwest-iowa-rng-project-hits-major-milestone-begins
[8] Gevo appears as the common "cluster" for the dairies here: https://www.epa.gov/sites/default/files/2020-10/agstar-livestock-ad-database.xlsx.

expanding, Kirkman, is partnering with California's Brightmark RNG Origination LLC[9], which sells RNG to U.S. Gain, which is active in the California LCFS market[10].

Based on my study of the effect outside of California of policies to incentivize the use of biodigesters and my review of the literature, I believe similar expansion phenomena are likely taking place in California's dairy sector and elsewhere. The proposed LCFS amendments will increase expansion and concentration[11]. For example, very recently, a local expert has argued that the flattening of the dairy herd in California in the last five years could be linked to biodigesters. Notably, both in California and Iowa, flat and increasing total herd sizes respectively have both been associated with a reduction in the number of diaries, as shown in Figure 1. Consolidation should be a concern for CARB, since there is extensive evidence that it is associated with more water quality problems, among other things[12].

Figure 2 – Number of licensed dairy herds in California and Iowa, 2007-2022



Source: USDA NASS Milk production reports
https://usda.library.cornell.edu/concern/publications/h989r321c?locale=en#release-items

The evidence strongly suggests that the rebound effect is already at work outside California's borders because of race to the bottom policies being enacted by other states. The current policy approach allows for negative crediting of biogas as a way to avoid leakage: the concern is that making California farmers pay for their methane emissions would cause milk production to move (leak) out of state, where emissions are unregulated. But while the approach ensures California farmers do not face an added burden, it does nothing to limit the expansion of dairies in and out of state. As a result, the proposed LCFS amendments likely will cause another type of leakage through the rebound effect: the expansion and concentration of dairy operations resulting

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[9] https://www.iowafarmbureau.com/Article/Carbon-neutral
[10] https://biomassmagazine.com/articles/us-gain-to-purchase-rng-from-brightmark-energy-16647
[11] Smith, A. (2022). The Dairy Cow Manure Goldrush. Retrieved from https://asmith.ucdavis.edu/news/revisiting-value-dairy-cow-manure; Smith, A. (2024). Cow Poop is Now a Big Part of California Fuel Policy. Retrieved from https://asmith.ucdavis.edu/news/cow-poop-now-big-part-california-fuel-policy .
[12] See for example Bian, Z., H. Tian, Q. Yang, R. Xu, S. Pan, and B. Zhang. 2021. "Production and application of manure nitrogen and phosphorus in the United States since 1860." Earth Syst. Sci. Data 13 (2):515-527. doi: 10.5194/essd-13-515-2021.

from the economic incentives provided by the LCFS and the decreased regulation of dairy operations will likely cause increased methane emissions that are not currently accounted for.

CARB's proposal to increase the carbon intensity target and therefore increase the economic value of methane captured from dairy operations will likely result in the expansion of dairy operations inside and outside of California.

I also want to note that the rebound effect has other substantial negative environmental impacts. In particular, as Table 1 shows, the expansion is occurring largely in Northwest Iowa, where CAFO production is already extremely elevated and there is little if any extra land available for spreading additional manure or digestate. This expansion will likely have both water quality and water quantity effects, and no entity is monitoring or assessing them. Notably, one of the Gevo dairies already leaked an estimated 376,000 gallons of manure water and was fined $10,000 in 2022. Another of the Gevo dairies started construction before receiving permission to do so[13].

This is particularly a concern because in 2017 EPA signed a settlement agreement limiting access to whatever information EPA has at its disposal regarding CAFOs[14] As a result, there is no national database that can be used to establish a national bottom-up[15] baseline of GHG emissions and other forms of pollution from CAFOs. This makes national level tracing of net changes in pollution and emissions as a result of the deployment of biodigesters extraordinarily difficult. In Iowa specifically, the DNR lack of monitoring capacity resulted in a de-delegation petition with EPA in 2007. As a result of the subsequent work plan[16], in 2017 the Iowa Department of Natural Resources identified 5,000 more animal feeding operations, some of which were CAFOs[17]. It is quite evident the Iowa DNR does not have the monitoring capacity to ensure compliance with the assumptions that CARB is making. CARB does not have that capacity either.

Recent changes to the USDA's Natural Resources Conservation Service (NRCS) list of practices eligible to receive subsidies under the Environmental Quality Incentive Program (EQIP) and substantial funding allocated to EQIP in the Inflation Reduction Act (IRA) also make it more likely that the rebound effect will increase in the United States. In particular, NRCS has added eligibility to receive subsidies to additional practices in their Climate-Smart Agriculture and Forestry (CSAF) Mitigation Activities List for FY2024 through EQIP and the Conservation Stewardship Program (CSP)[18]. These activities now include roofs and covers used to cover a waste management facility to capture biogas and waste storage facilities. The increased funding for the EQIP and CSP programs is substantial: $8.45 billion and $3.25 billion respectively[19]. Therefore, there are now subsidies available that will further incentivize the deployment of biodigesters. It is also important to note that CAFO operations that receive both federal subsidies to deploy biodigesters and LCFS subsidies for their methane could legitimately be considered a

[13] https://iowacapitaldispatch.com/2022/07/22/company-with-major-manure-leak-didnt-get-permits-to-build-two-facilities-dnr-says/

[14] Miller, D. L., & Muren, G. (2019). *CAFOs: What We Don't Know Is Hurting Us*, retrieved from https://www.nrdc.org/resources/cafos-what-we-dont-know-hurting-us

[15] Bottom up baselines include individual facilities and can trace aggregate changes to each of them.

[16] https://www.iowadnr.gov/Portals/idnr/uploads/afo/epa_dnr_workplan.pdf

[17] https://publications.iowa.gov/33733/

[18] https://www.nrcs.usda.gov/conservation-basics/natural-resource-concerns/climate/climate-smart-mitigation-activities

[19] https://www.farmers.gov/loans/inflation-reduction-investments

form of double dipping, that is paying twice for the same activity. This raises questions about the additionality of the GHG emissions that could occur.

In my professional opinion, California's ill-conceived policy is poised to trigger a new iteration of Cochrane's treadmill that will result in overproduction, further consolidation, and multiple negative environmental consequences[20]. As in the past, landowners will be the main beneficiaries of the policy. Biodigesters' adopters will benefit from temporary increased profits, overproduction will ensue, and the government will be called in to address the fallout. The climate benefits of this approach are dubious at best.

In summary:

a) CARB has not adequately included a full accounting of greenhouse gas emissions that properly considers the impact of biogas market prices and state-level regulatory settings on the US dairy industry. CARB is also ignoring the expansionary effects of the Inflation Reduction Act and the lack of additionality for methane reductions from digesters funded by the IRA. The information I have shown here regarding already occurring out of state effects illustrates that there does not exist at the moment a comprehensive inventory of biodigesters and it is therefore impossible for CARB to adequately consider national level impacts and back up any claims that the incentives included in the proposed LCFS amendments will not result in industry expansion and consolidation. I have in fact presented evidence that expansion is already occurring in Iowa, it is very strongly associated with the deployment of biodigesters, and an increased market signal to produce more credits will further exacerbate that expansionary effect;

b) The economic incentive to monetize manure-methane emissions as proposed by CARB will likely lead to further expansion in the dairy sector in Iowa. If such expansion were to extend to hog CAFOs, given that Iowa already produces one third of US hogs, the environmental impacts could be devastating considering Iowa alone. The national level effects would be worse;

c) The amendments do not just have the potential to result in direct and indirect environmental impacts in California and other states. Combined with federal policy and enhanced by race to the bottom state deregulation, they will substantially alter incentives and result in industry expansion.

[20]Levins, Richard A., and Willard W. Cochrane. 1996. "The Treadmill Revisited." *Land Economics* 72 (4):550-553. doi: 10.2307/3146915.

S I L V I A   S E C C H I

EDUCATION

1996 - 2000 Iowa State University Ames, IA, USA
Ph.D. in Economics
Concentrations: Environmental and Resource Economics, International Economics

1994-1995 University of Reading Reading, England
Master's Degree in Agricultural Economics
Fields: Econometrics and Economic Development

1987-1993 Università Commerciale L. Bocconi Milan, Italy
Laurea in economics
Specialization in International Economics

1985 - 1987 United World College of the Adriatic Duino, Italy
International Baccalaureate

ACADEMIC EXPERIENCE

2021-current University of Iowa Iowa City, IA
Professor *Department of Geographical and Sustainability Sciences*
2017-2021 University of Iowa Iowa City, IA
Associate Professor *Department of Geographical and Sustainability Sciences*

2014-2017 Southern Illinois University Carbondale, IL
Associate Professor *Department of Geography and Environmental Resources*
2008-2014 Southern Illinois University Carbondale, IL
Assistant Professor *Department of Agribusiness Economics*

2004-2008 Iowa State University Ames, IA
Associate Scientist *Center for Agricultural and Rural Development*
2001-2004 Iowa State University Ames, IA
Assistant Scientist *Center for Agricultural and Rural Development*

1996 – 2000 Iowa State University Ames, IA
Research Assistant *Center for Agricultural and Rural Development*

1995 - 1996 University of Reading Reading, England
Research Associate *Centre for Agricultural Strategy*

ADMINISTRATIVE EXPERIENCE

2016-2017 Southern Illinois University Carbondale, IL
Director, Environmental Resources & Policy Ph.D. Program
2009-2015 Southern Illinois University Carbondale, IL
Co-Director, Environmental Resources & Policy Ph.D. Program
Responsibilities included annual budgeting and personnel evaluations, recruiting, and representing the core curriculum at written and oral exams.

Department of Geographical and Sustainability Sciences
University of Iowa
310 Jessup Hall
Iowa City, Iowa 52242
Phone:(319) 335-1927 • E-Mail: silvia-secchi@uiowa.edu
Goigle Scholar: https://scholar.google.com/citations?user=rXte6MIAAAAJ&hl=en&oi=ao

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17. Liu, C.-C., Herriges, J.A., Kling, C.L., Secchi, S., Nassauer, J.I., & Phaneuf, D.J. (2014). A Comparison of Value Elicitation Question Formats in Multiple-Good Contingent Valuation. *Frontiers of Economics in China, 9*(1), 85-108. doi: doi:http://dx.doi.org/10.3868/s060-003-014-0006-2.

16. Druschke, C.G.*, & Secchi, S. (2014). The impact of gender on agricultural conservation knowledge and attitudes in an Iowa watershed. *Journal of Soil and Water Conservation, 69*(2), 95-106. doi: 10.2489/jswc.69.2.95.

15. Secchi S. (2013). Integrated Modeling for Conservation Policy Support. *Choices, 28*(3), 1-5.

14. Banerjee, S., Secchi, S., Fargione, J., Polasky, S., & Kraft, S.E. (2013). How to sell ecosystem services: a guide for designing new markets. *Frontiers in Ecology and the Environment, 11*(6), 297-304. doi: 10.1890/120044.

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12. Varble, S.*, & Secchi, S. (2013). Human consumption as an invasive species management strategy. A preliminary assessment of the marketing potential of invasive Asian carp in the US. *Appetite, 65*, 58-67. doi: http://dx.doi.org/10.1016/j.appet.2013.01.022.

11. Muste, M., Bennett, D., Secchi, S., Schnoor, J., Kusiak, A., Arnold, N., . . . Rapolu, U. (2013). End-To-End Cyberinfrastructure for Decision-Making Support in Watershed Management. *Journal of Water Resources Planning and Management, 139*(5). doi: doi:10.1061/(ASCE)WR.1943-5452.0000289.

10. Secchi, S., Gassman, P. W., Jha, M., Kurkalova, L.A., & Kling, C. L. (2011). Potential water quality changes due to corn expansion in the Upper Mississippi River Basin. *Ecological Applications, 21*(4), 1068-1084. doi: 10.1890/09-0619.1.

9. Secchi, S., Kurkalova, L.A., Gassman, P. W., & Hart, C. (2011). Land use change in a biofuels hotspot: The case of Iowa, USA. *Biomass and Bioenergy, 35*(6), 2391-2400.

8. Rabotyagov, S., Campbell, T., Jha, M., Gassman, P. W., Arnold, J., Kurkalova, L.A., . . . Kling, C. L. (2009). Least-cost control of agricultural nutrient contributions to the Gulf of Mexico hypoxic zone. *Ecological Applications, 20*(6), 1542-1555. doi: 10.1890/08-0680.1.

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6. Secchi, S., Gassman, P. W., Williams, J. R., & Babcock, B. A. (2009). Corn-based ethanol production and environmental quality: A case of Iowa and the Conservation Reserve Program. *Environmental Management, 44*(4), 732-744.

5. Secchi, S., Jha, M., Kurkalova, L.A., Feng, H. H., Gassman, P. W., & Kling, C. L. (2007). Privatizing ecosystem services: Water quality effects from a carbon market. *Choices, 22*(2), 97-102.

4. Secchi, S., Gassman, P. W., Jha, M., Kurkalova, L.A., Feng, H. H., Campbell, T., & Kling, C. L. (2007). The cost of cleaner water: Assessing agricultural pollution reduction at the watershed scale. *Journal of Soil and Water Conservation, 62*(1), 10-21.

3. Herriges, J. A., Secchi, S., & Babcock, B. A. (2005). Living with hogs in Iowa: The impact of livestock facilities on rural residential property values. *Land Economics, 81*(4), 530-545.

2. Jha, M., Gassman, P. W., Secchi, S., Gu, R., & Arnold, J. (2004). Effect of watershed subdivision on SWAT flow, sediment, and nutrient predictions. *JAWRA Journal of the American Water Resources Association, 40*(3), 811-825. doi: 10.1111/j.1752-1688.2004.tb04460.x

1. Hurley, T., Secchi, S., Babcock, B., & Hellmich, R. (2002). Managing the risk Of European Corn Borer resistance to Bt corn. *Environmental and Resource Economics, 22*(4), 537-558. doi: 10.1023/a:1019858732103.

BOOKS

Kling, K.L., S. Secchi, and M. Peters. 2011. NRCS Environmental Credit Trading Reference. Washington D.C. U.S. Department of Agriculture. URL: http://www.nrcs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb1045650.pdf

REFEREED EXTENSION PUBLICATIONS

Schulte, L.A., H. Asbjornsen, R. Atwell, C. Hart, M. Helmers, T. Isenhart, R. Kolka, M. Liebman, J. Neal, M. O'Neal, R. Schultz, S. Secchi, J. Thompson, M. Tomer, & J. Tyndall. 2008. Targeted Conservation Approaches for Improving Water Quality: Multiple Benefits for Expanded Opportunities. PMR 1002. Iowa State University Extension, Ames, IA.

REFEREED TEACHING MATERIALS

Cooke S.L., A.C. Lloyd*, A.D. Monteblanco & S. Secchi. 2015. Moving to higher ground: Ecosystems, Economics and Equity in the Floodplain. National Center for Case Study Teaching in Science. URL: http://sciencecases.lib.buffalo.edu/cs/collection/detail.asp?case_id=778&id=778

INVITED JOURNAL ARTICLES

6. Secchi S. Forthcoming. The Marginalization of the Environment in Agricultural Policy. Invited Forum. *Agricultural History*.

5. Secchi S. 2020. Response to Struckman – The political economy of unsustainable lock-ins in North American commodity agriculture: a path forward. "Political ecologies of inertia" Invited Commentary. *Nordia Geographical Publications 49*(5), 107–111.

4. Prokopy L, B. Gramig, A. Bower, S. Church, B. Ellison, K. Floress, P. Gassman, K. Genskow, D. Gucker, S. Hallett, J. Hill, N. Hunt, K. Johnson, I. Kaplan, P. Kelleher, H. Kok, M. Komp, P. Lammers, S. LaRose, M. Liebman, A. Margenot, D. Mulla, M. O'Donnell, A. Peimer, A. Reaves, K. Salazar, C. Schelly, K. Schilling, S. Secchi, A. Spaulding, D. Swenson, A. Thompson, & J. Ulrich-Schad. 2020. The Urgency of Transforming the Midwestern U.S. Landscape into more than corn and soybean. *Agriculture and Human Values 37*, 537–539. doi:10.1007/s10460-020-10077-x.

3. Secchi, S., Garvey, J., & Whiles, M. 2012. Multifunctional Floodplain Management: Looking Ahead From the 2011 Mississippi Floods. *National Wetlands Newsletter, 34*(5), 21-24.

2. Nassauer, J. I., Dowdell, J. A., Wang, Z., McKahn, D., Chilcott, B., Kling, C. L., & Secchi, S. 2011. Iowa farmers' responses to transformative scenarios for Corn Belt agriculture. *Journal of Soil and Water Conservation, 66*(1), 18A-24A. doi: 10.2489/jswc.66.1.18A

1. Secchi, S., Tyndall, J., Schulte, L. A., & Asbiornsen, H. 2008. High crop prices and conservation - Raising the stakes. *Journal of Soil and Water Conservation, 63*(3), 68A-73A. [2009 Editor's Choice Award].

BOOK CHAPTERS

11. Lauber K., V. Morris, J. Jacquet, P. Li, I. Moller, S. Secchi, A. Wijeratna, M. De Bona. Forthcoming. The Animal Agriculture Industry's Role in Obstructing Climate Action. In the First Global Assessment of Climate Obstruction (T. Roberts, C. Milani, J. Jacquet, and C. Downie eds.).

10. Varble S. & S. Secchi. 2018. Growing switchgrass in the Corn Belt: Barriers and drivers from an Iowa survey. In "Land Allocation for Biomass: Challenges and Opportunities" (R. Li and A. Monti eds.) Springer [peer reviewed]

9. Secchi S. & S. Soman. 2010. Mandatory and Voluntary Conservation Policies: Competing Visions or Complementary Approaches? In: Human Dimensions of Soil and Water Conservation: A Global Perspective. (T. Napier, ed.) Nova Science Publishers. [peer reviewed]

8. Kurkalova L.A., S. Secchi, & P. W. Gassman. 2009. Corn Stover Harvesting: Potential Supply and Water Quality Implications. In: Handbook of Bioenergy Economics and Policy (M. Khanna, J. Scheffran, & D. Zilberman, eds.) Springer. [peer reviewed]

7. Feng H. H., C. Kling L.A. Kurkalova, & S. Secchi. 2007. Subsidies! The Other Incentive-Based Instrument: the Case of the Conservation Reserve Program. In: Moving to Markets in Environmental Regulation: Lessons from Twenty Years of Experience (J. Freeman & C. Kolstad, eds.) Oxford University Press, New York. [peer reviewed]

6. Gassman P.W., S. Secchi, M. Jha & L.A. Kurkalova. 2006. Upper Mississippi River Basin modeling system part 1: SWAT Input data requirement and Issues. In: Coastal Hydrology and Processes (V.P. Singh & Y.J. Xu eds.) Water Resources Publications, Highland Ranch, CO.

5. Jha M., P.W. Gassman, S. Secchi, & J. Arnold. 2006. Upper Mississippi River Basin modeling system part 2: Baseline Simulation Results In: Coastal Hydrology and Processes (V.P. Singh & Y.J. Xu eds.) Water Resources Publications, Highland Ranch, CO.

4. Kling C.L., S. Secchi, M. Jha, H. Feng, P.W. Gassman, & L.A. Kurkalova. 2006. Upper Mississippi River Basin modeling system part 3: Conservation practice scenario results. In: Coastal Hydrology and Processes (V.P. Singh and Y.J. Xu eds.) Water Resources Publications, Highland Ranch, CO.

3. Secchi S., T. M. Hurley, B. Babcock & R. L. Hellmich. 2006. Managing European Corn Borer Resistance to Bt Corn with Dynamic Refuges. In: Regulating Agricultural Biotechnology: Economics and Policy (R. Just, J. Alston, & D. Zilberman eds.) Springer.

2. Secchi S., & B. A. Babcock. 2003. Pest Mobility, Market Share, and the Efficacy of Using Refuge Requirements for Resistance Management. In: Battling Resistance to Antibiotics and Pesticides: An Economic Approach (R. Laxminarayan, ed.), Resources for the Future, Washington DC. [peer reviewed]

1. Hurley T. M., S. Secchi, B. Babcock, & R. L. Hellmich. 2002. Managing the Risk of European Corn Borer Resistance to Bt Corn, In The Economics Of Managing Biotechnologies (T. Swanson, ed.) Kluwer: Dordrecht, The Netherlands. [peer reviewed article reprint]

GUEST EDITORSHIPS

Guest Co-Editor for *Economics Research International*'s special issue on the economics of biofuels, http://www.hindawi.com/journals/ecri/si/306959/ .

Guest Co-Editor for *Biomass and Bioenergy*'s special issue on land use change – Vol. 35(6).

PAPERS UNDER REVIEW

Secchi S. 2023. Wither WOTUS? Understanding the Cost Benefit Analysis of the Waters of the US rule. Revise and resubmit at *Applied Economics Teaching Resources.*

GRANTS

31. USDA NIFA. #DiverseCornBelt: Resilient Intensification through Diversity in Midwestern Agriculture. (L. Prokopy project PI, Secchi UIowa PI). 2021-2026. $10,000,000 (UIowa $ 467,776).

30. Healthier Workforce Center of the Midwest (NIOSH funding). Agricultural production practices and stress: a pilot study of women farmers in Iowa. (with C. Nichols). 2020-2021, $29,979.

29. NSF EAGER Germination - What we talk about when we talk about big ideas: Using case studies to train PhD students in ideation and questioning processes. Consultant (with A. Charles, N. Becker). 2018-2020, $117,729.

28. UIowa CGRER. A river runs through it: Surveying Iowa City residents' on water use, water quality and flood management (with K.E. Dalrymple). 2018-2020, $30,000.

27. Iowa State University - Land Use Impacts of RFS-Induced Agricultural Expansion 2018-2019, 71,540.

26. Walton Family Foundation - A Scorecard to measure States' Nutrient Reduction Strategies 2017-2019, $19,585.

25. INTERNAL - SIUC Undergraduate Research Assistantship. Creating an Atlas of Southern Illinois' Ecosystem Services. 2015-2016, $2,700.

24. USDA NIFA – Costs of continuous conservation tillage: estimation with incomplete data (with L.A. Kurkalova, T. Wade and R. Claassen), 2016-2018, $499,995.

23. Argonne National Lab (DoE funds) – Landscape by Design – Valuation of Ecosystem Services, 2015-2017, $49,736.

22. National Science Foundation - DYN COUPLED NATURAL-HUMAN. People, Water, and Climate: Adaptation and Resilience in Agricultural Watersheds (with D. Bennett, N. Basu, M. Muste, W. Gutowski) 2011-2017, $1,011,832.

21. Illinois DNR – Training, Certification, Pilot Incentive, Marketing, And Removal Research Project for the long-term strategy in reducing and controlling Asian Carp populations (with J. Garvey), 2011, $1,500,000.

20. National Science Foundation - DYN COUPLED NATURAL-HUMAN. Climate Change, Hydrology, and Landscapes of America's Heartland: A Multi-scale Natural-Human System (With C. Lant, S. Kraft, G. Misma, J. Nicklow, and J. Schoof) 2010-2014, $1,430,000.

19. USDA ERS Cooperative Agreement 58-6000-0-0056. Estimating the costs of continuous conservation tillage. 2010-2014. $30,887.

18. USDA CSREES AFRI Agribusiness Markets and Trade. An Analysis of the Impact of Biofuel Expansion through Linking of Agricultural and Energy Markets (With A. Elobeid and L.A. Kurkalova) 2010-2014, $360,396.

17. The Nature Conservancy. Floodplain Restoration Strategies Integrating Biomass plantings and Ecosystem Service Payments (With S. Kraft) 2009-2013, $112,536.

16. INTERNAL - SIUC Seed Grant. Economic And Environmental Assessment of the Use of Woody Biomass for Energy Production in Southern Illinois, 2009-2010, $14,985 + 1 month of Summer support.

15. INTERNAL - SIUC Undergraduate Research Assistantship. The Role of Federal and State Policy in Promoting Renewable Energy Production. 2009-2010, $5,400.

14. National Science Foundation Cyber-Enabled Discovery and Innovation Type II. Understanding Water-Human Dynamics with Intelligent Digital Watersheds. (with J. Schnoor, M. Muste, A. Kusiak and D. Bennett). 2009-2012, $899,391.

13. EPA, Region 7. Biofuel Feedstock Landscape Coverage for Five Biofuel Industry Scenarios (with R. Cruse, A. Elobeid and S. Tokgoz) 2008-2010, $150,000.

12. Iowa State University Agricultural Systems Initiative. Assessing alternative crop choices and environmental impacts of the bioeconomy: an integrated landscape approach (with M. Duffy and P.W. Gassman) 2007-2008, $15,000.

11. Agricultural Marketing Resource Center. Helping Farmers Make Decisions in the Bioeconomy: Mapping the Potential for Switchgrass in Iowa Relative to Corn and Soybeans. 2007-2008. (with B. Babcock and P.W. Gassman), $75,000.
10. Department of Energy-USDA. Expansion of ethanol production: evaluation of costs and benefits to rural communities in the Upper Mississippi River Basin. (with L. Kurkalova, C.L. Kling, P.W. Gassman, M. Jha, A. Carriquiry and D. Otto) 2006-2009, $676,722.
9. USDA Natural Resources Conservation Service. Environmental Credit Trading Handbook. 2006-2007 (with C.L. Kling), $84,150.
8. Prairie Rivers of Iowa R.C. & D and USDA Natural Resources Conservation Service. Rapid Watershed Assessment for the Boone River, the Upper Iowa and the South Skunk Watersheds (with T. Isenhart, C.L. Kling, P.W. Gassman and M. Tomer) 2006-2007, $72,500.
7. NASA and USDA Cooperative State Research, Education, and Extension Service. Interactive Drivers of Land Use/Land Cover Change in Agricultural Areas: Climate and Land Manager Choices. (with C.L. Kling, H. Feng, P.W. Gassman, and E. Tackle) 2006-2008, $465,900.
6. Iowa Farm Bureau, Leopold Center for Sustainable Development, Iowa Soybean Association, Iowa Corn Growers Association. Assessment of Conservation Practices on Agricultural Cropland in Iowa (with C.L. Kling, H. Feng, P. Gassman, and M. Jha) 2006, $72,500.
5. USDA CSREES Integrated Projects. Water Resource Degradation in the Boone Watershed: Integrating Stakeholder Knowledge and Preferences with Economic and Watershed Models (with C.L. Kling, M. Duffy, L. Kurkalova, H. Feng, P.W. Gassman, and J. Cooper) 2005-2008, $590,000.
4. Prairie Rivers of Iowa R.C. & D and Leopold Center for Sustainable Development. Boone River Watershed and Gordon's Marsh Project (with C.L. Kling, and P.W. Gassman) 2005-2006, $35,000.
3. Iowa State Water Resources Research Institute. Improving Water Quality in Iowa Rivers: Cost-Benefit Analysis of Adopting New Conservation Practices and Changing Agricultural Land Use (with C.L. Kling, H. Feng, P.W. Gassman, and L. Kurkalova) 2005-2006, $39,600.
2. National Science Foundation. Biocomplexity of Integrated Perennial-Annual Agroecosystems (Senior Personnel. Principal Investigators: H. Asbjornsen, R. M Cruse, C.L. Kling, M. Z Liebman, J. D Opsomer) 2005-2007, $ 99,998.
1. Iowa Department of Natural Resources. Costs of Adopting Conservation Practices on Agricultural Cropland in Iowa and Possible Nutrient Standards (with C.L. Kling, H. Feng, P. Gassman, and L. Kurkalova) 2004, $53,360.

TEACHING EXPERIENCE

Introduction to Sustainability (GEOG 2013). Class for the University's Gen Ed sustainability requirement Average class size 65.

Environmental Economics and Policy (GEOG 3800/5800). Double listed class for undergraduate and graduate students. Average class size: 30.

Environmental Impact Analysis (GEOG 4750). Average class size: 11.

Contemporary Environmental Issues (GEOG 1070). Class for the University's Gen Ed sustainability requirement. Average class size: 370.

Environmental and Energy Economics (GENV 422). Double listed class for undergraduate and graduate students. Average class size: 20.

Geography, People and the Environment (GENV 300i). Class for the University's core curriculum social sciences and interdisciplinary requirement. Average class size: 70.

Environmental Decision Making (Environmental Resources & Policy 502). Core class for the interdisciplinary ER&P Ph.D program. Average class size: 12.

Interdisciplinary Approaches to Environmental Issues (ABE 470). Team taught class, capstone for the Minor in Environmental Studies.

GRADUATE STUDENT ADVISEMENT

MASTERS STUDENT ADVISER
Amy Kopale – Masters in Geography, UIowa, 2019
Aleesandria Gonzalez- Masters in Geography, SIUC, 2017
Daniel Fucik - Masters in Geography, SIUC, 2016
Andisiwe Stuurman - Masters in Geography, SIUC (Fulbright scholar), 2015
Mohamud Esmail – Masters in Agribusiness Economics, SIUC, 2011
Alison Britt – Masters in Agribusiness Economics, SIUC, 2011
Kent Rupp – Masters in Agribusiness Economics, SIUC, 2011

PH.D. STUDENT ADVISER
Austin Holland – Ph.D. in Geography, UIowa, 2022
Shanna McClain (with C. Bruch) – Ph.D. in Environmental Resources & Policy, SIUC (IGERT fellow), 2016
Mukesh Bhattarai – Ph.D. in Environmental Resources & Policy, SIUC, 2016
Awoke Teshager (with J. Schoof) – Ph.D. in Environmental Resources & Policy, SIUC, 2016
Tom Shaw – Ph.D. in Environmental Resources & Policy, SIUC, 2015
Sarah Varble – Ph.D. in Environmental Resources & Policy, SIUC, 2014

MASTERS STUDENT COMMITTEE MEMBER
Tracy Fidler – Masters in Natural Resources and Environmental Sciences, UIUC, 2017
Jodie Hancock – Masters in Forestry, SIUC, 2017
Ann Rushing – Masters in Geography, SIUC, 2015
Brent Ritzler – Masters in Public Administration, SIUC, 2015
Lance Odum – Masters in Public Administration, SIUC, 2012
Andrew Johnson – Masters in Geography, SIUC, 2012

PH.D. STUDENT COMMITTEE MEMBER
Asif Rahman – Ph.D. in Geography, UIowa, current
Enes Yildirim – Ph.D. in Water Resources, UIowa, current
Oronde Drakes – Ph.D. in Geography, UIowa, current
Rebecca Kauten – Ph.D. in Geography, UIowa, 2019
Clara Mundia – Ph.D. in Environmental Resources & Policy, SIUC, 2017
Amanda Marshall – Ph.D. in Environmental Resources & Policy, SIUC, 2017
Dat Tran- Ph.D. in Energy & Environmental Systems, NCA&T University, 2016
Ross Guida – Ph.D. in Environmental Resources & Policy, SIUC, 2016
Obed Quaicoe- Ph.D. in Energy & Environmental Systems, NCA&T University, 2016
Artur Rombenso – Ph.D. in Zoology, SIUC, 2016
Wahid Rahman – Ph.D. in Environmental Resources & Policy, SIUC, 2014
Tim Stoebner – Ph.D. in Environmental Resources & Policy, SIUC, 2014
Steve Randall - Ph.D. in Energy & Environmental Systems, NCA&T University, 2012
Caroline Gottschalk Druschke – Ph.D in Rethoric, University of Illinois at Chicago, 2011

PROCEEDINGS

Jones, C., & S. Secchi. 2019. Reconciling Climate Change with Nitrate Impairment of Drinking Water: Policies for Iowa's Largest City. SUS-RURI: Developing a Convergence SUS Agenda for Redesigning the Urban-Rural Interface along the Mississippi River Watershed, Iowa State University and NSF, August 12-13, Ames, Iowa.

Kurkalova L. A., S. Secchi & P. W. Gassman. 2009. Greenhouse Gas Mitigation Potential of Corn Ethanol: Accounting for Corn Acreage Expansion. Proceedings of the 2007 National Conference on Environmental Science and Technology. G.Uzochukwu,; Schimmel, K.; Chang, S.-Y.; Kabadi, V.; Luster-Teasley, S.; Reddy, G.; Nzewi, E. (Eds.). Springer. p. 251-257.

Secchi S., P. W. Gassman, M. Jha, L. Kurkalova, & C. L. Kling. 2008. Water Quality Effects of Corn Ethanol versus Switchgrass-Based Biofuels in the Midwest. Proceedings of the Farm Foundation Conference: "Transition to a Bioeconomy: Environmental and Rural Development Impacts", October 15-16, 2008, Hyatt Regency At Union Station, St. Louis, MO. URL: http://www.farmfoundation.org/news/articlefiles/401-Final_version_Farm_Foundation%20feb%2020%2009.pdf

Secchi S. 2008. The Environmental Sustainability of Ethanol and Biofuels. Proceedings of the Iowa State University Extension and Town/Craft Roundtable: "Biofuels and the Rural Economy Roundtable", May 14, 2008, Perry, IA.

Gassman, P.W., S. Secchi, & M. Jha. 2008. Assessment of bioenergy-related scenarios for the Boone River watershed in north central Iowa. In: Proceedings of the 21st Century Watershed Technology: Improving Water Quality and Environment Conference, March 29-April 3, American Society of Agricultural and Biological Engineers, Concepción, Chile.

Gassman, P.W., S. Secchi, & M. Jha. 2007. An alternative approach for analyzing wetlands in SWAT for the Boone River watershed in north central Iowa. In: *4th International SWAT Conference Book of Abstracts*, July 3-7, UNESCO-IHE, Institute for Water Education, Delft, Netherlands.

Gassman, P.W., S. Secchi, & M. Jha. 2006. Application of SWAT for the Boone River watershed in north central Iowa. Presented at the American Society of Agricultural and Biological Engineers Annual Meeting, July 9-12, Portland, OR. ASABE Paper 062234, St. Joseph, MI.

Secchi S., H. H. Feng, L. A. Kurkalova, C. L. Kling, P. W. Gassman, & M. Jha. 2005. Nonpoint source needs assessment for Iowa part II: the cost of improving Iowa's water quality. Watershed Management to Meet Water Quality Standards and Emerging TMDL (Total Maximum Daily Load), Proceedings of the 3rd Conference 5-9 March 2005 Atlanta, Georgia. ASAE, St. Joseph, Michigan, pp.522-532.

Gassman, P.W., S. Secchi, M. Jha, L.A. Kurkalova, H.Feng, & C.L. Kling. 2005. Nonpoint source needs assessment for Iowa part III: economic and environmental outcomes. Watershed Management to Meet Water Quality Standards and Emerging TMDL (Total Maximum Daily Load), Proceedings of the 3rd Conference 5-9 March 2005 Atlanta, Georgia. ASAE, St. Joseph, Michigan, pp.533-542.

Gassman, P.W., S. Secchi, C.L. Kling, M. Jha, L.A. Kurkalova, & H.Feng. 2005. An analysis of the 2004 Iowa Diffuse Pollution Needs assessment using SWAT. *Proceedings of the SWAT 2005 3rd International Conference*, pp. 291-30111-15 July, Zurich, Switzerland.

Jha, M., P.W. Gassman, S. Secchi, J.G. Arnold, L.A. Kurkalova, H. Feng, & C.L. Kling. 2005. An assessment of alternative conservation practice and land use strategies on the hydrology and water quality of the Upper Mississippi River Basin. In: *Proceedings of the SWAT 2005 3rd International Conference,* pp. 444-453, July 11-15, Zurich, Switzerland.

Takle, E. S., M. Jha, P. W. Gassman, C. J. Anderson, & S. Secchi. 2005. Climate change impacts on the hydrology and water quality of the Upper Mississippi River Basin. In: *Proceedings of the SWAT 2005 3rd International Conference,* pp. 599-608. July 11-15, Zurich, Switzerland.

Feng H., C. L. Kling, L. A. Kurkalova, S. Secchi, & P. W. Gassman. 2005. The Conservation Reserve Program in the Presence of a Working Land Alternative: Implications for Environmental Quality, Program Participation, and Income Transfer. *American Journal of Agricultural Economics* 87 (5).

Jha M., P. W. Gassman, S. Secchi, & J. Arnold. 2003. Configuration of SWAT for the Upper Mississippi River Basin: an application to two subwatersheds. Proceedings of the Total Maximum Daily Load (TMDL) Environmental Regulations II, 8-12 November 2003, Albuquerque, New Mexico.

Secchi S. & B. A. Babcock. 2002. Pearls before Swine? Potential Trade-Offs Between the Human and Animal Use of Antibiotics. *American Journal of Agricultural Economics* 84 (5).

WORKING PAPERS

Dodder R.S., A. Elobeid, T. L. Johnson, P. O. Kaplan, L. A. Kurkalova, S. Secchi, & S. Tokgoz. 2011. Environmental Impacts of Emerging Biomass Feedstock Markets: Energy, Agriculture, and the Farmer. CARD Working Paper [11-WP 526].

Secchi S. 2007. Watching corn grow: a hedonic study of the Iowa landscape. Working paper 07-WP 445, Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, H.H. Feng, T. Campbell, & C.L. Kling. 2005. The Cost of Clean Water: Assessing Agricultural Pollution Reduction at the Watershed Scale. Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S., M. Jha, L.A. Kurkalova, H.H. Feng, P.W. Gassman, & C.L. Kling. 2005. The Designation of Co-benefits and Its Implication for Policy: Water Quality versus Carbon Sequestration in Agricultural Soils. Working paper 05-WP 389, Center for Agricultural and Rural Development, Ames, Iowa.

Kurkalova L.A., C. Burkart, & S. Secchi. 2004. Cropland Cash Rental Rates in the Upper Mississippi River Basin. Technical report 04-TR 47, Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S. 2002. Patient Behavior and Antibiotic Prescriptions: the Equilibrium Level of Antibiotic Use and the Role of a Market Permit System. Center for Agricultural and Rural Development, Ames, Iowa.

Babcock B.A., J. Beghin, M. Duffy, H.H. Feng, B. Hueth, C.L. Kling, L.A. Kurkalova, U. Schneider, S. Secchi, Q. Weninger, & J. Zhao. 2001. Conservation Payments: Challenges in Design and Implementation. Working paper 01-BP 34, Center for Agricultural and Rural Development, Ames, Iowa.

Secchi S. & B.A. Babcock. 2001. Optimal Antibiotic Usage with Resistance and Endogenous Technological Change. Working paper 01-WP 269, Center for Agricultural and Rural Development, Ames, Iowa.

Hurley T.M., S. Secchi, B.A. Babcock, & R. L. Hellmich. 1999. Managing the Risk of European Corn Borer Resistance to Transgenic Corn: An Assessment of Refuge Recommendations. Staff Report 99-Sr 88, Center for Agricultural And Rural Development, Ames, Iowa.

OTHER PUBLICATIONS

Vasto A., & Secchi S., 2021, Rural Water Systems in Iowa: Analysis of Opportunities and Challenges. Iowa Environmental Council. URL: https://www.iaenvironment.org/newsroom/water-and-land-news/council-releases-rural-water-system-report

Secchi S., & D. Cwiertny. 2019. Iowa's Grants to Counties Program: A Valuable but Underutilized Program for Protecting the Public Health of Private Well Users. University of Iowa Center for Health Effects of Environmental Contamination Policy Report 2019-01. URL: https://cheec.uiowa.edu/sites/cheec.uiowa.edu/files/CHEEC-2019-01_Grants_To_Counties_3_.pdf

Healy M.*, & S. Secchi. 2016. A Comparative Analysis of Ecosystem Service Valuation Decision Support Tools for Wetland Restoration. A Report Prepared for the Association of State Wetland Managers. URL: http://www.aswm.org/pdf_lib/ecosystem_service_valuation_032116.pdf

Secchi S. 2015. Background paper on Economic Valuation of Ecosystem Services from Working Lands Conservation, prepared for USDA's ERA and NRCS Economic Valuation of Conservation Based Ecosystem Services Workshop.

Braden J. & S. Secchi, 2014, C-FARE and AAEA Webinar "Policy Innovations in Nonpoint Source Pollution-policy". Friday, March 21, 2014.

Cooke S. L., A. C. Lloyd*, A. D. Monteblanco, & Silvia Secchi, 2013. Ecosystems, Economics, and Equity in the Floodplain. A case study developed for the National Socio-Environmental Synthesis Center Project Teaching Socio-Environmental Synthesis with Case Studies. URL: http://www.sesync.org/ecosystems-economics-and-equity-in-the-floodplain-case-study-5

Secchi S., 2009. Overview Presentation. NRCS and C-FARE Webinar "Environmental Markets: New Approaches for Natural Resources Management Webinar", February 23rd, 2009

Feng H., L. A. Kurkalova & S. Secchi. 2001. Multifunctionality: Market failure and options to internalise externalities: Applying the OECD framework - A review of literature in the USA, Consultant background paper for the OECD workshop "Multifunctionality: Applying the OECD Analytical Framework, Guiding Policy Design", July 2001.

INVITED CONFERENCE AND SEMINAR PRESENTATIONS

Invited plenary presentation, "Slaughtering Sacred Cows: Tech Fixes Won't Correct the Extractive Nature of US Agriculture", Sustainable Phosphorus Summit, November 1-2, 2022, Raleigh NC.

Invited presentation, Economic & Land Use Policies to Limit Nutrient Pollution: Perspectives from the Great Lakes and Beyond, Alliance for the Great Lakes, April 4, 2022, virtual event.

Seminar presentation, "A lonely stick amongst many carrots: The Conservation Compliance Program in the 21st Century", Paul H. O'Neill School, Indiana University, February 25, 2021, virtual event.

Seminar presentation, "The US census of agriculture as lens and mirror of long term changes in the rural Midwest", Faculty of Land and Food Systems, University of British Columbia, September 16 2020, virtual event.

Invited presentation "The role of policy in promoting sustainable floodplain management" at Emiquon Science 2015: River Floodplain Restoration and Connection, February 19th, 2015, Lewistown, IL

Invited Presentation "Understanding the links between humans, climate change, water and carbon in a Corn Belt Watershed", at the AGU Fall meeting, December 15-19th, 2014, San Francisco, CA.

Invited presentation "Promoting Bioenergy Crops: An economic perspective on challenges and opportunities" at the workshop Incorporating Bioenergy in Sustainable Landscape Designs Workshop Two: Agricultural Landscapes June 24–26th, 2014, Argonne National Laboratory, IL.

Invited presentation "Increased Biofuel Production and Water Resources" at the National Academies Roundtable on Science and Technology for Sustainability, May 20-21, 2014, Washington DC. URL: http://sites.nationalacademies.org/cs/groups/pgasite/documents/webpage/pga_088191.pdf

Invited speaker at the Indiana University-Purdue University first "Rivers of the Anthropocene" conference, January 23-24th, 2014, Indianapolis, IN.

Invited speaker at the MISI-ZIIBI: Living with the Great Rivers, Climate Adaptation Strategies in the Midwest River Basins, co-sponsored by Washington University in St. Louis and the Royal Netherlands Embassy, March 23rd, 2013, St. Louis, MO.

Plenary speaker at the 2013 Missouri River Natural Resources Conference and BiOp Forum "Beyond the Banks" March 12th, 2013, Jefferson City, MO.

Luncheon speaker at the Soil and Water Conservation Society Modeling Summit 2011 - Advancing the Science of Modeling, March 30th, 2011, Denver, CO.

Invited lecture to the "Food, Energy, and Quality of Life in Iowa" graduate class at Iowa State University, on the difference between ecological and environmental economics approaches to agricultural policy, September 21st, 2009.

North Carolina A&T State University, Energy and Environmental Systems Seminar, April 12th, 2010.

Iowa State University Biobased Industry Center Energy Camp, May 21st 2010.

University of Minnesota, Applied Economics Department, Environmental and Resource Economics Seminar, April 26th 2010.

University of Illinois at Urbana-Champaign, Department of Agricultural and Consumer Economics Seminar, September 10th 2010.

University of Iowa, Department of Geography, Kohn Colloquium, October 29th 2010.

CONFERENCE PAPERS AND POSTERS

Secchi S. 2022. Water Quality and Adaptation to Climate Change. Iowa Organic Conference, November 20-21, Iowa City, IA.

Secchi S. 2022. Slaughtering Sacred Cows: Tech Fixes Won't Correct the Extractive Nature of US Agriculture. Phosphorus Week, November 1-4, Raleigh, NC.

Secchi S. 2020. Understanding the Cost Benefit Analysis of the Waters of the US rule. Presidential Session on Pedagogical Tools: Fundamental Concepts and Methods. Annual Meeting of the Southern Economic Association, November 21-23 (virtual).

Secchi S. 2020. Regulatory Environmental Cost-Benefit Analysis: A Case Study of the Waters of the United States Rule. Innovations in Teaching Environmental and Resource Economics ENV/TLC Track session of the Annual Meeting of the Agricultural & Applied Economics Association, August 5 (virtual).

Secchi S. 2019. The State of Water Quality Strategies in the Mississippi River Basin: Is Cooperative Federalism Working? American Water Resources Association, Annual Water Resources Conference, November 3-6, Salt Lake City, UT.

Secchi S. 2015. The push and pull of conservation, energy and climate mitigation policies on agricultural landscapes: the case of conservation tillage. Conference on Complex Systems, September 26-30, Tempe, AZ.

Secchi S. 2015. The potential of conservation tillage payments as a climate mitigation strategy. AAG Annual Meeting, April 21-25, Chicago, IL.

Eichholz M. W., R. T. Alisauskas, J. O. Leafloor, S. Varble, & S. Secchi. 2013. Feasibility of Commercial Wildlife Exploitation as a Management Tool: Snow Geese as a Case Study of Overabundance. 20th Annual Conference of The Wildlife Society, October 5-10, Milwaukee, WI.

Secchi S. & S. Varble. 2013. We Can Beat Them If We Eat Them: Assessing the Marketing Potential of the Asian Carp in the US. Symposium on the Culture, Biology, and Management of Asian Carps in North America, 143rd Annual Meeting of the American Fisheries Society, September 8-12, Little Rock, AR.

Wade T., L.A. Kurkalova, & S. Secchi. 2013. Estimation of Discrete Choice Models with Aggregate Data: An Application to the Adoption of Conservation Tillage. Presented at the USDA ERS and Farm Foundation workshop "Agricultural Markets for Ecosystem Services: Greenhouse Gases, Conservation Practice Adoption & Behavioral Responses", August 8th, Washington D.C.

Secchi S. & L.A. Kurkalova. 2013. Estimating the Cost of Supplying Greenhouse Gas Offsets with Continuous Conservation Tillage. Presented at the USDA ERS and Farm Foundation workshop "Agricultural Markets for Ecosystem Services: Greenhouse Gases, Conservation Practice Adoption & Behavioral Responses", August 8th, Washington D.C.

Varble S., & S. Secchi. The Role of Watershed Management Groups and Key Stakeholders in the Resilience and Sustainability on a Rural Iowa Watershed. SWCS Annual meeting, Reno, NV 21-24 July 2013.

Varble S., D. Varble & S. Secchi. Potential for Perennial Crops for Bioenergy Production: Results of a Survey from an Iowa Watershed. SWCS Annual meeting, Reno, NV 21-24 July 2013.

Smith S., S. Varble & S. Secchi. 2013. Fish Consumers: Purchasing Habits and Environmental concerns. Selected Poster for the 2013 Annual ICHRIE Summer Conference, July 24-27, St. Louis, MO.

Wade T., L.A. Kurkalova, & S. Secchi. 2012. Using the Logit Model with Aggregated Choice Data in Estimation of Iowa Corn Farmers' Conservation Tillage Subsidies. AAEA Annual Meeting, August 12-14, Seattle, WA.

Kurkalova L.A., S. M. Randall, & S. Secchi. 2012. The Impact of Energy Price Changes on Cropping Patterns in Iowa. 31st USAEE/IAEE North American Conference, November 4-7, Austin, TX.

Kurkalova L.A., S. M. Randall, & S. Secchi. 2012. The Impact of Energy Price Changes on Cropping Patterns in Iowa. AERE Session at the Southern Economics Association Annual Meeting Nov 16-18, New Orleans, LA.

Secchi S. 2012. Integrating Biofuel Production and Mitigation Strategies Into Agricultural Landscapes. Bioenergy and Biodiversity: Oxymoron or Opportunity? Symposium at the Ecological Society of America Annual Meeting, 5-10 August, Portland, OR.

Kurkalova L.A., R. Dodder, A. Elobeid, T. Johnson, O. Kaplan, S. Secchi, & S. Tokgoz. 2011. Land-Use Impacts of Emerging Biomass Feedstock Markets: Accounting for Agricultural and Energy Market Interactions and the Variability of Local Conditions. Association of Environmental and Resource Economists' Inaugural Summer Conference, 9 - 10 June, Seattle, WA.

Secchi S., S. Esling, C. Lant, & J. A. Koropchak. 2011. The Environmental Resources and Policy Ph.D. Program at Southern Illinois University Carbondale: a Success Story. Facilitating Interdisciplinary Research and Education Symposium, March 28-29, Boulder, CO.

Secchi S., J. Fargione, J. Remo, B. Moseley, T. Strole & S. Kraft. 2010. Stacking Ecosystem Services in Reconnected Floodplains: Linking Socioeconomic and Biophysical Analysis to Improve Floodplain Management. Selected paper at the Soil and Water Conservation Society Annual Meeting, July 18-21, St. Louis, MO.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2010. Potential Water Quality Changes Due to Corn Expansion in The Upper Mississippi River Basin. Selected paper at the 4th World Congress of Environmental and Resource Economists, June 28-July 2, 2010, Montréal, Canada.

Kurkalova, L.A., S. Randall, & S. Secchi. 2010. Land-Use Implications of the Changes in Energy Prices. Selected Poster at the Agricultural and Applied Economics Association 2010 Annual Meeting, July 25-27, 2010, Denver, CO.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2009. The Water Quality Effects of Corn Expansion in the Midwest. Selected poster at the USDA, USGS, EPA and SWCS "Science to Solutions (Gulf Hypoxia)" workshop on December 9-11, 2009 Des Moines, IA.

Secchi S. 2009. Balancing Conservation Policy: Targeting Ecosystem Service Provision with Feedstock Production for the Bioeconomy in the Midwestern U.S. Invited presentation at the organized Symposium: "Integrating science and policy for watershed sustainability: Balancing hydrological services, quality of life, and economic vitality" (OOS #4185) at the Ecological Society of American Annual Meeting August 2-7 2009, Albuquerque, NM.

Secchi S., L.A. Kurkalova P.W. Gassman, & B. Babcock. 2009. Land Use and Environmental Impacts of Corn Grain vs. Cellulosic Ethanol: Policy Implication. Selected paper at the 2009 SWCS Annual Conference July 11-15, Dearborn, MI.

Secchi S. (Invited speaker). 2009. Ethanol Production and the Mississippi River, an Economic Perspective. 2009 Mississippi River Conference: "Visions of a Sustainable Mississippi River: Merging Ecological, Economic, and Cultural Values", organized by the National Great Rivers Research and Education Center and The Nature Conservancy, August 10 – 13, 2009, Collinsville, IL.

Kurkalova, L.A., S. Secchi, & P.W. Gassman. 2009. Harvesting Corn Stover and Crop Residue Management: The Impact of Conflicting Economic Incentives, Selected Poster at the Annual AERE Workshop - 2009 Theme: Energy and the Environment, Washington, DC June 18-20, 2009.

Kurkalova, L.A., S. Secchi, & P.W. Gassman. 2009. Effectiveness of Environmental Policies and Bioenergy Production Incentives. Selected paper at the SWCS Annual Conference July 11-15, 2009, Dearborn, MI.

Kurkalova, L.A., S. Secchi, & P.W. Gassman. 2009. Effectiveness of Environmental Policies and Bioenergy Production Incentives. Selected Poster at the AAEA & ACCI Joint Annual Meeting in Milwaukee, WI, July 26–28, 2009.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2008. Rotation and Water Quality Effects of Harvesting Corn Stover, Selected AERE paper at the AAEA & ACCI Joint Annual Meeting, July 27-29 2008, Orlando, FL (session 3059).

Secchi S., P.W. Gassman, & B.A. Babcock. 2008. Land Use and Environmental Impacts of Corn Grain versus Cellulosic Ethanol: a GIS Approach, Selected paper at the 28th USAEE/IAEE North American Conference, "Unveiling the Future of Energy Frontiers.", December 3-5 2008, New Orleans, LA, USA.

Secchi S., P.W. Gassman, M. Jha, L.A. Kurkalova, & C.L. Kling. 2008. Quality Effects of Corn Ethanol versus Switchgrass-Based Biofuels in the Midwest, Selected paper at the Farm Foundation Conference: Transition to a Bioeconomy: Environmental and Rural Development Impacts, October 15-16 2008, St. Louis, MO.

Secchi S., L.A. Kurkalova, J.C. Tyndall, P.W. Gassman, & C.L. Kling. 2008. The Next Step for the Bioeconomy: Mapping the Impact of Corn Stover Use on Crop Choice, Land Use, and Environmental Quality". Selected poster at the AAEA & ACCI Joint Annual Meeting, July 27-29 2008, Orlando, FL (session M56).

Secchi S. 2008. The Environmental Sustainability of Ethanol and Biofuels, Overview presentation at the Iowa State University Extension and Town/Craft Roundtable: "Biofuels and the Rural Economy Roundtable", May 14, 2008, Perry, IA.

Secchi S., L.A. Kurkalova, C.L. Kling, J. Cooper, P.W. Gassman, & M. Jha. 2006. Water Resource Degradation in the Boone Watershed: Integrating Economic and Watershed Models. Soil and Water Conservation Society workshop "Managing Agricultural Landscapes for Environmental Quality: Strengthening the Science Base", Kansas City, MO, October 2006.

Secchi S. 2005. Watching Corn Grow: a Hedonic Study of the Iowa Landscape, Eastern Economic Association Annual Conference, New York City, NY, March 2005.

Secchi S. 2001. Models to Support TMDL Development Across the Midwest (Symposium), American Agricultural Economics Association Annual Meeting, Chicago, IL, August 2001.

Secchi S., & B.A. Babcock. 2001. Optimal Pesticide Usage with Resistance and Endogenous Technological Change, American Agricultural Economics Association Annual Meeting, Chicago, IL, August 2001.

Secchi S., T. M. Hurley, & R. L. Hellmich. 2001. Managing European Corn Borer Resistance to Bt Corn with Dynamic Refuges, 5th ICABR International Conference, Ravello, Italy, June 2001.

Secchi S., & B.A. Babcock. 1999. A Model of Pesticide Resistance as a Common Property and Exhaustible Resource, American Agricultural Economics Association Annual Meeting, Nashville, TN, August 1999.

Secchi S., & B.A. Babcock. 1999. Managing Pest Resistance: The Potential Of Crop Rotations And Shredding, American Agricultural Economics Association Annual Meeting, Nashville, TN, August 1999.

PROFESSIONAL ACTIVITIES

Editorial Board of Conservation, Review Editor, Frontiers, 2019-present

Editorial Board, Applied Economic Perspectives and Policy, 2015-present

Oklahoma EPSCoR External Advisory Board Member 2017-2018

Participant at invitation-only Purdue University University of Illinois workshop "Scientific Challenges to Operationalizing Payments for Agro-Ecosystem Services (PAgES)" (organized by Ben Gramig and Sylvie Brouder). Indianapolis, IN, November 2017

Consultant, Walton Family Foundation – Developing a Score Card for Iowa and Illinois' Nutrient Reduction Strategies. 2016-2017

Program Committee Member for the 6th World Congress of Environmental and Resource Economists, 2018

National Science Foundation, panelist, 2010, 2011, 2014, 2016, 2017, 2018, 2019 and 2023. Ad hoc reviewer, 2012, 2013, 2014, 2016, 2017

USDA – NIFA panelist, 2017 and 2018. Ad hoc reviewer 2014 and 2016

Reviewer for Selected Paper Sessions of the American Agricultural Economics Association meetings, 2002, 2003, 2008 and 2016

Author of working paper II for the USDA and C-FARE workshop, 'Economic Valuation of Conservation Based Ecosystem Services', July 21, 2015, Washington, DC

Participant, inaugural SESYNC short course, Teaching Socio-Environmental Synthesis with Case Studies, July 23-26, 2013, Annapolis, MD

Planning Committee Member, AWRA 2013 Spring Specialty Conference: "Agricultural Hydrology and Water Quality II", March 25-27, St. Louis, MO

Participant, NSF workshop on Developing and Sustaining Interdisciplinary Graduate Programs, 7-8 October 2012, Coeur d'Alene, ID

EPA Star Fellowship Panelist, 2012

Program Committee Member for the 18th and 19th Annual Meetings of the European Association of Environmental and Resource Economists, 2011 and 2012

Member of the Middle Mississippi Wetland Field Station Advisory Committee Southern Illinois University, 2009- 2017

Rapporteur at the JRC/EEA/OECD Expert Consultation: "Review and inter-comparison of modeling land use change effects of bioenergy", Paris, France, 29-30 January 2009

Reviewer for the National Institutes for Water Resource - U.S. Geological Survey Competitive Grants Program, 2009 and 2011

Reviewer for the Collaborative, Highly Interdisciplinary Research Program at the Swiss Federal Institute of Technology, Zurich Research Commission, 2009

Reviewer for Selected Paper Sessions of the 3rd World Congress of Environmental and Resource Economists, 2006

Reviewer for USDA-CSREES Conservation Effects Assessment Project, 2005 and 2006

Reviewer of the Union of Concerned Scientists' report "CAFOs Uncovered: The Untold Costs of Confined Animal Feeding Operations" URL: http://www.ucsusa.org/food_and_environment/sustainable_food/cafos-uncovered.html.

Reviewer for: Agriculture, Agricultural and Resource Economics Review, Agriculture and Human Values, Agronomy Journal, Appetite, American Journal of Agricultural Economics, Applied Economic Perspectives and Policy, Applied Geography, Biofuels, Biological Invasions, Biomass & Bioenergy, BioScience, Choices, Ecology, Ecological Applications, Ecological Economics, Ecosystem Services, Energy Policy, Environmental and Development Economics, Environmental and Resource Economics, Environmental Management, Environmental Research

Letters, Environmental Science & Technology, Frontiers of Ecology and the Environment, GCB Bioenergy, Intelligent Systems in Accounting, Finance and Management, International Journal of Digital Earth, Journal of Agricultural and Applied Economics, Journal of Agricultural and Resource Economics, Journal of Applied Geography, Journal of Environmental Economics and Management, Journal of Great Lakes Research, Journal of Soil and Water Conservation, Land Use Policy, Landscape and Urban Planning, Journal of Natural Resources Policy Research, Journal of Soil and Water Conservation, Nature Climate Change, PLoS ONE, SAGE Open (Article Editor), Science of the Total Environment, Society & Natural Resources, Sustainability, Proceedings of the National Academies of Science, Transactions of ASABE

UNIVERSITY SERVICE

2019 – current, Governmental Relations Committee

2019 – current, Office of Sustainability Advisory Board

2019 – current, Center for Global & Regional Environmental Research Executive Committee

2018 – current, Center for Health Effects of Environmental Contamination Executive Committee

2020 – 2021, Sustainability Investment & Purchasing Practices Subcommittee

2019 – 2022, Underrepresented Students in Sustainability Mentoring Program Mentor

2018 – 2022, Faculty Assembly

ACADEMIC HONORS AND AWARDS

Southern Illinois University Early Career Faculty Excellence Award, 2012 [inaugural winner].

Yellow Ribbon Poster Presentation, with L.A. Kurkalova, and P. W. Gassman, Agricultural and Applied Economics Association, 2009.

2009 Editor's Choice Award, Journal of Soil and Water Conservation: Secchi, S., J. Tyndall, L.A. Schulte, and H. Asbjornsen. 2008. High crop prices and conservation: Raising the stakes. *Journal of Soil and Water Conservation* 63(3):68A-73A.

Iowa State University College of Agriculture and Life Science Team Award, to the Resource and Environmental Policy Division. 2008.

Second Place Poster Presentation, with M. Jha, L.A. Kurkalova, C.L. Kling, H. Feng, P.W. Gassman, and T. Campbell, American Agricultural Economics Association, 2005 and 2006.

Second Place Poster Presentation, with C.L. Kling, H. Feng, L.A. Kurkalova, P.W. Gassman, M. Jha, T. Campbell, A. Bhaskar, C. Burkart, S. Sengupta and R. Olson, American Agricultural Economics Association, 2004.

First Place Poster Presentation, with C.L. Kling, L.A. Kurkalova, and P.W. Gassman, American Agricultural Economics Association, 2003.

Outstanding Ph.D. Dissertation (Honorable Mention), American Agricultural Economics Association, 2001.

Professional Advancement Travel Grant, Iowa State University, 1999.

Premium for Academic Excellence Award, Iowa State University, 1996.

OUTREACH PRESENTATIONS AND PODCASTS

2021-2023 – We All Want Clean Water – Podcast co-host and producer (31 episodes)

2023 - The Power of Big Pork – Foodprint podcast

2022 - Iowa's Industrial Agriculture – The Checkout podcast

2022 - "Cows, Climate and Culture Wars: Putting Bad Policy Out to Pasture" virtual panel, Center for Biological Diversity.

2022 - "Human Rights and Climate Change: Iowa's Challenges & Opportunities" virtual panel, UI Center for Human Rights and the Environmental Law Initiative.

2022 – "Celebrating 50 years of the Clean Water Act", panel, Sierra Club, Waterloo, IA.

2020 – Webinars on Agriculture and Climate Change for the Iowa Farmers Union and Environment Iowa

2019 – Science Café, The current state of the Paris agreement, Fairfield and Mount Vernon, IA

2018 – Wonk Wednesday, America out of Paris: the current state of global climate change policy, University of Iowa, Iowa City, Iowa, United States

2018 – Rapid Response History, Liquid Gold or Fool's Gold? Biofuels in the US, University of Iowa, Iowa City, Iowa, United States

2011 – Carbondale Science Café' – Presentation on Biofuels, March 24

2009 – Speaker, "No Silver Bullets: Unintended Consequences Of Oil And Water Solutions", May 18, Indo-American Center, Chicago, IL

2008-2013 – The View: Expert opinions on a special series on energy for The Southern Illinoisan newspaper. 22 short perspectives 2022

SELECTED MEDIA

- Farmers Could Be the Nation's Leading Environmentalists *Mother Jones* 2024
- The myths we tell ourselves about American farming *Vox* 2023
- The Biden Administration Bets Big on 'Climate Smart' Agriculture *FERN/Yale360* 2023
- Opinion/Solutions: Ancient grain may help with climate change *The Atlanta Journal Constitution*
- Don't be fooled by exaggerated 'benefits' of carbon pipelines *Des Moines Register Opinion* 2022
- As Congress funds high-tech climate solutions, it also bets on a low-tech one: Nature *The Washington Post* 2022
- Expansion of a Lucrative Dairy Digester Market is Sowing Environmental Worries in the U.S. *Inside Climate News.* 2022
- Climate change is making it harder to provide clean drinking water in farm country *NPR*
- How Corn Ethanol for Biofuel Fed Climate Change *Civil Eats* 2022
- North Carolina's Department of Environmental Quality is facing its second complaint for permitting hog waste operations in poor communities of color *The Counter* 2021
- The USDA Wants to Make Farms Climate-Friendly. Will It Work? *Mother Jones/FERN* 2021
- Regenerative agriculture needs a reckoning *The Counter* 2021
- Tom Vilsack for USDA? Expect more inaction on hunger, discrimination, pollution and rural decline *Des Moines Register Opinion* 2021
- The Approaching Climate Crisis: What EPA Rollbacks Mean For Water And Air Quality In The Midwest, *Iowa Public Radio River to River* 2020

- Iowa scientists urge state leaders to use pandemic, derecho to prep for climate change, *Iowa City Press-Citizen* 2020
- Iowa's water quality strategy is not working. Here's what should be done instead. *Des Moines Register Opinion* (with Neil Hamilton, Matt Liebman, and Chris Jones) 2020
- Iowa Farmers Face Climate-Fueled Destruction, While the Industry Says it's 'Just Weather', *Civil Eats* 2020
- Democrats court Iowa farmers on climate, conservation, *E&E News* 2020
- Report: Many Iowa counties underusing private well testing funds, *The Gazette* 2019

MEMBERSHIPS

Agricultural & Applied Economics Association

Association of American Geographers

Association of Environmental and Resource Economists

Ecological Society of America

ATTACHMENT B

SWAPE Technical Consultation, Data Analysis and Litigation Support for the Environment

2656 29th Street, Suite 201
Santa Monica, CA 90405
Paul E. Rosenfeld, PhD
(310) 795-2335
prosenfeld@swape.com

February 14, 2024

Ellison Folk
Shute Mihaly & Weinberger LLP
396 Hayes Street
San Francisco, CA 94102

Subject: Comments on the Proposed Amendments to the Low Carbon Fuel Standard

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Dear Ms. Folk,

SWAPE was retained by Shute Mihaly & Weinberger LLP to provide written comments on the Proposed Amendments to the Low Carbon Fuel Standard ("LCFS") released by the California Air Resources Board ("CARB"), specifically the *Staff Report: Initial Statement of Reasons* ("ISOR") and the *Appendix D: Draft Environmental Impact Analysis for the Proposed Low Carbon Fuel Standard Regulation* ("EIA").[1, 2] Upon review, I have found that the ISOR and EIA inadequately addressed the following:

- Anaerobic digestate increases the potential for nitrate contamination of groundwater; and
- Anaerobic digestate increases N_2O and NOx emissions into the atmosphere; and
- Anaerobic digestate increases ammonia emissions, which is an odorous compound. Odor associated with anaerobic digestate soil application can result in odor complaints to nearby communities which are often of lower socioeconomic status resulting in environmental justice issues.

In "Table 1.1: Summary of Potential Environmental Impacts" in the ISOR, CARB listed the following impacts as "Potentially Significant and Unavoidable":[3]

- "Short-term Construction-Related and Long-Term Operational-Related Impacts on Air Quality"

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[1] ISOR.pdf.
[2] EIA.pdf.
[3] ISOR. PDF Pg. 64-65.

- "Short-Term Construction-Related and Long-Term Operational-Related Impacts to Geology and Soils"
- "Short-Term Construction-Related and Long-Term Operational-Related Impacts to Hydrology and Water Quality"

Upon review, I find the ISOR and EIA are insufficient in addressing my concerns regarding anaerobic digesters' air quality and groundwater impacts. The following are my comments regarding these documents.

Anaerobic Digestion

Anaerobic Digester Digestate Impact on Air

In the ISOR, CARB listed the impacts of "Short-term Construction-Related and Long-Term Operational-Related Impacts on Air Quality" as "Potentially Significant and Unavoidable".[4] The following section highlights a clear indication that CARB's analysis fell short in adequately assessing the significance of these impacts on air quality.

Anaerobic digestion efficiently decomposes waste into smaller molecules, enhancing their propensity to volatilize into the atmosphere. During the anaerobic digestion process, quantities of ammonia are produced as a byproduct. This odorous compound possesses the potential to cause irritation and discomfort to the throat, lungs, and eyes, and prolonged exposure to elevated ammonia levels can lead to lung damage.[5] Furthermore, ammonia emits a strong odor that is easily detectable at low concentrations and contributes to irritation such as immediate burning of the nose and respiratory tract.[6] From a study by Rosenfeld et. al. in 2000, anaerobic digestion can emit enough ammonia to contribute to odor emissions. The study mentions:

> *"Odor emissions from land application of biosolids have become a concern for biosolids managers. Chemical odorant emissions from biosolids were identified using gas chromatography-mass spectrometry and included dimethyl disulfide (DMDS), dimethyl sulfide (DMS), carbon disulfide (CS2), ammonia (NH3), trimethyl amine (TMA), and acetone."*[7]

This confirms that ammonia emissions from biosolids (digestate) are broken down during the anaerobic digestion process, potentially leading to increased ammonia concentration and, consequently, odor and health irritation.

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[4] ISOR. PDF Pg. 64-65.

[5] Centers for Disease Control and Prevention. *Ammonia: Exposure, Decontamination, Treatment*. Last Reviewed: February 6, 2023.

[6] New York State Department of Health. The Facts About Ammonia. Updated: July 28, 2004.

[7] Rosenfeld, P.E., and Henry C. L., (2000). Wood ash control of odor emissions from biosolids application. Journal of Environmental Quality. Vol 29, 1662-1668.

Another study, conducted by Holly et al. in 2017, evaluated the effects of anaerobic digestion on greenhouse gas and ammonia emissions during manure storage. According to Holly et al., anaerobic digestion can increase ammonia emissions. The study stated that the anaerobic digestion process "resulted in a gas emission tradeoff as it increased NH_3 [ammonia] emissions by 81% during storage, which could be mitigated by subsequent SLS [solid-liquid separation], manure storage covers, or other beneficial management practices."[8] The study further explains:

> *"During the AD process, methanogens and other microorganisms break down proteins, amino acids, and urea forming NH4 (Bernet et al., 2000). In addition, mineralization of organic N and volatile fatty acids during AD increases manure pH and available N (Petersen and Sommer, 2011), factors which increase NH3 emissions."*[9]

Holly et al. also found that nitrous oxide emissions were increased from anaerobically digested solids during storage:

> *"Overall, the methane emissions from storage were reduced by manure processing by 25%, 46%, and 68% for AD, SLS, and AD+SLS, respectively. However, these reductions from storage were somewhat negated when examing [sic] total GHG's to 44% and 27% for SLS and AD+SLS due to N2O losses from solid storage."*[10]

They concluded that greenhouse gas emissions were not further reduced when solid-liquid separation was employed in addition to anaerobic digestion as opposed to anaerobic digestion alone, as "anaerobically stacking digested solids increased emissions of N2O negating abatement of total GHG."[11] The findings of this study show the importance of considering nitrous oxide emissions from digestate solids in cumulative GHG emissions, which CARB failed to adequately address in the EIA. Furthermore, the ISOR and EIA claim methane reductions are achieved by digesters without any discussion of digestate-related N_2O, which Holly (2017) found negated methane reductions by more than 40 percent.

As anaerobic digestion breaks down organic material, biogas is produced. Preble et. al. (2020) explained that during biogas combustion in the anaerobic digestion process, ammonia is oxidized to nitrous oxides, which, in turn, increases nitrous oxide emissions.[12] The study "quantifies emission rates of GHGs, criteria air pollutants, and toxic/odorous compounds from the AD composting process."[13] The study further states:

> *"In situ measurements of key sources at two large-scale industrial facilities in California were conducted to quantify pollutant emission rates across the AD composting*

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[8] Holly et al., (2017). Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application.
[9] Ibid.
[10] Id. PDF Pg. 7.
[11] Id. PDF Pg. 9.
[12] Preble et. al. (2020). *Air Pollutant Emission Rates for Dry Anaerobic Digestion and Composting of Organic Municipal Solid Waste*. PDF Pg 2.
[13] Ibid.

> *process. These measurements established a strong relationship between flared biogas ammonia (NH3) content and emitted nitrogen oxides (NOx), indicating that fuel NOx formation is significant and dominates over the thermal or prompt NOx pathways when biogas NH3 concentration exceeds ~200 ppm."*[14]

The above study highlights a crucial aspect, noting that "biogas may contain significant amounts of ammonia (NH_3) that is produced during the degradation of amino acids during acidogenesis - one of the four primary stages in AD."[15] Additionally, it emphasizes the potential consequences, explaining that "the oxidation of NH_3 present in the biogas to nitrogen oxides ($NOx = NO + NO_2$) can cause elevated flare emissions that contribute to air quality problems and exceed permitted levels."[16]

Anaerobic digesters produce significant amounts of greenhouse gases, such as methane and carbon dioxide.[17] Notably, the combustion of biogas in an internal combustion engine yields high levels of air pollution, including carbon monoxide (CO), nitrogen oxides (NOx), sulfur dioxide (SO_2), and various hazardous air pollutants.[18] Biogas combustion also results in formaldehyde emissions. According to the EPA, formaldehyde is a "probable" carcinogen.[19] Based on an article by the Vermont Department of Environmental Conservation, anaerobic digesters can result in increased formaldehyde emissions from combustion of biogas. The article states:

> *"The use of internal combustion engines to burn biogas also generates substantially more formaldehyde emissions than would occur with other fuels or other combustion devices. According to the U.S. Environmental Protection Agency (US EPA), formaldehyde is ubiquitous and naturally occurring in the environment at low levels, contributing to asthma and eye and respiratory irritation. At higher concentration, it can cause severe irritation and is considered a probable human carcinogen by the US EPA."*[20]

The impact of emissions from anaerobic digestion on nearby communities, especially those in close proximity to dairy farms, is a critical aspect of environmental justice and public health. The emissions from anaerobic digestion can disproportionately affect nearby communities, particularly those adjacent to dairy farms, often comprising lower-income residents. Lower-income residents are often more vulnerable to the adverse effects of these emissions due to various factors, such as lack of resources, inadequate infrastructure, and the concentration of anaerobic digester facilities near these populations.

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[14] Id. PDF Pg 1.
[15] Ibid.
[16] Id. PDF pg 2.
[17] Anaerobic Digesters. Vermont Department of Environmental Conservation. Accessed January 26, 2024.
[18] Ibid.
[19] U.S. Environmental Protection Agency. Integrated Risk Information System (IRIS) on Formaldehyde. National Center for Environmental Assessment, Office of Research and Development, Washington, DC. 1999.
[20] Anaerobic Digesters. Vermont Department of Environmental Conservation. Accessed January 26, 2024.

The above section clearly highlights CARB's lack of extensive analysis in assessing the potential impacts of anaerobic digestion on air quality.

Anaerobic Digester Digestate Impact on Groundwater

In the ISOR, CARB listed the impacts of "Short-Term Construction-Related and Long-Term Operational-Related Impacts to Geology and Soils" and "Short-Term Construction-Related and Long-Term Operational-Related Impacts to Hydrology and Water Quality" as "Potentially Significant and Unavoidable".[21] This section serves as a response to CARB's analysis of these impacts.

Anaerobic digestion breaks down waste into a digestate of smaller molecules that are more susceptible to leaching into the groundwater. Several studies have found that anaerobic digestion leads to higher concentrations of ammonia in digestate, which can subsequently convert to nitrate. The leaching of nitrates into drinking water and food can lead to the onset of blue baby syndrome, also known as methemoglobinemia.[22] The consumption of nitrate reduces the ability of red blood cells to transport oxygen, leading to illness in infants younger than 12 months and presenting as a distinctive blue or brown tint to their skin.[23]

Figure 1. Baby with methemoglobinemia [24]

[21] ISOR. PDF Pg. 64-65.
[22] Nitrates, Blue Baby Syndrome, and Drinking Water: A Fact Sheet for Families. PEHSU. March 2016. PDF Pg. 1.
[23] Nitrates, Blue Baby Syndrome, and Drinking Water: A Fact Sheet for Families. PEHSU. March 2016. PDF Pg. 1.
[24] St. Bartholomew's Hospital, London/Photo Researchers (n.d.). American Scientist.

Lamolinara et al. (2022) found that digestate, the nutrient-rich product from anaerobic digestion of organic waste, can "contribute to nutrient pollution without comprehensive management strategies."[25] This type of pollution can lead to harmful algal blooms, hypoxia, and eutrophication.[26] Improper application of digestate has the potential to adversely affect both plant growth and soil health.[27] The chemical composition of digestate can present challenges for sustainable disposal.[28] Early application of digestate may lead to nutrient loss, translocation to deeper soil layers, or discharges of $NO3^-$ into groundwater.[29]

Anaerobic digestion breaks down waste, rendering it more susceptible to seepage into groundwater than undigested manure. Treatment lagoons are used to facilitate the waste treatment process and are lined, inhibiting nitrate from entering the groundwater. Anaerobic digestate is more extensively broken down compared to sludge from treatment lagoons. One study by Agga et al. (2022) indicated that treatment lagoons can reduce nitrogen compared to aerobic digestion:

> *"Unlike anaerobic digesters, uncovered lagoons are open to the air, photosynthesizing bacteria may develop that act to reduce nitrogen and sulfur-containing compounds and help eliminate odor in the effluent storage layer."*[30]

Nitrate pollution leading to groundwater contamination is much more likely to occur with anaerobically digested digestate, as the ammonia is more readily available for conversion into nitrate, which can then leach into groundwater. A 2010 study titled "Biogas Digestates as Organic Fertilizer in Different Crop Rotations" assessed bioenergy cropping systems for yield performance, ecological impacts, and economic feasibility. The research revealed that treatments with high digestate application rates could elevate the risk of $NO3^-$ discharges into groundwater.[31] Another study, by Fermoso et al. in 2019, highlighted that the prolonged use of digestate from anaerobic digesters could result in rapid nitrification of ammonium (NH4+-N) in the soil, making it readily accessible to crops and prone to leaching, potentially causing groundwater pollution.[32] A study by Amon et al. (2006) found that anaerobic digester digestate increases nitrate loss potential.[33] The study states:

> *"Anaerobic digestion reduces manure carbon and dry matter content by about 50%. NH4-N content and pH in digested slurry are higher than in untreated slurry (Messner, 1988). Thus, potentials for NH3 emissions during slurry storage are enhanced. Due to*

[25] Lamolinara et al. (2022). Anaerobic digestate management, environmental impacts, and techno-economic challenges. PDF Pg. 1.
[26] Ibid.
[27] Id. PDF Pg. 2.
[28] Ibid.
[29] Ibid.
[30] Agga et al. (2022). Lagoon, Anaerobic Digestion, and Composting of Animal Manure Treatments Impact on Tetracycline Resistance Genes. PDF Pg. 7.
[31] Formowitz and Fritz (2010). Biogas Digestates as Organic Fertilizer in Different Crop Rotations. PDF Pg. 4.
[32] Fermoso et al. (2019). Trace Elements in Anaerobic Biotechnologies. IWA. June 2019. PDF Pg. 187.
[33] Amon et al. (2006). Methane, nitrous oxide and ammonia emissions during storage and after application of dairy cattle slurry and influence of slurry treatment.

the reduced dry matter content, biogas slurry can infiltrate more rapidly into the soil, which reduces NH3 emissions after slurry application. However, the increased NH4-N content and pH give rise to higher NH3 loss potentials."[34]

There is a potential for nitrate contamination of groundwater, excessive accumulation of soil phosphorus, and eutrophication of surface waters from anaerobic digesters.[35] The above section clearly highlights CARB's lack of extensive analysis in assessing the potential impacts of anaerobic digestion on groundwater quality.

Conclusion: Anaerobic Digester Impacts Inadequately Evaluated

CARB failed to adequately address air quality, soil and geology, and groundwater quality issues in the ISOR and EIA. Further analysis is required to quantify the impact of increased anaerobic digesters and the impacts on groundwater and air quality, especially in locations where digestate is applied to soil. Further assessment is essential to properly evaluate the impact of emissions to air and discharges to groundwater from anaerobic digestion on nearby communities, specifically lower-income neighborhoods.

Disclaimer

SWAPE has received limited discovery regarding this project. Additional information may become available in the future; thus, we retain the right to revise or amend this report when additional information becomes available. Our professional services have been performed using that degree of care and skill ordinarily exercised, under similar circumstances, by reputable environmental consultants practicing in this or similar localities at the time of service. No other warranty, expressed or implied, is made as to the scope of work, work methodologies and protocols, site conditions, analytical testing results, and findings presented. This report reflects efforts which were limited to information that was reasonably accessible at the time of the work, and may contain informational gaps, inconsistencies, or otherwise be incomplete due to the unavailability or uncertainty of information obtained or provided by third parties.

Sincerely,

Paul Rosenfeld

Paul E. Rosenfeld, Ph.D.

Attachment A: Paul E. Rosenfeld CV

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[34] Ibid.

[35] Mahony et al. (2002) Feasibility Study for Centralised Anaerobic Digestion for Treatment of Various Waste and Wastewaters in Sensitive Catchment Areas. PDF Pg. 5.

SWAPE Technical Consultation, Data Analysis and Litigation Support for the Environment

SOIL WATER AIR PROTECTION ENTERPRISE
2656 29th Street, Suite 201
Santa Monica, California 90405
Attn: Paul Rosenfeld, Ph.D.
Mobil: (310) 795-2335
Office: (310) 452-5555
Fax: (310) 452-5550
Email: prosenfeld@swape.com

Paul Rosenfeld, Ph.D.

Chemical Fate and Transport & Air Dispersion Modeling

Principal Environmental Chemist

Risk Assessment & Remediation Specialist

Education

Ph.D. Soil Chemistry, University of Washington, 1999. Dissertation on volatile organic compound filtration.

M.S. Environmental Science, U.C. Berkeley, 1995. Thesis on organic waste economics.

B.A. Environmental Studies, U.C. Santa Barbara, 1991. Focus on wastewater treatment.

Professional Experience

Dr. Rosenfeld has over 25 years of experience conducting environmental investigations and risk assessments for evaluating impacts to human health, property, and ecological receptors. His expertise focuses on the fate and transport of environmental contaminants, human health risk, exposure assessment, and ecological restoration. Dr. Rosenfeld has evaluated and modeled emissions from oil spills, landfills, boilers and incinerators, process stacks, storage tanks, confined animal feeding operations, industrial, military and agricultural sources, unconventional oil drilling operations, and locomotive and construction engines. His project experience ranges from monitoring and modeling of pollution sources to evaluating impacts of pollution on workers at industrial facilities and residents in surrounding communities. Dr. Rosenfeld has also successfully modeled exposure to contaminants distributed by water systems and via vapor intrusion.

Dr. Rosenfeld has investigated and designed remediation programs and risk assessments for contaminated sites containing lead, heavy metals, mold, bacteria, particulate matter, petroleum hydrocarbons, chlorinated solvents, pesticides, radioactive waste, dioxins and furans, semi- and volatile organic compounds, PCBs, PAHs, creosote, perchlorate, asbestos, per- and poly-fluoroalkyl substances (PFOA/PFOS), unusual polymers, fuel oxygenates (MTBE), among other pollutants. Dr. Rosenfeld also has experience evaluating greenhouse gas emissions from various projects and is an expert on the assessment of odors from industrial and agricultural sites, as well as the evaluation of odor nuisance impacts and technologies for abatement of odorous emissions. As a principal scientist at SWAPE, Dr. Rosenfeld directs air dispersion modeling and exposure assessments. He has served as an expert witness and testified about pollution sources causing nuisance and/or personal injury at sites and has testified as an expert witness on numerous cases involving exposure to soil, water and air contaminants from industrial, railroad, agricultural, and military sources.

Professional History:

Soil Water Air Protection Enterprise (SWAPE); 2003 to present; Principal and Founding Partner
UCLA School of Public Health; 2007 to 2011; Lecturer (Assistant Researcher)
UCLA School of Public Health; 2003 to 2006; Adjunct Professor
UCLA Environmental Science and Engineering Program; 2002-2004; Doctoral Intern Coordinator
UCLA Institute of the Environment, 2001-2002; Research Associate
Komex H_2O Science, 2001 to 2003; Senior Remediation Scientist
National Groundwater Association, 2002-2004; Lecturer
San Diego State University, 1999-2001; Adjunct Professor
Anteon Corp., San Diego, 2000-2001; Remediation Project Manager
Ogden (now Amec), San Diego, 2000-2000; Remediation Project Manager
Bechtel, San Diego, California, 1999 – 2000; Risk Assessor
King County, Seattle, 1996 – 1999; Scientist
James River Corp., Washington, 1995-96; Scientist
Big Creek Lumber, Davenport, California, 1995; Scientist
Plumas Corp., California and USFS, Tahoe 1993-1995; Scientist
Peace Corps and World Wildlife Fund, St. Kitts, West Indies, 1991-1993; Scientist

Publications:

Rosenfeld P.E. and Spaeth K.R., (2023) Authors' Response to Letter to the Editor from Bullock and Ramacciotti, Volume 234, https://doi.org/10.1007/s11270-023-06165-3

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Rosenfeld, P.E., "The science for Perfluorinated Chemicals (PFAS): What makes remediation so hard?" Law Seminars International, (May 9-10, 2018) 800 Fifth Avenue, Suite 101 Seattle, WA.

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Sok, H.L.; Waller, C.C.; Feng, L.; Gonzalez, J.; Sutherland, A.J.; Wisdom-Stack, T.; Sahai, R.K.; Hesse, R.C.; **Rosenfeld, P.E.** (June 20-23, 2010). Atrazine: A Persistent Pesticide in Urban Drinking Water. *Urban Environmental Pollution*. Lecture conducted from Boston, MA.

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Rosenfeld, P.E. (April 19-23, 2009). Perfluoroctanoic Acid (PFOA) and Perfluoroactane Sulfonate (PFOS) Contamination in Drinking Water From the Use of Aqueous Film Forming Foams (AFFF) at Airports in the United States. *2009 Ground Water Summit and 2009 Ground Water Protection Council Spring Meeting*, Lecture conducted from Tuscon, AZ.

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Rosenfeld, P. E. (October 15-18, 2007). Moss Point Community Exposure To Contaminants From A Releasing Facility. *The 23rd Annual International Conferences on Soils Sediment and Water.* Platform lecture conducted at University of Massachusetts, Amherst MA.

Rosenfeld, P. E. (October 15-18, 2007). The Repeated Trespass of Tritium-Contaminated Water Into A Surrounding Community Form Repeated Waste Spills From A Nuclear Power Plant. *The 23rd Annual International Conferences on Soils Sediment and Water*. Platform lecture conducted from University of Massachusetts, Amherst MA.

Rosenfeld, P. E. (October 15-18, 2007). Somerville Community Exposure To Contaminants From Wood Treatment Facility Emissions. The *23rd Annual International Conferences on Soils Sediment and Water*. Lecture conducted from University of Massachusetts, Amherst MA.

Rosenfeld P. E. (March 2007). Production, Chemical Properties, Toxicology, & Treatment Case Studies of 1,2,3-Trichloropropane (TCP). *The Association for Environmental Health and Sciences (AEHS) Annual Meeting*. Lecture conducted from San Diego, CA.

Rosenfeld P. E. (March 2007). Blood and Attic Sampling for Dioxin/Furan, PAH, and Metal Exposure in Florala, Alabama. *The AEHS Annual Meeting.* Lecture conducted from San Diego, CA.

Hensley A.R., Scott, A., **Rosenfeld P.E.,** Clark, J.J.J. (August 21 – 25, 2006). Dioxin Containing Attic Dust And Human Blood Samples Collected Near A Former Wood Treatment Facility. *The 26th International Symposium on Halogenated Persistent Organic Pollutants – DIOXIN2006*. Lecture conducted from Radisson SAS Scandinavia Hotel in Oslo Norway.

Hensley A.R., Scott, A., **Rosenfeld P.E.,** Clark, J.J.J. (November 4-8, 2006). Dioxin Containing Attic Dust And Human Blood Samples Collected Near A Former Wood Treatment Facility. *APHA 134 Annual Meeting & Exposition.* Lecture conducted from Boston Massachusetts.

Paul Rosenfeld Ph.D. (October 24-25, 2005). Fate, Transport and Persistence of PFOA and Related Chemicals. Mealey's C8/PFOA. *Science, Risk & Litigation Conference.* Lecture conducted from The Rittenhouse Hotel, Philadelphia, PA.

Paul Rosenfeld Ph.D. (September 19, 2005). Brominated Flame Retardants in Groundwater: Pathways to Human Ingestion, *Toxicology and Remediation PEMA Emerging Contaminant Conference*. Lecture conducted from Hilton Hotel, Irvine California.

Paul Rosenfeld Ph.D. (September 19, 2005). Fate, Transport, Toxicity, And Persistence of 1,2,3-TCP. *PEMA Emerging Contaminant Conference.* Lecture conducted from Hilton Hotel in Irvine, California.

Paul Rosenfeld Ph.D. (September 26-27, 2005). Fate, Transport and Persistence of PDBEs. *Mealey's Groundwater Conference.* Lecture conducted from Ritz Carlton Hotel, Marina Del Ray, California.

Paul Rosenfeld Ph.D. (June 7-8, 2005). Fate, Transport and Persistence of PFOA and Related Chemicals. *International Society of Environmental Forensics: Focus on Emerging Contaminants*. Lecture conducted from Sheraton Oceanfront Hotel, Virginia Beach, Virginia.

Paul Rosenfeld Ph.D. (July 21-22, 2005). Fate Transport, Persistence and Toxicology of PFOA and Related Perfluorochemicals. *2005 National Groundwater Association Ground Water and Environmental Law Conference*. Lecture conducted from Wyndham Baltimore Inner Harbor, Baltimore Maryland.

Paul Rosenfeld Ph.D. (July 21-22, 2005). Brominated Flame Retardants in Groundwater: Pathways to Human Ingestion, Toxicology and Remediation. *2005 National Groundwater Association Ground Water and Environmental Law Conference.* Lecture conducted from Wyndham Baltimore Inner Harbor, Baltimore Maryland.

Paul Rosenfeld, Ph.D. and James Clark Ph.D. and Rob Hesse R.G. (May 5-6, 2004). Tert-butyl Alcohol Liability and Toxicology, A National Problem and Unquantified Liability. *National Groundwater Association. Environmental Law Conference*. Lecture conducted from Congress Plaza Hotel, Chicago Illinois.

Paul Rosenfeld, Ph.D. (March 2004). Perchlorate Toxicology. *Meeting of the American Groundwater Trust*. Lecture conducted from Phoenix Arizona.

Hagemann, M.F., **Paul Rosenfeld, Ph.D.** and Rob Hesse (2004). Perchlorate Contamination of the Colorado River. *Meeting of tribal representatives*. Lecture conducted from Parker, AZ.

Paul Rosenfeld, Ph.D. (April 7, 2004). A National Damage Assessment Model For PCE and Dry Cleaners. *Drycleaner Symposium. California Ground Water Association*. Lecture conducted from Radison Hotel, Sacramento, California.

Rosenfeld, P. E., Grey, M., (June 2003) Two stage biofilter for biosolids composting odor control. *Seventh International In Situ And On Site Bioremediation Symposium Battelle Conference* Orlando, FL.

Paul Rosenfeld, Ph.D. and James Clark Ph.D. (February 20-21, 2003) Understanding Historical Use, Chemical Properties, Toxicity and Regulatory Guidance of 1,4 Dioxane. *National Groundwater Association. Southwest Focus Conference. Water Supply and Emerging Contaminants*.. Lecture conducted from Hyatt Regency Phoenix Arizona.

Paul Rosenfeld, Ph.D. (February 6-7, 2003). Underground Storage Tank Litigation and Remediation. *California CUPA Forum*. Lecture conducted from Marriott Hotel, Anaheim California.

Paul Rosenfeld, Ph.D. (October 23, 2002) Underground Storage Tank Litigation and Remediation. *EPA Underground Storage Tank Roundtable*. Lecture conducted from Sacramento California.

Rosenfeld, P.E. and Suffet, M. (October 7- 10, 2002). Understanding Odor from Compost, *Wastewater and Industrial Processes. Sixth Annual Symposium On Off Flavors in the Aquatic Environment. International Water Association*. Lecture conducted from Barcelona Spain.

Rosenfeld, P.E. and Suffet, M. (October 7- 10, 2002). Using High Carbon Wood Ash to Control Compost Odor. *Sixth Annual Symposium On Off Flavors in the Aquatic Environment. International Water Association*. Lecture conducted from Barcelona Spain.

Rosenfeld, P.E. and Grey, M. A. (September 22-24, 2002). Biocycle Composting For Coastal Sage Restoration. *Northwest Biosolids Management Association*. Lecture conducted from Vancouver Washington..

Rosenfeld, P.E. and Grey, M. A. (November 11-14, 2002). Using High-Carbon Wood Ash to Control Odor at a Green Materials Composting Facility. *Soil Science Society Annual Conferenc*e. Lecture conducted from Indianapolis, Maryland.

Rosenfeld. P.E. (September 16, 2000). Two stage biofilter for biosolids composting odor control. *Water Environment Federation.* Lecture conducted from Anaheim California.

Rosenfeld. P.E. (October 16, 2000). Wood ash and biofilter control of compost odor. *Biofest.* Lecture conducted from Ocean Shores, California.

Rosenfeld, P.E. (2000). Bioremediation Using Organic Soil Amendments. *California Resource Recovery Association*. Lecture conducted from Sacramento California.

Rosenfeld, P.E., C.L. Henry, R. Harrison. (1998). Oat and Grass Seed Germination and Nitrogen and Sulfur Emissions Following Biosolids Incorporation with High-Carbon Wood-Ash. *Water Environment Federation 12th Annual Residuals and Biosolids Management Conference Proceedings*. Lecture conducted from Bellevue Washington.

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Rosenfeld, P.E., C.L. Henry, R. Harrison. (1998). Comparison of Microbial Activity and Odor Emissions from Three Different Biosolids Applied to Forest Soil. *Brown and Caldwell.* Lecture conducted from Seattle Washington.

Rosenfeld, P.E., C.L. Henry. (1998). Characterization, Quantification, and Control of Odor Emissions from Biosolids Application To Forest Soil. *Biofest.* Lecture conducted from Lake Chelan, Washington.

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Rosenfeld, P.E., C.L. Henry, R. B. Harrison, and R. Dills. (1997). Comparison of Odor Emissions from Three Different Biosolids Applied to Forest Soil. *Soil Science Society of America*. Lecture conducted from Anaheim California.

Teaching Experience:

UCLA Department of Environmental Health (Summer 2003 through 20010) Taught Environmental Health Science 100 to students, including undergrad, medical doctors, public health professionals and nurses. Course focused on the health effects of environmental contaminants.

National Ground Water Association, Successful Remediation Technologies. Custom Course in Sante Fe, New Mexico. May 21, 2002. Focused on fate and transport of fuel contaminants associated with underground storage tanks.

National Ground Water Association; Successful Remediation Technologies Course in Chicago Illinois. April 1, 2002. Focused on fate and transport of contaminants associated with Superfund and RCRA sites.

California Integrated Waste Management Board, April and May, 2001. Alternative Landfill Caps Seminar in San Diego, Ventura, and San Francisco. Focused on both prescriptive and innovative landfill cover design.

UCLA Department of Environmental Engineering, February 5, 2002. Seminar on Successful Remediation Technologies focusing on Groundwater Remediation.

University Of Washington, Soil Science Program, Teaching Assistant for several courses including: Soil Chemistry, Organic Soil Amendments, and Soil Stability.

U.C. Berkeley, Environmental Science Program Teaching Assistant for Environmental Science 10.

Academic Grants Awarded:

California Integrated Waste Management Board. $41,000 grant awarded to UCLA Institute of the Environment. Goal: To investigate the effect of high carbon wood ash on volatile organic emissions from compost. 2001.

Synagro Technologies, Corona California: $10,000 grant awarded to San Diego State University.
Goal: investigate the effect of biosolids for restoration and remediation of degraded coastal sage soils. 2000.

King County, Department of Research and Technology, Washington State. $100,000 grant awarded to University of Washington: Goal: To investigate odor emissions from biosolids application and the effect of polymers and ash on VOC emissions. 1998.

Northwest Biosolids Management Association, Washington State. $20,000 grant awarded to investigate effect of polymers and ash on VOC emissions from biosolids. 1997.

James River Corporation, Oregon: $10,000 grant was awarded to investigate the success of genetically engineered Poplar trees with resistance to round-up. 1996.

United State Forest Service, Tahoe National Forest: $15,000 grant was awarded to investigating fire ecology of the Tahoe National Forest. 1995.

Kellogg Foundation, Washington D.C. $500 grant was awarded to construct a large anaerobic digester on St. Kitts in West Indies. 1993

Deposition and/or Trial Testimony:

In the United States District Court for the Western District of Louisiana
Ricky Bush v. Clean Harbors Colfax LLC
Case No. 1:22-cv-02026-DDD-JPM
Rosenfeld Deposition 12-18-2023

In United States District Court of Hawaii
Patrick Feindt, Jr. et al. vs. The United States of America
Case No. 1:22-cv-LEK-KJM
Rosenfeld Deposition 11-29-2023

In the Circuit Court for the Twentieth Judicial Circuit St. Clair County, Illinois
Timothy Gray vs. Rural King et al.
Case No 2022-LA-355
Rosenfeld Deposition 9-26-2023

In United States District Court Eastern District of Wisconsin
Gary L. Siepe vs. Soo Line Railroad Company
Case No. 2:21-cv-00919
Rosenfeld Deposition 9-15-2023

In the Circuit Court of Cook County Illinois
Donald Fox vs. BNSF
Case No. 2021 L12
Rosenfeld Deposition 9-12-2023

In the Court of Common Please Cuyahoga County, Ohio
Thomas Schleich vs. Penn Central Corporation
Lead Case No. CV-20-939184
Rosenfeld Deposition 8-27-2023

In the Circuit Court of Jackson County Missouri at Kansas City
Timothy Dalsing vs. BNSF
Case No. No. 2216-cv06539
Rosenfeld Deposition 7-28-2023

In the United States District Court for the Southern District of Texas Houston Division
International Terminals Company LLC Deer Park Fire Litigation
Lead Case No. 4:19-cv-01460
Rosenfeld Deposition 7-25-2023

In the Circuit Court of Livingston County Missouri
Shirley Ralls vs. Canadian Pacific Railway and Soo Lind Railroad
Case No. 28LV-CV0020
Rosenfeld Daubert Hearing 7-18-2023 Trial Testimony 7-19-2023

In the Circuit Court of Cook County Illinois
Brenda Wright vs. Penn Central and Conrail
Case No. No. 2032L003966
Rosenfeld Deposition 6-13-2023

In the Circuit Court Common Please Philadelphia of Jefferson County Alabama
Frank Belle vs. Birmingham Southern Railroad Company et al.
Case No. 01-cv-2021-900901.00
Rosenfeld Deposition 4-6-2023

In the Circuit Court of Jefferson County Alabama
Linda De Gregorio vs. Penn Central
Case No. 002278
Rosenfeld Deposition 3-27-20203

In the United States District Court Eastern District of New York
Rosalie Romano et al. vs. Northrup Grumman Corporation
Case No. 16-cv-5760
Rosenfeld Deposition 3-16-2023

In the Superior Court of Washington, Spokane County
Judy Cundy vs. BNSF
Case No. 21-2-03718-32
Rosenfeld Deposition 3-9-2023

In The Court of Common Pleas of Philadelphia County, PA Civil Trial Division
Feaster v Conrail
Case No. 001075
Rosenfeld Deposition 2-1-2023

In United States District Court for the Central District of Illinois
Sherman vs. BNSF
Case No. 3:17-cv-01192
Rosenfeld Deposition 1-18-2023

In United States District Court District of Colorado
Gonzales vs. BNSF
Case No. 1:21-cv-01690
Rosenfeld Deposition 1-17-2023

In United States District Court District of Colorado
Abeyta vs. BNSF
Case No. 1:21-cv-01689-KMT
Rosenfeld Deposition 1-3-2023

In United States District Court For The Easter District of Louisiana
Nathaniel Smith vs. Illinois Central Railroad
Case No. 2:21-cv-01235
Rosenfeld Deposition 11-30-2022

In the Superior Court of the State of California, County of San Bernardino
Billy Wildrick, Plaintiff vs. BNSF Railway Company
Case No. CIVDS1711810
Rosenfeld Deposition 10-17-2022

In the State Court of Bibb County, State of Georgia
Richard Hutcherson, Plaintiff vs Norfolk Southern Railway Company
Case No. 10-SCCV-092007
Rosenfeld Deposition 10-6-2022

In the Civil District Court of the Parish of Orleans, State of Louisiana
Millard Clark, Plaintiff vs. Dixie Carriers, Inc. et al.
Case No. 2020-03891
Rosenfeld Deposition 9-15-2022

In The Circuit Court of Livingston County, State of Missouri, Circuit Civil Division
Shirley Ralls, Plaintiff vs. Canadian Pacific Railway and Soo Line Railroad
Case No. 18-LV-CC0020
Rosenfeld Deposition 9-7-2022

In The Circuit Court of the 13th Judicial Circuit Court, Hillsborough County, Florida Civil Division
Jonny C. Daniels, Plaintiff vs. CSX Transportation Inc.
Case No. 20-CA-5502

Rosenfeld Deposition 9-1-2022

In The Circuit Court of St. Louis County, State of Missouri
Kieth Luke et. al. Plaintiff vs. Monsanto Company et. al.
Case No. 19SL-CC03191
Rosenfeld Deposition 8-25-2022

In The Circuit Court of the 13th Judicial Circuit Court, Hillsborough County, Florida Civil Division
Jeffery S. Lamotte, Plaintiff vs. CSX Transportation Inc.
Case No. NO. 20-CA-0049
Rosenfeld Deposition 8-22-2022

In State of Minnesota District Court, County of St. Louis Sixth Judicial District
Greg Bean, Plaintiff vs. Soo Line Railroad Company
Case No. 69-DU-CV-21-760
Rosenfeld Deposition 8-17-2022

In United States District Court Western District of Washington at Tacoma, Washington
John D. Fitzgerald Plaintiff vs. BNSF
Case No. 3:21-cv-05288-RJB
Rosenfeld Deposition 8-11-2022

In Circuit Court of the Sixth Judicial Circuit, Macon Illinois
Rocky Bennyhoff Plaintiff vs. Norfolk Southern
Case No. 20-L-56
Rosenfeld Deposition 8-3-2022, Trial 1-10-2023

In Court of Common Pleas, Hamilton County Ohio
Joe Briggins Plaintiff vs. CSX
Case No. A2004464
Rosenfeld Deposition 6-17-2022

In the Superior Court of the State of California, County of Kern
George LaFazia vs. BNSF Railway Company.
Case No. BCV-19-103087
Rosenfeld Deposition 5-17-2022

In the Circuit Court of Cook County Illinois
Bobby Earles vs. Penn Central et. al.
Case No. 2020-L-000550
Rosenfeld Deposition 4-16-2022

In United States District Court Easter District of Florida
Albert Hartman Plaintiff vs. Illinois Central
Case No. 2:20-cv-1633
Rosenfeld Deposition 4-4-2022

In the Circuit Court of the 4th Judicial Circuit, in and For Duval County, Florida
Barbara Steele vs. CSX Transportation
Case No.16-219-Ca-008796
Rosenfeld Deposition 3-15-2022

In United States District Court Easter District of New York
Romano et al. vs. Northrup Grumman Corporation
Case No. 16-cv-5760
Rosenfeld Deposition 3-10-2022

In the Circuit Court of Cook County Illinois
Linda Benjamin vs. Illinois Central
Case No. No. 2019 L 007599
Rosenfeld Deposition 1-26-2022

In the Circuit Court of Cook County Illinois
Donald Smith vs. Illinois Central
Case No. No. 2019 L 003426
Rosenfeld Deposition 1-24-2022

In the Circuit Court of Cook County Illinois
Jan Holeman vs. BNSF
Case No. 2019 L 000675
Rosenfeld Deposition 1-18-2022

In the State Court of Bibb County State of Georgia
Dwayne B. Garrett vs. Norfolk Southern
Case No. 20-SCCV-091232
Rosenfeld Deposition 11-10-2021

In the Circuit Court of Cook County Illinois
Joseph Ruepke vs. BNSF
Case No. 2019 L 007730
Rosenfeld Deposition 11-5-2021

In the United States District Court For the District of Nebraska
Steven Gillett vs. BNSF
Case No. 4:20-cv-03120
Rosenfeld Deposition 10-28-2021

In the Montana Thirteenth District Court of Yellowstone County
James Eadus vs. Soo Line Railroad and BNSF
Case No. DV 19-1056
Rosenfeld Deposition 10-21-2021

In the Circuit Court Of The Twentieth Judicial Circuit, St Clair County, Illinois
Martha Custer et al. vs Cerro Flow Products, Inc.
Case No. 0i9-L-2295
Rosenfeld Deposition 5-14-2021
Trial October 8-4-2021

In the Circuit Court of Cook County Illinois
Joseph Rafferty vs. Consolidated Rail Corporation and National Railroad Passenger Corporation d/b/a AMTRAK,
Case No. 18-L-6845
Rosenfeld Deposition 6-28-2021

In the United States District Court For the Northern District of Illinois
Theresa Romcoe vs. Northeast Illinois Regional Commuter Railroad Corporation d/b/a METRA Rail
Case No. 17-cv-8517
Rosenfeld Deposition 5-25-2021

In the Superior Court of the State of Arizona In and For the Cunty of Maricopa
Mary Tryon et al. vs. The City of Pheonix v. Cox Cactus Farm, L.L.C., Utah Shelter Systems, Inc.
Case No. CV20127-094749

Rosenfeld Deposition 5-7-2021

In the United States District Court for the Eastern District of Texas Beaumont Division
Robinson, Jeremy et al vs. CNA Insurance Company et al.
Case No. 1:17-cv-000508
Rosenfeld Deposition 3-25-2021

In the Superior Court of the State of California, County of San Bernardino
Gary Garner, Personal Representative for the Estate of Melvin Garner vs. BNSF Railway Company.
Case No. 1720288
Rosenfeld Deposition 2-23-2021

In the Superior Court of the State of California, County of Los Angeles, Spring Street Courthouse
Benny M Rodriguez vs. Union Pacific Railroad, A Corporation, et al.
Case No. 18STCV01162
Rosenfeld Deposition 12-23-2020

In the Circuit Court of Jackson County, Missouri
Karen Cornwell, Plaintiff, vs. Marathon Petroleum, LP, Defendant.
Case No. 1716-CV10006
Rosenfeld Deposition 8-30-2019

In the United States District Court For The District of New Jersey
Duarte et al, Plaintiffs, vs. United States Metals Refining Company et. al. Defendant.
Case No. 2:17-cv-01624-ES-SCM
Rosenfeld Deposition 6-7-2019

In the United States District Court of Southern District of Texas Galveston Division
M/T Carla Maersk vs. Conti 168., Schiffahrts-GMBH & Co. Bulker KG MS "Conti Perdido" Defendant.
Case No. 3:15-CV-00106 consolidated with 3:15-CV-00237
Rosenfeld Deposition 5-9-2019

In The Superior Court of the State of California In And For The County Of Los Angeles – Santa Monica
Carole-Taddeo-Bates et al., vs. Ifran Khan et al., Defendants
Case No. BC615636
Rosenfeld Deposition 1-26-2019

In The Superior Court of the State of California In And For The County Of Los Angeles – Santa Monica
The San Gabriel Valley Council of Governments et al. vs El Adobe Apts. Inc. et al., Defendants
Case No. BC646857
Rosenfeld Deposition 10-6-2018; Trial 3-7-19

In United States District Court For The District of Colorado
Bells et al. Plaintiffs vs. The 3M Company et al., Defendants
Case No. 1:16-cv-02531-RBJ
Rosenfeld Deposition 3-15-2018 and 4-3-2018

In The District Court Of Regan County, Texas, 112th Judicial District
Phillip Bales et al., Plaintiff vs. Dow Agrosciences, LLC, et al., Defendants
Cause No. 1923
Rosenfeld Deposition 11-17-2017

In The Superior Court of the State of California In And For The County Of Contra Costa
Simons et al., Plaintifs vs. Chevron Corporation, et al., Defendants
Cause No. C12-01481
Rosenfeld Deposition 11-20-2017

In The Circuit Court Of The Twentieth Judicial Circuit, St Clair County, Illinois
Martha Custer et al., Plaintiff vs. Cerro Flow Products, Inc., Defendants
Case No.: No. 0i9-L-2295
Rosenfeld Deposition 8-23-2017

In United States District Court For The Southern District of Mississippi
Guy Manuel vs. The BP Exploration et al., Defendants
Case No. 1:19-cv-00315-RHW
Rosenfeld Deposition 4-22-2020

In The Superior Court of the State of California, For The County of Los Angeles
Warrn Gilbert and Penny Gilber, Plaintiff vs. BMW of North America LLC
Case No. LC102019 (c/w BC582154)
Rosenfeld Deposition 8-16-2017, Trail 8-28-2018

In the Northern District Court of Mississippi, Greenville Division
Brenda J. Cooper, et al., Plaintiffs, vs. Meritor Inc., et al., Defendants
Case No. 4:16-cv-52-DMB-JVM
Rosenfeld Deposition July 2017

In The Superior Court of the State of Washington, County of Snohomish
Michael Davis and Julie Davis et al., Plaintiff vs. Cedar Grove Composting Inc., Defendants
Case No. 13-2-03987-5
Rosenfeld Deposition, February 2017
Trial March 2017

In The Superior Court of the State of California, County of Alameda
Charles Spain., Plaintiff vs. Thermo Fisher Scientific, et al., Defendants
Case No. RG14711115
Rosenfeld Deposition September 2015

In The Iowa District Court In And For Poweshiek County
Russell D. Winburn, et al., Plaintiffs vs. Doug Hoksbergen, et al., Defendants
Case No. LALA002187
Rosenfeld Deposition August 2015

In The Circuit Court of Ohio County, West Virginia
Robert Andrews, et al. v. Antero, et al.
Civil Action No. 14-C-30000
Rosenfeld Deposition June 2015

In The Iowa District Court for Muscatine County
Laurie Freeman et. al. Plaintiffs vs. Grain Processing Corporation, Defendant
Case No. 4980
Rosenfeld Deposition May 2015

In the Circuit Court of the 17th Judicial Circuit, in and For Broward County, Florida
Walter Hinton, et. al. Plaintiff, vs. City of Fort Lauderdale, Florida, a Municipality, Defendant.
Case No. CACE07030358 (26)
Rosenfeld Deposition December 2014

In the County Court of Dallas County Texas
Lisa Parr et al, Plaintiff, vs. Aruba et al, Defendant.
Case No. cc-11-01650-E
Rosenfeld Deposition: March and September 2013

Rosenfeld Trial April 2014

In the Court of Common Pleas of Tuscarawas County Ohio
John Michael Abicht, et al., Plaintiffs, vs. Republic Services, Inc., et al., Defendants
Case No. 2008 CT 10 0741 (Cons. w/ 2009 CV 10 0987)
Rosenfeld Deposition October 2012

In the United States District Court for the Middle District of Alabama, Northern Division
James K. Benefield, et al., Plaintiffs, vs. International Paper Company, Defendant.
Civil Action No. 2:09-cv-232-WHA-TFM
Rosenfeld Deposition July 2010, June 2011

In the Circuit Court of Jefferson County Alabama
Jaeanette Moss Anthony, et al., Plaintiffs, vs. Drummond Company Inc., et al., Defendants
Civil Action No. CV 2008-2076
Rosenfeld Deposition September 2010

In the United States District Court, Western District Lafayette Division
Ackle et al., Plaintiffs, vs. Citgo Petroleum Corporation, et al., Defendants.
Case No. 2:07CV1052
Rosenfeld Deposition July 2009

ATTACHMENT C

Aaron Smith
Department of Agricultural and Resource Economics

Cow Poop is Now a Big Part of California Fuel Policy

Are the state's new low-carbon fuel regulations full of BS?

by Aaron David Smith | January 22, 2024

Every day, California farmers milk 1.7 million cows. Each cow generates about 7 gallons of milk and 100 gallons of waste. Most farmers process the waste (mostly manure) by washing it into lagoons where microbes break it down and, in the process, emit methane, a potent greenhouse gas.

These facts raise two questions. First, can we prevent the manure-eating microbes from sending methane into the atmosphere? Second, can we capture the methane and use it for energy?

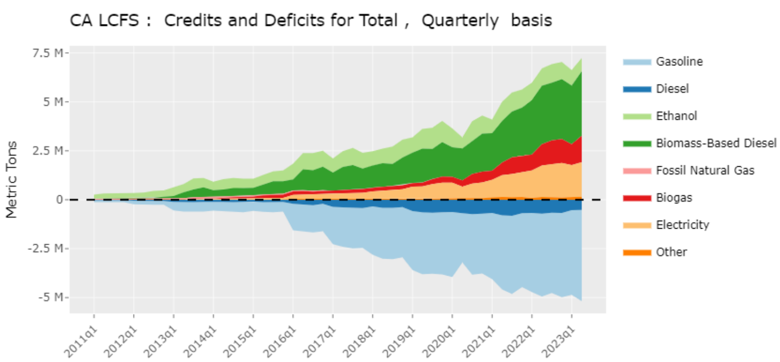
California has answered yes to both questions. On the first question, it aims to reduce methane emissions from livestock manure by 40% below 2013 levels by 2030 (codified in SB 1383). One way to achieve this goal would be to place the burden on farmers by charging them a methane emissions fee or requiring them to use practices or technologies that reduce methane emissions. This approach would raise the cost of producing milk and therefore increase the price consumers pay for dairy products. The cost increase may cause some farmers to move out of state, taking their methane emissions with them. This response, known as leakage, arises in many environmental policies, including in California's cap and trade program, as explained by Meredith in this blog.

California has chosen a different path. It has shoehorned dairy methane into a transportation program: the low carbon fuel standard (LCFS). This structure avoids leakage, but it makes consumers and producers of gasoline and diesel pay for reductions in dairy manure emissions.

Manure in the LCFS

To capture methane from manure lagoons, farmers install anaerobic digesters, which are essentially giant covers that seal manure in the lagoon to keep oxygen out while microbes feed on the contents. The captured methane — known as biogas — is then cleaned and injected into a natural gas pipeline, from which it has multiple uses including fueling a natural-gas powered vehicle and generating electricity.

This dairy biogas earns LCFS credits because it is considered a low carbon fuel. The LCFS sets a target for the average carbon intensity of transportation fuels consumed in the state. Fuels that are more carbon intensive than the target accrue deficits that must be balanced by credits earned by fuels that are less carbon intensive. The figure below shows that gasoline and diesel producers generate deficits, which they can offset by buying credits from producers of biogas and other lower-GHG fuels like electricity and renewable diesel.



Source: Our LCFS Data App. Click to view and download data using your web browser.

In the most recent LCFS data, dairy biogas contributed almost 20% of the credits in the LCFS program, yet it provided less than 1% of energy used for transportation. Dairy biogas has an outsized impact in the LCFS because it is treated very differently than most fuels. Last month's proposed LCFS amendments indicate that this differential treatment will continue.

The LCFS Assigns Dairy Biogas a Large Negative Carbon Intensity

Carbon intensity is the number of grams of carbon dioxide emissions produced per megajoule of energy. The California Air Resources Board (CARB) calculates this number for each fuel source using a life cycle analysis that accounts for tailpipe emissions as well as potential emissions throughout the fuel production process. For example, petroleum gasoline has a carbon intensity of 100.82 and an electric car powered by solar-generated electricity has a carbon intensity of zero. Most other fuels have carbon intensities between zero and 100.

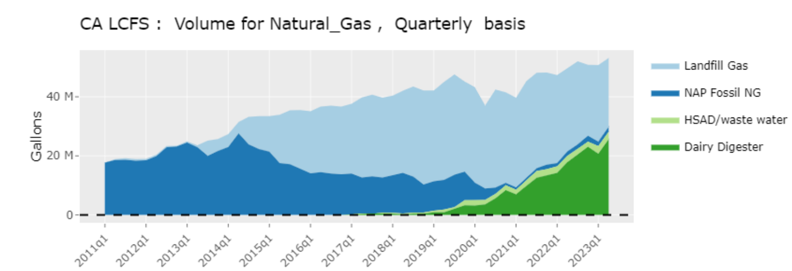
The carbon intensity of dairy biogas ranges between -102.79 and -790.41 depending on characteristics of the digester. The current average carbon intensity for dairy biogas is -269.

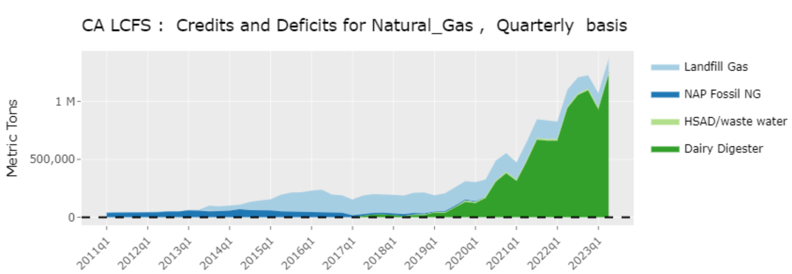
CARB assigns dairy biogas a negative carbon intensity because it gives credit for preventing methane emissions that would otherwise have occurred. Their argument is that, if a farmer had not installed a digester on a manure lagoon, then it would have sent methane into the atmosphere.

Microbes produce different amounts of gas inside a digester than they would in an open lagoon because of differing environmental factors such as oxygen exposure and temperature. The carbon intensity number is determined by the estimated emissions from the open lagoon (avoided methane) per unit of biogas produced. For example, in highly productive digesters, the amount of prevented methane is low as a proportion of the biogas produced, so such a digester would get a relatively small negative carbon intensity.

In the LCFS, fuels with a negative carbon intensity are very helpful in meeting the policy target because they can offset a lot of high-carbon fuel. For example, adding one average biogas-powered vehicle to the fleet would produce enough LCFS credits to cover the deficits incurred by 26 similar gasoline-powered vehicles.

This accounting scheme is one reason why dairy biogas has increased from almost non-existent five years ago to half of all natural gas used for transportation in the state. The other half is contributed by biogas captured from landfills. However, landfill gas gets a carbon intensity of 53 because it does not get credit for avoided-methane emissions. So, even though its fuel volumes are similar to dairy, it generates only a fraction of the credits, as shown in the figure below. Biogas can also earn LCFS credits by generating hydrogen or electricity for use in transportation, but these pathways have been used very little so far.





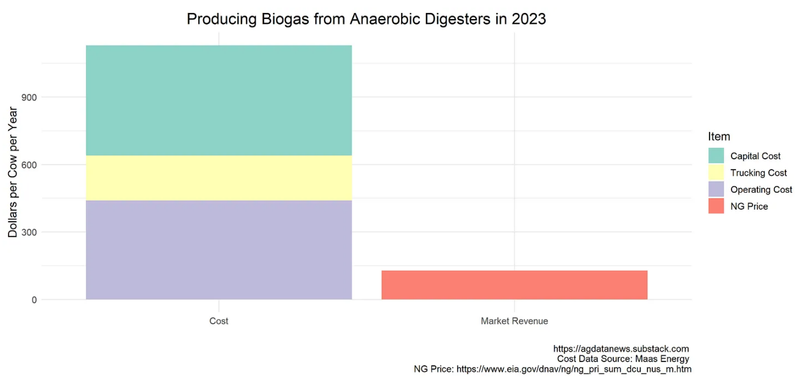
Source: Our [LCFS Data App](). Click to view and download data using your web browser.

Costs and Benefits of Anaerobic Digesters

In this 2023 blog, I showed that the cost of an anaerobic digester is about 10 times the market value of the gas it produces. A representative new digester costs about about $1130 per milking cow per year, comprising $490 in capital costs and $440 in operating costs, plus $200 in trucking costs if unable to connect directly to a gas pipeline. In 2023, revenue from selling gas was about $128, for a net cost of about $1000 per milking cow per year. This representative digester has a carbon intensity of -355, which corresponds to about 6 metric tons of CO2 equivalent emissions per milking cow per year.

So, for $1000 we reduce CO2 emissions by 6 metric tons, or $167 per ton.

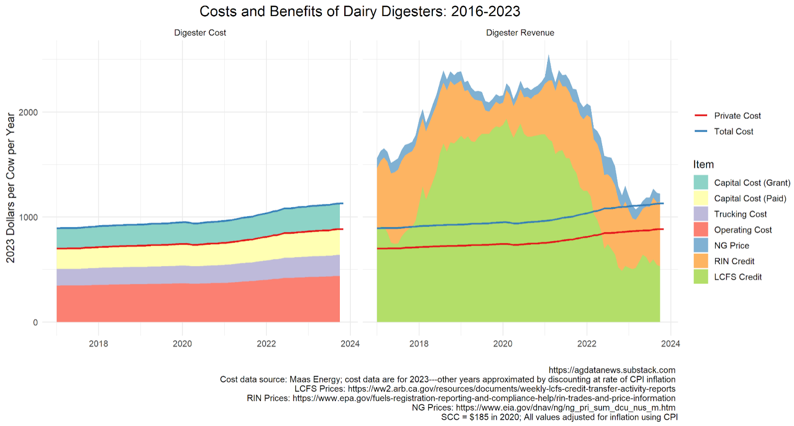
Methane is a far more powerful greenhouse gas than CO2, but it doesn't last nearly as long in the atmosphere. There is a vigorous scientific debate over how best to convert methane emissions into CO2 equivalent accounting for both how much it warms and when. Using an alternative approach would reduce the estimated emissions reduction by a factor of three and therefore raise the cost per ton by a factor of three. Moreover, all these numbers assume that CARB correctly estimates the amount of prevented emissions.



Incentives Facing Farmers

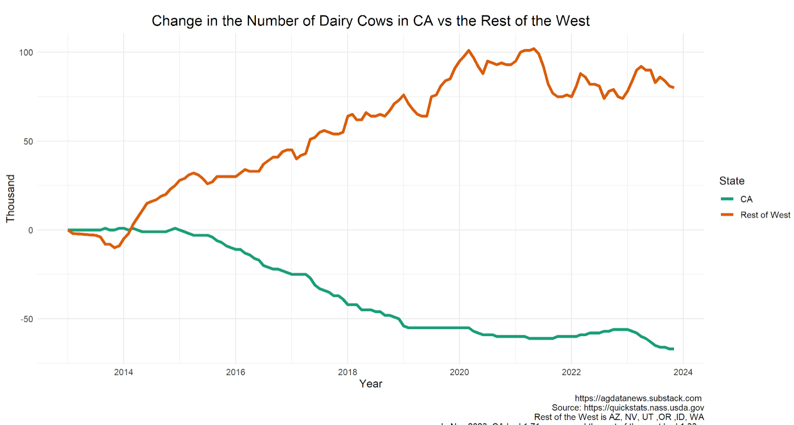
Anaerobic digesters receive government support through three programs. First, using proceeds from the state's cap and trade program, the California Department of Food and Agriculture offers grants to cover up to half the capital costs of building digesters. Second, sellers of dairy biogas generate credits in the federal renewable fuel standard (known as RINs). Third, they earn LCFS credits.

Between mid 2018 and the end of 2021, revenues from selling biogas and the associated RIN and LCFS credits were approximately double the cost of installing and running a typical digester, as shown in the figure below. LCFS credit prices have declined in the last two years, making the typical digester closer to a break even proposition. If and when credit prices go back up, then the profits will return.



High profits from operating digesters create the incentive for farmers to expand dairy herds for the purpose of generating manure rather than for producing milk. Between 2014 and 2019, California dairy cow numbers declined by 50,000 while the number of cows in other western states increased by 100,000 (see figure below). Since 2019, cow numbers have been relatively flat throughout the west.

It is possible that the advent of digesters in California stemmed the flow of cows out of the state. Dairy farmers outside California can access only two of the three digester programs accessible to California farmers. They are eligible to earn LCFS and RIN credits for their biogas, but they cannot receive California Department of Food and Agriculture grants to cover capital costs. Whether this grant funding is the difference between leaving and staying in California is an important topic for further research given the potential for emissions leakage if the state were to remove negative crediting but still require farmers to reduce manure methane emissions as per SB 1383.



What Next?

CARB is proposing several amendments to the LCFS. It considered removing the negative crediting of dairy biogas projects, but its proposal (which is currently out for comment) opted to continue negative credits until 2040 for biogas used directly in transportation and until 2045 for biogas used to produce hydrogen for transportation.

There is a long tradition in agriculture of governments paying farmers for environmental improvement, rather than placing the burden on farmers to make those improvements. As a result, consumers do not see the full cost to society of the food they eat. Instead, those costs are shifted to taxpayers or, in the case of dairy biogas, gasoline and diesel consumers. Such mispricing can cause costly misallocations of resources, as articulated often on this blog.

Leakage is the main argument given for continuing negative crediting. There are several ways to mitigate leakage. Some, such as border adjustments (tax dairy products coming into California) would be very difficult to operationalize. A good rule in policy is to directly target the problem you are trying to solve. In this case, the problem would be methane-mitigation costs imposed on farmers that cause them to move out of state. Negative crediting in the LCFS is a convoluted solution with numerous drawbacks. A direct solution could involve the state sharing the costs of methane mitigation practices, which they already do to some extent through California Department of Food and Agriculture programs.

I made the last three figures using this R code. This article is cross posted at the Energy Institute blog.

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ATTACHMENT D

Table 17. **Milk Cow Herd Size by Inventory and Sales: 2017**

[For meaning of abbreviations and symbols, see introductory text.]

Milk cow herd	Cattle and calves inventory							
	Total		Cows and heifers that calved		Milk cows		Other cattle (see text)	
	Farms	Number	Farms	Number	Farms	Number	Farms	Number
Farms with December 31, 2017 milk cow herd size of-								
1 to 9	380	20,704	380	11,584	380	767	237	9,120
10 to 19	26	1,307	26	767	26	306	17	540
20 to 49	32	2,009	32	1,467	32	919	22	542
50 to 99	20	3,102	20	1,971	20	1,467	14	1,131
100 to 199	62	23,398	62	15,780	62	9,209	55	7,618
200 to 499	249	139,592	249	83,919	249	81,452	231	55,673
500 to 999	296	368,808	296	211,922	296	209,626	278	156,886
1,000 to 2,499	390	1,117,162	390	648,456	390	638,080	369	468,706
2,500 to 4,999	163	988,072	163	550,937	163	546,617	154	437,135
5,000 or more	35	460,469	35	262,482	35	261,886	35	197,987
All farms with December 31, 2017 milk cow inventory	1,653	3,124,623	1,653	1,789,285	1,653	1,750,329	1,412	1,335,338
Farms with no milk cow inventory, on December 31, 2017	12,041	2,060,970	9,889	643,416	-	-	9,312	1,417,554
Total	13,694	5,185,593	11,542	2,432,701	1,653	1,750,329	10,724	2,752,892

Milk cow herd	Cattle and calves sales							Milk sales	
	Total			Cattle		Calves			
	Farms	Number	Value ($1,000)	Farms	Number	Farms	Number	Farms	Value ($1,000)
Farms with December 31, 2017 milk cow herd size of-									
1 to 9	203	(D)	21,310	170	(D)	94	(D)	24	176
10 to 19	19	(D)	727	17	511	10	(D)	14	693
20 to 49	31	1,456	1,406	31	1,312	11	144	31	3,384
50 to 99	20	1,190	985	20	834	14	356	17	5,040
100 to 199	62	9,566	7,206	62	(D)	45	(D)	60	30,513
200 to 499	239	50,907	36,800	237	28,036	183	22,871	249	324,622
500 to 999	293	109,999	73,414	292	(D)	230	(D)	296	829,287
1,000 to 2,499	381	383,639	245,585	371	185,095	321	198,544	390	2,385,176
2,500 to 4,999	160	350,862	250,365	158	184,466	130	166,396	163	1,967,972
5,000 or more	35	159,363	109,542	35	75,054	31	84,309	35	930,481
All farms with December 31, 2017 milk cow inventory	1,443	1,113,851	747,339	1,393	540,348	1,069	573,503	1,279	6,477,344
Farms with no milk cow inventory, on December 31, 2017	8,824	1,959,243	2,364,071	8,037	1,584,184	3,340	375,059	8	5,786
Total	10,267	3,073,094	3,111,410	9,430	2,124,532	4,409	948,562	1,287	6,483,130

Table 18. **Cattle and Calves - Number Sold Per Farm by Sales: 2017**

[For meaning of abbreviations and symbols, see introductory text.]

Number sold	Cattle and calves			Cattle weighing 500 pounds or more (see text)		Calves weighing less than 500 pounds	
	Farms	Number	Value ($1,000)	Farms	Number	Farms	Number
Total	10,267	3,073,094	3,111,410	9,430	2,124,532	4,409	948,562
Farms by number of cattle and calves sold-							
1 to 9	3,827	14,605	13,069	3,248	11,123	1,162	3,482
10 to 19	1,412	19,160	16,763	1,281	14,768	584	4,392
20 to 49	1,676	51,749	46,295	1,597	40,129	751	11,620
50 to 99	962	65,444	59,774	944	51,723	464	13,721
100 to 199	679	93,740	85,099	670	73,331	354	20,409
200 to 499	789	248,298	219,850	786	180,952	458	67,346
500 to 999	409	287,144	239,514	397	185,674	267	101,470
1,000 to 2,499	350	543,513	404,769	349	329,495	258	214,018
2,500 or more	163	1,749,441	2,026,277	158	1,237,337	111	512,104

Table 19. **Hogs and Pigs - Inventory: 2017 and 2012**

[For meaning of abbreviations and symbols, see introductory text.]

Hogs and pigs	2017		2012	
	Farms	Number	Farms	Number
Total hogs and pigs	1,389	96,456	1,437	111,893
Farms with -				
1 to 24	1,191	6,804	1,228	6,370
25 to 49	102	3,397	95	3,117
50 to 99	42	2,587	52	3,446
100 to 199	24	2,949	39	5,041
200 to 499	17	5,173	11	3,626
Total hogs and pigs - Con.				
Farms with - - Con.				
500 to 999	4	2,602	4	2,570
1,000 to 1,999	5	(D)	4	(D)
2,000 to 4,999	3	7,720	2	(D)
5,000 or more	1	(D)	2	(D)

Table 17. **Milk Cow Herd Size by Inventory and Sales: 2022**

[For meaning of abbreviations and symbols, see introductory text.]

Milk cow herd	Cattle and calves inventory							
	Total		Cows and heifers that calved		Milk cows		Other cattle	
	Farms	Number	Farms	Number	Farms	Number	Farms	Number
Farms with December 31, 2022 milk cow herd size of-								
1 to 9	256	2,675	256	1,686	256	549	142	989
10 to 19	20	634	20	474	20	221	10	160
20 to 49	9	474	9	300	9	247	6	174
50 to 99	10	1,379	10	949	10	739	6	430
100 to 199	20	6,352	20	3,907	20	2,947	18	2,445
200 to 499	79	46,997	79	28,378	79	25,889	75	18,619
500 to 999	153	207,253	153	117,051	153	113,880	149	90,202
1,000 to 2,499	315	909,087	315	525,903	315	518,014	304	383,184
2,500 or more	255	1,857,818	255	1,033,210	255	1,025,716	254	824,608
All farms with December 31, 2022 milk cow inventory	1,117	3,032,669	1,117	1,711,858	1,117	1,688,202	964	1,320,811
Farms with no milk cow inventory, on December 31, 2022	10,642	2,206,401	9,058	658,364	-	-	8,274	1,548,037
Total	11,759	5,239,070	10,175	2,370,222	1,117	1,688,202	9,238	2,868,848

Milk cow herd	Cattle and calves sales							Milk sales	
	Total			Cattle		Calves			
	Farms	Number	($1,000)	Farms	Number	Farms	Number	Farms	($1,000)
Farms with December 31, 2022 milk cow herd size of-									
1 to 9	113	947	950	91	703	44	244	7	49
10 to 19	16	2,240	(D)	14	(D)	14	(D)	4	(D)
20 to 49	8	394	(D)	7	(D)	5	(D)	7	1,303
50 to 99	10	919	918	10	633	8	286	10	4,256
100 to 199	20	2,318	2,345	19	1,568	13	750	20	16,207
200 to 499	79	18,132	16,040	79	10,253	58	7,879	79	149,465
500 to 999	153	68,727	55,500	153	34,030	129	34,697	153	677,867
1,000 to 2,499	315	362,613	285,505	315	171,601	277	191,012	315	3,083,205
2,500 or more	255	759,699	614,433	255	363,648	232	396,051	255	5,733,317
All farms with December 31, 2022 milk cow inventory	969	1,215,989	978,668	943	584,534	780	631,455	850	(D)
Farms with no milk cow inventory, on December 31, 2022	7,574	2,158,354	2,745,144	7,041	1,716,066	3,189	442,288	5	(D)
Total	8,543	3,374,343	3,723,812	7,984	2,300,600	3,969	1,073,743	855	9,675,301

Table 18. **Cattle and Calves - Number Sold per Farm by Sales: 2022**

[For meaning of abbreviations and symbols, see introductory text.]

Number sold	Cattle and calves			Cattle weighing 500 pounds or more		Calves weighing less than 500 pounds	
	Farms	Number	Value ($1,000)	Farms	Number	Farms	Number
Total	8,543	3,374,343	3,723,812	7,984	2,300,600	3,969	1,073,743
Farms by number of cattle and calves sold-							
1 to 9	3,004	11,780	11,174	2,562	8,911	938	2,869
10 to 19	1,088	14,487	13,647	1,012	11,161	469	3,326
20 to 49	1,460	44,805	42,102	1,438	33,330	733	11,475
50 to 99	767	52,773	52,539	761	40,178	409	12,595
100 to 199	614	84,987	84,399	611	67,048	316	17,939
200 to 499	666	204,620	204,669	666	154,158	390	50,462
500 to 999	351	245,642	227,405	351	171,526	237	74,116
1,000 to 2,499	344	552,451	479,768	344	311,896	291	240,555
2,500 or more	249	2,162,798	2,608,109	239	1,502,392	186	660,406

Table 19. **Hogs and Pigs - Inventory: 2022 and 2017**

[For meaning of abbreviations and symbols, see introductory text.]

Hogs and pigs	2022		2017	
	Farms	Number	Farms	Number
Total hogs and pigs	1,374	82,010	1,389	96,456
Farms with-				
1 to 24	1,157	7,121	1,191	6,804
25 to 49	110	3,745	102	3,397
50 to 99	52	3,153	42	2,587
100 to 199	24	3,339	24	2,949
200 to 499	22	5,298	17	5,173

Hogs and pigs	2022		2017	
	Farms	Number	Farms	Number
Total hogs and pigs - Con.				
Farms with- - Con.				
500 to 999	3	2,343	4	2,602
1,000 to 1,999	2	(D)	5	(D)
2,000 to 4,999	2	(D)	3	7,720
5,000 or more	2	(D)	1	(D)

ATTACHMENT E

Briefing Paper

FACTORY FARM DAIRIES, BIOGAS, AND THE DANGEROUS PATH CALIFORNIA IS ON

I. INTRODUCTION

Industrial dairies in the San Joaquin Valley, packing thousands, and sometimes tens of thousands of cows into a single facility, are a major source of local air and water pollution, nuisance odor, groundwater overdraft, and greenhouse gas emissions. Over the last decade, California has created a regulatory landscape that pays this industry to continue these polluting practices while producing factory farm gas, otherwise known as dairy biogas. These policies favor large-scale industrial dairies over smaller operations and lock in the most environmentally harmful industry practices that disproportionately harm low-income communities of color. And these policies actually *encourage dairies to create* methane and only *appear* to succeed in achieving massive greenhouse gas emissions reductions as a result of an overly narrow life cycle analysis for the fuel's "well-to-wheel" climate impacts. The good news is that California can, and must, choose another path – one that aligns with our climate and environmental health and equity objectives.

II. BACKGROUND – THE EVOLUTION OF MASSIVE DAIRIES IN THE SAN JOAQUIN VALLEY DESPITE KNOWN CLIMATE AND ENVIRONMENTAL IMPACTS WAS A POLICY CHOICE

The expansion and concentration of the California dairy industry over the last several decades has occurred with policymakers' knowledge of the industry's climate and community impacts. The California dairy sector in the 1950s milked about 800,000 cows on almost twenty thousand pasture-based farms. California land use and environmental policy allowed for the dairy industry to transition into gigantic, full confinement, industrial-style operations that liquefy and manage manure anaerobically in gigantic so-called lagoons. Now, the industry milks between 1.7 and 1.8 million cows on about 1,100 farms – the vast majority of which, and the largest of which are in the San Joaquin Valley.[1]

This shift to massive dairies concentrated in the San Joaquin Valley was a policy choice and business choice – it was neither accidental nor inevitable.

1 https://www.dairycares.com/post/keeping-cows-in-california-is-good-for-people-and-planet.

In the late 1990s, water quality regulators drove the relocation of the southern California dairy herd from the Chino Basin in San Bernardino County to the San Joaquin Valley when groundwater pollution from manure affected water quality. Rising housing costs in the Inland Empire produced a windfall for those dairies as they sold their land to developers and raced toward cheaper land – and fewer regulations – in the San Joaquin Valley. San Joaquin Valley counties welcomed those Chino-based dairy operators with open arms and authorized hundreds of new dairies and dairy expansions as the California dairy industry increased in size dramatically to over 1.8 million in 2008.[2] By 2008, there were about 1,900 dairy farms in California not only producing milk, but massive amounts of manure. For context, a 2,000 cow industrial dairy produces approximately the same amount of fecal waste as a city of one million people.[3] Many of the factory farms in the San Joaquin Valley are 3 to 5 times that size. Local county governments in the San Joaquin Valley supported this expansion as modern dairy operations overwhelmingly opted for liquefied manure management despite the known climate impacts from methane and known risks of groundwater contamination.[4] Local governments and the dairy operators themselves *knew* that the liquefied manure model of dairy production relied on an externalization of climate and adverse local pollution impacts, and adopted statements of overriding considerations to approve those projects despite "significant and unavoidable impacts" as allowed by the California Environmental Quality Act (CEQA). Several counties adopted land use policies that facilitated dairy citing and expansion while others allowed (and are continuing to allow) dairy expansions without requiring CEQA environmental review.

III. MASSIVE DAIRIES HAVE SIGNIFICANT AND HARMFUL ENVIRONMENTAL IMPACTS

A. Industrial Dairies Contribute to Dangerous Air Pollution

Dairies emit large amounts of volatile organic compounds (VOC), ammonia, nitrogen oxides (NOx), and dust which all contribute to extremely poor air quality in the San Joaquin Valley, a region out of compliance with state and federal air quality standards.

- VOCs are a precursor to ozone formation. The San Joaquin Valley has been designated as Extreme Nonattainment for EPA's 2008 8-hour ozone standard and 2012 8-hour ozone standard.[5] The San Joaquin Valley is also Severe Nonattainment for the state one hour ozone standard.[6] Dairies are the largest source of VOCs in the Valley.

2 *Id.*

3 Agricultural Waste Management Field Handbook, USDA (March 2008), Table 4-5. Available at: https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=31475.wba. See: https://www.holsteinusa.com/pdf/fact_sheet_cattle.pdf. Also see: *The Characterization of Feces and Urine* (2015), available at: https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4500995/.

4 *See, e.g.* Kings County Dairy Element Program EIR at 4.2-83 to 4.2-85, available at https://www.countyofkings.com/home/showpublisheddocument/4358/635277478494870000 (last visited October 24, 2022).

5 *Ambient Air Quality Standards and Valley Attainment Status*. Accessed January 9, 2022. Available at: https://www.valleyair.org/aqinfo/attainment.htm.

6 *Id.*

- Dairies also emit significant amounts of ammonia, a PM2.5 precursor. Recent research estimates that 1,690 people die in California annually as a result of agricultural ammonia emissions because ammonia and NOx create ammonium nitrate, the most prevalent form of PM2.5 in the San Joaquin Valley. The Valley is Serious Nonattainment for the Federal 1997 annual, the 2006 24-hour, and the 2012 annual PM2.5 standards.[7] Dairies are the largest source of ammonia in the Valley.

- Dairies also emit large amounts of NOx from manure application on crop land, which contributes to increasing the ozone concentration and PM2.5.

Both Ozone and PM2.5 result in serious and long lasting health impacts. Ozone can trigger chest pain, coughing, throat irritation, congestion, worsen bronchitis, emphysema, and asthma. Ozone also can reduce lung function and inflame the lining of the lungs. PM2.5 can cause eye, nose, throat and lung irritation, coughing, sneezing, runny nose and shortness of breath. Both ozone and PM2.5 exposures are correlated to increases in hospitalization, emergency room visits, and premature death from cardiovascular and respiratory disease.

In addition to PM2.5 and Ozone, dairies cause significant odors. Many Californians glimpse the impacts when they drive through the San Joaquin Valley, catch a whiff of manure odors, and roll up the windows. However, for residents who live near these facilities, there is no driving away from these extreme odors. Even going inside their homes does not always provide respite. Residents report odors following them indoors, permeating their clothes, and causing headaches.

B. Industrial Dairies Degrade Water Quality

With the average dairy cow producing approximately 148 pounds of manure each day,[8] California dairies contribute tens of millions of tons of manure each year. Untreated manure cannot be applied to crops for human consumption so there is limited acreage upon which manure may be applied. And there simply isn't enough. **Nitrate from manure leaches into groundwater and pollutes drinking water supplies**. Manure from lagoons, corrals, and, above all, applied to land leads to nitrate contamination.

The dairy industry's own report on nitrate pollution revealed the breadth and degree of groundwater contamination from dairies. The Central Valley Summary Representative Monitoring Report was prepared by the Central Valley Dairy Representative Monitoring Program, a nonprofit association of dairy owners and operators. It presents years of monitoring data from forty-two Central Valley dairies chosen to be representative of the industry in the region. Some findings of note:

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7 See: https://www3.epa.gov/airquality/greenbook/knca.html#PM-2.5.2012.San_Joaquin_Valley.

8 Agricultural Waste Management Field Handbook, USDA (March 2008), Table 4-5. Available at: https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=31475.wba.

- **Elevated nitrate-N (i.e., as nitrogen) concentrations were present beneath all monitored dairies.**[9]
- "…approximately 94 percent of nitrogen loading on dairies (that is, the portion of
- nitrogen that enters the soil and is not recovered by plants) occurs on cropland." [10]
- Dairies produce an "excess supply of nitrogen" in the form of manure than the amount that can be safely applied to cropland without causing or contributing to nitrate pollution.[11]

Larger, more concentrated herds mean more manure concentrated on the same or smaller land, thus exacerbating the issue of greater quantities of manure than cropland can absorb. A recent proposed dairy expansion in Merced notes that increased herd sizes (from under 3,000 to 7,300 cows) indicated in their environmental documents that manure exports would jump from about 9,000 tons to 49,000 tons annually. **No information was provided as to where that manure would be exported. Presumably, because there is nowhere for it to go.**

Nitrates in drinking water cause blue baby syndrome and have been linked to cancer. [12] The cost to treat drinking water – if treatment is even available – can make water bills unaffordable for many households and can be cost prohibitive for private well owners.

C. Industrial Dairies Are Water Hogs

The San Joaquin Valley is ground zero for critical groundwater overdraft and water scarcity.[13] Thousands of private and community water wells, upon which many Californians rely for drinking water, have already run dry.[14] Overdraft also impacts water quality. As groundwater supply decreases, concentrations of contaminants, especially arsenic, increase.[15]

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9 CENTRAL VALLEY DAIRY REPRESENTATIVE MONITORING PROGRAM, SUMMARY REPRESENTATIVE MONITORING REPORT (REVISED*) at 6 (Apr. 19, 2019), https://www.waterboards.ca.gov/centralvalley/water_issues/confined_animal_
10 facilities/groundwater_monitoring/srmr_20190419.pdf.
11 *Id.* at 10.
12 *Id.*
Ward MH, Jones RR, Brender JD, de Kok TM, Weyer PJ, Nolan BT, Villanueva CM, van Breda SG. Drinking Water Nitrate and Human Health: An Updated Review. Int J Environ Res Public Health. 2018 Jul 23;15(7):1557. doi:
13 10.3390/ijerph15071557. PMID: 30041450; PMCID: PMC6068531.
Critically Overdrafted Basins, CAL. DEP'T OF WATER RES., https://water.ca.gov/programs/groundwater management/bulletin-118/critically-overdrafted-basins (last visited Mar. 22, 2022) (showing most groundwater basins and subbasins in the San Joaquin Valley are critically overdrafted); see ELLEN HANAK ET AL., WATER AND THE FUTURE OF THE SAN JOAQUIN VALLEY (2019), PUB. POL. INST. OF CAL., https://www.researchgate.net/
14 publication/331476376_Water_and_the_Future_of_the_San_Joaquin_Valley.
Groundwater Management and Drought: An Interview with the San Joaquin Valley Partnership, CAL. DEP'T OF WATER RES., (Mar. 8, 2022), https://water.ca.gov/News/Blog/2022/March-22/Groundwater-Management-and-Drought-An-Interview-with-the-San-Joaquin-Valley-Partnership (noting that groundwater overdraft is causing domestic well owners to "lose access to their primary source of drinking water," leaving them unable to "afford or obtain services due to drilling backlogs or financial challenges" and forcing them to seek out and rely on emergency sources of drinking water); see Jelena Jezdimirovic et al., Will Groundwater Sustainability Plans End the Problem of Dry Drinking Water Wells?, PUB. POL'Y INST. OF CALIFORNIA (May 14, 2020),
15 https://www.ppic.org/blog/will-groundwater-sustainability-plans-end-the-problem-of-dry-drinking-water-wells/.
See: https://environment-review.yale.edu/overpumping-california-groundwater-could-lead-dangerous-arsenic-water-and-food.

Industrial dairies use massive amounts of water including groundwater in the extremely fragile San Joaquin Valley ecosystem. In addition to supplying large amounts of drinking water to cows, dairies need large amounts of water for liquefying and flushing manure and other pollutants for storage in lagoons, cooling animals, cleaning facilities, and irrigating crops. In addition, dairies rely upon water-intensive crops to feed dairy cows such as alfalfa. California's large dairies use an estimated 142 million gallons per day,[16] or almost 52 billion gallons per year.

D. Industrial Dairies Cause Dispoportionate Environmental Impacts

San Joaquin Valley residents are disproportionately Latino/a/e as compared to California as a whole. Seven central and southern San Joaquin Valley Counties (Kern to Stanislaus) have higher Latino/a/e populations than the state, with populations ranging from almost 50 percent to over 66 percent, as compared to the state population with 40 percent of residents classified as Latino/a/e. At least seven of eight San Joaquin Valley counties have a lower proportion of white residents as compared to the state as a whole.[17] **Therefore, policies that entrench and exacerbate air and water pollution in these regions have a racially disparate impact on Latino/a/e communities.**

Similarly, San Joaquin Valley counties are lower income and have more residents facing economic insecurity than the state as a whole. While median household income in California is approximately $84,000 countywide household median incomes in the central and southern San Joaquin Valley Counties range from approximately $57,000 to $68,000 The highest producing dairy counties in the state and in the San Joaquin Valley, Merced and Tulare, show median household incomes at $59,000 and $57,000 , 70% or less of statewide median income. Poverty rates hover around 22% and 19% in Merced and Tulare, respectively.

IV. FACTORY FARM GAS – AN INADEQUATE CLIMATE SOLUTION AND A HARM-INDUCING STRATEGY

A. Industrial Livestock Operations Contribute Significant Greenhouse Gas Emissions to the Atmosphere

In addition to local and regional air and water pollution, dairies are a substantial source of California's greenhouse gas emissions. **Livestock methane emissions account for 6.1 percent of statewide GHG emissions.**[18]

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16 Big Ag, Big Oil and California's Big Water Problem, Food and Water Watch. Available at: https://www.foodandwaterwatch.org/wp-content/uploads/2021/10/CA-Water-White-Paper.pdf.

17 According to recent census data, 36.5 percent of the state population is classified as white, non-Latino, while 7 of the 8 counties in the San Joaquin Valley have white, non-Latino populations that range from only 26.5 to 33.2 percent. *Id.*

18 California Greenhouse Gas Emissions for 2000-2020, October 26. 2022, Page 9. Available at: https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

Liquid manure-filled lagoons produce a significant amount, although not all, of livestock methane emissions. About half of a typical large dairy's methane emissions come from the cow's digestion processes (called enteric emissions). The industry's intentional decision to store manure in lagoons and subsequently apply wet manure to land is the direct cause of methane and nitrous oxide emissions from manure. Livestock operations remain free from regulation for greenhouse gas emissions despite their significant impact.

B. Dairy Digesters Do Not Adequately Address Climate and Other Pollutants from Livestock Operations and Perpetuate Dependence on Polluting Fuels

Dairy digesters purport to address methane emissions from massive amounts of liquefied manure stored anaerobically in lagoons. Digesters basically cover the intentionally-created manure pits, capture the various gasses, and deliver the gas to facilities that combust the fuel onsite or scrub out impurities leaving methane gas for off site combustion. Digesters do not do anything to address the roughly equal amount of GHG emissions from enteric fermentation (intestinal gasses) or from the composting and application of digested manure to land. The captured methane gas can be combusted onsite, used as a transportation fuel, combusted as a fuel, converted through steam reformation to produce hydrogen, or upgraded and injected into gas pipelines for transportation fuel, gas in buildings, generating electricity, and other uses. Some dairies have stand-alone digesters and some dairies participate in a factory farm gas cluster. A factory farm gas cluster connects several dairies and dairy digesters with an upgrading facility so that the gas from many dairies can be processed at one site and then injected into the gas pipeline. This "pipeline quality" gas, marketed as clean yet molecularly almost identical to conventional fossil gas, is subsidized by ratepayers and used to justify the continued operation of gas pipelines that otherwise should be phased out.

Digesters do not do anything to decrease overall air pollution or groundwater pollution from dairies.

C. The Relevant Regulatory History Has Exacerbated the Impacts from Industrial Livestock Operations

The Global Warming Solutions Act of 2006 (AB 32 [Nunez]) tasked CARB with developing a plan to reduce GHG emissions generally and in 2013, Senate Bill 605 (Lara) required CARB to develop a plan to reduce emissions of Short-Lived Climate Pollutants, including methane. In 2016, the legislature passed both SB 32 (Pavley) which built upon AB 32's GHG reduction mandates, and SB 1383 (Lara), which focused on methane and other short-lived climate pollutants. SB 1383 set methane emission targets and required CARB to develop and begin implementing a strategy to meet those targets. The bill specifically included a target for methane emission reductions from livestock manure and created both insulation from direct regulation of livestock methane and policies and incentives designed to increase production of factory farm gas. Notably, SB 1383 prohibited direct regulation of methane emissions from livestock manure until 2024 and required CARB to make significant findings of economic feasibility prior to instituting regulations and even further limited the state's authority to regulate enteric emissions.

Furthermore, it required CARB and the CPUC to develop financial mechanisms and incentives to support the production of dairy-produced energy.[19] In so doing, California transitioned from allowing the dairy industry to expand and emit more unabated methane regardless of its impact to rewarding the industry for its polluting practices and incentivizing the creation of even more liquefied manure at ever larger dairies. Protection from regulation coupled with increased subsidies and incentives illustrate the preferential treatment the dairy industry has been granted compared to other polluting sectors.[20]

In 2018, CARB updated the Low Carbon Fuel Standard (LCFS) program to incorporate "avoided methane" into the calculation of carbon intensity scores. The result: factory farm gas became the most carbon negative fuel in the LCFS market, and thus, the most valuable. The LCFS also allows dairies that are already being paid with public funds to reduce methane with dairy digesters to double-dip by claiming the LCFS incentive was the reason for the reductions, blatantly evading the AB 32 prohibition on "non-additional" reductions from being sold into market-based mechanisms.

D. Factory Farm Gas Production and Deployment is Significantly Subsidized and Therefore Highly Profitable for Large Dairies

The current regulatory landscape provides significant subsidies to dairies to install digesters and produce factory farm gas. This funding includes CDFA's DDRDP, CPUC ratepayer funding, CEC's PIER, EPIC, and Clean Transportation funding, and CARB's Aliso Canyon Mitigation Funding. To date just these direct cash subsidies total close to $700 million with the majority of this funding coming from legislative appropriations to the Dairy Digester and Research Development Program (DDRDP) and utility rate-payers. The Legislature, through annual appropriations from the Greenhouse Gas Reduction Fund and General Fund, has allocated over $200 million to the DDRDP and the CPUC has directed almost $400 million of rate–payer funds to support development and operations of dairy digesters and related infrastructure.

In addition to these direct subsidies along with credit sales available through California's Cap-and-Trade offset program, the Low Carbon Fuel Standard (LCFS) creates a lucrative credit market for industrial dairies that install digesters. CARB designed a life cycle analysis that excludes upstream and downstream greenhouse gas emissions and **treats liquified manure lagoons (and the methane they create) not as an intentionally chosen cost-cutting measure but as a necessary, inevitable part of operating a dairy, which it plainly is not.**

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19 See "Veto Request – Senate Bill 1383 (Lara) – Dairy Industry Exemptions from short-lived climate pollutants: methane emissions" (September 13, 2016) https://drive.google.com/file/d/1OhQ4bpGX6eNEhgC64Mneel2jpH6Ja5xl/view?usp=sharing

20 The legislative hearing for Senate Bill 1383 sheds light on the unprecedented benefits the Legislature provided the dairy industry, provoking a lobbyist for the oil industry to warn that it would return to the Legislature for its version of special treatment. See Assembly Natural Resources Committee, Hearing on Senate Bill 1383, available at http://calchannel.granicus.com/MediaPlayer.php?view_id=23&clip_id=4009 (beginning at hour 1:12) (last visited October 24, 2022).

As noted earlier, CARB has determined that methane captured through the production of gas magically makes biomethane carbon negative, and thus generates far more credits for sale in the LCFS credit market than if CARB had treated it like every other fuel. The result has been a deluge of credits which creates a massive windfall for industrial dairies and factory farm gas producers.

The dairy industry is very aware of the monumental investment California made to support the production of factory farm gas and the lucrative LCFS credit market for gas. In fact, the dairy industry itself anticipates a future where "milk has become the by-product of manure production." [21]

Studies project that larger dairies can enjoy a third to a half of their revenue from LCFS credit revenues,[22] begging the question - what's worth more, a cow's milk or its poop?[23] And the necessary follow-up: if we're even asking these questions, what perverse incentives have we created and to what consequences will they lead?

E. The Resulting Profit Incentive Favors and Entrenches Harmful Practices and Drives Industrial Dairy Expansions

The narrative echoed by the dairy industry and those that profit from buying and selling LCFS credits treats the methane pollution as some kind of inevitable consequence, a natural by-product of dairy production that demands a solution. This narrative entirely ignores the fact that the liquefied manure and the associated massive methane problem was the path that state and local governments and dairy operators themselves chose to follow despite knowing the environmental degradation those decisions would create. And now the state's solution to our methane disaster has itself reinforced harmful manure management and industrial-scale dairy practices that entrench and intensify air and water pollution. Data show that all of these incentives have contributed to an intensification of dairy expansions as dairy operators and those profiting from the LCFS respond to the market demand for manure-based fuels and the lucrative credit markets by expanding dairy operations to produce more manure.

Merced County provides an apt example of the effect this regulatory landscape has on expanding industrial dairy operations. For instance, the Merced Planning Department posts recently prepared environmental documents on the Merced County website.Based solely on the information on this website, Merced County has permitted, or is in the process of permitting, two biogas pipeline and infrastructure projects, ten dairy expansions, and one new 28,000 cow dairy.[24]

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21 See: https://hoards.com/article-30925-energy-revenue-could-be-a-game-changer-for-dairy-farms.html. Also see: https://twitter.com/drcrystalheath/status/1587320922578378752?s=20&t=sm90vQRFTh91HZ9zY4Yzgg.

22 Younes, A. and Fingerman, K. (2021). Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard. Arcata, CA. Available at: https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf.

23 Smith, Aaron (2021) "What's Worth More: A Cow's Milk or its Poop?" Ag Data News Blog. (February 2021) Available at https://asmith.ucdavis.edu/news/cow-power-rising.

24 See Environmental Documents, available at https://www.countyofmerced.com/414/Environmental-Documents (last visited December 19, 2022).

The biogas cluster and pipeline projects facilitate dairy expansions to monetize and incentivize increased dairy herds and manure generation. The total additional number of dairy cows (milk cows and support stock) from the above-listed projects is 46,148 cows. It's important to note that several counties do not require environmental review for dairy expansions. In those counties, it is much harder – if not impossible – to assess the extent to which dairies have grown and/or consolidated.

Both the historical expansion of the California Dairy industry and the more recent perverse effects of the LCFS that drive herd expansions show how local land use and Senate Bill 1383 have encouraged both dairy industry expansion and dramatic increases in methane pollution. And instead of requiring the industry to limit its pollution, the Legislature rewarded the reckless expansion by paying operators to profit from the methane emissions they chose to create in the first place. As one study on the impacts of the LCFS notes, "in this instance the largest polluter is the one receiving a large subsidy." [25]

F. Factory Farm Gas Production Itself Exacerbates Existing Environmental Impacts from Industrial Dairies

Factory farm gas production requires liquified manure lagoons, a profit-maximizing practice that exacerbates water pollution and as discussed throughout this briefing paper, subsidies for factory farm gas incentivize the growth of herds and concentration of animals, which results in increased air and water pollution. Additionally, the very production and use of factory farm gas creates pollution of its own.

Anaerobic digesters increase ammonia emissions, which in turn react with oxides of nitrogen (NOx) to form ammonium nitrate, which significantly contributes to fine particulate matter (PM2.5) pollution.[26] One study found that use of an anaerobic digester increased ammonia emissions from manure as a result of changes in the composition of digested, as compared to undigested, manure. [27]

Combusting factory farm gas on-site, including digester engines powering turbines to generate LCFS credits for electric vehicle fuel, emit significant and unabated additional NOx, PM2.5, and volatile organic compound (VOC) emissions in the air basin. Combined, both effects exacerbate the PM2.5 pollution crisis in the San Joaquin Valley. When upgraded to be used in place of fossil natural gas, it produces all the same emissions when combusted, whether as transportation fuel or used in buildings.

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25 Younes, A. and Fingerman, K. (2021). Quantification of Dairy Farm Subsidies Under California's Low Carbon Fuel Standard. Arcata, CA. Available at: https://www.arb.ca.gov/lists/com-attach/24-lcfs-wkshp-dec21-ws-AHVSN1MhVlpXNQRl.pdf.

26 Michael A. Holly et al., Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application Agriculture, 239 ECOSYSTEMS AND ENV'T 410, 418 (Feb. 15, 2017), https://doi.org/10.1016/j.agee.2017.02.007.

27 See Michael A. Holly et al., Greenhouse gas and ammonia emissions from digested and separated dairy manure during storage and after land application Agriculture, Ecosystems & Environment (2017).

Moreover, factory farm gas production relies upon methane digesters, which require "abundant water resources, with a ratio equal to 1:1 of the amount of water and manure to be loaded into the digester,"[28] to pump and dilute manure. In arid climates it may be necessary to pump groundwater for this purpose.[29]

G. Factory Farm Gas Credits Facilitate Ongoing Pollution from Fossil Fuel Production and Combustion

As described above, transportation fuels derived from dairy and swine manure receive LCFS credits and the amount of those credits entering the market has been drastically inflated as a result of improper negative carbon intensity values and non-additional credits. In 2021, these fuels represented approximately 10 percent of all credits sold.[30] Because the LCFS authorizes fuel producers to purchase credits to meet the LCFS market-based compliance mechanism's emission limits, the excessive and illegitimate credits generated by factory farm gas producers allow fossil fuel producers – oil companies – to refine and sell more of their fossil fuels. While communities in the San Joaquin Valley suffer the air, water, and nuisance pollution from factory farm gas fuel production, communities near refineries and near major transportation corridors endure racially disparate impacts from the production and combustion of fossil fuels benefitting from those credits. For example, Black Californians experience twice the PM2.5 burden of white Californians from Cap and Trade facilities, while "Black Californians experience PM2.5 concentrations from refineries that are three times greater than all other stationary source sectors combined that are covered by the Cap-and-Trade Program."[31] Further, "African American, Latino, and Asian Californians are exposed to more PM2.5 pollution from cars, trucks, and buses than white Californians. These groups are exposed to PM2.5 pollution 43, 39, and 21 percent higher, respectively, than white Californians." Additionally, "[T]he lowest-income households in the state live where PM2.5 pollution is 10 percent higher than the state average, while those with the highest incomes live where PM2.5 pollution is 13 percent below the state average."[32]

In other words, as a result of CARB's factory farm gas policies, communities on both sides of the LCFS credit transaction subsidize polluters with compromised health and well-being.

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28 Tatiana Nevzorova & Vladimir Kutcherov, Barriers to the wider implementation of biogas as a source of energy: A state-of-the-art review, 26 ENERGY STRATEGY REVIEWS 7 (Oct. 14, 2019), https://www.sciencedirect.com/science/article/pii/S2211467X19301075#bib113.

29 ENVTL. PROTECTION AGENCY, AGSTAR, PROJECT DEVELOPMENT HANDBOOK: A HANDBOOK FOR DEVELOPING ANAEROBIC DIGESTION/BIOGAS SYSTEMS ON FARMS IN THE UNITED STATES 9-5, https://www.epa.gov/sites/default/files/2014-12/documents/agstar-handbook.pdf (3rd Ed.).

30 See CARB, LCFS Quarterly Data Spreadsheet, available at https://ww2.arb.ca.gov/sites/default/files/2022-10/quarterlysummary_103122_1.xlsx (data available under "Feedstock" tab).

31 *Id.*

32 *Union of Concerned Sci., Inequitable Exposure to Air Pollution from Vehicles in California* (Feb. 2019), https://www.ucsusa.org/sites/default/files/attach/2019/02/cv-air-pollution-CA-web.pdf.

V. CHANGING COURSE: CREATING A NEW PATH FORWARD

We have the opportunity and need to reshape the regulatory framework for livestock methane and factory farm gas to effectively reduce greenhouse gas emissions from industrial livestock operations while cutting off profit motives for concentrating livestock and manure which intensify climate impacts, exacerbate environmental degradation, and perpetuate dumping on San Joaquin Valley communities. We lay out three approaches below for rectifying existing deficiencies: correcting inadequacies in the Low Carbon Fuel Standard program, regulating livestock methane emissions, and excluding factory farm gas from inclusion in our clean energy portfolio.

A. Fix the Low Carbon Fuel Standard Program

The legislature should step in to ensure an updating to the LCFS and other programs to account for full lifecycle emissions, prohibit claiming of non-additional reductions, prevent harm to lower income communities and communities of color, and eliminate windfall profits due to lack of regulation.

Although a number of regulatory actions are responsible for driving these troubling trends in California's dairy industry, the LCFS is currently the most directly responsible for incentivizing herd concentration and polluting manure management practices. CARB is preparing to open a rulemaking to update the LCFS yet,to date there has been no commitment to address the issues raised above. Although CARB staff have not released an official scope for the rulemaking, in a recent workshop CARB proposed continuing to issue the massively inflated credits until at least 2040.[33] Additionally, CARB has indicated that they will rely on the LCFS to ensure the ongoing profitability and viability of biomethane to facilitate its transition into industrial energy markets when its purported use as transportation fuels gives way to our electric vehicle future.

Given the urgency of the issue and CARB's demonstrated unwillingness to address the consequences of its failing regulatory approach, the Legislature is well-positioned to provide much-needed direction to CARB to ensure the program is in line with California's commitments to addressing GHG emissions and environmental injustice.

B. Eliminate Factory Farm Gas from Definitions of Renewable Energy

As brought to the forefront during hearings on SB 1020 last year, resources eligible to meet the requirements of the Renewable Portfolio Standard (RPS) and SB 100 (RPS plus zero carbon resources) include "digester gas" which includes factory farm gas.

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33 See presentation for CARB Low Carbon Fuel Standard Workshop November 9, 2022. Available at https://ww2.arb.ca.gov/sites/default/files/2022-11/LCFSPresentation.pdf.

The definition of factory farm gas as “renewable” supports its inclusion in existing climate programs, such as the LCFS[34] and emerging energy technologies, such as hydrogen[35] and opens up or expands markets and subsidies for the dirty fuel. By eliminating factory farm gas from the definition of renewable energy, California can ensure current and future efforts to transition California’s energy and transportation systems are real environmental justice solutions and not a polluting cash cow. Cleaning up our energy sector is challenging enough already without false solutions muddying the water.

C. Regulate Livestock Greenhouse Gas Emissions

As stated above, SB 1383 permits CARB to directly regulate livestock methane emissions starting in 2024 but provides CARB discretion and several off-ramps that provide ready justifications for CARB to continue the failing LCFS-centered strategy, including using the LCFS to subsidize factory farm gas for to support its growth in industrial sectors. The Legislature must direct CARB to adopt mandatory regulations and acknowledge the last-minute dairy methane provisions in Senate Bill 1383 were an unprecedented and ill-advised industry giveaway. California must treat the dairy industry like every other major source of greenhouse gas emissions. We cannot continue to treat the most climate-impacting practices as inevitable and force the public to pay polluters to stop polluting thereby rewarding the biggest and worst polluters.

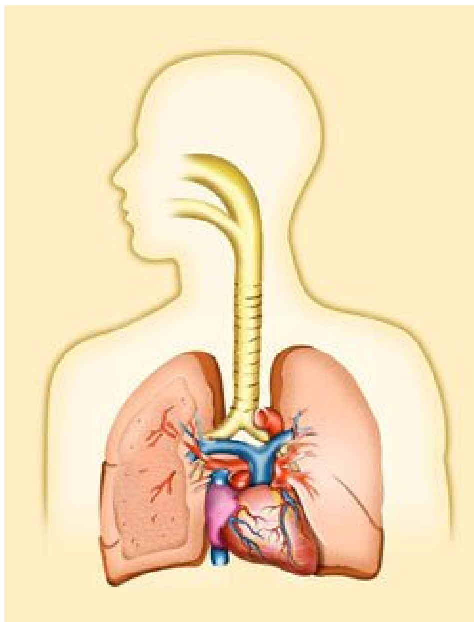
For more information contact: Jamie Katz, Staff Attorney, jbkatz@leadershipcounsel.org

34 Cal. Code Regs. Tit 17 § 95481-95482.
35 Pub. Res. Code § 25664

ATTACHMENT F

Health Effects of Ozone Pollution

Ozone in the air we breathe can harm our health, especially on hot sunny days when ozone can reach unhealthy levels. Even relatively low levels of ozone can cause health effects.



Ozone is a powerful oxidant that can irritate the airways.

For Healthcare Providers

Ozone and Your Patients' Health: Training for Healthcare Providers <https://epa.gov/ozone-pollution-and-your-patients-health>

Who is at risk?

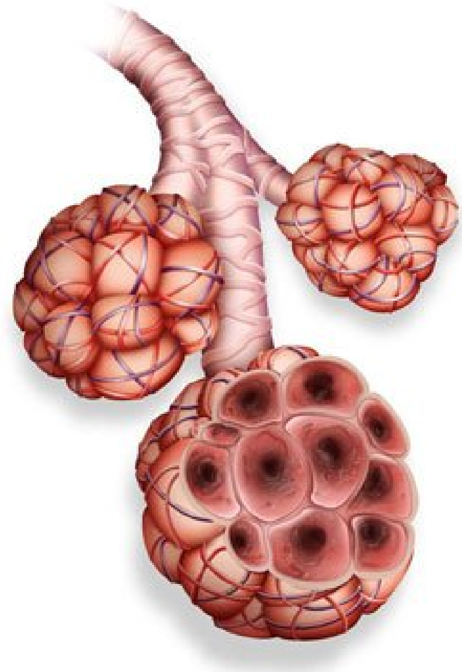
People most at risk from breathing air containing ozone include people with asthma, children, older adults, and people who are active outdoors, especially outdoor workers. In addition, people with certain genetic characteristics, and people with reduced intake of certain nutrients, such as vitamins C and E, are at greater risk from ozone exposure.

Children are at greatest risk from exposure to ozone because their lungs are still developing and they are more likely to be active outdoors when ozone levels are high, which increases their exposure. Children are also more likely than adults to have asthma.

What health problems can ozone cause?

Depending on the level of exposure, ozone can:

- Cause coughing and sore or scratchy throat.
- Make it more difficult to breathe deeply and vigorously and cause pain when taking a deep breath.
- Inflame and damage the airways.
- Make the lungs more susceptible to infection.
- Aggravate lung diseases such as asthma, emphysema, and chronic bronchitis.
- Increase the frequency of asthma attacks.



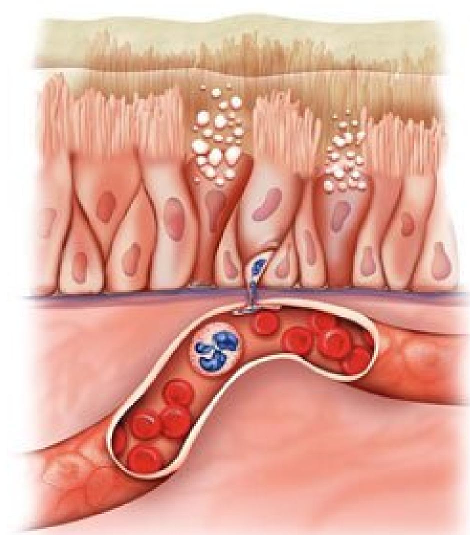
Ozone can cause the muscles in the airways to constrict, trapping air in the alveoli. This leads to wheezing and shortness of breath.

Some of these effects have been found even in healthy people, but effects can be more serious in people with lung diseases such as asthma. They may lead to increased school absences, medication use, visits to doctors and emergency rooms, and hospital admissions.

Long-term exposure to ozone is linked to aggravation of asthma, and is likely to be one of many causes of asthma development. Studies in locations with elevated concentrations also report associations of ozone with deaths from respiratory causes.

How can I reduce these health risks?

The AirNow Web site <http://www.airnow.gov/> provides daily air quality reports for many areas. These reports use the Air Quality Index (or AQI) to tell you how clean or polluted the air is.



With inflammation, the airway lining is damaged. It has been compared to the skin inflammation caused by sunburn.

EnviroFlash, a free service, can alert you via email when your local air quality is a concern. Sign up at www.enviroflash.info <http://www.enviroflash.info/>.

Pamphlets and other resources:

- Printable pamphlets and booklets about ozone effects on air quality and health. <https://epa.gov/ground-level-ozone-pollution/pamphlets-about-ozone-effects-air-quality-and-health>

- EPA's Air Quality Guide for Ozone <https://epa.gov/sites/production/files/2017-12/documents/air-quality-guide_ozone_2015.pdf> provides detailed information about what the Air Quality Index means. Helps determine ways to protect your family's health when ozone levels reach the unhealthy range, and ways you can help reduce ozone air pollution.
- Ozone and Your Patients' Health: Training for Health Care Providers <https://epa.gov/ozone-pollution-and-your-patients-health> is designed for family practice doctors, pediatricians, nurse practitioners, asthma educators, and other medical professionals who counsel patients about asthma and respiratory symptoms.
- AirNow Health Providers Information <https://www.airnow.gov/air-quality-and-health/your-health/> provides information on how to help patients protect their health by reducing their exposure to air pollution.
- EPA's Asthma Web Site <https://epa.gov/asthma> provides information for EPA's Communities in Action Asthma Initiative that includes programs to address indoor and outdoor environments that cause, trigger or exacerbate asthma symptoms.

Ozone Pollution Home <https://epa.gov/ground-level-ozone-pollution>

Ozone Basics <https://epa.gov/ground-level-ozone-pollution/ground-level-ozone-basics>

Health Effects

Ecosystem Effects <https://epa.gov/ground-level-ozone-pollution/ecosystem-effects-ozone-pollution>

Setting and Reviewing Ozone Standards <https://epa.gov/ground-level-ozone-pollution/setting-and-reviewing-standards-control-ozone-pollution>

Ozone Standards Regulatory Actions <https://epa.gov/ground-level-ozone-pollution/ozone-national-ambient-air-quality-standards-naaqs>

Implementing Ozone Standards <https://epa.gov/ground-level-ozone-pollution/applying-or-implementing-ozone-standards>

Ozone Implementation Regulatory Actions <https://epa.gov/ground-level-ozone-pollution/ozone-implementation-regulatory-actions>

SIP Checklist Guide <https://epa.gov/ground-level-ozone-pollution/state-implementation-plan-sip-checklist-guide>

SIP Training Presentations and Assistance <https://epa.gov/ground-level-ozone-pollution/implementation-training-and-assistance-state-and-local-air-agencies>

Implementation Data and Reports <https://epa.gov/ground-level-ozone-pollution/technical-data-and-reports-ozone-measurements-and-sip-status>

Contact Us <https://epa.gov/ground-level-ozone-pollution/forms/contact-us-about-ozone-pollution> to ask a question, provide feedback, or report a problem.

LAST UPDATED ON MAY 24, 2023

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ATTACHMENT G

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R09–OAR–2021–0884; FRL–9292–03–R9]

Clean Air Plans; 2012 Fine Particulate Matter Serious Nonattainment Area Requirements; San Joaquin Valley, California

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: On December 29, 2021, the Environmental Protection Agency (EPA or ''Agency'') published a proposed rule to approve the State of California's Serious area plan for the San Joaquin Valley (SJV) for the 2012 annual fine particulate matter ($PM_{2.5}$) national ambient air quality standards (NAAQS) for all Serious $PM_{2.5}$ area planning requirements, except for contingency measures, which the EPA proposed to disapprove. Based on adverse comments submitted on that proposed rule and as a result of a Ninth Circuit Court of Appeals decision on a related SJV $PM_{2.5}$ rulemaking for the 2006 24-hour $PM_{2.5}$ NAAQS, the EPA has reconsidered its prior proposal and now proposes to disapprove the State's plan for certain Serious area planning requirements for the 2012 annual $PM_{2.5}$ NAAQS. The nonattainment plan elements that the EPA proposes to disapprove include the plan's best available control measures (BACM) demonstration for ammonia and building heating, demonstrations of attainment and reasonable further progress, quantitative milestones, and motor vehicle emission budgets. The EPA is also proposing to disapprove the State's optional precursor demonstration for ammonia. We are not re-proposing any action on the Serious area requirements for emissions inventories nor contingency measures; our prior proposal to approve the emissions inventory element and to disapprove the contingency measure element of the nonattainment plan requirements for the 2012 annual $PM_{2.5}$ NAAQS remains unchanged. The EPA will accept comments on this new proposed rule during a 45-day public comment period and public hearing, as described in this notice.

DATES: Any comments must arrive by November 21, 2022.

Public hearings: The EPA will host two public hearings on this proposed rule. The first will take place November 2, 2022, 7:30 p.m. to 8:30 p.m. The second will take place November 3, 2022, 7:00 p.m. to 8:00 p.m. The hearings will be held to accept oral comments on this proposed rule. Immediately prior to each public hearing, and on October 28, 2022, the EPA will host public meetings on this proposed rule. For further information on the public hearings and public meetings, please see the **ADDRESSES** and **SUPPLEMENTAL INFORMATION** sections.

ADDRESSES: The November 2, 2022 public hearing will take place at Fresno City College, Old Administration Building, Room 251, 1101 E University Ave., Fresno, CA 93741. The November 3, 2022 public hearing will take place at Bakersfield College, Norman Levan Center, 1801 Panorama Drive, Bakersfield, CA 93305.

Submit your comments, identified by Docket ID No. EPA–R09–OAR–2021–0884, at *https://www.regulations.gov.* For comments submitted at *Regulations.gov*, follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from *Regulations.gov*. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud, or other file sharing system). For additional submission methods, please contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section. For the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *https://www.epa.gov/dockets/commenting-epa-dockets.*

FOR FURTHER INFORMATION CONTACT: For questions regarding this proposed rule, please contact Rory Mays, Air Planning Office (AIR–2), EPA Region IX, (415) 972–3227. For questions regarding the public hearings and related public meetings, please contact Kelley Xuereb, Immediate Office (AIR–1), EPA Region IX, (415) 947–4171. Both can be reached by emailing *SJVPublicMeetings@epa.gov.*

SUPPLEMENTARY INFORMATION: In addition to the two in-person public hearings, the EPA will host three public meetings. The public meetings are an informal opportunity to speak with EPA staff about the action. We will not accept public comments during the public meetings. The first meeting will be held virtually on October 28, 2022, 12:00 p.m. to 2:00 p.m. Participants can register to attend the meeting at: *https://usepa.zoomgov.com/meeting/register/vJItc-qppzooGCZI10LqoTXf6OpNZIVbWco.*

The second will take place on November 2, 2022, 5:30 p.m. to 7:00 p.m. prior to the public hearing at Fresno City College, Old Administration Building, Room 251, 1101 E University Ave., Fresno, CA 93741. The third will take place on November 3, 2022, 5:00 p.m. to 6:30 p.m. prior to the public hearing at Bakersfield College, Norman Levan Center, 1801 Panorama Drive, Bakersfield, CA 93305. Spanish translation will be available during all three events. If you would like to submit a request for reasonable accommodation, please email *SJVPublicMeetings@epa.gov.* For additional information and updates, please visit: *https://www.epa.gov/sanjoaquinvalley.*

Throughout this document, ''we,'' ''us,'' and ''our'' refer to the EPA.

Table of Contents

I. Background for Proposed Action

The EPA discussed background, applicable State implementation plan (SIP) submissions, completeness review, and Clean Air Act (CAA or ''Act'') requirements for the SJV Serious $PM_{2.5}$

nonattainment area[1] in sections I, II, and III of our December 29, 2021 proposed rule on California's Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS.[2] We refer to that proposed rule herein as the ''2021 Proposed Rule,'' briefly summarize the relevant CAA requirements and our previous proposed action with respect to those requirements here, and rely on the more detailed expositions in that proposed rule.

The EPA promulgated the primary annual $PM_{2.5}$ NAAQS of 12.0 micrograms per cubic meter (μg/m³) in 2012 (''2012 annual $PM_{2.5}$ NAAQS''),[3] designated and classified the SJV as Moderate nonattainment for this NAAQS in 2015,[4] and reclassified the SJV from Moderate to Serious nonattainment for this NAAQS in our final rule published November 26, 2021.[5] That reclassification action required California to submit a ''Serious area'' attainment plan. Such an attainment plan must include, among other things, provisions to assure that, under CAA section 189(b)(1)(B), the BACM for the control of direct $PM_{2.5}$ and $PM_{2.5}$ precursors are implemented no later than four years after reclassification of the area and a demonstration (including air quality modeling) that the plan provides for attainment of this NAAQS as expeditiously as practicable but no later than December 31, 2025. That reclassification action also triggered statutory deadlines for California to submit SIP submissions addressing the Serious area attainment plan requirements for the 2012 annual $PM_{2.5}$ NAAQS: June 27, 2023, for emissions inventories, BACM, and nonattainment new source review (NSR), and December 31, 2023, for the attainment demonstration and related planning requirements.

A. Applicable SIP Submissions, Completeness Review, and Clean Air Act Requirements

In this proposed rule, the EPA is proposing action on portions of two SIP submissions submitted by the California Air Resources Board (CARB) to address combined nonattainment plan requirements for the 1997, 2006, and 2012 $PM_{2.5}$ NAAQS in the SJV.[6] Specifically, the EPA is proposing to act only on those portions of the following two plan submissions that pertain to the Serious area requirements for the 2012 annual $PM_{2.5}$ NAAQS: (1) the ''2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards,'' adopted by the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD or District) on November 15, 2018, and by CARB on January 24, 2019 (''2018 $PM_{2.5}$ Plan''); [7] and (2) the ''San Joaquin Valley Supplement to the 2016 State Strategy for the State Implementation Plan,'' adopted by CARB on October 25, 2018 (''Valley State SIP Strategy'').

We refer to the relevant portions of these SIP submissions collectively in this proposal as the ''SJV $PM_{2.5}$ Plan'' or ''Plan.'' The SJV $PM_{2.5}$ Plan addresses attainment plan requirements for multiple $PM_{2.5}$ NAAQS in the SJV. CARB submitted the SJV $PM_{2.5}$ Plan to the EPA as a revision to the California SIP on May 10, 2019.[8] These SIP submissions became complete by operation of law on November 10, 2019.[9] In the 2021 Proposed Rule, we proposed to find that the 2018 $PM_{2.5}$ Plan and Valley State SIP Strategy each met the procedural requirements for public notice and hearing in CAA sections 110(a)(1) and (2) and 110(l) and 40 CFR 51.102.

In our 2021 Proposed Rule, we also summarized the CAA requirements applicable to Serious $PM_{2.5}$ nonattainment areas.[10] In the current proposed rule, we are proposing action with respect to the following requirements:

(1) Provisions to assure that BACM, including best available control technology (BACT), for the control of direct $PM_{2.5}$ and all $PM_{2.5}$ precursors shall be implemented no later than four years after the area is reclassified (CAA section 189(b)(1)(B)), unless the State elects to make an optional precursor demonstration that the EPA approves authorizing the State not to regulate one or more of these pollutants;

(2) A demonstration (including air quality modeling) that the plan provides for attainment as expeditiously as practicable but no later than the end of the tenth calendar year after designation as a nonattainment area (*i.e.,* December 31, 2025, for the SJV for the 2012 annual $PM_{2.5}$ NAAQS) (CAA sections 188(c)(2) and 189(b)(1)(A)(i));

(3) Plan provisions that require reasonable further progress (RFP) (CAA section 172(c)(2));

(4) Quantitative milestones that the State must meet every three years until the EPA redesignates the area to attainment and which demonstrate RFP toward attainment by the applicable date (CAA section 189(c)); and

(5) Motor vehicle emissions budgets (budgets) for 2025 (CAA section 176(c)).

We are also proposing to disapprove the State's optional precursor demonstration for ammonia.[11]

In addition, the State's Serious area plan must meet the general requirements applicable to all SIP submissions under section 110 of the CAA, including the requirement to provide necessary assurances that the implementing agencies have adequate personnel, funding, and authority under section 110(a)(2)(E); and the requirements concerning enforcement provisions in section 110(a)(2)(C).

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[1] For a precise description of the geographic boundaries of the SJV $PM_{2.5}$ nonattainment area, see 40 CFR 81.305.

[2] 86 FR 74310 (December 29, 2021).

[3] 78 FR 3086 (January 15, 2013) and 40 CFR 50.18. Unless otherwise noted, all references to the $PM_{2.5}$ standards in this notice, including all instances of ''2012 annual $PM_{2.5}$ NAAQS,'' are to the 2012 primary annual NAAQS of 12.0 μg/m³ codified at 40 CFR 50.18.

[4] 80 FR 2206 (January 15, 2015) (codified at 40 CFR 81.305).

[5] 86 FR 67343 (November 26, 2021).

[6] In our 2021 Proposed Rule, we also proposed action on a third SIP submission dated July 19, 2019. 86 FR 74310, 74311. However, the relevant component of that submission pertained only to contingency measures, and we are not modifying our proposed action on contingency measures in this proposed rule.

[7] The 2018 $PM_{2.5}$ Plan was developed jointly by CARB and the District.

[8] Letter dated May 9, 2019, from Richard W. Corey, Executive Officer, CARB, to Mike Stoker, Regional Administrator, EPA Region IX. Previously, in separate rulemakings, the EPA has finalized action on the portions of the SJV $PM_{2.5}$ Plan that pertain to the 1997 annual $PM_{2.5}$ NAAQS, the 1997 24-hour $PM_{2.5}$ NAAQS, the 2006 24-hour $PM_{2.5}$ NAAQS, and the Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS. See 86 FR 67329 (November 26, 2021) (final rule regarding the 1997 annual $PM_{2.5}$ NAAQS); 87 FR 4503 (January 28, 2022) (final rule regarding the 1997 24-hour $PM_{2.5}$ NAAQS); 85 FR 44192 (July 22, 2020) (final rule regarding the 2006 24-hour $PM_{2.5}$ NAAQS, except contingency measures); and 86 FR 67343 (November 26, 2021) (final rule regarding the Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS and contingency measures for the 2006 24-hour $PM_{2.5}$ NAAQS).

[9] 87 FR 74310, 74311–74312. We note that, with respect to plans previously required for the 1997, 2006, and 2012 $PM_{2.5}$ NAAQS, including the Moderate area plan only for the 2012 annual $PM_{2.5}$ NAAQS, the EPA had made findings of failure to submit effective January 7, 2019, that triggered sanctions clocks. 83 FR 62720 (December 6, 2018). Following the May 10, 2019 submission of the 2018 $PM_{2.5}$ Plan and Valley State SIP Strategy, the EPA affirmatively determined that the SIP submissions addressed the deficiency that was the basis for such findings, resulting in the termination of the associated sanctions clocks. Letter dated June 24, 2020, from Elizabeth Adams, Director, Air and Radiation Division, EPA Region IX, to Richard W. Corey, Executive Officer, CARB. However, the findings of failure to submit did not apply to the Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS because it was not yet required, and the June 24, 2020 completeness letter did not address the Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS.

[10] 87 FR 74310, 74313.

[11] We are not re-proposing any action on the Serious area requirements for emissions inventories nor contingency measures; our prior proposal to approve the emissions inventory element and to disapprove the contingency measure element of the nonattainment plan requirements for the 2012 annual $PM_{2.5}$ NAAQS remains unchanged.

The EPA provided its preliminary views on the CAA's requirements for particulate matter plans under part D, title I of the Act in the following guidance documents: (1) ''State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990'' (''General Preamble''); [12] (2) ''State Implementation Plans; General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990; Supplemental'' (''General Preamble Supplement''); [13] and (3) ''State Implementation Plans for Serious PM–10 Nonattainment Areas, and Attainment Date Waivers for PM–10 Nonattainment Areas Generally; Addendum to the General Preamble for the Implementation of Title I of the Clean Air Act Amendments of 1990'' (''General Preamble Addendum'').[14] More recently, in an August 24, 2016 final rule entitled, ''Fine Particulate Matter National Ambient Air Quality Standards: State Implementation Plan Requirements'' (''$PM_{2.5}$ SIP Requirements Rule''), the EPA established regulatory requirements and provided further interpretive guidance on the statutory SIP requirements that apply to areas designated nonattainment for all $PM_{2.5}$ NAAQS.[15] We discuss these regulatory requirements and interpretations of the Act as appropriate in our evaluation of the State's submissions below.

B. December 29, 2021 Proposed Rule

In our 2021 Proposed Rule, the EPA proposed to approve the SJV $PM_{2.5}$ Plan's: (1) emissions inventory for the 2013 base year; (2) precursor demonstrations that emissions of ammonia, sulfur oxides (SO_X), and volatile organic compounds (VOC) do not significantly contribute to exceedances of the 2012 annual $PM_{2.5}$ NAAQS in the SJV; (3) BACM demonstration for emission sources of direct $PM_{2.5}$ and nitrogen oxides (NO_X); (4) attainment demonstration based on air quality modeling [16] and emissions reductions related to aggregate commitments; (5) RFP demonstration; (6) quantitative milestones; and (7) motor vehicle emission budgets. We briefly summarize several aspects of those proposed approvals in the applicable sub-sections of section II of this proposed rule.

We also proposed to disapprove the Plan's contingency measures and noted the requirements for nonattainment NSR and the State's separate submission for the nonattainment NSR requirements. However, as we are not re-proposing any action on contingency measures nor nonattainment NSR in this proposed rule, we do not summarize those proposals herein.[17] In addition, we are not re-proposing any action on the Plan's precursor demonstrations for SO_X and VOC in this proposed rule; our 2021 Proposed Rule to approve the 2018 $PM_{2.5}$ Plan's demonstrations that emissions of SO_X and VOC do not significantly contribute to exceedances of the 2012 annual $PM_{2.5}$ NAAQS in the SJV remains unchanged.

Finally, we are not re-proposing any action in this proposed rule on the Plan's base year emissions inventory; our 2021 Proposed Rule to approve the 2018 $PM_{2.5}$ Plan's base year emissions inventory remains unchanged. Nevertheless, we briefly summarize our prior proposal [18] given the role that base year emissions inventories play in developing a plan's control strategy and attainment and RFP demonstrations.

The 2018 $PM_{2.5}$ Plan includes summaries of the planning emissions inventories for direct $PM_{2.5}$ and all $PM_{2.5}$ precursors (NO_X, SO_X,[19] VOC,[20] and ammonia) and related documentation. The Plan contains annual average daily emission inventories for 2013 through 2028 projected from the 2012 actual emissions inventory,[21] including the 2013 base year, the 2019 and 2022 RFP milestone years, the 2025 Serious area attainment year, and a 2028 post-attainment RFP year. The EPA proposed to approve the 2013 base year emissions inventory in the 2018 $PM_{2.5}$ Plan as meeting the requirements of CAA section 172(c)(3) and 40 CFR 51.1008. We also proposed to find that the future year baseline inventories in the 2018 $PM_{2.5}$ Plan satisfy the requirements of 40 CFR 51.1008(b)(2) and 51.1012(a)(2) and provide an adequate basis for the control measure, attainment, and RFP demonstrations for the 2012 annual $PM_{2.5}$ NAAQS in the 2018 $PM_{2.5}$ Plan.

C. Adverse Comments Submitted January 28, 2022

The EPA received adverse comments on our 2021 Proposed Rule from a coalition of 13 environmental, public health, and community organizations (collectively referred to herein as ''Public Justice'').[22] We are not responding to these comments (in the sense of a final rulemaking action) in this proposed rule, but the Agency has taken them into account with respect to the Serious area plan elements discussed in this proposed rule.

Overall, the commenters argue that the EPA must disapprove the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan based on alleged nonattainment plan requirement deficiencies in the submissions. We introduce these comments in this section of this proposed rule and present more detailed summaries and discussion of the comments in sections II.A (ammonia precursor demonstration), II.B.2 (BACM for ammonia emission sources), II.B.3 (BACM for building heating emission sources), II.C (attainment demonstration), and IV (Title VI of the Civil Rights Act).

Regarding CAA requirements for $PM_{2.5}$, Public Justice points to a history of failures to timely attain the 1997 annual $PM_{2.5}$ NAAQS in the SJV and states that ''[r]egulators point to a host of excuses from weather, to international sources, to Federal inaction, but repeatedly the State and Air District have refused to adopt feasible controls or regulate politically powerful entities'' such as agricultural sources of air pollution.[23] The commenters take issue with the EPA's proposal to approve the plan for the stricter 2012 standard ''without performing its duty to hold [CARB] and the [District] accountable to meet the

[12] 57 FR 13498 (April 16, 1992).

[13] 57 FR 18070 (April 28, 1992).

[14] 59 FR 41998 (August 16, 1994).

[15] 81 FR 58010 (August 24, 2016).

[16] We described 2018 $PM_{2.5}$ Plan's air quality modeling and our evaluation thereof in section IV.C of the 2021 Proposed Rule.

[17] Regarding nonattainment NSR, please see the EPA's separate rulemaking on the State's November 20, 2019 SIP submission of amendments to SJVUAPCD Rule 2201 (''New and Modified Stationary Source Review''). 87 FR 45730 (July 29, 2022) (proposed limited approval and limited disapproval of the Rule 2201 amendments).

[18] See section IV.A of the EPA's 2021 Proposed Rule.

[19] The SJV $PM_{2.5}$ Plan generally uses ''sulfur oxides'' or ''SO_X'' in reference to SO_2 as a precursor to the formation of $PM_{2.5}$. We use SO_X and SO_2 interchangeably throughout this notice.

[20] The SJV $PM_{2.5}$ Plan generally uses ''reactive organic gasses'' or ''ROG'' in reference to VOC as a precursor to the formation of $PM_{2.5}$. We use ROG and VOC interchangeably throughout this notice.

[21] 2018 $PM_{2.5}$ Plan, App. B, B–18.

[22] Comment letter dated and received January 28, 2022, from Brent Newell, Public Justice, et al., to Rory Mays, EPA, including Exhibits 1 through 47. We note, however, that there is no Exhibit 23; so, there are 46 exhibits in total. Email dated February 1, 2022, from Brent Newell, Public Justice, to Rory Mays, EPA Region IX. The 13 environmental, public health, and community organizations are Public Justice, Central Valley Environmental Justice Network, Association of Irritated Residents, Central Valley Air Quality Coalition, Leadership Counsel for Justice and Accountability, Valley Improvement Projects, The LEAP Institute, Little Manila Rising, Center for Race, Poverty, and the Environment, Central California Asthma Collaborative, Animal Legal Defense Fund, National Parks Conservation Association, and Food and Water Watch (collectively ''Public Justice'').

[23] Public Justice Comment Letter, 2.

minimum requirements Congress imposed to protect human health.'' [24] The commenters assert that the EPA relies on flawed, outdated information, ignores feasible controls, refuses to require regulation of ammonia, accepts aggregate commitments in lieu of other control strategies, and fails to address pollution sources in disadvantaged communities in the SJV.[25] With respect to specific CAA requirements, the commenters argue that the EPA must disapprove the Plan's emissions inventory, ammonia precursor demonstration, BACM demonstration, and aggregate commitments.

Regarding Title VI of the Civil Rights Act, the commenters argue that California must provide necessary assurances that the SIP complies with Title VI of the Civil Rights Act, pursuant to CAA section 110(a)(2)(E), and failed to do so.[26] The commenters state that ''$PM_{2.5}$ pollution has a disparate impact on the basis of race in the San Joaquin Valley'' and assert that the Plan fails to meet CAA requirements and ''deliberately ignores obvious sources and control options and inflicts disparate impacts on Black, Latino, Indigenous, and people of color'' in the SJV. Therefore, the commenters advocate that the EPA must disapprove the 2012 annual $PM_{2.5}$ portion of the SJV $PM_{2.5}$ Plan.[27] We address the commenters' Title VI comments in section IV of this proposed rule.

The EPA is now proposing to disapprove the Plan with respect to certain CAA requirements (BACM/BACT for ammonia emission sources, BACM/BACT for building heating emission sources, aggregate commitments, attainment demonstration, RFP demonstration, quantitative milestones, and motor vehicle emission budgets). However, we are not in this proposal comprehensively addressing all issues raised in the Public Justice comment letter.[28]

D. Ninth Circuit Decision on Related SJV $PM_{2.5}$ Plan

In a final rule published July 22, 2020, the EPA finalized approval of the portions of the SJV $PM_{2.5}$ Plan [29] that addressed the 2006 24-hour $PM_{2.5}$ NAAQS (except for contingency measures, which the EPA acted on in a subsequent action).[30] On September 17, 2020, a group of five environmental, public health, and community groups (collectively referred to herein as ''Medical Advocates'') petitioned the Ninth Circuit Court of Appeals (''Ninth Circuit'' or ''Court'') for review of the EPA's July 22, 2020 final rule.[31] On April 13, 2022, the Ninth Circuit issued a Memorandum opinion that granted in part and denied in part the petition (''Memorandum Opinion'').[32]

The Ninth Circuit denied the petitioners' challenge with respect to the EPA's approval of enforceable commitments in general and the EPA's approval of the Plan's demonstration of BACM, BACT, and most stringent measures (MSM) for emission sources of direct $PM_{2.5}$ and NO_X for purposes of the 2006 24-hour $PM_{2.5}$ NAAQS.

Significantly, however, the Ninth Circuit also denied in part and granted in part the petitioners' challenge with respect to the EPA's approval of the specific enforceable commitments employed as part of the SJV $PM_{2.5}$ Plan's control strategy to attain the 2006 24-hour $PM_{2.5}$ NAAQS in the SJV by December 31, 2024. The EPA evaluates enforceable commitments based on three factors: (1) the commitment represents a limited portion of the required emission reductions, (2) the State is capable of fulfilling its commitment, and (3) the commitment is for a reasonable and appropriate timeframe. The Ninth Circuit denied the petitioners' challenge with respect to the first and third factors but granted the petitioners' challenge with respect to the second factor.

The Ninth Circuit found that the EPA had misapplied the second factor concerning the State's ability to fulfill the aggregate commitments. The Court reasoned that EPA ''fail[ed] to provide evidence or a reasoned explanation for its conclusion that California will be able to fulfill its commitment'' in the face of a potential multi-billion dollar funding shortfall for incentive-based control measure commitments, ''which could result in emission reduction shortfalls of approximately 7% of the total NO_X reductions and 8% of the total $PM_{2.5}$ reductions necessary for attainment.'' [33] The Court also rejected the EPA's arguments that: (1) the funding shortfall may be smaller than projected, (2) emission reductions may be less expensive than the strategy predicts, (3) certain yet-to-be-quantified sources of reductions in the Plan may make up for shortfalls, and (4) California and the District may identify other measures to fulfill their commitments. Instead, the Court decided that, ''[b]ecause these speculative assertions are unsupported by the evidence, they fail to ensure that California and the District have a plausible strategy for achieving this portion of the attainment strategy, and therefore do not collectively satisfy the second factor of the EPA's three-factor test.'' [34] The Court concluded that the EPA's analysis with respect to the second factor for evaluating enforceable commitments was arbitrary and capricious, vacated the final rule with respect to this factor, and remanded the matter to the EPA for further consideration of the second factor.[35]

The EPA is currently considering how to address the Court's vacatur and remand with respect to the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan and is not proposing any action with respect to those standards in this proposed rule. However, the Ninth Circuit's decision is very relevant to this proposed rule because the State relied on a common control strategy, including the same enforceable commitments (*i.e.,* the same set of control measure commitments and aggregate tonnage commitments) for purposes of both the 2006 24-hour $PM_{2.5}$ NAAQS Serious area plan and the 2012 annual $PM_{2.5}$ NAAQS Serious area plan. The EPA acknowledges the deficiency in the factual support for the aggregate commitments identified by the Ninth Circuit and that this remains the case. If the EPA cannot approve the aggregate commitments, then this has a direct bearing on other elements of the State's Serious area SIP submissions for the 2012 annual $PM_{2.5}$ NAAQS. As discussed in section II.C of this proposed rule, based on our reconsideration of the facts concerning the enforceable commitments in the SJV $PM_{2.5}$ Plan with respect to the 2012 annual $PM_{2.5}$ NAAQS in light of the Ninth Circuit's decision, the EPA now proposes to disapprove the State's enforceable commitments and attainment demonstration.

[24] Id.

[25] Id. at 3.

[26] Id. at 10–14.

[27] Id. at 1 and 21.

[28] Additional source categories named by Public Justice include, for example, residential wood burning, open burning, conservation management practices at farming operations, soil NO_X emissions, stationary agricultural internal combustion engines, and cleaner mobile agricultural equipment engines. Public Justice Comment Letter, 18–20.

[29] 85 FR 44192.

[30] 86 FR 67343 (disapproving contingency measures for the 2006 24-hour $PM_{2.5}$ NAAQS).

[31] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #1 (9th Cir., September 17, 2020). The five environmental, public health, and community organizations, in order of appearance in the petition, are Medical Advocates for Healthy Air, National Parks Conservation Association, Association of Irritated Residents, and Sierra Club (collectively ''Medical Advocates'').

[32] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1 (9th Cir., April 13, 2022).

[33] Id. at 6.

[34] Id. at 7.

[35] Id. at 10.

II. Reconsideration of the San Joaquin Valley Serious $PM_{2.5}$ Plan

The EPA has reconsidered its 2021 Proposed Rule, based on adverse comments on that prior proposal and based on a Ninth Circuit Court of Appeals decision on a related SJV $PM_{2.5}$ rulemaking. After careful consideration of the issues raised by commenters and the court, the EPA now proposes to disapprove the State's plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV for certain Serious area planning requirements, including: (1) the Plan's precursor demonstration for ammonia; (2) BACM for ammonia emission sources and BACM for building heating emission sources; (3) the modeled attainment demonstration; (4) the RFP demonstration; (5) quantitative milestones; and (6) motor vehicle emission budgets.

In sections II.A through II.C of this proposed rule, pertaining to the Plan's precursor demonstration for ammonia as a $PM_{2.5}$ precursor; BACM/BACT analysis, and modeled attainment demonstration (including reliance on enforceable commitments), we present a brief summary of the 2021 Proposed Rule, a summary of the adverse comments and Ninth Circuit order, as appropriate, and our reconsidered proposal. In sections II.D and II.E, pertaining to the Plan's RFP demonstration, quantitative milestones, and motor vehicle emission budgets, we present a brief summary of the 2021 Proposed Rule and our reconsidered proposal.[36] We also note that sections II.A (ammonia precursor demonstration) and II.B.1 (BACM for ammonia emission sources) are inter-related in that potential control measures for ammonia emission sources play a role in both: (1) selecting a reasonable percent emission reduction to evaluate modeled ambient $PM_{2.5}$ responses to ammonia emission reductions; and (2) assessing the availability and application of BACM to such sources in the SJV.

A. Ammonia Precursor Demonstration

1. Summary of 2021 Proposed Rule

In our 2021 Proposed Rule, the EPA described the requirements for $PM_{2.5}$ precursor pollutants, summarized the State's submissions in the SJV $PM_{2.5}$ Plan, and presented our evaluation thereof.[37] We briefly summarize those here with respect to the Plan's demonstration for ammonia as a precursor to $PM_{2.5}$ for purposes of the 2012 annual $PM_{2.5}$ NAAQS in the SJV. For a comprehensive discussion of Federal requirements for $PM_{2.5}$ precursors and a summary of California's submission, please refer to the following headings in Section IV.B of the 2021 Proposed Rule: (1) Requirements for Control of $PM_{2.5}$ Precursors; and (2) Summary of State's Submission.

Regarding CAA requirements applicable to $PM_{2.5}$ precursors, we explained that the attainment plan requirements of Title I, subpart 4 apply to emissions of direct $PM_{2.5}$ and emissions of NO_X, ammonia, SO_2, and VOC as $PM_{2.5}$ precursors from all types of stationary, area, and mobile sources, except as otherwise provided in the Act. We further described how the EPA interprets section 189(e) concerning regulation of precursors from major stationary sources to authorize it to determine, under appropriate circumstances, that regulation of specific $PM_{2.5}$ precursors from other sources in a given nonattainment area is not necessary.

As explained in the $PM_{2.5}$ SIP Requirements Rule, a State may elect to submit to the EPA a "comprehensive precursor demonstration" for a specific nonattainment area to show that emissions of a particular precursor from existing sources located in the nonattainment area do not contribute significantly to $PM_{2.5}$ levels that exceed the standard in the area.[38] The contribution analysis may consider the sensitivity of $PM_{2.5}$ to decreases in emissions of the precursor, in addition to the contribution to ambient concentrations of $PM_{2.5}$.[39] If the EPA determines that the contribution of the precursor to $PM_{2.5}$ levels in the area is not significant and approves the demonstration, then the State is not required to control emissions of the relevant precursor in the attainment plan.[40]

The EPA issued the "$PM_{2.5}$ Precursor Demonstration Guidance" ("$PM_{2.5}$ Precursor Guidance"),[41] to provide recommendations to states for analyzing nonattainment area $PM_{2.5}$ and $PM_{2.5}$ precursor emissions and developing such optional precursor demonstrations, consistent with the $PM_{2.5}$ SIP Requirements Rule. The guidance also describes how the State may use a sensitivity-based test, in which the modeled sensitivity or response of ambient $PM_{2.5}$ concentrations to changes in emissions of the precursor is estimated and then compared to a contribution threshold. In addition to comparing the concentration or modeled response to the threshold, the State can consider other information in assessing whether the precursor significantly contributes. The EPA's recommended annual average contribution threshold for the 2012 annual $PM_{2.5}$ NAAQS is 0.2 μg/m³.[42] In other words, if the estimated contribution of a precursor at monitors is below this threshold, the EPA considers this evidence that the precursor does not contribute significantly to levels above the $PM_{2.5}$ NAAQS in the area in question; above this threshold, the EPA considers this evidence that the precursor does contribute significantly. The EPA considers this evidence in conjunction with additional information that the State may provide, and determines whether or not the precursor contributes significantly, and so whether the State must evaluate and implement controls of the precursor emissions to the appropriate level (*e.g.,* BACM).

The State presents its precursor demonstration primarily in Appendix G of the 2018 $PM_{2.5}$ Plan, with additional clarifying information in a series of emails available in the docket for this proposed rule. The State estimates that anthropogenic emissions of NO_X, ammonia, SO_X, and VOC will decrease by 64 percent (%), 1%, 6%, and 9%, respectively, between 2013 and 2025 based on its projected emissions accounting for existing and additional control measures in the Serious area plan.[43] Through a concentration-based analysis, CARB found that ammonium nitrate constituted 5.2 μg/m³ of the annual average $PM_{2.5}$ concentrations measured at the Bakersfield California Avenue monitor in 2015, exceeding the recommended threshold,[44] and proceeded to conduct a sensitivity-based analysis.

For analytical purposes in accordance with the EPA's guidance, the State then modeled the sensitivity of ambient $PM_{2.5}$ to hypothetical 30% and 70% reductions in anthropogenic emissions of ammonia in SJV for modeled years

[36] The Plan's RFP demonstration, quantitative milestones, and motor vehicle emission budgets were not the direct subject of adverse comments nor the Ninth Circuit decision. However, they are based on the Plan's control strategy to attain the 2012 annual $PM_{2.5}$ NAAQS and, thus, the flaws in the Plan's control strategy affect these additional required elements.

[37] 86 FR 74310, 74317–74321.

[38] 40 CFR 51.1006(a)(1).

[39] 40 CFR 51.1006(a)(1)(ii).

[40] 40 CFR 51.1006(a)(1)(iii).

[41] "$PM_{2.5}$ Precursor Demonstration Guidance," EPA–454/R–19–004, May 2019, including Memo dated May 30, 2019, from Scott Mathias, Acting Director, Air Quality Policy Division and Richard Wayland, Director, Air Quality Assessment Division, Office of Air Quality Planning and Standards (OAQPS), EPA to Regional Air Division Directors, Regions 1–10, EPA.

[42] $PM_{2.5}$ Precursor Guidance, 17.

[43] 2018 $PM_{2.5}$ Plan, Ch. 7, 7–5 and Table 7–2.

[44] 2018 $PM_{2.5}$ Plan, App. G, 3.

2013, 2020, and 2024. The results for 2024 are a proxy for the Plan's modeled attainment year of 2025 for the 2012 annual $PM_{2.5}$ NAAQS. For the 30% reduction results for 2024, upon which the State primarily relied, 2 out of 15 monitoring sites in SJV (Madera and Hanford) had modeled responses to ammonia reductions that were above the threshold. The ambient $PM_{2.5}$ response declines substantially from 2020 to 2024, with the decline being generally larger for the sites with the highest projected $PM_{2.5}$ levels. The State supplements the sensitivity analysis for ammonia with consideration of additional information such as emission trends, the appropriateness of future year versus base year sensitivity, available emission controls, and the severity of nonattainment.[45]

The State's precursor demonstration for ammonia also presents a review of District agricultural rules that control VOC emissions, but also provide ammonia reduction co-benefits. The State concludes that a 30% reduction is a reasonable upper bound on the potential ammonia reductions to model. Finally, the State's precursor demonstration presents extensive support for the State's conclusion that there is an ambient excess of ammonia relative to nitrate, *i.e.,* that particulate ammonium nitrate formation in SJV is NO_X-limited, and will become increasingly NO_X-limited as NO_X reductions increase into the future from the State's motor vehicle control program and other measures the State intends to undertake in the Serious area plan. Based on the forgoing considerations, the State concludes that ammonia emissions do not contribute significantly to ambient $PM_{2.5}$ levels that exceed the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

The EPA presented its initial evaluation of the State's ammonia precursor demonstration in section IV.B.3.a of the 2021 Proposed Rule, with more detailed summaries and evaluation in two EPA technical support documents (TSDs): ''Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS,'' February 2020 (''EPA's $PM_{2.5}$ Precursor TSD''), and ''Technical Support Document, EPA Evaluation of Ammonia Precursor Demonstration, San Joaquin Valley Moderate Area $PM_{2.5}$ Plan for the 2012 $PM_{2.5}$ NAAQS,'' August 2021 (''EPA's Ammonia Precursor TSD'').

We noted that the EPA's $PM_{2.5}$ Precursor Guidance provides for consideration of future year sensitivity and that consideration of additional information beyond the concentration-based and sensitivity-based analyses may be appropriate in assessing a precursor's significance. We summarized the State's assertions that 30% is a reasonable upper bound for potential ammonia emission reductions based on research cited in Appendix C of the 2018 $PM_{2.5}$ Plan concerning ammonia emissions and potential control options for agricultural sources.[46] However, we did not elaborate in the 2021 Proposed Rule as to why we proposed to agree that 30% was a reasonable upper bound.

We stated that ambient $PM_{2.5}$ responses to ammonia emission reductions decline over time, and in concert with the large projected NO_X emission reductions, with the largest declines occurring at sites with highest projected $PM_{2.5}$ levels. For the two sites (Madera and Hanford) where the State's modeled response in 2024 to a 30% ammonia emission reduction exceeded the recommended 0.2 μg/m³ threshold, we evaluated additional information and, based on that information, gave the modeled projected responses above the threshold at these sites less weight.

We also considered studies cited by CARB on the 2013 DISCOVER–AQ aircraft measurements and 2017 satellite measurements, both of which suggest that ammonia concentrations are underestimated in the SJV. We noted that if modeled ammonia concentrations were closer to observations, then the modeled response to ammonia precursor reductions would be lower than shown in the 2018 $PM_{2.5}$ Plan's precursor demonstration. Similarly, an increase in modeled ambient ammonia concentrations would also make the model response more consistent with the evidence from the multiple ambient measurement studies that suggest a very low ambient sensitivity to ammonia, based on measured excess ammonia relative to NO_X, the abundance of particulate nitrate relative to gaseous NO_X, and the large abundance of ammonia relative to nitric acid. These ambient measurement studies all conclude that there is a large amount of ammonia left over after reacting with NO_X, so that ammonia emission reductions would be expected mainly to reduce the amount of ammonia excess, rather than to reduce the particulate ammonium nitrate, and thus provided strong evidence independent of the modeling that ambient $PM_{2.5}$ levels would respond comparatively weakly to ammonia emissions reductions.

Regarding changes in the effect of ammonia emission reductions over time as other pollutant levels change, we stated it was appropriate to consider changes in atmospheric chemistry that may occur between the base or current year and the attainment year because the changes may ultimately affect the nonattainment area's progress toward expeditious attainment. We stated that the 2024 model results would in this case better represent the point in time at which it is appropriate to evaluate what potential ammonia controls could achieve, because of the steep decline in NO_X emissions the State projects will occur by 2024 and 2025 as a result of existing or intended control measures. We also noted that the projected annual average $PM_{2.5}$ concentration of 12.0 μg/m³, occurring at the Bakersfield-Planz monitoring site in 2025, would be reduced by 0.12 μg/m³, which would not be considered significant (it is below the EPA's recommended threshold of 0.2 μg/m³).

In sum, we concluded that the State had evaluated the sensitivity of ambient $PM_{2.5}$ levels to potential reductions in ammonia emissions using appropriate modeling techniques; the modeled response to ammonia reductions is likely lower than reported; and the State's choice of 2024 and 2025 as the reference points for purposes of evaluating the sensitivity of ambient $PM_{2.5}$ levels to ammonia emission reductions was well-supported. Based on all of these considerations, the EPA previously proposed to approve the State's demonstration that ammonia emissions do not contribute significantly to ambient $PM_{2.5}$ levels that exceed the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

2. Summary of Adverse Comments

Public Justice states that the ''EPA must disapprove the ammonia precursor demonstration'' and that ''CARB's tortured analysis (and EPA's proposed acceptance of it)'' is arbitrary and capricious. The commenter makes several assertions in support of this comment.[47]

First, Public Justice notes that CARB's analysis concluded that ammonia contributes 5.2 μg/m³ to annual average $PM_{2.5}$ concentrations, and that this is well above the EPA's recommended annual average contribution threshold of 0.2 μg/m³.[48] The commenters also

[45] Id. at App. G, 5.

[46] EPA's $PM_{2.5}$ Precursor TSD, 13.

[47] Public Justice Comment Letter, 16–18.

[48] The commenters note that 38% of the annual average ambient $PM_{2.5}$ in Bakersfield is ammonium nitrate. Public Justice Comment Letter, 6. See also, 2018 $PM_{2.5}$ Plan, Ch. 3, Figure 3–2 (''Bakersfield $PM_{2.5}$ Speciation (Average 2011 to 2013)'').

took issue with CARB and the EPA's arguments that such results overstate the role of ammonia because NO_X emissions decline over time, and the EPA's decision to look at the results of sensitivity modeling for the response of ambient $PM_{2.5}$ levels to potential ammonia emission reductions in the future year 2024. The commenters assert that this analytical approach of considering the projected sensitivity to ammonia reductions in the future year ''ignores the statutory imperative to demonstrate attainment as expeditiously as practicable,'' per CAA section 172(a)(2)(A), and that, even after evaluating the impact ''for the most favorable date'' (2024), CARB still found significant contribution for ammonia above the EPA's recommended threshold.

Second, Public Justice questioned CARB's reliance and the EPA's proposed acceptance of a sensitivity analysis that assumed only a 30% modeled reduction of ammonia emissions. Public Justice points out that the EPA's guidance for precursor demonstrations suggests that states should evaluate the effect of reducing emissions between 30% and 70%, and states that ''CARB argues, and EPA agrees, that only the minimal 30 percent control level is reasonable'' despite large ammonia sources (*e.g.,* ''industrial dairy and poultry operations'') never having been regulated in the SJV and the prospect for relatively easier and cheaper emission reductions than those for NO_X.[49] The commenters argue that ''[t]he analysis of potential controls is particular[ly] weak and ignores the wealth of literature demonstrating that strategies for reducing ammonia emissions from agriculture . . . are among the most effective for reducing PM concentrations,'' and cite several studies in support of this argument. The commenters further state that reducing ammonia emissions may be achieved through ''strategies such as improving livestock feed to reduce excreted nutrients, altering manure storage and handling practices to prevent [ammonia] emissions, and improving synthetic fertilizer use efficiency,'' again citing numerous studies.[50] The commenters state that agriculture is responsible for over 80% of ammonia emissions, and that confined animal facilities (CAFs) and fertilizer application account for 57% and 36%, respectively.[51] Moreover, the commenters assert that ''[n]o real analysis of control potential is offered'' in the State's precursor demonstration.

Third, with respect to the State and the EPA's evaluation of modeled ambient $PM_{2.5}$ responses to ammonia emission reductions in 2024, Public Justice states that, in the low (30%) emission scenario, 2 of 15 monitoring sites have responses over the 0.2 μg/m^3 recommended threshold and that the EPA argues ''with extremely biased evidence, that the results at one of the two monitors could be ignored and that ammonia emissions area likely underestimated.'' The commenters assert that ''EPA points to evidence that 'the State did not discuss' to discount the results'' for the Madera monitor, and that the EPA ''offers no excuse for discrediting the results at the other monitor.''

Fourth, the commenters claim that the EPA's evaluation of the precursor demonstration looked at supplemental ammonia emission studies but ignored supplemental studies showing that NO_X emissions from soil (''soil NO_X'') may be significantly underestimated. Public Justice states that the State and the EPA ''assert that NO_X emissions will be significantly reduced by 2024 even though the Plan currently does not explain how those NO_X reductions will occur.'' The commenters state that such approach is ''a one-sided attempt to explain away modeled results that ammonia contributes significantly to $PM_{2.5}$'' in the SJV and cannot overcome the Act's presumption that precursors must be controlled.

Finally, beyond the assertion that the State's precursor demonstration with respect to ammonia, and the EPA's proposed approval of it are incorrect, the commenters also argue that the State's failure to address ammonia as a precursor to $PM_{2.5}$ has disparate impacts on certain communities within SJV and ''avoids difficult political fights by sacrificing communities of color.'' Finally, the commenters refer to a 2021 research study that estimates that 1,690 people in California die annually due to agricultural ammonia emissions.[52]

3. The EPA's Reconsidered Proposal

The EPA agrees with certain points made by the commenters with respect to ammonia and disagrees with others. Overall, based on the adverse comments from Public Justice and a re-evaluation of the information provided by the State, we now conclude that the weight of evidence is insufficient to establish that ammonia does not contribute significantly to $PM_{2.5}$ levels above the NAAQS in the SJV. The EPA's further evaluation indicates that it is appropriate to retain the statutory presumption that ammonia must be regulated as a precursor for the 2012 annual $PM_{2.5}$ NAAQS in the SJV. Accordingly, if the EPA finalizes disapproval of the State's ammonia precursor demonstration, ammonia would remain a plan precursor, and the SJV would remain subject to the requirements to identify and implement BACM, BACT, and additional feasible measures on sources of ammonia emissions.

We first address the portion of the comment related to the sensitivity of the modeled $PM_{2.5}$ response to reductions in ammonia emissions and then turn to the portion of the comment addressing the amount of ammonia reductions that may be available.

a. Comments Related to Sensitivity Modeling Results

The measured ammonium nitrate portion of the annual average $PM_{2.5}$ concentration in Bakersfield in 2015 was 5.2 μg/m^3.[53] This is well above the EPA's recommended threshold in the $PM_{2.5}$ Precursor Guidance. However, the $PM_{2.5}$ SIP Requirements Rule, as interpreted by that guidance, provides the option for a State to conduct an analysis of the sensitivity of ambient $PM_{2.5}$ concentrations to emission reductions of a precursor pollutant to evaluate the significance of that precursor,[54] as the State did for the 2012

[49] Public Justice Comment Letter, 2, 5, and 16–17, and Exhibits 31 through 34.

[50] Public Justice Comment Letter, 16–17, Exhibits 35 through 40 and three additional studies: N. Cole, et al., ''Influence of dietary crude protein concentration and source on potential ammonia emissions from beef cattle manure,'' J. Anim. Sci. 83, 722, 2005; N. Cole, P. Defoor, M. Galyean, G. Duff, J. Gleghorn, ''Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers,'' J. Anim. Sci. 12, 3421–3432, 2006; and R. Todd, N. Cole, R. Clark, ''Reducing crude protein in beef cattle diet reduces ammonia emissions from artificial feedyard surfaces,'' J. Environ. Qual. 35, 404–411, 2006.

[51] Public Justice Comment Letter, 5–6, 16, citing See EPA Region IX, ''Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS.'' We note that our TSD in turn cited to State data sources, including the 2018 $PM_{2.5}$ Plan, App. G, Figure 3.

[52] Public Justice Comment Letter, 18. See Domingo, N.G.G., Balasubramanian, S., Thakrar, S.K., Clark, M.A., Adams, P.J., Marshall, J.D., Muller, N.Z., Pandis, S.N., Polasky, S., Robinson, A.L., Tessum, C.W., Tilman, D., Tschofen, P., & Hill, J.D., ''Air quality–related health damages of food,'' Proceedings of the National Academy of Sciences (Vol. 118, Issue 20, p. e2013637118), 2021, available at *https://doi.org/10.1073/pnas.2013637118,* attached as Exhibit 35. See **SUPPLEMENTARY INFORMATION** for ''Air quality-related health damages of food,'' Table S2 (''Annual emissions and mortality caused by agricultural production in the 10 states where emissions of (A) primary $PM_{2.5}$, (B) NH_3, (C) NO_X, (D) SO_2, and (E) NMVOCs lead to the highest total mortality'').

[53] 86 FR 74310, 74318 and 2018 $PM_{2.5}$ Plan, App. G, 3.

[54] 40 CFR 51.1006(a)(1)(ii).

annual $PM_{2.5}$ NAAQS in the SJV. Thus, the concentration-based contribution analysis alone (*i.e.,* the 5.2 μg/m³) is not necessarily determinative of a precursor's significance.

The commenters stated that reliance on a sensitivity-based test for 2024 ignores the statutory imperative for expeditious attainment. But, as noted in the preamble for the $PM_{2.5}$ SIP Requirements Rule in explaining the rationale for a sensitivity-based test, ''if conditions in a particular area are such that control of sources of one or more precursors does not reduce $PM_{2.5}$ concentrations in the area, then those controls will not help the area attain (expeditiously or otherwise).'' [55] Thus, if a precursor demonstration were to show that control of a particular precursor is not effective for reaching attainment, then the absence of such control would not violate the requirement for expeditious attainment.

As commenters noted, the State relied on its sensitivity-based contribution analysis for a future year (2024) to evaluate the significance of ammonia as a precursor to ambient $PM_{2.5}$ concentrations in the San Joaquin Valley. In our 2021 Proposed Rule, we discussed the State's selection of 2024 as an acceptable analysis year, given the projected steep decline in ambient $PM_{2.5}$ sensitivity to ammonia reductions over time as a result of projected changes in emissions (*i.e.,* large NO_X emission reductions as contemplated in the Plan, through existing measures and aggregate commitments), consistent with the facts and circumstances recommended for consideration in the EPA's $PM_{2.5}$ Precursor Guidance.[56]

The $PM_{2.5}$ Precursor Guidance provides for consideration of sensitivity in an appropriate future year.[57] Based on the State's control strategy, including baseline emission reduction measures and its control measure and aggregate tonnage commitments, the State estimated it would achieve over 200 tpd NO_X reductions by 2024, representing over 60% of the 2013 base year emissions inventory for NO_X.[58] Existing baseline measures already in the SIP are projected by the State to reduce annual average NO_X emissions in the SJV by 173.5 tpd, which is 83.7% of the 207.38 tpd of NO_X reductions modeled to attain the 2012 annual $PM_{2.5}$ NAAQS. Over 90% of the baseline NO_X reductions between 2013 and 2025 are due to the existing mobile source control program.[59] These reductions will occur regardless of any EPA action on the precursor demonstration or the 2018 $PM_{2.5}$ Plan as a whole. Similarly, additional measures adopted by the State through the end of 2021 further reduce NO_X emissions. Given the large NO_X emission reductions projected to occur by 2024 and 2025, the EPA has concluded that that the 2024 sensitivity model results better represent the atmospheric chemistry around the attainment date and in subsequent years than sensitivity modeling results from 2013 and even 2020.[60] Due to continued existing and anticipated NO_X reductions, the apparent $PM_{2.5}$ benefit of ammonia reductions in earlier years declines with time and does not reflect the ultimate, lower, benefit of such controls near the attainment year and later.

Thus, the EPA reasons that the Plan's baseline and additional control measures will change (and have already changed) the atmospheric chemistry conditions in the SJV, leading to ambient $PM_{2.5}$ formation that is much less sensitive to ammonia emission reductions in the attainment year. We maintain that the State's reliance on its sensitivity-based contribution analysis for 2024 to evaluate the significance of ammonia as a precursor is reasonable, well supported, and consistent with the $PM_{2.5}$ SIP Requirements Rule and EPA guidance.

The commenter correctly states that 2 of 15 sites in the 2024 model scenario based on a 30% reduction in ammonia emission were modeled to have an ambient $PM_{2.5}$ response greater than the EPA's recommended contribution threshold of 0.2 μg/m³. However, we disagree with the commenter's characterization that our further review of the sensitivity of the Madera and Hanford sites to ammonia emission reductions was argued ''with extremely biased evidence.'' [61]

For the Madera monitor (estimated sensitivity of 0.21 μg/m³ in 2024 to a 30% ammonia emission reduction), the commenter refers to the EPA's statement that the 2018 $PM_{2.5}$ Plan did not discuss the evidence for the 2013 monitored concentrations at this site being biased high (as a matter of the physical recordings of the monitor). However, the EPA did reference the State's prior analysis of such evidence, which we considered in our evaluation.[62] Aside from pointing out that this analysis was not included in the Plan itself, the comment does not offer analysis to the contrary, and the EPA continues to think that we reasonably weighed the technical information before us and, given the role of the 2013 monitored data in the sensitivity modeling conducted by the State, correctly concluded that ''if more typical Madera concentrations were used, it is likely that the 2024 Madera response to ammonia reductions would be below the contribution threshold'' and that the extra year of NO_X reductions from 2024 to 2025 would likely decrease the sensitivity below the recommended 0.2 μg/m³ threshold.

We further disagree with the commenter's assertion that we offered no reason for giving less weight to modeled sensitivity results for the Hanford monitor (estimated sensitivity of 0.26 μg/m³ in 2024 to a 30% ammonia emission reduction). We stated that we gave both Madera and Hanford modeled sensitivity lower weight in our overall assessment of ammonia as a precursor. Specifically for Hanford, we described evidence that the modeled sensitivity there was likely overestimated. That evidence included an independent study using data from the 2013 DISCOVER–AQ campaign that ''found that the [CMAQ] model underestimated ammonia at Hanford by a roughly a factor of four or five.'' [63] In our assessment, if the model's ammonia concentrations better matched the observations then there would be more of an ammonia excess in the model, and the modeled response to ammonia reductions would be lower.

More broadly, prior to publishing the 2021 Proposed Rule, the EPA reviewed available research including from supplemental materials from CARB, and found a consistent theme based on modeling analyses and ambient measurement studies—that ''there is a large amount of ammonia left over after reacting with NO_X, so that ammonia emission reductions would be expected mainly to reduce the amount of ammonia excess, rather than to reduce the particulate ammonium nitrate.'' [64] It is important to note that this ammonia excess is *measured,* and is independent

[55] 81 FR 58010, 58025.

[56] 86 FR 74310, 74320–74321 and $PM_{2.5}$ Precursor Guidance, 35.

[57] $PM_{2.5}$ Precursor Guidance, 35.

[58] 86 FR 74310, 74327, Table 4.

[59] 2018 $PM_{2.5}$ Plan, App. B, Table B–2.

[60] We address the potential impact of ammonia emissions on the requirement for expeditious attainment in our re-evaluation of the attainment demonstration in section II.C.3, below.

[61] Public Justice Comment Letter, 18.

[62] 86 FR 74310, 74320, fn. 91, and fn. 92. This analysis concluded that 2011–2013 Madera data did not fit the geographic pattern historically seen in relation to other monitors but returned to the historic pattern after corrections were made to the monitoring instrument operating procedures. Concentrations were estimated to be about 10% high during the period in question.

[63] 86 FR 74310, 74320.

[64] Id. See also, EPA's Ammonia Precursor TSD.

of any assumptions about the size of the ammonia or NO_X emissions inventories, and also independent of any uncertainties in the modeling exercise. The concerns raised by Public Justice about relative levels of ammonia and NO_X estimation are not sufficient to cause the EPA to revise the conclusion that $PM_{2.5}$ is likely to have low sensitivity to ammonia reductions, which is supported by the actual observed conditions. The ambient measurement evidence is strong and leads the EPA to believe that the modeled response to ammonia in the State's precursor demonstration may be overestimated. Therefore, we maintain that the EPA may give lower weight to the modeled sensitivities of ambient $PM_{2.5}$ concentrations to ammonia emission reductions at the Madera and Hanford sites.

The commenter states that the EPA's argument on the relative levels of ammonia and NO_X emissions looks at such ammonia studies but ''ignores supplemental studies showing that . . . soil NO_X emissions [may be significantly underestimated].'' [65] Unlike the general consensus in the ammonia studies described above, with respect to the amount of NO_X emitted by soil in the SJV the EPA believes that there is conflicting research. A conclusion of Almaraz et al. (2018) and Sha et al. (2021) cited by the commenters is that soil NO_X emissions are underestimated, and that they comprise 30–40% of total NO_X emission in California. While higher levels of soil NO_X (or NO_X more generally) would tend to increase the modeled sensitivity of ambient $PM_{2.5}$ to ammonia, we maintain that there is not a sufficient basis to conclude that higher soil NO_X emissions should be used in the air quality modeling for the SJV.[66]

In contrast to the studies just cited, Guo et al. (2020) [67] did not find such a discrepancy in emissions estimates, concluding that soil NO_X is about 1% of anthropogenic NO_X emissions. The fraction of nitrogen applied as fertilizer released as NO_X to the atmosphere was estimated by Almaraz et al. to be 15%, while seven other studies reviewed by Guo et al. estimated it to be 2% or less. Yet Almaraz et al., Sha et al., and Guo et al. all reported high agreement between their modeled and observed soil NO_X emissions. The Almaraz et al. study acknowledged the limited number of surface measurements that were available for purposes of comparing the model results and the difficulty in comparing the model results to the observations and noted the need for more field measurements. Guo et al. stated that obtaining an emission factor correlating NO_X emissions to fertilizer application from the data available in various studies (including Almaraz et al.) would be ''difficult or impossible'' due to the sparsity of data collected in terms of sampling length, sampling frequency, and the episodic nature of nitrogen gas emissions from soil.

In light of the uncertainties and disagreements among studies, the EPA does not believe that available research provides sufficient certainty about the magnitude and proportion of soil NO_X emissions attributable to agricultural fertilizer application to require substantial revisions in the NO_X emissions inventory nor the $PM_{2.5}$ modeling at this time.

In addition, as just described, multiple studies of ambient measurements show excess ammonia in the atmosphere, which is strong evidence of low sensitivity to ammonia reduction that is independent of the accuracy of estimates of precursor emissions from any source, including soil NO_X, and independent of any modeling. Thus, we disagree that the EPA ''ignored'' the supplemental soil NO_X studies; we were aware of and considered them, but they did not change our conclusion.

b. Comments Related to Scale of Potential Ammonia Emission Reductions

The 2018 $PM_{2.5}$ Plan includes modeling of 30% and 70% reductions in ammonia emissions and focuses on the results of the 30% reduction based on the assertion that the area could not achieve more than a 30% decrease in ammonia emissions. Public Justice questions the basis for the assertion that no more than 30% reductions are available. In this section, we examine, based on the submission, the $PM_{2.5}$ Precursor Guidance, and the Public Justice comment, the ammonia reductions that may be available in the SJV. Specifically, we explore the uncertainty with respect to both the current state of ammonia emissions and controls in the SJV and available research examining additional control options that may be available. We conclude that, based on the information before us, the 2018 $PM_{2.5}$ Plan does not provide sufficient support for the assertion that 30% is a reasonable upper bound on available ammonia reductions in the SJV.

The District presented its analysis of ammonia control for the primary ammonia source categories in the SJV in Appendix C, section C.25 (''Ammonia in the San Joaquin Valley'') of the 2018 $PM_{2.5}$ Plan. The EPA had reviewed this analysis for our assessment in the 2021 Proposed Rule that 30% was, for analytical purposes, a reasonable upper bound for ammonia emission reductions in the SJV, and referred to prior EPA analysis for our action on the 2006 24-hour $PM_{2.5}$ NAAQS portion of the 2018 $PM_{2.5}$ Plan.[68] In evaluating the Public Justice comments on the potential control of ammonia, however, we have re-evaluated other portions of the 2018 $PM_{2.5}$ Plan, including Appendix C, section C.25 and Appendix G,[69] and reviewed the studies cited by the commenters, as well as others from the EPA's own literature search.

As noted in the EPA's $PM_{2.5}$ Precursor Guidance,[70] and consistent with the $PM_{2.5}$ SIP Requirements Rule (40 CFR 51.1010(a)(2)(ii), 51.1006(a)(1)(ii)), the EPA may require the State to identify and evaluate potential control measures for a precursor to determine the potential emissions reductions achievable, as a part of the precursor analysis. The guidance states that this evaluation is particularly important when the $PM_{2.5}$ response to a 30% reduction in precursor emissions is close to the contribution threshold. In the case of a nonattainment area classified as Serious, this analysis would include identification and evaluation of measures that would constitute BACM/BACT level controls for such pollutant.[71]

[65] Public Justice Comment Letter, 18. Public Justice cited Almaraz et al. (2018), ''Agriculture is a major source of NO_X pollution in California,'' Science Advances, 4(1), doi:10.1126/sciadv.aao3477, 2018, available at *https://advances.sciencemag.org/content/4/1/eaao3477;* and Sha et al. (2021), ''Impacts of soil NO_X emission on O_3 air quality in rural California,'' Environmental Science & Technology, 55(10), 7113–7122, available at: doi:10.1021/acs.est.0c06834; available at *https://pubs.acs.org/doi/10.1021/acs.est.0c06834.*

[66] See also, EPA Region IX, ''Response to Comments Document for the EPA's Final Action on the San Joaquin Valley Serious Area Plan for the 2006 $PM_{2.5}$ NAAQS,'' June 2020, 148 and 158.

[67] Guo et al. (2020), ''Assessment of Nitrogen Oxide Emissions and San Joaquin Valley $PM_{2.5}$ Impacts From Soils in California,'' Journal of Geophysical Research: Atmospheres, 125(24), doi:10.1029/2020JD033304; available at *https://doi.org/10.1029/2020JD033304.*

[68] 86 FR 74310, 74319. See also, 85 FR 17382, 17395 (March 27, 2020), and EPA's $PM_{2.5}$ Precursor TSD, 13.

[69] See, *e.g.,* 2018 $PM_{2.5}$ Plan, App. G, 13, where CARB states that ''CARB staff, District staff, and the public process have not identified specific controls that are technologically and economically feasible to achieve reductions at the low end of the recommended sensitivity range (*i.e.,* 30 percent), much less at the upper end of the range.''

[70] $PM_{2.5}$ Precursor Guidance, 31.

[71] The $PM_{2.5}$ Precursor Guidance provides: ''[c]onsistent with the $PM_{2.5}$ SIP Requirements Rule, the EPA may in some cases require air agencies to evaluate available emissions controls in support of a precursor demonstration that relies on a

Even when the modeled responses are below the recommended 0.2 µg/m³ contribution threshold, or when particular responses are given less weight as we have discussed above for Madera and Hanford, the outcome of a sufficiently thorough controls evaluation and its conclusions on achievable emissions reductions may be important information for the EPA to consider in deciding whether to approve the precursor demonstration. Here, the State's ammonia precursor demonstration strongly relies on the assertion that no more than 30% ammonia reductions below current levels is achievable, but there is not a sufficiently thorough controls evaluation to support that assertion. Because the 30% value has not been adequately supported, the EPA cannot evaluate whether the modeled $PM_{2.5}$ reductions associated with a 30% reduction in ammonia represent the reductions that may be possible in the SJV.

The EPA also emphasizes that the 30% control threshold is part of an analytical test to help evaluate whether the State must regulate ammonia as a precursor for the 2012 annual $PM_{2.5}$ NAAQS in the area; it does not mean that if the State cannot control 30% of ammonia with BACM/BACT-level controls that there is per se no need to regulate ammonia. For example, if control of 25% of ammonia is necessary for attainment of the $PM_{2.5}$ NAAQS, then the fact that this is below 30% is irrelevant. Our attention to the 30% threshold in this notice is to help interpret the $PM_{2.5}$ responses to modeled ammonia emissions reductions in the State's precursor demonstration, which modeled a 30% reduction. This point is important analytically because, insofar as potential ammonia reductions could be larger than 30%, the modeled responses could be larger than those relied upon in the State's precursor analysis to support its determination that ammonia is not a significant precursor.

With respect to the State's assertion that 30% is a reasonable upper bound for potential ammonia emission reductions, we agree with the commenters that the analysis of potential ammonia controls provided by the State and the evaluation of that information by the EPA lacked detailed support and is not a sufficient basis for the EPA to affirm that 30% is a reasonable upper bound for potential ammonia emission reduction in the SJV. This, in turn, affects the EPA's interpretation of the results of modeled responses to ammonia reductions. There are two general deficiencies in the submitted analysis that create uncertainty as to the potential for ammonia emission reductions, as discussed below: (1) incomplete quantification of existing ammonia emission reductions from the largest sources of ammonia; and 2) incomplete consideration and evaluation of potential additional controls of ammonia emissions for sources in the SJV. We walk through these uncertainties for each of the largest sources of ammonia in the SJV (*i.e.,* CAFs and fertilizer application).

As an initial matter, the commenters state that ''[the State] argues, and EPA agrees, that only the minimal 30 percent control level is reasonable'' despite major ammonia sources never having been regulated in the SJV and the relatively easier and cheaper sources of emission reductions relative to NO_X. We understand this reference to ''major ammonia sources'' to mean the main source categories of ammonia emissions in the SJV, including CAFs and fertilizer application, which the State estimated to emit 57% and 36%, respectively, of the annual average ammonia emissions in the SJV in 2013.[72]

We agree with the commenters that neither CARB nor the District have imposed controls specifically to regulate ammonia. We note, however, that ammonia-specific controls are not required for approval of an ammonia precursor demonstration. Moreover, although there are not ammonia-specific controls in place for the largest source categories in the SJV, many sources of ammonia are in fact regulated by District rules, such as Rule 4570 (''Confined Animal Facilities''), Rule 4565 (''Biosolids, Animal Manure, and Poultry Litter Operations''), and Rule 4566 (''Organic Material Composting Operations''), which include enforceable requirements for VOC emissions that would, in general, achieve some degree of ammonia emission reductions. We agree with the general assertion, presented by the District in section C–25 (''Ammonia in the San Joaquin Valley'') of Appendix C of the 2018 $PM_{2.5}$ Plan, that some management practices to reduce VOCs in those rules also collaterally reduce ammonia emissions by limiting ammonia formation and volatilization, even though ammonia reductions are not legally required by these measures.[73]

Although we expect that existing VOC regulations are achieving a degree of ammonia control, there are multiple reasons why it is not clear, based on the record before us, how much reduction is being achieved, and thus how much additional reduction may be available. For example, regarding CAFs, as the EPA has previously noted,[74] the State has not sufficiently substantiated its calculation of 100 tpd of ammonia emission reductions attributed to Rule 4570. In the 2018 $PM_{2.5}$ Plan, the State referenced an outdated analysis from 2006 that relied on a different baseline emissions inventory, but has not supplemented this analysis, or reconciled it with more recent emissions inventory data.[75] We note that CARB has provided the EPA with significantly lower estimates of ammonia emission reductions achieved by SJVUAPCD Rule 4570 based on more recent calculations of reductions from a 2012 baseline emissions inventory.[76] The 2018 $PM_{2.5}$ Plan does not reconcile these differences, nor update the emission reduction estimate from the 2006-era analysis to the emissions inventory basis of the 2018 $PM_{2.5}$ Plan.

sensitivity analysis. [See 40 CFR 51.1009(a)(2) and 51.1010(a)(2).] It is particularly important for states to evaluate available controls where the recommended contribution threshold—that is, the threshold used for identifying an impact that is 'insignificant'—is close to being exceeded at the low end of the recommended sensitivity range (*e.g.,* 30 percent). In these cases, the EPA may determine that to sufficiently evaluate whether the area is sensitive to reductions, the State must determine the potential precursor emission reductions achievable through the implementation of available and reasonable controls for a Moderate area (or best controls for a Serious area).'' $PM_{2.5}$ Precursor Guidance at 31.

[72] See Public Justice Comment Letter, 6, citing EPA Region IX, ''Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS.''

[73] See, *e.g.,* 2018 $PM_{2.5}$ Plan, App. C, C–313 (for CAFs). The lack of controls specifically regulating *ammonia emissions* from the largest source categories through enforceable SIP requirements in the SJV is not an inherent deficiency of the precursor demonstration, but it does result in challenges for determining the potential for ammonia emission controls (*i.e.,* in determining the reductions that have already been achieved, and what additional reductions are available).

[74] 81 FR 69396, 69397–69398 (October 6, 2016).

[75] 2018 $PM_{2.5}$ Plan, App. C, C–311 to C–339 and SJVUAPCD, ''Final Draft Staff Report, Proposed Re-Adoption of Rule 4570 (Confined Animal Facilities),'' June 18, 2009, at Appendix F, ''Ammonia Reductions Analysis for Proposed Rule 4570 (Confined Animal Facilities),'' June 15, 2006 (discussing various assumptions underlying the District's calculation of ammonia emission factors without identifying relevant emissions inventories).

[76] Email dated September 3, 2015, from Gabe Ruiz, CARB, to Larry Biland and Andrew Steckel, EPA Region IX, regarding ''SJV Livestock Ammonia Emissions with and without Rule 4570.'' This email notes that 2011 ammonia emissions (pre-rule) were 316.8 tpd, 2012 emissions (without rule) were 323.8 tpd, and 2012 emissions (with rule) were 250.9 tpd. Thus, application of Rule 4570 would have achieved either 72.9 tpd of ammonia reductions, measured within 2012 with and without the rule, or 65.9 tpd, measured from the 2011 level (without rule) to the 2012 level (with rule).

In short, although we agree that some existing VOC controls will also result in ammonia reductions, a more detailed analysis it required to determine both the effectiveness of existing controls, and the additional controls that may be available. In the following, the EPA notes various uncertainties concerning ammonia emissions and in the amount of reductions achieved by specific rules as a byproduct of the existing VOC control measures. For a number of key source categories, ammonia measures require additional analysis to evaluate their potential to achieve additional emissions reductions, in part based on research studies included as exhibits to the Public Justice Comment Letter.

For CAFs, the District discusses in detail how Rule 4570 is structured (*e.g.,* to address varying types of CAFs); the five main CAF operations/emission sources: feeding, housing (including distinctions for housing configurations), solid waste, liquid waste, and land application of manure; the control menu requirements for each of those five operations; and research papers that estimate ammonia emission reductions from some of the measures.[77] However, the 2018 $PM_{2.5}$ Plan does not specify, even in an aggregated form, which control measures were selected by CAFs in their permits-to-operate with the District for each of the five operations and the scale of those selections by CAF size, nor does it quantify the emission reductions from those selections and scales. Thus it is unclear what level of ammonia control is being achieved, and, importantly for the precursor demonstration, unclear what level of further ammonia control may be possible. This uncertainty is increased by several provisions in Rule 4570 that allow CAF owners/operators to implement ''alternative mitigation measures'' [78] *in lieu of* the mitigation measures listed in the rule, without any requirement to ensure that such alternative mitigation measures achieve any particular level of ammonia emission reductions, or any ammonia reductions at all.[79]

Furthermore, for certain requirements, the 2018 $PM_{2.5}$ Plan assumes that a less effective control measure may be implemented given that the more effective control measure may be more costly. For instance, the District describes some research studies that relate to one or more of the options, but it is not clear whether and how the requirements of each option align with the practices evaluated in each study. The District cites a 2005 University of California study that manure from lagoons, diluted with irrigation water, and applied via surface gravity irrigation systems (*e.g.,* not applied with a drag hose or similar apparatus) commonly minimized ammonia losses from volatilization to the air to 10% or less.[80] However, it is not clear how the requirements of option H.2.a (liquid manure treated in an aerobic or anaerobic lagoon) or option H.2.b (24-hour limit for liquid manure standing on fields) may correspond to the study, whether any particular level of lagoon treatment or dilution prior to application would be needed, nor whether a combination of the two would be required to minimize ammonia losses to air to that degree.

For option H.2.c, the District states that use of a drag hose or similar apparatus could significantly reduce ammonia emissions, but without specifying how much or pointing to any supporting document, and only qualitatively asserting a relatively higher cost for using such equipment, and its limitations when a crop is growing.[81] The District states that ''[a]pplication of liquid or slurry manure with a drag hose or similar apparatus could result in significant [ammonia] reductions, but has higher costs compared to flood or furrow irrigation of liquid manure.'' [82] However, higher cost does not necessarily translate to the measure being economically infeasible, and thus the option to use flood or furrow irrigation alone may not represent the most appropriate method or level of control of ammonia for the land application of liquid manure. As a result, the District has not demonstrated that additional reductions are not feasible.

The District assumes that all dairies and other cattle facilities would select option H.2.b (24-hour limit for liquid manure standing on fields) and cites two studies that suggest substantial ammonia emission reductions from this limitation, assuming no ammonia emissions into the air after soil incorporation.[83] Based on one study, dairy CAF operations in the SJV would have hypothetically already reduced ammonia emissions to the air from land application of liquid manure from 66% ammonium nitrogen to 25% ammonium nitrogen by implementing option H.2.b (a 41% absolute reduction, or 62% relative reduction). Uncertainty about the options that are being chosen and implemented by regulated entities gives rise to uncertainty in the ammonia emission reductions that are being achieved. The permits-to-operate submitted by each dairy CAF are required to indicate which option has been selected.[84] Accordingly these permits, and associated compliance records, should contain information that would help to address this uncertainty. Furthermore, if injection via drag hose or similar apparatus (option H.2.c) is economically feasible, even if more expensive, implementation of such a measure could further reduce ammonia by 25% based on the same study, at least for a portion of the operating cycle (*e.g.,* when crops are not growing). Lastly, a combination of measures (*e.g.,* requiring that liquid manure be both treated in an anaerobic lagoon, aerobic lagoon, or digester, and that it be incorporated into the soil within 24 hours) or adjustment to existing options (*e.g.,* requiring incorporation of liquid manure within 6 hours, rather than 24 hours, and during cooler hours when ammonia volatilization is less) could hypothetically reduce ammonia emissions at these sources by more than 30%.[85]

In general, with respect to dairy CAFs, on a qualitative basis CAF operators have likely reduced ammonia emissions

[77] 2018 $PM_{2.5}$ Plan, App. C, C–312 to C–323.

[78] ''Alternative Mitigation Measure'' is defined in SJVUAPCD Rule 4570 as ''a mitigation measure that is determined by the APCO, [CARB], and EPA to achieve reductions that are equal to or exceed the reductions that would be achieved by other mitigation measures listed in this rule that owners/operators could choose to comply with rule requirements.'' SJVUAPCD Rule 4570 (amended October 21, 2010), section 3.4. Because SJVUAPCD Rule 4570 explicitly applies only to VOC emissions, the requirement for equivalent ''reductions'' in section 3.4 applies only to VOC emission reductions and does not apply to ammonia emission reductions.

[79] See, *e.g.,* SJVUAPCD Rule 4570 (amended October 21, 2010) at section 5.6, Table 4.1.F.

[80] University of California, Division of Agricultural and Natural Resources, Committee of Experts on Dairy Manure Management, ''Managing Dairy Manure in the Central Valley of California,'' June 2005.

[81] 2018 $PM_{2.5}$ Plan, App. C, C–323, referring to a 2008 report by Alberta Agriculture and Food (Canada). Albert Agriculture and Food, ''Ammonia Volatilization from Manure Application,'' February 2008 (''2008 Alberta Report''). That report estimates that injection into soil would reduce the average ammonium-nitrogen fraction loss (*i.e.,* to air) to 0% compared to incorporation within one day from surface application (25%) or compared to surface application with no incorporation (66%). 2008 Alberta Report, Table 2.

[82] 2018 $PM_{2.5}$ Plan, App. C, C–322 to C–323.

[83] 2018 $PM_{2.5}$ Plan, App. C, C–323, referring to two studies: the 2008 Alberta Report, and Chadwick et al. ''Emissions of Ammonia, Nitrous Oxide and Methane from Cattle Manure Heaps: Effect of Compaction and Covering,'' Atmosphere Environment, 39: 787–799 (2005); available at: *http://www.sciencedirect.com/science/article/pii/S135223100400994X.*

[84] Under District Rule 4570, section 5.1, owners/operators of CAFs subject to the rule must obtain a permit-to-operate for the facility, and that permit must include a facility emission mitigation plan, a facility emission inventory, and identify the mitigation measures selected for the facility.

[85] 2008 Alberta Report.

to a degree consistent with the options selected. However, there is not a quantitative basis to specify the degree and potential for further reduction. For some of the options within the menu of mitigation measures for each type of CAF in Rule 4570, there are research studies to support the basis of existing ammonia emission reductions. The generalized assumptions used by the State could be evaluated by an analysis of the options selected by CAFs in permits-to-operate with the District. Further assessment of available compliance records and examination of combinations of measures or adjustments to existing measures could help quantify additional potential ammonia emission reductions.

In addition, Public Justice cites several studies to support its assertion that reductions in agricultural ammonia emissions may be achieved through ''strategies such as improving livestock feed to reduce excreted nutrients, altering manure storage and handling practices to prevent [ammonia] emissions, and improving synthetic fertilizer use efficiency,'' and cites several studies to support this assertion.[86] The EPA considers these approaches to warrant examination as potential means to reduce ammonia and believes that more information regarding their efficacy as control measures and their economic and technical feasibility is needed to determine the amount of the potential additional ammonia control in the SJV.

For livestock feed, studies in 2005 and 2006 cited by the commenter found that ''decreasing the crude protein concentration of beef cattle finishing diets based upon steam-flaked corn from 13 to 11.5 percent decreased ammonia emissions by 30 to 44 percent.'' [87] A 2009 study cited by the commenter found that ''one feedyard feeding distillers grains averaged 149 grams of ammonia-N per head per day (NH3–N/head/day) over nine months, compared with 82 g NH3–N/head/day at another feedyard feeding lower protein steam-flaked, corn-based diets.'' [88] Nominally this would represent a 45% reduction in ammonia emissions from manure by going to a lower protein diet. However, the net ammonia emission reduction either from reducing crude protein levels in feed, or by providing a lower protein steam-flaked, corn-based diet rather than a distiller grain diet is unclear given the role of protein intake on the time for beef cattle to reach market weight or on milk production for dairy cattle.

For manure handling and storage practices, a 2011 inventory of mitigation methods by Price et al. identifies many mitigation methods for various kinds of CAFs, some of which may reduce ammonia emissions by 50–90%.[89] For example, Method 44 (''Washing down dairy cow collecting yards'') involves areas where dairy cows are collected on a concrete yard prior to milking and, after each milking event, the urine and manure in the area are removed by pressure washing or by hosing and brushing, resulting in up to 90% ammonia emission reductions. Method 62 (''Cover solid manure stores with sheeting'') involves covering solid manure heaps with plastic sheeting, resulting in ammonia emission reductions up to 90%.[90] However, the authors note that, for both Method 44 and Method 62, reducing ammonia emission from the milking areas would increase the ammonium content of the slurry, potentially leading to higher ammonia emissions during storage and spreading, but by a lower amount than the initial reduction amount. Method 71 (''Use slurry injection application techniques'') involves shallow (5–10 cm depth) or deep (25 cm depth) injection of slurry into the soil, resulting in ammonia emission reductions of 70% to 90%, respectively.

Mitigation methods are also described for other kinds of CAFs, such as pig farms and chicken farms. For example, Method 48 (''Install air-scrubbers or biotrickling filters to mechanically ventilated pig housing'') involves pig housing where specific technologies are used to capture up to 90% of the ammonia emissions into recirculation water that can then be used as a nitrogen-based fertilizer. Method 51 (''In-house poultry manure drying'') involves installation of ventilation/drying systems that reduce the moisture content of poultry litter, resulting in up to 50% ammonia emission reductions, though, as with the cattle examples, this could result in some increased emissions at subsequent steps (*e.g.,* storing poultry litter).

In addition to the 2011 inventory of mitigation methods, in September 2017, the EPA and the U.S. Department of Agriculture, Natural Resource Conservation Service released the ''Agricultural Air Quality Conservation Measures, Reference Guide for Poultry and Livestock Production Systems'' (2017 EPA–USDA Reference Guide). This reference guide discusses air quality conservation measures relating to nutrition and feed management, animal confinement, manure management, land application, and other supplemental practices. Among other things it includes Appendix A.1 (''Table of Mitigation Effectiveness for Selected Measures''), which lists 12 measures that may reduce ammonia emissions by more than 30%, Appendix A.2 (''List of State Programs and Regulations for AFO Air Emissions''), and Appendix A.3 (''List of AFO Air Quality Programs & Land-Grant Universities'').

In sum, various research studies on mitigating ammonia emissions from CAFs suggest that there may be potential for additional ammonia reductions from activities such as animal feeding and housing to manure storage, handling, and land application. While the Plan refers to and describes some of the research studies described herein (*e.g.,* the 2008 Alberta Report and the 2005 Chadwick paper), it is unclear the extent to which the higher emission reduction measures have been or could be implemented in the SJV and, when aggregated across all CAF operations, it remains unclear whether the total reduction from additional measures would be greater than the State's estimate of maximum available

[86] Public Justice Comment Letter, 16–18.

[87] Public Justice Comment Letter, Exhibit 36, 9. Exhibit 36 is: Preece, Sharon L.M. et al., ''Ammonia Emissions from Cattle Feeding Operations,'' Texas A&M AgriLife Extension Service, referring to Cole, N.A., R.N. Clark, R.W. Todd, C.R. Richardson, A. Gueye, L.W. Greene, and K. McBride, ''Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure,'' Journal of Animal Science 83:(3), 722 (2005); and Todd, R.W., N.A. Cole, and R.N. Clark, ''Reducing Crude Protein in Beef Cattle Diet Reduces Ammonia Emissions from Artificial Feedyard Surfaces.'' Journal of Environmental Quality. 35:(2), 404–411 (2006).

[88] Public Justice Exhibit 36, 10, referring to a study by Todd, R.W., N.A. Cole, D.B. Parker, M. Rhoades, and K. Casey. 2009. ''Effect of Feeding Distillers Grains on Dietary Crude Protein and Ammonia Emissions from Beef Cattle Feedyards.'' In Proceedings of the Texas Animal Manure Management Issues Conference, 83–90.

[89] Public Justice Comment Letter, Exhibit 39. Exhibit 39 is: Price et al., ''An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide,'' December 2011. For mitigation measures that may reduce ammonia emissions by 50–90%, for example, methods 43, 44, 47–51, 54–55, 62, 64, 70–71, and 73–74 on pages 70–71, 74–78, 81–84, 93–94, 105–108, and 110–112 respectively, achievable control efficiencies from these measures in the SJV would depend on an applicability and feasibility review.

[90] We note that District Rule 4570, Table 3.1, section F and Table 4.1, section F provide mitigation measure options for the storage of solid manure and separated solids from large dairy CAFs, including measures that involve covering dry manure piles and separated solids, respectively, outside of pens with a weatherproof covering from May through October. Thus, such mitigation measures, if selected, would not be required for the remaining four months of the year (June through September). Similar mitigation measure options in Rule 4570 for covering dry manure piles apply for beef feedlots, other cattle, swine, poultry, and other CAF types.

reductions.[91] Accordingly, the EPA concludes that the available information in the Plan is insufficient to conclude that the State has sufficiently examined and justified its estimate for the ammonia emission reductions that may be available from CAFs, which emit a majority of the ammonia in the SJV.

Regarding fertilizer application, Rule 4570 and Rule 4565 have provisions addressing the land application of manure from CAFs and of biosolids, animal manure, and poultry litter from composting operations (though these lack specific enforceable requirements for ammonia). However, more broadly, the District states that fertilizer application is the second largest ammonia source in the SJV and that the District does not have statutory authority to regulate such activities.[92] Notwithstanding this statement, the District describes key research assessing nitrogen in California, as well as regulations adopted by the California Water Resources Control Board, including orders adopted by the Central Valley Regional Water Quality Control Board (*e.g.,* a Nutrient Management Plan), the Irrigated Lands Regulatory Program (*e.g.,* a Nitrogen Management Plan), or other individual mechanisms.[93] These orders subject agricultural operators, including dairies, bovine feedlots, poultry operations, and crop farmers to ''waste discharge requirements that protect both surface water and groundwater.'' [94]

The EPA anticipates that such regulations are, in practice, likely to enhance the retention of nitrogen (whether from manure or nitrogen-based chemical fertilizers) for productive purposes in the SJV (*e.g.,* growing crops and enhancing soil health) and limit the loss of nitrogen as pollution to water and air (*e.g.,* potentially reduce ammonia emissions). However, to our knowledge, these regulations do not impose any enforceable requirement for ammonia emissions to the air, and thus render quantification difficult, as with Rule 4570.[95]

In addition, the District states that ''the overall efficiency of nitrogen usage at California farms is expected to increase and emissions of reactive nitrogen, including [ammonia], are expected to decrease significantly.'' We agree that managing the amount of nitrogen applied to the environment should reduce the potential for pollution to air, water, and land. However, the District does not attempt to quantify or otherwise substantiate the scale and timing of such potential ammonia emission reduction benefits, nor their enforceability, nor does it attempt to analyze how much additional reductions may be available. Overall, the EPA finds that the available evidence is insufficient to conclude that the State has sufficiently examined and justified its estimate for the ammonia emission reductions that may be available from fertilizer application, the second largest ammonia emission source in the SJV.

c. The EPA's Conclusion for Ammonia Precursor Demonstration

The EPA does not believe that the State has presented sufficient evidence that ammonia does not contribute significantly to $PM_{2.5}$ levels above the NAAQS. In the absence of an approved precursor demonstration, ammonia remains a plan precursor subject to the requirements of BACM, BACT, and additional feasible measures.

As discussed in our 2021 Proposed Rule,[96] the modeled response to 30% ammonia emissions reductions is above the EPA's recommended contribution threshold of 0.20 μg/m^3 at two monitoring sites, Madera and Hanford, providing evidence that ammonia significantly contributes to $PM_{2.5}$ in SJV. In the previous proposal, we gave those responses less weight, because of specific evidence available for these sites that the responses were overestimated. For Madera, the monitoring data used in estimating the model response are biased high, and therefore the modeled response of 0.21 μg/m^3, just above contribution threshold, is likely overestimated. For Hanford, several analyses showed ambient ammonia concentrations are underestimated, and so we believe that the modeled response of 0.26 μg/m^3 is likely overestimated. Supporting that conclusion is the evidence from ambient concentrations of excess ammonia relative to nitrate, which suggest that $PM_{2.5}$ responses to reductions of ammonia emissions would be dampened by the NO_X-limited nature of ammonium nitrate formation in the SJV.

All of those considerations remain for the current proposal. But in light of comments received and re-evaluation of the available evidence, the EPA believes we should give the Hanford response more weight, because that response would be larger if the ammonia reductions modeled were larger than the 30% assumed in the State's precursor demonstration. The previous subsection gave several examples of the uncertainty and possible underestimation of the ammonia benefit of available control measures to the SJV. The EPA does not believe there is sufficient quantitative evidence to rely on 30% as the amount of achievable reductions, and as the amount to use an upper bound on the ammonia emission reductions modeled in the State's precursor demonstration. A robust controls evaluation could show that a larger amount of reductions is achievable. If it is, then not only would the Hanford modeled response be larger, but additional monitoring sites could have a modeled response above the contribution threshold.

For example, with respect to the modeled 2024 ambient $PM_{2.5}$ responses to a 70% emission reduction, we note that the modeled high site of Bakersfield-Planz would have a response of 0.36 μg/m^3, the site with the largest modeled response would be 0.75 μg/m^3 at Hanford, and six sites (including Hanford) would have modeled responses greater than 0.5 μg/m^3. As a more modest example, interpolating between the available 30% and 70% modeled results, if 32% reductions are achievable, then three additional monitoring sites (Turlock, Merced-S. Coffee St., and Modesto) would reach the 0.2 μg/m^3 contribution threshold. The uncertainty over the ammonia response means that we cannot rely on 30% as an upper bound for ammonia emission reductions, and so the weight of evidence shifts relative to that in the 2021 Proposed Rule.

The discussion in this proposed rule, and the heavy reliance in the 2021 Proposed Rule, on the State's use of a 30% upper bound for potential reduction from controls should not be interpreted as establishing a 30% ''bright line'' for deciding whether a precursor should be regulated. The $PM_{2.5}$ Precursor Guidance recommends that 30% to 70% emissions reductions be modeled as a way of implementing the $PM_{2.5}$ SIP Requirements Rule's option in 40 CFR 51.1006(a)(1)(ii) for a State to assess the sensitivity of the atmospheric $PM_{2.5}$ to precursor emission reductions. The sensitivity of the atmosphere to reductions is a separate question from what reductions are achievable from controls; the latter is properly part of the control evaluation for BACM, BACT, and additional feasible measures. However, it is important to note that under 40 CFR

[91] In evaluating the aggregate reductions available across all sub-activities, it may be important to evaluate the extent to which reductions at one sub-activity may affect emissions at other stages of the process.

[92] 2018 $PM_{2.5}$ Plan, App. C, C–311.

[93] 2018 $PM_{2.5}$ Plan, App. C, C–339 to C–343.

[94] Id. at C–341.

[95] Unlike Rule 4570, which has been approved into the California SIP to limit VOC emissions, the State's water-related regulations on fertilizer application have not been submitted for approval into the California SIP.

[96] 86 FR 74310, 74320.

51.1010(a)(2)(ii), the EPA may require a control evaluation to help the EPA evaluate the precursor demonstration. The $PM_{2.5}$ Precursor Guidance explains that the additional information from a control evaluation is particularly important when modeled precursor contributions are close to the threshold for a 30% reduction.[97] But the regulations and guidance do not establish an automatic ''off ramp'' for a State to be discharged from the requirements for BACM, BACT, and additional feasible measures via a showing that achievable reductions are below a particular percentage.

We have no evidence that emission reductions below current emissions levels from BACM on all ammonia sources in the SJV would be as large as 70%, but the lack of a developed record showing what ammonia control measures are feasible and what they could achieve makes it harder for the EPA to assess this point. We also lack sufficient evidence to conclude that reasonable ammonia control measures could achieve no more than 30% reductions, and so cannot rely on that supposition in weighing the modeled responses to reductions and other evidence. Better quantification of the possible ammonia reductions from current levels that could result from additional controls would help resolve this issue. Reconciliation of modeled sensitivity with that expected from ambient studies would also be appropriate.

The EPA has re-examined the 2024 sensitivity analyses to both 30% and 70% ammonia emission reductions in light of the uncertainty that 30% represents a reasonable upper bound for potential ammonia emission reductions. We note that the State modeled 30% reduction scenarios and predicted ambient $PM_{2.5}$ responses above 0.2 $\mu g/m^3$ at 2 of 15 sites in 2024; and modeled the 70% reduction scenarios and predicted responses above 0.2 $\mu g/m^3$ at all monitors in 2024.[98] The EPA maintains that the State's reliance on its sensitivity-based contribution analysis for a future year (2024) to evaluate the significance of ammonia as a precursor is reasonable, well supported, and consistent with the EPA's guidance. There are also good reasons for giving less weight to the modeled responses at the Madera and Hanford sites, although those are tempered by the consideration that there is not good support for limiting the modeled ammonia reductions to 30%, leading to the possibility of larger responses at Hanford and of additional sites with responses above the contribution threshold.

The weight of the evidence, including at least one site above the EPA's recommended contribution threshold and the possibility of additional ones depending on the unknown amount of reductions achievable, favor retaining the presumption that ammonia must be regulated as a $PM_{2.5}$ precursor for the 2012 annual $PM_{2.5}$ NAAQS in the SJV. For the reasons explained above, the Plan both indicates that there are levels of ammonia control that could have a significant impact on $PM_{2.5}$ levels at multiple monitors in the SJV and does not dispose the potential availability of ammonia emission reductions at a level that would have such impacts. Therefore, the EPA proposes to disapprove the State's ammonia precursor demonstration for the Serious area requirements for purposes of the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

B. Best Available Control Measures

1. Statutory and Regulatory Requirements

Section 189(b)(1)(B) of the Act requires for any Serious $PM_{2.5}$ nonattainment area that the State submit provisions to assure that the best available control measures (BACM), including controls that reflect best available control technology (BACT), for the control of $PM_{2.5}$ and $PM_{2.5}$ precursors shall be implemented no later than four years after the date the area is reclassified as a Serious area. The EPA has defined BACM in the $PM_{2.5}$ SIP Requirements Rule to mean ''any technologically and economically feasible control measure that can be implemented in whole or in part within 4 years after the date of reclassification of a Moderate $PM_{2.5}$ nonattainment area to Serious and that generally can achieve greater permanent and enforceable emissions reductions in direct $PM_{2.5}$ emissions and/or emissions of $PM_{2.5}$ plan precursors from sources in the area than can be achieved through the implementation of reasonably available control measures (RACM) on the same source(s).'' [99]

The EPA generally considers BACM a control level that goes beyond existing RACM-level controls, for example by expanding the use of RACM controls or by requiring preventative measures instead of remediation.[100] Indeed, because states are required to implement BACM and BACT when a Moderate nonattainment area is reclassified as Serious due to its inability to attain the NAAQS through implementation of ''reasonable'' measures, it is logical that ''best'' control measures should represent a more stringent and potentially more technologically advanced or more costly level of control.[101] If RACM and RACT level controls of emissions have been insufficient to reach attainment, then the CAA Title I, Part D, subpart 4 provisions for $PM_{2.5}$ nonattainment plans contemplate the implementation of more stringent controls, controls on more sources, or other adjustments to the control strategy necessary to attain the NAAQS in the area. Thus, BACM/BACT determinations are to be ''generally independent'' of attainment for purposes of implementing the $PM_{2.5}$ NAAQS.[102]

Consistent with longstanding guidance provided in the General Preamble Addendum, the preamble to the $PM_{2.5}$ SIP Requirements Rule discusses the following steps for states to use in identifying and selecting the emission controls needed to meet the BACM/BACT requirements of 40 CFR 51.1010:

1. Develop a comprehensive emission inventory of all sources of $PM_{2.5}$ and $PM_{2.5}$ precursors from major and non-major stationary point sources, area sources, and mobile sources;
2. Identify potential control measures for all sources or source categories of emissions of $PM_{2.5}$ and relevant $PM_{2.5}$ plan precursors;
3. Determine whether an available control measure or technology is technologically feasible;
4. Determine whether an available control measure or technology is economically feasible; and
5. Determine the earliest date by which a control measure or technology can be implemented in whole or in part.[103]

The EPA allows states to consider factors such as a source's processes and operating procedures, raw materials, physical plant layout, and potential environmental impacts such as increased water pollution, waste disposal, and energy requirements when

[97] $PM_{2.5}$ Precursor Guidance, 31.

[98] 2018 $PM_{2.5}$ Plan, App. G, tables 4 through 7.

[99] 40 CFR 51.1000 (definitions). In longstanding guidance, the EPA has similarly defined BACM to mean, ''among other things, the maximum degree of emissions reduction achievable for a source or source category, which is determined on a case-by-case basis considering energy, environmental, and economic impacts.'' General Preamble Addendum, 42010, 42013.

[100] 81 FR 58010, 58081 and General Preamble Addendum, 42011, 42013.

[101] 81 FR 58010, 58081 and General Preamble Addendum, 42009–42010.

[102] $PM_{2.5}$ SIP Requirements Rule, 58081–58082. See also, General Preamble Addendum, 42011.

[103] 81 FR 58010, 58083–58085.

considering technological feasibility.[104] For purposes of evaluating economic feasibility, the EPA allows states to consider factors such as the capital costs, operating and maintenance costs, and cost effectiveness (*i.e.,* cost per ton of pollutant reduced by a measure or technology) associated with the measure or control.[105] For any potential control measure identified through the process described above that is eliminated from consideration, states are required to provide detailed written justification for doing so on the basis of technological or economic feasibility, including how its criteria for determining such feasibility are more stringent than those used for determining RACM/RACT.[106]

Once these analyses are complete, the State must use this information to develop enforceable control measures for all relevant source categories in the nonattainment area and submit them to the EPA for evaluation as SIP provisions to meet the basic requirements of CAA section 110 and any other applicable substantive provisions of the Act.

2. BACM for Ammonia Sources

As previously noted, as part of the EPA's 2021 Proposed Rule, we reviewed the State's analysis of ammonia control for the primary source categories of ammonia in the context of our evaluation of the State's precursor demonstration.[107] Because our prior proposal to approve the State's ammonia precursor demonstration would have relieved the State of its obligation to implement BACM for ammonia sources, we did not present a summary of the 2018 $PM_{2.5}$ Plan with respect to the BACM requirements for ammonia for the 2012 annual $PM_{2.5}$ NAAQS, nor our evaluation thereof. Given our reconsidered proposal to disapprove the State's ammonia precursor demonstration, in the following sections of this proposed rule we evaluate the District's control analysis for the two most substantial source categories of ammonia, which together sum to more than 90% of the emissions in the SJV: CAFs and fertilizer application.

a. Summary of State's Submission

The District presents its analysis of ammonia controls for the primary ammonia source categories in the SJV in Appendix C, section C.25 (''Ammonia in the San Joaquin Valley'') of the 2018 $PM_{2.5}$ Plan. The District evaluated its emission control measures for compliance with BACM for CAFs and described water-related measures applicable to fertilizer application that have co-benefits to air quality. The District presents its reasoning that measures that control VOC emissions, such as Rule 4570 for CAFs, also reduce ammonia emissions due to the physical processes occurring in decomposing manure and subsequent volatilization of decomposition products (like VOC and ammonia). As part of its process for identifying candidate BACM, considering the technical and economic feasibility of additional control measures, the District reviewed the EPA's guidance documents on BACM, and control measures implemented in other nonattainment areas in California and other states.[108]

For CAFs, the District discusses in detail how Rule 4570 (''Confined Animal Facilities'') is structured (*e.g.,* to address varying types of CAFs, including applicability thresholds); the five main CAF operations/emission sources: feeding, housing (including distinctions for housing configurations), solid waste, liquid waste, and land application of manure; and the control menu requirements for each of those five operations.[109] The District summarizes the specific requirements applicable to each type of cattle-based CAF, including dairies, beef feedlots, and ''other cattle'' and describes its basis for ammonia emission reductions estimates, including cited research papers.

The District also compares Rule 4570 to other CAF rules imposed by the South Coast Air Quality Management District (AQMD), Bay Area AQMD, Sacramento Metropolitan AQMD, Imperial County Air Pollution Control District (APCD), and the State of Idaho.[110] The District evaluates a potential additional control measure—application of sodium bisulfate to reduce pH and bacterial levels in bedding for dairy cattle—and concludes that such measure is not feasible based on a number of factors, including health and safety of dairy workers and animals, impacts on water quality, and overall cost and effectiveness.[111]

For fertilizer application, as described in section II.A.3 of this proposed rule, the District states that fertilizer application is the second largest ammonia source in the SJV and that the District does not have statutory authority to regulate such activities.[112] Notwithstanding, the District describes how regulations adopted by the California Water Resources Control Board, including orders adopted by the Central Valley Regional Water Quality Control Board (*e.g.,* a Nutrient Management Plan), the Irrigated Lands Regulatory Program (*e.g.,* a Nitrogen Management Plan), or other individual mechanisms [113] subject agricultural operators, including dairies, bovine feedlots, poultry operations, and crop farmers to ''waste discharge requirements that protect both surface water and groundwater.'' [114]

Overall, the District concludes that ''the Valley's ammonia emissions have been significantly reduced through stringent regulations, that additional ammonia control measures are infeasible, and that Valley sources are already implementing BACM.'' [115]

b. Summary of Adverse Comments

Public Justice states that ''[w]eaker controls are consistently allowed for agricultural sources,'' including an ''expansive menu of control options'' in Rule 4570, that they assert provide little to no emission reduction benefit.[116] More broadly, as described in section II.A.2 of this proposed rule, the commenters assert that ''[t]he analysis of potential controls is particular[ly] weak and ignores the wealth of literature demonstrating that strategies for reducing ammonia emissions from agriculture . . . are among the most effective for also reducing PM concentrations,'' and cite several studies in support of this argument.[117] The commenters further state that reducing ammonia emissions may be achieved through ''strategies such as improving livestock feed to reduce excreted nutrients, altering manure storage and handling practices to prevent [ammonia] emissions, and improving synthetic fertilizer use efficiency,'' again citing numerous studies.[118] The commenters

[104] 40 CFR 51.1010(a)(3)(i).

[105] 40 CFR 51.1010(a)(3)(ii).

[106] 40 CFR 51.1010(a)(3)(iii).

[107] 86 FR 74310, 74319. See also, 85 FR 17382, 17395 (March 27, 2020), and the EPA's $PM_{2.5}$ Precursor TSD, 13.

[108] 2018 $PM_{2.5}$ Plan, Chapter 4, section 4.3.1.

[109] 2018 $PM_{2.5}$ Plan, App. C, C–312 to C–323.

[110] 2018 $PM_{2.5}$ Plan, App. C, C–323 to C–337.

[111] 2018 $PM_{2.5}$ Plan, App. C, C–338 to C–339.

[112] 2018 $PM_{2.5}$ Plan, App. C, C–311.

[113] 2018 $PM_{2.5}$ Plan, App. C, C–339 to C–343.

[114] 2018 $PM_{2.5}$ Plan, App. C, C–341.

[115] 2018 $PM_{2.5}$ Plan, App C., C–312.

[116] Public Justice Comment Letter, 20.

[117] Public Justice Comment Letter, 16, Exhibits 31 through 34.

[118] Public Justice Comment Letter, 17, Exhibits 35 through 40 and three additional studies: N. Cole, et al., ''Influence of dietary crude protein concentration and source on potential ammonia emissions from beef cattle manure,'' J. Anim. Sci. 83, 722, 2005; N. Cole, P. Defoor, M. Galyean, G. Duff, J. Gleghorn, ''Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers,'' J. Anim. Sci. 12, 3421–3432, 2006; and R. Todd, N. Cole, R. Clark, ''Reducing crude protein in beef cattle diet reduces

argue that the EPA ''should reject the plan's BACM analysis for failing to justify these weaker controls, and for being inconsistent with the Title VI prohibition against policies and practices that inflict disparate impacts.''

c. The EPA's Reconsidered Proposal

As a result of our proposed conclusion that ammonia remains a regulated precursor for the 2012 annual $PM_{2.5}$ NAAQS in the SJV, the EPA has evaluated potential ammonia emissions control measures for the two most substantial source categories in the SJV and evaluated whether the State has implemented ammonia controls with a BACM/BACT level of stringency. Thus, the EPA has also evaluated the existing control measures that the State claims are BACM for two of the main sources of ammonia in the area, including confined animal facilities (CAFs) and fertilizer application.[119] As discussed below, we conclude that the SJV has not established that it has enforceable requirements in the SIP that meet a BACM level of stringency to reduce ammonia emissions from these two categories. Therefore, we propose to disapprove BACM for ammonia sources in the SJV.

Our basis for proposing to disapprove BACM for ammonia sources flows from the controls analysis we have reviewed and discuss in section II.A.3 of this proposed rule. We agree with the commenters that the analysis of potential controls in the 2018 $PM_{2.5}$ Plan was weak in two general areas: (1) incomplete quantification of existing ammonia emission reductions, and (2) lack of consideration of potential ammonia control measures identified in research studies. In that section we describe the Plan's weaknesses with respect to quantifying emission reductions and rely on that description for purposes of evaluating BACM.

Similarly, in section II.A.3, we discuss additional options for ammonia control that we will not reiterate here. Based on our review of the additional research studies cited by the commenters with respect to CAFs, measures such as those for adjusting the protein content of livestock feed (*e.g.,* reducing the portion of beef cattle finishing diets by 1.5% steam-flaked corn), manure handling and storage (*e.g.,* washing dairy cow collecting yards after each milking event, covering solid manure stores with sheeting), and land application of slurry (*e.g.,* injection application techniques), it appears that additional measures may be available to evaluate. Absent a thorough and more current evaluation of technological and economic feasibility of potential measures as applied in the SJV, we propose to find that the State has not demonstrated whether or how additional measures (*e.g.,* in the form of existing options that could also be feasibly implemented, or new options that may lead to increased reductions) may have been evaluated, implemented (even partially) by the existing rules, or set aside for reasons of technological feasibility or economic feasibility, consistent with the BACM requirements.

For fertilizer application, as discussed in section II.A.3 of this proposed rule, the District indicates that it does not have authority to regulate ammonia emissions from fertilizer application. Regardless of which State entity, as a matter of State law, has authority over this class of activities, CAA section 189(b)(1) requires that the State include provisions to ensure implementation of BACM for direct $PM_{2.5}$ and plan precursor emissions, and CAA section 110(a)(2)(E)(i) requires the State to provide necessary assurances that it has adequate authority to carry out the implementation plan for the area. While the Plan describes certain water-related measures (*e.g.,* Nutrient Management Plans and Nitrogen Management Plan) that subject agricultural operators, including dairies, bovine feedlots, poultry operations, and crop farmers to waste discharge requirements, and likely limit ammonia emissions to the air, to our knowledge, these regulations do not impose any enforceable requirement for ammonia emissions to the air, and thus suffer a similar problem as Rule 4570.[120]

We agree that as a general matter, managing the amount of nitrogen applied to the environment should reduce the potential for pollution to air, water, and land. However, the 2018 $PM_{2.5}$ Plan does not quantify or otherwise substantiate the scale and timing of such potential ammonia emission reduction benefits, nor their enforceability. We propose that the State has not adequately identified potential control measures, evaluated for BACM/BACT, nor demonstrated the implementation of BACM/BACT for controlling ammonia emissions from fertilizer application, the second largest source of such emissions in the SJV.

As a result of our proposal that the State has not demonstrated that BACM/BACT controls are in place for CAFs and fertilizer application, two source categories that make up more than 90% of the ammonia emissions in the SJV, we propose to disapprove the State's BACM demonstration for ammonia sources.

3. BACM for Building Heating Emission Sources

a. Summary of 2021 Proposed Rule

In our 2021 Proposed Rule, the EPA summarized the State's submission in the 2018 $PM_{2.5}$ Plan for the SJV and presented our BACM evaluation for emission sources of direct $PM_{2.5}$ and NO_X.[121] We briefly summarize those components here with respect to the State's BACM demonstration for building heating emission sources, such as water heaters and space heaters (*e.g.,* furnaces), in the SJV.

In Appendix C of the 2018 $PM_{2.5}$ Plan, the District identifies the stationary and area sources of direct $PM_{2.5}$ and NO_X in the SJV that are subject to District emission control measures and provides its evaluation of these regulations for compliance with BACM requirements. As part of its process for identifying candidate BACM, the District reviewed the EPA's guidance documents on BACM, additional guidance documents on control measures for direct $PM_{2.5}$ and NO_X emission sources, and control measures implemented in other ozone and $PM_{2.5}$ nonattainment areas in California and other states.[122] Based on these analyses, the District concludes that all best available control measures for stationary and area sources are in place in the SJV for NO_X and directly emitted $PM_{2.5}$ for purposes of meeting the BACM/BACT requirement for the 2012 annual $PM_{2.5}$ NAAQS.

With respect to building heating emission sources, the District presents its evaluations of Rule 4902 (''Residential Water Heaters'') and Rule 4905 (''Natural Gas-Fired, Fan-Type Central Furnaces'') in sections C.20 and C.21, respectively, of Appendix C of the 2018 $PM_{2.5}$ Plan. Both rules are point of sale rules that limit what kinds of residential water heaters and furnaces may be sold in the SJV. The District describes the types of equipment covered by each rule, compares the specific provisions of each rule that

ammonia emissions from artificial feedyard surfaces,'' J. Environ. Qual. 35, 404–411, 2006.

[119] By focusing on these two source categories, the EPA is not indicating that this is an exhaustive list of ammonia source categories that must be evaluated for BACM. However, because these two categories amount to more than 90% of the ammonia emissions in the SJV, we focus our analysis on these two categories.

[120] Unlike Rule 4570, which has been approved into the California SIP to limit VOC emissions, the State's water-related regulations on fertilizer application have not been submitted for approval into the California SIP.

[121] 86 FR 74310, 74324–74325.

[122] 2018 $PM_{2.5}$ Plan, Ch. 4, section 4.3.1.

limit NO_X emissions [123] to comparable rules in other California air districts, and concludes that each rule represents BACM for their respective source category.

Rule 4902 applies to natural gas-fired, residential water heaters with heat input rates less than or equal to 75,000 British thermal units per hour (Btu/hr). The District tightened the rule's NO_X limits in 2009; and the EPA approved the rule into the SIP in 2010.[124] The District estimates that, due to Rule 4902, annual average emissions of NO_X would decrease from 2.15 tpd in 2013 to 1.91 tpd in 2025 (0.24 tpd decrease) and annual average emissions of direct $PM_{2.5}$ would increase from 0.21 tpd in 2013 to 0.23 tpd in 2025 (0.02 tpd increase).[125]

In addition to comparing the NO_X limits in its Rule 4902 to rules in other California air districts, the District also presents a multi-factor comparison of natural gas-fired and propane-fired, water heaters to electric water heaters.[126] The District discussed the likely impacts of requiring electric water heaters, including the advantages such as no NO_X emissions,[127] less expensive purchase price, and smaller size, and the disadvantages such as higher cost of electricity, and the costs of residence modifications to convert to electric. Based on 2017–2018 data, which is consistent with the timing of Plan adoption in 2018, the District calculated emission reductions and cost effectiveness of the three kinds of water heaters by fuel type and concluded that ''[w]hile the lifetime cost of an electric water heater is higher than that of propane and natural gas, the emissions benefits may make converting to electric water heating a viable control strategy.'' [128] The analysis does not explore the cost effectiveness of such controls and Rule 4902 does not include any requirements regarding electrification.

Rule 4905 applies to natural gas-fired, fan-type central furnaces with heat input rates less than 175,000 Btu/hr and combination heating and cooling units with a rated cooling capacity of less than 65,000 Btu/hr. In 2015, the District tightened the rule's NO_X limits for residential units and expanded the rule to include commercial units and manufactured homes according to a phase-in schedule. The EPA approved the rule into the SIP in 2016.[129] The District estimates that, due to Rule 4905, annual average emissions for NO_X will decrease from 2.44 tpd in 2013 to 2.13 tpd in 2025 (0.31 tpd decrease) and annual average emissions for direct $PM_{2.5}$ will increase from 0.20 tpd in 2013 to 0.22 tpd in 2025 (0.02 tpd increase).[130] Given the need to extend certain compliance deadlines in subsequent amendments to Rule 4905 due to limited supply of certified compliant units,[131] the District states that it had identified no additional emission reduction measures for this source category as of that point in time.[132]

As noted in the EPA's 2021 Proposed Rule, we provided our evaluation of the District's BACM demonstration for stationary and area sources in general, and several source categories in more detail, in three documents: (1) section III of the EPA's ''Technical Support Document, EPA Evaluation, San Joaquin Valley Serious Area Plan for the 2012 Annual $PM_{2.5}$ NAAQS,'' December 2021 (''EPA's 2012 Annual $PM_{2.5}$ TSD''); (2) the EPA's ''Technical Support Document, EPA Evaluation of BACM/MSM, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS,'' February 2020 (''EPA's BACM/MSM TSD''); and (3) the EPA's ''Response to Comments Document for the EPA's Final Action on the San Joaquin Valley Serious Area Plan for the 2006 $PM_{2.5}$ NAAQS,'' June 2020 (''EPA's 2020 Response to Comments''). In particular, the EPA's 2020 Response to Comments presented our evaluation of the District's BACM demonstration for residential water heaters and residential and commercial, natural gas-fired, fan-type central furnaces.[133] At that time we found that the requirements for residential fuel combustion covered by Rule 4902 and Rule 4905 represented BACM.[134] In addition, the EPA concluded that setting a zero-NO_X standard for heating appliances in new buildings reasonably requires additional consideration and analysis of technological and economic feasibility by the District because, per the 2018 $PM_{2.5}$ Plan, the most common types of residential water heaters and furnaces are those that use natural gas as fuel.

We also noted that the building codes referenced by commenters at that time appear to be green building code ordinances that restrict or prohibit installation of natural gas or propane appliances in new construction.[135] Such ordinances, most of which appeared to have been adopted in late 2019 and early 2020, fell within a category known as ''reach codes,'' which are city and county building code standards for energy efficiency that exceed California's State-wide standards. We stated that California law requires local governments to submit proposed ordinances to the California Energy Commission (CEC) for a determination that they will be both cost effective and more energy efficient than statewide standards; compliance with this procedure is necessary for such measures to be enforceable.[136] We also noted that ordinances adopted by city councils and county officials are legally distinct from measures adopted by the governing boards of the respective air districts and that it did not appear at the time that California air districts had adopted similar restrictions.

b. Summary of Adverse Comments

Public Justice states that further emission controls are available for building heating via the electrification of furnaces, water heaters, and other gas-fired appliances.[137] The commenters refer to comments submitted by a group of environmental, public health, and community organizations (collectively referred to herein as ''NPCA'') on the EPA's proposed rule on the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan,[138] noting that building electrification requirements to reduce emissions from such sources already

[123] The District notes that equipment subject to Rule 4902 are fired on natural gas that meets California Public Utility Commission standards and, therefore, emit only low amounts of SO_X and direct $PM_{2.5}$. 2018 $PM_{2.5}$ Plan, App. C, C–288.

[124] 75 FR 24408 (May 5, 2010).

[125] 2018 $PM_{2.5}$ Plan, App. C, C–283.

[126] 2018 $PM_{2.5}$ Plan, App. C, C–288 to C–289.

[127] The EPA notes that while the NO_X emissions of electric water heaters and furnaces are zero, there could be an increase in NO_X emissions from electric power plants.

[128] 2018 $PM_{2.5}$ Plan, App. C, C–289.

[129] 81 FR 17390 (March 29, 2016).

[130] 2018 $PM_{2.5}$ Plan, App. C, C–290.

[131] The District further amended Rule 4902 in 2018, 2020, and 2021 to extend the compliance deadline for specific units due to limited supply of certified compliant units, with each amendment applying to a smaller subset of those specific units. See, *e.g.,* San Joaquin Valley UAPCD, ''Item Number 10: Adopt Proposed Amendments to Rule 4905 (Natural Gas-Fired, Fan-Type Central Furnaces),'' December 16, 2021, 2–3.

[132] 2018 $PM_{2.5}$ Plan, App. C, C–293. Unlike the District's consideration of electric water heaters, the District did not present an evaluation of electric furnaces in its analysis of Rule 4905.

[133] EPA's 2020 Response to Comments, Comment 6.O and Response 6.O, 142–148.

[134] EPA's 2020 Response to Comments, 146–147.

[135] EPA's 2020 Response to Comments, 147–148.

[136] California 2019 Building Energy Standards, at California Code of Regulations (CCR), Title 24, Part 1, Article 1, Sec. 10–106 (''Locally Adopted Energy Standards''); see also *https://ww2.energy.ca.gov/title24/2016standards/ordinances.*

[137] Public Justice Comment Letter, 19.

[138] Comment letter dated and received April 27, 2020, from Mark Rose, NPCA, et al., to Rory Mays, EPA, including Appendices A through G. The seven environmental and community organizations, in order of appearance in the letter, are the National Parks Conservation Association (NPCA), Earthjustice, Central Valley Air Quality Coalition, Coalition for Clean Air, Central Valley Environmental Justice Network, The Climate Center, and Central Valley Asthma Collaborative (collectively ''NPCA'').

exist in over 30 jurisdictions in California and other states. The commenters state that, since that time, additional jurisdictions have moved forward with gas bans, appliance standards, and other strategies for building heating.[139]

With respect to the EPA's response to the NPCA comments in 2020,[140] Public Justice argues that the ''EPA merely asserted that the District had found increased building electrification infeasible,'' despite the record showing that other jurisdictions required such measures, and assert that the District noted the potential of such measures but rejected them without explanation. The commenters further argue that the EPA did not rebut evidence on the benefits and feasibility of such measures, instead noting the need for further consideration, and that two years later, the Plan does not provide further consideration.

c. The EPA's Reconsidered Proposal

Based on the adverse comments from Public Justice, the EPA has reconsidered our proposed approval of the State's demonstration of BACM for NO_X and direct $PM_{2.5}$ emissions from building heating appliances, such as residential water heating and residential and commercial space heating. As discussed below, we now propose to disapprove the State's BACM demonstration for such building heating emission sources.

Although the EPA has previously approved the State's BACM demonstration for building heating emission sources in 2020 with respect to the 2006 24-hour $PM_{2.5}$ NAAQS portion of the 2018 $PM_{2.5}$ Plan, and such approval was upheld by the Ninth Circuit Court of Appeals,[141] several factors have reshaped the facts and circumstances of controlling emissions from such sources as of 2022 and beyond. First, while building ordinances that restrict or prohibit installation of natural gas or propane appliances in new construction were starting to appear in 2019 and 2020, as Public Justice correctly asserts, two additional years have passed and additional jurisdictions have adopted gas bans, appliance standards, and other strategies for building heating.[142] A recent policy brief published by the UCLA School of Law states that 52 cities and counties in California have adopted building codes to reduce their reliance on gas for building heating appliances, and discusses several examples.[143] The growth in the number and types of local control measures to reduce pollution from building heating by restricting or limiting the use of natural gas-fired heaters support their general availability as technologically feasible measures.

Second, the time horizon of the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan is one year later (2025 attainment date) than that of the 2006 24-hour $PM_{2.5}$ NAAQS portion of the Plan (2024 attainment date), affording additional time for potential control measures to achieve emission reductions that may assist attainment of the 2012 annual $PM_{2.5}$ NAAQS. Even if full implementation of such new measures is not possible by the applicable attainment date, the State should evaluate whether they could be implemented in part, consistent with the fifth step for BACM/BACT evaluation discussed in the $PM_{2.5}$ SIP Requirements Rule and the General Preamble (*i.e.,* to determine the earliest date by which a control measure or technology can be implemented in whole or in part).[144]

Third, some of the underlying bases for the District's cost comparison for residential water heating may have changed since the District's 2018 adoption of the Plan. For example, in comparing emission reductions and cost effectiveness of low-NO_X natural gas, propane, and electric water heaters, the District used data on energy factors and purchase price from Grainger Industrial Supply as of June 14, 2018, and lifetime energy cost data from the U.S. Energy Information Administration as of 2017. Furthermore, as claimed by Public Justice, the District did not explain its rejection of additional control measures of this type, other than to assert that they were generally more costly. Regarding residential and commercial space heating, CARB and the District did not provide a detailed economic feasibility analysis in the Plan. CARB and the District simply stated that, due to limited supply of certified compliant natural gas-fired units to comply with Rule 4905, they could identify no additional emission reduction measures. The incomplete cost analyses presented by the District, changes in costs over time, and lack of justification for rejecting measures to reduce pollution from building heating by restricting or limiting the use of natural gas-fired heaters indicate an insufficient economic feasibility analysis.

Fourth, CARB and at least one other air district (Bay Area AQMD) are moving forward in developing measures to set zero-emission standards for space heaters and water heaters. In developing its 2022 State SIP Strategy (for the 2015 ozone NAAQS), CARB has stated that the ''fuels we use and burn in buildings, primarily natural gas, for space and water heating contribute significantly to building-related criteria pollutant and GHG emissions and provide an opportunity for substantial emissions reductions where zero-emission technology is available.'' [145] Accordingly, CARB is developing zero-emission standard concepts and, given the intersection of air quality needs and other areas of building and energy regulation, and identifying other regulatory entities that they plan to engage, including the U.S. Department of Energy, CEC, and the California Building Standards Commission, Department of Housing and Community Development. We note, however, that the proposed 2022 State SIP Strategy released August 12, 2022, anticipates implementation starting in 2030, pending rule development and CARB Board hearing in 2025.[146]

The Bay Area AQMD hosted public meetings in 2021 and developed draft amendments to certain rules that would reduce NO_X emissions from residential and commercial furnaces and water heaters.[147] Specifically, Bay Area AQMD has developed draft amendments to two rules: (1) Regulation 9, Rule 4 (''Nitrogen Oxides from Fan Type Residential Central Furnaces''), which applies to furnaces with a heat input rate of less than 175,000 Btu/hr and combination heating and cooling units with a rated cooling capacity of less than 65,000 Btu/hr (like SJVUAPCD Rule 4905); and (2) Regulation 9, Rule 6 (''Nitrogen Oxides Emissions from

[139] Public Justice Comment Letter, 19, and Exhibits 41 through 44. Commenters also state that studies suggest these measures may provide particularly notable benefits to winter $PM_{2.5}$ peaks in the SJV. Id. at 19.

[140] EPA, ''Response to Comments Document for the EPA's Final Action on the San Joaquin Valley Serious Area Plan for the 2006 $PM_{2.5}$ NAAQS,'' June 2020. See Comment 6.O and Response 6.O on pages 142–147.

[141] Ninth Circuit Memorandum Order, 9. Regarding increased building electrification requirements, the Court stated that ''the EPA considered such an approach and reasonably accepted the State's determination that it was not feasible at this time.''

[142] See Public Justice Comment Letter, Exhibits 41 through 44.

[143] Heather Dadashi, Cara Horowitz, and Julia Stein, ''Pritzker Environmental Law and Policy Briefs, How Air Districts Can End NO_X Pollution From Household Appliances,'' Emmett Institute on Climate Change and the Environment, UCLA School of Law, March 2022, 8.

[144] 81 FR 58010, 58083–58085.

[145] CARB, ''Draft 2022 State Strategy for the State Implementation Plan,'' January 31, 2022, 86–88.

[146] CARB, ''Proposed 2022 State Strategy for the State Implementation Plan,'' August 12, 2022, 101–103.

[147] A summary of the Bay Area AQMD's rule development is available at: *https://www.baaqmd.gov/rules-and-compliance/rule-development/building-appliances.*

Natural Gas-Fired Boilers and Water Heaters''), which applies to water heaters with a rated heat input capacity of 75,000 Btu/hr or less (like SJVUAPCD Rule 4902), as well as additional source types and sizes.[148]

For Rule 4, Bay Area AQMD staff have developed draft amendments to lower the current NO_X emission limit for applicable furnaces from 40 nanograms of NO_X per joule of useful heat (ng/j) to 14 ng/j (which would match the limit in SJVUAPCD Rule 4905) in the short term (with a compliance date of January 1, 2023); followed by a zero-NO_X emission requirement (with a compliance date of January 1, 2029); and expand the applicability beyond fan-type central furnaces to other types of equipment (*e.g.,* wall furnaces and direct vent units).[149] For Rule 6, which contains NO_X limits for small boilers and water heaters, Bay Area AQMD staff proposes a zero-NO_X emission requirement. However, staff also note that while technologies achieving zero-NO_X emissions exist, ''they are limited in availability and can be expensive,'' that such standards would be ''technology and market-forcing,'' and, therefore, staff proposes compliance dates of January 1, 2027, and January 1, 2031, depending on equipment heat rate (*i.e.,* the size of the boiler or water heater).[150]

CARB and Bay Area AQMD efforts in this area underscore the importance of building heating emission sources, such as water heaters and space heaters (*e.g.,* furnaces), throughout California and the continued effort to implement available control measures for these sources for criteria pollutant attainment planning requirements. At the same time, while SJVUAPCD, CARB, and Bay Area AQMD each acknowledge that zero-NO_X emission technology for small residential and commercial space and water heating is available, it is unclear what a feasible implementation horizon might be in light of CARB's strategy and the Bay Area AQMD's draft amendments. The plan as submitted did not address how such implementation considerations may or may not affect the feasibility of setting such zero-NO_X emission standards for space and water heating in small residential and commercial buildings in the SJV.

Given the factors discussed above, we now propose that the State has not adequately identified potential control measures, evaluated for BACM/BACT, nor demonstrated the implementation of BACM/BACT for controlling NO_X and direct $PM_{2.5}$ emissions from building emission heating sources in the SJV.

C. Attainment Demonstration

1. Summary of 2021 Proposed Rule

In sections IV.C (air quality modeling) and IV.F (attainment demonstration) of our 2021 Proposed Rule, the EPA summarized the CAA and regulatory requirements for air quality modeling and attainment demonstrations, the State's submission in the SJV $PM_{2.5}$ Plan, and our evaluation thereof.[151] We briefly summarize those components herein.

Sections 188(c)(2) and 189(b)(1)(A) of the CAA require that Serious area plans must include a demonstration (including air quality modeling) that provides for attainment of the $PM_{2.5}$ NAAQS as expeditiously as practicable, but no later than the end of the tenth calendar year after the area's designation as nonattainment. The $PM_{2.5}$ SIP Requirements Rule also specifies that the control strategy in a Serious area attainment plan must provide for attainment as expeditiously as practicable.[152] The outermost statutory Serious area attainment date for the 2012 annual $PM_{2.5}$ NAAQS in the SJV is December 31, 2025 (absent an EPA-approved attainment date extension request under CAA section 188(e)). For purposes of determining the attainment date that is as expeditious as practicable, the State must conduct future year modeling that takes into account emissions growth, known emissions controls (including any controls that were previously determined to be RACM/RACT or BACM/BACT), any other emissions controls required to meet BACM/BACT, and additional measures as needed for expeditious attainment of the NAAQS. The regulatory requirements for Serious area plans are codified at 40 CFR 51.1010 (control strategy requirements) and 40 CFR 51.1011(b) (attainment demonstration and modeling requirements). We also described the EPA's $PM_{2.5}$ modeling guidance (''Modeling Guidance''),[153] including our recommendations therein for photochemical modeling, inputs, procedures, performance evaluation, emissions simulation, and calculating relative response factors (RRFs).

With respect to air quality modeling, the 2018 $PM_{2.5}$ Plan included the State's modeled attainment demonstration projecting that the SJV will attain the 2012 annual $PM_{2.5}$ NAAQS by December 31, 2025; the State's primary discussion of the photochemical modeling appears in Appendix K (''Modeling Attainment Demonstration''). The State provides a conceptual model of $PM_{2.5}$ formation in the SJV as part of the modeling protocol in Appendix L (''Modeling Protocol'') and describes emission input preparation procedures. The State presents additional relevant information in Appendix C (''Weight of Evidence Analysis'') of CARB's staff report for the 2018 $PM_{2.5}$ Plan,[154] which includes ambient trends and other data in support of the demonstration of attainment by 2025.

In the 2021 Proposed Rule, the EPA presented its review of the State's modeling approach and its many interconnected facets, including model input preparation, model performance evaluation, use of the model output for the numerical NAAQS attainment test, and modeling documentation, and found it to be generally consistent with the EPA's recommendations in the Modeling Guidance. We incorporated our evaluation of the Plan's modeling for the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan[155] and extended that evaluation with information specific to the 2012 annual $PM_{2.5}$ NAAQS. Overall, in the 2021 Proposed Rule, we considered the State's analyses consistent with the EPA's guidance on modeling for $PM_{2.5}$ attainment planning purposes and proposed to find that the modeling in the 2018 $PM_{2.5}$ Plan was adequate for the purposes of supporting the State's RFP demonstration and the attainment demonstration.

With respect to the attainment demonstration, the SJV $PM_{2.5}$ Plan includes a modeled demonstration projecting attainment of the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, based on emission reductions

[148] As in the San Joaquin Valley, larger boilers and similar equipment used in industrial, institutional, and large commercial settings are subject to other rules of the Bay Area AQMD, and therefore not subject to Rule 4 or Rule 6.

[149] Bay Area AQMD, ''Workshop Report, Draft Amendments to Building Appliance Rules—Regulation 9, Rule 4: Nitrogen Oxides from Fan Type Residential Central Furnaces and Rule 6: Nitrogen Oxide Emissions from Natural Gas-Fired Boilers and Water Heaters,'' September 2021, 1.

[150] Id.

[151] 86 FR 74310, 74322–74324 (air quality modeling) and 74325–74338 (attainment demonstration).

[152] 40 CFR 51.1011(b)(1); 81 FR 58010, 58087.

[153] Memorandum dated November 29, 2018, from Richard Wayland, Air Quality Assessment Division, OAQPS, EPA, to Regional Air Division Directors, EPA, Subject: ''Modeling Guidance for Demonstrating Air Quality Goals for Ozone, $PM_{2.5}$, and Regional Haze,'' (''Modeling Guidance'').

[154] CARB, ''Staff Report, Review of the San Joaquin Valley 2018 Plan for the 1997, 2006, and 2012 $PM_{2.5}$ Standards,'' release date December 21, 2018 (''CARB Staff Report'').

[155] EPA Region IX, ''Technical Support Document, EPA Evaluation of Air Quality Modeling, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS,'' February 2020 (''EPA's 2006 NAAQS Modeling TSD'').

from implementation of baseline control measures and the development, adoption, and implementation of additional control measures to meet specific enforceable commitments. In the EPA's 2021 Proposed Rule, we described how the Plan's control strategy was to reduce emissions from sources of NO_X and direct $PM_{2.5}$ and that most of the projected emission reductions are achieved by baseline measures—*i.e.,* the combination of State and District measures adopted prior to the State's and District's adoption of the Plan—that will achieve ongoing emission reductions from the 2013 base year to the 2025 projected attainment year.

The remainder of the Plan's emission reductions are to be achieved by additional measures to meet enforceable commitments, including potential regulatory and incentive-based measures and, as necessary, substitute measures.[156] In the Valley State SIP Strategy and the 2018 $PM_{2.5}$ Plan, CARB and the District, respectively, included commitments to take action on specific measures by specific years or to develop substitute measures (referred to as ''control measure commitments'') and to achieve specified amounts of NO_X and direct $PM_{2.5}$ emission reductions by certain dates (referred to as ''aggregate tonnage commitments'').[157] We refer to these complementary commitments herein as ''aggregate commitments.''

In the 2021 Proposed Rule, the EPA described several findings relating to our evaluation of the SJV $PM_{2.5}$ Plan's attainment demonstration. First, we proposed to approve the Plan's emissions inventories and to find the Plan's air quality modeling adequate.[158] Second, we proposed to find that the Plan provides for expeditious attainment through the timely implementation of the control strategy to reduce emissions from sources of NO_X and direct $PM_{2.5}$, including RACM, BACM, and any other emission controls necessary for expeditious attainment.

Third, the EPA proposed to find that the emissions reductions that are relied on for attainment in the SIP submission are creditable. We noted that the SJV $PM_{2.5}$ Plan relies principally on already adopted and approved rules to achieve the emissions reductions needed to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, and that the balance of the reductions that the State has modeled to achieve attainment by this date is currently represented by enforceable commitments that account for 13.8% of the NO_X and 8.0% of the direct $PM_{2.5}$ emissions reductions needed for attainment. In terms of our evaluation of CARB and the District's enforceable commitments, we proposed to find that circumstances in the SJV for the 2012 annual $PM_{2.5}$ NAAQS warrant the consideration of enforceable commitments and that the EPA's three criteria for such commitments had been met: (1) the commitments constitute a limited portion of the required emissions reductions; (2) both CARB and the District have demonstrated their capability to meet their commitments; and (3) the commitments are for an appropriate timeframe. We therefore proposed to approve the State's reliance on these enforceable commitments in its attainment demonstration.

Overall, in the 2021 Proposed Rule, we proposed to approve the SJV $PM_{2.5}$ Plan's demonstration of attainment of the 2012 annual $PM_{2.5}$ NAAQS by December 31, 2025, consistent with the requirements of CAA section 189(b)(1)(A). We presented the basis for our proposed determination in sections IV.F.3.a through IV.F.3.e of the 2021 Proposed Rule and provided further detail of our evaluation of baseline measures and the additional measures and aggregate commitments in sections II and IV, respectively, of the EPA's 2012 Annual $PM_{2.5}$ TSD.

2. Summary of Ninth Circuit Order and Adverse Comments

As introduced in section I.D of this proposed rule, in response to a petition for review of the EPA's approval of the 2006 24-hour $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan, the Ninth Circuit Court of Appeals issued a Memorandum Opinion that, in part, vacated the final action with respect the EPA's second factor for evaluating the validity of the State's enforceable commitments (*i.e.,* whether the State is capable of fulfilling its commitment). The Ninth Circuit's order is very relevant to this proposed rule because the State relied on the same common control strategy, including the same set of enforceable commitments (*i.e.,* the same set of control measure commitments and aggregate tonnage commitments) for both the 2006 24-hour $PM_{2.5}$ NAAQS Serious area plan and the 2012 annual $PM_{2.5}$ NAAQS Serious area plan.

The Ninth Circuit found that the EPA ''fail[ed] to provide evidence or a reasoned explanation for its conclusion that California will be able to fulfill its commitment'' in the face of a potential multi-billion dollar funding shortfall for incentive-based control measure commitments, ''which could result in emission reduction shortfalls of approximately 7% of the total NO_X reductions and 8% of the total $PM_{2.5}$ reductions necessary for attainment.'' [159] In response to the EPA's arguments that: (1) the funding shortfall may be smaller than projected; (2) emission reductions may be less expensive than the strategy predicts; (3) certain yet-to-be-quantified sources of reductions in the Plan may make up for shortfalls; and (4) California and the District may identify other measures to fulfill their commitments, the Court wrote that, ''[b]ecause these speculative assertions are unsupported by the evidence, they fail to ensure that California and the District have a plausible strategy for achieving this portion of the attainment strategy, and therefore do not collectively satisfy the second factor of the EPA's three-factor test.'' [160] It is important to emphasize that the State relied heavily on the projected emission reductions that it hopes to achieve through new control measures and emissions reductions reflected in the aggregate commitments. These reductions are crucial to the State meeting the modeled attainment demonstration and RFP requirements. If it is not credible that the State can meet the commitments, then the EPA cannot approve other nonattainment plan elements that rely upon them.

Separately, in comments on the EPA's 2021 Proposed Rule, Public Justice states that CARB and the District's aggregate tonnage commitments are to ''achieve a specific amount of reductions at the last possible moment prior to the attainment deadline with no concrete strategies for how that will be achieved.'' [161] They assert that prior plans with aggregate tonnage commitments for the 1997 annual $PM_{2.5}$ NAAQS by 2015 (*i.e.,* the 2008 $PM_{2.5}$ Plan) and then by 2020 (*i.e.,* the SJV $PM_{2.5}$ Plan) failed to attain those standards and that such past failures implies that the commitments failed to

[156] In this proposed rule, the term ''substitute measures'' means additional control measures that were not identified in CARB and the District's original control measure commitments in adopting the Valley State SIP Strategy and the 2018 $PM_{2.5}$ Plan, respectively. The ''substitute'' aspect primarily relates to emission reductions (*i.e.,* providing emission reductions where any adopted measure achieves less emission reductions than originally estimated, and/or providing emission reductions in lieu of any originally planned measure that is not adopted). They are also sometimes referred to as ''alternative measures'' in the SJV $PM_{2.5}$ Plan and adopting resolutions.

[157] CARB Resolution 18–49 and SJVUAPCD Governing Board Resolution 18–11–16, paragraph 6.

[158] Sections IV.A (emissions inventory) and IV.C (air quality modeling) of the 2021 Proposed Rule.

[159] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1 (9th Cir., April 13, 2022), 6.

[160] Id. at 7.

[161] Public Justice Comment Letter, 20.

deliver the promised clean air.[162] The commenters further state that ''deferred, unspecified, and last-minute promises to achieve reductions (*i.e.,* aggregate commitments), inflicts disparate impacts in violation of Title VI,'' irrespective of whether the commitments comply with the CAA.

3. The EPA's Reconsidered Proposal

As a result of the Ninth Circuit Memorandum Opinion with respect to the SJV $PM_{2.5}$ Plan's enforceable commitments, the EPA has reconsidered its proposed approval of the Plan's demonstration of attainment for the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, and now proposes to disapprove the Plan's attainment demonstration. The Ninth Circuit Memorandum Opinion raised concerns about the ability of CARB and the District to fulfill the commitments.

We present our reconsideration in the following sections of this proposed rule: (1) our reconsideration of CARB and the District's enforceable commitments and proposal that the commitments do not meet the second factor of the EPA's three-factor test (in section II.C.3.a); and (2) the effect of our proposed disapproval of the State's enforceable commitments and specific portions of the State's BACM demonstration on the modeled attainment demonstration (in section II.C.3.b).

a. Additional Measures and Enforceable Commitments

In this subsection we re-examine CARB and the District's enforceable commitments. We describe CARB and the District's progress in adopting specific measures that they committed to present for governing board adoption, and evaluate whether CARB and the District have demonstrated the capability to achieve specific tonnages of reductions that they committed to achieve by the 2025 attainment year. We first enumerate the measures that have already been approved into the SIP and quantify the amount of the tonnage commitment that these account for. We then calculate CARB and the District's remaining commitments as of the time of this notice, describe the strategy that CARB and the District have provided for achieving the remaining reductions (consisting of submitted measures that have not yet been approved into the SIP, adopted measures that have not yet been submitted to the EPA, measures under development, and other potential future measures), and calculate the reductions that may be associated with these measures. We conclude that although CARB and the District have made substantial progress toward achieving the committed-to reductions, CARB and the District have not presented a plausible strategy demonstrating that they are capable of achieving the *entirety* of the aggregate commitment.

In our 2021 Proposed Rule, the EPA described the SJV $PM_{2.5}$ Plan's series of CARB and District commitments to achieve emission reductions through additional control measures, beyond baseline measures, that are intended to contribute to expeditious attainment of the 2012 annual $PM_{2.5}$ NAAQS. For mobile sources, CARB identified a list of 12 State regulatory measures and 3 incentive-based measures that CARB has committed to propose to its Board for consideration by specific years.[163] For stationary sources, the District identified a list of nine regulatory measures and three incentive-based measures that the District has committed to propose to its Board for consideration by specific years.[164]

The Plan contains CARB's and the District's estimates of the emission reductions that could be achieved by each of these additional measures, if adopted as planned.[165] As we described in our 2021 Proposed Rule, CARB's commitments are contained in CARB Resolution 18–49 (October 25, 2018) and the Valley State SIP Strategy and consist of two parts: a control measure commitment and a tonnage commitment.

First, CARB has committed to ''begin the measure's public process and bring to the Board for consideration the list of proposed SIP measures outlined in the *Valley State SIP Strategy* and included in Attachment A, according to the schedule set forth.'' [166] By email dated November 12, 2019, CARB confirmed that it intended to begin the public process on each measure by discussing the proposed regulation or program at a public meeting (workshop, working group, or Board hearing) or in a publicly-released document, and to then propose the regulation or program to its Board.[167] Second, CARB has committed ''to achieve the aggregate emissions reductions outlined in the Valley State SIP Strategy of 32 tpd of NO_X and 0.9 tpd of $PM_{2.5}$ emissions reductions in the San Joaquin Valley by 2024 and 2025.'' [168] The Valley State SIP Strategy explains that CARB's overall commitment is to ''achieve the total emission reductions necessary to attain the Federal air quality standards, reflecting the combined reductions from the existing control strategy and new measures'' and that ''if a particular measure does not get its expected emissions reductions, the State is still committed to achieving the total aggregate emission reductions.'' [169]

Similarly, in our 2021 Proposed Rule, we explained that the District's commitments are contained in SJVUAPCD Governing Board Resolution 18–11–16 (November 15, 2018) and Chapter 4 of the 2018 $PM_{2.5}$ Plan and also consist of two parts: a control measure commitment and a tonnage commitment. First, the District has committed to ''take action on the rules and measures committed to in Chapter 4 of the Plan by the dates specified therein, and to submit these rules and measures, as appropriate, to CARB within 30 days of adoption for transmittal to EPA as a revision to the [SIP].'' [170] By email dated November 12, 2019, the District confirmed that it intended to take action on the listed rules and measures by beginning the public process on each measure, *i.e.,* discussing the proposed regulation or program at a public meeting, including a workshop, working group, or Board hearing, or in a publicly-released document, and then proposing the rule or measure to the SJVUAPCD Governing Board.[171] Second, the District has

[162] Public Justice refers specifically to the EPA's November 2016 finding of failure to attain and the EPA's November 2021 final disapproval of the 1997 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan. 81 FR 84481 (November 23, 2016) and 86 FR 67329 (November 26, 2021), respectively.

[163] CARB Resolution 18–49, Attachment A and Valley State SIP Strategy, Table 7 (''State Measures and Schedule for the San Joaquin Valley''). The schedule of proposed SIP measures in Table 7 includes two additional CARB measures: the second phase of the Advanced Clean Cars Program (''ACC 2'') and the ''Cleaner In-Use Agricultural Equipment'' measures. However, these measures are not scheduled for implementation until 2026 and 2030, respectively, which is after the January 1, 2025 implementation deadline under 40 CFR 51.1011(b)(5) for control measures necessary for attainment by December 31, 2025. Therefore, we are not reviewing these measures as part of the control strategy to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

[164] SJVUAPCD Governing Board Resolution 18–11–16 and 2018 $PM_{2.5}$ Plan, Table 4–4 (''Proposed Regulatory Measures'') and Table 4–5 (''Proposed Incentive-Based Measures'').

[165] 2018 $PM_{2.5}$ Plan, Ch. 4, Table 4–3 (''Emission Reductions from District Measures'') and Table 4–9 (''San Joaquin Valley Expected Emission Reductions from State Measures'') and Valley State SIP Strategy, Table 8 (''San Joaquin Valley Expected Emission Reductions from State Measures'').

[166] CARB Resolution 18–49, 5.

[167] Email dated November 12, 2019, from Sylvia Vanderspek, CARB, to Anita Lee, EPA Region IX, ''RE: SJV $PM_{2.5}$ information'' (attaching ''Valley State SIP Strategy Progress'') and CARB Staff Report, 14.

[168] CARB Resolution 18–49, 5.

[169] Valley State SIP Strategy, 7.

[170] SJVUAPCD Governing Board Resolution 18–11–16, 10–11.

[171] Email dated November 12, 2019, from Jon Klassen, SJVUAPCD, to Wienke Tax, EPA Region IX, ''RE: follow up on aggregate commitments in SJV $PM_{2.5}$ Plan'' (attaching ''District Progress in

committed to ''achieve the aggregate emissions reductions of 1.88 tpd of NO_X and 1.3 tpd of $PM_{2.5}$ by 2024/2025'' through adoption and implementation of these measures or, if the total emission reductions from these rules or measures are less than these amounts, ''to adopt, submit, and implement substitute rules and measures that achieve equivalent reductions in emissions of direct $PM_{2.5}$ or $PM_{2.5}$ precursors'' in the same implementation timeframes.[172]

In sections IV.F.3.c and IV.F.3.d of our 2021 Proposed Rule, the EPA described CARB's and the District's progress as of that point in time on their control measure commitments and progress towards fulfilling their respective aggregate commitments, respectively. Based on our reconsideration of the State's enforceable commitments in light of the Ninth Circuit Memorandum Opinion, while we propose to retain certain findings with respect to the State's progress, we now propose that the State has not adequately demonstrated that it can fulfill the remaining portions of its enforceable commitments (*i.e.,* the second factor of the EPA's three-factor test). We present our reconsidered evaluation of the status of CARB's and the District's control strategy and our three-factor test for enforceable commitments, as follows.

With respect to progress on the control measure commitments, CARB and the District together have adopted 18 measures of the 27 control measure commitments in the SJV $PM_{2.5}$ Plan and have begun the public process on 5 of the remaining control measure commitments, which is unchanged since the time of our 2021 Proposed Rule. This progress is described in further detail in CARB and the District's ''Progress Report and Technical Submittal for the 2012 $PM_{2.5}$ Standard San Joaquin Valley'' (2021 Progress Report).[173] For CARB's portion, CARB has adopted 10 of the 15 measures identified in its commitment (including one incentive-based measure) and begun the public process on 3 of the remaining 5 measures. For the District's portion of the control measure commitments, the District has adopted 8 of the 12 measures identified in its commitment (including one incentive-based measure) and begun the public process on 2 of the remaining 4 measures.

Although CARB and the District have made substantial progress in developing and adopting the regulatory measures listed in their respective control measure commitments, they have not yet fulfilled the commitments for several measures in accordance with the timeframes established in the SJV $PM_{2.5}$ Plan. We provide further detail on CARB and the District's control measure commitments in section IV.A of the EPA's 2012 Annual $PM_{2.5}$ TSD (including tables IV–A and IV–B regarding CARB and the District's control measure commitments, respectively).[174]

Regarding the remaining nine measures not yet proposed for board consideration, we continue to note that one measure, Rule 4550 (''Conservation Management Practices''), has an action year of 2022 in the 2018 $PM_{2.5}$ Plan (*i.e.,* the District has the remainder of 2022 to present a proposed measure for board consideration) and that four regulatory measures and four incentive-based measures are overdue. For the four regulatory measures, while CARB and the District have not proposed these measures to their respective boards, they began the public process on each of the four measures on time with respect to the schedule of their respective public process commitments. To our knowledge, CARB anticipates board consideration of the diesel fuel measures in 2022 and the forklift measure in 2022 or 2023 [175] and continues to develop the airport ground support equipment measure; the District continues to evaluate potential amendments to Rule 4692 in the near future.[176]

For the four incentive-based measures, CARB and the District continue to invest in reducing emissions from heavy-duty trucks and buses, off-road equipment, agricultural operation internal combustion engines, and commercial under-fired charbroiling.[177] However, while CARB and the District have discussed the proposed programs at board hearings,[178] to our knowledge, CARB and the District have not started the public process for the four incentive-based control measure commitments as enforceable measures to be submitted to the EPA for approval and inclusion as control measures in the California SIP. Furthermore, as discussed in section IV.F.3.c of our 2021 Proposed Rule, for heavy-duty trucks and off-road equipment, CARB acknowledges that many of the project lives do not span the attainment year [179] and, thus, while these projects may accelerate emission reductions and benefit communities in the SJV, the projects that qualify for SIP credit may be limited for the purposes of the 2012 annual $PM_{2.5}$ NAAQS Serious area attainment demonstration.

Overall, while CARB and the District have made substantial progress in developing and adopting the regulatory measures listed in their respective control measure commitments that were submitted in the SJV $PM_{2.5}$ Plan, in light of the Ninth Circuit Memorandum Opinion, we have reconsidered the effect of the eight overdue measures of the original commitments and in particular the overdue incentive-based measures, on our evaluation of CARB and the District's aggregate tonnage commitments and our three-factor test. Under the second factor of the EPA's test for enforceable commitments, the

Implementing Commitments with 2018 $PM_{2.5}$ Plan'').

[172] SJVUAPCD Governing Board Resolution 18–11–16, 10–11.

[173] ''Progress Report and Technical Submittal for the 2012 $PM_{2.5}$ Standard San Joaquin Valley,'' October 19, 2021. Transmitted to the EPA by letter dated October 20, 2021, from Richard W. Corey, Executive Officer, CARB, to Deborah Jordan, Acting Regional Administrator, EPA Region IX. See sections of 2021 Progress Report entitled ''Progress in Implementing District Measures'' and ''Progress in Implementing CARB Measures.''

[174] We note that Table IV–A of the EPA's 2012 Annual $PM_{2.5}$ TSD contained an error with respect to the adoption date of CARB's measure for Transportation Refrigeration Units Used for Cold Storage. While CARB had heard proposed amendments to the measure on September 23, 2021, the measure was not actually adopted until February 24, 2022, following further process and rule adjustments required by the Board. CARB Resolution 22–5, February 24, 2022.

[175] In the 2021 Progress Report (dated October 19, 2021), page 20, CARB indicates that the Zero-Emission Off-Road Forklift Regulation Phase 1 would be presented for Board consideration ''as early as 2022,'' while CARB's updated ''SJV $PM_{2.5}$ SIP Measure Tracking'' (dated December 2021) anticipates presenting the measure to the Board in Summer 2023.

[176] 2021 Progress Report, 8–9, 20–22, and tables 2 and 3.

[177] CARB, ''Long-Term Heavy-Duty Investment Strategy, Including Fiscal Year 2020–21 Three-Year Recommendations for Low Carbon Transportation Investments,'' (App. D to CARB's ''Proposed Fiscal Year 2021–22 Funding Plan for Clean Transportation Incentives''), release date October 8, 2021; and SJVUAPCD, ''Comprehensive Annual Financial Report, Fiscal Year Ended June 30, 2020,'' release date December 23, 2020. See also, 2021 Progress Report, 3 and 15.

[178] For example, CARB staff discussed the Accelerated Turnover of Trucks and Buses Incentive Measure at its annual 2020 update to the CARB Board. CARB presentation, ''Update on the 2018 $PM_{2.5}$ SIP for the San Joaquin Valley,'' October 22, 2020. District staff discussed and adopted an emission reductions strategy for commercial under-fired charbroiling, including incentives, in December 2020. SJVUAPCD, ''Item Number 11: Adopt Proposed Commercial Under-Fired Charbroiling Emission Reduction Strategy,'' December 17, 2020.

[179] Id. at 24 and 32. Generally, mobile source incentive projects implemented under the Carl Moyer program are under contract only during the ''project life'' and may not be credited with SIP emission reductions after the project life ends. EPA Region IX, ''Technical Support Document for EPA's Rulemaking for the California State Implementation Plan California Air Resources Board Resolution 19–26 San Joaquin Valley Agricultural Equipment Incentive Measure,'' February 2020, 12–13.

Agency must evaluate whether a State is capable of fulfilling such commitments. The tardiness of presenting these control measures for board consideration renders the reductions from these measures more speculative under the second factor.

With respect to the aggregate tonnage commitments to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV, we reiterate that CARB committed to achieve 32 tpd of NO_X and 0.9 tpd of $PM_{2.5}$ emissions reductions, and the District committed to achieve 1.88 tpd of NO_X and 1.3 tpd of $PM_{2.5}$ emissions reductions by 2025. These aggregate tonnage commitments sum to 33.88 tpd NO_X and 2.2 tpd direct $PM_{2.5}$. CARB and the District have committed to achieve these reductions via the 27 control measure commitments, or such other substitute measures as may be necessary, to achieve the aggregate tonnage commitments for NO_X and direct $PM_{2.5}$.

For the purpose of our analysis of the State's progress toward achieving its aggregate tonnage commitments, of the 18 measures adopted by December 2021, as well as the adoption of an important substitute measure (the Agricultural Burning Phase-out Measure [180]), the State has submitted 12 measures as revisions to the California SIP (*i.e.,* more than the 9 measures submitted to EPA as of the time of the 2021 Proposed Rule). Since December 2021, the EPA finalized or proposed approval of three control measure SIP submissions that were control measure commitments in the SJV $PM_{2.5}$ Plan.

First, the EPA finalized approval of the Heavy-Duty Vehicle Inspection Program (HDVIP) and Periodic Smoke Inspection Program (PSIP).[181] However, as in our 2021 Proposed Rule, CARB has not yet provided its analysis of the basis for this emission reduction estimate (of 0.02 tpd direct $PM_{2.5}$, per the State's 2021 Progress Report). Therefore, the EPA is not proposing at this time to credit this measure with any particular amount of emission reductions towards attainment of the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

Second, the EPA finalized approval of the Agricultural Burning Phase-out Measure,[182] which includes a schedule to phase-out (*i.e.,* introduce prohibitions of) agricultural burning for additional crop categories or materials accounting for a vast majority of the tonnage of agricultural waste in phases that started January 1, 2022, and become fully implemented by January 1, 2025.[183] The EPA received comments from the District that supported approval of the Agricultural Burning Phase-out Measure into the SIP while also advocating for a higher rule effectiveness rate (*i.e.,* 95% instead of EPA's proposed 80%),[184] which in turn would increase the amount of emission reductions that the EPA would credit towards fulfilling the District's aggregate tonnage commitment. We continue to evaluate these comments and for now have retained our proposal to credit the measure for emission reductions of 0.83 tpd NO_X and 1.23 tpd direct $PM_{2.5}$, consistent with the 80% rule effectiveness rate used by the EPA in the 2021 Proposed Rule.

Third, the EPA has proposed approval of Rule 4311 (''Flares''), as amended December 17, 2020.[185] The District's staff report for Rule 4311 estimates that the emission reductions from these amendments would be 0.19 tpd NO_X and 0.03 tpd direct $PM_{2.5}$ in 2025.[186] The EPA continues to evaluate the District's estimate with respect to SIP-creditable emission reductions, though we note that they are relatively small when compared to the overall 207.38 tpd NO_X and 6.4 tpd direct $PM_{2.5}$ modeled to attain the 2012 $PM_{2.5}$ NAAQS and to the combined aggregate tonnage commitments of 33.88 tpd NO_X and 2.2 tpd direct $PM_{2.5}$.

Similar to our 2021 Proposed Rule, we propose to credit reductions from three measures, all of which are now approved into the SIP and have large associated emission reductions of direct $PM_{2.5}$ and/or NO_X in the SJV.[187] The three measures are: Rule 4901 (''Wood Burning Fireplaces and Wood Burning Heaters''); two of three parts of the Agricultural Equipment Incentive Measure (for which we described our proposed SIP credit in the 2021 Proposed Rule); and the Agricultural Burning Phase-out Measure (for which we described our proposed SIP credit in this proposed rule).[188]

Based on these SIP-approved measures, our estimate of the remaining aggregate tonnage commitments remains the same as in our 2021 Proposed Rule. Specifically, in Table 1 herein we summarize the total NO_X and direct $PM_{2.5}$ emission reductions that the State models as sufficient to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, the emission reductions attributed to baseline measures and new control strategy measures (including only measures currently approved into the California SIP), and the emission reductions remaining as aggregate tonnage commitments.

TABLE 1—REDUCTIONS FOR ATTAINMENT IN 2025 AND AGGREGATE TONNAGE COMMITMENTS

		NO_X (tpd)	Direct $PM_{2.5}$ (tpd)
A	Total reductions from baseline and control strategy measures modeled to achieve attainment	207.38	6.4
B	Reductions from baseline measures	173.5	4.2
C	Reductions from additional measures *approved* into the California SIP	5.29	1.69
D	Total reductions remaining as commitments (A–B–C)	28.59	0.51
E	Percent of total reductions needed remaining as commitments (D/A)	13.8%	8.0%

Sources: 2018 $PM_{2.5}$ Plan, Ch. 4, tables 4–3 and 4–7, and Appendix B, tables B–1 and B–2.

[180] See 87 FR 36222 (June 16, 2022).

[181] 87 FR 27949 (May 10, 2022).

[182] 87 FR 36222.

[183] SJVUAPCD, ''Supplemental Report and Recommendations on Agricultural Burning,'' June 17, 2021 (''2021 Supplemental Report''), including Table 2–1 (''Accelerated Reductions by Crop Category'').

[184] Letter dated January 25, 2022, from Jonathan Klassen, Director of Air Quality Science and Planning, SJVUPACD, to Michael Regan, Administrator, U.S. EPA.

[185] 87 FR 3736 (January 25, 2022).

[186] SJVUAPCD, ''Item Number 12: Adopt Proposed Amendments to Rule 4311 (Flares),'' December 17, 2020, Attachment C (''Final Draft Staff Report with Appendices for Proposed Amendments to Rule 4311''), 21–22.

[187] The seven additional measures submitted as SIP revisions for which the EPA has not proposed action as of August 2022 include: the Innovative Clean Transit measure (submitted February 13, 2020); Rules 4306 and 4320 (submitted March 12, 2021); Rule 4702 (submitted October 15, 2021); Rules 4352 and 4354 (submitted March 9, 2022), and the Residential Wood Burning Incentive Measure (submitted March 17, 2022).

[188] Final actions on these measures are as follows: 85 FR 44206 (July 22, 2020) (Rule 4901), 86 FR 73106 (December 27, 2021) (Agricultural Equipment Incentive Measure), and 87 FR 36222 (June 16, 2022) (Agricultural Burning Phase-out Measure).

As shown in Table 1, 13.8% of the NO_X reductions necessary for attainment and 8.0% of the direct $PM_{2.5}$ reductions necessary for attainment remain as aggregate tonnage commitments (*i.e.,* combining CARB and the District's remaining commitments).[189] Based on the direct $PM_{2.5}$ emission reductions that the EPA has credited to Rule 4901 (0.2 tpd) and the Agricultural Burning Phase-out Measure (1.23 tpd), which add up to 1.43 tpd, we conclude that the District has exceeded its 1.3 tpd direct $PM_{2.5}$ commitment by 0.13 tpd.

Beyond the measures that the EPA has taken final action to approve into the California SIP and proposed to credit herein, CARB has provided updated emission reduction estimates for 10 additional measures, including 9 that have been adopted, as well as one substitute measure in development, as described in the 2021 Progress Report. The CARB measure with the largest updated emission reduction estimates is the Heavy-Duty Vehicle Inspection and Maintenance Program (''Heavy-Duty I/M'').

The District has similarly provided updated emission reduction estimates for seven additional measures, including six that have been adopted. The District measures with the largest updated emission reduction estimates include amendments to Rule 4702 (''Internal Combustion Engines'') (0.61 tpd NO_X), the Residential Wood Burning Devices Incentive Projects measure (0.33 tpd direct $PM_{2.5}$), and Rule 4354 (''Glass Melting Furnaces'') (0.5 tpd NO_X and 0.04 tpd direct $PM_{2.5}$), as well as amendments planned in 2022 to Rule 4550 (''Conservation Management Practices'') (0.32 tpd direct $PM_{2.5}$).

The EPA is not proposing to credit towards the aggregate tonnage commitments the updated emission reduction estimates from these additional District measures. We will review and act on the CARB and District measures submitted to date (Innovative Clean Transit, Rule 4306, Rule 4320, Rule 4702, Rule 4352, Rule 4354, and the Residential Wood Burning Incentive Measure), as well as future measure submissions, in separate rulemakings, during which time the public will have an opportunity to review and provide comment.

Although we are not proposing to credit reductions from these measures at this time, in order to determine whether CARB and District have the capability to meet their aggregate tonnage commitments, we have re-evaluated the updated emission reduction estimates to assess whether they could meet the NO_X and/or direct $PM_{2.5}$ emission reduction commitments with these measures or, if not, how much would remain of CARB and the District's unfulfilled aggregate tonnage commitments.

TABLE 2—HYPOTHETICAL EMISSION REDUCTIONS FROM ESTIMATED, ADOPTED, AND/OR SUBMITTED ADDITIONAL MEASURES AND EFFECT ON REMAINING AGGREGATE TONNAGE COMMITMENTS FOR 2025

		NO_X (tpd)	Direct $PM_{2.5}$ (tpd)
A	Total reductions needed from baseline and control strategy measures (see Table 1, row A of this proposed rule).	207.38	6.4
B	Total reductions remaining as commitments after SIP credit (see Table 1, row D of this proposed rule).	28.59	0.51
	CARB:		
	Submitted Measures:		
	HDVIP and PSIP [a]	0	0.02
	Innovative Clean Transit	0.017	<<0.01
C	Sub-Total	0.017	0.02
	Additional Adopted Measures:		
	Heavy-Duty I/M	14.7	0.03
	Amended Warranty Requirements for Heavy-Duty Vehicles	0.34	<<0.01
	Heavy-Duty Low-NO_X Engine Standard—California Action	0	0
	Advanced Clean Local Trucks (Last Mile Delivery)	0.08	<<0.01
	Zero-Emission Airport Shuttle Buses	<<0.01	<<0.01
	Small Off-Road Engines	0.155	0.007
	Transport Refrigeration Units Used for Cold Storage	0.04	0.01
	Agricultural Equipment Incentive Measure-Phase 1 (NRCS portion)	0.64	0.04
	Agricultural Equipment Incentive Measure Phase 2	4.9	0.5
D	Sub-Total	15.955	0.087
	Measures Not Yet Presented for Board Consideration: [b]		
	Zero-Emission Off-Road Forklift Regulation Phase 1	0.02	<<0.01
E	Sub-Total	4.92	0.5
F	*Grand Total for CARB (C+D+E)*	20.892	0.607
	SJVUAPCD:		
	Submitted Measures:		
	Rule 4311 (''Flares'')	0.19	0.03
	Rule 4306 (''Boilers, Steam Generators, and Process Heaters—Phase 3'')	0.19	0
	Rule 4320 (''Advanced Emission Reduction Option for Boilers, Steam Generators, and Process Heaters greater than 5 MMBtu/hr'') [c].	0	0
	Rule 4352 (''Solid Fuel Fired Boilers, Steam Generators, and Process Heaters'')	0.5	0.04
	Rule 4354 (''Glass Melting Furnaces'')	0.2	0.04

[189] However, we note that if the EPA were to grant maximum credit for the emission reductions calculated by the District for Rule 4311 (0.19 tpd NO_X and 0.03 tpd direct $PM_{2.5}$), the remaining aggregate tonnage commitments would be 28.4 tpd NO_X (13.7% of total reductions needed to attain in 2025) and 0.48 tpd direct $PM_{2.5}$ (7.5% of total reductions needed to attain in 2025).

TABLE 2—HYPOTHETICAL EMISSION REDUCTIONS FROM ESTIMATED, ADOPTED, AND/OR SUBMITTED ADDITIONAL MEASURES AND EFFECT ON REMAINING AGGREGATE TONNAGE COMMITMENTS FOR 2025—Continued

		NO_X (tpd)	Direct $PM_{2.5}$ (tpd)
	Rule 4702 (''Internal Combustion Engines'')	0.61	0
	Residential Wood Burning Incentive Measure	0	0.33
G	Sub-Total	1.69	0.44
	Measures Not Yet Presented for Board Consideration:		
	Rule 4550 (''Conservation Management Practices'')	0	0.32
H	Sub-Total	0	0.32
I	*Grand Total for SJVUAPCD (G+H)*	1.69	0.76
J	*Grand Total (F+I)*	22.58	1.37
K	Assuming maximum SIP credit, total reductions remaining as commitments (B–J)	6.01	−0.86

Sources: 2021 Progress Report, Table 2 and Table 3.

[a] As discussed herein, the EPA has taken final action to approve CARB's HDVIP and PSIP measure into the California SIP but we are not yet proposing SIP credit for these two measures.

[b] Given the complexities involved in regulating locomotive emissions, we have conservatively excluded from our analysis the emission reduction estimates in the 2021 Progress Report for CARB's In-Use Locomotive Measure.

[c] The District's draft staff report for Rule 4306 and Rule 4320 estimate emission reductions of 0.19 tpd NO_X and 0.45 tpd NO_X, respectively, in 2024. However, the District notes that it is not proposing the emission reductions from Rule 4320 for SIP credit at this time. SJVUAPCD, ''Draft Staff Report, Proposed Amendments to Rule 4306 (Boilers, Steam Generators, and Process Heaters—Phase 3), Proposed Amendments to Rule 4320 (Advanced Emission Reduction Options for Boilers, Steam Generators, and Process Heaters Greater Than 5.0 MMBtu/hr),'' November 25, 2020, 4.

Assuming the EPA were to agree with the maximum credit for the emission reductions estimated by CARB and the District in the 2021 Progress Report, these additional measures could achieve emission reductions of 22.58 tpd NO_X and 1.37 tpd direct $PM_{2.5}$. Combined with the reductions from additional measures already approved by EPA into the California SIP (5.29 tpd NO_X and 1.69 tpd direct $PM_{2.5}$, per Row C of Table 1 of this proposed rule), the State would achieve emission reductions of 27.87 tpd NO_X and 3.06 tpd direct $PM_{2.5}$. Compared to the combined aggregate tonnage commitments, the State would have remaining aggregate tonnage commitments of 6.01 tpd NO_X and would have exceeded the aggregate tonnage commitments by 0.86 tpd direct $PM_{2.5}$. More specifically, CARB would have remaining commitments of 6.65 tpd NO_X and 0.03 tpd direct $PM_{2.5}$, and the District would have exceeded its commitments by 0.64 tpd NO_X and 0.89 tpd direct $PM_{2.5}$.

However, given the remaining NO_X commitments for CARB, which are approximately 3% of the NO_X emission reductions modeled to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by 2025, we have given additional consideration to the evidence of emission reductions for two source categories that have large emission reduction estimates: Heavy-Duty I/M and the Agricultural Equipment Incentive Measures, including the NRCS portion of the Phase 1 measure adopted by CARB in 2019 and the Phase 2 measure slated for 2024 consideration, per the 2021 Progress Report.

With respect to Heavy-Duty I/M, in the Valley State SIP Strategy, CARB originally estimated that it would achieve 6.8 tpd NO_X and <0.1 tpd direct $PM_{2.5}$ in 2025 and described the regulatory concepts that would reflect the current (as of 2018) ''advanced engine and exhaust control technologies, including on-board diagnostics (OBD).'' [190] Since that time, as described in the State's 2021 Progress Report and the EPA's 2021 Proposed Rule, California has developed additional provisions related to Heavy-Duty I/M that the State estimates would achieve emission reductions of 14.7 tpd NO_X and 0.03 tpd direct $PM_{2.5}$ in 2025.[191]

While the EPA would still not propose to approve a specific amount of SIP-creditable reductions until after the State submits such measure in final form to the EPA as a revision to the SIP, we have re-examined the role of the potential additional emission reductions from Heavy-Duty I/M presented by CARB. As a qualitative matter, we agree that the requirements under California Senate Bill 210 (2019) that heavy-duty vehicles comply with Heavy-Duty I/M in order to register annually with the California Department of Motor Vehicles, as well as the implementation of roadside emissions monitoring (*i.e.,* the Portable Emissions AcQuisition System, ''PEAQS'') in the SJV to detect high emitting vehicles between periodic test cycles, are tangible additions that would increase the emission reductions relative to what was contemplated at the time of Plan adoption in November 2018 (by the District) and January 2019 (by CARB).

As a quantitative matter, however, the scale of the estimated 14.7 tpd NO_X emission reductions is roughly half the remaining aggregate commitment of 28.59 tpd NO_X and represents 7.1% of the 207.38 tpd NO_X modeled for attainment and a substantial increase from CARB's original estimate of 6.8 tpd NO_X (3.3% of the 207.38 tpd NO_X). This 14.7 tpd NO_X represents a substantial quantity that, pursuant to the Ninth Circuit Memorandum Opinion, must be supported by evidence to ''ensure that California and the District have a plausible strategy for achieving this portion of the attainment strategy'' in order to satisfy the second factor of the three-factor aggregate commitment test.[192] While CARB documented its extensive regulatory and technical

[190] Valley State SIP Strategy, 19–20 and Table 8.

[191] 2021 Progress Report, 19. CARB notes that further detail on emission reduction calculations can be found in the CARB staff report on Heavy-Duty I/M, released October 15, 2021. See, CARB, ''Staff Report: Initial Statement of Reasons, Public Hearing to Consider the Proposed Heavy-Duty Inspection and Maintenance Regulation,'' October 8, 2021, (''Heavy-Duty I/M ISOR'') and App. H (''Proposed Heavy-Duty Inspection and Maintenance Regulation, Standardized Regulatory Impact Assessment'').

[192] See *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1, 7 (9th Cir., April 13, 2022).

analyses in the measure's Initial Statement of Reasons and associated appendices,[193] CARB has not provided the detailed basis of its calculations of 14.7 tpd NO_X and 0.03 tpd direct $PM_{2.5}$ emission reductions to the EPA. Given that CARB may do so in a future control measure SIP submission, and we lack the record evidence to do so here, we do not suggest an alternative amount of emission reduction from Heavy-Duty I/M in this proposed rule. Rather, we note that the more detailed calculations and technical report necessary to support such an estimate, specific to the SJV and to annual average emission reductions in 2025, are not available, and therefore we do not have sufficient support in the record at this time to rely on the State's estimated reductions, in line with the Ninth Circuit Memorandum Opinion.

With respect to mobile agricultural equipment, the EPA has taken final action to approve the Funding Agricultural Replacement Measures for Emission Reductions (FARMER) program and the Carl Moyer Memorial Air Quality Standards Attainment Program (''Carl Moyer'') portions of CARB's first incentive measure on agricultural equipment in the SJV (''Agricultural Equipment Incentive Measure-Phase 1'') and proposed in our 2021 Proposed Rule to credit emission reductions of 4.46 tpd NO_X and 0.26 tpd direct $PM_{2.5}$ towards CARB's aggregate tonnage commitments.[194] CARB has estimated that it will achieve 4.9 tpd additional NO_X reductions, and 0.5 tpd additional direct $PM_{2.5}$ reductions through a second agricultural equipment incentive measure. In light of the Ninth Circuit Memorandum Opinion, and its finding that the EPA had not ensured that CARB and the District had a ''plausible strategy'' for achieving parts of the attainment strategy that relied on incentive-based reductions in the face of a budget shortfall for funding these measures, we must evaluate whether there is sufficient evidence in the record to establish a reasonable basis for concluding that any ''Phase 2'' agricultural equipment incentive measure will have sufficient funding to achieve the reductions ascribed to it.

As we noted in the EPA's 2021 Proposed Rule, fewer incentive-based emission reductions are needed to demonstrate attainment of the 2012 annual $PM_{2.5}$ NAAQS than were required in the portion of the SJV $PM_{2.5}$ Plan addressing the 2006 24-hour $PM_{2.5}$ NAAQS that was at issue in the *Medical Advocates* case.[195] In the Ninth Circuit Memorandum Opinion, the court pointed to a $2.6 billion shortfall between what the EPA calculated to be a need for $5 billion in funding and the more than $2 billion in funding that the State had ''identified or anticipated.''[196] Notably, funding for the Carl Moyer, California Assembly Bill 617, and FARMER programs were included in the ''identified or anticipated'' portion of the State's funding analysis, and not the ''incentive funding gap'' for which the Court found EPA's explanations justifying approval to be overly speculative.[197] Accordingly, we do not consider reliance on reductions from a Phase 2 agricultural equipment incentive measure to be prohibited by the Ninth Circuit Memorandum Opinion, to the extent that a Phase 2 rule would rely on the same, existing programs, and provided that evidence of sufficient identified or reasonably anticipated funding exists in the record.

As described in the EPA's analysis of the cost-effectiveness of the Agricultural Equipment Incentive Measure-Phase 1, based on information provided by CARB, the total project costs resulting in these emission reductions were $155 million for FARMER and $125 million for Carl Moyer, or $280 million combined.[198] As described in the EPA's 2021 Proposed Rule,[199] the SJV portion of the FARMER funding has typically been 80% of the State-wide allocation and the first three years of FARMER funding for the SJV were $108 million (fiscal year 2017–2018), $104.3 million (fiscal year 2018–2019), and $43.84 million (fiscal year 2019–2020).[200] For the current fiscal year (2021–2022), the District accepted $168.43 million in FARMER funds to replace agricultural equipment in the SJV.[201] Similarly, we noted that CARB expects Carl Moyer funding to increase in future years, following the enactment of California Assembly Bill 1274.[202]

Thus, while future funding allocations are subject to annual State and local funding cycles, given the renewed, large investment in the fiscal year 2021–2022 FARMER program, potential for increases in funding for the Carl Moyer program, and the success of these programs in meeting enforceability criteria for purposes of crediting emission reductions, the EPA anticipates that CARB will be able to develop an additional agricultural equipment incentive measure (''Agricultural Equipment Incentive measure-Phase 2'') that has funding levels comparable or larger than those for Phase 1 (*i.e.,* including the $168 million accepted by the District in March 2022) and that CARB's emission reduction estimates of 4.9 tpd NO_X and 0.5 tpd direct $PM_{2.5}$ by 2025, per the 2021 Progress Report, are reasonable and supported by identified or reasonably anticipated funding.

However, we have not yet taken final action on the NRCS portion of the Agricultural Equipment Incentive Measure-Phase 1 and, for this proposed rule, do not rely on the estimated emission reductions for that portion of the Agricultural Equipment Incentive Measure-Phase 1 (*i.e.,* 0.64 tpd NO_X and 0.04 tpd direct $PM_{2.5}$). Looking forward in time, this suggests some uncertainty regarding creditability of emission reductions from any portion of a Phase 2 agricultural equipment incentive measure that may be implemented through the NRCS program.

Furthermore, for any measure, to the extent that CARB or the District assumed a 100% rule effectiveness rate where the EPA is not able to confirm and approve such a rate, further discounts to the emission reductions estimated may be warranted in certain cases.[203] Accordingly, the overall remaining NO_X commitment could be larger than 6.01 tpd and the anticipated

[193] Heavy-Duty I/M ISOR and, for example, Heavy-Duty I/M ISOR, App. D (''Emissions Inventory Methods and Results, Proposed Heavy-Duty Inspection and Maintenance Regulation'') and App. H (''Proposed Heavy-Duty Inspection and Maintenance Regulation, Standardized Regulatory Impact Assessment'').

[194] 86 FR 74310, 74332; 86 FR 73106, 73109.

[195] 86 FR 74310, 74330. This is due to greater-than-expected reductions from committed to and substitute non-incentive regulatory measures, such as the Agricultural Burning Phase-Out Measure.

[196] *Medical Advocates for Healthy Air* v. *EPA,* Case No. 20–72780, Dkt. #58–1, 7; 85 FR 44192, 44201.

[197] CARB Staff Report, 27 (Table 9).

[198] Memorandum dated June 22, 2020, from Rebecca Newhouse, EPA Region IX, to docket number EPA–R09–OAR–2019–0318, Subject: ''Cost-effectiveness of Emission Reductions from the Valley Incentive Measure and Estimated Future Funding Needs for Additional Agricultural Equipment Replacements'' (''EPA Cost-Effectiveness Memo'').

[199] 86 FR 74310, 74337.

[200] CARB, ''Funding Agricultural Replacement Measures for Emission Reductions (FARMER) Program, San Joaquin Valley APCD,'' as reported through September 30, 2020.

[201] SJVUAPCD, ''Item Number 9: Accept $168,425,600 in State FARMER Program Funds for Use in the District's Agricultural Equipment Replacement Project,'' March 17, 2022.

[202] 2021 Progress Report, 22.

[203] For example, the District originally sought SIP credit of 0.26 tpd direct $PM_{2.5}$ emission reductions from Rule 4901 and the EPA is proposing 0.2 tpd direct $PM_{2.5}$ based on a 75% rule effectiveness rate. Similarly, CARB and the District sought SIP credit of 1.04 tpd NO_X and 1.54 tpd direct $PM_{2.5}$ emission reductions from the Agricultural Burning Phase-out Measure and the EPA is proposing 0.83 tpd NO_X and 1.23 tpd direct $PM_{2.5}$ based on an 80% rule effectiveness rate.

excess emission reductions for direct $PM_{2.5}$ could be smaller than 0.86 tpd.

Notwithstanding some uncertainty as to the scale of emission reductions from the Heavy-Duty I/M and the Agricultural Equipment Incentive Measures (*i.e.,* assuming that the additional measures with discrete emission reduction estimates in the 2021 Progress Report achieve their respective emission reductions), there remains at least 6.65 tpd NO_X and 0.03 tpd direct $PM_{2.5}$ in CARB's commitment for which the record does not contain a specific and plausible strategy to achieve. In our 2021 Proposed Rule we discussed two possible ways that CARB could fill this gap: (1) additional reductions from committed or substitute measures named by CARB, and (2) a hypothetical inter-pollutant trading of excess direct $PM_{2.5}$ emission reductions by the District for any shortfall in NO_X emission reductions by CARB. The Ninth Circuit Memorandum Opinion has established that these concepts in the absence of a specific SIP revision are too speculative and do not constitute a ''plausible strategy'' for achieving this portion of the commitment.

With respect to additional reductions from committed measures, in the 2021 Proposed Rule, we explored potential reductions from two incentive-based measures: Accelerated Turnover of Trucks and Buses Incentive Projects, and Accelerated Turnover of Off-road Equipment Incentive Projects.[204] CARB initially estimated that they would achieve 8 tpd NO_X reductions from Accelerated Turnover of Trucks and Buses Incentive Projects, and 1.5 tpd NO_X reductions from Accelerated Turnover of Off-road Equipment Incentive Projects.[205] However, CARB did not propose a measure to its board for either measure by 2021, as it had committed to do, nor to our knowledge has CARB started the public process for enforceable measures to be submitted to the EPA for inclusion as control measures in the California SIP.

In the 2021 Progress Report, CARB acknowledged that many of the project lives do not span the attainment year[206] and, thus, while these projects accelerate emission reductions and benefit communities in the SJV, the projects that qualify for SIP credit may be limited for the purposes of the 2012 annual $PM_{2.5}$ NAAQS Serious area attainment demonstration. In our 2021 Proposed Rule, we acknowledged these weaknesses in these incentive programs, but we nonetheless assumed that these measures may ultimately result in SIP-creditable emission reductions for a portion of the combined 9.5 tpd NO_X.[207] In light of the Ninth Circuit Memorandum Opinion, the EPA does not consider it appropriate to rely on reductions that have been rendered substantially less likely to occur by the State's update indicating that few emissions from these projects may be creditable.

Furthermore, while the State continues to invest heavily in the replacement of older, dirty heavy-duty vehicles and equipment on a State-wide basis,[208] we are not aware of a document that identifies specific funding amounts applied to the replacement of such equipment in the SJV within the specific timeline of the Plan's demonstration of attainment of the 2012 annual $PM_{2.5}$ NAAQS by December 31, 2025. In brief, the amount of funding that is specific to the SJV for these two measures for purposes of attainment of the 2012 annual $PM_{2.5}$ NAAQS is unclear, and this renders more speculative at least a portion of the large scale of NO_X emission reductions originally anticipated.[209]

With respect to substitute measures under development, CARB points to the In-Use Locomotive Rule (and estimates emission reductions of 1.14 tpd NO_X and 0.03 tpd direct $PM_{2.5}$ by 2025 in the SJV), which is slated for 2022 Board consideration.[210] However, as noted in our 2021 Proposed Rule,[211] given the complexities involved in regulating locomotive emissions, we have conservatively excluded from our analysis the emission reduction estimates in the 2021 Progress Report for CARB's In-Use Locomotive Measure.

In addition, CARB has identified further measures that were not included in the original control measure commitments that may provide emission reductions toward CARB's aggregate tonnage commitments.[212] These measures include Cargo Handling Equipment Registration, Construction and Mining Equipment Measure, and Co-Benefits from the Climate Program. However, we do not have information as to what these measures might entail, when the State may adopt or implement them, and what scale of emission reductions they could potentially achieve.

Based on the lack of information on funding and process for heavy-duty and off-road equipment incentive-based measures and the lack of information on other potential substitute measures, such as a Construction and Mining Equipment Measure, and in light of the Ninth Circuit Memorandum Opinion, we have reconsidered our evaluation of this prospect and now propose that there is not sufficient evidence to show that the Valley State SIP Strategy contains a ''plausible strategy'' to achieve the remaining NO_X and direct $PM_{2.5}$ emission reductions needed for attainment.

The other approach that the 2021 Proposed Rule discusses for filling the gap in CARB's strategy for achieving its commitment is based on a hypothetical future SIP revision. In the 2021 Progress Report, CARB and the District provided additional emissions analysis to assess how excess direct $PM_{2.5}$ emission reductions could be converted to equivalent NO_X emission reductions using an inter-pollutant trading ratio rooted in the sensitivity analyses of the 2018 $PM_{2.5}$ Plan.[213] CARB and the District have not formally submitted this analysis as a SIP revision to the EPA or requested that the EPA apply such inter-pollutant trading for purposes of fulfilling the aggregate tonnage commitments through an equivalent amount of emission reductions.

Consistent with past EPA action on $PM_{2.5}$ planning SIP submissions for the SJV,[214] where the State submits a SIP

[204] 86 FR 74310, 74335.

[205] Valley State SIP Strategy, Table 7.

[206] 2021 Progress Report at 24 and 32. Generally, mobile source incentive projects implemented under the Carl Moyer program are under contract only during the ''project life'' and may not be credited with SIP emission reductions after the project life ends. EPA Region IX ''Technical Support Document for EPA's Rulemaking for the California State Implementation Plan California Air Resources Board Resolution 19–26 San Joaquin Valley Agricultural Equipment Incentive Measure,'' February 2020, 12–13.

[207] 86 FR 74310, 74335.

[208] See, *e.g.,* CARB, ''Proposed Fiscal Year 2021–22 Funding Plan for Clean Transportation Incentives, Appendix D: Long-Term Heavy-Duty Investment Strategy,'' release date October 8, 2021.

[209] The EPA also notes that, for regulatory measures that have large estimated emission reductions, rather than incentive-based measures, CARB estimated that its Low-Emission Diesel Fuel Requirement would achieve an additional 1 tpd NO_X and 0.1 tpd direct $PM_{2.5}$ reductions. However, without near-term adoption and submission, its associated emission reductions may not be creditable towards the aggregate tonnage commitment for 2025.

[210] 2021 Progress Report, 20–21. Additional information on CARB's regulatory concepts for the In-Use Locomotive Measure are available at: *https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california/locomotives-and-railyards-meetings-workshops.*

[211] 86 FR 74310, 74334, fn. 228.

[212] CARB, ''SJV $PM_{2.5}$ SIP Measure Tracking,'' September 2021, 3. Available at: *https://ww2.arb.ca.gov/resources/documents/2018-san-joaquin-valley-pm25-plan.*

[213] 2021 Progress Report, Table 4 and 33–37.

[214] For example, the EPA has approved an inter-pollutant trading mechanism for use in transportation conformity analyses for the 2006 24-hour $PM_{2.5}$ NAAQS. 85 FR 44192, 44204. In that same final rule, the EPA approved the State's demonstration that it had fulfilled prior aggregate tonnage commitments, in part, by using an inter-pollutant trading approach that the EPA found

revision that would substitute reductions in one pollutant to achieve a tonnage commitment concerning a different pollutant (*e.g.,* substituting excess direct $PM_{2.5}$ reductions to satisfy a NO_X reduction commitment), it must include an appropriate inter-pollutant trading (IPT) ratio and the technical basis for such ratio in the plan submission itself, along with the requisite public process. The EPA will review any such IPT ratio and its bases before approving or disapproving any such SIP revision. The possibility of a future SIP submission discussing IPT does not constitute a ''plausible strategy'' for achieving reductions that are modeled to result in attainment. Thus, at this time, we are not proposing to approve any particular inter-pollutant trading approach for purposes of meeting the aggregate tonnage commitments, nor applying any excess reductions of one pollutant towards fulfilling a portion of committed reductions of the other pollutant.

The additional evaluation we have discussed herein as part of our reconsideration of the State's enforceable commitments requires us to re-evaluate the EPA's three-factor test for enforceable commitments. Based on our reconsideration, and consistent with the Ninth Circuit Memorandum Opinion, we retain our proposed findings that the State's commitments meet the first factor (the commitment represents a limited portion of the required reductions, *i.e.,* 13.8% of the NO_X and 8.0% of the direct $PM_{2.5}$ emission reductions necessary to attain) and the third factor (the commitment is for a reasonable and appropriate timeframe) of the three-factor test. However, we now propose that the State's commitments do not meet the second factor (regarding the State's capability to fulfill its commitments). Our analysis and findings for the first and third factors are presented in section IV.F.3.e of the 2021 Proposed Rule. We provide our reconsidered evaluation of the second factor as follows in this proposed rule.

As the EPA noted in our 2021 Proposed Rule, CARB and the District have been capable of developing and adopting many of the regulatory measures listed in their respective control measure commitments. However, the question before us more precisely is whether such substantial progress, coupled with the strategy submitted by the State for achieving the remaining reductions which the State has modeled as leading to attainment, is sufficient to show that the State is capable of fulfilling its *entire* aggregate tonnage commitments by 2025. Several components of our reconsideration suggest that the State may not be capable of fulfilling the entire aggregate tonnage commitment, particularly with respect to NO_X emission reductions from additional CARB measures.

First, in terms of additional measures for which CARB and the District provided updated emission reduction estimates, we have given additional consideration to the evidence of emission reductions for two source categories that have large emission reduction estimates: Heavy-Duty I/M and the Agricultural Equipment Incentive Measures. For Heavy-Duty I/M, CARB has not provided to the EPA a sufficient basis for its increase in estimated emission reductions from 6.8 tpd NO_X to 14.7 tpd NO_X, where the 14.7 tpd reduction amounts to 7.1% of the total emission reductions modeled for attainment of the 2012 annual $PM_{2.5}$ NAAQS. Although the EPA is confident, based on its review, that emission reductions are available in this category, and that the State is capable of achieving some amount of reductions, the State has not sufficiently supported its assertion that it is capable of achieving 14.7 tpd of NO_X and 0.03 tpd of direct $PM_{2.5}$. As discussed above, due to uncertainty surrounding the NRCS portion of the Agricultural Equipment Incentive Measure-Phase 1, we are not relying on reductions from that portion of the rule, and the creditability of any NRCS portion of a potential future Phase 2 has not been established.

Furthermore, for any measure, to the extent that CARB or the District assumed a 100% rule effectiveness rate where the EPA is not able to confirm and approve such a rate, further discounts to the emission reduction estimates may be warranted in certain cases.

Accordingly, the overall remaining NO_X commitment could be larger than 6.01 tpd and the anticipated excess emission reductions for direct $PM_{2.5}$ could be smaller than 0.86 tpd.

Second, even if the EPA were to assume maximum credit for the additional measures for which CARB and the District provided updated emission reduction estimates, CARB, in combination with the District, would still need emission reductions of at least 6 tpd NO_X to fulfill its commitments.[215] Moreover, the reductions from CARB's remaining incentive measures for Heavy-Duty vehicles and off-road equipment appear to be limited relative to the combined emission reduction estimate of 9.5 tpd NO_X in the Plan. Without documentation supporting the funding amounts to be applied in the SJV within the timeline of the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan, it is not clear that the full amount of these estimated reductions is supported by a ''plausible strategy'' to achieve them, as required in the Ninth Circuit Memorandum Opinion. In addition, the identified substitute measures lack sufficient detail to provide support for making up for NO_X emission reduction shortfalls from CARB's control measure commitments.

Given the gap between the reductions needed and the reductions for which CARB and the District have presented a non-speculative plan for achieving, we now propose that the State has not demonstrated that it is capable of fulfilling the remaining aggregate tonnage commitments necessary to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025, and therefore find that the SJV $PM_{2.5}$ Plan does not meet the second factor of our three-factor test for enforceable commitments.

b. Attainment Demonstration

Based on our reconsideration of the Plan's enforceable commitments described in section II.C.3.a of this proposed rule, and our reconsideration of the Plan's BACM demonstration for described in section II.B, we now propose to disapprove the SJV $PM_{2.5}$ Plan's modeled attainment demonstration for the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025. We discuss the interrelationship of these nonattainment plan elements as follows.

Regarding enforceable commitments, CAA section 110(a)(2)(A) provides that each SIP ''shall include enforceable emission limitations and other control measures, means or techniques . . . as well as schedules and timetables for compliance, as may be necessary or appropriate to meet the applicable requirements of [the Act].'' Section 172(c)(6) of the Act, which applies to nonattainment SIPs, is virtually identical to section 110(a)(2)(A). The EPA interprets the CAA to allow for approval of enforceable commitments that are limited in scope, where circumstances exist that warrant the use of such commitments in place of

adequate. 85 FR 44192, 44205; see also proposed rule at 85 FR 17382, 17406–17407 and associated EPA's General Evaluation TSD, Table III–C and section IV.

[215] As noted in this proposed rule, if the EPA were to assume credit for emission reductions from the additional District measures, the District would have exceeded its aggregate tonnage commitments by 0.64 tpd NO_X and 0.89 tpd direct $PM_{2.5}$.

adopted and submitted measures, and considers three factors in determining whether to approve the enforceable commitment.

Given our proposed finding above that the State has not met the second factor of the EPA's three-factor test (*i.e.,* whether the State is capable of fulfilling its commitment), the State is left with a gap between the reductions that it has modeled as necessary for attainment, and the reductions that the EPA may count as constituting the State's control plan. Therefore, the EPA proposes that the State's control strategy does not include sufficient enforceable measures, pursuant to CAA sections 110(a)(2)(A) and 172(c)(6), to achieve the necessary emission reductions to attain the 2012 annual $PM_{2.5}$ NAAQS in the SJV by December 31, 2025.

The lack of an approved control plan to achieve the reductions necessary to attain by 2025 is sufficient on its own to compel disapproval of the attainment demonstration. However, even if the State's control plan was sufficient to lead to attainment in 2025, the Public Justice Comment Letter and our reconsidered BACM analysis in section II.B of this notice raise additional issues regarding the sufficiency of the modeled attainment demonstration.

The State's attainment demonstration identifies the Bakersfield-Planz monitor as the design value monitor, and models this monitor as achieving the 12.0 µg/m³ concentration necessary for attainment in 2025.[216] The State's submission also indicates that the Bakersfield-Planz monitor is modeled to read 12.1 µg/m³ in 2024.[217] This represents a very narrow margin between modeled attainment in 2024 and 2025. In light of the Act's requirement to demonstrate attainment by the most expeditious date practicable, in order for the EPA to approve the Plan's demonstration that the area will attain by 2025, the State must also demonstrate that attainment by an earlier date is not practicable.

As explained in section II.B of this notice, the EPA now proposes to find that the State has not sufficiently demonstrated that it has implemented BACM for all necessary categories of sources. Most notably, the State has not sufficiently evaluated the amount of ammonia reductions that may be available. In light of the very small (0.1 µg/m³) gap between attaining in 2024 and 2025, and the State's sensitivity modeling in its precursor demonstration indicating that a 30% reduction in ammonia would reduce annual $PM_{2.5}$ concentrations at the Bakersfield-Planz monitor by 0.12 µg/m³ and a 70% reduction would reduce annual $PM_{2.5}$ concentrations at the Bakersfield-Planz monitor by 0.36 µg/m³, the State has not demonstrated that reductions from sources identified in section II.B could not expedite attainment.[218] As a result, even if the State's control plan was sufficiently concrete that the EPA could credit all reductions of NO_X and direct $PM_{2.5}$ that the State indicated that it intended to use to fulfill its aggregate commitments, the State is still required to demonstrate that the selected attainment year (*e.g.,* 2025) is as expeditious as practicable considering potential emission reductions from all plan precursors, including ammonia.

The EPA emphasizes that it is stating both that the Plan does not demonstrate that the SJV will attain by 2025 and that the State has not demonstrated that it could not attain sooner than 2025. These findings are not in tension with one another. Under the Act, the State must demonstrate that its control plan will be sufficient to attain the NAAQS, and to attain the NAAQS by the most expeditious date practicable. The State's failure to demonstrate that it could not attain sooner than 2025 is not inconsistent with the State also having other analytical or substantive flaws in its control plan to attain by 2025. The EPA is not proposing to find that the SJV can practicably attain by 2024, nor is the EPA proposing to find that the SJV could not possibly attain by 2025. Instead, the EPA is proposing, in light of the uncertainty regarding ammonia controls, to find that the State has failed to demonstrate that it could not practicably attain before 2025, and in light of identified deficiencies in the control plan, that the State's control strategy for attaining by 2025 is flawed.

Furthermore, for the 1997 annual $PM_{2.5}$ NAAQS, on November 8, 2021, the State submitted the ''Attainment Plan Revision for the 1997 Annual $PM_{2.5}$ Standard,'' which was adopted by the District on August 19, 2021, and by CARB on September 23, 2021 (''15 µg/m³ SIP Revision''). In that submission, the State updated its prior air quality modeling to account for more recent monitored air quality data. Specifically, the State estimated 2023 annual average concentrations starting from a 2018 monitored base year (*i.e.,* rather than a 2013 base year, in order to reflect updated monitored air quality data), and applied updated, scaled relative response factors (RRFs) to reflect emissions changes between 2018 and 2023.[219] Because this scaling indicated a significant change in the modeling results for the 1997 annual $PM_{2.5}$ NAAQS, and the modeling for the 2012 annual $PM_{2.5}$ NAAQS relies on many of the same models and assumptions, the result of the scaling analysis introduces additional uncertainty to the modeled attainment demonstration for the 2012 $PM_{2.5}$ NAAQS. Accordingly, we recommend updated modeling analysis for the 2012 annual $PM_{2.5}$ NAAQS.

As a result of our proposed disapproval of the control plan and the uncertainty regarding additional reductions that could be achieved by further BACM/BACT level controls for all appropriate plan precursors (particularly for ammonia), we now propose to disapprove the attainment demonstration for the 2012 annual $PM_{2.5}$ NAAQS.

D. Reasonable Further Progress Demonstration and Quantitative Milestones

1. Summary of 2021 Proposed Rule

In section IV.G of our 2021 Proposed Rule, the EPA described the requirements for RFP and quantitative milestones for a Serious $PM_{2.5}$ nonattainment area, summarized the State's submission in the 2018 $PM_{2.5}$ Plan for the SJV, and presented our evaluation thereof.[220] We briefly summarize those components here and rely on the more complete exposition in that proposed rule, except as described in section II.D.2 of this proposed rule (*i.e.,* the EPA's reconsidered proposal for RFP and quantitative milestones).

Regarding requirements, CAA section 172(c)(2) provides that all nonattainment area plans shall require RFP toward attainment. In addition, CAA section 189(c) requires that all $PM_{2.5}$ nonattainment area plans contain quantitative milestones for purposes of measuring RFP, as defined in CAA section 171(1), every three years until the EPA redesignates the area to attainment. Section 171(1) of the Act defines RFP as the annual incremental reductions in emissions of the relevant air pollutant as are required by part D, title I of the Act, or as may reasonably be required by the Administrator for the purpose of ensuring attainment of the

[216] 2018 $PM_{2.5}$ Plan, App. K, Table 39.

[217] Id. at Table 33.

[218] See 2018 $PM_{2.5}$ Plan, App. G, tables 4 through 7.

[219] 15 µg/m³ SIP Revision, Ch. 5, 5–9 to 5–12. See also 15 µg/m³ SIP Revision, App. K, 64–65. In the 15 µg/m³ SIP Revision, the State used existing modeling runs for 2020 and 2024 to compute RRFs for each $PM_{2.5}$ component using the standard approach recommended in the EPA's Modeling Guidance. Those RRFs were then scaled to reflect emissions changes between 2018 and 2023 to arrive at updated RRFs.

[220] 86 FR 74310, 74338–74345.

NAAQS by the applicable attainment date.

In addition to the EPA's longstanding guidance on the RFP requirements for PM, the Agency has established specific regulatory requirements for the $PM_{2.5}$ NAAQS in the $PM_{2.5}$ SIP Requirements Rule for purposes of satisfying the Act's RFP requirements and provided related guidance in the preamble to the rule. Specifically, under the $PM_{2.5}$ SIP Requirements Rule, for a $PM_{2.5}$ attainment plan a State must include an RFP analysis that includes, at minimum, the following four components: (1) an implementation schedule for control measures; (2) RFP projected emissions for direct $PM_{2.5}$ and all $PM_{2.5}$ plan precursors for each applicable milestone year, based on the anticipated control measure implementation schedule; (3) a demonstration that the control strategy and implementation schedule will achieve reasonable progress toward attainment between the base year and the attainment year; and (4) a demonstration that by the end of the calendar year for each triennial milestone date for the area, pollutant emissions will be at levels that reflect either generally linear progress or stepwise progress in reducing emissions on an annual basis between the base year and the attainment year.[221] Additionally, states should estimate the RFP projected emissions for each quantitative milestone year by sector on a pollutant-by-pollutant basis.[222]

Section 189(c) of the Act requires that $PM_{2.5}$ attainment plans include quantitative milestones that demonstrate RFP. The purpose of the quantitative milestones is to allow periodic evaluation of the State's progress towards attainment of the $PM_{2.5}$ NAAQS in the area consistent with RFP requirements. Because RFP is an annual emission reduction requirement and the quantitative milestones are to be achieved every three years, when a State demonstrates compliance with the quantitative milestone requirement, it should also demonstrate that RFP has been achieved during each of the relevant three years. Quantitative milestones should provide an objective means to evaluate progress toward attainment meaningfully, *e.g.,* through imposition of emissions controls in the attainment plan and the requirement to quantify those required emissions reductions on the schedule approved by the EPA and thus required to meet RFP.

As we noted in the 2021 Proposed Rule, the CAA does not specify the starting point for counting the three-year periods for quantitative milestones under CAA section 189(c). In the General Preamble and General Preamble Addendum, the EPA interpreted the CAA to require that the starting point for the first three-year period be the due date for the Moderate area plan submission.[223] Consistent with this longstanding interpretation of the Act, the $PM_{2.5}$ SIP Requirements Rule requires that each plan for a Serious $PM_{2.5}$ nonattainment area that demonstrates attainment by the end of the 10th calendar year following the date of designation contain quantitative milestones to be achieved no later than milestone dates 7.5 years and 10.5 years from the date of designation of the area.[224] The 2018 $PM_{2.5}$ Plan includes a demonstration designed to show attainment by the end of the 10th calendar year following designations (*i.e.,* December 31, 2025). Because the EPA designated the SJV nonattainment for the 2012 annual $PM_{2.5}$ NAAQS effective April 15, 2015,[225] the applicable quantitative milestone dates for purposes of the submitted Serious area plan for this NAAQS in the SJV are October 15, 2022, and October 15, 2025.

Quantitative milestones must provide for objective evaluation of reasonable further progress toward timely attainment of the $PM_{2.5}$ NAAQS in the area and include, at minimum, a metric for tracking progress achieved in implementing SIP control measures, including BACM and BACT, by each milestone date.[226]

The State presents its RFP demonstration and quantitative milestones for the 2012 annual $PM_{2.5}$ NAAQS in Appendix H of the 2018 $PM_{2.5}$ Plan. Following the identification of a transcription error in the RFP tables of Appendix H, the State submitted a revised version of Appendix H that corrects the transcription error and provides additional information on the RFP demonstration.[227] Given the State's conclusions that ammonia, SO_X, and VOC emissions do not contribute significantly to $PM_{2.5}$ levels that exceed the 2012 annual $PM_{2.5}$ NAAQS in the SJV, the RFP demonstration provided by the State only addresses emissions of direct $PM_{2.5}$ and NO_X.[228] Similarly, the State developed quantitative milestones based upon the Plan's control measure strategy to achieve emission reductions of direct $PM_{2.5}$ and NO_X.[229]

For the 2012 annual $PM_{2.5}$ NAAQS, the RFP demonstration in the Plan follows a stepwise approach due to the time required for CARB and the District ''to amend rules, develop programs, and implement the emission reduction measures.'' [230] The revised Appendix H provides clarifying information on the RFP demonstration, including additional information to justify the Plan's stepwise approach to demonstrating RFP. This clarifying information did not affect the Plan's quantitative milestones. It is important to note that the State evaluated what would be necessary for purposes of meeting RFP premised upon its approach to regulating only direct $PM_{2.5}$ and NO_X emissions, and upon a December 31, 2025 attainment date that itself depended upon the State achieving certain additional emission reductions though the enforceable commitments.

In our 2021 Proposed Rule we further described the State's RFP demonstration and quantitative milestones in the SJV $PM_{2.5}$ Plan, including, for example, the anticipated implementation schedule for CARB and District control measures, projected emissions for each RFP year and attainment year, and percent reductions to be achieved in each milestone year, which would be consistent with a stepwise approach. We noted that the reductions between the 2013 base year and 2019 milestone year are consistent with generally linear progress toward the targeted attainment date, while the reductions by the 2022 milestone year would fall short of the rate of reductions to show generally linear RFP. We also noted that the State relies on more substantial direct $PM_{2.5}$ and NO_X emission reductions by January 1, 2025, due in large part to CARB and the District's reliance on enforceable commitments to achieve additional $PM_{2.5}$ and NO_X emission reductions from new measures implemented by 2024. Lastly, we noted the State's overall conclusion that the adopted control strategy and additional commitments for reductions from new control programs by this time are adequate to meet the RFP requirement for the 2012 annual $PM_{2.5}$ NAAQS with

[221] 40 CFR 51.1012(a).

[222] 81 FR 58010, 58056.

[223] General Preamble, 13539 and General Preamble Addendum, 42016.

[224] 40 CFR 51.1013(a)(2)(i).

[225] 80 FR 2206.

[226] 81 FR 58010, 58064 and 58092.

[227] Appendix H to 2018 $PM_{2.5}$ Plan, submitted February 11, 2020, via the EPA State Planning Electronic Collaboration System. This revised version of Appendix H replaces the version submitted with the 2018 $PM_{2.5}$ Plan on May 10, 2019. All references to Appendix H in this proposed rule are to the revised version of Appendix H submitted February 11, 2020.

[228] 2018 $PM_{2.5}$ Plan, App. H, H–1.

[229] Id. at App. H, H–23 to H–24 (for CARB milestones) and H–20 to H–22 (for District milestones).

[230] Id. at App. H, H–4.

the projected attainment date of December 31, 2025.

Regarding quantitative milestones, Appendix H of the 2018 $PM_{2.5}$ Plan identifies October 15 milestone dates for the 2019 and 2022 RFP milestone years, the 2025 attainment year, and a post-attainment milestone year of 2028.[231] Appendix H also identifies target emissions levels to meet the RFP requirement for direct $PM_{2.5}$ and NO_X emissions for each of these milestone years,[232] as shown in Table 6 of our 2021 Proposed Rule, and control measures that CARB and the District already have in place or plan to implement by each of these years, in accordance with the control strategy in the Plan.[233]

We noted, however, that while quantitative milestones are required for 2019 in the context of the Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV (corresponding to the 4.5 years after the date of designation), we have already evaluated and approved the State's quantitative milestones for 2019, as supplemented by the 2018 $PM_{2.5}$ Plan.[234] Therefore, the EPA is not evaluating the 2019 milestones for purposes of the State's Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

Although the State's attainment demonstration for the 2012 annual $PM_{2.5}$ NAAQS does not rely on CARB's and the District's control measure commitments for emission reductions until 2024,[235] the RFP and quantitative milestone elements of the 2018 $PM_{2.5}$ Plan rely on these control measure commitments to demonstrate that the plan requires RFP toward attainment.[236] In our 2021 Proposed Rule we summarized the specific milestones identified by the State for each milestone year and with respect to the control measure commitments in each three-year period.

The EPA presented its evaluation of the State's RFP demonstration and quantitative milestones in section IV.G.3 of the 2021 Proposed Rule, with additional information in section V of the EPA's 2012 Annual $PM_{2.5}$ TSD. We previously proposed to approve the State's RFP demonstration and quantitative milestones.

2. The EPA's Reconsidered Proposal

As discussed in section II.C.3, we are now proposing to disapprove the attainment demonstration for the Serious area plan portion of the 2018 $PM_{2.5}$ Plan for the 2012 annual $PM_{2.5}$ NAAQS because we are proposing to not approve the State's control plan to achieve the reductions modeled for 2025 and the attainment demonstration does not demonstrate that the SJV could not practicably attain before 2025. The RFP demonstration in the Plan is deficient because it sets out a timeline for implementing the deficient control plan, which is not sufficient to ''ensure attainment'' under CAA section 171(l). The quantitative milestones do not ''demonstrate [RFP] toward attainment by the applicable date'' under CAA section 189(c), both because the Plan does not sufficiently demonstrate that the control plan will result in attainment, and because the plan does not sufficiently establish what the applicable date should be.[237] As a result, the EPA proposes to disapprove the Plan's Serious area RFP demonstration and quantitative milestones for the 2012 annual $PM_{2.5}$ NAAQS.

E. Motor Vehicle Emission Budgets

1. Summary of 2021 Proposed Rule

In section IV.I of our 2021 Proposed Rule, the EPA described the requirements for motor vehicle emission budgets (''budgets'') for a Serious $PM_{2.5}$ nonattainment area, summarized the State's submission in the 2018 $PM_{2.5}$ Plan for the SJV, and presented our evaluation thereof.[238] We briefly summarize those components here and rely on the more complete exposition in that proposed rule, except as described in section II.E.2 of this proposed rule (*i.e.,* the EPA's reconsidered proposal for budgets).

Section 176(c) of the CAA requires federally funded or approved actions in nonattainment and maintenance areas to conform to the SIP's goals of eliminating or reducing the severity and number of violations of the NAAQS and achieving expeditious attainment of the NAAQS. Conformity to the SIP's goals means that such actions will not: (1) cause or contribute to new violations of a NAAQS; (2) increase the frequency or severity of an existing violation; or (3) delay timely attainment of any NAAQS or any interim milestone.

Actions involving Federal Highway Administration (FHWA) or Federal Transit Administration (FTA) funding or approval are subject to the EPA's transportation conformity rule, codified at 40 CFR part 93, subpart A (''Transportation Conformity Rule''). Under this rule, metropolitan planning organizations (MPOs) in nonattainment and maintenance areas coordinate with State and local air quality and transportation agencies, the EPA, FHWA, and FTA to demonstrate that an area's regional transportation plan (RTP) and transportation improvement programs (TIP) conform to the applicable SIP. The MPO's demonstration is typically done by showing that estimated emissions from existing and planned highway and transit systems are less than or equal to the applicable budgets contained in adequate or approved control strategy implementation plans. An attainment plan for the $PM_{2.5}$ NAAQS should include budgets for the attainment year and each required RFP milestone year for direct $PM_{2.5}$ and $PM_{2.5}$ precursors subject to transportation conformity analyses. Budgets are generally established for specific years and specific pollutants or precursors and must reflect all of the motor vehicle control measures contained in the attainment and RFP demonstrations.[239]

In our 2021 Proposed Rule, we described how states should identify budgets for direct $PM_{2.5}$, NO_X, and all other $PM_{2.5}$ precursors for which the State and/or the EPA has determined that on-road emissions significantly contribute to $PM_{2.5}$ levels in the area for each RFP milestone year and the attainment year if the plan demonstrates attainment.[240] All direct $PM_{2.5}$ SIP budgets should include direct $PM_{2.5}$ motor vehicle emissions from tailpipes, brake wear, and tire wear.

We described the process by which the State and the EPA should determine

[231] 2018 $PM_{2.5}$ Plan, App. H, Table H–12.

[232] Id. at Table H–5.

[233] Id. at H–23 to H–24 (for CARB milestones) and H–20 to H–22 (for District milestones).

[234] 86 FR 67343, 67346.

[235] 2018 $PM_{2.5}$ Plan, Ch. 4, Table 4–3 (''Emission Reductions from District Measures'') and Table 4–9 (''San Joaquin Valley Expected Emission Reductions from State Measures'').

[236] 2018 $PM_{2.5}$ Plan, App. H, H–4 to H–10 (describing commitments by CARB and SJVUAPCD to adopt additional measures to fulfill tonnage commitments for 2024 and 2025, including ''action'' and ''implementation'' dates occurring before 2024 to ensure expeditious progress toward attainment).

[237] In addition, as discussed in section II.C.3.a of this proposed rule, the EPA notes that of the State's 27 control measure commitments, four regulatory measures and four incentive-based measures are overdue (*i.e.,* were due for board consideration in 2020 or 2021). It is not clear, based on the evidence before the EPA, that such measures will be presented to the CARB and District boards in the 2022 calendar year. Furthermore, to the extent the State relies on substitute measures to ultimately fulfill its aggregate tonnage commitments in 2025 (*e.g.,* the Agricultural Burning Phase-out Measure), the State has not provided quantitative milestones as part of a SIP revision that would provide for periodic evaluation of the State's progress in implementing such substitute measures. In addition, the State has not provided quantitative milestones for ammonia.

[238] 86 FR 74310, 74347–74351.

[239] 40 CFR 93.118(e)(4)(v).

[240] 40 CFR 93.102(b)(2)(iv) and (v).

whether other pollutant emissions (*i.e.,* for re-entrained road dust, VOC, SO_2, and ammonia) contribute significantly to the $PM_{2.5}$ nonattainment problem, either with respect to the whole plan or with respect to on-road mobile emissions, and therefore be subject to the transportation conformity requirements (*i.e.,* budgets for such pollutant(s) must be included in the plan). We further noted that transportation conformity trading mechanisms are allowed under 40 CFR 93.124 where a State establishes appropriate mechanisms for such trades and where the basis for the trading mechanism is the SIP attainment modeling that establishes the relative contribution of each $PM_{2.5}$ precursor pollutant.

The EPA's process for determining the adequacy of a budget consists of three basic steps: (1) notifying the public of a SIP submittal; (2) providing the public the opportunity to comment on the budgets during a public comment period; and (3) making a finding of adequacy or inadequacy.[241] The EPA can notify the public by either posting an announcement on the EPA's adequacy website notifying the public that the EPA has received a SIP submission that will be reviewed to determine if the budgets in that submission are adequate for transportation conformity purposes (40 CFR 93.118(f)(1)), or through a **Federal Register** notice of proposed rulemaking when the EPA reviews the adequacy of submitted motor vehicle emission budgets simultaneously with its review and action on the SIP itself (40 CFR 93.118(f)(2)).

The State includes budgets for direct $PM_{2.5}$ and NO_X emissions for the 2019 and 2022 RFP milestone years, the projected attainment year (2025), and one post-attainment year quantitative milestone (2028) in the 2018 $PM_{2.5}$ Plan.[242] The State establishes separate direct $PM_{2.5}$ and NO_X subarea budgets for each county, or partial county (for Kern County), in the SJV.[243] CARB calculated the budgets using EMFAC2014,[244] which was, at the time, CARB's latest version of the EMFAC model for estimating emissions from on-road vehicles operating in California that had been approved by EPA at the time of Plan development, and the latest modeled vehicle miles traveled and speed distributions from the SJV MPOs from the Final 2017 Federal Transportation Improvement Programs, adopted in September 2016. The budgets reflect annual average emissions consistent with the annual averaging period of the 2012 annual $PM_{2.5}$ NAAQS and the 2018 $PM_{2.5}$ Plan's RFP demonstration.

In our 2021 Proposed Rule, the EPA noted the following: (1) 2022 and 2025 are the required budget years applicable to the Serious area plan portion of the 2018 $PM_{2.5}$ Plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV (and that the attainment year of 2025 coincided with the latter milestone year based on timing of designations); (2) the EPA had approved the budgets for the 2022 RFP milestone year in acting on the Moderate area plan and, therefore, will not be acting on them again in acting on the Serious area plan;[245] (3) the EPA is not evaluating the 2019 budgets, which would neither be used in any future conformity determinations (as the plan contains budgets for 2022 and other future years), nor required for the submitted Serious area plan; and (4) the EPA would begin the motor vehicle emissions budget adequacy and approval review processes for the 2028 post-attainment milestone year budgets only if the area were to fail to attain the standard by December 31, 2025 (the applicable Serious area attainment date if the EPA were to finalize approval of the 2018 $PM_{2.5}$ Plan's attainment demonstration).

The Plan's direct $PM_{2.5}$ budgets include tailpipe, brake wear, and tire wear emissions but do not include paved road dust, unpaved road dust, and road construction dust emissions.[246] The State did not include budgets for VOC, SO_2, or ammonia, consistent with its precursor demonstration that control of these precursors would not significantly contribute to attainment of the 2012 annual $PM_{2.5}$ NAAQS. The State also included a discussion of the significance/insignificance factors for motor vehicle emissions of ammonia, SO_2, and VOC to support a finding of insignificance under the transportation conformity rule.[247] The State is not required to include re-entrained road dust in the $PM_{2.5}$ budgets under section 93.103(b)(3) unless the EPA or the State has made a finding that these emissions are significant, and neither the State nor the EPA has made such a finding. Nevertheless, the Plan includes a discussion of the significance/insignificance factors for re-entrained road dust and concludes that such emissions are insignificant.[248] The budgets included in the 2018 $PM_{2.5}$ Plan are shown in Table 3 of this proposed rule, which is identical to Table 9 of our 2021 Proposed Rule.

TABLE 3—MOTOR VEHICLE EMISSION BUDGETS FOR THE SAN JOAQUIN VALLEY FOR THE 2012 $PM_{2.5}$ STANDARD

[Annual average, tpd]

County	2022 (RFP year) [a]		2025 (attainment year)	
	$PM_{2.5}$	NO_X	$PM_{2.5}$	NO_X
Fresno	0.9	21.2	0.8	14.3
Kern	0.8	19.4	0.8	12.8
Kings	0.2	4.1	0.2	2.7
Madera	0.2	3.5	0.2	2.3
Merced	0.3	7.6	0.3	5.0
San Joaquin	0.6	10.0	0.6	6.9
Stanislaus	0.4	8.1	0.4	5.6
Tulare	0.4	6.9	0.4	4.7

Source: 2018 $PM_{2.5}$ Plan, Appendix D, Table 3–3. Budgets are rounded to the nearest tenth of a ton.

[241] 40 CFR 93.118(f).

[242] 2018 $PM_{2.5}$ Plan, App. D, Table 3–3.

[243] 40 CFR 93.124(c) and (d).

[244] EMFAC is short for *EM*ission *FAC*tor. The EPA announced the availability of the EMFAC2014 model for use in State implementation plan development and transportation conformity in California on December 14, 2015. The EPA's approval of the EMFAC2014 emissions model for SIP and conformity purposes was effective on the date of publication of the notice in the **Federal Register**.

[245] 86 FR 67343, 67346.

[246] 2018 $PM_{2.5}$ Plan, App. D, D–122 to D–123.

[247] 40 CFR 93.109(f).

[248] 2018 $PM_{2.5}$ Plan, App. D, D–121.

[a] The EPA has already approved the 2022 RFP budgets in our final rule on the State's Moderate area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

In our 2021 Proposed Rule, we also described the State's proposed trading mechanism in the 2018 $PM_{2.5}$ Plan for transportation conformity analyses that would allow future decreases in NO_X emissions from on-road mobile sources to offset any on-road increases in direct $PM_{2.5}$ emissions.

We presented our evaluation of the State's Serious area budgets for the 2012 annual $PM_{2.5}$ NAAQS in the SJV and proposed to approve the 2025 budgets. We noted our preliminary review of the budgets submitted for adequacy, which preceded our proposed approval of the budgets, consistent with the EPA's general process. Based on information in the Plan, we proposed that budgets were not required for SO_2, VOC, and ammonia.

Based on our proposed approval of the State's RFP and attainment demonstrations, and our review of the budgets in the Plan, we proposed that the 2025 budgets for RFP and attainment were consistent with those demonstrations, were clearly identified and precisely quantified, and met all other applicable statutory and regulatory requirements including the adequacy criteria in 40 CFR 93.118(e)(4) and (5). We provided a more detailed discussion of the budgets in section VI of the EPA's 2012 Annual $PM_{2.5}$ TSD. We noted that our proposed approval of the budgets for the 2012 annual $PM_{2.5}$ NAAQS did not affect the status of the previously approved budgets for the 1997 $PM_{2.5}$ NAAQS and related trading mechanism, which remain in effect for that $PM_{2.5}$ NAAQS, nor the 2006 24-hour $PM_{2.5}$ NAAQS and related trading mechanism, which remain in effect for that $PM_{2.5}$ NAAQS.[249]

Based on our review of the State's trading mechanism for transportation conformity analyses for the 2012 annual $PM_{2.5}$ NAAQS, the EPA previously proposed to approve the trading mechanism, which would allow future decreases in NO_X emissions from on-road mobile sources to offset any on-road increases in $PM_{2.5}$, using a 6.5:1 NO_X:$PM_{2.5}$ ratio.[250] To ensure that the trading mechanism does not affect the ability to meet the NO_X budget, we noted the following: (1) the Plan provides that the NO_X emission reductions available to supplement the $PM_{2.5}$ budget would only be those remaining after the NO_X budget has been met; (2) the SJV MPOs would have to document clearly the calculations used in the trading when demonstrating conformity, along with any additional reductions of NO_X and $PM_{2.5}$ emissions in the conformity analysis; and (3) the trading calculations must be performed prior to the final rounding to demonstrate conformity with the budgets. We summarized the technical bases for our proposed approval of the trading mechanism in the 2021 Proposed Rule and in section VI of the EPA's 2012 Annual $PM_{2.5}$ TSD.

Regarding the duration of budgets for the 2012 annual $PM_{2.5}$ NAAQS, the EPA noted that once budgets are approved, they cannot be superseded by revised budgets submitted for the same CAA purpose and the same year(s) addressed by the previously approved SIP until the EPA approves the revised budgets as a SIP revision. While CARB had requested in its letter submitting the 2018 $PM_{2.5}$ Plan that the EPA limit the duration of the budgets (*i.e.,* to allow an adequacy finding, rather than approval, of future SIP revision of budgets to replace the initial budgets),[251] CARB later clarified that since they have submitted EMFAC2021 for EPA review, they no longer request that we limit the duration of our approval.[252]

Lastly, in our 2021 Proposed Rule, the EPA proposed to disapprove the contingency measure element of the 2018 $PM_{2.5}$ Plan with respect to the Serious area requirements for the 2012 annual $PM_{2.5}$ NAAQS, and we are not modifying our proposed action on contingency measures in this proposed rule. Accordingly, we noted that if the EPA were to finalize the proposed disapproval of the 2012 annual $PM_{2.5}$ NAAQS Serious area contingency measure element, the area would be eligible for a protective finding under the transportation conformity rule because the 2018 $PM_{2.5}$ Plan reflects adopted control measures that fully satisfy the emissions reductions requirements for the RFP and attainment year of 2025.[253]

2. The EPA's Reconsidered Proposal

Based on the EPA's reconsideration and proposed disapprovals of the attainment and RFP demonstrations discussed herein, we have reconsidered our proposed approval of the Serious area budgets for the 2012 annual $PM_{2.5}$ NAAQS in the SJV. As discussed below, the EPA now proposes to disapprove the 2025 RFP and attainment year budgets.

As noted in section I.B of this proposed rule, we are not re-proposing any action on the Plan's precursor demonstrations for SO_X and VOC (*i.e.,* we retain our proposed approval that SO_X and VOC are not plan precursors for the 2012 annual $PM_{2.5}$ NAAQS in the SJV, and therefore SO_2 and VOC budgets would not be required, consistent with the transportation conformity regulation (40 CFR 93.102(b)(2)(v))). However, as discussed in section II.A.3 of this proposed rule, the EPA now proposes to disapprove the State's precursor demonstration that ammonia does not significantly contribute to exceedances of the 2012 annual $PM_{2.5}$ NAAQS in the SJV, and therefore the Plan's precursor demonstration would not address the State's obligation to consider whether ammonia budgets are necessary in the Serious area plan.

In the Plan, the State provides a discussion of the significance/insignificance factors for motor vehicle emissions of ammonia (and SO_2 and VOC), which would demonstrate a finding of insignificance under the transportation conformity rule.[254] The factors typically addressed for significance include an examination of the on-road contribution of ammonia to the total emissions, and the likelihood of future motor vehicle emission controls. We note that annual average ammonia emissions from on-road mobile sources are an estimated 3.4 tpd of a total of 324.3 tpd from all sources in 2025, or about 1% of the total ammonia emissions.[255] Based on our

[249] 76 FR 69896, 69923–69924 (November 9, 2011) (final rule approving direct $PM_{2.5}$ and NO_X budgets for 2012 and 2014 for the 1997 annual and 24-hour $PM_{2.5}$ NAAQS); and 85 FR 44192, 44204 (final rule approving direct $PM_{2.5}$ and NO_X budgets for 2020, 2023, and 2024 for the 2006 24-hour $PM_{2.5}$ NAAQS); and 86 FR 53150, 53176–53179 (September 24, 2021) (proposed rule to approve budgets from the 2018 $PM_{2.5}$ Plan for direct $PM_{2.5}$ and NO_X for 2017 and 2020 for the 1997 24-hour $PM_{2.5}$ NAAQS). We note that, following our 2021 Proposed Rule on the 2012 annual $PM_{2.5}$ NAAQS portion of the Plan, the EPA finalized approval of the 2017 and 2020 budgets for the 1997 24-hour $PM_{2.5}$ NAAQS portion of the Plan. 87 FR 4503.

[250] For example, a 1 tpd excess of direct $PM_{2.5}$ emissions from on-road mobile sources in 2025 could be offset by a 6.5 tpd reduction in NO_X emissions below the NO_X budget for on-road mobile sources in 2025.

[251] Letter dated May 9, 2019, from Richard W. Corey, Executive Officer, CARB, to Mike Stoker, Regional Administrator, EPA Region IX, 3.

[252] Email dated November 30, 2021, from Nesamani Kalandiyur, Manager, Transportation Analysis Section, Sustainable Transportation and Communities Division, CARB, to Karina O'Connor, EPA Region IX.

[253] 40 CFR 93.120(a)(3).

[254] For the criteria and procedures for demonstrating a finding of insignificance under the transportation conformity rule, see 40 CFR 93.109(f).

[255] 2018 $PM_{2.5}$ Plan, App. B, Table B–5.

review, and the small contribution of ammonia emissions from on-road mobile sources, the EPA agrees with the State's finding that on-road mobile source emissions of ammonia are insignificant and therefore the State is not required to include budgets for ammonia in its Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS in the SJV.

With respect to the 2025 RFP and attainment year, the EPA proposes to disapprove the direct $PM_{2.5}$ and NO_X budgets for 2025, as follows. While the 2025 budgets for RFP and attainment were clearly identified and precisely quantified, in this proposed rule the EPA proposes to disapprove the State's Serious area RFP and attainment demonstrations for the 2012 annual $PM_{2.5}$ NAAQS.[256] The EPA cannot approve budgets where the underlying CAA requirements (*i.e.,* RFP and attainment) are disapproved and therefore proposes to disapprove the 2025 budgets. The budgets, when considered together with all other emission sources, cannot be consistent with the applicable requirements for RFP and attainment of the 2012 annual $PM_{2.5}$ NAAQS given the proposed disapprovals of the RFP and attainment demonstrations. Therefore, we are proposing to disapprove the motor vehicle emissions budgets because they do not meet applicable statutory and regulatory requirements, including the adequacy criteria specified in the transportation conformity rule.[257] If the EPA finalizes the disapproval, the EPA would concurrently withdraw the adequacy finding for the 2025 RFP and attainment year motor vehicle emission budgets.[258]

Lastly, given that we now propose to disapprove the Plan's RFP and attainment demonstrations for the 2012 annual $PM_{2.5}$ NAAQS, rather than just the Serious area contingency measure element alone (as described in our 2021 Proposed Rule), the SJV would not be eligible for a protective finding under the transportation conformity rule because the 2018 $PM_{2.5}$ Plan's control measures do not fully satisfy the emissions reductions requirements for the RFP and attainment year of 2025.[259]

As a result, if the EPA finalizes our proposed disapproval of the budgets, upon the effective date of our final rule the area would be subject to a conformity freeze under 40 CFR 93.120 of the transportation conformity rule. No new transportation plan, TIP, or project may be found to conform until the State submits another control strategy implementation plan revision fulfilling the same CAA requirements, the EPA finds the budgets in the revised plan adequate or approves the budgets, the MPO makes a conformity determination for the new budgets, and the U.S. Department of Transportation makes a conformity determination.[260] In addition, only transportation projects outside of the first four years of the current conforming transportation plan and TIP or that meet the requirements of 40 CFR 93.104(f) during the resulting conformity freeze may be found to conform until California submits a new attainment and RFP plan for the 2012 annual $PM_{2.5}$ NAAQS and (1) the EPA finds the submitted budgets adequate per 40 CFR 93.118 or (2) the EPA approves the new attainment plan and conformity to the new plan is determined.[261] Furthermore, if, as a result of our final disapproval action, the EPA imposes highway sanctions under section 179(b)(1) of the Act two years from the effective date of our final rule, then the conformity status of the transportation plan and TIP will lapse on that date and no new transportation plan, TIP, or project may be found to conform until California submits a new plan for the 2012 annual $PM_{2.5}$ NAAQS, and conformity to the plan is determined.[262]

III. Environmental Justice Considerations

Executive Order 12898 (59 FR 7629, February 16, 1994) requires that Federal agencies, to the greatest extent practicable and permitted by law, identify and address disproportionately high and adverse human health or environmental effects of their actions on minority and low-income populations. Additionally, Executive Order 13985 (86 FR 7009, January 25, 2021) directs Federal Government agencies to assess whether, and to what extent, their programs and policies perpetuate systemic barriers to opportunities and benefits for people of color and other underserved groups, and Executive Order 14008 (86 FR 7619, February 1, 2021) directs Federal agencies to develop programs, policies, and activities to address the disproportionate health, environmental, economic, and climate impacts on disadvantaged communities.

To identify environmental burdens and susceptible populations in underserved communities in the SJV nonattainment area and to better understand the context of our proposed action on the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan on these communities, we conducted a screening-level analysis using the EPA's environmental justice (EJ) screening and mapping tool (''EJSCREEN'').[263] Our screening-level analysis indicates that all eight counties in the SJV score above the national average for the EJSCREEN ''Demographic Index'' (*i.e.,* ranging from 48% in Stanislaus County to 61% in Tulare County, compared to 36% nationally).[264] The Demographic Index is the average of an area's percent minority and percent low income populations, *i.e.,* the two populations explicitly named in Executive Order 12898.[265] All eight counties also score above the national average for demographic indices of ''linguistically isolated population'' and ''population with less than high school education.''

With respect to pollution, all eight counties score at or above the 97th percentile nationally for the $PM_{2.5}$ index and seven of the eight counties in the SJV score at or above the 90th percentile nationally for the $PM_{2.5}$ EJ index, which is a combination of the Demographic Index and the $PM_{2.5}$ index. Most counties also scored above the 80th percentile for each of 11 additional EJ indices included in the EPA's EJSCREEN analysis. In addition, several

[256] See 40 CFR 93.118(e)(4)(iii).

[257] 40 CFR 93.118(e)(4).

[258] The EPA found the 2025 budgets adequate in our 2021 Proposed Rule. See also, the EPA's 2012 Annual $PM_{2.5}$ TSD, 41.

[259] 40 CFR 93.120(a)(3).

[260] 40 CFR 93.120(a)(2).

[261] Id.

[262] 40 CFR 93.120(a)(1).

[263] EJSCREEN provides a nationally consistent dataset and approach for combining environmental and demographic indicators. EJSCREEN is available at *https://www.epa.gov/ejscreen/what-ejscreen.* The EPA used EJSCREEN to obtain environmental and demographic indicators representing each of the eight counties in the San Joaquin Valley. We note that the indicators for Kern County are for the entire county. While the indicators might have slightly different numbers for the SJV portion of the county, most of the county's population is in the SJV portion, and thus the differences would be small. These indicators are included in EJSCREEN reports that are available in the rulemaking docket for this action.

[264] EPA Region IX, ''EJSCREEN Analysis for the Eight Counties of the San Joaquin Valley Nonattainment Area,'' August 2022.

[265] EJSCREEN reports environmental indicators (*e.g.,* air toxics cancer risk, Pb paint exposure, and traffic proximity and volume) and demographic indicators (*e.g.,* people of color, low income, and linguistically isolated populations). The score for a particular indicator measures how the community of interest compares with the State, the EPA region, or the national average. For example, if a given location is at the 95th percentile nationwide, this means that only 5% of the US population has a higher value than the average person in the location being analyzed. EJSCREEN also reports EJ indexes, which are combinations of a single environmental indicator with the EJSCREEN Demographic Index. For additional information about environmental and demographic indicators and EJ indexes reported by EJSCREEN, see EPA, ''EJSCREEN Environmental Justice Mapping and Screening Tool—EJSCREEN Technical Documentation,'' section 2 (September 2019).

counties scored above the 90th percentile for certain EJ indices, including, for example, the Ozone EJ Index (Fresno, Kern, Madera, Merced, and Tulare counties), the National Air Toxics Assessment (NATA) Respiratory Hazard EJ Index (Madera and Tulare counties), and the Wastewater Discharge Indicator EJ Index (Merced, San Joaquin, Stanislaus, and Tulare counties).[266]

As discussed in the EPA's EJ technical guidance, people of color and low-income populations, such as those in the SJV, often experience greater exposure and disease burdens than the general population, which can increase their susceptibility to adverse health effects from environmental stressors.[267] Underserved communities may have a compromised ability to cope with or recover from such exposures due to a range of physical, chemical, biological, social, and cultural factors.[268] The EPA is committed to environmental justice for all people, and we acknowledge that the SJV nonattainment area includes minority and low income populations that are subject to higher levels of $PM_{2.5}$ and other pollution relative to State and national averages, and that such concerns could be affected by this action.

If the EPA were to finalize the proposed disapprovals described in section II of this proposed rule, California would be required to submit a plan revision for the SJV for the 2012 annual $PM_{2.5}$ NAAQS to address the identified deficiencies. In addition, as summarized in section V of this proposed rule, such final action would trigger clocks for the SJV for offset sanctions 18 months after the final rule effective date, highway funding sanctions six months after the offset sanctions, and the obligation for the EPA to promulgate a Federal implementation plan (FIP) within two years of the final rule effective date. These obligations ensure that the identified deficiencies are resolved in an expeditious manner, consistent with the principles of environmental justice.

We note that, in developing and proposing draft regulations for governing board consideration, both CARB and the District consider the potential benefits of proposed measures for reducing health hazards to disadvantaged communities, such as diesel PM exposure near Heavy-Duty truck corridors and indoor smoke exposure from residential wood burning. There may be further opportunities to address EJ concerns through such control development and implementation.

More broadly, California law has established additional requirements for community-focused action to reduce air pollution in the State. For example, in response to California Assembly Bill 617 (2017), CARB and the District have engaged communities in the SJV, performed technical evaluations, and ultimately selected four communities (South Central Fresno, Shafter, Stockton, and Arvin/Lamont) that are in varying stages of developing and implementing community air monitoring programs and community emission reduction programs.[269] Furthermore, grant programs implemented by the local, State, and Federal authorities may serve to smooth and accelerate emission reductions of $PM_{2.5}$ and its precursor pollutants in the SJV, thereby relieving some of the cumulative burden on disadvantaged communities in the SJV nonattainment area.[270]

IV. Title VI of the Civil Rights Act

As noted in section I.C of this proposed rule, the EPA received a comment letter dated January 28, 2022 (the Public Justice Comment Letter), on the 2021 Proposed Rule from a coalition of 13 organizations.

The commenters urge the EPA to disapprove the Serious area plan ''because EPA has failed to require CARB/SJV to provide necessary assurances that the State implementation plan complies with Title VI of the Civil Rights Act of 1964. The on-going environmental justice and air pollution crisis demand EPA reverse course and disapprove the 2012 plan.'' [271] To support this argument, the commenters provide information regarding the racial demographics of the SJV, the potential for disparate impacts from exposure to $PM_{2.5}$, and specific aspects of the SJV $PM_{2.5}$ Plan that the commenters believe result in disparate impacts. The commenters point to past precedent in which the EPA has considered compliance with Title VI of the Civil Rights Act (Title VI) in the SIP context through CAA section 110(a)(2)(E). The commenters also note that thus far California has provided no ''demonstration'' that the Serious area plan does not cause or exacerbate disparate impacts on affected communities in the SJV. Thus, the commenters assert that the EPA must disapprove the Serious area plan because the State did not provide ''required assurances'' of compliance with Title VI.

At this time, the EPA has not issued any guidance or regulations concerning what might be required for purposes of CAA section 110(a)(2)(E) as it regards Title VI. The EPA has addressed other aspects of section 110(a)(2)(E) in the context of infrastructure SIP submissions in its September 2013 ''Guidance on Infrastructure State Implementation Plan (SIP) Elements under Clean Air Act Sections 110(a)(1) and 110(a)(2).'' Similarly, EPA regulations only address other aspects of section 110(a)(2)(E) in 40 CFR Sections 51.230–232.

A. Background on CAA Section 110(a)(2)(E)

For purposes of background, section 110(a)(2)(E) of the CAA, in relevant part and with emphasis added, reads as follows:

> (2) Each implementation plan submitted by a State under this chapter shall be adopted by the State after reasonable notice and public hearing. Each such plan shall—. . .
>
> (E) provide (i) *necessary assurances* that the State (or, except where the Administrator deems inappropriate, the general purpose local government or governments, or a regional agency designated by the State or general purpose local governments for such purpose) will have adequate personnel, funding, and authority under State (and, as appropriate, local) law to carry out such implementation plan *(and is not prohibited by any provision of Federal or State law from carrying out such implementation plan or portion thereof),* (ii) requirements that the State comply with the requirements respecting State boards under section 7428 of this title, and (iii) necessary assurances that, where the State has relied on a local or regional government, agency, or instrumentality for the implementation of any plan provision, the State has responsibility for ensuring adequate implementation of such plan provision.[272]

[266] Notably, Tulare County scores above the 90th percentile on six of the 12 EJ indices in the EPA's EJSCREEN analysis, including the $PM_{2.5}$ EJ Index, which is the highest count among all SJV counties.

[267] EPA, ''Technical Guidance for Assessing Environmental Justice in Regulatory Analysis,'' section 4 (June 2016).

[268] Id. at section 4.1.

[269] For further information, see, *e.g.,* SJVUAPCD, ''Item Number 9: Receive Progress Reports on AB617 Community Emission Reduction Program Implementation,'' November 18, 2021.

[270] For example, through the EPA's Targeted Airshed Grant program, the District has competed for, and the EPA has granted 13 awards to the District from 2015 through 2021, totaling $77.4 million, to replace older, dirtier woodstoves, agricultural equipment, heavy-duty trucks and yard trucks, and agricultural nut harvesters with cleaner equipment. A list of the Targeted Airshed Grants the EPA awarded in fiscal years 2015–2020 is accessible online at *https://www.epa.gov/air-quality-implementation-plans/targeted-airshed-grant-recipients.* These EPA grants support projects to reduce emissions in areas facing the highest levels of ground-level ozone and $PM_{2.5}$.

[271] Public Justice Comment Letter, 2.

[272] 42 U.S.C. Section 7410(a)(2)(E) (emphasis added).

The EPA has previously addressed CAA section 110(a)(2)(E)(i), Title VI, and necessary assurances in a 2012 action on a nonattainment plan SIP submission from California for purposes of the ozone NAAQS.[273] Comments submitted on the EPA's April 24, 2012 proposed action contended that the SIP submission was not in compliance with CAA section 110(a)(2)(E) because of alleged violations of Title VI related to the regulation of pesticides as precursors to ozone (as volatile organic compounds). To evaluate the commenter's concerns, the EPA sought additional necessary assurances from the State concerning its regulation of pesticides. California submitted additional information to the EPA concerning the State's activities that were part of the resolution of a Title VI complaint, and additional information concerning the State's regulation of pesticides. California submitted this information to provide ''necessary assurances'' to the EPA that implementation of the requirements of the SIP submission would not violate Title VI. The EPA accepted this information as providing adequate necessary assurances for purposes of section 110(a)(2)(E) and did not require the State to make any substantive changes to support approval of the SIP revision.

Commenters in the 2012 action asserted that California had not provided sufficient necessary assurances. In the response to comments in the 2012 action, the EPA explained that ''Section 110(a)(2)(E), however, does not require a State to 'demonstrate' it is not prohibited by Federal or State law from implementing its proposed SIP revision. Rather, this section requires a State to provide 'necessary assurances' of this.'' [274] The EPA further explained,

> Courts have given EPA ample discretion in deciding what assurances are ''necessary'' and have held that a general assurance or certification is sufficient. (''EPA is entitled to rely on a state's certification unless it is clear that the SIP violates state law and proof thereof * * * is presented to EPA.'' *BCCA Appeal Group* v. *EPA,* 355 F.3d 817, 830 fn 11 (5th Cir. 2003)).[275]

The EPA received a petition for review (from groups overlapping with the groups that sent the Public Justice Comment Letter) of the EPA's October 26, 2012 final action which was reviewed and ultimately decided in EPA's favor by the Ninth Circuit Court of Appeals.[276] The Court used an arbitrary and capricious standard of review to evaluate the EPA's conclusion that the State had provided adequate ''necessary assurances'' that implementation of the SIP is not prohibited by Federal law—specifically, Title VI of the Federal Civil Rights Act of 1964—per the language of section 110(a)(2)(E). The Ninth Circuit found that the EPA fulfilled its duty to provide a reasoned judgment because its determination was cogently explained and supported by the record. In dismissing the petition, the Court explained that ''[t]he EPA has a duty to provide a reasoned judgment as to whether the State has provided 'necessary assurances,' but what assurances are 'necessary' is left to the EPA's discretion.'' [277]

B. Background on Title VI of the Civil Rights Act of 1964

For purposes of background context, Title VI prohibits recipients of Federal financial assistance from discriminating on the basis of race, color, or national origin. Under the EPA's nondiscrimination regulations, which implement Title VI and other civil rights laws,[278] recipients of EPA financial assistance are prohibited from taking actions in their programs or activities that are intentionally discriminatory and/or have an unjustified disparate impact.[279] This includes policies, criteria or methods of administering programs that are neutral on their face but have the effect of discriminating.[280] Under the EPA's regulation, recipients of EPA financial assistance are also required to have in place certain procedural safeguards, including grievance procedures that assure the prompt and fair resolution of external discrimination complaints.[281]

The EPA carries out its mandate to ensure that recipients of EPA financial assistance comply with their nondiscrimination obligations by investigating administrative complaints filed with the EPA alleging discrimination prohibited by Title VI and the other civil rights laws; [282] initiating affirmative compliance reviews; [283] and providing technical assistance to recipients to assist them in meeting their Title VI obligations. In the current matter being addressed in this action, no Title VI complaint was filed regarding CARB or the District.[284] Also, the EPA (through the External Civil Rights Compliance Office or ECRCO) has not initiated and is not currently conducting a compliance review of either CARB or SJVUAPCD.

C. Comments Received on 2021 Proposed Rule

The commenters raise the issue of compliance with section 110(a)(2)(E) with respect to Title VI. The commenters contend that the SIP submission for the SJV is not in compliance with CAA section 110(a)(2)(E) because California has not provided necessary assurances to ensure that implementation of the SIP is in compliance with Title VI. The commenters did not submit these specific comments to CARB or the SJVUAPCD during the State's development and adoption process of the proposed SIP revisions that are currently at issue. The commenters are not required to have done so to raise this issue with the EPA now, but as a result, the SIP submission to the EPA does not include any CARB or District response concerning this specific issue. In addition, the SIP submission does not include specifically identified necessary assurances per section 110(a)(2)(E) provided by the State.

At the outset, the EPA acknowledges the statements in the comment letter that the SJV area has historically been designated as nonattainment for the $PM_{2.5}$ NAAQS and that the SJV area includes higher representation of persons of color compared to the State average. Although in this action the EPA is not proposing to disapprove on the basis of CAA section 110(a)(2)(E), if the EPA disapproves the Serious area plan as proposed today, California would need to submit a revised Serious area plan for the SJV. The EPA expects that any such revision would comply with the requirements of section 110(a)(2)(E) and that CARB and the District will engage with the community through notice and comment during the SIP

[273] 77 FR 65294 (October 26, 2012) (final rule); 77 FR 24441 (April 24, 2012) (proposed rule).

[274] 77 FR 65294, 65302, column 2.

[275] Id.

[276] *El Comité Para El Bienstar de Earlimart et al. (El Comité)* v. *EPA,* 786 F.3d 688 (9th Cir. 2015).

[277] 786 F.3d at 700.

[278] 40 CFR part 7 and part 5.

[279] 40 CFR Sections 7.30 and 7.35.

[280] 40 CFR Section 7.35(b).

[281] 40 CFR Section 7.90.

[282] 40 CFR Section 7.120.

[283] 40 CFR Section 7.115.

[284] The EPA's External Civil Rights Compliance Office (ECRCO) contacted Mr. Brent Newell, signatory to the Public Justice Comment Letter, to see whether the commenters intended to file a Title VI administrative complaint with the EPA. In response, the commenters stated, ''[t]he comments submitted were neither intended nor styled as a Title VI complaint. The comments raise significant issues with respect to EPA's proposed approval, including the section 110(a)(2)(E) issues and EPA's authority and duty to enforce Title VI, and we expect EPA to respond to all of the issues in the final action/response to comments.'' Email exchange dated February 8, 2022, between Brent Newell, Public Justice and Lilian Dorka, Director, External Civil Rights Compliance Office, EPA Office of General Counsel.

development process for its revised Serious area plan prior to submitting a revised SIP to the EPA, and specifically with respect to necessary assurances relative to Title VI. The new SIP development process provides an important opportunity for CARB and the District to identify potential adverse disparate impacts on the basis of race, color, or national origin from its revised Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS and address them as appropriate.

The EPA acknowledges that it has not issued national guidance or regulations concerning implementation of section 110(a)(2)(E) as it pertains to consideration of Title VI and disparate impacts on the basis of race, color, or national origin in the context of the SIP program. Such guidance is forthcoming and will address CAA section 110(a)(2)(E)'s necessary assurance requirements as they relate to Title VI. In the interim, CARB and the District may find existing EPA and DOJ Title VI and environmental justice resources useful, even though these documents do not relate specifically to CAA section 110(a)(2)(E).[285] Additionally, the EPA's ECRCO is available to provide technical assistance regarding Title VI compliance to CARB and/or the District as they develop the revised Serious area plan for the 2012 annual $PM_{2.5}$ NAAQS.

V. Summary of Proposed Actions and Request for Public Comment

For the reasons discussed in this proposed rule, under CAA section 110(k)(3), the EPA proposes to disapprove, as a revision to the California SIP, the following portions of the SJV $PM_{2.5}$ Plan for the 2012 annual $PM_{2.5}$ NAAQS to address the CAA's Serious area planning requirements in the SJV nonattainment area:

(1) the demonstration that BACM, including BACT, for the control of ammonia emission sources and for the control of NO_X and direct $PM_{2.5}$ building heating emission sources will be implemented no later than 4 years after the area was reclassified (CAA section 189(b)(1)(B) and 40 CFR 51.1010(a));

(2) the demonstration that the Plan provides for attainment as expeditiously as practicable but no later than December 31, 2025 (CAA sections 188(c)(2) and 189(b)(1)(A) and 40 CFR 51.1011(b));

(3) plan provisions that require RFP toward attainment by the applicable date (CAA section 172(c)(2) and 40 CFR 51.1012(a));

(4) quantitative milestones that are to be achieved every three years until the area is redesignated attainment and that demonstrate RFP toward attainment by the applicable attainment date (CAA section 189(c) and 40 CFR 51.1013(a)(2)(i)); and

(5) motor vehicle emissions budgets for 2025 as shown in Table 3 of this proposed rule (CAA section 176(c) and 40 CFR part 93, subpart A).

We are also proposing to disapprove the State's precursor demonstration for ammonia. Our proposed action on the emissions inventory and contingency measure elements remains unchanged from our 2021 Proposed Rule.

If we finalize the proposed disapprovals for BACM, the attainment demonstration, RFP, quantitative milestones, or motor vehicle emission budgets, the offset sanction in CAA section 179(b)(2) would apply in the SJV 18 months after the effective date of a final disapproval, and the highway funding sanctions in CAA section 179(b)(1) would apply in the area six months after the offset sanction is imposed.[286] Neither sanction will be imposed under the CAA if the State submits and we approve, prior to the implementation of the sanctions, a SIP revision that corrects the deficiencies that we identify in our final action. The EPA intends to work with CARB and the SJVUAPCD to correct the deficiencies in a timely manner.

In addition to the sanctions, CAA section 110(c)(1) provides that the EPA must promulgate a Federal implementation plan (FIP) addressing any disapproved elements of an attainment plan two years after the effective date of disapproval unless the State submits, and the EPA approves, a SIP submission that cures the disapproved elements.

Furthermore, if we take final action disapproving the 2012 annual $PM_{2.5}$ NAAQS portion of the SJV $PM_{2.5}$ Plan, a conformity freeze will take effect upon the effective date of any final disapproval (usually 30 days after publication of the final action in the **Federal Register**). A conformity freeze means that only projects in the first four years of the most recent RTP and TIP can proceed. During a freeze, no new RTPs, TIPs, or RTP/TIP amendments can be found to conform.[287]

We will accept comments from the public on these proposals for the next 45 days. The deadline and instructions for submission of comments are provided in the **DATES** and **ADDRESSES** sections at the beginning of this proposed rule.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *https://www.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

This action does not impose an information collection burden under the PRA, because this proposed SIP disapproval, if finalized, will not in-and-of itself create any new information collection burdens, but will simply disapprove certain State requirements for inclusion in the SIP.

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. This action will not impose any requirements on small entities. This proposed SIP partial disapproval, if finalized, will not in-and-of itself create any new requirements but will simply disapprove certain State requirements for inclusion in the SIP.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action proposes to disapprove certain pre-existing requirements under State or local law, and imposes no new requirements. Accordingly, no additional costs to State, local, or tribal governments, or to the private sector, result from this action.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial

[285] See ECRCO's Toolkit Chapter I at: *https://www.epa.gov/sites/default/files/2017-01/documents/toolkit-chapter1-transmittal_letter-faqs.pdf,* January 18, 2017, and Department of Justice "Title VI Legal Manual (Updated)" at: *https://www.justice.gov/crt/fcs/T6Manual6.* See also, *e.g.,* EPA, "Guidance on Considering Environmental Justice During the Development of Regulatory Actions," (May 2015), and EPA, "Technical Guidance for Assessing Environmental Justice in Regulatory Analysis," (June 2016).

[286] 40 CFR 52.31.

[287] See 40 CFR 93.120(a).

direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175, because the SIP revision that the EPA is proposing to partially disapprove would not apply on any Indian reservation land or in any other area where the EPA or an Indian tribe has demonstrated that a tribe has jurisdiction, and will not impose substantial direct costs on tribal governments or preempt tribal law. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

The EPA interprets Executive Order 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children, per the definition of ''covered regulatory action'' in section 2–202 of the Executive Order. This action is not subject to Executive Order 13045 because this proposed SIP partial disapproval, if finalized, will not in-and-of itself create any new regulations, but will simply disapprove certain State requirements for inclusion in the SIP.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

Section 12(d) of the NTTAA directs the EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. The EPA believes that this action is not subject to the requirements of section 12(d) of the NTTAA because application of those requirements would be inconsistent with the CAA.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Population

Executive Order 12898 (59 FR 7629 (February 16, 1994)) establishes Federal executive policy on environmental justice. Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations and low-income populations in the United States. The EPA's evaluation of this issue is contained in the section of the preamble titled ''Environmental Justice Considerations.''

List of Subjects 40 CFR Part 52

Environmental protection, Air pollution control, Ammonia, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur dioxide, Volatile organic compounds.

Authority: 42 U.S.C. 7401 *et seq.*

Dated: September 28, 2022.

Martha Guzman Aceves,

Regional Administrator, Region IX.

[FR Doc. 2022–21492 Filed 10–4–22; 8:45 am]

BILLING CODE 6560–50–P

ATTACHMENT H

MENU

Particulate Matter (PM) Pollution

CONTACT US <https://epa.gov/pm-pollution/forms/contact-us-about-particulate-matter-pm-pollution>

Health and Environmental Effects of Particulate Matter (PM)

Health Effects

The size of particles is directly linked to their potential for causing health problems. Small particles less than 10 micrometers in diameter pose the greatest problems, because they can get deep into your lungs, and some may even get into your bloodstream.

Exposure to such particles can affect both your lungs and your heart. Numerous scientific studies have linked particle pollution exposure to a variety of problems, including:

- premature death in people with heart or lung disease
- nonfatal heart attacks
- irregular heartbeat
- aggravated asthma <https://epa.gov/asthma>
- decreased lung function
- increased respiratory symptoms, such as irritation of the airways, coughing or difficulty breathing.

People with heart or lung diseases, children, and older adults are the most likely to be affected by particle pollution exposure.

- AirNow <https://airnow.gov/> can help you monitor air quality near you, and protect yourself and your family from elevated PM levels.

Environmental Effects

Visibility impairment

Fine particles ($PM_{2.5}$) are the main cause of reduced visibility (haze) in parts of the United States, including many of our treasured national parks and wilderness areas. Learn more about visibility and haze <https://epa.gov/visibility>

Environmental damage

Particles can be carried over long distances by wind and then settle on ground or water. Depending on their chemical composition, the effects of this settling may include:

- making lakes and streams acidic
- changing the nutrient balance in coastal waters and large river basins
- depleting the nutrients in soil
- damaging sensitive forests and farm crops
- affecting the diversity of ecosystems
- contributing to acid rain effects <https://epa.gov/acidrain/effects-acid-rain>.

Materials damage

PM can stain and damage stone and other materials, including culturally important objects such as statues and monuments. Some of these effects are related to acid rain effects on materials <https://epa.gov/acidrain/effects-acid-rain#materials>.

Further Reading

Particle Pollution and Your Health (PDF)(2 pp, 320 K, About PDF <https://epa.gov/home/pdf-files>): Learn who is at risk from exposure to particle pollution, what health effects you may experience as a result of particle exposure, and simple measures you can take to reduce your risk.

How Smoke From Fires Can Affect Your Health <https://www.airnow.gov/air-quality-and-health/fires-and-your-health/>: It is important to limit your exposure to smoke -- especially if you may be susceptible.

EPA research on airborne particulate matter <https://epa.gov/air-research>: EPA supports research that provides the critical science on PM and other air pollutants to develop and implement Clean Air Act regulations that protect the quality of the air we breathe.

PM Home <https://epa.gov/pm-pollution>

Particulate Matter (PM) Basics <https://epa.gov/pm-pollution/particulate-matter-pm-basics>

Health and Environmental Effects

Setting and Reviewing PM Standards <https://epa.gov/pm-pollution/setting-and-reviewing-standards-control-particulate-matter-pm-pollution>

PM Standards Regulatory Actions <https://epa.gov/pm-pollution/national-ambient-air-quality-standards-naaqs-pm>

Implementing PM Standards <https://epa.gov/pm-pollution/applying-or-implementing-particulate-matter-pm-standards>

PM Implementation Regulatory Actions <https://epa.gov/pm-pollution/particulate-matter-pm-implementation-regulatory-actions>

SIP Checklist Guide <https://epa.gov/pm-pollution/pm-state-implementation-plan-sip-checklist-guide>

PM SIP Training Presentations <https://epa.gov/pm-pollution/pm-naaqs-implementation-training-and-assistance-state-and-local-air-agencies>

PM Data and SIP Status Reports <https://epa.gov/pm-pollution/technical-data-and-reports-particulate-matter-pm-measurements-and-sip-status>

Other Criteria Air Pollutants <https://epa.gov/criteria-air-pollutants>

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LAST UPDATED ON AUGUST 23, 2023

ATTACHMENT I

Understanding Global Warming Potentials

Greenhouse gases (GHGs) warm the Earth by absorbing energy and slowing the rate at which the energy escapes to space; they act like a blanket insulating the Earth. Different GHGs can have different effects on the Earth's warming. Two key ways in which these gases differ from each other are their ability to absorb energy (their "radiative efficiency"), and how long they stay in the atmosphere (also known as their "lifetime").

The Global Warming Potential (GWP) was developed to allow comparisons of the global warming impacts of different gases. Specifically, it is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, relative to the emissions of 1 ton of carbon dioxide (CO_2). The larger the GWP, the more that a given gas warms the Earth compared to CO_2 over that time period. The time period usually used for GWPs is 100 years. GWPs provide a common unit of measure, which allows analysts to add up emissions estimates of different gases (e.g., to compile a national GHG inventory), and allows policymakers to compare emissions reduction opportunities across sectors and gases.

- CO_2, by definition, has a GWP of 1 regardless of the time period used, because it is the gas being used as the reference. CO_2 remains in the climate system for a very long time: CO_2 emissions cause increases in atmospheric concentrations of CO_2 that will last thousands of years.
- Methane (CH_4) is estimated to have a GWP of 27-30 over 100 years. CH_4 emitted today lasts about a decade on average, which is much less time than CO_2. But CH_4 also absorbs much more energy than CO_2. The net effect of the shorter lifetime and higher energy absorption is reflected in the GWP. The CH_4 GWP also accounts for some indirect effects, such as the fact that CH_4 is a precursor to ozone, and ozone is itself a GHG.
- Nitrous Oxide (N_2O) has a GWP 273 times that of CO_2 for a 100-year timescale. N_2O emitted today remains in the atmosphere for more than 100 years, on average. (Learn why EPA's U.S. Inventory of Greenhouse Gas Emissions and Sinks uses a different value.)

- Chlorofluorocarbons (CFCs), hydrofluorocarbons (HFCs), hydrochlorofluorocarbons (HCFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) are sometimes called high-GWP gases because, for a given amount of mass, they trap substantially more heat than CO_2. (The GWPs for these gases can be in the thousands or tens of thousands.)

Frequently Asked Questions

Why do GWPs change over time?

> EPA and other organizations will update the GWP values they use occasionally. This change can be due to updated scientific estimates of the energy absorption or lifetime of the gases or to changing atmospheric concentrations of GHGs that result in a change in the energy absorption of 1 additional ton of a gas relative to another.

Why are GWPs presented as ranges?

> In the most recent report by the Intergovernmental Panel on Climate Change (IPCC), multiple methods of calculating GWPs were presented based on how to account for the influence of future warming on the carbon cycle. For this Web page, we are presenting the range of the lowest to the highest values listed by the IPCC.

What GWP estimates does EPA use for GHG emissions accounting, such as the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory) and the Greenhouse Gas Reporting Program?

The EPA considers the GWP estimates presented in the most recent IPCC scientific assessment to reflect the state of the science. In science communications, the EPA will refer to the most recent GWPs. The GWPs listed above are from the IPCC's Sixth Assessment Report, published in 2021.

The EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (Inventory) complies with international GHG reporting standards under the United Nations Framework Convention on Climate Change (UNFCCC). UNFCCC guidelines now require the use of the GWP values from the IPCC's Fifth Assessment Report (AR5), published in 2013. The Inventory also presents emissions by mass, so that CO_2 equivalents can be calculated using any GWPs, and emission totals using more recent IPCC values are presented in the annexes of the Inventory report for informational purposes.

The data collected by EPA's Greenhouse Gas Reporting Program is generally reported in mass units of greenhouse gas and is used in the Inventory. The Reporting Program, generally uses GWP values from the AR4 to determine whether facilities exceed reporting thresholds and to publish data in CO_2 equivalent values. The Reporting Program collects data about some industrial gases that do not have GWPs listed in the AR4; for these gases, the Reporting Program uses GWP values from other sources, such as the AR5.

EPA's CH_4 reduction voluntary programs also use CH_4 GWPs from the AR5 report for calculating CH_4 emissions reductions through energy recovery projects, for consistency with the national emissions presented in the Inventory.

Are there alternatives to the 100-year GWP for comparing GHGs?

The United States primarily uses the 100-year GWP as a measure of the relative impact of different GHGs. However, the scientific community has developed a number of other metrics that could be used for comparing one GHG to another. These metrics may differ based on timeframe, the climate endpoint measured, or the method of calculation.

For example, the 20-year GWP is sometimes used as an alternative to the 100-year GWP. Just like the 100-year GWP is based on the energy absorbed by a gas over 100 years, the 20-year GWP is based on the energy absorbed over 20 years. This 20-year GWP prioritizes gases with shorter lifetimes, because it does not consider impacts that happen more than 20 years after the emissions occur. Because all GWPs are calculated relative to CO_2, GWPs based on a shorter timeframe will be larger for gases with lifetimes shorter than that of CO_2, and smaller for gases with lifetimes longer than CO_2. For example, for CH_4, which has a short lifetime, the 100-year GWP of 27–30 is much less than the 20-year GWP of 81–83. For CF_4, with a lifetime of 50,000 years, the 100-year GWP of 7380 is larger than the 20-year GWP of 5300.

Another alternate metric is the Global Temperature Potential (GTP). While the GWP is a measure of the heat absorbed over a given time period due to emissions of a gas, the GTP is a measure of the temperature change at the end of that time period (again, relative to CO_2).The calculation of the GTP is more complicated than that for the GWP, as it requires modeling how much the climate system responds to increased concentrations of GHGs (the climate sensitivity) and how quickly the system responds (based in part on how the ocean absorbs heat).

GHG Emissions and Removals Home <https://epa.gov/ghgemissions>

Overview of Greenhouse Gases <https://epa.gov/ghgemissions/overview-greenhouse-gases>

Sources of GHG Emissions and Removals <https://epa.gov/ghgemissions/sources-greenhouse-gas-emissions>

- Global Emissions and Removals <https://epa.gov/ghgemissions/global-greenhouse-gas-emissions-data>
- National Emissions and Removals <https://epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks>
- State and Tribal GHG Data and Resources <https://epa.gov/ghgemissions/state-and-tribal-greenhouse-gas-data-and-resources>
- Facility-Level Emissions <https://epa.gov/ghgreporting>
- Gridded Methane Emissions <https://epa.gov/ghgemissions/us-gridded-methane-emissions>
- Carbon Footprint Calculator <https://epa.gov/ghgemissions/household-carbon-footprint-calculator>
- GHG Equivalencies Calculator <http://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator>
- Capacity Building for GHG Inventories <https://epa.gov/ghgemissions/capacity-building-national-greenhouse-gas-inventories>

Contact Us <https://epa.gov/ghgemissions/forms/contact-us-about-greenhouse-gas-emissions> to ask a question, provide feedback, or report a problem.

LAST UPDATED ON APRIL 18, 2023

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ATTACHMENT J

Aura

Atmospheric Chemistry

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View by Year View by Sensor

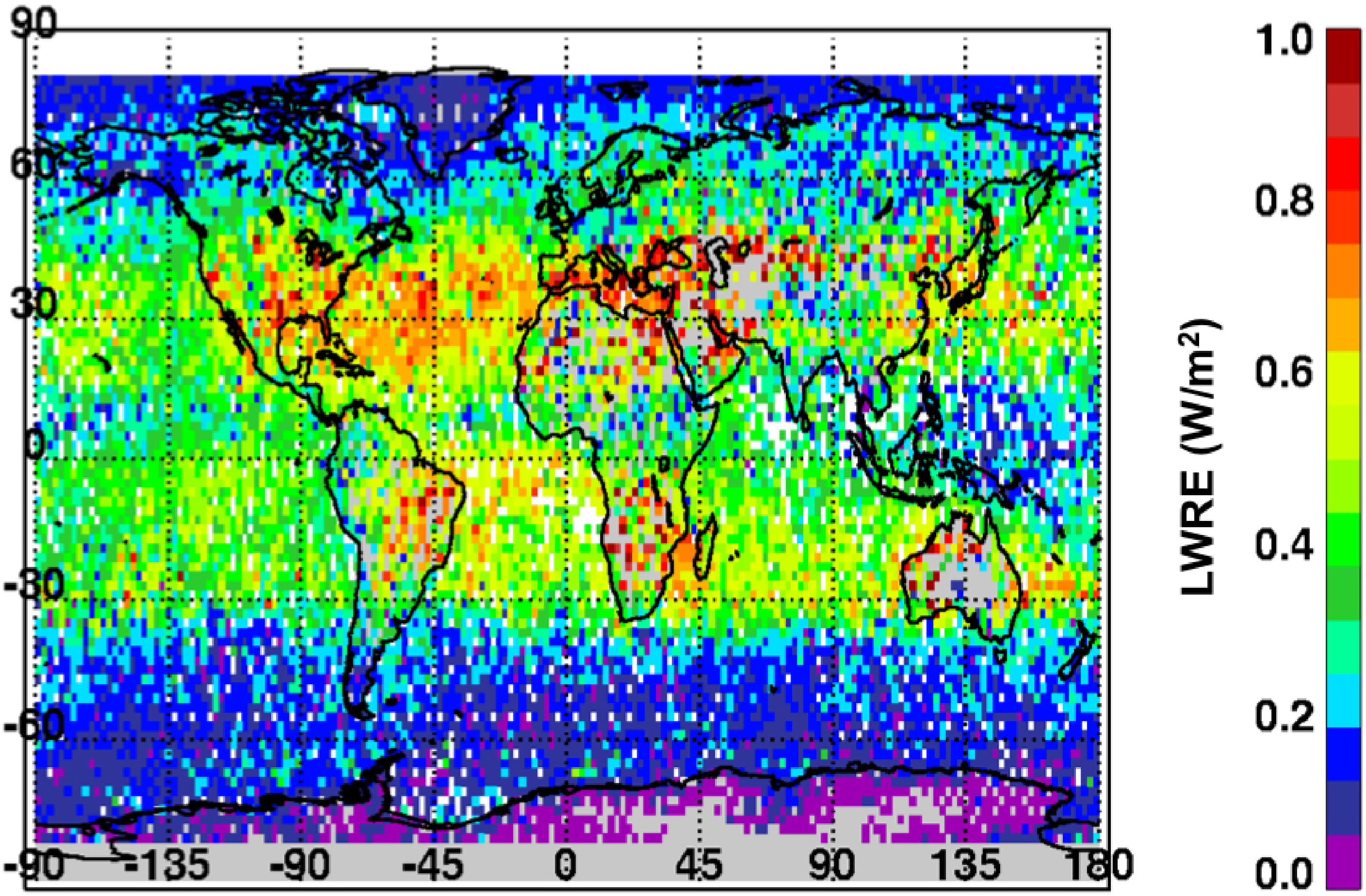
The greenhouse effect of tropospheric ozone

Tropospheric ozone (O_3) is the third most important anthropogenic greenhouse gas after carbon dioxide (CO_2) and methane (CH_4). Ozone absorbs infrared radiation (heat) from the Earth's surface, reducing the amount of radiation that escapes to space.

This map shows the longwave radiative effect (LWRE) of infrared radiation absorbed by tropospheric ozone in Watts/meter^2 as estimated from Aura's Tropospheric Emission Spectrometer (TES) top-of- atmosphere (TOA) observations. Data are averaged for August 2006 and include both clear-sky and cloudy scenes. Areas with no data are indicated in white over oceans and grey over land.

Higher values of trapped infrared radiation are caused by lofted ozone pollution in the northern mid-latitudes and from sources of biomass burning in the southern hemisphere.

This map shows the longwave radiative effect of infrared radiation absorbed by tropospheric ozone as estimated from TES top-of-atmosphere observations.



April 2011

Contact

NASA Official : Bryan.N.Duncan
Web Curator : Jennifer Brill

ATTACHMENT K

Last Updated 2/9/2024 Total Number of Applications (2.0) or Pathways (3.0) 2243

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
T1N-1356	Tier 1	2.0	Fuel Producer: Adecoagro Brasil Participacoes (4192) Facility Name: Adecoagro Vale do Ivinhema Ltda. (70496): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS211	46.32	12/20/2016	None	Ethanol	Adecoagro Brasil Participacoes (4192)	Adecoagro Vale do Ivinhema Ltda (70496)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1078	Tier 1	2.0	Producer: BIOSEV S.A. (3869) Facility Name: Usina Cresciumal (71068). Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export.	Brazil	Molasses	Ethanol	None	None	ETHM221	46.34	12/20/2016	None	Ethanol	BIOSEV SA (3869)	Usina Cresciumal (71068)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export	None	Retired
T1R-1008	Tier 1	2.0	Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Tallow; Biodiesel Produced in Canada	Ontario, Canada	Tallow	Biodiesel	BIOD023	46.36	BDT200L	34.97	6/30/2016	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	North American Tallow; Biodiesel Produced in Canada	None	Retired
T1R-1009	Tier 1	2.0	Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Soybean; Biodiesel Produced in Canada	Ontario, Canada	Soybean	Biodiesel	BIOD024	88.59	BDS200L	56.03	6/30/2016	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	North American Soybean; Biodiesel Produced in Canada	None	Retired
T1R-1010	Tier 1	2.0	Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Canola; Biodiesel Produced in Canada	Ontario, Canada	Canola	Biodiesel	BIOD026	67.32	BDCA200L	57.39	6/30/2016	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	North American Canola; Biodiesel Produced in Canada	None	Retired
T1R-1012	Tier 1	2.0	Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236). North American Corn Oil from Wet DGS of a Corn Ethanol plant; Biodiesel Produced in Canada	Ontario, Canada	North American Corn Oil from Wet DGS	Biodiesel	BIOD030	35.23	BDC200L	32.80	6/30/2016	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	North American Corn Oil from Wet DGS of a Corn Ethanol plant; Biodiesel Produced in Canada	None	Retired
T1N-1069	Tier 1	2.0	Fuel Producer: Usina Sao Domingos Acucar e Alcool S.A. (4252) Facility Name: Usina Sao Domingos Acucar e Alcool SA (70533): Brazilian sugarcane juice-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	Brazil	Sugarcane	Ethanol	None	None	ETHS234	46.44	5/19/2017	None	Ethanol	Usina Sao Domingos Acucar e Alcool SA (4252)	Usina Sao Domingos Acucar e Alcool SA (70533)	Brazilian sugarcane juicetoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1141	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Santa Helena (70558): Brazilian sugarcane molasses-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	Brazil	Molasses	Ethanol	None	None	ETHM230	46.44	5/19/2017	None	Ethanol	Raízen Energia S/A (3805)	Santa Helena (70558)	Brazilian sugarcane molassestoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1460	Tier 1	2.0	Fuel Producer: Usina Delta SA (3852) Facility Name: Usina Delta S/A Unidade Volta Grande (70371). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS214	46.49	12/20/2016	None	Ethanol	Usina Delta SA (3852)	Usina Delta S/A Unidade Volta Grande (70371)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1073	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869) Facility Name: Usina Vale do Rosário (70440). Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM200	46.52	3/31/2016	None	Ethanol	BIOSEV SA (3869)	Usina Vale do Rosário (70440)	Brazilian sugarcane byproduct molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1392	Tier 1	2.0	Fuel Producer: Usina São Martinho S.A. (3867) Facility Name: Usina São Martinho S.A. (70373). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS219	46.61	12/20/2016	None	Ethanol	Usina São Martinho SA (3867)	Usina São Martinho SA (70373)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
T1R-1040	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Australian Rendered Tallow to Renewable Diesel. Renewable Diesel Produced in Singapore.	Singapore	Australian Tallow	Renewable Diesel	RNWD004	33.46	RDT200L	36.83	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Australian Rendered Tallow to Renewable Diesel; Renewable Diesel Produced in Singapore	None	Retired
T1R-1041	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). North American Rendered Tallow to Renewable Diesel Produced in Singapore.	Singapore	North American Tallow	Renewable Diesel	RNWD005	49.69	RDT201L	34.19	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	North American Rendered Tallow to Renewable Diesel Produced in Singapore	None	Retired
T1R-1042	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). South East Asia Fish Oil to Renewable Diesel Produced in Singapore.	Singapore	South East Asian Fish Oil	Renewable Diesel	RNWD006	30.48	RDF200L	33.08	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	South East Asia Fish Oil to Renewable Diesel Produced in Singapore	None	Retired
T1R-1043	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327): New Zealand Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore	Singapore	Tallow	Renewable Diesel	RNWD007	36.57	RDT203L	34.81	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	New Zealand Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore	None	Retired
T1R-1045	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Midwest Corn Oil to Renewable Diesel Produced in Singapore.	Singapore	Midwest Corn Oil from Wet DGS	Renewable Diesel	RNWD026	39.13	RDC200L	37.39	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Midwest Corn Oil to Renewable Diesel Produced in Singapore	None	Retired
T1R-1046	Tier 1	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Global Mixed Used Cooking Oil to Renewable Diesel Produced in Singapore.	Singapore	Global Used Cooking Oil	Renewable Diesel	RNWD027	30.72	RDU201L	25.61	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Global Mixed Used Cooking Oil to Renewable Diesel Produced in Singapore	None	Retired
T1N-1400	Tier 1	2.0	Fuel Producer: Branco Peres Acucar e Alcool SA (5985) Facility Name: Branco Peres Acucar e Alcool SA (71077): Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS210	46.71	12/20/2016	None	Ethanol	Branco Peres Acucar e Alcool SA (5985)	Branco Peres Acucar e Alcool SA (71077)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1R-1058	Tier 1	2.0	Fuel Producer: Consolidated Biofuels Ltd. (3919) Facility Name: Consolidated Biofuels Ltd. (80304): North American low-free fatty acids (Used Cooking Oil) where "cooking" is required; Biodiesel Produced in Canada	Canada	Used Cooking Oil	Biodiesel	BIOD029	21.34	BDU211L	20.38	6/30/2016	None	Biodiesel	Consolidated Biofuels Ltd (3919)	Consolidated Biofuels Ltd (80304)	North American lowfree fatty acids (Used Cooking Oil)where "cooking" is required; Biodiesel Produced in Canada	None	Retired
T1N-1391	Tier 1	2.0	Fuel Producer: Noble Brasil S.A. (4232) Facility Name: Noble Brasil S/A - NBSA (UNP) (70527). Ethanol production from Brazilian sugarcane juice feedstock, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS218	46.72	12/20/2016	None	Ethanol	Noble Brasil SA (4232)	Noble Brasil S/A NBSA (UNP)(70527)	Ethanol production from Brazilian sugarcane juice feedstock, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1393	Tier 1	2.0	Fuel Producer: Usina São Martinho S.A. (3867) Facility Name: Sao Martinho S/A (70479). Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS213	46.80	12/20/2016	None	Ethanol	Usina São Martinho SA (3867)	Sao Martinho S/A (70479)	Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting	None	Retired
T1N-1062	Tier 1	2.0	Fuel Producer: Noble Brasil S.A. (4232) Facility Name: NG Bioenergia S/A - Potirendaba (71036). Ethanol production from Brazilian sugarcane Juice feedstock, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS212	46.83	9/1/2016	None	Ethanol	Noble Brasil SA (4232)	NG Bioenergia S/A Potirendaba (71036)	Ethanol production from Brazilian sugarcane Juice feedstock, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1R-1093	Tier 1	2.0	Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): North American Used Cooking Oil (UCO); Biodiesel Produced in Arkansas	Arkansas	Used Cooking Oil	Biodiesel	BIOD027	23.81	BDU207L	24.36	6/30/2016	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	North American Used Cooking Oil (UCO)Biodiesel Produced in Arkansas	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
T2N-1161	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; re-gasified to L-CNG on-site; fuel dispensed on-site	California	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF246	9.97	6/22/2017	Pathway Details (PDF)	Bio-CNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; regasified to LCNG onsite; fuel dispensed onsite	None	Retired
T1R-1124	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: EIF KC Landfill Gas LLC (71155). Kansas City landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	Kansas	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF230L	45.31	CNGLF230LR	50.80	9/30/2016	Previous Tier 1 CNG030; 32.92	Bio-CNG	Clean Energy (5481)	EIF KC Landfill Gas LLC (71155)	Kansas City landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1101	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Westside Gas Producers LLC (71151). Michigan landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Michigan	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF200L	48.65	LNGLF200LR	54.14	9/30/2016	Previous Tier 1 LNG025; 30.12	Bio-LNG	Clean Energy (5481)	Westside Gas Producers LLC (71151)	Michigan landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T2N-1163	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; re-gasified to L-CNG in California; fuel delivered to Bay Area by Truck	California	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF247	10.32	6/22/2017	Pathway Details (PDF)	Bio-CNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; regasified to LCNG in California; fuel delivered to Bay Area by Truck	None	Retired
T1R-1104	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Pinnacle Gas Producers, LLC (71153). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Ohio	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF201L	44.78	LNGLF201LR	50.27	9/30/2016	Previous Tier 1 LNG020; 25.5	Bio-LNG	Clean Energy (5481)	Pinnacle Gas Producers, LLC (71153)	Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1R-1103	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Pinnacle Gas Producers, LLC (71153). Ohio landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA	Ohio	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF224L	50.52	CNGLF224LR	56.01	9/30/2016	Previous Tier 1 CNG023; 27.62	Bio-CNG	Clean Energy (5481)	Pinnacle Gas Producers, LLC (71153)	Ohio landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA	None	Retired
T1R-1106	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: CERF Shelby LLC (71163). CERF Shelby landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Tennessee	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF202L	54.57	LNGLF202LR	60.06	9/30/2016	Previous Tier 1 LNG028; 43.83	Bio-LNG	Clean Energy (5481)	CERF Shelby LLC (71163)	CERF Shelby landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T2N-1165	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; re-gasified to L-CNG in California; fuel delivered to Southern California by Truck	California	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF248	13.29	6/22/2017	Pathway Details (PDF)	Bio-CNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; regasified to LCNG in California; fuel delivered to Southern California by Truck	None	Retired
T1R-1111	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Dallas Clean Energy McCommas Bluff (71009). Texas landfill gas to biomethane, delivered by pipeline, liquefied in Boron CA; re-gasified and compressed to CNG	Texas	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF227L	48.41	CNGLF227LR	53.90	9/30/2016	Previous Tier 1 CNG017; 35.11	Bio-CNG	Clean Energy (5481)	Dallas Clean Energy McCommas Bluff (71009)	Texas landfill gas to biomethane, delivered by pipeline, liquefied in Boron CA; regasified and compressed to CNG	None	Retired
T1R-1109	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Seneca Energy II, LLC (71156).New York landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	New York	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF203L	53.61	LNGLF203LR	59.10	9/30/2016	Previous Tier 1 LNG023; 32.03	Bio-LNG	Clean Energy (5481)	Seneca Energy II, LLC (71156)	New York landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1N-1656	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154) Facility Name: East Texas Renewables (F2942): Greenwood Farms landfill gas (TX) to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California**(Provisional)**	Texas	Landfill Gas	Compressed Natural Gas	None	None	CNGLF252	38.62	6/27/2017	None	Bio-CNG	Shell Energy North America (6154)	East Texas Renewables (F2942)	Greenwood Farms landfill gas (TX) to pipelinequality biomethane; delivered via pipeline to CNG Stations in California(Provisional)	None	Retired
T1N-1383	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Needle Mountain LNG PLant (95116). Texas landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to California.	Texas	Landfill Gas - L-CNG	Compressed Natural Gas	None	None	CNGLF222	48.91	9/30/2016	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	Needle Mountain LNG PLant (95116)	Texas landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to California	None	Retired

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T1R-1112	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Dallas Clean Energy McCommas Bluff (71009). Texas landfill gas to biomethane; delivered by pipeline; liquefied in Boron, CA	Texas	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF204L	45.26	LNGLF204LR	50.75	9/30/2016	Previous Tier 1 LNG018; 32.99	Bio-LNG	Clean Energy (5481)	Dallas Clean Energy McCommas Bluff (71009)	Texas landfill gas to biomethane; delivered by pipeline; liquefied in Boron, CA	None	Retired
T1N-1541	Tier 1	2.0	Fuel Producer: Athens Services (A431) Facility Name: La Puente (V4048). River Birch landfill (Avondale, LA) gas to pipeline-quality biomethane; delivered via pipeline to La Puente California and compressed to CNG (Provisional)	Louisiana	Landfill Gas	Compressed Natural Gas	CNGLF239	39.46	CNGLF239R	43.44	2/6/2019	None	Bio-CNG	Athens Services (A431)	La Puente (V4048)	River Birch landfill (Avondale, LA) gas to pipelinequality biomethane; delivered via pipeline to La Puente California and compressed to CNG (Provisional)	None	Retired
T1R-1224	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Montana-Dakota Utilities Billings Regional Landfill (71193). Montana landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	Montana	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF231L	49.9	CNGLF231LR	55.39	9/30/2016	Previous Tier 1 CNG058; 51.88	Bio-CNG	Clean Energy (5481)	MontanaDakota Utilities Billings Regional Landfill (71193)	Montana landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1115	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: LES Renewable NG, LLC - SWACO Facility (71157). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Ohio	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF205L	61.68	LNGLF205LR	67.17	9/30/2016	Previous Tier 1 LNG022; 33.19	Bio-LNG	Clean Energy (5481)	LES Renewable NG, LLC SWACO Facility (71157)	Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1R-1116	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Cedar Hills Landfill, Bio-Energy, LLC (71109). Washington landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Washington	Landfill Gas - CNG	Compressed Natural Gas	CNG009_1	13.67	CNGLF210L	30.90	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Cedar Hills Landfill, BioEnergy, LLC (71109)	Washington landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1117	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Cedar Hills Landfill, Bio-Energy, LLC (71109). Washington landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	Washington	Landfill Gas - CNG	Compressed Natural Gas	CNGLF229L	37.29	CNGLF229LR	42.78	9/30/2016	Previous Tier 1 CNG011; 20.23	Bio-CNG	Clean Energy (5481)	Cedar Hills Landfill, BioEnergy, LLC (71109)	Washington landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1118	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Cedar Hills Landfill, Bio-Energy, LLC (71109). Washington landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Washington	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF206L	34.72	LNGLF206LR	40.21	9/30/2016	Previous Tier 1 LNG014; 18.14	Bio-LNG	Clean Energy (5481)	Cedar Hills Landfill, BioEnergy, LLC (71109)	Washington landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1R-1119	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Complexe Enviro Progressive Itee (71198). Quebec landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	Canada	Landfill Gas - CNG	Compressed Natural Gas	CNGLF211L	38.56	CNGLF211LR	44.05	9/30/2016	Previous Tier 1 CNG049; 13.96	Bio-CNG	Clean Energy (5481)	Complexe Enviro Progressive Itee (71198)	Quebec landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1120	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Complexe Enviro Progressive Itee (71198). Quebec landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Canada	Landfill Gas - CNG	Compressed Natural Gas	CNG048	7.36	CNGLF212L	31.96	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Complexe Enviro Progressive Itee (71198)	Quebec landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1121	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Complexe Enviro Progressive Itee (71198). Quebec landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Canada	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF207L	37.03	LNGLF207LR	41.44	9/30/2016	Previous Tier 1 LNG033; 11.84	Bio-LNG	Clean Energy (5481)	Complexe Enviro Progressive Itee (71198)	Quebec landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1N-1540	Tier 1	2.0	Fuel Producer: Athens Services (A431) Facility Name: Irwindale (V5355). River Birch landfill (Avondale, LA) gas to pipeline-quality biomethane; delivered via pipeline to Irwindale California and compressed to CNG (Provisional)	Louisiana	Landfill Gas	Compressed Natural Gas	CNGLF238	39.73	CNGLF238R	43.72	2/6/2019	None	Bio-CNG	Athens Services (A431)	Irwindale (V5355)	River Birch landfill (Avondale, LA) gas to pipelinequality biomethane; delivered via pipeline to Irwindale California and compressed to CNG (Provisional)	None	Retired
T1R-1100	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Westside Gas Producers LLC (71151). Michigan landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA	Michigan	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF223L	51.80	CNGLF223LR	57.29	9/30/2016	Previous Tier 1 CNG032; 32.24	Bio-CNG	Clean Energy (5481)	Westside Gas Producers LLC (71151)	Michigan landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA	None	Retired

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T1R-1125	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: EIF KC Landfill Gas LLC (71155). Kansas City landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Kansas	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF209L	48.53	LNGLF209LR	54.02	9/30/2016	Previous Tier 1 LNG024; 30.8	Bio-LNG	Clean Energy (5481)	EIF KC Landfill Gas LLC (71155)	Kansas City landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1N-1635	Tier 1	2.0	Fuel Producer: Nardini Agroindustrial Ltda (4229) Facility Name: Nardini Agroindustrial Ltda (70525): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS232	46.88	2/2/2017	None	Ethanol	Nardini Agroindustrial Ltda (4229)	Nardini Agroindustrial Ltda (70525)	Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1480	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina São José da Estiva S.A. - Açúcar e Álcool (70431); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS239	44.53	8/17/2017	None	Ethanol	Copersucar (3702)	Usina São José da Estiva SA Açúcar e Álcool (70431)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1481	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina São José da Estiva S.A. - Açúcar e Álcool (70431); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting and electricity credit.	Brazil	Molasses	Ethanol	ETHM208L	46.14	ETHM237	45.06	8/17/2017	None	Ethanol	Copersucar (3702)	Usina São José da Estiva SA Açúcar e Álcool (70431)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting and electricity credit	None	Retired
T1N-1139	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Barra (70210) - Ethanol production from Brazilian sugarcane by-product molasses feedstock, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM214	47.05	6/6/2016	None	Ethanol	Raízen Energia S/A (3805)	Barra (70210)	Ethanol production from Brazilian sugarcane byproduct molasses feedstock, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1R-1178	Tier 1	2.0	Fuel Producer: California Ethanol & Power [CE+P] IV1 (C088) Facility Name: CE+P IV1 (90-08). California Sugarcane to ethanol, mechanized harvesting, Electricity credit, CNG co-product	California	Sugarcane	Ethanol	ETHS026	54.47	ETHS202L	22.44	3/31/2016	None	Ethanol	California Ethanol & Power [CE+P] IV1 (C088)	CE+P IV1 (90-08)	California Sugarcane to ethanol, mechanized harvesting, Electricity credit, CNG coproduct	None	Retired
T1N-1394	Tier 1	2.0	Fuel Producer: Usina Alto Alegre S/A - Açúcar e Álcool (5565) Facility Name: Unidade Junqueira (71018). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS215	47.23	12/20/2016	None	Ethanol	Usina Alto Alegre S/A Açúcar e Álcool (5565)	Unidade Junqueira (71018)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1142	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Benálcool (70549): Brazilian sugarcane molasses-based ethanol pathway, with credit for mechanized harvesting	Brazil	Molasses	Ethanol	None	None	ETHM234	47.63	5/19/2017	None	Ethanol	Raízen Energia S/A (3805)	Benálcool (70549)	Brazilian sugarcane molassesbased ethanol pathway, with credit for mechanized harvesting	None	Retired
T1N-1065	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869) Facility Name: Unidade MB (70568): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS208	47.68	6/6/2016	None	Ethanol	BIOSEV SA (3869)	Unidade MB (70568)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1189	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) Facility Name: USINA FRUTAL AÇÚCAR E ÁLCOOL (70579): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS206	47.73	6/6/2016	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	USINA FRUTAL AÇÚCAR E ÁLCOOL (70579)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1145	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Junqueira (70553): Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM217	47.82	7/8/2016	None	Ethanol	Raízen Energia S/A (3805)	Junqueira (70553)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1061	Tier 1	2.0	Fuel Producer: Noble Brasil S.A. (4232) Facility Name: Unidade Cantaduva (71061): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS225	47.86	12/20/2016	None	Ethanol	Noble Brasil SA (4232)	Unidade Cantaduva (71061)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired

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T1N-1371	Tier 1	2.0	Fuel Producer: Guarani SA (3890) Facility Name: Andrade Açúcar e Álcool SA (70451): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS226	47.89	12/20/2016	None	Ethanol	Guarani SA (3890)	Andrade Açúcar e Álcool SA (70451)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1395	Tier 1	2.0	Fuel Producer: Usina São Martinho S.A. (3867) Facility Name: Santa Cruz S/A Açúcar e Álcool (70484). Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS223	48.22	12/20/2016	None	Ethanol	Usina São Martinho SA (3867)	Santa Cruz S/A Açúcar e Álcool (70484)	Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting	None	Retired
T1N-1463	Tier 1	2.0	Fuel Producer: Tonon Bioenergia SA (4214) Facility Name: Santa Candida (70500). Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS224	48.35	12/20/2016	None	Ethanol	Tonon Bioenergia SA (4214)	Santa Candida (70500)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1377	Tier 1	2.0	Fuel Producer: Odebrecht Agroindustrial SA (5580) Facility Name: Usina Conquista do Pontal S/A (70494): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS231	48.39	12/20/2016	None	Ethanol	Odebrecht Agroindustrial SA (5580)	Usina Conquista do Pontal S/A (70494)	Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1077	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869) Facility Name: Unidade MB (70568): Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM228	48.63	2/15/2017	None	Ethanol	BIOSEV SA (3869)	Unidade MB (70568)	Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1759	Tier 1	2.0	Fuel Producer: Questar Fueling Company (Q500) Facility Name: River Birch, LLC (Sharing) (K200W): River Birch landfill gas to pipeline-quality biomethane; delivered via pipeline to Questar CNG stations in Buttonwillow, California **(Provisional)**	Louisiana	Landfill Gas	Compressed Natural Gas	CNGLF245	40.62	CNGLF245R	43.98	2/6/2019	None	Bio-CNG	Questar Fueling Company (Q500)	River Birch, LLC (Sharing)(K200W)	River Birch landfill gas to pipelinequality biomethane; delivered via pipeline to Questar CNG stations in Buttonwillow, California (Provisional)	None	Retired
T1R-1108	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Seneca Energy II, LLC (71156).New York landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	New York	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF226L	56.21	CNGLF226LR	61.70	9/30/2016	Previous Tier 1 CNG028; 34.15	Bio-CNG	Clean Energy (5481)	Seneca Energy II, LLC (71156)	New York landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1225	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Montana-Dakota Utilities Billings Regional Landfill (71193). Montana landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in CA	Montana	Landfill Gas - LNG	Liquefied Natural Gas	LNGLF210L	47.3	LNGLF210LR	52.79	9/30/2016	Previous Tier 1 LNG036; 49.76	Bio-LNG	Clean Energy (5481)	MontanaDakota Utilities Billings Regional Landfill (71193)	Montana landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in CA	None	Retired
T1N-1482	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Santa Adélia S.A. (70404); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS238	46.05	8/17/2017	None	Ethanol	Copersucar (3702)	Usina Santa Adélia SA (70404)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1483	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Santa Adélia S.A. (70404); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM210L	45.85	ETHM236	47.27	8/17/2017	None	Ethanol	Copersucar (3702)	Usina Santa Adélia SA (70404)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1459	Tier 1	2.0	Fuel Producer: Usina Delta SA (3852) Facility Name: Usina Delta S/A Unidade Delta (70367). Ethanol production from Brazilian sugarcane by-product molasses feedstock, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS220	49.69	12/20/2016	None	Ethanol	Usina Delta SA (3852)	Usina Delta S/A Unidade Delta (70367)	Ethanol production from Brazilian sugarcane byproduct molasses feedstock, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1616	Tier 1	2.0	Fuel Producer: Usina de Açúcar Santa Terezinha Ltda. (3921) Facility Name: Usina de Açúcar Santa Terezinha - Unidade Tapejara (70464): Brazilian sugarcane molasses-based ethanol, with credit for mechanized harvesting, and export of surplus cogenerated electricity.	Brazil	Molasses	Ethanol	None	None	ETHM224	52.78	12/20/2016	None	Ethanol	Usina de Açúcar Santa Terezinha Ltda (3921)	Usina de Açúcar Santa Terezinha Unidade Tapejara (70464)	Brazilian sugarcane molassesbased ethanol, with credit for mechanized harvesting, and export of surplus cogenerated electricity	None	Retired

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T1N-1462	Tier 1	2.0	Fuel Producer: Tonon Bioenergia SA (4214) Facility Name: Vista Alegre (70499): Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS230	53.40	12/20/2016	None	Ethanol	Tonon Bioenergia SA (4214)	Vista Alegre (70499)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1R-1516	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). California Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC123	60.74	ETHC269L	53.49	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	California Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	None	Retired
T1R-1258	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Ehrenberg LNG (C0660). North American Natural Gas pipelined to Ehrenberg (AZ) for liquefaction, then transported by truck to CA	Arizona	North American NG - LNG	Liquefied Natural Gas	LNG010	76.25	LNGF200L	86.22	9/30/2016	None	Fossil LNG	Clean Energy (5481)	Ehrenberg LNG (C0660)	North American Natural Gas pipelined to Ehrenberg (AZ)for liquefaction, then transported by truck to CA	None	Retired
T1N-1614	Tier 1	2.0	Fuel Producer: Usina de Açúcar Santa Terezinha Ltda. (3921) Facility Name: Usina de Açúcar Santa Terezinha - Unidade Terra Rica (71032): Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity exports.	Brazil	Sugarcane	Ethanol	None	None	ETHS228	53.69	12/20/2016	None	Ethanol	Usina de Açúcar Santa Terezinha Ltda (3921)	Usina de Açúcar Santa Terezinha Unidade Terra Rica (71032)	Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity exports	None	Retired
T1R-1264	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Cocal - Comércio Indústria Canaã Açucar e Alcool Ltda. (70419). Brazilian sugarcane by-product molasses-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	Brazil	Molasses	Ethanol	ETHM013	67.64	ETHM209L	46.04	3/31/2016	None	Ethanol	Copersucar (3702)	Cocal Comércio Indústria Canaã Açucar e Alcool Ltda (70419)	Brazilian sugarcane byproduct molassesbased ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	None	Retired
T1N-1607	Tier 1	2.0	Fuel Producer: Usina de Açúcar Santa Terezinha Ltda. (3921) Facility Name: Usina de Açúcar Santa Terezinha - Unidade de Ivaté (71030): Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM222	54.37	12/20/2016	None	Ethanol	Usina de Açúcar Santa Terezinha Ltda (3921)	Usina de Açúcar Santa Terezinha Unidade de Ivaté (71030)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1R-1280	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) Facility Name: Blue Skies Energy (71132). Michigan Landfill gas to pipeline-quality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA	Michigan	Landfill Gas - LNG	Liquefied Natural Gas	LNG017	24.90	LNGLF211L	55.38	9/30/2016	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Blue Skies Energy (71132)	Michigan Landfill gas to pipelinequality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA	None	Retired
T1R-1329	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: McCarty Road LFG Recovery Facility (71135). Texas landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in AZ; transported by trucks to California; re gasified and compressed to L CNG in CA	Texas	Landfill Gas - L-CNG	Compressed Natural Gas	CNG034	27.85	CNGLF234L	57.58	9/30/2016	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	McCarty Road LFG Recovery Facility (71135)	Texas landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in AZ; transported by trucks to California; re gasified and compressed to L CNG in CA	None	Retired
T1R-1282	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) Facility Name: Blue Skies Energy (71132). Michigan Landfill gas to pipeline-quality biomethane, delivered to California via pipeline for liquefaction	Michigan	Landfill Gas - LNG	Liquefied Natural Gas	LNG019	21.68	LNGLF212L	44.25	9/30/2016	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Blue Skies Energy (71132)	Michigan Landfill gas to pipelinequality biomethane, delivered to California via pipeline for liquefaction	None	Retired
T1R-1105	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: CERF Shelby LLC (71163). CERF Shelby landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA	Tennessee	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF225L	57.72	CNGLF225LR	63.21	9/30/2016	Previous Tier 1 CNG035; 45.95	Bio-CNG	Clean Energy (5481)	CERF Shelby LLC (71163)	CERF Shelby landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re gasified and compressed to L CNG in CA	None	Retired
T2N-1099	Tier 2	2.0	Fuel Producer: AltEn, LLC (6269) Facility Name: AltEn (70131): Midwest spent corn and sorghum seeds to produce ethanol, using grid electricity, natural gas, and biogas. (Provisional)	Nebraska	Spent Corn and Sorghum Seeds	Ethanol	None	None	ETHCSS200	59.29	12/26/2016	Application Package	Ethanol	AltEn, LLC (6269)	AltEn (70131)	Midwest spent corn and sorghum seeds to produce ethanol, using grid electricity, natural gas, and biogas(Provisional)	None	Retired
T1R-1305	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Pioneiros Bioenergia S.A. (70430). Brazilian sugarcane by-product molasses-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	Brazil	Molasses	Ethanol	ETHM017	58.48	ETHM211L	45.01	3/31/2016	None	Ethanol	Copersucar (3702)	Pioneiros Bioenergia SA (70430)	Brazilian sugarcane byproduct molassesbased ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	None	Retired

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T1R-1318	Tier 1	2.0	Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: RiverBirch LLC (K2000). Louisiana landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA (Provisional)	Louisiana	Landfill Gas - CNG	Compressed Natural Gas	CNGLF215L	37.23	CNGLF215LR	43.06	2/6/2019	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	RiverBirch LLC (K2000)	Louisiana landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA (Provisional)	None	Retired
T1R-1319	Tier 1	2.0	Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: McCarty Road Landfill (L9416). Texas landfill gas to pipeline-quality biomethane, delivered via pipeline, compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	CNG042	19.82	CNGLF216L	38.02	9/30/2016	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	McCarty Road Landfill (L9416)	Texas landfill gas to pipelinequality biomethane, delivered via pipeline, compressed to CNG in CA	None	Retired
T1R-1110	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Dallas Clean Energy McCommas Bluff (71009). Texas landfill gas to biomethane; delivered by pipeline; compressed in CA	Texas	Landfill Gas	Compressed Natural Gas	CNG016	28.42	CNGLF208L	41.35	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Dallas Clean Energy McCommas Bluff (71009)	Texas landfill gas to biomethane; delivered by pipeline; compressed in CA	None	Retired
T1R-1322	Tier 1	2.0	Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: BFI Usine de Triage Lachenaie Ltd (C3779). Quebec, Canada landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Canada	Landfill Gas - CNG	Compressed Natural Gas	CNG045	7.04	CNGLF218L	32.27	9/30/2016	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	BFI Usine de Triage Lachenaie Ltd (C3779)	Quebec, Canada landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1324	Tier 1	2.0	Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: Cedar Hills Landfill, LLC (71136). Washington landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	California	Landfill Gas - CNG	Compressed Natural Gas	CNG010	13.36	CNGLF219L	30.50	9/30/2016	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	Cedar Hills Landfill, LLC (71136)	Washington landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1326	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Needle Mountain LNG PLant (95116). North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck to CA	Arizona	North American NG - LNG	Liquefied Natural Gas	LNG011_1	76.48	LNGF201L	87.73	9/30/2016	None	Fossil LNG	Applied Natural Gas Fuels, Inc. (6174)	Needle Mountain LNG PLant (95116)	North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck to CA	None	Retired
T1R-1327	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Needle Mountain LNG PLant (95116). North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck; re-gasified and compressed to L-CNG in CA	Arizona	North American NG - L-CNG	Compressed Natural Gas	CNG015	76.87	CNGF202L	90.33	9/30/2016	None	Fossil CNG	Applied Natural Gas Fuels, Inc. (6174)	Needle Mountain LNG PLant (95116)	North American NG, delivered via pipeline; liquefied in Topock, AZ; delivered via truck; regasified and compressed to LCNG in CA	None	Retired
T1R-1328	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: McCarty Road LFG Recovery Facility (71135). Texas landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; transported by trucks to CA	Texas	Landfill Gas - LNG	Liquefied Natural Gas	LNG027	27.45	LNGLF213L	55.05	9/30/2016	None	Bio-LNG	Applied Natural Gas Fuels, Inc. (6174)	McCarty Road LFG Recovery Facility (71135)	Texas landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; transported by trucks to CA	None	Retired
T1R-1333	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fresh Kills Landfill (71203). New York landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in Arizona; transported by trucks to California; re-gasified and compressed to L-CNG in CA	New York	Landfill Gas - L-CNG	Compressed Natural Gas	CNG046	32.24	CNGLF236L	59.34	9/30/2016	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	Fresh Kills Landfill (71203)	New York landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in Arizona; transported by trucks to California; regasified and compressed to LCNG in CA	None	Retired
T1R-1330	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fort Bend Landfill Recovery (71139). North American Landfill Gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA	Arizona	Landfill Gas - LNG	Liquefied Natural Gas	LNG012_1	40.91	LNGLF214L	76.61	9/30/2016	None	Bio-LNG	Applied Natural Gas Fuels, Inc. (6174)	Fort Bend Landfill Recovery (71139)	North American Landfill Gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA	None	Retired
T1R-1281	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) Facility Name: Blue Skies Energy (71132). Michigan Landfill gas to pipeline-quality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA; re-gasified and compressed to L-CNG	Michigan	Landfill Gas - L-CNG	Compressed Natural Gas	CNG014	25.30	CNGLF232L	59.36	9/30/2016	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Blue Skies Energy (71132)	Michigan Landfill gas to pipelinequality biomethane, delivered to Topock, AZ via pipeline for liquefaction; transported by truck to CA; regasified and compressed to LCNG	None	Retired
T1R-1332	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fresh Kills Landfill (71203). New York landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to CA	New York	Landfill Gas - LNG	Liquefied Natural Gas	LNG032	31.84	LNGLF215L	56.74	9/30/2016	None	Bio-LNG	Applied Natural Gas Fuels, Inc. (6174)	Fresh Kills Landfill (71203)	New York landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona; transported by trucks to CA	None	Retired

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T1R-1114	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: LES Renewable NG, LLC - SWACO Facility (71157). Ohio landfill gas to pipeline-quality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; re-gasified and compressed to L-CNG in CA	Ohio	Landfill Gas - L-CNG	Compressed Natural Gas	CNGLF228L	64.28	CNGLF228LR	71.31	9/30/2016	Previous Tier 1 CNG026; 35.31	Bio-CNG	Clean Energy (5481)	LES Renewable NG, LLC SWACO Facility (71157)	Ohio landfill gas to pipelinequality biomethane, delivered via pipeline, liquefied in CA; transported by trucks; regasified and compressed to LCNG in CA	None	Retired
T1R-1359	Tier 1	2.0	Fuel Producer: SunLine Transit Agency (S317) Facility Name: Sunline Transit (H2505). Quebec, Canada landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Canada	Landfill Gas - CNG	Compressed Natural Gas	CNG050	6.28	CNGLF220L	31.17	9/30/2016	None	Bio-CNG	SunLine Transit Agency (S317)	Sunline Transit (H2505)	Quebec, Canada landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1364	Tier 1	2.0	Fuel Producer: Universal Biofuels Private, Ltd (6213) Facility Name: Universal Biofuels Private, Ltd (82702): Indian sourced high energy rendered tallow; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks); grid and backup diesel generator electricity	Biodiesel	Tallow	Biodiesel	BIOD039	57.84	BDT207L	37.97	12/20/2016	None	Biodiesel	Universal Biofuels Private, Ltd (6213)	Universal Biofuels Private, Ltd (82702)	Indian sourced high energy rendered tallow; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks)grid and backup diesel generator electricity	None	Retired
T1R-1365	Tier 1	2.0	Fuel Producer: Universal Biofuels Private, Ltd (6213) Facility Name: Universal Biofuels Private, Ltd (82702): Used Cooking Oil sourced world-wide where “cooking” is required; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks); grid and backup diesel generator electricity	Biodiesel	UCO	Biodiesel	BIOD040	24.45	BDU212L	26.07	12/20/2016	None	Biodiesel	Universal Biofuels Private, Ltd (6213)	Universal Biofuels Private, Ltd (82702)	Used Cooking Oil sourced worldwide where “cooking” is required; Biodiesel Produced in Andhra Pradesh, India; biomass (rice husks)grid and backup diesel generator electricity	None	Retired
T1R-1396	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Texas landfill gas to pipeline-quality biomethane, delivered via pipeline, compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	CNG043	24.49	CNGLF221L	38.02	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Texas landfill gas to pipelinequality biomethane, delivered via pipeline, compressed to CNG in CA	None	Retired
T2R-1044	Tier 2	2.0	Fuel Producer: Trestle Energy LLC (T315) Facility Name: Golden Grain Energy, LLC (shared facility) (7069S). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG	Iowa	Corn	Ethanol	ETHC116	70.65	ETHC273L	59.60	3/31/2016	None	Ethanol	Trestle Energy LLC (T315)	Golden Grain Energy, LLC(shared facility)(7069S)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T2R-1047	Tier 2	2.0	Fuel Producer: Poet DSM Project Liberty LLC (6232) Facility Name: Poet DSM Project Liberty LLC (71164). Corn Stover residue-based cellulosic ethanol with surplus steam and biogas export co-product credits	Iowa	Corn Stover	Ethanol	ETHB004	21.58	ETHCS201L	21.58	3/31/2016	None	Ethanol - Cellulosic	Poet DSM Project Liberty LLC (6232)	Poet DSM Project Liberty LLC (71164)	Corn Stover residuebased cellulosic ethanol with surplus steam and biogas export coproduct credits	None	Retired
T2R-1015	Tier 2	2.0	Fuel Producer: Abengoa Bioenergia Agroindustria Ltda (3924) Facility Name: Abengoa - São Luiz (70473). Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	Brazil	Molasses	Ethanol	ETHM010	54.92	ETHM213L	42.06	3/31/2016	None	Ethanol	Abengoa Bioenergia Agroindustria Ltda (3924)	Abengoa São Luiz (70473)	Brazilian sugarcane byproduct molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T2R-1033	Tier 2	2.0	Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). Landfill gas to hydrogen production via cracking of methane and transport by tube trailer	California	Landfill Gas	Hydrogen	HYGN010	-32.36	HYGLF200L	-5.28	9/30/2016	None	Hydrogen	LytEn (L700)	LytEn (K4933)	Landfill gas to hydrogen production via cracking of methane and transport by tube trailer	None	Retired
T2R-1034	Tier 2	2.0	Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). North American fossil NG and landfill gas to on-site hydrogen production via cracking of methane	California	Fossil NG & Landfill Gas	Hydrogen	HYGN007	15.29	HYGFLF200L	40.36	9/30/2016	None	Hydrogen	LytEn (L700)	LytEn (K4933)	North American fossil NG and landfill gas to onsite hydrogen production via cracking of methane	None	Retired
T2R-1035	Tier 2	2.0	Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). Landfill gas to on-site hydrogen production via cracking of methane	California	Landfill Gas	Hydrogen	HYGN008	-46.91	HYGLF201L	-12.65	9/30/2016	None	Hydrogen	LytEn (L700)	LytEn (K4933)	Landfill gas to onsite hydrogen production via cracking of methane	None	Retired
T2R-1036	Tier 2	2.0	Fuel Producer: LytEn (L700) Facility Name: LytEn (K4933). North American fossil NG and landfill gas to hydrogen production via cracking of methane and transport by tube trailer	California	Fossil NG & Landfill Gas	Hydrogen	HYGN009	29.84	HYGFLF201L	47.73	9/30/2016	None	Hydrogen	LytEn (L700)	LytEn (K4933)	North American fossil NG and landfill gas to hydrogen production via cracking of methane and transport by tube trailer	None	Retired

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T2R-1038	Tier 2	2.0	Fuel Producer: California Ethanol & Power [CE+P] IV1 (C088) Facility Name: CE+P IV1 (90-08). Sweet Sorghum to ethanol, mechanized harvesting, Electricity credit, CNG co-product	California	Sorghum	Ethanol	ETHG022	39.00	ETHG213L	30.63	3/31/2016	None	Ethanol	California Ethanol & Power [CE+P] IV1 (C088)	CE+P IV1 (90-08)	Sweet Sorghum to ethanol, mechanized harvesting, Electricity credit, CNG coproduct	None	Retired
T2R-1039	Tier 2	2.0	Fuel Producer: Biocom Energia (6099) Facility Name: Biocom Energia (81607): Spain sourced low-free fatty acids (Used Cooking Oil) where "cooking" is required; Biodiesel Produced in Spain	Spain	Used Cooking Oil (Spain)	Biodiesel	BIOD036	20.74	BDU208L	22.17	6/30/2016	None	Biodiesel	Biocom Energia (6099)	Biocom Energia (81607)	Spain sourced lowfree fatty acids (Used Cooking Oil)where "cooking" is required; Biodiesel Produced in Spain	None	Retired
T2R-1040	Tier 2	2.0	Fuel Producer: Biocom Energia (6099) Facility Name: Biocom Energia (81607): European sourced low-free fatty acids (Used Cooking Oil) where "cooking" is required; Biodiesel Produced in Spain	Spain	Used Cooking Oil (Europe)	Biodiesel	BIOD037	21.17	BDU209L	21.77	6/30/2016	None	Biodiesel	Biocom Energia (6099)	Biocom Energia (81607)	European sourced lowfree fatty acids (Used Cooking Oil)where "cooking" is required; Biodiesel Produced in Spain	None	Retired
T2R-1041	Tier 2	2.0	Fuel Producer: Biocom Energia (6099) Facility Name: Biocom Energia (81607): Low-free fatty acids (Used Cooking Oil) sourced from Rest of the World where "cooking" is required; Biodiesel Produced in Spain	Spain	Used Cooking Oil (Global)	Biodiesel	BIOD038	26.03	BDU210L	26.83	6/30/2016	None	Biodiesel	Biocom Energia (6099)	Biocom Energia (81607)	Lowfree fatty acids (Used Cooking Oil)sourced from Rest of the World where "cooking" is required; Biodiesel Produced in Spain	None	Retired
T2R-1043	Tier 2	2.0	Fuel Producer: Fulcrum Sierra BioFuels, LLC (F197) Facility Name: Fulcrum Sierra BioFuels, LLC (P3600). Fisher-Tropsch (FT) Diesel via Gasification and FT Synthesis of Municipal Solid Waste (MSW)	Nevada	Municipal Solid Waste (MSW)	Fischer-Tropsch Diesel (FTD)	FTD001	37.47	FTDMW200L	14.78	9/30/2016	None	FT Diesel	Fulcrum Sierra BioFuels, LLC (F197)	Fulcrum Sierra BioFuels, LLC (P3600)	FisherTropsch (FT)Diesel via Gasification and FT Synthesis of Municipal Solid Waste (MSW)	None	Retired
T2R-1077	Tier 2	2.0	Fuel Producer: Abengoa Bioenergy Biomass of Kansas (6254) Facility Name: Abengoa Bioenergy Biomass of Kansas, LLC (71183). Wheat Straw residue-based cellulosic ethanol with electricity co-product credit	Kansas	Wheat Straw	Ethanol	ETHB003	23.36	ETHWS200L	24.20	3/31/2016	None	Ethanol - Cellulosic	Abengoa Bioenergy Biomass of Kansas (6254)	Abengoa Bioenergy Biomass of Kansas, LLC (71183)	Wheat Straw residuebased cellulosic ethanol with electricity coproduct credit	None	Retired
T2R-1011	Tier 2	2.0	Fuel Producer: Abengoa Bioenergy Biomass of Kansas (6254) Facility Name: Abengoa Bioenergy Biomass of Kansas, LLC (71183). Corn Stover residue-based cellulosic ethanol with electricity co-product credit	Brazil	Corn Stover	Ethanol	ETHB002	29.52	ETHCS200L	32.82	3/31/2016	None	Ethanol - Cellulosic	Abengoa Bioenergy Biomass of Kansas (6254)	Abengoa Bioenergy Biomass of Kansas, LLC (71183)	Corn Stover residuebased cellulosic ethanol with electricity coproduct credit	None	Retired
T2R-1068	Tier 2	2.0	Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewable gasoline from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by rail to CA	Canada	Pyrolysis Oil from Forest Residue	Renewable Gasoline	RNWG001	20.12	RGFRP200L	21.17	9/30/2016	None	Renewable Gasoline	Ensyn Technologies Inc (6179)	Ensyn Ontario Facility (82219)	Renewable gasoline from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by rail to CA	None	Retired
T2R-1069	Tier 2	2.0	Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewable gasoline from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by truck to CA	Canada	Pyrolysis Oil from Forest Residue	Renewable Gasoline	RNWG002	25.03	RGFRP201L	26.08	9/30/2016	None	Renewable Gasoline	Ensyn Technologies Inc (6179)	Ensyn Ontario Facility (82219)	Renewable gasoline from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by truck to CA	None	Retired
T2R-1070	Tier 2	2.0	Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewable diesel from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by rail to CA	Canada	Pyrolysis Oil from Forest Residue	Biodiesel	RNWD028	21.67	RDFRP200L	22.42	9/30/2016	None	Renewable Diesel	Ensyn Technologies Inc (6179)	Ensyn Ontario Facility (82219)	Renewable diesel from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by rail to CA	None	Retired
T2R-1071	Tier 2	2.0	Fuel Producer: Ensyn Technologies Inc. (6179) Facility Name: Ensyn Ontario Facility (82219). Renewable diesel from forest residues via pyrolysis and co-processing of bio oil. Bio oil transport by truck to CA	Canada	Pyrolysis Oil from Forest Residue	Renewable Diesel	RNWD029	25.58	RDFRP201L	27.33	9/30/2016	None	Renewable Diesel	Ensyn Technologies Inc (6179)	Ensyn Ontario Facility (82219)	Renewbale diesel from forest residues via pyrolysis and coprocessing of bio Oil;Bio oil transport by truck to CA	None	Retired
T2R-1050	Tier 2	2.0	Fuel Producer: GranBio Investimentos S.A (6260) Facility Name: Bioflex AgroIndustrial SA (71192). Brazilian sugarcane straw residue-based cellulosic ethanol, with credit for electricity cogeneration and surplus export	Brazil	Sugarcane Straw	Ethanol	ETHB001	6.98	ETHSS200L	33.82	3/31/2016	None	Ethanol - Cellulosic	GranBio Investimentos S.A (6260)	Bioflex AgroIndustrial SA (71192)	Brazilian sugarcane straw residuebased cellulosic ethanol, with credit for electricity cogeneration and surplus export	None	Retired

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T2R-1080	Tier 2	2.0	Fuel Producer: Alameda-Contra Costa Transit District (A149) Facility Name: Division 2 (F1600). Hydrogen production via electrolysis using solar electricity	California	Solar Elericity via Electrolysis	Hydrogen	HYGN006	0.00	HYGE200L	0.00	9/30/2016	None	Hydrogen	AlamedaContra Costa Transit District (A149)	Division 2 (F1600)	Hydrogen production via electrolysis using solar electricity	None	Retired
T1R-1193	Tier 1	2.0	Fuel Producer: Green Plains Hereford LLC (6327) Facility Name: Green Plains Hereford LLC (70534). Midwest, Corn Ethanol, Dry Mill, NG	Texas	Corn	Ethanol	ETHC072	78.90	ETHC248L	67.60	3/31/2016	None	Ethanol	Green Plains Hereford LLC (6327)	Green Plains Hereford LLC (70534)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T2R-1117	Tier 2	2.0	Fuel Producer: Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Asian Used Cooking Oil to Renewable Diesel Produced in Singapore.	Singapore	Asian Used Cooking Oil	Renewable Diesel	RNWD009	16.21	RDU200L	16.89	6/30/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Asian Used Cooking Oil to Renewable Diesel Produced in Singapore	None	Retired
None	Lookup Table	3.0	California grid electricity used as a transportation fuel in California	California	Grid Electricity (039)	Electricity (ELC)	None	None	ELC000L00072019	81.49	NA	None	Electricity	NA	NA	California grid electricity used as a transportation fuel in California	None	Retired
T1N-1063	Tier 1	2.0	Fuel Producer: Noble Brasil S.A. (4232) Facility Name: Noble Brasil S/A - NBSA (UM) (70528): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS227	45.22	12/20/2016	None	Ethanol	Noble Brasil SA (4232)	Noble Brasil S/A NBSA (UM)(70528)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1079	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869) Facility Name: Usina Santa Elisa (71070). Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM201	45.50	3/31/2016	None	Ethanol	BIOSEV SA (3869)	Usina Santa Elisa (71070)	Brazilian sugarcane byproduct molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1085	Tier 1	2.0	Fuel Producer: USJ Açúcar e Álcool SA (3878) Facility Name: USJ Açúcar e Álcool S/A (70441): Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS209	46.26	7/8/2016	None	Ethanol	USJ Açúcar e Álcool SA (3878)	USJ Açúcar e Álcool S/A (70441)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1096	Tier 1	2.0	Fuel Producer: Glencane Bioenergia SA (4429) Facility Name: Glencane Bioenergia SA (71008). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS222	46.30	12/20/2016	None	Ethanol	Glencane Bioenergia SA (4429)	Glencane Bioenergia SA (71008)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1R-1214	Tier 1	2.0	Fuel Producer: Green Plains Central City (3368) Facility Name: Green Plains Central City LLC (70141). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC023	82.17	ETHC252L	70.71	3/31/2016	None	Ethanol	Green Plains Central City (3368)	Green Plains Central City LLC (70141)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1070	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	Texas	Corn	Ethanol	None	None	ETHC200	70.79	3/31/2016	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	None	Retired
T1N-1134	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Serra (70559): Brazilian sugarcane molasses-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM226	42.84	2/2/2017	None	Ethanol	Raízen Energia S/A (3805)	Serra (70559)	Brazilian sugarcane molassestoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1135	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Ipaussu (71058): Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export.	Brazil	Molasses	Ethanol	None	None	ETHM220	44.39	12/20/2016	None	Ethanol	Raízen Energia S/A (3805)	Ipaussu (71058)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export	None	Retired

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T1N-1569	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Corn to Ethanol, Dry Mill, Midwest, NG, 100% WDGS	Kansas	Corn	Ethanol	None	None	ETHC281	72.32	2/2/2017	None	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Corn to Ethanol, Dry Mill, Midwest, NG, 100% WDGS	None	Retired
T1N-1147	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Univalem (70550): Brazilian sugarcane molasses-to-ethanol pathway, with credit for mechanized harvesting	Brazil	Molasses	Ethanol	None	None	ETHM233	44.94	5/19/2017	None	Ethanol	Raízen Energia S/A (3805)	Univalem (70550)	Brazilian sugarcane molassestoethanol pathway, with credit for mechanized harvesting	None	Retired
T1N-1187	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) Facility Name: USINA MOEMA AÇÚCAR E ÁLCOOL LTDA (70386). Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS200	46.19	3/31/2016	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	USINA MOEMA AÇÚCAR E ÁLCOOL LTDA (70386)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1R-1088	Tier 1	2.0	Fuel Producer: Granite Falls Energy, LLC (4769) Facility Name: Granite Falls Energy, LLC (70071). Midwest, Corn Ethanol, Dry Mill, Mixed DDGS and MDGS, NG	Minnesota	Corn	Ethanol	ETHC094	85.08	ETHC242L	74.30	3/31/2016	None	Ethanol	Granite Falls Energy, LLC (4769)	Granite Falls Energy, LLC (70071)	Midwest, Corn Ethanol, Dry Mill, Mixed DDGS and MDGS, NG	None	Retired
T1R-1270 T1R-1271	Tier 1	2.0	Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels Albion (70283). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG	Nebraska	Corn	Ethanol	ETHC106 ETHC107	86.49 82.37	ETHC261L	74.66	3/31/2016	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Albion (70283)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG	None	Retired
T1N-1277	Tier 1	2.0	Fuel Producer: Elkhorn Valley Ethanol LLC (4833) Facility Name: Elkhorn Valley Ethanol LLC (70095). Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG	Nebraska	Corn	Ethanol	None	None	ETHC222	74.74	3/31/2016	None	Ethanol	Elkhorn Valley Ethanol LLC (4833)	Elkhorn Valley Ethanol LLC (70095)	Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG	None	Retired
T1N-1306	Tier 1	2.0	Fuel Producer: SeQuential (6129) Facility Name: SeQuential-Pacific Biodiesel, LLC. (83525): Raw Used Cooking Oil and Rendered Used Cooking Oil from close source (within 500 miles) to Biodiesel produced in Oregon	Oregon	Used Cooking Oil	Biodiesel	None	None	BDU213	25.67	7/1/2016	None	Biodiesel	SeQuential (6129)	SeQuentialPacific Biodiesel, LLC(83525)	Raw Used Cooking Oil and Rendered Used Cooking Oil from close source (within 500 miles)to Biodiesel produced in Oregon	None	Retired
T1R-1221	Tier 1	2.0	Fuel Producer: Green Plains Ord LLC (3360) Facility Name: Green Plains Ord LLC (70138). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC040	85.84	ETHC255L	74.84	3/31/2016	None	Ethanol	Green Plains Ord LLC (3360)	Green Plains Ord LLC (70138)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1320	Tier 1	2.0	Fuel Producer: Los Angeles County Metropolitan Transportation Authority (L440) Facility Name: LA Metro Aggregate (G0001). North American NG delivered via pipeline; compressed in CA	California	North American NG - CNG	Compressed Natural Gas	None	None	CNGF200	80.59	9/30/2016	None	Fossil CNG	Los Angeles County Metropolitan Transportation Authority (L440)	LA Metro Aggregate (G0001)	North American NG delivered via pipeline; compressed in CA	None	Retired
T1R-1219	Tier 1	2.0	Fuel Producer: Green Plains Shenandoah LLC (5073) Facility Name: Green Plains Shenandoah LLC (70149). Midwest, Corn Ethanol, Dry Mill, NG	Iowa	Corn	Ethanol	ETHC041	85.73	ETHC254L	74.87	3/31/2016	None	Ethanol	Green Plains Shenandoah LLC (5073)	Green Plains Shenandoah LLC (70149)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1186	Tier 1	2.0	Fuel Producer: Highwater Ethanol, LLC (3303) Facility Name: Highwater Ethanol, LLC (70235). Midwest, Corn Ethanol, Dry Mill, NG	Minnesota	Corn	Ethanol	ETHC115	85.90	ETHC247L	75.15	3/31/2016	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1336	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): Biodiesel produced from Midwest Canola Oil; Fuel produced in California	Stockton, California	Canola	Biodiesel	None	None	BDCA201	54.97	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Biodiesel produced from Midwest Canola Oil; Fuel produced in California	None	Retired

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T1N-1338	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF200	33.56	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1339	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): Biodiesel produced from Midwest Corn Oil; Fuel produced in California	Stockton, California	Corn Oil from Wet DGS	Biodiesel	None	None	BDC204	29.42	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Biodiesel produced from Midwest Corn Oil; Fuel produced in California	None	Retired
T1N-1340	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): Midwest Soybean; Biodiesel produced in California	Stockton, California	Soybean	Biodiesel	None	None	BDS201	52.45	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Midwest Soybean; Biodiesel produced in California	None	Retired
T1N-1341	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): North American high energy rendered Tallow; Biodiesel Produced in California	Stockton, California	Tallow	Biodiesel	None	None	BDT205	32.34	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	North American high energy rendered Tallow; Biodiesel Produced in California	None	Retired
T1N-1343	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728): California high energy rendered Used Cooking Oil (UCO); Biodiesel Produced in California	Stockton, California	Used Cooking Oil	Biodiesel	None	None	BDU206	16.31	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	California high energy rendered Used Cooking Oil (UCO)Biodiesel Produced in California	None	Retired
T1N-1756	Tier 1	2.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169) Facility Name: Hankinson Renewable Energy, LLC (70288): Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, and Syrup; NG	North Dakota	Corn	Ethanol	None	None	ETHC287	75.23	6/27/2017	None	Ethanol	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, and Syrup; NG	None	Retired
T1N-1346	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF201	36.17	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1347	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF202	34.82	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1348	Tier 1	2.0	Fuel Producer: Pacific Gas and Electric Company (C460) Facility Name: PG&E CNG Fueling Stations (M4675). North American NG delivered via pipeline; compressed in California	California	North American NG	Compressed Natural Gas	None	None	CNGF204	80.59	11/2/2016	None	Fossil CNG	Pacific Gas and Electric Company (C460)	PG&E CNG Fueling Stations (M4675)	North American NG delivered via pipeline; compressed in California	None	Retired
T1N-1354	Tier 1	2.0	Fuel Producer: CEVASA - Central Energetica Vale do Sapucai (3666) Facility Name: CEVASA - Central Energetica Vale do Sapucai (70701). Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS201	44.02	3/31/2016	None	Ethanol	CEVASA Central Energetica Vale do Sapucai (3666)	CEVASA Central Energetica Vale do Sapucai (70701)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1368	Tier 1	2.0	Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): U.S. sourced high energy rendered Tallow, Biodiesel produced in Arkansas and transported by rail to California	Arkansas	Tallow	Biodiesel	None	None	BDT210	40.69	12/20/2016	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	US sourced high energy rendered Tallow, Biodiesel produced in Arkansas and transported by rail to California	None	Retired
T1N-1279	Tier 1	2.0	Fuel Producer: Louis Dreyfus Commodities Grand Junction LLC (3137) Facility Name: Louis dreyfus Commodities Grand Junction LLC (70139). Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG	Iowa	Corn	Ethanol	None	None	ETHC224	76.01	3/31/2016	None	Ethanol	Louis Dreyfus Commodities Grand Junction LLC (3137)	Louis dreyfus Commodities Grand Junction LLC (70139)	Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG	None	Retired

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T1N-1372	Tier 1	2.0	Fuel Producer: Guarani SA (3890) Facility Name: Usina Vertente Ltda. (70447): Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS217	44.21	12/20/2016	None	Ethanol	Guarani SA (3890)	Usina Vertente Ltda (70447)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1373	Tier 1	2.0	Fuel Producer: SunLine Transit Agency (S317) Facility Name: Sunline Transit (H2505). River Birch landfill gas to biomethane; delivered by pipeline; compressed in CA	Louisiana	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF203	37.77	9/30/2016	None	Bio-CNG	SunLine Transit Agency (S317)	Sunline Transit (H2505)	River Birch landfill gas to biomethane; delivered by pipeline; compressed in CA	None	Retired
T1N-1375	Tier 1	2.0	Fuel Producer: Odebrecht Agroindustrial SA (5580) Facility Name: Alto Taquari (71019). Brazilian sugarcane juice-based ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS216	41.91	12/20/2016	None	Ethanol	Odebrecht Agroindustrial SA (5580)	Alto Taquari (71019)	Brazilian sugarcane juicebased ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1R-1157	Tier 1	2.0	Fuel Producer: Flint Hill Resources (4071) Facility Name: Fairmont (70103). Midwest, Corn Ethanol, Dry Mill, 91% DDGS, 9% MDGS, NG	Nebraska	Corn	Ethanol	ETHC064	86.62	ETHC243L	76.14	3/31/2016	None	Ethanol	Flint Hill Resources (4071)	Fairmont (70103)	Midwest, Corn Ethanol, Dry Mill, 91% DDGS, 9% MDGS, NG	None	Retired
T1R-1331	Tier 1	2.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) Facility Name: Fort Bend Landfill Recovery (71139). North American Landfill Gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA; re-gasified and compressed to L-CNG	Arizona	Landfill Gas - L-CNG	Compressed Natural Gas	CNG008_1	41.68	CNGLF235L	80.62	9/30/2016	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	Fort Bend Landfill Recovery (71139)	North American Landfill Gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in Arizona and transport to CA; regasified and compressed to LCNG	None	Retired
T1R-1169	Tier 1	2.0	Fuel Producer: Adkins Energy LLC (4767) Facility Name: Adkins Energy, LLC (70070). Midwest, Corn Ethanol, Dry Mill, 41% Dry DGS, 56% WDGS, NG	Illinois	Corn	Ethanol	ETHC114	86.33	ETHC244L	76.27	3/31/2016	None	Ethanol	Adkins Energy LLC (4767)	Adkins Energy, LLC (70070)	Midwest, Corn Ethanol, Dry Mill, 41% Dry DGS, 56% WDGS, NG	None	Retired
T1N-1235	Tier 1	2.0	Fuel Producer: Red Trail Energy LLC (4803) Facility Name: Red Trail Energy LLC (70077). Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG	North Dakota	Corn	Ethanol	None	None	ETHC219	76.46	3/31/2016	None	Ethanol	Red Trail Energy LLC (4803)	Red Trail Energy LLC (70077)	Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG	None	Retired
T1N-1397	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF204	33.85	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1398	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: Fort Bend Power Producers (shared facility) (7113s). Fort Bend landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Texas	Landfill Gas - CNG	Compressed Natural Gas	None	None	CNGLF205	34.38	9/30/2016	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers(shared facility)(7113s)	Fort Bend landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1399	Tier 1	2.0	Fuel Producer: GHI Energy, LLC (6156) Facility Name: GHI Energy, LLC (B8000). North American NG delivered via pipeline; compressed in CA	Texas	North American NG - CNG	Compressed Natural Gas	None	None	CNGF201	79.58	9/30/2016	None	Fossil CNG	GHI Energy, LLC (6156)	GHI Energy, LLC (B8000)	North American NG delivered via pipeline; compressed in CA	None	Retired
T1N-1403	Tier 1	2.0	Fuel Producer: New Leaf Biofuel (7768) Facility Name: New Leaf Biofuel (83541). Off-site Rendered Used Cooking Oil Biodiesel Produced in California	San Diego, California	Used Cooking Oil	Biodiesel	None	None	BDU201	15.86	6/30/2016	None	Biodiesel	New Leaf Biofuel (7768)	New Leaf Biofuel (83541)	Offsite Rendered Used Cooking Oil Biodiesel Produced in California	None	Retired
T1N-1406	Tier 1	2.0	Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Agri Industries (81926): Canola oil (produced in western Canada) biodiesel transported by rail from Lloydminster Alberta, Canada to Los Angeles, CA (the plant is co-located with crushing operation)	Canada	Canola	Biodiesel	None	None	BDCA202	51.33	6/30/2016	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Agri Industries (81926)	Canola oil (produced in western Canada)biodiesel transported by rail from Lloydminster Alberta, Canada to Los Angeles, CA (the plant is colocated with crushing operation)	None	Retired

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T1N-1457	Tier 1	2.0	Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Velva (82790): Canola oil biodiesel transported by rail from Velva, ND to Minot, ND to Los Angeles, CA (the plant is co-located with crushing operation)	North Dakota	Canola	Biodiesel	None	None	BDCA203	52.25	6/30/2016	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Velva (82790)	Canola oil biodiesel transported by rail from Velva, ND to Minot, ND to Los Angeles, CA (the plant is colocated with crushing operation)	None	Retired
T1R-1272 T1R-1273	Tier 1	2.0	Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels Aurora (70041). Midwest, Corn Ethanol, Dry Mill, NG	South Dakota	Corn	Ethanol	ETHC108 ETHC109	88.85 85.39	ETHC262L	76.74	3/31/2016	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1323	Tier 1	2.0	Fuel Producer: Prairie Horizon Agri-Energy, LLC (4760) Facility Name: Prairie Horizon Agri Energy, LLC (70659). Midwest, Corn Ethanol, Dry Mill, NG	Kansas	Corn	Ethanol	None	None	ETHC226	76.84	3/31/2016	None	Ethanol	Prairie Horizon AgriEnergy, LLC (4760)	Prairie Horizon Agri Energy, LLC (70659)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1464	Tier 1	2.0	Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Mexico (82791). Soybean oil biodiesel transported by rail from Mexico, Missouri to Richmond, CA	Mexico, Missouri	Soybean	Biodiesel	None	None	BDS202	50.85	6/30/2016	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Mexico (82791)	Soybean oil biodiesel transported by rail from Mexico, Missouri to Richmond, CA	None	Retired
T1N-1465	Tier 1	2.0	Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: ADM Mexico (82791). Soybean oil biodiesel transported by rail from Deerfield, MO to Richmond, CA (Soybean oil from adjacent crushing facility (81.9%) and 18.1% rail 311mi)	Deerfield, Missouri	Soybean	Biodiesel	None	None	BDS203	49.16	6/30/2016	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Mexico (82791)	Soybean oil biodiesel transported by rail from Deerfield, MO to Richmond, CA (Soybean oil from adjacent crushing facility (819% and 181% rail 311mi)	None	Retired
T1N-1466	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Pedra Agroindustrial S.A. (70415): Brazilian sugarcane juice-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS233	45.40	3/17/2017	None	Ethanol	Copersucar (3702)	Pedra Agroindustrial SA (70415)	Brazilian sugarcane juicetoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1467	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Pedra Agroindustrial S.A. (70415): Brazilian sugarcane molasses-to-ethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM229	46.06	3/17/2017	None	Ethanol	Copersucar (3702)	Pedra Agroindustrial SA (70415)	Brazilian sugarcane molassestoethanol pathway, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1468	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Usina Iacanga Açúcar e Álcool Ltda. (70398): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS229	43.56	12/20/2016	None	Ethanol	Copersucar (3702)	Usina Iacanga Açúcar e Álcool Ltda (70398)	Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1469	Tier 1	2.0	Fuel Producer: Copersucar (3702) Facility Name: Usina Iacanga Açúcar e Álcool Ltda. (70398): Brazilian sugarcane molasses-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM225	44.77	12/20/2016	None	Ethanol	Copersucar (3702)	Usina Iacanga Açúcar e Álcool Ltda (70398)	Brazilian sugarcane molassestoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1489	Tier 1	2.0	Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Crossett Biodiesel Pant (82217): High energy rendered Tallow; Biodiesel produced in Arkansas and transported by rail to California	Arkansas	Tallow	Biodiesel	None	None	BDT213	32.96	3/17/2017	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Crossett Biodiesel Pant (82217)	High energy rendered Tallow; Biodiesel produced in Arkansas and transported by rail to California	None	Retired
T1N-1490	Tier 1	2.0	Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Crossett Biodiesel Pant (82217): Biodiesel produced from Soybean Oil in Arkansas; Fuel transported via rail to California	Arkansas	Soybean	Biodiesel	None	None	BDS208	51.11	3/17/2017	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Crossett Biodiesel Pant (82217)	Biodiesel produced from Soybean Oil in Arkansas; Fuel transported via rail to California	None	Retired
T1N-1502	Tier 1	2.0	Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): U.S. sourced corn oil to Biodiesel produced in Arkansas; Fuel transported by rail to California	Arkansas	Corn Oil	Biodiesel	None	None	BDC210	38.75	5/19/2017	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	US sourced corn oil to Biodiesel produced in Arkansas; Fuel transported by rail to California	None	Retired

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T1N-1503	Tier 1	2.0	Fuel Producer: Rothsay, A Division of Darling International Canada Inc. (6190) Facility Name: Rothsay Biodiesel (83210). High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Canada, shipped by rail and truck to California	Canada	Used Cooking Oil	Biodiesel	None	None	BDU216	27.45	11/7/2016	None	Biodiesel	Rothsay, A Division of Darling International Canada Inc (6190)	Rothsay Biodiesel (83210)	High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Canada, shipped by rail and truck to California	None	Retired
T1R-1174	Tier 1	2.0	Fuel Producer: Heron Lake BioEnergy (4015) Facility Name: Heron Lake BioEnergy (70097). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG	Minnesota	Corn	Ethanol	ETHC091	88.69	ETHC245L	77.33	3/31/2016	None	Ethanol	Heron Lake BioEnergy (4015)	Heron Lake BioEnergy (70097)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T1N-1512	Tier 1	2.0	Fuel Producer: Rothsay, A Division of Darling International Canada Inc. (6190) Facility Name: Rothsay Biodiesel (83210). High energy rendered Tallow, Biodiesel produced in Canada, shipped by rail and truck to California	Canada	Tallow	Biodiesel	None	None	BDT209	36.15	11/7/2016	None	Biodiesel	Rothsay, A Division of Darling International Canada Inc (6190)	Rothsay Biodiesel (83210)	High energy rendered Tallow, Biodiesel produced in Canada, shipped by rail and truck to California	None	Retired
T1N-1534	Tier 1	2.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935) Facility Name: Community Fuels Port of Stockton (82728). Biodiesel produced from tallow (poultry fat) feedstock sourced in California only.	Stockton, California	Tallow	Biodiesel	None	None	BDT206	28.90	6/30/2016	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Biodiesel produced from tallow (poultry fat)feedstock sourced in California only	None	Retired
T1R-1123	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: EIF KC Landfill Gas LLC (71155). Kansas City landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Kansas	Landfill Gas	Compressed Natural Gas	CNG029	26.38	CNGLF213L	41.49	9/30/2016	None	Bio-CNG	Clean Energy (5481)	EIF KC Landfill Gas LLC (71155)	Kansas City landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1102	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Pinnacle Gas Producers, LLC (71153). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Ohio	Landfill Gas	Compressed Natural Gas	CNG022	21.01	CNGLF206L	41.61	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Pinnacle Gas Producers, LLC (71153)	Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1661	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154) Facility Name: Cambrian Energy/Southtex Fort Smith Treaters (C5950): Fort Smith landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in Califrnia **(Provisional)**	Arkansas	Landfill Gas	Compressed Natural Gas	None	None	CNGLF254	42.15	7/10/2017	None	Bio-CNG	Shell Energy North America (6154)	Cambrian Energy/Southtex Fort Smith Treaters (C5950)	Fort Smith landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in Califrnia (Provisional)	None	Retired
T1N-1667	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154) Facility Name: Edinburg Renewables LLC (J8601): Edinburg landfill gas (TX) to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California**(Provisional)**	Texas	Landfill Gas	Compressed Natural Gas	None	None	CNGLF249	43.26	6/27/2017	None	Bio-CNG	Shell Energy North America (6154)	Edinburg Renewables LLC (J8601)	Edinburg landfill gas (TX)to pipelinequality biomethane; delivered via pipeline to CNG Stations in California(Provisional)	None	Retired
T1R-1223	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Montana-Dakota Utilities Billings Regional Landfill (71193). Montana landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Montana	Landfill Gas	Compressed Natural Gas	CNG057	45.24	CNGLF214L	46.65	9/30/2016	None	Bio-CNG	Clean Energy (5481)	MontanaDakota Utilities Billings Regional Landfill (71193)	Montana landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1R-1099	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Westside Gas Prodcuers LLC (71151). Michigan landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Michigan	Landfill Gas	Compressed Natural Gas	CNG031	25.62	CNGLF237L	47.40	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Westside Gas Prodcuers LLC (71151)	Michigan landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1551	Tier 1	2.0	Fuel Producer: REG Grays Harbor, LLC (6326) Facility Name: REG Grays Harbor, LLC (82954). Canola Oil Biodiesel produced in Washington; BD transported by rail to California	Hoquiam, Washinton	Canola	Biodiesel	None	None	BDCA204	52.87	8/11/2016	None	Biodiesel	REG Grays Harbor, LLC (6326)	REG Grays Harbor, LLC (82954)	Canola Oil Biodiesel produced in Washington; BD transported by rail to California	None	Retired
T1N-1562	Tier 1	2.0	Fuel Producer: REG Grays Harbor, LLC (6326) Facility Name: REG Grays Harbor, LLC (82954). Used Cooking Oil (UCO) to Biodiesel produced in Washington, where cooking is not required; BD transported by rail to California	Hoquiam, Washinton	Used Cooking Oil	Biodiesel	None	None	BDU214	18.62	8/25/2016	None	Biodiesel	REG Grays Harbor, LLC (6326)	REG Grays Harbor, LLC (82954)	Used Cooking Oil (UCO)to Biodiesel produced in Washington, where cooking is not required; BD transported by rail to California	None	Retired

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T1N-1505	Tier 1	2.0	Fuel Producer: NuGen Energy, LLC (3332) Facility Name: NuGen Energy, LLC (70195). Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil; NG	South Dakota	Corn	Ethanol	None	None	ETHC277	77.93	11/2/2016	None	Ethanol	NuGen Energy, LLC (3332)	NuGen Energy, LLC (70195)	Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil; NG	None	Retired
T1N-1274	Tier 1	2.0	Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043). Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, NG	Iowa	Corn	Ethanol	None	None	ETHC220	78.14	3/31/2016	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC Fort Dodge (70043)	Midwest Corn, Ethanol, Dry Mill, DDGS, MDGS, Corn Oil, NG	None	Retired
T1R-1177	Tier 1	2.0	Fuel Producer: Advanced BioEnergy, LLC (4094) Facility Name: ABE South Dakota, LLC (70104). Midwest, Corn Ethanol, Dry Mill, 84% DDGS, 16% WDGS, NG	South Dakota	Corn	Ethanol	ETHC065	88.59	ETHC246L	78.32	3/31/2016	None	Ethanol	Advanced BioEnergy, LLC (4094)	ABE South Dakota, LLC (70104)	Midwest, Corn Ethanol, Dry Mill, 84% DDGS, 16% WDGS, NG	None	Retired
T1N-1574	Tier 1	2.0	Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): Canola oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	Iowa	Canola Oil	Biodiesel	None	None	BDCA205	61.94	2/2/2017	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Canola oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	None	Retired
T1N-1575	Tier 1	2.0	Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): Corn Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	Iowa	Corn Oil	Biodiesel	None	None	BDC206	29.46	2/2/2017	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Corn Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	None	Retired
T1N-1576	Tier 1	2.0	Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): Soy Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	Iowa	Soybean Oil	Biodiesel	None	None	BDS206	54.50	2/2/2017	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Soy Oil Biodiesel produced in Wall Lake, Iowa and transported by rail to California	None	Retired
T1N-1577	Tier 1	2.0	Western Iowa Energy (4670) Facility Name: Western Iowa Energy (82630): U.S. sourced rendered Tallow; Biodiesel Produced in Wall Lake, Iowa and transported by rail to California	Iowa	Tallow	Biodiesel	None	None	BDT211	31.19	2/2/2017	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	US sourced rendered Tallow; Biodiesel Produced in Wall Lake, Iowa and transported by rail to California	None	Retired
T1N-1583	Tier 1	2.0	Fuel Producer: Ag Processing Inc (4552) Facility Name: Ag Processing Inc - Sgt. Bluff (81733): Soybean Oil Biodiesel produced in Sergeant Bluff, Iowa; steam from coal-boiler used; Fuel transported by rail to California	Iowa	Soybean	Biodiesel	None	None	BDS207	52.22	2/2/2017	None	Biodiesel	Ag Processing Inc (4552)	Ag Processing Inc Sgt Bluff (81733)	Soybean Oil Biodiesel produced in Sergeant Bluff, Iowa; steam from coalboiler used; Fuel transported by rail to California	None	Retired
T1R-1268 T1R-1269	Tier 1	2.0	Fuel Producer: Valero Renewable Fuels (3201) Facility Name: Valero Renewable Fuels LLC - Albert City (70142). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG	Iowa	Corn	Ethanol	ETHC104_1 ETHC105_1	88.15 84.06	ETHC260L	78.62	3/31/2016	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC Albert City (70142)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG	None	Retired
T1N-1072	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG	Texas	Sorghum	Ethanol	None	None	ETHG200	79.03	3/31/2016	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG	None	Retired
T1N-1596	Tier 1	2.0	Fuel Producer: SunLine Transit Agency (S317) Facility Name: Sunline Transit (H2505). North American NG delivered via pipeline and compressed at Indio and Thousand Oaks California	California	North American NG	Compressed Natural Gas	None	None	CNGF203	78.21	11/2/2016	None	Fossil CNG	SunLine Transit Agency (S317)	Sunline Transit (H2505)	North American NG delivered via pipeline and compressed at Indio and Thousand Oaks California	None	Retired
T1N-1598	Tier 1	2.0	Fuel Producer: FutureFuel Chemical Company (4664) Facility Name: FutureFuel Chemical Company (82612): Biodiesel produced from Midwest Soybean oil in Arkansas; Fuel transported via rail to California	Arkansas	Soybean	Biodiesel	None	None	BDS211	59.53	5/19/2017	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	Biodiesel produced from Midwest Soybean oil in Arkansas; Fuel transported via rail to California	None	Retired

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T1N-1602	Tier 1	2.0	Fuel Producer: Imperial Western Products (9871) Facility Name: Imperial Western Products (81066): Average U.S. sourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California **(Provisional)**	California	Used Cooking Oil	Biodiesel	None	None	BDU219	21.73	1/27/2017	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Average US sourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California (Provisional)	None	Retired
T1N-1604	Tier 1	2.0	Fuel Producer: Imperial Western Products (9871) Facility Name: Imperial Western Products (81066): U.S. sourced corn oil to Biodiesel produced from Southern California, distributed to Southern California **(Provisional)**	California	Corn Oil	Biodiesel	None	None	BDC205	34.66	1/27/2017	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	US sourced corn oil to Biodiesel produced from Southern California, distributed to Southern California (Provisional)	None	Retired
T1R-1086 T1R-1087	Tier 1	2.0	Fuel Producer: Glacial Lakes Corn Processors (4764) Facility Name: Glacial Lakes Energy (70064). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG	South Dakota	Corn	Ethanol	ETHC058 ETHC059	91.18 86.69	ETHC241L	79.21	3/31/2016	None	Ethanol	Glacial Lakes Corn Processors (4764)	Glacial Lakes Energy (70064)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% MDGS, NG	None	Retired
T1N-1610	Tier 1	2.0	Fuel Producer: BIOX Canada Limited (3758) Facility Name: BIOX Canada Limited (80236): High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Hamilton, Ontario and transported by rail to California	Ontario, Canada	Used Cooking Oil	Biodiesel	None	None	BDU218	22.38	12/20/2016	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Hamilton, Ontario and transported by rail to California	None	Retired
T1N-1276	Tier 1	2.0	Fuel Producer: Elkhorn Valley Ethanol LLC (4833) Facility Name: Elkhorn Valley Ethanol LLC (70095). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	Nebraska	Corn	Ethanol	None	None	ETHC221	79.83	3/31/2016	None	Ethanol	Elkhorn Valley Ethanol LLC (4833)	Elkhorn Valley Ethanol LLC (70095)	Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T1N-1278	Tier 1	2.0	Fuel Producer: Louis Dreyfus Commodities Grand Junction LLC (3137) Facility Name: Louis dreyfus Commodities Grand Junction LLC (70139). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	Iowa	Corn	Ethanol	None	None	ETHC223	80.18	3/31/2016	None	Ethanol	Louis Dreyfus Commodities Grand Junction LLC (3137)	Louis dreyfus Commodities Grand Junction LLC (70139)	Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T1N-1620	Tier 1	2.0	Fuel Producer: Clinton Biodiesel, LLC (6485) Facility Name: Clinton Biodiesel LLC (82595): Soy oil Biodiesel produced from Midwest, transported by rail to California **(Provisional)**	Iowa	Soybean	Biodiesel	None	None	BDS205	54.81	12/20/2016	None	Biodiesel	Clinton Biodiesel, LLC (6485)	Clinton Biodiesel LLC (82595)	Soy oil Biodiesel produced from Midwest, transported by rail to California (Provisional)	None	Retired
T1R-1321	Tier 1	2.0	Fuel Producer: San Diego Metropolitan Transit Center (S304) Facility Name: Monroeville LFG, LLC (71136). Pennsylvania landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Pennsylvania	Landfill Gas	Compressed Natural Gas	CNG047	33.30	CNGLF217L	49.55	9/30/2016	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	Monroeville LFG, LLC (71136)	Pennsylvania landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1546	Tier 1	2.0	Fuel Producer: Athens Services (A431) Facility Name: Irwindale (V5355). Seneca Meadows solid waste landfill (Waterloo NY) gas to pipeline-quality biomethane; delivered via pipeline to Irwindale California and compressed to CNG	New York	Landfill Gas	Compressed Natural Gas	None	None	CNGLF241	50.37	11/2/2016	None	Bio-CNG	Athens Services (A431)	Irwindale (V5355)	Seneca Meadows solid waste landfill (Waterloo NY)gas to pipelinequality biomethane; delivered via pipeline to Irwindale California and compressed to CNG	None	Retired
T1N-1484	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Pioneiros Bioenergia S.A. (70430); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS237	46.51	8/17/2017	None	Ethanol	Copersucar (3702)	Pioneiros Bioenergia SA (70430)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1R-1107	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Seneca Energy II, LLC (71156). New York landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	New York	Landfill Gas	Compressed Natural Gas	CNG027	27.53	CNGLF207L	52.77	9/30/2016	None	Bio-CNG	Clean Energy (5481)	Seneca Energy II, LLC (71156)	New York landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T1N-1629	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Canton Renewables (71041): Sauk Trails Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona	Michigan	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF216	64.74	7/10/2017	None	Bio-LNG	Clean Energy (5481)	Canton Renewables (71041)	Sauk Trails Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona	None	Retired

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T1R-1022 T1R-1023	Tier 1	2.0	Fuel Producer: Glacial Lakes Corn Processors (4764) Facility Name: Aberdeen Energy (70299). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG	South Dakota	Corn	Ethanol	ETHC060 ETHC061	92.15 87.66	ETHC237L	80.19	3/31/2016	None	Ethanol	Glacial Lakes Corn Processors (4764)	Aberdeen Energy (70299)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, 100% WDGS, NG	None	Retired
T1N-1636	Tier 1	2.0	Fuel Producer: Usina Alta Mogiana S/A (4225) Facility Name: Usina Alta Mogiana S.A. - Acucar e Alcool (70498): Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM227	46.29	2/2/2017	None	Ethanol	Usina Alta Mogiana S/A (4225)	Usina Alta Mogiana SA Acucar e Alcool (70498)	Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity export, and mechanized harvesting	None	Retired
T1N-1647	Tier 1	2.0	Fuel Producer: Titan El Toro LLC (T153) Facility Name: Titan El Toro (T4201): North American NG delivered via pipeline; compressed in California	California	North American NG	Compressed Natural Gas	None	None	CNGF206	80.59	3/17/2017	None	Fossil CNG	Titan El Toro LLC (T153)	Titan El Toro (T4201)	North American NG delivered via pipeline; compressed in California	None	Retired
T1N-1626	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Canton Renewables (71041): Sauk Trails Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	Michigan	Landfill Gas	Compressed Natural Gas	None	None	CNGLF251	57.35	6/27/2017	None	Bio-CNG	Clean Energy (5481)	Canton Renewables (71041)	Sauk Trails Hills landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California	None	Retired
T1N-1666	Tier 1	2.0	Fuel Producer: GeoGreen Biofuels (3885) Facility Name: GeoGreen Biofuels (81199): California sourced Waste Oil (Used Cooking Oil) Biodiesel produced in California (**Provisional**)	California	Used Cooking Oil	Biodiesel	None	None	BDU222	18.26	3/17/2017	None	Biodiesel	GeoGreen Biofuels (3885)	GeoGreen Biofuels (81199)	California sourced Waste Oil (Used Cooking Oil)Biodiesel produced in California (Provisional)	None	Retired
T1N-1545	Tier 1	2.0	Fuel Producer: Athens Services (A431) Facility Name: Irwindale (V5355). Landfill gas from SWACO landfill in Grove City, OH is transported via pipeline to Irwindale California and compressed to CNG	Ohio	Landfill Gas	Compressed Natural Gas	None	None	CNGLF240	58.21	11/2/2016	None	Bio-CNG	Athens Services (A431)	Irwindale (V5355)	Landfill gas from SWACO landfill in Grove City, OH is transported via pipeline to Irwindale California and compressed to CNG	None	Retired
T1N-1704	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Ehrenberg LNG (C0660): North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona	Arizona	North American NG	Liquefied Natural Gas	None	None	LNGF202	91.03	7/10/2017	None	Fossil LNG	Clean Energy (5481)	Ehrenberg LNG (C0660)	North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona	None	Retired
T1N-1705	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Ehrenberg LNG (C0660): North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona; re-gasified to L-CNG in California	Arizona	North American NG	Liquefied Compressed Natural Gas	None	None	CNGF207	93.59	7/10/2017	None	Fossil CNG	Clean Energy (5481)	Ehrenberg LNG (C0660)	North American Natural Gas; delivered via pipeline; liquefied to LNG in Arizona; regasified to LCNG in California	None	Retired
T1N-1707	Tier 1	2.0	Fuel Producer: REG Newton, LLC (3514) Facility Name: REG Newton, LLC (80162): High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Iowa and transported by rail to California	Iowa	Used Cooking Oil	Biodiesel	None	None	BDU223	22.50	3/17/2017	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Iowa and transported by rail to California	None	Retired
T1N-1708	Tier 1	2.0	Fuel Producer: REG Newton, LLC (3514) Facility Name: REG Newton, LLC (80162): U.S. sourced Corn Oil Biodiesel produced in Iowa and transported by rail to California	Iowa	Corn Oil	Biodiesel	None	None	BDC208	34.10	3/17/2017	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	US sourced Corn Oil Biodiesel produced in Iowa and transported by rail to California	None	Retired
T1N-1711	Tier 1	2.0	Fuel Producer: Imperial Western Products (9871) Facility Name: Imperial Western Products (81066): CA-sourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California (**Provisional**)	California	Used Cooking Oil	Biodiesel	None	None	BDU220	20.96	1/27/2017	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	CAsourced rendered UCO to Biodiesel produced from Southern California, distributed to Southern California (Provisional)	None	Retired
T1N-1089	Tier 1	2.0	Fuel Producer: Heartland Corn Products (4827) Facility Name: Heartland Corn Products (70089). Midwest Corn, Ethanol, Dry Mill, DDGS, NG	Minnesota	Corn	Ethanol	None	None	ETHC204	80.24	3/31/2016	None	Ethanol	Heartland Corn Products (4827)	Heartland Corn Products (70089)	Midwest Corn, Ethanol, Dry Mill, DDGS, NG	None	Retired

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T1N-1721	Tier 1	2.0	Fuel Producer: Bio Etanol, S.A. (5834) Facility Name: Bio Etanol (Pantaleon), S.A. (71037): Guatemalan sugarcane by-product molasses-based ethanol with average production processes and electricity co-product credit	Guatemala	Molasses	Ethanol	None	None	ETHM231	40.20	5/19/2017	None	Ethanol	Bio Etanol, SA (5834)	Bio Etanol (Pantaleon), SA (71037)	Guatemalan sugarcane byproduct molassesbased ethanol with average production processes and electricity coproduct credit	None	Retired
T1N-1722	Tier 1	2.0	Fuel Producer: Bio Etanol, S.A. (5834) Facility Name: Bio Etanol (Concepcion), S.A. (71037): Guatemalan sugarcane by-product molasses-based ethanol with average production processes and co-product credit for surplus electricity export, and mechanized harvesting	Guatemala	Molasses	Ethanol	None	None	ETHM232	41.93	5/19/2017	None	Ethanol	Bio Etanol, SA (5834)	Bio Etanol (Concepcion), SA (71037)	Guatemalan sugarcane byproduct molassesbased ethanol with average production processes and coproduct credit for surplus electricity export, and mechanized harvesting	None	Retired
T1N-1733	Tier 1	2.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 650 miles, Biodiesel produced in Texas, shipped by rail to California	Texas	Used Cooking Oil (UCO)	Biodiesel	BDU227	20.83	BDU227R	22.45	11/28/2018	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 650 miles, Biodiesel produced in Texas, shipped by rail to California	None	Retired
T1N-1735	Tier 1	2.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by truck to California	Texas	Used Cooking Oil (UCO)	Biodiesel	BDU225	28.54	BDU225R	30.15	11/28/2018	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by truck to California	None	Retired
T1N-1736	Tier 1	2.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); Soybean Oil shipped by rail, biodiesel produced from soybean oil in Texas, shipped by rail to California	Texas	Soybean Oil	Biodiesel	BDS210	51.94	BDS210R	53.43	11/28/2018	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	Soybean Oil shipped by rail, biodiesel produced from soybean oil in Texas, shipped by rail to California	None	Retired
T1N-1571	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% WDGS	Kansas	Sorghum	Ethanol	None	None	ETHG216	80.38	2/2/2017	None	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% WDGS	None	Retired
T1N-1742	Tier 1	2.0	Fuel Producer: Lakeview Biodiesel, LLC (L430) Facility Name: Lakeview Biodiesel, LLC (W0607): Biodiesel produced from Soybean oil in Missouri; Fuel transported via rail to California **(Provisional)**	Missouri	Soybean	Biodiesel	None	None	BDS212	56.20	6/30/2017	None	Biodiesel	Lakeview Biodiesel, LLC (L430)	Lakeview Biodiesel, LLC (W0607)	Biodiesel produced from Soybean oil in Missouri; Fuel transported via rail to California (Provisional)	None	Retired
T1N-1568	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Corn to Ethanol, Dry Mill, Midwest, NG, 100% DDGS	Kansas	Corn	Ethanol	None	None	ETHC282	80.85	2/2/2017	None	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Corn to Ethanol, Dry Mill, Midwest, NG, 100% DDGS	None	Retired
T1N-1751	Tier 1	2.0	Fuel Producer: BUSTER BIOFUELS LLC (4166) Facility Name: BUSTER BIOFUELS LLC (83449): High energy rendered Used Cooking Oil (UCO) sourced locally and transported by truck, Biodiesel produced in California**(Provisional)**	California	Used Cooking Oil	Biodiesel	None	None	BDU230	21.53	6/28/2017	None	Biodiesel	BUSTER BIOFUELS LLC (4166)	BUSTER BIOFUELS LLC (83449)	High energy rendered Used Cooking Oil (UCO)sourced locally and transported by truck, Biodiesel produced in California(Provisional)	None	Retired
T1R-1241	Tier 1	2.0	Fuel Producer: Green Plains Holdings II LLC - Lakota (4755) Facility Name: Green Plains Holdings II LLC - Lakota (70051). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC024	91.60	ETHC256L	81.42	3/31/2016	None	Ethanol	Green Plains Holdings II LLC Lakota (4755)	Green Plains Holdings II LLC Lakota (70051)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1113	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: LES Renewable NG, LLC - SWACO Facility (71157). Ohio landfill gas to pipeline-quality biomethane; delivered via pipeline; compressed to CNG in CA	Ohio	Landfill Gas	Compressed Natural Gas	CNG025	28.68	CNGLF209L	60.92	9/30/2016	None	Bio-CNG	Clean Energy (5481)	LES Renewable NG, LLC SWACO Facility (71157)	Ohio landfill gas to pipelinequality biomethane; delivered via pipeline; compressed to CNG in CA	None	Retired
T2R-1067	Tier 2	2.0	Fuel Producer: Archer Daniels Midland Co (4888) Facility Name: Archer Daniels Midland Compnay - Columbus Dry Mill (70355). Midwest, Corn Ethanol, Dry Mill, NG, Closed-loop heat recovery, Cogeneration	Nebraska	Corn	Ethanol	ETHC018_2	87.11	ETHC274L	81.47	3/31/2016	None	Ethanol	Archer Daniels Midland Co (4888)	Archer Daniels Midland Compnay Columbus Dry Mill (70355)	Midwest, Corn Ethanol, Dry Mill, NG, Closedloop heat recovery, Cogeneration	None	Retired

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T1N-1234	Tier 1	2.0	Fuel Producer: Red Trail Energy LLC (4803) Facility Name: Red Trail Energy LLC (70077). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	North Dakota	Corn	Ethanol	None	None	ETHC218	82.30	3/31/2016	None	Ethanol	Red Trail Energy LLC (4803)	Red Trail Energy LLC (70077)	Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T1N-1506	Tier 1	2.0	Fuel Producer: NuGen Energy, LLC (3332) Facility Name: NuGen Energy, LLC (70195). Midwest Sorghum, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil, NG	South Dakota	Sorghum	Ethanol	None	None	ETHG214	85.72	11/2/2016	None	Ethanol	NuGen Energy, LLC (3332)	NuGen Energy, LLC (70195)	Midwest Sorghum, Ethanol, Dry Mill, DDGS, MDGS, and Corn Oil, NG	None	Retired
T1N-1143	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Bonfim (70548) - Ethanol production from Brazilian sugarcane by-product molasses feedstock, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM216	44.24	6/6/2016	None	Ethanol	Raízen Energia S/A (3805)	Bonfim (70548)	Ethanol production from Brazilian sugarcane byproduct molasses feedstock, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1570	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038): Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% DDGS	Kansas	Sorghum	Ethanol	None	None	ETHG217	88.90	2/2/2017	None	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Sorghum to Ethanol, Dry Mill, Midwest, NG, 100% DDGS	None	Retired
T1N-1191	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) Facility Name: USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483): Brazilian sugarcane juice-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS207	46.24	6/6/2016	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483)	Brazilian sugarcane juicetoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1491	Tier 1	2.0	Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398): High energy rendered Tallow; Biodiesel produced in Texas and transported by rail to California	Texas	Tallow	Biodiesel	None	None	BDT217	38.27	3/22/2017	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	High energy rendered Tallow; Biodiesel produced in Texas and transported by rail to California	None	Retired
T1N-1492	Tier 1	2.0	Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398): Biodiesel produced from Soybean Oil in Texas; Fuel transported via rail to California	Texas	Soybean	Biodiesel	None	None	BDS209	58.55	3/22/2017	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	Biodiesel produced from Soybean Oil in Texas; Fuel transported via rail to California	None	Retired
T1N-1493	Tier 1	2.0	Fuel Producer: Delek Renewables, LLC (5998) Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398): High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas, shipped by rail to California	Texas	Used Cooking Oil	Biodiesel	None	None	BDU224	28.40	3/22/2017	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas, shipped by rail to California	None	Retired
T1N-1617	Tier 1	2.0	Fuel Producer: REG Newton, LLC (3514) Facility Name: REG Newton, LLC (80162): U.S. sourced rendered Tallow; Biodiesel Produced in Iowa and transported by rail to California	Iowa	Tallow	Biodiesel	None	None	BDT212	35.94	2/2/2017	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	US sourced rendered Tallow; Biodiesel Produced in Iowa and transported by rail to California	None	Retired
T2N-1116	Tier 2	2.0	Fuel Producer: New Leaf Biofuel (7768) Facility Name: New Leaf Biofuel (83541). Self-rendered Used Cooking Oil Biodiesel Produced in California **(Provisional)**	San Diego, California	Used Cooking Oil	Biodiesel	None	None	BDU202	8.63	4/1/2016	None	Biodiesel	New Leaf Biofuel (7768)	New Leaf Biofuel (83541)	Selfrendered Used Cooking Oil Biodiesel Produced in California (Provisional)	None	Retired
T2N-1154	Tier 2	2.0	Fuel Producer: Biodico Westside (6231) Facility Name: Biodico Plant (83027): California Used Cooking Oil; Biodiesel produced in Five Points, California **(Provisional)**	California	Used Cooking Oil	Biodiesel	None	None	BDU229	14.97	6/1/2017	Pathway Details (PDF)	Biodiesel	Biodico Westside (6231)	Biodico Plant (83027)	California Used Cooking Oil; Biodiesel produced in Five Points, California (Provisional)	None	Retired
T2N-1159	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel dispensed on-site	California	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF217	7.39	6/22/2017	Pathway Details (PDF)	Bio-LNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel dispensed onsite	None	Retired

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T2N-1162	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Bay Area by Truck	California	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF218	7.74	6/22/2017	Pathway Details (PDF)	Bio-LNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Bay Area by Truck	None	Retired
T1N-1630	Tier 1	2.0	Fuel Producer: Clean Energy (5481) Facility Name: Canton Renewables (71041): Sauk Trails Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; re-gasified to L-CNG in California	Michigan	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF244	67.29	7/10/2017	None	Bio-CNG	Clean Energy (5481)	Canton Renewables (71041)	Sauk Trails Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; regasified to LCNG in California	None	Retired
T2N-1164	Tier 2	2.0	Fuel Producer: High Mountain Fuels, LLC (4293) Facility Name: Altamont Bio-LNG Plant (70526): Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Southern California by Truck	California	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF219	10.71	6/22/2017	Pathway Details (PDF)	Bio-LNG	High Mountain Fuels, LLC (4293)	Altamont BioLNG Plant (70526)	Tier 2 Method 2B Pathway; Altamont landfill gas delivered via pipeline to High Mountain Fuels; purified to biomethane and liquefied to LNG in California; fuel delivered to Southern California by Truck	None	Retired
T1N-1485	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Pioneiros Bioenergia S.A. (70430); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM235	47.56	8/17/2017	None	Ethanol	Copersucar (3702)	Pioneiros Bioenergia SA (70430)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T2N-1192	Tier 2	2.0	Fuel Producer: BUSTER BIOFUELS LLC (4166) Facility Name: BUSTER BIOFUELS LLC (83449): Raw Used Cooking Oil (UCO) sourced locally and transported by truck, Biodiesel produced in California **(Provisional)**	California	Used Cooking Oil	Biodiesel	None	None	BDU231	16.90	7/10/2017	Pathway Details (PDF)	Biodiesel	BUSTER BIOFUELS LLC (4166)	BUSTER BIOFUELS LLC (83449)	Raw Used Cooking Oil (UCO)sourced locally and transported by truck, Biodiesel produced in California (Provisional)	None	Retired
T1N-1627	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: Canton Renewables (71041); Sauk Trail Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California	Michigan	Landfill Gas	Liquefied Natural Gas	LNGLF221	66.93	LNGLF221R	72.42	8/16/2017	None	Bio-LNG	Clean Energy (5481)	Canton Renewables (71041)	Sauk Trail Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California	None	Retired
T1N-1628	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: Canton Renewables (71041); Sauk Trail Hills landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California; re-gassified to L-CNG in California	Michigan	Landfill Gas	Liquefied Compressed Natural Gas	CNGLF255	69.48	CNGLF255R	74.97	8/16/2017	None	Bio-CNG	Clean Energy (5481)	Canton Renewables (71041)	Sauk Trail Hills landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Boron; liquefied to LNG in California; regassified to LCNG in California	None	Retired
T1N-1651	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: JDP Renewables (L6161); Jefferson David Parish Sanitary landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Louisiana	Landfill Gas	Compressed Natural Gas	None	None	CNGLF260	39.31	8/24/2017	None	Bio-CNG	Shell Energy North America (6154)	JDP Renewables (L6161)	Jefferson David Parish Sanitary landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1654	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: JDP Renewables (L6161); Jefferson David Parish Sanitary landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	Louisiana	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF224	47.28	8/24/2017	None	Bio-LNG	Shell Energy North America (6154)	JDP Renewables (L6161)	Jefferson David Parish Sanitary landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	None	Retired
T1N-1655	Tier 1	2.0	Shell Energy North America (6154); JDP Renewables (L6161); Jefferson David Parish Sanitary landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; re-gasified in California (Provisional)	Louisiana	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF259	49.82	8/24/2017	None	Bio-CNG	Shell Energy North America (6154)	JDP Renewables (L6161)	Jefferson David Parish Sanitary landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; regasified in California (Provisional)	None	Retired
T1N-1659	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: East Texas Renewables (F2942); Greenwood Farms landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	Texas	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF223	46.60	8/24/2017	None	Bio-LNG	Shell Energy North America (6154)	East Texas Renewables (F2942)	Greenwood Farms landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	None	Retired
T1N-1660	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: East Texas Renewables (F2942); Greenwodd Farms landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; re-gasified in California (Provisional)	Texas	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF258	49.15	8/24/2017	None	Bio-LNG	Shell Energy North America (6154)	East Texas Renewables (F2942)	Greenwodd Farms landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; regasified in California (Provisional)	None	Retired

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T1N-1664	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Cambrian Energy/Southtex Fort Smith Treaters (C5950); Fort Smith landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	Arkansas	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF222	50.15	8/24/2017	None	Bio-LNG	Shell Energy North America (6154)	Cambrian Energy/Southtex Fort Smith Treaters (C5950)	Fort Smith landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona (Provisional)	None	Retired
T1N-1665	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Cambrian Energy/Southtex Fort Smith Treaters (C5950); Fort Smith landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; re-gasified and compressed in California (Provisional)	Arkansas	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF257	52.70	8/24/2017	None	Bio-CNG	Shell Energy North America (6154)	Cambrian Energy/Southtex Fort Smith Treaters (C5950)	Fort Smith landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona; regasified and compressed in California (Provisional)	None	Retired
T1N-1782	Tier 1	2.0	Fuel Producer: Usina Batatais S/A - Açúcar e Álcool (6446); Facility Name: Usina Batatais S.A. - Açucar e Álcool - Batatais Unit (70408); Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS236	48.71	8/17/2017	None	Ethanol	Usina Batatais S/A Açúcar e Álcool (6446)	Usina Batatais SA Açucar e Álcool Batatais Unit (70408)	Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting	None	Retired
T1N-1784	Tier 1	2.0	Fuel Producer: Usina Batatais S/A - Açúcar e Álcool (6446); Facility Name: Usina Batatais S.A. - Açucar e Álcool (70409); Brazilian sugarcane juice-based ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS235	47.53	8/17/2017	None	Ethanol	Usina Batatais S/A Açúcar e Álcool (6446)	Usina Batatais SA Açucar e Álcool (70409)	Brazilian sugarcane juicebased ethanol, with credit for mechanized harvesting	None	Retired
T1R-1787	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Costa Pinto (70552): Raizen Energia S.A., COPI: Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM219	44.19	ETHM219R	47.02	8/9/2017	Former T1N-1566, FPC: ETHM219	Ethanol	Raízen Energia S/A (3805)	Costa Pinto (70552)	Raizen Energia SA, COPI Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1R-1788	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Gasa (70551); Raizen Energia S.A., Usina Gasa, Sao Paulo, Brazil. Brazilian sugarcane -to-ethanol, with credit for mechanized harvesting	Brazil	Sugarcane	Ethanol	ETHS221	46.07	ETHS221R	46.91	8/9/2017	Former T1N-1210, FPC: ETHS221	Ethanol	Raízen Energia S/A (3805)	Gasa (70551)	Raizen Energia SA, Usina Gasa, Sao Paulo, Brazil. Brazilian sugarcane toethanol, with credit for mechanized harvesting	None	Retired
T1R-1789	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Rafard (70557): Raizen Energia S.A., Rafard Mill: Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM215	47.17	ETHM215R	48.76	8/9/2017	Former T1N-1140, FPC: ETHM215	Ethanol	Raízen Energia S/A (3805)	Rafard (70557)	Raizen Energia SA, Rafard Mill; Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1R-1790	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Paraguaçu (71057): Raizen Energia S.A., Paraguacu Mill, Sao Paulo, Brazil: Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM223	46.71	ETHM223R	49.32	8/9/2017	Former T1N-1146, FPC:ETHM223	Ethanol	Raízen Energia S/A (3805)	Paraguaçu (71057)	Raizen Energia SA, Paraguacu Mill, Sao Paulo, Brazil; Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1771	Tier 1	2.0	Fuel Producer: EM Gas Marketing, LLC (6287); Facility Name: Fresh Kills Landfill EMGM (7120t); Fresh Kills landfill gas to pipeline-quality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in California	New York	Landfill Gas	Compressed Natural Gas	None	None	CNGLF262	37.13	8/29/2017	None	Bio-CNG	EM Gas Marketing, LLC (6287)	Fresh Kills Landfill EMGM (7120t)	Fresh Kills landfill gas to pipelinequality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in California	None	Retired
T1N-1775	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Meadow Branch Landfill Gas Processing Facility (71252); Meadow Branch landfill gas to pipeline-quality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in CA (Provisional)	Tennessee	Landfill Gas	CNG	CNGLF261	38.51	CNGLF261R	52.14	5/11/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Meadow Branch Landfill Gas Processing Facility (71252)	Meadow Branch landfill gas to pipelinequality biomethane; delivered via pipeline to Orange County Transportation Authority and TruStar CNG Stations in CA (Provisional)	None	Retired
T1N-1755	Tier 1	2.0	Fuel Producer: REG New Boston, LLC (6067); Facility Name: REG New Boston, LLC (81490); High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas and transported by rail to California	Texas	Used Cooking Oil	Biodiesel	None	None	BDU232	20.23	8/31/2017	None	Biodiesel	REG New Boston, LLC (6067)	REG New Boston, LLC (81490)	High energy rendered Used Cooking Oil (UCO), Biodiesel produced in Texas and transported by rail to California	None	Retired
T2N-1191	Tier 2	2.0	Fuel Producer: USL Parallel Products of California (4018); Facility Name: USL Parallel Products of California (70122); Tier 2 Method 2B Pathway: Ethanol derived from recycled beverages in Rancho Cucamonga, California	California	Waste Beverage	Ethanol	None	None	ETHWB201	69.82	9/1/2017	Application Package	Ethanol	USL Parallel Products of California (4018)	USL Parallel Products of California (70122)	Tier 2 Method 2B Pathway Ethanol derived from recycled beverages in Rancho Cucamonga, California	None	Retired

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T1N-1693	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Santa Lúcia (70426); Brazilian sugarcane juice-to-ethanol pathway, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS241	46.88	9/1/2017	None	Ethanol	Copersucar (3702)	Usina Santa Lúcia (70426)	Brazilian sugarcane juicetoethanol pathway, with credit for mechanized harvesting	None	Retired
T1N-1643	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations	Ohio	Landfill Gas	Compressed Natural Gas	None	None	CNGLF264	43.97	9/5/2017	None	Bio-CNG	WM Renewable Energy, LLC (W978)	WM Renewable Energy of Ohio American Landfill (71222)	American landfill gas (Ohio)to pipelinequality biomethane; delivered via pipeline to California CNG Stations	None	Retired
T1N-1754	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; Re-gasified in CA	Ohio	Landfill Gas	Liquefied Compressed Natural Gas	None	None	CNGLF263	59.12	9/5/2017	None	Bio-CNG	WM Renewable Energy, LLC (W978)	WM Renewable Energy of Ohio American Landfill (71222)	American landfill gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; Regasified in CA	None	Retired
T1N-1477	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Barra Grande de Lençóis S.A. (70412); Brazilian sugarcane molases-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM205L	T1R-1259	ETHM239	48.90	9/5/2017	None	Ethanol	Copersucar (3702)	Usina Barra Grande de Lençóis SA (70412)	Brazilian sugarcane molasestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1753	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ (Provisional)	Ohio	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF225	56.57	9/5/2017	None	Bio-LNG	WM Renewable Energy, LLC (W978)	WM Renewable Energy of Ohio American Landfill (71222)	American landfill gas (Ohio)to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ (Provisional)	None	Retired
T2N-1197	Tier 2	2.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Rendered Used Cooking Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional)	Louisiana	Used Cooking Oil	Renewable Diesel	None	None	RDU203	24.35	9/11/2017	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Tier 2 Method 2B Pathway Renewable Diesel produced from Rendered Used Cooking Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional)	None	Retired
T2N-1198	Tier 2	2.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Non-Rendered Used Cooking Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional)	Louisiana	Used Cooking Oil	Renewable Diesel	None	None	RDU204	18.99	9/11/2017	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Tier 2 Method 2B Pathway Renewable Diesel produced from NonRendered Used Cooking Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional)	None	Retired
T2N-1199	Tier 2	2.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Corn Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional)	Louisiana	Corn Oil	Renewable Diesel	None	None	RDC202	34.32	9/11/2017	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Tier 2 Method 2B Pathway Renewable Diesel produced from Corn Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional)	None	Retired
T2N-1200	Tier 2	2.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Tallow, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional)	Louisiana	Tallow	Renewable Diesel	None	None	RDT206	35.71	9/11/2017	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Tier 2 Method 2B Pathway Renewable Diesel produced from Tallow, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional)	None	Retired
T2N-1201	Tier 2	2.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Tier 2 Method 2B Pathway: Renewable Diesel produced from Soy Oil, Fuel produced in Louisiana. Renewable Naphtha and LPG as co-products (Provisional)	Louisiana	Soybean Oil	Renewable Diesel	None	None	RDS201	56.57	9/11/2017	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Tier 2 Method 2B Pathway Renewable Diesel produced from Soy Oil, Fuel produced in Louisiana Renewable Naphtha and LPG as coproducts (Provisional)	None	Retired
T1N-1478	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S.A. (70406); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS242	48.86	9/19/2017	None	Ethanol	Copersucar (3702)	Açucareira Quatá SA (70406)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1479	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S.A. (70406); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM207L	45.97	ETHM240	50.69	9/19/2017	None	Ethanol	Copersucar (3702)	Açucareira Quatá SA (70406)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired

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T1N-1472	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Cerradão Ltda (70425); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS243	47.53	9/25/2017	None	Ethanol	Copersucar (3702)	Usina Cerradão Ltda (70425)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1473	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Cerradão Ltda (70425); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM212L	44.6	ETHM241	48.80	9/25/2017	None	Ethanol	Copersucar (3702)	Usina Cerradão Ltda (70425)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1474	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Açúcareira Zillo Lorenzetti S.A. (70432); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	ETHS205L	45.21	ETHS244	45.07	9/25/2017	None	Ethanol	Copersucar (3702)	Açúcareira Zillo Lorenzetti SA (70432)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1475	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Açúcareira Zillo Lorenzetti S.A. (70432); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM206L	46.32	ETHM242	46.26	9/25/2017	None	Ethanol	Copersucar (3702)	Açúcareira Zillo Lorenzetti SA (70432)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1757	Tier 1	2.0	Fuel Producer: REG New Boston, LLC (6067) ; Facility Name: REG New Boston, LLC (81490); U.S. sourced rendered Tallow; Biodiesel Produced in Texas and transported by rail to California	Texas	Tallow	Biodiesel	None	None	BDT218	34.27	9/25/2017	None	Biodiesel	REG New Boston, LLC (6067)	REG New Boston, LLC (81490)	US sourced rendered Tallow; Biodiesel Produced in Texas and transported by rail to California	None	Retired
T2N-1227	Tier 2	2.0	Fuel Producer: White Energy, Inc. (4745) ; Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038); Tier 2 Method 2B Pathway: Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Wet DGS, NG	Kansas	Wheat Starch Slurry	Ethanol	None	None	ETHWSS200	45.20	10/11/2017	Application Package	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Tier 2 Method 2B Pathway Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Wet DGS, NG	None	Retired
T2N-1228	Tier 2	2.0	Fuel Producer: White Energy, Inc. (4745) ; Facility Name: US Energy Partners, LLC (White Energy, Russell) (70038); Tier 2 Method 2B Pathway: Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Dry DGS, NG	Kansas	Wheat Starch Slurry	Ethanol	None	None	ETHWSS201	53.73	10/11/2017	Application Package	Ethanol	White Energy, Inc. (4745)	US Energy Partners, LLC (White Energy, Russell)(70038)	Tier 2 Method 2B Pathway Ethanol produced from Midwest Dry Mill, Wheat Starch Slurry, Dry DGS, NG	None	Retired
T2N-1190	Tier 2	2.0	Fuel Producer: Linde LLC (L012); Facility Name: Linde Canada LH2 Plant (R1980); Tier 2 Method 2B Pathway: Compressed H2 from Central Reforming of North American Natural Gas includes liquefaction and regasification steps. (Provisional)	California	North American NG	Hydrogen	None	None	HYGFCR200	165.88	10/13/2017	Application Package	Hydrogen	Linde LLC (L012)	Linde Canada LH2 Plant (R1980)	Tier 2 Method 2B Pathway Compressed H2 from Central Reforming of North American Natural Gas includes liquefaction and regasification steps (Provisional)	None	Retired
T1N-1192	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Facility Name: USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483); Brazilian sugarcane molasses-to-ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM246	46.78	11/6/2017	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	USINA OUROESTE AÇÚCAR E ÁLCOOL LTDA (70483)	Brazilian sugarcane molassestoethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1190	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Facility Name: USINA FRUTAL AÇÚCAR E ÁLCOOL (70579); Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM245	48.32	11/6/2017	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	USINA FRUTAL AÇÚCAR E ÁLCOOL (70579)	Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1188	Tier 1	2.0	Fuel Producer: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Facility Name: BUNGE ACUCAR E BIOENERGIA LTDA (3858) ; Brazilian sugarcane molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM244	48.60	11/6/2017	None	Ethanol	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	BUNGE ACUCAR E BIOENERGIA LTDA (3858)	Brazilian sugarcane molassesbased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1074	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Cresciumal (71068); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export.	Brazil	Sugarcane	Ethanol	None	None	ETHS245	47.72	11/6/2017	None	Ethanol	BIOSEV SA (3869)	Usina Cresciumal (71068)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting, and surplus cogenerated electricity export	None	Retired

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T1N-1075	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Santa Elisa (71070); Brazilian sugarcane juice-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS246	50.16	11/6/2017	None	Ethanol	BIOSEV SA (3869)	Usina Santa Elisa (71070)	Brazilian sugarcane juicebased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1076	Tier 1	2.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Vale do Rosário (70440); Brazilian sugarcane juice-based ethanol, with credit for electricity co-product export, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS247	52.07	11/6/2017	None	Ethanol	BIOSEV SA (3869)	Usina Vale do Rosário (70440)	Brazilian sugarcane juicebased ethanol, with credit for electricity coproduct export, and mechanized harvesting	None	Retired
T1N-1171	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Araraquara (71055); Brazilian sugarcane juice-to-ethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS248	46.16	11/6/2017	None	Ethanol	Raízen Energia S/A (3805)	Araraquara (71055)	Brazilian sugarcane juicetoethanol, with credit for surplus cogenerated electricity exports, and mechanized harvesting	None	Retired
T1N-1136	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Araraquara (71055); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	None	None	ETHM243	47.63	11/6/2017	None	Ethanol	Raízen Energia S/A (3805)	Araraquara (71055)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1786	Tier 1	2.0	Fuel Producer: Show Me Ethanol, LLC (7464); Facility Name: Show Me Ethanol (70300); Dry mill corn ethanol with co-production of DDGS, MDGS, and Corn Oil using natural gas and electricity power.	Missouri	Corn	Ethanol	None	None	ETHC294	77.26	12/21/2017	None	Ethanol	Show Me Ethanol, LLC (7464)	Show Me Ethanol (70300)	Dry mill corn ethanol with coproduction of DDGS, MDGS, and Corn Oil using natural gas and electricity power	None	Retired
T1N-1785	Tier 1	2.0	Fuel Producer: Homeland Energy Solutions LLC (3220) ; Facility Name: Homeland Energy Solutions LLC (70188); Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power (Provisional)	Iowa	Corn	Ethanol	None	None	ETHC292	73.11	12/21/2017	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Dry mill corn ethanol with coproduction of DDGS, MDGS, and corn oil using natural gas and electricity power (Provisional)	None	Retired
T1N-1470	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Cocal - Comércio Indústria Canaã Açucar e Alcool Ltda. (70419); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS249	47.66	11/29/2017	None	Ethanol	Copersucar (3702)	Cocal Comércio Indústria Canaã Açucar e Alcool Ltda (70419)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1471	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Cocal - Comércio Indústria Canaã Açucar e Alcool Ltda. (70419); Brazilian sugarcane molasses-to-ethanol, with credit for mechanized harvesting.	Brazil	Molasses	Ethanol	ETHM209L	46.04	ETHM247	48.41	11/29/2017	None	Ethanol	Copersucar (3702)	Cocal Comércio Indústria Canaã Açucar e Alcool Ltda (70419)	Brazilian sugarcane molassestoethanol, with credit for mechanized harvesting	None	Retired
T1N-1637	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: GSF Energy - Rumpke Landfill (71138); Rumpke landfill gas (OH) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ	Ohio	Landfill Gas	Liquefied Natural Gas	None	None	LNGLF227	64.62	12/21/2017	None	Bio-LNG	WM Renewable Energy, LLC (W978)	GSF Energy Rumpke Landfill (71138)	Rumpke landfill gas (OH)to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ	None	Retired
T1N-1638	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: GSF Energy - Rumpke Landfill (71138); Rumpke landfill gas (OH) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; re-gasified in CA	Ohio	Landfill Gas	Compressed Natural Gas	None	None	CNGLF268	67.17	12/21/2017	None	Bio-CNG	WM Renewable Energy, LLC (W978)	GSF Energy Rumpke Landfill (71138)	Rumpke landfill gas (OH)to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; regasified in CA	None	Retired
T1N-1634	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: GSF Energy - Rumpke Landfill (71138); Rumpke landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations	Ohio	Landfill Gas	Compressed Natural Gas	None	None	CNGLF265	52.32	12/1/2017	None	Bio-CNG	WM Renewable Energy, LLC (W978)	GSF Energy Rumpke Landfill (71138)	Rumpke landfill gas (Ohio)to pipelinequality biomethane; delivered via pipeline to California CNG Stations	None	Retired
T2N-1195	Tier 2	2.0	Fuel Producer: REG New Boston, LLC (6067) ; Facility Name: REG New Boston, LLC (81490): Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in New Boston, Texas and transported by rail to California.	Texas	Used Cooking Oil	Biodiesel	None	None	BDU237	14.75	1/8/2018	Application Package	Biodiesel	REG New Boston, LLC (6067)	REG New Boston, LLC (81490)	Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in New Boston, Texas and transported by rail to California	None	Retired

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T2N-1208	Tier 2	2.0	Fuel Producer: 3 Phases Renewables Inc. (P306) ; Facility Name: 3PR (P1225): Solar-based (Photovoltaic) Electricity for a Single Dual Port Electric Vehicle Charging Station.	California	Solar or Wind	Electricity	None	None	ELCR200	0.00	1/26/2018	Application Package	Electricity	3 Phases Renewables Inc (P306)	3PR (P1225)	Solarbased (Photovoltaic)Electricity for a Single Dual Port Electric Vehicle Charging Station	None	Retired
T2N-1166	Tier 2	2.0	Fuel Producer: REG Newton, LLC (3514) ; Facility Name: REG Newton, LLC (80162): Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in Newton, Iowa and transported by rail to California.	Iowa	Used Cooking Oil	Biodiesel	None	None	BDU235	15.49	1/8/2018	Application Package	Biodiesel	REG Newton, LLC (3514) ;	REG Newton, LLC (80162)	Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in Newton, Iowa and transported by rail to California	None	Retired
T2N-1158	Tier 2	2.0	Fuel Producer: FirstElement Fuel (E426): North American fossil NG to Hydrogen (H2) gas production by Steam Reforming of methane via pipeline to California then liquefied, re-gasified, and trucked to multiple H2 dispensing locations	California	North American Natural Gas	Hydrogen	None	None	HYGN001_2	151.01	4/5/2017	None	Hydrogen	FirstElement Fuel (E426)	North American fossil NG to Hydrogen (H2)	gas production by Steam Reforming of methane via pipeline to California then liquefied, regasified, and trucked to multiple H2 dispensing locations	None	Retired
T2N-1233	Tier 2	2.0	Fuel Producer: JC Chemical Co., Ltd. (6094) ; Facility Name: JC Chemical Co., Ltd. (81585); Tier 2 Method 2B Pathway: Rendered Used Cooking Oil (UCO), Biodiesel produced in Ulsan, South Korea and transported by ocean tanker to California	Korea, South	Used Cooking Oil	Biodiesel	None	None	BDU238	20.15	3/1/2018	Application Package	Biodiesel	JC Chemical Co Ltd (6094)	JC Chemical Co Ltd (81585)	Tier 2 Method 2B Pathway Rendered Used Cooking Oil (UCO), Biodiesel produced in Ulsan, South Korea and transported by ocean tanker to California	None	Retired
T2N-1216	Tier 2	2.0	Fuel Producer: General Biodiesel Seattle, LLC (3367); Facility Name: General Biodiesel Seattle, LLC (80086); Tier 2 Method 2B Pathway: Biodiesel produced from US sourced Used Cooking Oil (UCO). Fuel produced in Seattle, Washington and transported by rail to California (Provisional)	Washington	Used Cooking Oil	Biodiesel	None	None	BDU239	28.81	3/7/2018	Application Package	Biodiesel	General Biodiesel Seattle, LLC (3367)	General Biodiesel Seattle, LLC (80086)	Tier 2 Method 2B Pathway Biodiesel produced from US sourced Used Cooking Oil (UCO)Fuel produced in Seattle, Washington and transported by rail to California (Provisional)	None	Retired
T1N-1476	Tier 1	2.0	Fuel Producer: Copersucar (3702); Facility Name: Usina Barra Grande de Lençóis S.A. (70412); Brazilian sugarcane juice-to-ethanol, with credit for mechanized harvesting	Brazil	Sugarcane	Ethanol	None	None	ETHS250	47.71	3/13/2018	None	Ethanol	Copersucar (3702)	Usina Barra Grande de Lençóis SA (70412)	Brazilian sugarcane juicetoethanol, with credit for mechanized harvesting	None	Retired
T1N-1761	Tier 1	2.0	Fuel Producer: Dakota Spirit AgEnergy (6286) Facility Name: Dakota Spirit AgEnergy (71202): Corn Ethanol, Dry Mill, Midwest, Steam, NG	North Dakota	Corn	Ethanol	None	None	ETHC288	69.47	7/5/2017	None	Ethanol	Dakota Spirit AgEnergy (6286)	Dakota Spirit AgEnergy (71202)	Corn Ethanol, Dry Mill, Midwest, Steam, NG	None	Retired
T1N-1210	Tier 1	2.0	Fuel Producer: Raízen Energia S/A (3805) Facility Name: Gasa (70551). Brazilian sugarcane juice-to-ethanol pathway, with credit for surplus cogenerated electricity export and mechanized harvesting.	Brazil	Sugarcane	Ethanol	None	None	ETHS221	46.07	12/20/2016	None	Ethanol	Raízen Energia S/A (3805)	Gasa (70551)	Brazilian sugarcane juicetoethanol pathway, with credit for surplus cogenerated electricity export and mechanized harvesting	None	Retired
T1N-1382	Tier 1	2.0	Neste Singapore Pte Ltd (4137) Facility Name: Neste Singapore (80327). Global high Energy Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore	Singapore	Tallow	Renewable Diesel	None	None	RDT202	39.06	7/1/2016	None	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Global high Energy Rendered Tallow to Renewable Diesel; Fuel Produced in Singapore	None	Retired
T2N-1012	Tier 2	2.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066) (provisional); Tier 2 Method 2B Pathway: Uncooked Used Cooking Oil (UCO), Biodiesel produced in Coachella, California and transported by truck to locations in California (Provisional)	California	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU240	19.00	3/29/2018	Application Package	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Tier 2 Method 2B Pathway Uncooked Used Cooking Oil (UCO), Biodiesel produced in Coachella, California and transported by truck to locations in California (Provisional)	None	Retired
T2N-1229	Tier 2	2.0	Fuel Producer: SeQuential Pacific Biodiesel LLC (6129) ; Facility Name: SeQuential-Pacific Biodiesel, LLC. (83525); Tier 2 Method 2B Pathway: Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO). Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California (Provisional)	Oregon	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU241	18.43	3/29/2018	Application Package	Biodiesel	SeQuential Pacific Biodiesel LLC (6129)	SeQuentialPacific Biodiesel, LLC(83525)	Tier 2 Method 2B Pathway Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO)Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California (Provisional)	None	Retired
T1N-1768	Tier 1	2.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Rendered Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California	Illinois	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU242	21.84	4/2/2018	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Rendered Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California	None	Retired

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T1N-1770	Tier 1	2.0	Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: REG Seneca, LLC (80232); U.S. sourced rendered Tallow; Biodiesel Produced in Seneca, Illinois and transported by rail to California	Illinois	Tallow & Animal Fat	Biodiesel	None	None	BDT219	35.79	4/2/2018	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	US sourced rendered Tallow; Biodiesel Produced in Seneca, Illinois and transported by rail to California	None	Retired
T2N-1242	Tier 2	2.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953) ; Facility Name: Dansuk Industrial Co., Ltd (81302); Tier 2 Method 2B Pathway: Rendered Used Cooking Oil (UCO), Biodiesel produced in Shiheung-City, South Korea and transported by ocean tanker to California	South Korea	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU243	27.00	4/9/2018	Application Package	Biodiesel	Dansuk Industrial Co Ltd (5953)	Dansuk Industrial Co Ltd (81302)	Tier 2 Method 2B Pathway Rendered Used Cooking Oil (UCO), Biodiesel produced in ShiheungCity, South Korea and transported by ocean tanker to California	None	Retired
T1N-1621	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: CERF Shelby LLC (71163) (Provisional); North Shelby landfill gas (TN) to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	Tennessee	Landfill Gas	CNG	CNGLF250	54.87	CNGLF250R	55.00	4/25/2018	None	Bio-CNG	Clean Energy (5481)	CERF Shelby LLC (71163)(Provisional)	North Shelby landfill gas (TN)to pipelinequality biomethane; delivered via pipeline to CNG Stations in California	None	Retired
T1N-1624	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: CERF Shelby LLC (71163); North Shelby landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona	California	Landfill Gas	LNG	LNGLF220	62.18	LNGLF220R	62.30	4/25/2018	None	Bio-LNG	Clean Energy (5481)	CERF Shelby LLC (71163)	North Shelby landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; liquefied to LNG in Arizona	None	Retired
T1N-1625	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: CERF Shelby LLC (71163) (Provisional); North Shelby landfill gas to pipeline-quality biomethane; delivered via pipeline to Clean Energy Ehrenberg; re-gasified in California	California	Landfill Gas - L-CNG	CNG	CNGLF253	64.71	CNGLF253R	64.85	4/25/2018	None	Bio-CNG	Clean Energy (5481)	CERF Shelby LLC (71163)(Provisional)	North Shelby landfill gas to pipelinequality biomethane; delivered via pipeline to Clean Energy Ehrenberg; regasified in California	None	Retired
T1N-1812	Tier 1	2.0	Fuel Producer: Victor Valley Transit Authority (V056) ; Facility Name: River Birch Landfill (R7407); River Birch landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Texas	Landfill Gas	CNG	CNGLF269	40.73	CNGLF269R	44.33	2/6/2019	None	Bio-CNG	Victor Valley Transit Authority (V056)	River Birch Landfill (R7407)	River Birch landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T2N-1250	Tier 2	2.0	Fuel Producer: Apple (A449) ; Facility Name: VP02 (V8866); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity for 26 dual head ChargePoint electric vehicle charging stations (Provisional)	California	Solar or Wind	Electricity	None	None	ELCR201	0.00	5/4/2018	Application Package	Electricity	Apple (A449)	VP02 (V8866)	Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity for 26 dual head ChargePoint electric vehicle charging stations (Provisional)	None	Retired
T2N-1251	Tier 2	2.0	Fuel Producer: Apple (A449) ; Facility Name: HS01 (H3518); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity for seven dual head ChargePoint electric vehicle charging stations (Provisional)	California	Solar or Wind	Electricity	None	None	ELCR202	0.00	5/4/2018	Application Package	Electricity	Apple (A449)	HS01 (H3518)	Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity for seven dual head ChargePoint electric vehicle charging stations (Provisional)	None	Retired
T1N-1822	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154) ; Facility Name: Pine Hill Renewables, LLC (71288); Pine Hill landfill gas in Kilgore, TX to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Texas	Landfill Gas	CNG	None	None	CNGLF272	39.83	6/7/2018	None	Bio-CNG	Shell Energy North America (6154)	Pine Hill Renewables, LLC (71288)	Pine Hill landfill gas in Kilgore, TX to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T2N-1236	Tier 2	2.0	Fuel Producer: Adkins Energy LLC (4767) ; Facility Name: Adkins Energy, LLC (70070); Tier 2 Method 2B Pathway: Midwest sourced corn oil, Biodiesel produced in Lena, Illinois and transported by rail to California (Provisional)	Illinois	Corn Oil	Biodiesel	None	None	BDC214	37.31	6/15/2018	Application Package	Biodiesel	Adkins Energy LLC (4767)	Adkins Energy, LLC (70070)	Tier 2 Method 2B Pathway Midwest sourced corn oil, Biodiesel produced in Lena, Illinois and transported by rail to California (Provisional)	None	Retired
T2N-1232	Tier 2	2.0	Fuel Producer: ASB Biodiesel Hong Kong (6347) ; Facility Name: ASB Biodiesel Hong Kong (83359); Tier 2 Method 2B Pathway: Rendered Waste Oils and Greases, Biodiesel produced in Hong Kong and transported by ocean tanker to California	Hong Kong	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU245	27.80	6/21/2018	Application Package	Biodiesel	ASB Biodiesel Hong Kong (6347)	ASB Biodiesel Hong Kong (83359)	Tier 2 Method 2B Pathway Rendered Waste Oils and Greases, Biodiesel produced in Hong Kong and transported by ocean tanker to California	None	Retired
T2N-1202	Tier 2	2.0	Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: REG Seneca, LLC (80232); Tier 2 Method 2B Pathway: Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in Seneca, Illinois and transported by rail to California	Illinois	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU244	16.57	6/21/2018	Application Package	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Tier 2 Method 2B Pathway Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in Seneca, Illinois and transported by rail to California	None	Retired

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T2N-1257	Tier 2	2.0	Fuel Producer: Albertsons Companies, Inc. (A505) ; Facility Name: Safeway Tracy Distribution Center (17814); Tier 2 Method 2B Pathway: Wind electricity for charging electric forklifts in Tracy, California (Provisional)	California	Solar or Wind	Electricity	None	None	ELCR203	0.00	6/21/2018	Application Package	Electricity	Albertsons Companies, Inc (A505)	Safeway Tracy Distribution Center (17814)	Tier 2 Method 2B Pathway Wind electricity for charging electric forklifts in Tracy, California (Provisional)	None	Retired
T2N-1189	Tier 2	2.0	Fuel Producer: Linde LLC (L012); Facility Name: Linde Canada LH2 Plant (R1980); Tier 2 Method 2B Pathway: Compressed Hydrogen from co-product hydrogen produced at a sodium chlorate plant (includes liquefaction and regasification steps) and transported by truck to fueling stations in California (Provisional)	Canada	Sodium Chlorate Production Process	Hydrogen	None	None	HYGSC200	56.06	6/26/2018	Application Package	Hydrogen	Linde LLC (L012)	Linde Canada LH2 Plant (R1980)	Tier 2 Method 2B Pathway Compressed Hydrogen from coproduct hydrogen produced at a sodium chlorate plant (includes liquefaction and regasification steps)and transported by truck to fueling stations in California (Provisional)	None	Retired
T1N-1809	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Shade (71134); JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Pennsylvania	Landfill Gas	CNG	None	None	CNGLF273	49.77	6/27/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy Shade (71134)	JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1781	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Southern Alleghenies (PA) landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Pennsylvania	Landfill Gas	CNG	None	None	CNGLF274	58.84	6/27/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy Southern Alleghenies (71133)	Southern Alleghenies (PA)landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1831	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Raeger (71131); Laurel Highlands (PA) landfill gas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Pennsylvania	Landfill Gas	CNG	None	None	CNGLF275	42.86	6/27/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy Raeger (71131)	Laurel Highlands (PA)landfill gas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T2N-1243	Tier 2	2.0	Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: REG Seneca, LLC (80232); Tier 2 Method 2B Pathway: U.S. sourced Brown/Trap Grease as Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California	Illinois	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU246	23.18	7/27/2018	Application Package	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Tier 2 Method 2B Pathway US sourced Brown/Trap Grease as Used Cooking Oil (UCO), Biodiesel produced in Seneca, Illinois and transported by rail to California	None	Retired
T2N-1247	Tier 2	2.0	Fuel Producer: Southwest Iowa Renewable Energy (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Tier 2 Method 2B Pathway: Midwest, dry mill, corn ethanol produced using coal-derived steam and natural gas for process heat in Council Bluffs, Iowa and transported by rail to California	Iowa	Corn	Ethanol	None	None	ETHC298	79.79	8/2/2018	Application Package	Ethanol	Southwest Iowa Renewable Energy (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Tier 2 Method 2B Pathway Midwest, dry mill, corn ethanol produced using coalderived steam and natural gas for process heat in Council Bluffs, Iowa and transported by rail to California	None	Retired
T1N-1835	Tier 1	2.0	Fuel Producer: Ag Processing Inc (4552) ; Facility Name: AGP Methyl Ester (St Joseph) (81732); Biodiesel produced from Soybean Oil (self-extraction) in St. Joseph, Missouri and transported by rail to California.	Missouri	Soybean Oil	Biodiesel	None	None	BDS213	50.48	8/27/2018	None	Biodiesel	Ag Processing Inc (4552)	AGP Methyl Ester (St Joseph)(81732)	Biodiesel produced from Soybean Oil (selfextraction)in St Joseph, Missouri and transported by rail to California	None	Retired
T1N-1855	Tier 1	2.0	Fuel Producer: Ag Processing Inc (4552) ; Facility Name: Ag Processing Inc - Sgt. Bluff (81733); Biodiesel produced from Soybean Oil in Sergeant Bluff, Iowa (self-extraction) and transported by rail to California.	Iowa	Soybean Oil	Biodiesel	None	None	BDS214	50.03	8/27/2018	None	Biodiesel	Ag Processing Inc (4552)	Ag Processing Inc Sgt Bluff (81733)	Biodiesel produced from Soybean Oil in Sergeant Bluff, Iowa (selfextraction)and transported by rail to California	None	Retired
T2N-1249	Tier 2	2.0	Fuel Producer: Thumb BioEnergy (3862) ; Facility Name: Thumb BioEnergy (03862); Tier 2 Method 2B Pathway: Locally sourced, Self-Rendered Used Cooking Oil. Biodiesel produced in Sandusky, MI and transported by rail to California	Michigan	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU248	20.90	9/20/2018	Application Package	Biodiesel	Thumb BioEnergy (3862)	Thumb BioEnergy (03862)	Tier 2 Method 2B Pathway Locally sourced, SelfRendered Used Cooking Oil;Biodiesel produced in Sandusky, MI and transported by rail to California	None	Retired
T1N-1851	Tier 1	2.0	Fuel Producer: Solfuels USA LLC (S357) ; Facility Name: Solfuels USA LLC (82892); Biodiesel produced from Soybean Oil in Helena, Arkansas; Soybean extracted in the Midwest; Fuel transported by rail to California (Provisional)	Arkansas	Soybean Oil	Biodiesel	None	None	BDS215	55.10	9/20/2018	None	Biodiesel	Solfuels USA LLC (S357)	Solfuels USA LLC (82892)	Biodiesel produced from Soybean Oil in Helena, Arkansas; Soybean extracted in the Midwest; Fuel transported by rail to California (Provisional)	None	Retired
T1N-1861	Tier 1	2.0	Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); U.S. sourced rendered Tallow; Biodiesel Produced in Danville, Illinois and transported by rail to California (Provisional)	Illinois	Tallow & Animal Fat	Biodiesel	None	None	BDT220	36.80	9/20/2018	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	US sourced rendered Tallow; Biodiesel Produced in Danville, Illinois and transported by rail to California (Provisional)	None	Retired

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T1N-1862	Tier 1	2.0	Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); Rendered Used Cooking Oil (UCO), Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional)	Illinois	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU249	22.58	9/20/2018	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Rendered Used Cooking Oil (UCO), Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional)	None	Retired
T1N-1860	Tier 1	2.0	Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); U.S. sourced corn oil, Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional)	Illinois	Corn Oil	Biodiesel	None	None	BDC215	35.13	9/20/2018	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	US sourced corn oil, Biodiesel produced in Danville, Illinois and transported by rail to California (Provisional)	None	Retired
T1N-1864	Tier 1	2.0	Fuel Producer: Shell Energy North America (6154) ; Facility Name: Melissa Renewables, LLC (71407); Melissa landfill gas in Melissa, TX to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Texas	Landfill Gas	Compressed Natural Gas	None	None	CNGLF276	40.63	9/24/2018	None	Bio-CNG	Shell Energy North America (6154)	Melissa Renewables, LLC (71407)	Melissa landfill gas in Melissa, TX to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1811	Tier 1	2.0	Fuel Producer: Fuel Producer: San Diego Metropolitan Transit Center (S304) ; Facility Name: Facility Name: EBI Energie In (71254); EBI landfill gas in Saint-Thomas, Quebec to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	California	Landfill Gas	CNG	None	None	CNGLF277	32.28	10/3/2018	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	EBI Energie In (71254)	EBI landfill gas in SaintThomas, Quebec to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1863	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Charleston Landfill Gas Processing Facility (71314); Landfill gas in Charleston, West Virginia to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	West Virginia	Landfill Gas	CNG	None	None	CNGLF278	66.55	10/9/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Charleston Landfill Gas Processing Facility (71314)	Landfill gas in Charleston, West Virginia to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T1N-1832	Tier 1	2.0	Fuel Producer: Imperial Western Products (9871) ; Facility Name: Imperial Western Products (81066); U.S. sourced rendered Tallow; Biodiesel produced in Coachella, California (Provisional)	California	Tallow & Animal Fat	Biodiesel	None	None	BDT221	38.36	10/15/2018	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	US sourced rendered Tallow; Biodiesel produced in Coachella, California (Provisional)	None	Retired
T2N-1275	Tier 2	2.0	Fuel Producer: REG Danville, LLC (3723) ; Facility Name: REG Danville, LLC (80216); Tier 2 Method 2B Pathway: Biodiesel produced from U.S. sourced Non-Rendered Used Cooking Oil (UCO), Fuel produced in Danville, Illinois and transported by rail to California (Provisional)	Illinois	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU250	17.33	10/23/2018	Application Package	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Tier 2 Method 2B Pathway Biodiesel produced from US sourced NonRendered Used Cooking Oil (UCO), Fuel produced in Danville, Illinois and transported by rail to California (Provisional)	None	Retired
T1N-1837	Tier 1	2.0	Fuel Producer: POET Biorefining - Big Stone (4736) ; Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill, Wet, Modified, Dry DGS, and corn oil using natural gas, coal, and electricity; Starch ethanol produced from Corn using BPX process in Big Stone, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn	Ethanol	None	None	ETHC306	81.86	12/4/2018	None	Ethanol	POET Biorefining Big Stone (4736)	POET Biorefining Big Stone (70025)	Midwest Corn, Dry Mill, Wet, Modified, Dry DGS, and corn oil using natural gas, coal, and electricity; Starch ethanol produced from Corn using BPX process in Big Stone, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1259	Tier 2	2.0	Fuel Producer: POET Biorefining - Big Stone (4736) ; Facility Name: POET Biorefining - Big Stone (70025); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Big Stone, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS, and corn oil using natural gas, coal, and electricity; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Kernel Fiber	Ethanol	None	None	ETHCF206	38.58	12/4/2018	Application Package	Ethanol - Cellulosic	POET Biorefining Big Stone (4736)	POET Biorefining Big Stone (70025)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Big Stone, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS, and corn oil using natural gas, coal, and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1268	Tier 2	2.0	Fuel Producer: Powerflex (P343) ; Facility Name: Mountain View HS (50381); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity directly supplied to Electric Vehicle charging at Mountain View High School, California	California	Solar or Wind	Electricity	None	None	ELCR205	0.00	12/11/2018	Application Package	Electricity	Powerflex (P343)	Mountain View HS (50381)	Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity directly supplied to Electric Vehicle charging at Mountain View High School, California	None	Retired
T2N-1269	Tier 2	2.0	Fuel Producer: Powerflex (P343) ; Facility Name: Los Altos HS (45044); Tier 2 Method 2B Pathway: Solar-based (Photovoltaic) Electricity directly supplied to Electric Vehicle charging at Los Altos High School, California	California	Solar or Wind	Electricity	None	None	ELCR204	0.00	12/11/2018	Application Package	Electricity	Powerflex (P343)	Los Altos HS (45044)	Tier 2 Method 2B Pathway Solarbased (Photovoltaic)Electricity directly supplied to Electric Vehicle charging at Los Altos High School, California	None	Retired
T2N-1278	Tier 2	2.0	Fuel Producer: Pinal Energy LLC (4744); Facility Name: Pinal Energy LLC (70136); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Maricopa, Arizona; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Dry DGS; Corn Oil, Syrup; Ethanol transported by truck to California (Provisional)	Arizona	Corn	Ethanol	None	None	ETHC312	38.06	12/18/2018	Application Package	Ethanol	Pinal Energy LLC (4744)	Pinal Energy LLC (70136)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Maricopa, Arizona; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Dry DGS; Corn Oil, Syrup; Ethanol transported by truck to California (Provisional)	None	Retired

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T2N-1248	Tier 2	2.0	Fuel Producer: California Renewable Power LLC (CARP) (C196) ; Facility Name: California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270); Tier 2 Method 2B Pathway; Biogas produced from the anaerobic digestion of 100% green waste in Perris, California, upgraded to biomethane onsite, injected into pipeline, and compressed to transportation fuel in California (Provisional)	California	HSAD Food & Green Waste	CNG	None	None	CNGGW201	0.34	12/20/2018	Application Package	Bio-CNG	California Renewable Power LLC (CARP) (C196)	California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270)	Tier 2 Method 2B Pathway; Biogas produced from the anaerobic digestion of 100% green waste in Perris, California, upgraded to biomethane onsite, injected into pipeline, and compressed to transportation fuel in California (Provisional)	None	Retired
T1N-1865	Tier 1	2.0	Fuel Producer: W2Fuels (LVA Adrian Biofuel LLC) (3251) ; Facility Name: W2Fuels (LVA Adrian Biofuel LLC dba W2Fuel Adrian) (81095); Biodiesel produced from Soybean Oil in Adrian, Michigan and transported by rail to California (Provisional)	Michigan	Soybean Oil	Biodiesel	None	None	BDS216	55.74	12/21/2018	None	Biodiesel	W2Fuels (LVA Adrian Biofuel LLC)(3251)	W2Fuels (LVA Adrian Biofuel LLC dba W2Fuel Adrian)(81095)	Biodiesel produced from Soybean Oil in Adrian, Michigan and transported by rail to California (Provisional)	None	Retired
T1N-1883	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Cambrian Energy (C5950S); Landfill gas from Fort Smith, Arkansas to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Arkansas	Landfill Gas	CNG	None	None	CNGLF279	44.51	12/31/2018	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Cambrian Energy (C5950S)	Landfill gas from Fort Smith, Arkansas to pipelinequality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
T2N-1239	Tier 2	2.0	Fuel Producer: Neste Renewable Fuels Oy (3734) ; Facility Name: Neste Renewable Fuels - Porvoo (80272); Tier 2 Method 2B Pathway: Renewable Diesel produced from Globally Sourced Tallow, Fuel produced in Neste Porvoo Plant and transported by ocean tanker to California	Finland	Tallow & Animal Fat	Renewable Diesel	None	None	RDT208	45.08	1/16/2019	Application Package	Renewable Diesel	Neste Renewable Fuels Oy (3734)	Neste Renewable Fuels Porvoo (80272)	Tier 2 Method 2B Pathway Renewable Diesel produced from Globally Sourced Tallow, Fuel produced in Neste Porvoo Plant and transported by ocean tanker to California	None	Retired
T2N-1264	Tier 2	2.0	Fuel Producer: Neste Renewable Fuels Oy (3734) ; Facility Name: Neste Renewable Fuels - Porvoo (80272); Tier 2 Method 2B Pathway: Renewable Diesel produced from Globally Sourced Tallow. Shipped to Sluiskil Pre-treatment site. Fuel produced in Neste Porvoo Plant and transported to California (Provisional)	Finland	Tallow & Animal Fat	Renewable Diesel	None	None	RDT207	51.90	1/16/2019	Application Package	Renewable Diesel	Neste Renewable Fuels Oy (3734)	Neste Renewable Fuels Porvoo (80272)	Tier 2 Method 2B Pathway Renewable Diesel produced from Globally Sourced Tallow Shipped to Sluiskil Pretreatment site; Fuel produced in Neste Porvoo Plant and transported to California (Provisional)	None	Retired
T2N-1289	Tier 2	2.0	Fuel Producer: Neste Renewable Fuels Oy (3734) ; Facility Name: Neste Renewable Fuels - Porvoo (80272); Tier 2 Method 2B Pathway: Renewable Diesel produced from Globally Sourced UCO, Fuel produced in Neste Finland Plant and transported by ocean tanker to California (Provisional)	Finland	Used Cooking Oil (UCO)	Renewable Diesel	None	None	RDU205	30.97	1/16/2019	Application Package	Renewable Diesel	Neste Renewable Fuels Oy (3734)	Neste Renewable Fuels Porvoo (80272)	Tier 2 Method 2B Pathway Renewable Diesel produced from Globally Sourced UCO, Fuel produced in Neste Finland Plant and transported by ocean tanker to California (Provisional)	None	Retired
T2N-1246	Tier 2	2.0	Fuel Producer: Eco Solutions Co., Ltd (6266) ; Facility Name: Eco Solutions Co., Ltd (83159); Tier 2 Method 2B Pathway: Rendered Used Cooking Oil (UCO) sourced in South Korea, Biodiesel produced in Jeongeup-si, South Korea using bottom distillates as thermal energy, and transported by ocean tanker to California (Provisional)	South Korea	Used Cooking Oil (UCO)	Biodiesel	None	None	BDU251	22.31	3/18/2019	Application Package	Biodiesel	Eco Solutions Co Ltd (6266)	Eco Solutions Co Ltd (83159)	Tier 2 Method 2B Pathway Rendered Used Cooking Oil (UCO)sourced in South Korea, Biodiesel produced in Jeongeupsi, South Korea using bottom distillates as thermal energy, and transported by ocean tanker to California (Provisional)	None	Retired
B001101	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to Los Angeles, California (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B00110100	-372.35	4/10/2019	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ruckman Farm (71256)	Renewable Natural Gas (RNG)sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to Los Angeles, California (Provisional)	None	Retired
B001102	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	Missouri	Swine Manure (044)	Liquefied Natural Gas (LNG)	None	None	LNG044B00110200	-360.37	4/10/2019	Application Package	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Ruckman Farm (71256)	Renewable Natural Gas (RNG)sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	None	Retired
B001103	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to and re-gasified in California (Provisional)	Missouri	Swine Manure (044)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN044B00110300	-356.83	4/10/2019	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ruckman Farm (71256)	Renewable Natural Gas (RNG)sourced from Swine Manure of Ruckman Farms, Albany, Missouri; RNG pipelined to liquefaction facility in Topock, Arizona; delivered by truck to and regasified in California (Provisional)	None	Retired
A003301	Tier 1	3.0	Fuel Producer: CORN, LP (5065) ; Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill, Dry DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Goldfield, Iowa; Ethanol transported by rail to California **(Provisional)**	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00330100	70.34	4/15/2019	None	Ethanol	CORN, LP (5065)	CORN, LP (70145)	Midwest Corn, Dry Mill, Dry DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Goldfield, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A001701	Tier 1	3.0	Fuel Producer: Husker Ag LLC (5078) ; Facility Name: Husker Ag LLC (70151); Midwest Corn Starch Ethanol, Dry and Modified DGS, Natural Gas	Nebraska	Corn (009)	Ethanol (ETH)	ETHC295	74.03	ETH009A00170100	66.19	4/15/2019	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn Starch Ethanol, Dry and Modified DGS, Natural Gas	None	Retired

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A004301	Tier 1	3.0	Fuel Producer: Kansas Ethanol, LLC (5810); Facility Name: Kansas Ethanol, LLC (70279); Dry Mill Ethanol, using both Corn and Sorghum, Natural Gas, Grid Electricity, DDGS and wetcake **(Provisional)**	Kansas	Corn (009)	Ethanol (ETH)	ETHC299	67.83	ETH009A00430100	62.79	4/15/2019	None	Ethanol	Kansas Ethanol, LLC (5810)	Kansas Ethanol, LLC (70279)	Dry Mill Ethanol, using both Corn and Sorghum, Natural Gas, Grid Electricity, DDGS and wetcake (Provisional)	None	Retired
A006801	Tier 1	3.0	Fuel Producer: Kansas Ethanol, LLC (5810) ; Facility Name: Kansas Ethanol, LLC (70279); Midwest Sorghum, Dry Mill, Dry and Wet DGS, and Sorghum Oil; Natural Gas and grid electricity; Sorghum starch Ethanol produced in Lyons, Kansas and transported by rail to California (Provisional)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A00680100	67.59	4/15/2019	None	Ethanol	Kansas Ethanol, LLC (5810)	Kansas Ethanol, LLC (70279)	Midwest Sorghum, Dry Mill, Dry and Wet DGS, and Sorghum Oil; Natural Gas and grid electricity; Sorghum starch Ethanol produced in Lyons, Kansas and transported by rail to California (Provisional)	None	Retired
A006901	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754) ; Facility Name: Trenton Agri Products, LLC (70053; Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Trenton, Nebraska and transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC210	69.75	ETH009A00690100	65.13	4/16/2019	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053	Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Trenton, Nebraska and transported by rail to California	None	Retired
A008601	Tier 1	3.0	Fuel Producer: Bridgeport Ethanol, LLC 5934; Facility Name: Bridgeport Ethanol, LLC 70217; Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC229	67.43	ETH009A00860100	62.37	4/16/2019	None	Ethanol	Bridgeport Ethanol, LLC 5934;	Bridgeport Ethanol, LLC (70217)	Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California	None	Retired
A000701	Tier 1	3.0	Fuel Producer: Great Plains Ethanol (4727) ; Facility Name: Great Plains Ethanol, LLC (70012); Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC300	69.04	ETH009A00070100	65.21	5/6/2019	None	Ethanol	Great Plains Ethanol (4727)	Great Plains Ethanol, LLC (70012)	Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California	None	Retired
A000702	Tier 1	3.0	Fuel Producer: Great Plains Ethanol (4727) ; Facility Name: Great Plains Ethanol, LLC (70012); Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETHCF203	27.69	ETH012A00070200	25.06	5/6/2019	None	Ethanol - Cellulosic	Great Plains Ethanol (4727)	Great Plains Ethanol, LLC (70012)	Midwest Corn, Dry Mill, Dry, Modified, and Wet DGS; Corn Oil and Syrup using biomass, biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Chancellor, SD using BPX conversion method; Ethanol transported by rail to California	None	Retired
A003401	Tier 1	3.0	Fuel Producer: Siouxland Ethanol, LLC (5026) ; Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC343	69.28	ETH009A00340100	66.23	5/6/2019	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A003402	Tier 1	3.0	Fuel Producer: Siouxland Ethanol, LLC (5026) ; Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00340200	26.67	5/6/2019	None	Ethanol - Cellulosic	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using biogas, natural gas and grid electricity; Corn starch and Fiber ethanol produced in Jackson, NE using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A003601	Tier 1	3.0	Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC313	71.98	ETH009A00360100	67.09	5/6/2019	None	Ethanol	Mid America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A003602	Tier 1	3.0	Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETHC311	38.12	ETH012A00360200	32.40	5/6/2019	None	Ethanol - Cellulosic	Mid America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Madrid, Nebraska using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A003701	Tier 1	3.0	Fuel Producer: E Energy Adams, LLC (4831) ; Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Adams, Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC310	70.76	ETH009A00370100	66.53	3/29/2019	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Adams, Nebraska; Ethanol transported by rail to California (Provisional)	None	Retired
A004101	Tier 1	3.0	Fuel Producer: Marquis Energy - Wisconsin LLC (5750) ; Facility Name: Marquis Energy - Wisconsin LLC (70269); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Necedah, Wisconsin; Ethanol transported by rail to California	Wisconsin	Corn (009)	Ethanol (ETH)	None	None	ETH009A00410100	72.25	5/7/2019	None	Ethanol	Marquis Energy Wisconsin LLC (5750)	Marquis Energy Wisconsin LLC (70269)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Necedah, Wisconsin; Ethanol transported by rail to California	None	Retired

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A004601	Tier 1	3.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Madera LLC (70061); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas, on-site solar power, and grid electricity; Corn starch ethanol produced in Madera, California; Ethanol transported by rail to California (Provisional)	California	Corn (009)	Ethanol (ETH)	ETHC207R	72.94	ETH009A00460100	66.76	3/29/2019	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Madera LLC (70061)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas, onsite solar power, and grid electricity; Corn starch ethanol produced in Madera, California; Ethanol transported by rail to California (Provisional)	None	Retired
A005101	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00510100	69.86	5/7/2019	None	Ethanol	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005102	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00510200	30.32	5/7/2019	None	Ethanol - Cellulosic	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005301	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786); Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00530100	73.81	5/6/2019	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A005302	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00530200	66.94	5/6/2019	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A005303	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00530300	26.95	5/6/2019	None	Ethanol - Cellulosic	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A005201	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00520100	75.97	5/6/2019	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005202	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00520200	68.75	5/6/2019	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005203	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00520300	28.78	5/6/2019	None	Ethanol - Cellulosic	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005701	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782) ; Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00570100	76.25	5/6/2019	None	Ethanol	POET Biorefining Ashton (4782)	POET BIOREFINING ASHTON (OTTER CREEK ETHANOL, LLC)(70032)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005702	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782) ; Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00570200	67.07	5/6/2019	None	Ethanol	POET Biorefining Ashton (4782)	POET BIOREFINING ASHTON (OTTER CREEK ETHANOL, LLC)(70032)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005703	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782) ; Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00570300	28.39	5/6/2019	None	Ethanol - Cellulosic	POET Biorefining Ashton (4782)	POET BIOREFINING ASHTON (OTTER CREEK ETHANOL, LLC)(70032)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Ashton, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired

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A005801	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A00580100	81.17	5/7/2019	None	Ethanol	POET Biorefining Bingham Lake (4780)	POET BIOREFINING BINGHAM LAKE (ETHANOL 2000, LLP)(70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005802	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A00580200	71.82	5/7/2019	None	Ethanol	POET Biorefining Bingham Lake (4780)	POET BIOREFINING BINGHAM LAKE (ETHANOL 2000, LLP)(70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005803	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00580300	31.75	5/7/2019	None	Ethanol - Cellulosic	POET Biorefining Bingham Lake (4780)	POET BIOREFINING BINGHAM LAKE (ETHANOL 2000, LLP)(70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006201	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC307	79.20	ETH009A00620100	75.24	5/7/2019	None	Ethanol	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006202	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789) ; Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC307	79.20	ETH009A00620200	67.72	5/7/2019	None	Ethanol	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006203	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETHCF207	35.67	ETH012A00620300	27.36	5/7/2019	None	Ethanol - Cellulosic	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006301	Tier 1	3.0	Fuel Producer: POET Biorefining - Groton (4793); Facility Name: POET Biorefining - Groton (70013); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC308	78.56	ETH009A00630100	75.15	5/7/2019	None	Ethanol	POET Biorefining Groton (4793)	POET Biorefining Groton (70013)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006302	Tier 1	3.0	Fuel Producer: POET Biorefining - Groton (4793) ; Facility Name: POET Biorefining - Groton (70013); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC308	78.56	ETH009A00630200	67.60	5/7/2019	None	Ethanol	POET Biorefining Groton (4793)	POET Biorefining Groton (70013)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006303	Tier 1	3.0	Fuel Producer: POET Biorefining - Groton (4793) ; Facility Name: POET Biorefining - Groton (70013); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETHCF208	34.79	ETH012A00630300	27.48	5/7/2019	None	Ethanol - Cellulosic	POET Biorefining Groton (4793)	POET Biorefining Groton (70013)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Groton, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006401	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC309	78.06	ETH009A00640100	75.04	5/7/2019	Legacy CI is from a composite pathway containing both dry and wet DGS.	Ethanol	POET Biorefining Gowrie (4784)	POET Biorefining Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006402	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC309	78.06	ETH009A00640200	68.04	5/7/2019	Legacy CI is from a composite pathway containing both dry and wet DGS.	Ethanol	POET Biorefining Gowrie (4784)	POET Biorefining Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006403	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETHCF209	34.30	ETH012A00640300	27.72	5/7/2019	None	Ethanol - Cellulosic	POET Biorefining Gowrie (4784)	POET Biorefining Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A007401	Tier 1	3.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Stockton LLC (70319); Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	California	Corn (009)	Ethanol (ETH)	ETHC216	69.64	ETH009A00740100	65.77	3/29/2019	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	None	Retired
A007402	Tier 1	3.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Stockton LLC (70319); Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	California	Corn (009)	Ethanol (ETH)	ETHC217	65.36	ETH009A00740200	61.54	3/29/2019	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	None	Retired
A007403	Tier 1	3.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Stockton LLC (70319); Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	California	Corn Fiber (012)	Ethanol (ETH)	ETHCF202	39.45	ETH012A00740300	32.62	3/29/2019	None	Ethanol - Cellulosic	Pacific Ethanol West (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest and California Corn, Dry Mill, Dry and Wet DGS; Corn Oil, and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Stockton, California using Edeniq conversion method (Provisional)	None	Retired
A008801	Tier 1	3.0	Fuel Producer: Yuma Ethanol, LLC (4735) ; Facility Name: Yuma Ethanol, LLC (70024); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California	Colorado	Corn (009)	Ethanol (ETH)	ETHC228	67.68	ETH009A00880100	64.61	5/17/2019	None	Ethanol	Yuma Ethanol, LLC (4735)	Yuma Ethanol, LLC (70024)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California	None	Retired
A008901	Tier 1	3.0	Fuel Producer: Sterling Ethanol, LLC (4766) ; Facility Name: Sterling Ethanol, LLC (70660); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol produced in Sterling, Colorado; Ethanol transported by rail to California	Colorado	Corn (009)	Ethanol (ETH)	ETHC283	69.39	ETH009A00890100	64.10	5/17/2019	None	Ethanol	Sterling Ethanol, LLC (4766)	Sterling Ethanol, LLC (70660)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol produced in Sterling, Colorado; Ethanol transported by rail to California	None	Retired
A009901	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC303	78.68	ETH009A00990100	73.79	5/17/2019	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional)	None	Retired
A009902	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805) ; Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC302	66.74	ETH009A00990200	63.23	5/17/2019	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil using natural Gas and grid electricity; Corn starch Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California (Provisional)	None	Retired
A009401	Tier 1	3.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) ; Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas (cogen) and grid electricity; Corn starch Ethanol produced in Ceres, California (Provisional)	California	Corn (009)	Ethanol (ETH)	ETHC211	70.23	ETH009A00940100	67.03	5/21/2019	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural gas (cogen)and grid electricity; Corn starch Ethanol produced in Ceres, California (Provisional)	None	Retired
A005501	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779) ; Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A00550100	77.80	5/24/2019	None	Ethanol	POET Biorefining Glenville (4779)	POET BIOREFINING GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	None	Retired
A005502	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779) ; Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A00550200	69.57	5/24/2019	None	Ethanol	POET Biorefining Glenville (4779)	POET BIOREFINING GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	None	Retired
A005503	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779) ; Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00550300	29.51	5/24/2019	None	Ethanol - Cellulosic	POET Biorefining Glenville (4779)	POET BIOREFINING GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (Provisional)	None	Retired
A007801	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Shreveport Biogas (70121); Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to L-CNG in California (Provisional)	Louisiana	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A00780100	61.21	5/29/2019	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Shreveport Biogas (70121)	Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to LCNG in California (Provisional)	None	Retired

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A007802	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Shreveport Biogas (70121); Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to L-CNG in California (Provisional)	Louisiana	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A00780200	64.29	5/29/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Shreveport Biogas (70121)	Landfill gas from Shreveport, Louisiana to biomethane; pipelined to Applied Natural Gas Fuels facility for liquefaction in Topock, Arizona; transport by truck as LNG and regassified to LCNG in California (Provisional)	None	Retired
A009801	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805) ; Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Minden, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC225	67.10	ETH009A00980100	61.48	5/29/2019	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Minden, Nebraska; Ethanol transported by rail to California	None	Retired
A007201	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Shreveport Biogas (70121); Landfill gas from Shreveport, Louisiana to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Louisiana	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A00720100	40.37	5/29/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Shreveport Biogas (70121)	Landfill gas from Shreveport, Louisiana to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
A011001	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01100100	46.54	5/29/2019	None	Bio-CNG	U.S. Venture, Inc. (5504)	Ameresco Woodland Meadows Romulus, LLC (A0833)	Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	None	Retired
A011002	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	Michigan	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A01100200	63.69	5/29/2019	None	Bio-LNG	U.S. Venture, Inc. (5504)	Ameresco Woodland Meadows Romulus, LLC (A0833)	Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	None	Retired
A011003	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	Michigan	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A01100300	66.78	5/29/2019	None	Bio-CNG	U.S. Venture, Inc. (5504)	Ameresco Woodland Meadows Romulus, LLC (A0833)	Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (Provisional)	None	Retired
A008101	Tier 1	3.0	Fuel Producer: East Kansas Agri-Energy, LLC (4483) ; Facility Name: East Kansas Agri-Energy, LLC (83483); Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Garnett, Kansas and transported by truck and rail to California	Kansas	Corn (009)	Ethanol (ETH)	None	None	ETH009A00810100	67.53	5/30/2019	None	Ethanol	East Kansas Agri-Energy, LLC (4483)	East Kansas Agri-Energy, LLC (83483)	Midwest Corn, Dry Mill, Dry and Wet DGS, and Corn Oil; Natural Gas and grid electricity; Corn starch Ethanol produced in Garnett, Kansas and transported by truck and rail to California	None	Retired
A005001	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	Missouri	Corn (009)	Ethanol (ETH)	None	None	ETH009A00500100	70.67	6/3/2019	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	None	Retired
A005002	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	Missouri	Corn (009)	Ethanol (ETH)	None	None	ETH009A00500200	62.76	6/3/2019	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	None	Retired
A005003	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	Missouri	Corn (009)	Ethanol (ETH)	None	None	ETH012A00500300	23.18	6/3/2019	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (Provisional)	None	Retired
A009501	Tier 1	3.0	Fuel Producer: Clean Energy (5481); Facility Name: CEFARI RNG OKC, LLC (F00022); Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	Oklahoma	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A00950100	51.74	6/3/2019	None	Bio-CNG	Clean Energy (5481)	CEFARI RNG OKC, LLC (F00022)	Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (Provisional)	None	Retired
A006101	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC305	80.94	ETH009A00610100	76.85	6/5/2019	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006102	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETHC305	80.94	ETH009A00610200	69.76	6/5/2019	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired

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A006103	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETHCF205	36.92	ETH012A00610300	29.51	6/5/2019	None	Ethanol - Cellulosic	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A008303	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Distillers' Corn Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	Minnesota	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC211	33.52	BIO003A00830300	24.55	6/7/2019	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Distillers' Corn Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A008304	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A00830400	17.72	6/7/2019		Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A008305	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A00830500	11.99	6/7/2019		Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A008306	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	Minnesota	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT215	36.29	BIO002A00830600	28.89	6/7/2019	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A010002	Tier 1	3.0	Fuel Producer: The Andersons, Inc (5872); Facility Name: The Andersons Denison Ethanol (70135); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC275	76.35	ETH009A01000200	67.48	6/7/2019	None	Ethanol	The Andersons, Inc (5872)	The Andersons Denison Ethanol (70135)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	None	Retired
A005401	Tier 1	3.0	Fuel Producer: Poet Biorefining Corning (5046); Facility Name: Poet Biorefining Corning (70143); Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00540100	73.97	6/10/2019	None	Ethanol	Poet Biorefining Corning (5046)	Poet Biorefining Corning (70143)	Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005402	Tier 1	3.0	Fuel Producer: Poet Biorefining Corning (5046); Facility Name: Poet Biorefining Corning (70143); Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00540200	67.03	6/10/2019	None	Ethanol	Poet Biorefining Corning (5046)	Poet Biorefining Corning (70143)	Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005403	Tier 1	3.0	Fuel Producer: Poet Biorefining Corning (5046); Facility Name: Poet Biorefining Corning (70143); Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00540300	27.26	6/10/2019	None	Ethanol - Cellulosic	Poet Biorefining Corning (5046)	Poet Biorefining Corning (70143)	Midwest Corn, Dry Mill, Dry and Wet DGS, Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Corning, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005601	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00560100	74.83	6/10/2019	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005602	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A00560200	68.44	6/10/2019	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A005603	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A00560300	28.47	6/10/2019	None	Ethanol - Cellulosic	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired

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A006001	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC301	79.55	ETH009A00600100	73.99	6/10/2019	None	Ethanol	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006002	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC301	79.55	ETH009A00600200	66.22	6/10/2019	None	Ethanol	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A006003	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETHCF204	35.39	ETH012A00600300	26.08	6/10/2019	None	Ethanol - Cellulosic	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A010301	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC234L	67.73	ETH009A01030100	75.50	6/28/2019	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	None	Retired
A010305	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054) ; Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	None	None	ETH009A01030500	63.21	6/28/2019	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	None	Retired
A010306	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054) ; Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG003	73.39	ETH010A01030600	77.77	6/28/2019	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	None	Retired
A010307	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A01030700	65.48	6/28/2019	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn and Sorghum, Dry Mill, Dry and Wet DGS, Syrup, and Corn Oil; Natural Gas and grid electricity; Starch Ethanol produced in Garden City, Kansas and transported by rail to California	None	Retired
A010101	Tier 1	3.0	Fuel Producer: American Greenfuels, LLC (6341) ; Facility Name: AMERICAN GREENFUELS LLC (83357); New England sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in New Haven, Connecticut and transported by rail to California (Provisional)	Connecticut	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01010100	21.04	8/5/2019	None	Biodiesel	American Greenfuels, LLC (6341)	AMERICAN GREENFUELS LLC (83357)	New England sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in New Haven, Connecticut and transported by rail to California (Provisional)	None	Retired
A011201	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC315	72.14	ETH009A01120100	68.75	8/5/2019	None	Ethanol	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional)	None	Retired
A011202	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Marcus, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETHCF200R	44.19	ETH012A01120200	30.06	8/5/2019	None	Ethanol - Cellulosic	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Marcus, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A011203	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A01120300	65.90	8/5/2019	None	Ethanol	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Marcus, Iowa; Ethanol transported to California by rail (Provisional)	None	Retired
A012101	Tier 1	3.0	Fuel Producer: Golden Grain Energy, LLC (4829) ; Facility Name: Golden Grain Energy (70691); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC212	77.43	ETH009A01210100	73.76	8/5/2019	None	Ethanol	Golden Grain Energy, LLC (4829)	Golden Grain Energy (70691)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired

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A012102	Tier 1	3.0	Fuel Producer: Golden Grain Energy, LLC (4829); Facility Name: Golden Grain Energy (70691); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC213	73.86	ETH009A01210200	70.53	8/5/2019	None	Ethanol	Golden Grain Energy, LLC (4829)	Golden Grain Energy (70691)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Mason City, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A012103	Tier 1	3.0	Fuel Producer: Golden Grain Energy, LLC (4829); Facility Name: Golden Grain Energy (70691); Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Mason City, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01210300	29.09	8/5/2019	None	Ethanol - Cellulosic	Golden Grain Energy, LLC (4829)	Golden Grain Energy (70691)	Midwest Corn, Dry Mill; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Mason City, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A011801	Tier 1	3.0	Fuel Producer: Pacific Ethanol West (3697); Facility Name: Pacific Ethanol Magic Valley LLC (70291); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Burley, Idaho; Ethanol transported by rail to California	Idaho	Corn (009)	Ethanol (ETH)	ETHC251L	68.89	ETH009A01180100	66.44	8/6/2019	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Magic Valley LLC (70291)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Burley, Idaho; Ethanol transported by rail to California	None	Retired
A012502	Tier 1	3.0	Fuel Producer: Plymouth Energy LLC (5474); Facility Name: Plymouth Energy LLC (70183); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC286	75.94	ETH009A01250200	68.41	8/6/2019	None	Ethanol	Plymouth Energy LLC (5474)	Plymouth Energy LLC (70183)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California	None	Retired
A013701	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810) ; Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC208R	76.65	ETH009A01370100	72.86	8/5/2019	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	None	Retired
A013702	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC208R	76.65	ETH009A01370200	69.05	8/5/2019	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	None	Retired
A013703	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810) ; Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC208R	76.65	ETH009A01370300	65.76	8/5/2019	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Elecricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	None	Retired
A014501	Tier 1	3.0	Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC240L	74.00	ETH009A01450100	69.60	8/6/2019	None	Ethanol	Redfield Energy, LLC (4061)	Redfield Energy, LLC (70111)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California	None	Retired
A010201	Tier 1	3.0	Fuel Producer: Guardian Energy, LLC (3383); Facility Name: Guardian Energy, LLC (70289); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Janesville, Minnesota; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	ETHC289	75.43	ETH009A01020100	69.29	8/9/2019	None	Ethanol	Guardian Energy, LLC (3383)	Guardian Energy, LLC (70289)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Janesville, Minnesota; Ethanol transported by rail to California (Provisional)	None	Retired
A010202	Tier 1	3.0	Fuel Producer: Guardian Energy, LLC (3383); Facility Name: Guardian Energy, LLC (70289); Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Janesville, Minnesota using SOLITON conversion method; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01020200	26.35	8/9/2019	None	Ethanol - Cellulosic	Guardian Energy, LLC (3383)	Guardian Energy, LLC (70289)	Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Janesville, Minnesota using SOLITON conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A010901	Tier 1	3.0	Fuel Producer: SIMPLE FUELS BIODIESEL INC (3717) ; Facility Name: SIMPLE FUELS BIODIESEL (80207); U.S. sourced, Non-Rendered UCO; Biodiesel and Grid Electricity; Biodiesel produced in Chilcoot, CA; Biodiesel transported by truck to stations in California (Provisional)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01090100	14.73	9/24/2019	None	Biodiesel	SIMPLE FUELS BIODIESEL INC (3717)	SIMPLE FUELS BIODIESEL (80207)	U.S. sourced, Non-Rendered UCO; Biodiesel and Grid Electricity; Biodiesel produced in Chilcoot, CA; Biodiesel transported by truck to stations in California (Provisional)	None	Retired
A012001	Tier 1	3.0	Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC239L	70.04	ETH009A01200100	63.44	9/5/2019	None	Ethanol	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired

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A012002	Tier 1	3.0	Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Sioux Center, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETHCF201R	42.17	ETH012A01200200	45.82	9/5/2019	None	Ethanol - Cellulosic	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Midwest Corn, Dry Mill; Natural Gas and Grid Electricity; Fiber Ethanol produced in Sioux Center, Iowa using EDNIQ conversion method; Ethanol transported by rail to California (Provisional)	None	Retired
A012701	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01270100	28.33	9/24/2019	None	Ethanol - Cellulosic	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012702	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A01270200	75.89	9/24/2019	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012703	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A01270300	67.79	9/24/2019	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012801	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) ; Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A01280100	77.91	9/24/2019	None	Ethanol	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012802	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A01280200	67.99	9/24/2019	None	Ethanol	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012803	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794) ; Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01280300	28.29	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (Provisional)	None	Retired
A012901	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A01290100	74.62	9/24/2019	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Minnesota; Ethanol transported by rail to California (Provisional)	None	Retired
A012902	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A01290200	67.54	9/24/2019	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Minnesota; Ethanol transported by rail to California (Provisional)	None	Retired
A012903	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01290300	27.44	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Minnesota; Ethanol transported by rail to California (Provisional)	None	Retired
A013001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01300100	74.35	9/24/2019	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	None	Retired
A013002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01300200	67.34	9/24/2019	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	None	Retired

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A013003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01300300	27.54	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	None	Retired
A013601	Tier 1	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Live Oak Landfill Gas Plant (70002); Live Oak Landfill Gas plant landfill gas to pipelie-quality biomethane in Conley, GA; Deliverd via pipeline; Compressed to CNG in California (Provisional)	Georgia	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01360100	44.64	9/25/2019	None	Bio-CNG	Shell Energy North America (6154)	Live Oak Landfill Gas Plant (70002)	Live Oak Landfill Gas plant landfill gas to pipelie-quality biomethane in Conley, GA; Deliverd via pipeline; Compressed to CNG in California (Provisional)	None	Retired
A014101	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846); Facility Name: HPB - St. Joe Biodiesel LLC (80059); Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	Missouri	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC212	37.30	BIO003A01410100	29.40	9/25/2019	None	Biodiesel	High Plains Bioenergy (4846)	HPB - St. Joe Biodiesel LLC (80059)	Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	None	Retired
A014102	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846); Facility Name: HPB - St. Joe Biodiesel LLC (80059); Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	Missouri	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A01410200	34.21	9/25/2019	None	Biodiesel	High Plains Bioenergy (4846)	HPB - St. Joe Biodiesel LLC (80059)	Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	None	Retired
A013901	Tier 1	3.0	Fuel Producer: Midwest Renewable Energy (5214); Facility Name: Midwest Renewable Energy (70160); Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC279	69.83	ETH009A01390100	62.81	9/9/2019	None	Ethanol	Midwest Renewable Energy (5214)	Midwest Renewable Energy (70160)	Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California (Provisional)	None	Retired
A014001	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC297	69.11	ETH009A01400100	63.69	9/9/2019	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A014002	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715) ; Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC296	78.63	ETH009A01400200	72.42	9/9/2019	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A014003	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG219	76.92	ETH010A01400300	66.76	9/9/2019	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A014004	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG218	86.22	ETH010A01400400	75.50	9/9/2019	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A014601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	Michigan	Corn (009)	Ethanol (ETH)	None	None	ETH009A01460100	72.59	9/24/2019	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	None	Retired
A014602	Tier 1	3.0	Fuel Producer: Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	Michigan	Corn (009)	Ethanol (ETH)	None	None	ETH009A01460200	67.10	9/24/2019	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	None	Retired
A014603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	Michigan	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01460300	27.33	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	None	Retired

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A015501	Tier 1	3.0	Fuel Producer: Absolute Energy, LLC (5049) ; Facility Name: Absolute Energy, LLC (70144); Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC203	76.69	ETH009A01550100	67.97	9/24/2019	None	Ethanol	Absolute Energy, LLC (5049)	Absolute Energy, LLC (70144)	Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI (Provisional)	None	Retired
A017001	Tier 1	3.0	Fuel Producer: Pratt Energy, LLC (6127) ; Facility Name: Pratt Energy, LLC (70158); Midwest Corn, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site cogen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC317	65.03	ETH009A01700100	62.21	9/6/2019	None	Ethanol	Pratt Energy, LLC (6127)	Pratt Energy, LLC (70158)	Midwest Corn, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site cogen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	None	Retired
A017002	Tier 1	3.0	Fuel Producer: Pratt Energy, LLC (6127) ; Facility Name: Pratt Energy, LLC (70158); Midwest Corn, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC304	77.71	ETH009A01700200	76.40	9/6/2019	None	Ethanol	Pratt Energy, LLC (6127)	Pratt Energy, LLC (70158)	Midwest Corn, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	None	Retired
A017003	Tier 1	3.0	Fuel Producer: Pratt Energy, LLC (6127) ; Facility Name: Pratt Energy, LLC (70158); Midwest Sorghum, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A01700300	65.67	9/6/2019	None	Ethanol	Pratt Energy, LLC (6127)	Pratt Energy, LLC (70158)	Midwest Sorghum, Dry Mill; Wet DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	None	Retired
A017004	Tier 1	3.0	Fuel Producer: Pratt Energy, LLC (6127); Facility Name: Pratt Energy, LLC (70158); Midwest Sorghum, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A01700400	79.86	9/6/2019	None	Ethanol	Pratt Energy, LLC (6127)	Pratt Energy, LLC (70158)	Midwest Sorghum, Dry Mill; Dry DGS and Corn Oil; Natural Gas, Grid Electricity and on-site co-gen; Starch Ethanol produced in Pratt, Kansas; Ethanol transported by rail to California	None	Retired
A013101	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Soybean Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Soybean Oil (005)	Biodiesel (BIO)	BDS204	59.99	BIO005A01310100	57.00	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Soybean Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013102	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A01310200	52.00	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013103	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Corn Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC207	37.94	BIO003A01310300	27.90	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Corn Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013104	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU215	25.46	BIO001A01310400	21.00	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013105	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130) ; Facility Name: REG Mason City, LLC (82968); U.S. sourced Non-Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU236	18.34	BIO001A01310500	16.20	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Non-Rendered Used Cooking Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013106	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Rendered Animal Fat Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	Iowa	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT208	39.70	BIO002A01310600	32.50	10/8/2019	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Rendered Animal Fat Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	None	Retired
A013201	Tier 1	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Northeast Mississippi Landfill Gas Recovery Project (71317); Mississippi Landfill Gas to pipeline-quality biomethane in Walnut, MS; Delivered via pipeline; Compressed to CNG in California (Provisional)	Mississippi	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01320100	40.08	9/30/2019	None	Bio-CNG	Clean Energy (5481)	Northeast Mississippi Landfill Gas Recovery Project (71317)	Mississippi Landfill Gas to pipeline-quality biomethane in Walnut, MS; Delivered via pipeline; Compressed to CNG in California (Provisional)	None	Retired

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A015001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01500100	74.83	10/3/2019	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	None	Retired
A015003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01500300	27.72	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	None	Retired
A015101	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01510100	74.44	10/3/2019	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California (Provisional)	None	Retired
A015103	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108; Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01510300	27.69	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	None	Retired
A015201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A01520100	74.15	10/3/2019	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	None	Retired
A015203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	Ohio	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01520300	27.00	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	None	Retired
A015202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A01520200	67.32	10/3/2019	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	None	Retired
A015102	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) ; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01510200	67.72	10/3/2019	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	None	Retired
A016101	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	Texas	Corn (009)	Ethanol (ETH)	ETHC206	70.43	ETH009A01610100	64.69	10/8/2019	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Texas Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	None	Retired
A016103	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETHG202	77.05	ETH010A01610300	66.62	10/8/2019	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Texas Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	None	Retired
A016104	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	Texas	Corn (009)	Ethanol (ETH)	ETHC205	78.02	ETH009A01610400	72.64	10/8/2019	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Texas Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	None	Retired
A016105	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Texas Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETHG201	84.64	ETH010A01610500	74.57	10/8/2019	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Texas Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural gas and Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	None	Retired

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A015002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) ; Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A01500200	68.05	10/14/2019	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	None	Retired
A016401	Tier 1	3.0	Fuel Producer: BUSHMILLS ETHANOL, INC. (4063); Facility Name: BUSHMILLS ETHANOL, INC. (70109); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	ETHC236L	76.96	ETH009A01640100	67.23	10/15/2019	None	Ethanol	BUSHMILLS ETHANOL, INC. (4063)	BUSHMILLS ETHANOL, INC. (70109)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI. (Provisional)	None	Retired
A017501	Tier 1	3.0	Fuel Producer: Front Range Energy LLC (4758); Facility Name: Front Range Energy LLC (70058); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Windsor, Colorado; Ethanol transported by rail to California	Colorado	Corn (009)	Ethanol (ETH)	ETH009A01220100	63.60	ETH009A01750100	64.25	10/21/2019	None	Ethanol	Front Range Energy LLC (4758)	Front Range Energy LLC (70058)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Windsor, Colorado; Ethanol transported by rail to California	None	Retired
A015401	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional)	Kentucky	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01540100	54.66	11/5/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional)	None	Retired
A015402	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional)	Kentucky	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A01540200	71.50	11/5/2019	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional)	None	Retired
A015403	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional)	Kentucky	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A01540300	74.59	11/5/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional)	None	Retired
T2N-1019	Tier 2	2.0	Biomethane produced from the high-solids (greater than 15 percent total solids) anaerobic digestion of food and green wastes; compressed in CA	California	HSAD Food & Green Waste	Compressed Natural Gas	None	None	CNG005_1	-22.93	9/25/2018	None	Bio-CNG	Blue Line Transfer, Inc. (L500)	Blue Line Transfer, Inc. (B1725)	Biomethane produced from the highsolids (greater than 15 percent total solids)anaerobic digestion of food and green wastes; compressed in CA	None	Retired
None	Lookup Table	2.0	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling; export to the grid of surplus cogenerated electricity.	NA	Waste Water	Compressed Natural Gas (CNG)	None	None	CNG020_1	7.75	NA	None	Bio-CNG	NA	NA	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling; export to the grid of surplus cogenerated electricity.	None	Retired
None	Lookup Table	2.0	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling.	NA	Waste Water	Compressed Natural Gas (CNG)	None	None	CNG021_1	30.92	NA	None	Bio-CNG	NA	NA	Biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a California publicly owned treatment works; on-site, high speed vehicle fueling or injection of fuel into a pipeline for off-site fueling.	None	Retired
None	Lookup Table	2.0	Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps)	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYGN001_1	151.01	NA	None	Hydrogen	NA	NA	Compressed H2 from central reforming of NG (includes liquefaction and re-gasification steps)	None	Retired
None	Lookup Table	2.0	Liquid H2 from central reforming of NG	NA	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYGN002_1	143.51	NA	None	Hydrogen	NA	NA	Liquid H2 from central reforming of NG	None	Retired
None	Lookup Table	2.0	Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps)	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYGN003_1	105.65	NA	None	Hydrogen	NA	NA	Compressed H2 from central reforming of NG (no liquefaction and re-gasification steps)	None	Retired

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None	Lookup Table	2.0	Compressed H2 from on-site reforming of NG	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYGN004_1	105.13	NA	None	Hydrogen	NA	NA	Compressed H2 from on-site reforming of NG	None	Retired
None	Lookup Table	2.0	Compressed H2 from on-site reforming with renewable feedstocks	NA	Any Other Feedstock (998)	Gaseous Hydrogen (HYG)	None	None	HYGN005_1	88.33	NA	None	Hydrogen	NA	NA	Compressed H2 from on-site reforming with renewable feedstocks	None	Retired
A016501	Tier 1	3.0	Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California (Provisional)	Rhode Island	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01650100	15.24	12/16/2019	None	Biodiesel	NEWPORT BIODIESEL INC (7764)	NEWPORT BIODIESEL LLC (83532)	Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California (Provisional)	None	Retired
A016502	Tier 1	3.0	Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California (Provisional)	Rhode Island	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01650200	18.60	12/16/2019	None	Biodiesel	NEWPORT BIODIESEL INC (7764)	NEWPORT BIODIESEL LLC (83532)	Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California (Provisional)	None	Retired
A016301	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California	Texas	Corn (009)	Ethanol (ETH)	ETHC200	70.79	ETH009A01630100	64.74	12/16/2019	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California	None	Retired
A016302	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Kansas and Texas Sorghum, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETHG200	79.03	ETH010A01630200	66.63	12/16/2019	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Kansas and Texas Sorghum, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas and Grid electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California	None	Retired
T1N-1753	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: WM Renewable Energy of Ohio - American Landfill (71222); American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ	Ohio	Landfill Gas	LNG	LNGLF225	56.57	LNGLF225R	65.22	12/18/2019	None	Bio-LNG	WM Renewable Energy, LLC (W978)	WM Renewable Energy of Ohio - American Landfill (71222)	American landfill gas (Ohio) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ	None	Retired
T1N-1785	Tier 1	2.0	Fuel Producer: Homeland Energy Solutions LLC (3220) ; Facility Name: Homeland Energy Solutions LLC (70188); Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power.	Iowa	Corn	Ethanol	ETHC292	73.11	ETHC292R	74.42	12/18/2019	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power.	None	Retired
T2N-1229	Tier 2	2.0	Fuel Producer: SeQuential Pacific Biodiesel LLC (6129) ; Facility Name: SeQuential-Pacific Biodiesel, LLC. (83525); Tier 2 Method 2B Pathway: Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO). Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California	Oregon	Used Cooking Oil (UCO)	Biodiesel	BDU241	18.43	BDU241R	18.71	12/18/2019	Application Package	Biodiesel	SeQuential Pacific Biodiesel LLC (6129)	SeQuential-Pacific Biodiesel, LLC. (83525)	Tier 2 Method 2B Pathway: Biodiesel produced from US sourced uncooked Used Cooking Oil (UCO). Fuel is produced in Portland, Oregon and transported by heavy duty diesel truck to California	None	Retired
T1N-1809	Tier 1	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Johnstown Regional Energy - Shade (71134); JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	Pennsylvania	Landfill Gas	CNG	CNGLF273	49.77	CNGLF273R	52.94	12/18/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Shade (71134)	JRE's Shade landfill, Cairnbrook, PA gas in Pennsylvania to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	None	Retired
A010501	Tier 1	3.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Pyeongtaek 2 (80202); South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker	South Korea	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01050100	27.89	12/17/2019	None	Biodiesel	Dansuk Industrial Co., Ltd (5953)	Pyeongtaek 2 (80202)	South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker	None	Retired
A017601	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311) ; Facility Name: Meadow Branch (A2316); Landfill Gas generated at the Meadow Branch Landfill; upgraded to pipeline-quality biomethane in Athens, Tennesse; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01760100	49.24	12/18/2019	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Meadow Branch (A2316)	Landfill Gas generated at the Meadow Branch Landfill; upgraded to pipeline-quality biomethane in Athens, Tennesse; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	None	Retired
A011501	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	Texas	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNGWW201	43.02	CNG030A01150100	37.33	12/19/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ameresco San Antonio Biogas (71204)	Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	None	Retired
A016001	Tier 1	3.0	Fuel Producer: Iogen D3 Biofuel Partners LLC (6486); Facility Name: GSF Energy-Rumpke Landfill (71138S); Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01600100	44.90	12/20/2019	None	Bio-CNG	Iogen D3 Biofuel Partners LLC (6486)	GSF Energy-Rumpke Landfill (71138S)	Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	None	Retired

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B005402	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) ; Facility Name: Diamond Green Diesel LLC (81496); Renewable Diesel produced from U.S. sourced Rendered Used Cooking Oil/Waste Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RDU202R1	19.73	RND001B00540200	19.92	12/19/2019	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from U.S. sourced Rendered Used Cooking Oil/Waste Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	None	Retired
B005401	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Renewable Diesel produced from U.S. sourced Distillers' Corn Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	Louisiana	Distillers' Corn Oil (003)	Renewable Diesel (RND)	RDC201	31.27	RND003B00540100	27.42	12/19/2019	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from U.S. sourced Distillers' Corn Oil; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	None	Retired
B005403	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Renewable Diesel produced from U.S. sourced Rendered Tallow (animal and poultry fat); Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RDT204R1	30.79	RND002B00540300	31.86	12/19/2019	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from U.S. sourced Rendered Tallow (animal and poultry fat); Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in Norco, Louisiana and transported by ocean tanker to California (Provisional)	None	Retired
A013501	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846); Facility Name: High Plains Bioenergy (82883); Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (Provisional)	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT202	35.57	BIO002A01350100	32.07	12/20/2019	None	Biodiesel	High Plains Bioenergy (4846)	High Plains Bioenergy (82883)	Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (Provisional)	None	Retired
B003101	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied hydrogen from Mississippi landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gas to fueling stations	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B00310100	131.39	12/31/2019	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Liquefied hydrogen from Mississippi landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gas to fueling stations	None	Retired
B004501	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B00450100	25.08	12/27/2019	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Jet produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	None	Retired
B004502	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Renewable Diesel produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B00450200	25.08	12/27/2019	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Diesel produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B004503	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B00450300	25.08	12/27/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Naphtha produced from Rendered animal fat from JBS Brooks, Alberta, Canada; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B004401	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B00440100	42.91	12/27/2019	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Jet produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	None	Retired
B004301	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B00430100	37.13	12/27/2019	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	None	Retired
B004302	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Diesel produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RDT209	38.75	RND002B00430200	37.13	12/27/2019	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Diesel produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B004303	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNWN200	39.75	RNT002B00430300	37.13	12/27/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired

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B004402	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Diesel produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B00440200	42.91	12/27/2019	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Diesel produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B004403	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B00440300	42.91	12/27/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B004601	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491) ; Facility Name: Praxair Liquid H2 Source (F00053); Liquefied hydrogen North American fossil NG produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, CA and gaseous hydrogen transport by tube trailer to stations in Southern CA	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B00460100	158.15	12/31/2019	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Praxair Liquid H2 Source (F00053)	Liquefied hydrogen North American fossil NG produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, CA and gaseous hydrogen transport by tube trailer to stations in Southern CA	None	Retired
B004602	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Praxair Liquid H2 Source (F00053); Liquefied hydrogen from Mississippi landfill gas produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, California and gaseous hydrogen transport by tube trailer to stations in Southern CA	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B00460200	136.31	12/31/2019	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Praxair Liquid H2 Source (F00053)	Liquefied hydrogen from Mississippi landfill gas produced at Praxair Liquids Hydrogen Source, Ontario, California transported as liquid to transfill station in Etiwanda, California and gaseous hydrogen transport by tube trailer to stations in Southern CA	None	Retired
B004701	Tier 2	3.0	Fuel Producer: Sinclair Wyoming Refining Company (3994); Facility Name: Sinclair Wyoming Refining Company (83388); Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California (Provisional)	Wyoming	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B00470100	58.34	12/27/2019	Application Package	Renewable Diesel	Sinclair Wyoming Refining Company (3994)	Sinclair Wyoming Refining Company (83388)	Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California (Provisional)	None	Retired
B004901	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Sacramento Liquid Sacramento (F00103); Liquefied hydrogen from fossil natural gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B00490100	158.28	12/31/2019	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Air Products Sacramento Liquid Sacramento (F00103)	Liquefied hydrogen from fossil natural gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California	None	Retired
B004902	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Sacramento Liquid Sacramento (F00103); Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B00490200	136.44	12/31/2019	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Air Products Sacramento Liquid Sacramento (F00103)	Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, California transported as liquid to transfill station in Santa Clara, California and gaseous hydrogen transport by tube trailer to stations in Northern California	None	Retired
A019501	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060); Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A01950100	43.37	12/31/2019	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060)	Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	None	Retired
T2R-1105	Tier 2	2.0	Fuel Producer: Tracy Renewable Energy LLC (T534) Facility Name: Tracy Renewable Energy LLC (A0640): Ethanol Produced from California Energy Beets using biogas derived from anaerobic digestion of green wastes, manure and glycerin; with credit for avoided waste management and co-products (compost and animal feed).	California	Sugarbeets	Ethanol	ETHBE001	13.64	ETHB200L	7.18	5/16/2016	None	Ethanol	Tracy Renewable Energy LLC (T534)	Tracy Renewable Energy LLC (A0640)	Ethanol Produced from California Energy Beets using biogas derived from anaerobic digestion of green wastes, manure and glycerin; with credit for avoided waste management and coproducts (compost and animal feed)	None	Retired
T2R-1073	Tier 2	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). California, Dry Mill, Waste Wine Ethanol, NG	California	Waste Wine	Ethanol	ETHWB002	18.70	ETHWB200L	22.06	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	California, Dry Mill, Waste Wine Ethanol, NG	None	Retired
T1R-1518	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC125	67.92	ETHC271L	56.44	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	None	Retired
T1R-1248	Tier 1	2.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, California Corn, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC120	62.76	ETHC257L	56.82	3/31/2016	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	California Ethanol, California Corn, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer	None	Retired

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T1R-1195	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). California Corn, California Ethanol, Dry Mill, WDGS, North American LFG	California	Corn	Ethanol	ETHC117	65.07	ETHC249L	58.11	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	California Corn, California Ethanol, Dry Mill, WDGS, North American LFG	None	Retired
T1R-1250	Tier 1	2.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, Midwest Corn, Dry Mill, WDGS, North American LFG	California	Corn	Ethanol	ETHC122	69.78	ETHC259L	58.31	3/31/2016	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	California Ethanol, Midwest Corn, Dry Mill, WDGS, North American LFG	None	Retired
T1R-1199	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Corn, California Ethanol, Dry Mill, WDGS, North American, LFG	California	Corn	Ethanol	ETHC119	70.56	ETHC250L	59.04	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest Corn, California Ethanol, Dry Mill, WDGS, North American, LFG	None	Retired
T1R-1515	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). California Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC128	68.20	ETHC268L	60.27	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	California Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	None	Retired
T1R-1517	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). California Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC124	68.43	ETHC270L	61.94	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	California Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer	None	Retired
T1R-1513	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC127	75.34	ETHC267L	63.23	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Corn, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	None	Retired
T1R-1520	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	California	Sorghum	Ethanol	ETHG023	69.19	ETHG211L	64.34	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 100% Landfill Gas, With Lime Use in Fertilizer	None	Retired
T1R-1519	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC126	75.77	ETHC272L	64.89	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Corn, California Ethanol, Dry Mill, WDGS, 100% NG, With Lime Use in Fertilizer	None	Retired
T1N-1231	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). California Corn, Ethanol, Dry Mill, NG	California	Corn	Ethanol	None	None	ETHC217	65.36	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	California Corn, Ethanol, Dry Mill, NG	None	Retired
T1R-1251	Tier 1	2.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol; Midwest Grain Sorghum, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer	California	Sorghum	Ethanol	ETHG020	68.24	ETHG208L	66.07	3/31/2016	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	California Ethanol; Midwest Grain Sorghum, Dry Mill, WDGS, North American LFG, With Lime Use in Fertilizer	None	Retired
T1N-1358	Tier 1	2.0	Fuel Producer: Bridgeport Ethanol, LLC (5934) Facility Name: Bridgeport Ethanol, LLC (70217). Midwest Corn, Ethanol, Dry Mill, WDGS, NG	Nebraska	Corn	Ethanol	None	None	ETHC229	67.43	3/31/2016	None	Ethanol	Bridgeport Ethanol, LLC (5934)	Bridgeport Ethanol, LLC (70217)	Midwest Corn, Ethanol, Dry Mill, WDGS, NG	None	Retired
T1R-1249	Tier 1	2.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, California Corn, Dry Mill, WDGS, NG With Lime Use in Fertilizer	California	Corn	Ethanol	ETHC121	72.42	ETHC258L	67.46	3/31/2016	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	California Ethanol, California Corn, Dry Mill, WDGS, NG With Lime Use in Fertilizer	None	Retired

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None	Lookup Table	3.0	California grid electricity used as a transportation fuel in California	California	Grid Electricity (039)	Electricity (ELC)	None	None	ELC000L00072019	81.49	NA	None	Electricity	NA	NA	California grid electricity used as a transportation fuel in California	None	Retired
T1R-1197	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, North American LFG	California	Sorghum	Ethanol	ETHG018	68.19	ETHG206L	68.62	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, North American LFG	None	Retired
T1N-1230	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Corn, Ethanol, Dry Mill, NG	California	Corn	Ethanol	None	None	ETHC216	69.64	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest Corn, Ethanol, Dry Mill, NG	None	Retired
T1N-1609	Tier 1	2.0	Fuel Producer: Great Plains Ethanol (4727) Facility Name: Great Plains Ethanol, LLC (70012): Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, Corn Oil, and Syrup, Using NG, Wood, and Biogas	South Dakota	Corn	Ethanol	None	None	ETHC280	69.68	1/10/2017	None	Ethanol	Great Plains Ethanol (4727)	Great Plains Ethanol, LLC (70012)	Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, Corn Oil, and Syrup, Using NG, Wood, and Biogas	None	Retired
T1N-1152	Tier 1	2.0	Fuel Producer: Trenton Agri Products, LLC (4754) Facility Name: Trenton Agri Products, LLC (70053). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	None	None	ETHC210	69.75	3/31/2016	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1N-1592	Tier 1	2.0	Fuel Producer: Western Plains Energy, LLC (4740) Facility Name: Western Plains Energy, LLC (70030). Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, and Corn Oil, NG	Kansas	Corn	Ethanol	None	None	ETHC278	70.60	11/2/2016	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Corn, Ethanol, Dry Mill, DDGS, WDGS, and Corn Oil, NG	None	Retired
T1N-1070	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	Texas	Corn	Ethanol	None	None	ETHC200	70.79	3/31/2016	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	None	Retired
T1R-1514	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	California	Sorghum	Ethanol	ETHG025	76.91	ETHG210L	70.80	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Sorghum, California Ethanol, Dry Mill, WDGS, 3% Dairy Digester Gas, 97% NG, With Lime Use in Fertilizer	None	Retired
T1N-1500	Tier 1	2.0	Fuel Producer: POET Biorefining Mitchell (4789) Facility Name: POET Biorefining Mitchell (70016). Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	South Dakota	Corn	Ethanol	None	None	ETHC231	71.14	3/31/2016	None	Ethanol	POET Biorefining Mitchell (4789)	POET Biorefining Mitchell (70016)	Midwest Corn, Ethanol, Dry Mill, 100% WDGS, NG	None	Retired
T1R-1013 T1R-1052	Tier 1	2.0	Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095) Facility Name: Mid America Agri Products/Wheatland LLC (70153). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC110 ETHC111	82.76 76.68	ETHC235L	71.78	3/31/2016	None	Ethanol	Mid America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1003	Tier 1	2.0	Fuel Producer: Arkalon Ethanol, LLC (5715) Facility Name: Arkalon Ethanol, LLC (70247). Midwest, Corn Ethanol, Dry Mill, NG	Kansas	Corn	Ethanol	ETHC037	80.17	ETHC233L	71.79	3/31/2016	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1015	Tier 1	2.0	Fuel Producer: BUSHMILLS ETHANOL, INC. (4063) Facility Name: BUSHMILLS ETHANOL, INC. (70109). Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG	Minnesota	Corn	Ethanol	ETHC113	79.18	ETHC232L	72.55	3/31/2016	None	Ethanol	BUSHMILLS ETHANOL, Inc (4063)	BUSHMILLS ETHANOL, Inc (70109)	Midwest, Corn Ethanol, Dry Mill, 100% MDGS, NG	None	Retired

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T1R-1521	Tier 1	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317). Midwest Sorghum, California Ethanol, Dry Mill, Wet DGS, 100% NG, With Lime Use in Fertilizer	California	Sorghum	Ethanol	ETHG024	77.04	ETHG212L	72.59	3/31/2016	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Sorghum, California Ethanol, Dry Mill, Wet DGS, 100% NG, With Lime Use in Fertilizer	None	Retired
T1N-1539	Tier 1	2.0	Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn, Ethanol, Dry Mill, NG and Landfill Gas as process fuels	Nebraska	Corn	Ethanol	None	None	ETHC276	72.63	11/2/2016	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest, Corn, Ethanol, Dry Mill, NG and Landfill Gas as process fuels	None	Retired
T1N-1132	Tier 1	2.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Madera LLC (70061); Midwest Corn, CA Ethanol, Dry Mill, WDGS, NG	California	Corn	Ethanol	ETHC207	72.73	ETHC207R	72.94	5/16/2018	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Madera LLC (70061)	Midwest Corn, CA Ethanol, Dry Mill, WDGS, NG	None	Retired
T1N-1082	Tier 1	2.0	Fuel Producer: Little Sioux Corn Processors, LLLP (4728) Facility Name: LSCP, LLLP (70015). Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG **(Provisional)**	Iowa	Corn	Ethanol	None	None	ETHC202	73.55	3/31/2016	None	Ethanol	Little Sioux Corn Processors, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Ethanol, Dry Mill, 100% MDGS, NG (Provisional)	None	Retired
T1N-1176	Tier 1	2.0	Fuel Producer: High Plains Bioenergy (4846) Facility Name: High Plains Bioenergy (82883). Mixture of tallow & choice white grease biodiesel transported by rail to CA (30% tallow from local, the rest from KS,TX and NE)	Guymon, Oklahoma	Mixture of Tallow and Choice White Grease	Biodiesel	None	None	BDT202	35.57	6/30/2016	None	Biodiesel	High Plains Bioenergy (4846)	High Plains Bioenergy (82883)	Mixture of tallow & choice white grease biodiesel transported by rail to CA (30% tallow from local, the rest from KS,TX and NE)	None	Retired
T1R-1294	Tier 1	2.0	Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, 87% NG, 13% LFG	Nebraska	Corn	Ethanol	ETHC047	83.74	ETHC266L	73.78	3/31/2016	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest, Corn Ethanol, Dry Mill, 87% NG, 13% LFG	None	Retired
T1R-1292	Tier 1	2.0	Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, 90% NG, 10% LFG	Nebraska	Corn	Ethanol	ETHC046	84.41	ETHC265L	74.05	3/31/2016	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest, Corn Ethanol, Dry Mill, 90% NG, 10% LFG	None	Retired
T1R-1291	Tier 1	2.0	Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, 93% NG, 7% LFG	Nebraska	Corn	Ethanol	ETHC045	85.16	ETHC264L	74.37	3/31/2016	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest, Corn Ethanol, Dry Mill, 93% NG, 7% LFG	None	Retired
T1R-1216	Tier 1	2.0	Fuel Producer: Husker Ag LLC (5078) Facility Name: Husker Ag LLC (70151). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC092	81.92	ETHC253L	74.56	3/31/2016	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1032	Tier 1	2.0	Fuel Producer: E Energy Adams, LLC (4831) Facility Name: E energy Adams, LLC (70093). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC067_1	86.31	ETHC238L	74.62	3/31/2016	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired
T1R-1006	Tier 1	2.0	Fuel Producer: Bonanza BioEnergy, LLC (4054) Facility Name: Bonanza BioEnergy, LLC (70117). Midwest, Sorghum Ethanol, Dry Mill, NG	Kansas	Sorghum	Ethanol	ETHG003	73.39	ETHG205L	74.83	3/31/2016	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest, Sorghum Ethanol, Dry Mill, NG	None	Retired
T1R-1286	Tier 1	2.0	Fuel Producer: Siouxland Ethanol, LLC (5026) Facility Name: Siouxland Ethanol (70134). Midwest, Corn Ethanol, Dry Mill, NG	Nebraska	Corn	Ethanol	ETHC043	88.14	ETHC263L	75.27	3/31/2016	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest, Corn Ethanol, Dry Mill, NG	None	Retired

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T1R-1198	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697) Facility Name: Pacific Ethanol Stockton LLC (70319). Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, NG	California	Sorghum	Ethanol	ETHG019	79.97	ETHG207L	76.14	3/31/2016	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Stockton LLC (70319)	Midwest Grain Sorghum, California Ethanol, Dry Mill, WDGS, NG	None	Retired
T1R-1252	Tier 1	2.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566) Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234). California Ethanol, Midwest Grain Sorghum, Dry Mill, WDGS, NG, With Lime Use in Fertilizer	California	Sorghum	Ethanol	ETHG021	79.60	ETHG209L	76.33	3/31/2016	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	California Ethanol, Midwest Grain Sorghum, Dry Mill, WDGS, NG, With Lime Use in Fertilizer	None	Retired
T1N-1217	Tier 1	2.0	Fuel Producer: Western Plains Energy, LLC (4740) Facility Name: Western Plains Energy, LLC (70030). Midwest, Corn Ethanol, Dry Mill, MDGS, DDGS, NG	Kansas	Corn	Ethanol	None	None	ETHC214	76.66	3/31/2016	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest, Corn Ethanol, Dry Mill, MDGS, DDGS, NG	None	Retired
T1N-1081	Tier 1	2.0	Fuel Producer: Little Sioux Corn Processors, LLLP (4728) Facility Name: LSCP, LLLP (70015). Midwest Corn, Ethanol, Dry Mill, 100 % DDGS, NG **(Provisional)**	Iowa	Corn	Ethanol	None	None	ETHC201	77.66	3/31/2016	None	Ethanol	Little Sioux Corn Processors, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Ethanol, Dry Mill, 100 % DDGS, NG (Provisional)	None	Retired
T1N-1222	Tier 1	2.0	Fuel Producer: Poet Biorefining Emmetsburg (4792) Facility Name: Poet Biorefining Emmetsburg (70021). Midwest, Corn, Mixed DGS, Ethanol, Dry Mill, NG	Iowa	Corn	Ethanol	None	None	ETHC215	77.98	3/31/2016	None	Ethanol	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest, Corn, Mixed DGS, Ethanol, Dry Mill, NG	None	Retired
T1N-1593	Tier 1	2.0	Fuel Producer: Western Plains Energy, LLC (4740) Facility Name: Western Plains Energy, LLC (70030). Midwest Sorghum, Ethanol, Dry Mill, DDGS, WDGS, NG	Kansas	Sorghum	Ethanol	None	None	ETHG215	78.55	11/2/2016	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Sorghum, Ethanol, Dry Mill, DDGS, WDGS, NG	None	Retired
T1N-1072	Tier 1	2.0	Fuel Producer: White Energy, Inc. (4745) Facility Name: WE Hereford, LLC (70037). Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG	Texas	Sorghum	Ethanol	None	None	ETHG200	79.03	3/31/2016	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Texas Sorghum, Ethanol, Dry Mill, 100% WDGS, NG	None	Retired
T1R-1004	Tier 1	2.0	Fuel Producer: Arkalon Ethanol, LLC (5715) Facility Name: Arkalon Ethanol, LLC (70247). Midwest, Sorghum Ethanol, Dry Mill, NG	Kansas	Sorghum	Ethanol	ETHG004	76.22	ETHG204L	79.28	3/31/2016	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest, Sorghum Ethanol, Dry Mill, NG	None	Retired
T1N-1133	Tier 1	2.0	Fuel Producer: Pacific Ethanol West (3697) ; Facility Name: Pacific Ethanol Madera LLC (70061); Midwest Sorghum CA Ethanol, Dry Mill, DDGS, NG	California	Sorghum	Ethanol	ETHG203	80.51	ETHG203R	81.84	5/16/2018	None	Ethanol	Pacific Ethanol West (3697)	Pacific Ethanol Madera LLC (70061)	Midwest Sorghum CA Ethanol, Dry Mill, DDGS, NG	None	Retired
T1N-1499	Tier 1	2.0	Fuel Producer: POET Biorefining Mitchell (4789) Facility Name: Poet Biorefining Mitchell (70016). Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	South Dakota	Corn	Ethanol	None	None	ETHC230	81.74	3/31/2016	None	Ethanol	POET Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Ethanol, Dry Mill, 100% DDGS, NG	None	Retired
T1N-1151	Tier 1	2.0	Fuel Producer: Cornhusker Energy Lexington, LLC (7365) Facility Name: Lexington Ethanol Plant (70241). Midwest, Corn Ethanol, Dry Mill, 100% DDGS, WDGS, NG	Nebraska	Corn	Ethanol	None	None	ETHC209	85.58	3/31/2016	None	Ethanol	Cornhusker Energy Lexington, LLC (7365)	Lexington Ethanol Plant (70241)	Midwest, Corn Ethanol, Dry Mill, 100% DDGS, WDGS, NG	None	Retired
T2N-1137	Tier 2	2.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Soybean, Fuel produced in Louisiana and transported to California	Louisiana	Soybean	Renewable Diesel	None	None	RDS200	53.86	3/21/2017	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from US Soybean, Fuel produced in Louisiana and transported to California	None	Retired

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T2N-1138	Tier 2	2.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Used Cooking Oil, Fuel produced in Louisiana and transported to California	Louisiana	Used Cooking Oil	Renewable Diesel	None	None	RDU202	20.28	3/21/2017	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from US Used Cooking Oil, Fuel produced in Louisiana and transported to California	None	Retired
T2N-1144	Tier 2	2.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Corn Oil, Fuel produced in Louisiana and transported to California	Louisiana	Corn Oil	Renewable Diesel	None	None	RDC201	31.27	3/21/2017	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from US Corn Oil, Fuel produced in Louisiana and transported to California	None	Retired
T2R-1204	Tier 2	2.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Used Cooking Oil, Fuel produced in Louisiana and transported to California	Louisiana	Used Cooking Oil	Renewable Diesel	RDU202	20.28	RDU202R1	19.73	6/23/2017	None	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from US Used Cooking Oil, Fuel produced in Louisiana and transported to California	None	Retired
T2R-1205	Tier 2	2.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072) Facility Name: Diamond Green Diesel LLC (81496): Renewable Diesel produced from U.S. Tallow, Fuel produced in Louisiana and transported to California	Louisiana	Tallow	Renewable Diesel	RDT204	30	RDT204R1	30.79	6/23/2017	None	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Renewable Diesel produced from US Tallow, Fuel produced in Louisiana and transported to California	None	Retired
T1N-1572	Tier 1	2.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Dry mill corn ethanol with co-production of MDGS and corn oil using natural gas and electricity power.	Nebraska	Corn	Ethanol	None	None	ETHC293	68.89	12/21/2017	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Dry mill corn ethanol with coproduction of MDGS and corn oil using natural gas and electricity power	None	Retired
T2N-1210	Tier 2	2.0	Fuel Producer: Siouxland Energy Cooperative (4060) Facility Name: Siouxland Energy Cooperative (70112):Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Sioux Center, Iowa; Midwest Corn, Dry Mill, Wet DGS, Corn Oil, and Syrup; using natural gas and electricity; Ethanol transported by rail to California (Provisional)	Iowa	Corn Kernel Fiber	Ethanol	ETHCF201	29.93	ETHCF201R	42.17	11/29/2018	Pathway Details (PDF)	Ethanol - Cellulosic	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Sioux Center, Iowa; Midwest Corn, Dry Mill, Wet DGS, Corn Oil, and Syrup; using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1156	Tier 2	2.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ameresco San Antonio Biogas (71204); Tier 2 Method 2B Pathway: Pipeline quality biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a POTW using grid-based electricity, and delivered to CNG dispensing stations in California via pipeline	Texas	Waste Water	CNG	None	None	CNGWW201	43.02	3/16/2018	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ameresco San Antonio Biogas (71204)	Tier 2 Method 2B Pathway Pipeline quality biomethane produced from the mesophillic anaerobic digestion of wastewater sludge at a POTW using gridbased electricity, and delivered to CNG dispensing stations in California via pipeline	None	Retired
T1N-1814	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); Waste Management's Milam landfill, St. Louis, Illinois gas to pipeline-quality biomethane; delivered via pipeline to WM fueling stations in California (Provisional)	Illinois	Landfill Gas	CNG	None	None	CNGLF270	62.72	6/1/2018	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	Waste Management's Milam landfill, St Louis, Illinois gas to pipelinequality biomethane; delivered via pipeline to WM fueling stations in California (Provisional)	None	Retired
T1N-1815	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); Waste Management's Milam landfill, St. Louis, Illinois gas pipeline-quality biomethane; delivered via pipeline to liquifaction plant in Topock AZ, and transported by truck to WM fueling stations in California (Provisional)	Illinois	Landfill Gas	LNG	None	None	LNGLF228	76.13	6/1/2018	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	Waste Management's Milam landfill, St Louis, Illinois gas pipelinequality biomethane; delivered via pipeline to liquifaction plant in Topock AZ, and transported by truck to WM fueling stations in California (Provisional)	None	Retired
T1N-1816	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); Waste Management's Milam landfill, St. Louis, Illinois gas to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; Re-gasified and compressed in California. (Provisional)	Illinois	Landfill Gas	CNG	None	None	CNGLF271	78.68	6/1/2018	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	Waste Management's Milam landfill, St Louis, Illinois gas to pipelinequality biomethane; delivered via pipeline; liquefied to LNG in AZ; Regasified and compressed in California(Provisional)	None	Retired
T1N-1828	Tier 1	2.0	Fuel Producer: Husker Ag LLC (5078) ; Facility Name: Husker Ag LLC (70151); Midwest Corn, Ethanol, Dry Mill, NG, 100% DDGS, NG (Provisional)	Nebraska	Corn	Ethanol	None	None	ETHC295	74.03	7/9/2018	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn, Ethanol, Dry Mill, NG, 100% DDGS, NG (Provisional)	None	Retired
T1N-1859	Tier 1	2.0	Fuel Producer: Kansas Ethanol, LLC ; Facility Name: Kansas Ethanol, LLC (70279); Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuels. DDGS, WDGS, and corn oil as co-products (Provisional)	Kansas	Corn	Ethanol	None	None	ETHC299	67.83	8/27/2018	None	Ethanol	Kansas Ethanol, LLC (5810)	Kansas Ethanol, LLC (70279)	Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuelsDDGS, WDGS, and corn oil as coproducts (Provisional)	None	Retired

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T2N-1235	Tier 2	2.0	Fuel Producer: Pacific Ethanol West LLC (3697); Facility Name: Pacific Ethanol Stockton LLC (70319; Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Stockton, California; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Modified DGS (Provisional)	California	Corn Kernel Fiber	Ethanol	None	None	ETHCF202	39.45	9/28/2018	Application Package	Ethanol - Cellulosic	Pacific Ethanol West LLC (3697)	Pacific Ethanol Stockton LLC (70319)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Stockton, California; using natural gas and electricity; Midwest Corn, Dry Mill, Wet and Modified DGS (Provisional)	None	Retired
T2N-1252	Tier 2	2.0	Fuel Producer: Great Plains Ethanol (4727) ; Facility Name: Great Plains Ethanol, LLC (70012); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Chancellor, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas, and electricity; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Kernel Fiber	Ethanol	None	None	ETHCF203	27.69	9/28/2018	Application Package	Ethanol - Cellulosic	Great Plains Ethanol (4727)	Great Plains Ethanol, LLC (70012)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Chancellor, South Dakota; Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas, and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1266	Tier 2	2.0	Fuel Producer: Poet Biorefining Emmetsburg (4792) ; Facility Name: Poet Biorefining Emmetsburg (70021); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Emmetsburg, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Ethanol transported by rail to California (Provisional)	Iowa	Corn Kernel Fiber	Ethanol	None	None	ETHCF204	35.39	9/28/2018	Application Package	Ethanol - Cellulosic	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Emmetsburg, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1153	Tier 2	2.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Marcus, Iowa; Midwest Corn, Dry Mill, Modified and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California	Iowa	Corn Kernel Fiber	Ethanol	ETHCF200	31.23	ETHCF200R	44.19	11/29/2018	Application Package	Ethanol - Cellulosic	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using Edeniq process along with starch ethanol in Marcus, Iowa; Midwest Corn, Dry Mill, Modified and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California	None	Retired
T2N-1258	Tier 2	2.0	Fuel Producer: POET Biorefining - Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Hudson, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Kernel Fiber	Ethanol	None	None	ETHCF205	36.92	12/4/2018	Application Package	Ethanol - Cellulosic	POET Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Hudson, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1262	Tier 2	2.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Gowrie, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	Iowa	Corn Kernel Fiber	Ethanol	None	None	ETHCF209	34.30	12/4/2018	Application Package	Ethanol - Cellulosic	POET Biorefining Gowrie (4784)	POET Biorefining Gowrie (70033)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Gowrie, Iowa; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1261	Tier 2	2.0	Fuel Producer: POET Biorefining - Groton (4793) ; Facility Name: POET Biorefining - Groton (70013); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Groton, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Kernel Fiber	Ethanol	None	None	ETHCF208	34.79	12/4/2018	Application Package	Ethanol - Cellulosic	POET Biorefining Groton (4793)	POET Biorefining Groton (70013)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Groton, South Dakota; Midwest Corn, Dry Mill, Wet and Dry DGS, corn oil, and syrup using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1260	Tier 2	2.0	Fuel Producer: POET Biorefining - Mitchell (4789) ; Facility Name: Poet Biorefining Mitchell (70016); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Mitchell, South Dakota; Midwest Corn, Dry Mill, Wet, Dry DGS, corn oil, and syrup using natural gas, and electricity; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Kernel Fiber	Ethanol	None	None	ETHCF207	35.67	12/4/2018	Application Package	Ethanol - Cellulosic	POET Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn kernel fiber using BPX process along with starch ethanol in Mitchell, South Dakota; Midwest Corn, Dry Mill, Wet, Dry DGS, corn oil, and syrup using natural gas, and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1263	Tier 2	2.0	Fuel Producer: Mid America Agri Products/Wheatland, LLC (5095) ; Facility Name: Mid America Agri Products/Wheatland LLC (70153); Tier 2 Method 2B Pathway: Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Madrid, Nebraska; using natural gas and electricity; Midwest Corn, Dry Mill, Wet DGS and Corn Oil; Ethanol transported by rail to California (Provisional)	Nebraska	Corn	Ethanol	None	None	ETHC311	38.12	12/18/2018	Application Package	Ethanol	Mid America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Tier 2 Method 2B Pathway Cellulosic ethanol produced from Corn Kernel Fiber using Edeniq process along with starch ethanol in Madrid, Nebraska; using natural gas and electricity; Midwest Corn, Dry Mill, Wet DGS and Corn Oil; Ethanol transported by rail to California (Provisional)	None	Retired
T1N-1870	Tier 1	2.0	Fuel Producer: Pinal Energy LLC (4744); Facility Name: Pinal Energy LLC (70136); Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California (Provisional)	Arizona	Corn	Ethanol	None	None	ETHC314	74.77	12/21/2018	None	Ethanol	Pinal Energy LLC (4744)	Pinal Energy LLC (70136)	Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California (Provisional)	None	Retired
T2N-1279	Tier 2	2.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354); Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317); Tier 2 Method 2B Pathway: Corn starch ethanol produced in Pixley, California; using natural gas, dairy biomethane, and electricity; Midwest corn, dry mill, wet DGS (Provisional)	California	Corn	Ethanol	None	None	ETHC316	63.01	12/31/2018	Application Package	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Tier 2 Method 2B Pathway Corn starch ethanol produced in Pixley, California; using natural gas, dairy biomethane, and electricity; Midwest corn, dry mill, wet DGS (Provisional)	None	Retired
T2N-1290	Tier 2	2.0	Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Diesel produced from North American Tallow, in Paramount, California (Provisional)	California	Tallow & Animal Fat	Renewable Diesel	None	None	RDT209	38.75	1/16/2019	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Tier 2 Method 2B ApplicationRenewable Diesel produced from North American Tallow, in Paramount, California (Provisional)	None	Retired

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T2N-1287	Tier 2	2.0	Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Naphtha produced from North American Tallow, Naphtha produced in Paramount, California (Provisional)	California	Tallow & Animal Fat	Renewable Naphtha	None	None	RNWN200	39.75	3/14/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Tier 2 Method 2B ApplicationRenewable Naphtha produced from North American Tallow, Naphtha produced in Paramount, California (Provisional)	None	Retired
T1N-1805	Tier 1	2.0	Fuel Producer: Pacific Ethanol Holding Co LLC (3697); Facility Name: Pacific Ethanol Madera LLC (70061); Dry mill corn ethanol with co-production of WDGS, DDGS, corn oil, and syrup using natural gas and electricity power	California	Corn	Ethanol	ETHC290	69.81	ETHC290R	69.94	12/18/2019	None	Ethanol	Pacific Ethanol Holding Co LLC (3697)	Pacific Ethanol Madera LLC (70061)	Dry mill corn ethanol with co-production of WDGS, DDGS, corn oil, and syrup using natural gas and electricity power	None	Retired
T1N-1870	Tier 1	2.0	Fuel Producer: Pinal Energy LLC (4744); Facility Name: Pinal Energy LLC (70136); Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California	Arizona	Corn	Ethanol	ETHC314	74.77	ETHC314R	75.62	12/18/2019	None	Ethanol	Pinal Energy LLC (4744)	Pinal Energy LLC (70136)	Midwest Corn, Dry Mill, Wet and Dry DGS, Corn Oil, Syrup; Starch ethanol produced from corn using Edeniq process in Maricopa, Arizona; using natural gas and electricity; Ethanol transported by rail to California	None	Retired
T1N-1869	Tier 1	2.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	Nebraska	Corn	Ethanol	ETHC302	66.74	ETHC302R	68.86	12/18/2019	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	None	Retired
T1N-1868	Tier 1	2.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	Nebraska	Corn	Ethanol	ETHC303	78.68	ETHC303R	79.25	12/18/2019	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	None	Retired
T1N-1874	Tier 1	2.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727) ; Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas,and electricity; Starch ethanol produced from Corn using BPX process in Chancellor, South Dakota; Ethanol transported by rail to California	South Dakota	Corn	Ethanol	ETHC300	69.04	ETHC300R	69.07	12/18/2019	None	Ethanol	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill, Wet, Modified, and Dry DGS using natural gas, biomass, biogas,and electricity; Starch ethanol produced from Corn using BPX process in Chancellor, South Dakota; Ethanol transported by rail to California	None	Retired
T1N-1895	Tier 1	2.0	Fuel Producer: E Energy Adams, LLC (4831) ; Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Adams, Nebraska; Ethanol transported by rail to California	Nebraska	Corn	Ethanol	ETHC310	70.76	ETHC310R	71.08	12/18/2019	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Adams, Nebraska; Ethanol transported by rail to California	None	Retired
B003201	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: LAX Station (L0324); Gaseous Hydrogen from landfill gas from onsite SMR at the LAX station and dispensed in vehicles	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B00320100	158.25	1/13/2020	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	LAX Station (L0324)	Gaseous Hydrogen from landfill gas from onsite SMR at the LAX station and dispensed in vehicles	None	Retired
B003202	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: LAX Station (L0324); Gaseous Hydrogen from NA fossil natural gas from onsite SMR at the LAX station and dispensed in vehicles	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031B00320200	176.43	1/13/2020	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	LAX Station (L0324)	Gaseous Hydrogen from NA fossil natural gas from onsite SMR at the LAX station and dispensed in vehicles	None	Retired
T1N-1785	Tier 1	2.0	Fuel Producer: Homeland Energy Solutions LLC (3220) ; Facility Name: Homeland Energy Solutions LLC (70188); Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power	Iowa	Corn	Ethanol	ETHC292R	74.42	ETHC292R1	74.18	1/16/2020	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Dry mill corn ethanol with co-production of DDGS, MDGS, and corn oil using natural gas and electricity power	None	Retired
T1N-1869	Tier 1	2.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	Nebraska	Corn	Ethanol	ETHC302R	68.86	ETHC302R1	66.94	1/16/2020	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	None	Retired
T1N-1868	Tier 1	2.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC (70098); Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	Nebraska	Corn	Ethanol	ETHC303R	79.25	ETHC303R1	79.21	1/16/2020	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC (70098)	Midwest Corn, Dry Mill, Wet and Dry DGS, and corn oil using natural gas and electricity; Starch ethanol produced from Corn in Ravenna, Nebraska; Ethanol transported by rail to California	None	Retired

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B001801	Tier 2	3.0	Fuel Producer: BP Products North America, Inc (4320); Facility Name: Cherry Point Refinery (83736); U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA (Provisional)	Washington	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B00180100	26.92	12/6/2019	Application Package	Renewable Diesel	BP Products North America, Inc (4320)	Cherry Point Refinery (83736)	U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA (Provisional)	None	Retired
B003601	Tier 2	3.0	Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Facility Name: Praxair Ontario (F00084); Gaseous Hydrogen from Altamont landfill gas-derived biomethane liquefied and trucked from Livermore, CA to Ontario, CA; used as feedstock for hydrogen by SMR, distributed via tube trailer to stations in California (Provisional)	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B00360100	76.71	1/21/2020	Application Package	Hydrogen	HIGH MOUNTAIN FUELS LLC (4293)	Facility Name: Praxair Ontario (F00084)	Gaseous Hydrogen from Altamont landfill gas-derived biomethane liquefied and trucked from Livermore, CA to Ontario, CA; used as feedstock for hydrogen by SMR, distributed via tube trailer to stations in California (Provisional)	None	Retired
B003602	Tier 2	3.0	Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Praxair Ontario (F00084); Liquified Hydrogen from liquefied landfill gas at the landfill, transported to an SMR, gasified at a transfill, and dispensed in vehicles (Provisional)	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B00360200	96.41	1/21/2020	Application Package	Hydrogen	HIGH MOUNTAIN FUELS LLC (4293)	Praxair Ontario (F00084)	Liquified Hydrogen from liquefied landfill gas at the landfill, transported to an SMR, gasified at a transfill, and dispensed in vehicles (Provisional)	None	Retired
B004801	Tier 2	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Sacramento Hydrogen Plant (F00102); Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gaseous hydrogen to fueling stations in CA	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B00480100	138.90	1/29/2020	Application Package	Hydrogen	Shell Energy North America (6154)	Sacramento Hydrogen Plant (F00102)	Liquefied hydrogen from landfill gas at Air Products & Chemicals Inc., Sacramento, CA transported as liquid to transfill station in Santa Clara, CA and transported as gaseous hydrogen to fueling stations in CA	None	Retired
B000901	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Locust Ridge Farm (71298); Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B00090100	-323.83	1/31/2020	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Locust Ridge Farm (71298)	Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	None	Retired
B000902	Tier 2	3.0	Fuel Producer: Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Locust Ridge Farm (71298); Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Ridge Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ delivered by truck to and re-gasified in CA (Provisional)	Missouri	Swine Manure (044)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN044B00090200	-308.93	1/31/2020	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Locust Ridge Farm (71298)	Renewable Natural Gas (RNG) sourced from Swine Manure of Locust Ridge Farms, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ delivered by truck to and re-gasified in CA (Provisional)	None	Retired
B000903	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Locust Ridge Farm (71298); Liquefied Natural Gas (LNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	Missouri	Swine Manure (044)	Liquefied Natural Gas (LNG)	None	None	LNG044B00090300	-312.47	12/31/2019	Application Package	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Locust Ridge Farm (71298)	Liquefied Natural Gas (LNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	None	Retired
B001001	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B00100100	-345.68	1/31/2020	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	None	Retired
B001002	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	Missouri	Swine Manure (044)	Liquefied Natural Gas (LNG)	None	None	LNG044B00100200	-334.41	1/31/2020	Application Package	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, Arizona; delivered by truck to California (Provisional)	None	Retired
B001003	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to and re-gasified in CA (Provisional)	Missouri	Swine Manure (044)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN044B00100300	-330.87	1/31/2020	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) sourced from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to and re-gasified in CA (Provisional)	None	Retired
None	Lookup Table	3.0	California grid electricity used as a transportation fuel in California	California	Grid Electricity (039)	Electricity (ELC)	None	None	ELC000L00072020	82.92	NA	None	Electricity	NA	NA	California grid electricity used as a transportation fuel in California	None	Retired
T1R-1119	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: Complexe Enviro Progressive Ltee (71198); Quebec LFG to LNG then to L-CNG	California	Landfill Gas	CNG	CNGLF211LR	44.05	CNGLF211LR1	44.07	3/30/2020	None	Bio-CNG	Clean Energy (5481)	Complexe Enviro Progressive Ltee (71198)	Quebec LFG to LNG then to L-CNG	None	Retired

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T1R-1120	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: Complexe Enviro Progressive Itee (71198); Quebec LFG to CNG for California CNG stations	California	Landfill Gas	CNG	CNGLF212L	31.96	CNGLF212LR	31.98	3/30/2020	None	Bio-CNG	Clean Energy (5481)	Complexe Enviro Progressive Itee (71198)	Quebec LFG to CNG for California CNG stations	None	Retired
T1R-1121	Tier 1	2.0	Fuel Producer: Clean Energy (5481); Facility Name: Complexe Enviro Progressive Itee (71198); Quebec LFG to LNG facility in Boron for use in California	California	Landfill Gas	LNG	LNGLF207LR	41.44	LNGLF207LR1	41.46	3/30/2020	None	Bio-LNG	Clean Energy (5481)	Complexe Enviro Progressive Itee (71198)	Quebec LFG to LNG facility in Boron for use in California	None	Retired
T2N-1154	Tier 2	2.0	Fuel Producer: Biodico Westside (6231); Facility Name: Biodico Plant (83027); California Used Cooking Oil, Biodiesel produced in Five Points, California.	California	Used Cooking Oil (UCO)	Biodiesel	BDU229	14.97	BDU229R	25.91	4/2/2020	Application Package	Biodiesel	Biodico Westside (6231)	Biodico Plant (83027)	California Used Cooking Oil, Biodiesel produced in Five Points, California.	None	Retired
T1N-1572	Tier 1	2.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Dry mill corn ethanol with co-production of MDGS and corn oil using natural gas and electricity power.	Nebraska	Corn	Ethanol	ETHC293	68.89	ETHC293R	69.02	4/2/2020	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Dry mill corn ethanol with co-production of MDGS and corn oil using natural gas and electricity power.	None	Retired
T1N-1811	Tier 1	2.0	Fuel Producer: Fuel Producer: San Diego Metropolitan Transit Center (S304) ; Facility Name: Facility Name: EBI Energie In (71254); EBI landfill gas in Saint-Thomas, Quebec to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	California	Landfill Gas	CNG	CNGLF277	32.28	CNGLF277R	37.39	4/2/2020	None	Bio-CNG	San Diego Metropolitan Transit Center (S304)	EBI Energie In (71254)	EBI landfill gas in Saint-Thomas, Quebec to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	None	Retired
T1N-1859	Tier 1	2.0	Fuel Producer: Kansas Ethanol, LLC ; Facility Name: Kansas Ethanol, LLC (70279); Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuels. DDGS, WDGS, and corn oil as co-products	Kansas	Corn	Ethanol	ETHC299	67.83	ETHC299R	68.72	4/2/2020	None	Ethanol	Kansas Ethanol, LLC	Kansas Ethanol, LLC (70279)	Midwest Corn, Ethanol, Dry Mill, NG, and grid electricity as process fuels. DDGS, WDGS, and corn oil as co-products	None	Retired
T2N-1287	Tier 2	2.0	Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Naphtha produced from North American Tallow, Naphtha produced in Paramount, California	California	Tallow & Animal Fat	Renewable Naphtha	RNWN200	39.75	RNWN200R	43.14	4/2/2020	Application Package	Renewable Gasoline	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Tier 2 Method 2B Application: Renewable Naphtha produced from North American Tallow, Naphtha produced in Paramount, California	None	Retired
T2N-1290	Tier 2	2.0	Fuel Producer: AltAir Paramount, LLC (6281) ; Facility Name: AltAir Paramount, LLC (83180); Tier 2 Method 2B Application: Renewable Diesel produced from North American Tallow, in Paramount, California	California	Tallow & Animal Fat	Renewable Diesel	RDT209	38.75	RDT209R	39.91	4/2/2020	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Tier 2 Method 2B Application: Renewable Diesel produced from North American Tallow, in Paramount, California	None	Retired
A021201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California (Provisional)	Missouri	Corn (009)	Ethanol (ETH)	None	None	ETH009A02120100	75.09	4/28/2020	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California (Provisional)	None	Retired
A021202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California (Provisional)	Missouri	Corn (009)	Ethanol (ETH)	None	None	ETH009A02120200	65.67	4/28/2020	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California (Provisional)	None	Retired
A021203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) ; Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California (Provisional)	Missouri	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A02120300	26.19	4/28/2020	None	Ethanol - Cellulosic	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California (Provisional)	None	Retired
T1N-1384	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average North American Sourced Used Cooking Oil (energy required to render) to Biodiesel Produced in California	Bakersfield, California	North American Used Cooking Oil	Biodiesel	BDU203	18.18	BDU203R	18.31	6/9/2020	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average North American Sourced Used Cooking Oil (energy required to render)to Biodiesel Produced in California	None	Retired

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T1N-1386	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average U.S. Sourced Tallow to Biodiesel Produced in California	Bakersfield, California	North American Tallow	Biodiesel	BDT203	30.60	BDT203R	31.39	6/9/2020	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average US Sourced Tallow to Biodiesel Produced in California	None	Retired
T1N-1389	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average California Sourced Tallow to Biodiesel Produced in California	Bakersfield, California	California Tallow	Biodiesel	BDT204	28.45	BDT204R	28.92	6/9/2020	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average California Sourced Tallow to Biodiesel Produced in California	None	Retired
T2N-1107	Tier 2	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average North American Sourced Used Cooking Oil (energy not required to render) to Biodiesel Produced in California	Bakersfield, California	Used Cooking Oil	Biodiesel	BDU204	13.93	BDU204R	14.70	6/9/2020	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average North American Sourced Used Cooking Oil (energy not required to render) to Biodiesel Produced in California	None	Retired
T1N-1800	Tier 1	2.0	Fuel Producer: Crimson Renewable Enegy LP (4814) ; Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); Average California sourced Used Cooking Oil UCO) to Biodiesel produced in California	California	Used Cooking Oil	Biodiesel	BDU233	18.16	BDU233R	18.22	6/9/2020	None	Biodiesel	Crimson Renewable Enegy LP (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	Average California sourced Used Cooking Oil (UCO) to Biodiesel produced in California	None	Retired
A022801	Tier 1	3.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174); Facility Name: Apex LFG Energy (F00034); Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional)	Arizona	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02280100	77.65	6/16/2020	None	Bio-LNG	Applied Natural Gas Fuels, Inc. (6174)	Apex LFG Energy (F00034)	Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional)	None	Retired
A022802	Tier 1	3.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174); Facility Name: Apex LFG Energy (F00034); Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in CA (Provisional)	Arizona	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02280200	80.74	6/16/2020	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	Apex LFG Energy (F00034)	Biomethane from Landfill at Amsterdam, OH; Upgrading at Apex LFG Energy; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in CA (Provisional)	None	Retired
A022701	Tier 1	3.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174); Facility Name: Timberline Energy, LLC (F00028); Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional)	Arizona	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02270100	63.13	6/16/2020	None	Bio-LNG	Applied Natural Gas Fuels, Inc. (6174)	Timberline Energy, LLC (F00028)	Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck and dispensed at LNG Stations in California (Provisional)	None	Retired
A022702	Tier 1	3.0	Fuel Producer: Applied Natural Gas Fuels, Inc. (6174) ; Facility Name: Timberline Energy, LLC (F00028); Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in CA (Provisional)	Arizona	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02270200	66.21	6/16/2020	None	Bio-CNG	Applied Natural Gas Fuels, Inc. (6174)	Timberline Energy, LLC (F00028)	Biomethane from Landfill at Oklahoma City, OK; upgrading at Oklahoma, OK; Pipelined to ANGF in Topock, AZ for liquefaction to LNG; Delivered by truck to California; Regasified and compressed to LCNG and dispensed at CNG Stations in California (Provisional)	None	Retired
A021802	Tier 1	3.0	Fuel Producer: PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080); Facility Name: H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301); Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Washington	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02180200	50.02	6/22/2020	None	Bio-LNG	PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080)	H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301)	Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A021803	Tier 1	3.0	Fuel Producer: PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080); Facility Name: H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301); Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations; regassified, and compressed to L-CNG (Provisional)	Washington	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02180300	53.11	6/22/2020	None	Bio-CNG	PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080)	H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301)	Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to LNG Boron Plant, California for liquefaction to LNG; trucked to California LNG stations; regassified, and compressed to L-CNG (Provisional)	None	Retired
A021901	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc, pipelined to California for compression to CNG (Provisional)	Canada	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02190100	38.64	6/22/2020	None	Bio-CNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc in Quebec, Canada; pipelined to California for compression to CNG (Provisional)	None	Retired
A021902	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stationso California by pipeline, liquefied in California (Provisional)	Canada	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02190200	51.69	6/22/2020	None	Bio-LNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stations by pipeline, liquefied in California (Provisional)	None	Retired

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A021903	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified and compressed to L-CNG (Provisional)	Canada	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02190300	54.77	6/22/2020	None	Bio-CNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified and compressed to L-CNG (Provisional)	None	Retired
A021301	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00070100	65.21	ETH009A02130100	61.55	6/22/2020	None	Ethanol	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI (Provisional)	None	Retired
A021302	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00070200	25.06	ETH012A02130200	21.31	6/22/2020	None	Ethanol - Cellulosic	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
A019801	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00980100	61.48	ETH009A01980100	61.26	6/24/2020	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI (Provisional)	None	Retired
A019802	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A01980200	23.46	6/24/2020	None	Ethanol - Cellulosic	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California (Provisional)	None	Retired
A020901	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A01370100	72.86	ETH009A02090100	73.74	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
A020902	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A01370200	69.05	ETH009A02090200	70.47	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
A020903	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A01370300	65.76	ETH009A02090300	66.86	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
A020904	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A02090400	27.48	6/24/2020	None	Ethanol - Cellulosic	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California (Provisional)	None	Retired
A022401	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01120100	68.75	ETH009A02240100	69.32	6/24/2020	None	Ethanol	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A022402	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01120300	65.90	ETH009A02240200	66.23	6/24/2020	None	Ethanol	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A022403	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A02240300	63.27	6/24/2020	None	Ethanol	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A022404	Tier 1	3.0	Fuel Producer: LSCP, LLLP (4728); Facility Name: LSCP, LLLP (70015); Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A01120200	30.06	ETH012A02240400	23.96	6/24/2020	None	Ethanol - Cellulosic	LSCP, LLLP (4728)	LSCP, LLLP (70015)	Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A020001	Tier 1	3.0	Fuel Producer: GHI Energy, LLC (6156); Facility Name: Waste Management American Landfill (70421); Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF264	43.97	CNG025A02000100	40.13	6/29/2020	None	Bio-CNG	GHI Energy, LLC (6156)	Waste Management American Landfill (70421)	Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional)	None	Retired
B010001	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount California for Alternative Jet Fuel production (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B01000100	23.93	6/29/2020	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount California for Alternative Jet Fuel production (Provisional)	None	Retired
B010002	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount, California for Renewable Diesel production (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01000200	23.93	6/29/2020	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount, California for Renewable Diesel production (Provisional)	None	Retired
B010003	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Rendered Animal Fat Oil from Greely, Colorado transported by rail to AltAir Paramount plant in Paramount, California for Renewable Naphtha production (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01000300	23.93	6/29/2020	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Rendered Animal Fat Oil from Greely, Colorado transported by train to AltAir Paramount plant in Paramount, California for Renewable Naphtha production (Provisional)	None	Retired
B005901	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00590100	-558.62	6/30/2020	Application Package	Electricity	California Bioenergy LLC (B194)	ABEC Bidart-Old River LLC (F00113)	Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	None	Retired
B008901	Tier 2	3.0	Fuel Producer: Gallo Cattle Company, LP (C1029) ; Facility Name: Cottonwood Dairy (F00094); Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00890100	-108.43	6/30/2020	Application Package	Electricity	Gallo Cattle Company, LP (C1029)	Cottonwood Dairy (F00094)	Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional)	None	Retired
B009801	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980100	-355.35	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional)	None	Retired
B009802	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980200	-377.83	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	None	Retired
B009805	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980500	-368.04	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	None	Retired
B009806	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980600	-374.10	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	None	Retired
A021701	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	North Dakota	Corn (009)	Ethanol (ETH)	ETHC287	75.23	ETH009A02170100	69.84	7/27/2020	None	Ethanol	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired

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A021702	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); MMidwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	North Dakota	Corn (009)	Ethanol (ETH)	ETHC287	75.23	ETH009A02170200	66.96	7/27/2020	None	Ethanol	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	MMidwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired
A021703	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	North Dakota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A02170300	25.72	7/27/2020	None	Ethanol - Cellulosic	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired
A023201	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Renovar Arlington, LTD RNG Project (70501); Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG. (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02320100	43.15	7/24/2020	None	Bio-CNG	U.S. Venture, Inc. (5504)	Renovar Arlington, LTD RNG Project (70501)	Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG. (Provisional)	None	Retired
A023301	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional)	Kansas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02330100	45.91	7/24/2020	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional)	None	Retired
A023805	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Sanimax (Quebec City) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	Canada	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A02380500	36.98	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	Sanimax (Quebec City) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	None	Retired
A023808	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Sanimax (Hamilton) Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	Canada	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A02380800	22.81	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	Sanimax (Hamilton) Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	None	Retired
A024901	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A02490100	74.54	7/24/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional)	None	Retired
A024902	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A02490200	67.28	7/24/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (Provisional)	None	Retired
T1R-1184	Tier 1	2.0	Fuel Producer: BP Biofuels (4427) ; Facility Name: Ituiutaba Bioenergia Ltda (71006); Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	Brazil	Sugarcane (018)	Ethanol	ETHS204L	38.98	ETHS204LR	41.52	8/13/2020	None	Ethanol	BP Biofuels (4427)	Ituiutaba Bioenergia Ltda (71006)	Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	None	Retired
T1R-1185	Tier 1	2.0	Fuel Producer: BP Biofuels (4427) ; Facility Name: Ituiutaba Bioenergia Ltda (71006); Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	Brazil	Molasses (019)	Ethanol	ETHM204L	38.30	ETHM204LR	40.84	8/13/2020	None	Ethanol	BP Biofuels (4427)	Ituiutaba Bioenergia Ltda (71006)	Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	None	Retired
T1R-1183	Tier 1	2.0	Fuel Producer: BP Biofuels (4427) ; Facility Name: Central Itumbiara de Bioenergia e Alimentos Ltda (71007); Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	Brazil	Molasses (019)	Ethanol	ETHM203L	39.84	ETHM203LR	42.42	8/13/2020	None	Ethanol	BP Biofuels (4427)	Central Itumbiara de Bioenergia e Alimentos Ltda (71007)	Brazilian sugarcane by-product molasses-based ethanol, with credit for electricity co-product export, and mechanized harvesting	None	Retired
T1R-1182	Tier 1	2.0	Fuel Producer: BP Biofuels (4427) ; Facility Name: Central Itumbiara de Bioenergia e Alimentos Ltda (71007); Brazilian sugarcane juice-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	Brazil	Sugarcane (018)	Ethanol	ETHS203L	40.74	ETHS203LR	43.32	8/13/2020	None	Ethanol	BP Biofuels (4427)	Central Itumbiara de Bioenergia e Alimentos Ltda (71007)	Brazilian sugarcane juice-based ethanol with average production processes, with credit for electricity cogeneration and surplus export, and mechanization	None	Retired

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B005801	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) produced from Dairy Manure at T&M Bos Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00580100	-167.04	12/31/2019	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) produced from Dairy Manure at T&M Bos Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional)	None	Retired
B005802	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure at T&M Herrema Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00580200	-151.41	12/31/2019	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure at T&M Herrema Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional)	None	Retired
B005803	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure at T&M Windy Ridge Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00580300	-257.78	12/31/2019	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure at T&M Windy Ridge Dairy and upgraded to RNG at Generate Jasper Upgrader in Fair Oaks, Indiana; RNG pipelined to California for transportation use (Provisional)	None	Retired
B006001	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00600100	-255.74	2/24/2020	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Fair Oaks Upgrader, LLC (71001)	Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California (Provisional)	None	Retired
T1N-1387	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average California Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California (Provisional)	Bakersfield, California	CA Corn Oil from Wet DGS	Biodiesel	None	None	BDC202	27.45	6/30/2016	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average California Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California (Provisional)	None	Retired
T1N-1388	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average U.S. Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California **(Provisional)**	Bakersfield, California	U.S. Corn Oil from Wet DGS	Biodiesel	None	None	BDC203	28.48	6/30/2016	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average US Sourced Corn Oil from Wet DGS of a Dry Mill Corn Ethanol Plant to Biodiesel Produced in California (Provisional)	None	Retired
T1N-1543	Tier 1	2.0	Fuel Producer: Crimson Renewable Energy LP (4814) Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174): Average Global Sourced Used Cooking Oil (energy required to render) to Biodiesel Produced in California **(Provisional)**	Bakersfield, California	Global Used Cooking Oil	Biodiesel	None	None	BDU205	23.28	6/30/2016	None	Biodiesel	Crimson Renewable Energy LP (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Average Global Sourced Used Cooking Oil (energy required to render)to Biodiesel Produced in California (Provisional)	None	Retired
T1N-1670	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Valley LFG, LLC (71137); Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ	Pennsylvania	Landfill Gas	Liquefied Natural Gas	LNGLF226	66.92	LNGLF226R	70.36	9/22/2020	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Valley LFG, LLC (71137)	Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ	None	Retired
T1N-1671	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Valley LFG, LLC (71137); Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; re-gasified in CA.	Pennsylvania	Landfill Gas	Compressed Natural Gas	CNGLF266	69.47	CNGLF266R	72.91	9/22/2020	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Valley LFG, LLC (71137)	Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline; liquefied to LNG in AZ; re-gasified in CA.	None	Retired
T1N-1669	Tier 1	2.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Valley LFG, LLC (71137); Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations	Pennsylvania	Landfill Gas	Compressed Natural Gas	CNGLF267	54.61	CNGLF267R	57.83	9/22/2020	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Valley LFG, LLC (71137)	Valley landfill gas (PA) to pipeline-quality biomethane; delivered via pipeline to California CNG Stations	None	Retired
A027101	Tier 1	3.0	Fuel Producer: Jaxon Energy, LLC (6454) ; Facility Name: Jaxon Energy, LLC (83608); Distilled Corn Oil transported by truck to Renewable Diesel plant in Jackson, Missouri; Natural Gas and Electricity; Renewable Diesel transported by rail to California (Provisional)	Mississippi	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003A02710100	78.60	10/2/2020	None	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	Distilled Corn Oil transported by truck to Renewable Diesel plant in Jackson, Missouri; Natural Gas and Electricity; Renewable Diesel transported by rail to California (Provisional)	None	Retired
A026501	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: HUB CITY ENERGY LLC (70721); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A02650100	73.16	10/9/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	HUB CITY ENERGY LLC (70721)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI (Provisional)	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A024701	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02470100	49.78	10/13/2020	None	Bio-CNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG	None	Retired
B007201	Tier 2	3.0	Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180); Facility Name: WOF PNW Threemile Project (F00100); Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use (Provisional)	Oregon	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00720100	-188.78	9/30/2020	Application Package	Bio-CNG	IOGEN D3 BIOFUEL PARTNERS II LLC (7180)	WOF PNW Threemile Project (F00100)	Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use (Provisional)	None	Retired
B007901	Tier 2	3.0	Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B00790100	30.48	9/30/2020	Application Package	Renewable Diesel	Kern Oil & Refining Co. (5038)	Kern Oil & Refining Co. (80105)	Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional)	None	Retired
B007902	Tier 2	3.0	Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B00790200	41.85	9/30/2020	Application Package	Renewable Diesel	Kern Oil & Refining Co. (5038)	Kern Oil & Refining Co. (80105)	Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution (Provisional)	None	Retired
B010901	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01090100	-453.10	9/30/2020	Application Package	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	None	Retired
B010902	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01090200	-308.48	9/30/2020	Application Package	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	None	Retired
B010903	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01090300	-236.96	9/30/2020	Application Package	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use (Provisional)	None	Retired
B009601	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Dairy Dreams (F00127); Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00960100	-532.74	9/30/2020	Application Package	Bio-CNG	Clean Energy (5481)	Calumet - Dairy Dreams (F00127)	Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use (Provisional)	None	Retired
B009701	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Ponderosa (F00128); Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00970100	-372.20	9/30/2020	Application Package	Bio-CNG	Clean Energy (5481)	Calumet - Ponderosa (F00128)	Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use (Provisional)	None	Retired
B010801	Tier 2	3.0	Fuel Producer: AgPower Jerome, LLC (C1036); Facility Name: AgPower Jerome RNG Project (F00077); Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use (Provisional)	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01080100	-230.13	9/30/2020	Application Package	Bio-CNG	AgPower Jerome, LLC (C1036)	AgPower Jerome RNG Project (F00077)	Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use (Provisional)	None	Retired
A024201	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF250	54.87	CNG025A02420100	47.53	10/29/2020	None	Bio-CNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG	None	Retired
A024202	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations	Tennessee	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02420200	60.15	10/29/2020	None	Bio-LNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations	None	Retired

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A024203	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	Tennessee	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02420300	63.24	10/29/2020	None	Bio-CNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	None	Retired
A027201	Tier 1	3.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETHC295	74.03	ETH009A02720100	65.63	10/21/2020	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI. (Provisional)	None	Retired
A027202	Tier 1	3.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A02720200	26.60	10/21/2020	None	Ethanol - Cellulosic	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional)	None	Retired
A025901	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Distillers' Corn Oil (003)	Biodiesel (BIO)	None	None	BIO003A02590100	36.62	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	None	Retired
A025902	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A02590200	66.13	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	None	Retired
A025903	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A02590300	41.88	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	None	Retired
A024101	Tier 1	3.0	Fuel Producer: COMPLEXE ENVIRO CONNEXIONS LTEE (6282); Facility Name: Complexe Enviro Connexions (F00139); Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to California for compression to CNG (Provisional)	Canada	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02410100	29.92	11/12/2020	None	Bio-CNG	COMPLEXE ENVIRO CONNEXIONS LTEE (6282)	Complexe Enviro Connexions (F00139)	Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to California for compression to CNG (Provisional)	None	Retired
A024102	Tier 1	3.0	Fuel Producer: COMPLEXE ENVIRO CONNEXIONS LTEE (6282); Facility Name: Complexe Enviro Connexions (F00139); Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations in California (Provisional)	Canada	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02410200	42.70	11/12/2020	None	Bio-LNG	COMPLEXE ENVIRO CONNEXIONS LTEE (6282)	Complexe Enviro Connexions (F00139)	Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations in California (Provisional)	None	Retired
A024103	Tier 1	3.0	Fuel Producer: COMPLEXE ENVIRO CONNEXIONS LTEE (6282); Facility Name: Complexe Enviro Connexions (F00139); Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations; regasified, and compressed to L-CNG (Provisional)	Canada	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02410300	45.78	11/12/2020	None	Bio-CNG	COMPLEXE ENVIRO CONNEXIONS LTEE (6282)	Complexe Enviro Connexions (F00139)	Biomethane from Landfill at Quebec Canada, upgrading at Complexe Enviro Connexions Ltée, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to LNG stations; regasified, and compressed to L-CNG (Provisional)	None	Retired
A024801	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Starch Ethanol produced from Midwest corn, dry milled, produced with grid electricity and natural gas with DDGs, MDGS, and corn oil co-products	Iowa	Corn (009)	Ethanol (ETH)	ETHC220	78.14	ETH009A02480100	70.62	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Fort Dodge (70043)	Starch Ethanol produced from Midwest corn, dry milled, produced with grid electricity and natural gas with DDGs, MDGS, and corn oil co-products	None	Retired
A024802	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Fort Dodge, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC220	78.14	ETH009A02480200	67.47	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Fort Dodge (70043)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Fort Dodge, Iowa; Ethanol transported by rail to California	None	Retired
A025601	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Aurora, South Dakota (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC262L	76.74	ETH009A02560100	71.32	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Aurora, South Dakota (70041)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California	None	Retired

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A025602	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Aurora, South Dakota (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETHC262L	76.74	ETH009A02560200	68.05	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Aurora, South Dakota (70041)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Aurora, South Dakota; Ethanol transported by rail to California	None	Retired
A025401	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California; Composite CI	Iowa	Corn (009)	Ethanol (ETH)	ETHC260L	78.62	ETH009A02540100	69.55	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Albert City (70142)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Natural Gas, Grid Electricity; Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California; Composite CI	None	Retired
A025402	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC260L	78.62	ETH009A02540200	66.07	11/18/2020	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Albert City (70142)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Albert City, Iowa; Ethanol transported by rail to California	None	Retired
A024301	Tier 1	3.0	Fuel Producer: LES RENEWABLE NG LLC (6223); Facility Name: LES RENEWABLE NG LLC (71157); Biomethane from SWACO Landfill in Grove City, Ohio, upgrading at LES Renewable NG LLC, pipelined to California for compression to CNG	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02430100	60.40	11/19/2020	None	Bio-CNG	LES RENEWABLE NG LLC (6223)	LES RENEWABLE NG LLC (71157)	Biomethane from SWACO Landfill in Grove City, Ohio, upgrading at LES Renewable NG LLC, pipelined to California for compression to CNG	None	Retired
A028201	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail (Provisional)	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT202	35.57	BIO002A02820100	27.02	11/20/2020	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail (Provisional)	None	Retired
B011401	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied hydrogen from landfill gas at Fresno, Texas; liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to H2 stations in Northern California	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B01140100	109.68	11/25/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Liquefied hydrogen from landfill gas at Fresno, Texas; liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to H2 stations in Northern California	None	Retired
B011501	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426) ; Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Biomethane from BlueRidge landfill, Texas, hydrogen produced at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to fueling stations in Southern California.	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B01150100	73.14	11/25/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products and Chemicals SMR Wilmington. CA (F00068)	Biomethane from BlueRidge landfill, Texas, hydrogen produced at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to fueling stations in Southern California.	None	Retired
B012801	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied hydrogen from North American Natural Gas, produced at Air Products & Chemicals Inc., Sacramento, California transported as liquid hydrogen to liquid fueling stations in California	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B01280100	153.91	11/25/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Liquefied hydrogen from North American Natural Gas, produced at Air Products & Chemicals Inc., Sacramento, California transported as liquid hydrogen to liquid fueling stations in California	None	Retired
B010201	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020100	-408.6	CNG026B01020101	-408.62	12/3/2020	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	None	Retired
B010202	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01020200	-289.76	12/3/2020	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	None	Retired
B010203	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01020300	-308.74	12/3/2020	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	None	Retired
A024501	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00570100	76.25	ETH009A02450100	69.92	12/4/2020	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired

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A024502	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00570200	67.07	ETH009A02450200	62.54	12/4/2020	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A024503	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00570300	28.39	ETH012A02450300	22.56	12/4/2020	None	Ethanol - Cellulosic	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A025501	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Albion (702830); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC106	86.49	ETH009A02550100	71.02	12/3/2020	None	Ethanol	Valero Renewable Fuels (3201)	Albion (702830)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California	None	Retired
A025502	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Albion (702830); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC107	82.37	ETH009A02550200	67.05	12/3/2020	None	Ethanol	Valero Renewable Fuels (3201)	Albion (702830)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California	None	Retired
A029701	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Kansas	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02970101	58.34	12/15/2020	None	Bio-LNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A029702	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Kansas	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02970200	61.43	12/15/2020	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
B011901	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable jet fuel produced from animal fat; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B01190100	19.51	12/18/2020	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable jet fuel produced from animal fat; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	None	Retired
B011902	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable diesel produced from animal fat; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01190200	19.51	12/18/2020	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable diesel produced from animal fat; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional)	None	Retired
B011903	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable naphtha produced from animal fat; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01190300	19.51	12/18/2020	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable naphtha produced from animal fat; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional)	None	Retired
B008002	Tier 2	3.0	Fuel Producer: Bridge To Renewables, Benefit LLC (C1006); Facility Name: Blake's Landing Farms (F00019); Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI (Provisional)	California	Other Organic Waste (029)	Electricity (ELC)	None	None	ELC029B00800200	-233.49	12/31/2020	Application Package	Electricity	Bridge To Renewables, Benefit LLC (C1006)	Blake's Landing Farms (F00019)	Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI (Provisional)	None	Retired
B009901	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Midwest Corn Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Corn (009)	Ethanol (ETH)	ETHC282	80.85	ETH009B00990101	74.02	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	Midwest Corn Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired
B009902	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Midwest Corn Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Corn (009)	Ethanol (ETH)	ETHC281	72.32	ETH009B00990200	63.64	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	Midwest Corn Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired

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B009903	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); US-sourced Grain Sorghum Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG217	88.90	ETH010B00990300	77.27	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	US-sourced Grain Sorghum Ethanol, Dry Mill, Dry DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired
B009904	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); US-sourced Grain Sorghum Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG216	80.38	ETH010B00990400	66.90	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	US-sourced Grain Sorghum Ethanol, Dry Mill, Wet DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired
B009905	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Ethanol produced from Dry Mill, Wheat Starch Slurry, Dry DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Wheat Starch Slurry (014)	Ethanol (ETH)	ETHWSS201	53.73	ETH014B00990500	52.76	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	Ethanol produced from Dry Mill, Wheat Starch Slurry, Dry DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired
B009906	Tier 2	3.0	Fuel Producer: PureField Ingredients LLC (7241); Facility Name: PureField Ingredients LLC (70302); Ethanol produced from Dry Mill, Wheat Starch Slurry, Wet DGS, NG, electricity; Ethanol transported to CA by rail	Kansas	Wheat Starch Slurry (014)	Ethanol (ETH)	ETHWSS200	45.2	ETH014B00990600	47.78	12/31/2020	Application Package	Ethanol	PureField Ingredients LLC (7241)	PureField Ingredients LLC (70302)	Ethanol produced from Dry Mill, Wheat Starch Slurry, Wet DGS, NG, electricity; Ethanol transported to CA by rail	None	Retired
A024601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A02460100	77.21	12/29/2020	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	None	Retired
A024602	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	None	None	ETH009A02460200	69.47	12/29/2020	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	None	Retired
A024603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A02460300	29.41	12/29/2020	None	Ethanol - Cellulosic	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (Provisional)	None	Retired
B012701	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01270100	-417.35	12/31/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	None	Retired
B012702	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007) ; Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01270200	-417.27	12/31/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	None	Retired
B012703	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01270300	-418.90	12/31/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	None	Retired
B012704	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01270400	-392.44	12/31/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use (Provisional)	None	Retired
B014501	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B01450100	-287.07	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products and Chemicals SMR Wilmington. CA (F00068)	Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California	None	Retired

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B014502	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B01450200	-216.05	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products and Chemicals SMR Wilmington. CA (F00068)	Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to gaseous hydrogen production at Air Products & Chemicals Inc., Wilmington, California transported as gaseous hydrogen to hydrogen stations in California	None	Retired
B014601	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from landfill gas at Fresno, Texas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California; and transported as gaseous hydrogen to fueling stations in California	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B01460100	120.04	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Biomethane from landfill gas at Fresno, Texas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California; and transported as gaseous hydrogen to fueling stations in California	None	Retired
B014602	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); North American Natural Gas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California and transported as gaseous hydrogen to fueling stations in California	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B01460200	164.27	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	North American Natural Gas to Liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California; transported as liquid hydrogen to a transfill Station in Santa Clara, California and transported as gaseous hydrogen to fueling stations in California	None	Retired
B016401	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to hydrogen stations in California	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B01640100	-251.36	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California transported as liquid to hydrogen stations in California	None	Retired
B016402	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B01640200	-241.00	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Biomethane from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California	None	Retired
B016403	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California, transported to hydrogen stations in California	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B01640300	-179.71	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; liquid hydrogen produced at Air Products & Chemicals Inc., Sacramento, California, transported to hydrogen stations in California	None	Retired
B016404	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B01640400	-169.35	12/31/2020	Application Package	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Biomethane from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana to liquid hydrogen production at Air Products & Chemicals Inc., Sacramento, California; transported as liquid to a transfill station in Santa Clara, California; gasified and compressed and transported as gaseous hydrogen to fueling stations in California	None	Retired
B010201	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020100	-408.60	CNG026B01020101	-408.62	12/3/2020	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use (Provisional)	None	Retired
A027401	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Renovar Arlington, LTD RNG Project (70501); Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional)	Texas	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A02740100	38.37	3/1/2021	None	Bio-CNG	U.S. Venture, Inc. (5504)	Renovar Arlington, LTD RNG Project (70501)	Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional)	None	Retired
A033001	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00990100	73.79	ETH009A03300100	73.75	3/1/2021	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	None	Retired
A027901	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	Arkansas	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC210	38.75	BIO003A02790100	33.97	3/9/2021	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	None	Retired
A027902	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	Arkansas	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU207L	24.36	BIO001A02790200	27.05	3/9/2021	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	None	Retired

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A029801	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional)	Washington	Landfill Gas (025)	Compressed Natural Gas (CNG)	LNGLF206LR	40.21	CNG025A02980100	28.24	3/12/2021	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional)	None	Retired
A029802	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Washington	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNGLF206LR	40.21	LNG025A02980200	41.09	3/12/2021	None	Bio-LNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A029803	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Washington	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	CNGLF229LR	42.78	LCN025A02980300	44.18	3/12/2021	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A026703	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02670300	55.90	3/18/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Raeger (71131)	Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A026702	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02670200	52.82	3/18/2021	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Raeger (71131)	Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A026701	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF275	42.86	CNG025A02670100	35.51	3/18/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Raeger (71131)	Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG (Provisional)	None	Retired
A026203	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Shade (71134); Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to California for compression to CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF273R	49.77	CNG025A02620300	52.21	3/18/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Shade (71134)	Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to California for compression to CNG (Provisional)	None	Retired
A026202	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Shade (71134); Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02620200	72.80	3/18/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Shade (71134)	Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A026201	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Shade (71134); Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02620100	69.71	3/18/2021	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Shade (71134)	Biomethane from Johnstown Regional Energy - Shade Landfill in Cairnbrook, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A026401	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02640100	77.89	3/17/2021	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Southern Alleghenies (71133)	Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A026402	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02640200	80.98	3/17/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Southern Alleghenies (71133)	Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to Topock, Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A026403	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF274	58.84	CNG025A02640300	60.28	3/17/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Johnstown Regional Energy - Southern Alleghenies (71133)	Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG (Provisional)	None	Retired

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A029401	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETH009A01400200	72.42	ETH009A02940100	70.88	3/22/2021	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A029402	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETH009A01400100	63.69	ETH009A02940200	61.90	3/22/2021	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A029403	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum from Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A01400400	75.50	ETH010A02940300	74.04	3/22/2021	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Sorghum from Dry Mill; Dry DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California	None	Retired
A029404	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum from Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California.	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A01400300	66.76	ETH010A02940400	65.06	3/22/2021	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Sorghum from Dry Mill; Wet DGS, Corn oil and Syrup, Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California.	None	Retired
A031002	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Louisiana	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A03100200	53.73	3/18/2021	None	Bio-LNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A031003	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Louisiana	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A03100300	56.81	3/18/2021	None	Bio-CNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A031201	Tier 1	3.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	California	Soybean Oil (005)	Biodiesel (BIO)	BDS201	52.45	BIO005A03120100	57.16	3/23/2021	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	None	Retired
A031202	Tier 1	3.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	California	Canola Oil (006)	Biodiesel (BIO)	BDCA201	54.97	BIO006A03120200	51.65	3/23/2021	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	None	Retired
A031204	Tier 1	3.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production.	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT205	32.24	BIO002A03120400	31.28	3/23/2021	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production.	None	Retired
A031205	Tier 1	3.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT206	28.90	BIO002A03120500	32.45	3/23/2021	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	None	Retired
A031206	Tier 1	3.0	Fuel Producer: American Biodiesel, Inc., dba Community Fuels (4935); Facility Name: Community Fuels Port of Stockton (82728); US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A03120600	21.27	3/23/2021	None	Biodiesel	American Biodiesel, Inc., dba Community Fuels (4935)	Community Fuels Port of Stockton (82728)	US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	None	Retired
B005901	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00590100	-558.62	ELC026B00590101	-562.50	3/25/2021	Application Package	Electricity	California Bioenergy LLC (B194)	ABEC Bidart-Old River LLC (F00113)	Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	None	Retired

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B008901	Tier 2	3.0	Fuel Producer: Gallo Cattle Company, LP (C1029) ; Facility Name: Cottonwood Dairy (F00094); Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00890100	-108.43	ELC026B00890101	-126.52	3/25/2021	Application Package	Electricity	Gallo Cattle Company, LP (C1029)	Cottonwood Dairy (F00094)	Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California. (Provisional)	None	Retired
B013311	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01331100	26.5	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013312	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01331200	28.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
A029501	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU219	21.73	BIO001A02950100	21.93	4/1/2021	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	None	Retired
A029502	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU240	19	BIO001A02950200	16.98	4/1/2021	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	None	Retired
A030601	Tier 1	3.0	Fuel Producer: MONROEVILLE LFG, LLC (6317); Facility Name: MONROEVILLE LFG, LLC (71136); Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A03060100	41.93	4/6/2021	None	Bio-CNG	MONROEVILLE LFG, LLC (6317)	MONROEVILLE LFG, LLC (71136)	Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional)	None	Retired
B018908	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01890800	27.00	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018909	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01890900	28.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018917	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891700	27.00	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from Sanimax Montreal animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018918	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891800	28.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from Sanimax USA animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
None	Lookup Table	3.0	California grid electricity used as a transportation fuel in California	California	Grid Electricity (039)	Electricity (ELC)	None	None	ELC000L00072021	75.93	NA	None	Electricity	NA	NA	California grid electricity used as a transportation fuel in California	None	Retired
A028807	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Self Rendered Animal Fat Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	Iowa	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A02880700	24.50	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	Self Rendered Animal Fat Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	None	Retired

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A030901	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03090100	24.46	5/4/2021	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	Retired
A030902	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	ETHC247L	75.15	ETH009A03090200	71.95	5/4/2021	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	Retired
A036702	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional)	Tennessee	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A03670200	62.18	5/11/2021	None	Bio-LNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A036703	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional)	Tennessee	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A03670300	65.26	5/11/2021	None	Bio-CNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional)	None	Retired
A028501	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Zero Energy Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU204R	14.7	BIO001A02850100	12.91	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	US sourced Zero Energy Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	None	Retired
A028502	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); California sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A02850200	12.93	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	California sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	None	Retired
A028503	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU203R	18.31	BIO001A02850300	17.86	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	US sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	None	Retired
A028504	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A02850400	15.81	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	US sourced Low Energy Rendered Used Cooking Oil transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	None	Retired
A028505	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel ditribution by truck.	California	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC202 and BDC203	27.45 and 28.48	BIO003A02850500	25.22	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel ditribution by truck.	None	Retired
A028506	Tier 1	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT203R	31.39	BIO002A02850600	30.94	6/2/2021	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Enegy Bakersfield Biodiesel Plant (80174)	US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Biodiesel produced in California. In-state fuel distribution by truck.	None	Retired

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A035101	Tier 1	3.0	Fuel Producer: E Energy Adams, LLC (4831); Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00370100	66.53	ETH009A03510100	65.93	6/1/2021	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional)	None	Retired
A029002	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	Illinois	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A02900200	57.00	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	None	Retired
A029003	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	Illinois	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A02900300	53.00	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	None	Retired
A029006	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU246	23.18	BIO001A02900600	20.25	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	None	Retired
A034701	Tier 1	3.0	Fuel Producer: SENECA ENERGY II, LLC (6222); Facility Name: SENECA ENERGY (71156); Biomethane from biogas produced at the Seneca Meadows Landfill in Waterloo, New York; upgraded at Seneca Energy II facility; pipelined to California for compression to CNG. (Provisional)	New York	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF207L	52.77	CNG025A03470100	44.49	6/10/2021	None	Bio-CNG	SENECA ENERGY II, LLC (6222)	SENECA ENERGY (71156)	Biomethane from biogas produced at the Seneca Meadows Landfill in Waterloo, New York; upgraded at Seneca Energy II facility; pipelined to California for compression to CNG. (Provisional)	None	Retired
A030401	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Point Loma Digester Gas Project (F00027); Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional)	California	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A03040100	30.31	6/14/2021	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Point Loma Digester Gas Project (F00027)	Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional)	None	Retired
A034601	Tier 1	3.0	Fuel Producer: PINNACLE GAS PRODUCERS, LLC (6220); Facility Name: PINNACLE GAS PRODUCERS, LLC (71153); Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; upgrading at Pinnacle Gas Producers, LLC, pipelined to California for compression to CNG	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF206L	41.61	CNG025A03460100	63.75	6/16/2021	None	Bio-CNG	PINNACLE GAS PRODUCERS, LLC (6220)	PINNACLE GAS PRODUCERS, LLC (71153)	Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; upgrading at Pinnacle Gas Producers, LLC, pipelined to California for compression to CNG	None	Retired
A034602	Tier 1	3.0	Fuel Producer: PINNACLE GAS PRODUCERS, LLC (6220); Facility Name: PINNACLE GAS PRODUCERS, LLC (71153); Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California LNG stations	Ohio	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNGLF201LR	50.27	LNG025A03460200	76.91	6/16/2021	None	Bio-LNG	PINNACLE GAS PRODUCERS, LLC (6220)	PINNACLE GAS PRODUCERS, LLC (71153)	Biomethane from Pinnacle Road Landfill at Moraine, Ohio; Stony Hollow Landfill: Dayton; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California LNG stations	None	Retired
A034603	Tier 1	3.0	Fuel Producer: PINNACLE GAS PRODUCERS, LLC (6220); Facility Name: PINNACLE GAS PRODUCERS, LLC (71153); Biomethane from Pinnacle Road Landfill at Moraine; Stony Hollow Landfill at Dayton, Ohio; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	Ohio	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	CNGLF224LR	56.01	LCN025A03460300	80.00	6/16/2021	None	Bio-CNG	PINNACLE GAS PRODUCERS, LLC (6220)	PINNACLE GAS PRODUCERS, LLC (71153)	Biomethane from Pinnacle Road Landfill at Moraine; Stony Hollow Landfill at Dayton, Ohio; pipelined to Boron LNG Facility in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	None	Retired
A034501	Tier 1	3.0	Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG.	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF237L	47.40	CNG025A03450100	52.66	6/16/2021	None	Bio-CNG	WESTSIDE GAS PRODUCERS, LLC (6218)	WESTSIDE GAS PRODUCERS, LLC (71151)	Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG.	None	Retired
B016301	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Hilarides (F00006); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01630100	-758.46	6/21/2021	Application Package	Electricity	CleanFuture, Inc. (C1001)	Hilarides (F00006)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California. (Provisional)	None	Retired

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B019001	Tier 2	3.0	Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	Kansas	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B01900100	46.31	6/25/2021	Application Package	Renewable Diesel	East Kansas Agri-Energy, LLC (4483)	East Kansas Agri-Energy, LLC (83483)	Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	None	Retired
B019002	Tier 2	3.0	Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	Kansas	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	None	None	RNT003B01900200	46.31	6/25/2021	Application Package	Renewable Naphtha	East Kansas Agri-Energy, LLC (4483)	East Kansas Agri-Energy, LLC (83483)	Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	None	Retired
B019301	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity, then to California By rail and ocean tanker (Provisional)	North Dakota	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B01930100	34.90	6/25/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity, then to California By rail and ocean tanker (Provisional)	None	Retired
B019302	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by Rail and Ocean Tanker to California. (Provisional)	North Dakota	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B01930200	64.24	6/25/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by Rail and Ocean Tanker to California. (Provisional)	None	Retired
B019303	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Distillers' Corn Oil transported by Truck and Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional)	North Dakota	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	None	None	RNT003B01930300	34.90	6/25/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Distillers' Corn Oil transported by Truck and Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional)	None	Retired
B019304	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional)	North Dakota	Soybean Oil (005)	Renewable Naphtha (RNT)	None	None	RNT005B01930400	64.24	6/25/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by Rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha transported by Rail and Ocean Tanker to California. (Provisional)	None	Retired
B014301	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B00100100	-345.68	CNG044B01430100	-429.05	6/29/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations	None	Retired
B014901	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: South Meadows Farm (F00195); Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B01490100	-359.66	6/29/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	South Meadows Farm (F00195)	Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California (Provisional)	None	Retired
B016801	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B01680100	33.42	6/29/2021	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	None	Retired
B016802	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable diesel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01680200	33.42	6/29/2021	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable diesel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable diesel produced in California (Provisional)	None	Retired
B016803	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable naphtha produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01680300	33.42	6/29/2021	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable naphtha produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable naphtha produced in California (Provisional)	None	Retired
B019101	Tier 2	3.0	Fuel Producer: California Renewable Power LLC(C196); Facility Name: California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270); Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles. (Provisional)	California	Urban Landscaping Waste (028)	Compressed Natural Gas (CNG)	None	None	CNG028B01910100	2.51	6/29/2021	Application Package	Bio-CNG	California Renewable Power LLC(C196)	California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270)	Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles. (Provisional)	None	Retired

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A037601	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced and transported by truck in California (Provisional)	California	Distillers' Corn Oil (003)	Biodiesel (BIO)	None	None	BIO003A03760100	32.12	6/30/2021	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced and transported by truck in California (Provisional)	None	Retired
A036601	Tier 1	3.0	Fuel Producer: World Energy Rome, LLC (4533); Facility Name: World Energy Rome, LLC (82470); Midwest Soybean Oil transported by truck to Biodiesel Plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional)	Georgia	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A03660100	61.39	7/7/2021	None	Biodiesel	World Energy Rome, LLC (4533)	World Energy Rome, LLC (82470)	Midwest Soybean Oil transported by truck to Biodiesel Plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional)	None	Retired
A036602	Tier 1	3.0	Fuel Producer: World Energy Rome, LLC (4533); Facility Name: World Energy Rome, LLC (82470); US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional)	Georgia	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A03660200	24.94	7/7/2021	None	Biodiesel	World Energy Rome, LLC (4533)	World Energy Rome, LLC (82470)	US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Biodiesel produced in Rome, Georgia; Finished Fuel Transported to California By Rail (Provisional)	None	Retired
A036603	Tier 1	3.0	Fuel Producer: World Energy Rome, LLC (4533); Facility Name: World Energy Rome, LLC (82470); US Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Finished Fuel Transported to California By Rail (Provisional)	Georgia	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A03660300	36.60	7/7/2021	None	Biodiesel	World Energy Rome, LLC (4533)	World Energy Rome, LLC (82470)	US Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Rome, Georgia; Natural Gas and Grid Electricity; Finished Fuel Transported to California By Rail (Provisional)	None	Retired
A038601	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02560100	71.32	ETH009A03860100	72.20	7/13/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired
A038602	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02560200	68.05	ETH009A03860200	69.20	7/13/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired
A034801	Tier 1	3.0	Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional)	Texas	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT217	38.27	BIO002A03480100	30.80	7/28/2021	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional)	None	Retired
A037501	Tier 1	3.0	Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Seabreeze Energy Producers (70281); Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A03750100	37.82	8/20/2021	None	Bio-CNG	BLUE SOURCE LLC (6086)	Seabreeze Energy Producers (70281)	Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional)	None	Retired
B017301	Tier 2	3.0	Fuel Producer: DF-AP #1, LLC (C1122); Facility Name: Big Sky Dairy Digester (F00329); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California (Provisional)	Idaho	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01730100	-545.71	9/22/2021	Application Package	Electricity	DF-AP #1, LLC (C1122)	Big Sky Dairy Digester (F00329)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California (Provisional)	None	Retired
B017401	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	South Dakota	Corn (009)	Ethanol (ETH)	ETHC306	81.86	ETH009B01740100	75.91	9/24/2021	Application Package	Ethanol	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	None	Retired
B017402	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	South Dakota	Corn (009)	Ethanol (ETH)	ETHC306	81.86	ETH009B01740200	68.73	9/24/2021	Application Package	Ethanol	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	None	Retired
B017403	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California.	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETHCF206	38.58	ETH012B01740300	29.14	9/24/2021	Application Package	Ethanol - Cellulosic	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California.	None	Retired

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B018701	Tier 2	3.0	Fuel Producer: Dry Creek RNG LLC (C1098); Facility Name: Dry Creek RNG Project (F00342); Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional)	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01870100	-435.22	9/30/2021	Application Package	Bio-CNG	Dry Creek RNG LLC (C1098)	Dry Creek RNG Project (F00342)	Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
B021401	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Milford Farm (71483); Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (Provisional)	Utah	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B02140100	-413.67	9/30/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Milford Farm (71483)	Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (Provisional)	None	Retired
B021901	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: HOMAN FARM (71343); RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B02190100	-412.71	9/30/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	HOMAN FARM (71343)	RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use (Provisional)	None	Retired
B016501	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use (Provisional)	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020200	-289.76	CNG026B01650100	-406.35	9/30/2021	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
B018501	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01850100	-389.66	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	None	Retired
B018502	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01850200	-388.91	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	None	Retired
B019801	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01980100	-388.29	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
A039401	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00360100	67.09	ETH009A03940100	66.71	10/14/2021	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional)	None	Retired
A039402	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A00360200	32.40	ETH012A03940200	27.87	10/14/2021	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	None	Retired
A040201	Tier 1	3.0	Fuel Producer: Siouxland Ethanol, LLC (5026); Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00340100	66.23	ETH009A04020100	63.73	10/11/2021	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	None	Retired
A037903	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional)	Texas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A03790300	64.00	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional)	None	Retired
A037803	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A01610300	66.62	ETH010A03780300	66.28	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	None	Retired

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A037805	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (70039); Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A01610500	74.57	ETH010A03780500	73.81	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (70039)	Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	None	Retired
A042301	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETHC292	73.11	ETH009A04230100	70.88	10/26/2021	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional)	None	Retired
A042302	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04230200	24.02	10/26/2021	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional)	None	Retired
T1N-1769	Tier 1	2.0	Fuel Producer: Fuel Producer: REG Seneca, LLC (3652) ; Facility Name: Fuel Producer: REG Seneca, LLC (80232) ; U.S. sourced corn oil, Biodiesel produced in Seneca, Illinois and transported by rail to California	Illinois	Corn Oil	Biodiesel	None	None	BDC213	34.02	4/2/2018	None	Biodiesel	REG Seneca, LLC (3652)	Fuel Producer: REG Seneca, LLC (80232)	U.S. sourced corn oil, Biodiesel produced in Seneca, Illinois and transported by rail to California	None	Retired
A038001	Tier 1	3.0	Fuel Producer: GHI Energy, LLC (6156); Facility Name: Fort Bend Power Producers (shared facility) (7113s); Biomethane from Fort Bend Regional Landfill in Needville, Texas, pipelined to California for compression to CNG.	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A03800100	34.94	11/4/2021	None	Bio-CNG	GHI Energy, LLC (6156)	Fort Bend Power Producers (shared facility) (7113s)	Biomethane from Fort Bend Regional Landfill in Needville, Texas, pipelined to California for compression to CNG.	None	Retired
A041601	Tier 1	3.0	Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Greentree Landfill Gas Company (F00212); Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG.	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04160100	66.18	11/23/2021	None	Bio-CNG	TRUSTAR ENERGY LLC (6523)	Greentree Landfill Gas Company (F00212)	Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG.	None	Retired
A042601	Tier 1	3.0	Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced tallow; finished fuel transported to California by rail for use as a transportation fuel. (Provisional)	Iowa	(animal and poultry fat	Biodiesel (BIO)	BDT211	31.19	BIO002A04260100	29.23	12/22/2021	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Biodiesel produced from US sourced tallow; finished fuel transported to California by rail for use as a transportation fuel. (Provisional)	None	Retired
A042602	Tier 1	3.0	Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel. (Provisional)	Iowa	Soybean Oil (005)	Biodiesel (BIO)	BDS206	54.50	BIO005A04260200	55.05	12/22/2021	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel. (Provisional)	None	Retired
B020701	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02070100	-135.37	12/29/2021	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional)	None	Retired
B020702	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02070200	-211.01	12/29/2021	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional)	None	Retired
B022001	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: SOMERSET FARM (71381); Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02200100	-345.80	CNG044B02200101	-410.57	12/31/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	SOMERSET FARM (71381)	Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
B024001	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Distillers' Corn Oil (003	Renewable Diesel (RND)	RND003B01930100	None	RND003B02400100	29.79	12/28/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired

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B024002	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Soybean Oil (005)	Renewable Diesel (RND)	RND005B01930200	None	RND005B02400200	57.64	12/28/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024003	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S Sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	(animal and poultry fat	Renewable Diesel (RND)	None	None	RND002B02400300	33.34	12/28/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S Sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024004	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Distillers' Corn Oil (003	Renewable Naphtha (RNT)	RNT003B01930300	34.90	RNT003B02400400	29.79	12/28/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Corn Oil, pre-treated at Beatrice, NB; transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024005	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Soybean Oil (005)	Renewable Naphtha (RNT)	RNT005B01930400	64.24	RNT005B02400500	57.64	12/28/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024006	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	oking Oil/Waste Oil (UC	Renewable Naphtha (RNT)	None	None	RNT001B02400600	21.09	12/28/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024007	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	(animal and poultry fat	Renewable Naphtha (RNT)	None	None	RNT002B02400700	33.34	12/28/2021	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024008	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	oking Oil/Waste Oil (UC	Renewable Diesel (RND)	None	None	RND001B02400800	21.09	12/28/2021	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	Retired
B024101	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	California	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B02410100	54.68	12/28/2021	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	None	Retired
B024103	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	California	Canola Oil (006)	Renewable Diesel (RND)	None	None	RND006B02410300	51.87	12/28/2021	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	None	Retired

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A043602	Tier 1	3.0	Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04360200	24.89	2/1/2022	None	Ethanol	AL CORN CLEAN FUEL, LLC (4825)	AL CORN CLEAN FUEL, LLC (70087)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	Retired
B025101	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B02510100	60.13	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025102	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Distillers' Corn Oil (003	Renewable Diesel (RND)	RND003B00540100	27.42	RND003B02510200	27.64	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025103	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Diesel (RND)	RND001B00540200	19.92	RND001B02510300	19.75	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025104	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Diesel (RND)	None	None	RND001B02510400	18.16	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025105	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Diesel (RND)	RND002B00540300	31.86	RND002B02510500	32.14	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025106	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Diesel (RND)	None	None	RND002B02510600	42.48	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025107	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Soybean Oil (005)	Renewable Naphtha (RNT)	None	None	RNT005B02510700	60.13	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025108	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Distillers' Corn Oil (003	Renewable Naphtha (RNT)	None	None	RNT003B02510800	27.64	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025109	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Naphtha (RNT)	None	None	RNT001B02510900	19.75	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025110	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Naphtha (RNT)	None	None	RNT001B02511000	18.16	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B025111	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Naphtha (RNT)	None	None	RNT002B02511100	32.14	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired

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B025112	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Naphtha (RNT)	None	None	RNT002B02511200	42.48	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	None	Retired
B026801	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B00450100	25.08	AJF002B02680100	18.87	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired
B026802	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B00450200	25.08	RND002B02680200	18.87	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026803	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B00450300	25.08	RNT002B02680300	18.87	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B026810	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B01680100	33.42	AJF002B02681000	29.26	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired
B026811	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B01680200	33.42	RND002B02681100	29.26	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026812	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B01680300	33.42	RNT002B02681200	29.26	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B021601	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02160100	-382.83	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	None	Retired
B021602	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	None	None	LNG026B02160200	-369.56	3/30/2022	Application Package	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional)	None	Retired
B021603	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN026B02160300	-366.02	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional)	None	Retired
B021701	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02170100	-303.92	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	None	Retired
B021702	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	None	None	LNG026B02170200	-290.16	3/30/2022	Application Package	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional)	None	Retired

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B021703	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN026B02170300	-286.62	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional)	None	Retired
B026701	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	Distillers' Corn Oil (003	Biodiesel (BIO)	BIO003A02850500	25.22	BIO003B02670100	28.67	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	None	Retired
B026702	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	(animal and poultry fat	Biodiesel (BIO)	BIO002A02850600	30.94	BIO002B02670200	32.53	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	None	Retired
B028001	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	California	Swine Manure (044)	Gaseous Hydrogen (HYG)	None	None	HYG044B02800100	-374.14	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	None	Retired
B028002	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	California	Swine Manure (044)	Gaseous Hydrogen (HYG)	None	None	HYG044B02800200	-390.47	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	None	Retired
A045501	Tier 1	3.0	Fuel Producer: BLUE SOURCE LLC (6086) ; Facility Name: Theresa Street Water Resource Recovery Facility (F00343); Biomethane from Waste Water Treatment Plant in Lincoln Nebraska, pipelined to California, compressed to CNG as indirect accounting of RNG dispensed in California (Provisional)	Nebraska	Vastewater Sludge (030	Compressed Natural Gas (CNG)	None	None	CNG030A04550100	43.12	4/14/2022	None	Bio-CNG	BLUE SOURCE LLC (6086)	Theresa Street Water Resource Recovery Facility (F00343)	Biomethane from Waste Water Treatment Plant in Lincoln Nebraska, pipelined to California, compressed to CNG as indirect accounting of RNG dispensed in California (Provisional)	None	Retired
B037802	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B03780200	75.16	12/19/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	None	Retired
A016501	Tier 1	3.0	Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California	Rhode Island	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A01650100	15.24	BIO001A01650102	15.02	12/16/2019	None	Biodiesel	NEWPORT BIODIESEL INC (7764)	NEWPORT BIODIESEL LLC (83532)	Northeast US sourced Self-Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail to California	2021 AFPR Recert Complete	Retired
B004303	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	None	None	RNT002B00430300	37.13	12/27/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Naphtha produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
A016001	Tier 1	3.0	Fuel Producer: Iogen D3 Biofuel Partners LLC (6486); Facility Name: GSF Energy-Rumpke Landfill (71138S); Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01600100	44.90	CNG025A01600102	45.59	12/20/2019	None	Bio-CNG	Iogen D3 Biofuel Partners LLC (6486)	GSF Energy-Rumpke Landfill (71138S)	Landfill Gas generated at the Rumpke Landfill; upgraded to pipeline-quality biomethane in Cincinnati, Ohio; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	2021 AFPR Recert Complete	Retired
A016502	Tier 1	3.0	Fuel Producer: NEWPORT BIODIESEL INC (7764); Facility Name: NEWPORT BIODIESEL LLC (83532); Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California	Rhode Island	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A01650200	18.60	BIO001A01650202	17.61	12/16/2019	None	Biodiesel	NEWPORT BIODIESEL INC (7764)	NEWPORT BIODIESEL LLC (83532)	Northeast US sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Newport, RI; Biodiesel transported by rail California	2021 AFPR Recert Complete	Retired
B008901	Tier 2	3.0	Fuel Producer: Gallo Cattle Company, LP (C1029) ; Facility Name: Cottonwood Dairy (F00094); Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California.	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00890101	-126.52	ELC026B00890103	-93.58	3/25/2021	None	Electricity	Gallo Cattle Company, LP (C1029)	Cottonwood Dairy (F00094)	Low-CI electricity from dairy manure and cheese wastewater biogas, using reciprocating engine at Cottonwood Dairy in Atwater, California for use as transportation fuel in California.	2021 AFPR Recert Complete	Retired

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A029701	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Kansas	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02970101	58.34	LNG025A02970102	60.50	12/15/2020	None	Bio-LNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	2021 AFPR Recert Complete	Retired
B004301	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B00430100	37.13	AJF002B00430102	38.93	12/27/2019	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Jet produced from North America Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Jet produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B004403	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B00440300	42.91	RNT002B00440302	44.72	12/27/2019	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable Naphtha produced from Australia Rendered Animal Fat; Natural Gas, Grid Electricity and Hydrogen; Renewable Naphtha produced in California	2021 AFPR Recert Complete	Retired
B016801	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B01680100	33.42	AJF002B01680101	35.53	6/29/2021	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Renewable jet fuel produced from animal fat in Dinmore, Australia; natural gas, grid electricity and hydrogen; renewable jet fuel produced in California (Provisional)	2021 AFPR Recert Complete	Retired
A006402	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00640200	68.04	ETH009A00640200	64.75	5/7/2019	None	Ethanol	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
None	Lookup Table	3.0	CARBOB - based on the average crude oil supplied to California refineries and average California refinery efficiencies	California	Crude Oil	CARBOB	None	None	CBO000L00072019	100.82	NA	None	CARBOB	NA	NA	CARBOB based on the average crude oil supplied to California refineries and average California refinery efficiencies	None	
T1N-1734	Tier 1	2.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by rail to California	Texas	Used Cooking Oil (UCO)	Biodiesel	BDU226	22.80	BDU226R	24.41	11/28/2018	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	High energy rendered Used Cooking Oil (UCO), UCO shipped by truck less than 1,000 miles, Biodiesel produced in Texas, shipped by rail to California	None	
A007701	Tier 1	3.0	Fuel Producer: Western Plains Energy, LLC (4740) ; Facility Name: Western Plains Energy, LLC (70030); Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California	Kansas	Corn (009)	Ethanol (ETH)	ETHC278	70.60	ETH009A00770100	62.91	4/15/2019	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California	None	
A007702	Tier 1	3.0	Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Pathway Description: Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETHG215	78.55	ETH010A00770200	66.64	4/15/2019	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Corn and Sorghum, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn and Sorghum along with Syrup, Corn Oil in Oakley, Kansas; Ethanol transported by rail to California	None	
A003201	Tier 1	3.0	Fuel Producer: Scott Petroleum Inc. (4840); Facility Name: Scott Petroleum Biodiesel Refinery (82908); U.S. sourced Rendered UCO; Biodiesel produced in Greenville, MS and transported by rail to California	Mississippi	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU217	27.90	BIO001A00320100	20.92	5/28/2019	None	Biodiesel	Scott Petroleum Inc (4840)	Scott Petroleum Biodiesel Refinery (82908)	U.S. sourced Rendered UCO; Biodiesel produced in Greenville, MS and transported by rail to California	None	Retired
A003202	Tier 1	3.0	Fuel Producer: Scott Petroleum Inc. (4840); Facility Name: Scott Petroleum Biodiesel Refinery (82908); U.S. sourced Distillers' Corn Oil; Biodiesel produced in Greenville, MS and transported by rail to California	Mississippi	Distillers' Corn Oil (003)	Biodiesel (BIO)	None	None	BIO003A00320200	28.43	5/28/2019	None	Biodiesel	Scott Petroleum Inc (4840)	Scott Petroleum Biodiesel Refinery (82908)	U.S. sourced Distillers' Corn Oil; Biodiesel produced in Greenville, MS and transported by rail to California	None	Retired
None	Lookup Table	3.0	ULSD – based on the average crude oil supplied in California refineries and average California refinery efficiencies	NA	Crude Oil	Diesel	None	None	ULS000L00072019	100.45	NA	None	Diesel	NA	NA	ULSD – based on the average crude oil supplied in California refineries and average California refinery efficiencies	None	

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None	Lookup Table	3.0	Compressed Natural Gas from Pipeline Average North Amer	NA	North American Fossil NG (031)	Compressed Natural Gas (CNG)	None	None	CNG000L00072019	79.21	NA	None	Fossil CNG	NA	NA	Compressed Natural Gas from Pipeline Average North American Fossil Natural Gas	None	
None	Lookup Table	3.0	Fossil LPG from crude oil refining and natural gas processin	NA	Crude Oil	Propane (LPG)	None	None	LPG000L00072019	83.19	NA	None	Propane	NA	NA	Fossil LPG from crude oil refining and natural gas processing used as a transport fuel	None	
None	Lookup Table	3.0	Electricity that is generated from 100 percent zero-CI source	NA	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	NA	None	Electricity	NA	NA	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
None	Lookup Table	3.0	Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	NA	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025L00072019	99.48	NA	None	Hydrogen	NA	NA	Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
None	Lookup Table	3.0	Compressed H2 produced in California from central SMR of North American fossil-based NG	NA	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	NA	None	Hydrogen	NA	NA	Compressed H2 produced in California from central SMR of North American fossil-based NG	None	
None	Lookup Table	3.0	Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	NA	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	None	None	HYG037L00072019	10.51	NA	None	Hydrogen	NA	NA	Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	None	
None	Lookup Table	3.0	Compressed H2 produced in California from electrolysis using California average grid electricity	NA	Grid Electricity (039)	Gaseous Hydrogen (HYG)	None	None	HYG039L00072019	164.46	NA	None	Hydrogen	NA	NA	Compressed H2 produced in California from electrolysis using California average grid electricity	None	
None	Lookup Table	3.0	Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	NA	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025L00072019	129.09	NA	None	Hydrogen	NA	NA	Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
None	Lookup Table	3.0	Liquefied H2 produced in California from central SMR of North American fossil-based NG	NA	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	NA	None	Hydrogen	NA	NA	Liquefied H2 produced in California from central SMR of North American fossil-based NG	None	
A008302	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	Minnesota	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A00830200	48.49	6/7/2019	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A008301	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	Minnesota	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A00830100	53.68	6/7/2019	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	None	Retired
A010001	Tier 1	3.0	Fuel Producer: The Andersons, Inc (5872); Facility Name: The Andersons Denison Ethanol (70135); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC275	76.35	ETH009A01000100	71.62	6/7/2019	None	Ethanol	The Andersons, Inc (5872)	The Andersons Denison Ethanol (70135)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	None	Retired

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None	Lookup Table	3.0	Fuel Producer: BMW of North America, LLC (C1033); Smart Charging Lookup Table Pathway	NA	Smart Charging or Smart Electrolysis (047)	Electricity (ELC)	None	None	NA	N/A	6/30/2019	See CI's	Electricity	BMW of North America, LLC (C1033)	NA	Smart Charging Lookup Table Pathway	None	
A012501	Tier 1	3.0	Fuel Producer: Plymouth Energy LLC (5474); Facility Name: Plymouth Energy LLC (70183); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETHC285	83.47	ETH009A01250100	75.16	8/6/2019	None	Ethanol	Plymouth Energy LLC (5474)	Plymouth Energy LLC (70183)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Eletricity; Starch Ethanol produced in Merrill, Iowa; Ethanol transported by rail to California	None	
None	Lookup Table	3.0	Fuel Producer: Southern California Edison; Smart Charging Lookup Table Pathway	NA	Smart Charging or Smart Electrolysis (047)	Electricity (ELC)	None	None	NA	N/A	9/30/2019	See CI's	Electricity	Southern California Edison	NA	Smart Charging Lookup Table Pathway	None	
A014103	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846); Facility Name: HPB - St. Joe Biodiesel LLC (80059); Rendered Used Cooking Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	Missouri	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01410300	22.62	9/25/2019	None	Biodiesel	High Plains Bioenergy (4846)	HPB - St. Joe Biodiesel LLC (80059)	Rendered Used Cooking Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	None	
A017401	Tier 1	3.0	Fuel Producer: Nebraska Corn Processing (3516); Facility Name: Nebraska Corn Processing LLC (70230); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETHC227	71.84	ETH009A01740100	65.77	10/17/2019	None	Ethanol	Nebraska Corn Processing (3516)	Nebraska Corn Processing LLC (70230)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California	None	Retired
A011701	Tier 1	3.0	Fuel Producer: Raízen Tarumã S/A (3807); Facility Name: Maracaí (70347); Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Maracai, Brazil; Ethanol transported by Ocean Tanker to California	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A01170100	51.88	11/5/2019	None	Ethanol	Raízen Tarumã S/A (3807)	Maracaí (70347)	Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Maracai, Brazil; Ethanol transported by Ocean Tanker to California	None	
A015301	Tier 1	3.0	Fuel Producer: Raízen Tarumã S/A (3807); Facility Name: Tarumã (70338); Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Taruma, Brazil; Ethanol transported by Ocean Tanker to California	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A01530100	56.35	11/5/2019	None	Ethanol	Raízen Tarumã S/A (3807)	Tarumã (70338)	Brazilian Sugarcane, Credit for Electricity co-product export and mechanized harvesting; Ethanol produced from Sugarcane Juice and Molasses in Taruma, Brazil; Ethanol transported by Ocean Tanker to California	None	
A008201	Tier 1	3.0	Fuel Producer: GFP Ethanol, LLC dba Calgren Renewable Fuels (7354) ; Facility Name: GFP Ethanol, LLC dba Calgren Renewable Fuels (70317); Midwest Corn, Dry Mill; Wet DGS and Corn oil; Natural Gas and Biogas; Starch Ethanol produced in Pixley,California; Ethanol transported by truck to fueling stations (Provisional)	California	Corn (009)	Ethanol (ETH)	ETHC316	63.01	ETH009A00820100	58.95	12/17/2019	None	Ethanol	GFP Ethanol, LLC dba Calgren Renewable Fuels (7354)	GFP Ethanol, LLC dba Calgren Renewable Fuels (70317)	Midwest Corn, Dry Mill; Wet DGS and Corn oil; Natural Gas and Biogas; Starch Ethanol produced in Pixley,California; Ethanol transported by truck to fueling stations (Provisional)	None	
A016901	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California. (Provisional)	Arizona	Wastewater Sludge (030)	Liquefied Natural Gas (LNG)	None	None	LNG030A01690100	41.58	12/18/2019	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California. (Provisional)	None	Retired
A016902	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as (Provisional)	Arizona	Wastewater Sludge (030)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN030A01690200	44.67	12/18/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as (Provisional)	None	Retired
A011401	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in CA	Texas	Wastewater Sludge (030)	Liquefied Natural Gas (LNG)	None	None	LNG030A01140100	54.76	12/19/2019	None	Bio-LNG	Element Markets Renewable Energy, LLC (5877)	Ameresco San Antonio Biogas (71204)	Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in CA	None	
A011402	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877) ; Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling; upgraded to pipeline-quality biomethane in San Antonio, TX; delivered via pipeline to liquefaction facility in Topock, AZ; liquefied & transported by truck to CA; re-gasified & dispensed as CNG	Texas	Wastewater Sludge (030)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN030A01140200	57.84	12/19/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ameresco San Antonio Biogas (71204)	Biomethane generated at the SAWS Dos Rios Water Recycling; upgraded to pipeline-quality biomethane in San Antonio, TX; delivered via pipeline to liquefaction facility in Topock, AZ; liquefied & transported by truck to CA; re-gasified & dispensed as CNG	None	

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A013502	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846) ; Facility Name: High Plains Bioenergy (82883); Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	Oklahoma	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A01350200	55.82	12/20/2019	None	Biodiesel	High Plains Bioenergy (4846)	High Plains Bioenergy (82883)	Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	None	Retired
A013503	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846); Facility Name: High Plains Bioenergy (82883); Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	Oklahoma	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01350300	20.68	12/20/2019	None	Biodiesel	High Plains Bioenergy (4846)	High Plains Bioenergy (82883)	Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	None	Retired
B003301	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Air Products and Chemicals, Inc. (F00080); Liquefied Hydrogen from North American fossil natural gas at Air Products & Chemicals Inc., Sacramento, delivered to Compton, California by liquid hydrogen truck for use in forklifts	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B00330100	153.17	12/31/2019	Application Package	Hydrogen	CleanFuture, Inc. (C1001)	Air Products and Chemicals, Inc. (F00080)	Liquefied Hydrogen from North American fossil natural gas at Air Products & Chemicals Inc., Sacramento, delivered to Compton, California by liquid hydrogen truck for use in forklifts	None	
B003701	Tier 2	3.0	Fuel Producer: SMUD (S338); Facility Name: Van Warmerdam Dairy Digester (V4907); Low CI electricity from dairy manure biogas using reciprocating engine at Van Warmerdam Dairy in Galt, California for use as transportation fuel in California	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00370100	-592.68	12/31/2019	Application Package	Electricity	SMUD (S338)	Van Warmerdam Dairy Digester (V4907)	Low CI electricity from dairy manure biogas using reciprocating engine at Van Warmerdam Dairy in Galt, California for use as transportation fuel in California	None	
B003801	Tier 2	3.0	Fuel Producer: SMUD (S338); Facility Name: Van Steyn Dairy Digester (V1125); Low-CI electricity from dairy manure biogas using reciprocating engine at Van Steyn Dairy in Elk Grove, California for use as transportation fuel in California	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00380100	-630.72	12/31/2019	Application Package	Electricity	SMUD (S338)	Van Steyn Dairy Digester (V1125)	Low-CI electricity from dairy manure biogas using reciprocating engine at Van Steyn Dairy in Elk Grove, California for use as transportation fuel in California	None	
A016601	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Milam High Btu Gas Plant (71208); East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline; Compression to CNG stations in California	Illinois	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF270	62.72	CNG025A01660100	60.09	12/20/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline; Compression to CNG stations in California	None	
A016602	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978) ; Facility Name: Milam High Btu Gas Plant (71208); East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California LNG stations	Illinois	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNGLF228	76.13	LNG025A01660200	80.27	12/20/2019	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California LNG stations	None	
A016603	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Milam High Btu Gas Plant (71208); East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California to regasified and compressed to L-CNG	Illinois	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	CNGLF271	78.68	LCN025A01660300	83.36	12/20/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Milam High Btu Gas Plant (71208)	East Saint Louis Landfill Gas to pipeline-quality biomethane in Saint Louis, Illinois; Delivered via pipeline to liquefaction facility in Topock, Arizona; Transported by truck to California to regasified and compressed to L-CNG	None	
B005001	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen from fossil natural gas at Praxair-Linde Ontario, delivered to stations in Northern California by liquid hydrogen truck for use in fuel cell vehicles.	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B00500100	153.36	1/13/2020	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied Hydrogen from fossil natural gas at Praxair-Linde Ontario, delivered to stations in Northern California by liquid hydrogen truck for use in fuel cell vehicles.	None	
L000301	Lookup Table	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: CleanFuture (F00024); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	Oregon	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/28/2019	None	Electricity	CleanFuture, Inc. (C1001)	CleanFuture (F00024)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L000701	Lookup Table	3.0	Fuel Producer: EVgo Services LLC (C1101); Facility Name: EVgo Services LLC (F00033); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/3/2019	None	Electricity	EVgo Services LLC (C1101)	EVgo Services LLC (F00033)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L001301	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018) ; Facility Name: SRECTrade, Inc. Zero CI Electricity (F00043); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	5/7/2019	None	Electricity	SRECTrade, Inc (C1018)	SRECTrade, Inc. Zero CI Electricity (F00043)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

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L005901	Lookup Table	3.0	Fuel Producer: Alameda Municipal Power (C1021); Facility Name: Alamedia Municipal Power (F00056); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/14/2019	None	Electricity	Alameda Municipal Power (C1021)	Alamedia Municipal Power (F00056)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L006501	Lookup Table	3.0	Fuel Producer: ChargePoint, Inc. (C1028); Facility Name: Chargepoint, Inc. (F00061); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/27/2019	None	Electricity	ChargePoint, Inc. (C1028)	Chargepoint, Inc. (F00061)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L007501	Lookup Table	3.0	Fuel Producer: East Bay Community Energy Authority (C1022); Facility Name: East Bay Community Energy (F0054); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/25/2019	None	Electricity	East Bay Community Energy Authority (C1022)	East Bay Community Energy (F0054)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L008101	Lookup Table	3.0	Fuel Producer: BMW of North America, LLC (C1033); Facility Name: BMW of North America, LLC Corporate Headquarters (F00076); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	New Jersey	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/6/2019	None	Electricity	BMW of North America, LLC (C1033)	BMW of North America, LLC Corporate Headquarters (F00076)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L008201	Lookup Table	3.0	Fuel Producer: Port of Oakland (C1035); Facility Name: Port of Oakland (F00078); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/16/2019	None	Electricity	Port of Oakland (C1035)	Port of Oakland (F00078)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L008301	Lookup Table	3.0	Fuel Producer: Jaguar Land Rover North America, LLC (C1032); Facility Name: Jaguar Land Rover North America, LLC (F00083); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	New Jersey	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/29/2019	None	Electricity	Jaguar Land Rover North America, LLC (C1032)	Jaguar Land Rover North America, LLC (F00083)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L008701	Lookup Table	3.0	Fuel Producer: Sonoma Clean Power Authority (C1012); Facility Name: Golden Hills North Wind Energy Center (F00087); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/29/2019	None	Electricity	Sonoma Clean Power Authority (C1012)	Golden Hills North Wind Energy Center (F00087)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L009001	Lookup Table	3.0	Fuel Producer: Beyond Energy, LLC (C1041); Facility Name: Beyond Energy, LLC (F00090); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/25/2019	None	Electricity	Beyond Energy, LLC (C1041)	Beyond Energy, LLC (F00090)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L009301	Lookup Table	3.0	Fuel Producer: Bridge to Renewables, Benefit LLC (C1006); Facility Name: Bridge to Renewables Corporate Headquarters (F00099); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	Washington D.C.	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/3/2019	None	Electricity	Bridge to Renewables, Benefit LLC (C1006)	Bridge to Renewables Corporate Headquarters (F00099)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L009801	Lookup Table	3.0	Fuel Producer: San Deigo Metropolitan Transit Center (S304); Facility Name: San Deigo Metropolitan Transit System (F00106); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/3/2019	None	Electricity	San Deigo Metropolitan Transit Center (S304)	San Deigo Metropolitian Transit System (F00106)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L009901	Lookup Table	3.0	Fuel Producer: SMUD (S338); Facility Name: Sacramento Municipal Utility District (F00116); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/3/2019	None	Electricity	SMUD (S338)	Sacramento Municipal Utility District (F00116)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L010001	Lookup Table	3.0	Fuel Producer: Smart Charging Technologies (C1050); Facility Name: Smart Charging Technologies 0CI (F00122); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	Florida	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/17/2019	None	Electricity	Smart Charging Technologies (C1050)	Smart Charging Technologies 0CI (F00122)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

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L010101	Lookup Table	3.0	Fuel Producer: Enel X North America, Inc. (C1051); Facility Name: Enel X North America - eMobility (F00124); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	Massachusetts	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/18/2019	None	Electricity	Enel X North America, Inc. (C1051)	Enel X North America - eMobility (F00124)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L010201	Lookup Table	3.0	Fuel Producer: JC Sales (C1031); Facility Name: JC Sales (F00125); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/18/2019	None	Electricity	JC Sales (C1031)	JC Sales (F00125)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L010401	Lookup Table	3.0	Fuel Producer: Volta Industries, Inc. (C1025); Facility Name: Volta Industries, Inc. (F00115); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	1/10/2020	None	Electricity	Volta Industries, Inc. (C1025)	Volta Industries, Inc. (F00115)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
B001901	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Open Sky (F00007); Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00190100	-352.89	11/14/2019	Application Package	Electricity	CleanFuture, Inc. (C1001)	Open Sky (F00007)	Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California	None	Retired
L009501	Lookup Table	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	12/17/2019	None	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied H2 produced in California from central SMR of North American fossil-based NG	None	
L009701	Lookup Table	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products & Chemicals SMR Sacramento (F00069); Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025L00072019	129.09	12/4/2019	None	Hydrogen	FirstElement Fuel (E426)	Air Products & Chemicals SMR Sacramento (F00069)	Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
L005801	Lookup Table	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Central SMR (F00051); Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025L00072019	99.48	7/16/2019	None	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Air Products Central SMR (F00051)	Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
L005701	Lookup Table	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Air Products Central SMR (F00051); Compressed H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	7/16/2019	None	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Air Products Central SMR (F00051)	Compressed H2 produced in California from central SMR of North American fossil-based NG	None	
L007601	Lookup Table	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Carson Hydrogen Plant (F00059); Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025L00072019	99.48	7/12/2019	None	Hydrogen	Shell Energy North America (6154)	Carson Hydrogen Plant (F00059)	Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
L007701	Lookup Table	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025L00072019	99.48	7/12/2019	None	Hydrogen	FirstElement Fuel (E426)	Air Products and Chemicals SMR Wilmington. CA (F00068)	Compressed H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills	None	
L008901	Lookup Table	3.0	Fuel Producer: San Francisco Public Utilities Commission (C1003); Facility Name: R.C. Kirkwood Power House Units #1, #2, #3 (F00089); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/27/2019	None	Electricity	San Francisco Public Utilities Commission (C1003)	R.C. Kirkwood Power House Units #1, #2, #3 (F00089)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L009401	Lookup Table	3.0	Fuel Producer: Oxnard Harbor District (C1030); Facility Name: Oxnard Harbor District (F00105); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/30/2019	None	Electricity	Oxnard Harbor District (C1030)	Oxnard Harbor District (F00105)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
L010301	Lookup Table	3.0	Fuel Producer: Grant Farm dba Momentum Zero CI Electricity (C1054); Facility Name: Grant Farm dba Momentum (Zero-CI Lookup Table Pathway) (F00133); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	2/11/2020	None	Electricity	Grant Farm dba Momentum Zero CI Electricity (C1054)	Grant Farm dba Momentum (Zero-CI Lookup Table Pathway) (F00133)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L010501	Lookup Table	3.0	Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: 3Degrees Group, Inc. (F00137); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/9/2020	None	Electricity	3Degrees Group, Inc. (C1055)	3Degrees Group, Inc. (F00137)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L010801	Lookup Table	3.0	Fuel Producer: Cruise LLC (C1064); Facility Name: Cruise Corporate Headquarters (F00144); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/30/2020	None	Electricity	Cruise LLC (C1064)	Cruise Corporate Headquarters (F00144)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L010601	Lookup Table	3.0	Fuel Producer: Energy Mission Control (C1058); Facility Name: Energy Mission Control (F00142); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/27/2020	None	Electricity	Energy Mission Control (C1058)	Energy Mission Control (F00142)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
A019702	Tier 1	3.0	Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698) ; Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Soybean Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	Iowa	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A01970200	55.00	6/16/2020	None	Biodiesel	IOWA RENEWABLE ENERGY LLC (4698)	IOWA RENEWABLE ENERGY LLC (82854)	Midwest Sourced Soybean Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	None	
A019703	Tier 1	3.0	Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698) ; Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	Iowa	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A01970300	30.23	6/16/2020	None	Biodiesel	IOWA RENEWABLE ENERGY LLC (82854)	IOWA RENEWABLE ENERGY LLC (82854)	Midwest Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	None	
A019704	Tier 1	3.0	Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698) ; Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Used Cooking Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	Iowa	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A01970400	19.34	6/16/2020	None	Biodiesel	IOWA RENEWABLE ENERGY LLC (82854)	IOWA RENEWABLE ENERGY LLC (82854)	Midwest Sourced Used Cooking Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	None	
A020701	Tier 1	3.0	Fuel Producer: MEM RNG, LLC (2141); Facility Name: Blue Ridge Landfill, LLC (F00132); Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02070100	38.07	6/16/2020	None	Bio-CNG	MEM RNG, LLC (2141)	Blue Ridge Landfill, LLC (F00132)	Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel (Provisional)	None	Retired
A019701	Tier 1	3.0	Fuel Producer: IOWA RENEWABLE ENERGY LLC (4698); Facility Name: IOWA RENEWABLE ENERGY LLC (82854); Midwest Sourced Canola Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	Iowa	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A01970100	49.91	6/16/2020	None	Biodiesel	IOWA RENEWABLE ENERGY LLC (4698)	IOWA RENEWABLE ENERGY LLC (82854)	Midwest Sourced Canola Oil transported by truck to Biodiesel plant in Washington, IA; Natural Gas and Grid Electricity; Biodiesel produced in Washington and transported by rail to California	None	
A021801	Tier 1	3.0	Fuel Producer: PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080); Facility Name: H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301); Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to California for compression to CNG (Provisional)	Washington	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A02180100	37.19	6/22/2020	None	Bio-CNG	PUBLIC UTILITY DISTRICT NO. 1 OF KLICKITAT COUNTY (2080)	H.W. HILL RENEWABLE NATURAL GAS PROJECT (70301)	Biomethane from Landfill in Roosevelt, Washington; upgrading at Public Utility District No. 1 of Klickitat County, pipelined to California for compression to CNG (Provisional)	None	Retired
B009803	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980300	-192.49	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (Provisional)	None	Retired
B009804	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B00980400	-323.10	6/30/2020	Application Package	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (Provisional)	None	Retired

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A023801	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758) ; Facility Name: BIOX Canada Limited (80236); US Sourced Canola Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	Canada	Canola Oil (006)	Biodiesel (BIO)	BDCA200L	57.39	BIO006A02380100	54.22	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	US Sourced Canola Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	None	
A023802	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758) ; Facility Name: BIOX Canada Limited (80236); US Sourced Soybean Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	Canada	Soybean Oil (005)	Biodiesel (BIO)	BDS200L	56.03	BIO005A02380200	59.63	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	US Sourced Soybean Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	None	
A023803	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758) ; Facility Name: BIOX Canada Limited (80236); US Sourced Corn Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	Canada	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC200L	32.8	BIO003A02380300	30.86	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	US Sourced Corn Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	None	
A023804	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); U.S. Sourced (Various Products) Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	Canada	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT200L	34.97	BIO002A02380400	34.92	7/27/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	U.S. Sourced (Various Products) Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	None	
A023806	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Sanimax (Montreal) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	Canada	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A02380600	27.09	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	Sanimax (Montreal) Sourced Rendered Animal Fat (Tallow Oil) transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California	None	
A023807	Tier 1	3.0	Fuel Producer: Biox Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	Canada	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU218	22.38	BIO001A02380700	22.88	7/24/2020	None	Biodiesel	Biox Canada Limited (3758)	BIOX Canada Limited (80236)	US Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	None	
A017101	Tier 1	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNGDD201	-254.94	CNG026A01710100	-329.76	12/24/2019	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Fair Oaks Upgrader, LLC (71001)	Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California	None	Retired
L010901	Lookup Table	3.0	Fuel Producer: Marin Clean Energy (C1066); Facility Name: Marin Clean Energy (F00147); Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California	California	Zero-CI Sources Supplied via Green Tariff (048)	Electricity (ELC)	None	None	ELC048L00072019	0.00	5/12/2020	None	Electricity	Marin Clean Energy (C1066)	Marin Clean Energy (F00147)	Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California	None	
L011201	Lookup Table	3.0	Fuel Producer: City of Anaheim, Public Utilities Department (C1068); Facility Name: City of Anaheim, Public Utilities Department (F00157); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/30/2020	None	Electricity	City of Anaheim, Public Utilities Department (C1068)	City of Anaheim, Public Utilities Department (F00157)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L011501	Lookup Table	3.0	Fuel Producer: Powerflex (P343); Facility Name: PowerFlex Systems (F00162); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/30/2020	None	Electricity	Powerflex (P343)	PowerFlex Systems (F00162)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L011601	Lookup Table	3.0	Fuel Producer: Marin Clean Energy (C1066); Facility Name: Marin Clean Energy (F00147); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	5/14/2020	None	Electricity	Marin Clean Energy (C1066)	Marin Clean Energy (F00147)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L011801	Lookup Table	3.0	Fuel Producer: Wonderful Renewable Energy, LLC (C1080); Facility Name: Wonderful Renewable Energy, LLC (F00170); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/1/2020	None	Electricity	Wonderful Renewable Energy, LLC (C1080)	Wonderful Renewable Energy, LLC (F00170)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

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L012001	Lookup Table	3.0	Fuel Producer: 3 Phases Renewables Inc. (P306); Facility Name: 3 Phases Renewables Inc. (P1225); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/10/2020	None	Electricity	3 Phases Renewables Inc. (P306)	3 Phases Renewables Inc. (P1225)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L012201	Lookup Table	3.0	Fuel Producer: PowerFlex Systems, INC (C1092); Facility Name: PowerFlex Systems, Inc (F00197); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/30/2020	None	Electricity	PowerFlex Systems, INC (C1092)	PowerFlex Systems, Inc (F00197)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L012101	Lookup Table	3.0	Fuel Producer: San Diego Unified Port District (C1026); Facility Name: Port of San Diego (F00057); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/30/2020	None	Electricity	San Diego Unified Port District (C1026)	Port of San Diego (F00057)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L012301	Lookup Table	3.0	Fuel Producer: Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: Praxair - Ontario, CA (F00208); Liquefied H2 produced in California from central SMR of North American fossil-based NG	Canada	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	6/30/2020	None	Hydrogen	3Degrees Group, Inc. (C1055)	Praxair - Ontario, CA (F00208)	Liquefied H2 produced in California from central SMR of North American fossil-based NG	None	
L012401	Lookup Table	3.0	Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Hydrogen Research and Fueling Facility (F00145); Compressed H2 produced in California from electrolysis using California average grid electricity	California	Grid Electricity (039)	Gaseous Hydrogen (HYG)	None	None	HYG039L00072019	164.46	8/11/2020	None	Hydrogen	Cal State LA (C1063)	Cal State LA Hydrogen Research and Fueling Facility (F00145)	Compressed H2 produced in California from electrolysis using California average grid electricity	None	
L012701	Lookup Table	3.0	Fuel Producer: Pacific Merchant Shipping Association (C1099); Facility Name: Pacific Merchant Shipping Association (F00220); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/10/2020	None	Electricity	Pacific Merchant Shipping Association (C1099)	Pacific Merchant Shipping Association (F00220)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L010701	Lookup Table	3.0	Fuel Producer: CSG EV LLC (C1060); Facility Name: CSG EV LLC (F00141); Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	5/6/2020	None	Electricity	CSG EV LLC (C1060)	CSG EV LLC (F00141)	Electricity that is generated from 100 percent zeroCI sources used as a transportation fuel in California	None	
L011401	Lookup Table	3.0	Fuel Producer: PCS Energy (C1070); Facility Name: PCS Energy (F00159); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	5/13/2020	None	Electricity	PCS Energy (C1070)	PCS Energy (F00159)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L013501	Lookup Table	3.0	Fuel Producer: Eco Credit Traders LLC (C1107); Facility Name: Eco Credit Traders LLC (F00234); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/14/2020	None	Electricity	Eco Credit Traders LLC (C1107)	Eco Credit Traders LLC (F00234)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L013101	Lookup Table	3.0	Fuel Producer: Element Markets EV, LLC (C1093) ; Facility Name: Element Markets EV, LLC (F00232); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	Texas	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/18/2020	None	Electricity	Element Markets EV, LLC (C1093)	Element Markets EV, LLC (F00232)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A020101	Tier 1	3.0	Fuel Producer: Thumb BioEnergy (3862); Facility Name: Thumb BioEnergy (03862); Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail	Michigan	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU248	20.9	BIO001A02010100	15.80	9/29/2020	None	Biodiesel	Thumb BioEnergy (3862)	Thumb BioEnergy (03862)	Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail	None	Retired
A027801	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764) ; Facility Name: Aberdeen Energy (70299); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Mina, SD Ethanol transported by rail to California; Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETHC237L	80.19	ETH009A02780100	71.77	10/9/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Aberdeen Energy (70299)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil and Syrup, Natural Gas, Grid Electricity, Starch Ethanol produced in Mina, SD Ethanol transported by rail to California; Composite CI	None	

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A024702	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations	Michigan	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A02470200	62.68	10/13/2020	None	Bio-LNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations	None	Retired
A024703	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	California	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A02470300	65.77	10/13/2020	None	Bio-CNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	None	Retired
A025904	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A02590400	31.60	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	None	Retired
L013001	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc. Zero CI HYER (F00226); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	None	None	HYG037L00072019	10.51	9/30/2020	None	Hydrogen	SRECTrade, Inc (C1018)	SRECTrade, Inc. Zero CI HYER (F00226)	Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	None	
L013301	Lookup Table	3.0	Fuel Producer: Element Markets EV, LLC (C1093); Facility Name: 32-505 Harry Oliver Trail (F00233); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	None	None	HYG037L00072019	10.51	7/1/2020	None	Hydrogen	Element Markets EV, LLC (C1093)	32-505 Harry Oliver Trail (F00233)	Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources	None	
L013701	Lookup Table	3.0	Fuel Producer: MYNT SYSTEMS (C1112); Facility Name: MYNT SYSTEMS (F00294); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	11/2/2020	None	Electricity	MYNT SYSTEMS (C1112)	MYNT SYSTEMS (F00294)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
B011301	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C104); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced from biomethane of North American landfill gas at Linde-Praxair in Ontario, California; delivered to stations in Northern California by heavy-duty diesel truck, then compressed as gaseous hydrogen for use in hydrogen-fueled vehicles.	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B01130100	131.51	11/12/2020	Application Package	Hydrogen	Iwatani Corporation of America (C104)	Linde-Praxair (F00088)	Liquefied Hydrogen produced from biomethane of North American landfill gas at Linde-Praxair in Ontario, California; delivered to stations in Northern California by heavy-duty diesel truck, then compressed as gaseous hydrogen for use in hydrogen-fueled vehicles.	None	
A028401	Tier 1	3.0	Fuel Producer: BIOX Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Canadian Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	Canada	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02380800	22.81	BIO001A02840100	22.40	11/12/2020	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	Canadian Sourced Used Cooking Oil transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; Biodiesel produced in Ontario, Canada and transported by rail to California.	None	
L013801	Lookup Table	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Air Products and Chemicals SMR Wilmington. CA (F00068); Compressed H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	11/12/2020	None	Hydrogen	FirstElement Fuel (E426)	Air Products and Chemicals SMR Wilmington. CA (F00068)	Compressed H2 produced in California from central SMR of North American fossil-based NG	None	
L013901	Lookup Table	3.0	Fuel Producer: Penske Truck Leasing, Co., L.P. (C1116); Facility Name: Penske Truck Leasing (F00310); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	11/25/2020	None	Electricity	Penske Truck Leasing, Co., L.P. (C1116)	Penske Truck Leasing (F00310)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L014001	Lookup Table	3.0	Fuel Producer: NFI Industries (C1117); Facility Name: NFI Industries (F00311); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	11/25/2020	None	Electricity	NFI Industries (C1117)	NFI Industries (F00311)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A028001	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Glacial Lakes Energy (70064); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Watertown, South Dakota; Ethanol transported by rail to California, Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETHC241L	79.21	ETH009A02800100	72.66	12/8/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Glacial Lakes Energy (70064)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Watertown, South Dakota; Ethanol transported by rail to California, Composite CI	None	

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B002401	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Coronado Dairy Farm (F00009); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B00240100	-525.14	12/10/2020	Application Package	Electricity	CleanFuture, Inc. (C1001)	Coronado Dairy Farm (F00009)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California	None	Retired
A028301	Tier 1	3.0	Fuel Producer: BIOX Canada Limited (3758); Facility Name: BIOX Canada Limited (80236); Rendered Animal Fat Sourced from Sanimax Quebec City, Canada transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; transported by rail to California	Canada	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A02380500	36.98	BIO002A02830100	28.29	12/15/2020	None	Biodiesel	BIOX Canada Limited (3758)	BIOX Canada Limited (80236)	Rendered Animal Fat Sourced from Sanimax Quebec City, Canada transported by truck to Biodiesel plant in Hamilton, Ontario, Canada; Natural Gas and Grid Electricity; transported by rail to California	None	
L014301	Lookup Table	3.0	Fuel Producer: The Regents of the University of California (C1121); Facility Name: The Regents of the University of California (F00324); Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California	California	Zero-CI Sources Supplied via Green Tariff (048)	Electricity (ELC)	None	None	ELC048L00072019	0.00	12/28/2020	None	Electricity	The Regents of the University of California (C1121)	The Regents of the University of California (F00324)	Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California	None	
L014401	Lookup Table	3.0	Fuel Producer: S. C. Valley Transportation Authority (C1119); Facility Name: S.C. Valley Transportation Authority (F00328); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/24/2020	None	Electricity	S. C. Valley Transportation Authority (C1119)	S.C. Valley Transportation Authority (F00328)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L014801	Lookup Table	3.0	Fuel Producer: Toyota Motor North America (C1069); Facility Name: Toyota Motor North America (F00338); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	2/16/2021	None	Electricity	Toyota Motor North America (C1069)	Toyota Motor North America (F00338)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L015001	Lookup Table	3.0	Fuel Producer: Redwood Coast Energy Authority (R704); Facility Name: Redwood Coast Energy Authority (F00031); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	2/24/2021	None	Electricity	Redwood Coast Energy Authority (R704)	Redwood Coast Energy Authority (F00031)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L015201	Lookup Table	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. Venture, Inc. (F00345); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	2/24/2021	None	Electricity	U.S. Venture, Inc. (5504)	U.S. Venture, Inc. (F00345)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A033002	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00990200	63.23	ETH009A03300200	63.46	3/1/2021	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	None	Retired
A033003	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03300300	25.32	3/1/2021	None	Ethanol - Cellulosic	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California. (Provisional)	None	Retired
L015101	Lookup Table	3.0	Fuel Producer: PineSpire, LLC (C1128); Facility Name: PineSpire (F00344); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/4/2021	None	Electricity	PineSpire, LLC (C1128)	PineSpire (F00344)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A028701	Tier 1	3.0	Fuel Producer: Elkhorn Valley Ethanol LLC (4833); Facility Name: Elkhorn Valley Ethanol LLC (70095); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Norfolk, Nebraska; Ethanol transported by rail to California, Composite CI	Nebraska	Corn (009)	Ethanol (ETH)	T1N-1277, T1N-1276	74.74, 79.83	ETH009A02870100	71.99	3/22/2021	None	Ethanol	Elkhorn Valley Ethanol LLC (4833)	Elkhorn Valley Ethanol LLC (70095)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Norfolk, Nebraska; Ethanol transported by rail to California, Composite CI	None	Retired
A031001	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG (Provisional)	Louisiana	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A03100100	41.18	3/18/2021	None	Bio-CNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG (Provisional)	None	Retired

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B011101	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Stotz Dairy Southern (F00155); Dairy Biogas produced in Maricopa County, AZ from dairy manure covered anaerobic lagoons to produce electricity for import into California for electric vehicle charging	Arizona	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01110100	-762.09	3/23/2021	Application Package	Electricity	CleanFuture, Inc. (C1001)	Stotz Dairy Southern (F00155)	Dairy Biogas produced in Maricopa County, AZ from dairy manure covered anaerobic lagoons to produce electricity for import into California for electric vehicle charging	None	Retired
B012301	Tier 2	3.0	Fuel Producer: South San Francisco Scavengers (S283); Facility Name: South San Francisco Scavenger Company (J0500); Renewable Natural Gas (RNG) produced from Food Scraps and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling	California	Food Scraps/Waste (027)	Compressed Natural Gas (CNG)	None	None	CNG027B01230100	-79.91	3/29/2021	Application Package	Bio-CNG	South San Francisco Scavengers (S283)	South San Francisco Scavenger Company (J0500)	Renewable Natural Gas (RNG) produced from Food Scraps and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling	None	
B012302	Tier 2	3.0	Fuel Producer: South San Francisco Scavengers (S283); Facility Name: South San Francisco Scavenger Company (J0500); Renewable Natural Gas (RNG) produced from Urban Landscaping Waste and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling	California	Other Organic Waste (029)	Compressed Natural Gas (CNG)	None	None	CNG028B01230200	0.28	3/29/2021	Application Package	Bio-CNG	South San Francisco Scavengers (S283)	South San Francisco Scavenger Company (J0500)	Renewable Natural Gas (RNG) produced from Urban Landscaping Waste and upgraded at South San Francisco Scavenger Company facility in South San Francisco California; RNG used for onsite fueling	None	
A027601	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Meadow Branch Landfill Gas Processing Facility (71252); Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel (Provisional)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF261R	52.14	CNG025A02760100	47.41	3/25/2021	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Meadow Branch Landfill Gas Processing Facility (71252)	Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel (Provisional)	None	Retired
B014802	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Triple G Dairy (F00156); Low-CI electricity from biogas produced from dairy manure and organic substrates using reciprocating engine at Triple G Dairy in Maricopa County, Arizona for use as transportation fuel in California.	Arizona	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01480200	-493.57	3/30/2021	Application Package	Electricity	CleanFuture, Inc. (C1001)	Triple G Dairy (F00156)	Low-CI electricity from biogas produced from dairy manure and organic substrates using reciprocating engine at Triple G Dairy in Maricopa County, Arizona for use as transportation fuel in California.	None	Retired
B017201	Tier 2	3.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566); Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI (Provisional)	California	Corn (009)	Ethanol (ETH)	ETH009A00940100	67.03	ETH009B01720100	65.68	3/29/2021	Application Package	Ethanol	Aemetis Advanced Fuels Keyes, Inc (3566)	Aemetis Advanced Fuels Keyes, Inc (70234)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI (Provisional)	None	Retired
B013302	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B01330200	32.50	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013303	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B01330300	25.50	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013304	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B01330400	20.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013305	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B01330500	26.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013307	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01330700	37.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
B013308	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01330800	38.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired

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B013309	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B01330900	43.00	4/30/2021	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Lousiana and transported to California by ocean tanker (Provisional)	None	Retired
A029503	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); California sourced Rendered Animal Fat, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A02950300	33.86	4/1/2021	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	California sourced Rendered Animal Fat, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	None	
B018901	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	None	None	RNT003B01890100	33.00	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018902	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01890200	37.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018903	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT002B01890300	26.00	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018904	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B01890400	20.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018905	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B01890500	26.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018906	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01890600	38.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018907	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B01890700	43.50	4/30/2021	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018910	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891000	33.00	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018911	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891100	26.00	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018912	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891200	20.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired

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B018913	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891300	26.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018914	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891400	37.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018915	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891500	38.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
B018916	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B01891600	43.50	4/30/2021	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (Provisional)	None	Retired
A023901	Tier 1	3.0	Fuel Producer: M&N Participações S/A (C1082); Facility Name: Usina Giasa Ltda (F00192); Ethanol from sugarcane juice, with co-product credit for surplus cogenerated electricity exports; transport to California port via ocean tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A02390100	48.82	5/7/2021	None	Ethanol	M&N Participações S/A (C1082)	Usina Giasa Ltda (F00192)	Ethanol from sugarcane juice, with co-product credit for surplus cogenerated electricity exports; transport to California port via ocean tanker.	None	Retired
A028801	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Midwest Soybean Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	Iowa	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A02880100	58.00	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	Midwest Soybean Oil transported by truck to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	None	
A028802	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Canola Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail.	Iowa	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A02880200	54.00	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	Canola Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail.	None	
A028803	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Corn Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail.	Iowa	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC208	34.10	BIO003A02880300	28.50	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	Corn Oil transported by truck to Biodiesel plant in Newton, IA, US then to California By Rail.	None	
A028804	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); U.S. Sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	Iowa	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU223	22.50	BIO001A02880400	21.00	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	U.S. Sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	None	
A028805	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); Self Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	Iowa	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU235	15.49	BIO001A02880500	16.00	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	Self Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	None	
A028806	Tier 1	3.0	Fuel Producer: REG Newton, LLC (3514); Facility Name: REG Newton, LLC (80162); U.S. Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	Iowa	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT212	35.94	BIO002A02880600	33.50	5/11/2021	None	Biodiesel	REG Newton, LLC (3514)	REG Newton, LLC (80162)	U.S. Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Newton, Iowa; Biodiesel transported to California by Rail.	None	
A029601	Tier 1	3.0	Fuel Producer: Green Plains Central City (3368); Facility Name: Green Plains Central City LLC (70141); Ethanol from Corn Starch, MDGS, Corn Oil, NG & Grid Electricity; Transport by Rail to California.	Nebraska	Corn (009)	Ethanol (ETH)	ETHC023 (T1R-1214)	82.17	ETH009A02960100	65.97	5/7/2021	None	Ethanol	Green Plains Central City (3368)	Green Plains Central City LLC (70141)	Ethanol from Corn Starch, MDGS, Corn Oil, NG & Grid Electricity; Transport by Rail to California.	None	Retired

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A030903	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A03090300	68.76	5/4/2021	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	Retired
A036701	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG (Provisional)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A03670100	49.53	5/11/2021	None	Bio-CNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG (Provisional)	None	Retired
A028901	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Corn Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC215	35.13	BIO003A02890100	29.00	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Corn Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	
A028902	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Rendered Animal Fat Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT220	36.80	BIO002A02890200	33.50	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Rendered Animal Fat Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	
A028903	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Canola Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A02890300	53.00	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Canola Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	
A028904	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); Midwest Soybean Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A02890400	58.30	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	Midwest Soybean Oil transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	
A028905	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU249	22.58	BIO001A02890500	21.50	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	Retired
A028906	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); U.S sourced Used Cooking Oil; Zero rendering energy; transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU250	17.33	BIO001A02890600	17.00	6/7/2021	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	U.S sourced Used Cooking Oil; Zero rendering energy; transported by truck to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	None	
A036101	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A03610100	70.52	6/7/2021	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	None	Retired
A036102	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A03610200	63.38	6/7/2021	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	None	Retired
A036103	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03610300	23.59	6/7/2021	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (Provisional)	None	Retired
A029001	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Corn Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail	Illinois	Distillers' Corn Oil (003)	Biodiesel (BIO)	BDC213	34.02	BIO003A02900100	28.00	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Corn Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail	None	

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A029004	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU242	21.84	BIO001A02900400	20.75	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	None	Retired
A029005	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU244	16.57	BIO001A02900500	16.25	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail	None	Retired
A029007	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail	Illinois	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT219	35.79	BIO002A02900700	32.75	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Seneca, IL, US then to California By Rail	None	
L001701	Lookup Table	3.0	Fuel Producer: Tesla, Inc. (C1016); Facility Name: Tesla, Inc. (F00045); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	5/29/2019	None	Electricity	Tesla, Inc. (C1016)	Tesla, Inc. (F00045)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L006301	Lookup Table	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Carson Hydrogen Plant (F00059); Compressed H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	7/12/2019	None	Hydrogen	Shell Energy North America (6154)	Carson Hydrogen Plant (F00059)	Compressed H2 produced in California from central SMR of North American fossil-based NG.	None	
L007801	Lookup Table	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: Praxair Liquid H2 Source (F00053); Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills.	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025L00072019	129.09	7/16/2019	None	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	Praxair Liquid H2 Source (F00053)	Liquefied H2 produced in California from central SMR of biomethane (renewable feedstock) from North American landfills.	None	
L007901	Lookup Table	3.0	Fuel Producer: American Honda Motor Co., Inc. (C1023); Facility Name: American Honda Motor Co., Inc. (F00074); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/6/2019	None	Electricity	American Honda Motor Co., Inc. (C1023)	American Honda Motor Co., Inc. (F00074)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L009101	Lookup Table	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Air Products and Chemicals, Inc. (SFS) (F00092); Liquefied H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	9/26/2019	None	Hydrogen	CleanFuture, Inc. (C1001)	Air Products and Chemicals, Inc. (SFS) (F00092)	Liquefied H2 produced in California from central SMR of North American fossil-based NG.	None	
L009201	Lookup Table	3.0	Fuel Producer: Air Products and Chemicals, Inc. (C1042); Facility Name: APCI Wilmington Transfill (F00095); Compressed H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	9/27/2019	None	Hydrogen	Air Products and Chemicals, Inc. (C1042)	APCI Wilmington Transfill (F00095)	Compressed H2 produced in California from central SMR of North American fossil-based NG.	None	
L009601	Lookup Table	3.0	Fuel Producer: Paired Power (P995); Facility Name: McCalmont Engineering (22575); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	California	Directly Supplied Zero-CI Sources (049)	Electricity (ELC)	None	None	ELC049L00072019	0.00	3/30/2020	None	Electricity	Paired Power (P995)	McCalmont Engineering (22575)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	None	
L011301	Lookup Table	3.0	Fuel Producer: Trillium USA Company, LLC (C1056); Facility Name: Trillium USA Company, LLC (F00152); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	Texas	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/30/2020	None	Electricity	Trillium USA Company, LLC (C1056)	Trillium USA Company, LLC (F00152)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L012501	Lookup Table	3.0	Fuel Producer: Green Commuter (C1096) ; Facility Name: Green Commuter (F00214); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/8/2020	None	Electricity	Green Commuter (C1096)	Green Commuter (F00214)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	

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L012601	Lookup Table	3.0	Fuel Producer: EV CHARGING SOLUTIONS, INC. (C1095); Facility Name: EV Charging Solutions, Inc. (F00215); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/8/2020	None	Electricity	EV CHARGING SOLUTIONS, INC. (C1095)	EV Charging Solutions, Inc. (F00215)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L012801	Lookup Table	3.0	Fuel Producer: Ingram Micro, Inc. (C1102); Facility Name: Ingram Micro, Inc. (F00222); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/25/2020	None	Electricity	Ingram Micro, Inc. (C1102)	Ingram Micro, Inc. (F00222)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L012901	Lookup Table	3.0	Fuel Producer: Zeco Systems Inc. d/b/a Greenlots (C1097) ; Facility Name: Zeco Systems Inc. d/b/a Greenlots (F00225); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/11/2020	None	Electricity	Zeco Systems Inc. d/b/a Greenlots (C1097)	Zeco Systems Inc. d/b/a Greenlots (F00225)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L013601	Lookup Table	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Shell Energy North America (F00017); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	Texas	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	10/16/2020	None	Electricity	Shell Energy North America (6154)	Shell Energy North America (F00017)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L014101	Lookup Table	3.0	Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: Praxair - Ontario, CA (F00208); Liquified H2 produced in California from central SMR of North American fossil-based NG.	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	12/7/2020	None	Hydrogen	3Degrees Group, Inc. (C1055)	Praxair - Ontario, CA (F00208)	Liquefied H2 produced in California from central SMR of North American fossil-based NG.	None	
L015301	Lookup Table	3.0	Fuel Producer: Green Water and Power (C1123); Facility Name: Green Water and Power (F00322); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/15/2021	None	Electricity	Green Water and Power (C1123)	Green Water and Power (F00322)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L015501	Lookup Table	3.0	Fuel Producer: City of Santa Clara/Silicon Valley Power (C1130); Facility Name: BEAM EVARC Unit #334 (F00358); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	California	Directly Supplied Zero-CI Sources (049)	Electricity (ELC)	None	None	ELC049L00072019	0.00	5/25/2021	None	Electricity	City of Santa Clara/Silicon Valley Power (C1130)	BEAM EVARC Unit #334 (F00358)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	None	
L015401	Lookup Table	3.0	Fuel Producer: City of Santa Clara/Silicon Valley Power (C1130); Facility Name: BEAM EVARC Unit #333 (F00357); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	California	Directly Supplied Zero-CI Sources (049)	Electricity (ELC)	None	None	ELC049L00072019	0.00	5/25/2021	None	Electricity	City of Santa Clara/Silicon Valley Power (C1130)	BEAM EVARC Unit #333 (F00357)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	None	
L015601	Lookup Table	3.0	Fuel Producer: San Jose Clean Energy (C1120); Facility Name: San Jose Clean Energy (F00323); Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California.	California	Zero-CI Sources Supplied via Green Tariff (048)	Electricity (ELC)	None	None	ELC048L00072019	0.00	4/30/2021	None	Electricity	San Jose Clean Energy (C1120)	San Jose Clean Energy (F00323)	Electricity that is generated from 100 percent zero-CI sources supplied via Green Tariff used as a transportation fuel in California.	None	
L015701	Lookup Table	3.0	Fuel Producer: AMPLY Power, Inc. (C1134); Facility Name: AMPLY Power, Inc (F00364); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	4/21/2021	None	Electricity	AMPLY Power, Inc. (C1134)	AMPLY Power, Inc (F00364)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L015801	Lookup Table	3.0	Fuel Producer: Muza Energy (C1136); Facility Name: Muza Energy (F00369); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/3/2021	None	Electricity	Muza Energy (C1136)	Muza Energy (F00369)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A030201	Tier 1	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Melissa Renewables, LLC (71407); Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF276	40.63	CNG025A03020100	34.00	6/16/2021	None	Bio-CNG	Shell Energy North America (6154)	Melissa Renewables, LLC (71407)	Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG (Provisional)	None	Retired

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A029101	Tier 1	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Pine Hill Renewables, LLC (71288); Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNGLF272	39.83	CNG025A02910100	34.17	6/16/2021	None	Bio-CNG	Shell Energy North America (6154)	Pine Hill Renewables, LLC (71288)	Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG (Provisional)	None	Retired
A034502	Tier 1	3.0	Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations	Michigan	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNGLF200LR	54.14	LNG025A03450200	65.55	6/16/2021	None	Bio-LNG	WESTSIDE GAS PRODUCERS, LLC (6218)	WESTSIDE GAS PRODUCERS, LLC (71151)	Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations	None	
A034503	Tier 1	3.0	Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California stations	Michigan	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	CNGLF223LR	57.29	LCN025A03450300	68.64	6/16/2021	None	Bio-CNG	WESTSIDE GAS PRODUCERS, LLC (6218)	WESTSIDE GAS PRODUCERS, LLC (71151)	Biomethane from Westside Landfill at Three River, Michigan, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California stations	None	
A037301	Tier 1	3.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); Used Cooking Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail.	Texas	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU226R	24.41	BIO001A03730100	18.30	6/21/2021	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	Used Cooking Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail.	None	
A037302	Tier 1	3.0	Fuel Producer: Global Alternative Fuels, LLC (7765); Facility Name: Global Alternative Fuels, LLC (83533); Midwest Soybean Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail.	Texas	Soybean Oil (005)	Biodiesel (BIO)	BDS210R	53.43	BIO005A03730200	53.55	6/21/2021	None	Biodiesel	Global Alternative Fuels, LLC (7765)	Global Alternative Fuels, LLC (83533)	Midwest Soybean Oil transported by truck to Biodiesel plant in El Paso, Texas; biodiesel fuel then transported to California by rail.	None	
L015901	Lookup Table	3.0	Fuel Producer: Sol Systems LLC (C1133); Facility Name: Sol Systems, LLC (F00370); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	Washington D.C.	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/21/2021	None	Electricity	Sol Systems LLC (C1133)	Sol Systems, LLC (F00370)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
B017907	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); North America Sourced Corn Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	Singapore	Distillers' Corn Oil (003)	Renewable Diesel (RND)	RDC200L	37.39	RND003B01790700	36.43	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	North America Sourced Corn Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	None	
B017904	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); Globally Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	Singapore	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RDU201L	25.61	RND001B01790400	32.83	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Globally Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	None	
B017906	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); North America Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	Singapore	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B01790600	28.64	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	North America Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to California.	None	
B017905	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); South East Asia Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	Singapore	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RDU200L	16.89	RND001B01790500	24.29	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	South East Asia Sourced Used Cooking Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	None	
B017902	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); North America Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	Singapore	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RDT201L	34.19	RND002B01790200	40.10	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	North America Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	None	
B017903	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); Oceanic Sourced Rendered Animal Fat Oil transported by Truck and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	Singapore	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RDT200L	36.83	RND002B01790300	38.26	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Oceanic Sourced Rendered Animal Fat Oil transported by Truck and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	None	

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B017901	Tier 2	3.0	Fuel Producer: Neste Singapore Pte Ltd (4137); Facility Name: Neste Singapore (80327); Globally Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	Singapore	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RDT202	39.06	RND002B01790100	42.77	6/25/2021	Application Package	Renewable Diesel	Neste Singapore Pte Ltd (4137)	Neste Singapore (80327)	Globally Sourced Rendered Animal Fat Oil transported by Truck, Rail, and Ocean Tanker to Renewable Diesel plant in Singapore; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in Singapore and transported by Ocean Tanker to CA.	None	
B014001	Tier 2	3.0	Fuel Producer: Degrees3 Transportation Solutions, LLC (C1111); Facility Name: New Energy One (F00274); Low-CI electricity from dairy manure using reciprocating engine at Cedar Ridge in Filer, Idaho for use as transportation fuel in California	Idaho	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01400100	-698.21	6/29/2021	Application Package	Electricity	Degrees3 Transportation Solutions, LLC (C1111)	New Energy One (F00274)	Low-CI electricity from dairy manure using reciprocating engine at Cedar Ridge in Filer, Idaho for use as transportation fuel in California	None	
B013901	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ruckman Farm (71256); Renewable Natural Gas (RNG) from Swine Manure of Ruckman Farm, Allbany, Missouri; RNG is delivered via pipeline to Los Angeles, California and central California locations	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B00110100	-372.35	CNG044B01390100	-431.79	6/29/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ruckman Farm (71256)	Renewable Natural Gas (RNG) from Swine Manure of Ruckman Farm, Allbany, Missouri; RNG is delivered via pipeline to Los Angeles, California and central California locations	None	
B014101	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Locust Ridge Farm (71298); Renewable Natural Gas (RNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California areas	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B00090100	-323.83	CNG044B01410100	-449.66	6/29/2021	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Locust Ridge Farm (71298)	Renewable Natural Gas (RNG) from Swine Manure of Locust Ridge Farm, Harris, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California areas	None	
B016601	Tier 2	3.0	Fuel Producer: SMUD (S338); Facility Name: New Hope Dairy Digester (F00255); Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01660100	-750.81	6/28/2021	Application Package	Electricity	SMUD (S338)	New Hope Dairy Digester (F00255)	Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California. (Provisional)	None	Retired
A033901	Tier 1	3.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Cresciumal (71068); Ethanol from Brazilian sugarcane juice and molasses; road transport to port, ocean transport to California	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM221	46.34	ETH018A03390100	48.08	6/30/2021	None	Ethanol	BIOSEV S.A. (3869)	Usina Cresciumal (71068)	Ethanol from Brazilian sugarcane juice and molasses; road transport to port, ocean transport to California	None	
L016101	Lookup Table	3.0	Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Hydrogen Research and Fueling Facility (F00145); Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources.	California	Zero-CI Sources (037)	Gaseous Hydrogen (HYG)	None	None	HYG037L00072019	10.51	6/28/2021	None	Hydrogen	Cal State LA (C1063)	Cal State LA Hydrogen Research and Fueling Facility (F00145)	Compressed H2 produced in California from electrolysis using electricity generated from zero-CI sources.	None	
L016201	Lookup Table	3.0	Fuel Producer: Cal State LA (C1063); Facility Name: Cal State LA Structure E (F00376); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/29/2021	None	Electricity	Cal State LA (C1063)	Cal State LA Structure E (F00376)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A031501	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Ipiranga Agroindustrial SA (70398); Ethanol produced from Sugarcane juice and molasses in Brazil; co-product credit for surplus cogenerated electricity export; ethanol transported to California by ocean tanker via Cape Horn.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS229	43.56	ETH018A03150100	49.06	6/30/2021	None	Ethanol	Copersucar (3702)	Ipiranga Agroindustrial SA (70398)	Ethanol produced from Sugarcane juice and molasses in Brazil; co-product credit for surplus cogenerated electricity export; ethanol transported to California by ocean tanker via Cape Horn.	None	
A031701	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Usina São José da Estiva S.A. - Açúcar e Álcool (70431); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM237	45.06	ETH018A03170100	51.28	6/30/2021	None	Ethanol	Copersucar (3702)	Usina São José da Estiva S.A. - Açúcar e Álcool (70431)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A033301	Tier 1	3.0	Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Santa Cruz S/A Açúcar e Álcool (70484); Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS223	48.22	ETH018A03330100	50.06	7/1/2021	None	Ethanol	Usina São Martinho S.A. (3867)	Santa Cruz S/A Açúcar e Álcool (70484)	Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker.	None	Retired
A033201	Tier 1	3.0	Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Usina São Martinho S.A. (71100); Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS219	46.61	ETH018A03320100	50.99	6/30/2021	None	Ethanol	Usina São Martinho S.A. (3867)	Usina São Martinho S.A. (71100)	Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker.	None	Retired

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A033701	Tier 1	3.0	Fuel Producer: JC Chemical Co., Ltd. (6094); Facility Name: JC Chemical Co., Ltd. (81585); South Korea sourced rendered Used Cooking Oil transported by truck to Biodiesel plant in South Korea; Natural Gas, Grid Electricity; Biodiesel transported to California By Ocean Tanker (Provisional)	South Korea	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BDU238	20.15	BIO001A03370100	24.35	7/9/2021	None	Biodiesel	JC Chemical Co., Ltd. (6094)	JC Chemical Co., Ltd. (81585)	South Korea sourced rendered Used Cooking Oil transported by truck to Biodiesel plant in South Korea; Natural Gas, Grid Electricity; Biodiesel transported to California By Ocean Tanker (Provisional)	None	
A034101	Tier 1	3.0	Fuel Producer: Ag Processing Inc (4552); Facility Name: AGP Methyl Ester (St Joseph) (81732); Midwest Soybean Oil Extraction Facility co-located with a Biodiesel plant in St. Joseph, Missouri; Grid Electricity; Biodiesel produced in St. Joseph, Missouri; Finished Fuel transported to California By Rail	Missouri	Soybean Oil (005)	Biodiesel (BIO)	BDS213	50.48	BIO005A03410100	54.06	7/9/2021	None	Biodiesel	Ag Processing Inc (4552)	AGP Methyl Ester (St Joseph) (81732)	Midwest Soybean Oil Extraction Facility co-located with a Biodiesel plant in St. Joseph, Missouri; Grid Electricity; Biodiesel produced in St. Joseph, Missouri; Finished Fuel transported to California By Rail	None	
A038603	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03860300	28.03	7/13/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	Retired
A025201	Tier 1	3.0	Fuel Producer: Companhia Alcoolquimica Nacional (C1086); Facility Name: Companhia Alcoolquimica Nacional (F00194); Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A02520100	56.50	7/15/2021	None	Ethanol	Companhia Alcoolquimica Nacional (C1086)	Companhia Alcoolquimica Nacional (F00194)	Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity.	None	Retired
B019201	Tier 2	3.0	Fuel Producer: 3Degrees Group, Inc. (C1055); Facility Name: Praxair - Ontario, CA (F00208); Liquefied hydrogen from North American Natural Gas; produced at Praxair, Ontario, California transported as liquid to Hydrogen stations in California	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031B01920100	153.90	7/14/2021	Application Package	Hydrogen	3Degrees Group, Inc. (C1055)	Praxair - Ontario, CA (F00208)	Liquefied hydrogen from North American Natural Gas; produced at Praxair, Ontario, California transported as liquid to Hydrogen stations in California	None	
L016001	Lookup Table	3.0	Fuel Producer: InCharge Energy Inc. (C1137); Facility Name: InCharge Energy Inc Corporate Headquarters (F00375); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	7/22/2021	None	Electricity	InCharge Energy Inc. (C1137)	InCharge Energy Inc Corporate Headquarters (F00375)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A033501	Tier 1	3.0	Fuel Producer: COFCO International Brasil S.A. (C1110); Facility Name: Unidade POTIRENDABA (F00327); Ethanol produced from Sugarcane Juice and Molasses; exported to California by Ocean Tanker.; Co-Product Credit for surplus cogenerated electricity export.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS212	46.83	ETH018A03350100	52.19	7/28/2021	None	Ethanol	COFCO International Brasil S.A. (C1110)	Unidade POTIRENDABA (F00327)	Ethanol produced from Sugarcane Juice and Molasses; exported to California by Ocean Tanker.; Co-Product Credit for surplus cogenerated electricity export.	None	
A034001	Tier 1	3.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Usina Santa Elisa (71070); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS246	50.16	ETH018A03400100	52.45	7/27/2021	None	Ethanol	BIOSEV S.A. (3869)	Usina Santa Elisa (71070)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity.	None	
A033801	Tier 1	3.0	Fuel Producer: BIOSEV S.A. (3869); Facility Name: Unidade MB (70568); Ethanol produced from Brazilian Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS208 and ETHM228	47.68 and 48.63	ETH018A03380100	54.03	7/28/2021	None	Ethanol	BIOSEV S.A. (3869)	Unidade MB (70568)	Ethanol produced from Brazilian Sugarcane Juice and Molasses, and exported to California by Ocean Tanker; Co-Product Credit for export of surplus cogenerated electricity.	None	
A035001	Tier 1	3.0	Fuel Producer: Delek Renewables, LLC (5998); Facility Name: DELEK RENEWABLES NEW ALBANY BIODIESEL PLANT (80701); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Electricity; Biodiesel transported to California By Rail	Mississippi	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A03500100	31.11	7/29/2021	None	Biodiesel	Delek Renewables, LLC (5998)	DELEK RENEWABLES NEW ALBANY BIODIESEL PLANT (80701)	U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Electricity; Biodiesel transported to California By Rail	None	
A037401	Tier 1	3.0	Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Altamont Bio-LNG Plant (70526); Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations; regasified, and compressed to L-CNG. (Provisional)	California	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	CNGLF246, CNGLF247, and CNGLF248	9.97, 10.32 and 13.29	LCN025A03740100	18.96	7/29/2021	None	Bio-CNG	HIGH MOUNTAIN FUELS LLC (4293)	Altamont Bio-LNG Plant (70526)	Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations; regasified, and compressed to L-CNG. (Provisional)	None	Retired
A037402	Tier 1	3.0	Fuel Producer: HIGH MOUNTAIN FUELS LLC (4293); Facility Name: Altamont Bio-LNG Plant (70526); Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations. (Provisional)	California	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNGLF217 and LNGLF218	7.39 and 7.74	LNG025A03740200	15.87	7/29/2021	None	Bio-LNG	HIGH MOUNTAIN FUELS LLC (4293)	Altamont Bio-LNG Plant (70526)	Biomethane from Altamont Landfill in Livermore, California, liquefied on-site by Altamont Bio-LNG Plant to LNG; trucked in-state to California LNG stations. (Provisional)	None	Retired

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A035701	Tier 1	3.0	Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Crossett Biodiesel Plant (82217); U.S Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Crossett, Arkansas; Grid Electricity; Biodiesel fuel transported to California by rail.	Arkansas	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BDT213	32.96	BIO002A03570100	28.97	8/4/2021	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Crossett Biodiesel Plant (82217)	U.S Sourced Rendered Animal Fat Oil transported by truck and rail to Biodiesel plant in Crossett, Arkansas; Grid Electricity; Biodiesel fuel transported to California by rail.	None	
A039901	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO HARTLEY PLANT (70275); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A03990100	72.80	8/4/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO HARTLEY PLANT (70275)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional)	None	
A039902	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO HARTLEY PLANT (70275); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A03990200	68.94	8/4/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO HARTLEY PLANT (70275)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California. (Provisional)	None	
A039903	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO HARTLEY PLANT (70275); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03990300	26.60	8/4/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO HARTLEY PLANT (70275)	Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hartley, Iowa; Ethanol transported by rail to California (Provisional)	None	
L016301	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc Zero CI Direct Renewable Energy Stockton (F00378); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	California	Directly Supplied Zero-CI Sources (049)	Electricity (ELC)	None	None	ELC049L00072019	0.00	8/2/2021	None	Electricity	SRECTrade, Inc (C1018)	SRECTrade, Inc Zero CI Direct Renewable Energy Stockton (F00378)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	None	
L016401	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc Zero CI Direct Renewable Energy Dispersed (F00379); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	California	Directly Supplied Zero-CI Sources (049)	Electricity (ELC)	None	None	ELC049L00072019	0.00	8/5/2021	None	Electricity	SRECTrade, Inc (C1018)	SRECTrade, Inc Zero CI Direct Renewable Energy Dispersed (F00379)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California.	None	
L016601	Lookup Table	3.0	Fuel Producer: SunHarvest Partners LLC (C1147); Facility Name: SunHarvest Partners LLC (F00386); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/2/2021	None	Electricity	SunHarvest Partners LLC (C1147)	SunHarvest Partners LLC (F00386)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L016701	Lookup Table	3.0	Fuel Producer: Degrees3 Transportation Solutions, LLC (C1111); Facility Name: Degrees3 Transportation Solutions (F00385); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/5/2021	None	Electricity	Degrees3 Transportation Solutions, LLC (C1111)	Degrees3 Transportation Solutions (F00385)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L016501	Lookup Table	3.0	Fuel Producer: Peninsula Clean Energy (C1142); Facility Name: Peninsula Clean Energy (F00381); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/5/2021	None	Electricity	Peninsula Clean Energy (C1142)	Peninsula Clean Energy (F00381)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A015601	Tier 1	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Arizona	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A01560100	26.58	12/18/2019	None	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	None	Retired
A039501	Tier 1	3.0	Fuel Producer: Just Biodiesel Pty. Ltd. (C1037); Facility Name: Just Biodiesel Pty. Ltd. (F00079); Australia Sourced Used Cooking Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional)	Australia	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	None	None	BIO001A03950100	31.34	8/20/2021	None	Biodiesel	Just Biodiesel Pty. Ltd. (C1037)	Just Biodiesel Pty. Ltd. (F00079)	Australia Sourced Used Cooking Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional)	None	
A039502	Tier 1	3.0	Fuel Producer: Just Biodiesel Pty. Ltd. (C1037); Facility Name: Just Biodiesel Pty. Ltd. (F00079); Australia Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional)	Australia	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	None	None	BIO002A03950200	43.33	8/20/2021	None	Biodiesel	Just Biodiesel Pty. Ltd. (C1037)	Just Biodiesel Pty. Ltd. (F00079)	Australia Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Australia; Light Fuel Oil, Bottom Distillate, Bio Heating Oil, Grid Electricity; Biodiesel transported to California by Ocean Tanker. (Provisional)	None	

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L016801	Lookup Table	3.0	Fuel Producer: Disneyland Resort (C1150); Facility Name: Disneyland Resort (F00388); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/17/2021	None	Electricity	Disneyland Resort (C1150)	Disneyland Resort (F00388)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A035301	Tier 1	3.0	Fuel Producer: South Platte Renew (8380); Facility Name: 2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel. (Provisional)	Colorado	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A03530100	52.36	8/24/2021	None	Bio-CNG	South Platte Renew (8380)	2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641)	Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel. (Provisional)	None	Retired
A038501	Tier 1	3.0	Fuel Producer: Los Angeles County Sanitation District (L375); Facility Name: Biogas Conditioning System Facility (F00308); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite. (Provisional)	California	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A03850100	19.28	8/20/2021	None	Bio-CNG	Los Angeles County Sanitation District (L375)	Biogas Conditioning System Facility (F00308)	Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite. (Provisional)	None	Retired
A025801	Tier 1	3.0	Fuel Producer: Agro Industrial Tabu S.A. (C1088); Facility Name: Agro Industrial Tabu (F00205); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A02580100	51.59	9/3/2021	None	Ethanol	Agro Industrial Tabu S.A. (C1088)	Agro Industrial Tabu (F00205)	Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal.	None	Retired
A037201	Tier 1	3.0	Fuel Producer: USINAS ITAMARATI SA (1150); Facility Name: USINAS ITAMARATI SA (70942); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A03720100	58.21	9/17/2021	None	Ethanol	USINAS ITAMARATI SA (1150)	USINAS ITAMARATI SA (70942)	Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker.	None	
L017001	Lookup Table	3.0	Fuel Producer: Smart Charging Technologies (C1050) ; Facility Name: Burlington Distribution Hydrogen (F00396); Liquefied H2 produced in California from central SMR of North American fossil-based NG	California	North American Fossil NG (031)	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	9/13/2021	None	Hydrogen	Smart Charging Technologies (C1050)	Burlington Distribution Hydrogen (F00396)	Liquefied H2 produced in California from central SMR of North American fossil-based NG	None	
A037901	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (Provisional)	Texas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03790100	23.13	9/28/2021	None	Ethanol - Cellulosic	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (Provisional)	None	Retired
B019701	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (Provisional)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00580100	-167.04	CNG026B01970100	-177.03	9/28/2021	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (Provisional)	None	Retired
B019702	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00580200	-151.41	CNG026B01970200	-156.78	9/28/2021	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	None	Retired
B019703	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00580300	-257.78	CNG026B01970300	-295.26	9/28/2021	Application Package	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	None	Retired
B017502	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Giacomini Dairy (F00305); Low-CI Electricity from Dairy Manure and Cheese Wastewater Biogas using reciprocating engine at Giacomini Dairy in Point Reyes Station, California for use as transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B01750200	-431.65	9/30/2021	Application Package	Electricity	CleanFuture, Inc. (C1001)	Giacomini Dairy (F00305)	Low-CI Electricity from Dairy Manure and Cheese Wastewater Biogas using reciprocating engine at Giacomini Dairy in Point Reyes Station, California for use as transportation fuel in California. (Provisional)	None	
B018503	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01850300	-382.11	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	None	Retired

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B019802	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01980200	-414.26	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
B019804	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01980400	-405.41	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
B019805	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01980500	-385.40	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
A041801	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Ferrari Agroindustrial S.A. (70435); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04180100	51.83	9/30/2021	None	Ethanol	Copersucar (3702)	Ferrari Agroindustrial S.A. (70435)	Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker	None	
A040202	Tier 1	3.0	Fuel Producer: Siouxland Ethanol, LLC (5026); Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill; Edniq Fiber Conversion Process; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A00340200	26.67	ETH012A04020200	24.18	10/11/2021	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest Corn, Dry Mill; Edniq Fiber Conversion Process; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California. (Provisional)	None	
A037902	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional)	Texas	Corn (009)	Ethanol (ETH)	ETH009A01630100	64.74	ETH009A03790200	63.93	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (Provisional)	None	Retired
B019803	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B01980300	-420.69	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (Provisional)	None	Retired
A040801	Tier 1	3.0	Fuel Producer: Ag Processing Inc (4552); Facility Name: Ag Processing Inc - Sgt. Bluff (81733); Midwest Soybean Oil; Extraction Facility co-located with a Biodiesel plant in Sergeant Bluff, Iowa; Grid Electricity; Natural Gas; Finished Fuel transported to California by rail.	Iowa	Soybean Oil (005)	Biodiesel (BIO)	BDS214	50.03	BIO005A04080100	53.32	10/18/2021	None	Biodiesel	Ag Processing Inc (4552)	Ag Processing Inc - Sgt. Bluff (81733)	Midwest Soybean Oil; Extraction Facility co-located with a Biodiesel plant in Sergeant Bluff, Iowa; Grid Electricity; Natural Gas; Finished Fuel transported to California by rail.	None	
A041201	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Dry DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02480100	70.62	ETH009A04120100	73.30	10/18/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Fort Dodge (70043)	Midwest Corn, Dry Mill; Dry DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional)	None	
A041202	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Modified DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02480200	67.47	ETH009A04120200	69.83	10/18/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Fort Dodge (70043)	Midwest Corn, Dry Mill; Modified DGS, and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California. (Provisional)	None	
A041203	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Fort Dodge (70043); Midwest Corn, Dry Mill; Fiber ethanol via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa and transported by rail to California. (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04120300	26.83	10/18/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Fort Dodge (70043)	Midwest Corn, Dry Mill; Fiber ethanol via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa and transported by rail to California. (Provisional)	None	
A043001	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00690100	65.13	ETH009A04300100	64.99	10/18/2021	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	None	

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A043002	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04300200	27.97	10/18/2021	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	None	
A037801	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process ; Ethanol transported by rail to California (Provisional)	Texas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A03780100	25.36	9/28/2021	None	Ethanol - Cellulosic	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process ; Ethanol transported by rail to California (Provisional)	None	Retired
A037802	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Corn (009)	Ethanol (ETH)	ETH009A01610100	64.69	ETH009A03780200	66.38	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	None	Retired
A037804	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Corn (009)	Ethanol (ETH)	ETH009A01610400	72.64	ETH009A03780400	73.91	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	None	Retired
A041301	Tier 1	3.0	Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Imperial Landfill Gas Company, LLC (F00219); Biomethane from Imperial Landfill in Imperial, Pennsylvania, pipelined to California for compression to CNG.	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04130100	53.19	11/23/2021	None	Bio-CNG	TRUSTAR ENERGY LLC (6523)	Imperial Landfill Gas Company, LLC (F00219)	Biomethane from Imperial Landfill in Imperial, Pennsylvania, pipelined to California for compression to CNG.	None	
A039601	Tier 1	3.0	Fuel Producer: Adecoagro Brasil Participacoes (4192); Facility Name: Adecoagro Vale do Ivinhema Ltda. (70496); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS211 (T1N-1356)	46.32	ETH018A03960100	52.79	11/30/2021	None	Ethanol	Adecoagro Brasil Participacoes (4192)	Adecoagro Vale do Ivinhema Ltda. (70496)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	Retired
L017201	Lookup Table	3.0	Fuel Producer: ChargeLab Inc. (C1153); Facility Name: ChargeLab Inc. (F00448); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/8/2021	None	Electricity	ChargeLab Inc. (C1153)	ChargeLab Inc. (F00448)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
L017301	Lookup Table	3.0	Fuel Producer: Clean Skies USA LLC (C1161); Facility Name: Clean Skies USA (F00452); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	12/3/2021	None	Electricity	Clean Skies USA LLC (C1161)	Clean Skies USA (F00452)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California.	None	
A042501	Tier 1	3.0	Fuel Producer: ADM Agri-Industries Company (6137); Facility Name: ADM Agri Industries (81926); Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel.	Canada	Canola Oil (006)	Biodiesel (BIO)	BDCA202 (T1N-1406)	51.33	BIO006A04250100	47.65	12/16/2021	None	Biodiesel	ADM Agri-Industries Company (6137)	ADM Agri Industries (81926)	Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel.	None	Retired
A043301	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO CHARLES CITY PLANT (70042); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04330100	72.56	12/23/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO CHARLES CITY PLANT (70042)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	None	
A043302	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO CHARLES CITY PLANT (70042); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04330200	69.05	12/23/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO CHARLES CITY PLANT (70042)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	None	
A043303	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO CHARLES CITY PLANT (70042); Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04330300	26.79	12/23/2021	None	Ethanol	Valero Renewable Fuels (3201)	VALERO CHARLES CITY PLANT (70042)	Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Charles City, Iowa; Ethanol transported by rail to California. (Provisional)	None	

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A044501	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Bonfim (70548); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM216	44.24	ETH018A04450100	51.75	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Bonfim (70548)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A044601	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Ipaussu (71058); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM220	44.39	ETH018A04460100	48.27	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Ipaussu (71058)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A044801	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Paraguaçu (71057); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM223	46.71	ETH018A04480100	52.03	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Paraguaçu (71057)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A044901	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Rafard (70557); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM215R	48.76	ETH018A04490100	50.10	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Rafard (70557)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A044401	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Barra (70210); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04440100	53.17	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Barra (70210)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A043101	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Gasa (70551); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS221R	46.91	ETH018A04310100	48.01	12/23/2021	None	Ethanol	Raízen Energia S/A (3805)	Gasa (70551)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
B021801	Tier 2	3.0	Fuel Producer: Degrees3 Transportation Solutions, LLC (C1111) ; Facility Name: Blue Mountain Biogas, LLC; Low-CI Electricity from Swine Manure using reciprocating engine at Blue Mountain Biogas, LLC near Milford, Utah for use as transportation fuel in California (Provisional)	Utah	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	ELC026B02180100	-485.51	1/14/2022	Application Package	Electricity	Degrees3 Transportation Solutions, LLC (C1111)	Blue Mountain Biogas, LLC	Low-CI Electricity from Swine Manure using reciprocating engine at Blue Mountain Biogas, LLC near Milford, Utah for use as transportation fuel in California (Provisional)	None	
B024102	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Soybean Oil transported by rail and barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	California	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B02410200	58.16	12/28/2021	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Soybean Oil transported by rail and barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	None	
B024201	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as compressed hydrogen in tube trailers to fueling stations in California.	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B02420100	-293.72	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as compressed hydrogen in tube trailers to fueling stations in California.	None	
B024202	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as gaseous hydrogen in tube trailers to fueling stations in California.	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B02420200	-259.22	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as gaseous hydrogen in tube trailers to fueling stations in California.	None	
B024203	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as compressed hydrogen in tube trailers to fueling stations in California	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	None	None	HYG025B02420300	74.70	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as compressed hydrogen in tube trailers to fueling stations in California	None	
B024204	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as compressed hydrogen in tube trailers to fueling stations in California	California	h American Fossil NG (	Gaseous Hydrogen (HYG)	None	None	HYG031B02420400	115.15	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as compressed hydrogen in tube trailers to fueling stations in California	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B024205	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as liquefied hydrogen in tanker trailers to fueling stations in California.	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B02420500	-254.95	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; transported as liquefied hydrogen in tanker trailers to fueling stations in California.	None	
B024206	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B02420600	-239.31	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Digester #3, Fair Oaks Upgrader, Indiana; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California	None	
B024207	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as liquefied hydrogen in tankers to fueling stations in California	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B02420700	-220.45	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; transported as liquefied hydrogen in tankers to fueling stations in California	None	
B024208	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; regasified and distributed as compressed H2 in tube trailers to fueling stations in California	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B02420800	-204.81	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from dairy manure at Windy Ridge Digester, Jasper Upgrader, Indiana; regasified and distributed as compressed H2 in tube trailers to fueling stations in California	None	
B024209	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as liquefied Hydrogen in tankers to fueling stations in California	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B02420900	109.81	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from landfill gas generated at Blue Ridge Renewables in Fresno, Texas; transported as liquefied Hydrogen in tankers to fueling stations in California	None	
B024210	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from LFG generated at Blue Ridge Renewables in Fresno, Texas; regasified and distributed as compressed H2 in tube trailers to fueling stations in California	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B02421000	125.44	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from LFG generated at Blue Ridge Renewables in Fresno, Texas; regasified and distributed as compressed H2 in tube trailers to fueling stations in California	None	
B024211	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, California from North American Natural Gas; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California	California	h American Fossil NG (	Liquid Hydrogen (HYL)	None	None	HYL031B02421100	169.55	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, California from North American Natural Gas; regasified and distributed as compressed Hydrogen in tube trailers to fueling stations in California	None	
B024212	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as liquefied Hydrogen in tanker trailers to fueling stations in California	California	h American Fossil NG (	Liquid Hydrogen (HYL)	None	None	HYL031B02421200	153.91	12/28/2021	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility in Ontario, California using North American Natural Gas; transported as liquefied Hydrogen in tanker trailers to fueling stations in California	None	
A043601	Tier 1	3.0	Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04360100	71.53	2/1/2022	None	Ethanol	AL CORN CLEAN FUEL, LLC (4825)	AL CORN CLEAN FUEL, LLC (70087)	Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	Retired
A044701	Tier 1	3.0	Fuel Producer: Raízen Energia S/A (3805); Facility Name: Junqueira (70553); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHM217	47.82	ETH018A04470100	55.75	1/5/2022	None	Ethanol	Raízen Energia S/A (3805)	Junqueira (70553)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A039701	Tier 1	3.0	Fuel Producer: Archer Daniels Midland Co (4888); Facility Name: ADM Velva (82790); Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel.	North Dakota	Canola Oil (006)	Biodiesel (BIO)	BDCA203 (T1N-1457)	52.25	BIO006A03970100	47.44	12/20/2021	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Velva (82790)	Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel.	None	Retired
A040701	Tier 1	3.0	Fuel Producer: Guarani SA (3833); Facility Name: Tereos Açúcar e Etanol Brasil S.A. – Unidade Tanabi (F00098); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04070100	47.51	2/4/2022	None	Ethanol	Guarani SA (3833)	Tereos Açúcar e Etanol Brasil S.A. – Unidade Tanabi (F00098)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	

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A041701	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S/A – Filial Barra Grande (70412); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	ETHS250	47.71	ETH018A04170100	52.85	2/4/2022	None	Ethanol	Copersucar (3702)	Açucareira Quatá S/A – Filial Barra Grande (70412)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A042001	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S/A – Filial São José (70432); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04200100	49.11	2/22/2022	None	Ethanol	Copersucar (3702)	Açucareira Quatá S/A – Filial São José (70432)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
A045001	Tier 1	3.0	Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional)	Pennsylvania	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A04500100	58.09	2/22/2022	None	Biodiesel	WORLD ENERGY HARRISBURG LLC (6425)	WORLD ENERGY HARRISBURG LLC (81499)	Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional)	None	Retired
A045002	Tier 1	3.0	Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional)	Pennsylvania	oking Oil/Waste Oil (UC	Biodiesel (BIO)	None	None	BIO001A04500200	21.59	2/22/2022	None	Biodiesel	WORLD ENERGY HARRISBURG LLC (6425)	WORLD ENERGY HARRISBURG LLC (81499)	US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (Provisional)	None	Retired
A044001	Tier 1	3.0	Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional)	Kansas	Corn (009)	Ethanol (ETH)	None	None	ETH009A04400100	72.37	3/2/2022	None	Ethanol	Element, LLC (C1020)	Element (F00048)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional)	None	Retired
A044002	Tier 1	3.0	Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional)	Kansas	Corn (009)	Ethanol (ETH)	None	None	ETH009A04400200	62.07	3/2/2022	None	Ethanol	Element, LLC (C1020)	Element (F00048)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (Provisional)	None	Retired
L017401	Lookup Table	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Compressed H2 produced in California from central SMR of North American fossil-based NG	California	h American Fossil NG (	Gaseous Hydrogen (HYG)	None	None	HYG031L00072019	117.67	2/25/2022	None	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Compressed H2 produced in California from central SMR of North American fossil-based NG	None	
A041901	Tier 1	3.0	Fuel Producer: Copersucar (3702); Facility Name: Açucareira Quatá S.A. (70406); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04190100	53.36	3/21/2022	None	Ethanol	Copersucar (3702)	Açucareira Quatá S.A. (70406)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
B026804	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B01000100	23.93	AJF002B02680400	19.54	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired
B026805	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B01000200	23.93	RND002B02680500	19.54	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026806	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B01000300	23.93	RNT002B02680600	19.54	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B026807	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B01190100	19.51	AJF002B02680700	15.64	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired

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B026808	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B01190200	19.51	RND002B02680800	15.64	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026809	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B01190300	19.51	RNT002B02680900	15.64	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B026813	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B00430100	37.13	AJF002B02681300	32.93	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired
B026814	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B00430200	37.13	RND002B02681400	32.93	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026815	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B00430300	37.13	RNT002B02681500	32.93	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B026816	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B00440100	42.91	AJF002B02681600	38.43	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	None	Retired
B026817	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B00440200	42.91	RND002B02681700	38.43	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	None	Retired
B026818	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B00440300	42.91	RNT002B02681800	38.43	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	None	Retired
B021501	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02150100	-310.71	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	None	Retired
B021502	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	None	None	LNG026B02150200	-296.99	3/30/2022	Application Package	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG (Provisional)	None	Retired
B021503	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN026B02150300	-293.45	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG (Provisional)	None	Retired
A044201	Tier 1	3.0	Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04420100	72.16	3/29/2022	None	Ethanol	Lincolnway Energy, LLC (4830)	Lincolnway Energy (70092)	Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (Provisional)	None	Retired

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A044203	Tier 1	3.0	Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04420300	24.70	3/29/2022	None	Ethanol - Cellulosic	Lincolnway Energy, LLC (4830)	Lincolnway Energy (70092)	Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (Provisional)	None	Retired
B026703	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02850100	12.91	BIO001B02670300	15.71	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	None	Retired
B026704	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02850400	15.81	BIO001B02670400	16.34	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	None	Retired
B026705	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02850300	17.86	BIO001B02670500	20.86	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	None	Retired
B028003	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, California using Biomethane generated at Dos Rios Water Recycling Center, San Antonio, Texas; transported as L.H2 in tanker trailers to refueling stations in California.	California	Vastewater Sludge (03(	Liquid Hydrogen (HYL)	None	None	HYL030B02800300	109.01	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, California using Biomethane generated at Dos Rios Water Recycling Center, San Antonio, Texas; transported as L.H2 in tanker trailers to refueling stations in California.	None	
B028004	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane generated at SAWS Dos Rios Water Recycling Center in San Antonio, TX; transported as G.H2 in tube trailers to fueling stations in California.	California	Vastewater Sludge (03(	Gaseous Hydrogen (HYG)	None	None	HYG030B02800400	76.98	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane generated at SAWS Dos Rios Water Recycling Center in San Antonio, TX; transported as G.H2 in tube trailers to fueling stations in California.	None	
B028005	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Homan Farm, King City, MO; transported as L.H2 in tanker trailers to refueling stations in California.	California	Swine Manure (044)	Liquid Hydrogen (HYL)	None	None	HYL044B02800500	-338.45	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Homan Farm, King City, MO; transported as L.H2 in tanker trailers to refueling stations in California.	None	
B028006	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Valley View Farm, Greencastle, MO; transported as L.H2 in tanker trailers to refueling stations in California.	California	Swine Manure (044)	Liquid Hydrogen (HYL)	None	None	HYL044B02800600	-354.78	3/29/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied Hydrogen produced at Linde-Praxair SMR facility in Ontario, CA using Biomethane derived from swine manure produced at Valley View Farm, Greencastle, MO; transported as L.H2 in tanker trailers to refueling stations in California.	None	
A043701	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (Provisional)	Oklahoma	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04370100	37.00	4/11/2022	None	Bio-CNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (Provisional)	None	Retired
A043702	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Oklahoma	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A04370200	50.61	4/11/2022	None	Bio-LNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	Retired
A043703	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Oklahoma	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A04370300	53.70	4/11/2022	None	Bio-CNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	Retired
A045201	Tier 1	3.0	Fuel Producer: VALE DO PARANA S.A ALCOOL E ACUCAR (6079); Facility Name: VALE DO PARANA S.A ALCOOL E ACUCAR (71119); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04520100	50.69	4/11/2022	None	Ethanol	VALE DO PARANA S.A ALCOOL E ACUCAR (6079)	VALE DO PARANA S.A ALCOOL E ACUCAR (71119)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	

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A045601	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	California	Distillers' Corn Oil (003	Biodiesel	BIO003A03760100	32.12	BIO003A04560100	30.15	4/7/2022	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	None	Retired
A045602	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel	None	None	BIO001A04560200	23.48	4/7/2022	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	None	Retired
A045603	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	California	(animal and poultry fat	Biodiesel (BIO)	None	None	BIO002A04560300	36.09	4/7/2022	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (Provisional)	None	Retired
A045801	Tier 1	3.0	Fuel Producer: New Leaf Biofuel (7768); Facility Name: New Leaf Biofuel (83541); California Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	None	None	BIO001A04580100	14.69	5/10/2022	None	Biodiesel	New Leaf Biofuel (7768)	New Leaf Biofuel (83541)	California Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional)	None	Retired
A045802	Tier 1	3.0	Fuel Producer: New Leaf Biofuel (7768); Facility Name: New Leaf Biofuel (83541); California Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional)	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	None	None	BIO001A04580200	20.58	5/10/2022	None	Biodiesel	New Leaf Biofuel (7768)	New Leaf Biofuel (83541)	California Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in San Diego, California; Natural Gas and Grid Electricity; Biodiesel transported by truck to California blending terminals (Provisional)	None	Retired
B030201	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	Minnesota	Distillers' Corn Oil (003	Biodiesel (BIO)	BIO003A00830300	24.55	BIO003B03020100	24.50	6/3/2022	Application Package	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	None	Retired
B030202	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	Minnesota	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A00830400	17.72	BIO001B03020200	18.50	6/3/2022	Application Package	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	None	Retired
B030203	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	Minnesota	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A00830500	11.99	BIO001B03020300	12.50	6/3/2022	Application Package	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (Provisional)	None	Retired
B030204	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California (Provisional)	Minnesota	(animal and poultry fat	Biodiesel (BIO)	BIO002A00830600	28.89	BIO002B03020400	29.00	6/3/2022	Application Package	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California (Provisional)	None	Retired
A046101	Tier 1	3.0	Fuel Producer: GARLAND RENEWABLES, LLC (1639); Facility Name: GARLAND RENEWABLES, LLC (71921; Landfill Gas generated at Garland Landfill in Rowlett, Texas upgraded to Biomethane at Garland Renewables; pipelined to California for compression and distribution to CNG refueling stations. (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04610100	32.52	5/13/2022	None	Bio-CNG	GARLAND RENEWABLES, LLC (1639)	GARLAND RENEWABLES, LLC (71921	Landfill Gas generated at Garland Landfill in Rowlett, Texas upgraded to Biomethane at Garland Renewables; pipelined to California for compression and distribution to CNG refueling stations. (Provisional)	None	
A046601	Tier 1	3.0	Fuel Producer: INNOLTEK (C1126); Facility Name: INNOLTEK (F00340); Rendered Animal Fat Oil transported by truck to biodiesel plant in St-Jean-sur-Richelieu, Quebec, Canada; NG, grid electricity; finished fuel transported to California by Rail.	Canada	(animal and poultry fat	Biodiesel (BIO)	None	None	BIO002A04660100	34.76	6/13/2022	None	Biodiesel	INNOLTEK (C1126)	INNOLTEK (F00340)	Rendered Animal Fat Oil transported by truck to biodiesel plant in St-Jean-sur-Richelieu, Quebec, Canada; NG, grid electricity; finished fuel transported to California by Rail.	None	
A040601	Tier 1	3.0	Fuel Producer: EDINBURG RENEWABLES, LLC (6401); Facility Name: CITY OF EDINBURG LANDFILL (71223); Biomethane from City of Edinburg Landfill in Edinburg, Texas, upgrading at Edinburg Renewables, LLC, pipelined to California for compression to CNG.	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04060100	37.12	12/31/2021	None	Bio-CNG	EDINBURG RENEWABLES, LLC (6401)	CITY OF EDINBURG LANDFILL (71223)	Biomethane from City of Edinburg Landfill in Edinburg, Texas, upgrading at Edinburg Renewables, LLC, pipelined to California for compression to CNG.	None	

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B025001	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02500100	-182.67	6/28/2022	Application Package	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	None	Retired
B025002	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02500200	-267.51	6/28/2022	Application Package	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	None	Retired
B025003	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02500300	-255.34	6/28/2022	Application Package	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	None	Retired
B030701	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03070100	-353.38	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	None	Retired
B030702	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03070200	-405.57	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	None	Retired
B030703	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03070300	-255.83	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	None	Retired
B030705	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03070500	-366.91	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	None	Retired
B030704	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03070400	-249.43	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	None	Retired
B032901	Tier 2	3.0	Fuel Producer: Messer LLC (f.k.a. Linde LLC) (L012); Facility Name: Linde Praxair (F00477); Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; distributed 414 miles by liquid tanker to refueling stations.	California	h American Fossil NG (	Liquid Hydrogen (HYL)	None	None	HYL031B03290100	153.28	6/23/2022	Application Package	Hydrogen	Messer LLC (f.k.a. Linde LLC) (L012)	Linde Praxair (F00477)	Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; distributed 414 miles by liquid tanker to refueling stations.	None	
A044101	Tier 1	3.0	Fuel Producer: GREENAMERICA BIOFUELS ORD LLC (1481); Facility Name: GREEN PLAINS ORD, LLC (71641); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ord, Nebraska; Ethanol transported by truck and rail to California , Composite CI.	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A04410100	70.65	6/29/2022	None	Ethanol	GREENAMERICA BIOFUELS ORD LLC (1481)	GREEN PLAINS ORD, LLC (71641)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ord, Nebraska; Ethanol transported by truck and rail to California , Composite CI.	None	
B028301	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: DEER RUN RNG PROJECT (71482); Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02830100	-195.09	6/29/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	DEER RUN RNG PROJECT (71482)	Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	Retired
B030801	Tier 2	3.0	Fuel Producer: WOF SW GGP 1 LLC (W009); Facility Name: Green Gas Partners Stanfield (F00003); Biogas from dairy manure at Shamrock Farms, T&K Red River, and Zinke Dairy in Stanfield and Maricopa, AZ; upgraded to pipeline quality at Green Gas Partners Stanfield and pipelined to CA for transportation use (Provisional)	Arizona	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03080100	-362.84	6/30/2022	Application Package	Bio-CNG	WOF SW GGP 1 LLC (W009)	Green Gas Partners Stanfield (F00003)	Biogas from dairy manure at Shamrock Farms, T&K Red River, and Zinke Dairy in Stanfield and Maricopa, AZ; upgraded to pipeline quality at Green Gas Partners Stanfield and pipelined to CA for transportation use (Provisional)	None	

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B031001	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100100	-349.17	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B031002	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100200	-210.67	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B031004	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100400	-417.26	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B031003	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100300	-406.28	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B031005	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100500	-417.24	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B031006	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03100600	-356.29	6/28/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
A046201	Tier 1	3.0	Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04620101	33.08	6/23/2022	None	Ethanol	CORN, LP (5065)	CORN, LP (70145)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A046202	Tier 1	3.0	Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00330101	71.09	ETH009A04620201	70.62	6/23/2022	None	Ethanol	CORN, LP (5065)	CORN, LP (70145)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (Provisional)	None	Retired
L018801	Lookup Table	3.0	Fuel Producer: Silicon Valley Clean Energy (C1183); Facility Name: Silicon Valley Clean Energy Authority (F00484); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/14/2022	None	Electricity	Silicon Valley Clean Energy (C1183)	Silicon Valley Clean Energy Authority (F00484)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019101	Lookup Table	3.0	Fuel Producer: Southern California Edison (C1185); Facility Name: Southern California Edison (F00489); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/28/2022	None	Electricity	Southern California Edison (C1185)	Southern California Edison (F00489)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019301	Lookup Table	3.0	Fuel Producer: Skyview Finance Company 2, LLC (C1174); Facility Name: Skyview Finance Company 2, LLC ZCI CA B&C (F00492); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	3/28/2022	None	Electricity	Skyview Finance Company 2, LLC (C1174)	Skyview Finance Company 2, LLC ZCI CA B&C (F00492)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019401	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade, Inc. Zero CI Direct Renewable Energy Avenal (F00490); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Supplied Zero-CI Sourc	Electricity (ELC)	None	None	ELC049L00072019	0.00	4/8/2022	None	Electricity	SRECTrade, Inc (C1018)	SRECTrade, Inc. Zero CI Direct Renewable Energy Avenal (F00490)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

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L019601	Lookup Table	3.0	Fuel Producer: Redwood City School District (C1205); Facility Name: Redwood City School District (F00524); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/22/2022	None	Electricity	Redwood City School District (C1205)	Redwood City School District (F00524)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019701	Lookup Table	3.0	Fuel Producer: The Mobility House (C1200); Facility Name: The Mobility House (F00525); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/24/2022	None	Electricity	The Mobility House (C1200)	The Mobility House (F00525)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019801	Lookup Table	3.0	Fuel Producer: 7-Eleven, Inc. (C1204); Facility Name: 7-Eleven, Inc. (F00526); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	6/24/2022	None	Electricity	7-Eleven, Inc. (C1204)	7-Eleven, Inc. (F00526)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A041001	Tier 1	3.0	Fuel Producer: JAPUNGU AGROINDUSTRIAL LTDA (C1145); Facility Name: Japungu Agroindustrial Ltda (F00383); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04100100	52.77	7/18/2022	None	Ethanol	JAPUNGU AGROINDUSTRIAL LTDA (C1145)	Japungu Agroindustrial Ltda (F00383)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	Retired
A045701	Tier 1	3.0	Fuel Producer: BP Biofuels (4427); Facility Name: Tropical Bioenergia SA (71078); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A04570100	50.57	7/18/2022	None	Ethanol	BP Biofuels (4427)	Tropical Bioenergia SA (71078)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	None	
L019001	Lookup Table	3.0	Fuel Producer: San Francisco Bay Area Rapid Transit District (BART) (C1176); Facility Name: SF BART (F00482); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.0	3/17/2022	None	Electricity	San Francisco Bay Area Rapid Transit District (BART) (C1176)	SF BART (F00482)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A046702	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO LINDEN PLANT (70196); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A04670200	73.37	7/18/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO LINDEN PLANT (70196)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	None	
A046701	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO LINDEN PLANT (70196); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04670100	27.73	7/18/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO LINDEN PLANT (70196)	Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	None	
A046703	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO LINDEN PLANT (70196); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	None	None	ETH009A04670300	70.15	7/18/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO LINDEN PLANT (70196)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Linden, Indiana; Ethanol transported by rail to California. (Provisional)	None	
L020201	Lookup Table	3.0	Fuel Producer: County of Santa Clara (C1208); Facility Name: County of Santa Clara (F00530); Zero-CI electricity from solar PV generated in CA	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	7/11/2022	None	Electricity	County of Santa Clara (C1208)	County of Santa Clara (F00530)	Zero-CI electricity from solar PV generated in CA	None	
L020301	Lookup Table	3.0	Fuel Producer: City of Palo Alto Utilities (P600); Facility Name: City of Palo Alto Utilities (F00499); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	7/13/2022	None	Electricity	City of Palo Alto Utilities (P600)	City of Palo Alto Utilities (F00499)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A046801	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO WELCOME PLANT (70276); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04680100	26.52	7/20/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO WELCOME PLANT (70276)	Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	None	

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A046802	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO WELCOME PLANT (70276); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04680200	72.15	7/20/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO WELCOME PLANT (70276)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	None	
A046803	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: VALERO WELCOME PLANT (70276); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04680300	68.59	7/20/2022	None	Ethanol	Valero Renewable Fuels (3201)	VALERO WELCOME PLANT (70276)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Welcome, Minnesota; Ethanol transported by rail to California. (Provisional)	None	
A046902	Tier 1	3.0	Fuel Producer: BADGER STATE ETHANOL LLC (4469); Facility Name: Badger State Ethanol (70130); Midwest Corn, Dry Mill; Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin ; Ethanol transported by rail to California (Provisional)	Wisconsin	Corn (009)	Ethanol (ETH)	None	None	ETH009A04690200	69.34	9/19/2022	None	Ethanol	BADGER STATE ETHANOL LLC (4469)	Badger State Ethanol (70130)	Midwest Corn, Dry Mill; Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin ; Ethanol transported by rail to California (Provisional)	None	
A046903	Tier 1	3.0	Fuel Producer: BADGER STATE ETHANOL LLC (4469); Facility Name: Badger State Ethanol (70130); Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wisconsin and transported by rail to California (Provisional)	Wisconsin	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04690300	27.41	9/19/2022	None	Ethanol	BADGER STATE ETHANOL LLC (4469)	Badger State Ethanol (70130)	Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wisconsin and transported by rail to California (Provisional)	None	
A046901	Tier 1	3.0	Fuel Producer: BADGER STATE ETHANOL LLC (4469); Facility Name: Badger State Ethanol (70130); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin; Ethanol transported by rail to California (Provisional)	Wisconsin	Corn (009)	Ethanol (ETH)	None	None	ETH009A04690100	74.18	9/19/2022	None	Ethanol	BADGER STATE ETHANOL LLC (4469)	Badger State Ethanol (70130)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Wisconsin; Ethanol transported by rail to California (Provisional)	None	
L020601	Lookup Table	3.0	Fuel Producer: STX Commodities LLC (C1195) ; Facility Name: STX Commodities LLC 2.0 (F00539); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity	None	None	ELC037L00072019	0.00	9/14/2022	None	Electricity	STX Commodities LLC (C1195)	STX Commodities LLC 2.0 (F00539)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
B028201	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY S&S (71361); Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B02820100	-272.08	9/23/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	U.S. GAIN RNG FACILITY S&S (71361)	Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	Retired
B032301	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	California	Distillers' Corn Oil (003	Renewable Diesel (RND)	None	None	RND003B03230100	25.46	9/20/2022	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	None	
B033801	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: DALHART RNG, LLC (70981); Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (Provisional)	Texas	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B03380100	-417.96	9/23/2022	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	DALHART RNG, LLC (70981)	Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (Provisional)	None	Retired
B031101	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110101	-418.04	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031102	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110200	-383.14	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031103	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110300	-419.34	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired

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B031105	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110500	-276.38	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031104	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110400	-299.39	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031107	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110700	-341.84	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031106	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110600	-403.86	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031108	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03110800	-273.88	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	None	Retired
B031501	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03150100	-403.96	9/29/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (Provisional)	None	Retired
B034601	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAMB RNG PROJECT (71101); Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (Provisional)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03460100	-311.72	9/28/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET LAMB RNG PROJECT (71101)	Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (Provisional)	None	Retired
B034801	Tier 2	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Air Products and Chemicals SMR Wilmington (F00384); Gaseous Hydrogen produced in California by Central SMR of biomethane sourced from the District 45 dairy digester in Minnesota. Finished fuel is distributed to refueling stations in California by tube trailers, (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03480100	-147.20	9/29/2022	Application Package	Hydrogen	Shell Energy North America (6154)	Air Products and Chemicals SMR Wilmington (F00384)	Gaseous Hydrogen produced in California by Central SMR of biomethane sourced from the District 45 dairy digester in Minnesota. Finished fuel is distributed to refueling stations in California by tube trailers, (Provisional)	None	
B034901	Tier 2	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Carson Hydrogen Plant (F00059); Gaseous Hydrogen produced at the Carson Hydrogen Plant using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported via pipeline to refueling station in Torrance, California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03490100	-151.76	9/29/2022	Application Package	Hydrogen	Shell Energy North America (6154)	Carson Hydrogen Plant (F00059)	Gaseous Hydrogen produced at the Carson Hydrogen Plant using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported via pipeline to refueling station in Torrance, California. (Provisional)	None	
B035001	Tier 2	3.0	Fuel Producer: Shell Energy North America (6154); Facility Name: Sacramento Hydrogen Plant (F00102); L.H2 produced at Sacramento Hydrogen Plant using digester gas derived from District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported to trans-fill facility, re-gasified, recompressed; distributed to refueling stations. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03500100	-89.98	9/29/2022	Application Package	Hydrogen	Shell Energy North America (6154)	Sacramento Hydrogen Plant (F00102)	L.H2 produced at Sacramento Hydrogen Plant using digester gas derived from District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported to trans-fill facility, re-gasified, recompressed; distributed to refueling stations. (Provisional)	None	Retired
B035301	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY DALLMAN (71341); Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03530100	-344.72	9/29/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	U.S. GAIN RNG FACILITY DALLMAN (71341)	Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use (Provisional)	None	Retired
B036001	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03600100	-159.04	9/27/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (Provisional)	None	Retired

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B036003	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03600300	-104.64	9/27/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (Provisional)	None	Retired
B036002	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03600200	-120.27	9/27/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (Provisional)	None	Retired
B037301	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03730100	-107.85	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional)	None	
B037302	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03730200	-192.70	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional)	None	Retired
B037303	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03730300	-146.62	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR using Biomethane derived from digester gas generated at District 45 Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional)	None	
B037304	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03730400	-231.46	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional)	None	Retired
B037305	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas procured from District 45 Dairy Digester; L.H2 transported to trans-fill, regasified, and distributed to refuling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03730500	-92.22	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas procured from District 45 Dairy Digester; L.H2 transported to trans-fill, regasified, and distributed to refuling stations in California. (Provisional)	None	
B037306	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03730600	-177.06	9/29/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (Provisional)	None	Retired
L020701	Lookup Table	3.0	Fuel Producer: Apple (A449); Facility Name: VP02 (V8866); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/28/2022	None	Electricity	Apple (A449)	VP02 (V8866)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L020901	Lookup Table	3.0	Fuel Producer: Revolv Global Inc. (C1210); Facility Name: Revolv Global Inc. (F00553); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/28/2022	None	Electricity	Revolv Global Inc. (C1210)	Revolv Global Inc. (F00553)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
A048401	Tier 1	3.0	Fuel Producer: Heartland Corn Products (4827); Facility Name: Heartland Corn Products (70089); Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04840100	72.78	10/12/2022	None	Ethanol	Heartland Corn Products (4827)	Heartland Corn Products (70089)	Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	None	
A048402	Tier 1	3.0	Fuel Producer: Heartland Corn Products (4827); Facility Name: Heartland Corn Products (70089); Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04840200	26.07	10/12/2022	None	Ethanol - Cellulosic	Heartland Corn Products (4827)	Heartland Corn Products (70089)	Midwest Corn, Dry Mill; Fiber ethanol produced via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California (Provisional)	None	

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A048901	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Albion (70283); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A04890100	74.58	10/12/2022	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Albion (70283)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional)	None	
A048902	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Albion (70283); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A04890200	70.52	10/12/2022	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Albion (70283)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California. (Provisional)	None	
A048903	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Albion (70283); Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04890300	27.18	10/12/2022	None	Ethanol - Cellulosic	Valero Renewable Fuels (3201)	Valero Renewable Fuels Albion (70283)	Midwest Corn, Dry Mill; Fiber ethanol from Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Albion, Nebraska; Ethanol transported by rail to California (Provisional)	None	
A049001	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04900100	71.51	10/12/2022	None	Ethanol	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (Provisional)	None	Retired
A049002	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04900200	61.15	10/12/2022	None	Ethanol	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (Provisional)	None	Retired
A049003	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04900300	22.33	10/12/2022	None	Ethanol - Cellulosic	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (Provisional)	None	Retired
A049401	Tier 1	3.0	Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Tres Rios Water Reclamation Facility (F00443); Biomethane derived from anaerobic digestion of wastewater sludge. (Provisional)	Arizona	Vastewater Sludge (03	Compressed Natural Gas (CNG)	None	None	CNG030A04940100	27.41	10/10/2022	None	Bio-CNG	BLUE SOURCE LLC (6086)	Tres Rios Water Reclamation Facility (F00443)	Biomethane derived from anaerobic digestion of wastewater sludge. (Provisional)	None	
A047101	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A04710101	73.70	11/8/2022	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest Corn, Dry Mill; Dry DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional)	None	
A047102	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A04710201	64.99	11/8/2022	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest Corn, Dry Mill; Wet DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Trenton, Nebraska; Ethanol transported by rail to California. (Provisional)	None	
A047103	Tier 1	3.0	Fuel Producer: Trenton Agri Products, LLC (4754); Facility Name: Trenton Agri Products, LLC (70053); Midwest Corn, Dry Mill; Fiber ethanol from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Trenton, Nebraska and transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04710301	27.35	11/8/2022	None	Ethanol	Trenton Agri Products, LLC (4754)	Trenton Agri Products, LLC (70053)	Midwest Corn, Dry Mill; Fiber ethanol from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Trenton, Nebraska and transported by rail to California (Provisional)	None	
B032501	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline from soybean oil transported by barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	California	Soybean Oil (005)	Renewable Gasoline (RNG)	None	None	RNG005B03250100	63.35	12/20/2022	Application Package	Renewable Gasoline	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable gasoline from soybean oil transported by barge to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	None	
B032502	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline produced from soybean oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	California	Soybean Oil (005)	Renewable Gasoline (RNG)	None	None	RNG005B03250200	60.38	12/20/2022	Application Package	Renewable Gasoline	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable gasoline produced from soybean oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B032503	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline produced from canola oil transported by rail and ship to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	California	Canola Oil (006)	Renewable Gasoline (RNG)	None	None	RNG006B03250300	58.48	12/20/2022	Application Package	Renewable Gasoline	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable gasoline produced from canola oil transported by rail and ship to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/rail/pipeline (Provisional)	None	
B033701	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	California	Distillers' Corn Oil (003	Renewable Gasoline (RNG)	None	None	RNG003B03370100	30.86	12/20/2022	Application Package	Renewable Gasoline	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable gasoline produced from distiller's corn oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline (Provisional)	None	
B035201	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03520100	-411.77	12/5/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (Provisional)	None	Retired
B035202	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03520200	-351.51	12/5/2022	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (Provisional)	None	Retired
A048601	Tier 1	3.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Dansuk Industrial Co., Ltd (81302); South Korean Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in Siwha, South Korea ; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port and to California by Ocean tanker.	South Korea	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A01050100	27.89	BIO001A04860100	25.98	12/19/2022	None	Biodiesel	Dansuk Industrial Co., Ltd (5953)	Dansuk Industrial Co., Ltd (81302)	South Korean Sourced Self-rendered Used Cooking Oil transported by truck to Biodiesel plant in Siwha, South Korea ; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port and to California by Ocean tanker.	None	
A048602	Tier 1	3.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Dansuk Industrial Co., Ltd (81302); South Korean Sourced Rendered Tallow transported by truck to Biodiesel plant in Siwha, South Korea; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port to California by Ocean tanker.	South Korea	(animal and poultry fat	Biodiesel (BIO)	None	None	BIO002A04860200	37.80	12/19/2022	None	Biodiesel	Dansuk Industrial Co., Ltd (5953)	Dansuk Industrial Co., Ltd (81302)	South Korean Sourced Rendered Tallow transported by truck to Biodiesel plant in Siwha, South Korea; South Korean Natural Gas and Electricity; Biodiesel transported by truck to port to California by Ocean tanker.	None	
B036601	Tier 2	3.0	Fuel Producer: Element Markets Renewable Energy, LLC (5877); Facility Name: MILFORD FARM (71483); Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use (Provisional)	Utah	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02140100	-413.67	CNG044B03660100	-414.59	12/7/2022	Application Package	Bio-CNG	Element Markets Renewable Energy, LLC (5877)	MILFORD FARM (71483)	Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use (Provisional)	None	Retired
B037801	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Liquefied Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as liquefied Hydrogen in tanker trailers and re-gasified, recompressed, at refueling stations in California.	California	Landfill Gas (025)	Liquid Hydrogen (HYL)	None	None	HYL025B03780100	107.19	12/19/2022	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Liquefied Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as liquefied Hydrogen in tanker trailers and re-gasified, recompressed, at refueling stations in California.	None	
B038501	Tier 2	3.0	Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Green Valley Dairy LLC (F00198); Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03850100	-180.73	12/21/2022	Application Package	Bio-CNG	BLUE SOURCE LLC (6086)	Green Valley Dairy LLC (F00198)	Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	Retired
B039101	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported in tanker trailers; re-gasified, recompressed, and then dispensed as gaseous Hydrogen at the refueling stations in California.	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03910100	-197.27	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported in tanker trailers; re-gasified, recompressed, and then dispensed as gaseous Hydrogen at the refueling stations in California.	None	
B039102	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03910200	-236.03	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	None	
B039103	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in California; dispensed as gaseous Hydrogen.	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03910300	-181.64	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)Verification Body Name:	Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Jerseyland Dairy located in Sturgeon Bay, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in California; dispensed	None	

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B039201	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied hydrogen from dairy manure at DALLMAN RNG Project; liquid hydrogen production at Praxair Inc., Ontario, California transported as liquid to H2 stations in California.	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03920100	-269.91	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied hydrogen from dairy manure at DALLMAN RNG Project; liquid hydrogen production at Praxair Inc., Ontario, California transported as liquid to H2 stations in California.	None	
B039202	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B03920200	-308.67	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	None	
B039203	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426), Facility Name: Praxair SMR facility(F00394), Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in California; dispensed as gaseous Hydrogen.	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B03920300	-254.28	12/22/2022	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility using Biomethane derived from dairy manure digester gas generated at Dallman East River Dairy located in Brillion, Wisconsin; transported as liquefied Hydrogen in tanker trailers to the trans-fill center in California, regasified, recompressed, and transported to refueling stations in	None	
B034501	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAKESHORE RNG PROJECT (71321); Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03450100	-318.35	12/27/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET LAKESHORE RNG PROJECT (71321)	Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	Retired
B034701	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET BOXLER RNG PROJECT (71222); Biogas from dairy manure at Boxler Dairy in Varysburg, NY; upgraded to pipeline quality at Yellow Jacket Boxler RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03470100	-206.88	12/27/2022	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET BOXLER RNG PROJECT (71222)	Biogas from dairy manure at Boxler Dairy in Varysburg, NY; upgraded to pipeline quality at Yellow Jacket Boxler RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	
A048101	Tier 1	3.0	Fuel Producer: BP Bunge Bioenergia SA (C1196); Facility Name: USINA OUROESTE AÇÚCAR E ALCOOL (F00509); Ethanol derived from Brazilian sugarcane juice and molasses; mechanized harvesting, and credit for export of surplus cogenerated electricity; finished fuel exported to California via Panama Canal by ocean tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH019A04810100	49.73	12/27/2022	None	Ethanol	BP Bunge Bioenergia SA (C1196)	USINA OUROESTE AÇÚCAR E ALCOOL (F00509)	Ethanol derived from Brazilian sugarcane juice and molasses; mechanized harvesting, and credit for export of surplus cogenerated electricity; finished fuel exported to California via Panama Canal by ocean tanker.	None	
A048301	Tier 1	3.0	Fuel Producer: BP Bunge Bioenergia SA (C1196); Facility Name: AGROINDUSTRIAL SANTA JULIANA (F00507); Ethanol produced from Brazilian sugarcane juice and molasses; credit for mechanized harvesting and surplus cogenerated electricity export; finished fuel exported to California via Panama Canal by ocean tanker.	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH019A04830100	51.34	12/27/2022	None	Ethanol	BP Bunge Bioenergia SA (C1196)	AGROINDUSTRIAL SANTA JULIANA (F00507)	Ethanol produced from Brazilian sugarcane juice and molasses; credit for mechanized harvesting and surplus cogenerated electricity export; finished fuel exported to California via Panama Canal by ocean tanker.	None	
B037001	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: GREEN HILLS FARM (71881); Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B03700100	-408.25	12/28/2022	Application Package	Bio-CNG	Anew RNG, LLC (5877)	GREEN HILLS FARM (71881)	Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (Provisional)	None	Retired
B037101	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: WHITETAIL FARM (71882); Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	None	None	CNG044B03710100	-412.77	12/28/2022	Application Package	Bio-CNG	Anew RNG, LLC (5877)	WHITETAIL FARM (71882)	Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (Provisional)	None	Retired
L018901	Lookup Table	3.0	Fuel Producer: 4GEN LOGISTICS, L.L.C. (C1156); Facility Name: 4GEN Fastlane (F00432); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	00.00	3/25/2022	None	Electricity	4GEN LOGISTICS, L.L.C. (C1156)	4GEN Fastlane (F00432)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L019201	Lookup Table	3.0	Fuel Producer: Linde LLC (L012); Facility Name: Linde Praxair (F00477); Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; grid electricity; finished fuel distributed less than 100 miles to refueling stations by tanker truck.	California	h American Fossil NG (	Liquid Hydrogen (HYL)	None	None	HYL031L00072019	150.94	6/30/2022	None	Hydrogen	Linde LLC (L012)	Linde Praxair (F00477)	Liquefied Hydrogen produced in California from central SMR of North American fossil-based NG; grid electricity; finished fuel distributed less than 100 miles to refueling stations by tanker truck.	None	
L020501	Lookup Table	3.0	Fuel Producer: Total Warehouse Inc. (C1214); Facility Name: Total Warehouse Inc. (F00541); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity	None	None	ELC037L00072019	00.00	9/16/2022	None	Electricity	Total Warehouse Inc. (C1214)	Total Warehouse Inc. (F00541)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	

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A010501	Tier 1	3.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Pyeongtaek 2 (80202); South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker	South Korea	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A01050100	27.89	BIO001A01050101	25.00	12/17/2019	None	Biodiesel	Dansuk Industrial Co., Ltd (5953)	Pyeongtaek 2 (80202)	South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker	None	Retired
A012903	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A01290300	27.44	ETH012A01290301	27.01	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A013003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01300300	27.54	ETH012A01300301	25.09	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A014603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	Michigan	Corn Fiber (012)	Ethanol (ETH)	ETH012A01460300	27.33	ETH012A01460301	27.03	9/24/2019	None	Ethanol - Cellulosic	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Eletricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A015003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01500300	27.72	ETH012A01500301	27.19	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A015103	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108; Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01510300	27.69	ETH012A01510301	26.17	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 4064	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) 70108	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A015203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A01520300	27.00	ETH012A01520301	25.89	10/3/2019	None	Ethanol - Cellulosic	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A019802	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A01980200	23.46	ETH012A01980201	23.04	6/24/2020	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California	2021 AFPR Recert Complete	Retired
A020904	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A02090400	27.48	ETH012A02090401	25.14	6/24/2020	None	Ethanol - Cellulosic	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	
A021203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788) ; Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California	Missouri	Corn Fiber (012)	Ethanol (ETH)	ETH012A02120300	26.19	ETH012A02120301	25.32	4/28/2020	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A021703	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	North Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A02170300	25.72	ETH012A02170301	24.41	7/27/2020	None	Ethanol - Cellulosic	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Dry Mill; Fiber ethanol Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
A022404	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A02240400	23.96	ETH012A02240402	26.00	6/24/2020	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

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A024503	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A02450300	22.56	ETH012A02450303	24.71	12/4/2020	None	Ethanol - Cellulosic	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A024603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A02460300	29.41	ETH012A02460302	28.47	12/29/2020	None	Ethanol - Cellulosic	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A027202	Tier 1	3.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A02720200	26.60	ETH012A02720201	26.40	10/21/2020	None	Ethanol - Cellulosic	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn, Dry Mill; Fiber ethanol produced from Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	
A030901	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A03090100	24.46	ETH012A03090101	24.84	5/4/2021	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
B017403	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California.	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012B01740300	29.14	ETH012B01740301	29.48	9/24/2021	Application Package	Ethanol - Cellulosic	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Coal, Grid Electricity; Ethanol produced in Big Stone, South Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
B019001	Tier 2	3.0	Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	Kansas	Distillers' Corn Oil (003	Renewable Diesel (RND)	RND003B01900100	46.31	RND003B01900101	56.37	6/25/2021	Application Package	Renewable Diesel	East Kansas Agri-Energy, LLC (4483)	East Kansas Agri-Energy, LLC (83483)	Renewable diesel produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail (Provisional)	2021 AFPR Recert Complete	
B019002	Tier 2	3.0	Fuel Producer: East Kansas Agri-Energy, LLC (4483); Facility Name: East Kansas Agri-Energy, LLC (83483); Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail	Kansas	Distillers' Corn Oil (003	Renewable Naphtha (RNT)	RNT003B01900200	46.31	RNT003B01900201	56.37	6/25/2021	Application Package	Renewable Naphtha	East Kansas Agri-Energy, LLC (4483)	East Kansas Agri-Energy, LLC (83483)	Renewable naphtha produced from Distillers' Corn Oil in Kansas; natural gas, grid electricity and hydrogen; transport to California by rail	2021 AFPR Recert Complete	
A039402	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A03940200	27.87	ETH012A03940201	27.95	10/14/2021	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
A042302	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A04230200	24.02	ETH012A04230201	24.42	10/26/2021	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
B024103	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline	California	Canola Oil (006)	Renewable Diesel (RND)	RND006B02410300	51.87	RND006B02410301	52.90	12/28/2021	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Canola Oil transported by rail and ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline	2021 AFPR Recert Complete	
B024101	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline	California	Soybean Oil (005)	Renewable Diesel (RND)	RND005B02410100	54.68	RND005B02410101	55.39	12/28/2021	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Soybean Oil transported by rail to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge/ship/pipeline	2021 AFPR Recert Complete	
A043602	Tier 1	3.0	Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A04360200	24.89	ETH012A04360201	25.15	2/1/2022	None	Ethanol	AL CORN CLEAN FUEL, LLC (4825)	AL CORN CLEAN FUEL, LLC (70087)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired

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A037903	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California.	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03790300	64.00	ETH010A03790301	65.92	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California.	2021 AFPR Recert Complete	Retired
A049301	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill, Dry DGS and Corn Oil Co-Products; Natural Gas and Electricity. Ethanol produced from corn in Albert City, Iowa and transported by Rail to California (Provisional)	Iowa	Corn (009)		ETH009A02540100	69.55	ETH009A04930100	73.97	1/23/2023	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Albert City (70142)	Midwest Corn, Dry Mill, Dry DGS and Corn Oil Co-Products; Natural Gas and Electricity. Ethanol produced from corn in Albert City, Iowa and transported by Rail to California (Provisional)	None	
A049302	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201) ; Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Modified DGS, and Corn Oil Co-Products; Natural Gas, Grid Electricity; Ethanol produced in Albert City, Iowa and transported by Rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02540200	66.07	ETH009A04930200	70.72	1/23/2023	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Albert City (70142)	Midwest Corn, Dry Mill; Modified DGS, and Corn Oil Co-Products; Natural Gas, Grid Electricity; Ethanol produced in Albert City, Iowa and transported by Rail to California (Provisional)	None	
A049303	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201) ; Facility Name: Valero Renewable Fuels LLC - Albert City (70142); Midwest Corn, Dry Mill; Dry and Modified DGS Co-Products; Ethanol produced from BPX Fiber Conversion Process; Natural Gas, and Grid Electricity; Ethanol produced in Albert City, Iowa, and transpsorted by Rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04930300	27.65	1/23/2023	None	Ethanol - Cellulosic	Valero Renewable Fuels (3201)	Valero Renewable Fuels LLC - Albert City (70142)	Midwest Corn, Dry Mill; Dry and Modified DGS Co-Products; Ethanol produced from BPX Fiber Conversion Process; Natural Gas, and Grid Electricity; Ethanol produced in Albert City, Iowa, and transpsorted by Rail to California (Provisional)	None	
A008601	Tier 1	3.0	Fuel Producer: Bridgeport Ethanol, LLC 5934; Facility Name: Bridgeport Ethanol, LLC 70217; Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00860100	62.37	ETH009A00860101	63.00	4/16/2019	None	Ethanol	Bridgeport Ethanol, LLC 5934	Bridgeport Ethanol, LLC 70217	Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A021201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California	Missouri	Corn (009)	Ethanol (ETH)	ETH009A02120100	75.09	ETH009A02120102	75.47	4/28/2020	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A031201	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	California	Soybean Oil (005)	Biodiesel (BIO)	BIO005A03120100	57.16	BIO005A03120101	63.92	3/23/2021	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	2021 AFPR Recert Complete	Retired
A031202	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	California	Canola Oil (006)	Biodiesel (BIO)	BIO006A03120200	51.65	BIO006A03120201	59.19	3/23/2021	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	2021 AFPR Recert Complete	Retired
A031204	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production.	California	(animal and poultry fat	Biodiesel (BIO)	BIO002A03120400	31.28	BIO002A03120401	38.49	3/23/2021	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production.	2021 AFPR Recert Complete	Retired
A031205	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	California	(animal and poultry fat	Biodiesel (BIO)	BIO002A03120500	32.45	BIO002A03120501	39.35	3/23/2021	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	2021 AFPR Recert Complete	Retired
A031206	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A03120600	21.27	BIO001A03120601	26.60	3/23/2021	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	2021 AFPR Recert Complete	Retired
A034801	Tier 1	3.0	Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional)	Texas	(animal and poultry fat	Biodiesel (BIO)	BIO002A03480100	30.80	BIO002A03480101	31.95	7/28/2021	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (Provisional)	2021 AFPR Recert Complete	Retired

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A042602	Tier 1	3.0	Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel.	Iowa	Soybean Oil (005)	Biodiesel (BIO)	BIO005A04260200	55.05	BIO005A04260201	54.75	12/22/2021	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Biodiesel produced from US sourced Soy Oil; finished fuel transported by rail to California for use as a transportation fuel.	2021 AFPR Recert Complete	
A042601	Tier 1	3.0	Fuel Producer: Western Iowa Energy (4670); Facility Name: Western Iowa Energy (82630); Biodiesel produced from US sourced tallow; finished fuel transported by rail to California by rail for use as a transportation fuel.	Iowa	(animal and poultry fat	Biodiesel (BIO)	BIO002A04260100	29.23	BIO002A04260101	29.39	12/22/2021	None	Biodiesel	Western Iowa Energy (4670)	Western Iowa Energy (82630)	Biodiesel produced from US sourced tallow; finished fuel transported to California by rail for use as a transportation fuel.	2021 AFPR Recert Complete	
A043901	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Skyline RNG Facility (F00217); Biomethane from Landfill at Ferris, Texas upgrading at Waste Management, pipelined to California for compression to CNG (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A04390100	53.17	2/22/2022	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Skyline RNG Facility (F00217)	Biomethane from Landfill at Ferris, Texas upgrading at Waste Management, pipelined to California for compression to CNG (Provisional)	None	
A043902	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Skyline RNG Facility (F00217); Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Texas	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A04390200	68.92	2/22/2022	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Skyline RNG Facility (F00217)	Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California LNG stations (Provisional)	None	
A043903	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Skyline RNG Facility (F00217); Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Texas	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LCN025A04390300	72.00	2/22/2022	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Skyline RNG Facility (F00217)	Biomethane from Landfill at Ferris, Texas, pipelined to Applied LNG in Needles - California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	None	
B026701	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	Distillers' Corn Oil (003	Biodiesel (BIO)	BIO003B02670100	28.67	BIO003B02670101	28.80	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2021 AFPR Recert Complete	Retired
B026702	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	California	(animal and poultry fat	Biodiesel (BIO)	BIO002B02670200	32.53	BIO002B02670201	32.73	3/29/2022	Application Package	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2021 AFPR Recert Complete	Retired
A012001	Tier 1	3.0	Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01200101	65.30	ETH009A01200102	64.69	9/5/2019	None	Ethanol	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sioux Center, Iowa; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	
A012901	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01290100	74.62	ETH009A01290101	73.48	9/24/2019	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A012902	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01290200	67.54	ETH009A01290201	66.73	9/24/2019	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A013001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01300100	74.35	ETH009A01300101	72.10	9/24/2019	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indianna; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A049101	Tier 1	3.0	Fuel Producer: REG Grays Harbor, LLC (6326); Facility Name: REG Grays Harbor, LLC (82954); North American Sourced Canola Oil transported by truck, rail, and ocean tanker to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California	Washington	Canola Oil (006)	Biodiesel (BIO)	BDCA204	52.87	BIO006A04910100	49.00	2/13/2023	None	Biodiesel	REG Grays Harbor, LLC (6326)	REG Grays Harbor, LLC (82954)	North American Sourced Canola Oil transported by truck, rail, and ocean tanker to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California	None	

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A049102	Tier 1	3.0	Fuel Producer: REG Grays Harbor, LLC (6326); Facility Name: REG Grays Harbor, LLC (82954); North American Sourced Soybean Oil transported by rail to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California	Washington	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A04910200	55.00	2/13/2023	None	Biodiesel	REG Grays Harbor, LLC (6326)	REG Grays Harbor, LLC (82954)	North American Sourced Soybean Oil transported by rail to Biodiesel plant in Hoquiam, WA; Natural Gas and Grid Electricity; Biodiesel transported by truck and rail to California	None	
A049501	Tier 1	3.0	Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota ; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04950100	73.15	2/14/2023	None	Ethanol	RING-NECK ENERGY & FEED, LLC (6274)	RING-NECK ENERGY & FEED, LLC (70361)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota ; Ethanol transported by rail to California. (Provisional)	None	
A049502	Tier 1	3.0	Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274) ; Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A04950200	65.12	2/14/2023	None	Ethanol	RING-NECK ENERGY & FEED, LLC (6274)	RING-NECK ENERGY & FEED, LLC (70361)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	
A049503	Tier 1	3.0	Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04950300	26.69	2/14/2023	None	Ethanol - Cellulosic	RING-NECK ENERGY & FEED, LLC (6274)	RING-NECK ENERGY & FEED, LLC (70361)	Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	
A049505	Tier 1	3.0	Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Grain Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A04950500	77.07	2/14/2023	None	Ethanol	RING-NECK ENERGY & FEED, LLC (6274)	RING-NECK ENERGY & FEED, LLC (70361)	Midwest Grain Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	
A049506	Tier 1	3.0	Fuel Producer: RING-NECK ENERGY & FEED, LLC (6274); Facility Name: RING-NECK ENERGY & FEED, LLC (70361); Midwest Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A04950600	69.04	2/14/2023	None	Ethanol	RING-NECK ENERGY & FEED, LLC (6274)	RING-NECK ENERGY & FEED, LLC (70361)	Midwest Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	None	
A050601	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations	Louisiana	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A05060100	59.61	2/17/2023	None	Bio-LNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations	None	
A050602	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	Louisiana	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A05060200	62.70	2/17/2023	None	Bio-LNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, LA; upgrading at River Birch LLC and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	None	
A050702	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations	Canada	Landfill Gas (025)	Liquefied Natural Gas (LNG)	None	None	LNG025A05070200	51.26	2/24/2023	None	Bio-LNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California LNG stations	None	
A050703	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	Canada	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN025A05070300	54.35	2/24/2023	None	Bio-LNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energie Inc in Quebec, Canada and pipelined to Topock Arizona for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	None	
A027201	Tier 1	3.0	Fuel Producer: Husker Ag LLC (5078); Facility Name: Husker Ag LLC (70151); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI.	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A02720100	65.63	ETH009A02720101	65.00	10/21/2020	None	Ethanol	Husker Ag LLC (5078)	Husker Ag LLC (70151)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska ; Ethanol transported by rail to California , Composite CI.	2021 AFPR Recert Complete	
B001801	Tier 2	3.0	Fuel Producer: BP Products North America, Inc (4320); Facility Name: Cherry Point Refinery (83736); U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA	Washington	(animal and poultry fat	Renewable Diesel (RND)	RND002B00180100	26.92	RND002B00180102	35.02	12/6/2019	None	Renewable Diesel	BP Products North America, Inc (4320)	Cherry Point Refinery (83736)	U.S. and Canadian sourced Rendered Animal Fat Oil transported by truck; Grid Electricity, Steam, and Hydrogen; Renewable Diesel produced from co-processing with petroleum feedstock in a hydrotreater in Blaine, Washington; transported by ocean tanker to CA	2021 AFPR Recert Complete	

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A010002	Tier 1	3.0	Fuel Producer: The Andersons, Inc (5872); Facility Name: The Andersons Denison Ethanol (70135); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01000200	67.48	ETH009A01000201	67.11	6/7/2019	None	Ethanol	The Andersons, Inc (5872)	The Andersons Denison Ethanol (70135)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	2021 AFPR Recert Complete	Retired
A011501	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	Texas	Vastewater Sludge (030	Compressed Natural Gas (CNG)	CNG030A01150100	37.33	CNG030A01150101	36.77	12/19/2019	None	Bio-CNG	Anew RNG, LLC (5877)	Ameresco San Antonio Biogas (71204)	Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	2021 AFPR Recert Complete	Retired
A013002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01300200	67.34	ETH009A01300201	65.09	9/24/2019	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A013901	Tier 1	3.0	Fuel Producer: Midwest Renewable Energy (5214); Facility Name: Midwest Renewable Energy (70160); Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A01390100	62.81	ETH009A01390102	65.76	9/9/2019	None	Ethanol	Midwest Renewable Energy (5214)	Midwest Renewable Energy (70160)	Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A014501	Tier 1	3.0	Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A01450100	69.60	ETH009A01450102	68.61	8/6/2019	None	Ethanol	Redfield Energy, LLC (4061)	Redfield Energy, LLC (70111)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Redfield, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A014601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	Michigan	Corn (009)	Ethanol (ETH)	ETH009A01460100	72.59	ETH009A01460101	72.29	9/24/2019	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	2021 AFPR Recert Complete	Retired
A014602	Tier 1	3.0	Fuel Producer: Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	Michigan	Corn (009)	Ethanol (ETH)	ETH009A01460200	67.10	ETH009A01460201	66.61	9/24/2019	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	2021 AFPR Recert Complete	Retired
A015001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01500100	74.83	ETH009A01500101	74.03	10/3/2019	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A015002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819) ; Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01500200	68.05	ETH009A01500201	67.28	10/14/2019	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A015101	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01510100	74.44	ETH009A01510101	73.56	10/3/2019	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California	2021 AFPR Recert Complete	Retired
A015201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01520100	74.15	ETH009A01520101	72.75	10/3/2019	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A015202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01520200	67.32	ETH009A01520201	65.82	10/3/2019	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

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A015401	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional)	Kentucky	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01540100	54.66	CNG025A01540102	54.69	11/5/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (Provisional)	2021 AFPR Recert Complete	Retired
A015402	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional)	Kentucky	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A01540200	71.50	LNG025A01540202	72.09	11/5/2019	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (Provisional)	2021 AFPR Recert Complete	Retired
A015403	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional)	Kentucky	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A01540300	74.59	LCN025A01540302	75.18	11/5/2019	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (Provisional)	2021 AFPR Recert Complete	Retired
A015102	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064) ; Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01510200	67.72	ETH009A01510201	66.14	10/3/2019	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A015501	Tier 1	3.0	Fuel Producer: Absolute Energy, LLC (5049) ; Facility Name: Absolute Energy, LLC (70144); Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01550100	67.97	ETH009A01550101	67.61	9/24/2019	None	Ethanol	Absolute Energy, LLC (5049)	Absolute Energy, LLC (70144)	Midwest Corn, Dry Mill; Dry DGS, Modified DGS, and Corn Oil; Natural Gas and Grid Electricity; Starch Ethanol produced in St. Ansgar, Iowa; Ethanol transported by rail to California, Composite CI	2021 AFPR Recert Complete	
A016401	Tier 1	3.0	Fuel Producer: BUSHMILLS ETHANOL, INC. (4063); Facility Name: BUSHMILLS ETHANOL, INC. (70109); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI.		Corn (009)	Ethanol (ETH)	ETH009A01640100	67.23	ETH009A01640101	66.71	10/15/2019	None	Ethanol	BUSHMILLS ETHANOL, INC. (4063)	BUSHMILLS ETHANOL, INC. (70109)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn oil, and Syrup; Natural Gas, Grid and CHP-produced Electricity; Starch Ethanol produced in Atwater, MN; Ethanol transported by truck and rail to California, Composite CI.	2021 AFPR Recert Complete	
B004701	Tier 2	3.0	Fuel Producer: Wyoming Renewable Diesel Company LLC (1440); Facility Name: Wyoming Renewable Diesel Company LLC (82441); Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California	Wyoming	Soybean Oil (005)	Renewable Diesel (RND)	RND005B00470100	58.34	RND005B00470102	57.20	12/27/2019	None	Renewable Diesel	Wyoming Renewable Diesel Company LLC (1440)	Wyoming Renewable Diesel Company LLC (82441)	Renewable Diesel produced from US soybean oil. Fuel produced in Wyoming and transported to California	2021 AFPR Recert Complete	
A019501	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060); Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01950100	43.37	CNG025A01950101	44.78	12/31/2019	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060)	Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (Provisional)	2021 AFPR Recert Complete	Retired
B005901	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00590101	-562.50	ELC026B00590102	-568.21	3/25/2021	None	Electricity	California Bioenergy LLC (B194)	ABEC Bidart-Old River LLC (F00113)	Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	2021 AFPR Recert Complete	Retired
B006001	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00600100	-255.74	CNG026B00600102	-237.77	2/24/2020	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Fair Oaks Upgrader, LLC (71001)	Renewable Natural Gas (RNG) sourced from Dairy Manure of Fair Oak Farms and upgraded to RNG at Generate Fair Oaks Upgrader in Fair Oaks, Indiana; RNG pipelined to California	2021 AFPR Recert Complete	
A020901	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02090100	73.74	ETH009A02090102	72.71	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	
A020902	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02090200	70.47	ETH009A02090201	67.82	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	

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A020903	Tier 1	3.0	Fuel Producer: Dakota Ethanol, LLC (4810); Facility Name: Dakota Ethanol, LLC (70083); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02090300	66.86	ETH009A02090301	64.08	6/24/2020	None	Ethanol	Dakota Ethanol, LLC (4810)	Dakota Ethanol, LLC (70083)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Wentworth, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	
B007201	Tier 2	3.0	Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180); Facility Name: WOF PNW Threemile Project (F00100); Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use	Oregon	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00720100	-188.78	CNG026B00720102	-171.65	9/30/2020	None	Bio-CNG	IOGEN D3 BIOFUEL PARTNERS II LLC (7180)	WOF PNW Threemile Project (F00100)	Renewable Natural Gas (RNG) from Dairy Manure at Columbia River Dairy and Six Mile Farms, upgraded in Boardman, Oregon; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
A021202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California	Missouri	Corn (009)	Ethanol (ETH)	ETH009A02120200	65.67	ETH009A02120201	64.95	4/28/2020	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A021301	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02130100	61.55	ETH009A02130101	61.55	6/22/2020	None	Ethanol	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI	2021 AFPR Recert Complete	Retired
A021701	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	North Dakota	Corn (009)	Ethanol (ETH)	ETH009A02170100	69.84	ETH009A02170101	68.72	7/27/2020	None	Ethanol	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
A021702	Tier 1	3.0	Fuel Producer: Hankinson Renewable Energy, LLC (6169); Facility Name: Hankinson Renewable Energy, LLC (70288); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	North Dakota	Corn (009)	Ethanol (ETH)	ETH009A02170200	66.96	ETH009A02170201	65.89	7/27/2020	None	Ethanol	Hankinson Renewable Energy, LLC (6169)	Hankinson Renewable Energy, LLC (70288)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Hankinson, North Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
A021901	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc in Quebec, Canada; pipelined to California for compression to CNG	Canada	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02190100	38.64	CNG025A02190101	31.80	6/22/2020	None	Bio-CNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgrading at EBI Energie Inc in Quebec, Canada; pipelined to California for compression to CNG	2021 AFPR Recert Complete	
A021902	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stations by pipeline, liquefied in California	Canada	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02190200	51.69	LNG025A02190201	45.63	6/22/2020	None	Bio-LNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada and pipelined to Boron California for liquefaction to LNG; trucked to California LNG stations by pipeline, liquefied in California	2021 AFPR Recert Complete	
A021903	Tier 1	3.0	Fuel Producer: EBI ENERGIE INC. (6459); Facility Name: SAINT-THOMAS BIOMETHANE PLANT (71254); Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	Canada	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02190300	54.77	LCN025A02190301	48.72	6/22/2020	None	Bio-LNG	EBI ENERGIE INC. (6459)	SAINT-THOMAS BIOMETHANE PLANT (71254)	Biomethane from Landfill in Saint-Thomas, Quebec; upgraded at EBI Energy in Quebec, Canada; pipelined to Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2021 AFPR Recert Complete	
A022401	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02240100	69.32	ETH009A02240102	73.00	6/24/2020	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A022402	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02240200	66.23	ETH009A02240202	68.00	6/24/2020	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
B010901	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01090100	-453.10	CNG026B01090102	-288.39	9/30/2020	None	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Maple Leaf Dairy East and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	

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B010902	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01090200	-308.48	CNG026B01090202	-278.19	9/30/2020	None	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Maple Leaf Dairy West and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B010903	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Maple Leaf/Grotegut RNG Facility (F00167); Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01090300	-236.96	CNG026B01090302	-247.83	9/30/2020	None	Bio-CNG	Clean Energy (5481)	Maple Leaf/Grotegut RNG Facility (F00167)	Renewable Natural Gas (RNG) produced from Grotegut Dairy Farm and upgraded at Calumet – Maple Leaf/Grotegut RNG Facility, Newton, Wisconsin; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B009601	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Dairy Dreams (F00127); Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00960100	-532.74	CNG026B00960102	-372.40	9/30/2020	None	Bio-CNG	Clean Energy (5481)	Calumet - Dairy Dreams (F00127)	Renewable Natural Gas (RNG) produced from Dairy Manure at Dairy Dreams Farm and upgraded at Calumet - Dairy Dreams in Casco, Wisconsin; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B009701	Tier 2	3.0	Fuel Producer: Clean Energy (5481); Facility Name: Calumet - Ponderosa (F00128); Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00970100	-372.20	CNG026B00970101	-445.37	9/30/2020	None	Bio-CNG	Clean Energy (5481)	Calumet - Ponderosa (F00128)	Renewable Natural Gas (RNG) produced from Dairy Manure of Pagel's Ponderosa Dairy Farm and upgraded at Calumet-Ponderosa, Kewaunee, Wisconsin; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B010202	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020200	-289.76	CNG026B01020201	-392.30	12/3/2020	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Exum Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B010203	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020300	-308.74	CNG026B01020301	-399.36	12/3/2020	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Etter Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
A023301	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional)	Kansas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02330100	45.91	CNG025A02330102	47.10	7/24/2020	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (Provisional)	2021 AFPR Recert Complete	Retired
B010801	Tier 2	3.0	Fuel Producer: AgPower Jerome, LLC (C1036); Facility Name: AgPower Jerome RNG Project (F00077); Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01080100	-230.13	CNG026B01080101	-240.91	9/30/2020	None	Bio-CNG	AgPower Jerome, LLC (C1036)	AgPower Jerome RNG Project (F00077)	Renewable Natural Gas (RNG) produced from Dairy Manure at Double A Dairy and Double A Dairy #6 and upgraded at AgPower Jerome RNG in Jerome, Idaho; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
A026501	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: HUB CITY ENERGY LLC (70721); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02650100	73.16	ETH009A02650101	71.88	10/9/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	HUB CITY ENERGY LLC (70721)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Aberdeen, South Dakota; Ethanol transported by rail to California; Composite CI	2021 AFPR Recert Complete	
A024501	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02450100	69.92	ETH009A02450103	73.16	12/4/2020	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A024502	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02450200	62.54	ETH009A02450203	64.79	12/4/2020	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A024201	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02420100	47.53	CNG025A02420102	57.00	10/29/2020	None	Bio-CNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG	2021 AFPR Recert Complete	Retired

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A024601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	Ohio	Corn (009)	Ethanol (ETH)	ETH009A02460100	77.21	ETH009A02460101	76.22	12/29/2020	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A024602	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525) ; Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	Ohio	Corn (009)	Ethanol (ETH)	ETH009A02460200	69.47	ETH009A02460201	68.53	12/29/2020	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A024701	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896) ; Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02470100	49.78	CNG025A02470102	48.20	10/13/2020	None	Bio-CNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG	2021 AFPR Recert Complete	Retired
A024901	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02490100	74.54	ETH009A02490102	76.29	7/24/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	2021 AFPR Recert Complete	Retired
A024902	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02490200	67.28	ETH009A02490201	68.82	7/24/2020	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	2021 AFPR Recert Complete	Retired
A026701	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Johnstown Regional Energy - Raeger (71131); Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02670100	35.51	CNG025A02670102	35.69	3/18/2021	None	Bio-CNG	Anew RNG, LLC (5877)	Johnstown Regional Energy - Raeger (71131)	Biomethane from Johnstown Regional Energy - Raeger Landfill in Johnstown, Pennsylvania, pipelined to California for compression to CNG	2021 AFPR Recert Complete	
A026403	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Johnstown Regional Energy - Southern Alleghenies (71133); Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02640300	60.28	CNG025A02640302	58.15	3/17/2021	None	Bio-CNG	Anew RNG, LLC (5877)	Johnstown Regional Energy - Southern Alleghenies (71133)	Biomethane from Johnstown Regional Energy - Southern Alleghenies Landfill in Davidsville, Pennsylvania, pipelined to California for compression to CNG	2021 AFPR Recert Complete	
A027401	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: Renovar Arlington, LTD RNG Project (70501); Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional)	Texas	Vastewater Sludge (030	Compressed Natural Gas (CNG)	CNG030A02740100	38.37	CNG030A02740102	41.71	3/1/2021	None	Bio-CNG	U.S. Venture, Inc. (5504)	Renovar Arlington, LTD RNG Project (70501)	Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (Provisional)	2021 AFPR Recert Complete	Retired
B012701	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01270100	-417.35	CNG026B01270102	-419.62	12/31/2020	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at K&M Visser and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B012702	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01270200	-417.27	CNG026B01270201	-420.14	12/31/2020	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at Riverview Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B012703	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01270300	-418.90	CNG026B01270302	-420.70	12/31/2020	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at Little Rock and Blue Moon Dairy and upgraded at Calgren Dairy fuels in Pixley, California; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
B012704	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01270400	-392.44	CNG026B01270401	-410.41	12/31/2020	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure at 4K Dairy and upgraded at Calgren Dairy Fuels in Pixley, California; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	

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A029501	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02950100	21.93	BIO001A02950101	22.03	4/1/2021	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	2021 AFPR Recert Complete	Retired
A029502	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	California	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02950200	16.98	BIO001A02950201	16.71	4/1/2021	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	2021 AFPR Recert Complete	Retired
A029702	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Kansas	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02970200	61.43	LCN025A02970201	63.59	12/15/2020	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	2021 AFPR Recert Complete	Retired
A029801	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional)	Washington	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02980100	28.24	CNG025A02980101	28.80	3/12/2021	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (Provisional)	2021 AFPR Recert Complete	Retired
A029802	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	Washington	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02980200	41.09	LNG025A02980201	42.58	3/12/2021	None	Bio-LNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (Provisional)	2021 AFPR Recert Complete	Retired
A029803	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	Washington	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02980300	44.18	LCN025A02980301	45.67	3/12/2021	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	2021 AFPR Recert Complete	Retired
A030601	Tier 1	3.0	Fuel Producer: MONROEVILLE LFG, LLC (6317); Facility Name: MONROEVILLE LFG, LLC (71136); Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03060100	41.93	CNG025A03060101	42.85	4/6/2021	None	Bio-CNG	MONROEVILLE LFG, LLC (6317)	MONROEVILLE LFG, LLC (71136)	Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (Provisional)	2021 AFPR Recert Complete	Retired
B014301	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B01430100	-429.05	CNG044B01430101	-432.11	6/29/2021	None	Bio-CNG	Anew RNG, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations	2021 AFPR Recert Complete	Retired
A030902	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A03090200	71.95	ETH009A03090201	72.02	5/4/2021	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
B014901	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: South Meadows Farm (F00195); Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B01490100	-359.66	CNG044B01490101	-319.70	6/29/2021	None	Bio-CNG	Anew RNG, LLC (5877)	South Meadows Farm (F00195)	Renewable Natural Gas (RNG) from Swine Manure of South Meadows Farm, Browning, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California	2021 AFPR Recert Complete	
B016501	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01650100	-406.35	CNG026B01650101	-392.30	9/30/2021	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Biogas from Dairy Manure at Exum Dairy in Stratford, Texas; Upgraded biomethane pipelined to California for transportation use	2021 AFPR Recert Complete	
A033001	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03300100	73.75	ETH009A03300101	73.79	3/1/2021	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired

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B016301	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Hilarides (F00006); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California.	California	Dairy Manure (026)	Electricity (ELC)	ELC026B01630100	-758.46	ELC026B01630101	-756.24	6/21/2021	None	Electricity	CleanFuture, Inc. (C1001)	Hilarides (F00006)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Hilarides Dairy in Lindsay, California for use as transportation fuel in California.	2021 AFPR Recert Complete	
B017301	Tier 2	3.0	Fuel Producer: DF-AP #1, LLC (C1122); Facility Name: Big Sky Dairy Digester (F00329); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California	Idaho	Dairy Manure (026)	Electricity (ELC)	ELC026B01730100	-545.71	ELC026B01730101	-548.10	9/22/2021	None	Electricity	DF-AP #1, LLC (C1122)	Big Sky Dairy Digester (F00329)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California	2021 AFPR Recert Complete	Retired
B017402	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	South Dakota	Corn (009)	Ethanol (ETH)	ETH009B01740200	68.73	ETH009B01740201	69.33	9/24/2021	None	Ethanol	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
B017401	Tier 2	3.0	Fuel Producer: POET Biorefining - Big Stone (4736); Facility Name: POET Biorefining - Big Stone (70025); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	South Dakota	Corn (009)	Ethanol (ETH)	ETH009B01740100	75.91	ETH009B01740101	76.65	9/24/2021	None	Ethanol	POET Biorefining - Big Stone (4736)	POET Biorefining - Big Stone (70025)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Coal, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	2021 AFPR Recert Complete	
A034501	Tier 1	3.0	Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG.	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03450100	52.66	CNG025A03450101	53.05	6/16/2021	None	Bio-CNG	WESTSIDE GAS PRODUCERS, LLC (6218)	WESTSIDE GAS PRODUCERS, LLC (71151)	Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG.	2021 AFPR Recert Complete	Retired
A035101	Tier 1	3.0	Fuel Producer: E Energy Adams, LLC (4831); Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03510100	65.93	ETH009A03510101	67.49	6/1/2021	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (Provisional)	2021 AFPR Recert Complete	Retired
A036703	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional)	Tennessee	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A03670300	65.26	LCN025A03670301	66.26	5/11/2021	None	Bio-CNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (Provisional)	2021 AFPR Recert Complete	Retired
A036702	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional)	Tennessee	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A03670200	62.18	LNG025A03670201	63.18	5/11/2021	None	Bio-LNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (Provisional)	2021 AFPR Recert Complete	Retired
A037501	Tier 1	3.0	Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Seabreeze Energy Producers (70281); Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03750100	37.82	CNG025A03750101	38.37	8/20/2021	None	Bio-CNG	BLUE SOURCE LLC (6086)	Seabreeze Energy Producers (70281)	Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (Provisional)	2021 AFPR Recert Complete	Retired
B019101	Tier 2	3.0	Fuel Producer: California Renewable Power LLC(C196); Facility Name: California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270); Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles.	California	n Landscaping Waste (	Compressed Natural Gas (CNG)	CNG028B01910100	2.51	CNG028B01910101	72.26	6/29/2021	None	Bio-CNG	California Renewable Power LLC(C196)	California Renewable Power and Organics Recycling and Anaerobic Digestion Facility (71270)	Renewable Natural Gas (RNG) produced from mixed Urban Landscaping Waste and Food Scraps and upgraded at California Renewable Power and Organics Recycling and Anaerobic Digestion Facility in Perris, California; RNG used in CNG vehicles.	2021 AFPR Recert Complete	
B021901	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: HOMAN FARM (71343); RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02190100	-412.71	CNG044B02190101	-359.22	9/30/2021	None	Bio-CNG	Anew RNG, LLC (5877)	HOMAN FARM (71343)	RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	Retired
A008801	Tier 1	3.0	Fuel Producer: Yuma Ethanol, LLC (4735) ; Facility Name: Yuma Ethanol, LLC (70024); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California	Colorado	Corn (009)	Ethanol (ETH)	ETH009A00880100	64.61	ETH009A00880101	64.00	5/17/2019	None	Ethanol	Yuma Ethanol, LLC (4735)	Yuma Ethanol, LLC (70024)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

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A019801	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A01980100	61.26	ETH009A01980103	62.37	6/24/2020	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI	2021 AFPR Recert Complete	Retired
A021302	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A02130200	21.31	ETH012A02130203	21.93	6/22/2020	None	Ethanol - Cellulosic	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
B007901	Tier 2	3.0	Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B00790100	30.48	RND002B00790103	34.32	9/30/2020	Application Package	Renewable Diesel	Kern Oil & Refining Co. (5038)	Kern Oil & Refining Co. (80105)	Rendered animal fat sourced from California and transported by truck; Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution	2021 AFPR Recert Complete	
B007902	Tier 2	3.0	Fuel Producer: Kern Oil & Refining Co. (5038); Facility Name: Kern Oil & Refining Co. (80105); Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B00790200	41.85	RND002B00790203	43.24	9/30/2020	Application Package	Renewable Diesel	Kern Oil & Refining Co. (5038)	Kern Oil & Refining Co. (80105)	Renewable diesel produced from co-processing animal fat with fossil feedstock in a kerosene hydrotreater in Bakersfield, California and transported by truck for distribution	2021 AFPR Recert Complete	
B010201	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Greengasco, LLC (F00154); Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	Texas	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01020101	-408.62	CNG026B01020106	-403.57	12/3/2020	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Greengasco, LLC (F00154)	Renewable Natural Gas (RNG) produced from Dairy Manure at Westside Dairy and Eastside Dairy and upgraded at GreenGasco in Stratford, Texas; RNG pipelined to California for transportation use	2021 AFPR Recert Complete	
A025901	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Distillers' Corn Oil (003	Biodiesel (BIO)	BIO003A02590100	36.62	BIO003A02590102	37.49	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A025902	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	Soybean Oil (005)	Biodiesel (BIO)	BIO003A02590100	36.62	BIO005A02590202	66.85	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A025903	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (80316); U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	Tennessee	(animal and poultry fat	Biodiesel (BIO)	BIO003A02590100	36.62	BIO002A02590302	42.58	11/6/2020	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (80316)	U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A029002	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	Illinois	Soybean Oil (005)	Biodiesel (BIO)	BIO005A02900200	57.00	BIO005A02900201	58.00	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	2021 AFPR Recert Complete	Retired
A029003	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	Illinois	Canola Oil (006)	Biodiesel (BIO)	BIO006A02900300	53.00	BIO006A02900301	54.50	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Canola Oil transported by rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	2021 AFPR Recert Complete	
A029006	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	Illinois	oking Oil/Waste Oil (UC	Biodiesel (BIO)	BIO001A02900600	20.25	BIO001A02900601	22.00	6/8/2021	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	2021 AFPR Recert Complete	Retired
A030401	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Point Loma Digester Gas Project (F00027); Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional)	California	Vastewater Sludge (030	Compressed Natural Gas (CNG)	CNG030A03040100	30.31	CNG030A03040102	38.91	6/14/2021	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Point Loma Digester Gas Project (F00027)	Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (Provisional)	2021 AFPR Recert Complete	Retired

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B018502	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01850200	-388.91	CNG026B01850201	-366.51	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
B018701	Tier 2	3.0	Fuel Producer: Dry Creek RNG LLC (C1098); Facility Name: Dry Creek RNG Project (F00342); Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional)	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01870100	-435.22	CNG026B01870101	-421.53		Application Package	Bio-CNG	Dry Creek RNG LLC (C1098)	Dry Creek RNG Project (F00342)	Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
B019801	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194) ; Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980100	-388.29	CNG026B01980101	-294.40	9/30/2021	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
A039401	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California.	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03940100	66.71	ETH009A03940101	66.77	10/14/2021	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California.	2021 AFPR Recert Complete	Retired
B020702	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02070200	-211.01	CNG026B02070201	-193.95	12/29/2021	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (Provisional)	2021 AFPR Recert Complete	Retired
B020701	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02070100	-135.37	CNG026B02070101	-132.51	12/29/2021	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (Provisional)	2021 AFPR Recert Complete	Retired
A040201	Tier 1	3.0	Fuel Producer: Siouxland Ethanol, LLC (5026); Facility Name: Siouxland Ethanol (70134); Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A04020100	63.73	ETH009A04020101	63.80	10/11/2021	None	Ethanol	Siouxland Ethanol, LLC (5026)	Siouxland Ethanol (70134)	Midwest Corn, Dry Mill; Dry DGS and MDGS, Corn oil; Natural Gas, Landfill Gas, Combined-Heat and Power and Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California, Composite CI. (Provisional)	2021 AFPR Recert Complete	
B021601	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02160100	-382.83	CNG026B02160101	-333.34	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
B021603	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	LCN026B02160300	-366.02	LCN026B02160301	-315.22	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (Provisional)	2021 AFPR Recert Complete	Retired
B021602	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	LNG026B02160200	-369.56	LNG026B02160201	-318.76	3/30/2022	Application Package	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (Provisional)	2021 AFPR Recert Complete	Retired
B021702	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	LNG026B02170200	-290.16	LNG026B02170201	-259.30	3/30/2022	Application Package	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (Provisional)	2021 AFPR Recert Complete	Retired
B021703	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	LCN026B02170300	-286.62	LCN026B02170301	-255.76	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (Provisional)	2021 AFPR Recert Complete	Retired

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B021701	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02170100	-303.92	CNG026B02170101	-274.25	3/30/2022	Application Package	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
B022001	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: SOMERSET FARM (71381); Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02200101	-410.57	CNG044B02200102	-370.44	12/31/2021	Application Package	Bio-CNG	Anew RNG, LLC (5877)	SOMERSET FARM (71381)	Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (Provisional)	2021 AFPR Recert Complete	Retired
A041601	Tier 1	3.0	Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Greentree Landfill Gas Company (F00212); Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (Provisional)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A04160100	66.18	CNG025A04160101	71.21	11/23/2021	None	Bio-CNG	TRUSTAR ENERGY LLC (6523)	Greentree Landfill Gas Company (F00212)	Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (Provisional)	2021 AFPR Recert Complete	Retired
A042301	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A04230100	70.88	ETH009A04230101	72.01	10/26/2021	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
A037803	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03780300	66.28	ETH010A03780301	66.40	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A037805	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (70039); Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03780500	73.81	ETH010A03780502	74.69	9/29/2021	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (70039)	Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
B025106	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Diesel (RND)	RND002B02510600	42.48	RND002B02510601	47.48	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025112	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B02511200	42.48	RNT002B02511201	47.48	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Australian Sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B026802	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B02680200	18.87	RND002B02680201	18.93	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B026810	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B02681000	29.26	AJF002B02681001	29.78	3/28/2022	Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B026812	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B02681200	29.26	RNT002B02681201	29.78	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B026811	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	California	(animal and poultry fat	Renewable Diesel (RND)	RND002B02681100	29.26	RND002B02681101	29.78	3/28/2022	Application Package	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2021 AFPR Recert Complete	Retired

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B026803	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	California	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B02680300	18.87	RNT002B02680301	18.93	3/28/2022	Application Package	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B026801	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	California	(animal and poultry fat	Alternative Jet Fuel (AJF)	AJF002B02680100	18.87	AJF002B02680101	18.93		Application Package	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2021 AFPR Recert Complete	Retired
B036901	Tier 2	3.0	Fuel Producer: MONTAUK ENERGY HOLDINGS, LLC (6139); Facility Name: Pico Energy, LLC (71221); Biogas from dairy manure at B2 Dairy, B6 Dairy, Crossbred Dairy in Jerome, ID, and B5 Dairy in Wendell, ID; upgraded to pipeline quality at Pico Energy, LLC, and pipeline to CA for transportation use. (Provisional)	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03690100	-260.56	3/27/2023	Application Package	Bio-CNG	MONTAUK ENERGY HOLDINGS, LLC (6139)	Pico Energy, LLC (71221)	Biogas from dairy manure at B2 Dairy, B6 Dairy, Crossbred Dairy in Jerome, ID, and B5 Dairy in Wendell, ID; upgraded to pipeline quality at Pico Energy, LLC, and pipeline to CA for transportation use. (Provisional)	None	
A048801	Tier 1	3.0	Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional)	Kansas	Corn (009)	Ethanol (ETH)	None	None	ETH009A04880100	62.50	3/14/2023	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional)	None	
A048802	Tier 1	3.0	Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Midwest Grain Sorghum, Dry Mill; Wet DGS, Grain Sorghum oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A04880200	65.50	3/14/2023	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Grain Sorghum, Dry Mill; Wet DGS, Grain Sorghum oil and Syrup Co-products; Natural Gas, Grid Electricity, Zero-CI Electricity; Starch Ethanol produced in Oakle, KS ; Ethanol transported by rail to California (Provisional)	None	
A048803	Tier 1	3.0	Fuel Producer: Western Plains Energy, LLC (4740); Facility Name: Western Plains Energy, LLC (70030); Midwest Corn, Dry Mill; Fiber ethanol, Edeniq Fiber Conversion Protocol; Natural Gas, Grid Electricity, Zero-CI Electrcity; Starch Ethanol produced in Oakley,KS; Ethanol transported by rail to California (Provisional)	Kansas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04880300	24.50	3/14/2023	None	Ethanol	Western Plains Energy, LLC (4740)	Western Plains Energy, LLC (70030)	Midwest Corn, Dry Mill; Fiber ethanol, Edeniq Fiber Conversion Protocol; Natural Gas, Grid Electricity, Zero-CI Electrcity; Starch Ethanol produced in Oakley,KS; Ethanol transported by rail to California (Provisional)	None	
B038201	Tier 2	3.0	Fuel Producer: Madera Renewable Energy, LLC (C1140); Facility Name: Madera Renewable Energy, LLC (F00436); Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California. (Provisional)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B03820100	-758.40	3/28/2023	Application Package	Electricity	Madera Renewable Energy, LLC (C1140)	Madera Renewable Energy, LLC (F00436)	Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California. (Provisional)	None	Retired
B039301	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY CLOVER HILL (71261); Biogas from Dairy Manure at Clover Hill Dairy in Campbellsport, WI; upgraded to pipeline quality at US Gain RNG Facility Clover Hill; pipelined to California for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03930100	-204.42	3/30/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	U.S. GAIN RNG FACILITY CLOVER HILL (71261)	Biogas from Dairy Manure at Clover Hill Dairy in Campbellsport, WI; upgraded to pipeline quality at US Gain RNG Facility Clover Hill; pipelined to California for transportation use (Provisional)	None	
B040101	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504) ; Facility Name: YELLOW JACKET SWISS VALLEY RNG PROJECT (71161); Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (Provisional)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04010100	-216.27	3/30/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET SWISS VALLEY RNG PROJECT (71161)	Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (Provisional)	None	Retired
B040401	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: AUGEAN RNG PROJECT (71081); Biogas from dairy manure at Augean RNG project, Outlook, WA; upgraded to pipeline quality at Augean RNG Project; currently trucked to pipeline injection and pipelined to CA for transportation use. (Provisional)	Washington	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04040100	-216.63	3/28/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	AUGEAN RNG PROJECT (71081)	Biogas from dairy manure at Augean RNG project, Outlook, WA; upgraded to pipeline quality at Augean RNG Project; currently trucked to pipeline injection and pipelined to CA for transportation use. (Provisional)	None	
B042001	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: RIALTO Bioenergy (F00475); Bio-CNG from landfill-diverted food scraps sourced from multiple materials recovery facilities and upgraded at RIALTO Bioenergy facility in Bloomington, CA; Bio-CNG injected into California natural gas pipeline for transportation use (Provisional)	California	ood Scraps/Waste (02	Compressed Natural Gas (CNG)	None	None	CNG027B04200100	-28.20	3/22/2023	Application Package	Bio-CNG	Anew RNG, LLC (5877)	RIALTO Bioenergy (F00475)	Bio-CNG from landfill-diverted food scraps sourced from multiple materials recovery facilities and upgraded at RIALTO Bioenergy facility in Bloomington, CA; Bio-CNG injected into California natural gas pipeline for transportation use (Provisional)	None	
B042801	Tier 2	3.0	Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	Mississippi	Distillers' Corn Oil (003	Renewable Diesel (RND)	RND003A02710100	78.60	RND003B04280100	51.80	3/30/2023	Application Package	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	None	Retired

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B042802	Tier 2	3.0	Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	Mississippi	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04280200	80.81	3/30/2023	Application Package	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	None	Retired
A049701	Tier 1	3.0	Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Midwest Soybean Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	Canada	Soybean Oil (005)	Biodiesel (BIO)	None	None	BIO005A04970100	59.69	4/21/2023	None	Biodiesel	Canary Biofuels Inc. (1773)	Canary 1 (F00502)	Midwest Soybean Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	None	
A049702	Tier 1	3.0	Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Canola Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	Canada	Canola Oil (006)	Biodiesel (BIO)	None	None	BIO006A04970200	54.45	4/21/2023	None	Biodiesel	Canary Biofuels Inc. (1773)	Canary 1 (F00502)	Canola Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	None	
A049703	Tier 1	3.0	Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Corn Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	Canada	Distillers' Corn Oil (003	Biodiesel (BIO)	None	None	BIO003A04970300	29.99	4/21/2023	None	Biodiesel	Canary Biofuels Inc. (1773)	Canary 1 (F00502)	Corn Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	None	
A049704	Tier 1	3.0	Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Rendered Animal Fat Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	Canada	(animal and poultry fat	Biodiesel (BIO)	None	None	BIO002A04970400	34.62	4/21/2023	None	Biodiesel	Canary Biofuels Inc. (1773)	Canary 1 (F00502)	Rendered Animal Fat Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	None	
A049705	Tier 1	3.0	Fuel Producer: Canary Biofuels Inc. (1773); Facility Name: Canary 1 (F00502); Used Cooking Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	Canada	oking Oil/Waste Oil (UC	Biodiesel (BIO)	None	None	BIO001A04970500	22.66	4/21/2023	None	Biodiesel	Canary Biofuels Inc. (1773)	Canary 1 (F00502)	Used Cooking Oil transported by truck to Biodiesel plant in Lethbridge, Alberta, Canada then to California By Rail (Provisional)	None	
A051201	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A02940201	62.64	ETH009A05120100	63.80	5/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	None	Retired
A051202	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A02940101	71.64	ETH009A05120200	72.75	5/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	None	Retired
A051203	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715) ; Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A02940401	65.71	ETH010A05120300	65.71	5/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	None	Retired
A051204	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A02940301	74.71	ETH010A05120400	74.66	5/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Sorghum, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Liberal, Kansas; Ethanol transported by rail to California. Exclusion of steam energy for GNS production. (Provisional)	None	Retired
A005101	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00510100	69.86	ETH009A00510102	70.77	5/7/2019	None	Ethanol	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005102	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500) ; Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00510200	30.32	ETH012A00510202	30.54	5/7/2019	None	Ethanol - Cellulosic	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

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A049601	Tier 1	3.0	Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Fiber ethanol Edeniq 2.0; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center. Al ; Ethanol transported by rail to California (Provisional)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A04960100	23.77	4/26/2023	None	Ethanol - Cellulosic	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Midwest Corn, Dry Mill; Fiber ethanol Edeniq 2.0; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center. Al ; Ethanol transported by rail to California (Provisional)	None	
A049602	Tier 1	3.0	Fuel Producer: Siouxland Energy Cooperative (4060); Facility Name: Siouxland Energy Cooperative (70112); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center, IA ; Ethanol transported by rail to California (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A04960200	63.19	4/26/2023	None	Ethanol	Siouxland Energy Cooperative (4060)	Siouxland Energy Cooperative (70112)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Sioux Center, IA ; Ethanol transported by rail to California (Provisional)	None	
A020001	Tier 1	3.0	Fuel Producer: GHI Energy, LLC (6156); Facility Name: Waste Management American Landfill (70421); Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02000100	40.13	CNG025A02000101	37.64	6/29/2020	None	Bio-CNG	GHI Energy, LLC (6156)	Waste Management American Landfill (70421)	Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (Provisional)	2021 AFPR Recert Complete	Retired
B025104	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Diesel (RND)	RND001B02510400	18.16	RND001B02510401	17.92	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025101	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Soybean Oil (005)	Renewable Diesel (RND)	RND005B02510100	60.13	RND005B02510101	57.13	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025107	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Soybean Oil (005)	Renewable Naphtha (RNT)	RNT005B02510700	60.13	RNT005B02510701	57.13	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Soybean Oil transported by rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025109	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Naphtha (RNT)	RNT001B02510900	19.75	RNT001B02510901	19.77	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025108	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	Distillers' Corn Oil (003	Renewable Naphtha (RNT)	RNT003B02510800	27.64	RNT003B02510801	28.00	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025110	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	oking Oil/Waste Oil (UC	Renewable Naphtha (RNT)	RNT001B02511000	18.16	RNT001B02511001	17.92	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Low energy rendered Used Cooking Oil sourced from Darling Ingredients facilities and transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025111	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Naphtha (RNT)	RNT002B02511100	32.14	RNT002B02511101	33.08	3/28/2022	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
B025102	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge.	Louisiana	Distillers' Corn Oil (003	Renewable Diesel (RND)	RND003B02510200	27.64	RND003B02510201	28.00	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge.	2021 AFPR Recert Complete	
B025103	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge.	Louisiana	oking Oil/Waste Oil (UC	Renewable Diesel (RND)	RND001B02510300	19.75	RND001B02510301	19.77	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge.	2021 AFPR Recert Complete	

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B025105	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	Louisiana	(animal and poultry fat	Renewable Diesel (RND)	RND002B02510500	32.14	RND002B02510501	33.08	3/28/2022	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American Sourced Tallow transported by truck and rail to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; Finished Fuel transported to California by rail, ocean tanker, and/or barge. (Provisional)	2021 AFPR Recert Complete	
A038602	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A03860200	69.20	ETH009A03860201	69.61	7/13/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
A038601	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A03860100	72.20	ETH009A03860101	72.76	7/13/2021	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (Provisional)	2021 AFPR Recert Complete	Retired
A050201	Tier 1	3.0	Fuel Producer: Plymouth Energy LLC (5474) ; Facility Name: Plymouth Energy LLC (70183); Midwest Corn, Dry Mill; Dry and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Merrill, Iowa and transported by Rail to California; Composite CI (Provisional)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01250200	68.41	ETH009A05020100	63.91	5/18/2023	None	Ethanol	Plymouth Energy LLC (5474)	Plymouth Energy LLC (70183)	Midwest Corn, Dry Mill; Dry and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Merrill, Iowa and transported by Rail to California; Composite CI (Provisional)	None	
L021101	Lookup Table	3.0	Fuel Producer: SRECTrade, Inc (C1018); Facility Name: SRECTrade Inc (F00567); Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC049L00072019	0.00	2/17/2023	None	Electricity	SRECTrade, Inc (C1018)	SRECTrade Inc (F00567)	Electricity that is generated from 100 percent directly supplied zero-CI sources used as a transportation fuel in California	None	
A051801	Tier 1	3.0	Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180) ; Facility Name: ResilientIG Threemile Acquisition LLC (F00100); Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to CA and regasifed for use as LCNG	Oregon	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	None	None	LCN026A05180100	-156.47	5/26/2023	None	Bio-LNG	IOGEN D3 BIOFUEL PARTNERS II LLC (7180)	ResilientIG Threemile Acquisition LLC (F00100)	Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to CA and regasifed for use as LCNG	None	
A051802	Tier 1	3.0	Fuel Producer: IOGEN D3 BIOFUEL PARTNERS II LLC (7180) ; Facility Name: ResilientIG Threemile Acquisition LLC (F00100); Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC ; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to California for use as LNG	Oregon	Dairy Manure (026)	Liquefied Natural Gas (LNG)	None	None	LNG026A05180200	-152.93	5/26/2023	None	Bio-LNG	IOGEN D3 BIOFUEL PARTNERS II LLC (7180)	ResilientIG Threemile Acquisition LLC (F00100)	Biogas from Dairy Manure at Three Mile Farm in Boardman, OR; upgraded to pipeline quality at ResilientIG Threemile Acquisition LLC ; delivered via pipeline to liquefaction facility in Topock, AZ; delivered by truck to California for use as LNG	None	
A005301	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786); Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00530100	73.81	ETH009A00530103	72.85	5/6/2019	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005302	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00530200	66.94	ETH009A00530203	65.95	5/6/2019	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005303	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00530300	26.95	ETH012A00530303	25.98	5/6/2019	None	Ethanol - Cellulosic	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005201	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00520100	75.97	ETH009A00520103	74.36	5/6/2019	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005202	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00520200	68.75	ETH009A00520203	66.04	5/6/2019	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

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A005203	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785) ; Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00520300	28.78	ETH012A00520303	26.29	5/6/2019	None	Ethanol - Cellulosic	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A006101	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00610100	76.85	ETH009A00610102	75.21	6/5/2019	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A006102	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00610200	69.76	ETH009A00610202	65.67	6/5/2019	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A006103	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791) ; Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00610300	29.51	ETH012A00610302	26.04	6/5/2019	None	Ethanol - Cellulosic	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A012701	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A01270100	28.33	ETH012A01270103	28.29	9/24/2019	None	Ethanol - Cellulosic	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A012702	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01270200	75.89	ETH009A01270203	77.34	9/24/2019	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A012703	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01270300	67.79	ETH009A01270303	68.22	9/24/2019	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005601	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00560100	74.83	ETH009A00560102	73.89	6/10/2019	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005602	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00560200	68.44	ETH009A00560202	67.49	6/10/2019	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005603	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00560300	28.47	ETH012A00560302	28.27	6/10/2019	None	Ethanol - Cellulosic	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005801	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00580100	81.17	ETH009A00580102	73.74	5/7/2019	None	Ethanol	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A005802	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00580200	71.82	ETH009A00580202	68.00	5/7/2019	None	Ethanol	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired

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A005803	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00580300	31.75	ETH012A00580302	28.21	5/7/2019	None	Ethanol - Cellulosic	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A006401	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00640100	75.04	ETH009A00640102	72.37	5/7/2019	None	Ethanol	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A006403	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784) ; Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00640300	27.72	ETH012A00640302	24.60	5/7/2019	None	Ethanol - Cellulosic	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA, using BPX conversion method; Ethanol transported by rail to California	2021 AFPR Recert Complete	Retired
A013501	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A01350100	32.07	BIO002A01350102	31.65	12/20/2019	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	2021 AFPR Recert Complete	Retired
A014101	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	Missouri	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003A01410100	29.40	BIO003A01410102	27.16	9/25/2019	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441)	Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	2021 AFPR Recert Complete	Retired
A014102	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	Missouri	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A01410200	34.21	BIO002A01410202	32.08	9/25/2019	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441)	Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	2021 AFPR Recert Complete	Retired
A028201	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A02820100	27.02	BIO002A02820102	24.60	11/20/2020	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail	2021 AFPR Recert Complete	Retired
A027901	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	Arkansas	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003A02790100	33.97	BIO003A02790101	33.53	3/9/2021	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
A027902	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	Arkansas	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02790200	27.05	BIO001A02790202	26.13	3/9/2021	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (Provisional)	2021 AFPR Recert Complete	Retired
B028001	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	California	Swine Manure (044)	Gaseous Hydrogen (HYG)	HYG044B02800100	-374.14	HYG044B02800101	-296.05	6/7/2023	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Homan Farm, King City, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	None	
B028002	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	California	Swine Manure (044)	Gaseous Hydrogen (HYG)	HYG044B02800200	-390.47	HYG044B02800201	-368.94	6/7/2023	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at the Linde-Praxair SMR facility in Ontario, California using Biomethane derived from swine manure generated at Valley View Farm, Greencastle, Missouri; transported as G.H2 in tube trailers to refueling stations in California.	None	
B037802	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	California	Landfill Gas (025)	Gaseous Hydrogen (HYG)	HYG025B03780200	75.16	HYG025B03780201	99.94	6/7/2023	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Gaseous Hydrogen produced at Linde-Praxair SMR using Biomethane derived from landfill gas generated at Johnstown Regional Energy - Raeger Landfill in Johnstown, PA; finished fuel transported as gaseous Hydrogen in tube trailers to refueling stations in California.	None	

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A023201	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Renovar Arlington, LTD RNG Project (70501); Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG.	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02320100	43.15	CNG025A02320101	42.66	7/24/2020	None	Bio-CNG	U.S. Venture, Inc. (5504)	Renovar Arlington, LTD RNG Project (70501)	Biomethane from Landfill at Euless, TX 76040; Upgrading at US Gain; Pipelined to California for compression to CNG.	2021 AFPR Recert Complete	
B038301	Tier 2	3.0	Fuel Producer: EEC MARKET GROUP LLC (6496); Facility Name: NLC Energy Denmark LLC (70242); Biogas from dairy manure at Rolling Hills I, Rolling Hills II, Leiterman, Barta, Heim's Hillcrest, Branch View, and D&D in WI; upgraded to pipeline quality at NLC Energy Denmark LLC; pipelined to CA for transportation use (Provisional)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03830100	-284.21	6/22/2023	Application Package	Bio-CNG	EEC MARKET GROUP LLC (6496)	NLC Energy Denmark LLC (70242)	Biogas from dairy manure at Rolling Hills I, Rolling Hills II, Leiterman, Barta, Heim's Hillcrest, Branch View, and D&D in WI; upgraded to pipeline quality at NLC Energy Denmark LLC; pipelined to CA for transportation use (Provisional)	None	
B042603	Tier 2	3.0	Fuel Producer: Iwatani Corporation of America (C1024); Facility Name: Linde-Praxair (F00088); Hydrogen produced at Linde-Praxair SMR using North American Fossil Natural Gas; finished fuel transported as gaseous Hydrogen in tube-trailers to refueling stations in California.	California	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031B04260300	142.27	6/23/2023	Application Package	Hydrogen	Iwatani Corporation of America (C1024)	Linde-Praxair (F00088)	Hydrogen produced at Linde-Praxair SMR using North American Fossil Natural Gas; finished fuel transported as gaseous Hydrogen in tube-trailers to refueling stations in California.	None	
A050801	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Eugene/Springfield Water Pollution Control Facility (F00546); RNG produced from the mesophillic anaerobic digestion of wastewater sludge at the MWMC Regional Wastewater Treatment Plant using grid-based electricity, NG; CNG transported via pipeline; dispensed at refueling stations in California. (Provisional)	Oregon	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	None	None	CNG030A05080100	34.26	6/23/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Eugene/Springfield Water Pollution Control Facility (F00546)	RNG produced from the mesophillic anaerobic digestion of wastewater sludge at the MWMC Regional Wastewater Treatment Plant using grid-based electricity, NG; CNG transported via pipeline; dispensed at refueling stations in California. (Provisional)	None	
B041601	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Canola Oil (006)	Renewable Diesel (RND)	RND005B02400200	57.64	RND006B04160100	51.93	6/28/2023	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041602	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional)	North Dakota	Distillers' Corn Oil (003)	Renewable Diesel (RND)	RND003B02400100	29.79	RND003B04160200	29.65	6/28/2023	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional)	None	
B041603	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313; U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02400301	33.43	RND002B04160300	32.91	6/28/2023	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313	U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041604	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Soybean Oil (005)	Renewable Diesel (RND)	RND005B02400200	57.64	RND005B04160400	57.25	6/28/2023	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041605	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RND001B02400800	21.09	RND001B04160500	20.19	6/28/2023	Application Package	Renewable Diesel	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041606	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Canola Oil (006)	Renewable Naphtha (RNT)	None	None	RNT006B04160600	51.93	6/28/2023	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	North American sourced Canola Oil transported by rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041607	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional)	North Dakota	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	RNT003B02400400	29.79	RNT003B04160700	29.65	6/28/2023	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California By rail and ocean tanker (Provisional)	None	
B041608	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02400701	33.43	RNT002B04160800	32.91	6/28/2023	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Tallow transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	

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B041609	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Soybean Oil (005)	Renewable Naphtha (RNT)	RNT005B02400500	57.64	RNT005B04160900	57.25	6/28/2023	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Facility Name: Marathon Dickinson Refinery (F00313)	U.S sourced Soybean Oil transported by truck, rail, and barge to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041610	Tier 2	3.0	Fuel Producer: DAKOTA PRAIRIE REFINING (1166); Facility Name: Marathon Dickinson Refinery (F00313); U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	North Dakota	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	RNT001B02400600	21.09	RNT001B04161000	20.19	6/28/2023	Application Package	Renewable Naphtha	DAKOTA PRAIRIE REFINING (1166)	Marathon Dickinson Refinery (F00313)	U.S sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Dickinson, North Dakota; Natural Gas and Grid Electricity; transported to California by rail and ocean tanker (Provisional)	None	
B041701	Tier 2	3.0	Fuel Producer: WYNNEWOOD REFINING COMPANY, LLC (4148); Facility Name: WYNNEWOOD REFINING COMPANY (82420); Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	Oklahoma	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04170100	67.05	6/28/2023	Application Package	Renewable Diesel	WYNNEWOOD REFINING COMPANY, LLC (4148)	WYNNEWOOD REFINING COMPANY (82420)	Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	None	
B041702	Tier 2	3.0	Fuel Producer: WYNNEWOOD REFINING COMPANY, LLC (4148); Facility Name: WYNNEWOOD REFINING COMPANY (82420); Midwest Sourced Corn Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	Oklahoma	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B04170200	37.82	6/28/2023	Application Package	Renewable Diesel	WYNNEWOOD REFINING COMPANY, LLC (4148)	WYNNEWOOD REFINING COMPANY (82420)	Midwest Sourced Corn Oil transported by rail to Renewable Diesel plant in Wynnewood, OK; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	None	
B042101	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	Louisiana	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04210100	61.50	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B042102	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B04210200	32.50	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042103	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04210300	26.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042104	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04210400	20.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042105	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04210500	26.50	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042106	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04210600	31.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042107	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04210700	37.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042108	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04210800	39.50	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	

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B042109	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04210900	48.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042110	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04211000	24.00	6/29/2023	Application Package	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	None	
B042111	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	Louisiana	Soybean Oil (005)	Renewable Naphtha (RNT)	None	None	RNT005B04211100	62.00	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B042112	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	None	None	RNT003B04211200	33.00	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042113	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B04211300	26.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042114	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B04211400	20.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042115	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B04211500	27.00	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042116	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B04211600	31.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042117	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B04211700	37.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042118	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B04211800	40.00	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042119	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B04211900	48.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042120	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B04212000	24.50	6/29/2023	Application Package	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	None	

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B042121	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212100	62.00	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B042122	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212200	33.00	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042123	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212300	26.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042124	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212400	20.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042125	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212500	27.00	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042126	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212600	31.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042127	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212700	37.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042128	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212800	40.00	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042129	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04212900	48.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042130	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	Louisiana	Other Organic Waste (029)	Propane (LPG)	None	None	LPG029B04213000	24.50	6/29/2023	Application Package	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	None	
B042131	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	Louisiana	Soybean Oil (005)	Alternative Jet Fuel (AJF)	None	None	AJF005B04213100	62.00	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B042132	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Distillers' Corn Oil (003)	Alternative Jet Fuel (AJF)	None	None	AJF003B04213200	33.00	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Corn Oil transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	

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B042133	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04213300	26.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042134	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04213400	20.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Non-Rendered UCO transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042135	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04213500	27.00	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced UCO transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042136	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04213600	31.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042137	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04213700	37.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	North American sourced Tallow transported by truck, rail, and barge to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042138	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04213800	40.00	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	South American sourced Tallow transported by truck, rail, and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042139	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04213900	48.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Asia Pacific sourced Tallow transported by truck and ocean tanker to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Hydrogen, and Electricity; transported to California by truck and ocean tanker	None	
B042140	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	Louisiana	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04214000	24.50	6/29/2023	Application Package	Alternative Jet Fuel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Site-Specific Rendered Tallow Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Geismar, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by truck and ocean tanker	None	
B043001	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04300100	-236.90	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	None	
B043002	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04300200	-243.54	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility in Ontario, CA using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	None	
B043003	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR facility using Biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04300300	-132.07	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR facility using Biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; finished fuel transported in tanker trailers and dispensed at Hydrogen refueling stations in California. (Provisional)	None	
B043004	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tube-trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300400	-275.67	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from Yellow Jacket Lamb RNG Project, Oakfield, NY; finished fuel transported in tube-trailers to refueling stations in California. (Provisional)	None	

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B043005	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR using Biomethane procured from at Yellow Jacket Lakeshore RNG Project, Wilson, NY; finished fuel transported in tube-trailers to Hydrogen refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300500	-282.30	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR using Biomethane procured from at Yellow Jacket Lakeshore RNG Project, Wilson, NY; finished fuel transported in tube-trailers to Hydrogen refueling stations in California. (Provisional)	None	
B043006	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; transported in tube-trailers to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300600	-170.83	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; transported in tube-trailers to refueling stations in California. (Provisional)	None	
B043007	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300700	-221.27	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lamb RNG Project, Oakfield, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	None	
B043008	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lakeshore RNG Project, Wilson, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300800	-227.91	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, CA using biomethane procured from the Yellow Jacket Lakeshore RNG Project, Wilson, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	None	
B043009	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR in Ontario, CA; biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04300900	-116.43	6/27/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR in Ontario, CA; biomethane procured from Yellow Jacket Boxler RNG Project, Varysburg, NY; Re-gasified, Compressed at a trans-fill facility; distributed to refueling stations in California. (Provisional)	None	
B039401	Tier 2	3.0	Fuel Producer: Chevron Products Company (5086) ; Facility Name: Chevron El Segundo (01013); Soybean oil transported by rail to California; natural gas, steam, grid electricity and hydrogen; renewable diesel produced from co-processing soybean oil with fossil feedstock in a diesel hydrotreater (VGO unit) in El Segundo, California (PROV3.0)	California	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B03940100	51.74	6/30/2023	Application Package	Renewable Diesel	Chevron Products Company (5086)	Chevron El Segundo (01013)	Soybean oil transported by rail to California; natural gas, steam, grid electricity and hydrogen; renewable diesel produced from co-processing soybean oil with fossil feedstock in a diesel hydrotreater (VGO unit) in El Segundo, California (Provisional)	None	
B039601	Tier 2	3.0	Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at Lone Oak #1 Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use. (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03960100	-411.32	6/30/2023	Application Package	Bio-CNG	Lakeside Pipeline, LLC (C1158)	Lakeside Pipeline, LLC (F00480)	Biogas from dairy manure at Lone Oak #1 Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use. (Provisional)	None	
B039602	Tier 2	3.0	Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at Dixie Creek Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California For transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03960200	-416.41	6/30/2023	Application Package	Bio-CNG	Lakeside Pipeline, LLC (C1158)	Lakeside Pipeline, LLC (F00480)	Biogas from dairy manure at Dixie Creek Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California For transportation use (Provisional)	None	
B039603	Tier 2	3.0	Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at River Ranch Dairy In Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use. (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03960300	-417.71	6/30/2023	Application Package	Bio-CNG	Lakeside Pipeline, LLC (C1158)	Lakeside Pipeline, LLC (F00480)	Biogas from dairy manure at River Ranch Dairy In Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use. (Provisional)	None	
B039604	Tier 2	3.0	Fuel Producer: Lakeside Pipeline, LLC (C1158); Facility Name: Lakeside Pipeline, LLC (F00480); Biogas from dairy manure at Decade Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B03960400	-418.87	6/30/2023	Application Package	Bio-CNG	Lakeside Pipeline, LLC (C1158)	Lakeside Pipeline, LLC (F00480)	Biogas from dairy manure at Decade Dairy in Hanford, CA; upgraded to pipeline quality at Lakeside Pipeline, LLC; pipelined to California for transportation use (Provisional)	None	
B040301	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from dairy manure at Belonave Biogas LLC in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC; pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04030100	-419.40	6/30/2023	Application Package	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from dairy manure at Belonave Biogas LLC in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC; pipelined to California for transportation use (Provisional)	None	
A050101	Tier 1	3.0	Fuel Producer: BIOENERGETICA VALE DO PARACATU SA (1431); Facility Name: BIOENERGETICA VALE DO PARACATU SA (71521); Ethanol produced from sugarcane juice and molasses in Minas Gerais (Brazil); co-product credit for export of surplus cogenerated electricity; ethanol transported to California by Ocean tanker via Cape Horn; distributed to refueling stations by truck. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A05010100	50.89	7/3/2023	None	Ethanol	BIOENERGETICA VALE DO PARACATU SA (1431)	BIOENERGETICA VALE DO PARACATU SA (71521)	Ethanol produced from sugarcane juice and molasses in Minas Gerais (Brazil); co-product credit for export of surplus cogenerated electricity; ethanol transported to California by Ocean tanker via Cape Horn; distributed to refueling stations by truck.	None	

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B043801	Tier 2	3.0	Fuel Producer: Lone Oak Energy, LLC (C1177); Facility Name: Lone Oak Energy, LLC (F00542); Biogas from dairy manure at Lone Oak Farms #2 in Fresno, CA; upgraded to pipeline quality at Lone Oak Energy, LLC, trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04380100	-404.74	6/30/2023	Application Package	Bio-CNG	Lone Oak Energy, LLC (C1177)	Lone Oak Energy, LLC (F00542)	Biogas from dairy manure at Lone Oak Farms #2 in Fresno, CA; upgraded to pipeline quality at Lone Oak Energy, LLC, trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	
B045001	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: DEMETER RNG PROJECT (71302); Biogas from dairy manure at Endres Dairy, Maiers White Gold, Ripps Dairy Valley, Endres Berry Ridge, and Wagner Dairy in WI; upgraded to pipeline quality at DEMETER RNG PROJECT; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04500100	-191.29	6/30/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	DEMETER RNG PROJECT (71302)	Biogas from dairy manure at Endres Dairy, Maiers White Gold, Ripps Dairy Valley, Endres Berry Ridge, and Wagner Dairy in WI; upgraded to pipeline quality at DEMETER RNG PROJECT; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	None	
B046701	Tier 2	3.0	Fuel Producer: Lime (C1014); Facility Name: Lime Headquarters (F00036); Electricity from zero-CI sources used to power Lime's battery-electric scooters and bicycles in California. (3.0)	California	Solar (033)	Electricity (ELC)	None	None	ELC033B04670100	80.29	8/1/2023	Application Package	Electricity	Lime (C1014)	Lime Headquarters (F00036)	Electricity from zero-CI sources used to power Lime's battery-electric scooters and bicycles in California.	None	
L021801	Lookup Table	3.0	Fuel Producer: Swift Transportation Company of Arizona, LLC (C1230) ; Facility Name: Swift Transportation Co. of Arizona, LLC. (F00642); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	7/7/2023	None	Electricity	Swift Transportation Company of Arizona, LLC (C1230)	Swift Transportation Co. of Arizona, LLC. (F00642)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L021901	Lookup Table	3.0	Fuel Producer: Prologis Mobility (C1234); Facility Name: Prologis Mobility LLC (F00637); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	7/20/2023	None	Electricity	Prologis Mobility (C1234)	Prologis Mobility LLC (F00637)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L022001	Lookup Table	3.0	Fuel Producer: TeraWatt Infrastructure, Inc. (C1240); Facility Name: TeraWatt Infrastructure, Inc. (F00650); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	8/14/2023	None	Electricity	TeraWatt Infrastructure, Inc. (C1240)	TeraWatt Infrastructure, Inc. (F00650)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
B042201	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Five H in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220100	-416.31	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Five H in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
B042202	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Red Rock in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220200	-429.59	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Red Rock in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
B042203	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Vista Verde in Chowchilla, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220300	-249.95	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Vista Verde in Chowchilla, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
B042204	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Vander Woude in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220400	-260.14	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Vander Woude in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
B042205	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Rockshar in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220500	-411.49	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Rockshar in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
B042206	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Michael De Hoog in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220600	-418.96	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Michael De Hoog in Merced, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	

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B042207	Tier 2	3.0	Fuel Producer: Merced Pipeline LLC (C1199); Facility Name: Merced Pipeline, LLC (F00518); Renewable Natural Gas (RNG) from Dairy Manure at Double Diamond in El Nido, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04220700	-328.54	9/14/2023	Application Package	Bio-CNG	Merced Pipeline LLC (C1199)	Merced Pipeline, LLC (F00518)	Renewable Natural Gas (RNG) from Dairy Manure at Double Diamond in El Nido, CA and upgraded at Merced Pipeline, LLC Facility in Merced, CA; RNG pipelined to California for transportation use (Provisional)	None	
A051001	Tier 1	3.0	Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: NOBLE ROAD RNG LLC (72142); Biomethane from Noble Road Landfill in Shiloh, OH; upgrading at Noble Road RNG LLC, pipelined to California for compression to CNG (PROV3.0)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	None	None	CNG025A05100100	48.84	8/31/2023	None	Bio-CNG	TRUSTAR ENERGY LLC (6523)	NOBLE ROAD RNG LLC (72142)	Biomethane from Noble Road Landfill in Shiloh, OH; upgrading at Noble Road RNG LLC, pipelined to California for compression to CNG (Provisional)	None	
B047701	Tier 2	3.0	Fuel Producer: Cheyenne Renewable Diesel Company LLC (1647); Facility Name: Cheyenne Renewable Diesel Company LLC (F00494); Renewable Diesel produced from Soybean Oil pre-treated in Artesia, NM and transported by rail and truck to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (PROV3.0)	Wyoming	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04770100	69.78	9/28/2023	Application Package	Renewable Diesel	Cheyenne Renewable Diesel Company LLC (1647)	Cheyenne Renewable Diesel Company LLC (F00494)	Renewable Diesel produced from Soybean Oil pre-treated in Artesia, NM and transported by rail and truck to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (Provisional)	None	
B047702	Tier 2	3.0	Fuel Producer: Cheyenne Renewable Diesel Company LLC (1647); Facility Name: Cheyenne Renewable Diesel Company LLC (F00494); Renewable Diesel produced from Soybean Oil transported by rail to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (PROV3.0)	Wyoming	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04770200	69.41	9/28/2023	Application Package	Renewable Diesel	Cheyenne Renewable Diesel Company LLC (1647)	Cheyenne Renewable Diesel Company LLC (F00494)	Renewable Diesel produced from Soybean Oil transported by rail to Cheyenne, WY; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (Provisional)	None	
B047703	Tier 2	3.0	Fuel Producer: Cheyenne Renewable Diesel Company LLC (1647); Facility Name: Cheyenne Renewable Diesel Company LLC (F00494); Renewable Diesel produced from U.S. sourced tallow transported to Cheyenne, WY by truck and rail; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (PROV3.0)	Wyoming	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04770300	44.56	9/28/2023	Application Package	Renewable Diesel	Cheyenne Renewable Diesel Company LLC (1647)	Cheyenne Renewable Diesel Company LLC (F00494)	Renewable Diesel produced from U.S. sourced tallow transported to Cheyenne, WY by truck and rail; NG, Electricity, Alternate Fuel; finished fuel transported to California by Rail. (Provisional)	None	
L022201	Lookup Table	3.0	Fuel Producer: VERDANT ENERGY SERVICES LLC (C1048) ; Facility Name: Verdant Energy Services 0CI (F00661); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/26/2023	None	Electricity	VERDANT ENERGY SERVICES LLC (C1048)	Verdant Energy Services 0CI (F00661)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L022101	Lookup Table	3.0	Fuel Producer: Republic Services Procurement, Inc. (C1239); Facility Name: Republic Services Procurement, Inc. (F00660); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/22/2023	None	Electricity	Republic Services Procurement, Inc. (C1239)	Republic Services Procurement, Inc. (F00660)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
L022601	Lookup Table	3.0	Fuel Producer: Neutron Holdings, Inc. (dba Lime) (C1014); Facility Name: Neutron Holdings, Inc. (dba Lime) (F00036); Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California (3.0)	California	Zero-CI Sources (037)	Electricity (ELC)	None	None	ELC037L00072019	0.00	9/28/2023	None	Electricity	Neutron Holdings, Inc. (dba Lime) (C1014)	Neutron Holdings, Inc. (dba Lime) (F00036)	Electricity that is generated from 100 percent zero-CI sources used as a transportation fuel in California	None	
B044901	Tier 2	3.0	Fuel Producer: USL Parallel Products of California (4018); Facility Name: USL Parallel Products of California (70122); Ethanol from spoiled beverages produced by USL Parallel Products of California in Rancho Cucamonga, CA; ethanol blended in California for transportation use. (3.0)	California	Any Sugar Feedstock (040)	Ethanol (ETH)	ETHWB201	69.82	ETH040B04490100	126.33	10/2/2023	Application Package	Ethanol	USL Parallel Products of California (4018)	USL Parallel Products of California (70122)	Ethanol from spoiled beverages produced by USL Parallel Products of California in Rancho Cucamonga, CA; ethanol blended in California for transportation use.	None	
A051601	Tier 1	3.0	Fuel Producer: Granite Falls Energy, LLC (4769); Facility Name: Granite Falls Energy, LLC (70071); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (PROV3.0)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05160100	70.52	10/18/2023	None	Ethanol	Granite Falls Energy, LLC (4769)	Granite Falls Energy, LLC (70071)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (Provisional)	None	
A051602	Tier 1	3.0	Fuel Producer: Granite Falls Energy, LLC (4769); Facility Name: Granite Falls Energy, LLC (70071); Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (PROV3.0)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05160200	69.50	10/18/2023	None	Ethanol	Granite Falls Energy, LLC (4769)	Granite Falls Energy, LLC (70071)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (Provisional)	None	
A051603	Tier 1	3.0	Fuel Producer: Granite Falls Energy, LLC (4769); Facility Name: Granite Falls Energy, LLC (70071); Midwest Corn, Dry Mill; Fiber ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (PROV3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05160300	23.39	10/18/2023	None	Ethanol - Cellulosic	Granite Falls Energy, LLC (4769)	Granite Falls Energy, LLC (70071)	Midwest Corn, Dry Mill; Fiber ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Granite Falls, MN; Ethanol transported by Rail to California. (Provisional)	None	

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A052901	Tier 1	3.0	Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70150); Midwest Corn, Dry Mill; Corn Fiber Ethanol using the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05290100	41.63	10/10/2023	None	Ethanol - Cellulosic	Chief Ethanol Fuels, Inc (5110)	CHIEF ETHANOL FUELS INC (70150)	Midwest Corn, Dry Mill; Corn Fiber Ethanol using the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (Provisional)	None	
A052902	Tier 1	3.0	Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70150); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A05290200	80.80	10/10/2023	None	Ethanol	Chief Ethanol Fuels, Inc (5110)	CHIEF ETHANOL FUELS INC (70150)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (Provisional)	None	
A052903	Tier 1	3.0	Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70150); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A05290300	100.10	10/10/2023	None	Ethanol	Chief Ethanol Fuels, Inc (5110)	CHIEF ETHANOL FUELS INC (70150)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup Co-Products; Natural Gas, Grid Electricity; Starch Ethanol produced in Hastings, NE; Ethanol transported by Rail to California. (Provisional)	None	
A051901	Tier 1	3.0	Fuel Producer: Heron Lake BioEnergy (4015); Facility Name: Heron Lake BioEnergy (70097); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (PROV3.0)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05190100	72.01	10/18/2023	None	Ethanol	Heron Lake BioEnergy (4015)	Heron Lake BioEnergy (70097)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (Provisional)	None	
A051902	Tier 1	3.0	Fuel Producer: Heron Lake BioEnergy (4015); Facility Name: Heron Lake BioEnergy (70097); Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (PROV3.0)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05190200	70.62	10/18/2023	None	Ethanol	Heron Lake BioEnergy (4015)	Heron Lake BioEnergy (70097)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Heron Lake, Minnesota; Ethanol transported by Rail to California. (Provisional)	None	
A051903	Tier 1	3.0	Fuel Producer: Heron Lake BioEnergy (4015); Facility Name: Heron Lake BioEnergy (70097); Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Heron Lake, Minnesota, and transported by Rail to California. (PROV3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05190300	27.90	10/18/2023	None	Ethanol - Cellulosic	Heron Lake BioEnergy (4015)	Heron Lake BioEnergy (70097)	Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Heron Lake, Minnesota, and transported by Rail to California. (Provisional)	None	
A052001	Tier 1	3.0	Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70241); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00380100	77.4	ETH009A05200100	77.86	10/30/2023	None	Ethanol	Chief Ethanol Fuels, Inc (5110)	CHIEF ETHANOL FUELS INC (70241)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by Rail to California. (Provisional)	None	
A052002	Tier 1	3.0	Fuel Producer: Chief Ethanol Fuels, Inc (5110); Facility Name: CHIEF ETHANOL FUELS INC (70241); Midwest Corn, Dry Mill; Corn Kernel Fiber Ethanol produced by the EDENIQ Fiber Conversion Process in Lexington, NE; Natural Gas, Grid Electricity; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05200200	38.12	10/30/2023	None	Ethanol - Cellulosic	Chief Ethanol Fuels, Inc (5110)	CHIEF ETHANOL FUELS INC (70241)	Midwest Corn, Dry Mill; Corn Kernel Fiber Ethanol produced by the EDENIQ Fiber Conversion Process in Lexington, NE; Natural Gas, Grid Electricity; Ethanol transported by Rail to California. (Provisional)	None	
A052101	Tier 1	3.0	Fuel Producer: Green Plains Central City, LLC (3368); Facility Name: Green Plains Central City LLC (70141); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A05210100	75.51	10/31/2023	None	Ethanol	Green Plains Central City, LLC (3368)	Green Plains Central City LLC (70141)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (Provisional)	None	
A052102	Tier 1	3.0	Fuel Producer: Green Plains Central City, LLC (3368); Facility Name: Green Plains Central City LLC (70141); Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A02960100	65.97	ETH009A05210200	64.86	10/31/2023	None	Ethanol	Green Plains Central City, LLC (3368)	Green Plains Central City LLC (70141)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Central City, NE; Ethanol transported by Rail to California. (Provisional)	None	
B045801	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04580100	27.39	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B045802	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04580200	33.70	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B045803	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04580300	47.95	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B045804	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04580400	41.15	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B045806	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04580600	43.66	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; transported to California by truck and ocean tanker	None	
B045807	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California ocean t (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04580700	27.61	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California ocean t	None	
B045808	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California by ocea (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04580800	33.92	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California by ocea	None	
B045809	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04580900	41.36	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California	None	
B045810	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04581000	48.17	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; transported to California	None	
B045811	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and Ocean Tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; tr (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04581100	43.87	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and Ocean Tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable diesel; tr	None	
B045813	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California ocean tank (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04581300	27.61	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California ocean tank	None	
B045814	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by ocean t (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04581400	33.92	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by ocean t	None	
B045815	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04581500	48.17	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by	None	
B045816	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04581600	41.36	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; transported to California by	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B045817	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; trans (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04581700	43.87	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to Koole to co-produce renewable jet; trans	None	
B045819	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California ocean (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04581900	29.42	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California ocean	None	
B045820	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California by oc (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04582000	35.72	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to California by oc	None	
B045821	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californ (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04582100	49.97	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californ	None	
B045822	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californi (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04582200	43.17	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; transported to Californi	None	
B045824	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel; (3.0)	Finland	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04582400	45.68	11/9/2023	Application Package	Renewable Diesel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable diesel;	None	
B045825	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California ocean ta (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04582500	29.42	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California ocean ta	None	
B045826	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California by ocean (3.0)	Finland	Used Cooking Oil/Waste Oil (UCO) (001)	Alternative Jet Fuel (AJF)	None	None	AJF001B04582600	35.72	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced UCO transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California by ocean	None	
B045827	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04582700	43.17	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b	None	
B045828	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04582800	49.97	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	Globally sourced animal fat transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; transported to California b	None	
B045829	Tier 2	3.0	Fuel Producer: Neste Oyj (3734); Facility Name: Neste Renewable Fuels - Porvoo (80272); European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; tra (3.0)	Finland	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	None	None	AJF002B04582900	45.68	11/9/2023	Application Package	Alternative Jet Fuel	Neste Oyj (3734)	Neste Renewable Fuels - Porvoo (80272)	European sourced animal fat pre-treated at Sluiskil transported by truck, rail, and ocean tanker to Renewable Diesel plant in Porvoo, Finland; Natural Gas, Hydrogen and Grid Electricity; RD feedstock transported to TexMark to co-produce renewable jet; tra	None	
A052301	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05230100	73.75	11/6/2023	None	Ethanol	POET BIOREFINING - ARTHUR (1578)	Poet Biorefining - Arthur (71682)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional)	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A052302	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05230200	70.13	11/6/2023	None	Ethanol	POET BIOREFINING - ARTHUR (1578)	Poet Biorefining - Arthur (71682)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052303	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, ; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05230300	66.14	11/6/2023	None	Ethanol	POET BIOREFINING - ARTHUR (1578)	Poet Biorefining - Arthur (71682)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup, ; Natural Gas, Grid Electricity; Starch Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052304	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ARTHUR (1578); Facility Name: Poet Biorefining - Arthur (71682); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05230400	26.37	11/6/2023	None	Ethanol - Cellulosic	POET BIOREFINING - ARTHUR (1578)	Poet Biorefining - Arthur (71682)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Arthur, IA; Ethanol transported by Rail to California. (Provisional)	None	
A053101	Tier 1	3.0	Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Redfield, SD; Ethanol transported by Rail to California. (PROV3.0)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05310100	29.36	11/6/2023	None	Ethanol - Cellulosic	Redfield Energy, LLC (4061)	Redfield Energy, LLC (70111)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Redfield, SD; Ethanol transported by Rail to California. (Provisional)	None	
A053102	Tier 1	3.0	Fuel Producer: Redfield Energy, LLC (4061); Facility Name: Redfield Energy, LLC (70111); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Redfield, SD; Ethanol transported by Rail to California; Composite CI. (PROV3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A01450102	68.61	ETH009A05310200	67.95	11/6/2023	None	Ethanol	Redfield Energy, LLC (4061)	Redfield Energy, LLC (70111)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Redfield, SD; Ethanol transported by Rail to California; Composite CI. (Provisional)	None	
A052201	Tier 1	3.0	Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05220100	73.95	11/17/2023	None	Ethanol	Poet Biorefining - Shell Rock, LLC (1584)	Poet Biorefining - Shell Rock (71686)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052202	Tier 1	3.0	Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05220200	69.64	11/17/2023	None	Ethanol	Poet Biorefining - Shell Rock, LLC (1584)	Poet Biorefining - Shell Rock (71686)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052203	Tier 1	3.0	Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05220300	65.44	11/17/2023	None	Ethanol	Poet Biorefining - Shell Rock, LLC (1584)	Poet Biorefining - Shell Rock (71686)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052204	Tier 1	3.0	Fuel Producer: Poet Biorefining - Shell Rock, LLC (1584); Facility Name: Poet Biorefining - Shell Rock (71686); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05220400	26.04	11/17/2023	None	Ethanol - Cellulosic	Poet Biorefining - Shell Rock, LLC (1584)	Poet Biorefining - Shell Rock (71686)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Shell Rock, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052501	Tier 1	3.0	Fuel Producer: HEREFORD ETHANOL PARTNERS, LP (1501); Facility Name: HEREFORD ETHANOL PARTNERS, LP (21601; Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (PROV3.0)	Texas	Corn (009)	Ethanol (ETH)	ETHC248L	67.6	ETH009A05250100	65.34	11/16/2023	None	Ethanol	HEREFORD ETHANOL PARTNERS, LP (1501)	HEREFORD ETHANOL PARTNERS, LP (21601	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (Provisional)	None	
A052502	Tier 1	3.0	Fuel Producer: HEREFORD ETHANOL PARTNERS, LP (1501); Facility Name: HEREFORD ETHANOL PARTNERS, LP (21601; Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Sorghum Starch produced in Hereford, Texas; Ethanol transported by rail to California (PROV3.0)	Texas	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A05250200	66.44	11/16/2023	None	Ethanol	HEREFORD ETHANOL PARTNERS, LP (1501)	HEREFORD ETHANOL PARTNERS, LP (21601	Grain Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Sorghum Starch produced in Hereford, Texas; Ethanol transported by rail to California (Provisional)	None	
A052503	Tier 1	3.0	Fuel Producer: HEREFORD ETHANOL PARTNERS, LP (1501); Facility Name: HEREFORD ETHANOL PARTNERS, LP (21601; Midwest Corn and Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Hereford, Texas using Edeniq conversion method; Ethanol transported by rail to California (PROV3.0)	Texas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05250300	26.15	11/16/2023	None	Ethanol - Cellulosic	HEREFORD ETHANOL PARTNERS, LP (1501)	HEREFORD ETHANOL PARTNERS, LP (21601	Midwest Corn and Sorghum, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Hereford, Texas using Edeniq conversion method; Ethanol transported by rail to California (Provisional)	None	

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A052701	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05270100	71.98	11/17/2023	None	Ethanol	POET BIOREFINING - MENLO (1583)	MENLO (71685)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052702	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05270200	68.33	11/17/2023	None	Ethanol	POET BIOREFINING - MENLO (1583)	MENLO (71685)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052703	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05270300	64.40	11/17/2023	None	Ethanol	POET BIOREFINING - MENLO (1583)	MENLO (71685)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052704	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MENLO (1583); Facility Name: MENLO (71685); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05270400	25.02	11/17/2023	None	Ethanol - Cellulosic	POET BIOREFINING - MENLO (1583)	MENLO (71685)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Menlo, IA; Ethanol transported by Rail to California. (Provisional)	None	
A053301	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05330100	72.65	11/17/2023	None	Ethanol	POET BIOPROCESSING - FAIRBANK (1581)	FAIRBANK (71683)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional)	None	
A053302	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05330200	69.00	11/17/2023	None	Ethanol	POET BIOPROCESSING - FAIRBANK (1581)	FAIRBANK (71683)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional)	None	
A053303	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05330300	64.38	11/17/2023	None	Ethanol	POET BIOPROCESSING - FAIRBANK (1581)	FAIRBANK (71683)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional)	None	
A053304	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - FAIRBANK (1581); Facility Name: FAIRBANK (71683); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05330400	24.65	11/17/2023	None	Ethanol - Cellulosic	POET BIOPROCESSING - FAIRBANK (1581)	FAIRBANK (71683)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by proprietary fiber conversion process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Fairbank, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052801	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05280100	72.60	11/28/2023	None	Ethanol	POET BIOPROCESSING - IOWA FALLS (1582)	IOWA FALLS (71684)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052802	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05280200	70.11	11/28/2023	None	Ethanol	POET BIOPROCESSING - IOWA FALLS (1582)	IOWA FALLS (71684)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052803	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05280300	64.89	11/28/2023	None	Ethanol	POET BIOPROCESSING - IOWA FALLS (1582)	IOWA FALLS (71684)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional)	None	
A052804	Tier 1	3.0	Fuel Producer: POET BIOPROCESSING - IOWA FALLS (1582); Facility Name: IOWA FALLS (71684); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poets's proprietary Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05280400	24.29	11/28/2023	None	Ethanol - Cellulosic	POET BIOPROCESSING - IOWA FALLS (1582)	IOWA FALLS (71684)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poets's proprietary Fiber Conversion Process; Natural Gas, Grid Electricity; Corn Fiber Ethanol produced in Iowa Falls, IA; Ethanol transported by Rail to California. (Provisional)	None	

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B047301	Tier 2	3.0	Fuel Producer: SUNOMA RENEWABLE BIOFUEL, LLC (1781); Facility Name: Sunoma Renewable Biofuel, LLC (F00497); Biogas from dairy manure at Paloma dairy in Gila Bend, AZ; upgraded to pipeline quality at Sunoma Renewable Biofuel, LLC; pipelined to California for transportation use (PROV3.0)	Arizona	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04730100	-386.78	12/4/2023	Application Package	Bio-CNG	SUNOMA RENEWABLE BIOFUEL, LLC (1781)	Sunoma Renewable Biofuel, LLC (F00497)	Biogas from dairy manure at Paloma dairy in Gila Bend, AZ; upgraded to pipeline quality at Sunoma Renewable Biofuel, LLC; pipelined to California for transportation use (Provisional)	None	
B048201	Tier 2	3.0	Fuel Producer: Wyoming Renewable Diesel Company LLC (1440); Facility Name: Wyoming Renewable Diesel Company LLC (82441); North American sourced Animal Fat transported by rail to Renewable Diesel plant in Sinclair Wyoming; Natural Gas, Hydrogen, and Grid Electricity; transported to California by rail (3.0)	Wyoming	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04820100	33.19	12/6/2023	Application Package	Renewable Diesel	Wyoming Renewable Diesel Company LLC (1440)	Wyoming Renewable Diesel Company LLC (82441)	North American sourced Animal Fat transported by rail to Renewable Diesel plant in Sinclair Wyoming; Natural Gas, Hydrogen, and Grid Electricity; transported to California by rail	None	
B049201	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Canola Oil (006)	Renewable Diesel (RND)	None	None	RND006B04920100	54.20	12/6/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049202	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B04920200	28.60	12/6/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049203	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B04920300	58.00	12/6/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049204	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04920400	33.20	12/6/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049205	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B04920500	20.70	12/6/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049206	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Canola Oil (006)	Renewable Naphtha (RNT)	None	None	RNT006B04920600	54.20	12/6/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Canola Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049207	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	None	None	RNT003B04920700	28.60	12/6/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Distillers' Corn Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049208	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Soybean Oil (005)	Renewable Naphtha (RNT)	None	None	RNT005B04920800	58.00	12/6/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American sourced Soybean Oil transported by rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049209	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B04920900	33.20	12/6/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American and Mexico sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	
B049210	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: DIAMOND GREEN DIESEL - PORT ARTHUR (82621); North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (PROV3.0)	Texas	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B04921000	20.70	12/6/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	DIAMOND GREEN DIESEL - PORT ARTHUR (82621)	North American and Mexico sourced Used Cooking Oil transported by truck and rail to Renewable Diesel plant in Port Arthur Texas; Natural Gas, Hydrogen, and Grid Electricity; transported to California by ocean tanker (Provisional)	None	

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B049501	Tier 2	3.0	Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); North American sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas and Grid Electricity; transported to California by rail (PROV3.0)	Mississippi	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B04950100	63.29	12/18/2023	Application Package	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	North American sourced Animal Fat transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas and Grid Electricity; transported to California by rail (Provisional)	None	
A052601	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A05120200	72.75	ETH009A05260100	71.72	12/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional)	None	
A052602	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A05120100	63.8	ETH009A05260200	64.93	12/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional)	None	
A052603	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Midwest Corn, Dry Mill; Corn/Sorghum Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0)	Kansas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05260300	24.31	12/8/2023	None	Ethanol - Cellulosic	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Midwest Corn, Dry Mill; Corn/Sorghum Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Corn/Sorghum Fiber Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional)	None	
A052604	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A05120400	74.66	ETH010A05260400	74.26	12/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Sorghum, Dry Mill; Dry DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional)	None	
A052605	Tier 1	3.0	Fuel Producer: Arkalon Ethanol, LLC (5715); Facility Name: Arkalon Ethanol, LLC (70247); Sorghum, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (PROV3.0)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A05120300	65.71	ETH010A05260500	67.47	12/8/2023	None	Ethanol	Arkalon Ethanol, LLC (5715)	Arkalon Ethanol, LLC (70247)	Sorghum, Dry Mill; Wet DGS, Corn Oil, Natural Gas, and Grid Electricity; Starch Ethanol produced in Liberal, KS; Finished fuel transported to California by Rail. (Provisional)	None	
B042401	Tier 2	3.0	Fuel Producer: Air Liquide Hydrogen Energy US LLC (A491); Facility Name: North Las Vegas Liquid Hydrogen Plant (F00371); Liquefied Hydrogen produced in North Las Vegas, Nevada by steam methane reformation (SMR) of fossil-derived Natural Gas; NG, Grid Electricity; Liquid Hydrogen transported in tanker trailers to refueling stations in Northern and Southern California. (PROV3.0)	Nevada	North American NG	Liquid Hydrogen (HYL)	None	None	HYL031B04240100	188.60	12/21/2023	Application Package	Hydrogen	Air Liquide Hydrogen Energy US LLC (A491)	North Las Vegas Liquid Hydrogen Plant (F00371)	Liquefied Hydrogen produced in North Las Vegas, Nevada by steam methane reformation (SMR) of fossil-derived Natural Gas; NG, Grid Electricity; Liquid Hydrogen transported in tanker trailers to refueling stations in Northern and Southern California. (Provisional)	None	
B050101	Tier 2	3.0	Fuel Producer: ARTESIA RENEWABLE DIESEL COMPANY LLC (1646); Facility Name: RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381); U.S sourced Soybean Oil transported by Rail and pre-treated at the Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (PROV3.0)	New Mexico	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B05010100	57.67	12/20/2023	Application Package	Renewable Diesel	ARTESIA RENEWABLE DIESEL COMPANY LLC (1646)	RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381)	U.S sourced Soybean Oil transported by Rail and pre-treated at the Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (Provisional)	None	
B050102	Tier 2	3.0	Fuel Producer: ARTESIA RENEWABLE DIESEL COMPANY LLC (1646); Facility Name: RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381); U.S. sourced Distillers Corn Oil transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (PROV3.0)	New Mexico	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B05010200	30.05	12/20/2023	Application Package	Renewable Diesel	ARTESIA RENEWABLE DIESEL COMPANY LLC (1646)	RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381)	U.S. sourced Distillers Corn Oil transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (Provisional)	None	
B050103	Tier 2	3.0	Fuel Producer: ARTESIA RENEWABLE DIESEL COMPANY LLC (1646); Facility Name: RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381); U.S.-sourced Tallow transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (PROV3.0)	New Mexico	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05010300	34.05	12/20/2023	Application Package	Renewable Diesel	ARTESIA RENEWABLE DIESEL COMPANY LLC (1646)	RENEWABLE DIESEL UNIT (RDU) / PRE-TREATMENT UNIT (PTU) (82381)	U.S.-sourced Tallow transported by Rail and pre-treated at the Artesia Renewable Diesel plant in Artesia, New Mexico; Natural Gas, and Grid Electricity; finished fuel transported to California by Rail. (Provisional)	None	
B046101	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: HOLSUM RNG PROJECT (71481); Biogas from dairy manure at Holsum Elm Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (PROV3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04610100	-130.23	12/28/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	HOLSUM RNG PROJECT (71481)	Biogas from dairy manure at Holsum Elm Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (Provisional)	None	
B046102	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: HOLSUM RNG PROJECT (71481); Biogas from dairy manure at Holsum Irish Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (PROV3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04610200	-385.43	12/28/2023	Application Package	Bio-CNG	U.S. Venture, Inc. (5504)	HOLSUM RNG PROJECT (71481)	Biogas from dairy manure at Holsum Irish Dairy in Hilbert, WI; upgraded to pipeline quality at HOLSUM RNG PROJECT; pipelined to California for transportation use (Provisional)	None	

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B045901	Tier 2	3.0	Fuel Producer: Still Water Power, LLC (C1180); Facility Name: Still Water Power, LLC (F00552); Biogas from Dairy Manure at Still Water Dairy in Hanford, CA; upgraded to pipeline quality at Still Water Power, LLC; trucked to pipeline injection and pipelined to CA for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B04590100	-332.64	12/29/2023	Application Package	Bio-CNG	Still Water Power, LLC (C1180)	Still Water Power, LLC (F00552)	Biogas from Dairy Manure at Still Water Dairy in Hanford, CA; upgraded to pipeline quality at Still Water Power, LLC; trucked to pipeline injection and pipelined to CA for transportation use	None	
B049001	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: Bar 20 Biogas LLC (F00510); Low-CI electricity from dairy manure biogas using Solid Oxide Fuel Cell generator at Bar 20 Dairy in Kerman, CA for use as a transportation fuel in California (PROV3.0)	California	Dairy Manure (026)	Electricity (ELC)	None	None	ELC026B04900100	-790.41	12/28/2023	Application Package	Electricity	California Bioenergy LLC (B194)	Bar 20 Biogas LLC (F00510)	Low-CI electricity from dairy manure biogas using Solid Oxide Fuel Cell generator at Bar 20 Dairy in Kerman, CA for use as a transportation fuel in California (Provisional)	None	
B049401	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at the Air Liquide North Las Vegas Hydrogen Plant in Las Vegas, NV using Biomethane procured from the Yellow Jacket Lamb RNG Project in Oakfield, NY; finished fuel dispensed at Hydrogen refueling stations in California. (PROV3.0)	Nevada	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04940100	-158.06	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at the Air Liquide North Las Vegas Hydrogen Plant in Las Vegas, NV using Biomethane procured from the Yellow Jacket Lamb RNG Project in Oakfield, NY; finished fuel dispensed at Hydrogen refueling stations in California. (Provisional)	None	
B049402	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide North Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at refuelng stations in California. (PROV3.0)	Nevada	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04940200	-181.75	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide North Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Lakeshore RNG Project in Wilson, NY; finished fuel transported in tanker trailers and dispensed at refuelng stations in California. (Provisional)	None	
B049403	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; finished fuel transported and dispensed at Hydrogen refueling stations in California. (PROV3.0)	Nevada	Dairy Manure (026)	Liquid Hydrogen (HYL)	None	None	HYL026B04940300	-119.24	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from the Yellow Jacket Boxler RNG Project in Varysburg, NY; finished fuel transported and dispensed at Hydrogen refueling stations in California. (Provisional)	None	
B049404	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lamb RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations in California. (PROV3.0)	Nevada	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04940400	-141.61	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lamb RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations in California. (Provisional)	None	
B049405	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations. (PROV3.0)	Nevada	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04940500	-165.30	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Lakeshore RNG Project in Oakfield, NY; re-gasified & compressed in Livermore, CA; finished fuel transported to refueling stations. (Provisional)	None	
B049406	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Boxler RNG in Varysburg, NY; re-gasified & compressed in Livermore, CA; finished fuel dispensed at refueling stations in California. (PROV3.0)	Nevada	Dairy Manure (026)	Gaseous Hydrogen (HYG)	None	None	HYG026B04940600	-102.79	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using Biomethane procured from Yellow Jacket Boxler RNG in Varysburg, NY; re-gasified & compressed in Livermore, CA; finished fuel dispensed at refueling stations in California. (Provisional)	None	
B049407	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: AL North Las Vegas Liquid Hydrogen Plant (F00523); Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using N.A. Natural Gas; transported to trans-fill station in Livermore, CA in liquid tankers; re-gasified & compressed; finished fuel dispensed at refueling stations in California. (PROV3.0)	Nevada	North American Fossil NG (031)	Gaseous Hydrogen (HYG)	None	None	HYG031B04940700	205.05	12/29/2023	Application Package	Hydrogen	FirstElement Fuel (E426)	AL North Las Vegas Liquid Hydrogen Plant (F00523)	Liquefied Hydrogen produced at Air Liquide N. Las Vegas Hydrogen Plant using N.A. Natural Gas; transported to trans-fill station in Livermore, CA in liquid tankers; re-gasified & compressed; finished fuel dispensed at refueling stations in California. (Provisional)	None	
B050601	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Soybean Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (PROV3.0)	California	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B05060100	62.93	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	North American sourced Soybean Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (Provisional)	None	
B050602	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Canola Oil transported by rail and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (PROV3.0)	California	Canola Oil (006)	Renewable Diesel (RND)	None	None	RND006B05060200	56.54	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	North American sourced Canola Oil transported by rail and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (Provisional)	None	
B050603	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Distillers' Corn Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (PROV3.0)	California	Distillers' Corn Oil (003)	Renewable Diesel (RND)	None	None	RND003B05060300	35.24	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	North American sourced Distillers' Corn Oil, pre-treated at various facilities, transported by truck, rail, and barge to Renewable Diesel plant in Martinez, California; Natural Gas and Electricity; fuel produced in California (Provisional)	None	

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B050604	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Used Cooking Oil, pre-treated at various facilities, transported by truck and rail to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (PROV3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B05060400	29.22	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	North American sourced Used Cooking Oil, pre-treated at various facilities, transported by truck and rail to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (Provisional)	None	
B050605	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); North American sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, barge, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05060500	37.14	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	North American sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, barge, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (Provisional)	None	
B050606	Tier 2	3.0	Fuel Producer: MARTINEZ RENEWABLES LLC (1845); Facility Name: MARTINEZ REFINERY (90001); Globally sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05060600	46.40	12/26/2023	Application Package	Renewable Diesel	MARTINEZ RENEWABLES LLC (1845)	MARTINEZ REFINERY (90001)	Globally sourced Animal Fat, pre-treated at various facilities, transported by truck, rail, and ocean tanker to Renewable Diesel plant in Martinez, California; Natural Gas and Grid Electricity; fuel produced in California (Provisional)	None	
B051401	Tier 2	3.0	Fuel Producer: FM Jerseys Dairy Biogas, LLC (C1178); Facility Name: FM Jerseys Dairy Digester (F00479); Biogas from dairy manure at FM Jerseys Dairy in Tipton, CA; upgraded to pipeline quality at FM Jerseys Dairy Digester; trucked to pipeline injection and pipelined to CA for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	None	None	CNG026B05140100	-426.46	12/28/2023	Application Package	Bio-CNG	FM Jerseys Dairy Biogas, LLC (C1178)	FM Jerseys Dairy Digester (F00479)	Biogas from dairy manure at FM Jerseys Dairy in Tipton, CA; upgraded to pipeline quality at FM Jerseys Dairy Digester; trucked to pipeline injection and pipelined to CA for transportation use	None	
B052001	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528); Facility Name: Phillips 66 Rodeo (82191); Renewable diesel produced from Argentinian soybean oil transported by ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge (3.0)	California	Soybean Oil (005)	Renewable Diesel (RND)	None	None	RND005B05200100	61.98	12/26/2023	Application Package	Renewable Diesel	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable diesel produced from Argentinian soybean oil transported by ocean tanker to California; natural gas, steam, off gases, grid electricity and hydrogen; distributed in California via barge	None	
B054001	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American sourced canola oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker (3.0)	Louisiana	Canola Oil (006)	Renewable Diesel (RND)	None	None	RND006B05400100	55.11	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American sourced canola oil transported by truck, rail, and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker	None	
B054002	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B05400200	29.76	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054003	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05400300	46.07	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054004	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05400400	37.24	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054005	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	None	None	RND001B05400500	39.77	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054006	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	None	None	RND002B05400600	46.43	12/29/2023	Application Package	Renewable Diesel	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054007	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); North American sourced canola oil transported by truck, rail and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker (3.0)	Louisiana	Canola Oil (006)	Renewable Naphtha (RNT)	None	None	RNT006B05400700	55.11	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	North American sourced canola oil transported by truck, rail and barge to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by Ocean Tanker	None	

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B054008	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B05400800	29.76	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Oceania sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054009	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B05400900	46.07	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Oceania sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054010	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B05401000	37.24	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	South American sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054011	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	None	None	RNT001B05401100	39.77	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Asia sourced Used Cooking Oil transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
B054012	Tier 2	3.0	Fuel Producer: Diamond Green Diesel Holdings LLC (6072); Facility Name: Diamond Green Diesel LLC (81496); Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	None	None	RNT002B05401200	46.43	12/29/2023	Application Package	Renewable Naphtha	Diamond Green Diesel Holdings LLC (6072)	Diamond Green Diesel LLC (81496)	Asia sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Norco, Louisiana; Natural Gas, Grid Electricity, and Hydrogen; transported to California by ocean tanker	None	
A005001	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (3.0)	Missouri	Corn (009)	Ethanol (ETH)	ETH009A00500102	71.21	ETH009A00500103	70.13	10/17/2023	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport	2022 AFPR Recert Complete	
A005002	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (3.0)	Missouri	Corn (009)	Ethanol (ETH)	ETH009A00500202	63.83	ETH009A00500203	63.10	10/17/2023	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport	2022 AFPR Recert Complete	
A005003	Tier 1	3.0	Fuel Producer: POET Biorefining - Laddonia (4787); Facility Name: POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023); Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport (3.0)	Missouri	Corn (009)	Ethanol (ETH)	ETH012A00500302	23.97	ETH012A00500303	23.19	10/17/2023	None	Ethanol	POET Biorefining - Laddonia (4787)	POET BIOREFINING - LADDONIA (MISSOURI ETHANOL, LLC) (70023)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS and Corn Oil using natural gas; a cogeneration unit is used to generate electricity and steam from natural gas; Corn starch and Fiber ethanol produced in Laddonia, MO, using BPX conversion method; Ethanol transport	2022 AFPR Recert Complete	
A005101	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00510102	70.77	ETH009A00510103	69.15	11/7/2023	None	Ethanol	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005102	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00510202	30.54	ETH012A00510203	29.19	11/7/2023	None	Ethanol - Cellulosic	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Atlantic, Iowa using Edeniq conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005201	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785); Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00520103	74.36	ETH009A00520104	75.43	11/6/2023	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005202	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785); Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00520203	66.04	ETH009A00520204	66.02	11/6/2023	None	Ethanol	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	

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A005203	Tier 1	3.0	Fuel Producer: Poet Biorefining Hanlontown (4785); Facility Name: Poet Biorefining Hanlontown (70010); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00520303	26.29	ETH012A00520304	26.30	11/6/2023	None	Ethanol - Cellulosic	Poet Biorefining Hanlontown (4785)	Poet Biorefining Hanlontown (70010)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hanlontown, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005301	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786); Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00530103	72.85	ETH009A00530104	73.25	10/20/2023	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005302	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00530203	65.95	ETH009A00530204	66.39	10/20/2023	None	Ethanol	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005303	Tier 1	3.0	Fuel Producer: Poet Biorefining Jewell (4786) ; Facility Name: Poet Biorefining Jewell (70014); Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00530303	25.98	ETH012A00530304	26.35	10/20/2023	None	Ethanol - Cellulosic	Poet Biorefining Jewell (4786)	Poet Biorefining Jewell (70014)	Midwest Corn, Dry Mill, Wet and Dry DGS using natural gas and electricity; Starch ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Jewell Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005501	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779); Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00550101	77.66	ETH009A00550102	77.57	10/17/2023	None	Ethanol	POET Biorefining - Glenville (4779)	POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005502	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779); Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00550201	69.88	ETH009A00550202	69.86	10/17/2023	None	Ethanol	POET Biorefining - Glenville (4779)	POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005503	Tier 1	3.0	Fuel Producer: POET Biorefining - Glenville (4779); Facility Name: POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020); Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00550301	29.92	ETH012A00550302	30.11	10/17/2023	None	Ethanol - Cellulosic	POET Biorefining - Glenville (4779)	POET BIOREFINING - GLENVILLE (AGRA RESOURC (70020)	Midwest Corn, Dry Mill, Dry, Wet DGS and Corn Oil using natural gas and grid electricity; Starch and Fiber ethanol produced from Corn using BPX process along with Syrup, Corn Oil in Albert Lea MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005601	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00560102	73.89	ETH009A00560103	73.50	10/23/2023	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005602	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00560202	67.49	ETH009A00560203	66.85	10/23/2023	None	Ethanol	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005603	Tier 1	3.0	Fuel Producer: POET Biorefining - Coon Rapids (4783); Facility Name: POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00560302	28.27	ETH012A00560303	27.47	10/23/2023	None	Ethanol - Cellulosic	POET Biorefining - Coon Rapids (4783)	POET BIOREFINING - COON RAPIDS (TALL CORN ETHANOL, LLC) (70031)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Coon Rapids, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005801	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00580102	73.74	ETH009A00580103	78.77	10/23/2023	None	Ethanol	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A005802	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A00580202	68.00	ETH009A00580203	68.77	10/23/2023	None	Ethanol	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	

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A005803	Tier 1	3.0	Fuel Producer: POET Biorefining - Bingham Lake (4780) ; Facility Name: POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California (3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00580302	28.21	ETH012A00580303	29.07	10/23/2023	None	Ethanol - Cellulosic	POET Biorefining - Bingham Lake (4780)	POET BIOREFINING - BINGHAM LAKE (ETHANOL 2000, LLP) (70026)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Bingham Lake, MN using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006001	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00600102	76.01	ETH009A00600103	74.07	10/17/2023	None	Ethanol	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006002	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00600202	66.53	ETH009A00600203	64.20	10/17/2023	None	Ethanol	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006003	Tier 1	3.0	Fuel Producer: Poet Biorefining Emmetsburg (4792); Facility Name: Poet Biorefining Emmetsburg (70021); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00600302	26.40	ETH012A00600303	24.45	10/17/2023	None	Ethanol - Cellulosic	Poet Biorefining Emmetsburg (4792)	Poet Biorefining Emmetsburg (70021)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Emmetsburg, Iowa using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006101	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791); Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00610102	75.21	ETH009A00610103	74.60	10/23/2023	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006102	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791); Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00610202	65.67	ETH009A00610203	64.82	10/23/2023	None	Ethanol	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006103	Tier 1	3.0	Fuel Producer: Poet Biorefining Hudson (4791); Facility Name: Poet Biorefining Hudson (70022); Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00610302	26.04	ETH012A00610303	25.35	10/23/2023	None	Ethanol - Cellulosic	Poet Biorefining Hudson (4791)	Poet Biorefining Hudson (70022)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Hudson, SD, using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006201	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00620101	74.47	ETH009A00620102	73.69	10/17/2023	None	Ethanol	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006202	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789) ; Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A00620201	67.18	ETH009A00620202	65.82	10/17/2023	None	Ethanol	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006203	Tier 1	3.0	Fuel Producer: Poet Biorefining Mitchell (4789); Facility Name: Poet Biorefining Mitchell (70016); Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California (3.0)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A00620301	27.03	ETH012A00620302	25.91	10/17/2023	None	Ethanol - Cellulosic	Poet Biorefining Mitchell (4789)	Poet Biorefining Mitchell (70016)	Midwest Corn, Dry Mill, Dry and Wet DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Mitchell, SD using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006401	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784); Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00640102	72.37	ETH009A00640103	72.70	11/7/2023	None	Ethanol	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A006402	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784); Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A00640202	64.75	ETH009A00640203	64.56	11/7/2023	None	Ethanol	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	

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A006403	Tier 1	3.0	Fuel Producer: POET Biorefining - Gowrie (4784); Facility Name: POET Biorefining - Gowrie (70033); Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A00640302	24.60	ETH012A00640303	24.25	11/7/2023	None	Ethanol - Cellulosic	POET Biorefining - Gowrie (4784)	POET Biorefining - Gowrie (70033)	Midwest Corn, Dry Mill, Dry DGS, Wet DGS, Modified DGS, Syrup, and Corn Oil using natural gas and grid electricity; Corn starch and Fiber ethanol produced in Gowrie, IA using BPX conversion method; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A008301	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Soybean Oil (005)	Biodiesel (BIO)	BIO005A00830100	53.68	BIO005A00830102	54.50	12/4/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Soybean Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	2022 AFPR Recert Complete	
A008302	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Canola Oil (006)	Biodiesel (BIO)	BIO006A00830200	48.49	BIO006A00830201	49.00	12/4/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Canola Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	2022 AFPR Recert Complete	
A008304	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A00830401	18.00	BIO001A00830402	18.00	12/6/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	2022 AFPR Recert Complete	
A008305	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A00830501	13.00	BIO001A00830502	13.00	12/6/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Non-Rendered Used Cooking Oil; Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	2022 AFPR Recert Complete	
A008306	Tier 1	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California (3.0)	Minnesota	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A00830601	29.25	BIO002A00830602	29.25	12/6/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	U.S. sourced Tallow (Animal Fats); Natural Gas, Steam, and Grid Electricity; Biodiesel produced in Glenville, Minnesota and transported by rail to California	2022 AFPR Recert Complete	
A008601	Tier 1	3.0	Fuel Producer: Bridgeport Ethanol, LLC 5934; Facility Name: Bridgeport Ethanol, LLC 70217; Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A00860101	63.00	ETH009A00860102	63.66	11/7/2023	None	Ethanol	Bridgeport Ethanol, LLC 5934	Bridgeport Ethanol, LLC 70217	Midwest Corn, Dry Mill, Wet DGS and Corn Oil using natural gas and grid electricity; Corn starch ethanol produced in Bridgeport, Nebraska; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A008801	Tier 1	3.0	Fuel Producer: Yuma Ethanol, LLC (4735); Facility Name: Yuma Ethanol, LLC (70024); Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California (3.0)	Colorado	Corn (009)	Ethanol (ETH)	ETH009A00880101	64.00	ETH009A00880102	63.52	11/7/2023	None	Ethanol	Yuma Ethanol, LLC (4735)	Yuma Ethanol, LLC (70024)	Midwest Corn, Dry Mill, Wet DGS; Corn Oil and Syrup using natural Gas and grid electricity; Corn starch Ethanol produced in Yuma, Colorado; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A010001	Tier 1	3.0	Fuel Producer: The Andersons Marathon Holdings LLC (1143); Facility Name: DENISON ETHANOL PLANT (70884); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01000100	71.62	ETH009A01000101	72.26	11/7/2023	None	Ethanol	The Andersons Marathon Holdings LLC (1143)	DENISON ETHANOL PLANT (70884)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	2022 AFPR Recert Complete	
A010002	Tier 1	3.0	Fuel Producer: The Andersons Marathon Holdings LLC (1143); Facility Name: DENISON ETHANOL PLANT (70884); Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A01000201	67.11	ETH009A01000202	67.12	11/7/2023	None	Ethanol	The Andersons Marathon Holdings LLC (1143)	DENISON ETHANOL PLANT (70884)	Midwest Corn, Dry Mill, Dry and Modified DGS; Corn Oil and Syrup using natural gas and grid electricity; Corn starch Ethanol is produced in Denison, Iowa; Ethanol is transported by rail to California	2022 AFPR Recert Complete	
A009501	Tier 1	3.0	Fuel Producer: CEFARI RNG OKC, LLC (2220); Facility Name: CEFARI RNG OKC, LLC (70101); Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California (3.0)	Oklahoma	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A00950101	49.80	CNG025A00950102	52.00	11/14/2023	None	Bio-CNG	CEFARI RNG OKC, LLC (2220)	CEFARI RNG OKC, LLC (70101)	Landfill gas processes at CEFARI facility from Southwest Oklahoma City, Oklahoma to pipeline-quality biomethane; delivered via pipeline to CNG Stations in California	2022 AFPR Recert Complete	
A010501	Tier 1	3.0	Fuel Producer: Dansuk Industrial Co., Ltd (5953); Facility Name: Pyeongtaek 2 (80202); South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker (3.0)	South Korea	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A01050101	25.00	BIO001A01050102	25.28	11/6/2023	None	Biodiesel	Dansuk Industrial Co., Ltd (5953)	Pyeongtaek 2 (80202)	South Korea and Asian sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pyeongtaek, South Korea; Biodiesel transported by rail to California by ocean tanker	2022 AFPR Recert Complete	

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A011001	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Ameresco Woodland Meadows Romulus, LLC (A0833); Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California (3.0)	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01100101	48.21	CNG025A01100102	46.33	11/6/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	Ameresco Woodland Meadows Romulus, LLC (A0833)	Woodland Meadows landfill gas from Wayne, Michigan to pipeline-quality biomethane; delivered via pipeline to CNG stations in California; liquefied to LNG in Topock, Arizona; and transported by truck and re-gassified to L-CNG in California	2022 AFPR Recert Complete	
A011501	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ameresco San Antonio Biogas (71204); Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (3.0)	Texas	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A01150101	36.77	CNG030A01150102	36.73	11/3/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Ameresco San Antonio Biogas (71204)	Biomethane generated at the SAWS Dos Rios Water Recycling Center; upgraded to pipeline-quality biomethane in San Antonio, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	2022 AFPR Recert Complete	
B001901	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Open Sky (F00007); Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00190100	-352.89	ELC026B00190101	-364.41	11/13/2023	None	Electricity	CleanFuture, Inc. (C1001)	Open Sky (F00007)	Low-CI Electricity sourced from Dairy Manure Biogas using reciprocating engine in Open Sky Ranch, Riverdale, California; Electricity use as transportation fuel in California	2022 AFPR Recert Complete	
A012701	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A01270103	28.29	ETH012A01270104	27.92	11/7/2023	None	Ethanol - Cellulosic	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012702	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01270203	77.34	ETH009A01270204	77.70	11/7/2023	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012703	Tier 1	3.0	Fuel Producer: POET Biorefining - Preston (4790); Facility Name: POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01270303	68.22	ETH009A01270304	67.61	11/7/2023	None	Ethanol	POET Biorefining - Preston (4790)	POET BIOREFINING - PRESTON (PRO-CORN LLC) (70056)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Preston, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012801	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01280102	75.31	ETH009A01280103	75.28	10/17/2023	None	Ethanol	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012802	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A01280202	68.32	ETH009A01280203	67.59	10/17/2023	None	Ethanol	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012803	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794); Facility Name: POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California (3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A01280302	28.66	ETH012A01280303	28.18	10/17/2023	None	Ethanol - Cellulosic	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (4794)	POET BIOREFINING - LAKE CRYSTAL (NORTHSTAR ETHANOL, LLC) (70072)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Lake Crystal, MN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012901	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01290101	73.48	ETH009A01290102	73.58	11/7/2023	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012902	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01290201	66.73	ETH009A01290202	67.04	11/7/2023	None	Ethanol	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A012903	Tier 1	3.0	Fuel Producer: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728); Facility Name: POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A01290301	27.01	ETH012A01290302	27.13	11/7/2023	None	Ethanol - Cellulosic	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (5728)	POET BIOREFINING - LEIPSIC (SUMMIT ETHANOL, LLC) (70265)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Leipsic, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A013001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01300101	72.10	ETH009A01300102	72.00	11/7/2023	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A013002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01300201	65.09	ETH009A01300202	64.54	11/7/2023	None	Ethanol	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A013003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513); Facility Name: POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California (3.0)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01300301	25.09	ETH012A01300302	24.63	11/7/2023	None	Ethanol - Cellulosic	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (7513)	POET BIOREFINING - N MANCHESTER (N MANCHESTER ETHANOL, LLC) (70322)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Starch Ethanol produced in North Manchester, Indiana; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A013102	Tier 1	3.0	Fuel Producer: REG Mason City, LLC (6130); Facility Name: REG Mason City, LLC (82968); U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California (3.0)	Iowa	Canola Oil (006)	Biodiesel (BIO)	BIO006A01310202	50.11	BIO006A01310203	50.75	10/30/2023	None	Biodiesel	REG Mason City, LLC (6130)	REG Mason City, LLC (82968)	U.S. sourced Canola Oil transported by truck; Natural and Grid Electricity; Biodiesel produced in Mason City, Iowa and transported by rail to California	2022 AFPR Recert Complete	
A013501	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (3.0)	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A01350102	31.65	BIO002A01350103	31.65	12/11/2023	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Biodiesel produced from U.S-sourced Animal Fat; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	2022 AFPR Recert Complete	
A013502	Tier 1	3.0	Fuel Producer: High Plains Bioenergy (4846) ; Facility Name: High Plains Bioenergy (82883); Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (3.0)	Oklahoma	Soybean Oil (005)	Biodiesel (BIO)	BIO005A01350200	55.82	BIO005A01350201	55.82	12/11/2023	None	Biodiesel	High Plains Bioenergy (4846)	High Plains Bioenergy (82883)	Biodiesel produced from Midwest Soybean Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	2022 AFPR Recert Complete	
A013503	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California (3.0)	Oklahoma	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A01350300	20.68	BIO001A01350301	20.68	12/11/2023	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Biodiesel produced from U.S-sourced Used Cooking Oil; Natural Gas, Electricity; Biodiesel produced in Guymon, Oklahoma, transported by rail to California	2022 AFPR Recert Complete	
A013901	Tier 1	3.0	Fuel Producer: Midwest Renewable Energy (5214); Facility Name: Midwest Renewable Energy (70160); Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A01390102	65.76	ETH009A01390103	65.20	12/21/2023	None	Ethanol	Midwest Renewable Energy (5214)	Midwest Renewable Energy (70160)	Midwest Corn, Dry Mill, Wet DGS, Corn Oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Sutherland, Nebraska; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A014101	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California (3.0)	Missouri	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003A01410102	27.16	BIO003A01410103	27.78	10/31/2023	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441)	Midwest Corn Oil; Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	2022 AFPR Recert Complete	
A014102	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441); Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California (3.0)	Missouri	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A01410202	32.08	BIO002A01410203	31.88	10/31/2023	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Missouri, LLC (formerly known as HPB - St. Joe Biodiesel LLC) (80441)	Rendered Tallow (animal and poultry fat); Biodiesel produced in St. Joe, Missouri; Biodiesel transported by rail to California	2022 AFPR Recert Complete	
A014601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (3.0)	Michigan	Corn (009)	Ethanol (ETH)	ETH009A01460101	72.29	ETH009A01460102	72.48	10/23/2023	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	2022 AFPR Recert Complete	
A014602	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California (3.0)	Michigan	Corn (009)	Ethanol (ETH)	ETH009A01460201	66.61	ETH009A01460202	66.75	10/23/2023	None	Ethanol	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Caro, Michigan and transported by rail to California	2022 AFPR Recert Complete	

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A014603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781); Facility Name: POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California (3.0)	Michigan	Corn Fiber (012)	Ethanol (ETH)	ETH012A01460301	27.03	ETH012A01460302	27.27	10/23/2023	None	Ethanol - Cellulosic	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (4781)	POET BIOREFINING - CARO (MICHIGAN ETHANOL, LLC) (70028)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Caro, Michigan and transported by rail to California	2022 AFPR Recert Complete	
A015001	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01500101	74.03	ETH009A01500102	73.74	11/13/2023	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015002	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01500201	67.28	ETH009A01500202	66.96	11/13/2023	None	Ethanol	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Biogas, and Grid Electricity; Starch Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015003	Tier 1	3.0	Fuel Producer: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819); Facility Name: POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California (3.0)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01500301	27.19	ETH012A01500302	26.95	11/13/2023	None	Ethanol - Cellulosic	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (5819)	POET BIOREFINING - ALEXANDRIA (ULTIMATE ETHANOL, LLC) (70298)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Biogas, and Grid Electricity; Fiber Ethanol produced in Alexandria, IN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015101	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01510101	73.56	ETH009A01510102	73.60	10/23/2023	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN then transported by rail to California	2022 AFPR Recert Complete	
A015103	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California (3.0)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A01510301	26.17	ETH012A01510302	26.30	10/23/2023	None	Ethanol - Cellulosic	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Portland, IN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01520101	72.75	ETH009A01520102	72.34	11/13/2023	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A01520201	65.82	ETH009A01520202	65.13	11/13/2023	None	Ethanol	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518); Facility Name: POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California (3.0)	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A01520301	25.89	ETH012A01520302	26.01	11/13/2023	None	Ethanol - Cellulosic	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (7518)	POET BIOREFINING - FOSTORIA (FOSTORIA ETHANOL, LLC) (70323)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas and Grid Electricity; Fiber Ethanol produced in Fostoria, OH; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015401	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California (3.0)	Kentucky	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01540102	54.69	CNG025A01540103	55.00	12/11/2023	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline; Compression to CNG stations in California	2022 AFPR Recert Complete	
A015402	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations (3.0)	Kentucky	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A01540202	72.09	LNG025A01540203	73.15	12/11/2023	None	Bio-LNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California LNG stations	2022 AFPR Recert Complete	
A015403	Tier 1	3.0	Fuel Producer: WM Renewable Energy, LLC (W978); Facility Name: Outer Loop High Btu Gas Plant (71316); Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG (3.0)	Kentucky	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A01540302	75.18	LCN025A01540303	76.24	12/11/2023	None	Bio-CNG	WM Renewable Energy, LLC (W978)	Outer Loop High Btu Gas Plant (71316)	Louisville Landfill gas (KY) to pipeline-quality biomethane; Delivered via pipeline to liquefaction facility in Topock AZ; Transported by truck to California; Re-gasified and compressed to L-CNG	2022 AFPR Recert Complete	

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A015102	Tier 1	3.0	Fuel Producer: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064); Facility Name: POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A01510201	66.14	ETH009A01510202	66.24	10/23/2023	None	Ethanol	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (4064)	POET BIOREFINING - PORTLAND (PREMIER ETHANOL, LLC) (70108)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Portland, IN; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A015601	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel (3.0)	Arizona	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A01560100	26.58	CNG030A01560101	25.35	10/27/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; Delivered via pipeline to California; Dispensed as CNG fuel	2022 AFPR Recert Complete	
A016901	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California. (3.0)	Arizona	Wastewater Sludge (030)	Liquefied Natural Gas (LNG)	LNG030A01690100	41.58	LNG030A01690101	42.61	11/20/2023	None	Bio-LNG	Anew RNG, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to LNG stations in California.	2022 AFPR Recert Complete	
A016902	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Ninety-First Avenue Renewable Biogas LLC (70241); Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as (3.0)	Arizona	Wastewater Sludge (030)	Liquefied Compressed Natural Gas (LCN)	LCN030A01690200	44.67	LCN030A01690201	45.70	11/20/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Ninety-First Avenue Renewable Biogas LLC (70241)	Digester Gas generated at the 91st Ave WWTP; upgraded to pipeline-quality biomethane in Tolleson, Arizona; delivered via pipeline to liquefaction facility in Topock, Arizona; liquefied, and transported by truck to California; re-gasified and dispensed as	2022 AFPR Recert Complete	
A017101	Tier 1	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Fair Oaks Upgrader, LLC (71001); Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California (3.0)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026A01710100	-329.76	CNG026A01710101	-185.00	10/25/2023	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Fair Oaks Upgrader, LLC (71001)	Renewable Natural Gas (RNG) from Dairy and Swine Manure at the Site 3 digester, upgraded to RNG at Renewable Dairy Fuels (RDF) in Fair Oaks, Indiana; RNG pipelined to Bakersfield, California	2022 AFPR Recert Complete	
A017401	Tier 1	3.0	Fuel Producer: Nebraska Corn Processing (3516); Facility Name: Nebraska Corn Processing LLC (70230); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A01740100	65.77	ETH009A01740101	65.55	10/17/2023	None	Ethanol	Nebraska Corn Processing (3516)	Nebraska Corn Processing LLC (70230)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Grid Electricity; Starch Ethanol produced in Cambridge, Nebraska; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A019501	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060); Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel (3.0)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A01950101	44.78	CNG025A01950102	46.75	11/6/2023	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	GSF Energy, LLC – McCarty Road LFG Recovery Facility (F00060)	Landfill Gas generated at the McCarty Road Landfill; upgraded to pipeline-quality biomethane in Houston, Texas; Delivered via pipeline to California; Dispensed as CNG fuel	2022 AFPR Recert Complete	
B005901	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: ABEC Bidart-Old River LLC (F00113); Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California. (3.0)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00590102	-568.21	ELC026B00590103	-613.23	11/14/2023	None	Electricity	California Bioenergy LLC (B194)	ABEC Bidart-Old River LLC (F00113)	Low-CI electricity from dairy manure biogas using reciprocating engine at ABEC Bidart-Old River in Bakersfield, California for use as transportation fuel in California.	2022 AFPR Recert Complete	
A020001	Tier 1	3.0	Fuel Producer: GHI Energy, LLC (6156); Facility Name: Waste Management American Landfill (70421); Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel. (3.0)	Ohio	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02000101	37.64	CNG025A02000102	37.59	11/6/2023	None	Bio-CNG	GHI Energy, LLC (6156)	Waste Management American Landfill (70421)	Biomethane from WM American Landfill in Waynesburg, Ohio; Upgrading at the co-located upgrading facility; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel.	2022 AFPR Recert Complete	
A020101	Tier 1	3.0	Fuel Producer: Thumb BioEnergy (3862); Facility Name: Thumb BioEnergy (03862); Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail (3.0)	Michigan	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02010100	15.80	BIO001A02010101	15.14	10/31/2023	None	Biodiesel	Thumb BioEnergy (3862)	Thumb BioEnergy (03862)	Used Cooking Oil (zero rendering energy) transported by truck to Biodiesel plant in Sandusky, MI; Natural Gas and Eletricity; Biodiesel transported to California By Rail	2022 AFPR Recert Complete	
A020701	Tier 1	3.0	Fuel Producer: MEM RNG, LLC (2141); Facility Name: Blue Ridge Landfill, LLC (F00132); Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel (3.0)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02070100	38.07	CNG025A02070101	36.38	11/17/2023	None	Bio-CNG	MEM RNG, LLC (2141)	Blue Ridge Landfill, LLC (F00132)	Biomethane from Blue Ridge Landfill in Fresno, Texas; Pipelined to California for compression to CNG; Delivered and dispensed as CNG in California for the use in transportation fuel	2022 AFPR Recert Complete	
A021201	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California (3.0)	Missouri	Corn (009)	Ethanol (ETH)	ETH009A02120102	75.47	ETH009A02120103	74.18	10/24/2023	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO; Ethanol transported by rail to California	2022 AFPR Recert Complete	

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A021202	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California (3.0)	Missouri	Corn (009)	Ethanol (ETH)	ETH009A02120201	64.95	ETH009A02120202	64.00	10/24/2023	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Macon, MO ; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A021203	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788); Facility Name: POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017); Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California (3.0)	Missouri	Corn Fiber (012)	Ethanol (ETH)	ETH012A02120301	25.32	ETH012A02120302	24.65	10/24/2023	None	Ethanol	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (4788)	POET BIOREFINING - MACON (NORTHEAST MISSOURI GRAIN, LLC) (70017)	Midwest Corn, Dry Mill; Fiber ethanol produced using BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Macon, MO; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A021301	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02130101	61.55	ETH009A02130102	61.85	11/13/2023	None	Ethanol	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Dry DGS, Modified, and Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity, Biomethane, and Biomass; Starch Ethanol produced in Chancellor, SD; Ethanol transported by rail to California, Composite CI	2022 AFPR Recert Complete	
A021302	Tier 1	3.0	Fuel Producer: POET Biorefining - Chancellor, LLC (4727); Facility Name: POET Biorefining - Chancellor, LLC (70012); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California (3.0)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A02130203	21.93	ETH012A02130204	22.00	11/13/2023	None	Ethanol - Cellulosic	POET Biorefining - Chancellor, LLC (4727)	POET Biorefining - Chancellor, LLC (70012)	Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity, Biomethane, Biomass; Fiber Ethanol produced in Chancellor, South Dakota; Ethanol transported by rail to California	2022 AFPR Recert Complete	
B008002	Tier 2	3.0	Fuel Producer: Bridge To Renewables, Benefit LLC (C1006); Facility Name: Blake's Landing Farms (F00019); Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI (3.0)	California	Other Organic Waste (029)	Electricity (ELC)	ELC029B00800201	-221.76	ELC029B00800202	-346.47	12/11/2023	None	Electricity	Bridge To Renewables, Benefit LLC (C1006)	Blake's Landing Farms (F00019)	Low-CI electricity from dairy manure and creamery wastewater biogas using reciprocating engine at Blake's Landing Farm in Marshall, California and for use as transportation fuel in California; Composite CI	2022 AFPR Recert Complete	
A022401	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02240102	73.00	ETH009A02240103	73.85	12/12/2023	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A022402	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02240202	68.00	ETH009A02240203	67.75	12/12/2023	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A022403	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02240301	64.13	ETH009A02240302	66.00	12/12/2023	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A022404	Tier 1	3.0	Fuel Producer: LSCP, LLC (4728); Facility Name: LSCP, LLC (70015); Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A02240402	26.00	ETH012A02240403	26.00	12/12/2023	None	Ethanol	LSCP, LLC (4728)	LSCP, LLC (70015)	Midwest Corn, Dry Mill; Fiber ethanol from Edniq Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
B009801	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980101	-401.33	CNG026B00980102	-419.92	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Circle A digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California	2022 AFPR Recert Complete	
B009802	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980201	-402.07	CNG026B00980202	-418.16	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Robert Vander Eyk & Sons Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California	2022 AFPR Recert Complete	
B009803	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980300	-192.49	CNG026B00980301	-420.09	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Renewable Natural Gas (RNG) produced from Dairy Manure of Legacy Ranch digester, upgraded at Calgren Biofuels LLC in Pixley, California; RNG pipelined to Fresno and West Sacramento, California for use as transportation fuel in California	2022 AFPR Recert Complete	

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B009804	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980400	-323.10	CNG026B00980401	-419.74	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure of Cornerstone Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California	2022 AFPR Recert Complete	
B009805	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980501	-304.08	CNG026B00980502	-419.77	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California	2022 AFPR Recert Complete	
B009806	Tier 2	3.0	Fuel Producer: Calgren Dairy Fuels, LLC (C1007); Facility Name: Calgren Dairy Fuels, LLC (F00029); Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B00980601	-279.38	CNG026B00980602	-227.28	10/25/2023	None	Bio-CNG	Calgren Dairy Fuels, LLC (C1007)	Calgren Dairy Fuels, LLC (F00029)	Biomethane produced from Dairy Manure at J&J Vanderpoel Dairy digester, upgraded at Calgren Biofuels LLC in Pixley, California; pipelined to Fresno and West Sacramento, California, compressed to CNG for use as transportation fuel in California	2022 AFPR Recert Complete	
A023301	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG (3.0)	Kansas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02330102	47.10	CNG025A02330103	45.13	11/17/2023	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill in Lawrence, KS; upgrading at Renewable Power Producers, LLC; pipelined to California for compression to CNG	2022 AFPR Recert Complete	
B002401	Tier 2	3.0	Fuel Producer: CleanFuture, Inc. (C1001); Facility Name: Coronado Dairy Farm (F00009); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California (3.0)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B00240100	-525.14	ELC026B00240101	-760.21	11/13/2023	None	Electricity	CleanFuture, Inc. (C1001)	Coronado Dairy Farm (F00009)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Coronado Dairy in Tipton, California for use as transportation fuel in California	2022 AFPR Recert Complete	
A024501	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02450103	73.16	ETH009A02450104	73.27	10/18/2023	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A024502	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A02450203	64.79	ETH009A02450204	65.00	10/18/2023	None	Ethanol	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A024503	Tier 1	3.0	Fuel Producer: POET Biorefining - Ashton (4782); Facility Name: POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California (3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A02450303	24.71	ETH012A02450304	25.42	10/18/2023	None	Ethanol - Cellulosic	POET Biorefining - Ashton (4782)	POET BIOREFINING - ASHTON (OTTER CREEK ETHANOL, LLC) (70032)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ashton, Iowa; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A024201	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG (3.0)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02420102	57.00	CNG025A02420104	60.50	11/28/2023	None	Bio-CNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A024202	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations (3.0)	Tennessee	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02420201	63.35	LNG025A02420203	76.47	11/28/2023	None	Bio-LNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A024203	Tier 1	3.0	Fuel Producer: CERF SHELBY LLC (6228); Facility Name: CERF SHELBY LLC (71163); Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0)	Tennessee	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02420301	66.44	LCN025A02420303	79.55	11/28/2023	None	Bio-CNG	CERF SHELBY LLC (6228)	CERF SHELBY LLC (71163)	Biomethane from Landfill at Millington, Tennessee upgrading at CERF Shelby LLC, pipelined to Clean Energy Boron for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
A024601	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A02460101	76.22	ETH009A02460102	73.94	10/24/2023	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	

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A024602	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn (009)	Ethanol (ETH)	ETH009A02460201	68.53	ETH009A02460202	66.40	10/24/2023	None	Ethanol	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A024603	Tier 1	3.0	Fuel Producer: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525); Facility Name: POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327); Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California (3.0)	Ohio	Corn Fiber (012)	Ethanol (ETH)	ETH012A02460302	28.47	ETH012A02460303	26.48	10/24/2023	None	Ethanol - Cellulosic	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (7525)	POET BIOREFINING - MARION (MARION ETHANOL, LLC) (70327)	Midwest Corn, Dry Mill; Fiber ethanol from BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, Ohio; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A024701	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896); Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG (3.0)	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02470102	48.20	CNG025A02470104	50.00	11/28/2023	None	Bio-CNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill at 5011 Lilley Rd. Canton, MI 48188 upgrading at Canton Renewables, LLC, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A024702	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896); Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations (3.0)	Michigan	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02470200	62.68	LNG025A02470201	58.89	11/28/2023	None	Bio-LNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A024703	Tier 1	3.0	Fuel Producer: CANTON RENEWABLES, LLC (5896); Facility Name: CANTON RENEWABLES, LLC (71041); Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0)	Michigan	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02470300	65.77	LCN025A02470301	61.98	11/28/2023	None	Bio-CNG	CANTON RENEWABLES, LLC (5896)	CANTON RENEWABLES, LLC (71041)	Biomethane from Landfill in Canton, Michigan, upgrading at Canton Renewables, pipelined to Clean Energy Boron California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
A024901	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02490102	76.29	ETH009A02490103	76.56	10/24/2023	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Dry DGS DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	2022 AFPR Recert Complete	
A024902	Tier 1	3.0	Fuel Producer: Glacial Lakes Corn Processors (4764); Facility Name: Huron Energy, LLC (70722); Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A02490201	68.82	ETH009A02490202	68.67	10/24/2023	None	Ethanol	Glacial Lakes Corn Processors (4764)	Huron Energy, LLC (70722)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Huron, SD; Ethanol transported by rail to California, Composite CI	2022 AFPR Recert Complete	
A025901	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0)	Tennessee	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003A02590102	37.49	BIO003A02590103	36.92	11/1/2023	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (83730)	U.S sourced Corn Oil from DGS; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California	2022 AFPR Recert Complete	
A025902	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0)	Tennessee	Soybean Oil (005)	Biodiesel (BIO)	BIO005A02590202	66.85	BIO005A02590203	67.83	11/1/2023	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (83730)	U.S sourced Soybean Oil; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California	2022 AFPR Recert Complete	
A025903	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0)	Tennessee	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A02590302	42.58	BIO002A02590303	41.61	11/1/2023	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (83730)	U.S sourced Rendered Tallow; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California	2022 AFPR Recert Complete	
A025904	Tier 1	3.0	Fuel Producer: Bioenergy Development Group LLC (3785); Facility Name: Bioenergy Development Group, LLC (83730); U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California (3.0)	Tennessee	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02590400	31.60	BIO001A02590401	29.54	11/1/2023	None	Biodiesel	Bioenergy Development Group LLC (3785)	Bioenergy Development Group, LLC (83730)	U.S sourced Rendered UCO; Natural Gas and Grid Electricity; Biodiesel produced in Memphis, Tennessee and transported by rail to California	2022 AFPR Recert Complete	
A027401	Tier 1	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Renovar Arlington, LTD RNG Project (70501); Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California (3.0)	Texas	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A02740102	41.71	CNG030A02740103	41.23	10/27/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	Renovar Arlington, LTD RNG Project (70501)	Digester Gas generated at the Village Creek Water Reclamation Facility, Euless, Texas; upgraded to pipeline-quality biomethane in Texas; delivered via pipeline to CNG stations in California	2022 AFPR Recert Complete	

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A027901	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (3.0)	Arkansas	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003A02790101	33.53	BIO003A02790102	34.29	11/2/2023	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	Midwest Corn Oil transported by truck and rail to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California	2022 AFPR Recert Complete	
A027902	Tier 1	3.0	Fuel Producer: FutureFuel Chemical Company (4664); Facility Name: FutureFuel Chemical Company (82612); US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California (3.0)	Arkansas	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02790202	26.13	BIO001A02790203	26.62	11/2/2023	None	Biodiesel	FutureFuel Chemical Company (4664)	FutureFuel Chemical Company (82612)	US-sourced Used Cooking Oil transported by truck to biodiesel plant in Batesville, Arkansas; Biodiesel transported by rail to California	2022 AFPR Recert Complete	
A028201	Tier 1	3.0	Fuel Producer: Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846); Facility Name: Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883); Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail (3.0)	Oklahoma	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A02820102	24.60	BIO002A02820103	24.60	12/11/2023	None	Biodiesel	Seaboard Energy, LLC (formerly known as High Plains Bioenergy) (4846)	Seaboard Energy Oklahoma, LLC (formerly known as High Plains Bioenergy) (82883)	Rendered Animal Fat Oil transported by truck to biodiesel plant in Guymon, Oklahoma; biodiesel is then transferred to California By Rail	2022 AFPR Recert Complete	
A028905	Tier 1	3.0	Fuel Producer: REG Danville, LLC (3723); Facility Name: REG Danville, LLC (80216); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail. (3.0)	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02890500	21.50	BIO001A02890501	21.60	10/31/2023	None	Biodiesel	REG Danville, LLC (3723)	REG Danville, LLC (80216)	U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Danville, Illinois; Natural Gas, Electricity; Biodiesel then transported to California By Rail.	2022 AFPR Recert Complete	
A029002	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail. (3.0)	Illinois	Soybean Oil (005)	Biodiesel (BIO)	BIO005A02900201	58.00	BIO005A02900202	57.50	12/4/2023	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	Soybean Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail.	2022 AFPR Recert Complete	
A029004	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. (3.0)	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02900400	20.75	BIO001A02900401	21.25	11/8/2023	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil transported by truck and rail to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	2022 AFPR Recert Complete	
A029005	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail (3.0)	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02900500	16.25	BIO001A02900501	16.50	11/8/2023	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil, zero rendering energy, transported by truck and rial to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; then to California by rail	2022 AFPR Recert Complete	
A029006	Tier 1	3.0	Fuel Producer: REG Seneca, LLC (3652); Facility Name: REG Seneca, LLC (80232); U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail. (3.0)	Illinois	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02900601	22.00	BIO001A02900602	23.50	12/4/2023	None	Biodiesel	REG Seneca, LLC (3652)	REG Seneca, LLC (80232)	U.S sourced Used Cooking Oil, transported locally by truck to Biodiesel plant in Seneca, Illinois; Natural Gas and Electricity; biodiesel fuel then transported to California by rail.	2022 AFPR Recert Complete	
B013302	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Distillers' Corn Oil (003)	Renewable Diesel (RND)	RND003B01330200	32.50	RND003B01330202	32.50	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B013303	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RND001B01330300	25.50	RND001B01330302	25.50	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B013304	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RND001B01330400	20.00	RND001B01330402	20.00	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B013305	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Diesel (RND)	RND001B01330500	26.00	RND001B01330502	26.00	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	

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B013307	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B01330700	37.00	RND002B01330702	37.00	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B013308	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B01330800	38.00	RND002B01330802	38.00	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B013309	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B01330900	43.00	RND002B01330902	43.00	11/20/2023	None	Renewable Diesel	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable diesel produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable diesel produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
A029501	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. (3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02950101	22.03	BIO001A02950102	22.52	11/2/2023	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Rendered Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	2022 AFPR Recert Complete	
A029502	Tier 1	3.0	Fuel Producer: Imperial Western Products (9871); Facility Name: Imperial Western Products (81066); Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations. (3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A02950201	16.71	BIO001A02950202	16.80	11/2/2023	None	Biodiesel	Imperial Western Products (9871)	Imperial Western Products (81066)	Raw Used Cooking Oil sourced from surrounding states, transported by truck to Biodiesel plant in Coachella, California for on-site rendering; Natural Gas and Grid Electricity; Biodiesel transported by trucks to California refueling stations.	2022 AFPR Recert Complete	
A029701	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (3.0)	Kansas	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02970102	60.50	LNG025A02970103	52.93	11/16/2023	None	Bio-LNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A029702	Tier 1	3.0	Fuel Producer: RENEWABLE POWER PRODUCERS, LLC (6504); Facility Name: RENEWABLE POWER PRODUCERS, LLC (71289); Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0)	Kansas	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02970201	63.59	LCN025A02970202	56.01	11/16/2023	None	Bio-CNG	RENEWABLE POWER PRODUCERS, LLC (6504)	RENEWABLE POWER PRODUCERS, LLC (71289)	Biomethane from Landfill at Lawrence, Kansas, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
A029801	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG (3.0)	Washington	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02980101	28.80	CNG025A02980102	29.30	11/28/2023	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A029802	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations (3.0)	Washington	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A02980201	42.58	LNG025A02980202	38.46	11/28/2023	None	Bio-LNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A029803	Tier 1	3.0	Fuel Producer: PUGET SOUND ENERGY (6055); Facility Name: CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109); Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0)	Washington	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A02980301	45.67	LCN025A02980302	41.55	11/28/2023	None	Bio-CNG	PUGET SOUND ENERGY (6055)	CEDAR HILLS LANDFILL RECOVERY GAS PROJECT (71109)	Biomethane from Cedar Hills Landfill at Maple Valley, Washington upgrading at Puget Sound Energy, pipelined to Clean Energy Boron, California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
A027601	Tier 1	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Meadow Branch Landfill Gas Processing Facility (71252); Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel (3.0)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02760100	47.41	CNG025A02760101	45.83	11/6/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Meadow Branch Landfill Gas Processing Facility (71252)	Biomethane from landfill gas generated in Athens, Tennessee; upgraded at Meadow Branch Landfill Gas Processing Facility, pipelined to California, and dispensed as CNG fuel	2022 AFPR Recert Complete	
A030601	Tier 1	3.0	Fuel Producer: MONROEVILLE LFG, LLC (6317); Facility Name: MONROEVILLE LFG, LLC (71136); Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG (3.0)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03060101	42.85	CNG025A03060102	43.27	11/17/2023	None	Bio-CNG	MONROEVILLE LFG, LLC (6317)	MONROEVILLE LFG, LLC (71136)	Biomethane from Monroeville Landfill in Monroeville, PA, upgrading at Monroeville LFG, LLC, pipelined to California for compression to CNG	2022 AFPR Recert Complete	

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A029101	Tier 1	3.0	Fuel Producer: Morrow Renewables, LLC (C1224); Facility Name: Pine Hill Renewables, LLC (71288); Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG (3.0)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A02910100	34.17	CNG025A02910101	35.12	11/14/2023	None	Bio-CNG	Morrow Renewables, LLC (C1224)	Pine Hill Renewables, LLC (71288)	Biomethane from Pine Hill Landfill at Kilgore, Texas , upgrading at Pine Hill Renewables, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A030201	Tier 1	3.0	Fuel Producer: Morrow Renewables, LLC (C1224); Facility Name: Melissa Renewables, LLC (71407); Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG (3.0)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03020100	34.00	CNG025A03020101	34.04	11/14/2023	None	Bio-CNG	Morrow Renewables, LLC (C1224)	Melissa Renewables, LLC (71407)	Biomethane from Melissa Landfill at Melissa, Texas, upgrading at Melissa Renewables, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A030401	Tier 1	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: Point Loma Digester Gas Project (F00027); Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California. (3.0)	California	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A03040102	38.91	CNG030A03040103	48.72	10/27/2023	None	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	Point Loma Digester Gas Project (F00027)	Point Loma WWTP digester gas, upgraded to pipeline quality utilizing mainly only onsite produced power from biogas powered engines, injected into the pipeline and dispensed in California.	2022 AFPR Recert Complete	
B014301	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Valley View Farm (70021S); Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations (3.0)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B01430101	-432.11	CNG044B01430102	-429.14	11/3/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Valley View Farm (70021S)	Renewable Natural Gas (RNG) from Swine Manure of Valley View Farms, Greencastle, Missouri; transported by truck to pipeline injection point; delivered via pipeline to Los Angeles, California and central California locations	2022 AFPR Recert Complete	
A030901	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A03090101	24.84	ETH012A03090102	24.86	10/18/2023	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Fiber Ethanol Production Using Soliton Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A030902	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A03090201	72.02	ETH009A03090202	71.85	10/18/2023	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A030903	Tier 1	3.0	Fuel Producer: Highwater Ethanol, LLC (3303); Facility Name: Highwater Ethanol, LLC (70235); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A03090300	68.76	ETH009A03090301	68.28	10/18/2023	None	Ethanol	Highwater Ethanol, LLC (3303)	Highwater Ethanol, LLC (70235)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A031001	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG (3.0)	Louisiana	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03100100	41.18	CNG025A03100101	41.37	11/28/2023	None	Bio-CNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, upgrading at River Birch, LLC, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A031002	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations (3.0)	Louisiana	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A03100201	55.55	LNG025A03100202	50.02	11/28/2023	None	Bio-LNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A031003	Tier 1	3.0	Fuel Producer: River Birch, LLC (C1065); Facility Name: River Birch Landfill (F00278); Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (3.0)	Louisiana	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A03100301	58.64	LCN025A03100302	53.11	11/28/2023	None	Bio-CNG	River Birch, LLC (C1065)	River Birch Landfill (F00278)	Biomethane from River Birch Landfill in Avondale, Louisiana and Jefferson Parish Landfill in Westwego, Louisiana, pipelined to Clean Energy Boron in California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
A031201	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production (3.0)	California	Soybean Oil (005)	Biodiesel (BIO)	BIO005A03120101	63.92	BIO005A03120102	63.92	11/8/2023	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	Midwest Soybean Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	2022 AFPR Recert Complete	
A031202	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production (3.0)	California	Canola Oil (006)	Biodiesel (BIO)	BIO006A03120201	59.19	BIO006A03120202	59.19	11/8/2023	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	Canola Oil transported by truck and rail to Biodiesel plant in Stockton, California for biodiesel production	2022 AFPR Recert Complete	

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A031204	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production. (3.0)	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A03120401	38.49	BIO002A03120402	38.49	11/8/2023	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	US sourced Rendered Animal Fat Oil transported by rail to Biodiesel plant in Stockton, California, for biodiesel production.	2022 AFPR Recert Complete	
A031205	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production (3.0)	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A03120501	39.35	BIO002A03120502	39.35	11/8/2023	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	CA sourced Rendered Animal and Poultry Fat Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	2022 AFPR Recert Complete	
A031206	Tier 1	3.0	Fuel Producer: Canary Renewables Corp. (C1201); Facility Name: Canary Renewables Corp. Port of Stockton (82728); US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production (3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A03120601	26.60	BIO001A03120602	26.60	11/8/2023	None	Biodiesel	Canary Renewables Corp. (C1201)	Canary Renewables Corp. Port of Stockton (82728)	US sourced Used Cooking Oil transported by truck to Biodiesel plant in Stockton, California, for biodiesel production	2022 AFPR Recert Complete	
B016601	Tier 2	3.0	Fuel Producer: SMUD (S338); Facility Name: New Hope Dairy Digester (F00255); Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California. (3.0)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B01660100	-750.81	ELC026B01660101	-752.17	10/11/2023	None	Electricity	SMUD (S338)	New Hope Dairy Digester (F00255)	Low-CI electricity from dairy manure biogas using a reciprocating engine at New Hope Dairy in Galt, CA for use as a transportation fuel in California.	2022 AFPR Recert Complete	
A033001	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03300101	73.79	ETH009A03300102	73.76	11/13/2023	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A033002	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California. (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03300200	63.46	ETH009A03300201	62.43	11/13/2023	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Ravena, Nebraska; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A033003	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAPPA Ethanol Ravenna LLC; Midwest Corn, Dry Mill; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California. (3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A03300300	25.32	ETH012A03300301	24.72	11/13/2023	None	Ethanol - Cellulosic	KAAPA Ethanol Holdings LLC (4805)	KAPPA Ethanol Ravenna LLC	Midwest Corn, Dry Mill; Fiber ethanol using Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Ravenna, Nebraska; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A033201	Tier 1	3.0	Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Usina São Martinho S.A. (71100); Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A03320100	50.99	ETH018A03320101	52.31	10/24/2023	None	Ethanol	Usina São Martinho S.A. (3867)	Usina São Martinho S.A. (71100)	Ethanol produced from Sugarcane Juice and Molassesin Brazil, and transported to California by Ocean Tanker.	2022 AFPR Recert Complete	
A033301	Tier 1	3.0	Fuel Producer: Usina São Martinho S.A. (3867); Facility Name: Santa Cruz S/A Açúcar e Álcool (70484); Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A03330100	50.06	ETH018A03330101	50.36	10/25/2023	None	Ethanol	Usina São Martinho S.A. (3867)	Santa Cruz S/A Açúcar e Álcool (70484)	Ethanol produced from Sugarcane Juice and Molasses from Brazil, and transported to California by Ocean Tanker.	2022 AFPR Recert Complete	
A025201	Tier 1	3.0	Fuel Producer: Companhia Alcoolquimica Nacional (C1086); Facility Name: Companhia Alcoolquimica Nacional (F00194); Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A02520100	56.50	ETH018A02520101	58.50	11/13/2023	None	Ethanol	Companhia Alcoolquimica Nacional (C1086)	Companhia Alcoolquimica Nacional (F00194)	Ethanol from sugarcane juice and molasses; produced in NE Brazil, exported to California via ocean tanker; with co-product credit for export of surplus cogenerated electricity.	2022 AFPR Recert Complete	
B017201	Tier 2	3.0	Fuel Producer: Aemetis Advanced Fuels Keyes, Inc. (3566); Facility Name: Aemetis Advanced Fuels Keyes, Inc. (70234); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI (3.0)	California	Corn (009)	Ethanol (ETH)	ETH009B01720100	65.68	ETH009B01720101	64.07	11/27/2023	None	Ethanol	Aemetis Advanced Fuels Keyes, Inc. (3566)	Aemetis Advanced Fuels Keyes, Inc. (70234)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas and Dairy Manure Biogas, Grid Electricity; Starch Ethanol produced in California; Composite CI	2022 AFPR Recert Complete	
B017301	Tier 2	3.0	Fuel Producer: DF-AP #1, LLC (C1122); Facility Name: Big Sky Dairy Digester (F00329); Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California (3.0)	Idaho	Dairy Manure (026)	Electricity (ELC)	ELC026B01730101	-548.10	ELC026B01730102	-506.69	10/11/2023	None	Electricity	DF-AP #1, LLC (C1122)	Big Sky Dairy Digester (F00329)	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at Big Sky Dairy in Gooding, Idaho for use as transportation fuel in California	2022 AFPR Recert Complete	

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A034501	Tier 1	3.0	Fuel Producer: WESTSIDE GAS PRODUCERS, LLC (6218); Facility Name: WESTSIDE GAS PRODUCERS, LLC (71151); Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG. (3.0)	Michigan	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03450101	53.05	CNG025A03450102	60.00	11/28/2023	None	Bio-CNG	WESTSIDE GAS PRODUCERS, LLC (6218)	WESTSIDE GAS PRODUCERS, LLC (71151)	Biomethane from Westside Landfill at Three River, Michigan upgrading at Westside Gas Producers LLC, pipelined to California for compression to CNG.	2022 AFPR Recert Complete	
A034801	Tier 1	3.0	Fuel Producer: Delek Renewables, LLC (5998); Facility Name: Delek Renewables Cleburne Biodiesel Plant (81398); U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail (3.0)	Texas	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A03480101	31.95	BIO002A03480102	31.97	11/8/2023	None	Biodiesel	Delek Renewables, LLC (5998)	Delek Renewables Cleburne Biodiesel Plant (81398)	U.S Sourced Rendered Animal Fat Oil transported by truck to Biodiesel plant in Texas; Natural Gas and Grid Eletricity; Biodiesel transported to California By Rail	2022 AFPR Recert Complete	
A035101	Tier 1	3.0	Fuel Producer: E Energy Adams, LLC (4831); Facility Name: E energy Adams, LLC (70093); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI. (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03510101	67.49	ETH009A03510102	68.01	11/27/2023	None	Ethanol	E Energy Adams, LLC (4831)	E energy Adams, LLC (70093)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Adams, Nebraska; Ethanol transported by rail to California , Composite CI.	2022 AFPR Recert Complete	
A035301	Tier 1	3.0	Fuel Producer: South Platte Renew (8380); Facility Name: 2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel. (3.0)	Colorado	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A03530100	52.36	CNG030A03530101	46.66	11/14/2023	None	Bio-CNG	South Platte Renew (8380)	2900 SOUTH PLATTE RIVER DRIVE PROJECT (70641)	Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge in Colorado; grid electricity; compressed and transported to California via pipeline; dispensed as CNG for transportation fuel.	2022 AFPR Recert Complete	
A036101	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A03610100	70.52	ETH009A03610101	69.86	11/27/2023	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A036102	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (3.0)	Indiana	Corn (009)	Ethanol (ETH)	ETH009A03610200	63.38	ETH009A03610201	62.96	11/27/2023	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A036103	Tier 1	3.0	Fuel Producer: POET BIOREFINING - SHELBYVILLE (8841); Facility Name: Poet Biorefining - Shelbyville (20621); Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California. (3.0)	Indiana	Corn Fiber (012)	Ethanol (ETH)	ETH012A03610300	23.59	ETH012A03610301	23.24	11/27/2023	None	Ethanol	POET BIOREFINING - SHELBYVILLE (8841)	Poet Biorefining - Shelbyville (20621)	Midwest Corn, Dry Mill; Fiber ethanol BPX Fiber Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Shelbyville, IN; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A036701	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG (3.0)	Tennessee	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03670100	49.53	CNG025A03670101	51.45	11/20/2023	None	Bio-CNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN; upgrading at South Shelby RNG, LLC, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
A036702	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations (3.0)	Tennessee	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A03670201	63.18	LNG025A03670202	58.99	11/20/2023	None	Bio-LNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California LNG stations	2022 AFPR Recert Complete	
A036703	Tier 1	3.0	Fuel Producer: SOUTH SHELBY RNG, LLC (1236); Facility Name: South Shelby RNG, LLC (71241); Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG (3.0)	Tennessee	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A03670301	66.26	LCN025A03670302	62.07	11/20/2023	None	Bio-CNG	SOUTH SHELBY RNG, LLC (1236)	South Shelby RNG, LLC (71241)	Biomethane from Landfill at Memphis, TN, pipelined to Clean Energy Boron LNG Plant for liquefaction to LNG; trucked to California CNG stations; regasified, and compressed to L-CNG	2022 AFPR Recert Complete	
B018501	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01850101	-294.20	CNG026B01850102	-271.24	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #8 LLC dba S&S Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use	2022 AFPR Recert Complete	
B018502	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01850201	-366.51	CNG026B01850202	-282.99	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #9 LLC dba Moonlight Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use	2022 AFPR Recert Complete	

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B018503	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01850300	-382.11	CNG026B01850301	-401.96	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Renewable Natural Gas (RNG) from Dairy Manure of ABEC #15 LLC dba Hamstra Dairy Biogas and upgraded at CalBioGas West in Tulare, CA; RNG pipelined to California for transportation use	2022 AFPR Recert Complete	
A037501	Tier 1	3.0	Fuel Producer: BLUE SOURCE LLC (6086); Facility Name: Seabreeze Energy Producers (70281); Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG (3.0)	Texas	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A03750101	38.37	CNG025A03750102	41.43	11/6/2023	None	Bio-CNG	BLUE SOURCE LLC (6086)	Seabreeze Energy Producers (70281)	Biomethane from Landfill in Angleton, Texas upgrading at Seabreeze Energy Producers, pipelined to California for compression to CNG	2022 AFPR Recert Complete	
B018701	Tier 2	3.0	Fuel Producer: Dry Creek RNG LLC (C1098); Facility Name: Dry Creek RNG Project (F00342); Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use (3.0)	Idaho	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01870101	-421.53	CNG026B01870102	-421.46	10/30/2023	None	Bio-CNG	Dry Creek RNG LLC (C1098)	Dry Creek RNG Project (F00342)	Biogas from Dairy Manure at Dry Creek Dairy and Southside Dairy in Hansen, Idaho; Upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
A037801	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process; Ethanol transported by rail to California (3.0)	Texas	Corn Fiber (012)	Ethanol (ETH)	ETH012A03780100	25.36	ETH012A03780101	24.89	11/27/2023	None	Ethanol - Cellulosic	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill; Natural Gas, Grid Electricity; Corn and Sorghum Fiber Ethanol produced in Plainview, Texas via Edeniq Process; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037802	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0)	Texas	Corn (009)	Ethanol (ETH)	ETH009A03780200	66.38	ETH009A03780201	65.58	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037803	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03780301	66.40	ETH010A03780302	66.40	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037804	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (White Energy) (70039); Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0)	Texas	Corn (009)	Ethanol (ETH)	ETH009A03780400	73.91	ETH009A03780401	73.91	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (White Energy) (70039)	Midwest Corn, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037805	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: Plainview BioEnergy, LLC (70039); Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California (3.0)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03780502	74.69	ETH010A03780503	74.69	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	Plainview BioEnergy, LLC (70039)	Local Sorghum, Dry Mill, Dry DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Plainview, Texas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037901	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California (3.0)	Texas	Corn Fiber (012)	Ethanol (ETH)	ETH012A03790100	23.13	ETH012A03790101	23.13	11/27/2023	None	Ethanol - Cellulosic	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Dry Mill; Fiber ethanol; Natural Gas, Grid Electricity; Fiber Ethanol produced in Hereford, Texas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A037902	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (3.0)	Texas	Corn (009)	Ethanol (ETH)	ETH009A03790200	63.93	ETH009A03790201	63.93	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Midwest Corn, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A037903	Tier 1	3.0	Fuel Producer: White Energy, Inc. (4745); Facility Name: WE Hereford, LLC (70037); Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California. (3.0)	Texas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A03790301	65.92	ETH010A03790302	65.92	11/27/2023	None	Ethanol	White Energy, Inc. (4745)	WE Hereford, LLC (70037)	Local Sorghum, Dry Mill, Wet DGS; Natural Gas, Grid Electricity; Starch Ethanol produced in Hereford, Texas; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
B018901	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Distillers' Corn Oil (003)	Renewable Naphtha (RNT)	RNT003B01890100	33.00	RNT003B01890102	33.00	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	

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B018902	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B01890200	37.50	RNT002B01890202	37.50	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018903	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	RNT002B01890300	26.00	RNT002B01890302	26.00	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018904	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	RNT001B01890400	20.50	RNT001B01890402	20.50	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018905	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Used Cooking Oil/Waste Oil (UCO) (001)	Renewable Naphtha (RNT)	RNT001B01890500	26.50	RNT001B01890502	26.50	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018906	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B01890600	38.50	RNT002B01890602	38.50	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018907	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B01890700	43.50	RNT002B01890702	43.50	12/4/2023	None	Renewable Naphtha	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable naphtha produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable naphtha produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018910	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891000	33.00	LPG029B01891002	33.00	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from distilled corn oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018911	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891100	26.00	LPG029B01891102	26.00	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from North America sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018912	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891200	20.50	LPG029B01891202	20.50	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from US sourced non-rendered used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018913	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891300	26.50	LPG029B01891302	26.50	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from South American sourced used cooking oil; natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018914	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891400	37.50	LPG029B01891402	37.50	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from North America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B018915	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891500	38.50	LPG029B01891502	38.50	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from South America sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	

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B018916	Tier 2	3.0	Fuel Producer: REG Geismar, LLC (6268); Facility Name: REG Geismar, LLC (80180); Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker (3.0)	Louisiana	Other Organic Waste (029)	Propane (LPG)	LPG029B01891600	43.50	LPG029B01891602	43.50	12/4/2023	None	Propane	REG Geismar, LLC (6268)	REG Geismar, LLC (80180)	Renewable propane produced from Asia Pacific sourced animal fat (tallow); natural gas, grid electricity and hydrogen; renewable propane produced in Louisiana and transported to California by ocean tanker	2022 AFPR Recert Complete	
B019701	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (3.0)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01970100	-177.03	CNG026B01970101	-208.60	10/30/2023	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Bos Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	2022 AFPR Recert Complete	
B019702	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (3.0)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01970200	-156.78	CNG026B01970201	-149.41	10/30/2023	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Herrema Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	2022 AFPR Recert Complete	
B019703	Tier 2	3.0	Fuel Producer: Generate Indiana RNG Holdings, LLC (9889); Facility Name: Generate Jasper Upgrader, LLC (71002); Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California (3.0)	Indiana	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01970300	-295.26	CNG026B01970301	-332.22	10/30/2023	None	Bio-CNG	Generate Indiana RNG Holdings, LLC (9889)	Generate Jasper Upgrader, LLC (71002)	Renewable Natural Gas (RNG) from Dairy Manure of Windy Ridge Dairy, Fair Oaks, Indiana; delivered via pipeline to Bakersfield, California	2022 AFPR Recert Complete	
A038501	Tier 1	3.0	Fuel Producer: Los Angeles County Sanitation District (L375); Facility Name: Biogas Conditioning System Facility (F00308); Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite. (3.0)	California	Wastewater Sludge (030)	Compressed Natural Gas (CNG)	CNG030A03850100	19.28	CNG030A03850101	19.28	10/30/2023	None	Bio-CNG	Los Angeles County Sanitation District (L375)	Biogas Conditioning System Facility (F00308)	Biomethane produced from the mesophilic anaerobic digestion of wastewater sludge; grid electricity; finished fuel is compressed and dispensed as CNG transportation fuel onsite.	2022 AFPR Recert Complete	
B019801	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980101	-294.40	CNG026B01980102	-343.44	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 5 LLC dba Trilogy Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
B019802	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980200	-414.26	CNG026B01980201	-419.15	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 6 LLC dba Maple Dairy Biogas in Bakersfield, CA; upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
B019803	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980300	-420.69	CNG026B01980301	-413.34	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at ABEC# 7 LLC dba T&W Dairy Biogas in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
B019804	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980400	-405.41	CNG026B01980401	-324.70	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at BV Dairy Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
B019805	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use (3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B01980500	-385.40	CNG026B01980501	-420.53	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at Western Sky Biogas LLC in Bakersfield, CA; Upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
A025801	Tier 1	3.0	Fuel Producer: Agro Industrial Tabu S.A. (C1088); Facility Name: Agro Industrial Tabu (F00205); Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A02580100	51.59	ETH018A02580101	53.00	10/18/2023	None	Ethanol	Agro Industrial Tabu S.A. (C1088)	Agro Industrial Tabu (F00205)	Ethanol produced from Sugarcane Juice and Molasses in Brazil, and exported to California by Ocean Tanker via Panama Canal.	2022 AFPR Recert Complete	
A038601	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A03860101	72.76	ETH009A03860102	72.28	11/27/2023	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	

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A038602	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California. (3.0)	South Dakota	Corn (009)	Ethanol (ETH)	ETH009A03860201	69.61	ETH009A03860202	69.01	11/27/2023	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in South Dakota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A038603	Tier 1	3.0	Fuel Producer: Valero Renewable Fuels (3201); Facility Name: Valero Renewable Fuels Aurora (70041); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California. (3.0)	South Dakota	Corn Fiber (012)	Ethanol (ETH)	ETH012A03860300	28.03	ETH012A03860301	26.18	11/27/2023	None	Ethanol	Valero Renewable Fuels (3201)	Valero Renewable Fuels Aurora (70041)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in South Dakota; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A039401	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California. (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03940101	66.77	ETH009A03940102	66.96	11/27/2023	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Wet DGS, Syrup, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Nebraska; Ethanol transported by rail to California.	2022 AFPR Recert Complete	
A039402	Tier 1	3.0	Fuel Producer: America Agri Products/Wheatland, LLC (5095); Facility Name: Mid America Agri Products/Wheatland LLC (70153); Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California. (3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A03940201	27.95	ETH012A03940202	27.99	11/27/2023	None	Ethanol	America Agri Products/Wheatland, LLC (5095)	Mid America Agri Products/Wheatland LLC (70153)	Midwest Corn, Dry Mill; Fiber Ethanol Production via Soliton Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Nebraska and transported by rail to California.	2022 AFPR Recert Complete	
A039601	Tier 1	3.0	Fuel Producer: Adecoagro Brasil Participacoes (4192); Facility Name: Adecoagro Vale do Ivinhema Ltda. (70496); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A03960100	52.79	ETH018A03960101	53.07	11/13/2023	None	Ethanol	Adecoagro Brasil Participacoes (4192)	Adecoagro Vale do Ivinhema Ltda. (70496)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	2022 AFPR Recert Complete	
A039701	Tier 1	3.0	Fuel Producer: Archer Daniels Midland Co (4888); Facility Name: ADM Velva (82790); Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel. (3.0)	North Dakota	Canola Oil (006)	Biodiesel (BIO)	BIO006A03970100	47.44	BIO006A03970101	46.43	10/31/2023	None	Biodiesel	Archer Daniels Midland Co (4888)	ADM Velva (82790)	Canola oil extracted from co-located canola seed crushing operations in Velva, North Dakota, and used for biodiesel production; finished fuel transported to California by Rail for use as a transportation fuel.	2022 AFPR Recert Complete	
B020701	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02070101	-132.51	CNG026B02070102	-136.71	10/30/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz Home Farm and (5) satellite farms in Sun Prairie, WI; RNG pipelined to multiple California fueling stations	2022 AFPR Recert Complete	
B020702	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: Dane Renewable Energy, LLC (F00235); Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02070201	-193.95	CNG026B02070202	-185.59	10/30/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	Dane Renewable Energy, LLC (F00235)	Renewable Natural Gas (RNG) from Dairy Manure from the Statz B Farm; RNG pipelined to multiple California fueling stations	2022 AFPR Recert Complete	
A040401	Tier 1	3.0	Fuel Producer: Cargill Biodiesel (3683); Facility Name: Cargill Incorporated (36833); Midwest Soybean Oil produced onsite at the co-located crushing facility, and imported by truck and rail to the Biodiesel plant in Iowa Falls, Iowa; finished biodiesel transported to California by rail for transportation fuel. (3.0)	Iowa	Soybean Oil (005)	Biodiesel (BIO)	BIO005A04040100	54.36	BIO005A04040101	54.75	11/16/2023	None	Biodiesel	Cargill Biodiesel (3683)	Cargill Incorporated (36833)	Midwest Soybean Oil produced onsite at the co-located crushing facility, and imported by truck and rail to the Biodiesel plant in Iowa Falls, Iowa; finished biodiesel transported to California by rail for transportation fuel.	2022 AFPR Recert Complete	
B021401	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Milford Farm (71483); Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (PROV3.0)	Utah	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02140100	-413.67	CNG044B02140101	-417.05	12/11/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Milford Farm (71483)	Renewable Natural Gas (RNG) from Swine Manure from the South Cluster of Milford Farm, Milford, UT; RNG pipelined to multiple California fueling stations (Provisional)	2022 AFPR Recert Complete	
B021501	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02150100	-310.71	CNG026B02150101	-337.05	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC in Pickett, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use	2022 AFPR Recert Complete	
B021502	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	LNG026B02150200	-296.99	LNG026B02150201	-320.23	11/22/2023	None	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG is trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG trucked to California for use as LNG	2022 AFPR Recert Complete	

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B021503	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: Rosendale Renewable Energy, LLC (71041); Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	LCN026B02150300	-293.45	LCN026B02150301	-316.68	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	Rosendale Renewable Energy, LLC (71041)	Renewable Natural Gas (RNG) from Dairy Manure at Rosendale Farms and upgraded at Rosendale Renewable Energy, LLC, Pickett, WI; RNG trucked to pipeline injection and pipelined to Arizona where it is liquefied; LNG is trucked to California for use as L-CNG	2022 AFPR Recert Complete	
B021601	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02160101	-333.34	CNG026B02160102	-225.64	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to California for transportation use	2022 AFPR Recert Complete	
B021602	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	LNG026B02160201	-318.76	LNG026B02160202	-207.44	11/22/2023	None	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as LNG	2022 AFPR Recert Complete	
B021603	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: KEWAUNEE RENEWABLE ENERGY, LLC (71003); Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	LCN026B02160301	-315.22	LCN026B02160302	-203.89	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	KEWAUNEE RENEWABLE ENERGY, LLC (71003)	Renewable Natural Gas (RNG) from Dairy Manure at Kinnard Farms and upgraded at Kewaunee Renewable Energy, LLC in Casco, WI; RNG is trucked to pipeline injection and pipelined to Arizona for liquefaction and trucked to California for use as L-CNG	2022 AFPR Recert Complete	
B021701	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02170101	-274.25	CNG026B02170102	-234.87	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC in Grand Marsh, WI, LLC; RNG is trucked to pipeline injection and pipelined to California for transportation use	2022 AFPR Recert Complete	
B021702	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Natural Gas (LNG)	LNG026B02170201	-259.30	LNG026B02170202	-217.46	11/22/2023	None	Bio-LNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for final use	2022 AFPR Recert Complete	
B021703	Tier 2	3.0	Fuel Producer: DTE ENERGY TRADING, INC. (6545); Facility Name: NEW CHESTER RENEWABLE ENERGY, LLC (71181); Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG (3.0)	Wisconsin	Dairy Manure (026)	Liquefied Compressed Natural Gas (LCN)	LCN026B02170301	-255.76	LCN026B02170302	-213.91	11/22/2023	None	Bio-CNG	DTE ENERGY TRADING, INC. (6545)	NEW CHESTER RENEWABLE ENERGY, LLC (71181)	Renewable Natural Gas (RNG) from Dairy Manure at New Chester Farm and upgraded at NEW CHESTER RENEWABLE ENERGY, LLC, Grand Marsh, WI; RNG trucked to pipeline injection and pipelined to Arizona for liquefaction; LNG trucked to California for use as L-CNG	2022 AFPR Recert Complete	
B021901	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: HOMAN FARM (71343); RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use (3.0)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02190101	-359.22	CNG044B02190102	-403.69	11/3/2023	None	Bio-CNG	Anew RNG, LLC (5877)	HOMAN FARM (71343)	RNG produced from swine manure of Homan Farm and upgraded at Homan Farm Upgrading, King City, MO; RNG pipelined to California for transportation use	2022 AFPR Recert Complete	
B022001	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: SOMERSET FARM (71381); Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use (3.0)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B02200102	-370.44	CNG044B02200103	-382.99	10/30/2023	None	Bio-CNG	Anew RNG, LLC (5877)	SOMERSET FARM (71381)	Biogas from Swine Manure at Somerset Farm in Powersville, MO; upgraded biomethane pipelined to California for transportation use	2022 AFPR Recert Complete	
A041601	Tier 1	3.0	Fuel Producer: TRUSTAR ENERGY LLC (6523); Facility Name: Greentree Landfill Gas Company (F00212); Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (PROV3.0)	Pennsylvania	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A04160101	71.21	CNG025A04160102	74.90	10/31/2023	None	Bio-CNG	TRUSTAR ENERGY LLC (6523)	Greentree Landfill Gas Company (F00212)	Biomethane from Greentree Landfill in Kersey, Pennsylvania, pipelined to California for compression to CNG. (Provisional)	2022 AFPR Recert Complete	
A042301	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A04230101	72.01	ETH009A04230102	72.25	11/28/2023	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Ethanol produced in Lawler, Iowa; Ethanol transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
A042302	Tier 1	3.0	Fuel Producer: Homeland Energy Solutions LLC (3220); Facility Name: Homeland Energy Solutions LLC (70188); Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A04230201	24.42	ETH012A04230202	24.71	11/28/2023	None	Ethanol	Homeland Energy Solutions LLC (3220)	Homeland Energy Solutions LLC (70188)	Corn Kernel Fiber Ethanol produced from the EDENIQ process; Natural Gas, and Grid Electricity; Ethanol produced in Lawler, Iowa; and transported by rail to California (Provisional)	2022 AFPR Recert Complete	

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A042501	Tier 1	3.0	Fuel Producer: ADM Agri-Industries Company (6137); Facility Name: ADM Agri Industries (81926); Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel. (3.0)	Canada	Canola Oil (006)	Biodiesel (BIO)	BIO006A04250100	47.65	BIO006A04250101	46.82	10/31/2023	None	Biodiesel	ADM Agri-Industries Company (6137)	ADM Agri Industries (81926)	Biodiesel produced from canola oil obtained from co-located seed crushing facility; transported by rail from Alberta, Canada, to Los Angeles, California for use as a transportation fuel.	2022 AFPR Recert Complete	
A043601	Tier 1	3.0	Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (PROV3.0)	Minnesota	Corn (009)	Ethanol (ETH)	ETH009A04360100	71.53	ETH009A04360101	72.42	11/28/2023	None	Ethanol	AL CORN CLEAN FUEL, LLC (4825)	AL CORN CLEAN FUEL, LLC (70087)	Midwest Corn, Dry Mill; Dry DGS and Corn oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
A043602	Tier 1	3.0	Fuel Producer: AL CORN CLEAN FUEL, LLC (4825); Facility Name: AL CORN CLEAN FUEL, LLC (70087); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (PROV3.0)	Minnesota	Corn Fiber (012)	Ethanol (ETH)	ETH012A04360201	25.15	ETH012A04360202	25.90	11/28/2023	None	Ethanol	AL CORN CLEAN FUEL, LLC (4825)	AL CORN CLEAN FUEL, LLC (70087)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process (Edeniq); Natural Gas, Grid Electricity; Fiber Ethanol produced in Minnesota; Ethanol transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
A043701	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (PROV3.0)	Oklahoma	Landfill Gas (025)	Compressed Natural Gas (CNG)	CNG025A04370100	37.00	CNG025A04370101	37.00	11/20/2023	None	Bio-CNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for compression to CNG (Provisional)	2022 AFPR Recert Complete	
A043702	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (PROV3.0)	Oklahoma	Landfill Gas (025)	Liquefied Natural Gas (LNG)	LNG025A04370200	50.61	LNG025A04370201	53.28	11/20/2023	None	Bio-LNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California LNG stations (Provisional)	2022 AFPR Recert Complete	
A043703	Tier 1	3.0	Fuel Producer: LYNX RENEWABLE ENERGY LLC (1392); Facility Name: Lynx Renewable Energy (F00355); Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (PROV3.0)	Oklahoma	Landfill Gas (025)	Liquefied Compressed Natural Gas (LCN)	LCN025A04370300	53.70	LCN025A04370301	56.37	11/20/2023	None	Bio-CNG	LYNX RENEWABLE ENERGY LLC (1392)	Lynx Renewable Energy (F00355)	Biomethane from Landfill at Ardmore, Oklahoma, upgrading at Lynx Renewable Energy in Oklahoma, pipelined to California for liquefaction to LNG; trucked to California; regasified, and compressed to L-CNG (Provisional)	2022 AFPR Recert Complete	
B025001	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (PROV3.0)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02500100	-182.67	CNG026B02500101	-187.55	10/25/2023	None	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at District 45 farm in Hancock, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B025002	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (PROV3.0)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02500200	-267.51	CNG026B02500201	-258.09	10/25/2023	None	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at Riverview farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B025003	Tier 2	3.0	Fuel Producer: AMPRENEW OFFTAKE I LLC (9041); Facility Name: RDF STEVENS LLC (71701); Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (PROV3.0)	Minnesota	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02500300	-255.34	CNG026B02500301	-224.53	10/25/2023	None	Bio-CNG	AMPRENEW OFFTAKE I LLC (9041)	RDF STEVENS LLC (71701)	Biogas from dairy manure at West River farm in Morris, MN; upgraded to pipeline quality at RDF Stevens and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
A044001	Tier 1	3.0	Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (3.0)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A04400100	72.37	ETH009A04400101	74.48	11/27/2023	None	Ethanol	Element, LLC (C1020)	Element (F00048)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A044002	Tier 1	3.0	Fuel Producer: Element, LLC (C1020); Facility Name: Element (F00048); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California (3.0)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A04400200	62.07	ETH009A04400201	64.11	11/27/2023	None	Ethanol	Element, LLC (C1020)	Element (F00048)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity and Woody Biomass; Starch Ethanol produced in Colwich, Kansas; Ethanol transported by rail to California	2022 AFPR Recert Complete	
A044201	Tier 1	3.0	Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A04420100	72.16	ETH009A04420101	72.23	10/17/2023	None	Ethanol	Lincolnway Energy, LLC (4830)	Lincolnway Energy (70092)	Midwest Corn, Dry Mill; Dry and Wet DGS; Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Nevada, Iowa; transported by rail to California; Composite CI (Provisional)	2022 AFPR Recert Complete	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A044203	Tier 1	3.0	Fuel Producer: Lincolnway Energy, LLC (4830); Facility Name: Lincolnway Energy (70092); Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A04420300	24.70	ETH012A04420301	24.99	10/17/2023	None	Ethanol - Cellulosic	Lincolnway Energy, LLC (4830)	Lincolnway Energy (70092)	Corn Fiber Ethanol produced from Midwest Corn using the Edeniq Fiber Conversion Process; NG, Grid Electricity; Ethanol produced in Nevada, Iowa is transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
B026701	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0)	California	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003B02670101	28.80	BIO003B02670102	28.73	10/31/2023	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	Corn Oil transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2022 AFPR Recert Complete	
B026702	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002B02670201	32.73	BIO002B02670202	32.74	10/31/2023	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North American sourced Animal Fat transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2022 AFPR Recert Complete	
B026703	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001B02670300	15.71	BIO001B02670301	15.58	10/31/2023	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced Zero Energy Rendered UCO transported by truck and rail to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2022 AFPR Recert Complete	
B026704	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001B02670400	16.34	BIO001B02670401	16.15	10/31/2023	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced Low Energy Rendered UCO transported by truck to Biodiesel plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite Biodiesel produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2022 AFPR Recert Complete	
B026705	Tier 2	3.0	Fuel Producer: Crimson Renewable Energy LLC (4814); Facility Name: Crimson Renewable Energy Bakersfield Biodiesel Plant (80174); North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (PROV3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001B02670500	20.86	BIO001B02670501	20.74	10/31/2023	None	Biodiesel	Crimson Renewable Energy LLC (4814)	Crimson Renewable Energy Bakersfield Biodiesel Plant (80174)	North America sourced UCO Standard Rendering Energy, transported by truck and rail to BD plant in Bakersfield, California; Natural Gas and Grid Electricity; Composite BD produced by conventional and RepCat process. In-state fuel distribution by truck. (Provisional)	2022 AFPR Recert Complete	
A045001	Tier 1	3.0	Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (3.0)	Pennsylvania	Soybean Oil (005)	Biodiesel (BIO)	BIO005A04500100	58.09	BIO005A04500101	57.93	11/2/2023	None	Biodiesel	WORLD ENERGY HARRISBURG LLC (6425)	WORLD ENERGY HARRISBURG LLC (81499)	Midwest Soybean Oil transported by truck to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail.	2022 AFPR Recert Complete	
A045002	Tier 1	3.0	Fuel Producer: WORLD ENERGY HARRISBURG LLC (6425); Facility Name: WORLD ENERGY HARRISBURG LLC (81499); US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail. (3.0)	Pennsylvania	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001A04500200	21.59	BIO001A04500201	20.78	11/2/2023	None	Biodiesel	WORLD ENERGY HARRISBURG LLC (6425)	WORLD ENERGY HARRISBURG LLC (81499)	US sourced Used Cooking Oil transported by truck and rail to a Biodiesel plant in Harrisburg, Pennsylvania. Biodiesel transported to California by rail.	2022 AFPR Recert Complete	
B026801	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02680101	18.93	AJF002B02680103	22.00	12/14/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	
B026802	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02680201	18.93	RND002B02680203	22.00	12/14/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026803	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02680301	18.93	RNT002B02680303	22.00	12/14/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Brooks Alberta Canada transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B026804	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02680400	19.54	AJF002B02680402	22.00	12/14/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
B026805	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02680500	19.54	RND002B02680502	22.00	12/14/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026806	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02680600	19.54	RNT002B02680602	22.00	12/14/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Greely Colorado transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B026807	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02680700	15.64	AJF002B02680701	17.98	12/12/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	
B026808	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02680800	15.64	RND002B02680801	17.98	12/12/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026809	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02680900	15.64	RNT002B02680901	17.98	12/12/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Hyrum Utah transported by Truck and rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B026810	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02681001	29.78	AJF002B02681003	32.00	12/14/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	
B026811	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02681101	29.78	RND002B02681103	32.00	12/14/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026812	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02681201	29.78	RNT002B02681203	32.00	12/14/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Animal Fat Sourced from JBS Dinmore Australia transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B026813	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02681300	32.93	AJF002B02681301	37.00	12/12/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	
B026814	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02681400	32.93	RND002B02681401	37.00	12/12/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026815	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02681500	32.93	RNT002B02681501	37.00	12/12/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	North American Sourced Rendered Animal Fat transported by rail to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B026816	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Alternative Jet Fuel (AJF)	AJF002B02681600	38.43	AJF002B02681601	43.00	12/12/2023	None	Alternative Jet Fuel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Jet Fuel produced in California (Provisional)	2022 AFPR Recert Complete	

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B026817	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Diesel (RND)	RND002B02681700	38.43	RND002B02681701	43.00	12/12/2023	None	Renewable Diesel	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel produced in California (Provisional)	2022 AFPR Recert Complete	
B026818	Tier 2	3.0	Fuel Producer: AltAir Paramount, LLC (6281); Facility Name: AltAir Paramount, LLC (83180); Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (PROV3.0)	California	Tallow (animal and poultry fat) (002)	Renewable Naphtha (RNT)	RNT002B02681800	38.43	RNT002B02681801	43.00	12/12/2023	None	Renewable Naphtha	AltAir Paramount, LLC (6281)	AltAir Paramount, LLC (83180)	Site-Specific Rendered Australian Sourced Animal Fat transported by truck and ocean tanker to Renewable Diesel plant in Paramount, California; Natural Gas, Grid Electricity, and Hydrogen; Renewable Naphtha produced in California (Provisional)	2022 AFPR Recert Complete	
B028201	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY S&S (71361); Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02820100	-272.08	CNG026B02820101	-360.00	10/30/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	U.S. GAIN RNG FACILITY S&S (71361)	Biogas from dairy manure at Jerseyland Dairy in Sturgeon Bay, WI; upgraded to pipeline quality at U.S. GAIN RNG FACILITY S&S; trucked to pipeline injection and pipelined to CA for transportation use	2022 AFPR Recert Complete	
B028301	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: DEER RUN RNG PROJECT (71482); Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B02830100	-195.09	CNG026B02830101	-194.44	10/27/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	DEER RUN RNG PROJECT (71482)	Biogas from dairy manure at Deer Run in Kewaunee, WI; upgraded to pipeline quality at Deer Run RNG; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
A045601	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (3.0)	California	Distillers' Corn Oil (003)	Biodiesel	BIO003A04560100	30.15	BIO003A04560101	34.64	11/3/2023	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	California Sourced Corn Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals	2022 AFPR Recert Complete	
A045602	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (3.0)	California	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel	BIO001A04560200	23.48	BIO001A04560201	27.73	11/3/2023	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	North American Sourced Rendered Used Cooking Oil transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals	2022 AFPR Recert Complete	
A045603	Tier 1	3.0	Fuel Producer: SJV BIODIESEL LLC (7501); Facility Name: SJV BIODIESEL (80341); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals (3.0)	California	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002A04560300	36.09	BIO002A04560301	40.98	11/3/2023	None	Biodiesel	SJV BIODIESEL LLC (7501)	SJV BIODIESEL (80341)	North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Pixley California; Natural Gas, Dairy Biogas, and Electricity; Biodiesel transport by truck to California blending terminals	2022 AFPR Recert Complete	
A041001	Tier 1	3.0	Fuel Producer: JAPUNGU AGROINDUSTRIAL LTDA (C1145); Facility Name: Japungu Agroindustrial Ltda (F00383); Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	ETH018A04100100	52.77	ETH018A04100101	53.00	10/25/2023	None	Ethanol	JAPUNGU AGROINDUSTRIAL LTDA (C1145)	Japungu Agroindustrial Ltda (F00383)	Ethanol produced from Sugarcane Juice and Molasses, and exported to California by Ocean Tanker.	2022 AFPR Recert Complete	
B030201	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (3.0)	Minnesota	Distillers' Corn Oil (003)	Biodiesel (BIO)	BIO003B03020100	24.50	BIO003B03020102	24.50	12/4/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Corn Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California	2022 AFPR Recert Complete	
B030202	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001B03020200	18.50	BIO001B03020202	18.50	12/4/2023	None	Renewable Diesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California	2022 AFPR Recert Complete	
B030203	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California (3.0)	Minnesota	Used Cooking Oil/Waste Oil (UCO) (001)	Biodiesel (BIO)	BIO001B03020300	12.50	BIO001B03020302	12.50	12/4/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Non-Rendered Used Cooking Oil transported by truck and rail to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity; Biodiesel transported by truck and rail to California	2022 AFPR Recert Complete	
B030204	Tier 2	3.0	Fuel Producer: REG Albert Lea, LLC (4305); Facility Name: REG Albert Lea, LLC (82613); North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California (3.0)	Minnesota	Tallow (animal and poultry fat) (002)	Biodiesel (BIO)	BIO002B03020400	29.00	BIO002B03020402	29.00	12/4/2023	None	Biodiesel	REG Albert Lea, LLC (4305)	REG Albert Lea, LLC (82613)	North American Sourced Rendered Animal Fat transported by truck to Biodiesel plant in Albert Lea, MN; Natural Gas, Steam, Grid Electricity, and Renewable Electricity: Biodiesel transported by truck and rail to California	2022 AFPR Recert Complete	

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B030701	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03070100	-353.38	CNG026B03070101	-325.32	10/27/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Wreden Ranch Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B030702	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03070200	-405.57	CNG026B03070201	-361.69	10/27/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Hollandia Farms Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B030703	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03070300	-255.83	CNG026B03070301	-256.77	10/27/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Cloverdale Dairy in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B030704	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03070400	-249.43	CNG026B03070401	-247.40	10/27/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Valadao in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B030705	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Hanford LLC (F00435); Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03070500	-366.91	CNG026B03070501	-411.56	10/27/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Hanford LLC (F00435)	Biogas from dairy manure at Grimmius in Hanford, CA; upgraded to pipeline quality at CalBioGas Hanford and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031001	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100100	-349.17	CNG026B03100101	-420.78	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Double J in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031002	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100200	-210.67	CNG026B03100201	-257.14	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Rob Van Grouw in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031003	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100300	-406.28	CNG026B03100301	-415.27	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Mellema in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031004	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100400	-417.26	CNG026B03100401	-372.09	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Mineral King in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031005	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100500	-417.24	CNG026B03100501	-369.61	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Rancho Sierra Vista in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031006	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas North Visalia LLC (F00433); Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03100600	-356.29	CNG026B03100601	-324.13	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas North Visalia LLC (F00433)	Biogas from dairy manure at Jacobus De Groot #2 Dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas North Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031101	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110101	-418.04	CNG026B03110102	-348.56	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Aukeman Farm in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	

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B031102	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110200	-383.14	CNG026B03110201	-336.76	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Dykstra Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031103	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110300	-419.34	CNG026B03110301	-423.14	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Horizon Jersey Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031104	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110400	-299.39	CNG026B03110401	-334.72	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Rancho Teresita Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031105	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110500	-276.38	CNG026B03110501	-307.02	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Bos Farms Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031106	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110600	-403.86	CNG026B03110601	-392.14	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Riverbend South Dairy in Tulare, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031107	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110700	-341.84	CNG026B03110701	-318.92	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at El Monte Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B031108	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas South Tulare LLC (F00434); Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03110800	-273.88	CNG026B03110801	-331.28	11/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas South Tulare LLC (F00434)	Biogas from dairy manure at Scheenstra Dairy in Tipton, CA; upgraded to pipeline quality at CalBioGas South Tulare and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
A046201	Tier 1	3.0	Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (PROV3.0)		Corn Fiber (012)	Ethanol (ETH)	ETH012A04620101	33.08	ETH012A04620103	34.36	10/17/2023	None	Ethanol	CORN, LP (5065)	CORN, LP (70145)	Midwest Corn, Dry Mill; Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California (Provisional)	2022 AFPR Recert Complete	
A046202	Tier 1	3.0	Fuel Producer: CORN, LP (5065); Facility Name: CORN, LP (70145); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (PROV3.0)		Corn (009)	Ethanol (ETH)	ETH009A04620201	70.62	ETH009A04620202	73.77	10/17/2023	None	Ethanol	CORN, LP (5065)	CORN, LP (70145)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Iowa; Ethanol transported by rail to California, Composite CI (Provisional)	2022 AFPR Recert Complete	
B031501	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas West Visalia LLC (F00337); Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03150100	-403.96	CNG026B03150101	-409.96	12/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas West Visalia LLC (F00337)	Biogas from dairy manure at Udder dairy in Visalia, CA; upgraded to pipeline quality at CalBioGas West Visalia and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B033801	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: DALHART RNG, LLC (70981); Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (PROV3.0)	Texas	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B03380100	-417.96	CNG044B03380101	-430.20	12/11/2023	None	Bio-CNG	Anew RNG, LLC (5877)	DALHART RNG, LLC (70981)	Biogas from swine manure at Dalhart Farm in Dalhart, TX; upgraded to pipeline quality at Dalhart RNG and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B034501	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAKESHORE RNG PROJECT (71321); Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03450100	-318.35	CNG026B03450101	-296.42	10/27/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET LAKESHORE RNG PROJECT (71321)	Biogas from dairy manure at Lakeshore Dairy in Wilson, NY; upgraded to pipeline quality at Yellow Jacket Lakeshore RNG Project; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	

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B034601	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET LAMB RNG PROJECT (71101); Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (PROV3.0)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03460100	-311.72	CNG026B03460101	-272.73	11/22/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET LAMB RNG PROJECT (71101)	Biogas from dairy manure at Lamb Farm in Oakfield, NY; upgraded to pipeline quality at Yellow Jacket Lamb RNG Project and pipelined to California for transportation use (Provisional)	2022 AFPR Recert Complete	
B035301	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: U.S. GAIN RNG FACILITY DALLMAN (71341); Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use (3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03530100	-344.72	CNG026B03530101	-319.04	10/30/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	U.S. GAIN RNG FACILITY DALLMAN (71341)	Biogas from dairy manure at Callmann East River Dairy in Brillion, WI; upgraded to pipeline quality at U.S. Gain RNG Facility Dallman and pipelined to CA for transportation use	2022 AFPR Recert Complete	
B035201	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03520100	-411.77	CNG026B03520101	-423.12	12/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from dairy manure at Newhouse Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC in and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B035202	Tier 2	3.0	Fuel Producer: California Bioenergy LLC (B194); Facility Name: CalBioGas Kern LLC (F00336); Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (PROV3.0)	California	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03520200	-351.51	CNG026B03520201	-353.82	12/14/2023	None	Bio-CNG	California Bioenergy LLC (B194)	CalBioGas Kern LLC (F00336)	Biogas from Dairy Manure at McMoo Dairy in Bakersfield, CA; upgraded to pipeline quality at CalBioGas Kern LLC and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B036601	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: MILFORD FARM (71483); Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use (3.0)	Utah	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B03660100	-414.59	CNG044B03660101	-427.14	10/30/2023	None	Bio-CNG	Anew RNG, LLC (5877)	MILFORD FARM (71483)	Biogas from swine manure at Milford Farm in Milford, UT; upgraded to pipeline quality at Milford Farm and pipelined to CA for transportation use	2022 AFPR Recert Complete	
B036001	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	HYG026B03600100	-159.04	HYG026B03600101	-154.83	11/6/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR facility in Ontario, California using Biomethane derived from digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported as G.H2 in tube trailers to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	
B036002	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	HYL026B03600200	-120.27	HYL026B03600201	-118.90	11/6/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy manure digester gas and upgraded at Deer Run RNG Project in Kewaunee, WI; transported in liquid tanker trailers to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	
B036003	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	HYL026B03600300	-104.64	HYL026B03600301	-100.09	11/6/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	L.H2 produced central SMR using Biomethane derived from dairy digester gas upgraded at Deer Run RNG Project in Kewaunee, WI; transported as L.H2 in tankers to trans-fill center, re-gasified, compressed, and distributed to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	
B037001	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: GREEN HILLS FARM (71881); Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (PROV3.0)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B03700100	-408.25	CNG044B03700101	-402.51	10/27/2023	None	Bio-CNG	Anew RNG, LLC (5877)	GREEN HILLS FARM (71881)	Biogas from swine manure at Green Hills Farm in Unionville, MO; upgraded to pipeline-quality on-site at the farm and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B037101	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: WHITETAIL FARM (71882); Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (PROV3.0)	Missouri	Swine Manure (044)	Compressed Natural Gas (CNG)	CNG044B03710100	-412.77	CNG044B03710101	-374.61	10/27/2023	None	Bio-CNG	Anew RNG, LLC (5877)	WHITETAIL FARM (71882)	Biogas from swine manure at Whitetail Farm in Unionville, MO; upgraded to pipeline quality at Whitetail Farm and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B037302	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	HYL026B03730200	-192.70	HYL026B03730201	-182.54	11/13/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Liquefied Hydrogen produced at Praxair SMR using Biomethane derived from dairy digester gas generated at Riverview Dairy Digester; upgraded at RDF Stevens in Morris, MN; transported in tanker trailers to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	
B037304	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Gaseous Hydrogen (HYG)	HYG026B03730400	-231.46	HYG026B03730401	-218.47	11/13/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	Gaseous Hydrogen produced at Praxair SMR in Ontario, California using Biomethane derived from digester gas generated at Riverview Dairy Digester and upgraded at RDF Stevens in Morris, MN; transported in tube trailers to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	

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B037306	Tier 2	3.0	Fuel Producer: FirstElement Fuel (E426); Facility Name: Praxair SMR facility (F00394); L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (PROV3.0)	California	Dairy Manure (026)	Liquid Hydrogen (HYL)	HYL026B03730600	-177.06	HYL026B03730601	-163.73	11/13/2023	None	Hydrogen	FirstElement Fuel (E426)	Praxair SMR facility (F00394)	L.H2 produced at Praxair SMR using Biomethane upgraded at RDF Stevens in Morris, MN from digester gas produced at Riverview Dairy Digester; transported as L.H2 to trans-fill, regasified and compressed, then transported to refueling stations in California. (Provisional)	2022 AFPR Recert Complete	
A049001	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A04900100	71.51	ETH009A04900101	71.65	10/25/2023	None	Ethanol	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Dry DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
A049002	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	ETH009A04900200	61.15	ETH009A04900201	61.71	10/25/2023	None	Ethanol	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Wet DGS, Corn oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Oakley, Kansas; Ethanol transported by rail to California. (Provisional)	2022 AFPR Recert Complete	
A049003	Tier 1	3.0	Fuel Producer: Southwest Iowa Renewable Energy, LLC (5935); Facility Name: Southwest Iowa Renewable Energy, LLC (70326); Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	ETH012A04900300	22.33	ETH012A04900301	23.74	10/25/2023	None	Ethanol - Cellulosic	Southwest Iowa Renewable Energy, LLC (5935)	Southwest Iowa Renewable Energy, LLC (70326)	Midwest Corn, Dry Mill; Fiber ethanol via Edeniq Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Council Bluffs, Iowa; Ethanol transported by rail to California (Provisional)	2022 AFPR Recert Complete	
B038201	Tier 2	3.0	Fuel Producer: Madera Renewable Energy, LLC (C1140); Facility Name: Madera Renewable Energy, LLC (F00436); Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California. (3.0)	California	Dairy Manure (026)	Electricity (ELC)	ELC026B03820100	-758.40	ELC026B03820101	-756.17	11/27/2023	None	Electricity	Madera Renewable Energy, LLC (C1140)	Madera Renewable Energy, LLC (F00436)	Low-CI electricity from Dairy Manure biogas using reciprocating engine at Philip Verwey Dairy in Madera, CA for use as transportation fuel in California.	2022 AFPR Recert Complete	
B038501	Tier 2	3.0	Fuel Producer: Anew RNG, LLC (5877); Facility Name: Green Valley Dairy LLC (F00198); Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (PROV3.0)	Wisconsin	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B03850100	-180.73	CNG026B03850101	-180.62	11/28/2023	None	Bio-CNG	Anew RNG, LLC (5877)	Green Valley Dairy LLC (F00198)	Biogas from dairy manure at Green Valley Dairy in Krakow, WI; upgraded to pipeline quality at Green Valley Dairy; trucked to pipeline injection and pipelined to CA for transportation use (Provisional)	2022 AFPR Recert Complete	
B040101	Tier 2	3.0	Fuel Producer: U.S. Venture, Inc. (5504); Facility Name: YELLOW JACKET SWISS VALLEY RNG PROJECT (71161); Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (PROV3.0)	New York	Dairy Manure (026)	Compressed Natural Gas (CNG)	CNG026B04010100	-216.27	CNG026B04010101	-187.99	11/22/2023	None	Bio-CNG	U.S. Venture, Inc. (5504)	YELLOW JACKET SWISS VALLEY RNG PROJECT (71161)	Biogas from Dairy Manure at Swiss Valley Farms in Warsaw, NY; upgraded to pipeline quality at Yellow Jacket Swiss Valley RNG Project; pipelined to California for transportation use (Provisional)	2022 AFPR Recert Complete	
B042801	Tier 2	3.0	Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (PROV3.0)	Mississippi	Distillers' Corn Oil (003)	Renewable Diesel (RND)	RND003B04280100	51.80	RND003B04280101	53.52	11/6/2023	None	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	Midwest Sourced Corn Oil transported by truck and rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	2022 AFPR Recert Complete	
B042802	Tier 2	3.0	Fuel Producer: Jaxon Energy, LLC (6454); Facility Name: Jaxon Energy, LLC (83608); Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (PROV3.0)	Mississippi	Soybean Oil (005)	Renewable Diesel (RND)	RND005B04280200	80.81	RND005B04280201	83.76	11/6/2023	None	Renewable Diesel	Jaxon Energy, LLC (6454)	Jaxon Energy, LLC (83608)	Midwest Sourced Soybean Oil transported by rail to Renewable Diesel plant in Jackson, Mississippi; Natural Gas, Grid Electricity, and Hydrogen; Renewable Diesel transported by rail to California (Provisional)	2022 AFPR Recert Complete	
B048501	Tier 2	3.0	Fuel Producer: Trillium Transportation Fuels, LLC (T311); Facility Name: SANCO Services Anaerobic Digestor Plant (F00478); Biogas from landfill-diverted food scraps and urban landscaping waste upgraded at SANCO Services Anaerobic Digestor Plant facility in Escondido, CA; Bio-CNG injected into California natural gas pipeline for transportation use. (PROV3.0)	California	Other Organic Waste (029)	Compressed Natural Gas (CNG)	None	None	CNG029B04850100	-38.80	1/2/2024	Application Package	Bio-CNG	Trillium Transportation Fuels, LLC (T311)	SANCO Services Anaerobic Digestor Plant (F00478)	Biogas from landfill-diverted food scraps and urban landscaping waste upgraded at SANCO Services Anaerobic Digestor Plant facility in Escondido, CA; Bio-CNG injected into California natural gas pipeline for transportation use. (Provisional)	None	
B052101	Tier 2	3.0	Fuel Producer: PHILLIPS 66 COMPANY (4528) ; Facility Name: Phillips 66 Rodeo (82191); Renewable gasoline is derived from Argentinian soybean oil (soybean oil is produced in Argentina and transported by ocean tanker to California); Natural gas, steam, off-gases, grid electricity, and hydrogen are distributed in California via pipeline. (3.0)	California	Soybean Oil (005)	Renewable Gasoline (RNG)	None	None	RNG005B05210100	67.35	12/29/2023	Application Package	Renewable Gasoline	PHILLIPS 66 COMPANY (4528)	Phillips 66 Rodeo (82191)	Renewable gasoline is derived from Argentinian soybean oil (soybean oil is produced in Argentina and transported by ocean tanker to California); Natural gas, steam, off-gases, grid electricity, and hydrogen are distributed in California via pipeline.	None	
A019801	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI (3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A01980103	62.37	ETH009A01980105	62.23	1/9/2024	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Minden, Nebraska and transported by rail to California, Composite CI	2022 AFPR Recert Complete	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A019802	Tier 1	3.0	Fuel Producer: KAAPA Ethanol Holdings LLC (4805); Facility Name: KAAPA Ethanol LLC (70079); Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California (3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	ETH012A01980201	23.04	ETH012A01980202	22.96	11/13/2023	None	Ethanol	KAAPA Ethanol Holdings LLC (4805)	KAAPA Ethanol LLC (70079)	Midwest Corn, Dry Mill; Soliton Fiber Ethanol Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Minden Nebraska and transported by rail to California	2022 AFPR Recert Complete	
A053001	Tier 1	3.0	Fuel Producer: Guarani SA (3833); Facility Name: Usina Vertente Ltda. (70447); Sugarcane-derived ethanol produced in Brazil from sugarcane juice and molasses; mechanized harvesting; co-product credit for export of cogenerated electricity; finished fuel exported to California by Ocean Tanker. (3.0)	Brazil	Sugarcane (018)	Ethanol (ETH)	None	None	ETH018A05300100	48.78	1/8/2024	None	Ethanol	Guarani SA (3833)	Usina Vertente Ltda. (70447)	Sugarcane-derived ethanol produced in Brazil from sugarcane juice and molasses; mechanized harvesting; co-product credit for export of cogenerated electricity; finished fuel exported to California by Ocean Tanker.	None	
A053201	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Atlantic, Iowa; Ethanol transported by Rail to California , Composite CI (PROV3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05320100	66.20	1/11/2024	None	Ethanol	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Atlantic, Iowa; Ethanol transported by Rail to California , Composite CI (Provisional)	None	
A053202	Tier 1	3.0	Fuel Producer: Elite Octane, LLC (6500); Facility Name: Elite Octane, LLC (71287); Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Atlantic, Iowa and transported by Rail to California (PROV3.0)	Iowa	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05320200	26.80	1/11/2024	None	Ethanol - Cellulosic	Elite Octane, LLC (6500)	Elite Octane, LLC (71287)	Midwest Corn, Dry Mill; Fiber Ethanol produced by the EDENIQ Fiber Conversion Process; Natural Gas, Grid Electricity; Fiber Ethanol produced in Atlantic, Iowa and transported by Rail to California (Provisional)	None	
A054001	Tier 1	3.0	Fuel Producer: NuGen Energy, LLC (3332); Facility Name: NuGen Energy, LLC (70195); Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (PROV3.0)	South Dakota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05400100	72.33	1/23/2024	None	Ethanol	NuGen Energy, LLC (3332)	NuGen Energy, LLC (70195)	Midwest Corn, Dry Mill; Dry DGS and Modified DGS, Corn Oil; Natural Gas, Grid Electricity, Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (Provisional)	None	
A054002	Tier 1	3.0	Fuel Producer: NuGen Energy, LLC (3332); Facility Name: NuGen Energy, LLC (70195); Sorghum from Dry Mill; Dry DGS and Modified DGS, Corn Oil; Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (PROV3.0)	South Dakota	Grain Sorghum (010)	Ethanol (ETH)	None	None	ETH010A05400200	76.07	1/23/2024	None	Ethanol	NuGen Energy, LLC (3332)	NuGen Energy, LLC (70195)	Sorghum from Dry Mill; Dry DGS and Modified DGS, Corn Oil; Starch Ethanol produced in Marion, South Dakota; Finished fuel transported by Rail to California; Composite CI. (Provisional)	None	
A053601	Tier 1	3.0	Fuel Producer: Green Plains Superior LLC (5851); Facility Name: GREEN PLAINS SUPERIOR, LLC (70304); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Superior, Iowa; Finished fuel transported by Rail to California; Composite CI. (3.0)	Iowa	Corn (009)	Ethanol (ETH)	None	None	ETH009A05360100	70.98	1/31/2024	None	Ethanol	Green Plains Superior LLC (5851)	GREEN PLAINS SUPERIOR, LLC (70304)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Superior, Iowa; Finished fuel transported by Rail to California; Composite CI.	None	
A054101	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California , Composite CI. (PROV3.0)	Kansas	Corn (009)	Ethanol (ETH)	ETH009A01030102	71.24	ETH009A05410100	63.36	1/26/2024	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California , Composite CI. (Provisional)	None	
A054102	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Sorghum from Midwest; Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California; Composite CI. (PROV3.0)	Kansas	Grain Sorghum (010)	Ethanol (ETH)	ETH010A01030602	73.44	ETH010A05410200	67.05	1/26/2024	None	Ethanol	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Sorghum from Midwest; Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Garden City, Kansas; Finished fuel transported by Rail to California; Composite CI. (Provisional)	None	
A054103	Tier 1	3.0	Fuel Producer: Bonanza BioEnergy, LLC (4054); Facility Name: Bonanza BioEnergy, LLC (70117); Midwest Corn and Sorghum, Dry Mill; Corn-Sorghum Fiber Ethanol produced by the EDENIQ conversion method; Cellulosic Ethanol produced in Garden City, Kansas, and transported to California by Rail. (PROV3.0)	Kansas	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05410300	25.05	1/26/2024	None	Ethanol - Cellulosic	Bonanza BioEnergy, LLC (4054)	Bonanza BioEnergy, LLC (70117)	Midwest Corn and Sorghum, Dry Mill; Corn-Sorghum Fiber Ethanol produced by the EDENIQ conversion method; Cellulosic Ethanol produced in Garden City, Kansas, and transported to California by Rail. (Provisional)	None	
A053701	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03070100	74.08	ETH009A05370100	78.02	2/9/2024	None	Ethanol	POET BIOREFINING - FAIRMONT (1579)	FAIRMONT (71681)	Midwest Corn, Dry Mill; Dry DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional)	None	
A053702	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	ETH009A03070200	69.42	ETH009A05370200	75.27	2/9/2024	None	Ethanol	POET BIOREFINING - FAIRMONT (1579)	FAIRMONT (71681)	Midwest Corn, Dry Mill; Modified DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional)	None	

App/Pathway #	Class	Calculator Version	Applicant & Pathway Description	Facility Location	Feedstock	Fuel Type	Legacy FPC	Legacy CI	Current Certified FPC	Current Certified CI	Certification Date	Postings and Comments	Fuel Category	Company (ID)	Facility (ID)	Pathway Description	AFPR Recertification Status	Retired Pathway
A053703	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0)	Nebraska	Corn (009)	Ethanol (ETH)	None	None	ETH009A05370300	69.59	2/9/2024	None	Ethanol	POET BIOREFINING - FAIRMONT (1579)	FAIRMONT (71681)	Midwest Corn, Dry Mill; Wet DGS, Corn Oil; Natural Gas, Grid Electricity; Starch Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional)	None	
A053704	Tier 1	3.0	Fuel Producer: POET BIOREFINING - FAIRMONT (1579); Facility Name: FAIRMONT (71681); Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poet's proprietary fiber conversion process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (PROV3.0)	Nebraska	Corn Fiber (012)	Ethanol (ETH)	None	None	ETH012A05370400	30.06	2/9/2024	None	Ethanol - Cellulosic	POET BIOREFINING - FAIRMONT (1579)	FAIRMONT (71681)	Midwest Corn, Dry Mill; Corn Fiber Ethanol produced by Poet's proprietary fiber conversion process; Natural Gas, Grid Electricity; Cellulosic Ethanol produced in Fairmont, Nebraska and transported by Rail to California. (Provisional)	None	
A053901	Tier 1	3.0	Fuel Producer: Green Plains Otter Tail LLC (4180); Facility Name: GREEN PLAINS OTTER TAIL, LLC (70110); Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Fergus Falls, MN; Finished fuel transported by Rail to California; Composite CI. (3.0)	Minnesota	Corn (009)	Ethanol (ETH)	None	None	ETH009A05390100	72.83	2/1/2024	None	Ethanol	Green Plains Otter Tail LLC (4180)	GREEN PLAINS OTTER TAIL, LLC (70110)	Midwest Corn, Dry Mill; Dry DGS and Wet DGS, Corn Oil and Syrup; Natural Gas, Grid Electricity; Starch Ethanol produced in Fergus Falls, MN; Finished fuel transported by Rail to California; Composite CI.	None	

ATTACHMENT L

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-9169-1-0 **EXPIRATION DATE**: 10/31/2026

EQUIPMENT DESCRIPTION:
DIGESTER GAS OPERATION CONSISTING OF A 36,000,000 GALLON (EQUIVALENT TO 412'X507'X21.5') ANAEROBIC DIGESTER LAGOON WITH AN AIR/OXYGEN INJECTION SYSTEM FOR H2S CONTROL AND A GAS COLLECTION AND HANDLING SYSTEM SERVED BY A H2S SCRUBBER

PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. The digester system shall be designed to allow gas generated to be stored for more than 24 hours prior to venting in the event that the gas cannot be combusted in digester gas-fired engines or sent to another device with a VOC control efficiency of at least 95% by weight as determined by the APCO. [District Rule 2201]
4. The air/oxygen injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]
5. The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
6. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rule 1070]

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-9169-4-0 **EXPIRATION DATE**: 10/31/2026

EQUIPMENT DESCRIPTION:
250 KW BLOOM ENERGY MODEL ES5-EB2AAN DIGESTER GAS-FUELED FUEL CELL

PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-9169-5-0 **EXPIRATION DATE**: 10/31/2026

EQUIPMENT DESCRIPTION:
250 KW BLOOM ENERGY MODEL ES5-EB2AAN DIGESTER GAS-FUELED FUEL CELL

PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-9169-6-0 **EXPIRATION DATE**: 10/31/2026

EQUIPMENT DESCRIPTION:
249.5 KW BLOOM ENERGY MODEL ES5-DB2AAC DIGESTER GAS-FUELED FUEL CELL

PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

San Joaquin Valley
Air Pollution Control District

PERMIT UNIT: C-9169-7-0 **EXPIRATION DATE**: 10/31/2026

EQUIPMENT DESCRIPTION:
249.5 KW BLOOM ENERGY MODEL ES5-DB2AAC DIGESTER GAS-FUELED FUEL CELL

PERMIT UNIT REQUIREMENTS

1. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
4. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
5. Emissions from this fuel cell shall not exceed any of the following limits: 0.0024 lb-NOx/MW-hr, 0.002 lb-SOx/MW-hr, 0.007 lb-PM10/MW-hr, 0.04 lb-CO/MW-hr, or 0.025 lb-VOC/MW-hr. [District Rules 2201 and 4801]
6. The sulfur content of the digester gas used as fuel in this fuel cell shall not exceed 1 ppmv as H2S. [District Rule 2201]
7. Records demonstrating that the sulfur content of the gas used as fuel in this fuel cell does not exceed 1 ppmv as H2S shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070 and 2201]

ATTACHMENT M

FEB 2 1 2020

Doug Bryant
Maas Energy Works, Inc
3711 Meadow View Dr, #100
Redding, CA 96002

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: C-9133
Project Number: C-1193519

Dear Mr. Bryant:

Enclosed for your review and comment is the District's analysis of Lone Oak Energy LLC's application for an Authority to Construct for the installation of a 1,306 bhp digester gas-fired IC engine powering an electrical generator, at 10014 S McMullin Grade, Hanford.

The notice of preliminary decision for this project has been posted on the District's website (www.valleyair.org). After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Jesse A. Garcia of Permit Services at (559) 230-5918.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:jag

Enclosures

cc: Courtney Graham, CARB (w/ enclosure) via email

San Joaquin Valley Air Pollution Control District

Authority to Construct Application Review

Installation of a Digester Gas-Fired IC Engine with SCR

Facility Name:	Lone Oak Energy LLC	Date:	January 22, 2020
Mailing Address:	2911 Hanford Armona Rd Hanford, CA 93230	Engineer:	Jesse A. Garcia
		Lead Engineer:	Jerry Sandhu
Contact Person:	Doug Bryant		
Telephone:	(207) 691-8068		
E-Mail:	doug@maasenergy.com		
Application #(s):	C-9133-3-0		
Project #:	C-1193519		
Deemed Complete:	December 9, 2019		

I. Proposal

Lone Oak Energy LLC has requested an Authority to Construct (ATC) to install a 1,306 bhp digester gas-fired IC engine powering an electrical generator. This IC engine was originally permitted under ATC C-9133-1-0; however, the applicant has requested higher NO_X, CO and VOC emission factors during normal operation after the commissioning period. A summary of the emission factors from ATC -1-0 and the ones proposed under this project are shown in the following table:

Summary of Emission Factor Changes (ppmv)		
Pollutant	**From ATC -1-0**	**Proposed in this Project**
NO_X	5	10
CO	15	223
VOC	10	20

Since the equipment being permitted in this project was also authorized under ATC -1-0, the ATC issued in this project will cancel and supersede ATC -1-0 and the following condition will be included on the ATC:

- This Authority to Construct (ATC) cancels and supersedes ATC C-9133-1-0. [District Rule 2201]

II. Applicable Rules

Rule 1070 Inspections (12/17/92)
Rule 2201 New and Modified Stationary Source Review Rule (8/15/19)
Rule 2410 Prevention of Significant Deterioration (6/16/11)

Rule 2520 Federally Mandated Operating Permits (8/15/19)
Rule 4001 New Source Performance Standards (4/14/99)
Rule 4002 National Emission Standards for Hazardous Air Pollutants (5/20/04)
Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4701 Internal Combustion Engines - Phase 1 (8/21/03)
Rule 4702 Internal Combustion Engines (11/14/13)
Rule 4801 Sulfur Compounds (12/17/92)
CH&SC 41700 Health Risk Assessment
CH&SC 42301.6 School Notice
Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)
California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. Project Location

The facility is located at 10014 S McMullin Grade in Hanford, CA. The equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

The applicant is proposing to install one 1,306 bhp Caterpillar lean burn digester gas-fired IC engine. The engine will be equipped with an SCR system and an oxidation catalyst for emissions control and will power a generator. The electricity generated by this operation will be sold to utility grid. The engine will be permitted to operate up to 24 hours per day and 120 hours per year during the commissioning period (the time allowed during initial startup of the engine to perform testing, adjustment, tuning, and calibration of the IC engine without full operation of the SCR system and/or oxidation catalyst) and up to 24 hours per day and 8,500 hours per year after the commissioning period.

V. Equipment Listing

C-9133-3-0: 1,306 BHP CATERPILLAR MODEL G3516LE DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING MODEL COMBIKAT CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

VI. Emission Control Technology Evaluation

The proposed engine will be equipped with:

- Turbocharger
- Intercooler
- Positive Crankcase Ventilation (PCV)
- Air/Fuel Ratio or an O_2 Controller
- Lean Burn Technology

- Oxidation Catalyst
- Selective Catalytic Reduction (SCR)

The turbocharger reduces the NOx emission rate from the engine by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NOx.

The PCV system reduces crankcase VOC and PM_{10} emissions by at least 90% over an uncontrolled crankcase vent.

The fuel/air ratio controller (oxygen controller) is used to maintain the amount of oxygen in the exhaust stream to optimize catalyst function.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NOx formation.

An oxidation catalyst converts CO and VOC emissions to CO_2 and water. Typically, these catalysts are located prior to the urea injection site since the oxidation catalyst would otherwise convert the excess ammonia into NOx.

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent, in this case urea, are passed through an appropriate catalyst. Urea, will be injected upstream of the catalyst where it reacts and reduces NOx, over the catalyst bed, to form elemental nitrogen and other by-products. The use of a catalyst typically reduces the NOx emissions by up to 90%.

Additionally, prior to being combusted in the engine, the digester gas will be treated in a gas conditioning system to reduce the H_2S such that the sulfur content will not exceed 40 ppmv as H_2S.

VII. General Calculations

A. Assumptions

- To streamline emission calculations, $PM_{2.5}$ emissions are assumed to be equal to PM_{10} emissions.
- Higher Heating Value (HHV) for Digester Gas: 700 Btu/scf (proposed by the applicant, based on 70% methane content, also used in other similar District projects)
- Typical EPA F-factor for digester gas: 9,100 dscf/MMBtu (Estimated based on previous source tests and District practice)
- MMBtu/hr to bhp conversion 392.75 bhp-hr/MMBtu (per AP-42, Appendix A)

- Average sulfur content of the scrubbed digester gas: 40 ppmv as H_2S (proposed by applicant)
- Molar Specific Volume = 379.5 scf/lb-mol (60°F)
- Molecular weights:
  - NO_x (as NO_2) = 46 lb/lb-mol CO = 28 lb/lb-mol NH_3 = 17 lb/lb-mol
  - VOC (as CH_4) = 16 lb/lb-mol SO_x (as SO_2) = 64.06 lb/lb-mol
- Efficiency of engine = 30% (District practice)
- A commissioning period to perform testing, adjustment, tuning, and calibration of the IC engine without full operation of the SCR system or oxidation catalyst will be allowed during initial startup of the engine. The duration of the commissioning period shall last no more than 120 hours of operation of the engine without the SCR system or oxidation catalyst installed and operating at its maximum efficiency (proposed by applicant)
- During normal operation the engine will operate 24 hours/day and 8,500 hours per year (proposed by the applicant)
- Ammonia slip from SCR = 10 ppm (proposed by applicant)

B. Emission Factors

Emission Factors during the Commissioning Period:

The commissioning period precedes normal operation of a power plant. Activities conducted during the commissioning period typically include: checking all mechanical, electrical, and control systems for the units and related equipment; confirming the performance measures specified for the equipment; test firing the units; and tuning of the units and the generators. The early stages of commissioning are conducted prior to the installation of the emission control equipment to prevent its damage. In accordance with EPA's guidance, the commissioning period is considered the final phase of the construction process rather than initial startup of the equipment.[1] Therefore, other than quantifying emissions for New and Modified Source Review (NSR), source-specific emission limitations from applicable rules and regulations are generally not effective until completion of the commissioning period. Because emission control devices are not in place and functioning during commissioning, higher emission limits are required during this time.

[1] See US EPA Implementation Question and Answer Document for National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, April 2, 2013, Question 39 (http://www.epa.gov/ttn/atw/rice/20120717riceqaupdate.pdf)

Emission Factors for Digester Gas-Fired Engine (Commissioning Period)			
Pollutant	**g/bhp·hr**	**ppmvd (@ 15%O_2)**	**Source**
NOx	1.0	--	Information from Engine Supplier (Caterpillar)
SOx	0.04	40 ppmvd in fuel gas	BACT Requirement/Mass Balance Equation on the Following Page
PM_{10}	0.08	--	AP-42, Table 2.4-4, October 2008, See Equation on the Following Page
CO	4.4	--	Information from Engine Supplier (Caterpillar)
VOC	1.1	--	Information from Engine Supplier (Caterpillar)
NH_3	0.06	10 ppmvd	Proposed by the Applicant, See Conversion on the Following Page

Emission Factors during Normal Operation after the Commissioning Period:

The emission factors for NOx, CO, and VOC from the proposed engine during normal operation were proposed by the applicant and supported by information provided by the engine and catalyst supplier. The emission factors for NOx, CO, and VOC will be achieved with the use of the SCR and catalyst system. The emission factors for SOx, PM_{10}, and ammonia slip during normal operation are the same as the emission factors presented above for during the commissioning period. The unit conversions (from ppmvd to g/bhp-hr) for the emission factors are also shown below.

Emission Factors for Digester Gas-Fired Engine (Normal Operation)			
Pollutant	**g/bhp·hr**	**ppmvd (@ 15%O_2)**	**Source**
NOx	0.15	10 ppmvd	Proposed by the Applicant, See Conversion Below
SOx	0.04	40 ppmvd in fuel gas	Proposed by the Applicant, See Equation on the Following Page
PM_{10}	0.08	--	AP-42, Table 2.4-4, October 2008, See Conversion on the Following Page
CO	2.0	223 ppmvd	Proposed by the Applicant, See Conversion on the Following Page
VOC	0.10	20 ppmvd	Proposed by the Applicant, See Conversion on the Following Page
NH_3	0.06	10 ppmvd	Proposed by the Applicant, See Conversion on the Following Page

NOx – 10 ppmvd @ 15% O_2 as proposed by the Applicant

$$\frac{10\ \text{ft}^3\ \text{NOx}}{10^6\ \text{ft}^3} \times \frac{9{,}100\ \text{ft}^3}{1\text{MMBtu}} \times \frac{46\ \text{lb NOx}}{1\ \text{lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1\ \text{lb-mole}}{379.5\ \text{ft}^3} \times \frac{\text{MMBtu}}{392.75\ \text{bhp-hr}} \times \frac{453.6\ \text{g}}{\text{lb}} \times \frac{\text{Btu}_{\text{in}}}{0.30\ \text{Btu}_{\text{out}}} = 0.15\ \frac{\text{g-NOx}}{\text{bhp-hr}}$$

SOx – 40 ppmvd H_2S @ 15% O_2 in fuel gas

$$\frac{40\ ft^3\ H_2S}{10^6\ ft^3} \text{ x } \frac{32.06\ lb\ S}{lb\text{-}mol\ H_2S} \text{ x } \frac{lb\text{-}mole}{379.5\ ft^3} \text{ x } \frac{64.06\ lb\ SO_2}{32.06\ lb\ S} \text{ x } \frac{ft^3}{700\ Btu} \text{ x } \frac{10^6\ Btu}{MMBtu} = 0.00965\ \frac{lb\ SOx}{MMBtu}$$

$$0.00965\ \frac{lb\ SOx}{MMBtu} \text{ x } \frac{MMBtu}{392.75\ bhp\text{-}hr} \text{ x } \frac{Btu_{in}}{0.30\ Btu_{out}} \text{ x } \frac{453.59\ g}{lb} = 0.04\ \frac{g\text{-}SOx}{bhp\text{-}hr}$$

PM_{10} – AP-42, Table 2.4-4: 15 lb/10^6 dscf

15 lb-PM_{10}/10^6 dscf x 1 scf/ 700 Btu = 0.021 lb/MMBtu

$$0.021\ \frac{lb\ PM10}{MMBtu} \text{ x } \frac{1\ MMBtu}{10^6\ Btu} \text{ x } \frac{Btu_{in}}{0.30\ Btu_{out}} \text{ x } \frac{2{,}545\ Btu}{hp\text{-}hr} \text{ x } \frac{453.59\ g}{lb} = 0.08\ \frac{g\text{-}PM10}{bhp\text{-}hr}$$

CO – 223 ppmvd @ 15% O2

$$\frac{223\ ft^3\ CO}{10^6\ ft^3} \text{ x } \frac{9{,}100\ ft^3}{1\ MMBtu} \text{ x } \frac{28\ lb\ CO}{1\ lb\text{-}mole} \text{ x } \frac{20.9}{20.9-15} \text{ x } \frac{1\ lb\text{-}mole}{379.5\ ft^3} \text{ x } \frac{MMBtu}{392.75\ bhp\text{-}hr} \text{ x } \frac{453.6\ g}{lb} \text{ x } \frac{Btu_{in}}{0.30\ Btu_{out}} = 2.0\ \frac{g\text{-}CO}{bhp\text{-}hr}$$

VOC – 20 ppmvd @ 15% O_2 as proposed by the Applicant

$$\frac{20\ ft^3\ VOC}{10^6\ ft^3} \text{ x } \frac{9{,}100\ ft^3}{1\ MMBtu} \text{ x } \frac{16\ lb\ VOC}{1\ lb\text{-}mole} \text{ x } \frac{20.9}{20.9-15} \text{ x } \frac{1\ lb\text{-}mole}{379.5\ ft^3} \text{ x } \frac{MMBtu}{392.75\ bhp\text{-}hr} \text{ x } \frac{453.6\ g}{lb} \text{ x } \frac{Btu_{in}}{0.30\ Btu_{out}} = 0.10\ \frac{g\text{-}VOC}{bhp\text{-}hr}$$

NH_3 – 10 ppmvd @ 15% O_2 as proposed by the Applicant

$$\frac{10\ ft^3\ NH_3}{10^6\ ft^3} \text{ x } \frac{9{,}100\ ft^3}{MMBtu} \text{ x } \frac{17\ lb\ NH_3}{lb\text{-}mole} \text{ x } \frac{20.9}{20.9-15} \text{ x } \frac{1\ lb\text{-}mole}{379.5\ ft^3} \text{ x } \frac{MMBtu}{392.75\ bhp\text{-}hr} \times \frac{453.6\ g}{lb} \times \frac{Btu_{in}}{0.30\ Btu_{out}} = 0.06\ \frac{g\text{-}NH_3}{bhp\text{-}hr}$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since this is a new emissions unit, PE1 = 0 for all pollutants.

2. Post-Project Potential to Emit (PE2)

PE2 (lb/day) = [EF (g/hp-hr) x Rating (bhp) x 24 (hr/day)] / 453.6 (g/lb)

Daily PE2 During the Commissioning Period								
NO_X	1.0	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	69.1	(lb/day)
SO_X	0.04	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	2.8	(lb/day)
PM_{10}	0.08	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	5.5	(lb/day)
CO	4.4	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	304.0	(lb/day)
VOC	1.1	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	76.0	(lb/day)
NH_3	0.06	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	4.1	(lb/day)

Daily PE2 for the Engine after Completion of the Commissioning Period:

Daily PE for the proposed engine after completion of the commissioning period is calculated in the table below:

PE2 (lb/day) = [EF (g/hp-hr) x Rating (bhp) x 24 (hr/day)] / 453.6 (g/lb)

Daily PE2 After the Commissioning Period (Normal Operation)								
NO_X	0.15	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	10.4	(lb/day)
SO_X	0.04	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	2.8	(lb/day)
PM_{10}	0.08	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	5.5	(lb/day)
CO	2.0	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	138.2	(lb/day)
VOC	0.10	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	6.9	(lb/day)
NH_3	0.06	(g/bhp·hr) x	1,306	(bhp) x	24	(hr/day) ÷ 453.6 (g/lb) =	4.1	(lb/day)

Maximum Annual PE2 for the Engine Including the Commissioning Period:

As discussed above, the proposed engine will be allowed to operate up to 120 hours for commissioning during the first year of operation. The maximum annual PE for the engine will be calculated based on the maximum hours of operation during the commissioning period and the remaining hours during normal operation.

Annual PE2 During the Commissioning Period								
NO_X	1.0	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	346	(lb/yr)
SO_X	0.04	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	14	(lb/yr)
PM_{10}	0.08	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	28	(lb/yr)
CO	4.4	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	1,520	(lb/yr)
VOC	1.1	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	380	(lb/yr)
NH_3	0.06	(g/bhp·hr) x	1,306	(bhp) x	120	(hr/yr) ÷ 453.6 (g/lb) =	21	(lb/yr)

First Year Annual PE2 After the Commissioning Period											
NO_x	0.15	(g/bhp·hr)	x	1,306	(bhp)	x	8,380	(hr/yr) ÷ 453.6 (g/lb)	=	3,619	(lb/yr)
SO_x	0.04	(g/bhp·hr)	x	1,306	(bhp)	x	8,380	(hr/yr) ÷ 453.6 (g/lb)	=	965	(lb/yr)
PM_{10}	0.08	(g/bhp·hr)	x	1,306	(bhp)	x	8,380	(hr/yr) ÷ 453.6 (g/lb)	=	1,930	(lb/yr)
CO	2.0	(g/bhp·hr)	x	1,306	(bhp)	x	8,380	(hr/yr) ÷ 453.6 (g/lb)	=	48,255	(lb/yr)
VOC	0.10	(g/bhp·hr)	x	1,306	(bhp)	x	8,380	(hr/yr) ÷ 453.6 (g/lb)	=	2,413	(lb/yr)
NH_3	0.06	(g/bhp·hr)	x	1,306	(bhp)	x	8,380	(hr/yr) ÷ 453.6 (g/lb)	=	1,448	(lb/yr)

Maximum Annual PE2 from the Engine during 1st year, Including Commissioning:

Maximum Post-Project Daily and Annual PE2				
Pollutant	Daily (lb/day)	During Commissioning (lb/year)	After Commissioning (lb/year)	Total (lb/year)
NO_x	69.1	346	3,619	3,965
SO_x	2.8	14	965	979
PM_{10}	5.5	28	1,930	1,958
CO	304.0	1,520	48,255	49,775
VOC	76.0	380	2,413	2,793
NH_3	4.1	21	1,448	1,469

Annual PE2 for the Engine in years with no Commissioning:

The annual PE2 for the engine after completion of the first year of operation when there will not be any commissioning period is calculated as follows:

Annual PE2 After Year 1 with no Commissioning (Normal Operation)											
NO_x	0.15	(g/bhp·hr)	x	1,306	(bhp)	x	8,500	(hr/yr) ÷ 453.6 (g/lb)	=	3,671	(lb/yr)
SO_x	0.04	(g/bhp·hr)	x	1,306	(bhp)	x	8,500	(hr/yr) ÷ 453.6 (g/lb)	=	979	(lb/yr)
PM_{10}	0.08	(g/bhp·hr)	x	1,306	(bhp)	x	8,500	(hr/yr) ÷ 453.6 (g/lb)	=	1,958	(lb/yr)
CO	2.0	(g/bhp·hr)	x	1,306	(bhp)	x	8,500	(hr/yr) ÷ 453.6 (g/lb)	=	48,946	(lb/yr)
VOC	0.10	(g/bhp·hr)	x	1,306	(bhp)	x	8,500	(hr/yr) ÷ 453.6 (g/lb)	=	2,447	(lb/yr)
NH_3	0.06	(g/bhp·hr)	x	1,306	(bhp)	x	8,500	(hr/yr) ÷ 453.6 (g/lb)	=	1,468	(lb/yr)

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site. Pursuant to the applicant, the digester gas operation permitted under ATC C-9133-2-0 will be implemented and should be included in the SSPE1 calculation; however, as calculated in project C-1170074, the PE2 for the digester gas operation is 0 lb/year. Therefore, SSPE1 = 0 lb/year for all pollutants.

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

SSPE2 (lb/year)						
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC	NH_3
C-9133-2-0	0	0	0	0	0	0
C-9133-3-0	3,965	979	1,958	49,775	2,793	1,469
SSPE2	**3,965**	**979**	**1,958**	**49,775**	**2,793**	**1469**

5. Major Source Determination

Rule 2201 Major Source Determination:

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
SSPE1	0	0	0	0	0	0
SSPE2	3,965	979	1,958	1,958	49,775	2,793
Major Source Threshold	20,000	140,000	140,000	140,000	200,000	20,000
Major Source?	No	No	No	No	No	No

Note: $PM_{2.5}$ assumed to be equal to PM_{10}

As seen in the table above, the facility is not an existing Major Source and is not becoming a Major Source as a result of this project.

Rule 2410 Major Source Determination:

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Estimated Facility PE before Project Increase	0	0	0	0	0	0
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source?	No	No	No	No	No	No

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

Since this is a new emissions unit, BE = PE1 = 0 for all pollutants.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification.

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- Hydrogen sulfide (H2S)

I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is 250 tpy for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO_2	VOC	SO_2	CO	PM	PM_{10}
Total PE from New and Modified Units	2.0	1.4	0.5	24.9	1.0	1.0
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	N	N	N	N	N	N

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix E.

VIII. Compliance Determination

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

Pursuant to District Rule 2201, Section 4.1, BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an Adjusted Increase in Permitted Emissions (AIPE) exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

As seen in Section VII.C.2 above, the proposed engine will have a PE greater than 2.0 lb/day for NO_x, SO_x, PM_{10}, CO, and VOC. Therefore, BACT is triggered for NO_x, SO_x, PM_{10}, and VOC. However, BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 of this document.

The proposed engine will have a PE greater than 2.0 lb/day for NH3. However, NH3 slip emissions are the result from operation of an emissions control device (SCR) and not the emissions unit; therefore, this project does not trigger BACT for NH3 emissions.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore BACT is not triggered.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 and/or Federal Major Modification for any pollutant. Therefore BACT is not triggered for any pollutant.

2. BACT Guideline

BACT Guideline 3.3.15 applies to the proposed digester gas-fired IC engine. [Waste Gas-Fired IC Engines] (See Appendix B)

3. Top-Down BACT Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

Pursuant to the Top-Down BACT Analysis (See Appendix C), BACT has been satisfied with the following:

NO_X: NO_X emissions ≤ 0.15 g/bhp-hr
SO_X: Fuel sulfur content ≤ 40 ppmv (as H_2S)
PM_{10}: Fuel sulfur content ≤ 40 ppmv (as H_2S)
VOC: VOC emissions ≤ 0.10 g/bhp-hr

The following conditions will be placed on the ATC to ensure compliance with the BACT requirements during normal operation:

- This engine shall be fired on digester gas fuel only. [District Rule 2201]
- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

B. Offsets

1. Offset Applicability

Pursuant to District Rule 2201, Section 4.5, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
SSPE2	3,965	979	1,958	49,775	2,793
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

C. Public Notification

1. Applicability

Pursuant to District Rule 2201, Section 5.4, public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed,
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant, and/or
e. Any project which results in a Title V significant permit modification

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. Since this is not a new facility, public noticing is not required for this project for New Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

b. PE > 100 lb/day

The PE2 for this new unit is compared to the daily PE Public Notice thresholds in the following table:

PE > 100 lb/day Public Notice Thresholds			
Pollutant	**PE2 (lb/day)**	**Public Notice Threshold**	**Public Notice Triggered?**
NO_X	69.1	100 lb/day	No
SO_X	2.8	100 lb/day	No
PM_{10}	5.5	100 lb/day	No
CO	304.0	100 lb/day	Yes
VOC	76.0	100 lb/day	No
NH_3	4.1	100 lb/day	No

Therefore, public noticing for PE > 100 lb/day purposes is required.

c. Offset Threshold

Public notification is required if the pre-project Stationary Source Potential to Emit (SSPE1) is increased to a level exceeding the offset threshold levels. The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Thresholds				
Pollutant	**SSPE1 (lb/year)**	**SSPE2 (lb/year)**	**Offset Threshold**	**Public Notice Required?**
NO_X	0	3,965	20,000 lb/year	No
SO_X	0	979	54,750 lb/year	No
PM_{10}	0	1,958	29,200 lb/year	No
CO	0	49,775	200,000 lb/year	No
VOC	0	2,793	20,000 lb/year	No

As demonstrated above, there were no thresholds surpassed with this project; therefore public noticing is not required for offset purposes.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_x	3,965	0	3,965	20,000 lb/year	No
SO_x	979	0	979	20,000 lb/year	No
PM_{10}	1,958	0	1,958	20,000 lb/year	No
CO	49,775	0	49,775	20,000 lb/year	Yes
VOC	2,793	0	2,793	20,000 lb/year	No
NH_3	1,469	0	1,469	20,000 lb/year	No

As demonstrated above, the SSIPE for CO was greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating permit, this change is not a Title V significant Modification, and therefore public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project for CO emissions in excess of 100 lb/day and SSIPE greater than 20,000 lb/year. Therefore, public notice documents will be submitted to the California Air Resources Board (CARB) and a public notice will be electronically published on the District's website prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions

Proposed Rule 2201 (DEL) Conditions for Engine during Both Commissioning and Normal Operation:

- This engine shall be fired on digester gas fuel only. [District Rule 2201]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H_2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit.[2] [District Rules 2201, 4102, 4702, and 4801]
- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]
- Ammonia (NH_3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]
- All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Commissioning Period:

For the proposed engine, the DELs for NO_X, SO_X, PM_{10}, CO, and VOC are stated in the form of maximum emission factors (g/bhp-hr), the maximum engine horsepower rating (1,306 bhp), and maximum number of hours allowed for commissioning activities. The following conditions will be placed on the permit as a mechanism to ensure compliance.

- The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
- Commissioning activities are defined as, but not limited to, all adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The commissioning period shall terminate when the initial engine tuning has completed and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation of the engine. [District Rule 2201]

[2] Due to variations in sulfur content of the digester gas, an averaging time cannot be established until the unit has operated in a steadystate manner.

- The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rules 2201 and 4102]
- Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.08 g-PM_{10}/bhp-hr, 4.4 g-CO/bhp-hr, 1.1 g-VOC/bhp-hr. [District Rule 2201]
- At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
- At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
- The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system and oxidation catalyst, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system and oxidation catalyst. [District Rule 2201]

<u>Proposed Rule 2201 (DEL) Conditions during Normal Operation</u>:

- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

  Additionally, to limit annual emissions, the following condition will be included on the ATC:

- This engine shall not operate more than 8,500 hours per calendar year. [District Rule 2201]

E. Compliance Assurance

1. Source Testing

In accordance with District Policy APR 1705, source testing for NO_x, CO and VOC emissions from the digester gas fired IC engine served by a catalyst control system (including SCR and an oxidation catalyst) shall be conducted initially and at least once every 24 months thereafter. In addition, in order to assure compliance with the ammonia slip limit from the SCR system, source testing of the ammonia emissions will also be required initially and at least once every 24 months thereafter.

For PM_{10} emissions, the applicant has proposed to use an emission factor from AP-42, Section 2.4, which is applicable to municipal solid waste landfills. The digester gas fired in this engine should have a similar makeup to that of gas generated by a landfill. However, in order to assure that the engine is able to demonstrate compliance with the proposed PM_{10} emission factor, initial source testing will be required.

The engine is not served by any control devices for PM_{10} emissions. Therefore, it is not expected that the PM_{10} emissions will change much over time as long as the quality of the gas combusted in this unit remains fairly consistent. The facility will be required to monitor the sulfur content of the digester gas combusted in this unit at least once per quarter. The results of this quarterly monitoring should demonstrate that the quality of the gas combusted is consistent. Therefore, ongoing periodic source testing for PM_{10} emissions will not be required.

The following conditions will be placed on the permit to ensure compliance:

- Source testing to measure NO_x, CO, VOC, PM_{10}, and ammonia (NH_3) emissions from this unit shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201, and 4702]
- Source testing to measure NO_x, CO, VOC, and ammonia (NH_3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH_3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]
- The following methods shall be used for emissions source testing: NOx (ppmv) - EPA Method 7E; CO (ppmv) - EPA Method 10; VOC (ppmv) - EPA Method 18, 25A or 25B; stack gas oxygen - EPA Method 3 or 3A; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, ARB Method 5 (front half and back half), or ARB Method 5 (front half and back half) in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]
- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

2. Monitoring

The proposed digester gas-fired engine is subject to District Rule 4702 - Internal Combustion Engines. Section 5.8.1 of District Rule 4702 requires engines rated at least 1,000 bhp that can operate more than 2,000 hour per calendar year or equipped with external control devices to install, operate, and maintain an APCO-approved alternate monitoring plan. Section 5.8.9 of District Rule 4702 requires monitoring of NO_X emissions at least once every calendar quarter for a non-agricultural spark-ignited IC engine. However, Section 6.5.3 of District Rule 4702 requires monthly monitoring for engines equipped with non-certified control devices in order to demonstrate compliance with the emission limits in District Rule 4702. Therefore, monthly monitoring of NO_X, CO, and O_2 concentrations in accordance pre-approved alternate monitoring plan "A" will be required. Since the engine will be equipped with SCR, quarterly monitoring of ammonia slip will also be required.

The following conditions will be placed on the permit to ensure compliance:

- The permittee shall monitor and record the stack concentration of NO_x, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if 2 consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- The permittee shall monitor and record the stack concentration of NH_3 at least once every calendar quarter in which a source test is not performed. NH_3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]
- If the NOx, CO, or NH_3 concentrations, as measured by the portable analyzer or the District approved ammonia monitoring equipment, exceed the allowable emission concentration, the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours after detection. If the portable analyzer readings continue to exceed the allowable emissions concentration after 8 hours, the permittee shall notify the District within the following 1 hour, and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

In addition, Section 5.10.1 of District Rule 4702 requires an annual analysis of the sulfur content of engine fuel. Because of the variable content of digester gas, additional monitoring of the fuel sulfur content will be required.

The following conditions will be placed on the permits to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
- The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of

the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rules 2201 and 4702]

- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a digital analyzer approved for gaseous fuel analysis; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rules 2201 and 4702]

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201. The following recordkeeping conditions will be listed on the permit:

- The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
- Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]
- The permittee shall maintain records of: (1) the date and time of NO_x, CO, O2, and NH_3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH_3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rule 2201]
- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]
- Records of hydrogen sulfide analyzer(s) installed or utilized and the calibration records of such analyzer(s) shall be maintained. Records are only required on such analyzer(s) utilized to demonstrate compliance with this permit. [District Rule 2201]
- The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201
- {4051} The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

4. Reporting

No reporting is required to demonstrate compliance with Rule 2201.

F. Ambient Air Quality Analysis (AAQA)

Section 4.14 of District Rule 2201 requires that an AAQA be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The District's Technical Services Division conducted the required analysis. Refer to Appendix D of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_x, CO, and SO_x. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_x, CO, or SO_x.

The proposed location is in a non-attainment area for the state's PM_{10} as well as federal and state $PM_{2.5}$ thresholds. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for PM_{10} and $PM_{2.5}$.

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII.C.9 above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

Rule 4001 New Source Performance Standards (NSPS)

This rule incorporates NSPS from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR) and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

40 CFR 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

The purpose of 40 CFR 60 Subpart JJJJ is to establish New Source Performance Standards to reduce emissions of NO_x, SO_x, PM, CO, and VOC from new stationary spark ignition (SI) internal combustion (IC) engines.

Pursuant to Section 60.4230, compliance with this subpart is required for owners and operators of stationary SI IC engines that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: (a) on or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP); (b) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP; (c) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or (d) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

The engine is a 1,306 bhp SI ICE that was constructed after June 12, 2006 and manufactured after July 1, 2007; therefore, the engine is subject to this subpart. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, the requirements from this subpart will not be included in the permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

Rule 4002 National Emission Standards for Hazardous Air Pollutants (NESHAPs)

This rule incorporates NESHAPs from Part 63, Chapter 1, Title 40, Code of Federal Regulations (CFR) and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 63.

40 CFR 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Internal Combustion Engines

40 CFR 63 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. A major source of HAP emissions is a facility that has the potential to emit any single HAP at a rate of 10 tons/year or greater or any combinations of HAPs at a rate of 25 tons/year or greater. An area source of HAPs is a facility is not a major source of HAPs.

Pursuant to Section 63.6590(c), an affected source that is a new or reconstructed stationary Reciprocating Internal Combustion Engine (RICE) located at an area source must meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60, Subpart JJJJ, for spark ignition engines and no further requirements apply for such engines under this part.

As with 40 CFR 60, Subpart JJJJ, the District has not been delegated the authority to implement 40 CFR 63, Subpart ZZZZ for non-Major Sources; therefore, no requirements from this subpart will be included in the permit. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

Rule 4101 Visible Emissions

Rule 4101 states that no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

Since the engine is fired solely on gaseous fuel, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity.

The following condition will be listed on the permit as a mechanism to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

The following nuisance prohibition condition will be included on the permits:

- No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

An HRA is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Appendix D), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project.

The cancer risk for this project is shown below:

HRA Summary		
Unit	**Cancer Risk**	**T-BACT Required**
C-9133-3-0	0.0823 per million	No

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 20 in a million). As outlined by the HRA Summary in Appendix D of this report, the emissions increases for this project was determined to be less than significant.

The following condition will be listed on the permit as a mechanism to ensure compliance.

- The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rules 2201 and 4102]
- The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot. The higher of the two emission factors (0.08 g-PM_{10}/bhp-hr and 0.03 g-PM_{10}/bhp-hr) for the engine will be used to demonstrate compliance for the engine:

$$\frac{0.08\ \text{g}}{\text{hp}\cdot\text{hr}} \times \frac{1\ \text{hp}\cdot\text{hr}}{2{,}545\ \text{Btu}} \times \frac{10^6\ \text{Btu}}{9{,}100\ \text{dscf}} \times \frac{0.3\text{Btu}_{out}}{1\text{Btu}_{in}} \times \frac{15.43\ \text{grain}}{\text{g}} = 0.02\ \frac{\text{grain}}{\text{dscf}}$$

Since 0.02 grain/dscf is less than 0.1 grain/dscf, compliance with this rule is expected.

The following condition will be listed on the permits as a mechanism to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4701 Internal Combustion Engines – Phase I

The purpose of this rule is to limit the emissions of nitrogen oxides (NOx), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion (IC) engines.

The requirements of Rule 4702 are equivalent or more stringent than the requirements of this Rule. Since the proposed IC engines are subject to both Rules 4701 and 4702, compliance with Rule 4702 is sufficient to demonstrate compliance with this rule.

Rule 4702 Internal Combustion Engines

The purpose of this rule is to limit the emissions of nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compounds (VOC), and sulfur oxides (SOx) from IC engines.

This rule applies to any internal combustion engine with a rated brake horsepower of 25 brake horsepower or greater.

Section 5.2.1 requires that the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall not operate it in such a manner that results in emissions exceeding the limits in Table 1 of Rule 4702 until such time that the engine has demonstrated compliance with emission limits in Table 2 of Rule 4702 pursuant to the compliance deadlines in Section 7.5. In lieu of complying with Table 1 emission limits, the operator of a spark-ignited engine shall comply with the applicable emission limits pursuant to Section 8.0.

The engines are required to immediately comply with the emission limits contained in Table 2 since the applicable compliance dates have passed (except for an operator with at least 12 existing engines at one stationary source); therefore, the emissions limits in Table 1 of Rule 4702 are not applicable to the engine.

Section 5.2.2 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall comply with all the applicable requirements of the rule and the requirements of Section 5.2.2.1, 5.2.2.2, or 5.2.2.3, on an engine-by-engine basis.

Section 5.2.2.1 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited engine that is used exclusively in non-agricultural operations shall comply with Sections 5.2.2.1.1 through 5.2.2.1.3 on an engine-by-engine basis:

5.2.2.1.1 NOx, CO, and VOC emission limits pursuant to Table 2;
5.2.2.1.2 SOx control requirements of Section 5.7, pursuant to the deadlines specified in Section 7.5; and
5.2.2.1.3 Monitoring requirements of Section 5.10, pursuant to the deadlines specified in Section 7.5.

Section 5.2.2.2 allows that in lieu of complying with the NOx emission limit requirement of Section 5.2.2.1.1, an operator may pay an annual fee to the District, as specified in Section 5.6, pursuant to Section 7.6. As shown below, the applicant is proposing to comply with the NOx emission limit requirement of Table 2 as required by Section 5.2.2.1.1; therefore, no further discussion is required.

Section 5.2.2.3 allows that in lieu of complying with the NOx, CO, and VOC limits of Table 2 on an engine-by-engine basis, an operator may elect to implement an alternative emission control plan pursuant to Section 8.0. As shown below, the applicant is proposing to comply with the NOx, CO, and VOC emission limit requirements of Table 2; therefore, no further discussion is required.

Rule 4702, Table 2 Emission Limits/Standards for Spark-Ignited IC Engines rated >50 bhp Used in Non-Agricultural Operations (Emission Limits are effective according to the compliance schedule specified in Rule 4702, Section 7.5.)			
Engine Type	**NOx Emission Limit (ppmv @ 15% O_2, dry)**	**CO Emission Limit (ppmv @ 15% O_2, dry)**	**VOC Emission Limit (ppmv @ 15% O_2, dry)**
2. e. Lean-Burn, Not Listed Above	11 ppmv	2,000 ppmv	750 ppmv

The engine is operated as a separate stationary source on land leased from an existing dairy, and the District has determined that the engine is a non-agricultural IC engine. The engine is fired on digester gas which does not satisfy the definition of waste gas; therefore, the engine is required to comply with the following emissions limits from Table 2, Row 2.e: 11 ppmvd NOx, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2).

Therefore, the following, previously presented, condition will be listed on the permit as a mechanism to ensure compliance:

- After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

Section 5.2.3 applies to spark-ignited engines used exclusively in agricultural operations. As stated above, the engine is operated as part of a separate non-agricultural stationary source; therefore, Section 5.2.3 does not apply to the engine.

Section 5.2.4 applies to certified compression-ignited engines. The engine is not a compression-ignited engine; therefore, Section 5.2.4 does not apply to the engine.

Section 5.2.5 applies to non-certified compression-ignited engines. The engine is not a compression-ignited engine; therefore, Section 5.2.5 does not apply to the engine.

Section 5.3 requires that all continuous emission monitoring systems (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes. Any 15-consecutive minute block average CEMS measurement exceeding the applicable emission limits of this rule shall constitute a violation of this rule. The engine does not have CEMS installed; therefore this section of the rule is not applicable.

Section 5.4 specifies procedures to calculate percent emission reductions if percent emission reductions are used to comply with the NOx emission limits of Section 5.2. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the engine under this project; therefore, this section of the rule is not applicable.

Section 5.5 requires the operator of an internal combustion engine that uses percent emission reduction to comply with the NOx emission limits of Section 5.2 shall provide an accessible inlet and outlet on the external control device or the engine as appropriate for taking emission samples and as approved by the APCO. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the engine under this project; therefore, this section of the rule is not applicable.

Section 5.6 specifies procedures that operators of non-agricultural spark-ignited IC engines who elect to comply under Section 5.2.2.2 must use for calculation of the annual emissions fee. The applicant has proposed that the engine complies with the applicable emission limits of Table 2 of District Rule 4702; therefore, payment of annual emissions fees for the engine is not required and this section of the rule is not applicable.

Section 5.7 requires that on and after the compliance schedule specified in Section 7.5, operators of non-agricultural spark-ignited engines and non-agricultural compression-ignited engines shall comply shall comply with Sections 5.7.1, 5.7.2, 5.7.3, 5.7.4, 5.7.5, or 5.7.6:

5.7.1 Operate the engine exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or
5.7.2 Limit gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or
5.7.3 Use California Reformulated Gasoline for gasoline-fired spark-ignited engines; or
5.7.4 Use California Reformulated Diesel for compression-ignited engines; or
5.7.5 Operate the engine on liquid fuel that contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.4.6; or
5.7.6 Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

The average sulfur content of the digester gas fuel for the engine is limited to 40 ppmv or 0.04 g/bhp-hr (approximately equal to 0.008 grains sulfur per standard cubic feet[3]). The following condition will be listed on the permit as a mechanism to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H_2S. The applicant may utilize an averaging period of up to 24 hours in length for

[3]

$$0.04 \frac{g}{hp\cdot hr} \times \frac{39275hp\cdot hr}{MMBtu} \times \frac{MMBtu}{9{,}100dscf} \times \frac{0.30Btu_{out}}{1Btu_{in}} \times \frac{15.43grain}{g} = 0.008 \frac{grain}{dscf}$$

demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

Section 5.8 requires that the operator of a non-agricultural spark-ignited IC engine subject to the requirements of Section 5.2 or any engine subject to the requirements of Section 8.0 shall comply with the following requirements of Sections 5.8.1 – 5.8.11:

Section 5.8.1 stipulates that for each engine with a rated brake horsepower of 1,000 hp or greater and which is allowed to operate more than 2,000 hours per calendar year, or with an external emission control device, shall either install, operate, and maintain continuous monitoring equipment for NOx, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install, operate, and maintain APCO-approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system (CEMS), a parametric emissions monitoring system (PEMS), or an alternative monitoring system approved by the APCO. APCO-approved alternate monitoring shall consist of one or more of the following:

5.8.1.1 Periodic NOx and CO emission concentrations,
5.8.1.2 Engine exhaust oxygen concentration,
5.8.1.3 Air-to-fuel ratio,
5.8.1.4 Flow rate of reducing agents added to engine exhaust,
5.8.1.5 Catalyst inlet and exhaust temperature,
5.8.1.6 Catalyst inlet and exhaust oxygen concentration, or
5.8.1.7 Other operational characteristics.

The applicant has proposed to comply with this section of the rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic monitoring of NOx, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, the following condition will be placed on the permit as a mechanism to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

Section 5.8.2 requires that for each non-agricultural spark-ignited IC engine not subject to Section 5.8.1, the operator shall monitor operational characteristics recommended by the engine manufacturer or emission control system supplier, and approved by the APCO. The engine is subject to Section 5.8.1; therefore this section is not applicable.

Section 5.8.3 requires that for each engine with an alternative monitoring system, the operator shall submit to, and receive approval from the APCO, adequate verification of the alternative monitoring system's acceptability. The engine includes a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NOx, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, this section is satisfied.

Section 5.8.4 requires that for each engine with an APCO approved CEMS, operate the CEMS in compliance with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Appendix B (Performance Specifications), 40 CFR Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). The engine does not have CEMS installed; therefore, this section of the rule is not applicable.

Section 5.8.5 requires that each engine have the data gathering and retrieval capabilities of an installed monitoring system described in Section 5.8 approved by the APCO. As stated above, the engine includes an alternate emissions monitoring plan that has been pre-approved by the APCO. Therefore, this section is satisfied.

Section 5.8.6 requires that for each non-agricultural spark-ignited IC engine, the operator shall install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the operator may use an alternative device, method, or technique in determining operating time provided that the alternative is approved by the APCO. The operator shall maintain and operate the required meter in accordance with the manufacturer's instructions. The applicant has proposed a nonresettable elapsed operating time meter for the engine in this project. Therefore, the following condition will be placed on the permit as a mechanism to ensure compliance:

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]

Section 5.8.7 requires that for each engine, the operator shall implement the Inspection and Monitoring (I&M) plan submitted to and approved by the APCO pursuant to Section 6.5. The applicant has submitted an I&M program with this ATC application and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this rule.

Section 5.8.8 requires that for each engine, the operator shall collect data through the I&M plan in a form approved by the APCO. The applicant has submitted an I&M program and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this rule.

Section 5.8.9 requires for each non-agricultural spark-ignited IC engine, the operator shall use a portable NOx analyzer to take NOx emission readings to verify compliance with the emission requirements of Section 5.2 or Section 8.0 during each calendar quarter in which a source test is not performed. If an engine is operated less than 120 calendar days per calendar year, the operator shall take one NOx emission reading during the calendar year in which a source test is not performed and the engine is operated. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. All NOx emissions readings shall be reported to the APCO in a manner approved by the APCO. NOx emission readings taken pursuant to this section shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period. Therefore, the following conditions will be placed on the permit as a mechanism to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.8.10 specifies that the APCO shall not approve an alternative monitoring system unless it is documented that continued operation within ranges of specified emissions related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits and that the operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards. The permit for the engine includes a pre-approved alternate emissions monitoring plan that requires periodic NOx, CO, and O_2 emissions concentrations. Therefore, this section is satisfied.

Section 5.8.11 requires that for each non-agricultural spark-ignited IC engine subject to the Alternate Emission Control Plan (AECP) of Section 8.0, the operator shall install and operate a nonresettable fuel meter. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the engine; therefore this section of the rule is not applicable.

Section 5.9 specifies monitoring requirements for all other engines that are not subject to the requirements of Section 5.8. The engine is subject to the requirements of Section 5.8; therefore this section of the rule is not applicable.

Section 5.10 specifies SOx Emissions Monitoring Requirements. On and after the compliance schedule specified in Section 7.5, an operator of a non-agricultural IC engine shall comply with the following requirements:

5.10.1 An operator of an engine complying with Sections 5.7.2 or 5.7.5 shall perform an annual sulfur fuel analysis in accordance with the test methods in Section 6.4. The operator shall keep the records of the fuel analysis and shall provide it to the District upon request,

5.10.2 An operator of an engine complying with Section 5.7.6 by installing and operating a control device with at least 95% by weight SOx reduction efficiency shall submit for approval by the APCO the proposed the key system operating parameters and frequency of the monitoring and recording not later than July 1, 2013, and

5.10.3 An operator of an engine complying with Section 5.7.6 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit-to-Operate. Source tests shall be performed in accordance with the test methods in Section 6.4.

The following condition will be listed on the permit as a mechanism to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

Section 5.11 requires operators of engines used exclusively in agricultural operations that are not required to have a Permit-to-Operate pursuant to California Health and Safety Code Section 42301.16 but are required to comply with Section 5.2 of Rule 4702 shall register such engines pursuant to Rule 2250 (Permit-Exempt Equipment Registration). The engine is required to have a District Permit to Operate; therefore this section of the rule is not applicable.

Section 6.1 requires that the operator of an engine subject to the requirements of Rule 4702 shall submit to the APCO an approvable emission control plan of all actions to be taken to satisfy the emission requirements of Section 5.2 and the compliance schedules of Section 7.0. If there is no change to the previously-approved emission control plan, the operator shall submit a letter to the District indicating that the previously approved plan is still valid.

Section 6.1.1 specifies that the requirement to submit an emission control plan shall apply to the following engines:

6.1.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;

6.1.1.2 Engines subject to Section 8.0;

6.1.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;

6.1.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

Section 6.1.2 specifies that the emission control plan shall contain the following information, as applicable for the engines:

6.1.2.1 Permit-to-Operate number, Authority-to-Construct number, or Permit-Exempt Equipment Registration number,
6.1.2.2 Engine manufacturer,
6.1.2.3 Model designation and engine serial number,
6.1.2.4 Rated brake horsepower,
6.1.2.5 Type of fuel and type of ignition,
6.1.2.6 Combustion type: rich-burn or lean-burn,
6.1.2.7 Total hours of operation in the previous one-year period, including typical daily operating schedule,
6.1.2.8 Fuel consumption (cubic feet for gas or gallons for liquid) for the previous one-year period,
6.1.2.9 Stack modifications to facilitate continuous in-stack monitoring and to facilitate source testing,
6.1.2.10 Type of control to be applied, including in-stack monitoring specifications,
6.1.2.11 Applicable emission limits,
6.1.2.12 Documentation showing existing emissions of NO_x, VOC, and CO, and
6.1.2.13 Date that the engine will be in full compliance with this rule.

Section 6.1.3 requires that the emission control plan shall identify the type of emission control device or technique to be applied to each engine and a construction/removal schedule, or shall provide support documentation sufficient to demonstrate that the engines are in compliance with the emission requirements of this rule.

Section 6.1.4 requires that for an engine being permanently removed from service, the emission control plan shall include a letter of intent pursuant to Section 7.2. The applicant has submitted all the required information for Section 6.1 in the application for the engine evaluated under this project.

Section 6.2.1 requires that the operator of an engine subject to the requirements of Section 5.2 shall maintain an engine operating log to demonstrate compliance with Rule 4702. This information shall be retained for a period of at least five years, shall be readily available, and be made available to the APCO upon request. The engine operating log shall include, on a monthly basis, the following information:

6.2.1.1 Total hours of operation,
6.2.1.2 Type of fuel used,
6.2.1.3 Maintenance or modifications performed,
6.2.1.4 Monitoring data,
6.2.1.5 Compliance source test results, and
6.2.1.6 Any other information necessary to demonstrate compliance with this rule.
6.2.1.7 For an engine subject to Section 8.0, the quantity (cubic feet of gas or gallons of liquid) of fuel used on a daily basis.

The following condition will be placed on the permit as a mechanism to ensure compliance:

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.8 and Section 5.9 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request.

The following, previously presented, condition will be listed on the permit as a mechanism to ensure compliance:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

Section 6.2.3 requires that an operator claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. The applicant is not claiming an exemption for the engines under Section 4.2 or Section 4.3; therefore, this section does not apply.

Section 6.3 requires that the operator of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.2, shall comply with the compliance testing requirements of Section 6.3.

Section 6.3.1 specifies that the requirements of Sections 6.3.2 through Section 6.3.4 shall apply to the following engines:

6.3.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.3.1.2 Engines subject to Section 8.0;
6.3.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.3.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

Section 6.3.2 requires demonstration of compliance with applicable limits, ppmv or percent reduction, in accordance with the test methods in Section 6.4, as specified below:

6.3.2.1 By the applicable date specified in Section 5.2, and at least once every 24 months thereafter, except for an engine subject to Section 6.3.2.2.
6.3.2.2 By the applicable date specified in Section 5.2 and at least once every 60 months thereafter, for an agricultural spark-ignited engine that has been retro-fitted with a catalytic emission control device.

6.3.2.3 A portable NOx analyzer may be used to show initial compliance with the applicable limits/standards in Section 5.2 for agricultural spark-ignited engines, provided the criteria specified in Sections 6.3.2.3.1 to 6.3.2.3.5 are met, and a source test is conducted in accordance with Section 6.3.2 within 12 months from the required compliance date.

The following condition will be included in the permit as a mechanism to ensure compliance:

- Source testing to measure NOx, CO, VOC, and ammonia (NH_3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

Section 6.3.3 requires the operator to conduct emissions source testing with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. For emissions source testing performed pursuant to Section 6.3.2 for the purpose of determining compliance with an applicable standard or numerical limitation, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC shall be reported as methane. VOC, NOx, and CO concentrations shall be reported in ppmv, corrected to 15 percent oxygen. For engines that comply with a percent reduction limit, the percent reduction of NOx emissions shall also be reported.

The following conditions will be included in the permit as a mechanism to ensure compliance:

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH_3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

Section 6.3.4 requires that in addition to other information, the source test protocol shall describe which critical parameters will be measured and how the appropriate range for these parameters shall be established. The range for these parameters shall be incorporated into the I&M plan.

Section 6.3.5 specifies that engines that are limited by Permit-to-Operate or Permit-Exempt Equipment Registration condition to be fueled exclusively with PUC quality natural gas shall not be subject to the reoccurring source test requirements of Section 6.3.2 for VOC emissions. The engine is fueled by digester gas; therefore, this section does not apply.

Section 6.3.6 specifies requirements for spark-ignited engines for testing a unit or units that represent a specified group of units, in lieu of compliance with the applicable requirements of Section 6.3.2. Testing of representative units is not being proposed for the engine; therefore, this section does not apply.

Section 6.4 requires that the compliance with the requirements of Section 5.2 shall be determined, as required, in accordance with the following test procedures or any other method approved by EPA and the APCO:

6.4.1 Oxides of nitrogen - EPA Method 7E, or ARB Method 100.
6.4.2 Carbon monoxide - EPA Method 10, or ARB Method 100.
6.4.3 Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.
6.4.4 Volatile organic compounds - EPA Method 25A or 25B, or ARB Method 100. Methane and ethane, which are exempt compounds, shall be excluded from the result of the test.
6.4.5 Operating horsepower determination - any method approved by EPA and the APCO.
6.4.6 SO_x Test Methods

6.4.6.1 Oxides of sulfur – EPA Method 6C, EPA Method 8, or ARB Method 100.
6.4.6.2 Determination of total sulfur as hydrogen sulfide (H_2S) content – EPA Method 11 or EPA Method 15, as appropriate.
6.4.6.3 Sulfur content of liquid fuel – American Society for Testing and Materials (ASTM) D 6920-03 or ASTM D 5453-99.
6.4.6.4 The SO_x emission control system efficiency shall be determined using the following:
% Control Efficiency = $[(C_{SO2,\ inlet} - C_{SO2,\ outlet}) / C_{SO2,\ inlet}] \times 100$
Where:
$C_{SO2,\ inlet}$ = concentration of SO_x (expressed as SO_2) at the inlet side of the SO_x emission control system, in lb/Dscf
$C_{SO2,\ outlet}$ = concentration of SO_x (expressed as SO_2) at the outlet side of the SO_x emission control system, in lb/Dscf

6.4.7 The Higher Heating Value (hhv) of the fuel shall be determined by one of the following test methods:

6.4.7.1 ASTM D 240-02 or ASTM D 3282-88 for liquid hydrocarbon fuels.
6.4.7.2 ASTM D 1826-94 or ASTM 1945-96 in conjunction with ASTM D 3588-89 for gaseous fuel.

The following conditions will be listed on the permit as a mechanism to ensure compliance:

- The following methods shall be used for source testing: NO_x (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH_3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

- The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

Section 6.5 requires that the operator of an engine that is subject to the requirements of Section 5.2 or the requirements of Section 8.0 shall submit to the APCO for approval, an Inspection & Maintenance (I&M) plan that specifies all actions to be taken to satisfy the requirements of Sections 6.5.1 through Section 6.5.9 and the requirements of Section 5.8. The actions to be identified in the I&M plan shall include, but are not limited to, the information specified below. If there is no change to the previously approved I&M plan, the operator shall submit a letter to the District indicating that previously approved plan is still valid.

Section 6.5.1 specifies that the I&M plan requirements of Sections 6.5.2 through Section 6.5.9 shall apply to the following engines:

6.5.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.5.1.2 Engines subject to Section 8.0;
6.5.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0.
6.5.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0.

The engine is equipped with an SCR system for control of NOx and oxidation catalyst for control of CO and VOC. Therefore, the requirements of Sections 6.5.2 through 6.5.9 are applicable to the engine.

Section 6.5.2 requires procedures requiring the operator to establish ranges for control equipment parameters, engine operating parameters, and engine exhaust oxygen concentrations that source testing has shown result in pollutant concentrations within the rule limits.

Section 6.5.3 requires procedures for monthly inspections as approved by the APCO. The applicable control equipment parameters and engine operating parameters will be inspected and monitored monthly in conformance with a regular inspection schedule in the I&M plan.

Section 6.5.4 requires procedures for the corrective actions on the noncompliant parameter(s) that the operator will take when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NOx, CO, VOC, or oxygen concentrations.

Section 6.5.5 requires procedures for the operator to notify the APCO when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NOx, CO, VOC, or oxygen concentrations.

Section 6.5.6 requires procedures for and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that the engine is operated and maintained per the manufacturer's specifications.

Section 6.5.7 requires procedures and a schedule for using a portable NOx analyzer to take NOx emission readings pursuant to Section 5.8.9.

Section 6.5.8 requires procedures for collecting and recording required data and other information in a form approved by the APCO including, but not limited to, data collected through the I&M plan and the monitoring systems described in Sections 5.8.1 and 5.8.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO.

NOx Emissions:

In order to satisfy the I&M requirements for NOx emissions, the applicant has proposed to perform the following:

1. The applicant will take periodic NOx emission concentration measurements with a portable analyzer at least once every calendar quarter.

2. To ensure that NOx emissions concentrations are not being exceeded between periodic NOx portable analyzer measurements, the applicant is proposing to determine a correlation between the SCR system's reagent injection rate and NOx emissions. The appropriate ranges for each operating load will be established during initial source testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on the permit as a mechanism to ensure compliance:

- The SCR system reagent injection rate may be reestablished during a performance test by monitoring the SCR system reagent injection rate concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the performance test that result in compliance with the NOx emission limits shall be imposed as a condition in the Permit to Operate. [District Rule 4702]
- If the SCR system reagent injection rate is outside of the established acceptable range, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

- The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]
- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4102]
- If the NOx, CO, or NH_3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

In order to satisfy the I&M requirements for CO and VOC emissions, the applicant has proposed to perform the following:

1. The applicant will take periodic CO emission concentration measurements with a portable analyzer at least once every calendar quarter. Per the catalyst manufacturer, if the oxidation catalyst is controlling CO emissions, it should also be achieving the desired removal efficiency for VOC emissions. Therefore, quarterly emission concentration measurements with a portable analyzer for VOC emissions will not be required.

2. To ensure that CO and VOC emissions concentrations are not being exceeded between periodic CO emission concentration measurements, the applicant proposed to determine a correlation between the catalyst control system inlet exhaust temperature and back pressure. The appropriate ranges for each operating load were established during initial source testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on the permit as a mechanism to ensure compliance:

- The inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system may be reestablished during a performance test by monitoring concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system demonstrated during the performance test that result in compliance with the CO and VOC emission limits shall by imposed as a condition in the Permit to Operate [District Rule 4702]
- The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]
- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]
- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the

dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

Section 6.5.9 specifies procedures for revising the I&M plan. The I&M plan shall be updated to reflect any change in operation. The I&M plan shall be updated prior to any planned change in operation. An engine operator that changes significant I&M plan elements must notify the District no later than seven days after the change and must submit an updated I&M plan to the APCO no later than 14 days after the change for approval. The date and time of the change to the I&M plan shall be recorded in the engine operating log. For new engines and modifications to existing engines, the I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit-to-Operate or Permit-Exempt Equipment Registration. The operator of an engine may request a change to the I&M plan at any time. The applicant has proposed to comply with the I&M plan modification requirements per this section of the rule. The following condition will be listed on the permit as a mechanism to ensure compliance:

- {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

Section 7.0 specifies the schedules for compliance with the general requirements of Section 5.0 and the Alternative Emission Control Plan (AECP) option of Section 8.0. The engine was required to comply with the applicable sections of District Rule 4702 upon initial startup of the equipment; therefore, compliance with this section is expected.

Section 8.0 specifies requirements for use of an Alternative Emission Control Plan (AECP) to comply with the NOx emission requirements of Section 5.2 for a group of engines. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the engine; therefore, this section of the rule is not applicable.

Section 9.0 specifies requirements for certification of exhaust control systems for compliance with District Rule 4702. Certification under this section for the exhaust control systems for the proposed engine is not currently being proposed; therefore, this section of the rule is not applicable at this time.

Conclusion

As shown above, the engine satisfies all the requirements of Rule 4702. The following conditions will be added to the permit as a mechanism to ensure continued compliance:

- {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
- {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

Rule 4801 Sulfur Compounds

The purpose of this District Rule 4801 is to limit the emissions of sulfur compounds. The limit is that sulfur compound emissions (as SO_2) shall not exceed 0.2% by volume. Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume of SOx as (SO_2) = (n x R x T) ÷ P

Where:

n = moles SOx
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73 \text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

To demonstrate compliance with the sulfur compound emission limit of Rule 4801, the maximum sulfur compound emissions from the engine will be calculated using the maximum sulfur content allowed for the digester gas, which is 40 ppmv, equivalent to 0.00965 lb-SOx/MMBtu.

$$0.00965 \frac{lb}{MMBtu} \times \frac{1\,MMBtu}{9{,}100 scf_{exhaust}} \times \frac{1\,lb \cdot mol}{64\,lb \cdot SO_2} \times \frac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot {}^\circ R} \times \frac{520^\circ R}{14.7\,psi} \times 1{,}000{,}000\,ppm = \quad 6.29 \quad \text{ppmv}$$

Since 6.29 ppmv is ≤ 2000 ppmv, the engine is expected to comply with Rule 4801. The following condition will be placed on the permit as a mechanism to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702, and 4801]

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

Greenhouse Gas (GHG) Significance Determination

It is determined that no other agency has prepared or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

The proposed project is for installation of an IC engine that will combust dairy digester gas to produce electricity. The digester system at this facility diverts manure from an adjacent dairy to covered lagoon digester(s), which will result in the capture of the methane that would otherwise be released into the atmosphere from open basin(s)/pond(s) at the dairy. Combustion of the dairy digester gas in the engine will oxidize the methane in the gas to carbon dioxide and water vapor. Because methane has a global warming potential at least 21 times that of carbon dioxide, combustion of the methane from the dairy digester(s) will result in a large net decrease in the global warming potential emitted from the dairy when compared to uncontrolled levels. Therefore, the project will not result in an increase in project specific greenhouse gas emissions. The District therefore concludes that the project would have a less than cumulatively significant impact on global climate change.

District CEQA Findings

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that the activity will occur at an existing facility and the project involves negligible expansion of the existing or former use. Furthermore, the District determined that the activity will not have a significant effect on the environment. Therefore, the District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15301 (Existing Facilities), and finds that the project is exempt per the common sense exemption that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

Indemnification Agreement/Letter of Credit Determination

According to District Policy APR 2010 (CEQA Implementation Policy), when the District is the Lead or Responsible Agency for CEQA purposes, an indemnification agreement and/or a letter of credit may be required. The decision to require an indemnity agreement and/or a letter of credit is based on a case-by-case analysis of a particular project's potential for litigation risk, which in turn may be based on a project's potential to generate public concern, its potential for significant impacts, and the project proponent's ability to pay for the costs of litigation without a letter of credit, among other factors.

The criteria pollutant emissions and toxic air contaminant emissions associated with the proposed project are not significant, and there is minimal potential for public concern for this particular type of facility/operation. Therefore, an Indemnification Agreement and/or a Letter of Credit will not be required for this project in the absence of expressed public concern.

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATC C-9133-3-0 subject to the permit conditions on the attached draft ATC in Appendix A.

X. Billing Information

Annual Permit Fees			
Permit Number	**Fee Schedule**	**Fee Description**	**Annual Fee**
C-9133-3-0	3020-10-F	1,306 bhp IC engine	$900.00

Appendixes

A: Draft ATC
B: BACT Guideline
C: BACT Analysis
D: RMR and AAQA Summary
E: Quarterly Net Emissions Change

APPENDIX A
Draft ATC

San Joaquin Valley Air Pollution Control District

AUTHORITY TO CONSTRUCT

ISSUANCE DATE: DRAFT

PERMIT NO: C-9133-3-0

LEGAL OWNER OR OPERATOR: LONE OAK ENERGY LLC
MAILING ADDRESS: 2911 HANFORD ARMONA RD
HANFORD, CA 93230

LOCATION: 10014 S MCMULLIN GRDE
FRESNO, CA 93706

EQUIPMENT DESCRIPTION:
1,306 BHP CATERPILLAR MODEL G3516LE DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING MODEL COMBIKAT CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This Authority to Construct (ATC) cancels and supersedes ATC C-9133-1-0. [District Rule 2201]
2. {1407} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]
9. This engine shall be fired on digester gas fuel only. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

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Arnaud Marjollet, Director of Permit Services

10. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702 and 4801]
11. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]
12. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
13. Commissioning activities are defined as, but not limited to, all adjustments, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
14. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The commissioning period shall terminate when the initial engine tuning has completed and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation of the engine. [District Rule 2201]
15. The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]
16. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
17. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
18. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
19. Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.08 g-PM10/bhp-hr, 4.4 g-CO/bhp-hr, 1.1 g-VOC/bhp-hr. [District Rule 2201]
20. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]
21. Operation of this engine shall not exceed 8,500 hours per year. [District Rule 2201]
22. After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]
23. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rule 2201 and 4702]
24. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]
25. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

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CONDITIONS CONTINUE ON NEXT PAGE

26. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201 and 4702]

27. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201 and 4702]

28. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

29. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

30. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

31. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

32. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

33. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

34. The results of each source test shall be submitted to the District within 60 days after completion of source test. [District Rule 1081]

35. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

36. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a digital analyzer approved for gaseous fuel analysis; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

37. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

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CONDITIONS CONTINUE ON NEXT PAGE

38. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

39. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

40. If the NOx, CO, or NH3 concentrations, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

41. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

42. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

43. The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]

44. During initial performance testing, the SCR system reagent injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the initial performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

45. The SCR system reagent injection rate may be reestablished during a performance test by monitoring the SCR system reagent injection rate concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

46. If the SCR system reagent injection rate is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

47. During initial performance testing, the inlet temperature to the SCR system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). For each operating load, the established acceptable inlet temperature and back pressure ranges demonstrated during the initial performance test that result in compliance with the CO emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

48. The inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system may be reestablished during a performance test by monitoring concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system demonstrated during the performance test that result in compliance with the CO and VOC emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

49. The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]

50. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

52. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

53. Records of hydrogen sulfide analyzer(s) installed or utilized and the calibration records of such analyzer(s) shall be maintained. Records are only required on such analyzer(s) utilized to demonstrate compliance with this permit. [District Rule 2201]

54. {4051} The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

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CONDITIONS CONTINUE ON NEXT PAGE

55. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

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APPENDIX B
BACT Guideline

SJVAPCD Best Available Control Technology (BACT) Guideline 3.3.15*
Last Update: 3/6/2013

Waste Gas-Fired IC Engine**

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NO_x	0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent)		1. Fuel Cells (<0.05 lb/MW-hr) 2. Microturbines (<9 ppmv @ 15% O_2) 3. Gas Turbine (<9 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
SO_x	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S) (dry absorption, wet absorption, chemical H_2S reduction, water scrubber, or equivalent) (may be averaged up to 24 hours for compliance)		
PM_{10}	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S)		
CO	2.0 g/bhp-hr		1. Fuel Cells (<0.10 lb/MW-hr) 2. Microturbines (<60 ppmv @ 15% O_2) 3. Gas Turbine (<60 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
VOC	0.10 g/bhp-hr (lean burn and positive crankcase ventilation (PCV) or a 90% efficient crankcase control device or equivalent)		Fuel Cells (<0.02 lb-VOC/MW-hr as CH_4)

** *For the purposes of this determination, waste gas is a gas produced from the digestion of material excluding municipal sources such as waste water treatment plants, landfills, or any source where siloxane impurities are a concern.*

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Pages**

APPENDIX C
BACT Analysis

Top-Down BACT Analyses for the Digester Gas-Fired Engine

As stated above, the information form the existing District BACT Guideline 3.3.15 for Waste Gas-Fired IC Engines will be utilized for the BACT analysis for the proposed engine.

I. BACT Analysis for NOx Emissions:

a. Step 1 - List all control technologies

1) NOx emissions ≤ 0.15 g/bhp-hr = 10 ppmv NOx @ 15% O_2[4] (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

2) Fuel Cell (≤ 0.05 lb/MW-hr = 1.1 ppmv NOx @ 15% O_2[5]) (Alternate Basic Equipment)

3) Microturbine (< 9 ppmv NOx @ 15% O_2) (Alternate Basic Equipment)

4) Gas Turbine (< 9 ppmv NOx @ 15% O_2) (Alternate Basic Equipment)

Description of Control Technologies

1) NOx emissions ≤ 0.15 g/bhp-hr (10 ppmv NOx @ 15% O_2) (Selective Catalytic Reduction (SCR) or equivalent) (Achieved in Practice)

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NOx, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NOx emissions by up to 90%.

2) Fuel Cell (≤ 0.05 lb- NOx/MW-hr) (Alternate Basic Equipment)

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell. Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and

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4 $$\frac{0.15\text{ g NOx}}{\text{bhp - hr}} \times \frac{\text{MMBtu}}{9{,}100\text{ dscf}} \times \frac{30\%}{1} \times \frac{1\text{ lb - mol}}{46\text{ lb}} \times \frac{20.9 - 15}{20.9} \times \frac{379.5\text{ dscf}}{1\text{ lb mol}} \times \frac{393.75\text{ bhp - hr}}{\text{MMBtu}} \times \frac{\text{lb}}{453.6\text{ g}} = 10\text{ ppmv @ 15 \% O2}$$

5 $$\frac{0.05\text{ lb NOx}}{\text{MW - hr}} \times \frac{\text{MW}}{1{,}341\text{ bhp}} \times \frac{\text{MMBtu}}{9{,}100\text{ dscf}} \times \frac{30\%}{1} \times \frac{1\text{ lb - mol}}{46\text{ lb}} \times \frac{20.9 - 15}{20.9} \times \frac{379.5\text{ dscf}}{1\text{ lb mol}} \times \frac{393.75\text{ bhp - hr}}{\text{MMBtu}} = 1.1\text{ ppmv @ 15 \% O2}$$

solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these high temperature fuel cells are tolerant of CO_2 that is found in digester gas.

Fuel cells have recently been commercialized and offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells is the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense and, for digester gas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cell catalysts. Although this expense can be substantial, digester gas-fueled fuel cells have been installed at some wastewater treatment plants and fuel cells have also been fueled with other types of biogas (e.g. landfill gas and brewery wastewater gas).

3) Gas Turbine (< 9 ppmv NO_x @ 15% O_2) (Alternate Basic Equipment)

Gas turbines are internal combustion engines that operate on the Brayton (Joule) combustion cycle rather than the Otto combustion cycle used in reciprocating internal combustion engines or the diesel cycle for diesel engines. In the Brayton cycle the air flow and fuel injection are steady, and the different parts of the cycle occur continuously within different components of the system. In a gas turbine, fuel is continually injected into the combustion chamber or combustor and air is constantly drawn into the turbine and compressed. All elements of the Brayton cycle occur simultaneously in a gas turbine.

Gas turbines are one of the cleanest means of generating electricity. With the use of lean pre-mixed combustion or catalytic exhaust cleanup, NO_x emissions from large gas-fired turbines are generally in the single-digit ppmv range. These levels are generally for natural gas-fired units but they are considered technologically feasible for digester gas-fired units.

Gas turbines are available in sizes ranging from 500 kW - 25 MW. Based on contacts with turbine suppliers, digester gas-fired turbines used to produce electricity are expected to be available in the size range of 2 - 7 MW. According to Solar Turbines, the smaller digester gas-fired turbines are no longer actively produced or marketed since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

4) Microturbine (< 9 ppmv NO_x @ 15% O_2) (Alternate Basic Equipment)

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gases. According to the California Air Resources Board (ARB), there were approximately 200 digester gas-fired microturbines operating in

California as of the year 2006.[6] Microturbines generally have electrical efficiencies of 25 - 30%; however, the electrical efficiency of larger microturbines (≥ 200 kW) can range from 30 - 33%. Microturbine manufacturers include Capstone Microturbines and FlexEnergy.

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of NO_x, CO, and VOC than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low NO_x, or DLN) combustion technology. Microturbines manufacturers will generally guarantee NO_x emissions of 9 - 15 ppmv @ 15% O_2. However, several emission tests performed on digester gas-fired microturbines have demonstrated even lower emissions. A small number of dairy digester gas-fired microturbines have been installed[7], including Twin Birch Dairy and New Hope Farm View dairy and Twin Birch Dairy in New York, and den Dulk Dairy in Michigan.

The proposed project is for a large waste gas to energy facility and, although larger microturbines have recently become available, several microturbines (at least 5) would still be required to replace each engine. The applicant states that when they investigated microturbines they found that there were difficulties related to the loss of power and efficiency because of heat de-rating in warmer climates and the very high pressure requirement and parasitic load, which increased overall costs. In addition, a different applicant for digester gas projects recently permitted by the District (Projects S-1143770 and S-1143771) indicated that when they investigated microturbines they found that they could not secure the necessary financing for a waste gas to energy project of this size using microturbines and that the major microturbines vendors were unable to secure the debt. Although microturbines may not currently be a practical option for this particular project, they will be considered in the cost analysis below.

b. Step 2 - Eliminate technologically infeasible options

<u>Option 3 - Gas Turbine (≤ 9 ppmv NO_x @ 15% O_2) (Alternate Basic Equipment)</u>

Option 3, Gas Turbine, was determined to be infeasible for the proposed project because the available information indicates that the principal suppliers of gas turbines (Solar Turbines, Allison, and General Electric) do not currently produce or market waste gas-fired gas turbines rated less than 3 MW since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

The cost information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[8] (March 2015) and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][9] (October 5, 2015) also supports that gas turbines rated approximately 3 MW are not generally available. The smallest turbine

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[6] "Staff Report: Initial Statement of Reasons for Proposed Amendments to the Distributed Generation Certification Regulation" (9/1/2006), Cal EPA - ARB, Executive Summary Pg. ii (http://www.arb.ca.gov/regact/dg06/dgisor.pdf)
[7] See EPA AgStar Program "AgStar Project Profiles", http://www2.epa.gov/agstar/agstar-project-profiles
[8] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies
[9] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

for which the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies provides cost information is 3,304 kW and the smallest turbine for which the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] provides cost information is 2,500 kW.

The proposed project would require a gas turbine rated 1,028 kW, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas turbines are not considered feasible for this particular project and will be eliminated from consideration at this time.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NOx @ 15% O_2) (Alternate Basic Equipment)

2) Digester gas-fueled microturbines (Alternate Basic Equipment)

3) NOx emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy, a cost effectiveness analysis is required for the options that have not been determined to be achieved in practice. In accordance with the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), to determine the cost effectiveness of particular technologically feasible control options or alternate equipment options, the amount of emissions resulting from each option will be quantified and compared to the District Standard Emissions allowed by the District Rule that is applicable to the particular unit. The emission reductions will be equal to the difference between the District Standard Emissions and the emissions resulting from the particular option being evaluated.

The District has determined that the proposed digester gas-fueled IC engine is a non-agricultural IC engine. The lean burn, digester gas-fired, engine is subject to the following emission limits for non-agricultural, lean burn, waste gas fueled IC engines contained in District Rule 4702, Section 5.2.2, Table 2, 2.e: 11 ppmvd NOx (or 0.17 g/bhp-hr)[10], 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2). The proposed digester gas-fired digester engine is also subject to the New Source Performance Standards (NSPS) for IC Engines contained in 40 CFR 60 Subpart JJJJ, which includes a VOC emissions limit of 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane) for landfill and digester gas-fired IC engines. Therefore, the District Standard Emissions used for the BACT cost analysis below for the proposed engine will be based on the emission limits contained in these applicable regulations.

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$$\frac{11\,\text{ft}^3\ \text{NOx}}{10^6\ \text{ft}^3} \times \frac{9{,}100\,\text{ft}^3}{1\,\text{MMBtu}} \times \frac{46\,\text{lb NOx}}{1\,\text{lb-mole}} \times \frac{20.9}{20.9-15} \times \frac{1\,\text{lb-mole}}{379.5\,\text{ft}^3} \times \frac{\text{MMBtu}}{392.75\,\text{bhp-hr}} \times \frac{453.6\,\text{g}}{\text{lb}} \times \frac{\text{Btu}_{\text{in}}}{0.30\,\text{Btu}_{\text{out}}} = 0.17\ \frac{\text{g-NOx}}{\text{bhp-hr}}$$

Option 1: Fuel Cells (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_x @ 15% O_2) (Alternate Basic Equipment)

Because fuel cells have reduced NO_x and VOC emissions in comparison to a reciprocating IC engine, a Multi-Pollutant Cost Effectiveness Threshold (MCET) will be used to determine if this option is cost-effective. The following cost analysis will examine if the replacement of the proposed engine with a fuel cell is cost effective even when the additional operation costs of a fuel cell are not considered.

Assumptions

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 700 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Price for electricity: $127.72/MW-hr (*based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)*[11] *beginning June 1, 2016*)
- MMBtu/hr to bhp conversion: 392.75 (per AP-42, Appendix A)
- Btu to kW-hr conversion: 3,413 Btu/kW-hr (per AP-42, Appendix A)
- The initial capital costs and the operation costs for the digester gas-fueled IC engine and fuel cell will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[8] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][9]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and fuel cells, additional capital costs for the use of digester gas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [9]

Assumptions for the Proposed Digester Gas-Fired IC Engine

- The engine will operate at full load for 24 hours/day and 8,500 hours/year
- Typical thermal efficiencies for IC engines range from 30-35%. A worst case thermal efficiency of 30% will be used.
- The maximum total daily heating value of the digester gas used by the engine will be: 266.02 MMBtu/day (*1,306 bhp_{out}/engine x 1 bhp_{in}/0.30 bhp_{out} x 1 $MMBtu_{in}$/ 392.75 bhp_{in}-hr x 24 hr/day*)
- The maximum total annual heating value for of the digester gas used by the engine will be: 94,216 MMBtu/year (*1,306 bhp_{out}/engine x 1 bhp_{in}/0.30 bhp_{out} 1 $MMBtu_{in}$/ 392.75 bhp_{in}-hr x 8,500 hr/year*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,028 kW without add-on air pollution control equipment: $1,223/kW (*average of interpolated*

11 See: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/BioMAT/index.page, https://scebiomat.accionpower.com/biomat/home.asp, and http://www.sdge.com/procurement/bioenergy-market-adjusting-tariff-bio-mat)

values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies on page 2-15 and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] on page A-33)

- Additional capital investment for digester gas conditioning and cleanup for the engine: \$387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for digester-fueled IC engine rated 1,028 kW: \$1,610/kW
- Estimated operation costs for CHP IC engine rated 1,028 kW without add-on air pollution control costs: \$0.028/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies on page 2-17 and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] on page A-33*)
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that digester gas conditioning/cleanup costs are highly dependent on the quantity of digester gas being processed and contaminants being removed and that the differences in clean-up costs for digester gas-fired IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engine must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because required level of sulfur removal is adequate for use in the engine, there will be no increase in operating costs related to cleaning the digester gas for use in the engine.
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 11 ppmv @ 15% O_2 = 0.165 lb/MMBtu
- Rule 4702 VOC emission limit for non-agricultural, lean burn IC engines: 750 ppmv @ 15% O_2 as CH_4 = 1.0193 lb/MMBtu
- 40 CFR 60 Subpart JJJJ VOC emission limit for landfill and digester gas-fired IC engines: 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane)

<u>Assumptions for Fuel Cell System</u>

- Net electrical efficiency for a molten carbonate fuel cell (MCFC): 45% (*US EPA Combined Heat and Power Partnership Catalog of CHP Technologies gives efficiencies of 47% for a 300 kW MCFC and 42.5% for a 1,400 kW MCFC*)
- Size of fuel cell system needed to replace the proposed engine: 1,463 kW (estimated based on 266.02 MMBtu/day and 45% efficiency[12])
- Estimated Purchase and Installation Cost for Molten Carbonate Fuel Cell: \$4,474/kW (*Average of the two costs for largest Molten Carbonate Fuel Cells given in US EPA Combined Heat and Power Partnership document Catalog of CHP Technologies on page 6-16 and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] on page A-13; The U.S. Department of Energy Federal energy management Program (FEMP) document "Fuel Cells and Renewable Energy" (last updated 12-1-2014 and available at:* http://www.wbdg.org/resources/fuelcell.php)

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12 $$\frac{266.02\ \text{MMBtu}}{\text{day}} \text{ x } \frac{\text{kW - hr}}{3{,}410\ \text{Btu}} \text{ x } \frac{10^6\,\text{Btu}}{\text{MMBtu}} \text{ x } \frac{\text{day}}{24\ \text{hrs}} \times 45\% = 1{,}463\ \text{kW}$$

states, "Installation costs of a fuel cell system can range from \$5,000/kW to \$10,000/kW." Therefore, this estimate may be actually too low based on the recently reported costs for fuel cell power plants, such as the "Bloom Box".)

- Additional capital investment for digester gas conditioning and cleanup for the fuel cell: \$563/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for digester gas-fueled fuel cells rated ≥ 1,200 kW (the larger the capacity, the cheaper the cost) will be used: \$5,037/kW
- Typical operation costs for natural gas-fueled fuel cells, including stack replacement costs: \$0.04/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional operational costs for digester gas conditioning and cleanup for large fuel cells: \$0.15/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Operation Cost for digester gas-fueled fuel cells rated ≥ 1,200 kW(conservatively using the cheaper cost of the larger capacity fuel cell): \$0.19/kW-hr
- Unlike the proposed engine, a high-temperature fuel cell power plant must primarily operate at steady state conditions; there would not be the ability to store gas to generate more electricity during peak hours, which is the current business plan of the applicant. Because the price paid for electricity is greater during peak hours and less during other times, the price paid for electricity generated by a fuel cell power plant would be less. This would require the operator to alter their plans of operation and result in less revenue per kW-hr of electricity generated potentially offsetting the revenue from increased power generating capacity because of the higher efficiency of a fuel cell power plant. For more conservative analysis, the difference in the cost of peak and off-peak electricity was not considered in this comparison.

Capital Cost

The estimated increased incremental capital cost for replacement of the proposed engine with a fuel cell is calculated based on the difference in cost of a fuel cell power plant and the proposed IC engine.

The incremental capital cost for replacement of the proposed IC engine with a fuel cell power plant is calculated as follows:

(1,463 kW x \$5,037/kW) - (1,028 kW x \$1,610/kW) = \$5,714,051

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(I+1)^n]/[(I+1)^n-1]$$

Where:
A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$$A = [\$5,714,051 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \mathbf{\$931,390/year}$$

Annual Costs

Annual Operation and Maintenance Cost

The annual operation and maintenance costs for each option are calculated as follows:

Proposed 1,028 kW IC Engine

8,738,000 kW-hr/yr x $0.028/kW-hr = $244,664/year

Fuel Cells (Alternate Equipment)

12,435,500 kW-hr/yr x $0.19/kW-hr = $2,362,745/year

Annual Costs of Increased Maintenance

$2,362,745/yr - $244,664/yr = $2,118,081/year

Total Increased Annual Costs for Fuel Cell as an Alternative to the Proposed Engine

$931,390/year + $2,118,081/year = **$3,049,471/year**

Emission Reductions

NO_x and VOC Emission Factors

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_x emissions from the engine will be based on the NO_x emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.2, Table 2, 2.e. The District Standard Emissions for VOC emissions from the engine will be based on the New Source Performance Standard (NSPS) VOC emission limit for landfill and digester gas-fired IC engines from 40 CFR 60 Subpart JJJJ, since this limit is more stringent than the applicable emission limit in District Rule 4702.

The following emissions factors will be used for the cost analysis:

District Standard Emissions

0.165 lb-NO_x/MMBtu (11 ppmv NO_x @ 15% O_2)
0.111 lb-VOC/MMBtu (75 ppmv VOC @ 15% O_2)

Emissions from Fuel Cells as Alternative Equipment

0.016 lb-NO_x/MMBtu (0.05 lb-NO_x/MW-hr)
0.006 lb-VOC/MMBtu (0.02 lb-VOC/MW-hr)

Emission Reductions

The Proposed Engine Compared to Fuel Cells based on District Standard Emission Reductions

NO_x Emission Reductions (11 ppmv @ 15% $O_2 \rightarrow$ 0.05 lb-NO_x/MW-hr)

94,216 MMBtu/year x (0.165 lb-NO_x/MMBtu – 0.016 lb-NO_x/MMBtu)
= 14,038 lb-NO_x/year (7.0 ton-NO_x/year)

VOC Emission Reductions (1.0 g/bhp-hr $\rightarrow$ 0.02 lb-VOC/MW-hr)

94,216 MMBtu/year x (0.111 lb-VOC/MMBtu – 0.006 lb-VOC/MMBtu)
= 9,893 lb-VOC/year (4.9 ton-VOC/year)

Multi-Pollutant Cost Effectiveness Thresholds (MCET) for NO_x and VOC Reductions based on District Standard Emission Reductions

(7.0 ton-NO_x/year x \$24,500/ton-NO_x) + (4.9 ton-VOC/year x \$17,500/ton-VOC)
= **\$257,250/year**

As shown above, the annualized capital cost of this alternate option (\$3,049,471) exceeds the Multi-Pollutant Cost Effectiveness Threshold (MCET) calculated for the NO_x and VOC emission reductions (\$257,250). Therefore, this option is not cost effective and is being removed from consideration.

Options 2 and 3 – Microturbine and IC Engine with NOx Emissions ≤ 0.15 g/bhp-hr

The applicant is proposing a NOx limit of 0.08 g/bhp-hr. Since this proposed limit is lower than the remaining options, per District BACT Policy APR 1305, Section IX.D.1, a cost effectiveness analysis is not required and no further analysis is required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for the Digester Gas-fired Engine must be satisfied with the following: NO_x emissions ≤ 0.15 g/bhp-hr

The applicant has proposed to use an SCR system for the digester gas-fired lean burn IC engine to limit NO_x emissions to ≤ 0.15 g/bhp-hr. Therefore, the BACT requirements are satisfied.

2. BACT Analysis for SO_x Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce SO_x emissions from the proposed engine:

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice/Contained in SIP)

There are no options listed in the SJVUAPCD BACT Clearinghouse as alternate basic equipment.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

The control efficiency of each of the options above is estimated and the controls are ranked below based on the control effectiveness.

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for SO_x emissions from the proposed engine is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use addition of iron oxide chemicals to the digester, a biological sulfur removal system, and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engine to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_x are satisfied.

3. **BACT Analysis for PM_{10} Emissions:**

a. Step 1 - Identify all control technologies

Combustion of gaseous fuels generally does not result in significant emissions of particulate matter. Dairy anaerobic digester gas is the planned fuel for the proposed IC engine. The anaerobic digester gas will be composed primarily of methane (approximately 60% molar composition) and CO_2 (approximately 40% molar composition) and is expected to burn in a fairly clean manner. Particulate emissions from combustion of the digester gas are expected to primarily result from the incineration of fuel-born sulfur compounds (mostly H_2S) resulting in the formation of sulfur-containing particulate. Therefore, scrubbing of the digester gas is the principal means to reduce particulate emissions.

The following control was identified to reduce particulate matter emissions from combustion of the digester gas as fuel in the proposed engine:

1) Sulfur Content of fuel ≤ 40 ppmv as H_2S (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Sulfur Content of fuel gas ≤ 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for PM_{10} emissions from the proposed engine is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use addition of iron oxide chemicals to the digester, a biological sulfur removal system, and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engine to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for PM_{10} are satisfied.

4. **BACT Analysis for VOC Emissions:**

a. Step 1 - Identify all control technologies

The following options were identified to reduce VOC emissions:

1) VOC emissions ≤ 0.10 g/bhp-hr (lean burn or equivalent and positive crankcase ventilation) (Achieved in Practice)
2) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)
2) VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cell (≤ 0.02 lb/MW-hr VOC as CH_4) (Alternate Basic Equipment)

The multi-pollutant cost analysis performed above for the NO_x and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the NO_x and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

This has been identified as achieved in practice and has been proposed by the applicant. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the proposed engine is VOC emissions ≤ 0.10 g/bhp-hr. The applicant has proposed an IC engine with VOC emissions ≤ 0.10 g/bhp-hr. Therefore, the BACT requirements for VOC are satisfied.

APPENDIX D
HRA and AAQA Summary

San Joaquin Valley Air Pollution Control District
Risk Management Review and Ambient Air Quality Analysis

To:	Manuel Salinas – Permit Services
From:	Will Worthley – Technical Services
Date:	December 10, 2019
Facility Name:	LONE OAK ENERGY LLC
Location:	10014 S MCMULLIN GRDE, FRESNO
Application #(s):	C-9133-3-0
Project #:	C-1193519

1. Summary

1.1 RMR

Units	Prioritization Score	Acute Hazard Index	Chronic Hazard Index	Maximum Individual Cancer Risk	T-BACT Required	Special Permit Requirements
3-0	13.88	0.37	0.02	8.23E-08	No	Yes
Project Totals	13.88	0.37	0.02	8.23E-08		
Facility Totals	>1	0.64	0.03	1.41E-07		

1.2 AAQA

Pollutant	Air Quality Standard (State/Federal)				
	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass		Pass		
NO_x	Pass				Pass
SO_x	Pass	Pass		Pass	Pass
PM10				Pass[3]	Pass[3]
PM2.5				Pass[4]	Pass[4]

Notes:
1. Results were taken from the attached AAQA Report.
2. The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2) unless otherwise noted below.
3. Modeled PM10 concentrations were below the District SIL for non-fugitive sources of 5 μg/m^3 for the 24-hour average concentration and 1 μg/m^3 for the annual concentration.
4. Modeled PM2.5 concentrations were below the District SIL for non-fugitive sources of 1.2 μg/m^3 for the 24-hour average concentration and 0.2 μg/m^3 for the annual concentration.

To ensure that human health risks will not exceed District allowable levels; the following shall be included as requirements for:

Unit # 3-0

1. The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rules 2201 and 4102]
2. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction.

2. Project Description

Technical Services received a request on December 4, 2019 to perform a Risk Management Review (RMR) and Ambient Air Quality Analysis (AAQA) for the following:

- Unit -3-0: 1,306 BHP CATERPILLAR, MODEL G3516LE, DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING, MODEL COMBIKAT, CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

3. RMR Report

3.1 Analysis

The District performed an analysis pursuant to the District's Risk Management Policy for Permitting New and Modified Sources (APR 1905, May 28, 2015) to determine the possible cancer and non-cancer health impact to the nearest resident or worksite. This policy requires that an assessment be performed on a unit by unit basis, project basis, and on a facility-wide basis. If a preliminary prioritization analysis demonstrates that:

- A unit's prioritization score is less than the District's significance threshold and;
- The project's prioritization score is less than the District's significance threshold and;
- The facility's total prioritization score is less than the District's significance threshold

Then, generally no further analysis is required.

The District's significant prioritization score threshold is defined as being equal to or greater than1.0. If a preliminary analysis demonstrates that either the unit(s) or the project's or the facility's total prioritization score is greater than the District threshold, a screening or a refined assessment is required

If a refined assessment is greater than one in a million but less than 20 in one million for carcinogenic impacts (Cancer Risk) and less than 1.0 for the Acute and Chronic hazard indices(Non-Carcinogenic) on a unit by unit basis, project basis and on a facility-wide basis the proposed application is considered less than significant. For unit's that exceed a cancer risk of 1 in one million, Toxic Best Available Control Technology (TBACT) must be implemented.

Toxic emissions for this project were calculated using the following methods:

- Toxic emissions for this Dairy Gas Fired internal combustion (2 Stroke Lean Burn, or 4 Stroke Lean Burn, or 4 Stroke Rich Burn) Engine were calculated using emission factors from 2000, AP 42, Fifth Edition, Volume I, Chapter 3: Stationary Internal Combustion Sources, Section 2: Natural Gas-Fired Reciprocating Engines and Dairy Biomethane characterization from 2009 report, Pipeline Quality Biomethane: North American Guidance Document for Introduction o f Dairy Waste Derived Biomethane Into Existing Natural Gas Networks.

These emissions were input into the San Joaquin Valley APCD's Hazard Assessment and Reporting Program (SHARP). In accordance with the District's Risk Management Policy, risks from the proposed unit's toxic emissions were prioritized using the procedure in the 2016 CAPCOA Facility Prioritization Guidelines. The prioritization score for this proposed facility was greater than 1.0 (see RMR Summary Table). Therefore, a refined health risk assessment was required.

The AERMOD model was used, with the parameters outlined below and meteorological data for 2013-2017 from Fresno (rural dispersion coefficient selected) to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the SHARP Program, which then used the Air Dispersion Modeling and Risk Tool (ADMRT) of the Hot Spots Analysis and Reporting Program Version 2 (HARP 2) to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Source Process Rates					
Unit ID	**Process ID**	**Process Material**	**Process Units**	**Hourly Process Rate**	**Annual Process Rate**
3	1	Fuel Usage (Commissioning)	MMscf	0.013	1.59
3	1	NH3 (Commissioning)	Lbs	0.15	19
3	2	Fuel Usage (Non-Commissioning)	MMscf	0.013	112.9
3	2	NH3 (Non-Commissioning)	Lbs	0.16	1327

Point Source Parameters						
Unit ID	**Unit Description**	**Release Height (m)**	**Temp. (°K)**	**Exit Velocity (m/sec)**	**Stack Diameter (m)**	**Vertical/ Horizontal/ Capped**
3	Digester Engine (Non-Comissioning Period)	6.71	709	38.31	0.36	Vertical
3	Digester Engine (Comissioning Period)	6.71	709	38.31	0.36	Vertical

4. AAQA Report

The District modeled the impact of the proposed project on the National Ambient Air Quality Standard (NAAQS) and/or California Ambient Air Quality Standard (CAAQS) in accordance with District Policy APR-1925 (Policy for District Rule 2201 AAQA Modeling) and EPA's Guideline for Air Quality Modeling (Appendix W of 40 CFR Part 51). The District uses a progressive three level approach to perform AAQAs. The first level (Level 1) uses a very conservative approach. If this analysis indicates a likely exceedance of an AAQS or Significant Impact Level (SIL), the analysis proceeds to the second level (Level 2) which implements a more refined approach. For the 1-hour NO_2 standard, there is also a third level that can be implemented if the Level 2 analysis indicates a likely exceedance of an AAQS or SIL.

The modeling analyses predicts the maximum air quality impacts using the appropriate emissions for each standard's averaging period. Required model inputs for a refined AAQA include background ambient air quality data, land characteristics, meteorological inputs, a receptor grid, and source parameters including emissions. These inputs are described in the sections that follow.

Ambient air concentrations of criteria pollutants are recorded at monitoring stations throughout the San Joaquin Valley. Monitoring stations may not measure all necessary pollutants, so background data may need to be collected from multiple sources. The following stations were used for this evaluation:

Monitoring Stations				
Pollutant	**Station Name**	**County**	**City**	**Measurement Year**
CO	Tranquillity	Fresno	Fresno	2016
NOx	Fresno-Drummond	Fresno	Fresno	2016
PM10	Fresno-Drummond	Fresno	Fresno	2016
PM2.5	Tranquillity	Fresno	Fresno	2016
SOx	Fresno - Garland	Fresno	Fresno	2016

Technical Services performed modeling for directly emitted criteria pollutants with the emission rates below:

Emission Rates (lbs/hour)						
Unit ID	**Process**	**NOx**	**SOx**	**CO**	**PM10**	**PM2.5**
3	1	2.89	0.12	12.67	0.23	0.23

Emission Rates (lbs/year)						
Unit ID	**Process**	**NOx**	**SOx**	**CO**	**PM10**	**PM2.5**
3	1	3,965	979	49,776	1,958	1,958

The AERMOD model was used to determine if emissions from the project would cause or contribute to an exceedance of any state of federal air quality standard. The parameters outlined below and meteorological data for 2013-2017 from Fresno (rural dispersion coefficient selected) were used for the analysis:

The following parameters were used for the review:

Point Source Parameters						
Unit ID	**Unit Description**	**Release Height (m)**	**Temp. (°K)**	**Exit Velocity (m/sec)**	**Stack Diameter (m)**	**Vertical/ Horizontal/ Capped**
3	Digester Engine	6.71	709	38.31	0.36	Vertical

5. Conclusion

5.1 RMR

The cumulative acute and chronic indices for this facility, including this project, are below 1.0; and the cumulative cancer risk for this facility, including this project, is less than 20 in a million. In addition, the cancer risk for each unit in this project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit requirements listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

5.2 AAQA

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

6. Attachments

A. Modeling request from the project engineer

B. Additional information from the applicant/project engineer

C. Prioritization score w/ toxic emissions summary

D. Facility Summary

E. AAQA results

APPENDIX E
Quarterly Net Emissions Change (QNEC)

Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post-Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

$PE2_{quarterly} = PE2_{annual} \div 4$ quarters/year

$PE1_{quarterly} = PE1_{annual} \div 4$ quarters/year

Quarterly NEC [QNEC]			
Pollutant	**PE2 (lb/qtr)**	**PE1 (lb/qtr)**	**QNEC (lb/qtr)**
NO_X	991.25	0	991.25
SO_X	244.75	0	244.75
PM_{10}	489.50	0	489.50
CO	12,443.75	0	12,443.75
VOC	698.25	0	698.25

April 13, 2020

Doug Bryant
Maas Energy Works, Inc
3711 Meadow View Dr, #100
Redding, CA 96002

RE: Notice of Final Action - Authority to Construct for Lone Oak Energy LLC
Facility Number: C-9133
Project Number: C-1193519

Dear Mr. Bryant:

The Air Pollution Control Officer has issued the Authority to Construct permit to Lone Oak Energy LLC for the installation of a 1,306 bhp digester gas-fired IC engine powering an electrical generator, at 10014 S McMullin Grade, Hanford. Enclosed are the Authority to Construct permit and a copy of the notice of final action that has been posted on the District's website (www.valleyair.org).

Notice of the District's preliminary decision to issue the Authority to Construct permit was posted on February 21, 2020. The District's analysis of the proposal was also sent to CARB on February 21, 2020. No comments were received following the District's preliminary decision on this project.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Errol Villegas at (559) 230-6000.

Sincerely,

P. Arnaud Marjollet

Arnaud Marjollet
Director of Permit Services

AM:jag

Enclosures

cc: Courtney Graham, CARB (w/ enclosure) via email

Facility # C-9133
LONE OAK ENERGY LLC
2911 HANFORD ARMONA RD
HANFORD, CA 93230

AUTHORITY TO CONSTRUCT (ATC)

QUICK START GUIDE

1. **Pay Invoice**: Please pay enclosed invoice before due date.

2. **Fully Understand ATC**: Make sure you understand ALL conditions in the ATC prior to construction, modification and/or operation.

3. **Follow ATC**: You must construct, modify and/or operate your equipment as specified on the ATC. Any unspecified changes may require a new ATC.

4. **Notify District**: You must notify the District's Compliance Department, at the telephone numbers below, upon start-up and/or operation under the ATC. Please record the date construction or modification commenced and the date the equipment began operation under the ATC. You may NOT operate your equipment until you have notified the District's Compliance Department. A startup inspection may be required prior to receiving your Permit to Operate.

5. **Source Test**: Schedule and perform any required source testing. See http://www.valleyair.org/busind/comply/source_testing.htm for source testing resources.

6. **Maintain Records**: Maintain all records required by ATC. Records are reviewed during every inspection (or upon request) and must be retained for at least 5 years. Sample record keeping forms can be found at http://www.valleyair.org/busind/comply/compliance_forms.htm.

By operating in compliance, you are doing your part to improve air quality for all Valley residents.

For assistance, please contact District Compliance staff at any of the telephone numbers listed below.

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

AUTHORITY TO CONSTRUCT

PERMIT NO: C-9133-3-0 **ISSUANCE DATE:** 04/03/2020

LEGAL OWNER OR OPERATOR: LONE OAK ENERGY LLC
MAILING ADDRESS: 2911 HANFORD ARMONA RD
HANFORD, CA 93230

LOCATION: 10014 S MCMULLIN GRDE
FRESNO, CA 93706

EQUIPMENT DESCRIPTION:
1,306 BHP CATERPILLAR MODEL G3516LE DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A HUG ENGINEERING MODEL COMBIKAT CATALYST SYSTEM (SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM WITH OXIDATION CATALYST) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This Authority to Construct (ATC) cancels and supersedes ATC C-9133-1-0. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
3. No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]
9. This engine shall be fired on digester gas fuel only. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (559) 230-5950 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Samir Sheikh, Executive Director / APCO

Arnaud Marjollet, Director of Permit Services
C-9133-3-0 : Apr 3 2020 3:32PM -- GARCIAJ : Joint Inspection NOT Required

10. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H_2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702 and 4801]

11. This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rules 2201 and 4702]

12. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]

13. Commissioning activities are defined as, but not limited to, all adjustments, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]

14. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the engine is first fired, whichever occurs first. The commissioning period shall terminate when the initial engine tuning has completed and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation of the engine. [District Rule 2201]

15. The total number of firing hours of this unit without abatement of emissions by the SCR system and oxidation catalyst shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system or oxidation catalyst. Upon completion of these activities, the permittee shall provide written notice to the District and the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]

16. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]

17. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and the construction contractor, the Selective Catalytic Reduction (SCR) system and oxidation catalyst shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]

18. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]

19. Emission rates from this engine unit during the commissioning period shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.08 g-PM10/bhp-hr, 4.4 g-CO/bhp-hr, 1.1 g-VOC/bhp-hr. [District Rule 2201]

20. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

21. Operation of this engine shall not exceed 8,500 hours per year. [District Rule 2201]

22. After the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (equivalent to 10 ppmvd NOx @ 15% O_2), NOx referenced as NO_2; 0.08 g-PM10/bhp-hr; 2.0 g-CO/bhp-hr (equivalent to 223 ppmvd CO @ 15% O_2); or 0.10 g-VOC/bhp-hr (equivalent to 20 ppmvd VOC @ 15% O_2), VOC referenced as CH_4. [District Rules 2201 and 4702]

23. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rule 2201 and 4702]

24. Air-to-fuel ratio controller(s) shall be maintained and operated appropriately in order to ensure proper operation of the engine and control device to minimize emissions at all times. [District Rule 2201]

25. Ammonia (NH_3) emissions from this engine shall not exceed 10 ppmvd @ 15% O_2. [District Rules 2201 and 4102]

CONDITIONS CONTINUE ON NEXT PAGE

26. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 60 days upon end of the commissioning period. [District Rules 1081, 2201 and 4702]

27. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201 and 4702]

28. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur content analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

29. Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

30. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

31. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

32. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

33. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

34. The results of each source test shall be submitted to the District within 60 days after completion of source test. [District Rule 1081]

35. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

36. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a digital analyzer approved for gaseous fuel analysis; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

37. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

CONDITIONS CONTINUE ON NEXT PAGE

38. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

39. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

40. If the NOx, CO, or NH3 concentrations, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

41. All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

42. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

43. The permittee shall monitor and record the SCR system reagent injection rate and the engine operating load at least once per month. [District Rule 4702]

44. During initial performance testing, the SCR system reagent injection rate shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the initial performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

45. The SCR system reagent injection rate may be reestablished during a performance test by monitoring the SCR system reagent injection rate concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable SCR system reagent injection rate(s) demonstrated during the performance test that result in compliance with the NOx emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

46. If the SCR system reagent injection rate is outside of the established acceptable ranges established during the initial compliance test, the permittee shall return the SCR system reagent injection rate to within the established acceptable range as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate is returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

47. During initial performance testing, the inlet temperature to the SCR system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored concurrently with each testing run to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). For each operating load, the established acceptable inlet temperature and back pressure ranges demonstrated during the initial performance test that result in compliance with the CO emission limits shall by imposed as a condition in the final Permit to Operate. [District Rule 4702]

48. The inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system may be reestablished during a performance test by monitoring concurrently with each testing run to reestablish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limitations stated in this permit. Acceptable values and ranges may be reestablished for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). The acceptable inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system demonstrated during the performance test that result in compliance with the CO and VOC emission limits shall by imposed as a condition in the Permit to Operate. [District Rule 4702]

49. The permittee shall monitor and record the inlet temperature to the SCR system, the back pressure of the exhaust upstream of the catalyst control system, and the engine operating load at least once per month. [District Rule 4702]

50. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the acceptable ranges established during the initial compliance test, the permittee shall return the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system is not returned to within an acceptable range within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the SCR system and/or the back pressure of the exhaust upstream of the catalyst control system are returned to operating within the acceptable ranges specified within this permit. [District Rule 4702]

51. The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

52. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used during commissioning period(s), the type and quantity of fuel used during normal operation, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

53. Records of hydrogen sulfide analyzer(s) installed or utilized and the calibration records of such analyzer(s) shall be maintained. Records are only required on such analyzer(s) utilized to demonstrate compliance with this permit. [District Rule 2201]

54. The permittee shall record the total time the engine operates, in hours per calendar year. [District Rule 2201]

CONDITIONS CONTINUE ON NEXT PAGE

55. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

ATTACHMENT N

MAR 2 2 2016

N. Ross Buckenham
ABEC #3 LLC dba Lakeview Dairy Biogas
c/o California Bioenergy, LLC
2828 Routh St, Suite 500
Dallas, TX 75201-1438

Re: Notice of Preliminary Decision - Authority to Construct
Facility Number: S-8637
Project Number: S-1143770

Dear Mr. Buckenham:

Enclosed for your review and comment is the District's analysis of ABEC #3 LLC dba Lakeview Dairy Biogas's application for an Authority to Construct for installation of an anaerobic digester system and two 1,468 bhp digester gas-fired IC engines with selective catalytic reduction (SCR) systems for emissions control at Lakeview Farms dairy, at 17702 Bear Mountain Blvd, Bakersfield, CA.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. After addressing all comments made during the 30-day public notice period, the District intends to issue the Authority to Construct. Please submit your written comments on this project within the 30-day public comment period, as specified in the enclosed public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Ramon Norman of Permit Services at (559) 230-5909.

Sincerely,

Arnaud Marjollet
Director of Permit Services

AM:rn

Enclosures

cc: Tung Le, CARB (w/ enclosure) via email

San Joaquin Valley Air Pollution Control District
Authority to Construct Application Review
Digester System and Two Digester Gas-Fired IC Engines with SCR

Facility Name:	ABEC #3 LLC dba Lakeview Dairy Biogas	Date:	March 7, 2016
Mailing Address:	ABEC #3 LLC c/o California Bioenergy, LLC 2828 Routh Street, Suite 500 Dallas, TX 75201-1438	Engineer: Lead Engineer:	Ramon Norman Jerry Sandhu
Contact Person:	N. Ross Buckenham - California Bioenergy/ ABEC #3 LLC		
Telephone:	(214) 849-9886	Cell Phone:	(214) 906-9359
E-Mail:	rbuckenham@calbioenergy.com		
Application #(s):	S-8637-1-0, -2-0, and -3-0		
Project #:	S-1143770		
Deemed Complete:	May 14, 2015		

I. Proposal

ABEC #3 LLC dba Lakeview Dairy Biogas, a subsidiary of California Bioenergy, LLC, has requested Authority to Construct (ATC) permits to construct a covered lagoon anaerobic digester system (ATC S-8637-1-0) and to install two 1,468 bhp digester gas-fired IC engines (or approved engines of equal or lesser bhp) (ATCs S-8637-2-0 and -3-0) at Lakeview Farms dairy (Facility S-5254). Each engine will be equipped with a selective catalytic reduction (SCR) system for emissions control and will power an electrical generator that will produce up to 1,059 kW. The new digester will be constructed in an area of the existing dairy that is currently used for manure drying and storage. Lakeview Farms dairy will send manure from the dairy to the ABEC #3 LLC anaerobic digesters located on the dairy site. The digester system will produce renewable biogas that will be used to fuel the IC engine generator sets.

ABEC #3 LLC dba Lakeview Dairy Biogas and Lakeview Farms dairy, which are separate companies, are undertaking the project as a partnership. ABEC #3 LLC has provided information supporting that the dairy and the ABEC #3 LLC biogas facility will be separately owned and operated. The following is a summary of some of the information provided by the applicant. The proposed digester system at the dairy will be operated and maintained by ABEC #3 LLC. The responsibility of the dairy will be limited to providing the manure feedstock and disposing of the effluent, which the dairy already must do for compliance with water quality regulations. ABEC #3 LLC will not be involved at all in the dairy's primary activity, production of milk. The feedstock and lease agreements specify that ABEC #3 LLC will build, own, and operate the biogas facility and also allows ABEC #3 LLC to make plant and equipment improvements. The proposed digester gas-fired IC engine generator sets that will be constructed on land leased from the dairy site and will be owned, operated, and maintained by ABEC #3 LLC. ABEC #3 LLC will be solely responsible for ensuring that the digester system and digester gas-fired IC engines comply with all applicable air quality regulations. The generator sets will sell all the power generated to the grid and will not provide any power directly to the dairy. Because the dairy and the proposed digester gas power plant at the site will be separately owned and operated and will have different two-digit Standard Industrial Classification (SIC) codes (Industry Group 24: Dairy Farms for the dairy vs. Industry Group 49: Electric, Gas, And Sanitary Services for the IC engine generator sets), pursuant to Section 3.39 of District Rule 2201, the proposed digester system and the digester gas-fired IC engines will not be part of the dairy agricultural stationary source. Therefore, the digester system and digester gas-fired IC engines will be permitted as a separate non-agricultural stationary source (Facility S-8637).

II. Applicable Rules

Rule 2201	New and Modified Stationary Source Review Rule (4/21/11)
Rule 2410	Prevention of Significant Deterioration (6/16/11)
Rule 2520	Federally Mandated Operating Permits (6/21/01)
Rule 4101	Visible Emissions (2/17/05)
Rule 4102	Nuisance (12/17/92)
Rule 4201	Particulate Matter Concentration (12/17/92)
Rule 4701	Stationary Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702	Stationary Internal Combustion Engines (11/14/13)
Rule 4801	Sulfur Compounds (12/17/92)

40 CFR Part 60, Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

40 CFR Part 63, Subpart ZZZZ National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

CH&SC 41700 Health Risk Assessment

CH&SC 42301.6 School Notice

Public Resources Code 21000-21177: California Environmental Quality Act (CEQA)

California Code of Regulations, Title 14, Division 6, Chapter 3, Sections 15000-15387: CEQA Guidelines

III. Project Location

The ABEC #3 LLC Stationary Source (Facility S-8637) is located on Lakeview Farms dairy at 17702 Bear Mountain Blvd, Bakersfield, CA (Mt. Diablo Meridian T 31S, R 26E, Sec 20 in Kern County). The proposed equipment is not located within 1,000 feet of the outer boundary of a K-12 school. Therefore, the public notification requirement of California Health and Safety Code 42301.6 is not applicable to this project.

IV. Process Description

<u>Anaerobic Digester System</u>

An anaerobic digester is a sealed basin or tank that is designed to accelerate and control the decomposition of organic matter by microorganisms in the absence of oxygen. Anaerobic decomposition results in the conversion of organic compounds in the substrate into methane (CH_4), carbon dioxide (CO_2), and water rather than intermediate Volatile Organic Compounds (VOCs). The gas generated by this process is known as biogas, waste gas, or digester gas. In addition to methane and carbon dioxide, biogas may also contain small amounts of Nitrogen (N_2), Oxygen (O_2), Hydrogen Sulfide (H_2S), and Ammonia (NH_3). Biogas may also include trace amounts of various VOCs that remain from incomplete digestion of the volatile solids in the incoming substrate. Because biogas is mostly composed of methane, the main component of natural gas, the gas produced in the digester can be cleaned to remove H_2S and other impurities and used as fuel.

The proposed anaerobic digester system will be designed to process the manure generated by the cattle at Lakeview Farms dairy. The manure will be flushed from the cow housing areas at the dairy to a mechanical separation system prior to the digester system. This pre-digester mechanical separation system will remove fibrous solids from the manure. After the mechanical separation system, the liquid manure will flow to a sand settling lane that is designed to remove heavy solids by sedimentation. After the separation systems, the liquid manure will gravity flow into the proposed covered lagoon digesters. The liquid effluent from the covered lagoon digesters will be pumped to the existing large storage pond at the dairy from where it can be used to irrigate and fertilize adjacent cropland.

The proposed anaerobic digester system will process the liquid fraction from the dairy manure solid separation system. The anaerobic digester system will consist of an in-ground, covered lagoon anaerobic digester that will be divided into one or more cells. The final number of covered lagoon anaerobic digester cells and the final dimensions of each cell will be determined based on borings to locate subsurface sand and groundwater that are required to demonstrate compliance with the requirements of the Regional Water Quality Control Board. The preliminary information submitted by the applicant indicates that the first cell of the covered lagoon anaerobic digester will have the following approximate dimensions: 655 ft long by 262 ft wide at the top, with an average depth of 23 ft, and a side slope (run/rise) of 2.0 and that the second cell of the covered lagoon anaerobic digester will have the following approximate dimensions: 500 ft long by 200 ft wide at the top, with an average depth of 22.75 ft, and a side slope (run/rise) of 2.0. The covered lagoon digester will operate at ambient temperatures; however, the covered lagoon digester may utilize heat from the engines to warm the substrate to promote more efficient anaerobic digestion. An area located east of the existing lagoons at the dairy, which is currently used for drying and storage of solid manure, will be excavated to create the proposed covered lagoon anaerobic digester.

The applicant indicates that the lagoon cell(s) will be covered in accordance with Natural Resources Conservation Services (NRCS) Practice Standard Code 367 – Roofs and Covers. The bottom and the walls of the new lagoon cell(s) will be lined with high-density polyethylene (HDPE) membranes and a gas collection system will be installed. The new lagoon cells will be fitted with HDPE covers. The gas collection system will consist of perforated piping under the HDPE covers of the covered lagoons.

The covered lagoon digester will be equipped with an air injection system for removal of H_2S from the digester gas. The continuous injection of controlled quantities of air under the digester covers increases the amount of oxygen in the space under the digester covers and in the surface layer of the digester liquid, which facilitates oxidation of sulfides in the digester gas and at the surface of the liquid to elemental sulfur and water. Injection of air also promotes biological removal of H_2S from the digester gas by facilitating the establishment of sulfur oxidizing microorganisms, such as Thiobacillus species, which have the ability to grow under various environmental conditions and oxidize H_2S to elemental sulfur. The digester gas will be captured by the covered lagoon gas collection system and will be piped to the gas conditioning system for polishing to remove additional H_2S and for removal of moisture. The gas will then be sent to the engines for use as fuel to generate electricity for sale to a utility and to produce heat for the digester system. When the gas cannot be used in the engines, the digester gas will collect under the lagoon covers. As the gas collects under the lagoon covers, the pressure in the digesters will rise. In rare emergency situations when the gas cannot be combusted in the engines for an extended period, the pressure will cause the relief valves to open and release the digester gas, composed primarily of methane and carbon dioxide, into the atmosphere. As the pressure decreases, the gas relief valves will automatically close and normal operation will proceed.

When operating at full capacity, the digester system is expected to produce an average of 360,000 ft^3 of biogas per day. The applicant has indicated that the biogas produced by the covered lagoon digester will be composed of approximately 60-70% methane and 30-40% carbon dioxide. Because the proposed digester system will be able to store the biogas for extended periods under the digester covers and the proposed engines at the ABEC #3 LLC Stationary Source (Facility S-8637) will have more than sufficient capacity to combust all of the gas generated, no flare is being proposed for the digester installation at this facility.

Covered Lagoon Anaerobic Digester Measurements

The measurements given below for the proposed covered lagoon anaerobic digester cells at the ABEC #3 LLC Stationary Source (Facility S-8637) are based on the preliminary information provided by the applicant. As discussed above, the final number of covered lagoon anaerobic digester cells and the final dimensions of each cell will be determined based compliance with the requirements of the Regional Water Quality Control Board.

- 1st Covered Lagoon Anaerobic Digester Cell
  - Top Dimensions: 655 ft long x 262 ft wide
  - Average Depth: 23 ft
  - Side Slope (run/rise): 2.0
  - Approximate Volume (not including 2 ft. freeboard): 2,705,808 ft^3 (~20,239,444 gal)
- 2nd Covered Lagoon Anaerobic Digester Cell
  - Top Dimensions: 500 ft long x 200 ft wide
  - Average Depth: 22.75 ft
  - Side Slope (run/rise): 2.0
  - Approximate Volume (not including 2 ft. freeboard): 1,613,210 ft^3 (~10,612,380 gal)

Digester Gas-Fired IC Engines

The applicant is proposing to install two 1,468 bhp GE Jenbacher model J 320 GS-C82 lean burn digester gas-fired IC engines (or equivalent engines of equal or lesser rating approved by the District, such as 1,412 bhp Caterpillar model A3516A+ IC engines or 1,431 bhp Dresser Rand Guascor model SFGLD 560 IC engines). Each engine will be equipped with an SCR system and will power an electrical generator that will produce up to 1,059 kWe. Digester gas, which consists mostly of methane, the main component of natural gas, will be combusted in the IC engines to produce power. After initial removal of H_2S in the digester system, the digester gas will be piped to the gas conditioning system for polishing to remove H_2S using an iron sponge and/or activated carbon H_2S scrubber or an equivalent H_2S removal system and for removal of moisture. The digester gas will then be piped to the IC engines for use as fuel. The engines will power electrical generators that will produce power to be sold to a utility. Excess heat from the engines will be used in the first covered lagoon anaerobic digester (West

Lagoon Digester) to promote more efficient production of digester gas. The engines will be permitted to operate up to 24 hr/day and 8,760 hr/year.

In addition to the use of digester gas as fuel, the engines will also be permitted to use natural gas as fuel for no more than 96,000 kW-hrs of operation during initial utility interconnect testing in the event that insufficient digester gas is available for the engines at the time that the required utility testing is scheduled. The engines will remain subject to the same emission limits during the limited period that allows the use of natural gas fuel for required utility testing.

V. Equipment Listing

S-8637-1-0: ANAEROBIC DIGESTER SYSTEM CONSISTING OF COVERED LAGOON ANAEROBIC DIGESTER CELL(S) WITH PRESSURE/VACUUM VALVE(S) AND AN AIR INJECTION SYSTEM FOR CONTROL OF H2S

S-8637-2-0: 1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

S-8637-3-0: 1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

VI. Emission Control Technology Evaluation

Digester System (S-8637-1-0)

The digester system will be equipped with a pressure-vacuum (PV) relief valves or an emergency venting system. The digester gas will be scrubbed to remove hydrogen sulfide (H_2S) and will be used to fuel engines to generate electricity. Combustion of the digester gas in the engines will convert any VOCs present in the gas into carbon dioxide and water. As stated above, because the digester system will be able to store the gas for extended periods and the engines will have more than enough capacity to combust all of the gas generated, no flare is being proposed for this digester project.

H_2S Removal

As described above, the covered lagoon anaerobic digester will utilize an air injection system for removal of H_2S from the digester gas. The continuous injection of controlled quantities of air under the lagoon covers increases the amount of oxygen in the space under the digester covers and the surface layer of the liquid in the covered lagoon digester, which facilitates oxidation of sulfides in the digester gas and in the liquid surface to elemental sulfur and water.

The sulfur dissolves in the liquid in the digester and can be removed from the digester system by deposition and filtration. Injection of air also promotes biological removal of H_2S from the digester gas by facilitating the establishment of sulfur oxidizing microorganisms, such as Thiobacillus species, which have the ability to grow under various environmental conditions and oxidize H_2S to elemental sulfur and sulfates that can be removed from the digester system. Use of air injection to remove H_2S from digester gas has been shown to have higher effectiveness in covered lagoon digesters because the large areas under the lagoon covers facilitate contact with the digester gas and lagoon surface, which enables improved oxidation and biological reduction of sulfides. Successful installations of the air injection sulfur removal system have demonstrated significantly reduced operation costs when compared to other methods of sulfur removal.

For final polishing, the digester gas will be sent through an iron sponge H_2S scrubber and/or an activated carbon H_2S scrubber or an equivalent system to remove H_2S from the gas prior to combustion in the proposed engines.

An iron sponge scrubber is comprised of vessel(s) containing iron sponge, which consists of a hydrated form of iron oxide infused onto wood shavings. The wood shavings serve only as a carrier for the iron oxide powder. Iron oxide infused into the wood surface will not wash off or migrate with the gas. As the gas passes through the iron sponge material, the H_2S is removed by the following chemical reaction producing black iron sulfide and water:

$$H_2S + Fe(OH)_2 \rightarrow FeS + 2H_2O + \text{heat}$$

For the iron sponge to perform effectively, it must be maintained within a defined range of sufficient moisture content. This requirement is typically satisfied if the gas is saturated with water vapor, as is frequently the case with digester gas. If the iron sponge becomes dry, it can be re-wet and remain effective. The iron sponge reaction is not pressure sensitive.

Specially treated activated carbon can also be used to remove H_2S from gas streams. H_2S will be adsorbed as the gas flows through the activated carbon bed. Activated carbon has a large number of pores, which greatly increase the surface area for adsorption. Contaminants in the gas diffuse into these pores and are retained on the carbon surface due to both chemical and physical forces. Activated carbon used for the removal of H_2S is usually treated with chemical bases to increase the holding capacity for H_2S.

The proposed scrubber will consist of enclosed vessels filled with iron sponge and/or treated activated carbon. The digester gas will flow through the scrubber and then to a dryer and chiller to remove moisture. For continuous operation, there will be a secondary unit that will be brought online at specified times or when monitoring indicates that the primary unit is nearing saturation. Valves can be arranged so either bed can operate while the other is serviced. The useful life of the iron sponge and activated carbon vessels will vary depending on the inlet concentration of H_2S, the flow rate, and the mass in the vessels. Before a scrubber is completely spent, it must be regenerated or replaced. Spent iron sponge or activated carbon vessels will be sent to a regeneration facility or to an appropriate disposal facility.

The proposed scrubber will be capable of reducing H_2S concentrations in the digester gas to 40 ppmv or less. Reducing the H_2S concentration in the gas will minimize SO_X emissions from combustion and will also reduce the maintenance requirements for the engines and will protect catalysts from masking, plugging, and poisoning.

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

The proposed engines will be equipped with:
- Turbocharger
- Aftercooler
- Air/Fuel Ratio or an O_2 Controller
- Lean Burn Technology
- Positive Crankcase Ventilation (PCV) or 90% efficient control device
- Selective Catalytic Reduction (SCR)

The turbocharger reduces NO_X emissions from engines by increasing the efficiency and promoting more complete burning of the fuel.

The aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X.

The fuel/air ratio controller (oxygen controller) is used to maintain the amount of oxygen in the exhaust stream to optimize engine operation and catalyst function.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_X formation.

The PCV system or 90% efficient control device reduces crankcase VOC and PM_{10} emissions by at least 90% over an uncontrolled crankcase vent.

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent, in this case urea, pass through an appropriate catalyst. Urea, will be injected upstream of the catalyst where it is converted to ammonia. The ammonia is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%.

VII. General Calculations

A. Assumptions

- ABEC #3 LLC dba Lakeview Dairy Biogas (Facility S-8637) and Lakeview Farms dairy (Facility S-5254) are separate stationary sources at the same site.
- Because of the high moisture content of separated manure solids, PM emissions from the handling of separated solids for the digester system are considered negligible.
- Because the manure for the digester system will be taken from the mechanical separation system at Lakeview Farms dairy and the digested solids and effluent from the digester system will be returned to Lakeview Farms dairy for use, all emissions from the manure

processed in the digester system will be allocated to the liquid manure handling system at Lakeview Farms dairy.

- The proposed digester system will reduce potential VOC emissions from manure generated by the cattle at Lakeview Farms dairy. Manure that is currently stored in uncovered lagoon(s) and pond(s) will instead be placed in covered ponds at the ABEC #3 LLC facility, thereby decreasing volatilization of compounds from the manure. In a digester, most VOCs present will be converted to methane (an exempt compound) and carbon dioxide further reducing the potential for VOC emissions. Because results of dairy digester analyses have indicated very low VOC content (less than 1% by weight), fugitive VOC emissions from the digester system are assumed to be negligible, consistent with District Policy SSP 2015. During operation, the digester gas will be directed to the engines where the gas will be combusted resulting in the oxidation of gaseous hydrocarbons into carbon dioxide and water. Therefore, VOC emissions from the digester system are considered negligible.
- Molar composition of typical digester gas is about 60% methane and 40% carbon dioxide with trace amounts of hydrogen sulfide, VOC, and other compounds.[1]
- Typical Higher Heating Value for Digester Gas: 600 Btu/scf (Per AP-42 (4/00) - notes to Tables Table 3.1-1, Table 3.1-2b, Table 3.1-7, and Table 3.1-8)
- Typical EPA F-factor for Digester Gas: 9,100 dscf/MMBtu (dry, adjusted to 60 °F), (Estimated based on previous digester gas fuel analyses for source tests)
- Average sulfur content of the scrubbed digester gas: 40 ppmv as H_2S (required as BACT; approximately 2.4 grains/100 scf)
- bhp to Btu/hr conversion: 2,545 Btu/hp-hr
- Thermal efficiency of engines: commonly ≈ 33%
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Molecular weights:
  NO_X (as NO_2) = 46 lb/lb-mol   CO = 28 lb/lb-mol   NH3 = 17 lb/lb-mol
  VOC (as CH_4) = 16 lb/lb-mol SO_X (as SO_2) = 64.06 lb/lb-mol
- Each of the engines will be permitted to operate 24 hours/day and 365 days per year.
- There will be no increase in permitted emissions for the limited use of natural gas for required initial utility testing in the event that sufficient digester gas is not available for the engines at the time that the required initial utility testing is scheduled.
- PM2.5 emissions from the digester gas-fired IC engines are assumed to be equal to PM10 emissions.

[1] U.S. EPA AgSTAR (http://www2.epa.gov/agstar), "Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities" (November 2011, http://www2.epa.gov/agstar/agstar-market-opportunities-report); American Biogas Council – Frequent Questions (https://www.americanbiogascouncil.org/biogas_questions.asp); "Anaerobic Digestion Overview", David Schmidt, University of Minnesota Department of Biosystems and Agricultural Engineering (http://www.extension.umn.edu/agriculture/manure-management-and-air-quality/manure-treatment/docs/anaerobic-digestion-overview.pdf); and "Anaerobic Digestion of Animal Wastes: Factors to Consider", ATTRA - National Sustainable Agriculture Information Service (https://attra.ncat.org/attra-pub/summaries/summary.php?pub=307)

Assumptions for Commissioning Period

- The applicant has requested that the ATC permits include a commissioning period to allow testing, adjustment, tuning, and calibration of the engines without the SCR systems installed. The duration of the commissioning period shall consist of no more than 120 hours of operation of each engine without an SCR system installed.
- Engine emissions during the commissioning period will be calculated as uncontrolled based on information provided by the engine supplier.

B. Emission Factors

Emission Factors during the Commissioning Period:

The commissioning period precedes normal operation of a power plant. Activities conducted during the commissioning period typically include: checking all mechanical, electrical, and control systems for the units and related equipment; confirming the performance measures specified for the equipment; test firing the units; and tuning of the units and the generators. The early stages of commissioning are conducted prior to the installation of the emission control equipment to prevent damage to this equipment. In accordance with EPA's guidance, the commissioning period is considered the final phase of the construction process rather than initial startup of the equipment.[2] Therefore, other than quantifying emissions for New and Modified Source Review (NSR), source-specific emission limitations from applicable rules and regulations are generally not effective until completion of the commissioning period. Because emission control devices are not in place and functioning during commissioning, higher emission limits are required during this time.

The emission factors for NO_X (1.0 g/bhp-hr), CO (4.85 g/bhp-hr), and VOC (1.0 g/bhp-hr) for the commissioning period are the emission factors provided by the engine supplier for the engines without SCR systems or oxidation catalysts. The emission factors during the commissioning period for SO_X (0.04 g/bhp-hr), PM_{10} (0.07 g/bhp-hr), and ammonia slip (0.05 g/bhp-hr) after initial installation of the SCR system are assumed to be the same emissions factors as during normal operation. SO_X emissions are based on the maximum sulfur content of the dairy digester gas (required as BACT; approximately 2.4 grains/100 scf). PM_{10} emissions on a lb/MMBtu basis are assumed to be similar to natural gas-fueled IC engines. For more conservative PM_{10} emission calculations, the PM emission factor for rich burn natural gas-fueled engines given in EPA's Compilation of Air Pollutant Emission Factors (AP-42) is used because it is higher than the value for lean burn natural gas-fueled engines listed in EPA AP-42. The ammonia emission factor is based on the ammonia slip limit of 10 ppmv NH_3.

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[2] See US EPA Implementation Question and Answer Document for National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines and New Source Performance Standards for Stationary Compression Ignition and Spark Ignition Internal Combustion Engines, April 2, 2013, Question 39 (http://www.epa.gov/airtoxics/icengines/docs/20120717riceqaupdate.pdf)

Commissioning Period Emission Factors for Digester Gas-Fired Engines		
Pollutant	g/bhp·hr	Source
NO_X	1.0	Engine Supplier's Information
SO_X	0.04	40 ppmvd in fuel gas; BACT Requirement/Mass Balance equation below
PM_{10}	0.07	AP-42 (7/00) Table 3.2-3 (Conservative Value based on Rich-Burn Natural Gas Engines)
CO	4.85	Engine Supplier's Information
VOC	1.0	Engine Supplier's Information
NH_3	0.05	10 ppmvd @ 15% O_2 in exhaust; Required/Proposed – See equation below

SO_X – 40 ppmvd H_2S in fuel gas

$$\frac{40\,\text{ft}^3\,H_2S}{10^6\,\text{ft}^3} \times \frac{32.06\,\text{lb S}}{\text{lb-mol}\,H_2S} \times \frac{\text{lb-mole}}{379.5\,\text{ft}^3} \times \frac{64.06\,\text{lb}\,SO_2}{32.06\,\text{lb S}} \times \frac{\text{ft}^3}{600\,\text{Btu}} \times \frac{10^6\,\text{Btu}}{\text{MMBtu}} = 0.0113\,\frac{\text{lb SOx}}{\text{MMBtu}}$$

$$0.0113\,\frac{\text{lb SOx}}{\text{MMBtu}} \times \frac{1\,\text{MMBtu}}{10^6\,\text{Btu}} \times \frac{\text{Btu}_{in}}{0.33\text{Btu}_{out}} \times \frac{2{,}545\,\text{Btu}}{\text{hp-hr}} \times \frac{453.59\,\text{g}}{\text{lb}} = 0.040\,\frac{\text{g SOx}}{\text{bhp-hr}}$$

NH_3 – 10 ppmvd @ 15% O_2 in exhaust

$$\frac{10\,\text{ppmv}\,NH_3}{10^6} \times \frac{17\,\text{lb}\,NH_3}{\text{lb-mole}} \times \frac{\text{lb-mole}}{379.5\,\text{ft}^3} \times \frac{9{,}100\,\text{ft}^3}{\text{MMBtu}} \times \frac{20.9\%\,O_2}{(20.9-15)\%\,O_2} = 0.0144\,\frac{\text{lb}\,NH_3}{\text{MMBtu}}$$

$$0.0144\,\frac{\text{lb}\,NH_3}{\text{MMBtu}} \times \frac{1\,\text{MMBtu}}{10^6\,\text{Btu}} \times \frac{\text{Btu}_{in}}{0.33\text{Btu}_{out}} \times \frac{2{,}545\,\text{Btu}}{\text{hp-hr}} \times \frac{453.59\,\text{g}}{\text{lb}} = 0.05\,\frac{\text{g}\,NH_3}{\text{bhp-hr}}$$

Emission Factors during Normal Operation after the Commissioning Period:

The emission factors for NO_X (0.15 g/bhp-hr), CO (1.75 g/bhp-hr), and VOC (0.10 g/bhp-hr) for the proposed engines during normal operation were proposed by the applicant and are supported by information provided by the engine supplier. The emission factors for NO_X and VOC were required as BACT. The emission factors for SO_X (0.04 g/bhp-hr), PM_{10} (0.07 g/bhp-hr), and ammonia slip (0.05 g/bhp-hr) during normal operation are same as the emission factors presented above for the commissioning period.

Emission Factors for Digester Gas-Fired Engines (Normal Operation)				
Pollutant	g/bhp·hr	lb/MMBtu	ppmvd (@ 15%O_2)	Source
NO_X	0.15	0.0429	11 ppmvd	BACT Requirement; Proposed by Applicant – See equation on Page 11 below
SO_X	0.04	0.0113	40 ppmvd in fuel gas	BACT Requirement/Mass Balance equation above
PM_{10}	0.07	0.01941	--	AP-42 (7/00) Table 3.2-3 (Conservative Value based on Rich-Burn Natural Gas Engines)
CO	1.75	0.500	210 ppmvd	Proposed by Applicant – See equation on Page 11 below
VOC	0.10	0.0286	21 ppmvd as CH_4	BACT Requirement; Proposed by Applicant – See equation on Page 11 below
NH_3	0.05	0.0144	10 ppmvd	Required/Proposed – See equation above

NOx – 0.15 g/bhp-hr

$$0.15\,\frac{\text{g NOx}}{\text{bhp - hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp - hr}}{2{,}545\,\text{Btu}} \times \frac{0.33\,\text{Btu}_{out}}{1\,\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.0429\,\frac{\text{lb NOx}}{\text{MMBtu}}$$

$$0.0429\,\frac{\text{lb NOx}}{\text{MMBtu}} \times \frac{(20.9 - 15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb - mole}} \times \frac{\text{lb - mole}}{46\,\text{lb NOx}} \times \frac{10^6\,\text{ppmv}}{1} = 11\ \text{ppmvd NOx @ 15\%}\ O_2$$

CO – 1.75 g/bhp-hr

$$1.75\,\frac{\text{g CO}}{\text{bhp - hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp - hr}}{2{,}545\,\text{Btu}} \times \frac{0.33\,\text{Btu}_{out}}{1\,\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.500\,\frac{\text{lb CO}}{\text{MMBtu}}$$

$$0.500\,\frac{\text{lb CO}}{\text{MMBtu}} \times \frac{(20.9 - 15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb - mole}} \times \frac{\text{lb - mole}}{28\,\text{lb CO}} \times \frac{10^6\,\text{ppmv}}{1} = 210\ \text{ppmvd CO @ 15\%}\ O_2$$

VOC – 0.10 g/bhp-hr

$$0.10\,\frac{\text{g VOC}}{\text{bhp - hr}} \times \frac{1\,\text{lb}}{453.59\,\text{g}} \times \frac{1\,\text{hp - hr}}{2{,}545\,\text{Btu}} \times \frac{0.33\,\text{Btu}_{out}}{1\,\text{Btu}_{in}} \times \frac{10^6\,\text{Btu}}{1\,\text{MMBtu}} = 0.0286\,\frac{\text{lb VOC}}{\text{MMBtu}}$$

$$0.0286\,\frac{\text{lb VOC}}{\text{MMBtu}} \times \frac{(20.9 - 15)\%\ O_2}{20.9\%\ O_2} \times \frac{1\,\text{MMBtu}}{9{,}100\,\text{ft}^3} \times \frac{379.5\,\text{ft}^3}{\text{lb - mole}} \times \frac{\text{lb - mole}}{16\,\text{lb VOC}} \times \frac{10^6\,\text{ppmv}}{1} = 21\ \text{ppmvd VOC @ 15\%}\ O_2$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Since the digester system and the engines are new emissions units, PE1 = 0 for all affected pollutants.

2. Post Project Potential to Emit (PE2)

Digester System (S-8637-1-0)

As explained above, the digester system will be composed of sealed lagoons that will reduce VOC emissions from the manure and will have negligible fugitive emissions; therefore, VOC emissions from the manure will only be attributed to Lakeview Farms dairy for manure prior to entering the digester system and when returned to the dairy and emissions from the digester system are considered negligible.

Digester Gas-Fired Engines (S-8637-2-0 and -3-0)

Daily PE2 for Each Engine during the Commissioning Period:

Daily PE during the commissioning period for each of the proposed engines is calculated in the table below:

Daily PE for Engines S-8637-2-0 &-3-0 During the Commissioning Periods								
NO_X	1.0	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**77.7**	(lb/day)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.1**	(lb/day)
PM_{10}	0.07	(g/hp·hr) . x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.4**	(lb/day)
CO	4.85	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**376.7**	(lb/day)
VOC	1.0	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**77.7**	(lb/day)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.9**	(lb/day)

Daily PE2 for Each Engine during Normal Operation after the Commissioning Period:

Daily PE for each of the proposed engines during normal operation after completion of the commissioning periods is calculated in the table below:

Daily PE for Engines S-8637-2-0 &-3-0 After Commissioning								
NO_X	0.15	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**11.7**	(lb/day)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.1**	(lb/day)
PM_{10}	0.07	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**5.4**	(lb/day)
CO	1.75	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**135.9**	(lb/day)
VOC	0.10	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**7.8**	(lb/day)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	24	(hr/day) ÷ 453.59 (g/lb) =	**3.9**	(lb/day)

Maximum Annual PE2 for Each Engine During the first Year Including the Commissioning Periods:

As discussed above, each of the proposed engines will be allowed to operate up to 120 hours for commissioning during the first year of operation. The maximum annual PE for each engine will calculated based on the maximum hours of operation during the commissioning period and the remaining hours during normal operation.

NO_X
1,468 bhp x (1.0 g-NO_X/bhp-hr x 120 hr + 0.15 g-NO_X/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **4,583 lb-NO_X**

SO_X
1,468 bhp x (0.04 g-SO_X/bhp-hr x 120 hr + 0.04 g-SO_X/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **1,134 lb-SO_X**

PM_{10}
1,468 bhp x (0.07 g-PM_{10}/bhp-hr x 120 hr + 0.07 g-PM_{10}/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **1,985 lb-PM_{10}**

CO
1,468 bhp x (4.85 g-CO/bhp-hr x 120 hr + 1.75 g-CO/bhp-hr x 8,640 hr) ÷ 453.59 g/lb = **50,818 lb-CO**

VOC
1,468 bhp x (1.0 g-VOC/bhp-hr x 120 hr + 0.10 g-VOC/bhp-hr x 8,640 hr) ÷ 453.59 g/lb
= **3,185 lb-VOC**

NH_3
1,468 bhp x (0.05 g-NH_3/bhp-hr x 120 hr + 0.05 g-NH_3/bhp-hr x 8,640 hr) ÷ 453.59 g/lb
= **1,418 lb-NH_3**

Maximum Total Combined Annual PE2 from Both Engines, Including Commissioning:

The maximum total combined annual PE2 for both the engines, including commissioning emissions, is calculated as follows:

NO_X: 4,583 lb-NO_X/yr-engine x 2 engines = **9,166 lb-NO_X/yr**
SO_X: 1,134 lb-SO_X/yr-engine x 2 engines = **2,268 lb-SO_X/yr**
PM_{10}: 1,985 lb-PM_{10}/yr-engine x 2 engines = **3,970 lb-PM_{10}/yr**
CO: 50,818 lb-CO/yr-engine x 2 engines = **101,636 lb-CO/yr**
VOC: 3,185 lb-VOC/yr-engine x 2 engines = **6,370 lb-VOC/yr**
NH_3: 1,418 lb-NH_3/yr-engine x 2 engines = **2,836 lb-NH_3/yr**

Annual PE2 for Each Engine in years with no Commissioning:

The annual PE2 for each of the engines after completion of the first year of operation when there will not be any commissioning emissions is calculated as follows:

Annual PE2 for Engines S-8637-2-0 &-3-0 with no Commissioning								
NO_X	0.15	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**4,253**	(lb/yr)
SO_X	0.04	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,134**	(lb/yr)
PM_{10}	0.07	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,985**	(lb/yr)
CO	1.75	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**49,614**	(lb/yr)
VOC	0.10	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**2,835**	(lb/yr)
NH_3	0.05	(g/hp·hr) x	1,468	(hp) x	8,760	(hr) ÷ 453.59 (g/lb) =	**1,418**	(lb/yr)

Max Total Combined Annual PE2 from Both Engines in years with no Commissioning:

The maximum total combined annual PE2 for both the engines in years with no commissioning is calculated as follows:

NO_X: 4,253 lb-NO_X/yr-engine x 2 engines = **8,506 lb-NO_X/yr**
SO_X: 1,134 lb-SO_X/yr-engine x 2 engines = **2,268 lb-SO_X/yr**
PM_{10}: 1,985 lb-PM_{10}/yr-engine x 2 engines = **3,970 lb-PM_{10}/yr**
CO: 49,614 lb-CO/yr-engine x 2 engines = **99,228 lb-CO/yr**
VOC: 2,835 lb-VOC/yr-engine x 2 engines = **5,670 lb-VOC/yr**
NH_3: 1,418 lb-NH_3/yr-engine x 2 engines = **2,836 lb-NH_3/yr**

Maximum Daily and Annual PE2 from Calculations Above:

The maximum daily and annual emissions for each pollutant calculated above, including commissioning emissions, are shown in the table below.

Max. Post-Project Potential to Emit (PE2) for S-8637-2-0 &-3-0			
	Max. Daily Emissions for each engine (lb/day)	Max. Annual Emissions for each engine (lb/year)	Max. Total Combined Annual Emissions for both engines (lb/year)
NO_X	77.7	4,583	9,166
SO_X	3.1	1,134	2,268
PM_{10}	5.4	1,985	3,970
CO	376.7	50,818	101,636
VOC	77.7	3,185	6,370
NH_3	3.9	1,418	2,836

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to District Rule 2201, the SSPE1 is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of Emission Reduction Credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions (AER) that have occurred at the source, and which have not been used on-site.

Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 is equal to zero for all pollutants.

4. Post Project Stationary Source Potential to Emit (SSPE2)

Pursuant to District Rule 2201, the SSPE2 is the PE from all units with valid ATCs or PTOs at the Stationary Source and the quantity of ERCs which have been banked since September 19, 1991 for AER that have occurred at the source, and which have not been used on-site.

SSPE2 (lb/year)						
Permit Unit	NO_X	SO_X	PM_{10}	CO	VOC	NH_3
ATC S-8637-1-0 (Digester System)	0	0	0	0	0	0
ATC S-8637-2-0 (1,468 bhp Digester Gas Engine)[3]	4,583	1,134	1,985	50,818	3,185	1,418
ATC S-8637-3-0 (1,468 bhp Digester Gas Engine)[3]	4,583	1,134	1,985	50,818	3,185	1,418
SSPE2	9,166	2,268	3,970	101,636	6,370	2,836

[3] The SSPE2 values listed in this table include the worst case annual emissions during the 120 hours of allowed commissioning time where the engines are allowed to operate uncontrolled for setup and tuning purposes. After the first year, the PE for NO_X, CO, and VOC emissions will go down as the engines will no longer be allowed to operate without controls in place for these pollutants.

5. Major Source Determination

Rule 2201 Major Source Determination:

Pursuant to District Rule 2201, a Major Source is a stationary source with a SSPE2 equal to or exceeding one or more of the following threshold values. For the purposes of determining major source status the following shall not be included:

- any ERCs associated with the stationary source
- Emissions from non-road IC engines (i.e. transportable IC engines at a particular site at the facility for less than 12 months)
- Fugitive emissions, except for the specific source categories specified in 40 CFR 51.165

Rule 2201 Major Source Determination (lb/year)						
	NO_X	SO_X	PM_{10}	$PM_{2.5}$	CO	VOC
SSPE1	0	0	0	0	0	0
SSPE2	9,166	2,268	3,970	3,970	101,636	6,370
Major Source Threshold	20,000	140,000	140,000	200,000*	200,000	20,000
Major Source?	No	No	No	No	No	No

* The application for this project was deemed complete before 2/18/2016, which was when the District's PM2.5 Major Source Threshold was lowered to 140,000 lb/year

Note: PM2.5 assumed to be equal to PM10

Rule 2410 Major Source Determination:

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(iii). Therefore the PSD Major Source threshold is 250 tons per year (tpy) for any regulated NSR pollutant.

PSD Major Source Determination (tons/year)						
	NO2	VOC	SO2	CO	PM	PM10
Estimated Facility PE before Project Increase	0	0	0	0	0	0
PSD Major Source Thresholds	250	250	250	250	250	250
PSD Major Source ? (Y/N)	N	N	N	N	N	N

Because this is a new facility, the PE for all regulated NSR pollutants prior to the project is equal to zero.

As shown above, the facility is not an existing PSD major source for any regulated NSR pollutant expected to be emitted at this facility.

6. Baseline Emissions (BE)

The BE calculation (in lb/year) is performed pollutant-by-pollutant for each unit within the project to calculate the QNEC, and if applicable, to determine the amount of offsets required.

Pursuant to District Rule 2201, BE = PE1 for:

- Any unit located at a non-Major Source,
- Any Highly-Utilized Emissions Unit, located at a Major Source,
- Any Fully-Offset Emissions Unit, located at a Major Source, or
- Any Clean Emissions Unit, located at a Major Source.

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to District Rule 2201.

Since the proposed digester system and engines are new emissions units, BE = PE1 = 0 for all pollutants from each unit.

7. SB 288 Major Modification

SB 288 Major Modification is defined in 40 CFR Part 51.165 as "any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act."

Since this facility is not a major source for any of the pollutants addressed in this project, this project does not constitute an SB 288 major modification.

8. Federal Major Modification

District Rule 2201 states that a Federal Major Modification is the same as a "Major Modification" as defined in 40 CFR 51.165 and part D of Title I of the CAA.

Since this facility is not a Major Source for any pollutants, this project does not constitute a Federal Major Modification. Additionally, since the facility is not a major source for PM_{10} (140,000 lb/year), it is not a major source for PM2.5 (200,000 lb/year since the application for the project was deemed complete before 2/18/2016).

9. Rule 2410 – Prevention of Significant Deterioration (PSD) Applicability Determination

Rule 2410 applies to any pollutant regulated under the Clean Air Act, except those for which the District has been classified nonattainment. The pollutants which must be addressed in the PSD applicability determination for sources located in the SJV and which are emitted in this project are: (See 52.21 (b) (23) definition of significant)

- NO2 (as a primary pollutant)
- SO2 (as a primary pollutant)
- CO
- PM
- PM10
- Hydrogen sulfide (H2S)[4]
- Total reduced sulfur (inlcuding H2S)[4]

I. Project Emissions Increase - New Major Source Determination

The post-project potentials to emit from all new and modified units are compared to the PSD major source thresholds to determine if the project constitutes a new major source subject to PSD requirements.

The facility or the equipment evaluated under this project is not listed as one of the categories specified in 40 CFR 52.21 (b)(1)(i). The PSD Major Source threshold is 250 tons per year (tpy) for any regulated NSR pollutant.

PSD Major Source Determination: Potential to Emit (tons/year)						
	NO2	VOC	SO2	CO	PM	PM10
Total PE from New and Modified Units	4.6	3.2	1.1	50.8	2.0	2.0
PSD Major Source threshold	250	250	250	250	250	250
New PSD Major Source?	N	N	N	N	N	N

As shown in the table above, the potential to emit for the project, by itself, does not exceed any PSD major source threshold. Therefore Rule 2410 is not applicable and no further analysis is required.

10. Quarterly Net Emissions Change (QNEC)

The QNEC is calculated solely to establish emissions that are used to complete the District's PAS emissions profile screen. Detailed QNEC calculations are included in Appendix A.

[4] Because the facility is not included in the specific source categories listed in 40 CFR 51.165, for PSD purposes only non-fugitive emissions from the engine exhaust stacks must be addressed for this project. Although the sulfur (primarily H_2S) in the fuel will be converted almost entirely to SO_X during combustion, the maximum possible amount of H_2S and total reduced sulfur compounds from the engine stacks can be calculated by assuming that all sulfur in the fuel is emitted as H_2S. Based on the fuel sulfur limit of 40 ppmv as H_2S, the maximum possible H_2S emission factor for the engines is calculated to be 0.02 g-H_2S/bhp (0.0056 lb-H_2S/MMBtu), resulting in a total combined maximum of < 0.06 tpy H_2S from the exhaust stacks of both engines. This is well below the applicable PSD threshold of 250 tpy.

VIII. Compliance

Rule 2201 New and Modified Stationary Source Review Rule

A. Best Available Control Technology (BACT)

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis. Unless specifically exempted by Rule 2201, BACT shall be required for the following actions*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in an SB 288 Major Modification or a Federal Major Modification, as defined by the rule.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

a. New emissions units – PE > 2 lb/day

As seen in Section VII.C.2 above, the applicant is proposing to install a new digester system with and two new digester gas-fired IC engines.

Digester System (S-8637-1-0)

As explained above, the digester system will consist of sealed lagoon(s) that will reduce VOC emissions from the manure at the dairy and emissions from the digester system are considered negligible. Therefore BACT for new units with PE > 2 lb/day purposes is not required for the digester system.

Digester Gas-Fired Engines (S-8637-2-0 and -3-0)

The proposed engines will each have a PE greater than 2.0 lb/day for NO_X, SO_X, PM_{10}, CO, VOC, and NH_3. Therefore, BACT is triggered for NO_X, SO_X, PM_{10}, and VOC. As part of the BACT requirements, NH_3 slip from the SCR systems will also be limited. The PE for CO from each unit also exceeds 2.0 lb/day; however, BACT is not triggered for CO since the SSPE2 for CO is not greater than 200,000 lbs/year, as demonstrated in Section VII.C.5 above.

b. Relocation of emissions units – PE > 2 lb/day

As discussed in Section I above, there are no emissions units being relocated from one stationary source to another; therefore BACT is not triggered for relocation of an emissions unit.

c. Modification of emissions units – AIPE > 2 lb/day

As discussed in Section I above, there are no modified emissions units associated with this project. Therefore, BACT is not triggered for modification of a unit.

d. SB 288/Federal Major Modification

As discussed in Sections VII.C.7 and VII.C.8 above, this project does not constitute an SB 288 or Federal Major Modification. Therefore BACT is not triggered for Major Modification purposes.

2. BACT Guideline

S-8637-2-0 & -3-0

BACT Guideline 3.3.15 applies to the proposed digester gas-fired IC engines. (See Appendix B)

3. Top-Down BACT Analysis

Pursuant to the Top-Down BACT Analysis (See Appendix B), BACT has been satisfied with the following:

NO_X: NO_X emissions ≤ 0.15 g/bhp-hr
SO_X: Fuel sulfur content ≤ 40 ppmv (as H_2S)
PM_{10}: Fuel sulfur content ≤ 40 ppmv (as H_2S)
VOC: VOC emissions ≤ 0.10 g/bhp-hr
NH_3: NH_3 slip emissions ≤ 10 ppmv @ 15% O_2

B. Offsets

1. Offset Applicability

Offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the SSPE2 equals to or exceeds the offset threshold levels in Table 4-1 of Rule 2201.

The SSPE2 is compared to the offset thresholds in the following table.

Offset Determination (lb/year)					
	NO_X	SO_X	PM_{10}	CO	VOC
SSPE2	9,166	2,268	3,970	101,636	6,370
Offset Thresholds	20,000	54,750	29,200	200,000	20,000
Offsets triggered?	No	No	No	No	No

2. Quantity of Offsets Required

As seen above, the SSPE2 is not greater than the offset thresholds for all the pollutants; therefore offset calculations are not necessary and offsets will not be required for this project.

C. Public Notification

1. Applicability

Public noticing is required for:

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications,
b. Any new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any one pollutant,
c. Any project which results in the offset thresholds being surpassed, and/or
d. Any project with an SSIPE of greater than 20,000 lb/year for any pollutant.
e. Any project which results in a Title V significant permit modification

a. New Major Sources, Federal Major Modifications, and SB 288 Major Modifications

New Major Sources are new facilities, which are also Major Sources. As shown in Section VII.C.5 above, the SSPE2 is not greater than the Major Source threshold for any pollutant. Therefore, public noticing is not required for this project for new Major Source purposes.

As demonstrated in Sections VII.C.7 and VII.C.8, this project does not constitute an SB 288 or Federal Major Modification; therefore, public noticing for SB 288 or Federal Major Modification purposes is not required.

b. PE > 100 lb/day

Applications which include a new emissions unit with a PE greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements.

The PE2 for the proposed new IC engines is compared to the daily PE Public Notice thresholds in the following table:

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

PE > 100 lb/day Public Notice Thresholds			
Pollutant	PE2 (lb/day)	Public Notice Threshold	Public Notice Triggered?
NO_X	77.7	100 lb/day	No
SO_X	3.1	100 lb/day	No
PM_{10}	5.4	100 lb/day	No
CO	376.7	100 lb/day	**Yes**
VOC	77.7	100 lb/day	No
NH_3	3.9	100 lb/day	No

Therefore, public noticing for PE > 100 lb/day purposes is required.

c. Offset Threshold

The SSPE1 and SSPE2 are compared to the offset thresholds in the following table.

Offset Thresholds				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	0	9,166	20,000 lb/year	No
SO_X	0	2,268	54,750 lb/year	No
PM_{10}	0	3,970	29,200 lb/year	No
CO	0	101,636	200,000 lb/year	No
VOC	0	6,370	20,000 lb/year	No

As detailed above, there were no thresholds surpassed with this project; therefore public noticing is not required for surpassing an offset threshold.

d. SSIPE > 20,000 lb/year

Public notification is required for any permitting action that results in a SSIPE of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE = SSPE2 – SSPE1. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table.

SSIPE Public Notice Thresholds					
Pollutant	SSPE2 (lb/year)	SSPE1 (lb/year)	SSIPE (lb/year)	SSIPE Public Notice Threshold	Public Notice Required?
NO_x	9,166	0	9,166	20,000 lb/year	No
SO_x	2,268	0	2,268	20,000 lb/year	No
PM_{10}	3,970	0	3,970	20,000 lb/year	No
CO	101,636	0	101,636	20,000 lb/year	**Yes**
VOC	6,370	0	6,370	20,000 lb/year	No
NH_3	2,836	0	2,836	20,000 lb/year	No

As demonstrated above, the SSIPE for CO was greater than 20,000 lb/year; therefore public noticing for SSIPE > 20,000 lbs is required.

e. Title V Significant Permit Modification

Since this facility does not have a Title V operating, this change is not a Title V Significant Modification, and therefore public noticing is not required.

2. Public Notice Action

As discussed above, public noticing is required for this project for CO emissions from an emissions unit in excess of 100 lb/day and for an SSIPE for CO that exceeds 20,000 lb/yr. Therefore, public notice documents will be submitted to the California Air Resources Board (ARB) and a public notice will be published in a local newspaper of general circulation prior to the issuance of the ATC for this equipment.

D. Daily Emission Limits (DELs)

DELs and other enforceable conditions are required by Rule 2201 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity. The DEL must be contained in the latest ATC and contained in or enforced by the latest PTO and must be enforceable, in a practicable manner, on a daily basis. DELs are also required to enforce the applicability of BACT.

Proposed Rule 2201 (DEL) Conditions for the Digester System (S-8637-1-0)

As stated above, the digester system will reduce emissions from the manure produced by cattle at Lakeview Farms dairy. The following condition will be placed on the ATC permit to ensure that fugitive emissions from the digester system will be negligible:

- The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
- The air injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions for the Digester Gas-Fired Engines (S-8637-2-0 & -3-0)

Proposed Rule 2201 (DEL) Conditions for Engines during Both Commissioning and Normal Operation:

- This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]

- During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
- The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
- Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Commissioning Period:

For these digester gas-fired IC engines, the DELs for NO_X, PM_{10}, CO, and VOC are stated in the form of maximum emission factors (g/bhp-hr) and maximum number of hours allowed for commissioning activities.

- Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
- The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
- During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
- The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]

Proposed Rule 2201 (DEL) Conditions during Normal Operation:

For the proposed digester gas-fired IC engines, the DELs for NO_X, PM_{10}, CO, and VOC during normal operation are stated in the form of emission factors (g/hp-hr & ppmv), the maximum engine horsepower rating (1,468 bhp), and the maximum operational time of 24 hours per day.

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

E. Compliance Assurance

1. Source Testing

The proposed 1,468 bhp digester gas-fired engines are subject to District Rule 4702 - Internal Combustion Engines. Section 6.3.2.1 of District Rule 4702 requires source testing of NO_X, CO, and VOC emissions at least once every 24 months for a non-agricultural spark-ignited IC engine. The periodic source testing required by District Rule 4702 will ensure compliance with the applicable New Source Review (NSR) requirements NO_X, CO, and VOC. Therefore, source testing for NO_X, CO, and VOC will be required within 90 days of initial start-up and at least once 24 months thereafter. Since the control equipment will include an SCR system, periodic testing of ammonia slip will also be required. In addition, Section 5.10.1 of District Rule 4702 requires an annual analysis of the sulfur content of engine fuel. The PM_{10} emissions from the engine are not expected to change much over time as long as the quality of the gas used to fuel the engines remains consistent. The facility will be required to periodically monitor the sulfur content of the digester gas fuel, which should ensure that the quality of the digester gas fuel is consistent. Therefore, initial PM_{10} source testing will be required to demonstrate compliance with the PM_{10} emission limit, but ongoing PM_{10} source testing will not be required.

The proposed engines are also subject to 40 CFR 60, Subpart JJJJ – Standards of Performance for Stationary Spark Ignition Internal Combustion Engines. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, no testing requirements from this subpart will be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

The following conditions will be placed on the engine permits to ensure compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]
- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]
- Fuel sulfur analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided it to the District upon request. [District Rules 2201 and 4702]
- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

2. Monitoring

As stated above the engines are subject to District Rule 4702. Section 5.8.1 of District Rule 4702 requires engines rated at least 1,000 bhp that can operate more than 2,000 hour per calendar year or equipped with external control devices to install, operate, and maintain an APCO-approved alternate monitoring plan. Section 5.8.9 of District Rule 4702 requires monitoring of NO_X emissions at least once every calendar quarter for a non-agricultural spark-ignited IC engine. Therefore, quarterly monitoring of NO_X, CO, and O_2 concentrations in accordance with pre-approved alternate monitoring plan "A" within District Policy SSP 1810 will be required. Since the engines will be equipped with SCR, quarterly monitoring of ammonia slip will also be required.

The following conditions will be placed on the engine permits to ensure compliance:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]
- The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]
- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Because of the variable composition of digester gas, additional monitoring of the fuel sulfur content of the digester gas will be required. The following conditions will be placed on the engine permits to ensure compliance:

- The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]
- Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

3. Recordkeeping

Recordkeeping is required to demonstrate compliance with the offset, public notification and daily emission limit requirements of Rule 2201.

The following conditions will be listed on the engine permits:

- The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]
- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]
- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or

volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

4. Reporting

No reporting is required to demonstrate compliance with District Rule 2201.

As stated above, the proposed 1,468 bhp engines are subject to 40 CFR 60, Subpart JJJJ. 40 CFR 60, Subpart JJJJ requires uncertified engines rated 500 bhp or more to submit an initial notification to EPA. As explained above, the District has not been delegated the authority to implement this regulation for non-Major Sources; therefore, this requirement will not be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

F. Ambient Air Quality Analysis (AAQA)

District Rule 2201 requires that an ambient air quality analysis (AAQA) be conducted for the purpose of determining whether a new or modified Stationary Source will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Appendix C of this document for the AAQA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the AAQA summary sheet the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X. The proposed location is in a non-attainment area for the state's PM_{10} as well as federal and state $PM_{2.5}$ thresholds.

The results of the Criteria Pollutant Modeling conducted for the AAQA are summarized in the following table:

Criteria Pollutant Modeling Results*					
Digester Gas-Fired IC Engines	**1 Hour**	**3 Hours**	**8 Hours.**	**24 Hours**	**Annual**
CO	Pass	X	Pass	X	X
NO_X	Pass[1]	X	X	X	Pass
SO_X	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[2]	Pass[2]
H2S	Pass	X	X	X	X

* Results were taken from the PSD spreadsheet.

[1] The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.

[2] The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

[3] H_2S emissions must be limited to the value listed in the Proposed Permit Conditions section in order for this project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS).

Rule 2410 Prevention of Significant Deterioration

As shown in Section VII. C. 9. above, this project does not result in a new PSD major source or PSD major modification. No further discussion is required.

Rule 2520 Federally Mandated Operating Permits

Since this facility's potential emissions do not exceed any major source thresholds of Rule 2201, this facility is not a major source, and Rule 2520 does not apply.

Rule 4101 Visible Emissions

Rule 4101 states that no air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity.

Since the IC engines are fired solely on gaseous fuel, visible emissions are not expected to exceed Ringelmann 1 or 20% opacity.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Rule 4102 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained. Therefore, compliance with this rule is expected.

California Health & Safety Code 41700 (Health Risk Assessment)

District Policy APR 1905 – *Risk Management Policy for Permitting New and Modified Sources* specifies that for an increase in emissions associated with a proposed new source or modification, the District perform an analysis to determine the possible impact to the nearest resident or worksite.

A Health Risk Assessment (HRA) is not required for a project with a total facility prioritization score of less than one. According to the Technical Services Memo for this project (Appendix C), the total facility prioritization score including this project was greater than one. Therefore, an HRA was required to determine the short-term acute and long-term chronic exposure from this project. The results of the health risk assessment are summarized in the table below.

RMR Summary			
Categories	**1,468 bhp Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)**	**Project Totals**	**Facility Totals**
Prioritization Score[1]	107 (each)	214	>1
Acute Hazard Index	0.48 (each)[1]	0.95	0.95
Chronic Hazard Index	0.16 (each)	0.31	0.31
Maximum Individual Cancer Risk (10^{-6})	0.002 (each)	0.004	0.004
T-BACT Required?	**No**		
Special Permit Conditions?	**Yes**		

[1] H_2S emissions must be limited in order to achieve the acute hazard index score in this project and for the project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS). Please see special condition below.

Discussion of T-BACT

BACT for toxic emission control (T-BACT) is required if the cancer risk exceeds one in one million. As demonstrated above, T-BACT is not required for this project because the HRA indicates that the risk is not above the District's thresholds for triggering T-BACT requirements; therefore, compliance with the District's Risk Management Policy is expected.

District policy APR 1905 also specifies that the increase in emissions associated with a proposed new source or modification not have acute or chronic indices, or a cancer risk greater than the District's significance levels (i.e. acute and/or chronic indices greater than 1 and a cancer risk greater than 20 in a million). As outlined by the HRA Summary in Appendix C of this report, the emissions increases for this project was determined to be less than significant.

To ensure compliance with the HRA; the following condition will be listed on the engine permits:

Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

This condition, along with the engine rating in the equipment description, will ensure that the H_2S emissions from the engine exhaust stack shall not exceed 1.97 lb/hr, as required by the Health Risk Assessment.

Rule 4201 Particulate Matter Concentration

The purpose of this rule is to protect the ambient air quality by establishing a particulate matter emission standard. Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

$$0.07 \quad \frac{g}{hp \cdot hr} \times \frac{1 hp \cdot hr}{2{,}545 Btu} \times \frac{10^6 Btu}{9{,}100 dscf} \times \frac{0.33 Btu_{out}}{1 Btu_{in}} \times \frac{15.43 grain}{g} = \quad 0.015 \quad \frac{grain}{dscf}$$

Since 0.015 grain/dscf is less than 0.1 grain/dscf, compliance with this rule is expected.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4701 Stationary Internal Combustion Engines – Phase I

The requirements of Rule 4702 are equivalent or more stringent than the requirements of this Rule. Since the proposed IC engines are subject to both Rules 4701 and 4702, compliance with Rule 4702 is sufficient to demonstrate compliance with this rule.

Rule 4702 Internal Combustion Engines

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), volatile organic compounds (VOC), and sulfur oxides (SO_X) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower of 25 brake horsepower or greater.

Section 5.2.1 requires that the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall not operate it in such a manner that results in emissions exceeding the limits in Table 1 of Rule 4702 until such time that the engine has demonstrated compliance with emission limits in Table 2 of Rule 4702 pursuant to the compliance deadlines in Section 7.5. In lieu of complying with Table 1 emission limits, the operator of a spark-ignited engine shall comply with the applicable emission limits pursuant to Section 8.0. The proposed new engines are required to immediately comply with the emission limits contained in Table 2 since the applicable compliance dates have passed (except for an operator with at least 12 existing engines at one stationary source); therefore, the emissions limits in Table 1 of Rule 4702 are not applicable to the proposed engines.

Section 5.2.2 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited non-agricultural internal combustion engine rated > 50 bhp shall comply with all the applicable requirements of the rule and the requirements of Section 5.2.2.1, 5.2.2.2, or 5.2.2.3, on an engine-by-engine basis.

Section 5.2.2.1 requires that on and after the compliance schedule specified in Section 7.5, the operator of a spark-ignited engine that is used exclusively in non-agricultural operations shall comply with Sections 5.2.2.1.1 through 5.2.2.1.3 on an engine-by-engine basis:

5.2.2.1.1 NO_X, CO, and VOC emission limits pursuant to Table 2;

5.2.2.1.2 SO_X control requirements of Section 5.7, pursuant to the deadlines specified in Section 7.5; and

5.2.2.1.3 Monitoring requirements of Section 5.10, pursuant to the deadlines specified in Section 7.5.

Section 5.2.2.2 allows that in lieu of complying with the NO_X emission limit requirement of Section 5.2.2.1.1, an operator may pay an annual fee to the District, as specified in Section 5.6, pursuant to Section 7.6. Pursuant to Section 5.2.2.2.1, engines in the fee payment program shall have actual emissions not greater than the applicable limits in Table 1 during the entire time the engine is part of the fee payment program. Pursuant to Section 5.2.2.2.2, compliance with Section 5.7 and 5.10, pursuant to the deadlines specified in Section 7.5, is also required as part of the fee payment option.

Section 5.2.2.3 allows that in lieu of complying with the NO_X, CO, and VOC limits of Table 2 on an engine-by-engine basis, an operator may elect to implement an alternative emission control plan pursuant to Section 8.0. An operator electing this option shall not be eligible to participate in the fee payment option outlined in Section 5.2.2.2 and Section 5.6.

Rule 4702, Table 2 Emission Limits/Standards for Spark-Ignited IC Engines rated >50 bhp Used in Non-Agricultural Operations
(Emission Limits are effective according to the compliance schedule specified in Rule 4702, Section 7.5.)

Engine Type	NO_X Emission Limit (ppmv @ 15% O_2, dry)	CO Emission Limit (ppmv @ 15% O_2, dry)	VOC Emission Limit (ppmv @ 15% O_2, dry)
1. a. Rich-Burn, Waste Gas Fueled	50 ppmv	2,000 ppmv	250 ppmv
1. b. Rich-Burn, Cyclic Loaded, Field Gas Fueled	50 ppmv	2,000 ppmv	250 ppmv
1. c. Rich-Burn, Limited Use	25 ppmv	2,000 ppmv	250 ppmv
1. d. Rich-Burn, Not Listed Above	11 ppmv	2,000 ppmv	250 ppmv
2. a. Lean-Burn, 2-Stroke, Gaseous Fueled, >50 bhp & <100 bhp	75 ppmv	2,000 ppmv	750 ppmv
2. b. Lean-Burn, Limited Use	65 ppmv	2,000 ppmv	750 ppmv
2. c. Lean-Burn Engine used for gas compression	65 ppmv or 93% reduction	2,000 ppmv	750 ppmv
2. d. Waste Gas Fueled	65 ppmv or 90% reduction	2,000 ppmv	750 ppmv
2. e. Lean-Burn, Not Listed Above	11 ppmv	2,000 ppmv	750 ppmv

The proposed digester gas-fired engines will be operated as a separate stationary source than the dairy farm and the District has determined that the IC engines are a non-agricultural IC engines. The digester gas-fired, engines are waste gas-fired engines and are required to comply with the following emissions limits from Table 2, Row 2.d: 65 ppmvd NO_X, 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2).

Therefore, the following previously presented condition will be listed on the proposed ATC permits for the engines to ensure compliance:

- Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

Section 5.2.3.1 requires that the operator of a spark-ignited internal combustion engine rated > 50 bhp that is used exclusively in agricultural operations shall not operate it in such a manner that results in emissions exceeding the limits in Table 3 of Rule 4702 for the appropriate engine type on an engine-by-engine basis.

Section 5.2.3.2 allows that in lieu of complying with the NO_X, CO, and VOC limits of Table 3 on an engine-by-engine basis, an operator of a spark-ignited agricultural IC engine may elect to implement an alternative emission control plan pursuant to Section 8.0.

Section 5.2.3.3 requires an operator of an agricultural IC engine in that is subject to the applicable requirements of Table 3 shall not replace such engine with an engine that emits more emissions of NOx, VOC, and CO, on a ppmv basis, (corrected to 15% oxygen on a dry basis) than the engine being replaced.

As stated above, the proposed digester gas-fired engines will be operated as part of a separate non-agricultural stationary source; therefore, Section 5.2.3 does not apply to the proposed engines.

Section 5.2.4 requires the operator of a certified compression-ignited engine rated >50 bhp shall comply with the following requirements of Sections 5.2.4.1, 5.2.4.2, 5.2.4.3, 5.2.4.3, and 5.2.4.4. The proposed digester gas-fired engines are not compression-ignited engines; therefore, Section 5.2.4 does not apply to the proposed engines.

Section 5.3 requires that all continuous emission monitoring systems (CEMS) emissions measurements shall be averaged over a period of 15 consecutive minutes. Any 15-consecutive minute block average CEMS measurement exceeding the applicable emission limits of this rule shall constitute a violation of this rule. The IC engines proposed under this project will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.4 specifies procedures to calculate percent emission reductions if percent emission reductions are used to comply with the NO_X emission limits of Section 5.2. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.5 requires the operator of an internal combustion engine that uses percent emission reduction to comply with the NO_X emission limits of Section 5.2 shall provide an accessible inlet and outlet on the external control device or the engine as appropriate for taking emission samples and as approved by the APCO. The use of percent emission reductions to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.6 specifies procedures that operators of non-agricultural spark-ignited IC engines who elect to comply under Section 5.2.2.2 must use for calculation of the annual emissions fee. The applicant has proposed that the digester gas-fired engines comply with the applicable emission limits of Table 2 of District Rule 4702; therefore payment of annual emissions fees for the engines is not required and this section of the Rule is not applicable.

Section 5.7 requires that on and after the compliance schedule specified in Section 7.5, operators of non-agricultural spark-ignited engines and non-agricultural compression-ignited engines shall comply shall comply with Sections 5.7.1, 5.7.2, 5.7.3, 5.7.4, 5.7.5, or 5.7.6:

5.7.1 Operate the engine exclusively on PUC-quality natural gas, commercial propane, butane, or liquefied petroleum gas, or a combination of such gases; or
5.7.2 Limit gaseous fuel sulfur content to no more than five (5) grains of total sulfur per one hundred (100) standard cubic feet; or
5.7.3 Use California Reformulated Gasoline for gasoline-fired spark-ignited engines; or
5.7.4 Use California Reformulated Diesel for compression-ignited engines; or
5.7.5 Operate the engine on liquid fuel that contains no more than 15 ppm sulfur, as determined by the test method specified in Section 6.4.6; or
5.7.6 Install and properly operate an emission control system that reduces SO_2 emissions by at least 95% by weight as determined by the test method specified in Section 6.4.6.

To satisfy BACT, the average sulfur content of the digester gas fuel for the engine will be limited to 40 ppmv (approximately equal to 2.4 grains sulfur per 100 standard cubic feet). The following condition will be listed on the proposed engine ATC permits to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4702, and 4801]

Section 5.8 requires that the operator of a non-agricultural spark-ignited IC engine subject to the requirements of Section 5.2 or any engine subject to the requirements of Section 8.0 shall comply with the following requirements of Sections 5.8.1 – 5.8.11:

Section 5.8.1 stipulates that for each engine with a rated brake horsepower of 1,000 hp or greater and which is allowed to operate more than 2,000 hours per calendar year, or with an external emission control device, shall either install, operate, and maintain continuous monitoring equipment for NO_X, CO, and oxygen, as identified in Rule 1080 (Stack Monitoring), or install, operate, and maintain APCO-approved alternate monitoring. The monitoring system may be a continuous emissions monitoring system (CEMS), a parametric emissions monitoring system (PEMS), or an alternative monitoring system approved by the APCO. APCO-approved alternate monitoring shall consist of one or more of the following:

5.8.1.1 Periodic NO_X and CO emission concentrations,
5.8.1.2 Engine exhaust oxygen concentration,

5.8.1.3 Air-to-fuel ratio,
5.8.1.4 Flow rate of reducing agents added to engine exhaust,
5.8.1.5 Catalyst inlet and exhaust temperature,
5.8.1.6 Catalyst inlet and exhaust oxygen concentration, or
5.8.1.7 Other operational characteristics.

The applicant has proposed to comply with this section of the Rule by proposing a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, the following condition will be placed on the engine ATC permits:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

Section 5.8.2 requires that for each non-agricultural spark-ignited IC engine not subject to Section 5.8.1, the operator shall monitor operational characteristics recommended by the engine manufacturer or emission control system supplier, and approved by the APCO. The proposed engines will be subject to Section 5.8.1; therefore this section is not applicable.

Section 5.8.3 requires that for each engine with an alternative monitoring system, the operator shall submit to, and receive approval from the APCO, adequate verification of the alternative monitoring system's acceptability. The proposed ATC permits for the digester gas-fired engines include a pre-approved alternate emissions monitoring plan that specifies that the permittee perform periodic NO_X, CO, and O_2 emissions concentrations as specified in District Policy SSP-1810, dated 4/29/04. Therefore, this section is satisfied.

Section 5.8.4 requires that for each engine with an APCO approved CEMS, operate the CEMS in compliance with the requirements of 40 Code of Federal Regulations (CFR) Part 51, 40 CFR Parts 60.7 and 60.13 (except subsection h), 40 CFR Appendix B (Performance Specifications), 40 CFR Appendix F (Quality Assurance Procedures), and applicable provisions of Rule 1080 (Stack Monitoring). The IC engines proposed under this project will not have CEMS installed; therefore this section of the Rule is not applicable.

Section 5.8.5 requires that each engine have the data gathering and retrieval capabilities of an installed monitoring system described in Section 5.8 approved by the APCO. As stated above, the proposed ATC permits for the proposed digester gas-fired engines include an alternate emissions monitoring plan that has been pre-approved by the APCO. Therefore, this section is satisfied.

Section 5.8.6 requires that for each non-agricultural spark-ignited IC engine, the operator shall install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the operator may use an alternative device, method, or technique in determining operating time provided that the alternative is approved by the APCO. The operator shall maintain and operate the required meter in accordance with the manufacturer's instructions. The applicant has proposed a nonresettable elapsed operating time meter for the engines in this project. Therefore, the following condition will be placed on the engine ATC permits to ensure compliance:

- This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]

Section 5.8.7 requires that for each engine, the permittee shall implement the Inspection and Monitoring (I&M) plan submitted to and approved by the APCO pursuant to Section 6.5. The applicant has submitted an I&M program with this ATC application and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.8 requires that for each engine, collect data through the I&M plan in a form approved by the APCO. The applicant has submitted an I&M program and the requirements of this plan will be explained in detail in the section that covers Section 6.5 of this Rule.

Section 5.8.9 requires for each non-agricultural spark-ignited IC engine, use of a portable NO_X analyzer to take NO_X emission readings to verify compliance with the emission requirements of Section 5.2 or Section 8.0 during each calendar quarter in which a source test is not performed. If an engine is operated less than 120 calendar days per calendar year, the operator shall take one NO_X emission reading during the calendar year in which a source test is not performed and the engine is operated. All emission readings shall be taken with the engine operating either at conditions representative of normal operations or conditions specified in the Permit-to-Operate or Permit-Exempt Equipment Registration. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. All NO_X emissions readings shall be reported to the APCO in a manner approved by the APCO. NO_X emission readings taken pursuant to this section shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive minute sample reading or by taking at least five (5) readings evenly spaced out over the 15 consecutive-minute period. Therefore, the following conditions will be placed on the ATC permits:

- The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 5.8.10 specifies that the APCO shall not approve an alternative monitoring system unless it is documented that continued operation within ranges of specified emissions related performance indicators or operational characteristics provides a reasonable assurance of compliance with applicable emission limits and that the operator shall source test over the proposed range of surrogate operating parameters to demonstrate compliance with the applicable emission standards. The proposed ATC permits for the digester gas-fired engines include a pre-approved alternate emissions monitoring plan that requires periodic NO_X, CO, and O_2 emissions concentrations. Therefore, this section is satisfied.

Section 5.8.11 requires that for each non-agricultural spark-ignited IC engine subject to the Alternate Emission Control Plan (AECP) of Section 8.0, the operator shall install and operate a nonresettable fuel meter. In lieu of installing a nonresettable fuel meter, the operator may use an alternative device, method, or technique in determining daily fuel consumption provided that the alternative is approved by the APCO. The operator shall maintain, operate, and calibrate the required fuel meter in accordance with the manufacturer's instructions. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engines under this project; therefore this section of the Rule is not applicable.

Section 5.9 specifies monitoring requirements for all other engines that are not subject to the requirements of Section 5.8. The proposed spark-ignited non-agricultural digester gas-fired engines are subject to the requirements of Section 5.8; therefore this section of the Rule is not applicable.

Section 5.10 specifies SO_X Emissions Monitoring Requirements. On and after the compliance schedule specified in Section 7.5, an operator of a non-agricultural IC engine shall comply with the following requirements:

5.10.1 An operator of an engine complying with Sections 5.7.2 or 5.7.5 shall perform an annual sulfur fuel analysis in accordance with the test methods in Section 6.4. The operator shall keep the records of the fuel analysis and shall provide it to the District upon request,

5.10.2 An operator of an engine complying with Section 5.7.6 by installing and operating a control device with at least 95% by weight SOx reduction efficiency shall submit for approval by the APCO the proposed the key system operating parameters and frequency of the monitoring and recording not later than July 1, 2013, and

5.10.3 An operator of an engine complying with Section 5.7.6 shall perform an annual source test unless a more frequent sampling and reporting period is included in the Permit-to-Operate. Source tests shall be performed in accordance with the test methods in Section 6.4.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

Section 5.11 requires operators of engines used exclusively in agricultural operations that are not required to have a Permit-to-Operate pursuant to California Health and Safety Code Section 42301.16 but are required to comply with Section 5.2 of Rule 4702 shall register such engines pursuant to Rule 2250 (Permit-Exempt Equipment Registration). The proposed spark-ignited non-agricultural digester gas-fired engines are required to have a District Permit to Operate; therefore this section of the Rule is not applicable.

Section 6.1 requires that the operator of an engine subject to the requirements of Rule 4702 shall submit to the APCO an approvable emission control plan of all actions to be taken to satisfy the emission requirements of Section 5.2 and the compliance schedules of Section 7.0. If there is no change to the previously-approved emission control plan, the operator shall submit a letter to the District indicating that the previously approved plan is still valid.

Section 6.1.1 specifies that the requirement to submit an emission control plan shall apply to the following engines:

6.1.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;

6.1.1.2 Engines subject to Section 8.0;

6.1.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;

6.1.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

Section 6.1.2 specifies that the emission control plan shall contain the following information, as applicable for each engine:

6.1.2.1 Permit-to-Operate number, Authority-to-Construct number, or Permit-Exempt Equipment Registration number,

6.1.2.2 Engine manufacturer,

6.1.2.3 Model designation and engine serial number,

6.1.2.4 Rated brake horsepower,

6.1.2.5 Type of fuel and type of ignition,

6.1.2.6 Combustion type: rich-burn or lean-burn,

6.1.2.7 Total hours of operation in the previous one-year period, including typical daily operating schedule,

6.1.2.8 Fuel consumption (cubic feet for gas or gallons for liquid) for the previous one-year period,

6.1.2.9 Stack modifications to facilitate continuous in-stack monitoring and to facilitate source testing,

6.1.2.10 Type of control to be applied, including in-stack monitoring specifications,

6.1.2.11 Applicable emission limits,

6.1.2.12 Documentation showing existing emissions of NO_X, VOC, and CO, and

6.1.2.13 Date that the engine will be in full compliance with this rule.

Section 6.1.3 requires that the emission control plan shall identify the type of emission control device or technique to be applied to each engine and a construction/removal schedule, or shall provide support documentation sufficient to demonstrate that the engine is in compliance with the emission requirements of this rule.

Section 6.1.4 requires that for an engine being permanently removed from service, the emission control plan shall include a letter of intent pursuant to Section 7.2.

The applicant has submitted all the required information for Section 6.1 in the application for the IC engines evaluated under this project.

Section 6.2.1 requires that the operator of an engine subject to the requirements of Section 5.2 shall maintain an engine operating log to demonstrate compliance with Rule 4702. This information shall be retained for a period of at least five years, shall be readily available, and be made available to the APCO upon request. The engine operating log shall include, on a monthly basis, the following information:

6.2.1.1 Total hours of operation,
6.2.1.2 Type of fuel used,
6.2.1.3 Maintenance or modifications performed,
6.2.1.4 Monitoring data,
6.2.1.5 Compliance source test results, and
6.2.1.6 Any other information necessary to demonstrate compliance with this rule.
6.2.1.7 For an engine subject to Section 8.0, the quantity (cubic feet of gas or gallons of liquid) of fuel used on a daily basis.

The following condition will be placed on the ATC permits:

- The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

Section 6.2.2 requires that the data collected pursuant to the requirements of Section 5.8 and Section 5.9 shall be maintained for at least five years, shall be readily available, and made available to the APCO upon request.

The following previously presented condition will be listed on the proposed ATC permits to ensure compliance:

- All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

Section 6.2.3 requires that an operator claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and provided to the APCO upon request. The records shall include, but are not limited to, the following:

6.2.3.1 Total hours of operation,
6.2.3.2 The type of fuel used,
6.2.3.3 The purpose for operating the engine,
6.2.3.4 For emergency standby engines, all hours of non-emergency and emergency operation shall be reported, and
6.2.3.5 Other support documentation necessary to demonstrate claim to the exemption

The applicant is not claiming an exemption for the proposed engines under Section 4.2 or Section 4.3; therefore, this section does not apply.

Section 6.3 requires that the operator of an engine subject to the emission limits in Section 5.2 or the requirements of Section 8.2, shall comply with the compliance testing requirements of Section 6.3.

Section 6.3.1 specifies that the requirements of Section 6.3.2 through Section 6.3.4 shall apply to the following engines:

6.3.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;
6.3.1.2 Engines subject to Section 8.0;
6.3.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0;
6.3.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

Section 6.3.2 requires demonstration of compliance with applicable limits, ppmv or percent reduction, in accordance with the test methods in Section 6.4, as specified below:

6.3.2.1 By the applicable date specified in Section 5.2, and at least once every 24 months thereafter, except for an engine subject to Section 6.3.2.2.
6.3.2.2 By the applicable date specified in Section 5.2 and at least once every 60 months thereafter, for an agricultural spark-ignited engine that has been retro-fitted with a catalytic emission control device.
6.3.2.3 A portable NOx analyzer may be used to show initial compliance with the applicable limits/standards in Section 5.2 for agricultural spark-ignited engines, provided the criteria specified in Sections 6.3.2.3.1 to 6.3.2.3.5 are met, and a source test is conducted in accordance with Section 6.3.2 within 12 months from the required compliance date.

The following conditions will be included the ATC permits to ensure compliance:

- Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]
- Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

Section 6.3.3 requires the operator to conduct emissions source testing with the engine operating either at conditions representative of normal operations or conditions specified in the

Permit-to-Operate or Permit-Exempt Equipment Registration. For emissions source testing performed pursuant to Section 6.3.2 for the purpose of determining compliance with an applicable standard or numerical limitation, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC shall be reported as methane. VOC, NO_X, and CO concentrations shall be reported in ppmv, corrected to 15 percent oxygen. For engines that comply with a percent reduction limit, the percent reduction of NO_X emissions shall also be reported.

The following conditions will be included in the ATC permits to ensure compliance:

- {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]
- For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

Section 6.3.4 requires that in addition to other information, the source test protocol shall describe which critical parameters will be measured and how the appropriate range for these parameters shall be established. The range for these parameters shall be incorporated into the I&M plan.

Section 6.3.5 specifies that engines that are limited by Permit-to-Operate or Permit-Exempt Equipment Registration condition to be fueled exclusively with PUC quality natural gas shall not be subject to the reoccurring source test requirements of Section 6.3.2 for VOC emissions. The proposed engines will be fueled on digester gas; therefore this section does not apply.

Section 6.3.6 specifies requirements for spark-ignited engines for testing a unit or units that represent a specified group of units, in lieu of compliance with the applicable requirements of Section 6.3.2. Testing of representative units is not being proposed for the engines; therefore this section does not apply.

Section 6.4 requires that the compliance with the requirements of Section 5.2 shall be determined, as required, in accordance with the following test procedures or any other method approved by EPA and the APCO:

6.4.1 Oxides of nitrogen - EPA Method 7E, or ARB Method 100.
6.4.2 Carbon monoxide - EPA Method 10, or ARB Method 100.
6.4.3 Stack gas oxygen - EPA Method 3 or 3A, or ARB Method 100.
6.4.4 Volatile organic compounds - EPA Method 25A or 25B, or ARB Method 100. Methane and ethane, which are exempt compounds, shall be excluded from the result of the test.
6.4.5 Operating horsepower determination - any method approved by EPA and the APCO.
6.4.6 SO_X Test Methods
6.4.6.1 Oxides of sulfur – EPA Method 6C, EPA Method 8, or ARB Method 100.

6.4.6.2 Determination of total sulfur as hydrogen sulfide (H_2S) content – EPA Method 11 or EPA Method 15, as appropriate.

6.4.6.3 Sulfur content of liquid fuel – American Society for Testing and Materials (ASTM) D 6920-03 or ASTM D 5453-99.

6.4.6.4 The SO_X emission control system efficiency shall be determined using the following:

% Control Efficiency = $[(C_{SO2,\ inlet} - C_{SO2,\ outlet}) / C_{SO2,\ inlet}] \times 100$

Where:

$C_{SO2,\ inlet}$ = concentration of SO_X (expressed as SO_2) at the inlet side of the SO_X emission control system, in lb/Dscf

$C_{SO2,\ outlet}$ = concentration of SO_X (expressed as SO_2) at the outlet side of the SO_X emission control system, in lb/Dscf

6.4.7 The Higher Heating Value (hhv) of the fuel shall be determined by one of the following test methods:

6.4.7.1 ASTM D 240-02 or ASTM D 3282-88 for liquid hydrocarbon fuels.

6.4.7.2 ASTM D 1826-94 or ASTM 1945-96 in conjunction with ASTM D 3588-89 for gaseous fuel.

The following conditions will be listed on the proposed ATC permits to ensure compliance:

- The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]
- Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]
- The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

Section 6.5 requires that the operator of an engine that is subject to the requirements of Section 5.2 or the requirements of Section 8.0 shall submit to the APCO for approval, an Inspection & Maintenance (I&M) plan that specifies all actions to be taken to satisfy the requirements of Sections 6.5.1 through Section 6.5.9 and the requirements of Section 5.8. The actions to be identified in the I&M plan shall include, but are not limited to, the information specified below. If there is no change to the previously approved I&M plan, the operator shall submit a letter to the District indicating that previously approved plan is still valid.

Section 6.5.1 specifies that the I&M plan requirements of Sections 6.5.2 through Section 6.5.9 shall apply to the following engines:

6.5.1.1 Engines that have been retrofitted with an exhaust control device, except those certified per Section 9.0;

6.5.1.2 Engines subject to Section 8.0;

6.5.1.3 An agricultural spark-ignited engine that is subject to the requirements of Section 8.0.

6.5.1.4 An agricultural spark-ignited engine that has been retrofitted with a catalytic emission control and is not subject to the requirements of Section 8.0

The digester gas-fired IC engines evaluated under this project will be equipped with SCR systems for control of NO_X and oxidation catalysts for control of CO and VOC. Therefore, the requirements of Sections 6.5.2 through 6.5.9 are applicable to the engines.

Section 6.5.2 requires procedures requiring the operator to establish ranges for control equipment parameters, engine operating parameters, and engine exhaust oxygen concentrations that source testing has shown result in pollutant concentrations within the rule limits.

Section 6.5.3 requires procedures for monthly inspections as approved by the APCO. The applicable control equipment parameters and engine operating parameters will be inspected and monitored monthly in conformance with a regular inspection schedule in the I&M plan.

The digester gas-fired IC engines evaluated under this project will be equipped with SCR systems for control of NO_X and oxidation catalysts for control of CO and VOC. The applicant has proposed the following alternate monitoring program to ensure compliance with Sections 6.5.2 and 6.5.3 of the Rule.

<u>NO_X Emissions:</u>

In order to satisfy the I & M requirements for NO_X emissions, the applicant has proposed to perform the following:

1. Measurement of NOx emissions concentrations with a portable analyzer at least once every calendar quarter.

2. To ensure that NOx emissions concentrations are not being exceeded between periodic NOx portable analyzer measurements, the applicant is proposing to determine a correlation between the SCR system's reagent injection rate and the catalyst control system inlet exhaust temperature and NO_X emissions. The appropriate ranges for each operating load will be established during performance testing and will be monitored at least once per month.

<u>CO and VOC Emissions:</u>

In order to satisfy the I & M requirements for CO and VOC emissions, the applicant has proposed to perform the following:

1. Measurement of CO emissions concentrations with a portable analyzer at least once every calendar quarter. Generally, if the oxidation catalyst is controlling CO emissions, it should also be achieving the desired removal efficiency for VOC emissions. Therefore, no additional monitoring for VOC emissions is required.

2. To ensure that CO and VOC emissions concentrations are not being exceeded between periodic CO emissions concentration measurements, the applicant is proposing to determine a correlation between the catalyst control system inlet exhaust temperature and back pressure and CO emissions. The appropriate ranges for each operating load will be established during performance testing and will be monitored at least once per month.

Therefore, the following conditions will be listed on the proposed ATC permits to ensure compliance with the I & M requirements for NO_X, CO, and VOC:

- Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]
- If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]
- Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature(s) and back pressure(s) demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]
- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s)

within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

- The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

Section 6.5.4 requires procedures for the corrective actions on the noncompliant parameter(s) that the operator will take when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_X, CO, VOC, or oxygen concentrations.

Section 6.5.5 requires procedures for the operator to notify the APCO when an engine is found to be operating outside the acceptable range for control equipment parameters, engine operating parameters, and engine exhaust NO_X, CO, VOC, or oxygen concentrations.

The applicant has proposed that the alternate monitoring program will ensure compliance with these two sections of the Rule. Therefore, the following conditions will be listed on the proposed ATC permits to ensure compliance:

- If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]
- If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control

system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

- If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

Section 6.5.6 requires procedures for and corrective maintenance performed for the purpose of maintaining an engine in proper operating condition. The applicant has proposed that the engines will be operated and maintained per the specifications of the manufacturer or emissions control system supplier. Therefore, the following conditions will be listed on the proposed ATC permits:

- {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
- {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

Section 6.5.7 requires procedures and a schedule for using a portable NO_X analyzer to take NO_X emission readings pursuant to Section 5.8.9. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the Rule. The following previously proposed condition will be listed on the proposed ATC permits:

- {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

Section 6.5.8 requires procedures for collecting and recording required data and other information in a form approved by the APCO including, but not limited to, data collected through the I&M plan and the monitoring systems described in Sections 5.8.1 and 5.8.2. Data collected through the I&M plan shall have retrieval capabilities as approved by the APCO. The applicant has proposed that the alternate monitoring program will ensure compliance with this section of the Rule.

The following condition will be listed on the proposed ATC permits to ensure compliance:

- The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

Section 6.5.9 specifies procedures for revising the I&M plan. The I&M plan shall be updated to reflect any change in operation. The I&M plan shall be updated prior to any planned change in operation. An engine operator that changes significant I&M plan elements must notify the District no later than seven days after the change and must submit an updated I&M plan to the APCO no later than 14 days after the change for approval. The date and time of the change to the I&M plan shall be recorded in the engine operating log. For new engines and modifications to existing engines, the I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit-to-Operate or Permit-Exempt Equipment Registration. The operator of an engine may request a change to the I&M plan at any time.

The applicant has proposed to comply with the I&M plan modification requirements per this section of the Rule. The following condition will be listed on the proposed ATC permits to ensure compliance:

- {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

Section 7.0 specifies the schedules for compliance with the general requirements of Section 5.0 and the Alternative Emission Control Plan (AECP) option of Section 8.0. The proposed IC engines will be required to comply with the applicable sections of District Rule 4702 upon initial startup of the equipment; therefore, compliance with this section is expected.

Section 8.0 specifies requirements for use of an Alternative Emission Control Plan (AECP) to comply with the NO_X emission requirements of Section 5.2 for a group of engines. Requirements for use of an AECP include: only engines subject to Section 5.2 are eligible for inclusion in an AECP; during any seven consecutive day period, the operator shall operate all engines in the AECP to achieve an actual aggregate NO_X emission level that is ≤ 90% of the NO_X emissions that would be obtained by controlling the engines to comply individually with the NO_X limits in Section 5.2; the operator shall establish a NO_X emission factor limit for each engine; the operator must submit the AECP at least 18 months before compliance with the emission limits in Section 5.2 is required and receive approval from the APCO; the operator must submit and updated or modified AECP for approval by the APCO prior to any modifications; and the operator must maintain records necessary to demonstrate compliance with AECP. The use of an Alternate Emission Control Plan to comply with Section 5.2 is not being proposed for the IC engines proposed under this project; therefore this section of the Rule is not applicable.

Section 9.0 specifies requirements for certification of exhaust control systems for compliance with District Rule 4702. Certification under this section for the exhaust control systems for the IC engines under this project is not currently being proposed and, in addition, certification under this section of the Rule would require that the engines or identical units with the same fuel supply and exhaust control systems were operating and could be source tested to demonstrate compliance with the applicable limits; therefore this section of the Rule is not applicable.

Conclusion

As shown above, the proposed non-agricultural, digester gas-fired, lean burn, IC engines are expected to comply with the applicable requirements of Rule 4702 upon initial operation and no further discussion is required.

Rule 4801 Sulfur Compounds

The purpose of this District Rule 4801 is to limit the emissions of sulfur compounds. The limit is that sulfur compound emissions (as SO_2) shall not exceed 0.2% by volume. Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume of SO_X as (SO_2) = (n x R x T) ÷ P
Where:

n = moles SO_X
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73\,\text{psi}\cdot\text{ft}^3}{\text{lb}\cdot\text{mol}\cdot{}^\circ\text{R}}$

$$0.0113\ \frac{lb}{MMBtu}\times\frac{1\,MMBtu}{9{,}100\,scf_{exhaust}}\times\frac{1\,lb\cdot mol}{64\,lb\cdot SO_2}\times\frac{10.73\,psi\cdot ft^3}{lb\cdot mol\cdot{}^\circ R}\times\frac{520^\circ R}{14.7\,psi}\times 1{,}000{,}000\,ppm = 7.4\ \text{ppmv}$$

Since 7.4 ppmv is ≤ 2000 ppmv, the engines are expected to comply with Rule 4801. The following condition will be placed on the engine ATC permits to ensure compliance:

- The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]

40 CFR 60 Subpart JJJJ Standards of Performance for Stationary Spark Ignition Internal Combustion Engines

This rule incorporates the New Source Performance Standards (NSPS) from Part 60, Chapter 1, Title 40, Code of Federal Regulations (CFR); and applies to all new sources of air pollution and modifications of existing sources of air pollution listed in 40 CFR Part 60.

The purpose of 40 CFR 60 Subpart JJJJ is to establish New Source Performance Standards to reduce emissions of NO_X, SO_X, PM, CO, and VOC from new stationary spark ignition (SI) internal combustion (IC) engines.

Pursuant to Section 60.4230, compliance with this subpart is required for owners and operators of stationary SI IC engines that commence construction after June 12, 2006, where the stationary SI ICE are manufactured: (a) on or after July 1, 2007, for engines with a maximum engine power greater than or equal to 500 HP (except lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP); (b) on or after January 1, 2008, for lean burn engines with a maximum engine power greater than or equal to 500 HP and less than 1,350 HP; (c) on or after July 1, 2008, for engines with a maximum engine power less than 500 HP; or (d) on or after January 1, 2009, for emergency engines with a maximum engine power greater than 19 KW (25 HP).

The proposed engines are 1,468 bhp SI ICEs that will be constructed after June 12, 2006 and manufactured after July 1, 2007; therefore, the engines are subject to this subpart. However, the District has not been delegated the authority to implement 40 CFR 60, Subpart JJJJ for non-Major Sources; therefore, the requirements from this subpart will not be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

40 CFR 63 Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Stationary Internal Combustion Engines

40 CFR 63 Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAPs) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. A major source of HAP emissions is a facility that has the potential to emit any single HAP at a rate of 10 tons/year or greater or any combinations of HAPs at a rate of 25 tons/year or greater. An area source of HAPs is a facility is not a major source of HAPs.

Pursuant to Section 63.6590(c), an affected source that is a new or reconstructed stationary Reciprocating Internal Combustion Engine (RICE) located at an area source must meet the requirements of 40 CFR 63, Subpart ZZZZ by meeting the requirements of 40 CFR 60, Subpart IIII, for compression ignition engines or 40 CFR 60, Subpart JJJJ, for spark ignition engines and no further requirements apply for such engines under this part. As with 40 CFR 60, Subpart JJJJ, the District has not been delegated the authority to implement 40 CFR 63, Subpart ZZZ for non-Major Sources; therefore, no requirements from this subpart will be included in the ATC permits. However, the applicant will be responsible for compliance with the applicable requirements of this regulation.

California Health & Safety Code 42301.6 (School Notice)

The District has verified that this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Environmental Quality Act (CEQA)

CEQA requires each public agency to adopt objectives, criteria, and specific procedures consistent with CEQA Statutes and the CEQA Guidelines for administering its responsibilities under CEQA, including the orderly evaluation of projects and preparation of environmental documents. The District adopted its *Environmental Review Guidelines* (ERG) in 2001. The basic purposes of CEQA are to:

- Inform governmental decision-makers and the public about the potential, significant environmental effects of proposed activities;
- Identify the ways that environmental damage can be avoided or significantly reduced;
- Prevent significant, avoidable damage to the environment by requiring changes in projects through the use of alternatives or mitigation measures when the governmental agency finds the changes to be feasible; and
- Disclose to the public the reasons why a governmental agency approved the project in the manner the agency chose if significant environmental effects are involved.

Greenhouse Gas (GHG) Significance Determination

It is determined that no other agency has or will prepare an environmental review document for the project. Thus the District is the Lead Agency for this project.

The proposed project is for construction of a renewable energy plant at an existing dairy facility. The proposed renewable energy plant will combust dairy digester gas in IC engines to produce electricity. The proposed project will involve diverting manure from existing open basin(s) and pond(s) at the dairy to covered lagoon digester(s), which will result in the capture of much of the methane that is currently released into the atmosphere from the open basins and pond at the dairy. Combustion of the dairy digester gas at the proposed renewable energy plant will oxidize the methane in the gas to carbon dioxide and water vapor. Because methane has a global warming potential at least 21 times that of carbon dioxide, combustion of the methane from the dairy digesters will result in a large net decrease in the global warming potential emitted from the dairy when compared to current levels. Therefore, the project will not result in an increase in project specific greenhouse gas emissions. The District therefore concludes that the project would have a less than cumulatively significant impact on global climate change.

District CEQA Findings

The District is the Lead Agency for this project because there is no other agency with broader statutory authority over this project. The District performed an Engineering Evaluation (this document) for the proposed project and determined that, although the project is considered to take place at a separate stationary source for NSR purposes, the activity will occur on previously developed land at an existing dairy facility and the project involves negligible expansion of the existing use. Furthermore, the District determined that the activity will not have a significant effect on the environment. The District finds that the activity is categorically exempt from the provisions of CEQA pursuant to CEQA Guideline § 15301 (Existing Facilities), and finds that the project is exempt per the general rule that CEQA applies only to projects which have the potential for causing a significant effect on the environment (CEQA Guidelines §15061(b)(3)).

IX. Recommendation

Compliance with all applicable rules and regulations is expected. Pending a successful NSR Public Noticing period, issue ATCs S-8637-1-0, -2-0, and -3-0 subject to the permit conditions on the attached draft ATC in Appendix D.

X. Billing Information

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
S-8367-1-0	3020-06	Covered Lagoon Digester	$111.00
S-8367-2-0	3020-10-F	1,468 bhp IC engine	$785.00
S-8367-3-0	3020-10-F	1,468 bhp IC engine	$785.00

Appendixes

A: Quarterly Net Emissions Change (QNEC)
B: BACT Analysis for the Proposed Digester Gas-Fired IC Engines
C: Summary of Health Risk Assessment (HRA) and Ambient Air Quality Analysis (AAQA)
D: Draft ATCs (S-8367-1-0, -2-0, & -3-0)

APPENDIX A
Quarterly Net Emissions Change (QNEC)

Quarterly Net Emissions Change (QNEC)

The Quarterly Net Emissions Change is used to complete the emission profile screen for the District's PAS database. The QNEC shall be calculated as follows:

QNEC = PE2 - PE1, where:

QNEC = Quarterly Net Emissions Change for each emissions unit, lb/qtr.
PE2 = Post Project Potential to Emit for each emissions unit, lb/qtr.
PE1 = Pre-Project Potential to Emit for each emissions unit, lb/qtr.

Using the values in Sections VII.C.2 and VII.C.1 in the evaluation above, quarterly PE2 and quarterly PE1 can be calculated as follows:

S-8637-1-0 (Digester System)

PE1 (lb/qtr) S-8637-1-0					
	PE1 (lb/year)	÷	4 qtr/year	=	PE1 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

PE2 (lb/qtr) S-8637-1-0					
	PE2 (lb/year)	÷	4 qtr/year	=	PE2 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

Quarterly NEC [QNEC] S-8637-1-0					
	PE2 (lb/qtr)	-	PE1 (lb/qtr)	=	NEC (lb/qtr)
NO_X	0.0	-	0.0	=	0.0
SO_X	0.0	-	0.0	=	0.0
PM_{10}	0.0	-	0.0	=	0.0
CO	0.0	-	0.0	=	0.0
VOC	0.0	-	0.0	=	0.0

S-8637-2-0 & -3-0 (1,468 bhp Digester Gas-Fired, Lean Burn, IC Engines)

PE1 (lb/qtr) S-8637-2-0 & -3-0					
	PE1 (lb/year)	÷	4 qtr/year	=	PE1 (lb/qtr)
NO_X	0	÷	4 qtr/year	=	0.0
SO_X	0	÷	4 qtr/year	=	0.0
PM_{10}	0	÷	4 qtr/year	=	0.0
CO	0	÷	4 qtr/year	=	0.0
VOC	0	÷	4 qtr/year	=	0.0

PE2 (lb/qtr) S-8637-2-0 & -3-0					
	PE2 (lb/year)	÷	4 qtr/year	=	PE2 (lb/qtr)
NO_X	4,583	÷	4 qtr/year	=	1,145.8
SO_X	1,134	÷	4 qtr/year	=	283.5
PM_{10}	1,985	÷	4 qtr/year	=	496.3
CO	50,818	÷	4 qtr/year	=	12,704.5
VOC	3,185	÷	4 qtr/year	=	796.3

Quarterly NEC [QNEC] S-8637-2-0 & -3-0					
	PE2 (lb/qtr)	-	PE1 (lb/qtr)	=	NEC (lb/qtr)
NO_X	1,145.8	-	0.0	=	1,145.8
SO_X	283.5	-	0.0	=	283.5
PM_{10}	496.3	-	0.0	=	496.3
CO	12,704.5	-	0.0	=	12,704.5
VOC	796.3	-	0.0	=	796.3

APPENDIX B

BACT Analysis for Digester Gas-Fired IC Engines

SJVAPCD Best Available Control Technology (BACT) Guideline 3.3.15*

Last Update: 3/6/2013

Waste Gas-Fired IC Engine**

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NO_X	0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent)		1. Fuel Cells (<0.05 lb/MW-hr) 2. Microturbines (<9 ppmv @ 15% O_2) 3. Gas Turbine (<9 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
SO_X	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S) (dry absorption, wet absorption, chemical H_2S reduction, water scrubber, or equivalent) (may be averaged up to 24 hours for compliance)		
PM_{10}	Sulfur content of fuel gas ≤ 40 ppmv (as H_2S)		
CO	2.0 g/bhp-hr		1. Fuel Cells (<0.10 lb/MW-hr) 2. Microturbines (<60 ppmv @ 15% O_2) 3. Gas Turbine (<60 ppmv @ 15% O_2) *(Note: gas turbines only ABE for projects ≥ 3 MW)*
VOC	0.10 g/bhp-hr (lean burn and positive crankcase ventilation (PCV) or a 90% efficient crankcase control device or equivalent)		Fuel Cells (<0.02 lb-VOC/MW-hr as CH_4)
Ammonia (NH_3) Slip	≤ 10 ppmv @ 15% O_2		

*** For the purposes of this determination, waste gas is a gas produced from the digestion of material excluding municipal sources such as waste water treatment plants, landfills, or any source where siloxane impurities are a concern.*

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is required for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Pages**

3.3.15

Top-Down BACT Analysis for Project S-1143770
Digester Gas-Fired IC Engines

Current District BACT Guideline 3.3.15 applies to the proposed waste gas-fired IC engines. In accordance with the District BACT policy, information from District BACT Guideline 3.3.15 will be utilized for the BACT analysis for the digester gas-fired engines proposed under this project.

I. Proposal and Process Description

ABEC #3 LLC dba Lakeview Dairy Biogas, a subsidiary of California Bioenergy, LLC, has requested Authority to Construct (ATC) permits to construct a covered lagoon anaerobic digester system (ATC S-8637-1-0) and to install two 1,468 bhp digester gas-fired IC engines (or approved engines of equal or lesser bhp) (ATCs S-8637-2-0 and -3-0) at Lakeview Farms dairy (Facility S-5254). Each engine will be equipped with a selective catalytic reduction (SCR) system for emissions control and will power an electrical generator that will produce up to 1,059 kWe. The covered lagoon digester will utilize an air injection system for biological removal of H_2S from the digester gas. After initial removal of H_2S in the covered lagoon digester, the digester gas will be captured by the covered the lagoon gas collection system and will be piped to the gas conditioning system for polishing to remove additional H_2S by an iron sponge scrubber and/or activated carbon or an equivalent H_2S removal system and for removal of moisture. The cleaned digester gas, which consists mostly of methane, the main component of natural gas, will then be sent to the engines for use as fuel to generate electricity for sale to a utility and to produce heat for the digester system.

II. BACT Applicability

New emissions units – PE > 2.0 lb/day

New Emissions Unit BACT Applicability for S-8637-2-0 & -3-0 After Commissioning				
Pollutant	PE2 for each unit after commissioning (lb/day)	BACT Threshold (lb/day)	SSPE2 (lb/yr)	BACT Triggered?
NO_X	11.7	> 2.0	N/A	**Yes**
SO_X	3.1	> 2.0	N/A	**Yes**
PM_{10}	5.4	> 2.0	N/A	**Yes**
CO	135.9	> 2.0 and SSPE2 ≥ 200,000 lb/yr	101,636	No
VOC	7.8	> 2.0	N/A	**Yes**
NH_3	3.9	> 2.0	N/A	**Yes**

* BACT is not required for CO from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

III. Top-Down BACT Analyses for the Digester Gas-Fired Engines

As stated above, the information form the existing District BACT Guideline 3.3.15 for Waste Gas-Fired IC Engines will be utilized for the BACT analysis for the proposed digester gas-fired IC engines under this project.

1. BACT Analysis for NO_X Emissions:

a. Step 1 - List all control technologies

District BACT Guideline 3.3.15 lists the following options to reduce NO_X emissions from waste gas-fired IC engines:

1) NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)
2) Fuel Cell (≤ 0.05 lb/MW-hr) (Alternate Basic Equipment)
3) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)
4) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Description of Control Technologies

1) NO_X emissions ≤ 0.15 g/bhp-hr (9-11 ppmv NO_X @ 15% O_2) (Selective Catalytic Reduction (SCR) or equivalent) (Achieved in Practice)

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%.

2) Fuel Cell (≤ 0.05 lb- NO_X/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Fuel cells use an electrochemical process to produce a direct electric current without the combustion of fuel. Fuel cells use externally supplied reactant gases (hydrogen and oxygen) that are combined in a catalytic process. Like a battery, the electric potential generated by a fuel cell is accessed by connecting an external load to the anode and cathode plates of the fuel cell. Because the fuel for a fuel cell is supplied externally, it does not run down like a battery. However, the fuel cell stack must be periodically replaced because of deactivation of catalytic materials contained in the fuel cell, which results in reduced conversion efficiencies. Since fuel cells require pure hydrogen gas for fuel, hydrocarbons used to power fuel cells must be purified and reformed prior to use. The reformation process can occur in an external fuel processor or through internal reforming in the fuel cell. Both molten carbonate fuel cells and solid oxide fuel cells can internally reform the hydrocarbon fuel to hydrogen for use in the fuel cell. Additionally, these high temperature fuel cells are tolerant of CO_2 that is found biogas.

Fuel cells have recently been commercialized and offer the advantages of high efficiency, nearly negligible emissions, and very quiet power generation. The greatest deterrent to increased use of fuel cells is the significantly higher expense when compared to other generation technologies. These higher costs include the initial capital expense and, for biogas installations, the increased ongoing expenses associated with the extensive cleanup required to remove contaminants that can poison fuel cell catalysts. Although this expense can be substantial, biogas-fueled fuel cells have been installed at some wastewater treatment plants and fuel cells have also been fueled with other types of biogas (e.g. landfill gas and brewery wastewater gas).

3) Gas Turbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Gas turbines are internal combustion engines that operate on the Brayton (Joule) combustion cycle rather than the Otto combustion cycle used in reciprocating internal combustion engines or the diesel cycle for diesel engines. In the Brayton cycle the air flow and fuel injection are steady, and the different parts of the cycle occur continuously within different components of the system. In a gas turbine, fuel is continually injected into the combustion chamber or combustor and air is constantly drawn into the turbine and compressed. All elements of the Brayton cycle occur simultaneously in a gas turbine.

Gas turbines are one of the cleanest means of generating electricity. With the use of lean pre-mixed combustion or catalytic exhaust cleanup, NO_X emissions from large gas-fired turbines are generally in the single-digit ppmv range. These levels are generally for natural gas-fired units but they are considered technologically feasible for biogas-fired units.

Gas turbines are available in sizes ranging from 500 kW - 25 MW. Based on contacts with turbine suppliers, biogas-fired turbines used to produce electricity are expected to be available in the size range of 2 - 7 MW. According to Solar Turbines, the smaller biogas-fired turbines are no longer actively produced or marketed since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

4) Microturbine (< 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Microturbines are small gas turbines rated between 25 kW and 500 kW that burn gaseous and liquid fuels to generate electricity or provide mechanical power. Microturbines were developed from turbocharger technologies found in large trucks and the turbines in aircraft auxiliary power units. Microturbines can be operated on a wide variety of fuels, including natural gas, liquefied petroleum gas, gasoline, diesel, landfill gas, and digester gases. According to the California Air Resources Board (ARB), there were approximately 200 biogas-fired microturbines operating in California as of the year 2006.[5] Microturbines generally have electrical efficiencies

[5] "Staff Report: Initial Statement of Reasons for Proposed Amendments to the Distributed Generation Certification Regulation" (9/1/2006), Cal EPA - ARB, Executive Summary Pg. ii (http://www.arb.ca.gov/regact/dg06/dgisor.pdf)

of 25-30%; however, the electrical efficiency of larger microturbines (≥ 200 kW) can range from 30-33%. Microturbine manufacturers include Capstone Microturbines and FlexEnergy.

Microturbines without add-on controls can meet very stringent emission limits and have significantly lower emissions of NO_X, CO, and VOC than uncontrolled reciprocating engines because most microturbines operating on gaseous fuels utilize lean premixed (dry low NO_X, or DLN) combustion technology. Microturbines manufacturers will generally guarantee NO_X emissions of 9-15 ppmv @ 15% O_2. However, several emission tests performed on biogas-fired microturbines have demonstrated even lower emissions. A small number of dairy digester gas-fired microturbines have been installed[6], including Twin Birch Dairy and New Hope Farm View dairy and Twin Birch Dairy in New York, and den Dulk Dairy in Michigan.

The proposed project is for a large waste gas to energy facility and, although larger microturbines have recently become available, several microturbines (at least 4) would still be required to replace each engine. The applicant states that when they investigated microturbines they found that they could not secure the necessary financing for a waste gas to energy project of this size using microturbines and that the major microturbines vendors were unable to secure the debt. Although microturbines may not currently be a practical option for this particular project, they will be considered in the cost analysis below.

b. Step 2 - Eliminate technologically infeasible options

Option 3 - Gas Turbine (≤ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Option 3, Gas Turbine, was determined to be infeasible for the proposed project because the available information indicates that the principal suppliers of gas turbines (Solar Turbines, Allison, and General Electric) do not currently produce or market waste gas-fired gas turbines rated less than 3 MW since this size range is generally covered by other generation technologies such as reciprocating IC engines and microturbines.

The cost information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[7] (March 2015) and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8] (October 5, 2015) also supports that gas turbines rated approximately 3 MW are not generally available. The smallest turbine for which the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies provides cost information is 3,304 kW and the smallest turbine for which the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] provides cost information is 2,500 kW.

[6] See EPA AgStar Program "AgStar Project Profiles", http://www2.epa.gov/agstar/agstar-project-profiles
[7] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies
[8] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

The proposed project would require gas turbines rated 1,059 kW each, which is below the range that is currently being marketed by turbine manufacturers; therefore, gas turbines are not considered feasible for this particular project and will be eliminated from consideration at this time.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)
2) Digester gas-fueled microturbines (Alternate Basic Equipment)
3) NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Pursuant to Section IX.D of District Policy APR 1305 – BACT Policy, a cost effectiveness analysis is required for the options that have not been determined to be achieved in practice. In accordance with the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), to determine the cost effectiveness of particular technologically feasible control options or alternate equipment options, the amount of emissions resulting from each option will be quantified and compared to the District Standard Emissions allowed by the District Rule that is applicable to the particular unit. The emission reductions will be equal to the difference between the District Standard Emissions and the emissions resulting from the particular option being evaluated.

The District has determined that the proposed digester gas-fueled IC engines are non-agricultural IC engines. The lean burn, digester gas-fired, engines are subject to the following emission limits for non-agricultural, lean burn, waste gas fueled IC engines contained in District Rule 4702, Section 5.2.2, Table 2, 2.d: 65 ppmvd NO_X (or 90% reduction), 2,000 ppmvd CO, and 750 ppmvd VOC (all measured @ 15% O_2). The proposed digester engines are also subject to the New Source Performance Standards (NSPS) for IC Engines contained in 40 CFR 60 Subpart JJJJ, which includes a more stringent VOC emissions limit of 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane) for landfill and digester gas-fired IC engines. Therefore, the District Standard Emissions used for the BACT cost analysis below for the proposed engines will be based on the emission limits contained in these applicable regulations.

Option 1: Fuel Cells (≤ 0.05 lb/MW-hr ≈ 1.5 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

Because fuel cells have reduced NO_X and VOC emissions in comparison to a reciprocating IC engine, a Multi-Pollutant Cost Effectiveness Threshold (MCET) will be used to determine if this option is cost-effective. The following cost analysis demonstrates that replacement of the proposed engines with a fuel cell is not cost effective even when the additional operation costs of a fuel cell are not considered.

Assumptions

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 600 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- Price for electricity: $127.72/MW-hr (*based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)*[9] *in February 2016*)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engines and fuel cells will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[7] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][8]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and fuel cells, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [8]

<u>Assumptions for Proposed Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)</u>

- Each engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines: 33% (*Conservative estimate, as discussed above, US EPA Combined Heat and Power Partnership Catalog of CHP Technologies lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system*)
- The maximum total daily heating value of the digester gas used by each engine will be: 271.71 MMBtu/day (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 24 hr/day x 1 engine*)
- The maximum total annual heating value for of the digester gas used by each engine will be: 99,175.4 MMBtu/year (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 8,760 hr/year x 1 engine*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,059 kW without add-on air pollution control equipment: $1,752/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engines: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)

[9] See: http://www.pge.com/en/b2b/energysupply/wholesaleelectricsuppliersolicitation/BioMAT/index.page, https://scebiomat.accionpower.com/biomat/home.asp, and http://www.sdge.com/procurement/bioenergy-market-adjusting-tariff-bio-mat)

- Total Installation Cost for biogas-fueled IC engine rated 1,059 kW: $2,139/kW
- Estimated operation costs for CHP IC engine rated 1,059 kW without add-on air pollution control costs: $0.020/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engines must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because required level of sulfur removal is adequate for use in the engines, there will be no increase in operating costs related to cleaning the digester gas for use in IC engines.
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% O_2 = 0.2540 lb/MMBtu
- Rule 4702 VOC emission limit for non-agricultural, lean burn IC engines: 750 ppmv @ 15% O_2 as CH_4 = 1.0193 lb/MMBtu
- 40 CFR 60 Subpart JJJJ VOC emission limit for landfill and digester gas-fired IC engines: 1.0 g/bhp-hr (or 80 ppmv @ 15% O_2 reported as propane)

<u>Assumptions for Fuel Cell System</u>

- Net electrical efficiency for a molten carbonate fuel cell (MCFC): 45% (*US EPA Combined Heat and Power Partnership Catalog of CHP Technologies gives efficiencies of 47% for a 300 kW MCFC and 42.5% for a 1,400 kW MCFC*)
- Size of fuel cell system needed to replace each proposed engine: 1,500 kW (estimated based on 271.71 MMBtu/day and 45% efficiency)
- Estimated Purchase and Installation Cost for Molten Carbonate Fuel Cell: $4,550/kW (*Average of the two costs for largest Molten Carbonate Fuel Cells given in US EPA Combined Heat and Power Partnership document Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]; The U.S. Department of Energy Federal energy management Program (FEMP) document "Fuel Cells and Renewable Energy" (last updated 12-1-2014 and available at: <u>http://www.wbdg.org/resources/fuelcell.php</u>) states, "Installation costs of a fuel cell system can range from $5,000/kW to $10,000/kW." Therefore, this estimate may be actually too low based on the recently reported costs for fuel cell power plants, such as the "Bloom Box".*)
- Additional capital investment for biogas conditioning and cleanup for fuel cells: $563/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled fuel cells rated ≥ 1,200 kW: $5,113/kW

- Typical operation costs for natural gas-fueled fuel cells, including stack replacement costs: \$0.04/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional operational costs for biogas conditioning and cleanup for large fuel cells: \$0.15/kW-hr (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Operation Cost for biogas-fueled fuel cells rated ≥ 1,200 kW: \$0.19/kW-hr
- Fuel Cell NO_X emissions: 0.01 - 0.02 lb/MW-hr *(Note: Fuel cells have been certified to the ARB Distributed Generation Certification level of 0.07 lb-NO_X/MW-hr but measured emissions from fuel cells are generally much lower)*
- Fuel Cell VOC emissions: 0.02 lb-VOC/MW-hr (≤ 2.0 ppmv VOC @ 15% O_2 as CH_4 based on ARB Distributed Generation Certification level of 0.02 lb-VOC/MW-hr and emission tests on fuel cells)
- Unlike the proposed engines, a high-temperature fuel cell power plant must primarily operate at steady state conditions; there would not be the ability to store gas to generate more electricity during peak hours, which is the current business plan of the applicant. Because the price paid for electricity is greater during peak hours and less during other times, the price paid for electricity generated by a fuel cell power plant would be less. This would require the operator to alter their plans of operation and result in less revenue per kW-hr of electricity generated potentially offsetting the revenue from increased power generating capacity because of the higher efficiency of a fuel cell power plant. For more conservative analysis, the difference in the cost of peak and off-peak electricity was not considered in this comparison.

Capital Cost

The estimated increased incremental capital cost for replacement of the proposed engines with fuel cells is calculated based on the difference in cost of a fuel cell power plant and the proposed IC engines.

The incremental capital cost for replacement of the proposed IC engines with a fuel cell power plant is calculated as follows:

(1,500 kW x \$5,113/kW) - (1,059 kW x \$2,139/kW) = \$5,404,299

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

A = $[P \times i(I+1)^n]/[(I+1)^n-1]$

Where: A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

A = $[\$5,404,299 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$
= **$879,525/year**

Annual Costs

Electricity Generated

The amount of electricity potentially generated by each option is calculated as follows:

Each Proposed IC Engine
1,059 kW x 8,760 hr/yr = 9,276,840 kW-hr/year

Fuel Cells (Alternate Equipment)
271.71 MMBtu/day x 10^6 Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,413 Btu x 0.45 (electrical efficiency) = 1,493 kW

99,175.4 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.45 (electrical efficiency) = 13,076,159 kW-hr /year

Cost Decrease from Increased Revenue for Power Generation from Replacing each Proposed 1,059 kW Engine with a Fuel Cell
(9,276,840 kW-hr/yr - 13,076,159 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = -$485,249/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Each Proposed 1,059 IC kW Engine
9,276,840 kW-hr/yr x $0.020/kW-hr = $185,537/year

Fuel Cells (Alternate Equipment)
13,076,159 kW-hr/yr x $0.19/kW-hr = $2,484,470/year

Annual Costs of Increased Maintenance
$2,484,470/yr - $185,537/yr = $2,298,933/year

Total Increased Annual Costs for Fuel Cell as an Alternative to Each Proposed Engine

$879,525/year + (-$485,249/year) + $2,298,933/year = **$2,693,209/year**

Emission Reductions:

NO$_X$ and VOC Emission Factors:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO$_X$ emissions from the engines will be based on the NO$_X$ emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.1, Table 1, 2.b. The District Standard Emissions for VOC emissions from the engines will be based on the New Source Performance Standard (NSPS) VOC emission limit for landfill and digester gas-fired IC engines from 40 CFR 60 Subpart JJJJ, since this limit is more stringent than the applicable emission limit in District Rule 4702.

The following emissions factors will be used for the cost analysis:

District Standard Emissions: 0.2540 lb-NO$_X$/MMBtu (65 ppmv NO$_X$ @ 15% O_2) and 1.0 g-VOC/bhp-hr

Emissions from Fuel Cells as Alternative Equipment: 0.01 lb-NO$_X$/MW-hr and 0.02 lb-VOC/MW-hr as CH_4

Emission Reductions:

Each Proposed Engine Compared to Fuel Cells based on District Standard Emission Reductions

NO$_X$ Emission Reductions (65 ppmv @ 15% O_2 → 0.01 lb-NO$_X$/MW-hr)
(99,175.4 MMBtu/yr x 0.2540 lb-NO$_X$/MMBtu) – (13,076,159 kW-hr/yr x 1 MW/1,000 kW x 0.01 lb-NO$_X$/MW)
= 25,060 lb-NO$_X$/year (12.53 ton-NO$_X$/year)

VOC Emission Reductions (1.0 g/bhp-hr → 0.02 lb-VOC/MW-hr)
(1,468 bhp/engine x 8,760 hr/yr x 1 engine x 1.0 g-VOC/bhp-hr x 1 lb/453.59 g) – (13,076,159 kW-hr/yr x 1 MW/1,000 kW x 0.02 lb-VOC/MW)
= 28,089 lb-VOC/year (14.04 ton-VOC/year)

Multi-Pollutant Cost Effectiveness Thresholds (MCET) for NO$_X$ and VOC Reductions based on District Standard Emission Reductions

(12.53 ton-NO$_X$/year x \$24,500/ton-NO$_X$) + (14.04 ton-VOC/year x \$17,500/ton-VOC)
= **\$552,685/year**

As shown above, the annualized capital cost of this alternate option exceeds the Multi-Pollutant Cost Effectiveness Threshold (MCET) calculated for the NO$_X$ and VOC emission reductions. Therefore, this option is not cost effective and is being removed from consideration.

Option 2 - Microturbines ($\leq$ 9 ppmv NO_X @ 15% O_2) (Alternate Basic Equipment)

The cost analysis below demonstrates that the NO_X emission reductions achieved by replacement of the proposed engines with microturbines would not be cost effective based on the District's Revised BACT Cost Effectiveness Thresholds (May 14, 2008).

In addition, it should be noted that large lean burn IC engines generally have higher overall efficiencies than microturbines. The difference in efficiency between engines and microturbines will minimize and possibly eliminate any overall differences in NO_X emissions between these options. For example, information from a Capstone Turbine Corporation specification sheet indicates that the guaranteed NO_X emissions rate of 9 ppmvd @ 15% O_2 for their 1,000 kW renewable gas fuel microturbine package is equivalent to 0.14 g-NO_X/hp-hr.[10] This level is not significantly different than the current BACT requirement for waste gas-fired engines of 0.15 g-NO_X/bhp-hr.

The following discussion demonstrates how the difference the efficiency of engines and microturbines can affect the emission rate. NO_X emissions from the engines will be limited to no more than 0.15 g/bhp-hr (approximately 11 ppmv NO_X @ 15% O_2). Microturbine suppliers will generally guarantee NO_X emissions $\leq$ 9 ppmv @ 15% O_2 For digester gas-fired microturbines. The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11] (March 2015), Table 2-2: Gas Spark Ignition Engine CHP - Typical Performance Parameters, lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12] (October 5, 2015), Page A-28 indicates that "Typical observed efficiencies on IC engines deployed in the SGIP are 27% for electrical conversion (HHV)..." Therefore, the expected HHV electrical efficiency of each of the proposed 1,059 kW engines is between 27-36.8%.

The US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies"[11], Table 5-2: Gas Spark Ignition Engine CHP - Microturbine Cost and Performance Characteristics, lists HHV electrical efficiencies of 26-28% for microturbine systems rated at least 200 kW. The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12], Table A-15: Microturbine Electrical Conversion Efficiency, lists a HHV electrical efficiencies of 21% for microturbines based on SGIP metered data. Therefore, the expected HHV electrical efficiency of large microturbines is between 21-28%.

The maximum expected NO_X emission factor for the proposed engine-generator sets is approximately 0.47 lb/MW-hr (based on 0.15 g/bhp-hr and 95% generator efficiency). Based on 9 ppmv NO_X @ 15% O2 and the expected range of microturbine electrical conversion efficiency given above, the NO_X emission factor from large digester gas-

[10] See: http://www.adigo.no/wordpress/wp-content/uploads/2015/02/CR1000-teknisk-spesifikasjon-engelsk.pdf. Note that because of lower efficiencies for smaller microturbines, the guaranteed emission rate of 9 ppmvd NO_X @ 15% O_2 from smaller units will actually be higher than 0.15 g-NO_X/bhp-hr
[11] US EPA Combined Heat and Power Partnership "Catalog of CHP Technologies" (March 2015) http://www.epa.gov/chp/catalog-chp-technologies
[12] SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] (October 5, 2015) http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=7889

fueled microturbines is expected to range from 0.43 – 0.57 lb/MW-hr. Because, the maximum NO_X emission factor for the proposed engine-generator sets falls within this range, the options could be considered equivalent.

Assumptions

- Digester Gas F-Factor: 9,100 dscf/MMBtu (dry, adjusted to 60 °F)
- Higher Heating Value for Dairy Digester Gas: 600 Btu/scf
- Molar Specific Volume = 379.5 scf/lb-mol (at 60°F)
- bhp-hr to Btu conversion: 2,545 Btu/hp-hr
- Btu to kW-hr conversion: 3,413 Btu/kW-hr
- The initial capital costs and the operation costs for the digester gas-fueled IC engines and microturbines will be based on information given in the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies[11] and the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report][12]
- Because the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies only provides cost information for natural gas-fueled engines and microturbines, additional capital costs for the use of biogas are taken from the SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] [12]
- The SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report] indicates that biogas conditioning/cleanup costs are highly dependent on the quantity of biogas being processed and contaminants being removed and that the differences in clean-up costs for biogas-fueled IC engines, microturbines, and gas turbines "reflect the greater rigor in the removal of the hydrogen sulfide". The digester gas used to fuel the engines or microturbines must be limited to a sulfur content of no more than 40 ppmv as H_2S to satisfy BACT for SO_X. Because required level of sulfur removal is adequate for use in both engines and microturbines and the same amount of total digester gas will be available for either option, there will be no difference in operating costs related to cleaning the digester gas for use in IC engines or microturbines.
- Price for electricity: $127.72/MW-hr (based on the California Bioenergy Market Adjusting Tariff (BioMAT) initial contract price offered by Investor Owned Utilities (PG&E, SCE, and SDG&E)[9] in February 2016)

<u>Assumptions for Proposed Digester Gas-Fired IC Engines (S-8637-2-0 & -3-0)</u>

- Each engine will operate at full load for 24 hours/day and 8,760 hours/year
- Typical efficiency for IC engines: 33% (*Conservative estimate, as discussed above, the US EPA Combined Heat and Power Partnership Catalog of CHP Technologies lists HHV electrical efficiencies of 34.5% for a 633 kW system and 36.8% for a 1,121 kW system*)
- The maximum total daily heating value of the digester gas used by each engine will be: 271.71 MMBtu/day ($1{,}468\ bhp_{out}/engine \times 1\ bhp_{in}/0.33\ bhp_{out} \times 2{,}545\ Btu_{in}/bhp_{in}\text{-}hr \times 1\ MMBtu/10^6\ Btu \times 24\ hr/day \times 1\ engine$)

- The maximum total annual heating value for of the digester gas used by each engine will be: 99,175.4 MMBtu/year (*1,468 bhp_{out}/engine x 1 bhp_{in}/0.33 bhp_{out} x 2,545 Btu_{in}/bhp_{in}-hr x 1 MMBtu/10^6 Btu x 8,760 hr/year x 1 engine*)
- Estimated purchase and installation cost for CHP IC engine rated approximately 1,059 kW without add-on air pollution control equipment: $1,752/kW (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Additional capital investment for biogas conditioning and cleanup for IC engines: $387/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled IC engine rated 1,059 kW: $2,139/kW
- Estimated operation costs for CHP IC engine rated 1,059 kW without add-on air pollution control costs: $0.020/kW-hr (*average of interpolated values from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies and SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Rule 4702 NO_X emission limit for non-agricultural, lean burn IC engines: 65 ppmv @ 15% O_2 = 0.2540 lb/MMBtu

<u>Assumptions for Microturbines</u>

- Net HHV electrical efficiency for a 950 kW net (1,000 kW nominal capacity) microturbine package: 24.5% (*conservative estimate, SGIP metered data indicates an efficiency of 21%*)
- Estimated Size of microturbine system needed to replace each engine: 950 kW net (1,000 kW nominal capacity)
- Estimated Purchase and Installation Cost for 950 kW net (1,000 kW nominal capacity) microturbine package: $2,500/kW (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- Estimated additional capital investment for biogas conditioning and cleanup for microturbines: $744/kW (*SGIP 2015 Self-Generation Incentive Program Cost Effectiveness Study [Final Report]*)
- Total Installation Cost for biogas-fueled microturbine system rated 950 kW net (1,000 kW nominal capacity): $3,244/kW
- Typical operation costs for a 950 kW net (1,000 kW nominal capacity) microturbine package: $0.012/kW-hr (*from US EPA Combined Heat and Power Partnership Catalog of CHP Technologies*)
- NO_X Emissions for Digester gas-fueled microturbines: ≤ 9 ppmv NO_X @ 15% O_2 (~ 0.0352 lb-NOx/MMBtu)

Capital Cost

The estimated increased incremental capital cost for replacement of each the proposed engines with microturbines is calculated based on the difference in cost of a microturbine system and the proposed IC engines.

The incremental capital cost for replacement of the proposed IC engines with a microturbine system is calculated as follows:

(950 kW x $3,244/kW) - (1,059 kW x $2,139/kW) = $816,599

Annualized Capital Cost

Pursuant to District Policy APR 1305, section X (11/09/99), the incremental capital cost for the purchase of the fuel cell system will be spread over the expected life of the system using the capital recovery equation. The expected life of the entire system will be estimated at 10 years. A 10% interest rate is assumed in the equation and the assumption will be made that the equipment has no salvage value at the end of the ten-year cycle.

$$A = [P \times i(I+1)^n]/[(I+1)^n-1]$$

Where:
A = Annual Cost
P = Present Value
I = Interest Rate (10%)
N = Equipment Life (10 years)

$$A = [\$816{,}599 \times 0.1(1.1)^{10}]/[(1.1)^{10}-1]$$
$$= \mathbf{\$132{,}898/year}$$

Annual Costs

Electricity Generated

The amount of electricity potentially generated by each option is calculated as follows:

Each Proposed IC Engine
1,059 kW x 8,760 hr/yr = 9,276,840 kW-hr/year

950 kW (net) Microturbine Package (Alternate Equipment)
271.71 MMBtu/day x 10^6 Btu/MMBtu x 1 day/24 hr x 1 kW-hr/3,413 Btu x 0.245 (electrical efficiency) = 813 kW

99,175.4 MMBtu/yr x 10^6 Btu/MMBtu x 1 kW-hr/3,413 Btu x 0.245 (electrical efficiency) = 7,119,242 kW-hr /year

Cost of Decreased Revenue from Power Generation from Replacing each Proposed 1,059 kW Engine with Microturbines
(9,276,840 kW-hr/yr - 7,119,242 kW-hr/yr) x 1 MW/1,000 kW x $127.72/MW-hr = $275,568/year

Annual Operation and Maintenance Cost
The annual operation and maintenance costs for each option are calculated as follows:

Each Proposed 1,059 kW IC Engine
9,276,840 kW-hr/yr x $0.020/kW-hr = $185,537/year

Microturbines (Alternate Equipment)
7,119,242 kW-hr/yr x $0.012/kW-hr = $85,431/year

Cost from Annual Decrease in Maintenance Costs
$85,431/yr - $185,537/yr = -$100,106/year

Total Increased Annual Costs for Microturbines as an Alternative to Each Proposed Engine

$132,898/year + $275,568/year + (-$100,106/year) = **$308,360/year**

Emission Reductions:

NO_X Emission Factors:

Pursuant to the District's Revised BACT Cost Effectiveness Thresholds Memo (5/14/08), District Standard Emissions that will be used to calculate the emission reductions from alternative equipment.

The District Standard Emissions for NO_X emissions from the engines will be based on the NO_X emission limit for non-agricultural, lean burn IC engines from District Rule 4702, Section 5.2.1, Table 1, 2.b.

The following emissions factors will be used for the cost analysis:

District Standard Emissions: 0.2540 lb-NO_X/MMBtu (65 ppmv NO_X @ 15% O_2)

Emissions from Microturbines as Alternative Equipment: 0.0352 lb-NO_X/MMBtu (9 ppmv NO_X @ 15% O_2)

Emission Reductions for Each Proposed Engine Compared to Microturbines based on District Standard Emission Reductions

NO_X Emission Reductions (65 ppmv @ 15% O_2 → 9 ppmv @ 15% O_2)
99,175.4 MMBtu/yr x (0.2540 lb-NO_X/MMBtu – 0.0352 lb-NO_X/MMBtu)
= 21,700 lb-NO_X/year (10.85 ton-NO_X/year)

Cost of NO_X Emission Reductions

Cost of reductions = ($308,360/year)/[(21,700 lb-NO_X/year)(1 ton/2000 lb)]
= **$28,420/ton of NO_X reduced**

As shown above, the cost of the NO_X emission reductions for replacing each of the proposed engines with microturbines exceeds the $24,500/ton cost effectiveness threshold of the District BACT policy. Therefore, this option is not cost effective and is being removed from consideration.

Option 3: NO_X emissions ≤ 0.15 g/bhp-hr (lean-burn engine with SCR, rich-burn engine with 3-way catalyst, or other equivalent) (Achieved in Practice)

This option is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for the Digester Gas-fired Engines must be satisfied with the following: NO_X: NO_X emissions to ≤ 0.15 g/bhp-hr

The applicant has proposed to use SCR systems for the digester gas-fired lean burn IC engines to reduce NO_X emissions to ≤ 0.15 g/bhp-hr. Therefore, the BACT requirements are satisfied.

2. BACT Analysis for SO_X Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce SO_X emissions from the proposed engine:

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice/Contained in SIP)

There are no options listed in the SJVUAPCD BACT Clearinghouse as alternate basic equipment.

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

The control efficiency of each of the options above is estimated and the controls are ranked below based on the control effectiveness.

1) Sulfur Content of fuel gas not exceeding 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved practice and has been proposed by the applicant; therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for SO_X emissions from the proposed engines is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use a biological sulfur removal system and iron sponge and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_X are satisfied.

3. **BACT Analysis for PM_{10} Emissions:**

a. Step 1 - Identify all control technologies

Combustion of gaseous fuels generally does not result in significant emissions of particulate matter. Dairy anaerobic digester gas is the planned fuel for the proposed IC engines. The anaerobic digester gas will be composed primarily of methane (approximately 60% molar composition) and CO_2 (approximately 40% molar composition) and is expected to burn in a fairly clean manner. Particulate emissions from combustion of the digester gas are expected to primarily result from the incineration of fuel-born sulfur compounds (mostly H_2S) resulting in the formation of sulfur-containing particulate. Therefore, scrubbing of the digester gas is the principal means to reduce particulate emissions.

The following control was identified to reduce particulate matter emissions from combustion of the digester gas as fuel in the proposed engines:

1) Sulfur Content of fuel ≤ 40 ppmv as H_2S (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Sulfur Content of fuel gas ≤ 40 ppmv as H_2S (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option listed above has been identified as achieved in practice. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for PM_{10} emissions from the proposed engines is fuel gas sulfur content not exceeding 40 ppmv as H_2S. The applicant has proposed to use a biological sulfur removal system and iron sponge and/or carbon canister scrubbers (or an equivalent sulfur removal system) to reduce the sulfur content of the digester gas combusted in the engines to ≤ 40 ppmv as H_2S. Therefore, the BACT requirements for SO_X are satisfied.

4. BACT Analysis for VOC Emissions:

a. Step 1 - Identify all control technologies

The following options were identified to reduce VOC emissions:

1) VOC emissions ≤ 0.10 g/bhp-hr (lean burn or equivalent and positive crankcase ventilation) (Achieved in Practice)
2) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) Fuel Cell (≤ 0.02 lb/MW-hr) (Alternate Basic Equipment)
2) VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

Option 1: Fuel Cell (≤ 0.02 lb/MW-hr VOC as CH_4) (Alternate Basic Equipment)

The multi-pollutant cost analysis performed above for the NO_X and VOC emissions demonstrated that the annualized cost of this alternate option exceeds the Multi Pollutant Cost Effectiveness Threshold calculated for the NO_X and VOC emission reductions achieved by this technology. Therefore, this option is not cost effective and is being removed from consideration.

Option 2: VOC emissions ≤ 0.10 g/bhp-hr (Achieved in Practice)

This has been identified as achieved in practice and has been proposed by the applicant. Therefore, the option required and is not subject to a cost analysis.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for VOC emissions from the proposed engines is VOC emissions ≤ 0.10 g/bhp-hr. The applicant has proposed IC engines with VOC emissions ≤ 0.10 g/bhp-hr. Therefore, the BACT requirements for VOC are satisfied.

5. BACT Analysis for NH_3 Slip Emissions:

A Selective Catalytic Reduction (SCR) system operates as an external control device where flue gases and a reagent (e.g. urea or ammonia) are passed through an appropriate catalyst. The reagent is used to reduce NO_X, over the catalyst bed, to form elemental nitrogen, water vapor, and other by-products. The use of a catalyst typically reduces the NO_X emissions by up to 90%. Ammonia slip is the result of unreacted ammonia exiting the SCR system.

a. Step 1 - Identify all control technologies

The District has not established a cost effectiveness threshold for ammonia. Therefore, only options that are determined to be Achieved-in-Practice controls will be considered for ammonia in this analysis.

District BACT Guideline 3.3.15 lists an ammonia slip emission limit of 10 ppmvd @ 15% O_2 as an Achieved in Practice BACT requirement for waste gas-fired IC engines.

1) NH_3 emissions ≤ 10 ppmvd @ 15% O_2 (Achieved in Practice)

b. Step 2 - Eliminate technologically infeasible options

There are no technologically infeasible options to eliminate from step 1.

c. Step 3 - Rank remaining options by control effectiveness

1) NH_3 emissions ≤ 10 ppmvd @ 15% O_2 (Achieved in Practice)

d. Step 4 - Cost Effectiveness Analysis

The only option above is achieved in practice and has been proposed by the applicant. Additionally, as stated above, a cost effectiveness threshold for ammonia has not been established by the District. Therefore a cost analysis is not required.

e. Step 5 - Select BACT

Pursuant to the above BACT Analysis, BACT for NH_3 slip emissions from the proposed engines is NH_3 slip emissions ≤ 10 ppmvd @ 15% O_2. The applicant has proposed IC engines with NH_3 slip emissions ≤ 10 ppmvd @ 15% O_2. Therefore, the BACT requirements for NH_3 slip are satisfied.

APPENDIX C

Summary of Health Risk Assessment (HRA) and Ambient Air Quality Analysis (AAQA)

San Joaquin Valley Air Pollution Control District
REVISED Risk Management Review

To:	Ramon Norman – Permit Services
From:	Yu Vu – Technical Services
Date:	October 22, 2015
Facility Name:	ABEC #3 dba Lakeview Dairy Biogas
Location:	17702 Bear Mountain Blvd, Bakersfield, CA 93311 at Lakeview Dairy (S-5254)
Application #(s):	S-8637-2-0, 3-0
Project #:	S-1143770

A. RMR SUMMARY

RMR Summary			
Categories	**1,468 BHP Bio Gas Engines (Unit 2-0 & 3-0)**	**Project Totals**	**Facility Totals**
Prioritization Score	107 (ea.)	214	>1
Acute Hazard Index	0.48 (ea.)[1]	0.95	0.95
Chronic Hazard Index	0.16 (ea.)	0.31	0.31
Maximum Individual Cancer Risk (10^{-6})	0.002 (ea.)	0.004	0.004
T-BACT Required?	**No**		
Special Permit Conditions?	**Yes**		

[1] H_2S emissions must be limited in order to achieve the acute hazard index score in this project and for the project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS). Please see special condition below.

<u>**Proposed Permit Conditions**</u>

To ensure that human health risks will not exceed District allowable levels; the following permit conditions must be included for:

<u>Unit # 2-0, 3-0</u>

1) The H_2S emissions from the engine shall not exceed 1.97 lbs/hr. as determined by source testing. [District Rule 2201]

B. RMR REPORT

I. Project Description

Technical Services received a request on October 7, 2015, to perform a revised Risk Management Review for a proposed installation of two 1,468 BHP Dairy Bio gas-fired full time IC engines. Per the project engineer, the following changes to the project were made in this revision:

1) An increase in each engine's rating from 1,412 bhp to 1,468 bhp.
2) An increase in digester gas consumption of each engine from 16,303 scf/hr and 142,812,528 scf/yr to 16,327 scf/hr and 143,024,520 scf/yr.
3) A change in the stack parameters, resulting in the stack exit velocity of each engine increasing from 19.766 m/s to 23.636 m/s.

II. Analysis

Technical Services performed a prioritization using the District's HEARTs database. Since the total facility prioritization score was greater than one, a refined health risk assessment was required. Emissions calculated using District approved Dairy Bio Gas emission factors for internal combustion were input into the HEARTs database. The AERMOD model was used, with the parameters outlined below and meteorological data for 2004-2008 from Fellows to determine the dispersion factors (i.e., the predicted concentration or X divided by the normalized source strength or Q) for a receptor grid. These dispersion factors were input into the Hot Spots Analysis and Reporting Program (HARP) risk assessment module to calculate the chronic and acute hazard indices and the carcinogenic risk for the project.

The following parameters were used for the review:

Analysis Parameters Unit 2-0, 3-0			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	9.144	**Closest Receptor (m)**	Various
Stack Diameter. (m)	0.4572	**Type of Receptor**	Business
Stack Exit Velocity (m/s)	23.636	**Max Hours per Year**	8,760
Stack Exit Temp. (°K)	699.817	**Fuel Type**	Dairy Bio Gas
BHP	1,468		

Technical Services performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR. The emission rates used for criteria pollutant modeling were:

Pollutant	lb/hr	lb/yr
CO	15.6966	50,818
NO_x	3.2364	4,582.7
SO_x	0.1295	1,134.0
PM_{10}	0.2265	1,984.6
H_2S	6.0834	N/A

The results from the Criteria Pollutant Modeling are as follows:

Criteria Pollutant Modeling Results*

Bio-Gas Engine	1 Hour	3 Hours	8 Hours	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass[1]	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass[2]	Pass[2]
H_2S	Pass[3]	X	X	X	X

*Results were taken from the attached PSD spreadsheet.
[1]The project was compared to the 1-hour NO2 National Ambient Air Quality Standard that became effective on April 12, 2010 using the District's approved procedures.
[2]The criteria pollutants are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).
[3]H_2S emissions must be limited to the value listed in the Proposed Permit Conditions section in order for this project to not cause an exceedance of the California Ambient Air Quality Standard (CAAQS).

III. Conclusion

The acute and chronic indices are below 1.0 and the cancer risk factor associated with the project is less than 1.0 in a million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed on page 1 of this report must be included for this proposed unit.

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

IV. Attachments

A. RMR request from the project engineer
B. Additional information from the applicant/project engineer
C. Toxic emissions summary
D. Prioritization score
E. Facility Summary

APPENDIX D
Draft ATCs
(S-8637-1-0, -2-0, & -3-0)

FOR PROJECT FILE
Emissions Profiles

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

DRAFT

PERMIT NO: S-8637-1-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
MAILING ADDRESS: 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION: 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
ANAEROBIC DIGESTER SYSTEM CONSISTING OF COVERED LAGOON ANAEROBIC DIGESTER CELL(S) WITH PRESSURE/VACUUM VALVE(S) AND AN AIR INJECTION SYSTEM FOR CONTROL OF H2S

CONDITIONS

1. {271} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]
2. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
3. The VOC content of the digester gas produced by the digester system shall not exceed 10% by weight. [District Rule 2201]
4. The digester system cover(s) shall be designed and installed in accordance with Natural Resources Conservation Services (NRCS) Practice Standard Code 367 - Roofs and Covers. [District Rule 2201]
5. The digester system shall be designed to allow gas generated during summer conditions to be stored for more than 24 hours prior to venting in the event that the gas cannot be combusted in digester gas-fired engines or sent to another device with a VOC control efficiency of at least 95% by weight as determined by the APCO. [District Rule 2201]
6. The air injection system shall be maintained and operated in accordance with the supplier's recommendations to minimize the concentration of hydrogen sulfide (H2S) in the digester gas. [District Rule 2201]
7. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 1070 and 2201]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services
S-8637-1-0 : Mar 16 2016 1:06PM – NORMANR : Joint Inspection NOT Required

8. {3658} This permit does not authorize the violation of any conditions established for this facility in the Conditional Use Permit (CUP), Special Use Permit (SUP), Site Approval, Site Plan Review (SPR), or other approval documents issued by a local, state, or federal agency. [Public Resources Code 21000-21177: California Environmental Quality Act]

DRAFT

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-8637-2-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
MAILING ADDRESS: 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION: 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This facility (Facility S-8637) and the adjacent dairy operation (Facility S-5254) shall be operated as separate stationary sources. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

YOU MUST NOTIFY THE DISTRICT COMPLIANCE DIVISION AT (661) 392-5500 WHEN CONSTRUCTION IS COMPLETED AND PRIOR TO OPERATING THE EQUIPMENT OR MODIFICATIONS AUTHORIZED BY THIS AUTHORITY TO CONSTRUCT. This is NOT a PERMIT TO OPERATE. Approval or denial of a PERMIT TO OPERATE will be made after an inspection to verify that the equipment has been constructed in accordance with the approved plans, specifications and conditions of this Authority to Construct, and to determine if the equipment can be operated in compliance with all Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District. Unless construction has commenced pursuant to Rule 2050, this Authority to Construct shall expire and application shall be cancelled two years from the date of issuance. The applicant is responsible for complying with all laws, ordinances and regulations of all other governmental agencies which may pertain to the above equipment.

Seyed Sadredin, Executive Director / APCO

DRAFT

Arnaud Marjollet, Director of Permit Services
S-8637-2-0 : Mar 16 2016 1:06PM – NORMANR Joint Inspection NOT Required

9. This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]
10. During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
11. The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
12. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H_2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
13. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]
14. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]
15. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
16. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
17. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
18. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
19. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
20. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
21. During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
22. The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]
23. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

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24. Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

25. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]

26. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

27. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]

28. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

29. Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]

30. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

31. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

32. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

33. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

34. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

35. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

36. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

37. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

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38. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

40. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

41. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

42. If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

43. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

44. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

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45. Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

46. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

47. Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature and back pressure demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

48. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

49. The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

50. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

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52. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

53. The permittee shall obtain written District approval for the use of any equivalent control equipment not specifically approved by this Authority to Construct. Approval of the equivalent control equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate control equipment is equivalent to the specifically authorized equipment. [District Rule 2010]

54. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

55. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

56. No emission factor and no emissions shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

San Joaquin Valley
Air Pollution Control District

AUTHORITY TO CONSTRUCT

PERMIT NO: S-8637-3-0 **ISSUANCE DATE:** DRAFT

LEGAL OWNER OR OPERATOR: ABEC #3 LLC DBA LAKEVIEW DAIRY BIOGAS
MAILING ADDRESS: 2828 ROUTH ST, SUITE 500
DALLAS, TX 75201-1438

LOCATION: 17702 BEAR MOUNTAIN BLVD
BAKERSFIELD, CA 93311

EQUIPMENT DESCRIPTION:
1,468 BHP GE JENBACHER MODEL J 320 GS-C82 (OR DISTRICT APPROVED EQUIVALENT) DIGESTER GAS-FIRED LEAN-BURN IC ENGINE WITH A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AND AN IRON SPONGE AND/OR CARBON H2S REMOVAL SYSTEM (OR APPROVED EQUIVALENT H2S REMOVAL SYSTEM) POWERING AN ELECTRICAL GENERATOR

CONDITIONS

1. This facility (Facility S-8637) and the adjacent dairy operation (Facility S-5254) shall be operated as separate stationary sources. [District Rule 2201]
2. All equipment shall be maintained in good operating condition and shall be operated in a manner consistent with good air pollution control practice to minimize emissions of air contaminants. [District Rule 2201]
3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]
4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]
5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]
6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap (flapper ok), roof overhang, or any other obstruction. [District Rule 4102]
7. {4261} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]
8. {3203} This engine shall be operated within the ranges that the source testing has shown result in pollution concentrations within the emissions limits as specified on this permit. [District Rule 4702]

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Arnaud Marjollet, Director of Permit Services

9. This engine shall only be fueled with digester gas except in the case that sufficient digester gas is unavailable for the engine at the time that the required one-time initial utility interconnect testing is scheduled. If sufficient digester gas is unavailable for the engine at the time that the required initial utility interconnect testing is scheduled, the engine will be permitted to use sufficient natural gas fuel to complete the required utility interconnect testing. [District Rule 2201]
10. During times this engine is fueled with natural gas for required initial utility interconnect testing, the engine shall continue to comply with all emission standards and limitations contained in this permit. [District Rule 2201]
11. The total amount of electrical energy produced by this engine while fueled on natural gas for required one-time initial utility interconnect testing shall not exceed 96,000 kW-hrs. The following records shall be maintained: 1) date(s) and time(s) that this engine is fueled with natural gas for utility testing, 2) the total amount of electrical energy (kW-hr) produced by this engine when fueled with natural gas for utility testing, and 3) the total number of hours that this engine is fueled with natural gas. [District Rule 2201]
12. The sulfur content of the digester gas used as fuel in this engine shall not exceed 40 ppmv as H2S. The applicant may utilize an averaging period of up to 24 hours in length for demonstration of compliance with the fuel sulfur content limit. [District Rules 2201, 4102, 4702, and 4801]
13. This engine shall be equipped with an operational non-resettable elapsed time meter. [District Rules 2201 and 4702]
14. {1897} This engine shall be equipped with either a positive crankcase ventilation (PCV) system that recirculates crankcase emissions into the air intake system for combustion, or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]
15. Commissioning activities are defined as, but not limited to, all testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the construction contractor to ensure safe and reliable operation of the reciprocating IC engine, emission control equipment, and associated electrical delivery systems. [District Rule 2201]
16. Commissioning period shall commence when all mechanical, electrical, and control systems are installed and individual system startup has been completed, or when the reciprocating engine is first fired, whichever occurs first. The commissioning period shall terminate when the engine has completed initial performance testing, completed initial engine tuning, and the engine is available for commercial operation. The total duration of the commissioning period for this engine shall not exceed 120 hours of operation. [District Rule 2201]
17. The owner/operator shall minimize the emissions from the engine to the maximum extent possible during the commissioning period. [District Rule 2201]
18. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the engine shall be tuned to minimize emissions. [District Rule 2201]
19. At the earliest feasible opportunity, in accordance with the recommendations of the equipment supplier and/or the construction contractor, the emission control catalyst system(s) shall be installed, adjusted, and operated to minimize emissions from this unit. [District Rule 2201]
20. The permittee shall submit a summary of activities to be performed during the commissioning period to the District at least two weeks prior to the first firing of this engine. The summary shall include a list of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but are not limited to, the tuning of the engine, the installation and operation of the SCR system, the installation, calibration, and testing of emissions monitors, and any activities requiring the firing of this unit without abatement by the SCR system. [District Rule 2201]
21. During the commissioning period emission rates from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.07 g-PM10/bhp-hr, 4.85 g-CO/bhp-hr, 1.0 g-VOC/bhp-hr. [District Rule 2201]
22. The total number of firing hours of this unit without abatement of emissions by the SCR system shall not exceed 120 hours during the commissioning period. Such operation of this unit without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system. Upon completion of these activities, the unused balance of the 120 firing hours without abatement shall expire. [District Rule 2201]
23. The permittee shall record total operating time of the engine in hours during the commissioning period. [District Rule 2201]

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24. Coincident with the end of the commissioning period, emissions from this IC engine shall not exceed any of the following limits: 0.15 g-NOx/bhp-hr (for periodic alternate monitoring, equivalent to 11 ppmvd NOx @ 15% O2), NOx referenced as NO2; 0.07 g-PM10/bhp-hr; 1.75 g-CO/bhp-hr (for periodic alternate monitoring, equivalent to 210 ppmvd CO @ 15% O2); 0.10 g-VOC/bhp-hr (for periodic alternate monitoring, equivalent to 21 ppmvd VOC @ 15% O2), VOC referenced as CH4. [District Rules 2201 and 4702]

25. The SCR catalyst shall be maintained and replaced in accordance with the recommendations of the catalyst manufacturer or emission control supplier. Records of catalyst maintenance and replacement shall be maintained. [District Rules 2201 and 4702]

26. Ammonia (NH3) emissions from this engine shall not exceed 10 ppmvd @ 15% O2. [District Rules 2201 and 4102]

27. Source testing to measure NOx, CO, VOC, PM10, and ammonia (NH3) emissions from this unit shall be conducted within 90 days of initial start-up. [District Rules 1081, 2201, and 4702]

28. Source testing to measure NOx, CO, VOC, and ammonia (NH3) emissions from this unit shall be conducted at least once every 24 months. [District Rules 1081, 2201, and 4702]

29. Fuel sulfur content analysis shall be performed within 90 days of initial start-up using EPA Method 11 or EPA Method 15, as appropriate. [District Rules 2201 and 4702]

30. Fuel sulfur content analysis shall be performed at least annually using EPA Method 11 or EPA Method 15, as appropriate. Records of the fuel sulfur analysis shall be maintained and provided to the District upon request. [District Rules 2201 and 4702]

31. {3791} Emissions source testing shall be conducted with the engine operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. [District Rule 4702]

32. For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit, the test cannot be used to demonstrate compliance with an applicable limit. VOC emissions shall be reported as methane. NOx, CO, VOC, and NH3 concentrations shall be reported in ppmv, corrected to 15% oxygen. [District Rules 2201 and 4702]

33. The following methods shall be used for source testing: NOx (ppmv) - EPA Method 7E or ARB Method 100; CO (ppmv) - EPA Method 10 or ARB Method 100; VOC (ppmv) - EPA Method 18, 25A or 25B, or ARB Method 100; stack gas oxygen - EPA Method 3 or 3A or ARB Method 100; stack gas velocity - EPA Method 2 or EPA Method 19; stack gas moisture content - EPA Method 4; PM10 (filterable and condensable) - EPA Method 201 and 202, EPA Method 201a and 202, or ARB Method 5 in combination with Method 501; NH3 - BAAQMD ST-1B or SCAQMD Method 207-1. Alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4702]

34. The Higher Heating Value (HHV) of the fuel gas shall be determined using ASTM D1826, ASTM 1945 in conjunction with ASTM D3588, or an alternative method approved by the District. [District Rules 2201 and 4702]

35. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

36. The results of each source test shall be submitted to the District within 60 days after completion of the source test. [District Rule 1081]

37. The sulfur content of the digester gas used to fuel the engine shall be monitored and recorded at least once every calendar quarter in which a fuel sulfur analysis is not performed. If quarterly monitoring shows a violation of the fuel sulfur content limit of this permit, monthly monitoring will be required until six consecutive months of monitoring show compliance with the fuel sulfur content limit. Once compliance with the fuel sulfur content limit is shown for six consecutive months, then the monitoring frequency may return to quarterly. Monitoring of the sulfur content of the digester gas fuel shall not be required if the engine does not operate during that period. Records of the results of monitoring of the digester gas fuel sulfur content shall be maintained. [District Rule 2201]

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38. Monitoring of the digester gas sulfur content shall be performed using gas detection tubes calibrated for H2S; a Testo 350 XL portable emission monitor; a continuous fuel gas monitor that meets the requirements specified in SCAQMD Rule 431.1, Attachment A; District-approved source test methods, including EPA Method 15, ASTM Method D1072, D4084, and D5504; District-approved in-line H2S monitors; or an alternative method approved by the District. Prior to utilization of in-line monitors to demonstrate compliance with the digester gas sulfur content limit of this permit, the permittee shall submit details of the proposed monitoring system, including the make, model, and detection limits, to the District and obtain District approval for the proposed monitor(s). [District Rule 2201]

39. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

40. The permittee shall monitor and record the stack concentration of NOx, CO, and O2 at least once every calendar quarter (in which a source test is not performed) using a portable emission monitor that meets District specifications. [In-stack monitors may be allowed if they satisfy the standards for portable analyzers as specified in District policies and are approved in writing by the APCO.] Monitoring shall be performed not less than once every month for 12 months if two consecutive deviations are observed during quarterly monitoring. Monitoring shall not be required if the engine is not in operation, i.e. the engine need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the engine unless monitoring has been performed within the last month if on a monthly monitoring schedule, or within the last quarter if on a quarterly monitoring schedule. Records must be maintained of the dates of non-operation to validate extended monitoring frequencies. [District Rules 2201 and 4702]

41. The permittee shall monitor and record the stack concentration of NH3 at least once every calendar quarter in which a source test is not performed. NH3 monitoring shall be conducted utilizing District approved gas-detection tubes or a District approved equivalent method. Monitoring shall not be required if the unit is not in operation, i.e. the unit need not be started solely to perform monitoring. Monitoring shall be performed within 5 days of restarting the unit unless monitoring has been performed within the last quarter. [District Rules 2201 and 4102]

42. If the NOx, CO, or NH3 concentrations corrected to 15% O2, as measured by the portable analyzer or the District-approved ammonia monitoring equipment, exceed the respective permitted emissions concentration(s), the permittee shall return the emissions to within the acceptable range as soon as possible, but no longer than 8 hours of operation after detection. If the portable analyzer or ammonia monitoring equipment readings continue to exceed the permitted emissions concentration(s) after 8 hours of operation after detection, the permittee shall notify the District within the following 1 hour and conduct a certified source test within 60 days of the first exceedance. In lieu of conducting a source test, the permittee may stipulate a violation has occurred, subject to enforcement action. The permittee must then correct the violation, show compliance has been re-established, and resume monitoring procedures. If the deviations are the result of a qualifying breakdown condition pursuant to Rule 1100, the permittee may fully comply with Rule 1100 in lieu of the performing the notification and testing required by this condition. [District Rules 2201 and 4702]

43. {3787} All alternate monitoring parameter emission readings shall be taken with the unit operating either at conditions representative of normal operations or conditions specified in the permit-to-operate. The analyzer shall be calibrated, maintained, and operated in accordance with the manufacturer's specifications and recommendations or a protocol approved by the APCO. Emission readings taken shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15 consecutive-minute sample reading or by taking at least five (5) readings, evenly spaced out over the 15 consecutive-minute period. [District Rule 4702]

44. The permittee shall maintain records of: (1) the date and time of NOx, CO, O2, and NH3 measurements, (2) the O2 concentration in percent and the measured NOx, CO, and NH3 concentrations corrected to 15% O2, (3) make and model of exhaust gas analyzer, (4) exhaust gas analyzer calibration records, (5) the method of determining the NH3 emission concentration, and (6) a description of any corrective action taken to maintain the emissions within the acceptable range. [District Rules 2201 and 4702]

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CONDITIONS CONTINUE ON NEXT PAGE

45. Within 90 days of initial start-up, the SCR system reagent injection rate and inlet temperature to the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the NOx emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the acceptable SCR system reagent injection rate(s) and inlet temperature(s) to the catalyst control system demonstrated to result in compliance with the NOx emission limit(s) shall be maintained and made available for inspection upon request. [District Rule 4702]

46. If the SCR system reagent injection rate and/or the inlet temperature to the catalyst control system is outside of the established acceptable range(s), the permittee shall return the SCR system reagent injection rate and inlet temperature to the catalyst control system to within the established acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the SCR system reagent injection rate and inlet temperature to the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of NOx and O2 at least once every month. Monthly monitoring of the stack concentration of NOx and O2 shall continue until the operator can show that the SCR system reagent injection rate and inlet temperature to the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the NOx emission limit(s) of this permit. [District Rule 4702]

47. Within 90 days of initial start-up, the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system shall be monitored to establish acceptable values and ranges that provide a reasonable assurance of ongoing compliance with the emissions limit(s) stated in this permit. Acceptable values and ranges shall be established for each load that the engine is expected to operate at, in a minimum of 10% increments (e.g. 70%, 80%, and 90%). Records of the established acceptable inlet temperature and back pressure demonstrated to result in compliance with the CO and VOC emission limits shall be maintained and made available for inspection upon request. [District Rule 4702]

48. If the inlet temperature to the catalyst control system and/or the back pressure of the exhaust upstream of the catalyst control system is outside of the established acceptable range(s), the permittee shall return the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system back to the acceptable range(s) as soon as possible, but no longer than 8 hours after detection. If the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are not returned to within acceptable range(s) within 8 hours, the permittee shall notify the District within the following 1 hour and begin monitoring and recording the stack concentration of CO and O2 at least once every month. Monthly monitoring of the stack concentration of CO and O2 shall continue until the operator can show that the inlet temperature to the catalyst control system and the back pressure of the exhaust upstream of the catalyst control system are operating within the acceptable range(s) demonstrated to result in compliance with the CO emission limit(s) of this permit. [District Rule 4702]

49. The permittee shall monitor and record the engine operating load, the SCR system reagent injection rate, the inlet temperature to the catalyst control system, and the back pressure of the exhaust upstream of the catalyst control system at least once per month. [District Rule 4702]

50. The permittee shall maintain an engine operating log to demonstrate compliance. The engine operating log shall include, on a monthly basis, the following information: the total hours of operation, the type and quantity of fuel used, maintenance and modifications performed, monitoring data, compliance source test results, and any other information necessary to demonstrate compliance. Quantity of fuel used shall be recorded in standard cubic feet using a non-resettable, totalizing mass or volumetric fuel flow meter or other APCO approved-device. [District Rules 2201 and 4702]

51. {3212} The permittee shall update the I&M plan for this engine prior to any planned change in operation. The permittee must notify the District no later than seven days after changing the I&M plan and must submit an updated I&M plan to the APCO for approval no later than 14 days after the change. The date and time of the change to the I&M plan shall be recorded in the engine's operating log. For modifications, the revised I&M plan shall be submitted to and approved by the APCO prior to issuance of the Permit to Operate. The permittee may request a change to the I&M plan at any time. [District Rule 4702]

CONDITIONS CONTINUE ON NEXT PAGE

52. All records shall be maintained and retained for a minimum of five (5) years, and shall be made available for District inspection upon request. All records may be maintained and submitted in an electronic format approved by the District. [District Rules 2201 and 4702]

53. The permittee shall obtain written District approval for the use of any equivalent control equipment not specifically approved by this Authority to Construct. Approval of the equivalent control equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate control equipment is equivalent to the specifically authorized equipment. [District Rule 2010]

54. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

55. Alternate equipment shall be of the same class and category of source as the equipment authorized by the Authority to Construct. [District Rule 2201]

56. No emission factor and no emissions shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

ATTACHMENT O

Application No. B0104

Staff Summary

California Bioenergy LLC
ABEC #3 LLC dba Lakeview Farms Dairy Biogas, Bakersfield, CA
Electricity from Dairy Manure Biogas

Intermediate Facility:
Lakeview Farms Dairy, Bakersfield, CA

Deemed Complete: 5/15/2020
Posted for Comment: 11/9/2020
Certified: TBD
CI Effective: TBD

Pathway Summary

California Bioenergy LLC seeks certification of a Tier 2 pathway for electricity from dairy manure biogas produced by a reciprocating internal combustion (IC) engine and generator at the ABEC #3 LLC dba Lakeview Farms Dairy Biogas (ABEC #3) and supplied to the California electricity grid for use in transportation using book-and-claim accounting for low-CI electricity.[1]

The covered lagoon digester captures methane that would otherwise be vented to the atmosphere. The ABEC #3 digester is registered with the Climate Action Reserve (CAR1316/CALS6316; listed date: 09/05/2018; crediting period expiration: 12/31/2027) and has previously generated ARB Offset Credits under California's Cap & Trade program.

The dairy has an average cattle population of about 9,000. In the baseline scenario, manure is either collected via a flush system or left in a dry lot. For the baseline, manure from open lot corrals and milking parlor was collected via flush and scraped for heifers in open lot corrals. Flushed manure was sent to anaerobic storage after solids separation using a stationary screen with a portion of the manure collected from milking cows in open lot corral sent directly to anaerobic storage. Separated solids and scrapped manure was piled in open lots and exported off farm on an annual basis. Prior to installation of the digester, incomplete removal of volatile solids (VS) occurred annually in the anaerobic storage and as a result, no lagoon cleanouts were modeled.

[1] All citations to the LCFS Regulation are found in Title 17, California Code of Regulations (CCR), section 95480-95503. Book-and-claim accounting for low-CI electricity is primarily addressed in section 95488.8(i) of the LCFS Regulation.

With the installation of the project, manure that was sent to anaerobic storage was diverted to the digester. Additionally, manure from heifers in open lot corrals was collected via vacuum and sent to the anaerobic digestion. The covered lagoon digester captures methane that would otherwise be vented to the atmosphere.

Biogas captured by the covered lagoon is either sent to a 1MW Caterpillar internal combustion engine for electricity generation or vented. The compressor draws the gas through the hydrogen sulfide (H_2S) removal system, which consists of an iron sponge and an activated carbon tank that reduces the H_2S concentration to below air permitted levels. The internal combustion engine converts roughly one third of energy in biogas to electricity. A portion of the biogas produced by the covered lagoon digester that is not destroyed by the engine generator is vented rather than flared. This vented methane is separately metered and included in the pathway emissions in the Simplified Calculator. Grid and on-site generated electricity is used to power the mixers in the digester, blowers to move gas through the system, electronic instrumentation, and internal combustion engine.

Carbon Intensity of Electricity Pathway

The CI is determined from life cycle analysis conducted using a modified version of the Board-approved Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure.[2] The calculator was modified in accordance with regulatory requirements and LCFS Guidance Document 19-06,[3] and has been determined to be equivalent to CA-GREET3.0 pursuant to section 95488.7(a)(1) of the LCFS regulation. The applicant has provided operational data and supporting documentation for assessment of baseline emissions, biogas production, electricity generation from dairy biogas, and venting for a period of 24 months, from March 2018 to February 2020.

The following table lists the proposed CI for this pathway.

[2] The Tier 1 Simplified CI Calculator for Biomethane from Anaerobic Digestion of Dairy and Swine Manure (August 13, 2018), incorporated by reference in the LCFS Regulation, section 95488.3(b).
[3] LCFS Guidance 19-06 (Revised October 2019): Determining Carbon Intensity of Dairy and Swine Manure Biogas to Electricity Pathways

Proposed Pathway CI

Fuel & Feedstock	Pathway FPC	Pathway Description	Carbon Intensity (gCO2e/MJ)
Low-CI Electricity from Dairy Manure Biogas	TBD	Low-CI Electricity from Dairy Manure Biogas using reciprocating engine at ABEC #2 LLC dba West Star North Dairy Biogas in Bakersfield, California for use as transportation fuel in California.	-382.98

Operating Conditions

The certified CI value in the above table may be used to report and generate credits for fuel quantities that are produced at the facility in the manner described in the applicant's Life Cycle Analysis (LCA) report, and dispensed for transportation use in California, subject to the following requirements and conditions:

1. Fuel pathway holders are subject to the requirements of the California Air Resources Board's (CARB) Low Carbon Fuel Standard (LCFS) regulation, which appears at sections 95480 to 95503 of title 17, California Code of Regulations. Requirements include ongoing monitoring, reporting, recordkeeping, and third-party verification of operational CI and a controlled process for providing product transfer documents or other similar records to counterparties or CARB.

2. No later than October 1, 2020, equipment to continuously measure and record methane concentration in biogas at least every 15 minutes must be installed to report the monthly weighted average methane concentration in fields 2.5 and 2.7 in the Annual Fuel Pathway Report submitted to CARB for third-party verification of the operational CI.

3. To confirm compliance with LCFS Regulation section 95488.8(h) and demonstrate use of directly supplied low-CI process energy in annual Fuel Pathway Reports, the fuel pathway holder must demonstrate retirement of the corresponding quantity of Renewable Electricity Certificates (RECs) that were generated for the quantity of low-CI electricity consumed within the fuel pathway (use of onsite electricity from biogas in field 2.17). For each quarter of operation, the number of RECs that are associated with process energy must be retired in a WREGIS retirement sub-account named "Low-CI Process Energy at LCFS Facility [ID number]", where the LCFS Facility ID is the number assigned in the AFP at the time of facility registration. These RECs and the associated environmental attributes can no longer be sold, transferred, or claimed by any entity or for any other purpose. The WREGIS report demonstrating REC retirement must be downloaded from WREGIS and uploaded to the AFP as part

of each annual Fuel Pathway Report to demonstrate the quantity of electricity from biogas that is consumed within the fuel pathway and claimed to lower the CI of the produced fuel.

Note that this retirement account for process energy is distinct from and in addition to the requirement for any fuel reporting entity claiming electricity as supplied for use as transportation fuel in the LRT under this pathway to demonstrate quarterly REC retirement as part of each quarterly report.

4. The electricity, including the environmental attributes associated with the electricity, claimed under this pathway shall not be claimed under any other program notwithstanding the exceptions listed in LCFS Regulation section 95488.8(i)(1). The LCFS places no restrictions on the use of any voluntary emissions reductions credits generated by the project for emissions that are demonstrated to be additional to reductions claimed under the LCFS.

5. The fuel pathway holder must include the assumptions and calculations used to establish the fraction of solids input to each manure management system in its annual Fuel Pathway Report submitted to CARB for third-party verification of the operational CI.

6. Any quantity of biomethane metered as captured that cannot be demonstrated by meter records to have been destroyed, must be calculated by energy balance and accounted for in the CI as a fugitive methane emission if the calculated value exceeds the default 2% fugitive emission.

Staff Analysis and Recommendation

Staff has reviewed the application and has replicated, using the Tier 2 modified version of the Simplified CI Calculator, the CI values calculated by the applicant. EcoEngineers (H3-20-008) submitted a positive validation statement. Staff recommends this application be certified after all the comments received during the 10-day comment period are addressed satisfactorily by the applicant. The certification is subject to the operating conditions set forth in this document.

ATTACHMENT P

DEC 17 2010

Jim Rexroad
Avenal Power Center LLC
500 Dallas Street, Level 31
Houston, TX 77002

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Rexroad:

Enclosed is the District's final determination of compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

The changes made to the PDOC were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Also enclosed is an invoice for the engineering evaluation fees pursuant to District Rule 3010. Please remit the amount owed, along with a copy of the attached invoice, within 60 days.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

cc: Gary Rubenstein, Sierra Research

DEC 17 2010

Mike Tollstrup, Chief
Project Assessment Branch
Stationary Source Division
California Air Resources Board
PO Box 2815
Sacramento, CA 95812-2815

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Tollstrup:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

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Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

Seyed Sadredin
Executive Director/Air Pollution Control Officer

Northern Region
4800 Enterprise Way
Modesto, CA 95356-8718
Tel: (209) 557-6400 FAX: (209) 557-6475

Central Region (Main Office)
1990 E. Gettysburg Avenue
Fresno, CA 93726-0244
Tel: (559) 230-6000 FAX: (559) 230-6061

Southern Region
34946 Flyover Court
Bakersfield, CA 93308-9725
Tel: 661-392-5500 FAX: 661-392-5585

www.valleyair.org www.healthyairliving.com

DEC 17 2010

Gerardo C. Rios (AIR 3)
Chief, Permits Office
Air Division
U.S. E.P.A. - Region IX
75 Hawthorne Street
San Francisco, CA 94105

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Rios:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

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The changes made to the Preliminary Determination of Compliance (PDOC) were in direct response to comments received from the oversight agencies and other interested parties. It is District practice to require an additional 30-day comment period for a project if changes received during the initial 30-day comment period result in a significant emissions increase that affects or modifies the original basis for approval. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements. Therefore, publication of the PDOC for an additional 30-day comment period is not required.

Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING™

DEC 17 2010

Joseph Douglas
Project Manager
California Energy Commission
1516 Ninth Street
Sacramento, CA 95814

Re: Notice of Final Determination of Compliance (FDOC)
Project Number: C-1100751 – Avenal Power Center LLC (08-AFC-01)

Dear Mr. Douglas:

Enclosed is the District's Final Determination of Compliance (FDOC) for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

Notice of the District's preliminary decision was published on July 27, 2010. All comments received following the District's preliminary decision on this project were considered. A summary of the comments received and the District responses to those comments can be found in Attachments J, K, L, and M of the enclosed FDOC package.

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Thank you for your cooperation in this matter. If you have any questions, please contact Mr. Jim Swaney of the Permit Services Division at (559) 230-5900.

Sincerely,

David Warner
Director of Permit Services

DW:df

Enclosures

Fresno Bee

NOTICE OF FINAL DETERMINATION OF COMPLIANCE

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District has issued a Final Determination of Compliance (FDOC) to Avenal Power Center LLC for the installation of a nominal 600 MW combined cycle power plant, located at NE¼ Section 19, T21S, R18E – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 in Avenal, CA.

All comments received following the District's preliminary decision on this project were considered. Changes were made to the DOC in direct response to comments received from the oversight agencies and other interested parties. The changes made were minor and did not increase permitted emission levels or trigger additional public notification requirements.

The application review for project C-1100751 is available for public inspection at http://www.valleyair.org/notices/public_notices_idx.htm and the **SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 1990 EAST GETTYSBURG AVENUE, FRESNO, CA 93726.**

FINAL DETERMINATION OF COMPLIANCE EVALUATION

Avenal Power Center Project
California Energy Commission
Application for Certification Docket #: 08-AFC-01

Facility Name:	Avenal Power Center, LLC
Mailing Address:	500 Dallas Street, Level 31 Houston, TX 77002
Contact Name:	Jim Rexroad
Telephone:	(713) 275-6147
Fax:	(713) 275-6115
Cell:	(832) 748-1060
E-Mail:	jim.Rexroad@macquarie.com
Alternate Contact:	Eric Walther
Telephone:	(916) 444-6666
Fax:	(916) 444-8373
Cell:	(916) 883-8774
E-Mail:	ewalther@sierraresearch.com
Alternate Contact:	Tracey Gilliland
Telephone:	(713) 275-6148
Cell:	(512) 217-3002
E-Mail:	tracey.gilliland@macquarie.com
Engineer:	Derek Fukuda, Air Quality Engineer
Lead Engineer:	Joven Refuerzo, Supervising Air Quality Engineer
Project #:	C-1100751
Application #'s:	C-3953-10-1, C-3953-11-1, C-3953-12-1, C-3953-13-1, and C-3953-14-1
Submitted:	March 3, 2010

Table of Contents

I. PROPOSAL:

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 564 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

While Avenal Power Center, LLC has already received a Determination of Compliance for the above described facility, they are now proposing to limit the annual facility wide NO_X emissions from 288,618 lb/year to 198,840 lb/year, and the annual facility wide CO emissions from 1,205,418 lb/year to 197,928 lb/year. The effect of these limits will be two-fold: one, should the facility operate to its full permitted extent, it will have the lowest annual average permitted emissions of NO_X (0.045 lb-NOx/MWh) and CO (0.044 lb-CO/MWh) of any natural gas fired power plant known to the District; and two, the facility will be limited to less than the 100 tons/year major source thresholds of the federal prevention of significant deterioration program.

The Avenal Energy Project is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

The California Energy Commission (CEC) is the lead agency for this project for the requirements of the California Environmental Quality Act (CEQA).

The facility submitted an application to revise their existing DOC issued under Project C-1080386. This revision consists of limiting the annual facility wide NO_X emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year. The equipment the DOC was issued for in project C-1080386 has not been implemented. All units in this project will be treated as new emissions units.

II. APPLICABLE RULES:

Rule 1080 Stack Monitoring (12/17/92)
Rule 1081 Source Sampling (12/16/93)
Rule 1100 Equipment Breakdown (12/17/92)
Rule 2010 Permits Required (12/17/92)
Rule 2201 New and Modified Stationary Source Review Rule (9/21/06)
Rule 2520 Federally Mandated Operating Permits (6/21/01)
Rule 2540 Acid Rain Program (11/13/97)

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics (6/18/98)
Rule 4001 New Source Performance Standards (4/14/99)
Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units
Subpart GG - Standards of Performance for Stationary Gas Turbines
Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Subpart JJJJ -Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
Subpart KKKK – Standards of Performance for Stationary Combustion Turbines
Rule 4002 National Emissions Standards for Hazardous Air Pollutants (5/20/2004)
Subpart ZZZZ - National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
Rule 4101 Visible Emissions (2/17/05)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4202 Particulate Matter Emission Rate (12/17/92)
Rule 4301 Fuel Burning Equipment (12/17/92)
Rule 4305 Boilers, Steam Generators and Process Heaters – Phase 2 (8/21/03)
Rule 4306 Boilers, Steam Generators and Process Heaters – Phase 3 (10/16/08)
Rule 4351 Boilers, Steam Generators and Process Heaters – Phase 1 (8/21/03)
Rule 4701 Stationary Internal Combustion Engines – Phase 1 (8/21/03)
Rule 4702 Stationary Internal Combustion Engines – Phase 2 (1/18/07)
Rule 4703 Stationary Gas Turbines (9/20/07)
Rule 4801 Sulfur Compounds (12/17/92)
Rule 8011 General Requirements (8/19/04)
Rule 8021 Construction, Demolition, Excavation, Extraction and Other Earthmoving Activities (8/19/04)
Rule 8031 Bulk Materials (8/19/04)
Rule 8041 Carryout and Trackout (8/19/04)
Rule 8051 Open Areas (8/19/04)
Rule 8061 Paved and Unpaved Roads (8/19/04)
Rule 8071 Unpaved Vehicle/Equipment Traffic Areas (9/16/04)
Rule 8081 Agricultural Sources (9/16/04)
California Environmental Quality Act (CEQA)
California Code of Regulations (CCR), Section 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment)
California Health & Safety Code (CH&S), Sections 2423 (Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment) 41700 (Health Risk Analysis), 42301.6 (School Notice), 44300 (Air Toxic “Hot Spots”), and 93115 (Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines)

III. PROJECT LOCATION:

The proposed equipment will be located within NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-035 (See Attachment B). The closest population center is the residential district of Avenal approximately 6 miles to the southwest. The City of Huron is located approximately 8 miles to the north, and the City of Coalinga is located approximately 16 miles to the west.

The site is located northeast of the city of Avenal, in Kings County. The proposed location is not within 1,000' of a K-12 school.

IV. PROCESS DESCRIPTION:

Combined-Cycle Combustion Turbine Generators

Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_X combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_X (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.0 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 2.0 ppmvd @ 15% O_2
SO_X: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf))
PM_{10}: 0.0048 lb/MMBtu (without duct burner firing)
0.0050 lb/MMBtu (with duct burner firing)

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the

HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_X in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_X to nitrogen and water, resulting in a reduced concentration of NO_X in the exhaust gases exiting the stack.

Duct Burners

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_X burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump
Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator
One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

V. EQUIPMENT LISTING:

C-3953-10-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

C-3953-11-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

C-3953-12-1: 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

C-3953-13-1: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-1: 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

i. C-3953-10-1 and C-3953-11-1 (Turbines)

Each CTG will be equipped with a Dry Low NO_X combustor and will exhaust into a Selective Catalytic Reduction [SCR] system with ammonia injection, and a CO catalyst. The use of Dry Low NO_X combustors and a SCR system with ammonia injection can achieve a NO_X emission rate of 2.0 ppmvd @ 15% O_2. CO emissions of 2.0 ppmvd @ 15% O_2 have been demonstrated with the use of an oxidation catalyst [(1)]. And the use of DLN combustors and good combustion practices can achieve VOC emissions of 2.0 ppmvd @ 15% O_2.

Emissions from natural gas-fired turbines include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when combusting natural gas. Virtually all gas turbine NO_X emissions originate as NO. This NO is further oxidized in the exhaust system or later in the atmosphere to form the more stable NO_2 molecule. There are two mechanisms by which NO_X is formed in turbine combustors: 1) the oxidation of atmospheric nitrogen found in the combustion air (thermal NO_X and prompt NO_X), and 2) the conversion of nitrogen chemically bound in the fuel (fuel NO_X).

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and subsequently react to form oxides of nitrogen. Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, H, and NH are oxidized to form NO_X. Prompt NO_X is formed in both fuel-rich flame zones and dry low NO_X (DLN) combustion zones. The contribution of prompt NO_X to overall NO_X emissions is relatively small in conventional near-stoichiometric combustors, but this contribution is an increasingly significant percentage of overall thermal NO_X emissions in DLN combustors. For this reason prompt NO_X becomes an important consideration for DLN combustor designs, and establishes a minimum NO_X level attainable in lean mixtures.

Fuel NO_X is formed when fuels containing nitrogen are burned. Molecular nitrogen, present as N_2 in some natural gas, does not contribute significantly to fuel NO_X formation. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content in the fuel. When compared to thermal NO_X, fuel NO_X is not currently a major contributor to overall NO_X emissions from stationary gas turbines firing natural gas.

The level of NO_X formation in a gas turbine, and hence the NO_X emissions, is unique (by design factors) to each gas turbine model and operating mode. The primary factors that determine the amount of NO_X generated are the combustor design, the types of fuel being burned, ambient conditions, operating cycles, and the power output of the turbine.

[1] Based on information supplied by the CTG manufacturer and information contained in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document.

The design of the combustor is the most important factor influencing the formation of NO_X. Design parameters controlling air/fuel ratio and the introduction of cooling air into the combustor strongly influence thermal NO_X formation. Thermal NO_X formation is primarily a function of flame temperature and residence time. The extent of fuel/air mixing prior to combustion also affects NO_X formation. Simultaneous mixing and combustion results in localized fuel-rich zones that yield high flame temperatures in which substantial thermal NO_X production takes place. Injecting water or steam into a conventional combustor provides a heat sink that effectively reduces peak flame temperature, thereby reducing thermal NO_X formation. Premixing air and fuel at a lean ratio approaching the lean flammability limit (approximately 50% excess air) significantly reduces peak flame temperature, resulting in minimum NO_X formation during combustion. This is known as dry low NO_X (DLN) combustion.

Selective Catalytic Reduction systems selectively reduce NO_X emissions by injecting ammonia (NH_3) into the exhaust gas stream upstream of a catalyst. Nitrogen oxides, NH_3, and O_2 react on the surface of the catalyst to form molecular nitrogen (N_2) and H_2O. SCR is capable of over 90 percent NO_X reduction. Titanium oxide is the SCR catalyst material most commonly used, though vanadium pentoxide, noble metals, or zeolites are also used. The ideal operating temperature for a conventional SCR catalyst is 600 to 750 °F. Exhaust gas temperatures greater than the upper limit (750 °F) will cause NO_X and NH_3 to pass through the catalyst unreacted. Ammonia slip will be limited to 10 ppmvd @ 15% O_2.

Carbon monoxide is formed during the combustion process due to incomplete oxidation of the carbon contained in the fuel. Carbon monoxide formation can be limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air and good air/fuel mixing during combustion minimize CO emissions. Therefore, lowering combustion temperatures and staging combustion to limit NO_X formation can result in increased CO emissions.

Post-combustion CO controls, such as oxidizing catalysts can also be used to reduce CO emissions. An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO_2).

Inlet air temperature and density directly affects turbine performance. The hotter and drier the inlet air temperature, the lower the efficiency and capacity of the turbine. Conversely, colder air improves the efficiency and reduces emissions by reducing the amount of fuel required to achieve the required turbine output. The inlet air cooler will allow the turbine to operate in a more efficient manner than it would without it. The increased efficiency will reduce the amount of fuel necessary to achieve the required power output. The reduction in fuel consumption will result in lower combustion contaminant emissions.

The inlet air filter will remove particulate matter from the combustion air stream, reducing the amount of particulate matter emitted.

The lube oil coalescer will result in the merging together of oil mist to form larger droplets. The larger droplets will return to the oil stream instead of being emitted.

ii. C-3953-12-1 (Boiler)

Emissions from natural gas-fired boilers include NO_X, CO, VOC, PM_{10}, and SO_X.

NO_X is the major pollutant of concern when burning natural gas. NO_X formation is either due to thermal fixation of atmospheric nitrogen in the combustion air (thermal NO_X) or due to conversion of chemically bound nitrogen in the fuel (fuel NO_X). Due to the low fuel nitrogen content of natural gas, nearly all NO_X emissions are thermal NO_X. Formation of thermal NO_X is affected by four furnace zone factors: (1) nitrogen concentration, (2) oxygen concentration, (3) peak temperature, and (4) time of exposure at peak temperature.

The Cleaver Brooks boiler will control the formation of thermal NO_X with an Cleaver Brooks ultra low NO_X burner. Cleaver Brooks burners reduce NO_X by pre-mixing gaseous fuel and combustion air in a region near the burner exit, at a stoichiometry that minimizes Prompt NO_X. This also eliminates the traditional NO_X versus CO tradeoff.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The diesel-fired emergency IC engine (fire pump) will be equipped with a turbocharger, an intercooler/aftercooler, and will be fired on very low (0.0015%) sulfur diesel.

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.[2]

The turbocharger reduces the NO_X emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

The use of low sulfur (0.0015% by weight sulfur maximum) diesel fuel reduces SO_X emissions by approximately 99% from standard diesel fuel.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

The natural gas-fired emergency IC engine (generator) will be equipped with an intercooler/aftercooler, lean burn technology, and will be fired on PUC-Regulated natural gas.

The emission control devices/technologies and their effect on natural gas engine emissions are detailed below.

[2] From "Non-catalytic NO_x Control of Stationary Diesel Engines", by Don Koeberlein, CARB.

The intercooler/aftercooler functions in conjunction with the turbocharger to reduce the inlet air temperature. By reducing the inlet air temperature, the peak combustion temperature is lowered, which reduces the formation of thermal NO_X. NO_X emissions are reduced by approximately 15% with this control technology.

Lean burn technology increases the volume of air in the combustion process and therefore increases the heat capacity of the mixture. This technology also incorporates improved swirl patterns to promote thorough air/fuel mixing. This in turn lowers the combustion temperature and reduces NO_X formation.

VII. GENERAL CALCULATIONS:

The facility has proposed to limit the annual facility wide NO_X emission to 198,840 lb/year, and the annual facility wide CO emission to 197,928 lb/year.

All PM_{10} emissions are assumed to be $PM_{2.5}$ emissions.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- Maximum daily emissions for each CTG for VOC, PM_{10} and SO_X during the commissioning period are estimated assuming twenty-four (24) hours operating while firing at full load.
- The commissioning period will not exceed 408 hours per CTG and the emissions emitted during the commissioning period will accrue towards the maximum annual emissions limit.
- Maximum daily emissions for each CTG for NO_X, CO, and VOC are estimated assuming six (6) hours operating in startup and shutdown mode and eighteen (18) hours operating while firing at full load with operation of the duct burner.
- Maximum daily emissions for each CTG for PM_{10}, SO_X, and NH_3 are estimated assuming twenty-four (24) hours operating while firing at full load with the operation of the duct burner.
- Maximum annual emissions for each CTG for VOC are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was

operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule.

- The facility has proposed a facility wide NO_X emission limit of 198,840 lb/year. To determine the validity of this limit, the maximum annual emissions for each CTG for NO_X are estimated assuming the CTG is operated according to a weekend and weekday hot start scenario. The weekend and weekday hot start scenario results in CTG operation of 547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated NO_X emissions from an individual turbine operating at this scenario (calculated in Section VII.C.2) is not greater than the proposed facility wide NO_X emission limit; however the NO_X emissions from the operation of both turbines according to this scenario are far greater than the proposed facility wide NO_X emission limit. Therefore, the facility wide limit is a valid limit and the NO_X emissions from the turbines will ultimately be restricted by this limit.

- The facility has proposed a facility wide CO emission limit of 197,928 lb/year. To determine the validity of this limit, the maximum annual emissions for each CTG for CO are estimated assuming the CTG is operated according to a weekend shutdown and weekday hot start scenario. The weekend shutdown and weekday hot start scenario results in CTG operation of 624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. This scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, these units cannot be held to this specific operational schedule. The calculated CO emissions from this scenario (calculated in Section VII.C.2) are greater than the proposed facility wide CO emission limit; therefore the facility wide emissions limit is a valid limit and the turbine's CO emissions will ultimately be restricted by this limit.

- Maximum annual emissions for each CTG for PM_{10}, SO_X, and NH_3 are estimated assuming the CTG is operated according to a baseload scenario. The baseload scenario results in CTG operation of 800 hours operating while firing at full load with the duct burner and 7,960 hours operating while firing at full load without the duct burner.

ii. C-3953-12-1 (Boiler)

- External O_2 stack gas concentration is 3%.
- Natural gas F factor is 8,710 dscf/MMBtu (Ref. 40 CFR Part 60, Appendix A, Method 19).
- Heating value of natural gas is 1,013 Btu/scf (per applicant).
- The applicant is proposing a maximum natural gas usage rate of 37.4 MMBtu/hr.
- Maximum SO_X emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

  (1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
  = 0.00282 lb/MMBtu

- Maximum daily and annual emissions for all pollutants are estimated assuming twelve (12) hours per day and 1,248 hours per year operating at full load.[3]
- Operating schedule of 12 hr/day and 1,248 hrs/year.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

- Diesel F factor (adjusted to 60 °F) is 9,051 dscf/MMBtu.
- Density of diesel is 7.1 lb/gal.
- Higher heating value of diesel is 137,000 Btu/scf.
- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

iv. C-3953–14-1 (Natural gas IC engine powering electrical generator)

- EPA F-factor (adjusted to 60 °F) is 8,578 dscf/MMBtu (40 CFR 60 Appendix B)
- Fuel heating value 1,013 Btu/dscf (per applicant)
- Maximum daily SO_X emission factor determined by performing a mass balance assuming a natural gas sulfur content of 1 gr S/100 scf. Calculation shown below.

  (1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
  = 0.00282 lb/MMBtu

- BHP to Btu/hr conversion is 2,542.5 Btu/hp·hr.
- Thermal efficiency of the engine: commonly ≈ 35%.
- Emissions are based on 24 hours per day (maximum emergency use) and 50 hours per year of operation (maximum non-emergency use).

[3] Applicant has indicated that the unit will be used a maximum of 12 hours on a startup day.

B. Emission Factors

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The maximum air contaminant mass emission rates (lb/hr) during the commissioning period estimated by the facility (see Attachment C) for the proposed CTGs are summarized below:

Commissioning Period Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A[5]	N/A[4]

The maximum air contaminant mass emission rates (lb/hr) with and without duct burner firing, concentrations (ppmvd @ 15% O_2), and startup and shutdown emissions rates (lb/hr) provided by the applicant (see Attachment D for applicant proposed emissions) for the proposed CTGs are summarized below.

The emission rates from the turbines and duct burners are calculated below:

Maximum Emission Rate Without Duct Burner Firing:

The worst-case NO_X, PM_{10}, CO, VOC, and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 32 °F. The worst-case SO_X mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG without the duct burner firing:

Emission Rate (lb/hr) = CTG Max Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= 13.55 lb-NO_X/hr

CO Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= 8.35 lb-CO/hr

VOC Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0018 lb-VOC/MMBtu)
= 3.34 lb-VOC/hr

PM_{10} Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.0048 lb-PM_{10}/MMBtu)
= 8.91 lb-PM_{10}/hr

[4] PM_{10} and SO_X emissions during commissioning period are equal to the maximum hourly emissions during baseload facility operation.

SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= 5.23 lb-SO_X/hr

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:
ppm is the emission concentration in ppmvd @ 15% O_2 (10 ppmv)
MW is the molecular weight of the pollutant: (MW_{NH3} = 17 lb/lb-mol)
2.64 x 10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w/o duct burner 1.832 MMscf/hour, as calculated below)
(1,856.3 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 1.832 MMscf/hr
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 1.832 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= 25.31 lb-NH3/hr

Maximum Emission Rates and Concentrations Without Duct Burner Firing (@ 100% Load & 32 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	13.55	8.35	3.34	8.91	5.23	25.31
ppmvd @ 15% O_2 limits	2.0	2.0	1.4	--	--	10.0
lb/MMBtu*	0.0073	0.0045	0.0018	0.0048	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

<u>Maximum Emission Rate With Duct Burner Firing:</u>

The worst-case NO_X, SO_X, PM_{10}, CO, VOC, and NH_3 mass emission rates are when each turbine operates at 100% load and an ambient air inlet temperature of 101 °F. The worst-case SO_X mass emission rate will be determined assuming a natural gas sulfur content of 1 gr S/100 scf. The following equation will be used to calculate the emission rate of the CTG with the duct burner firing:

Emission Rate (lb/hr) = [CTG Max Heat Input + Duct Burner Max Heat Input] (MMBtu/hr) x Emission Factor (lb/MMBtu)

NO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0073 lb-NO_X/MMBtu)
= 17.20 lb-NO_X/hr

CO Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0045 lb-CO/MMBtu)
= **10.60 lb-CO/hr**

VOC Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0025 lb-VOC/MMBtu)
= **5.89 lb-VOC/hr**

PM_{10} Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.0050 lb-PM_{10}/MMBtu)
= **11.78 lb-PM_{10}/hr**

SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.00282 lb-SO_X/MMBtu)
= **6.65 lb-SO_X/hr**

NH3 Emission Rate (lb/hr) = ppm x MW x (2.64×10^{-9}) x ff x HV x FL x [20.9 / (20.9 – O_2%)]

Where:
ppm is the emission concentration in ppmvd @ 15% O_2 (10 ppmv)
MW is the molecular weight of the pollutant: (MW_{NH3} = 17 lb/lb-mol)
2.64×10^{-9} is one over the molar specific volume (lb-mol/MMscf, at 60 °F)
ff is the F-factor for natural gas: (8,578 scf/MMBtu, at 60 °F)
HV is the heating value of natural gas: (1,013 Btu/scf)
FL is the amount of natural gas each turbine can burn in any given hour: (CTG w duct burner 2.326 MMscf/hour, as calculated below)
(2,356.5 MMBtu/hr) ÷ (1,013 MMBtu/MMscf) = 2.326 MMscf/hr
O_2 is the stack oxygen content to which the emission concentrations are corrected: (15%)

NH_3 Emission Rate (lb/hr) = 10 x 17 x (2.64×10^{-9}) (lb-mol/MMscf) x 8,578 (scf/MMBtu) x 1,013 (Btu/scf) x 2.326 (MMscf/hr) x [20.9 / (20.9 – 15.0)]
= **32.13 lb-NH3/hr**

Maximum Emission Rates and Concentrations With Duct Burner Firing (@ 100% Load & 101 °F)						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	17.20	10.60	5.89	11.78	6.65	32.13
ppmvd @ 15% O_2 limits	2.0	2.0	2.0	--	--	10.0
lb/MMBtu*	0.0074	0.0045	0.0025	0.0050	0.00282	--

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Startup and Shutdown Emissions					
	NO_X	CO	VOC	PM_{10}	SO_X
Maximum Mass Emission Rate (per turbine, lb/hr)	160	1,000	16	N/A(6)	N/A[5]
Average Mass Emission Rate (per turbine, lb/hr)	80	900	16	N/A(6)	N/A(6)

ii. C-3953-12-1 (Boiler)

For the new boiler, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant. The SO_X emission factor is calculated as shown below.

Boiler Emission Factors*		
Pollutant	ppmv @ 3%O_2	lb/MMBtu
NO_X	9.0	0.011
CO	50.0	0.037
VOC	10.0	0.0043
PM_{10}	--	0.005
SO_X**	--	0.00282

*Note: lb/MMBtu equivalent of ppmv values @ 3% O_2 as provided by the Applicant
** SO_X emission factor based on the maximum proposed sulfur content of 1 gr/100 dscf.

(1 ~~gr S~~/100 ~~dscf~~ x 1 ~~lb S~~/7000 ~~gr~~ x 64 lb SO_X/32 ~~lb S~~ x 1 ~~scf~~/1013 ~~Btu~~ x 10^6 ~~Btu~~/MMBtu)
= 0.00282 lb/MMBtu

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

For the new emergency diesel-fired IC engine powering a fire water pump, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the sulfur content in the diesel fuel (0.0015% sulfur).

Diesel-fired IC Engine Emission Factors		
	g/hp·hr	Source
NO_X	3.4	Engine Manufacturer
CO	0.447	Engine Manufacturer
VOC	0.38	Engine Manufacturer
PM_{10}	0.059	Engine Manufacturer
*SO_X	0.005	Mass Balance Equation Below

[5] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions during baseload facility operation.

$$^{*}0.0015\% \times \frac{7.1\,lb \cdot fuel}{gallon} \times \frac{2\,lb \cdot SO_2}{1\,lb \cdot S} \times \frac{1\,gal}{137{,}000\,Btu} \times \frac{1\,hp\,input}{0.35\,hp\,out} \times \frac{2{,}542.5\,Btu}{hp \cdot hr} \times \frac{453.6\,g}{lb} = 0.005\,\frac{g\,SOx}{hp \cdot hr}$$

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

For the new emergency natural gas-fired IC engine powering an electrical generator, the emissions factors for NO_X, CO, VOC, and PM_{10} are provided by the applicant and are guaranteed by the engine manufacturer. The SO_X emission factor is calculated using the fuel sulfur content from District Policy APR 1720.

Natural Gas-fired IC Engine Emission Factors		
	g/hp·hr	Source
NO_X	1.0	Engine Manufacturer
CO	0.6	Engine Manufacturer
VOC	0.33	Engine Manufacturer
PM_{10}	0.034	Engine Manufacturer
**SO_X	0.0094	Mass Balance Equation Below

**SO_X is calculated as follows:

$$0.00285\,\frac{lb-SO_x}{MMBtu} \times \frac{1\,MMBtu}{1{,}000{,}000\,Btu} \times \frac{2{,}542.5\,Btu}{bhp-hr} \times \frac{1\,bhp\,input}{0.35\,bhp\,out} \times \frac{453.6\,g}{lb} = 0.0094\,\frac{g-SO_x}{bhp-hr}$$

C. Calculations

1. Pre-Project Potential to Emit (PE1)

Section 3.26 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. Since this is a brand new facility, the pre-project potential to emit (PE1) for all the emissions units associated with this project is equal to zero.

2. Post Project Potential to Emit (PE2):

i. C-3953-10-1 and C-3953-11-1 (Turbines)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_X, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit					
	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO_X	160	17.20	13.55	13.55	240.00
CO	1,000	10.60	8.35	8.35	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM_{10}	N/A(6)	11.78	8.91	8.91	23.56
SO_X	N/A(7)	6.65	5.23	5.23	13.30
NH_3	N/A	32.13	25.31	25.31	64.26

b. Maximum Daily PE

Maximum daily emissions for NO_X, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for PM_{10}, SO_X, and NH3 are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for PM_{10}, SO_X, and NH3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

Maximum Daily Potential to Emit (w/ Startup and Shutdown)				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (101° F)	Emissions Rate @ 100% Load without duct burner (32° F)	DEL (per CTG)
NO_X	80 lb/hr (avg)	17.20 lb/hr	13.03 lb/hr	789.6 lb/day
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	5,590.8 lb/day
VOC	16 lb/hr (avg)	5.89 lb/hr	3.34 lb/hr	202.0 lb/day
PM_{10}	N/A(7)	11.78 lb/hr	8.91 lb/hr	282.7 lb/day
SO_X	N/A(7)	6.65 lb/hr	5.23 lb/hr	159.6 lb/day
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	771.1 lb/day

[6] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

c. Maximum Annual PE

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_X emission factors used to calculate the annual potential emissions will be based on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

SO_X EF = (0.36 ~~gr S~~/100 ~~dscf~~) x (1 ~~lb S~~/7000 ~~gr~~) x (64 lb SO_X/32 ~~lb S~~) x (1 ~~scf~~/1013 ~~Btu~~) x (10^6 ~~Btu~~/MMBtu)
= 0.001 lb-SO_X/MMBtu

<u>CTG w/o Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 1.86 lb-SO_X/hr

<u>CTG w/ Duct Burner Firing:</u>
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= 2.36 lb-SO_X/hr

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

<u>Scenario 1) Weekend and Weekday Hot Start:</u>

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	**143,951 lb/year**
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	557,033 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	**34,489 lb/year**
PM_{10}	N/A(7)	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO_X	N/A(7)	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

<u>Scenario 2) Weekend Shutdown and Weekday Hot Start:</u>

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 2) Weekend Shutdown and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	601,810 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM_{10}	N/A(7)	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO_X	N/A(7)	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Baseload Scenario*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	74,946 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,777 lb/year
PM_{10}	N/A(7)	11.27 lb/hr	9.00 lb/hr	**80,656 lb/year**
SO_X	N/A(7)	2.36 lb/hr	1.86 lb/hr	**16,694 lb/year**
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	**219,972 lb/year**

* Emission factors were taken from Table 6.2-1.1 in the DOC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit		
	Annual PE (per CTG)	Scenario
NO_X	143,951 lb/year	Scenario 1
CO	197,928 lb/year	Facility Wide Limit
VOC	34,489 lb/year	Scenario 2
PM_{10}	80,656 lb/year	Scenario 3
SO_X	16,694 lb/year	Scenario 3
NH_3	219,972 lb/year	Scenario 3

d. *Maximum Quarterly PE*

Maximum quarterly emissions for each unit will be determined by dividing the maximum annual emissions into 4 quarters:

Maximum Quarterly Potential to Emit						
	NO_X	CO	VOC	PM_{10}	SO_X	NH_3
1st Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
2nd Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
3rd Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993
4th Quarter	35,987.75	49,482	8,622.25	20,164	4,173.5	54,993

ii. C-3953-12-1 (Boiler)

The potential to emit for the boiler is calculated as follows, and summarized in the table below.

PE_{NOx} = (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.41 lb NO_X/hr**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **4.9 lb NO_X/day**

= (0.011 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **513 lb NO_X/year**

= (513 lb NO_X/year) ÷ (4 qtr/year)
= **128 lb NO_X/qtr**

PE_{CO} = (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **1.38 lb CO/hr**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **16.6 lb CO/day**

= (0.037 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **1,727 lb CO/year**

= (1,727 lb CO/year) ∗ (4 qtr/year)
= **432 lb CO/qtr**

PE_{VOC} = (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.16 lb VOC/hr**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.9 lb VOC/day**

= (0.0043 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **201 lb VOC/year**

= (201 lb/year) ∗ (4 qtr/year)
= **50 lb VOC/qtr**

PE_{PM10} = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb PM_{10}/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb PM_{10}/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb PM_{10}/year**

= (233 lb/year) ∗ (4 qtr/year)
= **58 lb PM_{10}/qtr**

PE_{SOx} = (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.11 lb SO_X/hr**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **1.3 lb SO_X/day**

= (0.00282 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **132 lb SO_X/year**

= (132 lb/year) ∗ (4 qtr/year)
= **33 lb SO_X/qtr**

Post Project Potential to Emit (PE2) (C-3953-12-1)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	0.41	4.9	128	513
CO	1.38	16.6	432	1,727
VOC	0.16	1.9	50	201
PM_{10}	0.19	2.2	58	233
SO_X	0.11	1.3	33	132

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{NOx} = (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **2.16 lb NO_X/hr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **51.8 lb NO_X/day**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **27 lb NO_X/qtr**

= (3.4 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **108 lb NO_X/year**

PE_{CO} = (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.28 lb CO/hr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb ∗ (24 hr/day)
= **6.8 lb CO/day**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **4 lb CO/qtr**

= (0.447 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **14 lb CO/year**

PE_{VOC} = (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.24 lb VOC/hr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **5.8 lb VOC/day**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **3 lb VOC/qtr**

= (0.38 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **12 lb VOC/year**

PE_{PM10} = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb PM_{10}/year**

PE_{SOx} = (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.00 lb SO_X/hr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.1 lb SO_X/day**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.005 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **0 lb SO_X/year**

Post Project Potential to Emit (PE2) (C-3953-13-1)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	2.16	51.8	27	108
CO	0.28	6.8	4	14
VOC	0.24	5.8	3	12
PM_{10}	0.04	0.9	0.5	2
SO_X	0.00	0.1	0	0

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

The emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

PE_{NOx} = (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **1.90 lb NO_X/hr**

= (1.0 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **45.5 lb NO_X/day**

$= (1.0 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr})$
$= \mathbf{24 \text{ lb } NO_X\text{/qtr}}$

$= (1.0 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year})$
$= \mathbf{95 \text{ lb } NO_X\text{/year}}$

$PE_{CO} = (0.6 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb})$
$= \mathbf{1.14 \text{ lb CO/hr}}$

$= (0.6 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day})$
$= \mathbf{27.3 \text{ lb CO/day}}$

$= (0.6 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr})$
$= \mathbf{14 \text{ lb CO/qtr}}$

$= (0.6 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year})$
$= \mathbf{57 \text{ lb CO/year}}$

$PE_{VOC} = (0.33 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb})$
$= \mathbf{0.63 \text{ lb VOC/hr}}$

$= (0.33 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day})$
$= \mathbf{15.0 \text{ lb VOC/day}}$

$= (0.33 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr})$
$= \mathbf{8 \text{ lb VOC/qtr}}$

$= (0.33 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year})$
$= \mathbf{31 \text{ lb VOC/year}}$

$PE_{PM10} = (0.034 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb})$
$= \mathbf{0.06 \text{ lb } PM_{10}\text{/hr}}$

$= (0.034 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (24 \text{ hr/day})$
$= \mathbf{1.5 \text{ lb } PM_{10}\text{/day}}$

$= (0.034 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (12.5 \text{ hr/qtr})$
$= \mathbf{1 \text{ lb } PM_{10}\text{/qtr}}$

$= (0.034 \text{ g/hp·hr}) * (860 \text{ hp}) \div (453.6 \text{ g/lb}) * (50 \text{ hr/year})$
$= \mathbf{3 \text{ lb } PM_{10}\text{/year}}$

PE_{SOx} = (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.02 lb SO_X/hr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.4 lb SO_X/day**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0 lb SO_X/qtr**

= (0.0094 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1 lb SO_X/year**

Post Project Potential to Emit (PE2) (C-3953-14-1)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
NO_X	1.90	45.5	24	95
CO	1.14	27.3	14	57
VOC	0.63	15.0	8	31
PM_{10}	0.06	1.5	1	3
SO_X	0.02	0.4	0	1

3. Pre-Project Stationary Source Potential to Emit (SSPE1)

Pursuant to Section 4.9 of District Rule 2201, the Pre-project Stationary Source Potential to Emit (SSPE1) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. Since this is a new facility, there are no valid ATCs, PTOs, or ERCs at the Stationary Source; therefore, the SSPE1 will be equal to zero.

4. Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site. The District is issuing a DOC for this project and not individual ATC's. Therefore, the SSPE2 will be determined by summing the potential emissions from the units included in the DOC.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)							
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3	$PM_{2.5}$ ***
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972	80,656
C-3953-11-1			34,489	80,656	16,694	219,972	80,656
C-3953-12-1			201	233	132	0	233
C-3953-13-1			12	2	0	0	2
C-3953-14-1			31	3	1	0	3
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,222**	**161,550**	**33,521**	**439,944**	**161,550**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.
*** All PM_{10} emissions are $PM_{2.5}$.

5. Major Source Determination

Pursuant to Section 3.24 of District Rule 2201, a major source is a stationary source with post-project emissions or a Post-project Stationary Source Potential to Emit (SSPE2), equal to or exceeding one or more of the following threshold values.

Major Source Determination						
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)	$PM_{2.5}$ (lb/year)
Post-project SSPE (SSPE2)	198,840	197,928	69,222	161,550	33,521	161,550
Major Source Threshold	50,000	200,000	50,000	140,000	140,000	200,000
Major Source?	Yes	No	Yes	Yes	No	No

6. Annual Baseline Emissions (BE)

Per District Rule 2201, Section 3.7, the baseline emissions, for a given pollutant, shall be equal to the pre-project potential to emit for:

- Any emission unit located at a non-major source,
- Any highly utilized emission unit, located at a major source,
- Any fully-offset emission unit, located at a major source, or
- Any clean emission unit located at a major source

otherwise,

BE = Historic Actual Emissions (HAE), calculated pursuant to Section 3.22 of District Rule 2201

As shown above, this facility will be a major source for NO_X, VOC, and PM_{10} emissions after this project. However, since the units in this project are all new emissions units, there are no historical actual emissions or pre-project potential to emit. Therefore, the baseline NO_X, CO, VOC, PM_{10} and SO_X emissions will be set equal to the following:

BE = 0 lb/year

7. Major Modification

Major Modification is defined in 40 CFR Part 51.165 as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under the Act.*"

Since this is a new facility, this project cannot be considered a Major Modification.

8. Federal Major Modification

As shown above, this project does not constitute a Major Modification. Therefore, in accordance with District Rule 2201, Section 3.17, this project does not constitute a Federal Major Modification and no further discussion is required.

VIII. COMPLIANCE:

Rule 1080 Stack Monitoring

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEMs), and specifies performance standards for the equipment and administrative requirements for recordkeeping, reporting, and notification.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The two CTGs will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

- Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

- Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

- The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

ii. C-3953-12-1 (Boiler)

The boiler will be equipped with operational CEMs for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

- {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

- {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

- {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

- {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

- {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

Rule 1081 Source Sampling

This Rule requires adequate and safe facilities for use in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

- Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

- Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

- Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001]

- Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

- Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

ii. C-3953-12-1 (Boiler)

The requirements of this Rule will be included in the operating permit. Compliance with this Rule is anticipated.

Proposed Rule 1081 Conditions:

- The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Rule 1100 Equipment Breakdown

This Rule defines a breakdown condition and the procedures to follow if one occurs. The corrective action, the issuance of an emergency variance, and the reporting requirements are also specified.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The requirements of this Rule will be included in the operating permits. Compliance with this Rule is anticipated.

Proposed Rule 1100 Conditions:

- Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

- The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

Rule 2010 Permits Required

This Rule requires any person building, altering, or replacing any operation, article, machine, equipment, or other contrivance, the use of which may cause the issuance of air contaminants, to first obtain authorization from the District in the form of an ATC. By the submission of a DOC application, Avenal Power Center, LLC is complying with the requirements of this Rule.

Rule 2201 New and Modified Stationary Source Review Rule

A. BACT:

1. BACT Applicability

BACT requirements are triggered on a pollutant-by-pollutant basis and on an emissions unit-by-emissions unit basis for the following*:

a. Any new emissions unit with a potential to emit exceeding two pounds per day,
b. The relocation from one Stationary Source to another of an existing emissions unit with a potential to emit exceeding two pounds per day,
c. Modifications to an existing emissions unit with a valid Permit to Operate resulting in an AIPE exceeding two pounds per day, and/or
d. Any new or modified emissions unit, in a stationary source project, which results in a Major Modification.

*Except for CO emissions from a new or modified emissions unit at a Stationary Source with an SSPE2 of less than 200,000 pounds per year of CO.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

As seen in Section VII.C.2.b of this evaluation, the applicant is proposing to install two new combustion turbine generators with PEs greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, PM_{10}, and SO_X criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

The PE of ammonia is greater than two pounds per day for the two CTGs. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NO_X. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

ii. C-3953-12-1 (Boiler)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new boiler with a PE greater than 2 lb/day for NO_X, CO, VOC, PM_{10}, and SO_X. BACT is triggered for NO_X, VOC, and PM_{10} criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new diesel-fired IC engine (fire pump) with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

As seen in Section VII.C.2 of this evaluation, the applicant is proposing to install a new natural gas-fired IC engine (generator) with a PE greater than 2 lb/day for NO_X, CO, and VOC. BACT is triggered for NO_X, and VOC criteria pollutants since the PEs are greater than 2 lbs/day. Since the SSPE2 for CO is not greater than 200,000 lbs/year, BACT is not triggered for CO emissions.

2. BACT Guidance

The District BACT Clearinghouse was created to assist applicants in selecting appropriate control technology for new and modified sources, and to assist the District staff in conducting the necessary BACT analysis. The Clearinghouse will include, for various class and category of sources, available control technologies and methods that meet one or more of the following conditions:

- Have been achieved in practice for such emissions unit and class of source; or
- Are contained in any SIP approved by the EPA for such emissions unit category and class of source; or
- Are any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found to be technologically feasible for such class or category of sources or for a specific source.

Attachment E will include the BACT Guidelines from the BACT Clearinghouse applicable to the new emissions units associated with this project.

i. C-3953-10-1 and C-3953-11-1 (Turbines)

BACT Guideline 3.4.2 is applicable to the two combustion turbine generator installations [Gas Fired Turbine = or > 50 MW, Uniform Load, with Heat Recovery].

ii. C-3953-12-1 (Boiler)

BACT Guideline 1.1.2 is applicable to the 37.4 MMBtu/hr boiler. [Boiler - > 20 MMBtu/hr, Natural gas-fired, base-loaded or with small load swings.]

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

BACT Guideline 3.1.4, applies to the diesel-fired emergency IC engine powering a fire pump. [Emergency Diesel I.C. Engine Driving a Fire Pump]

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

BACT Guideline 3.1.8, applies to the natural gas-fired emergency IC engine powering an electrical generator. [Emergency Gas-Fired I.C. Engine > or = 250 hp, Lean Burn]

3. Top-Down Best Available Control Technology (BACT) Analysis

Per Permit Services Policies and Procedures for BACT, a Top-Down BACT analysis shall be performed as a part of the application review for each application subject to the BACT requirements pursuant to the District's NSR Rule.

For Permit Units C-3953-10-1 and -11-1 see Attachment F.

For Permit Unit C-3953-12-1 see Attachment F.

For Permit Unit C-3953-13-1 see Attachment F.

For Permit Unit C-3953-14-1 see Attachment F.

4. BACT Summary:

i. C-3953-10-1 and C-3953-11-1 (Turbines)

BACT has been satisfied by the following:

NO_X: 2.0 ppmv @ 15% O_2 (1-hour rolling average, except during startup/shutdown) with Dry Low NO_X Combustors, SCR with ammonia injection and natural gas fuel.

VOC: 1.5 ppmv @ 15% O_2 (without duct burner firing; 3-hour rolling average).
2.0 ppmv @ 15% O_2 (with duct burner firing; 3-hr rolling average).

PM_{10}: Air inlet filter cooler, lube oil vent coalescer, and natural gas fuel

SO_X: PUC regulated natural gas with a sulfur content of 1.0 gr/100 scf or less

ii. C-3953-12-1 (Boiler)

BACT has been satisfied by the following:

NO_X: 9.0 ppmv @ 15% O_2 with Ultra Low NO_X burners and natural gas fuel.

VOC: Natural gas fuel.

PM_{10}: Natural gas fuel.

SO_X: Natural gas fuel.

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

BACT has been satisfied by the following:

NO_X: Certified NO_X emissions of 6.9 g/hp·hr or less

VOC: No VOC control. Any add on VOC control device would void the Underwriters Laboratory (UL) certification.

iv. C-3953-14-1 (Natural gas IC engine powering electrical generator)

BACT has been satisfied by the following:

NO_X: = or < 1.0 g/bhp-hr (lean burn natural gas fired engine, or equal)

VOC: 90% control efficiency (oxidation catalyst, or equal)

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

C. Offsets:

1. Offset Applicability:

Pursuant to Section 4.5.3, offset requirements shall be triggered on a pollutant by pollutant basis and shall be required if the Post-project Stationary Source Potential to Emit (SSPE2) equals to or exceeds emissions of 20,000 lbs/year for NO_X and VOC, 200,000 lbs/year for CO, 54,750 lbs/year for SO_X and 29,200 lbs/year for PM_{10}. As seen in the table below, the facility's SSPE2 is greater than the offset thresholds for NO_X, CO, VOC, PM_{10}, and SO_X emissions. Therefore, offset calculations are necessary.

Offset Determination					
	NO_X (lb/year)	CO (lb/year)	VOC (lb/year)	PM_{10} (lb/year)	SO_X (lb/year)
Post-project SSPE (SSPE2)	198,840	197,928	69,222	161,550	33,521
Offset Threshold	20,000	200,000	20,000	29,200	54,750
Offsets Required?	Yes	No	Yes	Yes	No

2. Quantity of Offsets Required:

Per District Rule 2201, Section 4.6.1, emission offsets shall not be required for increases in carbon monoxide in attainment areas if the applicant demonstrates to the satisfaction of the APCO, that the Ambient Air Quality Standards are not violated in the areas to be affected, and such emissions will be consistent with Reasonable Further Progress, and will not cause or contribute to a violation of Ambient Air Quality Standards.

Per Sections 4.7.2 and 4.7.3, the quantity of offsets in pounds per year for NO_X, VOC, and PM_{10} is calculated as follows for sources with an SSPE1 less than the offset threshold levels before implementing the project being evaluated.

Offsets Required (lb/year) = ([SSPE2 – Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

Where,
SSPE2 = Post Project Facility Potential to Emit, (lb/year)
ICCE = Increase in Cargo Carrier Emissions, (lb/year)
DOR = Distance Offset Ratio, determined pursuant to Section 4.8

Per Section 4.6.2, emergency equipment that is used exclusively as emergency standby equipment for electrical power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year of non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power, is exempt from providing emission offsets. Therefore, permit units C-3953-13-1 and C-3953-14-1 will be exempt from providing offsets and the emissions associated with these permit units contributing to the SSPE2 should be removed prior to calculating actual offset amounts.

Offset = ([SSPE2 – Emergency Equipment - Offset Threshold] + ICCE) x DOR, for all new or modified emissions units in the project,

<u>NO_X Offset Calculations:</u>

The facility has proposed to provide the same quarterly offsets that were required to be provided in the facility's initial project (C-1080386). The reason for this request is to enable the facility to preserve full flexibility to operate the facility at the previously permitted rates during any calendar quarter, provided the new annual emission limits are not exceeded. The facility is required to maintain a 12 month rolling calculation of their NO_X and CO emissions; therefore compliance with this quarterly limit will be enforceable. The quarterly offsets from project C-1080386 are shown below.

Quarterly Emissions to be Offset (Project C-1080386)

Annual Offsets = 268,415 lb/year * DOR

Quarterly Offsets $_{1st\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{2nd\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{3rd\ Qtr}$ = 67,103.75 lbs of NO_X * DOR
Quarterly Offsets $_{4th\ Qtr}$ = 67,103.75 lbs of NO_X * DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of NO_X ERC's that need to be withdrawn is:

Offsets Required = 268,415 lb-NO_X/year x 1.5
Offsets Required = 402,623 lb-NO_X/year

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
NO_X	100,655	100,656	100,656	100,656	402,623

The applicant has stated that the facility plans to use ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 to offset the increases in NO_X emissions associated with this project. The above Certificates have available quarterly NO_X credits as follows:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-899-2	2,243	2,243	2,243	2,243	**8,972**
ERC #C-902-2	13,879	6,131	1,086	8,539	**29,635**
ERC #N-720-2	0	9	1,255	437	**1,701**
ERC #N-722-2	0	1,166	88,317	1,422	**90,905**
ERC #N-726-2	0	0	4,728	0	**4,728**
ERC #N-728-2	10,542	3,731	2,487	5,171	**21,931**
ERC #S-2814-2	6,121	13,869	18,914	11,461	**50,365**
ERC #S-2321-2*	51,000	51,000	51,000	51,000	**204,000**
Total	**83,784**	**78,147**	**170,027**	**80,269**	**412,227**

*ERC certificate split from this ERC.

Project NO_X offset requirements

The applicant states that NO_X ERC certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2 will be utilized to supply the NO_X offset requirements.

Per Rule 2201 Section 4.13.8, Actual Emission Reductions (i.e. ERCs) that occurred from April through November (i.e. 2nd and 3rd Quarter), inclusive, may be used to offset increases in NO_X or VOC during any period of the year. Since 3rd quarter NO_X ERCs will be used to offset NO_X emissions, the above applies to the NO_X ERCs.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
NO_X Emissions to be offset: (at a 1.5:1 DOR):	100,655	100,656	100,656	100,656
Available ERCs from certificates C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, and S-2321-2*:	83,784	78,147	170,027	80,269
3rd qtr. ERCs applied to 1st qtr. ERCs:	16,871	0	-16,871	0
3rd qtr. ERCs applied to 2nd qtr. ERCs:	0	22,509	-22,509	0
3rd qtr. ERCs applied to 4th qtr. ERCs:	0	0	-20,387	20,387
Remaining ERCs from certificates S-2321-2:	0	0	9,604	0
Remaining NO_X emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly NO_X emissions increases associated with this project.

VOC Offset Calculations:

VOC SSPE2 = 69,222 lb/year
C-3953-13-1 (VOC) = 12 lb/year
C-3953-14-1 (VOC) = 31 lb/year
VOC offset threshold = 20,000 lb/year

Offsets = [69,222 – (12) – (31) – 20,000]
= 49,179 lb/year ∗ DOR

Calculating the appropriate quarterly emissions to be offset is as follows:

Offsets = (49,179 lb/year ÷ 4 qtr/year) ∗ DOR
= 12,294.75 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ DOR

Pursuant to Section 4.8 of District Rule 2201, the distance offset ratio shall be 1.0:1 if the emission offsets originated at the same Stationary Source as the new or modified emissions unit; 1.2.1 for Non-Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; 1.3.1 for Major Sources if the emission offsets originated within 15 miles of the new or modified emissions unit's Stationary Source; or 1.5:1 if the emission offsets originated 15 miles or more from the new or modified emissions unit's Stationary Source.

Assuming a worst case offset ratio of 1.5:1, the amount of VOC ERC's that need to be withdrawn is:

$PE_{1st\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{2nd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{3rd\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs
$PE_{4th\ Qtr}$ = 12,294.75 lbs of VOC ∗ 1.5 = 18,442 lbs

Calculating the appropriate quarterly emissions to be offset is as follows:

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
VOC	18,442	18,442	18,442	18,442	73,769

The applicant has stated that the facility plans to use ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 to offset the increases in VOC emissions associated with this project. The above Certificates have available quarterly VOC credits as follows:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-897-1	45	45	45	45	**180**
ERC #C-898-1	5,480	6,496	4,696	6,616	**23,288**
ERC #N-724-1	0	0	241	0	**241**
ERC #N-725-1	0	0	709	0	**709**
ERC #S-2812-1	31,432	31,424	31,417	31,417	**125,690**
ERC #S-2813-1	12,500	12,500	12,500	12,500	**50,000**
ERC #S-2817-1	11,431	11,424	11,417	11,417	**45,689**
Total	**60,887**	**61,887**	**61,022**	**61,991**	**245,787**

Project VOC offset requirements

The applicant states that NO_X ERC certificates C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, and S-2817-1 will be utilized to supply the VOC offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
VOC Emissions to be offset: (at a 1.5:1 DOR):	18,442	18,442	18,442	18,442
Available ERCs from certificates C-897-1, C-898-1, N-724-1, N-725-1,	5,525	6,541	5,691	6,661
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
VOC Emissions to be offset: (at a 1.5:1 DOR):	12,917	11,901	12,751	11,781
Available ERCs from certificates S-2812-1, S-2813-1, and S-2817-1	55,363	55,348	55,334	55,334
Remaining ERCs from certificates S-2812-1, S-2813-1, and S-2817-1:	42,446	43,447	42,583	43,553
Remaining VOC emissions to be offset (at a 1.5:1 DOR):	0	0	0	0

As seen above, the facility has sufficient credits to fully offset the quarterly VOC emissions increases associated with this project.

PM_{10} Offset Calculations:

PM_{10} SSPE2 = 161,550 lb/year
C-3953-13-1 (PM_{10}) = 2 lb/year
C-3953-14-1 (PM_{10}) = 3 lb/year
PM_{10} Offset threshold = 29,200 lb/year

Offsets = [(161,550 – (2) – (3) - 29,200 + 0) x DOR]
= 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Offsets = (132,345 lb/year ÷ 4 qtr/year) ∗ DOR
= 33,086 lb/qtr ∗ offset ratio

$PE_{1st\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{2nd\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{3rd\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR
$PE_{4th\ Qtr}$ = 33,086 lbs of PM_{10} ∗ DOR

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

Quantity of Offsets Required					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	Total (lb/year)
PM_{10}	49,630	49,629	49,629	49,630	198,518

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

Offset Proposal					
	1st Quarter (lb/qtr)	2nd Quarter (lb/qtr)	3rd Quarter (lb/qtr)	4th Quarter (lb/qtr)	**Total (lb/year)**
ERC #C-896-4	80	80	80	80	**320**
ERC #N-721-4	0	0	3,215	0	**3,215**
ERC #N-723-4	0	0	985	0	**985**
ERC #S-2791-5	92,179	23,666	69,157	96,288	**281,290**
ERC #S-2790-5	12,862	491	0	8,499	**21,852**
ERC #S-2789-5	6	14	12	8	**40**
ERC #S-2788-5	5	7	3	6	**21**
ERC #N-762-5	21,000	21,000	21,000	21,000	**84,000**
Total	**126,131**	**45,256**	**94,449**	**125,877**	**391,723**

Project PM_{10} offset requirements

The applicant states either PM_{10} ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} at an interpollutant ratio of 1.0:1 (see Attachment H). Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_X ERCs are being used to offset PM_{10} emissions, the above applies to the SO_X ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM_{10} emissions to be offset with SO_X ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1st qtr. ERCs applied to 2nd qtr. ERCs:	-4,371	4,371	0	0
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM_{10} emissions increases associated with this project.

<u>Offset Conditions:</u>

The following conditions will ensure compliance with the offset requirements of this rule:

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

- Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

- ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

D. Public Notification:

1. Applicability

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Major Modifications
- New emission units with a PE > 100 lb/day of any one pollutant (IPE Notifications)
- Any project which results in the offset thresholds being surpassed (Offset Threshold Notification), and/or
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant. (SSIPE Notice)

a. New Major Source Notice Determination

New Major Sources are new facilities, which are also Major Sources.

As shown in Section VII.C.6 above, the SSPE2 is greater than the Major Source threshold for NO_X, VOC, and PM_{10}. Therefore, public noticing is required for this project for new Major Source purposes because this facility is becoming a new Major Source.

b. Major Modification

As demonstrated in Section VII.C.7 above, this project does not constitute a Major Modification; therefore, public noticing for Major Modification purposes is not required.

c. PE Notification

Applications which include a new emissions unit with a Potential to Emit greater than 100 pounds during any one day for any pollutant will trigger public noticing requirements. The potential to emit for each unit is summarized in the table below.

Post-Project Potential to Emit						
Permit Unit	NO_X (lb/day)	CO (lb/day)	VOC (lb/day)	PM_{10} (lb/day)	SO_X (lb/day)	NH_3 (lb/day)
C-3953-10-1	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-11-1	789.6	5,590.8	202.0	282.7	159.6	771.1
C-3953-12-1	4.9	16.6	1.9	2.2	1.3	0
C-3953-13-1	51.8	6.8	5.8	0.9	0.1	0
C-3953-14-1	45.5	27.3	15.0	1.5	0.4	0
Threshold (lb/day)	**100**	**100**	**100**	**100**	**100**	**100**
Notification Required?	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

According to the table above, permit units C-3953-10-1 and -11-1 will each have a Potential to Emit greater than 100 lb/day for NO_X, CO, VOC, PM_{10}, SO_X, or NH_3 emissions. Therefore, public noticing will be required for PE > 100 lbs/day purposes.

e. Offset Threshold

Public notification is required if the Pre-Project Stationary Source Potential to Emit (SSPE1) is increased from a level below the offset threshold to a level exceeding the emissions offset threshold, for any pollutant.

The following table compares the SSPE1 with the SSPE2 in order to determine if any offset thresholds have been surpassed with this project.

Offset Threshold				
Pollutant	SSPE1 (lb/year)	SSPE2 (lb/year)	Offset Threshold	Public Notice Required?
NO_X	0	198,840	20,000 lb/year	Yes
CO	0	197,928	200,000 lb/year	No
VOC	0	69,222	20,000 lb/year	Yes
PM_{10}	0	161,550	29,200 lb/year	Yes
SO_X	0	33,521	54,750 lb/year	No

As detailed above, offset thresholds were surpassed for NO_X, VOC, and PM_{10} emissions with this project; therefore public noticing is required for offset purposes.

f. SSIPE Notification

Public notification is required for any permitting action that results in a Stationary Source Increase in Permitted Emissions (SSIPE) of more than 20,000 lb/year of any affected pollutant. According to District policy, the SSIPE is calculated as the Post Project Stationary Source Potential to Emit (SSPE2) minus the Pre-Project Stationary

Source Potential to Emit (SSPE1), i.e. SSIPE = SSPE2 – SSPE1. The values for SSPE2 and SSPE1 are calculated according to Rule 2201, Sections 4.9 and 4.10, respectively. The SSIPE is compared to the SSIPE Public Notice thresholds in the following table:

SSIPE Notification					
Pollutant	**SSPE2 (lb/year)**	**SSPE1 (lb/year)**	**SSIPE (lb/year)**	**SSIPE Public Notice Threshold**	**Public Notice Required?**
NO_X	198,840	0	198,840	20,000 lb/year	Yes
CO	197,928	0	197,928	20,000 lb/year	Yes
VOC	69,222	0	69,222	20,000 lb/year	Yes
PM_{10}	161,550	0	161,550	20,000 lb/year	Yes
SO_X	33,521	0	33,521	20,000 lb/year	Yes

As demonstrated above, the SSIPE's for NO_X, CO, VOC, PM_{10} and SO_X emissions were greater than 20,000 lb/year; therefore public noticing for SSIPE purposes is required.

2. Public Notice Requirements

Section 5.5 details the actions taken by the District when pubic noticing is triggered according to the application types above. Since public noticing requirements are triggered for this project (i.e. New Major Source, PE's > 100 lbs/day, offset thresholds being exceeded, and SSIPEs greater than 20,000 lbs/year), the District shall public notice this project according to the requirements of Section 5.5.

E. Daily Emission Limits:

Daily emissions limitations (DELs) and other enforceable conditions are required by Section 3.15 to restrict a unit's maximum daily emissions, to a level at or below the emissions associated with the maximum design capacity.

Proposed Rule 2201 (DEL) Conditions:

The following condition will be included to demonstrate compliance with facility wide annual NO_X and CO emissions limits.

- Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

i. C-3953-10-1 and C-3953-11-1 (Turbines)

For the turbines, the DELs for NO_X, CO, VOC, PM_{10}, SO_X, and NH_3 will consist of lb/day and/or emission factors.

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

- Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

- Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

- The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

- Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

In addition to the daily emissions limits specified above, the following conditions will also be included to ensure continued compliance for the proposed turbines:

- Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

- Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

ii. C-3953-12-1 (Boiler)

The DELs for the boiler will consist of lb/MMBtu and ppmv emissions limits. This will be sufficient to establish a maximum daily potential to emit based on the maximum daily fuel use limit.

- Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00282 lb/MMBtu. [District Rules 2201, 4305, 4306, and 4351]

In addition the following permit conditions will appear on the permit:

- {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

iii. C-3953-13-1 (Diesel IC engine fire pump)

For the emergency IC engine powering a fire pump, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

For the emergency IC engine powering a generator, the DELs will be stated in the form of emission factors, the maximum engine horsepower rating, and the maximum operational time of 24 hours per day.

- Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

F. Compliance Certification:

Section 4.15.2 of this Rule requires the owner of a new major source or a source undergoing a major modification to demonstrate to the satisfaction of the District that all other major sources owned by such person and operating in California are in compliance with all applicable emission limitations and standards. As discussed above, this facility is a new major source; therefore this requirement is applicable. Included in Attachment I is Avenal Power Center's certification for the Avenal Energy Project.

G. Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether the operation of the proposed equipment will cause or make worse a violation of an air quality standard. The Technical Services Division of the SJVAPCD conducted the required analysis. Refer to Attachment G of this document for the AQIA summary sheet.

The proposed location is in an attainment area for NO_X, CO, and SO_X. As shown by the table below, the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X.

AAQA Results Summary					
Pollutant	1 hr Average	3 hr Average	8 hr Average	24 hr Average	Annual Average
CO	Pass	N/A	Pass	N/A	N/A
NO_X	Pass	N/A	N/A	N/A	Pass
SO_X	Pass	Pass	N/A	Pass	Pass

The proposed location is in a non-attainment area for PM_{10}. The increase in the ambient PM_{10} concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	5	N/A	N/A	N/A

Calculated Contribution					
Pollutant	Calculated Contributions ($\mu g/m^3$)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	0.38	1.6	N/A	N/A	N/A

As shown, the calculated contribution of PM_{10} will not exceed the EPA significance level. This project is not expected to cause or make worse a violation of an air quality standard.

H. Compliance Assurance:

1. Source Testing

i. C-3953-10-1 and C-3953-11-1

District Rule 4703 requires NO_X and CO emission testing as well as percent turbine efficiency testing on an annual basis. The District Source Test Policy (APR 1705 10/09/97) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and PM_{10} emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, source testing for NO_X, CO, VOC, PM_{10}, and ammonia slip will be required within 60 days after the end of the commissioning period and at least once every 12 months thereafter.

Also, initial source testing of NO_X, CO, and VOC startup emissions will be required for one gas turbine engine initially and not less than every seven years thereafter. This testing will serve two purposes: to validate the startup emission estimates used in the emission calculations and to verify that the CEMs accurately measure startup emissions.

Each CTG will have a separate exhaust stack. The units will be equipped with CEMs for NO_X, CO, and O_2. Each CTG will be equipped with an individual CEM. Each CEM will have two ranges to allow accurate measurements of NO_X and CO emissions during startup. The CEMs must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR Part 75.

40 CFR Part 60 subpart KKKK requires that fuel sulfur content be documented or monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

40 CFR Part 60 subpart Db requires NO_X testing for the duct burners. The District will accept the NO_X source testing required by District Rule 4703 as equivalent to NO_X testing required by 40 CFR 60 subpart Db.

ii. C-3953-12-1

This unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*. Source testing requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

iii. C-3953-13-1 and C-3953-14-1

Pursuant to District Policy APR 1705, source testing is not required for emergency standby IC engines to demonstrate compliance with Rule 2201.

2. Monitoring

i. C-3953-10-1 and C-3953-11-1

Monitoring of NO_X emissions is required by District Rule 4703. The applicant has proposed a CEMS for NO_X.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

40 CFR Part 60 Subpart KKKK and District Rule 4703 requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart KKKK requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas & Electric (PG&E), may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to allow the facility to demonstrate compliance with the limit by providing gas purchase contracts, supplier certification, tariff sheet or transportation contract; or, if these documents cannot be provided, physically monitor the fuel sulfur content weekly for eight consecutive weeks and semi-annually thereafter if the fuel sulfur content remains below 1.0 gr/scf. Avenal Power Center, LLC will be operating these turbines in compliance with the fuel sulfur content monitoring requirements as described in the Rule 4001, Subpart KKKK discussion below. Therefore, compliance with the monitoring requirements will be satisfied.

ii. C-3953-12-1

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to monitoring requirements. Monitoring requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

iii. C-3953-13-1 and C-3953-14-1

No monitoring is required to demonstrate compliance with Rule 2201.

3. Recordkeeping

i. C-3953-10-1 and C-3953-11-1

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.F.2 of this document for a discussion of the parameters that will be monitored.

ii. C-3953-12-1

As required by District Rule 4305, *Boilers, Steam Generators and Process Heaters, Phase 2*, and District Rule 4306, *Boilers, Steam Generators and Process Heaters, Phase 3*, this unit is subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rules 4305 and 4306, will be discussed in Section VIII, *District Rules 4305 and 4306*, of this evaluation.

The following permit condition will be listed on permit as follows:

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

iii. C-3953-13-1 and C-3953-14-1

Recordkeeping is required to demonstrate compliance with the offset, public notification, and daily emission limit requirements of Rule 2201. As required by District Rule 4702, *Stationary Internal Combustion Engines - Phase 2*, these IC engines are subject to recordkeeping requirements. Recordkeeping requirements, in accordance with District Rule 4702, will be discussed in Section VIII, *District Rule 4702*, of this evaluation.

4. Reporting

i. C-3953-10-1 and C-3953-11-1

40 CFR Part 60 Subpart KKKK requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart KKKK requires the reporting of exceedences of the NO_X emission limit of the permit. Such reporting will be required.

ii. C-3953-12-1

No reporting is required to demonstrate compliance with Rule 2201.

iii. C-3953-13-1 and C-3953-14-1

No reporting is required to demonstrate compliance with Rule 2201.

Rule 2520 Federally Mandated Operating Permits

This project will be subject to Rule 2520 (Title V) because it will meet the following criteria specified in section 2.0:

- Section 2.3 states, "Any major source." The facility will be a major source for NO_X, VOC, and PM_{10} after this project.

- Section 2.4 states, "Any emissions unit, including an area source, subject to a standard or other requirement promulgated pursuant to section 111 (NSPS) or 112 (HAPs) of the CAA..." The turbines are subject to NSPS.

- Section 2.5 states "A source with an acid rain unit for which application for an acid rain permit is required pursuant to Title IV (Acid Rain Program) of the CAA." The turbines are subject to the acid rain program.

- Section 2.6 states, "Any source required to have a preconstruction review permit pursuant to the requirements of the prevention of significant deterioration (PSD) program under Title I of the Federal Clean Air Act." This facility is not required to obtain a PSD permit.

Pursuant to Rule 2520 section 5.3.1 Avenal Power Center must submit a Title V application within 12 months of commencing operations. No action is required at this time.

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

Rule 2540 Acid Rain Program

The proposed CTG's are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. Federal regulations require submission of an acid rain permit application at least 24 months before the later of 1/1/2000 or the date the unit expects to generate electricity. The facility anticipates beginning commercial operation in November of 2011.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_X and SO_X emissions and a relatively small quantity of SO_X allowances (from a national SO_X allowance bank) will be required as well as the use of a NO_X CEM.

The following condition will be placed on permits C-3953-10-1, -11-1 and -14-1 to ensure that Avenal Power Center, LLC submits an application to comply with the requirements of the acid rain program within the appropriate timeframe:

- Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

Rule 2550 Federally Mandated Preconstruction Review for Major Sources of Air Toxics

Section 2.0 states, "*The provisions of this rule shall only apply to applications to construct or reconstruct a major air toxics source with Authority to Construct issued on or after June 28, 1998.*" The applicant has provided the following analysis for Noncriteria pollutants/HAPs.

Noncriteria pollutants are compounds that have been identified as pollutants that pose a significant health hazard. Nine of these pollutants are regulated under the Federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[7]

In addition to these nine compounds, the federal Clean Air Act lists 189 substances as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The SJVAPCD has also published a list of compounds it defines as potential toxic air contaminants (Toxics Policy, May 1991; Rule 2-1-316). Any pollutant that may be emitted from the project and is on the federal New Source Review List, the federal Clean Air Act list, and/or the SJVAPCD toxic air contaminant list has been evaluated.

Noncriteria pollutant emission factors for the analysis of emissions from the gas turbines were obtained from AP-42 (Table 3.1-3, 4/00, and Table 3.4-1 of the Background Document for Section 3.1), from the California Air Resources Board's CATEF database for gas turbines, and from source tests on a similar turbine. Specifically, factors for all pollutants except formaldehyde, hexane, propylene, and naphthalene and other PAHs were taken from AP-42.[8] AP-42 did not contain factors for hexane or propylene, and did not include speciated data for PAHs. Factors for these pollutants and for naphthalene were taken from the CATEF database (mean values). The emission factor for formaldehyde was taken from the results of a June 2000 source test on a dry Low NO_X combustor-equipped large frame turbine.

[7] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission (CEC).
[8] Factors for acrolein and benzene reflect the use of an oxidation catalyst and were taken from Table 3.4-1 of the Background Document for Section 3.1.

Hazardous Air Pollutant Emissions (per CATEF)
Avenal Energy Project – GE Frame 7 (with Duct Burners)

Hazardous Air Pollutant	CATEF Emission Factor (lb/MMSCF)(1)	Maximum Hourly Emissions per Turbine (lb/hr) (2)	Maximum Annual Emissions per Turbine (tpy) (3)	Maximum Annual Emissions both Turbines (tpy)
Acetaldehyde	4.08E-02	0.09	0.33	0.67
Acrolein	3.69E-03	0.01	0.03	6.04E-02
Benzene	3.33E-03	0.01	0.03	5.45E-02
1,3-Butadiene	4.39E-04	9.38E-04	3.59E-03	7.19E-03
Ethyl benzene	3.26E-02	0.07	0.27	0.53
Formaldehyde	1.65E-01	0.35	1.35	2.70
Hexane	2.59E-01	0.55	2.12	4.24
Naphthalene	1.33E-03	2.84E-03	1.09E-02	2.18E-02
Polycyclic aromatic hydrocarbons (PAH)	---	---	---	---
Anthracene	3.38E-05	7.22E-05	2.77E-04	5.53E-04
Benzo(a)anthracene	2.26E-05	4.83E-05	1.85E-04	3.70E-04
Benzo(a)pyrene	1.39E-05	2.97E-05	1.14E-04	2.28E-04
Benzo(b)fluoranthrene	1.13E-05	2.41E-05	9.25E-05	1.85E-04
Benzo(k)fluoranthrene	1.10E-05	2.35E-05	9.00E-05	1.80E-04
Chrysene	2.52E-05	5.38E-05	2.06E-04	4.12E-04
Dibenz(a,h)anthracene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Indeno(1,2,3-cc)pyrene	2.35E-05	5.02E-05	1.92E-04	3.85E-04
Propylene oxide	2.96E-02	6.32E-02	2.42E-01	0.48
Toluene	1.33E-01	0.28	1.09	2.18
Xylenes	6.53E-02	0.14	0.53	1.07
Total			**6.01**	**12.02**

(1) From AP-42 and CATEF databases and source tests.
(2) Based on a maximum hourly turbine fuel use of 2,224.1 MMBtu/hr (with duct burner) and fuel HHV of 1,021 Btu/scf. (2.14 MMscf/hr)
(3) Based on a maximum annual turbine fuel use of 16,711,728 MMBtu/year (with duct burner) and fuel HHV of 1,021 Btu/scf. (16,368 MMscf/yr)

Although the turbines/HRSGs will be equipped with oxidation catalyst systems, only the acrolein and benzene emission factors reflect any control effectiveness. As discussed above, these factors are based on test data rather than any assumption regarding catalyst control efficiency.

Therefore, as emissions of each individual HAP are below 10 tons per year and total HAP emissions are below 25 tons per year, the Avenal Power Center, LLC Project will not be a major air toxics source and the provisions of this rule do not apply.

Rule 4001 New Source Performance Standards

<u>40 CFR 60 – Subpart Dc</u>

NSPS Subpart Dc applies to steam generating units that are constructed, reconstructed, or modified after 6/9/89 and have a maximum design heat input capacity of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr. Subpart Dc has standards for SO_X and PM_{10}.

<u>60.42c – Standards for Sulfur Dioxide</u>

Since coal is not combusted by the boiler in this project, the requirements of this section are not applicable.

<u>60.43c – Standards for Particulate Matter</u>

The boiler is not fired on coal, combusts mixtures of coal with other fuels, combusts wood, combusts mixtured of wood with other fuels, or oil; therefore it will not be subject to the requirements of this section.

<u>60.44c – Compliance and Performance Tests Methods and Procedures for Sulfur Dioxide.</u>

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

<u>60.45c – Compliance and Performance Test Methods and Procedures for Particulate Matter</u>

Since the boiler in this project is not subject to the particulae matter requirements of this subpart, no testing to show compliance is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

<u>60.46c – Emission Monitoring for Sulfur Dioxide</u>

Since the boiler in this project is not subject to the sulfur dioxide requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

<u>60.47c – Emission Monitoring for Particulate Matter</u>

Since the boiler in this project is not subject to the particulate matter requirements of this subpart, no monitoring is required. Therefore, the requirements of this section are not applicable to the boiler in this project.

60.48c – Reporting and Recordingkeeping Requirements

Section 60.48c (a) states that the owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

(1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

The design heat input capacity and type of fuel combusted at the facility will be listed on the unit's equipment description. No conditions are required to show compliance with this requirement.

(2) If applicable, a copy of any Federally enforceable requirement that limits the annual capacity factor for any fuel mixture of fuels under §60.42c or §40.43c.

This requirement is not applicable since the units are not subject to §60.42c or §40.43c.

(3) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

The facility has not proposed an annual capacity factor; therefore one will not be required.

(4) Notification if an emerging technology will be used for controlling SO_2 emissions. The Administrator will examine the description of the control device and will determine whether the technology qualifies as an emerging technology. In making this determination, the Administrator may require the owner or operator of the affected facility to submit additional information concerning the control device. The affected facility is subject to the provisions of §60.42c(a) or (b)(1), unless and until this determination is made by the Administrator

This requirement is not applicable since the units will not be equipped with an emerging technology used to control SO_2 emissions.

Section 60.48 c (g) states that the owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. The following conditions will be added to the permit to assure compliance with this section.

- A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

- Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

Section 60.48 c (i) states that all records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. District Rule 4306 requires that records be kept for five years.

40 CFR 60 – Subpart GG

40 CFR Part 60 Subpart GG applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules per hour (10.2 MMBtu/hr), that commence construction, modification, or reconstruction after October 3, 1977. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(a), states that this subpart applies to all stationary gas turbines with a heat input greater than 10.7 gigajoules (10 MMBtu) per hour, which commenced construction, modification, or reconstruction after February 18, 2005. Avenal Power Center, LLC has indicated that the installation and construction of the proposed turbines will be completed in 2011. Therefore, these turbines also meet the applicability requirements of this subpart.

40 CFR 60 Subpart KKKK, Section 60.4305(b), states that stationary combustion turbines regulated under this subpart are exempt from the requirements of 40 CFR 60 Subpart GG. As discussed above, 40 CFR 60 Subpart KKKK is applicable to these proposed turbines. Therefore, they are exempt from the requirements of 40 CFR 60 Subpart GG and no further discussion is required.

40 CFR 60 - Subpart IIII

§60.4200 - Applicability

40 CFR Part 60 Subpart IIII applies to all owners and operators of stationary compression ignited internal combustion engines that commence construction after July 11, 2005, where the engines are:

1) Manufactured after April 1, 2006, if not a fire pump engine.
2) Manufactured as a National Fire Protection Association (NFPA) fire pump engine after July 1, 2006.

Since the proposed engines will be installed after July 11, 2005 and will be manufactured after April 1, 2006, this subpart applies.

All of the applicable standards of this subpart are less restrictive than current District requirements. This engine will comply with all current District standards so further discussion is required.

40 CFR Part 60, Subpart JJJJ

The engine in this project is rated at over 100 bhp and per 60.4233(e) is subject to the limits presented in Table 1 of this subpart. The Table 1 limits as well as the proposed emissions are shown on the following table. This regulation does not specify an emissions averaging period.

	Table 1 Limit	Proposed Emissions	Compliant
NOx (g/bhp-hr)	2.0	1.0	Yes
CO (g/bhp-hr)	4.0	0.6	Yes
VOC (g/bhp-hr)	1.0	0.33	Yes

Therefore, the natural gas-fired IC engine in this project meets all applicable requirements of this subpart.

40 CFR 60 – Subpart KKKK

40 CFR Part 60 Subpart KKKK applies to all stationary gas turbines rated at greater than or equal to 10 MMBtu/hr that commence construction, modification, or reconstruction after February 18, 2005. The proposed gas turbines involved in this project have a rating of 1,794.5 MMBtu/hr and will be installed after February 18, 2005. Therefore, this subpart applies to these gas turbines.

Subpart KKKK established requirements for nitrogen oxide (NO_X) and sulfur dioxide (SO_X) emissions.

Section 60.4320 - Standards for Nitrogen Oxides:

Paragraph (a) states that NO_X emissions shall not exceed the emission limits specified in Table 1 of this subpart. Paragraph (b) states that if you have two or more turbines that are connected to a single generator, each turbine must meet the emission limits for NO_X. Table 1 states that new, modified, or reconstructed turbines firing natural gas with a combustion turbine heat input at peak load of greater than 850 MMBtu/hr shall meet a NO_X emissions limit of 15 ppmvd @ 15% O_2 or 54 ng/J of useful output (0.43 lb/MWh).

Avenal Power Center is proposing a NO_X emission concentration limit of 2.0 ppmvd @ 15% O_2 for each turbine. Therefore, the proposed turbines will be operating in compliance with the NO_X emission requirements of this subpart. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.44 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 6.13 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.72 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.28 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.23 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.97 lb/hr; or SOx (as SO2) – 5.11 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

Section 60.4330 - Standards for Sulfur Dioxide:

Paragraph (a) states that if your turbine is located in a continental area, you must comply with one of the following:

(1) Operator must not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 nanograms per Joule (ng/J) (0.90) pounds per megawatt-hour (lb/MWh)) gross output; or
(2) Operator must not burn in the subject stationary combustion turbine any fuel which contains total potential sulfur emissions in excess of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input.

Avenal Power Center is proposing to burn natural gas fuel in each of these turbines with a maximum sulfur content of 1.0 grain/ 100 scf (0.00285 lb/MMBtu). Therefore, the proposed turbines will be operating in compliance with the SO_X emission requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

Section 60.4335 – NO_X Compliance Demonstration, with Water or Steam Injection:

Paragraph (a) states that when a turbine is using water or steam injection to reduce NO_X emissions, you must install, calibrate, maintain and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine when burning a fuel that requires water or steam injection for compliance.

Avenal Power Center does not use water or steam injection in their turbines therefore; the requirements of this section are not applicable to the turbines in this project.

Section 60.4340 – NO_X Compliance Demonstration, without Water or Steam Injection:

Paragraph (b) states that as an alternative to annual source testing, the facility may install, calibrate, maintain and operate one of the following continuous monitoring systems:

(1) Continuous emission monitoring as described in §§60.4335(b) and 60.4345, or
(2) Continuous parameter monitoring

Avenal Power Center has proposed to install a CEMS system as described in §§60.4335(b) and 60.4345 therefore; the following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

Section 60.4345 – CEMS Equipment Requirements:

Paragraph (a) states that each NO_X diluent CEMS must be installed and certified according to Performance Specification 2 (PS 2) in Appendix B to this part, except the 7-day calibration drift is based on unit operating days, not calendar days. With state approval, Procedure 1 in Appendix F to this part is not required. Alternatively, a NO_X diluent CEMS that is installed and certified according to Appendix A of Part 75 of this chapter is acceptable for use under this subpart. The relative accuracy test audit (RATA) of the CEMS shall be performed on a lb/MMBtu basis.

Paragraph (b) states that as specified in §60.13(e)(2), during each full unit operating hour, both the NO_X monitor and the diluent monitor must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each 15-minute quadrant of the hour, to validate the hour. For partial unit operating hours, at least one valid data point must be obtained with each monitor for each quadrant of the hour in which the unit operates. For unit operating hours in which required quality assurance and maintenance activities are performed on the CEMS, a minimum of two valid data points (one in each of two quadrants) are required for each monitor to validate the NO_X emission rate for the hour.

Paragraph (c) states that each fuel flowmeter shall be installed, calibrated, maintained, and operated according to the manufacturer's instructions. Alternatively, with state approval, fuel flowmeters that meet the installation, certification, and quality assurance requirements of Appendix D to Part 75 of this chapter are acceptable for use under this subpart.

Paragraph (d) states that each watt meter, steam flow meter, and each pressure or temperature measurement device shall be installed, calibrated, maintained, and operated according to manufacturer's instructions.

Paragraph (e) states that the owner or operator shall develop and keep on-site a quality assurance (QA) plan for all of the continuous monitoring equipment described in paragraphs (a), (c), and (d) of this section. For the CEMS and fuel flow meters, the owner or operator may, with state approval, satisfy the requirements of this paragraph by implementing the QA program and plan described in section 1 of Appendix B to Part 75 of this chapter.

Avenal Power Center will be required to install and operate a NO_X CEMS in accordance with the requirements of this section. As discussed above, Avenal Power Center is not required to install a fuel flow meter, watt meter, steam flow meter, or a pressure or temperature measurement device to comply with the requirements of this subpart. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

- The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

<u>Section 60.4350 – CEMS Data and Excess NO_X Emissions:</u>

Section 60.4350 states that for purposes of identifying excess emissions:

(a) All CEMS data must be reduced to hourly averages as specified in §60.13(h).

(b) For each unit operating hour in which a valid hourly average, as described in §60.4345(b), is obtained for both NO_X and diluent monitors, the data acquisition and handling system must calculate and record the hourly NO_X emission rate in units of ppm or lb/MMBtu, using the appropriate equation from Method 19 in Appendix A of this part. For any hour in which the hourly average O_2 concentration exceeds 19.0 percent O_2 (or the hourly average CO_2 concentration is less than 1.0 percent CO_2), a diluent cap value of 19.0 percent O_2 or 1.0 percent CO_2 (as applicable) may be used in the emission calculations.

(c) Correction of measured NO_X concentrations to 15 percent O_2 is not allowed.

(d) If you have installed and certified a NO_X diluent CEMS to meet the requirements of Part 75 of this chapter, states can approve that only quality assured data from the CEMS shall be used to identify excess emissions under this subpart. Periods where the missing data substitution procedures in Subpart D of Part 75 are applied are to be reported as monitor downtime in the excess emissions and monitoring performance report required under §60.7(c).

(e) All required fuel flow rate, steam flow rate, temperature, pressure, and megawatt data must be reduced to hourly averages.

(f) Calculate the hourly average NO_X emission rates, in units of the emission standards under §60.4320, using either ppm for units complying with the concentration limit or the equations 1 (simple cycle turbines) or 2 (combined cycle turbines) listed in §60.4350, paragraph (f).

Avenal Power Center is proposing to monitor the NO_X emissions rates from the turbines with a CEMS. The CEMS system will be used to determine if, and when, any excess NO_X emissions are released to the atmosphere from the turbine exhaust stacks. The CEMS will be operated in accordance with the methods and procedures described above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

<u>Section 60.4355 – Parameter Monitoring Plan:</u>

This section sets forth the requirements for operators that elect to continuously monitor parameters in lieu of installing a CEMS for NO_X emissions. As discussed above, Avenal Power Center is proposing to install CEMS on each of these turbines that will directly measure NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Sections 60.4360, 60.4365 and 60.4370 – Monitoring of Fuel Sulfur Content:

Section 60.4360 states that an operator must monitor the total sulfur content of the fuel being fired in the turbine, except as provided in §60.4365. The sulfur content of the fuel must be determined using total sulfur methods described in §60.4415. Alternatively, if the total sulfur content of the gaseous fuel during the most recent performance test was less than half the applicable limit, ASTM D4084, D4810, D5504, or D6228, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17), which measure the major sulfur compounds, may be used.

Section 60.4365 states that an operator may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for units located in continental areas and 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for units located in noncontinental areas or a continental area that the Administrator determines does not have access to natural gas and that the removal of sulfur compounds would cause more environmental harm than benefit. You must use one of the following sources of information to make the required demonstration:

(a) The fuel quality characteristics in a current, valid purchase contract, tariff sheet or transportation contract for the fuel, specifying that the maximum total sulfur content for oil use in continental areas is 0.05 weight percent (500 ppmw) or less and 0.4 weight percent (4,000 ppmw) or less for noncontinental areas, the total sulfur content for natural gas use in continental areas is 20 grains of sulfur or less per 100 standard cubic feet and 140 grains of sulfur or less per 100 standard cubic feet for noncontinental areas, has potential sulfur emissions of less than less than 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas and has potential sulfur emissions of less than less than 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas; or

(b) Representative fuel sampling data which show that the sulfur content of the fuel does not exceed 26 ng SO_2/J (0.060 lb SO_2/MMBtu) heat input for continental areas or 180 ng SO_2/J (0.42 lb SO_2/MMBtu) heat input for noncontinental areas. At a minimum, the amount of fuel sampling data specified in section 2.3.1.4 or 2.3.2.4 of Appendix D to Part 75 of this chapter is required.

Avenal Power Center is proposing to operate these turbines on natural gas that contains a maximum sulfur content of 1.0 grains/100 scf. Primarily, the natural gas supplier should be able to provide a purchase contract, tariff sheet or transportation contract for the fuel that demonstrates compliance with the natural gas sulfur content limit. However, Avenal Power Center has asked that the option of either using a purchase contract, tariff sheet or transportation contract or actually physically monitoring the sulfur content be incorporated into their permit.

Section 60.4370 states that the frequency of determining the sulfur content of the fuel must be as follows:

(a) *Fuel oil.* For fuel oil, use one of the total sulfur sampling options and the associated sampling frequency described in sections 2.2.3, 2.2.4.1, 2.2.4.2, and 2.2.4.3 of Appendix D to Part 75 of this chapter (*i.e.*, flow proportional sampling, daily sampling, sampling from the unit's storage tank after each addition of fuel to the tank, or sampling each delivery prior to combining it with fuel oil already in the intended storage tank).

(b) *Gaseous fuel.* If you elect not to demonstrate sulfur content using options in §60.4365, and the fuel is supplied without intermediate bulk storage, the sulfur content value of the gaseous fuel must be determined and recorded once per unit operating day.

(c) *Custom schedules.* Notwithstanding the requirements of paragraph (b) of this section, operators or fuel vendors may develop custom schedules for determination of the total sulfur content of gaseous fuels, based on the design and operation of the affected facility and the characteristics of the fuel supply. Except as provided in paragraphs (c)(1) and (c)(2) of this section, custom schedules shall be substantiated with data and shall be approved by the Administrator before they can be used to comply with the standard in §60.4330.

When actually required to physically monitor the sulfur content in the fuel burned in these turbines, Avenal Power Center is proposing a custom monitoring schedule. The District and EPA have previously approved a custom monitoring schedule of at least one per week. Then, if compliance with the fuel sulfur content limit is demonstrated for eight consecutive weeks, the monitoring frequency shall be at least once every six months. If any six month monitoring period shows an exceedance, weekly monitoring shall resume. Avenal Power Center is proposing to follow this same pre-approved fuel sulfur content monitoring scheme for the turbines. The following condition will ensure continued compliance with the requirements of this section:

- The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

Section 60.4380 – Excess NO_X Emissions:

Section 60.4380 establishes reporting requirements for periods of excess emissions and monitor downtime. Paragraph (a) lists requirements for operators choosing to monitor parameters associated with water or steam to fuel ratios. As discussed above, Avenal Power Center is not proposing to monitor parameters associated with water or steam to fuel ratios to predict what the NO_X emissions from the turbines will be. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

Paragraph (b) states that for turbines using CEM's:

(1) An excess emissions is any unit operating period in which the 4-hour or 30-day rolling average NO_X emission rate exceeds the applicable emission limit in §60.4320. For the purposes of this subpart, a "4-hour rolling average NO_X emission rate" is the arithmetic average of the average NO_X emission rate in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given hour and the three unit operating hour average NO_X emission rates immediately preceding that unit operating hour. Calculate the rolling average if a valid NO_X emission rate is obtained for at least 3 of the 4 hours. For the purposes of this subpart, a "30-day rolling average NO_X emission rate" is the arithmetic average of all hourly NO_X emission data in ppm or ng/J (lb/MWh) measured by the continuous emission monitoring equipment for a given day and the twenty-nine unit operating days immediately preceding that unit operating day. A new 30-day average is calculated each unit operating day as the average of all hourly NO_X emissions rates for the preceding 30 unit operating days if a valid NO_X emission rate is obtained for at least 75 percent of all operating hours.

(2) A period of monitor downtime is any unit operating hour in which the data for any of the following parameters are either missing or invalid: NO_X concentration, CO2 or O_2 concentration, fuel flow rate, steam flow rate, steam temperature, steam pressure, or megawatts. The steam flow rate, steam temperature, and steam pressure are only required if you will use this information for compliance purposes.

(3) For operating periods during which multiple emissions standards apply, the applicable standard is the average of the applicable standards during each hour. For hours with multiple emissions standards, the applicable limit for that hour is determined based on the condition that corresponded to the highest emissions standard.

Paragraph (c) lists requirements for operators who choose to monitor combustion parameters that document proper operation of the NO_X emission controls. Avenal Power Center is not proposing to monitor combustion parameters that document proper operation of the NO_X emission controls. Therefore, the requirements of this paragraph are not applicable and no further discussion is required.

The following condition will ensure continued compliance with the requirements of this section:

- Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

Section 60.4385 – Excess SO_X Emissions:

Section 60.4385 states that if an operator chooses the option to monitor the sulfur content of the fuel, excess emissions and monitoring downtime are defined as follows:

(a) For samples of gaseous fuel and for oil samples obtained using daily sampling, flow proportional sampling, or sampling from the unit's storage tank, an excess emission occurs each unit operating hour included in the period beginning on the date and hour of any sample for which the sulfur content of the fuel being fired in the combustion turbine exceeds the applicable limit and ending on the date and hour that a subsequent sample is taken that demonstrates compliance with the sulfur limit.

(b) If the option to sample each delivery of fuel oil has been selected, you must immediately switch to one of the other oil sampling options (i.e., daily sampling, flow proportional sampling, or sampling from the unit's storage tank) if the sulfur content of a delivery exceeds 0.05 weight percent. You must continue to use one of the other sampling options until all of the oil from the delivery has been combusted, and you must evaluate excess emissions according to paragraph (a) of this section. When all of the fuel from the delivery has been burned, you may resume using the as-delivered sampling option.

(c) A period of monitor downtime begins when a required sample is not taken by its due date. A period of monitor downtime also begins on the date and hour of a required sample, if invalid results are obtained. The period of monitor downtime ends on the date and hour of the next valid sample.

Avenal Power Center will be following the definitions and procedures specified above for determining periods of excess SO_X emissions. Therefore, the proposed turbines will be operating in compliance with the requirements of this section.

Sections 60.4375, 60.4380, 60.4385 and 60.4395 – Reporting:

These sections establish the reporting requirements for each turbine. These requirements include methods and procedures for submitting reports of monitoring parameters, annual performance tests, excess emissions and periods of monitor downtime. Avenal Power Center is proposing to maintain records and submit reports in accordance with the requirements specified in these sections. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NO_X emissions, nature and the cause of excess (if known), corrective actions taken and preventative measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period and used to determine compliance with an emissions standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

Section 60.4400 – NO_X Performance Testing:

Section 60.4400, paragraph (a) states that an operator must conduct an initial performance test, as required in §60.8. Susequent NO_X performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test).

Paragraphs (1), (2) and (3) set fourth the requirements for the methods that are to be used during source testing.

Avenal Power Center will be required to source test the exhaust of these turbines within 120 days of initial startup and at least once every 12 months thereafter. They will be required to source test in accordance with the methods and procedures specified in paragraphs (1), (2), and (3). Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following conditions will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Section 60.4405 – Initial CEMS Relative Accuracy Testing:

Section 60.4405 states that if you elect to install and certify a NO_X-diluent CEMS, then the initial performance test required under §60.8 may be performed in the alternative manner described in paragraphs (a), (b), (c) and (d). Avenal Power Center has not indicated that they would like to perform the initial performance test of the CEMS using the alternative methods described in this section. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4410 – Parameter Monitoring Ranges:

Section 60.4410 sets fourth requirements for operators that elect to monitor combustion parameters or parameters indicative of proper operation of NO_X emission controls. As discussed above, Avenal Power Center is proposing to install a CEMS system to monitor the NO_X emissions from each of these turbines and is not proposing to monitor combustion parameters or parameters indicative of proper operation. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 60.4415– SO_X Performance Testing:

Section 60.4415 states that an operator must conduct an initial performance test, as required in §60.8. Subsequent SO_2 performance tests shall be conducted on an annual basis (no more than 14 calendar months following the previous performance test). There are three methodologies that you may use to conduct the performance tests.

(1) If you choose to periodically determine the sulfur content of the fuel combusted in the turbine, a representative fuel sample would be collected following ASTM D5287 (incorporated by reference, see §60.17) for natural gas or ASTM D4177 (incorporated by reference, see §60.17) for oil. Alternatively, for oil, you may follow the procedures for manual pipeline sampling in section 14 of ASTM D4057 (incorporated by reference, see §60.17). The fuel analyses of this section may be performed either by you, a service contractor retained by you, the fuel vendor, or any other qualified agency. Analyze the samples for the total sulfur content of the fuel using:

(i) For liquid fuels, ASTM D129, or alternatively D1266, D1552, D2622, D4294, or D5453 (all of which are incorporated by reference, see §60.17); or

(ii) For gaseous fuels, ASTM D1072, or alternatively D3246, D4084, D4468, D4810, D6228, D6667, or Gas Processors Association Standard 2377 (all of which are incorporated by reference, see §60.17).

Avenal Power Center is proposing to periodically determine the sulfur content of the fuel combusted in each of these turbines when valid purchase contracts, tariff sheets or transportation contract is not available. The sulfur content will be determined using the methods specified above. Therefore, the proposed turbines will be operating in compliance with the requirements of this section. The following condition will ensure continued compliance with the requirements of this section:

- Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

Methodologies (2) and (3) are applicable to operators that elect to measure the SO_2 concentration in the exhaust stream. Avenal Power Center is not proposing to measure the SO_2 in the exhaust stream of the turbines. Therefore, the requirements of these methodologies are not applicable and no further discussion is required.

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this subpart. Therefore, compliance with the requirements of Subpart KKKK is expected and no further discussion is required.

Rule 4002 National Emissions Standards for Hazardous Air Pollutants (NESHAP)

40 CFR 63 Subpart ZZZZ

Subpart ZZZZ establishes national emission limitations and operating limitations for hazardous air pollutants (HAP) emitted from stationary reciprocating internal combustion engines (RICE) located at major and area sources of HAP emissions. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and operating limitations.

§6585(b) states, "A major source of HAP emissions is a plant site that emits or has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year, except that for oil and gas production facilities, a major source of HAP emissions is determined for each surface site."

§6585(c) states, "An area source of HAP emissions is a source that is not a major source."

The facility is not a major source as defined in §6585(b). Therefore, this facility is an area source of HAP emissions.

§6590(a) states, "An affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand." Since the engines in this project are new stationary RICE's at an area source of HAP emissions, they are defined as affected sources.

§6590(a)(2) defines the criteria for an new stationary RICE as follows:

> (i) A stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after December 19, 2002.
>
> (ii) A stationary RICE with a site rating of equal to or less than 500 brake HP located at a major source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.
>
> (iii) A stationary RICE located at an area source of HAP emissions is new if you commenced construction of the stationary RICE on or after June 12, 2006.

This facility is an area source of HAP emissions. The engines at this facility have not been constructed and therefore meets the definition of an new stationary RICE as defined in §6590(a)(2)(iii).

§6590(b)(1) states that an affected source which meets either of the criteria in paragraphs (b)(1)(i) through (ii) of this section does not have to meet the requirements of this subpart and of subpart A of this part except for the initial notification requirements of §63.6645(f).

> (i) The stationary RICE is a new or reconstructed emergency stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.
>
> (ii) The stationary RICE is a new or reconstructed limited use stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions.

Since the enignes in this project are not located at a major source of HAP emissions they do not qualify for the limited requirements stated above.

§6590(b)(2) and (3) apply to landfill or digester gas fired RICE's and existing RICE's. Since the engines in ths project are not exsiting RICE's and are fired on diesel fuel or natural gas, these sections do not apply to the RICE's in this project.

§6590(c) states that an affected source that is listed below must meet the requirements of this part by meeting the requirements of 40 CFR part 60 subpart IIII, for compression ignition engines or 40 CFR part 60 subpart JJJJ, for spark ignition engines. No further requirements apply for such engines under this part.

- new or reconstructed stationary RICE located at an area source,
- new or reconstructed stationary RICE located at a major source of HAP emissions and is a spark ignition 2 stroke lean burn (2SLB) stationary RICE with a site rating of less than 500 brake HP, a spark ignition 4 stroke lean burn (4SLB) stationary RICE with a site rating of less than 250 brake HP, or a 4 stroke rich burn (4SRB) stationary RICE with a site rating of less than or equal to 500 brake HP, a stationary RICE with a site rating of less than or equal to 500 brake HP which combusts landfill or digester gas equivalent to 10 percent or more of the gross heat input on an annual basis, an emergency or limited use stationary RICE with a site rating of less than or equal to 500 brake HP,
- or a compression ignition (CI) stationary RICE with a site rating of less than or equal to 500 brake HP,

Since both the RICE's in this project are new stationary RICE's located at an area source, they will demonstrate compliance with this Subpart by demonstrating compliance with the requirements of 40 CFR part 60 subpart IIII and for compression ignition engines and 40 CFR part 60 subpart JJJJ for spark ignited engines. As shown previously in this evaluation, the RICE's in this project meet the requirements of 40 CFR part 60 subpart IIII and subpart JJJJ; therefore they meet the requirements of this subpart.

Rule 4101 Visible Emissions

Per Section 5.0, no person shall discharge into the atmosphere emissions of any air contaminant aggregating more than 3 minutes in any hour which is as dark as or darker than Ringelmann 1 (or 20% opacity).

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

ii. C-3953-12-1 (Boiler)

Based on past experiences with natural gas-fired boilers, no visible emissions are expected to be as dark as or darker than Ringelmann 1 (or 20% opacity). The following condition will be placed on the DOC to assure compliance with this rule.

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iii. C-3953-13-1 (Diesel IC engine powering fire water pump)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

The following condition will be listed on the DOC to ensure compliance:

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

Rule 4102 Nuisance

Section 4.0 prohibits discharge of air contaminants which could cause injury, detriment, nuisance or annoyance to the public. Public nuisance conditions are not expected as a result of these operations, provided the equipment is well maintained as required by permit conditions. Therefore, the following condition will be added to the permit to assure compliance with this rule.

- {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

A. California Health & Safety Code 41700 (Health Risk Analysis)

A Health Risk Assessment (HRA) is required for any increase in hourly or annual emissions of hazardous air pollutants (HAPs). HAPs are limited to substances included on the list in CH&SC 44321 and that have an OEHHA approved health risk value. The installation of the permit units for the power plant results in increases in emissions of HAPs.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Under the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit as shown in the table below:

Screen HRA Summary				
	Acute Hazard Index	Chronic Hazard Index	70 yr Cancer Risk	T-BACT Required?
C-3953-10-1 (Turbine #1)	0.0	0.0	0.02	No
C-3953-11-1 (Turbine #2)	0.0	0.0	0.02	No
C-3953-12-1 (Auxiliary Boiler)	0.0	0.0	0.01	No
C-3953-13-1 (Diesel-Fired IC Engine Fire Pump)	N/A*	N/A*	0.01	No
C-3953-14-1 (NG-Fired IC Engine Generator)	0.2	0.0	0.0	No

* Acute and Chronic Hazard Indices were not calculated since there is not a risk factor or the risk factor is so low that it has been determined to be insignificant for this type of unit.

B. Discussion of Toxics BACT (TBACT)

TBACT is triggered if the cancer risk exceeds one in one million and if either the chronic or acute hazard index exceeds 1. The results of the health risk assessment show that none of the TBACT thresholds are exceeded. TBACT is not triggered.

Rule 4201 Particulate Matter Concentration

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

i. C-3953-10-1 and –11-1 (Turbines)

PM Conc. (gr/scf) = (PM emission rate) x (7000 gr/lb)

PM_{10} emission rate = 11.78 lb/hr. Assuming 100% of PM is PM_{10}
Exhaust Gas Flow = 1,071,653 dscfm

PM Conc. (gr/scf)=[(11.78 lb/hr) ∗ (7,000 gr/lb)] ÷ [(1,071,653 ft^3/min) ∗ (60 min/hr)]
PM Conc. = 0.0012 gr/scf

Calculated emissions are well below the allowable emissions level. It can be assumed that emissions from all these turbines will not exceed the allowable 0.1 gr/scf. Therefore, compliance with Rule 4201 is expected.

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

ii. C-3953-12-1 (Boiler)

Section 3.1 prohibits discharge of dust, fumes, or total particulate matter into the atmosphere from any single source operation in excess of 0.1 grain per dry standard cubic foot.

F-Factor for NG: 8,578 dscf/MMBtu at 60 °F
PM10 Emission Factor: 0.005 lb-PM10/MMBtu
Percentage of PM as PM10 in Exhaust: 100%
Exhaust Oxygen (O_2) Concentration: 3%
Excess Air Correction to F Factor = $\dfrac{20.9}{(20.9 - 3)}$ = 1.17

$$GL = \left(\frac{0.005\ lb-PM}{MMBtu} \times \frac{7,000\, grain}{lb-PM}\right) / \left(\frac{8,578\ ft^3}{MMBtu} \times 1.17\right)$$

$$GL = 0.0035\ grain/dscf < 0.1\, grain/dscf$$

Therefore, compliance with District Rule 4201 requirements is expected and a permit condition will be listed on the permit as follows:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iii. C-3953-13-1 (Diesel IC engine fire pump)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.059\ \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1\,bhp-hr}{2,542.5\,Btu} \times \frac{10^6\,Btu}{9,051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = 0.014\ \frac{grain-PM}{dscf}$$

Since 0.014 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

Particulate matter emissions from the engine will be less than or equal to the rule limit of 0.1 grain per cubic foot of gas at dry standard conditions as shown by the following:

$$0.034 \ \frac{g-PM_{10}}{bhp-hr} \times \frac{1g-PM}{0.96g-PM_{10}} \times \frac{1bhp-hr}{2{,}542.5\,Btu} \times \frac{10^6\,Btu}{9{,}051\,dscf} \times \frac{0.35\,Btu_{out}}{1\,Btu_{in}} \times \frac{15.43\,grain}{g} = \ 0.008 \ \frac{grain-PM}{dscf}$$

Since 0.008 grain-PM/dscf is ≤ to 0.1 grain per dscf, compliance with Rule 4201 is expected.

Therefore, the following condition will be listed on the DOC to ensure compliance:

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

Rule 4202 Particulate Matter Emission Rate

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to any of the permit units in this project, and no further discussion is required.

Rule 4301 ***Fuel Burning Equipment***

Rule 4301 limits air contaminant emissions from fuel burning equipment as defined in the rule. Section 3.1 defines fuel burning equipment as "any furnace, boiler, apparatus, stack, and all appurtenances thereto, used in the process of burning fuel for the primary purpose of producing heat or power by indirect heat transfer".

i. C-3953-10-1 and C-3953-11-1 (Turbines)

The CTG's primarily produce power mechanically, i.e. the products of combustion pass across the power turbine blades which causes the turbine shaft to rotate. The turbine shaft is coupled to an electrical generator shaft which is rotated to produce electricity. Because the CTG's primarily produce power by mechanical means, it does not meet the definition of fuel burning equipment. Therefore, Rule 4301 does not apply to the affected equipment and no further discussion is required.

ii. C-3953-12-1 (Boiler)

District Rule 4301 Limits			
Pollutant	NO_2	Total PM	SO_2
C-3953-12-1 (lb/hr)	0.41	0.19	0.10
Rule Limit (lb/hr)	140	10	200

The above table indicates compliance with the maximum lb/hr emissions in this rule; therefore, continued compliance is expected.

iii. C-3953-13-1 (Diesel IC engine fire pump)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

iv. C-3953-14-1 (Natural gas IC engine electrical generator)

Rule 4301 does not apply to the affected equipment and no further discussion is required.

Rule 4304 Tuning Procedure for Boilers, Steam Generators and Process Heaters

This rule is only applicable to unit C-3953-12-1.

Pursuant to District Rules 4305 and 4306, Section 6.3.1, the boiler is not required to tune since it follows a District approved Alternate Monitoring scheme where the applicable emission limits are periodically monitored. Therefore, the unit is not subject to this rule.

Rule 4305 Boilers Steam Generators and Process Heaters – Phase 2

This rule is only applicable to unit C-3953-12-1.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4305, the unit is subject to District Rule 4305, *Boilers, Steam Generators and Process Heaters – Phase 2.*

In addition, the unit is also subject to District Rule 4306, *Boilers, Steam Generators and Process Heaters – Phase 3.*

Since emissions limits of District Rule 4306 and all other requirements are equivalent or more stringent than District Rule 4305 requirements, compliance with District Rule 4306 requirements will satisfy requirements of District Rule 4305.

Conclusion

Therefore, compliance with District Rule 4305 requirements is expected and no further discussion is required.

Rule 4306 Boilers Steam Generators and Process Heaters – Phase 3

This rule is only applicable to unit C-3953-12-1.

The unit is natural gas-fired with a maximum heat input of 37.4 MMBtu/hr. Pursuant to Section 2.0 of District Rule 4306, the unit is subject to District Rule 4306.

Section 5.1, NO_X and CO Emissions Limits

Section 5.1.1 requires that except for units subject to Sections 5.2, NO_X and carbon monoxide (CO) emissions shall not exceed the limits specified in the following table. All ppmv emission limits specified in this section are referenced at dry stack gas conditions and 3.00 percent by volume stack gas oxygen. Emission concentrations shall be corrected to 3.00 percent oxygen in accordance with Section 8.1.

With a maximum heat input of 37.4 MMBtu/hr, the applicable emission limit category is listed in Section 5.1.1, Table 1, Category B, from District Rule 4306.

Rule 4306 Emissions Limits				
Category	Operated on gaseous fuel		Operated on liquid fuel	
	NO_X Limit	CO Limit	NO_X Limit	CO Limit
B. Units with a rated heat input greater than 20.0 MMBtu/hr, except for categories C, D, E, F, G, H, and I units	9 ppmv or 0.011 lb/MMBtu	400 ppmv	40 ppmv or 0.052 lb/MMBtu	400 ppmv

For the unit:

- the proposed NO_x emission factor is 9 ppmvd @ 3% O_2 (0.011 lb/MMBtu), and
- the proposed CO emission factor is 50 ppmvd @ 3% O_2 (0.037 lb/MMBtu).

Therefore, compliance with Section 5.1 of District Rule 4306 is expected.

A permit condition listing the emissions limits will be listed on permit as shown in the DEL section above.

Section 5.2, Low Use

The unit annual heat input will exceed the 9 billion Btu heat input per calendar year criteria limit addressed by this section. Since the unit is not subject to Section 5.2, the requirements of this section do not apply to the unit.

Section 5.3, Startup and Shutdown Provisions

Section 5.3 states that on and after the full compliance schedule specified in Section 7.1, the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 shall not apply during start-up or shutdown provided an operator complies with the requirements specified in Sections 5.3.1 through 5.3.4.

According to boiler manufacturers, low NO_X burners will achieve their rated emissions within one to two minutes of initial startup and do not require a special shutdown procedure. Because of the short duration before achieving the rated emission factor following startup, the unit will be subject to the applicable emission limits of Sections 5.1, 5.2.2 and 5.2.3 while in operation.

Section 5.4, Monitoring Provisions

Section 5.4.2 requires that permit units subject to District Rule 4306, Section 5.1 emissions limits shall either install and maintain Continuous Emission Monitoring (CEM) equipment for NO_X, CO and O_2, or install and maintain APCO-approved alternate monitoring.

The facility has proposed to install a CEMS system to satisfy the requirements of this section. The following condition will assure compliance with this section.

- {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

Since the unit is not subject to the requirements listed in Section 5.2.1 or 5.2.2, it is not subject to Section 5.4.3 requirements.

Since the unit is not subject to the requirements of category H (maximum annual heat input between 9 billion and 30 billion Btu/year) listed in Section 5.1.1, it is not subject to Section 5.4.4 requirements.

Section 5.5, Compliance Determination

Section 5.5.1 requires that the operator of any unit shall have the option of complying with either the applicable heat input (lb/MMBtu) emission limits or the concentration (ppmv) emission limits specified in Section 5.1. The emission limits selected to demonstrate compliance shall be specified in the source test proposal pursuant to Rule 1081 (Source Sampling). Therefore, the following condition will be listed on the permit as follows:

- {2976} The source plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

Section 5.5.2 requires that all emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0. Therefore, the following permit condition will be listed on the permit as follows:

- {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

Section 5.5.4 requires that for emissions monitoring pursuant to Sections 5.4.2, 5.4.2.1, and 6.3.1 using a portable NO_X analyzer as part of an APCO approved Alternate Emissions Monitoring System, emission readings shall be averaged over a 15 consecutive-minute period by either taking a cumulative 15-consecutive-minute sample reading or by taking at least five (5) readings evenly spaced out over the 15-consecutive-minute period.

Since the applicant does not use a portable analyzer to satisfy the monitoring requirements of District Rule 4306 the requirements of Section 5.5.4 do not apply.

Section 5.5.5 requires that for emissions source testing performed pursuant to Section 6.3.1 for the purpose of determining compliance with an applicable standard or numerical limitation of this rule, the arithmetic average of three (3) 30-consecutive-minute test runs shall apply. If two (2) of three (3) runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. Therefore, the following permit condition will be listed on the permit as follows:

- {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

Section 6.1, Recordkeeping

Section 6.1 requires that the records required by Sections 6.1.1 through 6.1.3 shall be maintained for five calendar years and shall be made available to the APCO upon request. Failure to maintain records or information contained in the records that demonstrate noncompliance with the applicable requirements of this rule shall constitute a violation of this rule.

A permit condition will be listed on the permit as follows:

- {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

Section 6.1.2 requires that the operator of a unit subject to Section 5.2 shall record the amount of fuel use at least on a monthly basis. Since the unit is not subject to the requirements listed in Section 5.2, it is not subject to Section 6.1.2 requirements.

Section 6.1.3 requires that the operator of a unit subject to Section 5.2.1 or 6.3.1 shall maintain records to verify that the required tune-up and the required monitoring of the operational characteristics have been performed. The unit is not subject to Section 6.1.3. Therefore, the requirements of this section do not apply to the unit.

Section 6.2, Test Methods

Section 6.2 identifies the following test methods as District-approved source testing methods for the pollutants listed:

Pollutant	Units	Test Method Required
NO_X	ppmv	EPA Method 7E or ARB Method 100
NO_X	lb/MMBtu	EPA Method 19
CO	ppmv	EPA Method 10 or ARB Method 100
Stack Gas O_2	%	EPA Method 3 or 3A, or ARB Method 100
Stack Gas Velocities	ft/min	EPA Method 2
Stack Gas Moisture Content	%	EPA Method 4

The following permit conditions will be listed on the permit as follows:

- {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]
- {2977} NO_X emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]
- {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]
- {2979} Stack gas oxygen (O_2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

Section 6.3, Compliance Testing

Section 6.3.1 requires that this unit be tested to determine compliance with the applicable requirements of section 5.1 and 5.2.3 not less than once every 12 months. Upon demonstrating compliance on two consecutive compliance source tests, the following source test may be deferred for up to thirty-six months.

The following permit conditions will be listed on the permit as follows:

- {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]
- {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]
- {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

Section 6.4, Emission Control Plan (ECP)

Section 6.4.1 requires that the operator of any unit shall submit to the APCO for approval an Emissions Control Plan according to the compliance schedule in Section 7.0 of District Rule 4306.

The proposed modified unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule and with periodic monitoring and source testing requirements. Therefore, this current application for the new proposed unit satisfies the requirements of the Emission Control Plan, as listed in Section 6.4 of District Rule 4306. No further discussion is required.

Section 7.0, Compliance Schedule

Section 7.0 indicates that an operator with multiple units at a stationary source shall comply with this rule in accordance with the schedule specified in Table 2, Section 7.1 of District Rule 4306.

The unit will be in compliance with the emissions limits listed in table 1, Section 5.1 of this rule, and periodic monitoring and source testing as required by District Rule 4306. Therefore, requirements of the compliance schedule, as listed in Section 7.1 of District Rule 4306, are satisfied. No further discussion is required.

Conclusion

Conditions will be incorporated into the permit in order to ensure compliance with each section of this rule, see attached draft permit(s). Therefore, compliance with District Rule 4306 requirements is expected.

Rule 4351 Boilers Steam Generators and Process Heaters – Phase 1

This rule is only applicable to unit C-3953-12.

This rule applies to boilers, steam generators, and process heaters at NO_x Major Sources that are not located west of Interstate 5 in Fresno, Kings, or Kern counties. If applicable, the emission limits, monitoring provisions, and testing requirements of this rule are satisfied when the unit is operated in compliance with Rule 4306. Therefore, compliance with this rule is expected.

Rule 4701 Internal Combustion Engines – Phase 1

This rule is only applicable to units C-3953-13-1 and –14-1.

Pursuant to Section 7.5.2.3 of District Rule 4702, as of June 1, 2006 District Rule 4701 is no longer applicable to diesel-fired emergency standby or emergency IC engines. Therefore, this diesel-fired emergency IC engine will comply with the requirements of District Rule 4702 and no further discussion is required.

Rule 4702 Internal Combustion Engines – Phase 2

This rule is only applicable to units C-3953-13-1 and –14-1.

The purpose of this rule is to limit the emissions of nitrogen oxides (NO_X), carbon monoxide (CO), and volatile organic compounds (VOC) from internal combustion engines.

This rule applies to any internal combustion engine with a rated brake horsepower greater than 50 horsepower.

Pursuant to Section 4.2, except for the requirements of Sections 5.7 and 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following condition:

1) An emergency standby engine as defined in Section 3.0 of this rule, and provided that it is operated with a nonresettable elapsed operating time meter. In lieu of a nonresettable time meter, the owner of an emergency engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Section 3.15 defines an "Emergency Standby Engine" as an internal combustion engine which operates as a temporary replacement for primary mechanical or electrical power during an unscheduled outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the operator. An engine shall be considered to be an emergency standby engine if it is used only for the following purposes: (1) periodic maintenance, periodic readiness testing, or readiness testing during and after repair work; (2) unscheduled outages, or to supply power while maintenance is performed or repairs are made to the primary power supply; and (3) if it is limited to operate 100 hours or less per calendar year for non-emergency purposes. An engine shall not be considered to be an emergency standby engine if it is used: (1) to reduce the demand for electrical power when normal electrical power line service has not failed, or (2) to produce power for the utility electrical distribution system, or (3) in conjunction with a voluntary utility demand reduction program or interruptible power contract.

Therefore, unit C-3953-14-1, the emergency standby IC engine powering an electrical generator involved with this project will only have to meet the requirements of Sections 5.7 and 6.2.3 of this Rule.

Pursuant to Section 4.3, except for the requirements of Section 6.2.3, the requirements of this rule shall not apply to an internal combustion engine that meets the following conditions:

1) The engine is operated exclusively to preserve or protect property, human life, or public health during a disaster or state of emergency, such as a fire or flood, and
2) Except for operations associated with Section 4.3.1.1, the engine is limited to operate no more than 100 hours per calendar year as determined by an operational nonresettable elapsed operating time meter, for periodic maintenance, periodic readiness testing, and readiness testing during and after repair work of the engine, and
3) The engine is operated with a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, unit C-3953-13-1, the emergency IC engine powering a firewater pump involved with this project will only have to meet the requirements of Section 6.2.3 of this Rule.

Section 5.7 of this Rule requires that the owner of an emergency standby engine shall comply with the requirements specified in Section 5.7.2 through Section 5.7.5 below:

1) Properly operate and maintain each engine as recommended by the engine manufacturer or emission control system supplier.

2) Monitor the operational characteristics of each engine as recommended by the engine manufacturer or emission control system supplier.

3) Install and operate a nonresettable elapsed operating time meter. In lieu of installing a nonresettable time meter, the owner of an engine may use an alternative device, method, or technique, in determining operating time provided that the alternative is approved by the APCO and is allowed by Permit-to-Operate or Stationary Equipment Registration condition. The owner of the engine shall properly maintain and operate the time meter or alternative device in accordance with the manufacturer's instructions.

Therefore, the following conditions will be listed on the DOC to ensure compliance:

C-3953-14-1 (Natural Gas IC engine electrical generator)

- This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

- During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

- This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

- An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

- This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

- This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

Section 6.2.3 requires that an owner claiming an exemption under Section 4.2 or Section 4.3 shall maintain annual operating records. This information shall be retained for at least five years, shall be readily available, and submitted to the APCO upon request and at the end of each calendar year in a manner and form approved by the APCO. Therefore, the following conditions will be listed on the DOC to ensure compliance:

C-3953-13-1 (Diesel IC engine fire pump)

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

In addition, the following condition will be listed on the DOC to ensure compliance:

- {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

- {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

- {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

C-3953-14-1 (Natural Gas IC engine electrical generator)

- The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

- All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

Rule 4703 Stationary Gas Turbines

This rule is only applicable to units C-3953-10-1 and -11-1.

Rule 4703 is applicable to stationary gas turbines with a rating greater than 0.3 megawatts. The facility proposes to install two 180 MW gas turbines. Therefore the requirements of this rule apply to the proposed turbines.

Section 5.1 – NO_X Emission Requirements:

Section 5.1.1 (Tier I) of this rule limits the NO_X emissions from stationary gas turbine systems greater than 10 MW, and equipped with Selective Catalytic Reduction (SCR). Since the proposed turbines will meet the more stringent Tier 2 emission equirements in Section 5.1.2, compliance with this section is assured.

Section 5.1.2 (Tier 2) of this rule limits the NO_X emissions from combined cycle, stationary gas turbine systems rated at greater than 10 MW to 5 ppmv @ 15% O_2 (Standard option) and 3 ppmv @ 15% O_2 (Enhanced Option). Section 7.2.1 (Table 7-1) sets a compliance date of April 30, 2004 for the Standard Option and Section 7.2.4 sets a compliance date of April 30, 2008 for the Enhanced Option. As discussed above, the proposed turbines will be limited to 2.0 ppmv @ 15% O_2 (based on a 1-hour average), therefore compliance with this section is expected. The following conditions will ensure continued compliance with the requirements of this section:

- Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

Section 5.2 – CO Emission Requirements:

Per Table 5-3 of section 5.2, the CO emissions concentration from the proposed turbines (General Electric Frame 7) must be less than 25 ppmvd @ 15% O_2. Rule 4703 does not include a specific averaging period requirement for demonstrating compliance with the CO emission limit. However, District practice is to have an applicant demonstrate compliance with the CO emissions on a turbine with three hour averaging periods. Therefore, compliance with the CO emission limit shall be demonstrated by an average over a three hour period.

Avenal Power Center is proposing a CO emission concentration limit of 2 ppmvd @ 15% O_2 and will demonstrate compliance using three hour averaging periods. Therefore, the proposed turbines will be operating the turbine in compliance with the CO emission requirements of this rule. The DEL conditions shown in the Section 5.1.2 compliance section will ensure continued compliance with the requirements of this section.

Section 5.3 – Startup and Shutdown Requirements:

This section states that the emission limit requirements of Sections 5.1.1, 5.1.2 or 5.2 shall not apply during startup, shutdown, or a reduced load period provided an operator complies with the requirements specified below:

- The duration of each startup or each shutdown shall not exceed two hours, and the duration of each reduced load period shall not exceed one hour, except as provided below.
- The emission control system shall be in operation and emissions shall be minimized insofar as technologically feasible during startup, shutdown, or a reduced load period.
- An operator may submit an application to allow more than two hours for each startup or each shutdown or more than one hour for each reduced load period provided the operator meets all of the conditions specified in the rule.

Avenal Power Center is proposing to incorporate startup and shutdown provisions into the operating requirements for each of the proposed turbines. They have proposed that the duration of each startup or shutdown event will last no more than six hours per day. Since this proposed duration is longer than what is allowed in Section 5.3.1.1, the facility must meet the requirements of Section 5.3.3.2. Section 5.3.3.2 states that at a minimum, a justification for the increased duration shall include the following:

A clear identification of the control technologies or strategies to be utilized; and

The facility has identified the following control technologies:

- Dry low-NOx combustors in the turbines;
- Oxidation catalyst in the HRSGs;
- SCR in the HRSGs;
- Good combustion practices;

- Upon startup, the ammonia injection upstream of the SCR catalyst will be started as soon as the catalyst and ammonia injection system warm to their minimum operating temperatures specified by the SCR vendor.

A description of what physical conditions prevail during the period that prevent the controls from being effective; and

The combined-cycle equipment startup duration depends on how fast the thick steel walls of the common steam turbine can be warmed to operating temperature without generating stress cracks. Steam developed in the HRSG from the heated turbine exhaust is admitted into the steam turbine at a controlled temperature to heat it as rapidly as possible without causing stress cracking. The steam temperature is controlled by limiting the load on the gas turbine. The allowable rate of temperature increase at the steam turbine is the limiting factor determining how quickly the gas turbines can achieve higher loads. This, in turn, limits how quickly the gas turbine combustors can achieve the lowest emitting operating mode, and this latter step is necessary for the units to be able to comply with the limits of Rule 4703.

A reasonably precise estimate as to when the physical conditions will have reached a state that allows for the effective control of emissions; and

Startup information provided by the turbine and HRSG vendors indicates that for a cold startup, a minimum of four hours is required for the unit to come into compliance with the limits of Rule 4703. Depending on the temperature of the steam turbine at the time the start is initiated, shorter durations may be possible.

A detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity; and

The facility has provided the District with a detailed list of activities to be performed during the period and a reasonable explanation for the length of time needed to complete each activity.

A description of the material process flow rates and system operating parameters, etc., the operator plans to evaluate during the process optimization; and an explanation of how the activities and process flow affect the operation of the emissions control equipment; and

The startup duration depends on the allowable ramp rate of the steam temperature to the steam turbine, which depends on the acceptable rate of increase of the metal temperature of the HRH and HP bowls at the steam turbine inlets. The maximum steam temperature is set by applying an allowable differential above the metal temperature. The differential is determined by the steam turbine supplier, and is imposed by the supplier's control system to avoid damage to the steam turbine from thermal stress. The control system limits gas turbine load to control the steam temperature. Manual override of the gas turbine load limit by the operator reduces the life expectancy of the steam turbine.

In addition, the time prior to initiation of ammonia flow to the SCR system depends on the temperature of the SCR catalyst. The catalyst bed is warmed by the exhaust flow from the gas turbine. The total mass of metal and water in the HRSG tubes, piping, and drums removes heat from the gas turbine exhaust as it warms. This extends the time required to heat the SCR catalyst to the minimum temperature at which ammonia may be injected upstream of the catalyst bed to begin reducing NOx to N_2. The steam turbine and SCR catalyst temperatures are all monitored by the plant control system, and the turbine ramp rate and SCR initiation sequence are governed by the equipment/system manufactúrer's recommended procedures.

The basis for the requested additional duration.

The startup curve in Attachment I and the description of activities above demonstrate that the minimum time required for a cold startup of the plant as currently configured is approximately 4 hours. This startup time is contingent upon all of the activities being performed in time to support subsequent activities. Any delay in preparation of the supporting systems will result in a corresponding delay in startup and/or loading of the gas turbines. To be confident that the startup time allowed is adequate and will not be exceeded, one hour is added to the above startup time to account for possible delays.

Since the facility has demonstrated compliance and provided all the information asked for in Section 5.3.3.2, the proposed increase in startup and shutdown emissions is compliant with District Rule 4703. The following conditions will ensure continued compliance with the requirements of this section:

- During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

- Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

- The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

- The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

Section 6.2 - Monitoring and Recordkeeping:

Section 6.2.1 requires the owner to operate and maintain continuous emissions monitoring equipment for NO_X and oxygen, or install and maintain APCO-approved alternate monitoring. As discussed earlier in this evaluation, the applicant operates a Continuous Emissions Monitoring System (CEMS) that monitors the NO_X and oxygen content of the turbine exhaust. Therefore, the requirements of this section have been satisfied. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4335(b)(1)]

Section 6.2.2 specifies monitoring requirements for turbines without exhaust-gas NO_X control devices. Each of the proposed turbines will be equipped with an SCR system that is designed to control NO_X emissions. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.3 requires that for units 10 MW and greater that operated an average of more than 4,000 hours per year over the last three years before August 18, 1994, the owner or operator shall monitor the exhaust gas NO_X emissions. The proposed turbines have not been installed. Therefore, they were not in operation prior to August 18, 1994 and the requirements of this section are not applicable. No further discussion is required.

Section 6.2.4 requires the facility to maintain all records for a period of five years from the date of data entry and shall make such records available to the APCO upon request. Avenal Power Center will be required to maintain all records for at least five years and make them available to the APCO upon request. Therefore, the proposed turbines will be operating in compliance with the five year recordkeeping requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

Section 6.2.5 requires that the owner or operator shall submit to the APCO, before issuance of the Permit to Operate, information correlating the control system operating to the associated measure NO_X output. This information may be used by the APCO to determine compliance when there is no continuous emission monitoring system for NO_X available or when the continuous emissions monitoring system is not operating properly. Avenal Power Center will be required, by permit condition, to submit information correlating the NO_X control system operating parameters to the associated measured NO_X output. Therefore, the proposed turbines will be operating in compliance with the control system operating parameter requirements of this rule. The following condition will ensure continued compliance with the requirements of this section:

- The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

Section 6.2.6 requires the facility to maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local startup and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used. Avenal Power Center will be required to maintain records of each item listed above. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule. The following conditions will ensure continued compliance with the requirements of this section:

- The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

- The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

Section 6.2.7 establishes recordkeeping requirements for units that are exempt pursuant to the requirements of Section 4.2. Each of the proposed turbines is subject to the requirements of this rule. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.2.8 requires owners or operators performing startups or shutdowns to keep records of the duration of each startup and shutdown. As discussed in the Section 6.2.6 discussion above for this rule, Avenal Power Center will be required, by permit condition, to maintain records of the date, time and duration or each startup and shutdown. Therefore, the proposed turbines will be operating in compliance with the recordkeeping requirements of this rule.

Sections 6.3 and 6.4 - Compliance Testing:

Section 6.3.1 states that the owner or operator of any stationary gas turbine system subject to the provisions of Section 5.0 of this rule shall provide source test information annually regarding the exhaust gas NO_X and CO concentrations. The turbines operated by Avenal Power Center are subject to the provisions of Section 5.0 of this rule. Therefore, each turbine is required to test annually to demonstrate compliance with the exhaust gas NO_X and CO concentrations. The following condition will ensure continued compliance with the requirements of this section:

- Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

Section 6.3.2 specifies source testing requirements for units operating less than 877 hours per year. As discussed above, the proposed turbines will be allowed to operate in excess of 877 hours per year. Therefore, the requirements of this section are not applicable and no further discussion is required.

Section 6.3.3 states that units with intermittently operated auxiliary burners shall demonstrate compliance with the auxiliary burner both on and off. The following condition will ensure continued compliance with the requirements of this section:

- Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

Section 6.4 states that the facility must demonstrate compliance annually with the NO_X and CO emission limits using the following test methods, unless otherwise approved by the APCO and EPA:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.

- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.

- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.

- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

The following condition will ensure continued compliance with the test method requirements of this section:

- The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

Conclusion:

Conditions will be incorporated into these permits in order to ensure compliance with each applicable section of this rule. Therefore, compliance with the requirements of Rule 4703 is expected and no further discussion is required.

Rule 4801 Sulfur Compounds

Per Section 3.1, a person shall not discharge into the atmosphere sulfur compounds, which would exist as a liquid or gas at standard conditions, exceeding in concentration at the point of discharge: 0.2 % by volume calculated as SO_2 on a dry basis averaged over 15 consecutive minutes:

i. C-3953-10-1 and –11-1 (Turbines)

The sulfur of the natural gas fuel is 1.0 gr/100 dscf.

The ratio of the volume of the SO_X exhaust to the entire exhaust for one MMBtu of fuel combusted is:

Volume of SO_X: $V = \frac{n \cdot R \cdot T}{P}$

Where:

- n = number of moles of SO_X produced per MMBtu of fuel.
- Weight of SO_X as SO_2 is 64 lb/(lb-mol)
- $n = \frac{0.00282\ lb}{MMBtu} \times \frac{1\ (lb-mol)}{64\ lb} = 0.000045\ (lb-mol)$

- $R = \dfrac{0.7302\, ft^3 \cdot atm}{(lb - mol)°R}$
- T = 500 °R
- P = 1 atm

Thus, volume of SO_X per MMBtu is:

$$V = \frac{n \cdot R \cdot T}{P}$$

$$V = \frac{0.000045\ (lb - mol) \cdot \dfrac{0.7302\ ft^3 \cdot atm}{(lb - mol)\ °R} \cdot 500\ °R}{1\ atm}$$

$$V = 0.016\ ft^3$$

Since the total volume of exhaust per MMBtu is 8,578 scf, the ratio of SO_X volume to exhaust volume is

$$= \frac{0.016}{8{,}578} = 0.0000019 = 1.9\ ppmv = 0.00019\%\ by\ volume$$

1.9 ppmv ≤ 2000 ppmv, therefore the turbines, the boiler, and the gas engine are expected to comply with Rule 4801.

ii. C-3953-12-1 (Boiler)

Using the ideal gas equation and the emission factors presented in Section VII, the sulfur compound emissions are calculated as follows:

Volume $SO_2 = \dfrac{n\,RT}{P}$

With:

N = moles SO_2
T (Standard Temperature) = 60°F = 520°R
P (Standard Pressure) = 14.7 psi
R (Universal Gas Constant) = $\dfrac{10.73\,psi \cdot ft^3}{lb \cdot mol \cdot °R}$

$$\frac{0.00282\, lb - SOx}{MMBtu} \times \frac{MMBtu}{8{,}578\, dscf} \times \frac{1\, lb \cdot mol}{64\, lb} \times \frac{10.73\, psi \cdot ft^3}{lb \cdot mol \cdot °R} \times \frac{520°R}{14.7\, psi} \times \frac{1{,}000{,}000 \cdot parts}{million} = 1.97 \frac{parts}{million}$$

$$SulfurConcentration = 1.97\frac{parts}{million}$$ < 2,000 ppmv (or 0.2%)

Therefore, compliance with District Rule 4801 requirements is expected.

iii. C-3953-13-1 (Diesel IC engine powering a fire water pump)

Using the ideal gas equation, the sulfur compound emissions are calculated as follows:

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73 \text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

$$\frac{0.000015\, lb - S}{lb - fuel} \times \frac{7.1\text{ lb}}{\text{gal}} \times \frac{64\text{ lb} - SO_2}{32\text{ lb} - S} \times \frac{1\text{ MMBtu}}{9{,}051\text{ scf}} \times \frac{1\text{ gal}}{0.137\text{ MMBtu}} \times \frac{\text{lb} - \text{mol}}{64\text{ lb} - SO_2} \times \frac{10.73\text{ psi} - \text{ft}^3}{\text{lb} - \text{mol} - {}^\circ\text{R}} \times \frac{520^\circ\text{R}}{14.7\text{ psi}} \times 1{,}000{,}000 = 1.0\text{ ppmv}$$

Since 1.0 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

iv. C-3953-14-1 (Natural gas IC engine powering an electrical generator)

Volume SO_2 = (n x R x T) ÷ P
n = moles SO_2
T (standard temperature) = 60 °F or 520 °R
R (universal gas constant) = $\frac{10.73 \text{psi} \cdot \text{ft}^3}{\text{lb} \cdot \text{mol} \cdot {}^\circ\text{R}}$

$$2.85\ \frac{lb - S}{MMscf - gas} \times \frac{1\, scf - gas}{1{,}000\, Btu} \times \frac{1\, MMBtu}{8{,}578\, scf} \times \frac{1\, lb - mol}{64\, lb - S} \times \frac{10.73\, psi - ft^3}{lb - mol - {}^\circ R} \times \frac{520^\circ R}{14.7\, psi} \times 1{,}000{,}000 = 1.97\ \text{ppmv}$$

Since 1.97 ppmv is ≤ 2,000 ppmv, this engine is expected to comply with Rule 4801. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3491} This IC engine shall be fired on Public Utility Commission (PUC) regulated natural gas only. [District Rules 2201 and 4801]

District Rule 8011	***General Requirements***
District Rule 8021	***Construction, Demolition, Excavation, Extraction And Other Earthmoving Activities***
District Rule 8031	***Bulk Materials***
District Rule 8041	***Carryout And Trackout***
District Rule 8051	***Open Areas***
District Rule 8061	***Paved And Unpaved Roads***
District Rule 8071	***Unpaved Vehicle/Equipment Traffic Areas***
District Rule 8081	***Agricultural Sources***

The construction of this new facility will involve excavation, extraction, construction, demolition, outdoor storage piles, paved and unpaved roads.

The regulations from the 8000 Series District Rules contain requirements for the control of fugitive dust. These requirements apply to various sources, including construction, demolition, excavation, extraction, mining activities, outdoor storage piles, paved and unpaved roads. Compliance with these regulations will be required by the following permit conditions, which will be listed on each permit as follows:

- Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

- An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

- An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

- Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

- Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

- Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

- On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

- Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

- Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

California Environmental Quality Act (CEQA)

The District determined that the California Energy Commission (CEC) is the public agency having principal responsibility for approving the project, therefore establishing the CEC as the Lead Agency (CEQA Guidelines §15051(b). The District is a Responsible Agency for the project because of its discretionary approval power over the project via its Permits Rule (Rule 2010) and New Source Review Rule (Rule 2201), (CEQA Guidelines §15381). The District's engineering evaluation of the project (this document) demonstrates that compliance with District rules and permit conditions would reduce Stationary Source emissions from the project to levels below the District's significance thresholds for criteria pollutants. The District has determined that no additional findings are required (CEQA Guidelines §15096(h)).

California Health & Safety Code, Section 42301.6 (School Notice)

As discussed in Section III of this evaluation, this site is not located within 1,000 feet of a school. Therefore, pursuant to California Health and Safety Code 42301.6, a school notice is not required.

California Health & Safety Code, Section 44300 (Air Toxic "Hot Spots")

Section 44300 of the California Health and Safety Code requires submittal of an air toxics "Hot Spot" information and assessment report for sources with criteria pollutant emissions greater than 10 tons per year. However, Section 44344.5 (b) states that a new facility shall not be required to submit such a report if all of the following conditions are met:

1. The facility is subject to a district permit program established pursuant to Section 42300.

2. The district conducts an assessment of the potential emissions or their associated risks, and finds that the emissions will not result in a significant risk.

3. The district issues a permit authorizing construction or operation of the new facility.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than ten (10) in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

Title 13 California Code of Regulations (CCR), Section 2423 – Exhaust Emission Standards and Test Procedures, Off-Road Compression-Ignition Engines and Equipment (Required by Title 17 CCR, Section 93115 for New Emergency Diesel IC Engines)

The requirements of this section are only applicable to C-3953-13-1.

Particulate Matter and VOC + NO_X, and CO Exhaust Emissions Standards:

This regulation stipulates that off-road compression-ignition engines shall not exceed the following applicable emissions standards.

Title 13 CCR, Section 2423 lists a diesel particulate emission standard of 0.15 g/bhp-hr (with 1.341 bhp/kW, equivalent to 0.20 g/kW-hr) for 2003 - 2005 model year engines with maximum power ratings of 174.3 - 301.6 bhp (equivalent to 130 - 225 kW). The PM standards given in Title 13 CCR, Section 2423 are less stringent than the PM standards given in Title 17 CCR, Section 93115 (ATCM), thus the ATCM standards are the required standards and will be discussed in the following section.

Title 17 CCR, Section 93115, (e)(2)(A)(3)(b) stipulates that new stationary emergency diesel-fueled CI engines (> 50 bhp) must meet the VOC + NO_X, and CO standards for off-road engines of the same model year and maximum rated power as specified in the Off-Road Compression-Ignition Engine Standards (Title 13 CCR, Section 2423) or the Tier 1 standards for an off-road engine if no standards have been established for an off-road engine of the same model year and maximum rated power.

In addition, Title 17 CCR, Section 93115, (e)(2)(A)(4)(a)(II) allows new direct-drive emergency fire pump engines to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (title 13 CCR, section 2423) until three years after the date the Tier 3 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 3 emission standards, until three years after the date the Tier 4 standards are applicable for off-road engines with the same maximum rated power. At that time, new direct-drive emergency diesel-fueled fire-pump engines (>50 bhp) are required to meet the Tier 4 emission standards; and not operate more than the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 – "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition, which is incorporated herein by reference. In addition, this subsection does not limit engine operation for emergency use and for emission testing to show compliance with (e)(2)(A)4. For this project the proposed emergency diesel IC engine will be used to power a firewater pump and is therefore allowed to meet the Tier 2 emission standards specified in the Off-Road Compression Ignition Engine Standards for off-road engines three years after the applicable dates specified. This additional three-year allowance is reflected in the following table.

The engine involved with this project is a certified 2007 model engine. The following table compares the requirements of Title 13 CCR, Section 2423 to the emissions factors for the 288 bhp Cummins Model #CFP83-F40 diesel-fired emergency IC engine as given by the manufacturer (for NO_X + VOC and PM emissions).

Requirements of Title 13 CCR, Section 2423							
Source	Maximum Rated Power	Model Year	NO_X	VOC	NO_X + VOC	CO	PM
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	1996-2002 (Tier 1)	6.9 g/bhp-hr (9.2 g/kW-hr)	1.0 g/bhp-hr (1.3 g/kW-hr)	--	8.5 g/bhp-hr (11.4 g/kW-hr)	0.40 g/bhp-hr (0.54 g/kW-hr)
Title 13 CCR, §2423	**174.3 – 301.6 bhp (130 - 225 kW)**	**2003-2005, extended to 2008 (Tier 2)**	--	--	**4.9 g/bhp-hr (6.6 g/kW-hr)**	**2.6 g/bhp-hr (3.5 g/kW-hr)**	**0.15 g/bhp-hr (0.20 g/kW-hr)**
Title 13 CCR, §2423	174.3 – 301.6 bhp (130 - 225 kW)	2006 and later, extended to 2009 (Tier 3)	--	--	3.0 g/bhp-hr (4.0 g/kW-hr)	2.6 g/bhp-hr (3.5 g/kW-hr)	0.15 g/bhp-hr (0.20 g/kW-hr)
Cummins, Model #CFP83-F40	288 bhp	2007	--	--	3.8g/bhp-hr (5.1 g/kW-hr)	0.447 g/bhp-hr (0.60 g/kW-hr)	0.059 g/bhp-hr (0.079 g/kW-hr)
Meets Standard?			N/A	N/A	Yes	Yes	Yes

As presented in the table above, the proposed engine will satisfy the requirements of this section and compliance is expected.

The engine manufacturer's data and/or CARB/EPA engine certification for this engine lists a NO_X emissions factor of 3.4 g/bhp-hr, a VOC emissions factor of 0.38 g/bhp-hr, a NO_X + VOC emission factor of 3.8 g/bhp-hr, a CO emission factor of 0.447 g/bhp-hr, and a PM_{10} emissions factor of 0.059 g/bhp-hr, all of which satisfy the requirements of 13 CCR, Section 2423. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

<u>Right of the District to Establish More Stringent Standards:</u>

This regulation also stipulates that the District:

1. May establish more stringent diesel PM, NO_X + VOC, VOC, NO_X, and CO emission rate standards; and

2. May establish more stringent limits on hours of maintenance and testing on a site-specific basis; and
3. Shall determine an appropriate limit on the number of hours of operation for demonstrating compliance with other District rules and initial start-up testing

The District has not established more stringent standards at this time. Therefore, the standards previously established in this Section will be utilized.

Title 17 California Code of Regulations (CCR), Section 93115 - Airborne Toxic Control Measure (ATCM) for Stationary Compression-Ignition (CI) Engines

The requirements of this section are only applicable to C-3953-13-1.

Emergency Operating Requirements:

This regulation stipulates that no owner or operator shall operate any new or in-use stationary diesel-fueled compression ignition (CI) emergency standby engine, in response to the notification of an impending rotating outage, unless specific criteria are met.

This section applies to emergency standby IC engines that are permitted to operate during non-emergency conditions for the purpose of providing electrical power. However, District Rule 4702 states that emergency standby IC engines may only be operated during non-emergency conditions for the purposes of maintenance and testing. Therefore, this section does not apply and no further discussion is required.

Fuel and Fuel Additive Requirements:

This regulation also stipulates that as of January 1, 2006 an owner or operator of a new or in-use stationary diesel-fueled CI emergency standby engine shall fuel the engine with CARB Diesel Fuel.

Since the engine involved with this project is a new or in-use stationary diesel-fueled CI emergency standby engine, these fuel requirements are applicable. Therefore, the following condition (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

At-School and Near-School Provisions:

This regulation stipulates that no owner or operator shall operate a new stationary emergency diesel-fueled CI engine, with a PM_{10} emissions factor > than 0.01 g/bhp-hr, for non-emergency use, including maintenance and testing, during the following periods:

1. Whenever there is a school sponsored activity, if the engine is located on school grounds, and
2. Between 7:30 a.m. and 3:30 p.m. on days when school is in session, if the engine is located within 500 feet of school grounds.

The District has verified that the engine is not located within 500 feet of a K-12 school. Therefore, conditions prohibiting non-emergency usage of the engine during school hours will not be placed on the permit.

Recordkeeping Requirements:

This regulation stipulates that as of January 1, 2005, each owner or operator of an emergency diesel-fueled CI engine shall keep a monthly log of usage that shall list and document the nature of use for each of the following:

a. Emergency use hours of operation;
b. Maintenance and testing hours of operation;
c. Hours of operation for emission testing;
d. Initial start-up hours; and
e. If applicable, hours of operation to comply with the testing requirements of National Fire Protection Association (NFPA) 25 — "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 1998 edition;
f. Hours of operation for all uses other than those specified in sections 'a' through 'd' above; and
g. For in-use emergency diesel-fueled engines, the fuel used. The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:

    I. Identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
    II. Amount of fuel purchased;
    III. Date when the fuel was purchased;
    IV. Signature of owner or operator or representative of owner or operator who received the fuel; and
    V. Signature of fuel provider indicating fuel was delivered.

The proposed new emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

- {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

PM Emissions and Hours of Operation Requirements for New Diesel Engines:

This regulation stipulates that as of January 1, 2005, no person shall operate any new stationary emergency diesel-fueled CI engine that has a rated brake horsepower greater than 50, unless it meets all of the following applicable emission standards and operating requirements.

1. Emits diesel PM at a rate greater than 0.01 g/bhp-hr or less than or equal to 0.15 g/bhp-hr; or
2. Meets the current model year diesel PM standard specified in the Off-Road Compression Ignition Engine Standards for off-road engines with the same maximum rated power (Title 13 CCR, Section 2423), whichever is more stringent; and
3. Does not operate more than 50 hours per year for maintenance and testing purposes. Engine operation is not limited during emergency use and during emissions source testing to show compliance with the ATCM.

The proposed emergency diesel IC engine powering a firewater pump is exempt from the operating hours limitation provided the engine is only operated the amount of hours necessary to satisfy National Fire Protection Association (NFPA) regulations. Therefore, the following conditions (previously proposed in this engineering evaluation) will be listed on the DOC to ensure compliance:

- Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

- {3816} This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

IX. RECOMMENDATION:

Compliance with all applicable prohibitory rules and regulations is expected. Issue the Final Determination of Compliance for the facility subject to the conditions presented in Attachment A.

X. BILLING INFORMATION:

Annual Permit Fees			
Permit Number	Fee Schedule	Fee Description	Annual Fee
C-3953-10-1	3020-08B-B	180,000 kW	$12,229.00
C-3953-11-1	3020-08B-B	180,000 kW	$12,229.00
C-3953-12-1	3020-02-H	37.4 MMBtu/hr boiler	$953.00
C-3953-13-1	3020-10-C	288 bhp IC engine	$222.00
C-3953-14-1	3020-10-E	860 bhp IC engine	$557.00

ATTACHMENT A

FDOC CONDITIONS

EQUIPMENT DESCRIPTION, UNIT C-3953-10-1:
180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program. [District Rule 2540]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,087 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

7. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201]

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

12. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

13. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns~~,~~ provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

14. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

15. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

16. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in

accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

18. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

19. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

20. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

21. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

22. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

23. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

24. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

25. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

26. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the equipment malfunction or failure, the date and cause of the initial failure, the estimated

emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

35. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from

the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

37. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

38. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

42. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

43. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

44. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance

with the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

45. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

48. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

49. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

50. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

52. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

53. The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

54. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

55. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

56. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

57. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

58. Disturbances of soil related to any construction, demolition, excavation, extraction, or other earthmoving activities shall comply with the requirements for fugitive dust control in District Rule 8021 unless specifically exempted under Section 4.0 of Rule 8021 or Rule 8011. [District Rules 8011 and 8021]

59. An owner/operator shall submit a Dust Control Plan to the APCO prior to the start of any construction activity on any site that will include 10 acres or more of disturbed surface area for residential developments, or 5 acres or more of disturbed surface area for non-residential development, or will include moving, depositing, or relocating more than 2,500 cubic yards per day of bulk materials on at least three days. [District Rules 8011 and 8021]

60. An owner/operator shall prevent or cleanup any carryout or trackout in accordance with the requirements of District Rule 8041 Section 5.0, unless specifically exempted under Section 4.0 of Rule 8041 (8/19/04) or Rule 8011(8/19/04). [District Rules 8011 and 8021]

61. Whenever open areas are disturbed, or vehicles are used in open areas, the facility shall comply with the requirements of Section 5.0 of District Rule 8051, unless specifically exempted under Section 4.0 of Rule 8051 or Rule 8011. [District Rules 8011 and 8051]

62. Any paved road or unpaved road shall comply with the requirements of District Rule 8061 unless specifically exempted under Section 4.0 of Rule 8061 or Rule 8011. [District Rules 8011 and 8061]

63. Water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure shall be applied to unpaved vehicle travel areas as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

64. Where dusting materials are allowed to accumulate on paved surfaces, the accumulation shall be removed daily or water and/or chemical/organic dust stabilizers/suppressants shall be applied to the paved surface as required to maintain continuous compliance with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011 and limit Visible Dust Emissions (VDE) to 20% opacity. [District Rule 8011 and 8071]

65. On each day that 50 or more Vehicle Daily Trips or 25 or more Vehicle Daily Trips with 3 axles or more will occur on an unpaved vehicle/equipment traffic area, permittee shall apply water, gravel, roadmix, or chemical/organic dust stabilizers/suppressants, vegetative materials, or other District-approved control measure as required to limit Visible Dust Emissions to 20% opacity and comply with the requirements for a stabilized unpaved road as defined in Section 3.59 of District Rule 8011. [District Rule 8011 and 8071]

66. Whenever any portion of the site becomes inactive, Permittee shall restrict access and periodically stabilize any disturbed surface to comply with the conditions for a stabilized surface as defined in Section 3.58 of District Rule 8011. [District Rules 8011 and 8071]

67. Records and other supporting documentation shall be maintained as required to demonstrate compliance with the requirements of the rules under Regulation VIII only for those days that a control measure was implemented. Such records shall include the type of control measure(s) used, the location and extent of coverage, and the date, amount, and frequency of application of dust suppressant, manufacturer's dust suppressant product information sheet that identifies the name of the dust suppressant and application instructions. Records shall be kept for one year following project completion that results in the termination of all dust generating activities. [District Rules 8011, 8031, and 8071]

EQUIPMENT DESCRIPTION, UNIT C-3953-11-1:
180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

5. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

6. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

7. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

8. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

9. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

10. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

11. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content of no greater than 1.0 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

12. Annual average of the sulfur content of the CTG shall not exceed 0.36 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

13. The owner or operator shall install, certify, maintain, operate and quality-assure a Continuous Emission Monitoring System (CEMS) which continuously measures and records the exhaust gas NO_X, CO and O_2 concentrations. Continuous emissions monitor(s) shall be capable of monitoring emissions during normal operating conditions, and during startups and shutdowns, provided the CEMS passes the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEMS cannot be demonstrated during startup conditions, CEMS results during startup and shutdown events shall be replaced with startup emission rates obtained from source testing to determine compliance with emission limits contained in this document. [District Rules 1080 and 4703 and 40 CFR 60.4340(b)(1)]

14. The CEMS shall complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the EPA. [District Rule 1080 and 40 CFR 60.4345(b)]

15. The NO_X, CO and O_2 CEMS shall meet the requirements in 40 CFR 60, Appendix F Procedure 1 and Part 60, Appendix B Performance Specification 2 (PS 2), or shall meet equivalent specifications established by mutual agreement of the District, the ARB, and the EPA. [District Rule 1080 and 40 CFR 60.4345(a)]

16. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

17. The owner/operator shall perform a relative accuracy test audit (RATA) for NO_X, CO and O_2 as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality

assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

18. APCO or an authorized representative shall be allowed to inspect, as determined to be necessary, the required monitoring devices to ensure that such devices are functioning properly. [District Rule 1080]

19. Results of the CEM system shall be averaged over a one hour period for NO_X emissions and a three hour period for CO emissions using consecutive 15-minute sampling periods in accordance with all applicable requirements of CFR 60.13. [District Rule 4703 and 40 CFR 60.13]

20. Results of continuous emissions monitoring shall be reduced according to the procedures established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

21. The owner or operator shall, upon written notice from the APCO, provide a summary of the data obtained from the CEM systems. This summary shall be in the form and the manner prescribed by the APCO. [District Rule 1080]

22. The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

23. Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

24. The owner or operator shall submit a written report of CEM operations for each calendar quarter to the APCO. The report is due on the 30th day following the end of the calendar quarter and shall include the following: Time intervals, data and magnitude of excess NOx emissions, nature and the cause of excess (if known), corrective actions taken and preventive measures adopted; Averaging period used for data reporting corresponding to the averaging period specified in the emission test period used to determine compliance with an emission standard; Applicable time and date of each period during which the CEM was inoperative (monitor downtime), except for zero and span checks, and the nature of system repairs and adjustments; A negative declaration when no excess emissions occurred. [District Rule 1080 and 40 CFR 60.4375(a) and 60.4395]

25. Permittee shall notify the District of any breakdown condition as soon as reasonably possible, but no later than one hour after its detection, unless the owner or operator demonstrates to the District's satisfaction that the longer reporting period was necessary. [District Rule 1100, 6.1]

26. The District shall be notified in writing within ten days following the correction of any breakdown condition. The breakdown notification shall include a description of the

equipment malfunction or failure, the date and cause of the initial failure, the estimated emissions in excess of those allowed, and the methods utilized to restore normal operations. [District Rule 1100, 7.0]

27. Emission rates from this unit (with duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) – 17.20 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) – 5.89 lb/hr and 2.0 ppmvd @ 15% O2; CO – 10.60 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 11.78 lb/hr; or SOx (as SO2) – 6.65 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

28. Emission rates from this unit (without duct burner firing), except during startup and shutdown periods, shall not exceed any of the following limits: NOx (as NO2) - 13.55 lb/hr and 2.0 ppmvd @ 15% O2; VOC (as methane) - 3.34 lb/hr and 1.4 ppmvd @ 15% O2; CO – 8.35 lb/hr and 2.0 ppmvd @ 15% O2; PM10 – 8.91 lb/hr; or SOx (as SO2) – 5.23 lb/hr. NOx (as NO2) emission limits are one hour rolling averages. All other emission limits are three hour rolling averages. [District Rules 2201, 4001, and 4703]

29. During start-up and shutdown, CTG exhaust emission rates shall not exceed any of the following limits: NO_X (as NO_2) – 160 lb/hr; CO – 1,000 lb/hr; VOC (as methane) – 16 lb/hr; PM_{10} – 11.78 lb/hr; SO_X (as SO_2) – 6.652 lb/hr; or NH_3 – 32.13 lb/hr. [District Rules 2201 and 4703]

30. Daily emissions from the CTG shall not exceed the following limits: NO_X (as NO_2) – 412.8 lb/day; CO – 254.4 lb/day; VOC – 141.4 lb/day; PM_{10} – 282.7 lb/day; SO_X (as SO_2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

31. Emissions from this unit, on days when a startup and/or shutdown occurs, shall not exceed the following limits: NOx (as NO2) – 789.6 lb/day; VOC – 202.0 lb/day; CO – 5,590.8 lb/day; PM10 – 282.7 lb/day; SOx (as SO2) – 159.6 lb/day, or NH_3 – 771.1 lb/day. [District Rule 2201]

32. The ammonia (NH3) emissions shall not exceed 10 ppmvd @ 15% O2 over a 24 hour rolling average. [District Rule 2201]

33. The CTG shall be fired exclusively on PUC-regulated natural gas with a sulfur content no greater than 1.0 grain of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201 and 40 CFR 60.4330(a)(2)]

34. Annual emissions from the CTG, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 143,951 lb/year; CO – 197,928 lb/year; VOC – 34,489 lb/year; PM_{10} – 80,656 lb/year; or SO_X (as SO_2) – 16,694 lb/year; or NH_3 – 208,708 lb/year. [District Rule 2201]

35. The duration of each startup or shutdown shall not exceed six hours. Startup and shutdown emissions shall be counted toward all applicable emission limits. [District Rules 2201 and 4703]

36. Each one hour period shall commence on the hour. Each one hour period in a three hour rolling average will commence on the hour. The three hour average will be compiled from the three most recent one hour periods. Each one hour period in a twenty-four hour average for ammonia slip will commence on the hour. [District Rule 2201]

37. Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Each month in the twelve consecutive month rolling average emissions shall commence at the beginning of the first day of the month. The twelve consecutive month rolling average emissions to determine compliance with annual emissions limitations shall be compiled from the twelve most recent calendar months. [District Rule 2201]

38. Startup shall be defined as the period of time during which a unit is brought from a shutdown status to its operating temperature and pressure, including the time required by the unit's emission control system to reach full operations. Shutdown shall be defined as the period of time during which a unit is taken from an operational to a non-operational status by allowing it to cool down from its operating temperature to ambient temperature as the fuel supply to the unit is completely turned off. [District Rules 2201 and 4703]

39. The emission control systems shall be in operation and emissions shall be minimized insofar as technologically feasible during startup and shutdown. [District Rule 4703]

40. The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Emission Monitoring and Testing. [District Rule 1081]

41. Source testing to measure startup NOx, CO, and VOC mass emission rates shall be conducted for one of the gas turbines (C-3953-10 or C-3953-11) prior to the end of the commissioning period and at least once every seven years thereafter. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

42. Source testing (with and without duct burner firing) to measure the NOx, CO, and VOC emission rates (lb/hr and ppmvd @ 15% O2) shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rules 1081 and 4703]

43. Source testing (with and without duct burner firing) to measure the PM10 emission rate (lb/hr) and the ammonia emission rate shall be conducted within 60 days after the end of the commissioning period and at least once every twelve months thereafter. [District Rule 1081]

44. Compliance with natural gas sulfur content limit shall be demonstrated within 60 days after the end of the commissioning period and weekly thereafter. After demonstrating compliance with the fuel sulfur content limit for 8 consecutive weeks for a fuel source, then the testing frequency shall not be less than monthly. If a test shows noncompliance with

the sulfur content requirement, the source must return to weekly testing until eight consecutive weeks show compliance. [District Rules 1081, 2540, and 4001].

45. Demonstration of compliance with the annual average sulfur content limit shall be demonstrated by a 12 month rolling average of the sulfur content either (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) tested using ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [District Rules 1081 and 2201]

46. Source testing to determine compliance with the NOx, CO and VOC emission rates (lb/hr and ppmvd @ 15% O_2), NH3 emission rate (ppmvd @ 15% O_2) and PM_{10} emission rate (lb/hr) shall be conducted at least once every 12 months. [District Rules 1081, 2201 and 4703 and 40 CFR 60.4400(a)]

47. Compliance with the NO_X and CO emission limits shall be demonstrated with the auxiliary burner both on and off. [District Rule 4703]

48. Compliance demonstration (source testing) shall be District witnessed, or authorized and samples shall be collected by a California Air Resources Board certified testing laboratory. Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified 30 days prior to any compliance source test, and a source test plan must be submitted for approval 15 days prior to testing. The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

49. The following test methods shall be used: NO_X - EPA Method 7E or 20; CO - EPA Method 10 or 10B; VOC - EPA Method 18 or 25; PM10 - EPA Method 5 (front half and back half) or 201 and 202a; ammonia - BAAQMD ST-1B; and O_2 - EPA Method 3, 3A, or 20. EPA approved alternative test methods as approved by the District may also be used to address the source testing requirements of this permit. [District Rules 1081 and 4703 and 40 CFR 60.4400(1)(i)]

50. The sulfur content of each fuel source shall be: (i) documented in a valid purchase contract, a supplier certification, a tariff sheet or transportation contract or (ii) monitored within 60 days of the end of the commission period and weekly thereafter. If the sulfur content is demonstrated to be less than 1.0 gr/100 scf for eight consecutive weeks, then the monitoring frequency shall be every six months. If the result of any six month monitoring demonstrates that the fuel does not meet the fuel sulfur content limit, weekly monitoring shall resume. [District Rule 2201 and 40 CFR 60.4360, 60.4365(a) and 60.4370(c)]

51. Excess emissions shall be defined as any operating hour in which the 4-hour or 30-day rolling average NO_X concentration exceeds applicable emissions limit and a period of monitor downtime shall be any unit operating hour in which sufficient data are not obtained to validate the hour for either NO_X or O2 (or both). [40 CFR 60.4380(b)(1)]

52. Fuel sulfur content shall be monitored using one of the following methods: ASTM Methods D1072, D3246, D4084, D4468, D4810, D6228, D6667 or Gas Processors Association Standard 2377. [40 CFR 60.4415(a)(1)(i)]

53. The permittee shall submit to the District information correlating the NO_X control system operating parameters to the associated measured NO_X output. The information must be sufficient to allow the District to determine compliance with the NO_X emission limits of this permit during times that the CEMS is not functioning properly. [District Rule 4703]

54. The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 1080 and 2201 and 40 CFR 60.8(d)]

55. The permittee shall maintain the following records: date and time, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a continuous monitoring system or monitoring device was inoperative, and maintenance of any continuous emission monitor. [District Rules 2201 and 4703]

56. The permittee shall maintain the following records: hours of operation, fuel consumption (scf/hr and scf/rolling twelve month period), continuous emission monitor measurements, calculated ammonia slip, and calculated NOx mass emission rates (lb/hr and lb/twelve month rolling period). [District Rules 2201 and 4703]

57. The owner or operator of a stationary gas turbine system shall maintain all records of required monitoring data and support information for inspection at any time for a period of five years. [District Rules 2201 and 4703]

EQUIPMENT DESCRIPTION, UNIT C-3953-12-1:
37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide NOx (as NO2) emission reduction credits for the following quantities of emissions: 1st quarter – 67,103 lb; 2nd quarter – 67,104 lb; 3rd quarter – 67,104 lb; and 4th quarter – 67,104 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

3. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide VOC emission reduction credits for the following quantities of emissions: 1st quarter – 12,294 lb; 2nd quarter – 12,295 lb; 3rd quarter – 12,295 lb; and 4th quarter – 12,295 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. [District Rule 2201]

4. Prior to initial operation of C-3953-10-1, C-3953-11-1, and C-3953-12-1, permittee shall provide PM_{10} emission reduction credits for the following quantities of emissions: 1st quarter – 33,086 lb; 2nd quarter – 33,086 lb; 3rd quarter – 33,086 lb; and 4th quarter – 33,086 lb. Offsets shall be provided at the appropriate distance ratio specified in Rule 2201. SOx ERC's may be used to offset PM10 increases at an interpollutant ratio of 1.0 lb-SOx : 1.0 lb-PM10. [District Rule 2201]

5. ERC certificate numbers (or any splits from these certificates) C-897-1, C-898-1, N-724-1, N-725-1, S-2812-1, S-2813-1, S-2817-1, C-899-2, C-902-2, N-720-2, N-722-2, N-726-2, N-728-2, S-2814-2, S-2321-2, C-896-4, N-721-4, N-723-4, S-2791-5, S-2790-5, S-2789-5, S-2788-5, or N-762-5 shall be used to supply the required offsets, unless a revised offsetting proposal is received and approved by the District, upon which this determination of compliance (DOC) shall be reissued, administratively specifying the new offsetting proposal. Original public noticing requirements, if any, shall be duplicated prior to reissuance of the DOC. [District Rule 2201]

6. The permittee shall obtain written District approval for the use of any equivalent equipment not specifically approved by this DOC. Approval of the equivalent equipment shall be made only after the District's determination that the submitted design and performance of the proposed alternate equipment is equivalent to the specifically authorized equipment. [District Rule 2201]

7. The permittee's request for approval of equivalent equipment shall include the make, model, manufacturer's maximum rating, manufacturer's guaranteed emission rates, equipment drawing(s), and operational characteristics/parameters. [District Rule 2010]

8. Alternate equipment shall be of the same class and category of source as the equipment authorized by the DOC. [District Rule 2201]

9. No emission factor and no emission shall be greater for the alternate equipment than for the proposed equipment. No changes in the hours of operation, operating rate, throughput, or firing rate may be authorized for any alternate equipment. [District Rule 2201]

10. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

11. {1407} All equipment shall be maintained in good operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

12. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

13. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

14. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

15. {2964} The unit shall only be fired on PUC-regulated natural gas. [District Rule 2201]

16. Emission rates from this unit shall not exceed any of the following limits: NOx (as NO2) - 9.0 ppmvd @ 3% O2 or 0.011 lb/MMBtu; VOC (as methane) - 10.0 ppmvd @ 3% O2; CO - 50.0 ppmvd @ 3% O2 or 0.037 lb/MMBtu; PM10 - 0.005 lb/MMBtu; or SOx (as SO2) - 0.00285 lb/MMBtu. [District Rules 2201, 4305, and 4306]

17. {2972} All emissions measurements shall be made with the unit operating either at conditions representative of normal operations or conditions specified in the Permit to Operate. No determination of compliance shall be established within two hours after a continuous period in which fuel flow to the unit is shut off for 30 minutes or longer, or within 30 minutes after a re-ignition as defined in Section 3.0 of District Rule 4306. [District Rules 4305 and 4306]

18. {3467} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted within 60 days of initial start-up. [District Rules 2201, 4305, and 4306]

19. {3466} Source testing to measure NOx and CO emissions from this unit while fired on natural gas shall be conducted at least once every twelve (12) months. After demonstrating compliance on two (2) consecutive annual source tests, the unit shall be tested not less than once every thirty-six (36) months. If the result of the 36-month source test demonstrates that the unit does not meet the applicable emission limits, the source testing frequency shall revert to at least once every twelve (12) months. [District Rules 4305 and 4306]

20. {2976} The source test plan shall identify which basis (ppmv or lb/MMBtu) will be used to demonstrate compliance. [District Rules 4305 and 4306]

21. {109} Source testing shall be conducted using the methods and procedures approved by the District. The District must be notified at least 30 days prior to any compliance source test, and a source test plan must be submitted for approval at least 15 days prior to testing. [District Rule 1081]

22. {2977} NOx emissions for source test purposes shall be determined using EPA Method 7E or ARB Method 100 on a ppmv basis, or EPA Method 19 on a heat input basis. [District Rules 4305 and 4306]

23. {2978} CO emissions for source test purposes shall be determined using EPA Method 10 or ARB Method 100. [District Rules 4305 and 4306]

24. {2979} Stack gas oxygen (O2) shall be determined using EPA Method 3 or 3A or ARB Method 100. [District Rules 4305 and 4306]

25. {2980} For emissions source testing, the arithmetic average of three 30-consecutive-minute test runs shall apply. If two of three runs are above an applicable limit the test cannot be used to demonstrate compliance with an applicable limit. [District Rules 4305 and 4306]

26. {110} The results of each source test shall be submitted to the District within 60 days thereafter. [District Rule 1081]

27. A non-resettable, totalizing mass or volumetric fuel flow meter to measure the amount of fuel combusted in the unit shall be installed, utilized and maintained. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

28. Permittee shall maintain daily records of the type and quantity of fuel combusted by the boiler. [District Rules 2201 and 40 CFR 60.48 (c)(g)]

29. {2983} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rules 1070, 4305, and 4306]

30. {1832} The exhaust stack shall be equipped with a continuous emissions monitor (CEM) for NOx, CO, and O2. The CEM shall meet the requirements of 40 CFR parts 60 and 75 and shall be capable of monitoring emissions during startups and shutdowns as well as during normal operating conditions. [District Rules 2201 and 1080]

27\. {1833} The facility shall install and maintain equipment, facilities, and systems compatible with the District's CEM data polling software system and shall make CEM data available to the District's automated polling system on a daily basis. [District Rule 1080]

28. {1834} Upon notice by the District that the facility's CEM system is not providing polling data, the facility may continue to operate without providing automated data for a maximum of 30 days per calendar year provided the CEM data is sent to the District by a District-approved alternative method. [District Rule 1080]

29. {1835} The exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods and shall be equipped with safe permanent provisions to sample stack gases with a portable NOx, CO, and O2 analyzer during District inspections. The sampling ports shall be located in accordance with the CARB regulation titled California Air Resources Board Air Monitoring Quality Assurance Volume VI, Standard Operating Procedures for Stationary Source Emission Monitoring and Testing. [District Rule 1081]

30. {1836} Results of continuous emissions monitoring shall be reduced according to the procedure established in 40 CFR, Part 51, Appendix P, paragraphs 5.0 through 5.3.3, or by other methods deemed equivalent by mutual agreement with the District, the ARB, and the EPA. [District Rule 1080]

31. {1837} Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

32. {1838} The owner/operator shall perform a relative accuracy test audit (RATA) as specified by 40 CFR Part 60, Appendix F, 5.11, at least once every four calendar quarters. The permittee shall comply with the applicable requirements for quality assurance testing and maintenance of the continuous emission monitor equipment in accordance with the procedures and guidance specified in 40 CFR Part 60, Appendix F. [District Rule 1080]

33. {1839} The permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions, nature and cause of excess emissions (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

EQUIPMENT DESCRIPTION, UNIT C-3953-13-1:
288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

3. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

4. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

5. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

6. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

7. {3395} Only CARB certified diesel fuel containing not more than 0.0015% sulfur by weight is to be used. [District Rules 2201 and 4801 and 17 CCR 93115]

8. {3403} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702 and 17 CCR 93115]

9. Emissions from this IC engine shall not exceed any of the following limits: 3.4 g-NOx/bhp-hr, 0.447 g-CO/bhp-hr, or 0.38 g-VOC/bhp-hr. [District Rule 2201 and 13 CCR 2423 and 17 CCR 93115]

10. Emissions from this IC engine shall not exceed 0.059 g-PM10/bhp-hr based on USEPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102 and 13 CCR 2423 and 17 CCR 93115]

11. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. For testing purposes, the engine shall only be operated the number of hours necessary to comply with the testing requirements of the National Fire Protection Association (NFPA) 25 - "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems", 1998 edition. Total hours of operation for all maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702 and 17 CCR 93115]

12. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

13. {3489} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, and the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.). For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702 and 17 CCR 93115]

14. {3475} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702 and 17 CCR 93115]

EQUIPMENT DESCRIPTION, UNIT C-3953-14-1:
860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

1. Permittee shall submit an application to comply with SJVUAPCD District Rule 2520 - Federally Mandated Operating Permits within twelve months of commencing operation. [District Rule 2520]

2. Permittee shall submit an application to comply with SJVUAPCD District Rule 2540 - Acid Rain Program within 12 months of commencing operation. [District Rule 2540]

3. Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NO_X (as NO_2) – 198,840 lb/year; CO – 197,928 lb/year. [District Rule 2201

4. {98} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

5. {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

6. {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

7. {1898} The exhaust stack shall vent vertically upward. The vertical exhaust flow shall not be impeded by a rain cap, roof overhang, or any other obstruction. [District Rule 4102]

8. {3492} This IC engine shall be equipped with a three-way catalyst. [District Rule 2201]

9. {3404} This engine shall be equipped with an operational non-resettable elapsed time meter or other APCO approved alternative. [District Rule 4702]

10. Emissions from this IC engine shall not exceed any of the following limits: 1.0 g-NOx/bhp-hr, 0.034 g-PM10/bhp-hr, 0.6 g-CO/bhp-hr, or 0.33 g-VOC/bhp-hr. [District Rule 2201]

11. {3405} This engine shall be operated and maintained in proper operating condition as recommended by the engine manufacturer or emissions control system supplier. [District Rule 4702]

12. {3478} During periods of operation for maintenance, testing, and required regulatory purposes, the permittee shall monitor the operational characteristics of the engine as recommended by the manufacturer or emission control system supplier (for example: check engine fluid levels, battery, cables and connections; change engine oil and filters; replace engine coolant; and/or other operational characteristics as recommended by the manufacturer or supplier). [District Rule 4702]

13. This engine shall be operated only for testing and maintenance of the engine, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 50 hours per calendar year. [District Rule 4702]

14. {3807} An emergency situation is an unscheduled electrical power outage caused by sudden and reasonably unforeseen natural disasters or sudden and reasonably unforeseen events beyond the control of the permittee. [District Rule 4702]

15. {3808} This engine shall not be used to produce power for the electrical distribution system, as part of a voluntary utility demand reduction program, or for an interruptible power contract. [District Rule 4702]

16. {3496} The permittee shall maintain monthly records of emergency and non-emergency operation. Records shall include the number of hours of emergency operation, the date and number of hours of all testing and maintenance operations, the purpose of the operation (for example: load testing, weekly testing, rolling blackout, general area power outage, etc.) and records of operational characteristics monitoring. For units with automated testing systems, the operator may, as an alternative to keeping records of actual operation for testing purposes, maintain a readily accessible written record of the automated testing schedule. [District Rule 4702]

17. {3497} All records shall be maintained and retained on-site for a minimum of five (5) years, and shall be made available for District inspection upon request. [District Rule 4702]

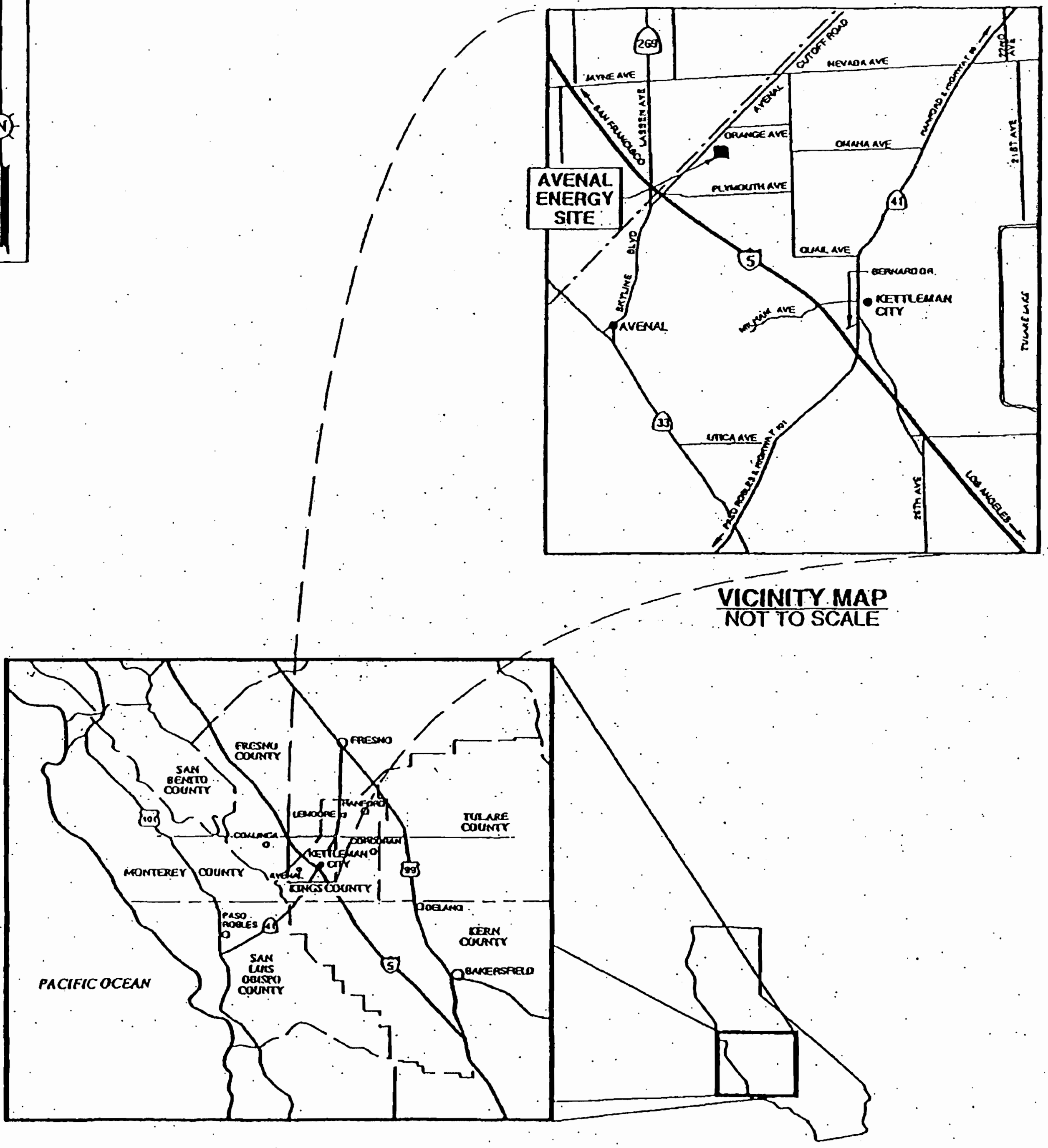
ATTACHMENT B

Project Location and Site Plan

ATTACHMENT C

CTG Commissioning Period Emissions Data

290317-AFC-2.0-1 REV1 09/05/08



REGIONAL MAP

0 60 120 MILES

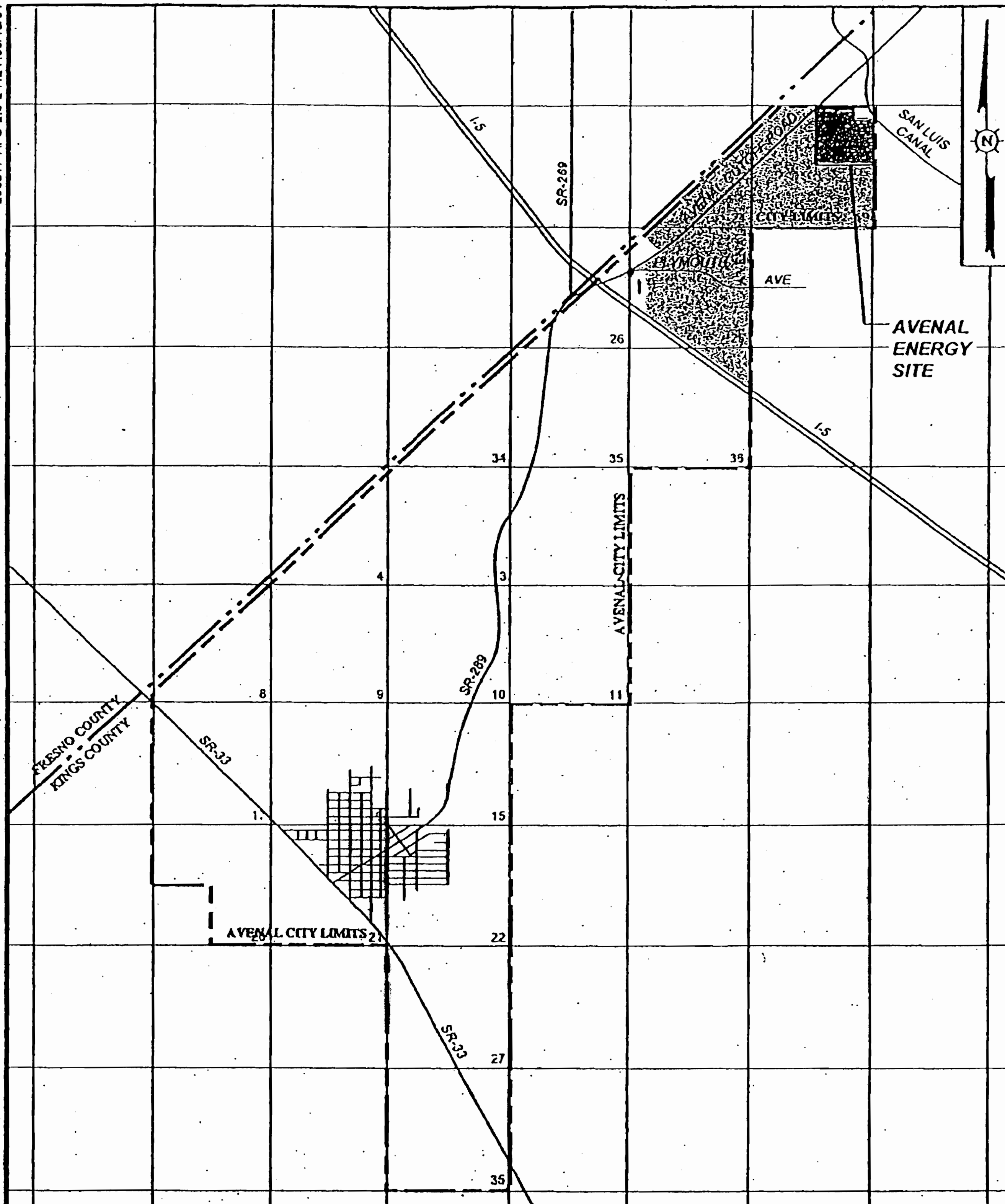
APPROXIMATE SCALE

REGIONAL LOCATION MAP

FEDERAL ENERGY AVENAL, LLC

AVENAL ENERGY | FIGURE 2.0-1

280317-AFC-2.0-2 REV.09/13/01



LEGEND

INDUSTRIAL ZONE (CITY OF AVENAL GENERAL PLAN AND ZONING ORDINANCE)

0 6,000 12,000 FEET

SCALE

REFERENCE: CITY OF AVENAL GENERAL PLAN.

1 36.074 -120.093

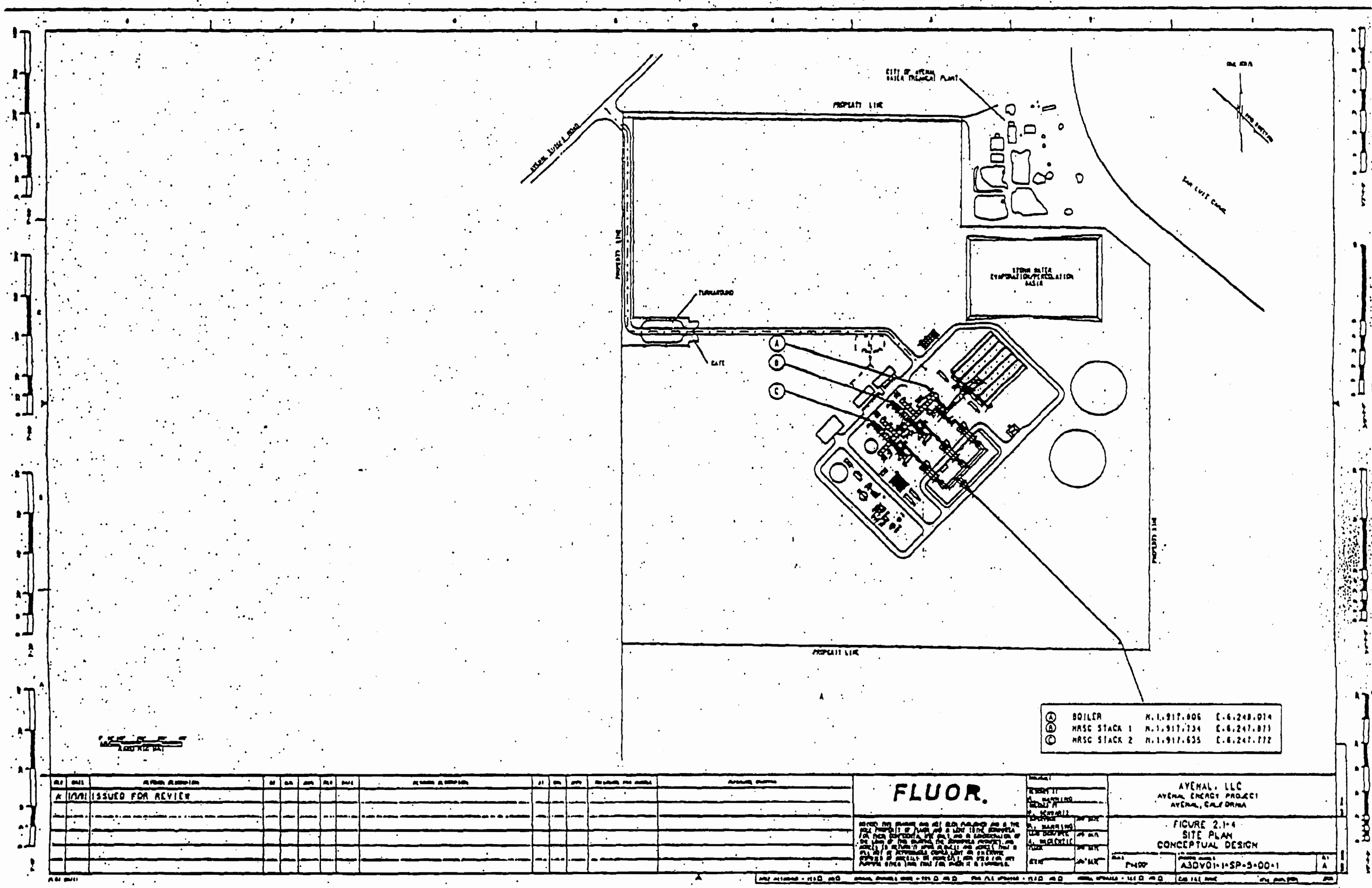
AV

SITE LOCATION

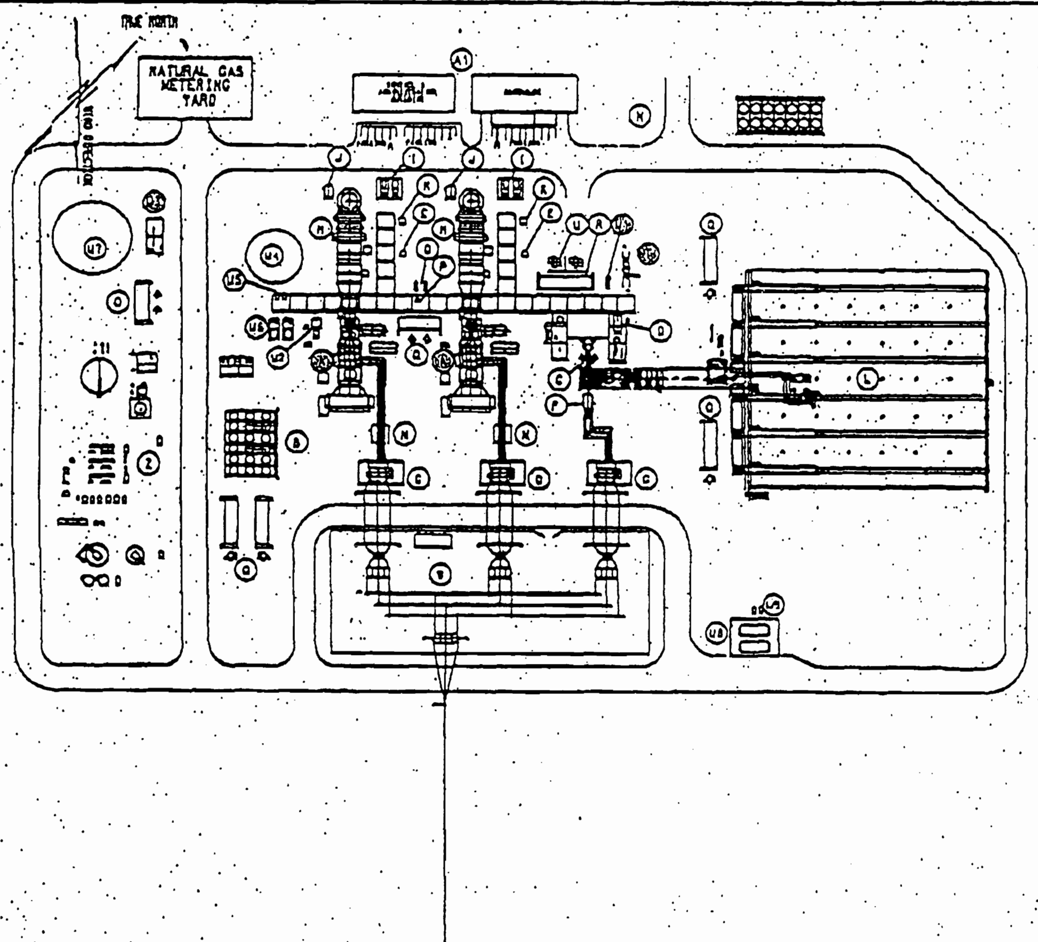
② Rd crosses horiz rd near development
36.109 -120.0486

FEDERAL POWER AVENAL, LLC

AVENAL ENERGY	FIGURE 2.0-2



CITY OF AVENAL WATER TREATMENT PLANT
PROPERTY LINE
STORM WATER EVAPORATION/PERCOLATION BASIN
TURNAROUND
GATE
A BOILER N.1,917,806 E.6,248,014
B HRSG STACK 1 N.1,917,734 E.6,247,873
C HRSG STACK 2 N.1,917,635 E.6,247,772
A ISSUED FOR REVIEW
FLUOR.
AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA
FIGURE 2.1-4
SITE PLAN
CONCEPTUAL DESIGN
A3DV01-1-SP-5-00-1



MAJOR EQUIPMENT LIST

- A GAS TURBINE GENERATOR
- B INLET AIR CHILLERS
- C STEAM TURBINE
- D STG LUBE OIL SKID
- E HRSG BLOW DOWN DRUM
- F STG GENERATOR
- G MAIN TRANSFORMERS
- H HEAT RECOVERY STEAM GENERATOR
- I HP/IP BOILER FEED WATER PUMPS
- J CONTINUOUS EMISSIONS MONITORING SYSTEM
- K HRSG BLOWDOWN SUMP
- L AIR COOLED CONDENSER
- M GENERATOR BREAKERS
- N CLOSED COOLING WATER AIR COOLER
- O CIRCULATING COOLING WATER PUMPS
- P CLOSED COOLING WATER EXPANSION TANK
- Q POWER DISTRIBUTION CENTER (480 V)
- R POWER DISTRIBUTION CENTER (4160 V)
- S
- T AUXILIARY BOILER
- U UNIT AUXILIARY TRANSFORMER
- V
- W SWITCHYARD
- X RAW WATER SOFTENER CLARIFIERS (RWSC)
- Y RWSC FILTER PRESS
- Z ZERO LIQUID DISCHARGE FACILITY (ZLDF)

- A1 SEPTIC TANK & LEACH FIELD (IMMEDIATELY NW)
- A2 STORM WATER EVAPORATION/PERCOLATION BASIN

UTILITIES

- U1 STANDBY DIESEL GENERATOR
- U2 OIL/WATER SEPARATOR
- U3 FIREWATER PUMP HOUSE
- U4 DEMINERALIZED WATER STORAGE TANK
- U5 DEMINERALIZED WATER PUMPS
- U6 PLANT/INSTRUMENT AIR COMPRESSORS
- U7 RAW WATER/FIREWATER STORAGE TANKS
- U8 AMMONIA STORAGE TANKS
- U9 AMMONIA TRANSFER PUMPS

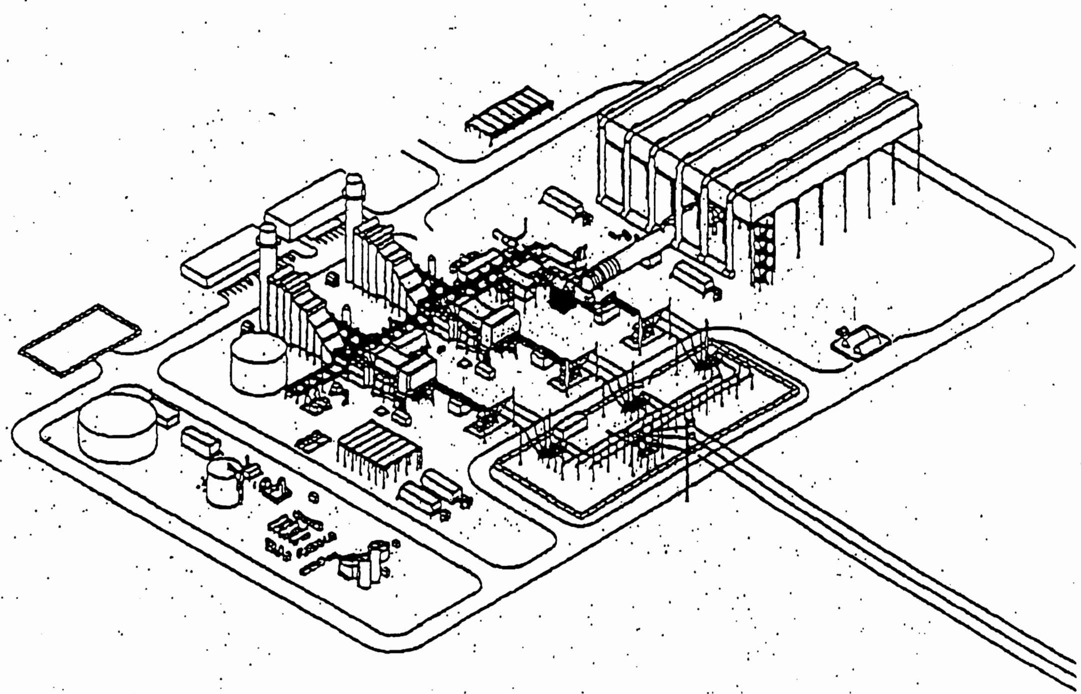
A		ISSUED FOR REVIEW

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

FIGURE 2.3-3
PLOT PLAN
CONCEPTUAL DESIGN

P-126' | A3DY01-1-PP-0-00-1 | A



A	[illegible]	ISSUED FOR REVIEW

FLUOR.

AVENAL, LLC
AVENAL ENERGY PROJECT
AVENAL, CALIFORNIA

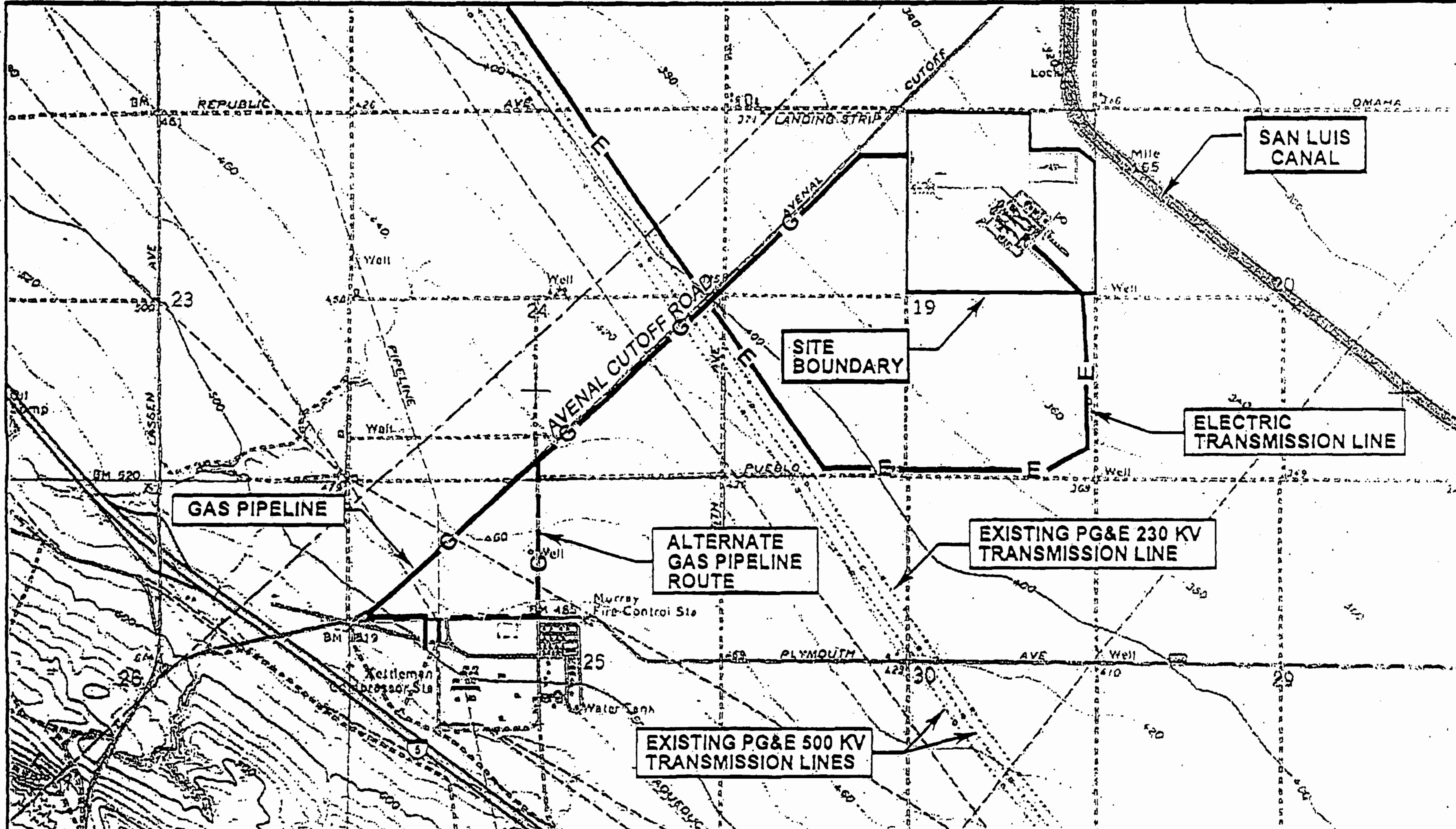
ISO VIEW
CONCEPTUAL DESIGN

NONE

A3OYDY-1-PP-0-00-2

A

290317-AFC-2.1-1A REV. 09/05/06



REFERENCE:
U.S.G.S 7.5 MINUTE TOPOGRAPHIC SERIES MAP OF LA CIMA, CALIFORNIA, DATED 1978.

NATURAL GAS AND ELECTRICAL INTERCONNECTION ROUTES

FEDERAL POWER AVENAL LLC

AVENAL ENERGY | FIGURE 2.1-1A

ATTACHMENT D

CTG Emissions Data

The maximum heat input rates (fuel consumption rates) for the gas turbines, duct burners, and auxiliary boiler are shown in Table 6.2-22.

TABLE 6.2-22
MAXIMUM FACILITY FUEL USE, MMBTU (HHV)

Period	Gas Turbines and Duct Burners (each[a])	Auxiliary Boiler	Total Fuel Use (all Units)
Per Hour	2,356.5	37.4	4,750
Per Day	56,555[b]	449[c]	113,111[d]
Per Year	16,176,000[e]	46,650[f]	32,353,000[g]

Notes:
[a] Each of two trains.
[b] Based on 24 hours per day of duct firing.
[c] Based on a startup day, during which the auxiliary boiler would be used 12 hours.
[d] The maximum facility fuel use day, during which the turbines run 24 hours with duct firing, has no use of the auxiliary boiler (i.e., no startup).
[e] Based on maximum fuel use of 7,960 hours per year without duct firing, and 800 hours per year with duct firing, per turbine.
[f] Based on 1,248 hours of operation per year.
[g] Based on baseload scenario (see Footnote d) that includes no operation of the auxiliary boiler.

CTG Emissions During Startup and Shutdown

Maximum emission rates expected to occur during a startup or shutdown are shown in Table 6.2-23. PM_{10} and SO_2 emissions have not been included in this table because emissions of these pollutants depend on fuel flow, which will be lower during a startup period than during baseload facility operation.

TABLE 6.2-23
FACILITY STARTUP/SHUTDOWN EMISSION RATES[a]

	NOx	CO	VOC
Startup/Shutdown, lb/hour, average	80	900	16
Startup/Shutdown, lb/~~start~~, hour maximum	160	1,000	16

[a] Estimated based on vendor data and source test data. See Appendix 6.2-1, Table 6.2-1.6 and -1.7.

The analysis of maximum facility emissions of each criteria pollutant was based on the turbine/HRSG and auxiliary boiler emission factors shown in Tables 6.2-19, 6.2-20, and 6.2-21; the startup emission rates shown in Table 6.2-23; the three operating scenarios described above, and the ambient conditions that result in the highest emission rates. The maximum annual, daily, and hourly emissions of each criteria pollutant for the Project are shown in Table 6.2-24 and are based on the following operating conditions and scenario parameters:

CTG Emissions During Commissioning

Gas turbine commissioning is the process of initial startup, tuning and adjustment of the new CTGs and auxiliary equipment and of the emission control systems. The commissioning process consists of sequential test operation of each of the two gas turbines up through increasing load levels, and with successive application of the air pollution control systems. The total set of commissioning tests will require approximately 410 operating hours for each CTG. With the planned sequential testing of the two gas turbines, the overall length of the commissioning period would be approximately 3 months. Commissioning of the proposed project may be phased into two commissioning periods each approximately 1.5 months long.

There are several commissioning modes. The first is the period prior to SCR system installation, when the combustor is being tuned. During this mode, the NO_x emissions control system would not be functioning and the combustor would not be tuned for optimum performance. CO emissions would also be affected because combustor performance would not yet be optimized. The second emissions scenario will occur when the combustor has been tuned but the SCR installation is not complete, and other parts of the gas turbine operating system are being checked out. Because the combustor would be tuned but the emission control system installation would not be complete, NO_x and CO levels could again be affected.

Noncriteria Pollutant Emissions

Noncriteria pollutants are compounds that have been identified as pollutants that pose a potential health hazard. Nine of these pollutants are regulated under the federal New Source Review program: lead, asbestos, beryllium, mercury, fluorides, sulfuric acid mist, hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds.[24] In addition to these nine compounds, the federal Clean Air Act listed 187 to 189[25] substances at different times as potential hazardous air pollutants (Clean Air Act Sec. 112(b)(1)). The State of California defined a set of toxic air contaminants through Assembly Bill (AB) 2588, the Air Toxics "Hot Spots" Information and Assessment Act. The SJVAPCD published a list of compounds it defined as potential toxic air contaminants in its May 1991 Toxics Policy. Any pollutant that may be emitted from the Project and is on the federal New Source Review list, the federal Clean Air Act list, the AB2588 list or

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[24] These pollutants are regulated under federal and state air quality programs; however, they are evaluated as noncriteria pollutants by the California Energy Commission.
[25] Currently 187 substances are listed.

ATTACHMENT D

CTG Emissions Data

Table 8.2-1.1
Emissions and Operating Parameters for New Turbines
Avenal Energy Project

	Case 1 101°F Full Load w/ DB[1]	Case 5 63°F Full Load w/ DB[1]	Case 9 32°F Full Load w/ DB[1]	Case 2 101°F Full Load no DB	Case 6 63°F Full Load no DB	Case 10 32°F Full Load no DB	Case 4 101°F 50% Load	Case 8 63°F 50% Load	Case 12 32°F 50% Load
Ambient Temp, °F	101	63	32	101	63	32	101	63	32
GT Load, %	100%	100%	100%	100%	100%	100%	50%	50%	50%
Both GTs Gross Power, MW	344.8	345.0	359.0	345.5	345.6	359.5	144.1	168.6	183.2
STG Gross Power, MW	290.8	273.3	254.7	171.6	176.1	177.7	118.3	127.6	130.6
Plant Gross Power Output, MW	635.6	618.3	613.7	517.2	521.7	537.2	262.5	296.2	313.9
Plant Net Power Output, MW	600.0	600.0	600.0	483.7	506.5	525.5	250.3	286.3	304.8
GTs Fuel Flow, kpph	156.4	156.4	161.8	156.4	156.4	161.8	87.2	96.2	102.2
DBs Fuel Flow, kpph	49.0	39.8	31.0	0.0	0.0	0.0	0.0	0.0	0.0
GTs Heat Input, MMBtu/hr (HHV)	1,794.2	1,794.3	1,855.4	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
DBs Heat Input, MMBtu/hr (HHV)	562.3	454.4	356.3	0.0	0.0	0.0	0.0	0.0	0.0
Total Heat Input, MMBtu/hr (HHV)	2,356.5	2,248.6	2,211.8	1,795.6	1,795.4	1,856.3	1,001.4	1,104.3	1,171.9
Stack Flow, lb/hr	3,653,000	3,650,000	3,759,000	3,628,000	3,630,000	3,743,000	2,232,700	2,336,800	2,413,300
Stack Flow, acfm	1,044,365	1,025,495	1,069,836	1,051,631	1,037,822	1,071,653	620,528	644,316	666,146
Stack Temp, °F	195.3	184.9	189.0	207.4	198.8	200.9	180.2	175.8	177.4
Stack exhaust, vol%									
O_2 (dry)	11.40%	11.87%	12.34%	13.76%	13.77%	13.78%	14.46%	14.11%	13.93%
CO_2 (dry)	5.42%	5.16%	4.89%	4.09%	4.08%	4.08%	3.70%	3.89%	3.89%
H_2O	10.54%	10.03%	9.12%	8.39%	8.28%	7.78%	8.07%	7.97%	7.63%
Emissions									
NO_x, ppmvd @ 15% O_2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NO_x, lb/hr[2]	17.13	16.34	16.06	13.03	13.03	13.47	7.26	8.01	8.51
NO_x, lb/MMBtu (HHV)	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073	0.0073
SO_2, ppmvd @ 15% O_2 [3]	0.139	0.139	0.140	0.140	0.140	0.140	0.140	0.140	0.140
SO_2, lb/hr[2,3]	1.66	1.59	1.56	1.27	1.27	1.31	0.71	0.78	0.83
SO_2, lb/MMBtu (HHV)[3]	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007	0.0007
CO, ppmvd @ 15% O_2	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
CO, lb/hr[2]	20.86	19.90	19.56	15.86	15.86	16.39	8.84	9.75	10.36
CO, lb/MMBtu (HHV)	0.0089	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088	0.0088
VOC, ppmvd @ 15% O_2[4]	2.0	2.0	2.0	1.4	1.4	1.4	1.4	1.4	1.4
VOC, lb/hr[2,4]	5.98	5.68	5.59	3.17	3.17	3.28	1.77	1.95	2.07
VOC, lb/MMBtu (HHV)[4]	0.0025	0.0025	0.0025	0.0018	0.0018	0.0018	0.0018	0.0018	0.0018
PM_{10}, lb/hr[2,5]	11.81	11.27	10.78	9.00	9.00	9.00	9.00	9.00	9.00
PM_{10}, lb/MMBtu (HHV)[5]	0.0050	0.0050	0.0049	0.0050	0.0050	0.0048	0.0090	0.0081	0.0077
PM_{10}, gr/SCF (dry)[5]	0.00189	0.00179	0.00165	0.00142	0.00142	0.00137	0.00230	0.00220	0.00212
NH_3, ppmvd @ 15% O_2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
NH_3, lb/hr[2]	35.39	33.57	32.66	26.28	26.25	26.98	14.60	16.08	17.02
CO_2, lb/MMBtu (HHV)[7]	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0	117.0
CH_4, lb/MMBtu (HHV)[8]	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013	0.013
N_2O, lb/MMBtu (HHV)[8]	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022	0.00022
CO_2, lb/hr[9]	275,599	262,984	258,674	210,000	209,976	217,102	117,114	129,153	137,055
CH_4, lb/hr[9]	30.7	29.2	28.8	23.4	23.4	24.1	13.0	14.4	15.2
N_2O, lb/hr[9]	0.52	0.50	0.49	0.40	0.40	0.41	0.22	0.24	0.26

1) Includes duct burner firing only up to plant maximum output of 600 MW.

2) All mass flow values reported are on a per stack basis. Plant total mass flows are double these values.

3) All of the assumed 0.25 gr S in 100 scf of the fuel is assumed to be converted to SO_2 with no SO_3 conversion.

4) Based on an assumption that 20% of reported UHC emissions are VOCs.

5) Includes front-half (filterable) portion only. Back-half (condensible) portion is excluded.

6) CH_4 emission factor (kg/MMBtu) = 0.0059

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.

7) CO_2 emission factor (kg/MMBtu) = 53.06

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Carbon Dioxide Emission Factors and Oxidation Rates for Stationary Combustion, August 10, 2007.

8) N_2O emission factor (kg/MMBtu) = 0.0001

ARB, *Draft Emission Factors for Mandatory Reporting Program*, Table of Methane and Nitrous Oxide Emission Factors for Stationary Combustion by Sector and Fuel Type, August 10, 2007.

ATTACHMENT E

SJVAPCD BACT Guidelines 1.1.2, 3.1.4, 3.1.8, and 3.4.2

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 1.1.2*

Last Update: 3/14/2002

Boiler: > 20.0 MMBtu/hr, Natural gas fired, base-loaded or with small load swings.**

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	Natural gas fuel with LPG backup		
NOx	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Ultra-Low NOx main burner system burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire).	9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu/hr) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NOx@ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire).	
PM10	Natural gas fuel with LPG backup		
SO	Natural gas fuel with LPG backup		
VOC	Natural gas fuel with LPG backup		

** For the purpose of this determination, "small load swings" are defined as normal operational load fluctuations which are within the operational response range of an Ultra-Low NOx burner system(s).

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.4*

Last Update: 6/30/2001

Emergency Diesel I.C. Engine Driving a Fire Pump

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO		Oxidation Catalyst	
NOx	Certified NOx emissions of 6.9 g/bhp-hr or less		
PM10	0.1 grams/bhp-hr (if TBACT is triggered) (corrected 7/16/01) 0.4 grams/bhp-hr (if TBACT is not triggered)		
SOx	Low-sulfur diesel fuel (500 ppmw sulfur or less) or Very Low-sulfur diesel fuel (15 ppmw sulfur or less), where available.		
VOC	Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]	Catalytic Oxidation	

1. Any engine model included in the ARB or EPA diesel engine certification lists and identified as having a PM10 emission rate of 0.149 grams/bhp-hr or less, based on ISO 8178 test procedure, shall be deemed to meet the 0.1 grams/bhp-hr requirement.
2. A site-specific Health Risk Analysis is used to determine if TBACT is triggered. (Clarification added 05/07/01)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.1.8*

Last Update: 4/4/2002

Emergency Gas-Fired IC Engine - > or = 250 hp, Lean Burn

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	= or < 2.75 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	> or = 80% control efficiency (Rich-burn engine with NSCR, or equal)
NOx	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)		= or > 90% control efficiency (Rich-burn engine with NSCR, or equal)
PM10	Natural gas fuel		
VOC	= or < 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)	90% control efficiency (Oxidation catalyst, or equal)	= or > 50% control efficiency (Rich-burn engine with NSCR, or equal)

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.2*

Last Update: 10/1/2002

Gas Turbine - = or > 50 MW, Uniform Load, with Heat Recovery

Pollutant	Achieved in Practice or contained in the SIP	Technologically Feasible	Alternate Basic Equipment
CO	6.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	4.0 ppmv @ 15% O2 (Oxidation catalyst, or equal)	
NOx	2.5 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	2.0 ppmv dry @ 15% O2 (1-hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)	
PM10	Air inlet filter cooler, lube oil vent coalescer and natural gas fuel, or equal		
SOx	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more that 0.75 grams S/100 dscf, or equal.		
VOC	2.0 ppmv @ 15% O2	1.5 ppmv @ 15% O2	

** Applicability lowered to > 50 MW pursuant to CARB Guidance for Permitting Electrical Generation Technologies. Change effective 10/1/02. Corrected error in applicability to read 50 MW not 50 MMBtu/hr effective 4/1/03.

BACT is the most stringent control technique for the emissions unit and class of source. Control techniques that are not achieved in practice or contained in s a state implementation plan must be cost effective as well as feasible. Economic analysis to demonstrate cost effectiveness is requried for all determinations that are not achieved in practice or contained in an EPA approved State Implementation Plan.

***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

ATTACHMENT F

Top Down BACT Analysis
(C-3953-10-1, -11-1, -12-1, -13-1, and –14-1)

Units C-3953-10-1 and –11-1 (Turbines)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)
2. 2.5 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing the use of a selective catalytic reduction system with NO_X emissions of 2.0 ppmv @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of a Selective Catalytic Reduction system with emissions of less than or equal to 2.0 ppmvd @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). The facility has proposed to use an inlet air filtration and cooling system, water injection, and a Selective Catalytic Reduction system on each of these turbines to achieve NO_X emissions of less than or equal to 2.0 ppmv @ 15% O_2 (1 hr average, excluding startup and shutdown), (Selective catalytic reduction, or equal). Therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- 2.0 ppmvd VOC @ 15% O_2

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies technologically feasible BACT as the following:

- 1.5 ppmvd VOC @ 15% O_2

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 1.5 ppmvd VOC @ 15% O_2
2. 2.0 ppmvd VOC @ 15% O_2

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing VOC emissions of 1.4 ppmvd @ 15% O_2 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O_2 when it is fired with the duct burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O_2 did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O_2 emission factor will be determine to meet the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel or LPG with emissions of less than or equal to 2.0 ppmv @ 15% O_2. The facility has proposed to use natural gas fuel with emissions of less than or equal to 2.0 ppmv @ 15% O_2; therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

III. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM_{10} emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Air inlet filter, lube oil vent coalescer and natural gas fuel or equal

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use an air in inlet filter, lube oil vent coalescer and natural gas fuel or equal. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of an air inlet filter, lube oil vent coalescer and natural gas fuel or equal. Avenal Power Center is proposing to use an air inlet filter, lube oil vent coalescer and natural gas fuel or equal; therefore, BACT is satisfied.

Units C-3953-10-1 and –11-1 (Turbines)

IV. SO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.4.2 identifies achieved in practice BACT as the following:

- PUC-regulated natural gas fuel; or
- Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.4.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. PUC-regulated natural gas fuel
2. Non-PUC-regulated gas with no more than 0.75 grains S/100 dscf, or equal

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to use PUC-regulated natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of PUC-regulated natural gas fuel. Avenal Power Center has proposed to fire each of the turbines solely on PUC-regulated natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies technologically feasible BACT as the following:

- 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Selective Catalytic Reduction, Low Temperature Oxidizer, or equal and a < 30 ppmv NO_X @ 3% O2 igniter system (if the igniter system is used to heat the boiler at low fire)
2. 9.0 ppmvd @ 3% O2 (0.0108 lb/MMBtu) Ultra-Low NOx main burner system and a natural gas or LPG fired igniter system (if the igniter system is used to heat the boiler at low fire)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NOx emissions from the boiler will not exceed 9.0 ppmv @ 3% O_2. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be NO_X emissions of less than 9.0 ppmvd @ 3% O_2. The facility has proposed NO_X emissions of less than 9.0 ppmv @ 3% O_2. Therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for VOC emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-12-1 (Boiler)

III. PM_{10} Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

General control for PM_{10} emissions include the following options:

SJVAPCD BACT Clearinghouse Guideline 1.1.2 identifies achieved in practice BACT as the following:

- Natural gas fuel with LPG backup

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 1.1.2 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All of the listed controls are considered technologically feasible for this application.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. Natural gas fuel with LPG backup

Step 4 - Cost Effectiveness Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant is proposing to solely use natural gas fuel. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the use of natural gas fuel. Avenal Power Center is proposing to use natural gas fuel; therefore, BACT is satisfied.

Units C-3953-13-1 (Diesel IC engine powering fire water pump)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Certified NO_X emissions of 6.9 g/bhp-hr or less

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their emission factor:

1. Certified NO_X emissions of 6.9 g/bhp-hr or less

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the NOx emissions from the engine will not exceed 3.4 g/bhp-hr. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be Certified NO_X emissions of 6.9 g/bhp-hr or less. The facility has proposed NO_X emissions of less than 6.9 g/bhp-hr. Therefore, BACT is satisfied.

Units C-3953-13-1 (Diesel IC engine powering fire water pump)

II. VOC Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies achieved in practice BACT as the following:

- Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

SJVAPCD BACT Clearinghouse Guideline 3.1.4 identifies technologically feasible BACT as the following:

- Catalytic Oxidation

SJVAPCD BACT Clearinghouse Guideline 3.1.4 does not identify any alternate basic equipment BACT control alternatives.

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. Catalytic Oxidation
2. Positive crankcase ventilation [unless it voids the Underwriters Laboratories (UL) certification]

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from Step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

However, this engine has been UL Certified, and the UL certification does not include a catalytic oxidation system or a positive crankcase ventilation system, and the addition of a catalytic oxidation system or a positive crankcase ventilation system would void the UL certification, which is required for firewater pump engines. Therefore, both the catalytic oxidation system and the positive crankcase ventilation system options will not be required.

Step 5 - Select BACT

BACT for VOC emissions from this emergency diesel IC engine powering a firewater pump is having no control technology for VOC emissions. The applicant has proposed to install a 288 bhp emergency diesel IC engine powering a firewater pump with no control technology for VOC emissions; therefore BACT for VOC emissions is satisfied.

Units C-3953-14-1 (Natural gas IC engine powering electrical generator)

I. NO_X Top-Down BACT Analysis

Step 1 - Identify All Possible Control Technologies

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 does not identify any technologically feasible BACT control alternatives.

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 90% control efficiency (rich-burn engine with NSCR or equal)

Step 2 - Eliminate Technologically Infeasible Options

All control options listed in step 1 are technologically feasible.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

The following options are ranked based on their control efficiency:

1. ≥ 90% control efficiency (rich-burn engine with NSCR or equal)
2. NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

Step 4 - Cost Effective Analysis

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

1. ≥ 90% control efficiency (rich-burn engine with NSCR or equal)

District Policy establishes annual cost thresholds for imposed control based upon the amount of pollutants abated by the controls. If the cost of control is at or below the threshold, it is considered a cost effective control. If the cost exceeds the threshold, it is not cost effective and the control is not required. Per District BACT Policy, the maximum cost limit for NO_X reduction is $9,700 per ton of NO_X reduced.

Based upon the fact that there are only a few existing IC engine installations within this class and category of source that operate with emissions of ≤ 1.0 g NO_X/hp-hr, the District will assume that the Industry Standard will be 2.8 g NO_X/hp-hr (lb/MMBtu converted to g/hp-hr, Attachment I), pursuant to a AP-42 (07/00) values of uncontrolled four-stroke lean burn IC engines (< 90% load).

AP-42 publishes an uncontrolled NO_X value of 2.21 lb/MMBtu (90 – 105% load), which is approximately 13.4 g NO_X/hp-hr. Several major engine manufacturers were surveyed (Cummins, Caterpillar, and Waukesha) and the District found that lean burn engines sold by these engine manufacturers do not emit emissions close to the uncontrolled value for 90 – 105% load, published in AP-42. Based on the discussions with service representatives of each engine manufacturer, emissions were closer to the AP-42 value published for the < 90% load, which was around 2.5 g NO_X/hp-hr than it was for the value published for the 90 – 105% load. Therefore, industry standard for lean burn natural gas-fired emergency IC engine will be 2.8 g NO_X/hp-hr.

The proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>NO_X (annual):</u>

$$\frac{2.8\,\cancel{g}}{\cancel{hp\text{-}hr}} \times \frac{860\,\cancel{hp}}{1} \times \frac{lb}{453.6\,\cancel{g}} \times \frac{50\,\cancel{hr}}{year} = 265 \text{ lb } NO_X/year$$

PE_{NOx} = 265 lb NO_X/year = 0.1325 tons NO_X/year

The proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a NO_X control efficiency of ≥ 90% can be calculated as:

<u>NO_X (annual):</u>

$$\frac{7.4\,\cancel{g}^{(1)}}{\cancel{hp\text{-}hr}} \times \frac{(1-0.9)}{1} \times \frac{860\,\cancel{hp}}{1} \times \frac{lb}{453.6\,\cancel{g}} \times \frac{50\,\cancel{hr}}{year} = 70 \text{ lb } NO_X/year$$

PE_{NOx} = 70 lb NO_X/year = 0.035 tons NO_X/year

District BACT policy demonstrates how to calculate the cost effectiveness of alternate basic equipment or process:

CE_{alt} = $(Cost_{alt} - Cost_{basic}) \div (Emission_{basic} - Emission_{alt})$

[1] Pursuant to AP-42 (07/00) the NO_X value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)

where,

CE_{alt} = the cost effectiveness of alternate basic equipment expressed as dollars per ton of emissions reduced

$Cost_{alt}$ = the equivalent annual capital cost of the alternate basic equipment plus its annual operating cost

$Cost_{basic}$ = the equivalent annual capital cost of the proposed basic equipment, without BACT, plus its annual operating cost

$Emission_{basic}$ = the emissions from the proposed basic equipment, without BACT.

$Emission_{alt}$ = the emissions from the alternate basic equipment

The District conducted research to determine the appropriate cost information for installing a rich burn IC engine with a Non-Selective Catalytic Reduction System versus the cost information for installing a uncontrolled lean burn IC engine. Based on information from various engine manufacturers, the initial costs for installing an uncontrolled rich burn engine versus an uncontrolled lean burn engine would be minimal. The main difference in cost would be incurred in the installation of the NSCR system and the air to fuel ratio controller to the rich burn IC engine.

According to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" (pgs. V-2 & V-3), the approximate capital cost for installing a NSCR system for a 1,000 hp engine would be approximately $28,000, the capital cost for installing an air to fuel ratio controller would be $5,300, and the overall installation cost would be $2,500. The CARB RACT/BARCT document also states the annual cost for operating and maintenance is between $8,000 – 10,000, but these values are assuming full time operation. Since the proposed installation will be limited only to emergency operation and testing and maintenance, a conservative assumption of $1,000 per year will be utilized for this evaluation.

Per District BACT Policy, the equivalent annual capital cost is calculated as follows:

$$A\ (\$/yr) = P \times [i \times (1 + i)^n] \div [(1 + i)^n - 1]$$

Where:
- A = Equivalent annual capital cost of the control equipment
- P = Present value of the control equipment including installation
- i = interest rate (10% used as default value)
- n = equipment life (10 years used as default value)

Using a total capital cost of $35,800 in the above equation results in an equivalent annual cost of $5,826/year. Adding this equivalent annual cost to the annual operating cost of $1,000/year, the ($Cost_{alt}$ - $Cost_{basic}$) is equal to $6,826/year. It should be noted that the operating the rich burn IC engine versus a lean burn IC engine would result in an efficiency loss and would potentially result in higher annual fuel expenses. These costs will be set aside for the present and only a partial cost analysis will be performed.

District BACT policy also requires the use of a Multi-Pollutant Cost Effectiveness Threshold (MCET) for a BACT option controlling more than one pollutant. The installation of a NSCR system will control NO_X, CO, and VOC emissions. Therefore, the MCET is calculated as follows:

$$\text{MCET (\$/yr)} = (E_{NOx} \times T_{NOx}) + (E_{CO} \times T_{CO}) + (E_{VOC} \times T_{VOC})$$

Where:
E_{NOx} = tons-NO_X controlled/yr
E_{CO} = tons-CO controlled/yr
E_{VOC} = tons-VOC controlled/yr
T_{NOx} = District's cost effectiveness threshold for NO_X
= \$9,700/ton-NO_X
T_{CO} = District's cost effectiveness threshold for CO
= \$300/ton-CO
T_{VOC} = District's cost effectiveness threshold for VOCs
= \$5,000/ton-VOCs

Since this BACT cost effectiveness analysis is analyzing alternate basic equipment with a control technology which controls multiple pollutants; in order to calculate the cost effectiveness for the alternate basic equipment, the District will take the MCET and compare that value with the ($Cost_{alt}$ – $Cost_{basic}$), to determine if this control technology is cost effective.

To determine E_{CO}, the District has to establish what Industry Standard is for CO emissions. As detailed above, engines with NO_X emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for CO emissions @ < 90% load (1.83 g CO/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

<u>CO (annual):</u>

$$\frac{1.83\ \cancel{g}}{\cancel{hp\text{-}hr}} \times \frac{860\ \cancel{hp}}{1} \times \frac{lb}{453.6\ \cancel{g}} \times \frac{50\ \cancel{hr}}{year} = 173\ \text{lb CO/year}$$

PE_{CO} = 173 lb CO/year = 0.0865 ton CO/year

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB (pg. B-20), the CO control effectiveness from a NSCR system is greater than 80%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a CO control efficiency of ≥ 80% can be calculated as:

CO (annual):

$$\frac{11.6\ \cancel{g}^{(2)}}{\cancel{hp\text{-}hr}}\ \Big|\ \frac{(1-0.8)}{1}\ \Big|\ \frac{860\ \cancel{hp}}{1}\ \Big|\ \frac{lb}{453.6\ \cancel{g}}\ \Big|\ \frac{50\ \cancel{hr}}{year} = 220\ lb\ CO/year$$

PE_{CO} = 220 lb CO/year = 0.11 ton CO/year

As demonstrated above, the CO emissions from the rich burn IC engine with a NSCR system are higher than the uncontrolled CO emissions from the lean burn IC engine. Therefore, CO will not be included in the MCET calculations.

To determine E_{VOC}, the District has to establish what Industry Standard is for VOC emissions. Again, as detailed above, engines with NO_X emissions of 2.8 g/hp-hr (per AP-42) were deemed as the industry standard for this class and category of source. Therefore, the District will also take AP-42 values for VOC emissions (0.39 g VOC/hp-hr) and deem that value as industry standard for this class and category of source.

Therefore, the proposed annual emissions from a lean burn IC engine using industry standard values can be calculated as:

VOC (annual):

$$\frac{0.39\ \cancel{g}}{\cancel{hp\text{-}hr}}\ \Big|\ \frac{860\ \cancel{hp}}{1}\ \Big|\ \frac{lb}{453.6\ \cancel{g}}\ \Big|\ \frac{50\ \cancel{hr}}{year} = 37\ lb\ VOC/year$$

PE_{VOC} = 37 lb VOC/year = 0.0185 ton VOC/year

Pursuant to the guidance document "RACT/BARCT for Stationary Spark-Ignited IC Engines" created by CARB, the VOC control effectiveness from a NSCR system is greater than 50%. Therefore, the proposed annual emissions from a rich burn engine equipped the a Non-Selective Catalytic Reduction system with a VOC control efficiency of ≥ 50% can be calculated as:

VOC (annual):

$$\frac{0.10\ \cancel{g}^{(3)}}{\cancel{hp\text{-}hr}}\ \Big|\ \frac{(1-0.5)}{1}\ \Big|\ \frac{860\ \cancel{hp}}{1}\ \Big|\ \frac{lb}{453.6\ \cancel{g}}\ \Big|\ \frac{50\ \cancel{hr}}{year} = 5\ lb\ VOC/year$$

PE_{VOC} = 5 lb VOC/year = 0.0025 ton VOC/year

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[2] Pursuant to AP-42 (07/00) the CO value for uncontrolled four-stroke rich burn IC engines @ < 90% load. (lb/MMBtu converted to g/hp-hr, Attachment I)
[3] Pursuant to AP-42 (07/00) the VOC value for uncontrolled four-stroke rich burn IC engines. (lb/MMBtu converted to g/hp-hr, Attachment I)

Calculating for the MCET derives the following:

E_{NOx} = 0.1325 tpy – 0.035 tpy = 0.0975 tpy
E_{VOC} = 0.0185 tpy – 0.0025 tpy = 0.016 tpy

MCET ($/yr) = (0.0975 x $9,700) + (0.016 x $5,000) = $1,026/year

As presented above, ($Cost_{alt}$ – $Cost_{basic}$) is equal to $6,826/year.

This value is greater than the MCET; therefore, it has been determine that the installation of a rich burn IC engine with a NSCR system as alternate basic equipment is not cost effective using just the partial cost analysis.

2. NO_X emissions of ≤ 1.0 g/bhp-hr (lean-burn natural gas fired engine or equal)

The applicant has proposed that the NOx emissions from the engine will not exceed 1.0 g/bhp-hr. This is the highest ranking remaining control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - <u>Select BACT</u>

BACT for the emission unit is determined to be NO_X emissions of 1.0 g/bhp-hr or less. The facility has proposed NO_X emissions of less than 1.0 g/bhp-hr. Therefore, BACT is satisfied.

<u>Units C-3953-14-1 (Natural gas IC engine powering electrical generator)</u>

II. VOC Top-Down BACT Analysis

Step 1 - <u>Identify All Possible Control Technologies</u>

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies achieved in practice BACT as the following:

- ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies technologically feasible BACT as the following:

- 90% control efficiency (Oxidation catalyst, or equal)

SJVAPCD BACT Clearinghouse Guideline 3.1.8 identifies alternate basic equipment BACT as the following:

- ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)

Step 2 - <u>Eliminate Technologically Infeasible Options</u>

All control options listed in step 1 are technologically feasible.

Step 3 - <u>Rank Remaining Control Technologies by Control Effectiveness</u>

The following options are ranked based on their control efficiency:

1. 90% control efficiency (Oxidation catalyst, or equal)
2. ≥ 50% control efficiency catalyst (rich-burn engine with NSCR or equal)
3. ≤ 1.0 g/bhp-hr (Lean burn natural gas fired engine, or equal)

Step 4 - <u>Cost Effective Analysis</u>

A cost effective analysis must be performed for all control options in the list from step 3 in the order of their ranking to determine the cost effective option with the lowest emissions.

The applicant has proposed the engine will be equipped with an oxidation catalyst with 90% control of VOC emissions. This is the highest ranking control option listed in Step 3 above. Therefore, in accordance with District policy APR 1305 (BACT), Section IX.D, a cost effective analysis is not necessary and no further discussion is required.

Step 5 - Select BACT

BACT for the emission unit is determined to be the used of an oxidation catalyst with 90% control of VOC emissions. The facility has proposed to install an oxidation catalyst with 90% control of VOC emission. Therefore, BACT is satisfied.

ATTACHMENT G

Health Risk Assessment and Ambient Air Quality Analysis

San Joaquin Valley Unified Air Pollution Control District

MEMORANDUM

DATE: June 14, 2014

TO: Derek Fukuda, AQE—Permit Services

FROM: Leland Villalvazo, SAQS—Technical Services

SUBJECT: Revised NO_2 1-hour NAAQA Assessment for Avenal Power Center

Technical Services was requested to revise the RMR and AAQA assessment performed for project C-1011324, dated June 25, 2002, to lower the NOx and CO annual emission levels.

A review of the previous project indicated that the major item of concern was the 1-hour standard for NO_2. The previous assessment was based on the State standard of 339 ug/m^3 whereas the new federal standard 188.68 ug/m^3. The assessment contained in this memo will primarily address the new federal NO_2 NAAQS and any updates needed to the previous RMR assessment.

Background:
EPA has revised the primary NO_2 NAAQS in order to provide requisite protection of public health. Specifically, EPA has established a new 1-hour standard at a level of 100 ppb (188.68 ug/m^3), based on the 3-year average of the annual 98th percentile of the daily maximum 1-hour concentrations, to supplement the existing annual standard. EPA has also established requirements for NO_2 monitoring network that will include monitors at locations where maximum NO_2 concentrations are expected to occur, including within 50 meters of major roadways, as well as monitors sited to measure the area-wide NO_2 concentrations that occur more broadly across communities.

The final rule was signed on January 22, 2010. The effective date of the new 1 hour standard is 60 days after the final rule has been published in the Federal Register. The final rule was published in the Federal Register on Feb 9, 2010. The effective date is April 12, 2010.

Results:
Based on guidance from EPA dated February 25, 2010, the District has updated the AAQA assessment to include the new NO_2 1-hour standard, see below. The results follow the procedure outlined in the District's interim draft guidance document entitled "Modeling Procedure to Address The New Federal 1 Hour NO_2 Standard".

Commissioning	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**142.21**	**103.15**	245.36	188.68	F	-56.68
Tier II (max 8th)	**90.10**	**103.15**	193.25	188.68	F	-4.57
Tier III (ave.5yr)	**71.94**	**103.15**	175.09	188.68	**P**	13.58
Tier IV	**140.37**		140.37	188.68	**P**	48.31

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**142.21398**	**107.17307**	**110.4651**	**109.99858**	**105.1162**	**142.21**
Tier II (max 8th)	**80.85338**	**85.86045**	**84.64008**	**88.85226**	**90.10016**	**90.1**

*Ozone from Visalia

Operational	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**152.79**	**103.15**	255.94	188.68	F	-67.26
Tier II (max 8th)	**87.94**	**103.15**	191.09	188.68	F	-2.41
Tier III (ave.5yr)	**82.43**	**103.15**	185.58	188.68	**P**	3.10
Tier IV			0.00	188.68	P	188.68

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**152.79148**	**91.1532**	**93.47387**	**93.23991**	**90.56206**	**152.79**
Tier II (max 8th)	**87.7931**	**86.3495**	**86.51813**	**87.38902**	**87.93997**	**87.94**

*Ozone from Visalia

Conclusion

Based on the updated RMR, the risk from this facility is less than 10 in one million. **In accordance with the District's Risk Management Policy, the project is approved without Toxic Best Available Control Technology (T-BACT).**

To ensure that human health risks will not exceed District allowable levels; the permit conditions listed below must be included for the proposed unit(s).

These conclusions are based on the data provided by the applicant and the project engineer. Therefore, this analysis is valid only as long as the proposed data and parameters do not change.

The emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS.

Conditions

1. PM_{10} emission rate shall not exceed **0.059 g/HP-hr (note method) for the 288 hp engine** (C-3953-13-1).

2. The 860 hp engine (C-3953-14-1) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **50 hours per year**.

Commissioning	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**142.21**	**103.15**	245.36	188.68	F	-56.68
Tier II (max 8th)	**90.10**	**103.15**	193.25	188.68	F	-4.57
Tier III (ave.5yr)	**71.94**	**103.15**	175.09	188.68	P	13.58
Tier IV	**140.37**		140.37	188.68	P	48.31

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**142.21398**	**107.17307**	**110.4651**	**109.99858**	**105.1162**	**142.21**
Tier II (max 8th)	**80.85338**	**85.86045**	**84.64008**	**88.85226**	**90.10016**	**90.1**

*Ozone from Visalia

Operational	Modeling	Design Value	Impact	NAAQS Limit	Pass / Fail	Margin
District Tiers	ug/m3					
Tier I (max yr)	**152.79**	**103.15**	255.94	188.68	F	-67.26
Tier II (max 8th)	**87.94**	**103.15**	191.09	188.68	F	-2.41
Tier III (ave.5yr)	**82.43**	**103.15**	185.58	188.68	P	3.10
Tier IV			0.00	188.68	P	188.68

Year	2004	2005	2006	2007	2008*	Max
Tier I (max yr)	**152.79148**	**91.1532**	**93.47387**	**93.23991**	**90.56206**	**152.79**
Tier II (max 8th)	**87.7931**	**86.3495**	**86.51813**	**87.38902**	**87.93997**	**87.94**

*Ozone from Visalia

Diesel I.C. Engines (DICE)
Screening Risk Tool

Project Information

Region	C
Facility ID:	3953
Unit #:	13-1
Project #:	110751
Date:	7/14/2010

Met Station

District	SJVAPCD
Met Site	HANFORD
Model Type	RURAL
Year:	2008

Engine Data

BHP:	288
% Load:	100
PM10 EF (g/BHP):	0.059
Hours / Yr:	100
Lbs / Yr:	3.75

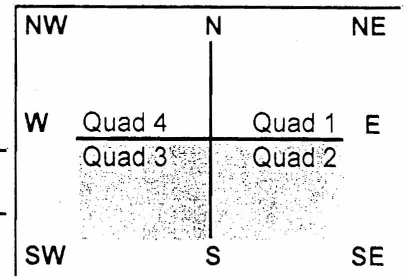
Convert to G/BHP

Convert to G/KW

Update Emissions

Receptor Data

Quad	QUAD 1
Distance(m)	50
Miles:	
Feet	
Yards:	
10th Mi:	



Cancer Risk

Resident Risk: In a Million	0.24
Maximum Res. Risk	1.98
Worker Adjustment Factor %	37.91
Worker Risk: In a Million	0.09
Maximum Worker Risk	0.75
Quad:	2
Distance:	50

Calculate Risk

Print Form

New | View Eng Data | SAVE | Close Form

14-1

Print Worksheet

INTERNAL COMBUSTION (NG)
EMISSION FACTORS
(LBS. / MMCF)

FACILITY NAME:
DATE:

Receptor Distance: 1206

Priority Score 0.092999134

Total hrs. of operation 50.00 | MMCF/HR 0.0071 | MMCF/YR 0.36

POLLUTANT	EMISSION FACTOR (MMCF/HR) <1000	>1000	TURBINE	Acute REL	Chronic REL	Cancer URF
Acetaldehyde	0.944	1.1328	0.037	0	9	2.70E-06
Acrolein	0.3783	0.454	0.009	0.19	2.00E-02	0
Benzene	3.257	3.9084	0.0113	1300	71	2.90E-05
Formaldehyde	32.4963	38.9956	0.094	94	3.6	6.00E-06
Naphthalene	0.1785	0.1785	0.0008	0	14	0
PAH's	0.0179	0.0179	0.0002	0		1.70E-03
Propylene	16.2259	19.4711	1.0522	0	0	0
Toluene	1.1145	1.3374	0.0726	37000	200	0
Xylenes	0.4048	0.4858	0.0289	22000	300	0
Ethyl Benzene	0.3257	0.3908	0.0132	0	0	0
Hexane	0.7491	0.8989	1.75	0	0	0

	<1000 EMISSION FACTORS	LBS./HR.	G/SEC	LBS./YR.	G/SEC	Acute Score	Chronic Score	Carcinogenic Score	Non-Carcinogenic Score
Acetaldehyde	0.944	6.70E-03	**8.45E-04**	3.35E-01	**4.82E-06**	0	0.11170667	0.001538201	0.111706667
Acrolein	0.3783	2.69E-03	**3.39E-04**	1.34E-01	**1.93E-06**	21.204711	20.144475	0	21.20471053
Benzene	3.257	2.31E-02	**2.92E-03**	1.16E+00	**1.66E-05**	0.0266823	0.048855	0.057002386	0.048855
Formaldehyde	32.4963	2.31E-01	**2.91E-02**	1.15E+01	**1.66E-04**	3.6817616	9.61348875	0.117669102	9.61348875
Naphthalene	0.1785	1.27E-03	**1.60E-04**	6.34E-02	**9.12E-07**	0	0.01357875	0	0.01357875
PAH's	0.0179	1.27E-04	**1.60E-05**	6.35E-03	**9.15E-08**	0	0	0.018364505	0
Propylene	16.2259	1.15E-01	**1.45E-02**	5.76E+00	**8.29E-05**	0	0	0	0
Toluene	1.1145	7.91E-03	**9.98E-04**	3.96E-01	**5.70E-06**	0.0003208	0.00593471	0	0.005934713
Xylenes	0.4048	2.87E-03	**3.62E-04**	1.44E-01	**2.07E-06**	0.000196	0.00143704	0	0.00143704
Ethyl Benzene	0.3257	2.31E-03	**2.92E-04**	1.16E-01	**1.66E-06**	0	0	0	0
Hexane	0.7491	5.32E-03	**6.71E-04**	2.66E-01	**3.83E-06**	0	0	0	0

San Joaquin Valley Unified Air Pollution Control District

MEMORANDUM

DATE: June 25, 2002

TO: Errol Villegas, SAQE—Permit Services

FROM: Esteban Gutierrez, AQS—Technical Services

SUBJECT: AAQA and RMR Modeling request for Duke energy Avenal LLC.

As per your request, Technical Service performed modeling for criteria pollutants CO, NOx, SOx and PM_{10}; as well as a RMR for, two turbines, two IC engines, nineteen (19) cooling towers and a boiler for a power plant. The engineer supplied the maximum fuel rate as well as process rates for all of the units described above. ISCST3 model was used to determine dispersion value for cancer risk exposure.

The results from the RMR modeling runs and Criteria Pollutant Modeling are as follows:

RMR Modeling Results

REFINED HRA SUMMARY			
Device	**(2) Turbines**	**Boiler**	**(3) 4 cell tower**
Fuel	**NG**	**NG**	
Prioritization Score	0.8242	.0107	N/A
Cancer Risk	N/A	N/A	N/A
Acute Hazard Index	N/A	N/A	N/A
Chronic Hazard Index	N/A	N/A	N/A
TBACT Required?	No	No	No

REFINED HRA SUMMARY			
Device	**7 cell tower**	**300 Hp ICE**	**660 HP ICE**
Fuel		**Diesel**	**Diesel**
Prioritization Score	N/A	N/A	N/A
Cancer Risk	N/A	2.01E-6	1.00E-6
Acute Hazard Index	N/A	N/A	N/A
Chronic Hazard Index	N/A	N/A	N/A
Maximum operating Hrs		200	38
TBACT Required?	No	Yes	No

Criteria Pollutant Modeling Results*
Values are in ug/m^3

	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	Pass	X	Pass	X	X
NO_x	Pass***	X	X	X	Pass
SO_x	Pass	Pass	X	Pass	Pass
PM_{10}	X	X	X	Pass**	Pass**

*Results were taken from the attached PSD spreadsheet.
**The criteria pollutants noted by a double asterisk (**) are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2). Operating time for 24 hour risk was adjusted for PM10 levels.
*** Passing score was obtained from running OLM (Ozone Limiting Method.)

(2) NG Turbines Stack Parameters			
Source Type	Point	**Process Rate (T1) MMbtu/yr**	16,958,390
Stack Height (m)	44.2	**Process Rate (T2) MMbtu/yr**	20,582,010
Stack Diam. (m)	5.49	**Hours of operation yr (T1)**	8400
Gas Exit Velocity (m/sec) T1	20.4	**Hours of operation yr (T2)**	8760
Stack Gas Temp (°K)	356	**Receptor Distance (m)**	1609
Location Type	Rural		

7 Cell Cooling Tower Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	13.7	**Process Rate Gal/Yr**	57,153,744,000
Stack Diam. (m)	9.64	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	8.10	**Hours of operation**	8760
Stack Gas Temp (°K)	293		

(3) 4 Cell Cooling Towers Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	16.08	**Process Rate Gal/Yr**	5,308,560,000
Stack Diam. (m)	3.57	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	11.46	**Hours of operation**	8760
Stack Gas Temp (°K)	293		

Boiler Stack Parameters			
Source Type	Point	**Location Type**	Rural
Stack Height (m)	11.28	**Process Rate MMbtu/yr**	93,500
Stack Diam. (m)	0.812	**Receptor Distance (m)**	1609
Gas Exit Velocity (m/sec)	12.2	**Hours of operation**	2500
Stack Gas Temp (°K)	476		

Diesel Engine (300 Hp)			
Source Type	Point	**Closest Receptor (m)**	1609
Stack Height (m)	3.04	**Location Type**	RURAL
Stack Diam. (m)	0.13	**Max Operating (hr/yr)**	**100**
Gas Exit Velocity (m/sec)	67.1	**Fuel Type**	Diesel
Stack Gas Temp (°K)	716	**PM10 g/bhp-hr**	0.09

Diesel Engine (660 Hp)			
Source Type	Point	Closest Receptor (m)	1609
Stack Height (m)	3.04	Location Type	RURAL
Stack Diam. (m)	0.23	Max Operating (hr/yr)	38
Gas Exit Velocity (m/sec)	45.0	Fuel Type	Diesel
Stack Gas Temp (°K)	799	PM10 g/bhp-hr	0.4

Conclusion:

The Criteria modeling runs indicate that the emissions from the proposed equipment will not have an adverse impact on the State and National AAQS. Therefore, no further modeling will be required to demonstrate that the AAQS or EPA's level of significance would be exceeded.

The carcinogenic risk for the 300 hp engine is 2.01E-06, which is below the maximum allowable risk of 10 in a million for diesel IC engines emitting ≤ 0.149g PM_{10}/bhp/hr. The risk for the 660 hp engine is 1.00E-06 which is the allowable risk of one in a million for engines emitting > 0.149g PM_{10}/bhp/hr. Therefore, **the project is approved for permitting, and TBACT is required for the 300 hp engine.** In order to assure compliance with the assumptions made for the risk management review the following conditions listed on the PTO are required:

1. Only CARB certified fuel containing not more than 0.05% sulfur by weight is to be used in these engines.

2. PM_{10} emission rate shall not exceed **0.09 g/HP-hr (note method) for the 300 hp engine** (C-3953-8-0).

3. PM_{10} emission rate shall not exceed **0.40 g/HP-hr (note method) for the 660 hp engine** (C-3953-9-0).

4. The exhaust stacks shall not be fitted with a rain caps, or any other similar devices, that impedes vertical exhaust flow.

5. The 300 hp engine (C-3953-8-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **100 hours per year**.

6. The 660 hp engine (C-3953-9-0) shall only be operated for maintenance, testing, required regulatory purposes, and during emergency situations. Operation of the engine for maintenance and testing purposes shall not exceed **38 hours per year**.

7. The 660 hp engine (C-3953-9-0) shall not operate more than **7 hours in any rolling 24 hr period during maintenance, testing, and required regulatory purposes.**

ATTACHMENT H

SO_X for PM_{10} Interpollutant Offset Analysis

SO_X for PM_{10} Interpollutant Offset Analysis
Avenal Power Center, LLC

Facility Name:	Avenal Power Center, LLC	Date:	June 30, 2010
Mailing Address:	500 Dallas Street. Level 31 Houston, TX 77002	Engineer: Lead Engineer:	Derek Fukuda Joven Refuerzo
Contact Person:	Jim Rexroad		
Telephone:	(713) 275-6147		
Application #:	C-3953-10-1, -11-1, -12-1, -13-1, and -14-1		
Project #:	C-1100751		
Location:	NE¼ Section 19, Township 21 South, Range 18 East – Mount Diablo Base Meridian on Assessor's Parcel Number 36-170-032		
Complete:	March 18, 2010		

I. Proposal

Avenal Power Center, LLC is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "merchant" electrical power generation facility (Avenal Energy Project). The Avenal Energy Project will be a combined-cycle power generation facility consisting of two natural gas-fired combustion turbine generators (CTGs) each with a heat recovery steam generator (HRSG) and a 562.3 MMBtu/hr duct burner. Also proposed are a 300 MW steam turbine, a 37.4 MMBtu/hr auxiliary boiler, a 288 hp diesel-fired emergency IC engine powering a water pump, a 860 hp natural gas-fired emergency IC engine powering a 550 kW generator and associated facilities. The plant will have a nominal rating of 600 MW.

In addition, Avenal Power Center, LLC has proposed to limit the annual facility wide NO_X emissions to 198,840 lb/year, and the annual facility wide CO emissions to 197,928 lb/year.

Facility C-3953 will become a major source for NO_X, VOC, and PM_{10}. There will be an increase in emissions for all pollutants and offsets are required for NO_X, VOC, and PM_{10} emissions.

II. Applicable Rules

Rule 2201 New and Modified Stationary Source Review Rule (9/21/06) (Section 3.30 and 4.13.3.2)

III. Process Description

Combined-Cycle Combustion Turbine Generators

Each natural gas-fired General Electric Frame 7 Model PG7241FA combined-cycle combustion turbine generator (CTG) will be equipped with Dry Low NO_X combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, a duct burner, and a heat recovery steam generator (HRSG). Each CTG will drive an electrical generator to produce approximately 180 MW of electricity. The plant will be a "combined-cycle plant," since the gas turbine and a steam turbine both turn electrical generators and produce power.

Each CTG will turn an electrical generator, but will also produce power by directing exhaust heat through its HRSG, which supplies steam to the steam turbine nominally rated at 300 MW, which turns another electrical generator.

Since two HRSGs will feed a single steam turbine generator, this design is referred to as a "two-on-one" configuration.

The CTGs will utilize Dry Low NO_X (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:

NO_X: 2.0 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 2.0 ppmvd @ 15% O_2
SO_X: 0.00282 lb/MMBtu (Hourly and Daily Limits; based on 1.0 gr S/100 dscf)
0.001 lb/MMBtu (Annual average; based on 0.36 gr S/100 dscf))
PM_{10}: 0.0107 lb/MMBtu

Continuous emissions monitoring systems (CEMs) will sample, analyze, and record NO_X, CO, and O_2 concentrations in the exhaust gas for each CTG.

Heat Recovery Steam Generators (HRSGs)

The HRSGs provide for the transfer of heat from the CTG exhaust gases to condensate and feedwater to produce stream. Each HRSG will be approximately 90 feet high and will have an exhaust stack approximately 145 feet tall by 19 feet in diameter. The size and shape of the HRSGs are specific to their intended purpose of high efficiency recycling of waste heat from the CTG.

The HRSGs will be multi-pressure, natural-circulation boilers equipped with transition ducts and duct burners. Pressure components of each HRSG include a low pressure (LP) economizer, LP evaporator, LP deaerator/drum, LP superheater, intermediate pressure (IP) economizer, IP evaporator, IP drum, IP superheaters, high pressure (HP) economizer, HP evaporator, HP drum, and HP superheaters and reheaters.

Superheated HP steam is produced in the HRSG and flows to the steam turbine throttle inlet. The exhausted cold reheat steam from the steam turbine is mixed with IP steam from the HRSG and reintroduced into the HRSG through the reheaters. The hot reheat steam flows back from the HRSG into the STG. The LP superheated steam from the HRSG is admitted to the LP condenser. The condensate is pumped from the condenser back to the HRSG by condensate pumps. The condensate is preheated by an HRSG feedwater heater. Boiler feedwater pumps send the feedwater through economizers and into the boiler drums of the HRSG, where steam is produced, thereby completing the steam cycle.

Each HRSG is equipped with a SCR system that uses aqueous ammonia in conjunction with a catalyst bed to reduce NO_X in the CTG exhaust gases. The catalyst bed is contained in a catalyst chamber located within each HRSG. Ammonia is injected upstream of the catalyst bed. The subsequent catalytic reaction converts NO_X to nitrogen and water, resulting in a reduced concentration of NO_X in the exhaust gases exiting the stack.

Duct Burners

Duct burners are installed in the HRSG transition duct between the HP superheater and reheat coils. Through the combustion of natural gas, the duct burners heat the CTG exhaust gases to generate additional steam at times when peak power is needed. The duct burners are also used as needed to control the temperature of steam produced by the HRSGs. The duct burners will have a maximum heat input rating of 562 MMBtu/hr on a higher heating value (HHV) basis per HRSG, and are expected to operate no more than 800 hours per year.

Steam Turbine Generator

The steam turbine system consists of a 300 MW nominally rated reheat steam turbine generator (STG), governor system, steam admission system, gland steam system, lubricating oil system, including oil coolers and filters and generator coolers. Steam from the HP superheater, reheater and IP superheater sections of the HRSG enters the corresponding sections of the STG as described previously. The steam expands through the turbine blading to drive the steam turbine and its generator. Upon exiting the turbine, the steam enters the deaerating condenser, where it is condensed to water.

Auxiliary Boiler

One 37.4 MMBtu/hr Cleaver Brooks Model CBL700-900-200#ST natural gas-fired boiler equipped with an Cleaver Brooks Model ProFire Ultra Low NO_X burner, capable of providing up to 25,000 pounds per hour (lb/hr) of saturated steam. The boiler will be used to provide steam as needed for auxiliary purposes.

Diesel-Fired Emergency IC Engine Powering a Fire Pump

Emergency firewater will be provided by three pumps (a jockey pump, a main fire pump, and a back-up fire pump); two powered by electric motors and the other powered by a diesel-fired internal combustion engine. If the jockey pump is unable to maintain a set operating pressure in the piping network, the electric motor-driven fire pump will start automatically. If the electric motor-driven fire pump is unable to maintain a set operating pressure, the diesel engine-driven fire pump will start automatically. The diesel-fired engine will be rated at 288 horsepower. The engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

Natural Gas-Fired Emergency IC Engine Powering an Electrical Generator
One 860 hp Caterpillar Model G3512LE natural gas-fired IC engine generator set will provide power to the essential service AC system in the event of grid failure or loss of outside power to the plant. This engine will be limited to no greater than 50 hours per year of non-emergency operation in accordance with the applicant's proposal.

IV. Equipment Listing:

C-3953-10-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #1 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-11

C-3953-11-1: 180 MW NOMINALLY RATED COMBINED-CYCLE POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC FRAME 7 MODEL PG7241FA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR WITH DRY LOW NO_X COMBUSTOR, A SELECTIVE CATALYTIC REDUCTION (SCR) SYSTEM, AN OXIDATION CATALYST, HEAT RECOVERY STEAM GENERATOR #2 (HRSG) WITH A 562 MMBTU/HR DUCT BURNER AND A 300 MW NOMINALLY RATED STEAM TURBINE SHARED WITH C-3953-10

C-3953-12-1: 37.4 MMBTU/HR CLEAVER BROOKS MODEL CBL-700-900-200#ST NATURAL GAS-FIRED BOILER WITH A CLEAVER BROOKS MODEL PROFIRE, OR DISTRICT APPROVED EQUIVALENT, ULTRA LOW NOX BURNER

C-3953-13-1: 288 BHP CLARKE MODEL JW6H-UF40 DIESEL-FIRED EMERGENCY IC ENGINE POWERING A FIRE PUMP

C-3953-14-1: 860 BHP CATERPILLAR MODEL 3456 NATURAL GAS-FIRED EMERGENCY IC ENGINE POWERING WITH NON-SELECTIVE CATALYTIC REDUCTION (NSCR) POWERING A 500 KW ELECTRICAL GENERATOR

V. Interpollutant Offset Ratio Proposal SO_X for PM_{10}

Rule 2201, New and Modified Stationary Source Review, specifically allows the use of PM_{10} precursor ERCs to offset PM_{10} increases:

> *4.13.3 Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, that the emission increases from the new or modified source will not cause or contribute to a violation of an Ambient Air Quality Standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements of this rule.*
>
> *4.13.3.2 Interpollutant offsets between PM10 and PM10 precursors may be allowed.*

Based on this language, an applicant must demonstrate an appropriate interpollutant offset ratio, based on an air quality analysis (that is, based on the science of the precursor-to-PM_{10} relationship given the atmospheric chemistry and the meteorology of the locale).

The SO_X for PM_{10} interpollutant ratio of 1.000:1 is based on District analysis (see Appendix A). The originating location of reduction of the proposed ERC certificates are greater than 15 miles from the proposed project. Therefore, a distance offset ratio of 1.5 applies. Combining the interpollutant and distance offset ratio, an overall SO_X for PM10 offset ratio of 1.000 x 1.5 = 1.5:1 is valid for project C-1100751.

IV. Project Offset Calculations

i. C-3953-10-1 and C-3953-11-1 (Turbines)

a. Maximum Hourly PE

The maximum hourly potential to emit for NO_X, CO, and VOC from each CTG will occur when the unit is operating under start-up mode. The maximum hourly PE for both turbines operating together is when both are starting up and firing their duct burners.

The combined startup NOx emissions from the two turbines will be limited to 240 lbs/hr [maximum startup emission rate (160 lbs/hr) + average startup emission rate (80 lbs/hr)]. Similarly, the combined startup CO emissions from the two turbines will be limited to 1,902 lbs/hr, [maximum startup emission rate (1,000 lbs/hr) + average startup emission rate (902 lbs/hr)].

The maximum hourly emissions are summarized in the table below:

Maximum Hourly Potential to Emit					
	Maximum Startup/Shutdown Emissions (lb/hr)	Turbine w/ Duct Burner Emissions Rate	Turbine #1 Emissions (lb/hr)	Turbine #2 Emissions (lb/hr)	Maximum Hourly Emissions for Both Turbines
NO_X	160	17.20	13.55	13.55	240.00
CO	1,000	10.60	8.35	8.35	1,902.00
VOC	16	5.89	3.34	3.34	32.00
PM_{10}	N/A[1]	11.78	8.91	8.91	23.56
SO_X	N/A[7]	6.65	5.23	5.23	13.30
NH_3	N/A	32.13	25.31	25.31	64.26

b. *Maximum Daily PE*

Maximum daily emissions for NO_X, CO, and VOC occurs when each CTG undergoes six (6) hours operating in startup or shutdown mode, and eighteen (18) hours operating with duct burner firing at full load. The startup and shutdown emissions for PM_{10}, SO_X, and NH3 are will be lower or equivalent to the emissions rate when the unit is fired at 100% load; therefore the maximum daily emissions for PM_{10}, SO_X, and NH3 occurs when each CTG is operated for twenty four (24) hours with duct burner firing at full load. The results are summarized in the table below:

Maximum Daily Potential to Emit (w/ Startup and Shutdown)				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (101° F)	Emissions Rate @ 100% Load without duct burner (32° F)	DEL (per CTG)
NO_X	80 lb/hr (avg)	17.20 lb/hr	13.03 lb/hr	789.6 lb/day
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	5,590.8 lb/day
VOC	16 lb/hr (avg)	5.89 lb/hr	3.34 lb/hr	202.0 lb/day
PM_{10}	N/A[8]	11.78 lb/hr	8.91 lb/hr	282.7 lb/day
SO_X	N/A[8]	6.65 lb/hr	5.23 lb/hr	159.6 lb/day
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	771.1 lb/day

c. *Maximum Annual PE*

The facility has indicated that the turbines will be operated in one of three different scenarios: weekend and weekday hot start scenario, weekend shutdown and weekday hot start scenario, and baseload scenario. The SO_X emission factors used to calculate the annual potential emissions will be based

[1] PM_{10} and SO_X emissions during startups and shutdowns are lower than maximum hourly emissions.

on the applicant proposed average natural gas sulfur limit 0.36 gr/100 dscf.

SO_X EF = (0.36 ~~gr-S~~/100 ~~dscf~~) x (1 ~~lb-S~~/7000 ~~gr~~) x (64 lb SO_X/32 ~~lb-S~~) x (1 ~~scf~~/1013 ~~Btu~~) x (10^6 ~~Btu~~/MMBtu)
= 0.001 lb-SO_X/MMBtu

CTG w/o Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (1,856.3 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **1.86 lb-SO_X/hr**

CTG w/ Duct Burner Firing:
SO_X Emission Rate (lb/hr) = (2,356.5 MMBtu/hr) x (0.001 lb-SO_X/MMBtu)
= **2.36 lb-SO_X/hr**

Potential annual emissions for each pollutant will be calculated for each of the three scenarios in the tables below:

Scenario 1) Weekend and Weekday Hot Start:

547.5 (1.5 hr/hot start x 365 hot start/yr) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 6,683 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 1) Weekend and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG))
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	**143,951 lb/year**
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	557,033 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	**34,489 lb/year**
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	74,091 lb/year
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	15,337 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	208,708 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 2) Weekend Shutdown and Weekday Hot Start:

624 ((1.5 hr/hot start x 208 hot start/yr) + (6.0 hr/cold start x 52 cold starts/year)) hours operating in startup and shutdown mode, 800 hours operating while firing at full load with the duct burner, and 3,800 hours operating while firing at full load without the duct burner. Since startup and shutdown emission rates for PM_{10}, SO_X, and NH3 are less than the emission rate when the CTG is fired at 100% load w/o the duct burner, the startup and shutdown emission rates will be assumed to be equivalent to the CTG fired at 100% load w/o the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Scenario 2) Weekend Shutdown and Weekday Hot Start*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	112,506 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	601,810 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	26,574 lb/year
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	48,832 lb/year
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	10,117 lb/year
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	137,675 lb/year

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Scenario 3) Baseload:

800 hours operating while firing at full load with the duct burner, and 7,960 hours operating while firing at full load without the duct burner. Since the CTGs will be fired throughout the year, the emission factors for the unit when fired at the average ambient temperature (63° F) will be used to calculate the potential annual emissions.

Annual Potential to Emit Baseload Scenario*				
	Average Startup/Shutdown Emissions Rate	Emissions Rate @ 100% Load with duct burner (63° F)	Emissions Rate @ 100% Load without duct burner (63° F)	Annual PE (per CTG)
NO_X	80 lb/hr (avg)	16.34 lb/hr	13.03 lb/hr	116,791 lb/year
CO	900 lb/hr (avg)	10.60 lb/hr	8.35 lb/hr	74,946 lb/year
VOC	16 lb/hr (avg)	5.68 lb/hr	3.17 lb/hr	29,777 lb/year
PM_{10}	N/A(8)	11.27 lb/hr	9.00 lb/hr	**80,656 lb/year**
SO_X	N/A(8)	2.36 lb/hr	1.86 lb/hr	**16,694 lb/year**
NH_3	N/A	32.13 lb/hr	25.31 lb/hr	**219,972 lb/year**

* Emission factors were taken from Table 6.2-1.1 in the ATC application submittal.

Maximum Annual Potential to Emit:

The highest annual potential emissions, for each pollutant, from the three different scenarios will be taken to determine the maximum annual potential to emit for the CTG. The results are summarized in the table below:

Maximum Annual Potential to Emit		
	Annual PE (per CTG)	Scenario
NO_X	143,951 lb/year	Scenario 1
CO	197,928 lb/year	Facility Wide Limit
VOC	34,489 lb/year	Scenario 2
PM_{10}	80,656 lb/year	Scenario 3
SO_X	16,694 lb/year	Scenario 3
NH_3	219,972 lb/year	Scenario 3

ii. C-3953-12-0 (Boiler)

The PM_{10} potential to emit for the boiler is calculated as follows, and summarized in the table below.

PE_{PM10} = (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr)
= **0.19 lb PM_{10}/hr**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (12 hr/day)
= **2.2 lb PM_{10}/day**

= (0.005 lb/MMBtu) ∗ (37.4 MMBtu/hr) ∗ (1,248 hr/year)
= **233 lb PM_{10}/year**

= (233 lb/year) ∗ (4 qtr/year)
= **58 lb PM_{10}/qtr**

Post Project Potential to Emit (PE2) (C-3953-12-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.19	2.2	58	233

iii. C-3953-13-0 (Diesel IC engine powering fire water pump)

The PM_{10} emissions for the emergency fire pump engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb)
= **0.04 lb PM_{10}/hr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **0.9 lb PM_{10}/day**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **0.5 lb PM_{10}/qtr**

= (0.059 g/hp·hr) ∗ (288 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **1.9 lb PM_{10}/year**

Post Project Potential to Emit (PE2) (C-3953-13-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.04	0.9	0.5	2

iv. C-3953-14-0 (Natural gas IC engine powering electrical generator)

The PM_{10} emissions for the emergency IC engine is calculated as follows, and summarized in the table below:

PE_{PM10} = (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb)
= **0.06 lb PM_{10}/hr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (24 hr/day)
= **1.5 lb PM_{10}/day**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (12.5 hr/qtr)
= **1 lb PM_{10}/qtr**

= (0.034 g/hp·hr) ∗ (860 hp) ÷ (453.6 g/lb) ∗ (50 hr/year)
= **3 lb PM_{10}/year**

Post Project Potential to Emit (PE2) (C-3953-14-0)				
	Hourly Emissions (lb/hr)	Daily Emissions (lb/day)	Quarterly Emissions (lb/qtr)	Annual Emissions (lb/year)
PM_{10}	0.06	1.5	1	3

Post-Project Stationary Source Potential to Emit (SSPE2)

Pursuant to Section 4.10 of District Rule 2201, the Post Project Stationary Source Potential to Emit (SSPE2) is the Potential to Emit (PE) from all units with valid Authorities to Construct (ATC) or Permits to Operate (PTO) at the Stationary Source and the quantity of emission reduction credits (ERC) which have been banked since September 19, 1991 for Actual Emissions Reductions that have occurred at the source, and which have not been used on-site.

Post-project Stationary Source Potential to Emit [SSPE2] (lb/year)						
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972
C-3953-11-1			34,489	80,656	16,694	219,972
C-3953-12-1			201	233	132	0
C-3953-13-1			12	2	0	0
C-3953-14-1			31	3	1	0
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,222**	**161,550**	**33,521**	**439,944**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

Total Emissions to be Offset

Pursuant to District Rule 2201, Section 4.6, emission offsets shall not be required for emergency equipment that is used exclusively as emergency standby equipment for electric power generation or any other emergency equipment as approved by the APCO that does not operate more than 200 hours per year for non-emergency purposes and is not used pursuant to voluntary arrangements with a power supplier to curtail power. Therefore the emission from the diesel-fired fire water pump and the natural gas-fired emergency standby generator are not required to be offset.

Emission to be Offset (lb/year)						
Permit Unit	NO_X *	CO **	VOC	PM_{10}	SO_X	NH_3
C-3953-10-1	198,840	197,928	34,489	80,656	16,694	219,972
C-3953-11-1			34,489	80,656	16,694	219,972
C-3953-12-1			201	233	132	0
Post-project SSPE (SSPE2)	**198,840**	**197,928**	**69,179**	**161,545**	**33,520**	**439,944**

* The facility has proposed to limit the NO_X emission from this facility to 198,840 lb/year.
** The facility has proposed to limit the CO emission from this facility to 197,928 lb/year.

Offset Calculations:

PM_{10}:

SSPE2 (PM_{10}) = 161,545 lb/year
Offset threshold (PM_{10}) = 29,200 lb/year
ICCE = 0 lb/year

Offsets Required (lb/year) = [(161,545 – 29,200 + 0) x DOR]
= 132,345 lb/year x DOR

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
33,087	33,086	33,086	33,086

The applicant is proposing to use ERC Certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 which have an original site of reduction greater than 15 miles from the location of this project. Therefore, a distance offset ratio of 1.5:1 is applicable and the amount of PM_{10} ERCs that need to be withdrawn is:

Offsets Required (lb/year) = 132,345 lb/year x 1.5
= 198,518 lb/year
= 99.26 ton/yr

Calculating the appropriate quarterly emissions to be offset is as follows (in lb/qtr):

1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
49,630	49,629	49,629	49,630

The applicant has stated that the facility plans to use ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 to offset the increases in PM_{10} emissions associated with this project. The applicant has purchased the following quarterly amounts of the above certificates:

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
ERC #C-896-4	80	80	80	80
ERC #N-721-4	0	0	3,215	0
ERC #N-723-4	0	0	985	0
ERC #S-2791-5	92,179	23,666	69,157	96,288
ERC #S-2790-5	12,862	491	0	8,499
ERC #S-2789-5	6	14	12	8
ERC #S-2788-5	5	7	3	6
ERC #N-762-5	21,000	21,000	21,000	21,000

Project PM_{10} offset requirements

The applicant states either PM_{10} ERC certificates C-894-4, N-721-4, N-723-4, N-762-5, S-2788-5, S-2789-5, S-2790-5, and 2791-5 will be utilized to supply the PM_{10} offset requirements.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,630	49,629	49,629	49,630
Available ERCs from certificates C-896-4, N-721-4, and N-723-4:	80	80	4,280	80
ERCs applied from certificates C-896-4, N-721-4, and N-723-4 fully withdrawn as certificates C-896-4, N-721-4, and N-723-4:	-80	-80	-4,280	-80
Remaining ERCs from certificate C-896-4, N-721-4, and N-723-4:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550

Per Rule 2201 Section 4.13.3.2, interpollutant offsets between PM_{10} and PM_{10} precursors (i.e. SO_X) may be allowed. The applicant is proposing to use interpollutant offsets SO_X for PM_{10} at an interpollutant ratio of 1.0:1 (see Appendix A). This interpollutant ratio has been evaluated by the District's modeler, James Sweet, Air Quality Project Planner. Per Rule 2201 Section 4.13.7, Actual Emission Reductions (i.e. ERCs) that occurred from October through March (i.e. 1st and 4th Quarter), inclusive, may be used to offset increases in PM during any period of the year. Since the SO_X ERCs are being used to offset PM_{10} emissions, the above applies to the SO_X ERCs.

In addition, the overall offset ratio is equal to the multiplication of the distance and interpollutant ratios (1.5 x 1.000 = 1.5).

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM_{10} Emissions to be offset: (at a 1.5:1 ratio):	49,550	49,549	45,349	49,550
Remaining PM_{10} emissions to be offset with SO_X ERCs (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	49,550	49,549	45,349	49,550
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	33,873	21,512	21,015	29,513
Remaining ERCs from certificates N-762-5, S-2788-5, S-2789-5, and S-2790-5:	0	0	0	0
Remaining PM_{10} emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Remaining PM10 Emissions to be offset: (at a 1.5:1 distance ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	92,179	23,666	69,157	96,288
1st qtr. ERCs applied to 2nd qtr. ERCs:	-4,371	4,371	0	0
Adjusted Remaining ERCs from certificate S-2791-5:	87,808	28,037	69,157	96,288
Remaining PM10 emissions to be offset (at a 1.5:1 ratio and a 1.000:1 interpollutant SO_X:PM_{10} ratio):	15,677	28,037	24,334	20,037
ERCs applied from certificate S-2791-5 partially withdrawn:	15,677	28,037	24,334	20,037
Remaining ERCs from certificate S-2791-5:	72,131	0	44,823	76,251

As seen above, the facility has sufficient credits to fully offset the quarterly SO_X and PM_{10} emissions increases associated with this project.

V. Conclusion

Approve use of an overall SO_X for PM_{10} interpollutant offset ratio of 1.5:1 (1.000 x 1.5).

VI. Recommendation

Compliance with all applicable rules and regulations is expected. Issue Authorities to Construct C-3953-10-1, -11-1, -12-1, -13-1, and -14-1 with a SO_X for PM_{10} interpollutant offset ratio of 1.000:1.

Appendix

A: District Review and Approval

Appendix A

District Review and Approval

Interpollutant Offset Ratio Explanation

The Air District's Rule 2201, "New and Modified Source Review", requires facilities to supply "emissions offsets" when a permittee requests new or modified permits that allow emissions of air contaminants above certain annual emission offset thresholds. In addition, Rule 2201 allows interpollutant trading of offsets amongst criteria pollutants and their precursors upon the appropriate scientific demonstration of an adequate trading ratio, herein referred to as the interpollutant ratio. A technical analysis is required to determine the interpollutant offset ratio that is justified by evaluation of atmospheric chemistry. This evaluation has been conducted using the most recent modeling analysis available for the San Joaquin Valley. The results of the analysis are designed to be protective of health for the entire Valley for the entire year, by applying the most stringent interpollutant ratio throughout the Valley.

It is appropriate for District particulate offset requirements to be achieved by either a reduction of directly emitted particulate or by reduction of the gases, called particulate precursors, which become particulates from chemical and physical processes in the atmosphere. The District interpollutant offset relationship quantifies precursor gas reductions sufficient to serve as a substitute for a required direct particulate emissions reduction. Emission control measures that reduce gas precursor emissions at the facility may be used to provide the offset reductions. Alternatively, emission credits for precursor reductions may be used in accordance with District regulations.

The amount of particulate formed by the gaseous emissions must be evaluated to determine how much credit should be given for the gaseous reductions. Gases combine and merge with other material adding molecular weight when forming into particles. Some of the gases do not become particulate matter and remain a gas. Both the extent of conversion into particles and resulting weight of the particles are considered to establish mass equivalency between direct particulate emissions and particulate formed from gas precursors. The Interpollutant offset ratio is expressed as a per-ton equivalency.

The District interpollutant analysis uses the most recent and comprehensive modeling of San Joaquin Valley particulate formation from sulfur oxides (SOx) and nitrogen oxides (NOx). Modeling compares industrial directly emitted particulate to particulate matter from precursor emissions. The interpollutant modeling procedure, assumptions and uncertainties are documented in an extensive analysis file. Additional documentation of the modeling procedure for the San Joaquin Valley is contained in the 2008 PM2.5 Plan and its appendices. The 2008 PM2.5 Plan provides evaluation of the atmospheric relationships for direct particulate emissions and precursor gases when they are highest during the fourth quarter of the year. The southern portion of the Valley is evaluated by both receptor modeling and regional modeling of chemical relationships for precursor particulate formation. Regional modeling was conducted for the entire Valley through 2014. The two modeling approaches are combined to determine interpollutant offset ratios applicable to, and protective of, the entire Valley (SOx for PM 1:1 and NOx for PM 2.629:1).

DEVELOPMENT OF THE INTERPOLLUTANT RATIO

For the proposed substitution of reductions of sulfur oxides (SOx) or nitrogen oxides (NOx) for directly emitted particulate matter

March 2009

Introduction

Goal of Interpollutant Evaluation: Establish the atmospheric exchange relationship for substitution of alternative pollutant or precursor reductions for required reductions of directly emitted particulate

Evaluation to establish the atmospheric relationship of different pollutants is required as a prerequisite for establishing procedures for allowing a required reduction to be met by substitution of a reduction of a different pollutant or pollutant precursor. Proposed new facility construction or facility modifications may result in increased emissions of a pollutant. The District establishes requirements for reductions of the pollutant to "offset" the proposed increase. A facility may propose a reduction of an alternative pollutant or pollutant precursor where reductions of that material have already been achieved at the facility beyond the amount required by District regulations or where emission reductions credits for reductions achieved by other facilities are economically available; however, for such a substitution to be allowed the District must establish equivalency standards for the substitution. The equivalency relationship used for offset requirements is referred to in this discussion as the interpollutant ratio. The interpollutant ratio is a mathematical formula expressing the amount of alternative pollutant or precursor reduction required to be substituted for the required regulatory reduction. This discussion is limited to the atmospheric relationships and does not address other policy or regulatory requirements for offsets such as are contained in District Rule 2201.

The following description is provided to explain key elements of the analysis conducted to develop the atmospheric relationship between the commonly requested substitutions. Emission reductions of sulfur oxide emissions or nitrogen oxide emissions are proposed by many facilities as a substitution for reduction of directly emitted particulates. Elemental and organic carbon emissions are the predominant case and dominant contribution to directly emitted particulate mass from industrial facilities, although other types of directly emitted particulates do occur. Therefore this atmospheric analysis examines directly emitted carbon particulates from industrial sources in comparison to the formation of particles from gaseous emissions of sulfur oxides and nitrogen oxides.

Analyses included in Interpollutant evaluation

Factors Considered

The foundation for this analysis is provided by the atmospheric modeling conducted for the 2008 PM2.5 Plan. Modeling conducted for this State Implementation Plan was conducted by the District and the California Air Resources Board using a variety of modeling approaches. Each separate model has technical limitations and uncertainties. To reduce the uncertainty of findings, a combined evaluation of results of all of the modeling methods is used to establish "weight of evidence" support for technical analysis and conclusions. The modeling methods are supported by a modeling protocol which was sent to ARB and EPA Region IX for review and was included in the appendices to the Plan.

The analysis file prepared for the interpollutant ratio evaluation includes emissions inventories, regional model daily output files, chemical mass balance modeling and speciated rollback modeling as produced for the 2008 PM2.5 Plan. This well examined and documented modeling information was used as a starting point for additional evaluation to determine interrelationships between directly emitted pollutants and particulates from precursors.

The interpollutant ratio analysis is limited to evaluation of directly emitted PM2.5 from industrial sources and formation of PM2.5 from precursor gases. While both directly emitted particulates and particulate from precursor gases also occur in the PM10 size range, there is much more uncertainty associated with deposition rates and particle formation rates for the larger size ranges. Additionally, because PM2.5 is a subset of PM10; all reductions of PM2.5 are fully creditable as reductions towards PM10 requirements. This analysis concentrates on the quarter of the year when both directly emitted carbon from industrial sources and secondary particulates are measured at the highest levels. Assessing atmospheric ratios at low concentrations is subject to much greater uncertainty and has limited value toward assessment of actions to comply with the air quality standards.

Elements from 2008 PM 2.5 Plan

- Regional modeling daily output for eleven locations
- Chemical Mass Balance (CMB) modeling for four locations – source analysis, speciation profile selection, event meteorology evaluation
- Receptor speciated rollback modeling with adjustment for nitrate nonlinearity for four locations, evaluation of spatial extent of contributing sources
- Emission inventories and projections to future years as developed for the 2008 PM 2.5 Plan

- Modeling protocols for receptor modeling, regional modeling, and Positive matrix Factorization (PMF) analysis and evaluation of technical issues applicable to particulate formation in the San Joaquin Valley
- Model performance analysis as documented in appendices to the 2008 PM 2.5 Plan

Extension by additional analysis

Additional evaluation was conducted to evaluate the receptor modeling relationship between direct PM from industrial sources and sulfate and nitrate particulate formed from SOx and NOx precursor gases. Area of influence adjustments were evaluated to ensure appropriate consideration of contributing source area for different types of pollutants for both directly emitted and secondary particulate. This evaluation was possible only for the southern four Valley counties and was conducted for both 2000 and 2009.

The regional model output was evaluated for the fourth quarter to evaluate general atmospheric chemistry in 2005 and 2014 to determine the correlation between northern and southern areas of the Valley. This evaluation determined that the atmospheric chemistry observed and modeled in the north was within the range of values observed and modeled in the southern SJV. This establishes that a ratio protective of the southern Valley will also be protective in the north.

The District determined from the additional analyses of both receptor and regional modeling that the most stringent ratio determined for the southern portion of the Valley would also be protective of the northern portion of the Valley. Due to the regional nature of these pollutants, actions taken in other counties must be assumed to have at least some influence on other counties; therefore to achieve attainment at the earliest practical date it is appropriate to require all counties to establish a consistent interpollutant ratio for the entire District.

Strengths

The interpollutant ratio analysis uses established and heavily reviewed modeling and outputs as foundation data. Analysis of model performance has already been completed for the models and for the emissions inventories used for this analysis. The modeling was performed in accordance with protocols developed by the District and ARB and in accordance with modeling guidelines established by EPA. The combination of modeling approaches provides an analysis for the current year and provides projection to 2014. Weight of evidence comparison of various modeling approaches establishes the reliability of the foundation modeling, with all modeling approaches showing strong agreement in predicted results. Additional analysis performed to develop the interpollutant ratio uses both regional and receptor evaluations which were the primary models used for the 2008 PM 2.5 Plan.

Limitations

Both industrial direct emissions and secondary formed particulate may be both PM2.5 and PM10. The majority of secondary particulates formed from precursor gases are in the PM2.5 range as are most combustion emissions from industrial stacks, however both secondary and stack emissions do contain particles larger than PM2.5. Regional modeling is more reliable for the smaller fraction due to travel distances and deposition rates. Large particles have much higher deposition and are much more difficult to replicate with a regional model. This leads to a strong technical preference for evaluating both emission types in terms of PM2.5 because the integration of receptor analysis and regional modeling for coarse particle size range up to PM10 has a much greater associated uncertainty.

Analyses contained in Receptor modeling

Factors Considered

This modeling approach uses speciated linear modeling based on chemical mass balance evaluation of contributing sources with San Joaquin Valley specific identification of contributing source profiles, adjustments from regional modeling for the nonlinearity of nitrate formation, adjustments for area of influence impacts of contributing sources developed from back trajectory analysis of high concentration particulate episodes and projections of future emission inventories as developed for the 2008 PM2.5 Plan.

Analyses in receptor modeling that use input from regional modeling

The receptor modeling analysis uses a modified projection of nitrate particulate formation from nitrogen oxides based upon results of regional modeling. The atmospheric chemistry associated with nitrate particulate formation has been determined to be nonlinear; while the default procedures for speciated rollback modeling assume a linear relationship. This adjustment has been demonstrated as effective in producing reliable atmospheric projections for the prior PM10 Plans.

Extension by additional analysis

Additional evaluations were added to results of the receptor modeling performed for the 2008 PM2.5 Plan. Calculations determine the observed micrograms per ton of emission for each contributing source category that can be resolved by chemical mass balance modeling methods. These ten categories allow differentiation of industrial direct emissions of organic and elemental carbon from other sources that emit elemental and organic carbon. The interpollutant calculation is developed as an addition to the receptor analysis by calculating the ratio of emissions per ton of directly emitted industrial PM2.5 to the per ton ratio of secondary particulate formed from NOx and SOx emissions. Summary tables and issue and documentation discussion was added to the analysis.

Strengths

Receptor modeling provides the ability to separately project the effect of different key sources contributing to carbon and organic carbon. This is critical for establishing the atmospheric relationship between industrial emissions and the observed concentrations due to industrial emissions. Regional modeling methods at this time do not support differentiation of vegetative and motor vehicle carbon contribution from the emissions form industrial sources. The area of influence of contributing sources was also considered as a factor with the methods developed by the District to incorporate the gridded footprint of contributing sources into the receptor analysis. While regional models use gridded emissions, current regional modeling methods do not reveal the resulting area of influence of contributing sources.

Limitations

Receptor modeling uses linear projections for future years and cannot account for equilibrium limitations that would occur if a key reaction became limited by reduced availability of a critical precursor due to emission reductions. The regional model was used to investigate this concern and did not project any unexpected changes due to precursor limitations.

Analyses contained in Regional modeling

Factors Considered

The analysis file includes the daily modeling output representing modeled values for the base year 2005 and predicted values for 2014 for each of the eleven Valley sites that have monitoring data for evaluation of the models performance in predicting observed conditions. These sites are located in seven of the eight Valley counties. Madera County does not have monitoring site data for this comparison.

Modeling data for all quarters of the year was provided. Due to the higher values that occur due to stagnation events in the fourth quarter, both industrial carbon concentrations and secondary particulates forming from gases are highest in the fourth quarter. Evaluating the interpollutant ratio for other quarters would be less reliable and of less significance to assisting in the reduction of high particulate concentrations. Modeling for lower values has higher uncertainty. Modeling atmospheric ratios when the air quality standard is being met are axiomatically not of value to determining offset requirements intended to assist in achieving compliance with the air quality standard. However, for consistency of analysis between sites, days when the standard was being met during the fourth quarter were not excluded from the interpollutant ratio analysis. Bakersfield fourth quarter modeled data included only eight days that were at or below the standard. Fresno and Visalia sites averaged twelve days; northern sites 24 days and the County of Kings 38 days.

Modeling output provided data for both 2005 and 2014. While there is substantial emissions change projected for this period, the regional modeling evaluation does not project much change in the atmospheric ratios of directly emitted pollutants and secondary pollutants from precursor gases. This indicates that the equilibrium processes are not expected to encounter dramatic change due to limitation of reactions by scarcity of one of the reactants. This further justifies using the receptor evaluation determining the interpollutant ratio for 2009 through the year 2014 without further adjustment. If observed air quality data demonstrates a radical shift in chemistry or components during the next few years, such a change could indicate that a limiting reaction has been reached that was not projected by the model and such radical changes might require reassessment of the conclusion that the ratio should remain unchanged through 2014.

Extension by additional analysis

Regional modeling results prepared for the 2008 PM2.5 Plan were analyzed to extract fourth quarter data for all sites. The atmospheric chemistry for all counties was analyzed for consistency and variation. This analysis provided a determination that the secondary formation chemistry and component sources contributing to concentrations observed in the north fell within the range of values similarly determined for the southern four counties. Based upon examination of the components and chemistry, the northern counties would be expected to have an interpollutant ratio value less than the ratio determined for Kern County but greater than the one for Tulare County. This establishes that the interpollutant ratio determined by receptor analysis of the southern four counties provides a value that is also sufficiently protective for the north.

Strengths

Regional models provide equilibrium based evaluations of particulate formed from precursor gases and provide a regional assessment that covers the entire Valley. The projection of particulate formed in future years is more reliable than linear methods used for receptor modeling projections.

Limitations

The regional model does not provide an ability to focus on industrial organic carbon emissions separate from other carbon sources such as motor vehicles, residential wood smoke, cooking and vegetative burning. Regional modeling does not provide an assessment method for determination of sources contributing at each site or the area of influence of contributing emissions. Receptor analysis provides a more focused tool for this aspect of the evaluation.

Results and Documentation

SJVAPCD Interpollutant Ratio Results

SOx for PM ratio: 1.000 ton of SOx per ton of PM

NOx for PM ratio: 2.629 tons of NOx per ton of PM

These ratios do not include adjustments for other regulatory requirements specified in provisions of District Rule 2201.

The results of the modeling analysis developed an atmospheric interpollutant ratio for NOx to PM of 2.629 tons of NOx per ton of PM. This result was the most stringent ratio from the assessment industrial carbon emissions to secondary particulates at Kern County; with Fresno, Tulare and Kings counties having a lower ratio. The assessment of chemistry from the regional model required comparison of total carbon to secondary particulates and is therefore not directly useful to establish a ratio. However, the regional model does provide an ability to compare the general atmospheric similarity and compare changes in chemistry due to Plan reductions. Evaluation revealed that the atmospheric chemistry of San Joaquin, Stanislaus and Merced counties falls within the range of urban characteristics evaluated for the southern four counties; therefore the ratio established should be sufficiently protective of the northern four counties. Additionally, comparison of future year chemistry showed minimal change in pollutant ratio due to the projected changes in the emission inventory from implementation of the Plan. The SOx ratio as modeled indicates a value of less than one to one due to the increase in mass for conversion of SOx to a particulate by combination with other atmospheric compounds; however, the District has set guidelines that require at least one ton of an alternative pollutant for each required ton of reduction in accordance with District Rule 2201 Section 4.13.3. Therefore the SOx interpollutant ratio is established as 1.000 ton of SOx per ton of PM. These ratios do not include adjustments for other regulatory considerations, such as other provisions of District Rule 2201.

A guide to the key technical topics and the reference material relevant to that topic is found on the next page. References from the 2008 PM2.5 Plan may be obtained by requesting a copy of that document and its appendices or by downloading the document from http://www.valleyair.org/Air_Quality_Plans/AQ_Final_Adopted_PM25_2008.htm. References in Italics are spreadsheets included in the interpollutant analysis file "09 Interpollutant Ratio Final 032909.xls" which includes 36 worksheets of receptor modeling information from the 2008 PM2.5 Plan, 11 modified and additional spreadsheets for this analysis and two spreadsheets of regional model daily output. This file is generally formatted for printing with the exception of the two spreadsheets containing the regional model output "*Model-Daily Annual*" and "*Model-Daily Q4*" which are over 300 pages of raw unformatted model output files. The remainder of the file is formatted to print at approximately 100 pages. This file will be made available on request but is not currently posted for download.

Interpollutant Ratio Issues & Documentation

	TOPIC	Reference
1	**Reason for using PM2.5 for establishing the substitution relationship between direct emitted carbon PM and secondary nitrate and sulfate PM:** consistency of relationship between secondary particulates and industrial direct carbon combustion emissions.	2008 PM2.5 Plan, Sections 3.3.2 through 3.4.2
2	**Reason for using 4th Quarter analysis:** Highest PM2.5 for all sites.	*DV Qtrs*
3	**Reason for using analysis of southern SJV sites to apply to regional interpollutant ratio:** Northern site chemistry ratios are within the range of southern SJV ratios. Peak ratio will be protective for all SJV counties.	*Q4 Model Pivot, Model-site chem, Model-Daily Q4*
4	**Reason for using combined results of receptor and regional model:** Receptor model provides breakdown of different carbon sources to isolate connection between industrial emissions and secondary PM.	2008 PM2.5 Plan, Appendix F
	Regional model provides atmospheric information concerning the northern SJV not available from receptor analysis.	2008 PM2.5 Plan, Appendix G
5	**Most significant contributions of receptor evaluation:** Separation of industrial emissions from other source types. Area of influence evaluation for contributing sources.	2008 PM2.5 Plan, Appendix F
6	**Most significant contributions of regional model:** Scientific equilibrium methods for atmospheric chemistry projections for 2014. Receptor technique is limited to linear methods.	2008 PM2.5 Plan, Appendix G
7	**Common area of influence adjustments used for all receptor evaluations:** Geologic & Construction, Tire and Brake Wear, Vegetative Burning - contribution extends from more than just the urban area (L2) Mobile exhaust (primary), Organic Carbon (Industrial) primary, Unassigned - contribution extends from more than larger area, subregional (L3) Secondary particulates from carbon sources are dominated by the local area with some contribution from the surrounding area (average of L1 and L2) Marine emissions not found present in CMB modeling for this analysis.	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
8	**Variations to reflect secondary area of influence specific to location:** Fresno: Evaluation shows extremely strong urban signature (L1) for secondary sources Kern: Evaluation shows a strong urban signature mixed with emissions from the surrounding industrial areas (average L1 and L2) for both carbon and secondary sources Kings and Tulare: Prior evaluation has show a shared metropolitan contribution area (L2)	Modeling evaluation by J. W. Sweet February 2009 Reflected in *IPR* <u>County</u> *2000-2009* worksheets
9	**Reasons for using 2009 Interpollutant Ratio Projection:** 2009 Interpollutant ratio is consistent with current emissions inventories	2008 PM2.5 Plan
	Regional modeling does not show a significant change in chemical relationships through 2014.	*Q4 Model Pivot*
10	**Reason for using SOx Interpollutant Ratio at 1.000:** A minimum offset ratio is established as 1.000 to 1.000 consistent with prior District policy and procedure for interpollutant offsets.	District Rule 2201 Section 4.13.3

ATTACHMENT I

Additional Supplemental Information

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES[a]
(SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	4.08 E+00	B
NO_x[c] <90% Load	8.47 E-01	B
CO[c] 90 - 105% Load	3.17 E-01	C
CO[c] <90% Load	5.57 E-01	B
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	1.47 E+00	A
Methane[g]	1.25 E+00	C
VOC[h]	1.18 E-01	C
PM10 (filterable)[i]	7.71 E-05	D
PM2.5 (filterable)[i]	7.71 E-05	D
PM Condensable[j]	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[k]	<4.00 E-05	E
1,1,2-Trichloroethane[k]	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene[k]	2.67E-04	D
1,3-Dichloropropene[k]	<2.64 E-05	E
2-Methylnaphthalene[k]	3.32 E-05	C
2,2,4-Trimethylpentane[k]	2.50 E-04	C
Acenaphthene[k]	1.25 E-06	C

Table 3.2-3. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE RICH-BURN ENGINES[a]
(SCC 2-02-002-53)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	2.21 E+00	A
NO_x[c] <90% Load	2.27 E+00	C
CO[c] 90 - 105% Load	3.72 E+00	A
CO[c] <90% Load	3.51 E+00	C
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	3.58 E-01	C
Methane[g]	2.30 E-01	C
VOC[h]	2.96 E-02	C
PM10 (filterable)[i,j]	9.50 E-03	E
PM2.5 (filterable)[j]	9.50 E-03	E
PM Condensable[k]	9.91 E-03	E
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[l]	2.53 E-05	C
1,1,2-Trichloroethane[l]	<1.53 E-05	E
1,1-Dichloroethane	<1.13 E-05	E
1,2-Dichloroethane	<1.13 E-05	E
1,2-Dichloropropane	<1.30 E-05	E
1,3-Butadiene[l]	6.63 E-04	D
1,3-Dichloropropene[l]	<1.27 E-05	E
Acetaldehyde[l,m]	2.79 E-03	C
Acrolein[l,m]	2.63 E-03	C
Benzene[l]	1.58 E-03	B
Butyr/isobutyraldehyde	4.86 E-05	D
Carbon Tetrachloride[l]	<1.77 E-05	E

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%	
Type of fuel (use table above)	4 GAS
O2 correction (i.e., 3%)	15 %
Enter LB/MMBTU emission factor	
NOx	0.847 LB/MMBTU
CO	0.130 LB/MMBTU
VOC (as methane)	0.000 LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS	
NOx	229.94 ppmv
CO	57.98 ppmv
VOC (as methane)	0.00 ppmv

pV = R*T		
pressure (p)	1	atm
universal gas constant (R*)	0.7302	atm-scf/lbmole-oR
temperature (oF)	60	oF
calculated		
molar specific volume (V)	379.5	scf/lbmole
Molecular weights		
NOx	46	lb/lb-mole
CO	28	lb/lb-mole
VOC (as methane)	16	lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F		
COAL (ANTHRACITE)	10100 DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780 DSCF/MMBTU	COAL
COAL (LIGNITE)	9860 DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160 DSCF/MMBTU	OIL
GAS (NATURAL)	8710 DSCF/MMBTU	GAS
GAS (PROPANE)	8710 DSCF/MMBTU	GAS
GAS (BUTANE)	8710 DSCF/MMBTU	GAS
WOOD	9240 DSCF/MMBTU	WOOD
WOOD BARK	9600 DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570 DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710 DSCF/MMBTU	GAS

Parts Per Million Volume => Grams/Brake Horsepower - Hour

ppmv => g/Bhp-hr

Variables:		
Engine Size:	860	hp
NO_x:	230	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given:		
Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.236	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
$MW_{(NOx)}$:	46	as NO_2
$MW_{(CO)}$:	28	
$MW_{(VOC)}$:	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula:

$$\frac{\text{ppmv}}{1} \cdot \frac{\text{F-factor}}{1} \cdot \frac{MW_{pollutant}}{1} \cdot \frac{20.9}{(20.9 - O_2\%)} \cdot \frac{1}{\text{Conversion \#1}} \cdot \frac{1}{\text{Conversion \#2}} \cdot \frac{\text{Conversion \#3}}{1} \cdot \frac{1}{\text{Engine Eff.}} =$$

for NOx:

$$\frac{230\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{46\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{1\ \text{lb-mol}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 2.750 g/bhp-hr | 2365 g/hr | 5.21465 lbs/hr | 125 lbs/day

for CO:

$$\frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{28\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC:

$$\frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{16\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

	SELECTION #
COAL (ANTHRACITE)	0
COAL (BITUMINOUS)	1
COAL (LIGNITE)	2
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	3
GAS (NATURAL)	4
GAS (PROPANE)	5
GAS (BUTANE)	6
WOOD	7
WOOD BARK	8
MUNICIPAL SOLID WASTE	9

STANDARD O2 CORRECTION FOR EXTERNAL COMBUSTION IS 3%	
Type of fuel (use table above)	4 GAS
O2 correction (i.e., 3%)	15 %
Enter LB/MMBTU emission factor	
NOx	2.270 LB/MMBTU
CO	0.130 LB/MMBTU
VOC (as methane)	0.000 LB/MMBTU

CALCULATED EQUIVALENT CONCENTRATIONS	
NOx	616.25 ppmv
CO	57.98 ppmv
VOC (as methane)	0.00 ppmv

pV = R*T		
pressure (p)	1	atm
universal gas constant (R*)	0.7302	atm-scf/lbmole-oR
temperature (oF)	60	oF
calculated		
molar specific volume (V)	379.5	scf/lbmole
Molecular weights		
NOx	46	lb/lb-mole
CO	28	lb/lb-mole
VOC (as methane)	16	lb/lb-mole

F FACTORS FROM EPA METHOD 19 @ 68 F			
COAL (ANTHRACITE)	10100	DSCF/MMBTU	COAL
COAL (BITUMINOUS)	9780	DSCF/MMBTU	COAL
COAL (LIGNITE)	9860	DSCF/MMBTU	COAL
OIL (CRUDE, RESIDUAL, OR DISTILLATE)	9160	DSCF/MMBTU	OIL
GAS (NATURAL)	8710	DSCF/MMBTU	GAS
GAS (PROPANE)	8710	DSCF/MMBTU	GAS
GAS (BUTANE)	8710	DSCF/MMBTU	GAS
WOOD	9240	DSCF/MMBTU	WOOD
WOOD BARK	9600	DSCF/MMBTU	WOOD BARK
MUNICIPAL SOLID WASTE	9570	DSCF/MMBTU	SOLID WASTE
F FACTOR USED IN CALCULATIONS	8710	DSCF/MMBTU	GAS

Parts Per Million Volume -> Grams Brake Horsepower - Hour

ppmv -> g/Bhp-hr

Variables:		
Engine Size:	860	hp
NO_x:	616	ppmv
CO:	0	ppmv
VOC:	0	ppmv (as CH_4)
O_2 level:	15	%
Engine Efficiency:	35	% (Assumed)
F-factor:	8578	dscf/MMBtu
Fuel Type	1	

OIL (CRUDE, RESIDUAL, OR DISTILLATE)	0
GAS (NATURAL)	1
GAS (PROPANE)	2
GAS (BUTANE)	3

Given:		
Conversion #1:	379.5	dscf/lb-mol
Conversion #2:	393.286	bhp-hr/MMBtu
Conversion #3:	453.59	g/lb
$MW_{(NO_x)}$:	46	as NO_2
$MW_{(CO)}$:	28	
$MW_{(VOC)}$:	16	as CH_4
O_2 Correction:	3.542	
Pressure (p)	1	atm
Temp (°F)	60	°F

Formula:

$$\frac{\text{ppmv}}{1} \cdot \frac{\text{F-factor}}{1} \cdot \frac{MW_{pollutant}}{1} \cdot \frac{20.9}{(20.9 - O_2\%)} \cdot \frac{1}{\text{Conversion \#1}} \cdot \frac{1}{\text{Conversion \#2}} \cdot \frac{\text{Conversion \#3}}{1} \cdot \frac{1}{\text{Engine Eff.}} =$$

for NO_x:

$$\Rightarrow \frac{616\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{46\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{1\ \text{lb-mol}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 7.365 g/bhp-hr | 6334 g/hr | 13.9662 lbs/hr | 335 lbs/day

for CO:

$$\Rightarrow \frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{28\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

for VOC:

$$\Rightarrow \frac{0\ \cancel{\text{parts}}}{10^6\ \cancel{\text{parts}}} \cdot \frac{8578\ \cancel{\text{dscf}}}{\cancel{\text{MMBtu}}} \cdot \frac{16\ \cancel{\text{lb}}}{\cancel{1\ \text{lb-mol}}} \cdot \frac{20.9}{20.9 - 15} \cdot \frac{\cancel{\text{lb}}}{379.5\ \cancel{\text{dscf}}} \cdot \frac{\cancel{\text{MMBtu}}}{393.24\ \text{bhp-hr}} \cdot \frac{453.59\ \text{g}}{\cancel{\text{lb}}} \cdot \frac{1}{35\%} =$$

= 0.000 g/bhp-hr | 0 g/hr | 0 lbs/hr | 0 lbs/day

RECEIVED
JUL 0 3 2008
Permits Srvc
SJVAPCD

Avenal Power Center, LLC
500 Dallas Street, Level 31
Houston, TX 77002

COPY

July 1, 2008

RE: Certification of Avenal Energy, owned by Avenal Power Center, LLC

I, Stuart Zisman, on behalf of Avenal Power Center, LLC, hereby certify under penalty of perjury as follows:

1. I am authorized to make this certification on behalf of Avenal Power Center, LLC.
2. This certification is made pursuant to Section 4.15.2 of Rule 2201 of the Rules and Regulations of the San Joaquin Valley Unified Air Pollution Control District.
3. To the best of the undersigned's knowledge, relative to Section 4.15.2 of District Rule 2201, Avenal Power Center, LLC. does not currently own, operate or control any Major Stationary Source or federal major modification in the State of California other than the proposed Avenal Energy Project.

Each of the statements herein is made in good faith. Accordingly, it is Avenal Power Center, LLC's understanding in submitting this certification that the SJVUAPCD shall take no action against Avenal Power Center, LLC or any of its employees based on any statement made in this certification.

Stuart Zisman
Vice President
Avenal Power Center, LLC

7/1/08
Dated

Joseph Forbes
Senior Lawyer

ATTACHMENT J

EPA Comments and District Responses

EPA Comments / District Response

The comments (from Gerardo Rios) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

EPA Comments – Letters Dated September 13, 2010

EPA Comment #1:

Applicable federal requirements include thresholds for defining a major source of criteria pollutant emissions. For those sources where emission estimates and/or emission limits are relatively close to the federal thresholds, EPA encourages the following: (a) refinement of emissions and compliance demonstration methods that would ensure the thresholds would not be exceeded, and/or (b) a 5-10% buffer between the permitted emission limits and the federal threshold.

The proposed annual NOx emission and CO emission limits are within a margin of less than 5% of the federal annual threshold limit for defining a new major stationary source under the Federal Prevention of Significant Deterioration (PSD) permit program. The threshold is 100 tons per year (tpy) each. If the limits of these pollutants are relaxed, the facility may be subject to the applicable federal requirements, such as the Federal Prevention of Significant Deterioration (PSD) permitting program (See 40 CFR Part 52.21 (r)(4)).

District's Response:

The permitted emissions from this facility are below PSD thresholds. The facility's NO_X and CO emissions limits are included as permit conditions on the PDOC. The facility is also required to maintain records to demonstrate that they do not exceed these emission limits.

In addition, emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.

EPA Comment #2:

In the "General Calculations" section (See PDOC Page 27, Section VII. C. 5), the District compares the annual emission estimates for regulated pollutants to the major source threshold to determine whether a pollutant is subject to major source requirements for NO_X, CO, VOC, PM_{10}, and SO_X emissions. However,

$PM_{2.5}$, which also is a regulated pollutant, is not included. On May 8, 2008 EPA finalized regulations to implement the NSR program for $PM_{2.5}$. A source that emits or has the potential to emit 100 tpy or more PM2.5 in a nonattainment area is defined as a major stationary source. (Reference 40 CFR Part 51, Appendix S.) We recommend the District include in its evaluation the $PM_{2.5}$ emission estimates with a comparison to the federal nonattainment major source threshold of 100 tpy (or 200,000 pounds per year).

District's Response:

The potential emissions of PM_{10} from the facility are 161,552 lb-PM_{10}/year (Calculated in the PDOC). Using the conservative assumption that all PM_{10} is $PM_{2.5}$, it is clear that the $PM_{2.5}$ emissions from this facility will not exceed the major source threshold of 100 tons/year. However, to avoid any confusion, the District will revise the PDOC to discuss the potential emissions of $PM_{2.5}$ from this operation.

EPA Comment #3:

The proposed annual emissions (calculated on a twelve consecutive month rolling basis) from the facility are 198,840 pounds per year (lb/yr) NO_X and 197,928 lb/year CO. (See PDOC Page 27, Section VII. C. 5) These annual emissions are equivalent to 99.4 tpy of NO_X emissions and 98.9 tpy of CO emissions, both of which are relatively close to the federal PSD permit program applicability threshold of 100 tpy for each ofthese pollutants. A proposed permit condition requiring that annual emissions not exceed these levels has been added to all combustion related equipment. The condition reads as follows:

> *"Annual emissions from the facility, calculated on a twelve month rolling basis, shall not exceed any of the following limits: NOx (as N02) -198,840 lb/year; CO -197,928lb/year."*

In a review of the post-project potential to emit annual emission estimates in Sections VII.C.2.i through C.2.iv. (See PDOC Pages 16-26) for each piece of equipment, we noted that the combustion turbine operations contribute the majority of NOx and CO emissions.

Based on discussions with the District, we understand that in addition to the 12-month rolling facility NOx and CO emission limits that are equivalent to 99.4 tpy and 98.9, respectively, the District has made no other changes to the current FDOC permit conditions. These conditions include, but are not limited to, the following: continuous emissions monitoring of NO_X and CO; compilation of emissions on a daily, monthly, 12 consecutive month rolling average, and annual basis; quarterly reporting of excess emissions; and acid rain (40 CFR Part 75) compliance requirements.

At this time, it appears the proposed requirements provide practically and federally enforceable conditions based on our understanding of the proposed revision. However, given that the NO_X permit limit is within less than 1% of the PSD permit threshold and the CO limit is within 1.1% of the PSD permit threshold, we suggest that the District consider requiring Avenal to report more frequently emissions as the actual emissions approach or exceed 90% of the 12-consecutive month rolling average permit limit to assure the 100 tpy threshold is not exceeded.

<u>District's Response:</u>

Emissions from the turbine units are monitored with a CEMS system. The CEMS system continuously monitors the emissions from the turbine units and reports any exceedance of the permitted emissions rates to the District. These notifications are received on a daily basis. The emissions from the turbine units are also required to be compiled on a daily basis. The monitoring and reporting requirements in the PDOC are more than sufficient to assure compliance with the annual emissions limitations. No changes are being made to address this comment.

<u>EPA Comment #4:</u>

The District concludes on pp. 53-54 of the PDOC that the proposed project will not cause a violation of an air quality standard for NOx, and refers to Appendix G. PDOC Appendix G contains some additional detail on the air quality impact analysis for the l-hour N02 NAAQS, effective April 12, 2010, and states that "the emissions from the proposed equipment will not cause or contribute significantly to a violation of the State and National AAQS." The following are our comments specific to PDOC Appendix G:

a. SIP-Approved Rule 2201 -The District's approved SIP, in District Rule 2201, Section 4.14.1, provides that modeling used for purposes of determining whether a new or modified stationary source's emissions will cause or make worse the violation of an Ambient Air Quality Standard shall be consistent with the requirements contained in the most recent edition of EPA's "Guideline on Air Quality Models." This EPA guideline is found in 40 CFR Part 51, Appendix w. EPA recently has had occasion to review and comment on the applicant's l-hour N02 NAAQS analysis for the project in the context of the applicant's pending PSD permit application before EPA.

   We recognize that certain aspects of the project for which Avenal seeks a minor source permit vary from the project for which it seeks a PSD permit, in particular, the proposed addition of a facility-wide NOx emissions limit of the equivalent of approximately 99.4 tons per year (tpy) to the minor source permit. However, given that the equipment emitting NOx from the two projects has the same permitted hourly emission rates, many of the comments EPA made concerning consistency with 40 CFR Part 51, Appendix W in reviewing the applicant's l-hour N02 NAAQS analysis for PSD purposes may be relevant to the l-hour N02 NAAQS analysis for this minor source permit as well. We have attached for your consideration our comments dated June 15, 2010 and August 12, 2010 on the l-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes. We would be happy to discuss any issues or questions you may have concerning these comments.

b. EPA Guidance Memorandum -We also note that EPA recently issued guidance relating to modeling for the l-hour N02 NAAQS, with a cover memorandum entitled *Guidance Concerning Implementation of the 1-hour N02 NAAQS for the Prevention of Significant Deterioration Program,* dated June 29, 2010, that included two attached guidance documents, one of which was entitled *Applicability of Appendix W Modeling Guidance for the 1-hour N02 National Ambient Air Quality Standard,* dated June 28, 2010. We understand that the District is aware of this guidance, and we encourage the District to refer to this guidance for further detail on this subject.

c. Assumptions and Decision-making Process -The District's rationale in Appendix G for its conclusion that the project's emissions will not cause or contribute significantly to a violation of the l-hour N02 NAAQS is not clear from the documents provided. For example, the table addressing "Operational" scenarios on page 2 of Appendix G indicates that Tier 1 and Tier 2 impacts are each greater than the N02 NAAQS limit, while Tier III and Tier IV impacts are each below the N02 NAAQS limit. Furthermore, it is unclear how the modeling analysis meets the requirements of Appendix W (See Comment 4.a.) or whether the District intended to follow those requirements for the proposed permit revision. We recommend that the District provide a discussion of which Tier the District is relying upon to support its conclusion, the basis for selecting that Tier, and the modeling inputs, assumptions, etc. for that Tier.

District's Response:

a. *The District has reviewed your comments dated June 15, 2010 and August 12, 2010 on the 1-hour N02 NAAQS analysis that Avenal submitted to EPA for PSD purposes, and has no comments at this time. We did not use Avenal Power's analysis to make determinations of NAAQS impacts, but used our own guidance to perform the NO2 modeling (please see responses below).*
b. *The District has reviewed the documents stated above and developed a modeling guidance to address EPA's memos that were provided to the modelers at EPA Region 9. The District is currently waiting for EPA's*

response to this guidance, and is, in fact, working with EPA, ARB, and CAPCOA on developing statewide policy on how to implement our guidance, or something similar. The Avenal Power project was analyzed under this guidance, and the project was approved under Tier III of that guidance.

c. *The District uses a tiered approach when determining compliance with any NAAQS. This approach is similar to that required by OAQPS in their memos which require that each progressively more accurate tier be used (Tier I-Complete Conversion, Tier II-NO2 Ration and Tier III-OLM) until compliance is demonstrated. This project was approved under Tier III. We believe our guidance is consistence with EPA modeling practices and direction, and as we have stated above, we are patiently awaiting EPA's input on our guidance.*

EPA Comment #5, Joint letter to District and Avenal Power Center, LLC:

Avenal Power Center, LLC (Avenal) recently applied for a minor source New Source Review (NSR) permit from the San Joaquin Valley Pollution Control District (SJVAPCD or District) for the Avenal Energy Project. This permit seeks authority to construct the project with emissions limits below the major source thresholds triggering Clean Air Act (CAA) prevention of significant deterioration (PSD) preconstruction review. On July 28, 2010, SJVAPCD's public notice announcing its Preliminary Determination of Compliance for this minor source permit application was published in the Fresno Bee, triggering a public review and comment period for the proposed permit.

Concurrently, Avenal is seeking a PSD permit from EPA Region 9 for essentially the same project, but with greater emissions exceeding the major source threshold and thereby triggering PSD preconstruction review. The applicant's simultaneous application for both a minor source permit and a major souce PSD permit for the project raises a potential concern about circumvention of PSD preconstruction requirements.

EPA guidance on this subject states:

> Parts C and D of the Clean Air Act exhibit Congress's clear intent that new major sources of air pollution be subject to preconstruction review. The purposes for these programs cannot be served without this essential element. Therefore, attempts to expedite construction by securing minor source status through receipt of operational restrictions from which the source intends to free itself shortly after operation are to be treated as circumvention of the preconstruction review requirements... If a major source or major modification permit application is filed simultaneously with or at approximately the same time as the minor source construction permit, this is strong evidence of an intent to circumvent the requirements of preconstruction review.

Guidance on Limiting Potential to Emit in New Source Permitting, Terrell E. Hunt and John S. Seitz, dated June 13, 1989, at pp. 13-14.

We recommend that the applicant carefully review the guidance quoted above and other applicable EPA guidance on this topic prior to commencing construction of the project under the minor source permit, should that permit be finalized by the SJVAPCD.

District's Response:

The District disagrees that if Avenal were to construct under a California Energy Commission license that incorporates this minor source Determination of Compliance (DOC), it would be circumvention of the PSD preconstruction review.

Circumvention might occur if a source obtained a minor source permit and soon thereafter sought a PSD permit due to a small increase in emissions, and not as a new source. In this case, Avenal has applied for a PSD permit as a new source. If they construct as a minor source and don't receive a PSD permit, they will have to continue to comply with the minor source limits. However, constructing as a minor source and then obtaining a PSD permit as a new major source and operating in accordance with that PSD permit cannot be viewed as circumvention. Therefore, the EPA process, not the District's minor source permitting process, will determine whether circumvention will occur, and circumvention will not occur if EPA requires a PSD permit if Avenal pursues a permit with emissions above the PSD triggers.

ATTACHMENT K

Green Action Comments and District Responses

Greenaction Comments / District Response

The comments (from Bradley Angel) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Greenaction Comments – Letter Dated September 11, 2010

<u>Greenaction Comment #1:</u>

The Air District failed to conduct a proper and thorough public notice and public participation process. The failure to conduct proper notice and participation processes to the mostly low-income, Latino and Spanish-speaking residents of the nearest communities (Avenal, Huron and Kettleman City) violated the Air District's own environmental justice policy. The Air District's claim that you met your agency's required notice and participation mandates is insufficient as your own environmental justice policy commits the agency to uphold environmental justice.

Failing to notify residents or their organizations, failing to hold a public hearing and failing to provide Spanish-speaking residents equal time to comment as English speakers is a violation of environmental justice and civil rights policies and laws.

We are surprised and disappointed that the Air District would only translate information into Spanish following concerns being raised by Greenaction, and after the comment period already began. On August 20, 2010, we received an email from Dave Warner of the Air District that stated:

> Bradley,
>
> The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at http://www.valleyair.org/General_info/SpanishHmong_Resources.htm

As this email was sent one week into the revised comment period, and as Spanish-speakers had not yet had the opportunity to read information in Spanish, this shows that there has been an unequal opportunity to comment that is improper.

The Air District's notice was inadequate for all of the affected public. No resident or organization representing residents received notice. We only learned of the original comment period from US EPA after it already had begun.

The Air District published a "Notice" in the Fresno Bee, but not in any Kings County or Spanish-language paper.

Even after meeting with the Air District on August 30, 2010 to raise all these concerns, the Air District refused to hold a public hearing, provide proper notice or provide equal opportunities to the Spanish-speaking residents who comprise a major percentage of residents of Avenal, Kettleman City and Huron.

Due to the discriminatory and disproportionate impact on low-income, Latino and Spanish-speakers of the lack of notice and full public participation notice for a project that would emit pollutants into an already over-polluted area, the Air District has violated its own environmental justice policy as well as California Government Code section 11135 and Title VI of the US Civil Rights Act of 1964.

District's Response:

The District complied with all applicable regulatory public noticing requirements with respect to the Avenal Power Center Preliminary Determination of Compliance (PDOC) and in fact took considerable actions that went far beyond statutory requirements. The District properly published notice of the proposed issuance of the PDOC in a newspaper of general circulation, in this case, the Fresno Bee whose distribution does cover the area in question. This notice was published according to our federally approved Rule 2201, which defines the timing and process of such notices. There is no additional direction on public noticing in the District's Environmental Justice Strategy document, contrary to the commenter's claims.

However, we went far beyond our required notification processes for this project, as follows:

1. *We published this notice, as we do all public notices, on the District's website, valleyair.org. This is not required by any rule or regulation, but is part of our continuing effort to make information available and accessible.*

2. *Upon hearing on August 16 of the commenter's concern that he was not notified of the District proposal to issue a DOC, we promptly, on August 18, notified him that we would extend the public noticing period for him and his clients a full additional 30 days from the date that he heard about our proposal. This was not required, since the commenter had not requested that he be informed of our actions on this project, and therefore he was not on record as an interested party. However, in the interests of providing the maximum reasonable opportunity for comment, we offered this accommodation.*

3. *Upon receiving the commenter's subsequent August 19 request for bilingual information on the project, and a public hearing, on August 20 we sent the commenter the following email, from which he quoted an excerpt above. We are providing it in full, below, as it explains our response in some additional detail that was missing from the commenter's excerpt:*

Bradley,

The San Joaquin Valley Air Pollution Control District will prepare aSpanish translation of a summary of the District's preliminary decision to issue a Determination of Compliance on the Avenal Power Center. This document should be available late on Monday, and we will post it on our Spanish-language link on our District website, at http://www.valleyair.org/General_info/SpanishHmong_Resources.htm

We would welcome your assistance in distributing it to your Spanish-speaking clients and associates. We will also be pleased to accept comments in Spanish as we have translation capabilities here at the District. As you are aware, we have already extended the public comment period to September 13, 2010, and we believe the above steps will provide you and your Spanish speaking associates ample opportunity to provide comment on our proposal.

I just want to make sure you understand the status of this project atthis time as it pertains to the District. The District is taking public comment on a Preliminary Determination of Compliance, which is a recommendation to the California Energy Commission (CEC) that the project will comply with District regulations. We are not aware of any requirement that we hold a meeting for the purpose of receiving verbal comments.

We are not going to hold a public hearing on this project at this time. Ours is not a final permitting decision and there is no hearing process associated with it - the CEC has the sole power plant licensing authority in the state of California for power plants over 50 megawatts. They conduct any necessary public hearings associated with such a license. Our action is a certification to the CEC that, if granted, CEC's license would meet our air quality requirements. CEC is able to accept or reject our proposed conditions of approval, or can make air quality permitting decisions contrary to our determination of compliance. In addition, the CEC makes all determinations regarding power plant siting.

> *Finally, contrary to your contention below, the District is not required to hold a public hearing, by rule or by policy We believe the process described above will assure an efficient, fair, and productive public comment process.*
>
> *Dave Warner*
> *Director of Permit Services*
> *San Joaquin Valley APCD*

In summary, we confirmed that we would prepare a Spanish-language summary of the project and make it available to the commenter for his outreach efforts. We also confirmed our commitment to address any comments we received in Spanish, and we explained the limitations of our role in the permitting process to provide clarity to any potential commenters. None of this was required by our rules and regulations, but was intended to provide additional opportunity for community members to participate in the process.

4. *We then worked through the weekend to create a summary of the project, translate it to Spanish, and post it on the website the very next working day, Monday, August 23.*

5. *Next, on August 24 we agreed to meet with the commenter and any of his clients and community members on August 30. The commenter and other activist organization representatives attended the meeting, but, disappointingly, no independent community members. Again, this meeting was not required by any rule or regulation.*

6. *Finally, we granted another request from another employee of GreenAction that she be provided with an additional day to persuade community members of Avenal and Kettleman City to submit comments, extending the comment period to September 14, for a total public comment period of 53 days instead of the required 30 days. This provided GreenAction the opportunity to persuade community members to submit the comments summarized in the next comment section. And again, there was certainly no rule or regulation that required this accommodation.*

In summary, contrary to the assertions of the commenter, the District not only met all legal requirements but went far beyond them in providing the public opportunities to comment on the Avenal Power Center Project.

Greenaction Comment #2:

The claim by the company and the Air District that there would be substantially less emissions than were stated in the initial permit application dramatically conflicts with earlier information and needs extensive scrutiny including a full public environmental review. If there really would be dramatically lower emissions than first claimed, we wonder why the company did not state this initially, raising questions as to whether the lower, newer estimate is based solely on a desire to avoid a PSD permit requirement and protracted appeals and legal battles.

District's Response:

While no response is necessary, it should be noted that the proposal for lower annual emissions was only possible after rigorous analysis by Avenal Power of actual emissions data from other recently constructed similar power plants. In addition, it seems remarkable that there should be a complaint about a company committing to lower emissions from a facility, regardless of the purpose or intent of the proposal.

Greenaction Comment #3:

The Air District's claim that there would be "zero impact" from the proposed power plant's emissions flies in the face of reality. A huge fossil fuel power plant, no matter how much cleaner than others of its kind, still will have pollution impacts. This "zero impact" claim ignores the fact that this would be a fossil fuel power plant that would have emissions and use fuels that contribute to climate change, would emit a broad range of pollutants, and its emissions would act cumulatively in concert with the many other pollution sources in the area.

The proposed fossil fuel power plant would be close to Kettleman City, a small low-income community of color that is suffering a horrible health crisis involving a large number of birth defects and infant deaths. Even a minor increase in emissions near this community could have severe and unforeseen health impacts due to the current health vulnerability of residents. In addition, the entire San Joaquin Valley already suffers from high rates of asthma, and if built this power plant would emit asthma-triggering pollutants.

District's Response:

The District has searched the PDOC and has not been able to locate the phrase "zero impact".

However, the District has performed a Health Risk Assessment (HRA) as well as an Ambient Air Quality Analysis (AAQA) for this facility. The HRA was performed using the AERMOD model and Hot Spots Analysis and Reporting Program (HARP), and demonstrated that the acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Pursuant to the District's risk management policy, Policy APR 1905, TBACT is not required for any proposed emissions unit with a cancer risk less than one in one million, and chronic or acute hazard index less than 1.

The AAQA demonstrated that the proposed equipment will not cause a violation of an air quality standard for NO_X, CO, or SO_X. In addition, as shown in the PDOC, the calculated contribution of PM_{10} will not exceed the EPA significance level. Therefore, this project will not cause or contribute significantly to a violation of the State or National AAQS.

Greenaction Comment #4:

This proposed fossil fuel power plant is not needed. Many things have changed since the CPUC originally determined that the Avenal Power Center was needed. As California emerges from an economic recession, the energy landscape has changed. PG&E now has access to more electricity generation than it needs. Last summer, PG&E's territory operated with a 44% reserve margin during summer peak. This extraordinarily high margin is in part due to the CPUC's success at increasing energy efficiency and the demand decrease from the recession. These factors, along with delayed facility retirements and inflated population and energy export assumptions made by the CEC demonstrate that the 600 MWs that the Avenal Power Center would generate are no longer needed. Even PG&E has forecasted a decrease in need. In addition, several large solar projects are to be sited here, and other solar projects are already underway, providing truly clean and renewable energy instead of dirty fossil fuel energy.

Despite all this evidence, Avenal Power Center continues its push for this power plant. The pollution and health effects of this proposed facility are unacceptable when the new capacity is clearly not needed. Finally, allowing unneeded fossil fuel energy would also likely crowd out renewable projects.

District's Response:

The District is not able to take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission.

ATTACHMENT L

NRDC and CRPE Comments and District Responses

National Resources Defense Council (NRDC) and Center on Race, Poverty & The Environment (CRPE) Comments / District Response

The comments (from Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

NRDC and CRPE Comments – Letter Dated September 13, 2010

NRDC and CRPE Comment #1:

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year*–$1,600 per person – in the San Joaquin Valley.

District's Response:

The District has demonstrated in the PDOC that the proposed facility is in compliance with all applicable NO_X and VOC rules and regulations. It should be noted that these rules and regulations are among the strictest and most stringent in the nation and are designed to protect the health of the residents of the San Joaquin Valley.

NRDC and CRPE Comment #2:

The June, 2009 EPA Statement of Basis And Ambient Air Quality Impact Report for a prevention of significant deterioration (PSD) permit states, at page 14, that emissions of CO and NOx from the Project are expected to be 1,205,400 pounds per year and 288,600 pounds per year, respectively. The July 13, 2010 Revised Preliminary Determination of Compliance for the Project states, at page 1, that emissions of CO will now be 197,928 pounds per year and NOx 198,840 pounds per year, both to be enforced as permit limitations. Conveniently, this would bring both the CO and NOx emissions under the 100-ton limit for major sources under Title V of the Clean Air Act. This change in emission numbers was accomplished with no changes to the setup or operation of the Project itself.

In addition, this sentence occurs relating to the new CO and NOx limits:

> If the annual [CO/NOx] emissions from these units exceed this value, they will be set equal to the proposed facility wide [CO/NOx] emission limit.

Revised PDOC at pages 9 (NOx) and 10 (CO). There are two ways to read this confusing sentence. One is that the sub-100 tons limits are meaningless and will be ignored if exceeded. The other is that APCD is attempting to engage in the type of "flexible permitting" that USEPA has disapproved in Texas. In either case, the federal Clean Air Act has been violated.

District's Response:

The District agrees that the wording in the PDOC is slightly confusing. The intent of the statement was to explain that the potential annual emissions from each of the turbines was calculated based on a stated scenario that was provided by the applicant and that if the unit was not operated exactly in accordance with this scenario, there was the potential for higher NO_X and CO emissions from the unit. However, the total emissions from the facility would not be allowed to exceed the proposed facility wide NO_X and CO emissions limits.

The stated scenario is an estimate of what the projected annual emissions from the unit could be if it was operated according to that schedule. Since the operational schedule of the power plant is based on electrical demand, the facility cannot be held to a specific operational schedule. The main point to understand is that the annual emissions from the facility will not exceed the facility wide limit that is stated as a condition on the PDOC, and therefore the impact from the facility's emissions will not be greater than that evaluated by the District.

Attached Letter Addressed to U.S. EPA - Dated October 14, 2009

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comments

The following comments were sent to U.S. EPA on October 14, 2009 from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit on behalf of El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, the Center on Race, Poverty, & the Environment, and the Natural Resources Defense Council. These comments were not sent to the District therefore, the District did not previously respond to the comments. These comments refer to the DOC performed in District project C-1080386, which analyzed the prior, higher-emitting proposal. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments (from Maricela Mares Alatorre, Bradley Angel, Ingrid Brostrom and David Pettit) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's responses.

<u>El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #1:</u>

The proposed Avenal Energy project in Kings County will add hundreds of tons of air pollution per year to what is already one of the most degraded airsheds in the United States. NOx and VOCs are ozone (commonly known as "smog") precursors and fine particle (PM2.5) precursors. Both ozone and PM2.5 levels in the San Joaquin Valley constitute a public health crisis. The Environmental Working Group published the Air Resources Board's estimates that show 1,292 San Joaquin Valley residents die each year from long-term exposure to PM2.5. Ozone and PM pollution exacerbate respiratory conditions, including asthma, increase hospitalizations and emergency room visits, contribute to cardiac illnesses, and increase school and work absenteeism. The American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, and Fresno as the third, fourth, and sixth most ozone-polluted counties in the United States, respectively. For long term exposure to PM2.5, the American Lung Association ranks the San Joaquin Valley counties of Kern, Tulare, Kings, and Fresno as the first, fourth, seventh, and eighth most polluted counties. A document prepared jointly by the California Air Resources Board and the American Lung Association describes ozone as

> a powerful oxidant that can damage the respiratory tract, causing inflammation and irritation, and induces symptoms such as coughing, chest tightness, shortness of breath, and worsening of asthma symptoms. Ozone in sufficient doses increases the permeability of lung cells, rendering them more susceptible to toxins and microorganisms. The greatest risk is to those who are more active outdoors during smoggy periods, such as children, athletes, and outdoor workers. Exposure to levels of ozone above the current ambient air quality standard leads to lung inflammation and lung tissue damage, and a reduction in the amount of air inhaled into the lungs. Recent evidence has, for the first time, linked the onset of asthma to exposure of elevated ozone levels in exercising children (McConnell 2002). These levels of ozone also reduce crop and timber yields, damage native plants, and damage materials such as rubber, paints, fabric, and plastics.

The document also shows the significant health effects and costs of exposure to fine particulate matter and ozone in California. In late 2008, Jane V. Hall, Ph.D., and Victor Brajer, Ph.D., published a comprehensive analysis of the effects from not meeting the 1997 8-hour ozone standard and the 2008 PM2.5. The health effects of not meeting these standards, and their concomitant economic values, inflict a conservative measurable cost of $5.7 billion *each year* –$1,600 per person – in the San Joaquin Valley.

<u>District's Response:</u>

This is the same comment that was made in the NRDC and CRPE Letter Dated September 13, 2010 and addressed above. See above for District Response.

<u>El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #2:</u>

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

<u>District's Response:</u>

The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.

In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.

The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.

El Pueblo Para Aire y Agua Limpio/People for Clean Air and Water, GreenAction for Health & Environmental Justice, NRDC and CRPE Comment #3:

The Project is expected to emit 80.7 tons/year of PM/PM10. *See* the June 16, 2009 EPA Statement of Basis and Ambient Air Quality Impact Report at p. 14. As we discuss below, we believe that the Project's plan to offset these PM emissions through SOx offsets is invalid under the Clean Air Act. Accordingly, ambient air quality will be impaired by the Project.

As you know, the San Joaquin Valley is in non-attainment for PM2.5. The Project proposes to meet 98% of its PM offset requirements from SOx offsets at a one-to-one ratio. *See* Final Staff Report, Air Quality Table 19. This is highly problematic for a number of reasons.

First, the one-to-one ratio ignores the very different health risks of SOx and PM. The U.S. EPA has found that particulate matter can cause or contribute to increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing, for example; decreased lung function; aggravated asthma; development of chronic bronchitis; irregular heartbeat; nonfatal heart attacks; and premature death in people with heart or lung disease.

Second, the Project applicants should not be allowed to use PM10 as a surrogate for PM2.5 emissions.

District's Response:

The facility is not using PM_{10} as a surrogate for $PM_{2.5}$. The facility has proposed to offset PM_{10} emissions with SO_X ERCs at the District evaluated interpollutant offset ratios. District Rule 2201, Section 4.13.3 allows for the use of interpollutant offsets at ratios based on air quality analysis. The SO_X for PM_{10} offset ratio used in this project is based on the best available science for determining how much PM_{10} SO_X can create. In addition, the facility is not a Major Source for $PM_{2.5}$ emissions; therefore $PM_{2.5}$ requirements will not be addressed in this project.

Attached Letter Addressed to U.S. EPA - Dated October 15, 2009

EarthJustice Comments

The following comments were sent to U.S. EPA on October 15, 2009 from Paul Cort of EarthJustice. These comments were not sent to the District therefore, the District did not respond to the comments. These comments refer to the DOC performed in District project C-1080386. In addition, all comments received by the District for project C-1080386 were addressed in the FDOC for that project.

The revised PDOC being processed as District project C-1100751 will obviously have similarities to the PDOC processed in District project C-1080386. It is also obvious that changes to the PDOC were made and therefore, not all comments made in the October 14, 2009 letter are still applicable. However, because these comments have been referenced in other correspondence regarding the latter project, we are addressing them at this time.

The applicable comments from Paul Cort regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) are encapsulated below followed by the District's response.

EarthJustice Comment #1:

Commenter's find it stunning that the proposed permit does not even mention CO2 emissions or controls. EPA is well aware that the Environmental Appeals Board ("EAB") has returned multiple PSD permits for failing to consider whether CO2 is a pollutant "subject to regulation" under the Clean Air Act. *See In re Deseret Power Elec. Coop.*, PSD Appeal No. 07 - 03 (EAB Nov. 13, 2008); *In re Northern Mich. University Ripley Heating Plant*, PSD Appeal No. 08 - 02 (EAB Feb. 18, 2009). In light of these decisions, EPA Region 9 also withdrew portions of the PSD Permit issued to Desert Rock Energy Company in order to reconsider the issue of whether CO2 is a pollutant subject to regulation. Yet EPA proposes a PSD permit for another power plant that will emit over 1.7 million tons of CO2 each year without any discussion of these contentious issues whatsoever. EPA must revise the proposed permit to explain EPA's position on BACT for CO2 so that the public can comment on the control levels selected or EPA's rationale for refusing to impose such controls.

District's Response:

This is the same comment that was made in the NRDC and CRPE Letter dated September 13, 2010 and addressed above. See above for District Response.

EarthJustice Comment #2:

The BACT determinations proposed by the Project and EPA are flawed in several respects. The BACT determinations do not comply with federal PSD program top-down BACT analysis requirements. The PSD permit is also flawed in that the applicant did not perform a BACT analysis for greenhouse gas emissions. Additionally, the proposed CO emission limitation for the combustion turbines is not BACT.

District's Response:

The District does not have the authority to issue PSD permits. Any PSD related questions are inappropriate for discussion under the District public noticing comment period.

In addition, since the District is not the lead agency for CEQA, GHG will not be addressed by the District.

The revised project proposed to limit the annual CO emissions to under 200,000 lb/year. Therefore, BACT for CO is not triggered and any discussion of BACT for CO is unnecessary.

EarthJustice Comment #3:

The Proposed Permit Fails to Demonstrate that the Avenal Project Will Not Cause or Contribute to Violations of National Ambient Air Quality Standards for Ozone and Fine Particulate Matter.

District's Response:

The facility is not a Major Source for $PM_{2.5}$; therefore $PM_{2.5}$ (fine particulate matter) requirements will not be addressed in this project.

There is no EPA approved model capable of accounting for the photochemical complexities of regional ozone formation to determine the impacts of ozone from a single site due to NOx and VOC emissions. In addition, the facility in this project does not directly emit ozone. Therefore, an analysis of nearby ozone emissions impacts was not performed in this project. Finally, we believe that our very strict standards for NOx and VOC from new sources, among the most stringent in the nation, are sufficient safeguard to prevent any single source from contributing significantly to a violation of the ozone NAAQS.

ATTACHMENT M

Rob Simpson Comments and District Responses

Public Comments / District Response

The comments (from Rob Simpson) regarding the Preliminary Determination of Compliance for Avenal Power Center LLC (District facility C-3953) is encapsulated below followed by the District's response.

Rob Simpson Comments – Emailed Letters Received November 17, 2010

Simpson Comment #1 - Public Notice:

The notice was not given to me in sufficient enough time to prepare adequate comments. The newspaper notice does not provide enough information about the project to the public and was not published in Spanish.

District's Response:

On the contrary, although Mr. Simpson was not on record as being interested in receiving information regarding this specific project, we are always quite interested in providing interested parties an opportunity to provide input, and so we provided a full 30-day period for Mr. Simpson to comment, the same amount of time provided all interested parties on all permitting projects. As for the second comment, please refer to our response to GreenAction's comment #1.

Simpson Comment #2:

The revised PDOC seems to have one purpose, evasion of the Clean Air Act requirements for the Prevention of Significant Deterioration (PSD). The only change in the revised permit is a limitation on annual NOx and CO emissions but the way the permit is worded this limitation is not federally enforceable. Page 9 of the PDOC states that,

> *"The facility has proposed to limit the annual facility wide NOx emissions to 198,840 lb/year. If the annual NOx emissions from these units exceed this value, they will be set equal to the proposed facility wide NOx emission limit."*

Page 10 of the PDOC states:

> *"The facility has proposed to limit the annual facility wide CO emissions to 197,928 lb/year. If the annual CO emissions from 'these units exceed this value, they will be set equal to the proposed facility wide CO emission limit."*

So essentially there is no change from the original permit and the Avenal Power Project still requires a PSD permit. Issuance of this permit would be a violation of the Clean Air Act and the district and the applicant would be subject to enforcement.

District's Response:

See response to NRDC and CRPE comment #2.

Simpson Comment #3 - The District is the Lead Agency for this Project:

The CEC appears to no longer be the lead agency for the project the district under CEQA, CEC or District rules. The District is now the lead agency since the purpose of the revision to the permit is merely to avoid PSD review and the CEC has no jurisdiction over PSD issues on this project. Thus the district is now the lead agency for review of this project and must conduct a complete EIR prior to issuance of an Authority to Construct for this project.

District's Response:

The District is not the lead agency for this project. Pursuant to California Public Resources Code Section 25500, the CEC "shall have the exclusive power to certify all sites (for power plants over 50 MW) and related facilities in the state". The California Public Resources Code further states that "the issuance of a certificate by the commission shall be in lieu of any permit, certificate, or similar document required by any state, local or regional agency".

Simpson Comment #4 - Is an FDOC an ATC?:

- Does the FDOC process comport with the Districts Federal permitting requirements?
- Is it the federal New Source Review (NSR) permit?
- Has the prior FDOC expired for this facility?
- Has the Applicant commenced construction or use of the prior FDOC?

District's Response:

The FDOC complies with Federal non-attainment pollutant permitting requirements, as implemented with the District's EPA-approved non-attainment NSR rule. This rule requires the District to issue a Determination of Compliance, rather than an Authority to Construct because, as noted above, the CEC has the sole licensing authority for large power plants in California. Our NSR rule does not incorporate federal attainment NSR (PSD) requirements. EPA retains the sole authority to issue PSD permits in the San Joaquin Valley.. The prior FDOC is tied to the CEC's license that has been issued, therefore it has not expired. However, the facility has not commenced construction or use of the prior FDOC. The FDOC under which construction is commenced (and only after CEC has approved any related licensing action) will determine the conditions under which the facility must operate.

Simpson Comment #5:

- I contend that the Warren Alquist Act hijacks air districts authority under the Clean Air Act in conflict with Federal law, does the District agree?.
- Does the District agree with the Brief submitted by the South Coast Air District (Exhibit 3) in the Humboldt Superior Court proceeding regarding a power plant permit that I appealed?

District's Response:

The District does not agree with either the "hijack" comment or the South Coast AQMD's brief on the subject. State law provides the CEC with sole permitting authority, but does not allow them to issue a license that violates the District's regulations. The DOC process provides the District ample opportunity to provide the appropriate guidance to the CEC prior to their licensing process. This process does not violate federal permitting requirements in any way. The federal EPA has approved the DOC process as embodied in the language of the District's NSR rule and that approval explicitly acknowledges that the process complies with federal permitting requirements.

Simpson Comment #6:

The District indicated in emails that it did not intend to issue an Authority to Construct for this project. Please provide some indication of how the permit would be enforceable without an Authority to Construct and who could enforce the State and Federal aspects of the permit. The PDOC has extensive references to an ATC.

District's Response:

Thank you for pointing out that we referred to the DOC as the ATC several times in our evaluation. We apologize for that error. The District has removed all references to the issuance of ATC's in the FDOC evaluation.

Pursuant to District Rule 2201, Section 5.8.9, the APCO shall issue a Permit to Operate to any applicant receiving a certificate from the California Energy Commission pursuant to this rule provided that the construction or modification is in compliance with all conditions of the certificate and of the Determination of Compliance, and provided that the Permit to Operate includes the conditions prescribed in Section 5.7. The District will then perform inspections of the facility to determine if it meets all requirements on their PTO.

Simpson Comment #7 - The BACT Analysis for the Permit is Defective:

The district's top down BACT analysis for NOx is defective because it fails to:

- Identify any alternative technologies or work practices which are technologically feasible for reducing NOx emissions, and
- To quantify the collateral impacts from the selection of SCR as the proposed alternative, and
- Identify combustion technologies that are effective is reducing NO_X emissions. (i.e. steam injection, dry low NO_X combustors, and catalytic combustors), and
- Analyze post-combustion controls including selective noncatalytic combustion and EM, and
- Evaluate the risk of an accident from the transport of NH_3, and
- Evaluate NH_3 as a precursor to PM2.5.

District's Response:

The District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The existing Top-Down BACT Analysis did not consider any NO_X emissions control other than the use of SCR to lower the NO_X emissions to 2.0 ppmvd @ 15% O_2, as no more efficient technology has been identified. Pursuant to the District BACT Policy, no analysis is necessary for a project in which the most effective control alternative listed in the BACT Guideline is selected. BACT Guideline 3.4.2 identifies BACT for NO_X as the use of SCR or equal to meet an emission concentration limit of 2.0 ppmvd @ 15% O_2 as the most stringent technologically feasible NO_X requirement. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.

In addition, BACT only covers operational emissions; therefore the risk from accidents during the transport of NH_3 is not evaluated and can not be evaluated under the District's NSR rule.

The evaluation of NH_3 as a precursor to $PM_{2.5}$ was not performed since the facility is not a Major Source for $PM_{2.5}$ emissions. However, it should be noted that the Valley's atmosphere does contain ammonia, largely from the Valley's considerable agricultural operations, and relatively small amounts caused by SCR systems are insignificant and are quite worth the significant NOx emissions reductions generated by the SCR. In addition, the District did analyze the health risk impacts of the NH3 emissions that are resulting from the requirement that SCR be installed, and there is no significant risk. Also see the response to comment #17, below.

Simpson Comment #8 - NO_X Emissions During Startup and Shut Down:

Emissions are greater during startups, shutdowns and combustor tuning periods than they are during steady-state operation, the BACT limits established for steady-state operations are not technically feasible during these periods. As these limits are not "achievable" during these operating modes, they are not "Best Available Control Technology" as defined in the Federal Regulations. Therefore, alternate BACT limits must be specified for these modes of operation. The discussion of Best Available Control Technologies does not include information on minimizing startup emissions or startup durations. The U.S. Environmental Protection Agency (U.S. EPA) requires that BACT apply not only during normal steady-state operations but also during transient operating periods such as startups. The District should consider conducting, as part of the BACT analysis, a review of combustion turbine and combined cycle system operational controls or design features that can shorten start up and shutdown events and optimize emission control systems.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised.

Simpson Comment #9 - BACT VOC Emission Limit:

The district has selected a VOC emission limit of 1.4 ppmvd @ 15% 02 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% 02 when it is fired with the duct burners. The BAAQMD has recently established a BACT VOC emission limit for large gas turbines for VOC's. BACT is the use of good combustion practice and abatement with an oxidation catalyst to achieve a permit limit for each gas turbine of 0.616 lb per hour or 0.00127 lb/MMBtu, which is equivalent to 1 ppm POC, 1-hr average. Since VOC emissions contribute to ozone formation and the district is in severe non attainment for the 8-hour ozone standard the district should adhere to the lower VOC emission rate or provide a top down BACT evaluation which shows that this rate is not achievable or is not cost effective.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. The District Top-Down BACT Analysis did not consider any VOC emissions control other than limiting the VOC emissions to 2.0 ppmvd @ 15% O_2 when the duct burner is fired, and 1.5 ppmvd @ 15% O_2 when the duct burner is not fired.

The applicant proposed VOC emissions of 1.4 ppmvd @ 15% O_2 when the unit is fired without the duct burner and 2.0 ppmvd @ 15% O_2 when it is fired with the duct *burner. The BACT analysis that established the Technologically Feasible BACT option of 1.5 ppmvd @ 15% O_2 did not take into account emissions from a duct burner. Therefore the applicants proposed 1.4 ppmvd VOC @ 15% O_2 emission factor will be determine to meet the highest ranking control option listed in the BACT. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed.*

Simpson Comment #10 - BACT $PM_{2.5}$ / PM_{10} Emission Limit:

The permit proposes to allow the project to emit as much as 11.78 pounds per hour of PM-10 with the project utilizing duct firing. According to BAAQMD the projects listed in the table below all have lower PM emission limits than those proposed for this project. BACT for PM 2.5 for large combined cycle turbines with duct firing is 9 pounds per hour. The district needs to impose this limit in the FDOC.

District's Response:

As noted above, the District did not re-evaluate BACT for this proposal as the daily emissions were not revised. *District BACT Policy, Section IX.D, states that a cost effective analysis is not necessary for a project in which the most effective control alternative is selected. BACT Guideline 3.4.2 identifies BACT for PM_{10} as the use of an air inlet filter, lube oil vent coalescer and natural gas fuel. Since the applicant proposed the most effective BACT control alternative, no evaluation of other control technologies were performed. In addition, it is likely that a PM10 limit of 11.78 lb/hr is substantially the same as a PM2.5 limit of 9.0 lbs/hr, as PM2.5 is a fraction of PM10.*

Simpson Comment #11 - Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether 'the operation of the proposed equipment will cause or make worse a violation of an air quality standard. For NOx the impact analysis conducted by the district in Attachment G page 2 demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the 98^{th} percentile of the annual distribution of the daily 1 hour max ppb /ug/m3 for the Visalia site which is 115.72 ug/m3. So the project does in fact violate the new federal NO2 standard and thus cannot be permitted.

District's Response:

The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour *max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.*

Simpson Comment #12:

The PDOC uses the PM-10 surrogate approach to analyze the particulate matter impacts from the project. On October 20, 2010, the USEPA issued a final rule providing modeling thresholds for evaluating impacts of PM2.5 emissions under the Prevention of Significant Deterioration (PSD) program and the Non attainment NSR program. The rule establishes Class I and Class II Increment Thresholds and Significant Impact Levels (SILs), and a Significant Monitoring Concentration (SMC) threshold. The project according to the analysis presented on page 54 exceeds both the significant impact levels for the annual PM 2.5 standard and the 24 PM 2.5 hour standard. The FDOC needs to address the compliance of the project with the new rules.

District's Response:

The project does not trigger PSD permitting and the facility is not a Major Source for $PM_{2.5}$ emissions. Therefore, the District is not required to perform modeling to evaluate impacts of $PM_{2.5}$.

Simpson Comment #13 - Federal 1 hour NO2 Standard:

The permit does not present an adequate and complete analysis for the new Federal 1 hour NO2 standard. The district failed to include information on any nearby sources which are required to be modeled with Avenal's emissions. A full impact analysis should be presented in the permit for the public to comment on using the EPA's Guideline on Air Quality Models (40 CFR Part 51 Appendix W).

District's Response:

This project does not trigger a PSD permit and therefore it is not required to follow the guideline on air quality models in 40 CFR Part 51 Appendix W. If it did trigger PSD permitting, the federal EPA would be obligated to perform such modeling, if appropriate.

Simpson Comment #14:

The revised permit should provide the input data that was used to determine compliance with the new NO2 standard. Emission factors and NO2 inventories should be presented for the public to review not just the information that is presented on page 2 Attachment G. The analysis on page 2 Attachment G demonstrates that the project does violate the new NO2 standard for all tiers when using District approved 3 yr Ave. of the 98^{th} percentile of the annual distribution of the daily 1 hour max ppb / ug/m3 for the Visalia site which is 115.72 ug/m3.

District's Response:

The impact analysis in Attachment G clearly states that the project passes the AAQA at Tier III for both the commissioning periods and normal operational periods. The District used the 3 year average daily distribution of daily 1 hour max ppb /ug/m3 for the Hanford site. The District used the numbers from the Hanford site because it is closer to the facility's location than the Visalia site.

Simpson Comment #15:

Modeling for the NO2 standard should indicate whether worst case emissions which would be the start up and shut down emissions for the project were utilized in the modeling for compliance with the standard.

District's Response:

The District performed modeling during the commissioning period and the standard operational period to determine compliance with the NO2 standard. The modeling performed by the District for these periods demonstrated compliance with the NO2 standards.

Simpson Comment #16 - The Proposed Interpollutant Trade Values Violates EPA Guidance and $PM_{2.5}$ NSR Regulations:

Based on an EPA assessment, the preferred trading ratios for SO2 to PM2.5 was set at 40:1.

District's Response:

The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.

Simpson Comment #17 - Ammonia Emissions:

Other power plant turbines have achieved a 2 ppm NO_X limit with a 5 ppm NH_3 slip limit.

The district must consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The district is not an isolated island.

District's Response:

Ammonia is an integral part of the NOx emissions control system when using SCR. The District has no regulatory basis for restricting ammonia slip to 5 ppmv. Ammonia is not a criteria air contaminant or a "precursor" as defined in District Rule 2201. The District's BACT Clearinghouse does not specify an ammonia slip rate for combustion turbines using SCR. While ammonia emissions may be restricted as part of a health risk evaluation that determines an unacceptable health risk from the ammonia to exposed populations, this is not the case with Avenal Power Center. The risk due to all toxic air contaminant emissions, including 10 ppmv ammonia, was found to be not significant.

A high ammonia slip from the turbine will not lead to increased PM_{10} formation in the atmosphere. The air basin currently has an excess of ammonia emissions; therefore lowering ammonia emissions will not reduce PM formation. This is demonstrated in the Districts $PM_{2.5}$ plan which does not not rely on ammonia reductions to reduce $PM_{2.5}$, but rather relies largely on NO_X reductions.

Generally, increased ammonia injection rates, and therefore increased ammonia slip rates, are required to maintain NOx BACT performance levels (2.0 ppmv) as the catalyst ages. Allowances for operation at the end of the economic life of a control technology and for periods of non-steady state operation (including startup and shutdown which can result in ammonia slip higher than 5 ppmv) are part of a BACT determination.

Simpson Comment #18 - Emission Reduction Credits:

ERC's used on the prior PDOC are unavailable for use on the new PDOC.

District's Response:

The ERC listed in the previous FDOC and the ones listed in the new PDOC will only be used for one of the projects. Once they are withdrawn for either project, they will no longer be available to be withdrawn for the remaining project. In addition, the applicant has provided sufficient ERC's of offset the emissions increase in either one of the projects.

Simpson Comment #19:

The PDOC indicates that the closest population center is the residential district of Avenal approximately 6 miles to the southwest. Are there people residing or working closer than that to the project? Could there be sensitive receptors closer to the site?

District's Response:

According to the application submitted by the facility, the nearest resident is 7,700 feet to the Northeast and the nearest business is 3,957 feet to the Northwest. However, our analysis of emissions and risk from those emissions is based on a theoretical long-term exposure at the point of maximum pollutant concentration. Therefore, our conclusion that there will be no significant risk from any emissions from this facility is not dependant on receptor location.

Simpson Comment #20:

It appears that there are residential structures and extensive farm land around the site. Could emissions from the facility affect crops or wildlife?

District's Response:

Such issues are addressed in the CEC's CEQA-equivalent process and are not a part of the District's analysis. However, it should be noted that the District's Health Risk Assessment (HRA) is a multipathway assessment of risk, and would include the affect on public health generated by pollutant deposition on plants and animals that are subsequently ingested by the public.

Simpson Comment #21:

- Has the District conducted and Environmental Justice analysis of the projects effects? Could farm workers be an environmental justice community that suffers a greater impact due to hard physical labor in the vicinity of the project, lack of health care, poverty and additional stressors like chemicals used in farming?
- Can farming activities cause additional air quality impacts that could contribute to a negative cumulative effect?
- Will this facility induce growth?
- Could on site Solar pre-heaters reduce Air quality impacts?
- Can this facility cause an increase of greenhouse gas emissions?
- Are there potential negative localized effects of Greenhouse gases?
- How does this plan comport with AB32?
- How does this plan comport with EXECUTIVE ORDER S-3-05?
- Has the District studied the potential air quality effects of the use of imported LNG?
- The District should study the life cycle effects of fossil fuel extraction and delivery?
- Has the District studied the effects of the facility utilizing water from the California Aqueduct?
- Will the vaporization of this water lead to negative air quality effects by increasing PM or other pollutants in the Air?

- Will the use of this water cause negative air quality effects by the diversion of water that could be utilized for farming or other uses?
- Will the pumping of this water through the Aqueduct, from its source, cause Air quality emissions?
- Is it legal to use Potable water for this Power plant use?
- As water quality changes will these effects change?
- Are there methods of minimizing these potential effects? Dry cooling for instance?

District's Response:

These questions should be directed to the CEQA lead agency for this project (CEC). Since the District is not the lead agency for this project, these comments will not be addressed at this time.

Simpson Comment #22:

How much money does the District receive if this project is approved? Denied?

District's Response:

Whether the project is approved or denied, the District receives application filing fees for all proposed equipment, and hourly engineering fees for the time spent evaluating the project. At this time, we would expect the total will be approximately $5,000. In addition, if the project is approved, the District will receive an annual permit fee to maintain the facility's permits, of approximately $26,000 per year. This latter amount would be the same whether the facility constructs under the conditions of this FDOC and a subsequent CEC approval, or under the existing FDOC which the CEC used in issuing the existing power plant license.

Comments Received from Rob Simpson in Exhibit 4:

The document provided labeled Exhibit 4 is the same document that Mr. Simpson presented as testimony for the CEC Hearings under proceeding 08-AFC-01. This exhibit was discussed at the Pre-Hearing Conference on June 30, 2009. After a review of the document, the CEC Committee overseeing the project concluded that the only information that would be allowed as testimony would be the information included in Exhibit W. A discussion of this can be found in the Pre-Hearing Conference Transcript, available at: http://www.energy.ca.gov/sitingcases/avenal/documents/2009-06-30_TRANSCRIPT.PDF. The District agrees with CEC's conclusion and will respond to the comments presented in Exhibit W. All additional comments in Exhibit 4 are documents pertaining to projects unrelated to this project, and comments that are not applicable to this project.

Simpson Comment #23:

The applicant proposes to offset the projects PM 2.5 emissions on a pound for pound basis with SOx offsets. Proposed interpollutant trading ratios are required to be scientifically justified with a site specific air quality analysis, as required by Rule 2201, Section 4.13.3. The PDOC attempts to establish an interpollutant ratio based on modeling analyses performed in the Districts 2008 PM 2.5 plan.

The EPA has finalized its regulations to implement the New Source Review (NSR) program for fine particulate matter on July 15, 2008. Their recommended ratio of SOx offsets to PM 2.5 offsets is 40 tons of SOx for each ton of PM 2.5. The applicant is proposing a ratio that is 40 times less stringent than EPA has recommended.

In addition the CEC and the air district allow the project to emit 33,521 pounds of SO2 with no mitigation despite the alleged CEC policy to offset all PM2.5 precursors. If one pound of SO2 offsets 1 pound of PM 2.5 the CEC and the Air District are allowing 33,521 pounds of SO2 to remain unmitigated. The new EPA rules on PM 2.5 require a pound for pound offset ratio for PM 2.5 precursors. If the districts assumption that one pound of SOx offsets 1 pound of PM 2.5 as allowed in the interpollutant trade the district is allowing 33,521 pounds of SOx to remain unmitigated creating 33,521 pounds of PM 2.5 in violation of CEQA and EPA NSAR rules for PM 2.5.

District's Response:

The facility did not propose to offset $PM_{2.5}$ emissions with SO2 credits. Furthermore, this facility is not a Major Source for $PM_{2.5}$; therefore the District did not evaluate $PM_{2.5}$ emissions. This comment is not applicable to this project.

Simpson Comment #24:

The FDOC allows an ammonia slip of 10 ppm. The 5 ppm ammonia limit in combination with a 2 ppm NO limit has already been required for some CEC licensed facilities. In the alternative the District could perform a site specific analysis that demonstrates that no particulate matter will be formed locally or district wide due to the ammonia slip emissions and require mitigation if the analysis demonstrates that there is significant secondary particulate matter formation from the ammonia emissions from the LGS.

The district must also consider the transport of the ammonia emissions to regions that may not be ammonia rich outside of the San Joaquin Valley. The transportation and storage of ammonia presents a risk of an ammonia release in the event of a major accident.

District's Response:

This comment was addressed in the District response to Rob Simpson Comment #17 above.

Comments Received from Rob Simpson in Exhibit 5:

The document labeled Exhibit 5, submitted by Rob Simpson, discusses the California energy landscape. The District does not take the California energy landscape into account when determining if a new project will meet applicable air quality rules and regulations. This comment should be directed to the California Energy Commission (CEC).

ATTACHMENT Q

	NOx	SOx	PM10	CO	VOC	PM2.5	MW/hour	% of Avenal Electricity
One Digester (lbs/year)	9,166	2,268	3,970	101,636	6,370	3970	1.059	
One Digester (tons/year)	4.58	1.13	1.99	50.82	3.19	1.99		
25 Digesters (lbs/year)	229,150	56,700	99,250	2,540,900	159,250	99,250	26.475	4.41%
25 Digesters (tons/year)	114.58	28.35	49.63	1,270.45	79.63	49.63		
Avenal (lbs/year)	198,840	33,521	161,550	197,928	69,222	161550	600	
Avenal (tons/year)	99.42	16.76	80.78	98.96	34.61	80.775		
Pollution Difference Digesters vs. Avenal (tons/year)	15.16	11.59	-31.15	1,171.49	45.01	-31.15		

Source: Lakeview Dairy Biogas digester Authority to Construct Permit March 22, 2016, Post-Project Stationary Source Potential to Emit (SSPE2) at 14, 20

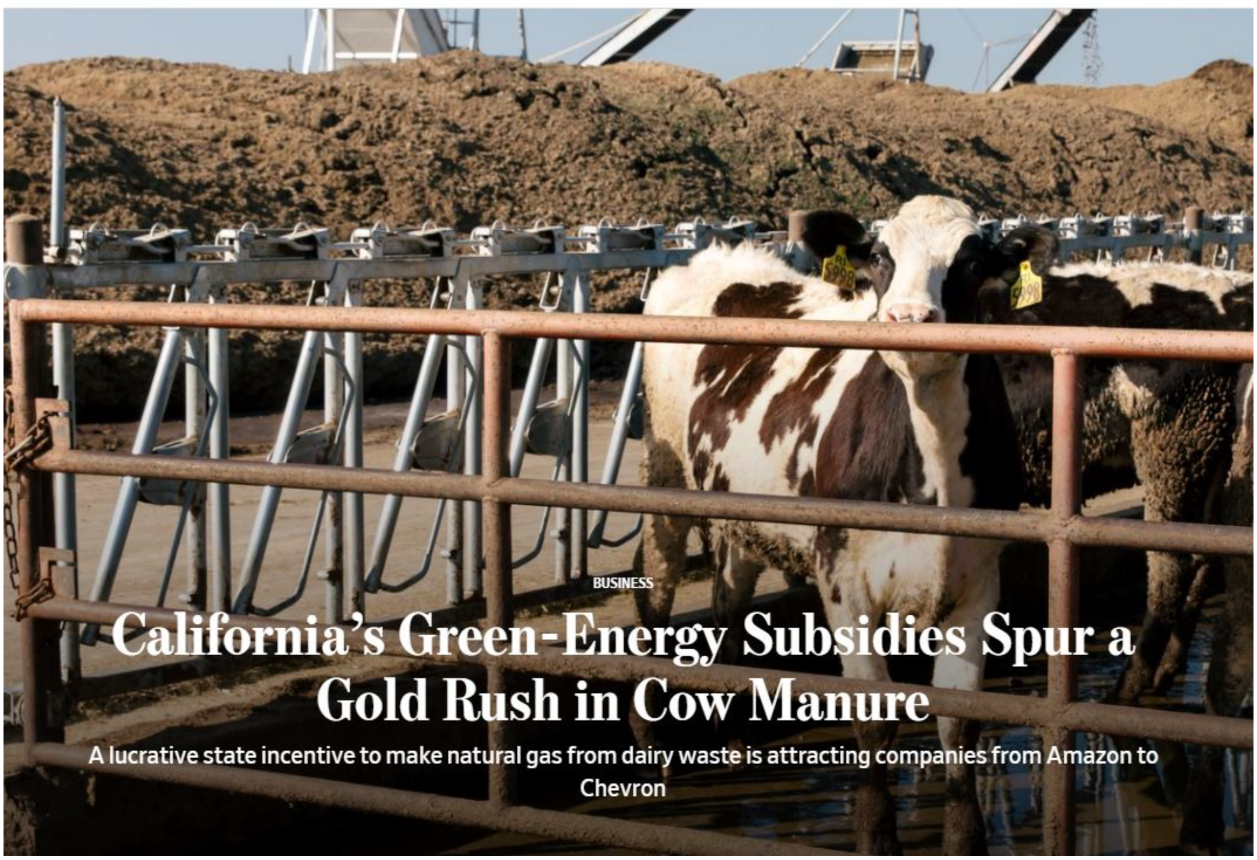
Source: Avenal Power Center Authority to Construct Permit No. December 17, 2010, Post-Project Stationary Source Potential to Emit (SSPE2) at 27.

ATTACHMENT R

BEFORE THE CALIFORNIA AIR RESOURCES BOARD

PETITION FOR RECONSIDERATION OF THE DENIAL OF THE PETITION FOR RULEMAKING TO EXCLUDE ALL FUELS DERIVED FROM BIOMETHANE FROM DAIRY AND SWINE MANURE FROM THE LOW CARBON FUEL STANDARD PROGRAM

THE WALL STREET JOURNAL.



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percent on high PM2.5 days.[119]

The "disadvantaged communities" of California, as defined pursuant to California Senate Bill 535, are concentrated in the San Joaquin Valley.[120] Seven of the eight counties in the Valley (all except San Joaquin County) report mean income well below the 120% limit that defines low-income.[121] Every county in the San Joaquin Valley has lower household and per capita incomes, and higher poverty rates than California as a whole.[122] While median household income in California in 2019 was $75,235, countywide household median incomes for San Joaquin Valley counties ranged from $49,687 to $64,432. The highest producing dairy counties in the state and in the San Joaquin Valley, Merced and Tulare, show median household incomes at $53,672 and $49.687—both at 71 percent or below statewide median income.[123]

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[119] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS 3-2 to 3-3 (Nov. 15 2018), https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf.

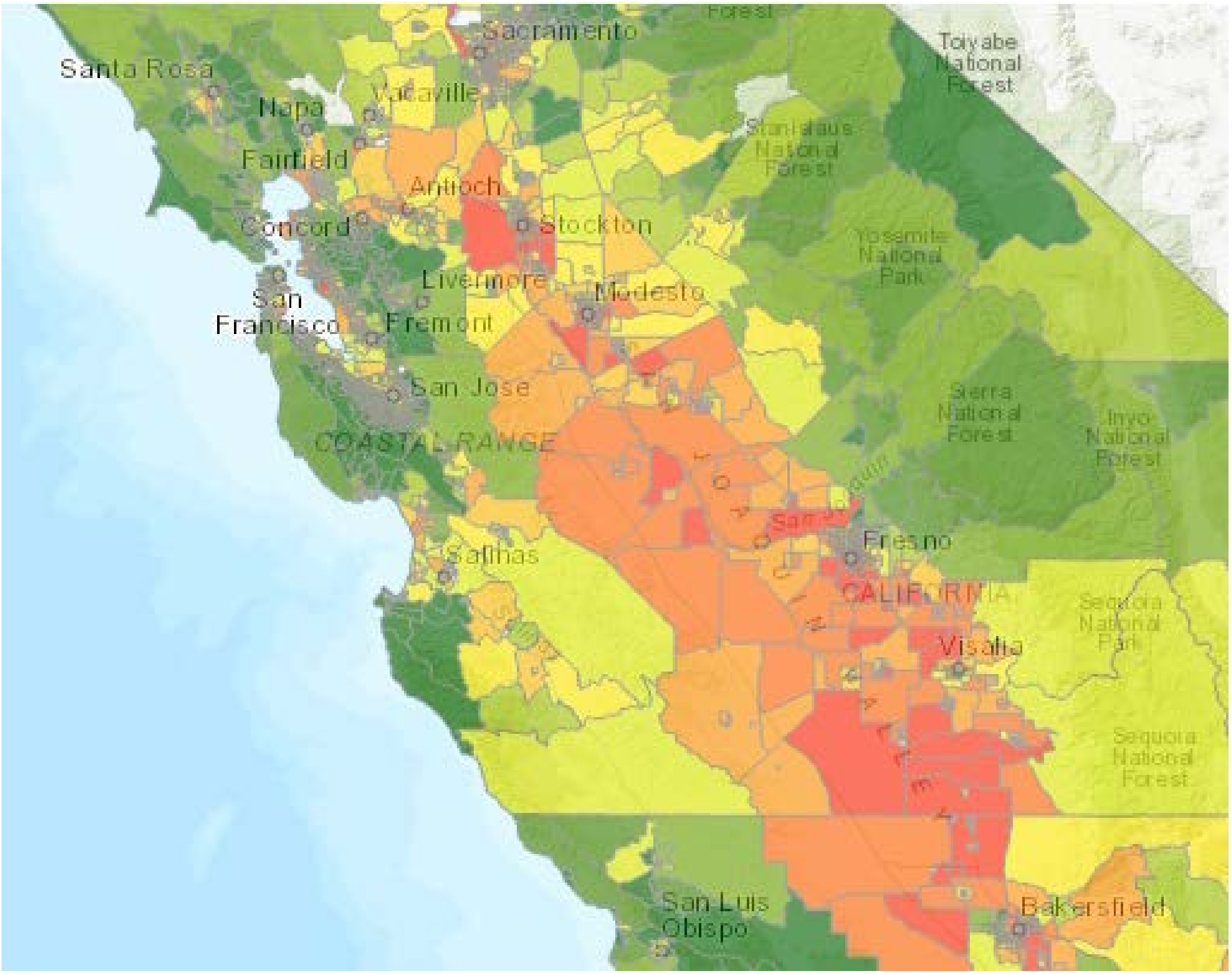
[120] CALEPA, DESIGNATION OF DISADVANTAGED COMMUNITIES PURSUANT TO SENATE BILL 535 (DE LEÓN) 1-32 (Apr. 2017), https://calepa.ca.gov/wp-content/uploads/sites/6/2017/04/SB-535-Designation-Final.pdf. All eight counties of the San Joaquin Valley exhibit the highest scores indicating the greatest pollution burden relative to the rest of California. *See Maps & Data*, CAL. OFFICE OF ENV'T HEALTH HAZARD ASSESSMENT, https://oehha.ca.gov/calenviroscreen/maps-data (last visited Mar. 25, 2022) (flagging areas of California that exhibit high to low pollution burden scores); *see also infra* page 27, San Joaquin Valley CalEviroScreen 4.0 map.

[121] Section 39711 of the Health and Safety Code sets the ceiling for low-income communities at 120% of the area median income. Additionally, Section 39711 designates communities with disproportionate environmental impacts and concentrations of low income, high unemployment, low educational attainment, and other burdensome socioeconomic factors as disadvantaged communities. Attach. 10, *Income Limits*, U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il.html#2020_data (last updated Apr. 1, 2020) (choose 30% Income Limit for ALL Areas (Excel)); Attach. 11, *FY 2020 State Income Limits* (2020), U.S. DEP'T OF HOUSING AND URBAN DEV., https://www.huduser.gov/portal/datasets/il/il20/State-Incomelimits-Report-FY20r.pdf.

[122] Attach. 12, *Quick Facts*, U.S. CENSUS, https://www.census.gov/quickfacts/fact/table/POP645219 (last visited Mar. 25, 2022).

[123] Poverty rates in every single county in the San Joaquin Valley also exceed poverty rates in California, with Merced and Tulare facing 17 and 18.9 percent poverty rates, respectively (as compared to 11.8 percent at the statewide level). *Id.*

San Joaquin Valley, CalEnviroScreen 4.0



San Joaquin Valley residents are disproportionately Latino as compared to California as a whole. All eight San Joaquin Valley Counties have higher Latino populations than the state, with populations ranging from 42 percent to 65.6 percent, as compared to the state population with 39.4 percent of residents classified as Latino. At least seven of eight San Joaquin Valley counties have a lower proportion of white residents as compared to the state as a whole.[124] Merced and Tulare counties have white, non-Latino populations of 26.5 and 27.7 percent, and Latino populations of 65.6 and 61 percent, respectively.[125] Like Merced and Tulare, Kern County also demonstrates much higher Latino populations than the rest of the state, with a Latino population of 54.6 percent.

[124] According to recent census data, 36.5 percent of the state population is classified as white, non-Latino, while 7 of the 8 counties in the San Joaquin Valley have white, non-Latino populations that range from only 26.5 to 33.2 percent. *Id.*
[125] *Id.* at 114.

i. Factory farm gas increases ammonia emissions.

Industrial dairies in the San Joaquin Valley are the largest source of ammonia.[126] Factory farm gas production adds even more ammonia to the air basin: one study documents that ammonia emissions from digestate increased 81% relative to raw manure.[127] Anaerobic digestion causes this increase in ammonia emissions, "due to an increased concentration of ammoniacal nitrogen."[128] Ammonia reacts with oxides of nitrogen to form ammonium nitrate, the most significant component of the San Joaquin Valley's PM2.5 pollution problem.[129]

CARB has analyzed the impact of ammonia emissions on ambient PM2.5 as part of the recent 2018 PM2.5 Plan for the Valley. CARB found that ammonia contributed 5.2 $\mu g/m^3$ to the ambient air and found that a 30 percent and 70 percent reduction in ammonia would result in a range of ambient reductions in PM2.5 from 0.08 to 2.3 $\mu g/m^3$.[130] For context, the 2012 annual PM2.5 standard is 12 $\mu g/m^3$.[131] The overall contribution of ammonia from current dairy activities would only increase as more anaerobic digesters cause an increase in ammoniacal nitrogen in the digestate and thus increase ammonia emitted into the air basin. This air pollution impact interferes with efforts to attain the PM2.5 24-hour and annual standards and causes a disparate impact on the basis of race and income. CARB cannot ignore this reality and must grant the Petition.

ii. Factory farm gas electricity pathways increase ozone and PM2.5 precursors.

The Petition identifies the on-site combustion of factory farm gas using internal combustion engines to power turbines for electricity generation at dairy operations as a significant air quality impact in the San Joaquin Valley Air Basin.[132] This form of factory farm gas fuel pathway to generate LCFS credits produces negative CI fuel pathways designated for electric vehicles. For example, CARB certified a pathway for such fuel generated at the Hilarides Dairy for a -758.46 CI in B016301[133] and at the Bidart-Old River Dairy for a -558.62 CI in B005901.[134] To date, Petitioners have identified eight certified pathways generating electric vehicle fuel in factory farm gas-powered engines, all located in the San Joaquin Valley, and an

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[126] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS, APPENDIX B AND APPENDIX G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf *and* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
[127] *See* Holly, et al., *supra* note 41.
[128] *Id.*
[129] SJVAPCD, 2018 PLAN FOR THE 1997, 2006, AND 2012 PM2.5 STANDARDS, APPENDIX B AND APPENDIX G, *available at* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/B.pdf *and* http://valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
[130] SJVAPCD, 2018 PM2.5 PLAN, APPENDIX G, 3 and tables 2 through 7 (Oct. 2018), https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/G.pdf.
[131] *See* 78 Fed. Reg. 3086 (Jan. 15, 2013).
[132] Petition, *supra* note 1, at 30.
[133] CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B016301 (certified June 21, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0163_cover.pdf.
[134] CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B005901 (re-certified Mar. 25, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0059_cover.pdf.

additional number of similar facilities out of state.[135] Petitioners have further identified an additional three pending pathway certification applications, including one for the Lakeview Dairy.[136]

These fuel pathways represent a pollution-intensive form of fuel and one that rewards the developer with an extremely low CI value, creating an incentive to further develop this form of fuel pathway and thus even more air pollution in the Valley. To illustrate, the Lakeview Dairy Biogas project in Kern County uses two internal combustion engines to produce over 1,000 kW of electricity on-site and has applied for a fuel with a -382.98 CI value.[137] And this project, as permitted by the Air District with required pollution control technology, still emits 4.58 tons/year of NOx, 1.98 tons/year of PM2.5, and 3.18 tons/year of VOC after the imposition of Best Available Control Technology as required by the State Implementation Plan.[138] Compared to a natural gas combined cycle plant in Avenal also permitted by the Air District, the Lakeview digester project produces much higher levels of NOx, sulfur oxides (SOx), and VOC emissions per unit of electricity generated.[139] However, unlike the natural gas plant, Lakeview Dairy Biogas is not required to purchase emission reduction credits for the air pollution emitted.[140] This facility *increases* air pollution in the San Joaquin Valley.

With eight certified pathways and at least three more pending, CARB will soon be allowing the functional equivalent of the Avenal Power Center operating at about 50 percent capacity and without having offset that pollution with emission reduction credits. Another dozen electric fuel pathways powered by factory farm gas-fueled engines at Valley dairies would emit the same amount of NOx pollution as Avenal at full capacity, but only generate 4.4 percent of the electricity.[141] A similar pattern results from the emissions of VOCs.[142] This absurdity is compounded by Air District offset thresholds such that the digester engines do not buy emissions offsets and thus add more air pollution to the air basin, while in theory the Avenal Power Center would have had to purchase offsets from other sources to achieve a no net increase. This occurs in one of the most polluted air basins in the United States and classified as nonattainment for several fine particulate matter National Ambient Air Quality Standards.[143] CARB has effectively allowed the LCFS to add more air pollution to the San Joaquin Valley, call it "renewable" fuel

[135] *See* CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APPS. B001901, B003701, B008901, B005901, B016601, B003801, B002401, and B016301.
[136] *See* CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APPS. B0104, B0105, and B0106.
[137] SJVAPCD, NOTICE OF PRELIMINARY DECISION – AUTHORITY TO CONSTRUCT (Mar. 22, 2016), http://www.valleyair.org/notiCes/Docs/2016/03-22-16_(S-1143770)/S-1143770.pdf; CALEPA & CAL. AIR RES. BD., LCFS TIER 2 PATHWAY APP. B0104 (certified TBD), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0104_summary.pdf.
[138] SJVAPCD, *supra* note 137, at 14.
[139] Attach. 13, Digester v. Avenal Comparison; Attach. 14, SJVAPCD, NOTICE OF FINAL DETERMINATION OF COMPLIANCE, AVENAL POWER CENTER, 3, 27 (Dec. 17, 2010). Producing 1.059 megawatts and emitting 4.58 tons/year of NOx, the Lakeview turbine generates 0.17 percent of the electricity while the engines powering the turbine emit 4.6 percent of the NOx pollution.
[140] Attach. 15, SJVAPCD, NOTICE OF PRELIMINARY DECISION – AUTHORITY TO CONSTRUCT 14 (Mar. 22, 2016).
[141] Digester v. Avenal Comparison, *supra* note 139. This assumes that Lakeview represents the average emissions from these factory farm gas operations.
[142] *Id*.
[143] 80 Fed. Reg. 18,528 (April 7, 2015); 81 Fed. Reg. 84,481 (November 23, 2016); 80 Fed. Reg. 2,206, 2,217 (January 15, 2015).

for electric vehicles, and then allows credits from that fuel to be sold to fossil fuel deficit holders who then may increase the pollution from their fuels sold in California. By allowing polluting factory farm gas to generate credits for "renewable" electric vehicle fuel, despite the harmful health impacts associated with emissions from the use of factory farm gas to generate that electricity, CARB ignores its statutory obligation not to "interfere with, efforts to achieve and maintain federal and state ambient air quality standards and to reduce toxic air contaminant emissions."[144] CARB must also grant the Petition and ensure the LCFS-related air pollution does not inflict a disparate impact on the basis of race, and must ensure that the LCFS complies with AB 32, Government Code § 11135, and Title VI of the Civil Rights Act.

d. Factory farm gas fuels consume significant energy inputs to produce which render factory farm gas much more pollution intensive than previously disclosed.

As noted above, Petitioners have submitted comments on dozens of pathway certifications and consistently have objected to the heavy redaction of information as proprietary and confidential business information. Until recently, Petitioners have not seen some of the fuel inputs for factory farm gas development as a result of this heavy-handed redaction. But recently, fuel pathway applications from Wisconsin-based factory farm gas operators shed much-needed transparency on the energy-intensive generation of factory farm gas. CARB should grant the Petition and, because such information was unavailable at the time of the Petition, also consider and disclose net energy consumption when calculating the CI values for factory farm-gas derived fuels.

First, the significance of the redactions to date have rendered meaningful public review of fuel consumption and energy inputs impossible. Below is an example of an application from a Sacramento-area factory farm gas project which claimed one of the largest negative CIs.[145]

[144] § 38562(b).
[145] SMUD, NEW HOPE DAIRY DIGESTER GREET LCFS PATHWAY TO PRODUCE ELECTRICITY TO CHARGE ELECTRIC VEHICLES IN SMUD REGION & CALIFORNIA (Dec. 4, 2020), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0166_1_report.pdf.

Sacramento 1500 Cow dairy 06/03/2021

4. Life Cycle Results for Carbon Intensity

The calculated Carbon Intensity for New Hope dairy digester system to charge electric vehicles = **-750.81** **gCO_{2e}/MJ**, see table below.

[redacted]

Page | 8 New Hope Dairy Digester to EV Pathway Application No. B0166 Facility ID: F00255 Copyright © 2020

Still other pathway applications fully redact all input data and only disclose the final CI. This CI calculation from the Western Sky Dairy in Kern County illustrates this degree of redaction.[146]

Exhibit 25. Total Carbon Intensity for Dairy Manure Pathway-Western Sky Biogas LLC

Process Stage	Carbon Intensity (gCO_2e/MJ Biogas)
Diesel Consumption	[redacted]
Electricity Consumption	[redacted]
Loss/Fugitives	[redacted]
Biomethane Transmission	[redacted]
Compression of CNG	[redacted]
Tailpipe Emissions	[redacted]
Methane Avoided	[redacted]
CO_2 Diverted	[redacted]
Final CNG CI (gCO_2e/MJ)	-385.40

09/30/2021 Kern County, CA

[146] CALIFORNIA BIOENERGY, LIFE-CYCLE ASSESSMENT OF DAIRY MANURE BIOGAS TO CNG (Sep. 30, 2021), https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0198_report.pdf. Also noteworthy is the fact that Western Sky Dairy is one of the eight dairies generating reductions credited towards the DDRDP, the Aliso Canyon Mitigation Agreement, and the LCFS.

ATTACHMENT S

Ammonia: Supplemental Information for EPA in Support of 15 µg/m3 Annual PM2.5 Standard

March 2023

Table of Contents

Executive Summary

The California Air Resources Board (CARB) and San Joaquin Valley Air Pollution Control District (District) are providing this information at the request of United States Environmental Protection Agency (EPA) staff to further clarify the assessment of ammonia as a precursor to fine particulate matter (PM2.5) in the San Joaquin Valley (Valley). Specifically, this supplemental information summarizes previous information submitted to EPA and also provides new information intended to support EPA action on the Attainment Plan Revision for the 1997 Annual PM2.5 Standard (15 µg/m3 SIP Revision) submitted to EPA in 2021.

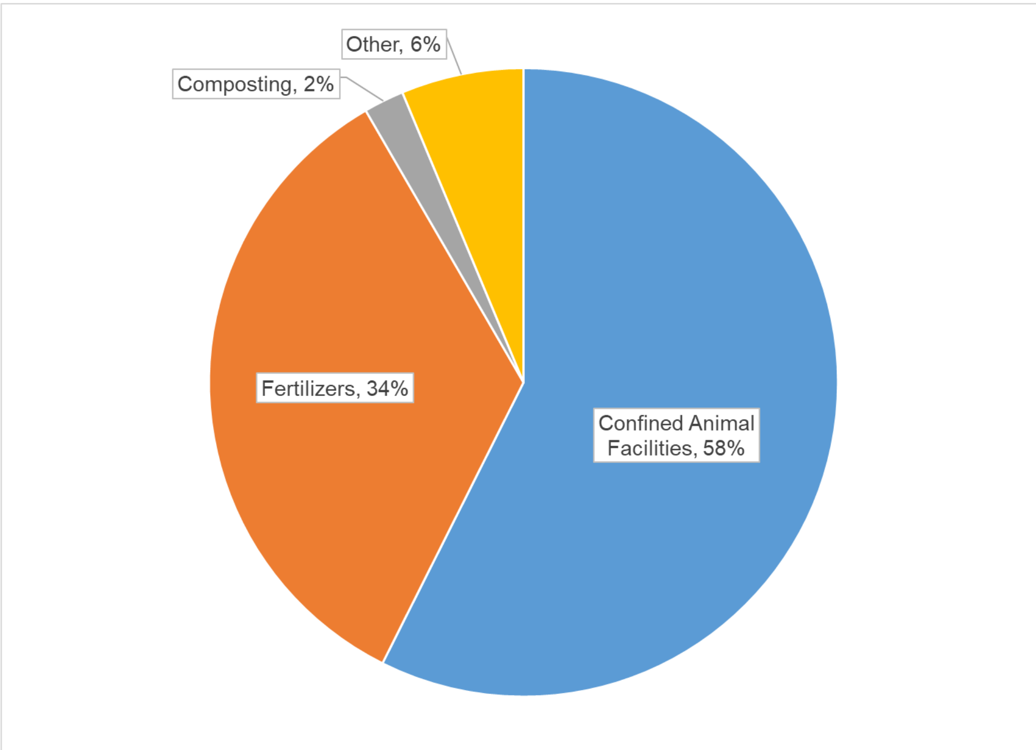
This document summarizes and reinforces the findings on ammonia as a precursor previously submitted to EPA in four documents provided between 2019 and 2021. CARB and the District continue to assert that, as documented in previous submittals, ammonia is not a significant attainment precursor for PM2.5 in the Valley for the 15 microgram per cubic meter (µg/m3) annual PM2.5 standard. PM2.5 is a complex mixture of many chemical species. Roughly 40 percent of PM2.5 is made up of ammonium nitrate particulate which is itself a combination of two precursors, ammonia and oxides of nitrogen (NOx). NOx emissions in the Valley come primarily from mobile sources while ammonia emissions come primarily from area sources. Ammonium nitrate reductions are critical for the Valley to attain the 15 ug/m3 annual PM2.5 air quality standards and provide cleaner air to residents. Ammonium nitrate formation is limited by the precursor, either ammonia or NOx, in least supply. Due to these complex reactions, when a pollutant is abundant, controlling that pollutant may not lead to PM2.5 air quality improvement. In other words, in order to reduce a secondary pollutant like ammonium nitrate PM2.5, controls need to target the pollutant that limits the chemical reaction.

Multiple field studies in the Valley have confirmed that NOx is the limiting precursor to ammonium nitrate formation and that there is a far greater amount of ammonia in the Valley's air than is necessary to participate in the chemistry that leads to ammonium nitrate. Thus, NOx reductions are key for reducing ammonium nitrate and PM2.5 levels in the Valley. The attainment strategy recognizes this scientific finding and calls for significant NOx reductions, primarily achieved through CARB's mobile source control measures. Air quality modeling also shows that the effectiveness of ammonia controls will rapidly decrease through the 2023 timeframe as the Valley's air becomes even more NOx-limited due to dramatic and ongoing reductions in NOx from these mobile source control measures.

EPA guidance recommends modeling emissions reductions of PM2.5 precursors of between 30 and 70 percent to evaluate if precursor emissions reductions have a significant impact on PM2.5 levels, 0.25 µg/m3 for the 15.0 µg/m3 annual PM2.5 standard. At a 30 percent reduction in ammonia emissions, one site, Hanford, exceeded the 0.25 µg/m3 threshold with a value of 0.26 µg/m3. Further, nationwide, ammonia emissions are flat indicating that the sources are not being controlled significantly.

Per EPA's request, the District and CARB analyzed potential control measures to reduce ammonia emissions to evaluate whether a 30 percent reduction in emissions is feasible. Thus, negating consideration of the 70 percent precursor evaluation. For an effective control measure evaluation, it is necessary to characterize and understand the key sources of ammonia in the Valley. The three main sources of ammonia emissions in the Valley from stationary and area sources, which account for 94 percent of the Valley's ammonia emissions as shown below in Figure ES-1, are the focus of the evaluation. These are confined animal facilities (contributing 186.5 tons per day (tpd) of ammonia emissions in 2023), agricultural fertilizers (111.2 tpd), and composting of solid and biological waste (6.7 tpd)[1].

Figure ES-1: Sources of Ammonia in the San Joaquin Valley



Specific to the confined animal facility category, the District conducted a new, extensive evaluation of potential measures to control sources of ammonia emissions for this submittal for the15 µg/m3 SIP Revision. EPA provided the list of measures to CARB and the District, and requested that the measures and studies referenced be addressed specifically for the Valley. In this evaluation, the District has identified only a few measures that have the theoretical potential to reduce additional ammonia emissions beyond the practices currently enforced through District Rule 4570 (Confined Animal Facilities). These measures are reducing crude protein content in feed for beef finishing cattle, incorporation of solid manure within 24 hours, and acidifying amendments for poultry litter and manure. Despite the technological and economic feasibility issues of these mitigation measures, the District evaluated the potential emission reductions and the impact they might have on the Valley's total ammonia emissions inventory if these measures were to be implemented. Through this

[1] 15 µg/m3 SIP Revision

evaluation, the District identified a total of 6.6 tpd of ammonia emission reductions from confined animal facilities.

For the fertilizer category, CARB has not identified effective mechanisms within its authority to regulate air emissions of ammonia from fertilizers. Furthermore, CARB and the District are unaware of any other jurisdictions with rules regulating fertilizer application. Nor has EPA staff identified any rules applicable to regulating air emissions from non-organic fertilizer application. In addition, CARB and the District did not identify feasible control measures for composting or other emissions sources. Based on this extensive evaluation, identified feasible controls, as summarized below in Table ES-1, can reduce ammonia emissions by approximately 2 percent. Therefore, CARB and the District conclude that a 30 percent reduction in ammonia emissions is not achievable.

Table ES-1. Estimated Feasible Ammonia Emission Reductions

Emissions Category	Emissions (tpd, 2023)	Identified Controls	Feasible Ammonia Reductions
Confined Animal Feeding	186.5	• Reducing crude protein content in feed for beef finishing cattle • Incorporation of solid manure within 24 hours • Acidifying amendments for poultry litter and manure	6.6 tpd
Fertilizers	111.2	No authority or feasible controls identified	0
Composting	6.7	No additional feasible controls identified at this time	0
Other sources	20.5	No feasible controls identified	0
Total Ammonia	324.9		6.6 tpd

CARB has followed EPA guidance to evaluate whether ammonia contributes significantly to PM2.5 levels that exceed the 15 µg/m3 annual standard NAAQS. While a precursor sensitivity analysis showed a small impact when ammonia was reduced by 30 percent, achieving this level of control in practice is infeasible. Thus, considering relevant contextualizing information including available controls, CARB determined that ammonia emission reductions do not improve PM2.5 levels that exceed the annual 15 µg/m3 standard in the San Joaquin Valley. Therefore, CARB has excluded ammonia as an attainment precursor and from control requirements in the SIP.

1. Background

PM2.5 is made up of many constituent particles that are either directly emitted, such as soot and dust, or formed through complex reactions of gases in the atmosphere. NOx, sulfur dioxide (SO2), volatile organic compounds (VOCs), and ammonia are gases that are precursors to PM2.5, transforming into particles through physical and chemical atmospheric processes.

Ammonium nitrate (NH4NO3) is a constituent of PM2.5, making up about 40 percent of PM2.5 mass in the Valley. Ammonium nitrate forms when nitrogen dioxide (NO2) reacts with highly oxidizing species in the atmosphere to form nitric acid (HNO3). Nitric acid then reacts with ammonia (NH3) to yield ammonium nitrate as a particle. Since ammonia reacts chemically in this way to form a particle, ammonia is a precursor to PM2.5.

Lowering PM2.5 concentrations to levels that meet the 15 µg/m3 annual PM2.5 standard will rely upon an effective control strategy for ammonium nitrate. The amount of ammonium nitrate that can form in the atmosphere is limited by whichever precursor, either NOx or ammonia, is in least supply, and research studies confirm that there are relatively fewer NOx molecules in the air in the Valley than ammonia. This implies that reducing NOx, the limiting precursor in this case, is more effective for reducing ammonium nitrate concentrations and thus improving PM2.5 air quality.

The 2018 PM2.5 Plan was developed jointly by CARB and the District to address four PM2.5 federal ambient air quality standards: the 15 µg/m3 annual, 65 µg/m3 24-hour, 35 µg/m3 24-hour, and 12 µg/m3 annual standards. For the 15 µg/m3 annual standard, the 2018 PM2.5 Plan established 2020 as the attainment date. In 2020, one air monitoring site—Bakersfield-Planz—recorded a design value over the standard despite excluding the impacts of wildfires. Since the 2020 attainment date was no longer approvable, EPA proposed, on July 22, 2021, to partially approve and partially disapprove the portions of the 2018 PM2.5 Plan pertaining to the 15 µg/m3 annual standard.[2] Specifically, EPA proposed to disapprove the following SIP elements related to the attainment demonstration for the 15 µg/m3 standard: the precursor demonstration (including for ammonia), BACM/BACT demonstration, five percent demonstration, attainment demonstration, reasonable further progress demonstration, quantitative milestone demonstration, motor vehicle emissions budgets, and contingency measure. EPA proposed to approve the 2013 base year emissions inventories.[3]

[2] 86 FR 38652. EPA's final disapproval published November 26, 2021 (86 FR 67329)

[3] The 2018 PM2.5 Plan used CEPAM 2016 version 1.05. Any new analysis in this supplemental document uses the same version of the emissions inventory.

The District and CARB quickly revised the 2018 PM2.5 SIP to address the disapproval and demonstrate attainment of the 15 µg/m3 annual PM2.5 standard as soon as possible. Accordingly, the agencies worked together to develop the Attainment Plan Revision for the 1997 Annual PM2.5 Standard (15 µg/m3 SIP Revision). The 15 µg/m3 SIP Revision amends the 2018 PM2.5 Plan to update the SIP elements associated with the disapproved attainment demonstration and demonstrates that the Valley will meet the 15 µg/m3 annual PM2.5 standard in 2023, including at the high site of Bakersfield-Planz with a 2023 design value (DV) of 14.7 µg/m3.

The 15 µg/m3 SIP Revision satisfies statutory requirements for a Clean Air Act §189(d) plan for a Serious nonattainment area SIP submission. The Valley is able to demonstrate attainment with reductions in emissions of NOx and PM2.5 coming from (1) ongoing implementation of CARB and the District's existing control strategy, (2) newly adopted CARB and District measures providing near-term reductions, and (3) a CARB aggregate emission reduction commitment made for the 15 µg/m3 SIP Revision for reductions in 2023 from measures in the 2018 PM2.5 Plan. Similar to the precursor demonstration for the 12 µg/m3 annual standard which projected attainment in 2025 and relied upon the 35 µg/m3 24-hour 2024 precursor demonstration, the 15 µg/m3 SIP Revision also relies on the EPA approved.[4] precursor demonstration associated with the 35 µg/m3 24-hour PM2.5 standard. Both are within one year of the 35 µg/m3 24-hour PM2.5 standard attainment deadline and precursor sensitivities can be assumed to be very similar to those modeled in 2024 The District Governing Board adopted the 15 µg/m3 SIP Revision on August 19, 2021, and the CARB Board adopted it on September 23, 2021. Subsequently, CARB submitted the adopted 15 µg/m3 SIP Revision to EPA as a revision to the California SIP on November 8, 2021.

CARB has provided supplemental information on ammonia to EPA on four previous occasions, as outlined below in Table 1. This supplemental document summarizes findings and information in those previous submittals, and also provides new, extensive evaluation. It is provided in support of EPA action on the 15 µg/m3 SIP Revision.

[4] See also "Technical Support Document, EPA Evaluation of $PM_{2.5}$ Precursor Demonstration, San Joaquin Valley $PM_{2.5}$ Plan for the 2006 $PM_{2.5}$ NAAQS," February 2020.

Table 1. Previous Submittals to EPA of Supplemental Information on Ammonia

Document	Date Provided to EPA	Delivery Method(s)	Key Points
Appendix G 2018 PM2.5 Plan	January 2019	The precursor analysis required for the SIP by the CAA	• Includes sensitivity analyses showing that 30% reduction of ammonia in the SIP base year of 2013 would have PM2.5 benefit, but in future years as the Valley becomes more NOx-limited, ammonia reductions would not have PM2.5 benefit • Considering relevant contextualizing information such as emissions trends, research, and available controls, CARB determined that emissions of ammonia do not contribute significantly to PM2.5 levels that exceed the PM2.5 standards in SJV, and therefore excluded ammonia from control requirements in the SIP.
Submittal letter with attachment	May 2019	Provided as attachment to letter submitting the comprehensive 2018 PM2.5 SIP to EPA	• Cites studies showing ammonia is in excess of NOx in the Valley, making NOx the limiting precursor to control for PM2.5 benefits • Indicates that the Valley will only become more NOx-limited in future years as NOx continues to decrease and ammonia levels remain stable • Highlights CARB research efforts on ammonia
Clarifying Information on Ammonia	October 2019	Emailed directly to EPA staff	• Explains that 30% ammonia reduction is infeasible, points out that fertilizer (a major ammonia source in SJV) is not within CARB's authority to control • Explains that SJVAPCD is already implementing BACT for ammonia • Summarizes ammonia-related research at CARB
Ammonia Update 2017 Data for EPA	September 2021	Emailed directly to EPA staff and published as attachment to staff report for Board item related to SJV PM2.5	• Provides new data from a 2017 study in the Valley supporting our previous findings that ammonia is not a significant precursor

2. Precursor Demonstration

EPA finalized a PM2.5 SIP Requirements Rule[5] (Rule) that identifies the four PM2.5 precursor pollutants—NOx, SO_2, VOCs, and ammonia—that "must be evaluated for potential control measures in any $PM_{2.5}$ attainment plan."[6] The Rule permits air agencies to "submit an optional precursor demonstration designed to show that for a specific PM2.5 nonattainment area, emissions of a particular precursor from sources within the nonattainment area do not or would not contribute significantly to PM2.5 levels that exceed" the National Ambient Air Quality Standards (NAAQS).[7] If the agency's demonstration is approved by EPA, the attainment plan "may exclude that precursor from certain control requirements under the Clean Air Act."[8]

In Appendix G to the 2018 PM2.5 Plan, CARB included precursor demonstrations for three PM2.5 precursors, including ammonia. Following EPA guidance, the ammonia precursor demonstration analyzed "the relationship between precursor emissions and the formation of secondary PM2.5 components"[9] using an air quality model, and take into consideration additional relevant factors.

EPA PM2.5 Precursor Demonstration Guidance

In November 2016, EPA published a draft guidance document to "assist air agencies who may wish to submit PM2.5 precursor demonstrations."[10] The document provides recommendations or guidelines, as authorized under the Clean Air Act, "that will be useful to air agencies in developing the precursor demonstrations by which the EPA can ultimately determine whether sources of a particular precursor contribute significantly to PM2.5 levels that exceed the standard in a particular nonattainment area."[11] Recommendations include modeling procedures for conducting the required analysis and contribution thresholds to determine the impact of a precursor on PM2.5 levels.[12] The guidance also describes an analytical process to perform the precursor demonstration, involving (1) a concentration-based analysis followed by (2) a sensitivity-based analysis and (3) consideration of additional information including what is achievable through controls.

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[5] 81 FR 58010 (August 24, 2016)

[6] EPA. *PM2.5 Precursor Demonstration Guidance: Draft for Public Review and Comment*. 17 Nov. 2016. Web. 3 Oct. 2017. <www.epa.gov/sites/production/files/2016-11/documents/transmittal_memo_and_draft_pm25_precursor_demo_guidance_11_17_16.pdf>. Page 7

[7] Ibid. 7

[8] Ibid. 7

[9] Ibid. 26

[10] Ibid. 7

[11] Ibid. 7-8

[12] Ibid. 9

Concentration-Based Analysis

The evaluation of precursors begins with a concentration-based analysis using ambient data to determine whether precursor emissions contribute to total PM2.5 concentrations.[13] Each precursor's impact on total $PM_{2.5}$ mass is compared to contribution thresholds. EPA recommends values for these thresholds, or air quality concentrations below which air quality impacts are not statistically significantly different from "the inherent variability in the measured atmospheric conditions," and thus do not contribute to PM2.5 concentrations that exceed the NAAQS.[14] The threshold given in the guidance document is 0.2 µg/m3 for the annual PM2.5 standard.[15] This threshold was calculated based on EPA's guidance for the 12 µg/m3 annual NAAQS. If adjusted to reflect the 15 µg/m3 annual standard, the 0.2 µg/m3 threshold for the 12 µg/m3 annual PM2.5 standard increases to 0.25 µg/m3 for the 15 µg/m3 annual PM2.5 standard. As shown below in Table 2, based on this metric, ammonia contributes to total PM2.5 mass in the Valley in amounts that exceed EPA's recommended thresholds.

Table 2. Contribution of Ammonia to Total PM2.5 Mass

Species	Precursor	Species Contribution (ug/m3) to PM2.5 Mass*	Over Threshold?
Ammonium nitrate	Ammonia	5.2	Yes

* 2015 annual average for Bakersfield

This concentration-based analysis, however, does not accurately capture the impact of reductions of precursor emissions on PM2.5 levels. Since the concentration-based analysis shows the precursors contribute to total PM2.5 mass in amounts over EPA's recommended thresholds, CARB proceeded to conduct an optional sensitivity-based analysis to demonstrate that reductions of ammonia will have a negligible impact on PM2.5.

Sensitivity-Based Analysis

The SIP Requirements Rule allows for a sensitivity-based analysis to examine the degree to which PM2.5 levels are sensitive to precursor reductions. According to the guidance:

> This modeling analysis examines the sensitivity of ambient $PM_{2.5}$ concentrations in the nonattainment area to certain amounts of decreases in the precursor emissions in the area.… Where decreases in emissions of the precursor result in negligible air quality impacts (i.e., the area is "not sensitive" to decreases), such a small degree of impact is

[13] Ibid. 8

[14] Ibid. 14, 15

[15] Ibid. 15-16

not significant and can be considered to not "contribute" to PM2.5 concentrations for the purposes of determining whether control requirements should apply.[16]

Generally, EPA recommends that the precursor demonstration "should be based on current conditions to demonstrate that precursor emissions do not contribute significantly to $PM_{2.5}$ concentrations in the nonattainment area."[17] This means evaluating emissions in a selected base year, which may be the present or a previous year.

For each existing PM2.5 monitor location in the area,[18] the first step for estimating PM2.5 impacts from ammonia in the base year is to estimate the average PM2.5 concentration on an annual basis. The second step is to calculate the annual average PM2.5 concentration at each monitor with a specified percent reduction in precursor emissions, still in the base year.[19] The difference between these two calculated PM2.5 values is the impact on PM2.5 levels from precursor emissions reductions.[20] Note that "precursor demonstrations do not examine changes in emissions *between a base year and a future year*. Instead, the calculation of relative changes in $PM_{2.5}$ concentrations occur *between a modeled case with all emissions and a modeled case with reduced precursor emissions*" (emphasis added).[21] In addition, EPA recommends modeling reductions of between 30 and 70 percent of precursor emissions.[22]

EPA guidance recommends a range of 30 to 70 percent since emission reductions need to be large enough to test the interaction of the precursor. In general, the recommended range is reasonable for NOx and SO2, this range is not reasonable for ammonia. As indicated in the EPA guidance, between 2011 and 2017, the median change in SO2 and NOx emissions was -63.6 and -31.8 percent, while the median change in ammonia was a positive 0.8 percent. The large reductions in NOx and SO2 emissions are in response to reasonable controls that are available and in practice at sources. The slight increase nationally of ammonia is indicative of the lack of controls on ammonia sources across the nation. While new types of controls are being developed for ammonia, the availability and magnitude of ammonia controls that meet EPA's requirements for submittal into the SIP along with ammonia emission reductions trends support that the 30 percent reduction may not be reasonable.

The third step in the sensitivity-based analysis is to compare the modeled impact on PM2.5 levels from a decrease in ammonia emissions to contribution thresholds for annual average PM2.5. Following the analytical process outlined in the EPA precursor demonstration guidance and summarized above, CARB has evaluated ammonia in the Valley. The results of the sensitivity-based analysis and consideration of additional information are presented below.

[16] Ibid. 25
[17] Ibid. 33
[18] Ibid. 16
[19] Ibid. 36
[20] Ibid. 36
[21] Ibid. 34
[22] Ibid. 29

CARB staff used an air quality model to estimate the PM2.5 design value for the annual standard in the base year of 2013 at each Valley monitor. Then, CARB staff applied the recommended lower bound of a 30 percent reduction to ammonia emissions and used the air quality model to estimate the PM2.5 design values. The difference between the two design values represents the modeled impact on PM2.5 levels of a 30 percent reduction in ammonia emissions in 2013. This is the value that is compared to EPA's adjusted contribution threshold for the 15 μg/m3 annual standard of 0.25 μg/m3 to establish if PM2.5 levels are sensitive to this level of ammonia reduction. For completeness, CARB staff repeated this analysis, applying instead the EPA-recommended upper bound of a 70 percent reduction to ammonia emissions in the base year. The results are shown in Table 3.

Table 3. Base Year 2013 PM2.5, 30 and 70 Percent Reduction in Ammonia Emissions

Site	2013 Baseline DV	2013 DV with 30% Ammonia Reduction	Difference	2013 DV with 70% Ammonia Reduction	Difference
Bakersfield-Planz	17.19	16.76	0.43	15.72	1.47
Madera	16.93	16.29	0.64	14.81	2.12
Hanford	16.54	15.82	0.72	14.24	2.30
Visalia	16.20	15.82	0.38	14.80	1.40
Clovis	16.12	15.80	0.32	14.95	1.17
Bakersfield-California	16.02	15.58	0.44	14.47	1.55
Fresno-Garland	14.98	14.69	0.29	13.91	1.07
Turlock	14.88	14.46	0.42	13.46	1.42
Fresno-HW	14.22	13.95	0.27	13.17	1.05
Stockton	13.14	12.84	0.30	12.10	1.04
Merced-S Coffee	13.10	12.65	0.45	11.60	1.50
Modesto	13.03	12.66	0.37	11.78	1.25
Merced-M	10.97	10.77	0.20	10.23	0.74
Manteca	10.09	9.85	0.24	9.27	0.82
Tranquility	7.72	7.33	0.39	6.46	1.26

From this analysis, the estimated air quality impact of reducing ammonia emissions by the lower bound of 30 percent in the base year exceeds EPA's adjusted annual threshold of 0.25 μg/m3 at all but two Valley monitors for the SIP base emission inventory year, 2013, 10 years ago. Reducing emissions by the upper bound of 70 percent also shows impacts above the threshold for this time period.

It is not possible, however, to conclude from this analysis that emissions of ammonia contribute significantly to PM2.5 levels. In this case, ammonia emissions have an impact above the recommended contribution threshold even at the lower bound of 30 percent emission reduction, but this does not necessarily mean the precursor contributes significantly to PM2.5 levels that exceed the NAAQS. Making the appropriate determination about the ammonia emission reduction impact requires further analysis of additional factors, such as future emission controls and potential controls on the precursors as allowed per the EPA guidance.

Consideration of Additional Information

To supplement modeling analysis, EPA guidance also allows an air agency to consider additional information, assessing the significance of a precursor "'based on the facts and circumstances of the area.'"[23] The guidance states:

> If the estimated air quality impact exceeds the recommended contribution thresholds…, this fact does not necessarily preclude approval of the precursor demonstration. There may be cases where it could be determined that precursor emissions have an impact above the recommended contribution thresholds, yet do not "significantly contribute" to levels that exceed the standard in the area.[24]

In these cases, an air agency may "provide EPA with information related to other factors they believe should be considered in determining whether the contribution of emissions of a particular precursor to levels that exceed the NAAQS is 'significant' or not."[25] Such factors may include: trends in emissions of other precursors such as NOx,[26] anticipated growth or loss of emissions sources,[27] and the consequent appropriateness of modeling impacts in a future year instead of a base year;[28] "available emissions controls,"[29] and "the severity of nonattainment at relevant monitors."[30] Other factors the agency may consider are: the amount by which a precursor's contribution exceeds the recommended contribution thresholds; source characteristics (e.g., source type, stack height, location); analyses of speciation data and precursor emission inventories; chemical tracer studies; and special

[23] Ibid. 17
[24] Ibid. 17
[25] Ibid. 17
[26] Ibid. 17
[27] Ibid. 17
[28] Ibid. 33
[29] Ibid. 29
[30] Ibid. 17

intensive measurement studies to evaluate specific atmospheric chemistry in an area. The agency may also provide other information not listed here.[31]

CARB and the District conducted additional analysis related to these factors in accordance with EPA guidance to provide information related to other factors beyond the concentration- and sensitivity-based analyses that should be considered in determining whether the contribution of ammonia emissions to levels that exceed the 15 μg/m3 annual PM2.5 is "significant" or not. These analyses are described below.

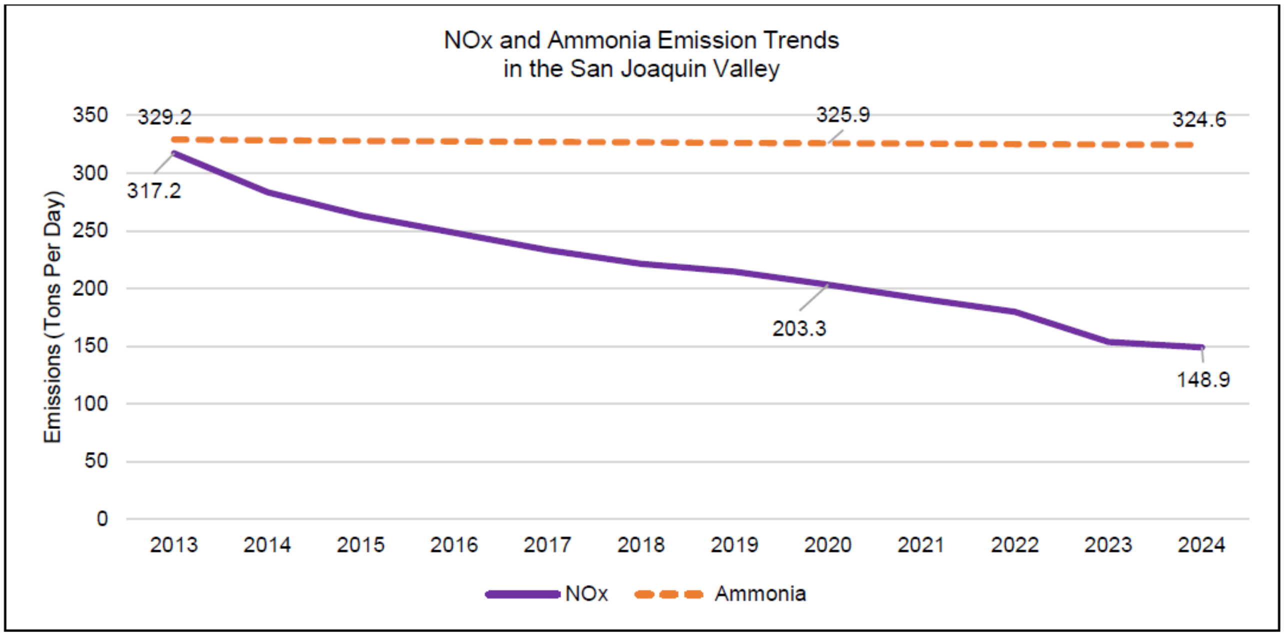
Emissions Trends and Studies

CARB has an extensive suite of measures in place to reduce NOx emissions from mobile sources that reduce ammonium nitrate. Between 2013 and 2024, total NOx emissions are projected to decline 53 percent. Meanwhile, total ammonia emissions are expected to remain flat, as shown in Figure 1. The District adopted four rules[32] between 2004 and 2011 with measures that provided ammonia emissions reductions in the Valley; however, reductions from these existing control measures are already accounted for in the inventory, prior to the 2018 PM2.5 SIP base year of 2013. In the future, emissions from the main sources of ammonia—dairies, fertilizer, and non-dairy livestock operations—are not anticipated to either increase or decrease substantially.

[31] Ibid. 17

[32] District Rule 4550: Conservation Management Practices (adopted 2004); Rule 4565: Biosolids, Animal Manure, and Poultry Litter Operations (adopted 2007); Rule 4566: Organic Material Composting Operations (adopted 2011); and Rule 4570: Confined Animal Facilities (adopted 2006, amended 2010)

Figure 1. NOx and ammonia emission trends in the San Joaquin Valley between 2013 and 2024



Source: CEPAM 2016 v 1.05

The steep downward trend of NOx emissions and the stability of ammonia emissions between 2013 and 2024 along with the time that has passed since 2013, lead CARB staff to conclude that modeling the impact of ammonia emissions reductions in the future, rather than the base year, is appropriate and more representative of the Valley's emissions conditions. EPA guidance states that, in some situations, it may be "more appropriate to model future conditions that provide a more representative sensitivity analysis."[33] This approach is applicable in the Valley. Although emissions of NOx and ammonia are of roughly similar magnitude in the base year, thereby leading to some modeled sensitivity of PM2.5 levels to a 30 percent reduction in ammonia emissions, these conditions do not persist and are not representative in the future.

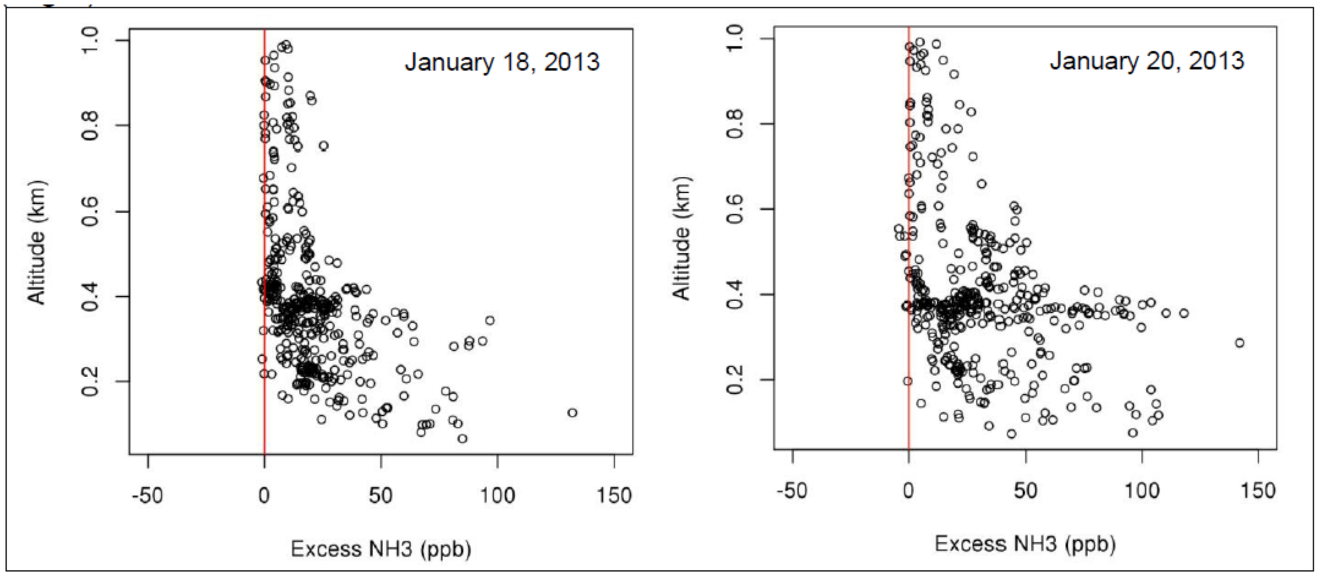
As early as the 1995 Integrated Modeling Study (IMS95), in situ measurements in the San Joaquin Valley indicated the region was ammonia-saturated, which supports NOx being the controlling precursor to ammonium nitrate formation (Kumar et al., 1998; Blanchard et al, 2000). Wintertime measurements five years later during the CRPAQS field study (December 1999 through February 2001) were consistent with the IMS95 findings, where nearly all of the measurements were ammonia-saturated (Lurmann et al., 2006). Lurmann et al. (2006) note that "[t]he consistent excess of NH3 over nitric acid levels indisputably

[33] EPA. PM2.5 Precursor Demonstration Guidance: Draft for Public Review and Comment. Page 33

shows that secondary ammonium nitrate formation is more limited by nitric acid availability than NH3 within the SJV and in the foothills."[34]

More recent measurements during the DISCOVER-AQ field campaign in January and February 2013 (Parworth et al., 2017; and Figure 2), support previous findings of an ammonia-saturated environment, where a small to moderate reduction in ammonia emissions is likely to have little to no effect on ammonium nitrate concentrations.

Figure 2. Excess ammonia (NH3) in the San Joaquin Valley on Jan 18 (Left) and Jan 20 (Right) based on NASA aircraft measurements in 2013



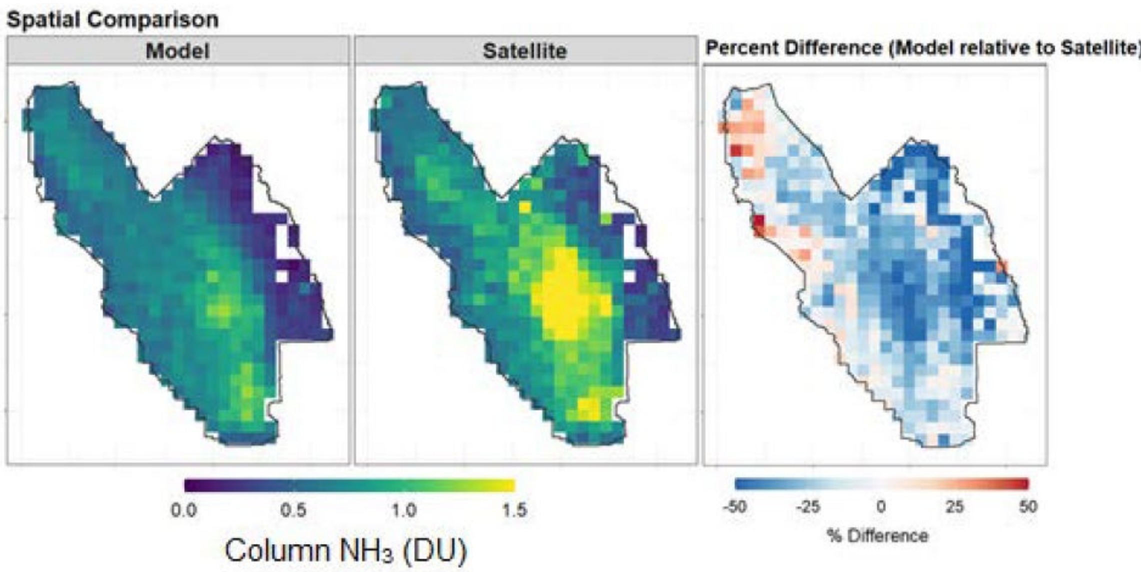
Since ammonium nitrate formation is limited by NOx, reducing NOx emissions is the more effective strategy for reducing ammonium nitrate and PM2.5. Other research has found that ammonia concentrations in the San Joaquin Valley have increased, further confirming that NOx reductions are the most effective path to reducing PM2.5.

A 2017 study using satellite data also aligns with this previous research. Measurements of column-integrated ammonia taken from the Infrared Atmospheric Sounding Interferometer (IASI), an instrument housed aboard the European Space Agency's MetOP-A satellite which passes over California daily, suggest that CARB's emissions inventory currently underestimates ammonia emissions in the Valley. These results suggest the 2018 PM2.5 Plan modeled sensitivity to ammonia reductions is overstated and further reinforces the efforts to develop and deploy ammonia controls would not move the Valley forward on the path to reducing PM2.5 concentrations, and that NOx emissions reductions are the most effective strategy to reduce ammonium nitrate.

[34] Lurmann et al. "Processes influencing secondary aerosol formation in the San Joaquin Valley during winter." Journal of the Air & Waste Management Association. 2006. Web. 3 Oct. 2017. Page 1688

Figure 3 shows the annual average of column ammonia in 2017 from IASI (Satellite) and Community Multiscale Air Quality (CMAQ) (Model). The model is biased low for column ammonia in the Valley. This bias is most noticeable in Tulare County, where both the model and satellite show an ammonia hotspot, but the model shows about half as much ammonia as the satellite.

Figure 3. Maps of annual average ammonia from CMAQ (Model; left), IASI (Satellite; middle), and the percentage difference (DU, 1 DU = 2.69e16 molecules/cm2)



With these new findings from the 2017 study aligning with previous findings from IMS95, CRPAQS, and DISCOVER-AQ, CARB staff's conclusion based on the scientific analysis available continues to be that focusing on NOx emission reductions is key to improving the health of Valley residents and actions to reduce ammonia will not provide significant PM2.5 air quality improvements.

Future Year Modeling

Analysis of NOx and ammonia emissions trends, discussed above, indicated that modeling the impact of ammonia emissions reductions in the future, rather than the base year, is appropriate and more representative of the Valley's emissions conditions. In accordance with EPA guidance, CARB staff repeated the sensitivity-based analysis of ammonia for the future year of 2024.[35] Staff used an air quality model to estimate the PM2.5 design value for the annual standard in 2024 at each Valley monitor. Then, CARB staff applied a 30 percent

[35] The attainment year for the 15 µg/m3 annual standard, as presented in the 15 µg/m3 SIP Revision, is 2023. Since 2023 is only one year before 2024, precursor sensitivities in 2023 are assumed to be very similar to those modeled in 2024. Thus, CARB's determination in the 2018 PM2.5 Plan—that emissions of ammonia do not contribute significantly to PM2.5 levels that exceed the standards in the area—remains the same in relation to the 15 µg/m3 SIP Revision, and CARB continued to exclude ammonia from control requirements in the SIP.

reduction to ammonia emissions and used the air quality model to estimate the PM2.5 design values in 2024. The difference between the two design values represents the modeled impact on PM2.5 levels of a 30 percent reduction in ammonia emissions in each attainment year. For completeness, CARB staff repeated this analysis, applying instead the EPA-recommended upper bound of a 70 percent reduction to ammonia emissions in 2024. The results are shown in Table 4.

Table 4. Future Year 2024 PM2.5, 30 and 70 Percent Reduction in Ammonia Emissions

Site	2024 Baseline DV	2024 DV with 30% Ammonia Reduction	Difference	2024 DV with 70% Ammonia Reduction	Difference
Bakersfield-Planz	12.03	11.79	0.12	11.55	0.36
Madera	11.98	11.77	0.21	11.32	0.66
Hanford	10.52	10.26	0.26	9.77	0.75
Visalia	11.09	10.97	0.12	10.71	0.38
Clovis	11.37	11.27	0.10	11.05	0.32
Bakersfield-California	11.01	10.78	0.12	10.54	0.36
Fresno-Garland	10.43	10.33	0.10	10.22	0.32
Turlock	11.14	10.95	0.16	10.53	0.61
Fresno-HW	10.02	9.92	0.10	9.68	0.34
Stockton	10.66	10.50	0.16	10.14	0.52
Merced-S Coffee	9.65	9.47	0.18	9.12	0.53
Modesto	9.97	9.79	0.18	9.41	0.56
Merced-M	8.61	8.53	0.08	8.35	0.26
Manteca	7.97	7.85	0.12	7.57	0.40
Tranquility	5.54	5.42	0.12	5.19	0.35

In 2024, the modeled air quality impact of reducing ammonia emissions by 30 percent falls under EPA's adjusted annual threshold of 0.25 µg/m3 for the 15 µg/m3 annual standard at all but one Valley monitor. The estimated air quality impact of reducing ammonia emissions by the upper bound of 70 percent in 2024 exceeds EPA's recommended thresholds for the annual standard at all sites. It is important to note that while EPA recommends a 30 percent analysis, achieving a 30 percent reduction in ammonia is not feasible.

Relevant Monitors

The impact of ammonia on PM2.5 at monitors that form the basis of the attainment finding for the Valley is the focus of this analysis. For purposes of demonstrating attainment of the PM2.5 standards, the design sites are Bakersfield and Fresno. EPA guidance permits consideration of "the severity of nonattainment at relevant monitors,"[36] and in 2024, PM2.5 levels are not sensitive to ammonia reductions at these design sites.

The Hanford site shows an impact that is 0.01 µg/m3 over the adjusted 0.25 µg/m3 threshold for the 15 µg/m3 annual PM2.5 standard. Based on CARB staff analysis, for Hanford, while the impact is over EPA's recommended significance level, achieving the level of controls needed for a 30 percent reduction of ammonia is not feasible, as discussed below.

Analysis of Available Emissions Controls

Another factor that may be considered as additional information is available emissions controls on ammonia. The availability of ammonia emissions controls is relevant to the decision-making process, influencing the extent of reasonable modeled reductions. While EPA recommends modeling emissions reductions of between 30 and 70 percent to estimate PM2.5 impacts, CARB staff, District staff, and the public process have not identified specific controls that are technologically and economically feasible to achieve reductions at the low end of the recommended sensitivity range (i.e., 30 percent), much less at the upper end of the range.

For this supplemental document, at EPA staff's request, CARB and the District have expanded on earlier analyses, assessing potential controls on ammonia sources identified by EPA to analyze the appropriateness of the 30 percent reduction threshold for the precursor analysis.

It is important to note that not all control measure concepts are appropriate to be submitted into the SIP as rules. Any rules that are submitted into the SIP must meet EPA requirements, and should:

- Include enforceable emission limitations and other control measures, means, or techniques, as well as schedules and timetables for compliance, as may be necessary to meet the requirements of the Clean Air Act [Act section 110(a)(2)(A)];
- Provide necessary assurances that the State will have adequate personnel, funding, and authority under State law to carry out such SIP (and is not prohibited by any provision of federal or state law from carrying out such SIP) [Act section 110(a)(2)(E)];

[36] EPA. PM2.5 Precursor Demonstration Guidance: Draft for Public Review and Comment. Page 17

- Be adopted by a State after reasonable notice and public hearing [Act section 110(l)]; and
- Not interfere with any applicable requirement concerning attainment and reasonable further progress, or any other applicable requirement of the Act [Act section 110(l)].

The supplemental evaluation of potential controls on ammonia sources identified by EPA is found in Section 3 below.

3. Evaluation of Potential Controls on Ammonia Emissions Sources

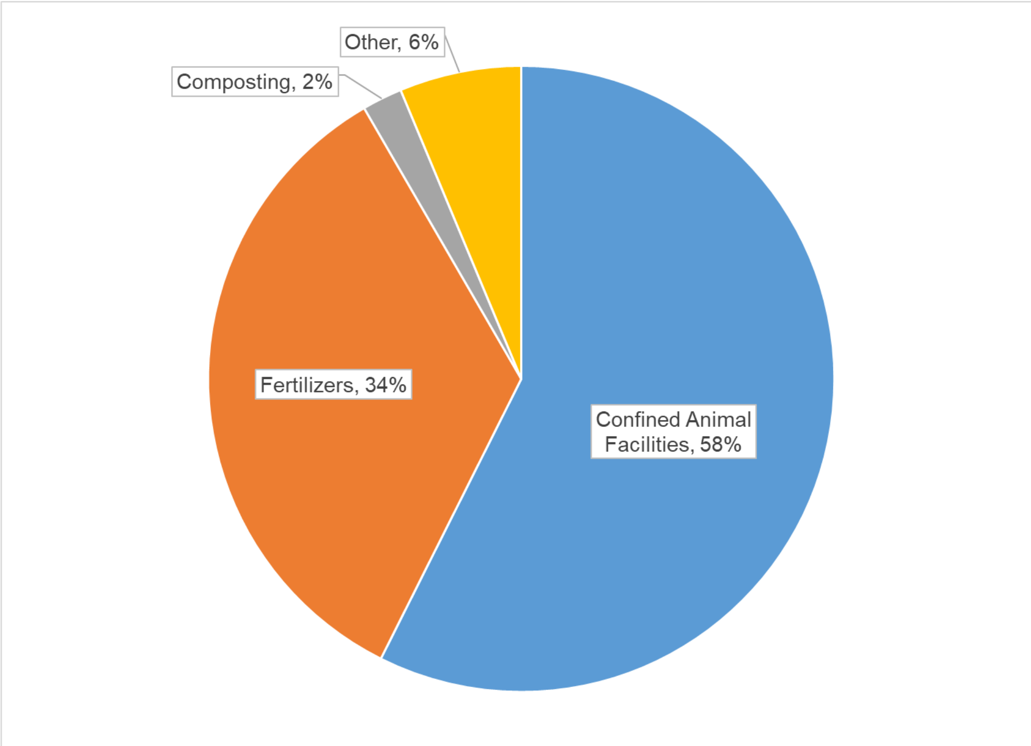
The District and CARB analyzed potential control measures to reduce ammonia emissions in order to evaluate whether a 30 percent reduction in emissions is feasible. For an effective control measure evaluation, it is necessary to characterize and understand the key sources of ammonia in the Valley.

The three main sources of ammonia emissions in the Valley from stationary and area sources, which account for 94 percent of the Valley's ammonia emissions[37], are the focus of the evaluation. Although the base year inventory for the *2018 PM2.5 Plan* is 2013, and previous ammonia technical submittals to EPA have focused on that year, the data and figures below reflect the projected ammonia inventory for 2023. The increased level of control due to the implementation of San Joaquin Valley Air Pollution Control District (District) rules and regulations is already incorporated into the projected emission inventory.

- Confined Animal Facilities (CAFs) with 186.5 tons per day (tpd);
- Agricultural Fertilizers at 111.2 tpd; and
- Composting Solid Waste Operations at 6.7 tpd.

[37] Based on CEPAM 2016 Ozone SIP v1.05 Annual Average Emissions Inventory for 2023

Figure 4: Sources of Ammonia in the San Joaquin Valley[38]



Since the primary source of ammonia emissions in the Valley are from CAFs, the District will focus its evaluation on the different types of animal operations, specifically dairies, which account for the majority of ammonia emissions.

The total ammonia emissions in the Valley in 2023 are 324.9 tons per day. As shown in Table 5 below, to reduce the total ammonia emissions by 30 percent, 50 percent, and 70 percent, emissions from CAFs would need to be further reduced by 52 percent, 87 percent, and 122 percent respectively. As shown in the evaluation below, the District has only identified a few measures that have the theoretical potential to reduce additional ammonia emissions, which may achieve a total of up to 2 percent reduction in emissions notwithstanding technological and economic feasibility considerations. These reductions are not capable of achieving the lower bound level of 30 percent reductions, and the 50 percent and 70 percent reduction levels are infeasible.

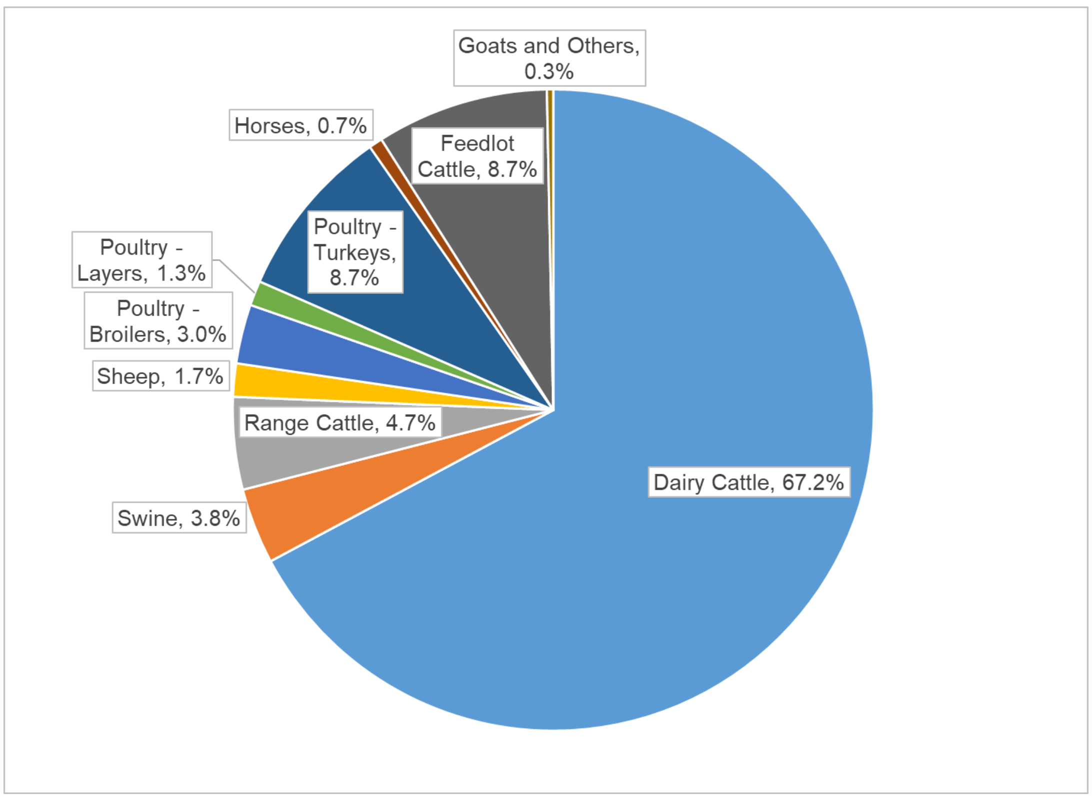
[38] Ibid. 36

Table 5: CAF Emission Reduction Analysis

	30% Reduction	50% Reduction	70% Reduction
Theoretical Ammonia Reductions (tpd)	97.5	162.4	227.4
% reduction required from CAFs	52%	87%	122%

As shown below in Figure 5, dairy cattle emissions account for 67.2 percent of ammonia emissions from CAFs.

Figure 5: Ammonia from CAFs in the San Joaquin Valley[39]



The total ammonia emissions in the Valley in 2023 are 324.9 tons per day. As shown in Table 6 below, to reduce the total ammonia emissions by 30 percent, 50 percent, and 70 percent, emissions from dairy cattle would need to be reduced by 78 percent, 130 percent, and 181 percent, respectively.

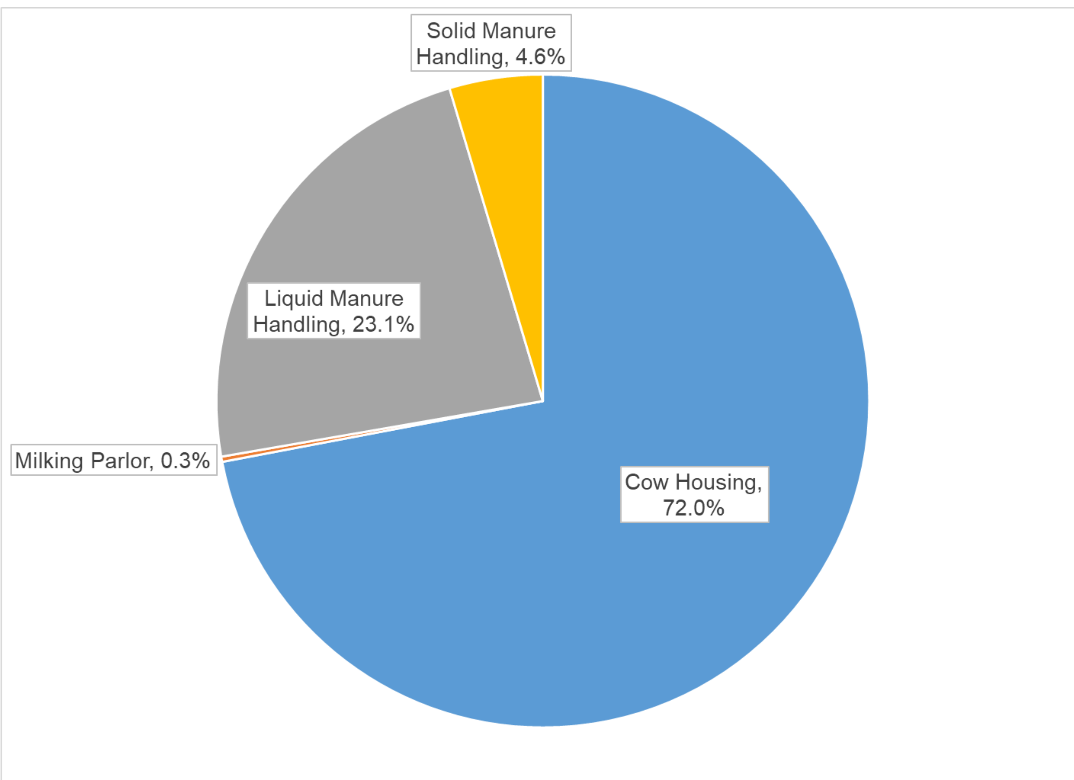
[39] Ibid. 36

Table 6: Dairy Cattle Emission Reductions Analysis

	30% Reduction	50% Reduction	70% Reduction
Theoretical Ammonia Reductions (tpd)	97.5	162.4	227.4
% reduction required of dairy cattle	78%	130%	181%

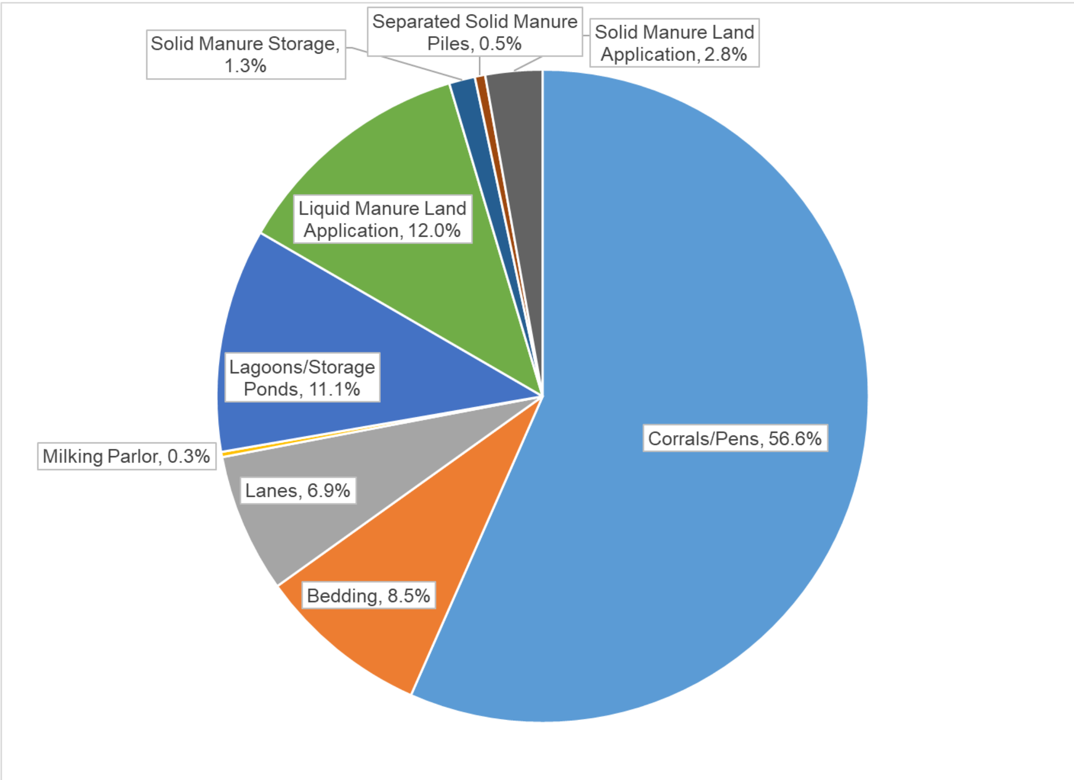
As shown in Figure 6, the primary source of ammonia emissions from dairy cattle is cow housing (72 percent). Figure 7 further evaluates ammonia emissions from dairy cattle by illustrating the different categories such as corrals/pens (56.6 percent), liquid manure land application (12 percent), and lagoons/storage ponds (11.1 percent), etc. Accordingly, the District has provided an evaluation of mitigation measures for dairy cattle focusing on housing, land application techniques, and solid and liquid manure handling.

Figure 6: Ammonia from Dairy Cattle in the San Joaquin Valley[40]



[40] Based on District ammonia emission factors for dairy cattle.

Figure 7: Ammonia from Dairy Cattle in the San Joaquin Valley (cont.)[41]



Based on the emission inventory analysis above, reducing ammonia emissions by the lower bound precursor demonstration threshold of 30 percent would require eliminating over 50 percent of ammonia emissions from CAFs, or nearly 80 percent of emissions from only dairy cattle, beyond the ammonia emission reductions already achieved by the requirements of District Rule 4570 (Confined Animal Facilities). A 70 percent reduction of ammonia emissions in the District would require the elimination of all CAFs in the District in addition to other categories that have already achieved significant ammonia reductions.

Inventory of Confined Animal Facilities in the Valley

The District reviewed current permitted facilities in the Valley. Demonstrated below in Table 7 is the count of permitted facilities by type that are subject to Rule 4570, and the controlled ammonia emissions from each type of facility.

[41] Ibid.

Table 7: Inventory of Confined Animal Facilities in the Valley

Facility Type	# of Facilities Subject to Rule 4570[42]	Ammonia Emissions from Facility Type (tpd)[43]
Dairies	865	125.3
Beef Feedlots	8	16.2
Other Cattle	77	8.7
Chicken – Broilers	47	5.6
Chicken – Layers	12	2.3
Turkeys	21	16.3
Swine	1	7.1

District Rule 4570 (Confined Animal Facilities)

Background

The largest source of ammonia in the Valley is CAFs. The District has implemented Rule 4570 to reduce emissions from this source category, and requires the most stringent requirements for reducing emissions from CAFs in the nation. Rule 4570 was originally adopted on June 15, 2006, and was again amended on October 21, 2010. District Rule 4570 applies to facilities where animals are corralled, penned, or otherwise caused to remain in restricted areas and primarily fed by a means other than grazing for at least 45 days in any twelve-month period. In addition to limiting volatile organic compound (VOC) emissions, District Rule 4570 includes measures that limit ammonia emissions from these operations.

Evaluation of District Rule 4570

District Rule 4570 includes multiple mitigation measures that control ammonia emissions from CAFs. Since these facilities generally cover a large area and have different processes, a single mitigation measure or technology is generally not sufficient to control overall emissions from the facility. Due to the varying types of operations and emissions sources at

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[42] Review of District permits database (January 2023)
[43] Ibid. 36

these facilities, each CAF requires a site-specific constellation of measures to achieve overall emission reductions.

District Rule 4570 includes a large number of measures that must be implemented by each CAF and also requires additional measures to be selected from a menu of mitigation measures options to achieve additional emission reductions. The menu approach gives the facilities the flexibility to achieve the required emission reductions by selecting mitigation measures that are most practical and effective for their operation. As discussed in the staff report for the 2010 amendments to District Rule 4570,[44] the design and operation of each CAF differs depending on animal type, regional climatic conditions, business practices, and the preferences of the owners/operators. Because of this, no two CAFs are identical. In addition to air quality regulations, CAFs are subject to other regulations to protect water quality and the environment. These additional regulations often restrict how CAFs can operate.

It is not feasible for all CAFs to implement the same measures due to various factors, such as infrastructure, conditional use permits, water quality regulations, production contracts, and other limitations. The options included in District Rule 4570 provide the owners and operators of CAFs much-needed flexibility to choose the mitigation measures that make the best environmental and economic sense for their facility, while maximizing the amount of emission reductions. The required measures have reduced ammonia emissions by over 100 tpd.[45]

Other Air District Rules

The District provided an in-depth review of Rule 4570 in Appendix C of the *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards* (*2018 PM2.5 Plan*), [46] including a comprehensive analysis of Rule 4570, in which the District compared emissions limits, optional control requirements, and work practices in Rule 4570 to comparable requirements in rules from the following areas:

- South Coast Air Quality Management District (SCAQMD) Rule 223 (Emission Reduction Permits for Large Confined Animal Facilities)
- SCAQMD Rule 1127 (Emission Reductions from Livestock Waste)

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[44] SJVAPCD. *Staff Report for 2010 Amendments Rule 4570 (Confined Animal Facilities).* Available at: *http://valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2010/October/Agenda_Item_7_Oct_21_2010.pdf*

[45] Appendix F of the Staff Report for the June 2009 re-adoption of Rule 4570, starting on the 329th page of the pdf available here: *https://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2009/June/Agenda%20Item_10_June_18_2009.pdf*

[46] SJVAPCD. *2018 Plan for the 1997, 2006, and 2012 PM2.5 Standards.* Appendix C, pages C-311 – C-339. Available at: *https://www.valleyair.org/pmplans/documents/2018/pm-plan-adopted/2018-Plan-for-the-1997-2006-and-2012-PM2.5-Standards.pdf*

- Bay Area Air Quality Management District (BAAQMD) Regulation 2, Rule 10 (Large Confined Animal Facilities)
- Ventura County Air Pollution Control District (VCAPCD) Rule 23 (Exemptions from Permit)
- Sacramento Metropolitan Air Quality Management District (SMAQMD) Rule 496 (Large Confined Animal Facilities)
- Imperial County Air Pollution Control District (ICAPCD) Rule 217 (Large Confined Animal Facilities Permits Required) and Policy Number 38 (Recommended Mitigation Measures for Large Confined Animal Facilities)
- Idaho Administrative Procedure Act 58.01.01 Sections 760-764 (Rules for the Control of Ammonia from Dairy Farms)

In addition to these rules, the District's *2016 Plan for the 2008 8-hour Ozone Standard* (*2016 Ozone Plan*)[47] included a comparison of District Rule 4570 to requirements from the following:

- Butte County Air Pollution Control District (BCAQMD) Rule 450 (Large Confined Animal Facilities)
- Yakima Regional Clean Air Agency (Air Quality Management Policy and Best Management Practices for Dairy Operations)

Through the rule comparisons included in the *2018 PM2.5 Plan* and the *2016 Ozone Plan*, the District demonstrated that Rule 4570 was more stringent than the above rules in other areas, at the time of each plan's adoption. The areas mentioned above have not changed or amended their respective rules since the District's previous evaluations, except for the Yakima Regional Clean Air Agency, which rescinded their policy for dairies in 2018. The District has found no new requirements in other areas, but has reevaluated the rules above and found that Rule 4570 continues to implement the most stringent requirements for CAFs.

Federal Actions and Guidance

The evaluation of appropriate practices and measures to reduce emissions from confined animal facilities requires accurate methodologies to estimate emissions. The National Academy of Sciences identified the lack of methodologies to estimate emissions from animal feeding operations (AFOs) in 2002. In response, EPA announced an opportunity for AFOs to sign a voluntary consent agreement and final order known as the Air Compliance Agreement (2005).[48] The goal of the agreement was to develop scientifically credible methodologies for estimating emission models produced by AFOs. AFOs that chose to participate in the agreement provided the funding for the National Air Emissions Monitoring Study (NAEMS). As part of the agreement, EPA agreed not to sue participating AFOs for certain violations of

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[47] SJVAPCD. *2016 Plan for the 2008 8-hour Ozone Standard*. Available at: *http://valleyair.org/Air_Quality_Plans/Ozone-Plan-2016/Adopted-Plan.pdf*

[48] See 70 FR 4958. (January 31, 2005). Retrieved from: *https://www.epa.gov/sites/default/files/2016-06/documents/afolagooneemreport2012draftappe.pdf*

the Clean Air Act (CAA), Compensation, and Liability Act (CERCLA), and Emergency Planning and Community Right-to-Know Act (EPCRA), provided that the AFOs comply with the agreement's conditions.

The NAEMS monitored 25 AFOs in various regions of the country to have equipment installed for ammonia, hydrogen sulfide, particulate matter, and VOC emissions monitoring. Separate draft models of swine, poultry, and dairy AFOs emissions were created using the monitoring data and input from the EPA Science Advisory Board.[49]

While data collection took place from 2007 to 2010, these draft models only became publicly available in August 2020, August 2021, and June 2022 for swine, poultry, and dairy AFOs respectively. EPA's final models to estimate emissions from AFOs are not yet available. Currently, EPA projects that finalization of all draft models will occur in late 2023.[50] Though EPA has not provided final guidance on emission estimation methodologies for CAFs, the District has reviewed information from EPA and many other sources in order to use the best information available to calculate emissions from CAFs.

District Efforts

The District first began permitting agricultural sources in 2004, and since that time District staff members have gained a great deal of experience in the evaluation of emissions from agricultural sources through collaborative efforts with other institutions, agencies, and interested stakeholders. The District has also been thoroughly involved in collaborative scientific research efforts to evaluate emissions from agricultural sources. This is particularly true of the agricultural emissions research efforts in California. The District has played an important role in coordination of these efforts through the San Joaquin Valleywide Air Pollution Study Agency (Study Agency) and the Study Agency's Agricultural Air Quality Research Committee (AgTech). The District has also been at the forefront of developing and implementing regulations to reduce emissions from CAFs.

The District will continue to track the development of rules, regulations, research/studies, and practices for CAFs to ensure the best available control measures and most stringent measures are in place in the Valley, in coordination with industry stakeholders, researchers, CARB, and other agencies.

Evaluation of Mitigation Measures for Confined Animal Facilities

In the Federal Register posting for the proposed partial approval and partial disapproval of portions of the state implementation plan revisions for the 1997 annual PM2.5 standard,[51]

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[49] Livestock and Poultry Environmental Learning Community. *NAEMS: How It Was Done and Lessons Learned*. April 20, 2022. Retrieved from: *https://lpelc.org/naems/*

[50] EPA. *National Air Emissions Monitoring Study*. Retrieved from: *https://www.epa.gov/afos-air/national-air-emissions-monitoring-study#naems-status*

[51] See 86 FR 38662. (July 22, 2021). Retrieved from: *https://www.govinfo.gov/content/pkg/FR-2021-07-22/pdf/2021-15551.pdf*

EPA indicates that further evaluation of potential control measures for ammonia sources is needed. In EPA's proposed disapproval of portions of the *2018 PM2.5 Plan* for the 2012 annual PM2.5 standard,[52] EPA refers to several studies that were cited in a Public Justice comment letter[53] that evaluate CAF mitigation measures that have the potential to achieve additional ammonia reductions. In the same proposal, EPA noted that the United States Department of Agriculture (USDA) National Resources Conservation Service (NRCS) has collaborated to develop a "Reference Guide for Poultry and Livestock Production Systems" (NRCS Reference Guide) [54] that lists 12 measures that may reduce ammonia emissions by more than 30%. EPA also cited a 2011 inventory of mitigation methods by Price et al. prepared for the UK government (UK User Guide) that identifies several ammonia mitigation methods for UK farms.[55]

Following the proposed disapprovals and several meetings with EPA Region 9 staff, the District was provided with a list of mitigation measures generated by EPA Region 9 staff for evaluation, many of which the District has already evaluated over the years. As discussed earlier, it is also important to note that EPA has been committed to addressing emission from livestock operations under a voluntary "safe harbor" consent agreement put into place by EPA in 2005. While the San Joaquin Valley has regulated emissions from livestock operations since 2005, EPA is still in the process of evaluating emissions and establishing the regulatory framework under this consent agreement, and the District will continue supporting the national effort to address emissions from these operations. This list encompassed publications that evaluated potential ammonia emission reductions for either individual mitigation measures or compilations of mitigation measures. The publications provided to the District included a wide variety of mitigation measures such as reducing crude protein content in feed, litter amendments, injection/incorporation of manure, changing land use from arable to woodland, and reducing human consumption of meat and eggs.

Though some of the suggested measures have related studies that appear to demonstrate potential feasibility, it is imperative to consider the conditions under which the studies were performed and how those conditions compare to the Valley. Several of the studies evaluated were conducted in areas outside of California, and many outside of the nation. Notably, CAFs in the Valley face unique challenges, including hot, dry summers, drought conditions,

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[52] See 87 FR 60494. (October 5, 2022). Retrieved from: *https://www.govinfo.gov/content/pkg/FR-2022-10-05/pdf/2022-21492.pdf*

[53] Public Justice, et al. (January 28, 2022). Group Comment Letter *Re: Clean Air Plans; 2012 Fine Particulate Matter Serious Nonattainment Area Requirements; San Joaquin Valley, California*; EPA-R09-OAR-2021-0884. Retrieved from: *https://www.regulations.gov/comment/EPA-R09-OAR-2021-0884-0136*

[54] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[55] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*

and strict water regulations, which may not have been considered in some of the publications and studies that evaluated these methods. Valley dairies in particular are typically much larger than dairies in other areas. Based on information from the USDA National Agricultural Statistics Service, the average dairy in the Valley has almost 1,600 cows compared to a national average of less than 300 cows per dairy outside of California.[56, 57] The UK User Guide, which contains many of the measures evaluated in this document, indicated that the average UK dairy has 170 cows. The differences in climate, typical management practices, size of operations, and regulatory environment affect the types of mitigation measures that can be applied to each operation.

Many of the mitigation measures for consideration by EPA were not applicable to the Valley, were unreasonable or unenforceable, or were based on limited research (e.g. research conducted in other countries with drastically different operating and natural characteristics). The complete list of potential mitigation measures provided by EPA Region 9 staff can be found in Appendix A. The District's evaluation of all potential mitigation measures provided by EPA is included in the following sections.

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[56] Hanson, M. (2021) U.S. Dairy Herd Hits 27-year High. *Dairy Herd Management*. Retrieved from: *https://www.dairyherd.com/news/dairy-production/us-dairy-herd-hits-27-year-high*
[57] Latest USDA Statistics for average size of dairies excluding California, retrieved from: *https://downloads.usda.library.cornell.edu/usda-esmis/files/h989r321c/7d279w693/f7624g40c/mkpr0222.pdf* (about 270 cows per dairy outside California)

Nutrition and Feed Management (Feeding)

Table 8: Nutrition and Feed Management Measures Evaluated

Method	Measure	CAF Type	Reference
Reducing Crude Protein (Beef)	Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure	Beef	Preece[58]
	Reducing Crude Protein in Beef Cattle Diet Reduces Ammonia Emissions from Artificial Feedyard Surfaces	Beef	Todd[59]
	Reduce Dietary Crude Protein in Beef Cattle	Beef	Cole (2005)[60]
Reducing Crude Protein (Dairy)	Reducing Dietary Protein Decreased the Ammonia Emitting Potential of Manure from Commercial Dairy Farms	Dairy	Hristov[61]
Reducing Crude Protein (Swine)	Reduce Crude Protein Content from Finishing Pig Houses	Swine	Hayes[62]

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[58] Preece, Sharon L.M. et al., ''Ammonia Emissions from Cattle Feeding Operations,'' Texas A&M AgriLife Extension Service, referring to Cole, N.A., R.N. Clark, R.W. Todd, C.R. Richardson, A. Gueye, L.W. Greene, and K. McBride, ''Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure,'' Journal of Animal Science 83:(3), 722 (2005)

[59] Todd, R.W., N.A. Cole, and R.N. Clark, ''Reducing Crude Protein in Beef Cattle Diet Reduces Ammonia Emissions from Artificial Feedyard Surfaces.'' Journal of Environmental Quality. 35:(2), 404–411 (2006).

[60] Cole, N., et al., Influence of dietary crude protein concentration and source on potential ammonia emissions from beef cattle manure. J. Anim. Sci. 83, 722 (2005).

[61] Hristov, A. N., Heyler, K., Schurman, E., Griswold, K., Topper, P., Hile, M., ... & Dinh, S. (2015). CASE STUDY: Reducing dietary protein decreased the ammonia emitting potential of manure from commercial dairy farms. The Professional Animal Scientist, 31(1), 68-79

[62] Hayes ET, Leek AB, Curran TP, et al. The influence of diet crude protein level on odour and ammonia emissions from finishing pig houses. Bioresource Technology, 2004

Method	Measure	CAF Type	Reference
Feed Timing	Phase, Group, and Split Sex-Feeding	Beef	Cole (2006)[63]
	Group and Phase Feeding	All	NRCS[64]
	Phase Feeding	All	Guthrie[65]
Wet Distillers Grain	Reduce Feeding of Wet Distillers Grain	Beef	Todd[66]
Grazing	Increase Grazing Time for Dairy Cattle	Dairy	Guthrie
Feed Additives	Feed Additives for Poultry	Poultry	NRCS

Reducing Crude Protein Content for Beef Cattle - ***(applies to beef cattle only)***

EPA noted that studies in 2005 and 2006 found that "*decreasing the crude protein concentration of beef cattle finishing diets based upon steam-flaked corn from 13 to 11.5 percent decreased ammonia emissions by 30 to 44 percent.*"

In the 2005 study, steers were randomly assigned to one of nine dietary treatments (three formulated dietary crude protein (CP) concentrations and three supplemental urea:cottonseed meal ratios). Steers were confined to tie stalls, and feces and urine excreted were collected and frozen after approximately 30, 75, and 120 days on feed. As protein concentration in diet increased from 11.5 to 13 percent, in vitro daily ammonia emissions

[63] Cole NA, Defoor PJ, Galyean ML, Duff GC, Gleghorn JF. "Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers", Journal of Animal Science, 2006

[64] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[65] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[66] Todd, R.W., N.A. Cole, D.B. Parker, M. Rhoades, and K. Casey. 2009. "Effect of Feeding Distillers Grains on Dietary Crude Protein and Ammonia Emissions from Beef Cattle Feedyards." In Proceedings of the Texas Animal Manure Management Issues Conference, 83–90.

increased 60 to 200 percent, due primarily to increased urinary nitrogen excretion. As days on feed increased, in vitro ammonia emissions also increased.

This study had a small sample size with 54 cattle used for nine dietary treatments (six cattle per treatment). These results are only applicable to the finishing cycle of beef cattle lives (four to six months of age), and not applicable to milk cows and support stock at dairies. There are very few finishing cycle feeder beef cattle in the Valley. Most beef cattle in California are beef calves and stockers, fed through grazing. Most of these cattle are sent outside of California for the finishing cycle.[67, 68]

Notably, beef finishing cattle make up a small part of the overall inventory of cattle in the Valley. The current feedlot cattle inventory includes all feedlot cattle; however, the lives of beef cattle are divided into different phases of production. Cow and calf pairs are raised on rangeland. Weaned yearlings/stockers may continue to be raised on rangeland or be sent to yearling/stocker feedlots until a weight of approximately 800 to 900 pounds. Finally, beef cattle are sent to other feedlots out of California for the finishing phase, in which the cattle are fed for four to six months until they reach the desired finished weight. Because of the higher cost of feeding cattle in California and the lack of sufficient beef processing capacity, most of feedlot cattle in California are yearlings/stockers for which this measure does not apply.[69]

If dietary protein concentrations are decreased to the point that animal performance is adversely affected, then total ammonia emissions could be increased because animals require more days on feed to reach market weight and condition. There was also little change in ammonia between the 13 percent and 14.5 percent CP groups.

In the 2006 study, two groups of steers were fed diets with either 11.5 or 13 percent CP and all urine and feces were collected. Manure from steers fed 11.5 percent CP diet had less urine, less urinary nitrogen, and a lesser fraction of total nitrogen in urine, compared with the 13 percent crude protein diet. Decreasing CP in beef cattle diets from 13 to 11.5 percent significantly decreased ammonia emission by 44 percent in closed chamber experiment, and decreased mean daily ammonia flux by 29 percent, 30 percent, and 52 percent in spring, summer, and autumn field trials, respectively. No difference was observed in winter.

Additionally, National Research Council (NRC) Nutrient Requirements of Beef Cattle states that decreasing the CP concentration in the diet can potentially reduce animal performance, prolonging the time necessary to reach market weight and potentially increasing ammonia

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[67] Andersen, M.A., Blank, S.C., LaMendola, T, Sexton, R.J., "California's Cattle and Beef Industry at the Crossroads", California Agriculture 56(5),152-156. Retrieved from: *https://doi.org/10.3733/ca.v056n05p152*
[68] Saitone, T.L., "Livestock and Rangeland in California", Livestock and Rangeland in California. Retrieved from: *https://s.giannini.ucop.edu/uploads/giannini_public/94/c1/94c100fd-9626-47d4-8b82-0bfdb1081a57/livestock_and_rangeland.pdf*
[69] Forero, L., Barry, S., Larson, S. (2021). Beef Cattle on California Annual Grasslands: Production Cycle and Economics. *University of California Agriculture and Natural Resources*. Retrieved from: *https://anrcatalog.ucanr.edu/pdf/8687.pdf*

emissions over the life of the cattle. Because adequate protein levels are required for optimal growth, decreasing CP levels hinder the ability to meet daily weight gain goals.

The overall effectiveness of this measure is unclear because of the small sample size and short period of the study. NRC Nutrient Requirements of Beef cattle states that decreasing the CP concentration in the diet can potentially reduce animal performance. Higher CP levels may be needed to meet daily weight gain goals.

If decreasing the CP content of the diet adversely affects performance, any short-term ammonia reductions can be negated by the longer time on feed required for animals to reach their target market weight and condition.[70] While there may be ammonia reductions in the short term, longer time on feed will result in additional ammonia emissions for the additional amount of time it takes for the animals to reach the appropriate weight. Thus, overall emissions may ultimately be the same, or possibly even increase. Due to the limited pool of data and only studying emissions for 21 days, more research is needed to show a full-cycle of emissions and full impact to the animals.

Despite the uncertainties discussed above, the District further evaluated the potential emission reductions of implementing this measure in the Valley. This analysis is provided below.

The feedlot cattle inventory in the Valley includes calves, beef stockers, yearlings, and finishing cattle. This measure is only applicable to beef finishing cattle. It will be conservatively assumed that 50 percent of the feedlot cattle in the Valley are beef finishing cattle. The ammonia emissions from young beef cattle compared to beef finishing cattle will be assumed to be proportional to their nitrogen excretion. Based on information from the American Society of Agricultural and Biological Engineers (ASABE),[71] it is estimated that the average daily nitrogen excretion for beef finishing cattle is 25.7 percent higher than young beef cattle. Therefore, the overall control efficiency for this measure can be estimated as follows:

$$30\% \times 50\% \times 1.257 = 18.9\%$$

No costs for implementation of this measure in the United States could be located. Notably, feed costs are a significant part of the overall costs of raising livestock, often representing as much as 60-70 percent of production costs,[72] and protein is often the most expensive

[70] Cole NA, Defoor PJ, Galyean ML, Duff GC, Gleghorn JF. "Effects of phase-feeding of crude protein on performance, carcass characteristics, serum urea nitrogen concentrations, and manure nitrogen of finishing beef steers", Journal of Animal Science, 2006.

[71] American Society of Agricultural and Biological Engineers. (March 2005). ASABE D384.2 Manure Production and Characteristics. Retrieved from: *https://elibrary.asabe.org/abstract.asp?aid=32018*

[72] Strauch, B.A., Stockton, M.C. (Sep 2013). Feed Cost Cow-Q-Lator. NebGuide. University of Nebraska–Lincoln Extension, Institute of Agriculture and Natural Resources (G2214). Retrieved from: *https://extensionpublications.unl.edu/assets/pdf/g2214.pdf*

component in livestock feed.[73] As a result, beef cattle producers will generally avoid overfeeding protein to minimize productions costs. Therefore, the actual emission reductions from this measure may be significantly lower to nothing since most beef cattle producers will already try to minimize feeding excess protein whenever feasible.

The District has concluded that the measure requires further research on both the effect on production and overall costs, and therefore is not a viable mitigation option to include in Rule 4570 at this time. The District will continue to evaluate the feasibility of this option as practices evolve and further research is conducted.

Reducing Crude Protein Content for Dairy Cattle - ***(applies to dairy cattle only)***

In a compilation by Bittman[74] it was recommended that the average CP content of diets for dairy cattle should not exceed 15-16 percent of the dry matter (DM). Phase feeding can be applied in such a way that the CP content of dairy diets is gradually decreased from 16 percent of DM just before calving and in early lactation to below 14 percent in late lactation and the main part of the dry period.

A study[75] measured the effect of reducing the CP content of ammonia emitting potential of dairy manure in a controlled environment. Eleven Pennsylvania dairies with gutter-scrape, gravity-flow, or flush manure-management systems participated in the study. In the study, the CP concentration of the feed for cows that were identified as high-producing cows was decreased from an average of 16.5 to 15.4 percent for the dairies included in the study. Fecal and urine samples were collected from the dairies in the fall of 2009, spring of 2010, fall of 2010, and spring of 2011. The study indicated that laboratory ammonia emissions from reconstituted manure was on average 23 percent lower for the low CP diet versus the high CP diet. No difference was seen in milk yield and milk composition during the low CP and the high CP diet, with average milk yields of 32.2 kg/day and 32.5 kg/day. The researchers that conducted the study concluded that the ammonia emitting potential of dairy manure can be reduced by moderately decreasing dietary CP content.

Although effects of reducing the CP content of the feed for dairy cows may merit further research, there are questions related to the applicability of this study to dairy cattle in the Valley. One important question is if the milk production of the cows in the study is comparable to the milk production of cows in the Valley. The average milk production of the high-producing cows included in the study was only 32.2-32.5 kg/day. In comparison, according to information from USDA National Agricultural Statistics Service, on average, milk

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[73] North Dakota State University (NDSU). (Dec 2019). Comparing Value of Feedstuffs (AS1742). Retrieved from: *https://www.ag.ndsu.edu/publications/livestock/comparing-value-of-feedstuffs*

[74] Bittman, S., Dedina, M., Howard C.M., Oenema, O., Sutton, M.A., (eds). (2014). "Options for Ammonia Mitigation: Guidance from the UNECE Task Force on Reactive Nitrogen," Centre for Ecology and Hydrology, Edinburgh, UK. Retrieved from: *http://www.vuzt.cz/svt/vuzt/publ/P2014/037.pdf*

[75] Hristov, A. N., Heyler, K., Schurman, E., Griswold, K., Topper, P., Hile, M., ... & Dinh, S. (2015). CASE STUDY: Reducing dietary protein decreased the ammonia emitting potential of manure from commercial dairy farms. The Professional Animal Scientist, 31(1), 68-79

cows in California produced approximately 36.2 kg/day of milk in 2021, [76] with high-producing cows in the Valley producing at a rate of 44 to over 50 kg/day of milk per dairy cow.[77] Therefore, although the cows in the study were identified as high-producing cows that were expected to produce greater amounts of milk, the average milk cow in California produces more milk than the cows in this study. Higher levels of milk production require higher levels of protein, so it is likely that reducing the CP content of feed will reduce milk yields of cows that produce milk.

In communications with the District, Dr. Peter Robinson, UC Davis Extension Specialist, Dairy Cattle Nutritional Management Department of Animal Science, stated that the optimal CP level for high-producing dairy cows in the Valley is around 16.8 percent, which is the level that dairy typically feed their high-producing cows. He also states that when CP levels are decreased to levels that are a little lower than required, milk production tends to be negatively impacted immediately. Dr. Robinson's recommended CP content is based on 14 large on-farm studies that he has completed in the Valley from 2005 to the present. [78] Based on the data he provided from these studies, feed with a CP content of approximately 16.9 percent resulted in maximum milk production for high-producing cows in the Valley, which was about 48.5 kg/day of milk, 50 percent more than the milk production of the high-producing cows in this study. Therefore, 50 percent more high-producing cows would be needed to produce the same amount of milk, which would negate the ammonia reductions from this measure. Another potential issue with the study is that manure samples of a specific size were used to compare the ammonia emitting potential of the manure, but it is unclear if the changes in feed composition affected manure production, which could also affect ammonia emissions.

As discussed above, California dairy operators typically feed their high-producing cows a diet that has CP content near the optimum level of 16.8 percent, and decreasing the CP content of the diet can have an adverse effect on milk production in dairy cattle. Thus, CP reductions for dairy cattle must be closely managed to avoid impacting productivity (e.g., milk yield, fat corrected yield, milk protein yield). Additionally, Dr. Robinson stated that most cows need to recoup body weight during later lactation and that lowering the CP percentage in the diet during this period could have very negative impacts on both milk yield and body weight recovery.

Because nutrient concentrations in feed and feed ingredients vary considerably, reducing CP in diets will require additional lab analyses of feed to ensure that animals receive sufficient nutrients, which will result in increased costs. Dairy operators have no incentive to overfeed

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[76] USDA, National Agricultural Statistics Service. Milk Production (February 2022). *https://downloads.usda.library.cornell.edu/usda-esmis/files/h989r321c/7d279w693/f7624g40c/mkpr0222.pdf*

[77] Data from studies of dairy cows in the San Joaquin Valley provided by Dr. Peter Robinson, UC Davis Extension Specialist, Dairy Cattle Nutritional Management Department of Animal Science. *https://animalbiology.ucdavis.edu/people/peter-robinson*

[78] A list of selected scientific publications by Peter Robinson, PhD is available on the UC Davis website at: *https://animalscience.ucdavis.edu/people/faculty/peter-robinson/Articles/Scientific-Publications*

protein since high protein feeds are usually the most expensive ingredients. The percent of CP in the diets fed that California dairy operators feed to dairy cattle has been significantly reduced from previous levels. According to Dr. Robinson, CP in the diets of dairy cows was frequently in excess of 20 percent in the 1980s and 1990s, but that has decreased to the current level of 16.8 percent today. In communication with District staff, Dr. Robert Hagevoort, Extension Dairy Specialist and Topliff Dairy Chair, New Mexico State University, [79] also confirmed similar reductions in the CP content of dairy feed for dairies in the western U.S. compared to previous levels.

In addition, reducing the CP content to the recommended levels is difficult for cattle that graze or are fed a large amount of grass because grass has higher amounts of protein. The NRCS Reference Guide indicates that reduction of CP can also cause deficiency in certain amino acids that can adversely affect animal performance, such as weight gain.

California dairies are expected to continue to try to improve feed efficiency and minimize environmental impacts. However, it is not feasible to require this measure at this time because of questions that remain about the impact on milk production, animal health, and costs on California dairies. Therefore, the District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Reducing Protein Content for Swine - ***(applies to swine only)***

Research indicates that low-protein diets may result in poorer performance in finishing pigs than conventional diets.[80] The NRCS Reference Guide indicates that changes to animal diets generally increase costs because of the time and expense of diet formulation and acquisition of new ingredients, and that the availability of additives and feedstuff fluctuates. Additionally, there are increased costs for low-protein feed due to the need to supplement with amino acids found in protein like crystalline lysine, threonine, tryptophan, methionine and valine. As previously shown, emissions from swine are a small part of the District's ammonia inventory, as there is only one permitted swine facility in the District. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Reduce Feeding of Wet Distillers Grain - ***(applies to beef cattle only)***

In another study, EPA noted that "one feedyard feeding distillers grains averaged 149 grams of ammonia-N per head per day (ammonia–N/head/day) over nine months, compared with 82 g ammonia–N/head/day at another feedyard feeding lower protein steamflaked, corn-based diets." Nominally, this would represent a 45 percent reduction in ammonia emissions from manure by going to a lower protein diet. However, the net ammonia emission reduction either from reducing crude protein levels in feed, or by providing a lower protein steam-flaked, corn-based diet rather than a distiller grain diet is unclear given the role of protein

[79] *https://dairy.nmsu.edu/faculty-staff/robert-hagevoort.html* (accessed March 15, 2023)

[80] Hayes ET, Leek AB, Curran TP, et al. The Influence of Diet Crude Protein Level on Odour and Ammonia Emissions from Finishing Pig Houses. Bioresource Technology, 2004

intake on the time for beef cattle to reach market weight or on milk production for dairy cows.[81]

This study involved two years of near-continuous ammonia emission data collections at two feedyards. Cattle were fed either conventional feed or wet distillers grains (WDG). Ammonia emissions were 36 percent higher for cattle that were fed WDG.

This study is only applicable to WDG, a feed byproduct of ethanol production. The study notes that WDG typically contains 20 percent or more of protein. That is higher than the ideal diet protein content of 11.5-13.5 percent for beef cattle. This feed is not common in California, because WDG is sold primarily to dairies or cattle feedlots within the immediate vicinity of an ethanol plant, and California only grows 0.07 percent of the nation's corn[82], and produces 0.8 percent[83] of the nation's ethanol. Since dairies in the Valley do not feed WDG, and there is almost no means for WDG feed to be acquired by Valley dairies, this measure is already being implemented and no further emission reductions can be achieved.

Phase, Group, and Split Sex-Feeding - *(applies to all CAFs)*

The NRCS Reference Guide and a compilation by Guthrie, Giles, etc.[84] focus on mitigation measures for feed management including group and phase feeding, dietary formulation changes, and feed additives. Controlling the protein content of feed is a key element to lowering nitrogen content of manure. Protein naturally contains nitrogen compounds that are often broken down into simple compounds such as ammonia. Group and phase feeding allows the animal to receive the proper nutrition intake by separating animals by age or sex. This allows for a specific diet tailored to each group in order to reduce manure excretion and nitrogen content. Split sex feeding programs are already included as a mitigation option in District Rule 4570 for swine facilities.

The Reference Guide states that dietary formulation changes involve changes in feed ingredients or ration formulations to provide essential available nutrients to meet animal requirements while minimizing excess amounts of nutrients.

Because feed is one of the most significant costs for confined animal facilities, producers work with nutritionists to design diets to maximize feed efficiency and minimize excess nutrients to reduce overall costs. Confined animal facilities work to continually improve feed formulations to deliver nutrients in the amounts required to meet production goals. Overfeeding is undesirable because it will increase costs and farming operations have overall small margins of profit. Operations that overfeed would not be able to compete and would

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[81] Todd, R.W., N.A. Cole, D.B. Parker, M. Rhoades, and K. Casey. (2009). "Effect of Feeding Distillers Grains on Dietary Crude Protein and Ammonia Emissions from Beef Cattle Feedyards." In Proceedings of the Texas Animal Manure Management Issues Conference, 83–90.

[82] United States Department of Agriculture - National Agricultural Statistics Service, 2017 Census of Agriculture

[83] U.S. Energy Information Administration, State Energy Data 2020: Production

[84] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

not remain in business because they would not be able to compete with operations that formulate rations for greater efficiency.

As a result of genetic selection and improved diets, milk production per cow has increased and feed usage has decreased by 77 percent.[85] For poultry, it is estimated that genetic selection and the current feed practices have reduced nitrogen excretion by poultry by up to 55 percent.[86]

Rule 4570 includes mitigation options for feeding animals in accordance with NRC Guidelines. The NRC Guidelines establish different nutrition requirements for animals at different ages and stages of production. Nutritionists formulate diets to meet the requirements at these different ages and stages of production.

As stated above, farms already formulate diets to maximize feed efficiency and minimize excess nutrients. There are many challenges to further dietary changes[87], including:

- Nutrient concentrations in feed and feed ingredients vary considerably; therefore, changing feed formulations of diets will require additional lab analyses of feed resulting in increased costs
- Changes in dietary formulations increase feed costs due to the time and expense of diet formulation and acquisition of new ingredients
- Reduction of crude protein nitrogen can cause deficiency in certain amino acids, such as lysine, threonine, and methionine, that can adversely affect animal performance, including growth and milk production
- Crude protein reductions for dairy cattle must be closely managed to avoid impacting productivity

As discussed above, confined animal facilities already formulate diets to maximize feed efficiency and minimize excess nutrients to reduce overall costs and remain competitive. Rule 4570 includes mitigation options for feeding animals in accordance with NRC Guidelines, which includes specific nutrient requirements for different animals. Therefore, this measure is already implemented by the confined animal facilities in the Valley and any ammonia reductions from this measure are already being attained.

[85] McCabe, C. (2021). How Dairy Milk Has Improved its Environmental and Climate Impact. Clarity and Leadership for Environmental Awareness and Research at UC Davis. Retrieved from: *https://clear.ucdavis.edu/explainers/how-dairy-milk-has-improved-its-environmental-and-climate-impact*

[86] United States Department of Agriculture - Natural Resources Conservation Service. (2020). Feed and Animal Management for Poultry. Nutrient Management Technical Note No. 190-NM-4. Retrieved from: *https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=45569.wba*

[87] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems", pp. 12-13. September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

Phase feeding and split-sex feeding have been commonly used at confined animal facilities throughout the nation for many years, particularly on larger operations,[88, 89, 90, 91] and are a standard practice for the relatively larger confined animal facilities subject to District permitting requirements in the Valley. Because of the higher cost of production in California, confined animal facilities are larger operations compared to other states to take advantage of economies of scale. The standard practice at these operations is to separate animals by phases, ages, or groups that are fed specific diets. At dairies, calves, young heifers, bred heifers, dry cows, milk cows in different stages of lactation, and sick cattle are placed in separate groups and fed rations that are specifically formulated. Beef cattle are separated into cows and calf pairs raised on rangeland, bulls, yearlings/stockers, and finishing cattle, which are fed a separate diet. Broiler chickens are typically fed three to four different diets during their grow-out period and turkeys may be fed up to six diets during their grow-out period to match the specific age or stage of production.[92] It is estimated that genetic selection and the current feed practices have reduced ammonia reduced nitrogen excretion by poultry by up to 55 percent.

Phase feeding is the standard practice in the Valley which also allows for reduction in feed costs and meet production goals. In addition, Rule 4570 includes feeding animals in accordance with NRC Guidelines. The NRC Guidelines establish different nutrition requirements for animals at different ages and stages of production. Nutritionists formulate diets to meet the requirements at these different ages and stages of production. Because phase feeding is in practice at the majority if not all of confined animal facilities in the Valley, any ammonia reductions of this practice are currently being achieved. No additional ammonia reductions are expected from the suggested mitigation measure.

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[88] Carter, S., Sutton, A., Stenglein, R. (2012). Diet and Feed Management to Mitigate Airborne Emissions – Air Quality Education In Animal Agriculture. *USDA National Institute of Food and Agriculture*. Retrieved from: *https://lpelc.org/wp-content/uploads/2019/03/Dietand-Feed-FINAL.pdf*

[89] Van Heutgen, E. (2010) Growing-Finishing Swine Nutrient Recommendations and Feeding Management. Pork Information Gateway Factsheets Number PIG 07-01-09. *https://porkgateway.org/resource/growing-finishing-swine-nutrient-recommendations-and-feeding-management/*

[90] USDA Animal and Plant Health Inspection Service (APHIS). Iowa State University (2022) US Poultry Industry Manual - Broilers: brooding. Poultry FAD Preparedness & Response Series. *https://www.thepoultrysite.com/articles/fad-broilers-brooding*

[91] Miles, R.D., Jacob, J.P. (2000) Feeding the Commercial Egg-Type Laying Hen. Florida Cooperative Extension Service, Institute of Food and Agricultural Sciences, University of Florida. *https://ucanr.edu/sites/placernevadasmallfarms/files/102990.pdf*

[92] Moss A, Chrystal P, Cadogan D, Wilkinson S, Crowley T, Choct M. (2021). "Precision feeding and precision nutrition: a paradigm shift in broiler feed formulation?" *Animal Bioscience*, 2021;34(3):354-362. Retrieved from: *https://www.animbiosci.org/journal/view.php?doi=10.5713/ab.21.0034*

<u>Increase Grazing Time for Dairy Cattle</u> - *(applies to dairy cattle only)*

A compilation by Guthrie[93] states that increased grazing time could reduce ammonia from dairy operations by up to 50 percent as distributed urine can be absorbed into soil and broken down before ammonia is released. However, this practice is not feasible in the Valley, as there is not sufficient land to graze cattle and the arid climate generally requires irrigation to grow crops.

The University of California Agricultural and Natural Resources (UC ANR) publication[94] estimates that the long-term carry capacity of rangeland for grazing in Madera County is 15 or 16 acres per 1,000 lb animal unit; therefore, based on the information in this publication approximately 21-22 acres of unirrigated rangeland would be required to allow a typical 1,400 lb mature dairy cow to graze. The University of California Cooperative Extension (UCCE) publication[95] indicates that 15-18 acres of unirrigated rangeland are required to support a 1,200 lb cow in the Sierra Foothills for one year, and that one acre of irrigated pasture would produce enough forage to feed a 1,200 lb cow for six months. Based on the information in these publications, it is estimated that in the San Joaquin Valley 15-22 acres of unirrigated land would be required for each mature cow to graze for a year, one acre of irrigated pasture would be required for a mature cow to graze for six months, and two acres of irrigated pasture would be required for a mature cow to graze for one year. The enormous amount of land required to graze cattle on non-irrigated land clearly makes this infeasible. Based on information from the USDA National Agricultural Statistics Service, the average dairy in the Valley has approximately 1,600 milk and dry cows, not including heifers and calves. Therefore, it is estimated the average dairy in the Valley would require 1,600 acres of land to graze its mature cows for 6 months and 3,200 acres of land to graze its mature cows for one year. Because of the often arid conditions in the Valley, this land would need to be regularly irrigated to sustain sufficient forage for grazing. Additionally, this measure would be impossible to implement as a result of the ongoing severe drought, the Sustainable Groundwater Management Act (SGMA), and limitations on water usage pose severe challenges to the Valley.

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[93] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[94] George, M., Frost, W., and McDougald, N. (December 2020). Ecology and Management of Annual Rangelands Series Part 8: Grazing Management. University of California Agricultural and Natural Resources Publication 8547. https://anrcatalog.ucanr.edu/pdf/8547.pdf

[95] Macon, D., and Meyer, H. (June 2018). How Many Cows Can My Property Support? - Basics of Carrying Capacity, Stocking Rate, and Pasture Irrigation. University of California Cooperative Extension. *UCCE Placer/Nevada Publication 31 1005.* Retrieved from: *https://projects.sare.org/wp-content/uploads/Pub-31-1005-Carrying-Capacity-and-Stocking-Rate.pdf*

The study Survey of Dairy Housing and Manure Management Practices in California[96] reported that in 2007, the average number of milk and dry cows of dairies that responded to the survey in Tulare County was 1,800 cows and that these dairies had 524 acres on which manure was applied to grow feed. Assuming that the acreage for feed production on a dairy in the Valley is proportional to the number of mature cows, the average dairy in Valley with 1,600 mature cows is estimated to have approximately 466 acres of land used for feed production. If half of this land is maintained for feed production and the mature cows at the dairy are grazed on irrigated pasture for six months, the average dairy would require approximately 1,367 additional acres (1,600 acres – 233 acres). For grazing of mature cows on irrigated pasture for the entire year, the average dairy in the Valley with 1,600 mature cows would require approximately 2,734 additional acres (3,200 acres – 467 acres). Information from the USDA National Agricultural Statistics Service indicates that there are currently 965 dairies and 1.5 million milk and dry cows in the Valley. Therefore, 1.5 million acres of irrigated pasture would need to be available for grazing if dairy cows in the Valley graze for just six months and 3 million acres of irrigated pasture would need to be available for dairy cows in the Valley to graze for the entire year.

Because the amount of land needed is not available, this mitigation measure is not feasible in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Feed Additives for Poultry - ***(applies to poultry only)***

Feed additives such as minerals, antibiotics, and digestive aids are another option to mitigate emissions. These additives can allow for improved nutrient absorption and minimize nitrogen excretion. Feed additives are a mitigation option included in District Rule 4570 for poultry.

Feed additives are more commonly used with poultry than with ruminants, such as cattle, because of the differences in how the digestive system works in ruminants compared to poultry. Additives in the feed of poultry operations can be absorbed by these animals. However, feed and feed additives are pre-digested by rumen bacteria prior to being absorbed in the digestive system of ruminants, which may alter the composition of many feed additives. The use of the rumen bacteria in the digestive system of ruminants that pre-digest feed allows cattle, and other ruminants to utilize various feeds that cannot be digested by non-ruminants.

Rule 4570 requires owners/operators of a layer CAF to implement at least one of the following feed mitigation measures:

- Feed according to NRC guidelines; or
- Feed animals probiotics designed to improve digestion according to manufacturer recommendations; or

[96] Meyer, D., Price, P.L., Rossow, H.A., Silva-del-Rio, N., Karle, B., Robinson, P.H., DePeters, E.J., and Fadel, J. (2011) Survey of dairy housing and manure management practices in California. Journal Dairy Sci. 94:4744-4750. *https://doi.org/10.3168/jds.2010-3761*

- Feed animals an amino acid supplemented diet to meet their nutrient requirements; or
- Feed animals feed additives such as amylase, xylanase, and protease, designed to maximize digestive efficiency according to manufacturer recommendations.

Feed is one of the most significant costs for confined animal facilities, therefore producers work with nutritionists to design diets that maximize feed efficiency, increase feed adsorption, and reduce costs. For poultry, it is estimated that genetic selection and the current feed practices have reduced nitrogen excretion by poultry by up to 55 percent.

There are challenges to increase usage of feed additives. Feed is one of the most significant costs of production and feed additives will increase feed costs due to the time and expense of diet formulation and feed additive acquisition. Some additives have negative effects and may increase emissions of some pollutants. The use of antibiotics as feed additives has also been subject to greater restrictions because of efforts to combat increasing bacterial resistance to antibiotics.

The Reference Guide states that many feed additives are already "regularly used to improve nutrient absorption from feed ingredients." Although the Reference Guide suggests that feed additives may improve nutrient absorption and decrease emissions of some pollutants, it does not specify which additives reduce which pollutants for different animals or the amount of each additive required.

Although the suggested measure lacks the specificity needed for a regulation, confined animal facilities already formulate diets to maximize nutrient adsorption, including the use of various feed additives. In addition, Rule 4570 includes feeding animals in accordance with NRC Guidelines, which includes specific nutrient requirements for different animals, and the option to utilize various feed additives. Therefore, because this measure is already used by the confined animal facilities in the Valley and included in Rule 4570, any ammonia reductions from this measure are already being achieved in the District.

It is critical for farmers to have the flexibility to decide the kind of mitigation measures that will work best for their specific operation by taking into consideration animal health and welfare, productivity, food safety and overall bio-security issues. The District's menu of feeding options in Rule 4570 provides farmers with this flexibility, while also requiring the most stringent measures for controlling emissions from confined animal facilities.

Animal Confinement (Housing)

Table 9: Animal Confinement Measures Evaluated

Method	Measure	CAF Type	Reference
Biofilters and Wet Scrubbers	Enclosed Barns with Biofiltration Systems	Dairy	Kresge[97]
	Biofilters	All	NRCS[98]
	Install Air-Scrubbers or Biotrickling Filters to Mechanically Ventilated Pig Housing	Swine	Price[99]
	Air Scrubbing Techniques	All	Guthrie[100]
	Wet Scrubbers	All	NRCS
Washing Floors/Lanes	Clean Lanes at Dairies	Dairy	Beene[101]
	Washing Floors and Other Soiled Areas in Livestock Facilities	All	Guthrie
	Scrape/Flush Freestall Lanes	Dairy	Mendes[102]

[97] Kresge, L., Strochlic, R. (2007). Clearing the Air: Mitigating the Impact of Dairies on Fresno County's Air Quality and Public Health. California Institute for Rural Studies.
[98] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*
[99] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from:
https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf
[100] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*
[101] Beene, M., Krauter, C., Goorahoo, D. (2005). Ammonia Fluxes from Animal Housing at a California Free Stall Dairy. California State University, Fresno. Center for Irrigation Technology and Plant Science Department. Retrieved from: *https://www3.epa.gov/ttnchie1/conference/ei15/session6/beene.pdf*
[102] Mendes, L.B., Pieters, J.G., Snoek, D., Ogink N.W.M., Brusselman, E., Demeyer, P. (2017). Reduction of Ammonia Emissions from Dairy Cattle Cubicle Houses via Improved Management or Design-Based Strategies: A Modeling Approach, In *Science of The Total Environment*, Volume 574, 2017, Pages 520-531, ISSN 0048-9697. Retrieved from: *https://www.sciencedirect.com/science/article/abs/pii/S0048969716319970?via%3Dihub*

Method	Measure	CAF Type	Reference
	Washing Down Dairy Cow Collecting Yards	Dairy	Price
Corral Management	Constantly Manage Corrals	Dairy	Card[103]
	Frequency of Corral Manure Management	Dairy	Schmidt[104]
Floor Design	Floor Design Including Slates, Grooves, V-Shaped Gutters and Sloping Floors to Collect and Contain Slurry Faster	Dairy, Swine	Guthrie
	Part-slatted Floor Design for Pig Housing	Swine	Price
	Adapt Dairy Housing	Dairy	Pinder[105]
	Separate Urine/Manure with 3% Floor Slope	Dairy	Braam[106]
Additional Straw Bedding	Additional Targeted Straw-bedding for Cattle Housing	All cattle	Price
	Straw Bedding for Cattle Housing	All cattle	Guthrie
Other Housing	Optimal Barn Acclimatization with Roof Insulation and/or Automatically Controlled Natural Ventilation	All	Guthrie
	Oil Spray/Sprinkling	Swine	NRCS

[103] Card, T. and Schmidt, C. (May 2006). Dairy Air Emissions Report: Summary of Dairy Emission Estimation Procedures. Final Report to CARB.

[104] Schmidt, C.E., T. Card, P. Gaffney, and S. Hoyt. (2005). Assessment of Reactive Organic Gases and Amines from a Northern California Dairy Using the EPA Surface Emissions Isolation Flux Chamber. Presented at the 14th Annual Emission Inventory Conference of the U.S. Environmental Protection Agency, Las Vegas, NV.

[105] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: *https://pubs.acs.org/doi/pdf/10.1021/es060379a*

[106] Braam, C., Ketelaars, J., Smits, M. (1997). Effects of floor design and floor cleaning on ammonia emission from cubicle houses for dairy cows, *Wageningen Journal of Life Sciences.* Retrieved from: *https://library.wur.nl/ojs/index.php/njas/article/view/525*

Method	Measure	CAF Type	Reference
	Convert Caged Laying Hen Housing from Deep-Pit Storage to Belt Manure Removal	Poultry	Price
	More Frequent Manure Removal from Laying Hen Housing with Belt Clean Systems	Poultry	Price
	In-House Poultry Manure Drying	Poultry	Price

Biofilters - *(applies to all CAFs)*

A biofilter is an air filtration and odor mitigation system that channels building exhaust through a mixture of organic materials that support microbial growth. Biofilters have been identified in several publications as a potential ammonia mitigation method, including the NRCS Reference Guide. The reference guide notes many considerations that must be taken into account when implementing these systems, including that they require careful design, monitoring, and maintenance, and have very high associated costs.

Initial costs and challenges include the replacement of existing ventilation fans in order to provide the necessary airflow and the energy to overcome the added pressure drop caused by the biofilter. Biofilters require increased retention time; however increasing the retention time usually increases the system static pressure, which can compromise the ventilation system performance. It is typically not practical to treat all of the exhaust air during the summer when a large amount of ventilation flow is required to remove excessive heat from the production house. Lower ventilation airflow may also lead to heat stress in the animals.

Different types of biofilters have their own disadvantages. Flat open biofilter beds are easier to construct and generally cost less; however, they require very large footprints. Vertical biofilters are more difficult to construct and are more expensive, and biological material can settle, causing air leaks, which will reduce the performance of the system. In addition, biofilter media will need to be replaced periodically.

Biofilters require ongoing maintenance to prevent air leakage, dust accumulation, and air constriction in the media to ensure effectiveness of the system performance. Monitoring and maintenance of the filter media moisture is essential to operation of the biofilter, and sprinklers or other wetting systems may be required. Rodents and weeds have also been a problem for some biofilters.

Included in Appendix B, is a cost-effectiveness analysis that demonstrates the economic infeasibility of biofilters. District Rule 4570 does provide options for facilities to use emissions control devices such as biofilters; however, it is not feasible to require all facilities subject to Rule 4570 to install biofilters as they are not cost-effective or practical for livestock facilities in the Valley. The District has concluded that the measure discussed is not a viable mitigation measure to require in Rule 4570.

Air-Scrubbers/Wet Scrubbers - ***(applies to all CAFs)***

Several compilations of mitigation measures, including the NRCS Reference Guide and UK User Guide, list air scrubbing as a potential method of capturing ammonia from animal housing; however, there are considerable costs and challenges associated with the implementation of scrubbers at animal facilities. One such challenge is that off-the-shelf industrial scrubbers are typically not applicable to animal production systems, due to the variation and dynamic changes of such biological systems (e.g., housing structure variation, changes in ventilation airflow rate/pattern in response to the changes of air temperature, manure management practices, unique PM characteristics).

The practicality of scrubbers is limited due to their potential to compromise the ventilation airflow rate needed to control temperature in production houses to ensure animal health. There are added costs for the replacement of existing ventilation fans in order to provide the necessary airflow and the energy to overcome the added pressure drop because of the scrubber. Additionally, it is typically not practical to treat all of the exhaust air during the summer when a large amount of ventilation flow is required to remove excess heat from the production house and prevent heat stress in the animals.

Additional costs and challenges to scrubbers include the ongoing maintenance required to prevent dust accumulation and air constriction in the media to ensure effectiveness of the system performance. There are also potential dangers in transporting and handling materials such as acid used in the scrubber. Furthermore, wet scrubbers require large supplies of water and special wastewater handling systems that are not typical at animal production operations. This increased water usage is not practical in the Valley because of limited availability of water due to drought and increasing restrictions on the amount of usable groundwater, due to SGMA.

The UK User Guide identifies installing air-scrubbers as a mitigation method specifically for pig housing, however concludes that the practical application of this method is only to new purpose-built buildings. Included in Appendix B is a cost-effectiveness analysis of scrubbers for swine facilities. The District found that scrubbers are not cost effective, and are therefore not technologically or economically feasible to require in the Valley. District Rule 4570 does provide options for facilities to use emissions control devices such as scrubbers; however, it is not feasible to require all facilities subject to Rule 4570 to install scrubbers. The District has concluded that the measure discussed is not a viable mitigation measure to require in Rule 4570.

Washing Floors/Lanes - ***(applies to all CAFs)***

Several publications include the washing of floors and other soiled areas in livestock facilities as a potential mitigation method to reduce ammonia emissions. The UK User Guide includes a more specific measure involving washing down the concrete areas where dairy cows are collected prior to and after each milking even, through pressure washing or by hosing and brushing.

District Rule 4570 includes the requirement to clean the manure from the lanes, where the majority of manure is excreted, at dairies and other cattle facilities. The majority of cow holding areas at Valley dairies are equipped with sprinkler pens for washing the cows, and are periodically washed throughout the day, rather than scraped once per day.[107] Additionally, Rule 4570 requires constant washing of milking parlor floors to remove manure, which is also standard practice for California dairies. It is essential for all areas of milking parlors, including the milking parlor floors, to be the one of the cleanest parts of the dairy to ensure that the milk from the cows is clean and uncontaminated. There is a constant need for flushing and cleaning of the milking parlor because milk that is contaminated cannot be sold. Therefore, whenever practical, Rule 4570 requires cleaning of areas where the majority of manure accumulates.

Operators of dairy CAFs are required to implement several mitigation measures related to the cleaning of floors/lanes to comply with District Rule 4570, including the following:

Required Measures:

- Flush or hose milking parlor immediately prior to, immediately after, or during each milking;
- Pave feedlanes, where present, for a width of at least 8 feet along the corral side of the feedlane fence for milk and dry cows and at least 6 feet along the corral side of the feedlane for heifers; and
- Flush, scrap, or vacuum freestall flush lanes immediately prior to, immediately after, or during each milking; or flush or scrape freestall flush lanes at least 3 times per day.

Additional Measures (must select at least one of the following):

- Use non-manure-based bedding and non-separated solids based bedding for at least 90 percent of the bedding material, by weight, for freestalls;
- For a large dairy CAF, remove manure that is not dry from individual cow freestall beds or rake, harrow, scrape, or grade freestall bedding at least once every 7 days; or
- For a medium dairy CAF, remove manure that is not dry from individual cow freestall beds or rake, harrow, scrape, or grade freestall bedding at least once every 14 days.

Operators of other cattle CAFs are required to implement the following mitigation measures to comply with District Rule 4570:

- Vacuum, scrape, or flush freestalls at least once every 7 days;

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[107] Chang, A., T. Harter, J. Letey, D. Meyer, R. D. Meyer, M. Campbell-Mathews, F. Mitloehner, S. Pettygrove, P. Robinson, R. Zhang (2006) Managing Dairy Manure in the Central Valley of California; University of California Committee of Experts on Dairy Manure Management Final Report to the Regional Water Quality Control Board, Region 5, Sacramento, June 2005. *https://ucanr.edu/sites/groundwater/files/136450.pdf*

- Pave feedlanes, where present, for a width of at least 6 feet along the corral side of the feedlane
- Either use non-manure-based bedding and non-separated solids based bedding for at least 90 percent of the bedding material, by weight, for freestalls; or remove manure that is not dry from individual cow freestall beds or rake, harrow, scrape, or grade bedding in freestalls at least once every seven days.

In conclusion, the District already requires mitigation measures that require CAFs to wash floors and/or lanes inside of cow housing areas. No additional ammonia reductions are expected from the suggested mitigation measure.

Corral Management - ***(applies to all cattle)***

Proper management of manure in animal housing areas will stabilize the nitrogen compounds, which will reduce the rate that these compounds are converted to ammonia that can be lost to the atmosphere. Research by Card and Schmidt (2005) supports that management of manure in corrals reduces ammonia emissions from the corrals and points out that of two dairies tested, the ammonia emissions from the dairy with constantly managed corrals had “exceptionally low ammonia emissions.” Follow-up research by Card and Schmidt (2009) at one of the dairies studied indicated that ammonia emissions were significantly reduced (>80 percent reduction comparing 2008 to 2005 reported ammonia emissions) when the frequency of management of the manure in the corrals was increased.

Rule 4570 includes requirements for management of corrals to prevent excessive buildup of manure, designing or managing corrals to prevent excessive moisture, and periodic scraping and removal of manure from corrals. Under Rule 4570, dairy, beef feedlot, and other cattle facilities are required to implement four to six measures for corral management depending on facility type, as well as select one additional mitigation measure as detailed below:

Required Measures

- Pave feedlanes, where present, for a width of at least 8 feet along the corral side of the feedlane fence for milk and dry cows and at least 6 feet along the corral side of the feedlane for heifers (*dairy and other cattle*);
- Clean manure from corrals at least 4 times per year with at least 60 days between cleaning; or clean corrals at least once between April and July and at least once between September and December (*dairy*);
- Scrape corrals twice a year with at least 90 days between cleanings, excluding the removal of in-corral mounds (*beef feedlot and other cattle*);
- Scrape, vacuum or flush concrete lanes in corrals at least once every day for mature cows and every 7 days for support stock; or clean concreted lanes such that the depth of manure does not exceed 12 inches at any point or time (*dairy and other cattle*);
- Inspect water pipes and troughs and repair leaks at least once every 7 days;
- Choose one of the following:
    - Slope the surface of the corrals at least 3 percent where the available space for each animal is 400 square feet or less. Slope the surface of the corrals at least

1.5 percent where the available space for each animal is more than 400 square feet per animal;
    - Maintain corrals to ensure proper drainage preventing water from standing more than 48 hours; or
    - Harrow, rake, or scrape corrals sufficiently to maintain a dry surface.
- If the CAF has shade structures, they must choose one of the following:
    - Install shade structures such that they are constructed with a light permeable roofing material;
    - Install all shade structures uphill of any slope in the corral;
    - Clean manure from under corral shades at least once every 14 days, when weather permits access into the corral (*dairy*); or
    - Install shade structure so that the structure has a North/South orientation.

Additional Measures

- Manage corrals such that the manure depth in the corral does not exceed 12 inches at any time or point, except for in-corral mounding. Manure depth may exceed 12 inches when corrals become inaccessible due to rain events. The facility must resume management of the manure depth of 12 inches or lower immediately upon the corral becoming accessible.
- Knockdown fence line manure build-up prior to it exceeding a height of 12 inches at any time or point. Manure depth may exceed 12 inches when corrals become inaccessible due to rain events. The facility must resume management of the manure depth of 12 inches or lower immediately upon the corral becoming accessible.
- Use lime or a similar absorbent material in the corral according to the manufacturer's recommendation to minimize moisture in the corrals; or apply thymol to the corral soil in accordance with the manufacturer's recommendation (*dairy and other cattle*).

In conclusion, the District already requires mitigation measures that minimize emissions from corral housing areas. No additional ammonia reductions are expected from the suggested mitigation measure.

Floor Design - ***(applies to dairy cattle and swine only)***

Several publications list different floor design types for collecting and containing slurry that may reduce ammonia emissions that include slats, grooves, v-shaped gutters, and sloping floors. The measures included in these documents are applicable to small dairies in which cows are kept in stables or cubicle-type housing that is common on small European dairies in which manure was allowed to accumulate. These measures are also applicable to manure handled as a slurry, and does not apply to the larger dairies in the Valley that are subject to District permitting, which handle very little manure as a slurry.[108] It should also be noted that

[108] Marklein, A. R., Meyer, D., Fischer, M. L., Jeong, S., Rafiq, T., Carr, M., and Hopkins, F. M. (2021) Facility-scale inventory of dairy methane emissions in California: implications for mitigation, Earth Syst. Sci. Data, 13, 1151–1166, *https://doi.org/10.5194/essd-13-1151-2021*, 2021.

most physical changes to existing dairy barns must be incorporated at the design stage, and are not practical for existing structures, resulting in significantly higher capital costs.

Valley dairies have paved lanes to facilitate manure removal, as required by Rule 4570. The lanes on the dairies are sloped to allow manure to be sent to a lagoon system. In addition, Rule 4570 requires that manure must be periodically removed from the lanes where the cattle spend the majority of their time. Therefore, Rule 4570 already incorporates control measures for specialized floor design and this is already being implemented by dairies in the Valley.

Rule 4570 requirements for dairy and other cattle facilities are as follows:

- Pave feedlanes, where present, for a width of at least 8 feet along the corral side of the feedlane fence for milk and dry cows and at least 6 feet along the corral side of the feedlane for heifers and other cattle.
- For corrals, choose one of the following:
    - Slope the surface of the corrals at least 3 percent where the available space for each animal is 400 square feet or less. Slope the surface of the corrals at least 1.5 percent where the available space for each animal is more than 400 square feet per animal;
    - Maintain corrals to ensure proper drainage preventing water from standing more than 48 hours;
    - Harrow, rake, or scrape corrals sufficiently to maintain a dry surface.

The UK User Guide includes a floor design measure specifically for swine that aims to reduce the overall emitting surface area of slurry by replacing fully slatted floors with part-slatted floors. This type of floor design is already a requirement at the only swine facility in the District. The facility has a specific permit condition that states "Permittee shall use a slatted floor system (slatted floors over deep pits or shallow flush alleys), with daily manure removal for shallow flush alleys and weekly removal from deep pits." Under Rule 4570, swine CAFs are required to implement measures for animal housing that includes the use of a similar slatted floor system, as follows:

- Use a slatted floor system (slatted floors over deep pits or shallow flush alleys), with daily manure removal for shallow flush alleys and weekly removal from deep pits.

In conclusion, the District already requires a mitigation measure for swine CAFs to minimize emissions from animal housing areas through the use of a slatted floor system. No additional ammonia reductions are expected from the suggested mitigation measure.

<u>Separate Urine/Manure with 3 Percent Floor Slope</u> - *(applies to dairy cattle only)*

In one study[109] completed in the Netherlands, ammonia emissions from cubicle housing with a slatted floor, used on small dairies in Europe, were compared with two different solid floor systems: a non-sloped and a 3 percent one-sided sloped floor, combined with a highly frequent or normal removal of manure by a scraper. The study results indicated that the slope of the floor had more impact on reducing ammonia emissions than increasing the scraping frequency. Solid floors with a slope decreased ammonia emissions compared to slatted floors. However, the study indicated that solid floors without a slope may not decrease ammonia emission compared with slatted floors.

Cubicle housing with slatted floors and manure pits under the housing areas are not used for dairy cattle in the Valley. The typical practice is to house cattle in barns or corrals with flushed or scraped lanes. These lanes are sloped to facilitate flushing of the manure to the lagoon system. Additionally, Rule 4570 includes requirements that corrals be sloped, which allows urine to drain away, which reduces the conversion of urea in urine to ammonia since it will have less contact with enzymes in feces that promote this transformation.

District Rule 4570 requires dairy, beef feedlot, and other cattle facilities to implement the following mitigation measure, or an equivalent measure:

- Slope the surface of the corrals at least 3 percent where the available space for each animal is 400 square feet or less. Slope the surface of the corrals at least 1.5 percent where the available space for each animal is more than 400 square feet per animal.

In conclusion, the District Rule 4570 already includes mitigation measures involving sloped floors for cattle facilities. No additional ammonia reductions are expected from the suggested mitigation measure.

<u>Additional Targeted Straw-Bedding for Cattle Housing</u> - *(applies to dairy and other cattle only)*

This method involves adding extra straw bedding to cattle houses, targeting the wetter and dirtier areas of the house. This measure is applicable to small dairy farms that house cattle indoors and use a solid manure handling system, such as small dairy farms in Europe; however, most dairies in the Valley handle the majority of the manure as a liquid and do not use straw bedding. One study[110] indicated that storage or treatment ponds were found on 95.9% of dairies, and another report prepared for CARB states that, "*California dairy effluent*

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[109] Braam, C., Ketelaars, J., Smits, M. (1997). Effects of floor design and floor cleaning on ammonia emission from cubicle houses for dairy cows, *Wageningen Journal of Life Sciences*. Retrieved from: *https://library.wur.nl/ojs/index.php/njas/article/view/525*

[110] Meyer, D., Price, P.L., Rossow, H.A., Silva-del-Rio, N., Karle, B., Robinson, P.H., DePeters, E.J., and Fadel, J. (2011) Survey of dairy housing and manure management practices in California. Journal Dairy Sci. 94:4744-4750. *https://doi.org/10.3168/jds.2010-3761*

often runs 1% total solids."[111] These dairies also use frequent flushing to remove the manure instead of absorbing with straw, thereby reducing emissions through flushing. Beef cattle in the Valley are not housed indoors; therefore, this measure would not apply to beef cattle in the Valley.

For areas of the dairy that would benefit from this method, the use of straw, or other non-manure based bedding for cow housing is included as a menu option for cattle housed in barns, as shown below:

- Use non-manure-based bedding and non-separated solids based bedding for at least 90 percent of the bedding material, by weight, for freestalls (e.g. rubber mats, almond shells, sand, or waterbeds).

In conclusion, the District already has a mitigation measure option to minimize emissions from cow bedding. No additional ammonia reductions are expected from the suggested mitigation measure.

Optimal Barn Acclimatization with Roof Insulation and/or Automatically Controlled Natural Ventilation - *(applies to all CAFs)*

The compilation by Guthrie, et al.[112] includes ammonia mitigation measures that involve specific building design to provide optimal barn acclimatization. This measure was based on information from the United Nations Economic Commission for Europe (UNECE) compilation Framework Code for Good Agricultural Practice for Reducing Ammonia Emissions.[113] The UNECE publication stated that for cattle cubicle housing was considered the reference and that for cattle housed in cubicles with traditional slats, and claimed that this measure can moderately reduce ammonia by 20% compared to conventional cubicle housing.

Cubicle housing with traditional slats is not typically used to house cattle in the Valley; therefore, this measure is not applicable to cattle in the Valley. In cubicle housing with traditional slats, the manure that cattle excrete seeps through the slats and falls to an alley or a storage pit below the housing area. In the Valley, dairy cattle are typically housed in barns or corrals with lanes that are flushed or scraped to remove manure to a separate area for storage. In cubicle housing with traditional slats, a large amount of the ammonia emissions are from the manure stored in an alley or pit below the housing area. Therefore, this measure

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[111] Meyer, D, Heguy, J., Karle, B. and Robinson, P. (2019) Characterize Physical and Chemical Properties of Manure in California Dairy Systems to Improve Greenhouse Gas Emission Estimates. California Environmental Protection Agency, Air Resources Board. *https://ww2.arb.ca.gov/sites/default/files/classic/research/apr/past/16rd002.pdf*

[112] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[113] UNECE. 2015. United Nations Economic Commission for Europe Framework Code for Good Agricultural Practice for Reducing Ammonia Emissions. United Nations Economic Commission for Europe Convention on Long-range Transboundary Air Pollution. *https://unece.org/environment-policy/publications/framework-code-good-agricultural-practice-reducing-ammonia*

would not reduce ammonia emissions from cattle housing in the Valley because manure is stored in a different area.

In addition, these measures are not feasible for many existing buildings and must be incorporated in the initial design stage of a new build. For poultry, new houses generally incorporate insulation and controlled ventilation. However, this measure is generally not feasible for implementation at Valley dairies or other cattle facilities. Due to the warm climate in the Valley, barns used for cattle consist of a roof with open sides to allow for adequate airflow and cooling. These structures would need to be completely redesigned and reconstructed to implement this mitigation measure, and there would be substantial cost to enclose the cattle and equip the barns with ventilation systems to supply sufficient airflow for the cattle. Furthermore, the increased airflow from the fans required for ventilation may promote increased emissions from the barns rather than reduce ammonia.

In conclusion, the suggested measure is not applicable to cattle facilities in the Valley and would not result in any additional ammonia reductions.

Oil Spray/Sprinkling - *(applies to swine only)*

Sprinkling of vegetable oil in animal production areas has been demonstrated as an effective measure within swine barns for PM mitigation, with observed smaller reductions of ammonia ranging from 0-30 percent. However, results of research on the effect of this practice on ammonia emissions vary greatly.[114] This practice requires daily labor if applied by hand, and requires additional time during room washing to remove oil residue. Additionally, oil residue can cause ventilation fans to become stuck in on or off positions, preventing them from operating correctly to ensure proper ventilation and cooling of animals. As mentioned above, current research shows considerable variability in the potential ammonia emission reductions of this measure; therefore, it is currently uncertain if this measure will reduce ammonia emissions and the magnitude of any potential reductions. Furthermore, the NRCS Reference Guide indicates that this measure is applicable to swine barns, which contribute a very small amount to the District's ammonia inventory with only one permitted facility in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Convert Caged Laying Hen Housing from Deep-Pit Storage to Belt Manure Removal - *(applies to poultry only)*

This measure applies to high-rise laying hen housing with deep pit storage. In a deep-pit storage system, laying hens are kept in tiered cages and the manure from laying hens drops into a pit below the cages where it may be stored for months prior to removal. The UK User Guide identifies that replacing this system with a series of belts below each tier of cages,

[114] Harmon, J., Hoff, S., Rieck-Hinz, A. (2014). Animal Housing – Vegetable Oil Sprinkling Overview. *Air Management Practices Assessment Tool*, Iowa State University. Retrieved from: *https://store.extension.iastate.edu/product/Animal-Housing-Vegetable-Oil-Sprinkling-Overview*

which remove manure from the house, could have the potential to reduce ammonia emissions.

In the United States, the overall trend for farms that produce eggs has been to shift away from high-rise laying hen housing with tiered cages to cage-free housing. In 2018, voters in California approved Proposition 12, also known as the Farm Animal Confinement Initiative.[115] Proposition 12 requires that animals held in buildings, such as laying hens, breeding sows, or veal calves, *"be housed in confinement systems that comply with specific standards for freedom of movement, cage-free design, and minimum floor space."* Implementation of the law began on January 1, 2022, and as a result all eggs produced in California must be procured only from hens in cage-free housing. High-rise hen houses in which egg-laying hens are kept in cages are no longer legal in California. There are significant questions that need to be answered regarding the practicality, cost, and overall ammonia emission reductions of implementing this measure for cage-free hen houses. Therefore, the District has concluded that this measure is not a viable mitigation option to include in Rule 4570 at this time.

More Frequent Manure Removal from Laying Hen Housing with Belt Clean Systems - *(applies to poultry only)*

This method identified in the UK User Guide increases the frequency of manure removal to twice weekly, and relies on the rapid removal of manure from the house prior to the peak rate of ammonia emission. This measure is only applicable to laying hen houses that are already equipped with belt manure removal systems, and is not feasible for the majority of existing laying hen houses in the Valley given the significant facility reconstruction costs and potential space/infrastructure limitations at existing facilities.

In addition, as explained above, all eggs produced in California must be procured only from hens in cage-free housing and there are significant questions that need to be answered regarding the practicality, cost, and overall ammonia emission reductions of implementing this measure for cage-free hen houses. Therefore, the District has concluded that this measure is not a viable mitigation option to include in Rule 4570 at this time.

In-House Poultry Manure Drying - *(applies to poultry only)*

In-house poultry manure drying, as identified in the UK User Guide, is applicable to poultry housing, and involves the installation of ventilation/drying systems that reduce the moisture content of poultry litter. The author expects implementation of this method to be low to moderate, due to the practical limitations involved with installing systems in existing buildings. Forced air drying systems are not feasible for houses in which the birds are raised on litter because the litter remains in the houses with the birds until cleaned out to prepare

[115] California Proposition 12, Animal Care Program. Retrieved from: *https://www.cdfa.ca.gov/AHFSS/AnimalCare/*

for another flock. Following BACT Guidelines 5.7.1[116] and 5.7.2[117], this practice is evaluated as a potential BACT measure for new or expanding facilities; the required mitigation measure is as follows:

- Completely enclosed mechanically ventilated layer housing with evaporative cooling pads, mixing fans, and a computer control system.

In conclusion, the District already has a mechanism to implement this mitigation measure for expanding or new poultry housing operations. No additional ammonia reductions are expected from the suggested mitigation measure.

Manure Management (Storage)

Table 10: Manure Management (Storage) Measures Evaluated

Method	Measure	CAF Type	Reference
Lagoon Management	Replace Lagoons with Deep Tanks	Dairy	Guthrie[118]
	Oxygenation of Liquid Manure Lagoons	All	NRCS[119]
Storage Bags	Storage Bags	Dairy	Guthrie
Manure Storage Covers	Liquid Manure Storage Covers	All	NRCS
		All	Marks[120]
	Solid Manure Storage Covers	All	NRCS

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[116] https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/bact/BACTID773.pdf?:linktarget=_self&:embed=yes
[117] https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/bact/BACTID774.pdf?:linktarget=_self&:embed=yes
[118] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*
[119] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*
[120] Marks, R. (2001). Cesspools of Shame: How Factory Farm Lagoons and Sprayfields Threaten Environmental and Public Health. *Natural Resources Defense Council and the Clean Water Network*. Retrieved from: *https://www.nrdc.org/sites/default/files/cesspools.pdf*

Method	Measure	CAF Type	Reference
		All	Price[121]
		All	Chadwick[122]
	Allow Cattle Slurry Stores to Develop a Natural Crust	Dairy	Price
Solid-Liquid Separation	Solid-Liquid Separation	All	NRCS
Anaerobic Digesters	Anaerobic Digesters	Dairy	NRCS
		Dairy	Marks
		Dairy	Kresge[123]
Amendments/Additives	Litter Amendments and Manure Additives	All	NRCS
	Acidifying Slurry and Shifting Chemical Balance from Ammonia to Ammonium	All	Guthrie
	Acidifying Amendments and Additives for Poultry Litter	Poultry	Price

[121] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*

[122] Chadwick, D.R. (2005). Emissions of Ammonia, Nitrous Oxide and Methane from Cattle Manure Heaps: Effect of Compaction and Covering. *Atmosphere Environment*, Vol. 39, Issue 4: 787-799. Retrieved from: *https://www.sciencedirect.com/science/article/abs/pii/S135223100400994X*

[123] Kresge, L., Strochlic, R. (2007). Clearing the Air: Mitigating the Impact of Dairies on Fresno County's Air Quality and Public Health. *California Institute for Rural Studies.*

Method	Measure	CAF Type	Reference
	Urease Inhibitors	All Cattle	Pinder[124]
		All Cattle	Preece[125]
Surface Cooling	Surface Cooling of Slurry Manure	All	Guthrie
pH of Manure	Lowering pH of Manure	All	Preece
On-farm Composting	Composting	All Cattle	NRCS

Replace Lagoons with Deep Tanks - ***(applies to dairy cattle only)***

A compilation[126] indicated that replacing lagoons with deep tanks can reduce ammonia emissions by 30-60 percent. The information from the compilation indicates that this measure is applicable to manure that is handled as a slurry. The reductions in ammonia emissions are a result of the smaller surface area of the manure in contact with the air from which ammonia may be emitted. Storage of manure in deep tanks is not a feasible measure for the District due to the size of dairies in the Valley and the way that manure is typically handled. As previously mentioned, the average dairy in the Valley has almost 1,600 cows compared to a national average of less than 300 cows per dairy outside of California[127, 128] and are larger than the typical European dairies for which this measure was considered. In addition, dairies in the Valley typically handle liquid manure as a dilute liquid with rather than a thick slurry.

[124] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: https://pubs.acs.org/doi/pdf/10.1021/es060379a

[125] Preece, S., Cole, N., Todd, R., Auvermann, B. (2017). Ammonia Emissions from Cattle Feeding Operations. *Texas A&M AgriLife Extension Service.* Retrieved from: http://baen.tamu.edu/wp-content/uploads/sites/24/2017/01/E-632.-Ammonia-Emissions-from-Cattle-Feeding-Operations.pdf

[126] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society.* Retrieved from: https://www.rand.org/pubs/research_reports/RR2695.html

[127] Hanson, M. (2021) U.S. Dairy Herd Hits 27-year High. *Dairy Herd Management.* Retrieved from: https://www.dairyherd.com/news/dairy-production/us-dairy-herd-hits-27-year-high

[128] Latest USDA Statistics for average size of dairies excluding California. Retrieved from: https://downloads.usda.library.cornell.edu/usda-esmis/files/h989r321c/7d279w693/f7624g40c/mkpr0222.pdf (about 270 cows per dairy outside California)

The dilute dairy manure typically handled in the Valley has a solids content of 2 percent or less while slurry manure has a solids content of about 10 percent. As a result, the volume of manure handled would be approximately 27 times greater than the average dairy outside of California that handles dairy manure as a slurry. It is not practical to construct tanks that would contain such large amounts of manure. Notably, the depth of lagoons and storage ponds is limited to protect groundwater because a minimum distance is required between the bottom of the lagoons and storage ponds and the groundwater.[129,130] Therefore, the tanks would need to be constructed aboveground. However, it is not practical to construct tanks aboveground because of the large amount of liquid manure that must be stored. Pumping the manure into aboveground tanks would require larger amounts of energy. Also, it is possible the release of the ammonia conserved in the manure tanks will be delayed until the manure is sent to a storage pond or applied to land. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

<u>Oxygenation of Liquid Manure Lagoons</u> - *(applies to all CAFs)*

The NRCS Reference guide states that large land footprint of naturally aerobic lagoons is not practical for many farms. This is particularly applicable to the large farms in the Valley. Naturally aerobic lagoons are not feasible in the Valley because the dairies in the Valley would require an extremely large footprint. The design criteria of naturally aerobic lagoons in the USDA-NRCS Practice Standard Code 359 will be used to illustrate the approximate size that would be required for naturally aerated lagoons for confined animal facilities in the Valley. USDA-NRCS Practice Standard Code 359 requires that naturally aerobic lagoons be designed to have a minimum treatment surface area as determined on the basis of daily BOD_5 loading per unit of lagoon surface. The standard specifies that the maximum loading rate of naturally aerobic lagoons shall not exceed the loading rate indicated by the USDA-NRCS Agricultural Waste Management Field Handbook (AWMFH)[131] or the maximum loading rate according to state regulatory requirements, whichever is more stringent.

According to Figure 10-30 (August 2009) of the latest version of the AWMFH, the maximum aerobic lagoon lading rate for the Valley is 45 - 55 lb-BOD_5/acre-day. Based on information from the USDA National Agricultural Statistics Service, the average dairy in the Valley has approximately 1,600 milk and dry cows. Based on a typical dairy herd composition, the average dairy in the Valley is estimated to have approximately 1,348 milk cows, 252 dry cows,

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[129] California Regional Water Quality Control Board Central Valley Region Order R5-2013-0122 – Reissued Waste Discharge Requirements General Order for Existing Milk Cow Dairies. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

[130] California Regional Water Quality Control Board Central Valley Region Order R5-2017-0058 –Waste Discharge Requirements General Order for Confined Bovine feeding Operations. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2017-0058.pdf*

[131] United States Department of Agriculture (USDA) Natural Resources Conservation Service (NRCS), Agricultural Waste Management Field Handbook (AWMFH). Retrieved from: *https://directives.sc.egov.usda.gov/viewerfs.aspx?hid=21430*

and 1,153 heifers and calves. According to Table 4-5 (March 2008) of the USDA-NRCS AWMFH, the total daily manure produced by each milk cow, dry cows, and 970 lb heifer will have an average BOD loading of 2.9 lb-BOD_5/day, 1.4 lb-BOD_5/day, and 1.2 lb-BOD_5/day, respectively. The average BOD loading of manure produced by smaller heifers and calves is estimated based on manure volatile solids excretion rates. Assuming that 80 percent of the manure will be flushed to the lagoon system, the minimum lagoon surface area required for a naturally aerobic lagoon treating manure from an average size dairy in the Valley with 1,600 milk and dry cows can be calculated as follows:

BOD_5 loading (lb/day)

1,348 milk cows x 2.9 lb-BOD_5/cow-day x 0.80 = 3,127 lb-BOD_5/day

252 dry cows x 1.4 lb-BOD_5/cow-day x 0.80 = 282 lb-BOD_5/day

457 heifers (15-24 months) x 1.2 lb-BOD_5/heifer-day x 0.80 = 439 lb-BOD5/day

366 heifers (7-14 months) x 0.83 lb-BOD_5/heifer-day x 0.80 = 243 lb-BOD_5/day

182 heifers (4-6 months) x 0.47 lb-BOD_5/heifer-day x 0.80 = 68 lb-BOD_5/day

148 calves (0-3 months) x 0.27 lb-BOD_5/heifer-day x 0.80 = 32 lb-BOD_5/day

Total BOD loading = 3,127 lb-BOD_5/day + 282 lb-BOD_5/day + 439 lb-BOD_5/day + 243 lb-BOD_5/day + = 68 lb-BOD_5/day + 32 lb-BOD_5/day = 4,191 lb-BOD_5/day

Minimum Surface Area Required for a Naturally Aerobic Lagoon for an Average San Joaquin Valley Dairy

Minimum Surface (acres) in areas with a maximum loading rate of 55 lb-BOD_5/acre-day =

4,191 lb-BOD_5/day ÷ 55 lb-BOD_5/acre-day = 76.2 acres

Minimum Surface (acres) in areas with a maximum loading rate of 45 lb-BOD_5/acre-day =

4,191 lb-BOD_5/day ÷ 45 lb-BOD_5/acre-day = 93.1 acres

As shown above the minimum surface area required for a naturally aerobic lagoon treating manure from an average size dairy in the Valley would range from approximately 76.2 – 93.1 acres. This amount of land is not typically available and would require the removal of land that is currently used to produce feed or other crops. Construction of a lagoon over 76 acres in size would be a massive project that would have numerous challenges and high costs for both design and construction. For example, the expense of lining a lagoon of this size would be extremely high. To comply with the requirements of the Central Valley Regional Water Quality Control Board, new lagoons and ponds that store dairy manure in the Valley have generally needed to comply with the Central Valley Regional Water Quality Control Board Tier 1 design standards, which require a lagoon or pond with a double liner constructed of high density polyethylene (HDPE) or material of equivalent durability with a leachate collection and removal system. The Capital Press article[132] indicated that the cost for the installation of double-liner for an existing lagoon at a dairy near Sunnyside, Washington in 2016 was roughly $500,000 for each lagoon and the lagoons averaged 78,000 square feet each. Based on this information, the cost of a double liner for a lagoon storing dairy manure is estimated to be about $7.88 per square foot and $343,253 per acre in 2022. Therefore, the cost for the liner for a lagoon only with an area of 76.2 to 93.1 acres would be $26,555,879 to $31,956,854.

In addition to construction costs, there would also be an increase in expenses for designing and maintaining lagoons of such a large size. To comply with the requirements of Regional Water Quality Control Board and Mosquito Abatement District the lagoon would need to be regularly cleared of any dead algae, vegetation, and floating debris that could create a habitat for mosquitos and other vectors that carry diseases. Therefore, as a result of the large size of the lagoons, the maintenance required to comply with these regulations would be difficult and there would also be increased costs. Finally, ammonia emissions may increase from naturally aerobic lagoons because of the large surface in contact with the atmosphere.

The NRCS Reference Guide states that the energy required at an animal production operation to introduce enough oxygen for complete aerobic treatment using mechanical aeration is very expensive and aeration of the surface of the liquid manure is more common.

The Government of Ontario publication[133] states that there are several disadvantages for on-farm use of mechanical aeration and specifically lists the following:

- High initial costs
- High energy costs
- High maintenance costs
- Effectiveness is reduced in cold weather
- The introduction of antibiotics and sanitizers can upset or destroy the required aerobic bacteria
- Nitrogen loss to the atmosphere is increased with mechanical aeration

This publication cautions that improperly designed mechanical aeration systems may contribute more odor than what is reduced through the mixing of air into the liquid, which indicates that mechanical aeration of manure can increase emissions.

The very high cost of complete mechanical aeration makes this option infeasible for farms. For complete aerobic treatment of a lagoon, sufficient oxygen must be delivered into the lagoon and the oxygen delivered must be completely mixed throughout the lagoon. A report

[132] Wheat, D. (2018). Dairy Installs Double Liner in Its Lagoon. Capital Press. Updated December 13, 2018. Retrieved from: *https://www.capitalpress.com/state/washington/dairy-installs-double-liner-in-its-lagoon/article_9ded077e-db11-5cc5-adb7-aa7ebee6e5b9.html*

[133] Government of Ontario. (2006). "Aeration of Liquid Manure". Retrieved from: *https://www.ontario.ca/page/aeration-liquid-manurehttps://www.ontario.ca/page/aeration-liquid-manure*

by the University of California (UC) Davis[134] states, "*Mixing is important to ensure uniformity of temperature and composition throughout the volume, e.g., continuous bulk turnover is needed to eliminate quiescent zones or sludge layers where anaerobic conditions persist. Also, relatively vigorous mixing (high turbulence) prevents clumping of organisms/substrate, and reduces diffusion resistance by thinning the film thickness through which dissolved oxygen must migrate (diffuse) to reach substrate particles and organisms.*" Delivery of oxygen and mixing of the oxygen throughout a lagoon requires substantial amounts of energy. The cost of electricity for complete aeration can be estimated based on the amount of oxygen that needs to be supplied and the energy required for complete mixing of oxygen throughout a lagoon. The Government of Ontario publication indicates that for complete aeration of manure, oxygen must be supplied in an amount equal to twice the BOD in the manure.

A publication[135] indicates that approximately 1.5 to 2.5 pounds of oxygen is required to digest one pound of Biological Oxygen Demand (BOD_5) with additional oxygen required for conversion of ammonia to nitrate (NO3-) (nitrification). In this publication, Dr. Ruihong Zhang of UC Davis estimated that 2.4 lbs (1.1 kg) of oxygen (O_2) per cow must be provided each day for removal of BOD and an additional 3 lbs (1.4 kg) per cow for oxidation of 70 percent of the nitrogen, which is a ratio of approximately 2.25 lb of oxygen per lb of BOD. It will be estimated that 2 lb of oxygen per 1 lb of BOD_5 is required for nitrification of ammonia.

As discussed above, the lagoons for an average size dairy in the Valley with 1,600 mature cows will have a BOD loading rate of approximately 4,191 lb-BOD_5/day. Based on the data gathered in the UC Davis report, aeration efficiencies for mechanical aerators ranged from 0.10 to 0.68 kg of oxygen provided per kW-hr of energy utilized.[136] The most efficient aerator tested installed in dairy lagoons had an aeration efficiency of 0.49 kg-O_2/kW-hr. These efficiency tests were performed in clean water. The efficiency of the aerators will be lower in liquid manure because of the higher amount of solids that it contains compared to clean water. The yearly energy requirement for a mechanically aerated lagoon treating flushed manure an average size dairy in the Valley is calculated as follows:

[134] Williams, R.B., Elmashad, H., Kaffka, S. (2020). Research and Technical Analysis to Support and Improve the Alternative Manure Management Program Quantification Methodology. *University of California, Davis, California Biomass Collaborative*, CARB Agreement No. 17TTD010. Retrieved from: *https://ww2.arb.ca.gov/sites/default/files/auction-proceeds/ucd_ammp_qm_analysis_final_april2020.pdf*

[135] San Joaquin Valley Dairy Manure Technology Feasibility Assessment Panel. (2005) An Assessment of Technologies for Management and Treatment of Dairy Manure in California's San Joaquin Valley. California Air Resources Board

[136] Zhang, R., Sun, H., Kamthunzi, W.M., Collar, C.A., Mitloehner, F.M. (2007) Aerator Performance for Wastewater Lagoon Application, ASABE. *https://elibrary.asabe.org/abstract.asp?aid=23832*

Oxygen Requirement for Average Size Dairy in the Valley

4,191 lb-BOD_5/day x 1 kg/2.2046 lb = 1,901 kg-BOD_5/day x 2 = 3,802 kg-BOD_5/day

Electricity for High Efficiency Aerator

3,802 kg-BOD_5/day ÷ (0.68 kg-O_2/kW-hr) x (365 day/year) = 2,040,779 kW-hr/year

Electricity for Low Efficiency Aerator

3,802 kg-BOD_5/day ÷ (0.10 kg-O_2/kW-hr) x (365 day/year) = 13,877,300 kW-hr/year

Electricity for Complete Mixing of Air

The UC Davis report estimates that mixing for complete aeration of a dairy lagoon would require 3,300 kW-hr per milk cow per year. The energy required for mixing for complete aeration for an average sized dairy in the Valley is calculated as follows:

1,348 milk cows x 3,300 kW-hr/milk cow-year = 4,448,400 kW-hr/year

Total Electricity Required for Complete Aeration with High Efficiency Aerator

2,040,779 kW-hr/year + 4,448,400 kW-hr/year = 6,489,179 kW-hr/yr

Total Electricity Required for Complete Aeration with Low Efficiency Aerator

13,877,300 kW-hr/year + 4,448,400 kW-hr/year = 18,325,700 kW-hr/yr

Cost of Electricity for Complete Mechanical Aeration of a Lagoon Treating Manure from an Average Size Dairy in the Valley:

The cost for electricity will be based upon the average price for industrial electricity in California for the year December 2021 through November 2020, as taken from the Energy Information Administration (EIA) website:

Average Cost for electricity = $0.1685/kW-hr

The electricity costs for complete aeration are calculated as follows:

Low Cost Estimate (High Efficiency Aerator)

6,489,179 kW-hr/year x $0.1685/kW-hr = $1,093,427/year

High Cost Estimate (Low Efficiency Aerator)

18,325,700 kW-hr/year x $0.1685/kW-hr = $3,087,880/year

As shown above, the estimated cost for only the electricity for a mechanically aeration to reduce ammonia emissions from an average size dairy in the Valley ranges from nearly $1.1 million per year to nearly $3.1 million per year. This cost does not include the design and construction of the mechanical aeration system or any additional operational costs. However, it is clear that the cost of electricity alone would make this system economically infeasible, especially when considering that the price of electricity is expected to continue to increase.

Although the NRCS Reference Guide states that surface aeration of manure is more common because of the difficulty and expense of complete mechanical aeration, the amount of oxygen provided by aeration of the surface of liquid manure would not be sufficient to oxidize ammonia. Any ammonia oxidized would be converted to nitrite and nitrate. Increased concentrations of nitrite and nitrate in the liquid manure may require treatment to protect water quality or increase emissions of NOx or nitrous oxide (N2O).

Although surface aeration may sometimes reduce odors of some compounds, surface aeration may actually increase ammonia emissions because it accelerates the release of carbon dioxide (CO2), an acidic gas, which increases the pH of the manure promoting increased ammonia emissions.[137, 138] Additionally, low levels of aeration will not provide sufficient oxygen for treatment, but can increase the transfer of emissions from the manure to the air because of the increased disturbance at the surface of the liquid manure.

Naturally aerated lagoons are not feasible in the Valley because of the large land requirements, fully mechanically aerated lagoons are not practical because of the high energy requirements and costs, and surface aeration is not expected to reduce ammonia emissions; therefore, this is not a feasible measure to reduce ammonia emissions from liquid manure in the Valley.

The District is unaware of any instances in which oxygenation demonstrates to be a practical technology on any farm to decrease ammonia emissions from liquid manure and has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

<u>Storage Bags</u> - *(applies to dairy cattle only)*

Manure storage bags have primarily been used to store manure from pig farms in Europe and Canada. They have also recently started to be used to store manure on some dairy farms that are relatively small compared to the typical dairies in the Valley. The storage of manure in bags is only suitable for small dairies that handle manure as a slurry. Manure storage bags are not suitable for large dairies that handle dilute liquid manure because of the large volumes of manure that must be stored until it can be applied to cropland. The majority of dairies in the Valley are large flush dairies in which liquid manure mixed with water is stored in large earthen lagoons or ponds until it can be applied to cropland. Dairies that handle

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[137] Zhao, B., Chen, S. (2003). Ammonia Volatilization from Dairy Manure under Anaerobic and Aerated Conditions at Different Temperature. Paper number 034148, 2003 American Society of Agricultural and Biological Engineers Annual Meeting. Retrieved from: *https://elibrary.asabe.org/abstract.asp?aid=13892*
[138] Kaffka, S., Barzee, T., El-Mashad, H., Williams, R., Zicari, S., Zhang, R. (2016). Evaluation of Dairy Manure Management Practices for Greenhouse Gas Emissions Mitigation in California. Final Technical Report to the State of California Air Resources Board Contract #14-456. Retrieved from: *https://biomass.ucdavis.edu/wp-content/uploads/ARB-Report-Final-Draft-Transmittal-Feb-26-2016.pdf*

manure as a slurry without the addition of water are extremely rare in the Valley. [139] In addition, lagoons and storage ponds that hold manure are required to be lined in order to reduce the chances of manure contaminating the groundwater. Manure storage bags may not be allowed because there is a high possibility that something may puncture the bag causing manure to leak, which could degrade groundwater.

The District is unaware of any dairies in the Valley that are currently using storage bags to store manure. Manure storage bags are not suitable for the typical size dairies in the Valley and there are questions about if these bags would comply with existing California regulations, including water regulations. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Liquid Manure Storage Covers - ***(applies to all CAFs)***

The NRCS Reference Guide includes manure storage covers as a potential measure to reduce emissions from the storage of manure. Manure can be handled and stored in the form of a thick slurry, a dilute liquid, or as a solid. A study[140] notes that placing a cover over a lagoon can reduce emissions, however the different cover types have both benefits and drawbacks. Such covers include, natural or synthetic and they may be flexible or rigid, which vary in cost. The type of cover that is appropriate for each operation depends on the size and type of manure storage, environmental factors, and the goals of the farm. Manure storage covers limit emissions by slowing diffusion of gases and reducing the effects of wind on the surface of the manure. Although manure storage covers may reduce pollutants directly emitted from the manure, they do not destroy or eliminate pollutants such as ammonia. Rather, concentrations of these pollutants increase in the stored manure and additional measures would be required to prevent their release when the manure is removed from storage.

As previously mentioned, Valley dairies that handle manure as a slurry without the addition of water are extremely rare and therefore certain types of manure covers are generally not applicable. The NRCS Reference Guide notes that concrete covers cannot be used on earthen or steel manure storages and natural covers (e.g. straw, barely, cornstalks) are impractical if the surface area of the storage is very large. Dairies in the Valley primarily store liquid manure with low solids content in large earthen lagoons or ponds,[141] therefore concrete covers and natural covers cannot feasibly be used to cover liquid manure in the

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[139] Marklein, A. R., Meyer, D., Fischer, M. L., Jeong, S., Rafiq, T., Carr, M., and Hopkins, F. M. (2021) Facility-Scale Inventory of Dairy Methane Emissions in California: Implications for Mitigation, Earth Syst. Sci. Data, 13, 1151–1166, *https://doi.org/10.5194/essd-13-1151-2021*, 2021.

[140] Marks, R. (2001). Cesspools of Shame: How Factory Farm Lagoons and Sprayfields Threaten Environmental and Public Health. *Natural Resources Defense Council and the Clean Water Network*. Retrieved from: *https://www.nrdc.org/sites/default/files/cesspools.pdf*

[141] Meyer, D., Price, P.L., Rossow, H.A., Silva-del-Rio, N., Karle, B., Robinson, P.H., DePeters, E.J., and Fadel, J. (2011) Survey of Dairy Housing and Manure Management Practices in California. Journal Dairy Sci. 94:4744-4750. *https://doi.org/10.3168/jds.2010-3761*

Valley. Additionally, the Valley regulations from the Regional Water Quality Control Board[142] and mosquito abatement districts[143] generally require the removal of any materials that would form natural covers in order to decrease the chances for the proliferation of mosquitos and other vectors.

Although covers made of rigid plastic, such as HDPE, may be a potential option to cover lagoons and ponds that store liquid manure in the Valley, they would be very prohibitively expensive because of the large area that would need to be covered. As previously mentioned, the average dairy in the Valley has almost 1,600 cows compared to a national average of less than 300 cows per dairy outside of California. Since the Valley dairies are larger compared to other dairies in the nation, the lagoons and ponds that store liquid manure are also several times larger compared to the national average dairy that stores mostly undiluted slurry manure.

Moreover, manure covers do not destroy ammonia, rather they create a barrier that suppresses emissions of ammonia from the manure and air space above the manure. This leads to increased concentrations of ammonia and other air contaminants in the manure and air space above the manure, which will just delay the release of ammonia until it is sent to a different pond or applied to land. The increase concentration of ammonia in the manure will also increase the pH and subsequently increase the potential for ammonia emissions. Furthermore, because of the warm climate of the Valley, covering a lagoon with a plastic cover would turn the lagoon into an anaerobic digester. The majority of anaerobic digesters operating on dairies in the Valley are already covered lagoon digesters. The Reference Guide also states that gases will build up under impermeable covers that must be flared or utilized in another way. Flaring or combusting these gases would produce NO_X, which is the primary precursor for PM2.5 in the Valley, as well as direct PM2.5 emissions.

The District has permitted several facilities to construct and operate a covered lagoon. However, in each case, the covered lagoon was part of a digester system to capture biogas/digester-gas, and the cost of the system was funded by grants from the California Department of Food and Agriculture (CDFA) Dairy Digester Research and Development Program.

In conclusion, it is not reasonable to require covers to reduce ammonia emissions from liquid manure storage in the Valley given the high expense associated to the practice and the fact that the practice is not expected to result in any overall reductions of ammonia emissions in the Valley, but could increase emissions of other pollutants.

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[142] California Regional Water Quality Control Board Central Valley Region. Order R5-2013-0122. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

[143] The Fresno County Mosquito Control Districts. Retrieved from: *https://fresnocountymosquito.org/*

<u>Solid Manure Storage Covers</u> - *(applies to all CAFs)*

EPA identified Method 62 (Cover solid manure sources with sheeting) from the UK User Guide, noting that it could result in ammonia emission reductions up to 90 percent. Method 62 involves covering solid manure stores with sheeting, which provides a physical barrier preventing the release of ammonia to the air. EPA acknowledged that this method "would increase ammonium content of the slurry, potentially leading to higher ammonia emissions during storage and spreading." District Rule 4570, EPA acknowledges, contains mitigation measure options for the covering of dry manure piles, and in most cases, facilities are required to cover manure and separated solids or else remove them from the facility.[144]

Storage of solid manure/separated solids contributes a very small amount of total ammonia emissions in the Valley, by making up less than 2 percent of the total ammonia emissions from dairies. Nonetheless, covering for solid manure/separated solids during the months of October through May is included in Rule 4570 and required for most dairies during these 8 months of the year, which include the District's PM2.5 season.

Based on District permitting records covering solid manure or separated manure solids during October through May is required by 729 dairies, 84 percent of the dairies are subject to Rule 4570, and a larger percentage of the total dairy cattle since this measure is required for all dairies that are classified as large confined animal facilities under the rule.

Covers for solid manure/separated solids is not required during the summer because solid manure is primarily composed of organic material that is combustible and during the hot summers in the Valley, elevated temperatures increase the chances of spontaneous combustion of manure piles.[145] Therefore, for safety reasons manure covers cannot be required during the hotter summer months. However, through District Rule 4570, the District requires CAFs to cover solid manure/separated solids during the colder winter months, as shown below:

- Cover dry manure outside the housing with a weatherproof covering from October through May, except for times when wind events remove the covering, not to exceed 24 hours per event.
- Cover separated solids outside the housing with a weatherproof covering from October through May, except for times when wind events remove the covering, not to exceed 24 hours per event.

[144] Chadwick, D.R. (2005). Emissions of Ammonia, Nitrous Oxide and Methane from Cattle Manure Heaps: Effect of Compaction and Covering. *Atmosphere Environment*, Vol. 39, Issue 4: 787-799. Retrieved from: *https://www.sciencedirect.com/science/article/abs/pii/S135223100400994X*

[145] Westendorf, M. L. "Animal Science Update: Spontaneous Combustion". New Jersey Farmer. August 15, 2016. Page 6. *https://plant-pest-advisory.rutgers.edu/spontaneous-combustion/*

In conclusion, the District already has a mechanism to implement this mitigation measure for solid manure/separated solid stored onsite. No additional ammonia reductions are expected from the suggested mitigation measure.

Allow Cattle Slurry Stores to Develop a Natural Crust - ***(applies to dairy cattle only)***

This measure identified in the UK User Guide involves retaining a surface crust on slurry stores, composed of fiber and bedding material present in cattle slurry, for as long as possible. This practice is applicable to thick slurry manure, which differs from the typical liquid manure stored in the Valley. The dilute liquid manure handled in the Valley is stored in ponds and lagoons much larger than storages used for slurry manure in other regions, and does not contain enough solids to form a natural crust.

Additionally, this practice is more applicable to cooler climates, while in the Valley's warm climate, floating debris on liquid manure create a habitat for mosquitos and other vectors that carry diseases, including West Nile virus, zika, dengue, chikungunya, and St. Louis encephalitis.[146] To reduce the potential for the propagation of mosquitos and other disease carrying vectors, Regional Water Quality Control Board[147] and Mosquito Abatement District regulations require the removal of any dead algae, vegetation, and floating debris, including those that would form a natural crust on the surface of a lagoon or pond.[148] Thus, this practice is not allowed in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Solid-Liquid Separation - ***(applies to all CAFs)***

The NRCS Reference Guide states that for manure streams handled as a slurry, separation of the solid and liquid portions prior to storage, additional treatment, and/or land application may reduce odor and other gaseous emissions, particularly for undersized lagoons. Various solid separation technologies are used for these purposes, including screens, rotary drums, centrifugal tanks, earthen pits, weeping walls, settling basins and screw-presses.

Dairies in the Valley primarily handle liquid manure that has been diluted with water, rather than slurry manure, and the effluent from dairies in California often has a total solids content of only 1 percent;[149] therefore this measure is not directly applicable to most dairies in the Valley. The NRCS Reference Guide indicates that solid-liquid separation does not work well for manure streams with very low or very high solids content, unless advanced technologies

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[146] The Fresno County Mosquito Control Districts. Retrieved from: *https://fresnocountymosquito.org/*

[147] California Regional Water Quality Control Board Central Valley Region. Order R5-2013-0122. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

[148] Collar, C. (2005). West Nile Virus – How Dairies Can Help 'Fight the Bite. *University of California, Davis, Cooperative Extension.* Retrieved from: *https://cemerced.ucanr.edu/newsletters/September_200523148.pdf*

[149] Meyer, D, Heguy, J., Karle, B. and Robinson, P. (2019) Characterize Physical and Chemical Properties of Manure in California Dairy Systems to Improve Greenhouse Gas Emission Estimates. California Environmental Protection Agency, Air Resources Board. Retrieved from: *https://ww2.arb.ca.gov/sites/default/files/classic/research/apr/past/16rd002.pdf*

or multiple separation stages or screen sizes are used to remove large and small solids from the manure stream separately. These technologies will have additional challenges and increased costs. Additionally, some studies indicate that the majority of ammonia nitrogen in dilute manure streams remains in the liquid portion and are not removed by solid-liquid separation. The NRCS Reference Guide indicates that some separator designs may increase emissions of gases or particles during the separation process. Dried separated solids may also increase the potential for PM emissions.

As mentioned above, this control measure is applicable to manure handled as a slurry rather than the dilute liquid manure that is typically handled on dairies in the Valley. Therefore, this practice is not directly applicable to dairies in the Valley. However, for cattle facilities that handle liquid manure, Rule 4570 does allow the facilities to choose the option to remove solids from the waste system with a solid separator system prior to the waste entering the lagoon. This option has been chosen by the vast majority cattle facilities that handle liquid manure, including over 90 percent of dairy cattle facilities subject to Rule 4570.[150] The option in Rule 4570 is as follows:

- Remove solids from the waste system with a solid separator system, prior to the waste entering the lagoon.

In conclusion, the District already has a mitigation measure option to minimize emissions from solid-liquid manure separation. No additional ammonia reductions are expected from the suggested mitigation measure.

Anaerobic Digesters - ***(applies to dairy cattle only)***

Anaerobic digesters are storage or treatment lagoons that are undergoing anaerobic reactions, primarily located at dairies. Digesters are outfitted with roofs and covers that enclose all anaerobic emissions within the system and vent to a gas collection system that eliminates undesired methane emissions. The microbes performing anaerobic reactions in lagoons convert nitrogen to form various new compounds, including ammonia. Through the implementation of its Short-Lived Climate Pollutant Strategy and SB 1383,[151] the State of California has funded the installation of over 120 dairy digester systems throughout the state to reduce methane emissions, with the majority of installations in the San Joaquin Valley. Through the generation of vehicle renewable natural gas, some dairy digester systems have the potential of reducing vehicle-related NOx, PM2.5, air toxics, and greenhouse gas (GHG) emissions.

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[150] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*

[151] CARB. Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target. (March 2022). Retrieved from: *https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwiayMXd4af9AhXWrmoFHYf2BNsQFnoECBAQAQ&url=https%3A%2F%2Fww2.arb.ca.gov%2Fsites%2Fdefault%2Ffiles%2F2022-03%2Ffinal-dairy-livestock-SB1383-analysis.pdf&usg=AOvVaw32GB5_r8-3GsSd57-XTnyo*

Some forms of energy conversion from biogas (e.g., burning biogas in an engine to produce electricity) may increase emissions of NOx, a precursor for PM2.5 and ozone, and direct PM2.5 emissions. These emissions can have a negative impact in the Valley, which is designated as nonattainment for PM2.5 and ozone This technology is very expensive, due to capital costs, operation, and maintenance expenses. It also requires significant addition of water, and may not be feasible in water-limited areas.

The NRCS Reference Guide includes anaerobic digesters as a measure to reduce VOCs and GHG emissions, but does not indicate that it reduces ammonia. Some of the information discussed in the NRCS Reference Guide about anaerobic digestion indicates a potential for increased ammonia emissions. The results of some studies also indicate that there is a potential for increased ammonia emissions following digestion.[152] There is limited information regarding the potential and scale of ammonia emissions impacts associated with digester, and California does not currently attribute any increased ammonia impacts from the implementation of dairy digester systems.

At this time there are significant uncertainties about the overall effect of anaerobic digesters on ammonia emissions from manure and additional research is needed to better understand this, particularly for digesters in the Valley. Because of this and the very high costs associated with installation of anaerobic digesters, they are not a feasible option to implement into Rule 4570 at this time. However, this practice would be evaluated as a potential BACT measure for any new or expanding operations; the required mitigation measure from BACT Guideline 5.8.6[153], is as follows:

- Anaerobic treatment lagoon designed according to NRCS Guideline 359.

In conclusion, the District already has a mechanism to implement this mitigation measure for expanding or new confined animal facilities. No additional ammonia reductions are expected from the suggested mitigation measure.

Manure Additives - ***(applies to all CAFs)***

Manure amendments are not practical for manure handled as a dilute liquid, which is typical for Valley dairies, because the large volume of water mixed with the manure greatly increases the amount of an amendment required to change the properties of liquid manure, such as pH. The addition of certain amendments also increases the risk of foaming in liquid manure, which can damage pumps.[154] For slurry and liquid manure, it is difficult and costly to apply a

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[152] Koirala, K., Ndegwa, P.M., Joo, H.S., Frear, C., Stockle, C.O., Harrison, J.H. (2013). Impact of Anaerobic Digestion of Liquid Dairy Manure on Ammonia Volatilization Process. *American Society of Agricultural and Biological Engineers,* Vol. 56(5): 1959-1966. Retrieved from: *https://labs.wsu.edu/ndegwa/documents/2016/09/Article-57.pdf/*

[153] CARB BACT Guidelines Tool. Retrieved from: https://ww2.arb.ca.gov/sites/default/files/classic/technology-clearinghouse/bact/BACTID781.pdf?:linktarget=_self&:embed=yes

[154] USDA NRCS/EPA (2017) Agricultural Air Quality Conservation Measures Reference Guide for Poultry and Livestock Production Systems. *https://www.nrcs.usda.gov/sites/default/files/2022-06/Ag_AQ_Conservation_Measures_Poultry_and_Livestock_September_2017.pdf*

sufficient amount of amendments to change the pH of the manure because of its natural buffering capacity, or resistance to changes in pH due to its chemical properties.

The NRCS Reference Guide states, *"It is often difficult to establish microbiological additives due to competition from naturally-occurring bacteria in manure."* The microbes in microbial additives are often out-competed by the naturally occurring microorganisms, because of the abundance of diverse microorganisms that are naturally present in manure that can multiply rapidly when favorable conditions are present. As a result, microbial additives are often ineffective or must be continually added to the manure. A study[155] conducted by Iowa State University, clearly demonstrates that many questions remain unanswered about the general effectiveness of microbial additives used to reduce emissions. The study evaluated 12 commercial microbial additives that were marketed for their ability to reduce emissions of odorous VOCs, H2S, ammonia, GHG, and odors. The results indicated that emissions from the treated manure were not statistically significant to the untreated manure for any of the 12 products tested. Thus, the ability of microbial additives to reduce emissions from manure remains unproven. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Acidifying Slurry and Shifting Chemical Balance from Ammonia to Ammonium - *(applies to all CAFs)*

This mitigation method mentioned in the compilation by Guthrie, et al.[156] involves the use of manure amendments to minimize ammonia emissions. Manure amendments are not practical for manure handled as a dilute liquid, which is typical for Valley dairies, because the large volume of water mixed with the manure greatly increases the amount of an amendment required to change the properties of liquid manure, such as pH. The addition of certain amendments also increases the risk of foaming in liquid manure, which can damage pumps. For slurry and liquid manure, it is difficult and costly to apply a sufficient amount of amendments to change the pH of the manure because of natural buffering capacity. Notably, some additives can even increase emissions of certain pollutants and can be toxic to handle.

Moreover, any additives to the manure require approval of the Water Quality Control Board.[157] The Water Quality Control Board has determined that increased salinity is a threat

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[155] Koziel, J., Chen, B., Andersen, D., Parker, D., Bialowiec, A., Banik, C., Lee, M., O'Brien, S., Ma, H., Meiirkhanuly, Z., Wi, J., Li, P., Iowa State University. (2021). Evaluating Manure Additives for Odor Mitigation. *National Hog Farmer*. Retrieved from: *https://www.nationalhogfarmer.com/agenda/evaluating-manure-additives-odor-mitigation*

[156] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[157] California Regional Water Quality Control Board Central Valley Region. (March 2017). Resolution R5-2017-0031 (Accepting the Salt and Nitrate Management Plan). Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/resolutions/r5-2017-0031_res.pdf*

to water quality in the Valley.[158] As a result, in many cases the application of amendments and additives that use salts to change pH will not be allowed.

For reasons discussed above, manure amendments are not practical for most operations in the Valley. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Acidifying Amendments and Additives for Poultry Litter - ***(applies to poultry only)***

This method involves the application of aluminum to poultry litter to reduce the pH of the litter. However, poultry operations have already reduced nitrogen excretion by 55 percent and are not a significant source of ammonia in the Valley. Use of acidifying litter amendments is more common for poultry litter however, any additives to the manure require approval of the Water Quality Control Board. The Water Quality Control Board has determined that increased salinity is a threat to water quality in the Valley.[159, 160] As a result, in many cases the application of amendments and additives that use salts to change pH will not be allowed.

Notably, some additives can increase emissions of certain pollutants and can be toxic to handle. For example, the litter in poultry houses in the Valley are drier than many other parts of the country and therefore aluminum would need to be applied as a liquid. Nevertheless, liquid aluminum is an acid that is dangerous to handle and requires a certified applicator to be hired which results in higher costs.

Despite the uncertainties above, the District further evaluated the potential emission reductions of implementing this measure in the Valley. This analysis is provided below.

Ammonia is a weak base and reducing the pH of litter binds ammonia and reduces its volatilization. Aluminum sulfate, also known as alum, is a common compound used to treat poultry litter to reduce ammonia emissions and bind phosphorous to prevent runoff. The typical recommended application rate for aluminum sulfate is 0.1 to 0.2 lb of aluminum sulfate per broiler placed.[161] The higher the aluminum sulfate application rate, the higher the ammonia control and phosphorus binding ability of aluminum sulfate. The lower recommended application rate will control ammonia emissions for about half the time as the

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[158] California Regional Water Quality Control Board Central Valley Region. (May 2006). Salinity in the Central Valley. Retrieved from: *https://www.waterboards.ca.gov/waterrights/water_issues/programs/bay_delta/california_waterfix/exhibits/docs/CDWA%20et%20al/SDWA_206.pdf*

[159] California Regional Water Quality Control Board Central Valley Region. (May 2006). Salinity in the Central Valley. Retrieved from: *https://www.waterboards.ca.gov/waterrights/water_issues/programs/bay_delta/california_waterfix/exhibits/docs/CDWA%20et%20al/SDWA_206.pdf*

[160] California Regional Water Quality Control Board Central Valley Region. (March 2017). Resolution R5-2017-0031 (Accepting the Salt and Nitrate Management Plan). Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/resolutions/r5-2017-0031_res.pdf*

[161] See Moore, P. Treating Poultry Litter with Aluminum Sulfate. USDA ARS. Developed by Livestock GRACEnet. *https://www.ars.usda.gov/ARSUserFiles/np212/LivestockGRACEnet/AlumPoultryLitter.pdf*

higher recommended application rate.[162, 163] Young chicks are more vulnerable to higher ammonia concentrations in the houses; however, ammonia emissions are lower because of the lower amount of manure produced by the smaller birds. These recommended application rates are based on broilers with a finished weight of approximately four pounds. Larger birds will require correspondingly larger application rates to achieve the same control of ammonia.[164]

A study published in 2020 found that an application rate of 98 kg of aluminum sulfate per 100 square meters incorporated into litter reduced overall ammonia emissions from broilers by 35 percent.[165] In the study, the birds were placed in 2.1 m by 1.8 m pens with 50 birds per pen to evaluate different treatments. Therefore, the application rate of alum on a per bird basis was calculated as follows:

98 kg/100 m^2 x 2.1 m × 1.8 m ÷ 50 bird = 0.074 kg/bird

The application rate of 0.074 kg/bird is equivalent to an application rate 0.16 lb-aluminum sulfate per bird. Therefore, it will be assumed that this is the application rate required to reduce ammonia emissions by 35 percent. The District's current ammonia emission factor for broiler chickens is 0.0958 lb-NH3/bird-year. Thus, the ammonia emission reductions for this practice can be calculated as follows:

0.0958 lb-NH3/bird-year x 35% = 0.0335 lb-NH3/bird/year

The cost of the emission reductions is based on the cost of the purchase and application of aluminum sulfate. Because of the typically dry conditions in the Valley, liquid aluminum sulfate is preferred because moisture is required for aluminum sulfate to react with ammonia. A USDA-ARS publication[166] indicates that one ton of aluminum sulfate is equivalent to 370 gallons of liquid aluminum sulfate. Based on a web search, the price of aluminum sulfate is estimated to be $1,155 per 55 gallon drum.[167] The customer applicator rate is assumed to be

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[162] Moore, P., Watkins, S. Treating Poultry Litter with Alum. University of Arkansas (U of A) Division of Agriculture Cooperative Extension Service. *https://www.uaex.uada.edu/publications/PDF/FSA-8003.pdf*
[163] Moore, P., Miles, D., Burns, R. (March 2019). Reducing Ammonia Emissions from Poultry Litter with Alum. Livestock and Poultry Environmental Learning Community (LPELC). *https://lpelc.org/reducing-ammonia-emissions-from-poultry-litter-with-alum/*
[164] Anderson, K.; Moore, P.A., Jr.; Martin, J.; Ashworth, A.J. (2020) Effect of a New Manure Amendment on Ammonia Emissions from Poultry Litter. *Atmosphere*, *11*, 257. *https://doi.org/10.3390/atmos11030257*
[165] Penn, C., Zhang, H (April 2017) Alum-Treated Poultry Litter as a Fertilizer Source. Oklahoma State University Extension. *https://extension.okstate.edu/fact-sheets/alum-treated-poultry-litter-as-a-fertilizer-source.html#nitrogen-content-of-alum-treated-litter*
[166] See Moore, P. Treating Poultry Litter with Aluminum Sulfate. USDA ARS. Developed by Livestock GRACEnet. *https://www.ars.usda.gov/ARSUserFiles/np212/LivestockGRACEnet/AlumPoultryLitter.pdf*
[167] Alliance Chemical, Price of Aluminum Sulfate 50%. Retrieved from: *https://alliancechemical.com/product/aluminum-sulfate-50/?attribute_pa_size=55-gallon&attribute_pa_packaging-type=drum&gclid=EAIaIQobChMIurHTv9WT_QIVMRPUAR1c5QvKEAQYASABEgJ5__D_BwE*

$100 for each broiler house housing 20,000 birds. Therefore, the total cost for each application of aluminum sulfate on a per bird basis is calculated as follows:

0.16 lb-aluminum sulfate/bird x 1 ton/2,000 lb x 370 gal-aluminum sulfate/ton-aluminum sulfate x $1,155/55 gal-aluminum sulfate + $100/20,000 bird = $0.63/bird

Approximately 6.7 broiler flocks are produced each year and aluminum sulfate must be applied prior to placing each flock; therefore, the annual cost of this measure on a bird capacity basis is 6.7/year x $0.63/bird = $4.22/bird capacity-year.

The cost effectiveness of the ammonia reductions from this measure are calculated as follows:

$4.22/bird-year ÷ 0.0335 lb-NH3/bird-year x 2,000 lb/ton = $251,940/ton-NH3 reduced

As demonstrated above, the potential reductions from this measure are not cost effective, with a cost effectiveness of $251,940 per ton of ammonia reduced. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

<u>Urease Inhibitors</u> - *(applies to all cattle)*

A study[168] indicates that the information for this control measure was taken from AirControlNet, a software tool previously used by EPA to estimate the cost of emission reductions. The AirControlNET v.4.1 Documentation Report[169] indicates that the specific chemical additive that this measure refers to was N-(n-butyl) thiophosphoric triamide (NBPT), which was being sold under the trade name Conserve-Nr. NBPT is a type of urease inhibitor. The cost information was provided by a supplier of the chemical and appears to be an underestimate.

Urease inhibitors inhibit the action of the enzyme urease. Urease, which is present in feces and produced by soil microorganisms, converts urea into ammonia, which can then volatilize. Although there are many compounds that can inhibit urease, only a few are non-toxic, effective at low concentrations, and chemically stable. Urease inhibitors have shown promising results for reducing nitrogen emissions from urea-based fertilizers, but some studies indicate that there remain questions about their effectiveness in reducing ammonia from manure.[170]

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[168] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: *https://pubs.acs.org/doi/pdf/10.1021/es060379a*

[169] E.H. Pechan & Associates, Inc. (September 2005). AirControlNET v.4.1 Documentation Report. Retrieved from: *https://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=P1012ZYW.TXT*

[170] Lasisi, A.A., Akinremi, O.O., and Kumaragamage, D. "Ammonia emission from manures treated with different rates of urease and nitrification inhibitors," Canadian Journal of Soil Science 100(3), 198-205, (25 February 2020). Retrieved from: *https://doi.org/10.1139/cjss-2019-0128*

Urease inhibitors appear to reduce ammonia emissions for relatively short periods of time and must be reapplied, and the buildup of urea in the pen surface may require that the NBPT additions increase with time to continue to control ammonia. Because of the need to re-apply increasing amounts of urease inhibitors as manure and urea accumulate, there will be increased costs.

Additionally, there is evidence that urease inhibitors may alter plant metabolism and lead to accumulation of urea in plant tissue,[171] which can have negative effects on crops. Urea inhibitors will also increase the amount of nitrogen in the manure, and to comply with Water Quality Control Board Regulations, some farms would need to acquire additional cropland to apply the manure or identify ways to export the manure to ensure that nitrogen is not over-applied.

It appears that the treatment of animal manure with urease inhibitors has not yet been commercialized. This is likely because of the limited chemical stability of the inhibitors, the need for reapplication, the lack of efficient and automated application systems, and a subsequent increase in the cost for the farmer. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Surface Cooling of Slurry Manure - *(applies to all CAFs)*

The publication by Guthrie, et al.[172] suggests this measure for CAFs with a slurry manure handling system. The measure involves lowering the temperature of the slurry in the channels by pumping a coolant (e.g., groundwater) through a series of fins floating on the slurry. This measure appears to be largely theoretical, and the District is not aware of any instances in which cooling of liquid or slurry manure has been used to reduce emissions from animal production operations. Furthermore, there are high costs for installation of piping and pumping coolant and circulation of coolant through manure, and recycling groundwater may not be permitted in some regions. For these reasons, this measure is unproven and not feasible to implement in the Valley.

Feeding Strategies to Lower the pH of Manure - *(applies to all CAFs)*

Livestock feeding strategies can influence the pH of manure and urine. The pH of manure can be lowered by increasing the fermentation in the large intestine. This increases the volatile fatty acids (VFA) content of the manure and causes a lower pH. The pH of urine can be lowered by lowering the electrolyte balance of the diet. Furthermore, the pH of urine can be lowered by adding acidifying components to the diet. A low pH of the manure and urine

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[171] Zanin L, Venuti S, Tomasi N, Zamboni A, De Brito Francisco RM, Varanini Z, Pinton R. (2016) Short-Term Treatment with the Urease Inhibitor N-(n-Butyl) Thiophosphoric Triamide (NBPT) Alters Urea Assimilation and Modulates Transcriptional Profiles of Genes Involved in Primary and Secondary Metabolism in Maize Seedlings. Front Plant Sci. 2016 Jun 22;7:845. doi: 10.3389/fpls.2016.00845. PMID: 27446099; PMCID: PMC4916206.
[172] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

excreted also results in a low pH of the slurry/manure during storage even after a certain storage period. This pH effect can reduce ammonia emissions from slurries during storage and also following application. This measure is primarily for non-ruminants, such as poultry and pigs and is not recommended for cattle.

The pH of freshly excreted urine mainly depends on the electrolyte content of the diet. The pH of urine will eventually rise towards alkaline values due to the hydrolysis of urea irrespective of initial pH; however, the initial pH and the pH buffering capacity of urine affect the rate of ammonia volatilization from urine immediately following urination. Lowering the pH of urine of ruminants is theoretical possible. However, it has not been demonstrated to be feasible on actual farms. Lowering the pH of cattle manure is also theoretically possible, but this might easily coincide with disturbed rumen fermentation and is therefore not recommended. Since this measure has not been demonstrated for cattle and remains theoretical, it is premature to consider it as part of any regulatory efforts.

The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Land Application of Manure

Table 11: Land Application of Manure Measures Evaluated

Method	Measure	CAF Type	Reference
Timing of Land Application	Timing of Land Application	All Cattle	NRCS[173]
	Optimal Weather Conditions for Spreading	All Cattle	Guthrie[174]
Injection	Injection	All Cattle	NRCS
	Use Slurry Injection Application Techniques	All Cattle	Price[175]
	Injector	All Cattle	Guthrie

[173] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf

[174] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: https://www.rand.org/pubs/research_reports/RR2695.html

[175] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from: https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf

Method	Measure	CAF Type	Reference
	Open-slot Injection	All Cattle	Webb[176]
	Injector	All Cattle	Eory[177]
	Injection Techniques	All Cattle	Bittman[178]
	Injection into the Soil	All Cattle	Preece[179]
Incorporation of Liquid and Solid Manure	Incorporation	All Cattle	NRCS
	Incorporate Manure into the Soil	All Cattle	Price
	Incorporation of Manure	All Cattle	Guthrie
	Incorporation of Surface-Applied Solid Manure and Slurry into Soil	All Cattle	Bittman
	Incorporation into the Soil	All Cattle	Preece
	Incorporate Manure into the Soil	All Cattle	Atia[180]

[176] Webb, J., Pain B., Bittman, S., Morgan J. The impacts of manure application methods on emissions of ammonia, nitrous oxide and on crop response—a review. Agric. Ecosyst. Environ. 137, 39–46 (2010). Retrieved from: *https://www.sciencedirect.com/science/article/abs/pii/S0167880910000046?via%3Dihub*

[177] Eory, V., Rees, B., Topp, K., Dewhurst, R., et al. ClimateXChange, "On-farm technologies for the reduction of greenhouse gas emissions in Scotland," March 2016. Retrieved from: *https://www.climatexchange.org.uk/media/1927/on-farm_technology_report.pdf*

[178] Bittman, S., Dedina, M., Howard C.M., Oenema, O., Sutton, M.A., (eds), 2014, "Options for Ammonia Mitigation: Guidance from the UNECE Task Force on Reactive Nitrogen," Centre for Ecology and Hydrology, Edinburgh, UK. Retrieved from: *http://www.vuzt.cz/svt/vuzt/publ/P2014/037.pdf*

[179] Preece, Sharon L.M. et al., ''Ammonia Emissions from Cattle Feeding Operations,'' Texas A&M AgriLife Extension Service, referring to Cole, N.A., R.N. Clark, R.W. Todd, C.R. Richardson, A. Gueye, L.W. Greene, and K. McBride, ''Influence of Dietary Crude Protein Concentration and Source on Potential Ammonia Emissions from Beef Cattle Manure,'' Journal of Animal Science 83:(3), 722 (2005)

[180] Atia, A. (2008). Ammonia volatilization from manure application. Alberta Agriculture, Food and Rural Development. Retrieved from: *https://open.alberta.ca/dataset/b115d4b8-982d-43d5-97a6-1d987bf8ba01/resource/863253f1-22f1-4a7b-950a-c424ef5cc9e5/download/2008-538-3.pdf*

Method	Measure	CAF Type	Reference
	Immediate Incorporation of Applied Manure	All Cattle	Pinder[181]
Band Spreading	Banding	All Cattle	NRCS
	Slurry Band Spreading Application Techniques	All Cattle	Price
	Band Spreading	All Cattle	Guthrie
	Band Spreading Slurry	All Cattle	Bittman
Other Land Application	Slurry Dilution	All Cattle	Bittman
	Transport Manure to Neighboring Farms	All Cattle	Price

Timing of Land Application - ***(applies to all cattle)***

This measure requires operators to apply the correct amount of necessary nutrients to crops when they are most in demand and in locations where they can be accessed by specific plants. Applying nutrients in spring prior to planting, when crops are ready to utilize the nitrogen, can reduce ammonia emissions compared to applying in fall. Applying at lower soil temperatures can also help to reduce near-term ammonia emissions due to reduced microbial activity in cooler soils. Split application to better time the nutrient application to crop needs can also be beneficial.

Although not specifically included in Rule 4570, the measure is already required for confined animal facilities in the Valley that apply manure to land. California Regional Water Quality Control Board regulations[182] require that manure may only be applied to land at agronomic rates in accordance with an approved nutrient management plan, and that nutrients, including nitrogen, may only be applied at times when plants can utilize these nutrients. The rate of application of manure and process wastewater for each crop in each land application area (also considering sources of nutrients other than manure or process wastewater) to meet each crop's needs without exceeding the application rates is specified in the Regional Water Quality Control Board Technical Standard.

[181] Pinder, R., Adams, P., Pandis, S. (2007). Ammonia Emission Controls as a Cost-Effective Strategy for Reducing Atmospheric Particulate Matter in the Eastern United States. *Environmental Science and Technology*, Volume 41, Pages 380-386. Retrieved from: *https://pubs.acs.org/doi/pdf/10.1021/es060379a*

[182] California Regional Water Quality Control Board Central Valley Region. Order R5-2013-0122. Retrieved from: *https://www.waterboards.ca.gov/centralvalley/board_decisions/adopted_orders/general_orders/r5-2013-0122.pdf*

The NRCS Reference Guide estimates that this measure will reduce ammonia emissions from land application by 65-70 percent. Because this measure is already required, as an industry standard, these reductions have already been achieved in the Valley.

Injection - ***(applies to all cattle)***

Applying manure to the soil surface without incorporation can lead to significant emissions of ammonia and other odorous gases. Several of the mitigation measure compilations evaluated by the District included injection of liquid or slurry manure as an option to reduce ammonia emissions from land application. However, this method is more applicable to slurry manure than the dilute liquid manure applied to land in the Valley. Additionally, the equipment needed to transport and inject the dilute liquid manure, which is not typically used in the Valley, would have high costs for fuel and would increase emissions of NOx and PM2.5.

Estimated ammonia emissions reductions from the injection of liquid manure are based on the assumption that surface broadcasting of liquid manure is the typical practice. Broadcasting of liquid manure results in higher emissions because of the larger amount of surface area of the liquid manure that will be in direct contact with the atmosphere. However, nearly all liquid manure in the Valley is diluted and applied via surface gravity irrigation systems, such as flood and furrow irrigation. Because of the much lower concentration of ammonia in the diluted liquid manure typically applied in the Valley, and the reduced surface area of liquid manure in furrow and flood irrigation systems compared to broadcasting, ammonia emissions from the application of liquid manure in the Valley is already much lower than traditional surface broadcasting. A report prepared by the University of California Division of Agricultural and Natural Resources Committee of Experts on Dairy Manure Management[183] indicates that in California, "nearly all" manure from lagoons is diluted with irrigation water and applied via surface gravity irrigation systems and that "during irrigations, farmers commonly dilute lagoon water with 5 to 10 parts of fresh source water." The report goes on to state that "in systems with frequent, but well diluted manure water applications, ammonia losses from the ground surface will commonly be minimal during the irrigation (10 percent or less)." The Ammonia Volatilization from Manure Application fact sheet,[184] estimates that ammonia losses from unincorporated manure to be 66 percent in the spring and early fall; this the standard practice in the Valley of applying manure by gravity flow irrigation is already estimated to reduce ammonia emissions by at least 85 percent compared to broadcasting of manure.

Furthermore, to avoid damaging growing crops, injection of liquid manure can only be performed prior to planting the crop, typically a maximum of two times per year.

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[183] Chang, A., T. Harter, J. Letey, D. Meyer, R. D. Meyer, M. Campbell-Mathews, F. Mitloehner, S. Pettygrove, P. Robinson, R. Zhang (2006) Managing Dairy Manure in the Central Valley of California; University of California Committee of Experts on Dairy Manure Management Final Report to the Regional Water Quality Control Board, Region 5, Sacramento, June 2005. *https://ucanr.edu/sites/groundwater/files/136450.pdf*

[184] Atia, A. (2008). Ammonia volatilization from manure application. Alberta Agriculture, Food and Rural Development. Retrieved from: *https://open.alberta.ca/dataset/b115d4b8-982d-43d5-97a6-1d987bf8ba01/resource/863253f1-22f1-4a7b-950a-c424ef5cc9e5/download/2008-538-3.pdf*

Additionally, the amount of nitrogen that can be applied to cropland is limited to protect water quality. Many agricultural areas in the Valley already have nitrate levels in the groundwater that are above acceptable limits, and many dairies are required to reduce the amount of nitrogen applied to land. Injection of manure reduces the amount of nitrogen emitted to the air, but the retained nitrogen is placed in the soil. Thus, injection of manure into the soil will increase the amount of nitrogen in the cropland and may not be feasible for some dairies, or will require additional land in order to comply with their nutrient management plans.

District Rule 4570 includes the requirement to minimize the amount of emissions from applying liquid manure to the soil. These mitigation measures include an option to inject liquid manure, as shown below:

- Apply liquid/slurry manure via injection with drag hose or similar apparatus

In conclusion, the District already has mitigation measures for liquid manure injection. No additional ammonia reductions are expected from the suggested mitigation measures.

Incorporation of Liquid Manure - *(applies to all cattle)*

Many mitigation measure compilations included incorporation of slurry and liquid manure into soil as an option to reduce ammonia emissions.[185] However, as discussed above, nearly all liquid manure in the Valley is diluted and applied via surface gravity irrigation systems, such as flood and furrow irrigation. Because of the of the much lower concentration of ammonia in the diluted liquid manure typically applied in the Valley, ammonia emissions from the application of liquid manure in the Valley is already much lower than the emissions from broadcasting slurry manure.

Slurry manure is not typically applied in the Valley and liquid manure in the Valley is diluted prior to application. However, District Rule 4570 includes a mitigation option to minimize the amount of emissions from incorporating liquid manure to the soil, as shown below:

- Allow liquid manure to stand in the fields for no more than 24 hours after irrigation.

In conclusion, the District already has mitigation measures for the incorporation of liquid manure. No additional ammonia reductions are expected from the suggested mitigation measures.

Incorporation of Solid Manure - *(applies to all cattle)*

The NRCS Reference Guide and UK User Guide include methods for incorporation of solid manure that involve mixing manure with surface soil to reduce the exposed surface area of the manure. The reference guide advises that incorporation should occur as soon as possible

[185] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

after the manure is applied, or at least within 24 hours, to reduce ammonia emissions. In the Valley, solid manure land application accounts for less than 3 percent of total ammonia emissions from dairies and incorporation of solid manure within 72 hours is already required for over 80 percent of cattle facilities that apply manure to land.

To avoid damaging growing crops, incorporation of solid manure can only be performed prior to planting the crop, typically a maximum of two times per year. Almost all dairies in the Valley use a double-crop farming system for their cropland to maximize the amount of manure that can be applied and increase the amount of feed produced for the cattle, with some dairies using a triple-crop system. In the typical double-crop system used on Valley dairies, corn for silage is planted in late April through June to be harvested in September, and winter forage (e.g. wheat, oats, barley, etc.) is planted in late September to be harvested in April or May.[186,187] Because of the very short time frame available between crops, the standard practice in the Valley is to incorporate applied solid manure as soon as practical so the land can be prepared for the next crop.

Solid manure applied to cropland is often incorporated immediately after application; however, additional time may sometimes be required due to unforeseen circumstances, such as difficult weather conditions, equipment breakdowns, or the unavailability of the contractors that perform the work since they may be busy at other farms that are also preparing to plant the next crop. With this under consideration, Rule 4570 gives additional time to account for the unforeseen circumstances that may unexpectedly delay incorporation of manure into cropland within 24 hours, as shown below:

- Incorporate all solid manure within 72 hours of land application.

The District is further evaluating requiring solid manure applied to cropland to be incorporated within 24 hours. An analysis of this measure, including the control efficiency and estimated costs, is below.

The control efficiency for incorporation is estimated based on information from the Chesapeake Bay Program Watershed Model report.[188] This report includes estimations of ammonia emission reductions for low-disturbance incorporation and high-disturbance incorporation of manure. The report gives vertical tillage as an example of low-disturbance incorporation and states that for high-disturbance incorporation, chisel plowing followed by

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[186] University of California, Davis. UC Drought Management – Corn. Retrieved from: *https://ucmanagedrought.ucdavis.edu/Agriculture/Crop_Irrigation_Strategies/Corn/*

[187] Ag Proud – Progressive Dairy. 12-Month Forage Pays. Retrieved from: *https://www.agproud.com/articles/30676-12-month-forage-pays*

[188] Chesapeake Bay Phase 6.0 Manure Incorporation and Injection Expert Review Panel: Dell, C., Allen, A., Dostie, D., Meinen, R., Maguire, R (December 2016) Manure Incorporation and Injection Practices for Use in Phase 6.0 of the Chesapeake Bay Program Watershed Model. Prepared for Chesapeake Bay Program, Annapolis, MD 21403. CBP/TRS-309-16. EPA Contract No. EP-C-12-055. *https://d18lev1ok5leia.cloudfront.net/chesapeakebay/documents/Phase_6_FINAL_MII_Final_Report.pdf*

secondary tillage with a disk harrow or field cultivator is expected to be the most common practice. Information in the report indicates that with low-disturbance incorporation, ammonia emissions are reduced 34 percent when manure is incorporated within 72 hours and 50 percent when manure is incorporated within 24 hours. The report also indicates that with high-disturbance incorporation, ammonia emissions are reduced 50 percent when manure is incorporated within 72 hours and 75 percent when manure is incorporated within 24 hours. Based on this information, the ammonia (NH3) emissions from incorporation of solid manure within 72 hours and 24 hours are estimated as follows:

<u>Low-Disturbance Incorporation of Solid Manure within 72 Hours</u>

Control Efficiency: 34%

Percent NH3 emissions of manure that is not incorporated: 66%

<u>Low-Disturbance Incorporation of Solid Manure within 24 Hours</u>

Control Efficiency: 50%

Percent NH3 emissions of manure that is not incorporated: 50%

<u>High-Disturbance Incorporation of Solid Manure within 72 Hours</u>

Control Efficiency: 50%

Percent NH3 emissions of manure that is not incorporated: 50%

<u>High-Disturbance Incorporation of Solid Manure within 24 Hours</u>

Control Efficiency: 75%

Percent NH3 emissions of manure that is not incorporated: 25%

The ammonia control efficiency for incorporation of solid manure within 24 hours rather than 72 hours, compared to the ammonia emissions from solid manure that is not incorporated is estimated as follows:

<u>Low-Disturbance Incorporation of Solid Manure within 24 Hours</u>

66% - 50% = 16%

<u>High-Disturbance Incorporation of Solid Manure within 24 Hours</u>

75% - 50% = 25%

The ammonia emissions from solid manure land application are approximately 2.8 percent of the ammonia emissions from dairies and other cattle facilities; therefore, the overall control efficiency of this measure is estimated to be:

<u>Low-Disturbance Incorporation of Solid Manure within 24 Hours</u>

17% x 2.8% = 0.48% of total NH3 emissions from cattle

High-Disturbance Incorporation of Solid Manure within 24 Hours

25% x 2.8% = 0.7% of total NH_3 emissions from cattle

The incremental ammonia control efficiency for incorporation of solid manure within 24 hours compared to incorporation of solid manure within 72 hours is calculated as follows.

Low-Disturbance Incorporation of Solid Manure within 24 Hours

1 – (50%/66%) = 24.2%

High-Disturbance Incorporation of Solid Manure within 24 Hours

1 – (50%/75%) = 33.3%

This control efficiency is just for the application of solid manure to cropland, which is a very small portion of the total emissions from cattle facilities.

The cost of more rapid incorporation varies greatly, depending whether a farm already has the required equipment available or if the farm requires an additional tractor and must contract with a custom farm service to implement this practice. For farms for which the required equipment for more rapid incorporation is available, it will be assumed that the primary cost of this measure will be the additional labor required to operate the equipment, to ensure that the manure is incorporated within the required timeframe. For other farms for which the required equipment is not available, it will be assumed that they must hire a custom farm service to ensure that manure is incorporated within the required timeframe. The labor costs for incorporation of solid manure and the costs for hiring a custom farm service will be estimated based on information from the University of California Cooperative Extension.[189, 190] The costs for labor and hiring a custom farm service for low-disturbance incorporation of solid manure are assumed to be similar to finish discing of a field, and the costs for labor and hiring a custom farm service for high-disturbance incorporation of manure are assumed to be similar to chiseling a field followed by discing.

Based on the University of California Cooperative Extension publications, the incremental cost for low-disturbance incorporation of solid manure is estimated to be approximately $2.64 per acre if only additional labor is required, and $15.37 per acre if a custom farm service must be used. At dairies in the Valley, solid manure is typically applied to land twice per year so the overall cost for low-disturbance incorporation of solid manure is as follows:

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[189] University of California Cooperative Extension, Agriculture and Natural Resources, Agricultural Issues Center (2016) 2016 Sample Costs to Establish and Produce Alfalfa, Tulare County, Southern San Joaquin Valley, 300 Acre Planting. *https://coststudyfiles.ucdavis.edu/uploads/cs_public/1c/e2/1ce256d0-957e-4bd4-b17e-18fef4efcedd/16alfalfasjv300acfinal_41916.pdf*

[190] University of California Cooperative Extension, Agriculture and Natural Resources, Agricultural Issues Center (2016) 2016 Sample Costs to Establish and Produce Alfalfa, Tulare County, Southern San Joaquin Valley, 50 Acre Planting. *https://coststudyfiles.ucdavis.edu/uploads/cs_public/24/b6/24b68b4a-4c04-4853-b127-d3461e1a248f/16alfalfasjv50ac_final_4192016.pdf*

<u>Incremental Labor Cost for Low-Disturbance Incorporation of Solid Manure within 24 Hours</u>

$2.64/acre x 2 time/year = $5.28/acre-year.

<u>Incremental Cost for Custom Farm Service for Low-Disturbance Incorporation of Solid Manure within 24 Hours</u>

$15.37/acre x 2 time/year = $30.74/acre-year.

Based on the University of California Cooperative Extension publications, the incremental cost for high-disturbance incorporation of solid manure is estimated to be approximately $6.60 per acre if only additional labor is required, and $64.21 per acre if a custom farm service must be used. As mentioned above, at dairies in the Valley solid manure is typically applied to land twice per year so the overall cost for high-disturbance incorporation of solid manure is as follows:

<u>Incremental Labor Cost for High-Disturbance Incorporation of Solid Manure within 24 Hours</u>

$6.60/acre x 2 time/year = $13.20/acre-year.

<u>Incremental Cost for Custom Farm Service for High-Disturbance Incorporation of Solid Manure within 24 Hours</u>

$64.21/acre x 2 time/year = $128.42/acre-year.

Estimated ammonia emissions from unincorporated manure will be based on measurements included in the 2008 Dairy Emission Study report by Schmidt.[191] Based on measurements in this study, ammonia emissions from unincorporated solid manure are estimated to be approximately 4 lb-NH3/acre-year.

The cost effectiveness of the potential ammonia reductions for low-disturbance incorporation of solid manure with 24 hours compared to incorporation with 72 hours are estimated as follows:

<u>NH3 Emissions for Low-Disturbance Incorporation of Solid Manure within 72 hours:</u>

4 lb-NH3/acre-year x 66% = 2.64 lb-NH3/acre-year

<u>NH3 Emissions for Low-Disturbance Incorporation of Solid Manure within 24 hours:</u>

4 lb-NH3/acre-year x 50% = 2.0 lb-NH3/acre-year

<u>Potential NH3 Emission Reductions for Low-Disturbance Incorporation within 24 hours</u>

= 2.64 lb-NH3/acre-year - 2.0 lb-NH3/acre-year = 0.64 lb-NH3/acre-year

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[191] Schmidt, C., Card, T. (August 2009) 2008 Dairy Air Emissions Report: Summary of Dairy Emission Estimation Procedures. Prepared for the San Joaquin Valleywide Air Pollution Study Agency

Cost Effectiveness if Only Additional Labor is Required

Cost of NH3 reductions: $5.28/acre-year ÷ 0.64 lb-NH3/acre-year x 2,000 lb/ton = $16,500/ton-NH3

Cost Effectiveness if Custom Farm Service is Required

Cost of NH3 reductions: $30.74/acre-year ÷ 0.64 lb-NH3/acre-year x 2,000 lb/ton = $96,063/ton-NH3

The cost effectiveness of the potential ammonia reductions for high-disturbance incorporation of solid manure with 24 hours compared to incorporation with 72 hours are estimated as follows:

NH3 Emissions for High-Disturbance Incorporation of Solid Manure within 72 hours:

4 lb-NH3/acre-year x 50% = 2.0 lb-NH3/acre-year

NH3 Emissions for High-Disturbance Incorporation of Solid Manure within 24 hours:

4 lb-NH3/acre-year x 25% = 1.0 lb-NH3/acre-year

Potential NH3 Emission Reductions for High-Disturbance Incorporation within 24 hours

= 2.0 lb-NH3/acre-year - 1.0 lb-NH3/acre-year = 1.0 lb-NH3/acre-year

Cost Effectiveness if Only Additional Labor is Required

Cost of NH3 reductions: $13.20/acre-year ÷ 1.0 lb-NH3/acre-year x 2,000 lb/ton = $26,400/ton-NH3

Cost Effectiveness if Custom Farm Service is Required

Cost of NH3 reductions: $128.42/acre-year ÷ 1.0 lb-NH3/acre-year x 2,000 lb/ton = $256,840/ton-NH3

As explained above, cattle facilities that apply solid manure to cropland incorporate the manure as quickly as possible in order to prepare for planting of the next crop; so this is already an industry standard, therefore, many cattle facilities are already attaining the potential ammonia emission reductions of this practice, except when conditions make this impractical.

In conclusion, the District already has mitigation measures for incorporation of solid manure. No additional ammonia reductions are expected from the suggested mitigation measures.

<u>Band Spreading</u> - *(applies to all cattle)*

This practice[192] reduces volatilization of ammonia by using low-pressure application near the ground. Band spreading of manure can only be done during very limited periods immediately prior to planting of a crop, a maximum of two times per year. This practice is primarily applicable to slurry manure rather than flush manure, and has limited applicability to the Valley in which most manure is applied as a liquid or a solid. Band spreading is generally a slower operation (with lower application rates), so there may be some issues with labor availability. Additionally, there are high costs due to the initial investment of new machines, as well as the costs of ongoing maintenance and fuel.

As previously discussed, nearly all liquid manure in the Valley is diluted and applied via surface gravity irrigation systems, such as flood and furrow irrigation, which allows manure to flow on the ground without using pressure to apply liquid manure. Due to the much lower concentration of ammonia in the diluted liquid manure typically applied in the Valley, and the reduced surface area of liquid manure in furrow and flood irrigation systems compared to broadcasting, ammonia emissions from the application of liquid manure in the Valley is already much lower than traditional surface broadcasting and also expected to be lower than emissions from liquid manure applied with band spreading. Moreover, trucks used for these methods would damage growing crops and directly emit NOx and PM, hindering the District's efforts to attain the PM2.5 and ozone national ambient air quality standards (NAAQS). The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

<u>Slurry Dilution</u> - *(applies to all cattle)*

This method involves the dilution of slurry with water to decrease the ammonium-N concentration, as well as increase the rate of infiltration into the soil following spreading on land. For undiluted slurry, dilution must be at least 1:1 (one part slurry to one part water) to reduce emissions by at least 30 percent.

This practice is applicable to manure handled as a slurry. The slurry manure would be diluted by 50 percent so it can be infiltrated into soil more quickly. The ammonia reductions for this measure are proportional to the extent of dilution. The majority of dairies in the Valley are large flush dairies in which liquid manure mixed with water is stored in large earthen lagoons or ponds until it can be applied to cropland. The typical practice in the Valley is to dilute manure with irrigation water when it is applied to cropland. The liquid handled on Valley dairies typically has a DM content of 2 percent or less. This manure is then commonly further diluted with 5 to 10 parts of fresh source water during irrigation. Because of this, ammonia emissions from the typical application of liquid manure can be estimated to be more than 90 percent lower than the ammonia emissions from this practice (4.5 percent DM applied,

[192] Chang, A., T. Harter, J. Letey, D. Meyer, R. D. Meyer, M. Campbell-Mathews, F. Mitloehner, S. Pettygrove, P. Robinson, R. Zhang (2006) Managing Dairy Manure in the Central Valley of California; University of California Committee of Experts on Dairy Manure Management Final Report to the Regional Water Quality Control Board, Region 5, Sacramento, June 2005. *https://ucanr.edu/sites/groundwater/files/136450.pdf*

compared to 0.2 percent DM applied). The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Transport Manure to Neighboring Farms - ***(applies to all cattle)***

This mitigation measure does not result in overall decreases in ammonia emissions. Although ammonia emissions are reduced from the exporting farm, these emissions are transferred to the receiving farm.

Regional Water Quality Control Board regulations prohibit the over-application of nutrients from manure in the Valley and already only allow manure to be applied at agronomic rates in accordance with an approved nutrient or waste management plan. Nutrient management plans require that farms transport excess manure to other fields or identify other uses for excess manure. Transporting manure would increase emissions of NOx and PM2.5 from fuel use, and these emissions would hinder the District's efforts to attain the PM2.5 and ozone NAAQS. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Other Mitigation Measures

Table 12: Other Mitigation Measures Evaluated

Method	Measure	CAF Type	Reference
Other	Pasture and Range Management: Stocking Density	Other Cattle	NRCS[193]
	Improved Livestock Genetics	All	Price[194]
	Planting a Tree Shelter Belt	All	Guthrie[195]
	Using Plants with Improved Nitrogen Use Efficiency	All Cattle	Guthrie
	Changing Land from Arable to Woodland	All	Guthrie
	Reduced Consumption of Meat and Eggs by Humans	All	Guthrie

Pasture and Range Management: Stocking Density - ***(applies to grazing cattle only)***

The NRCS Reference Guide lists managing animal stocking density at grazing-based livestock operations as a mitigation method for ammonia emissions. However, the District does not have authority to regulate animals on pasture or rangeland, as they are not confined. This measure also does not recommend a specific stocking density; however, cattle that graze on pastureland and rangeland in California generally require low stocking densities to provide sufficient forage for cattle. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

[193] EPA-USDA NRCS. "Reference Guide for Poultry and Livestock Production Systems." September 2017. Retrieved from: *https://www.epa.gov/sites/default/files/2017-01/documents/web_placeholder.pdf*
[194] Price et al., "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture, User Guide," December 2011. Retrieved from:
https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf
[195] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

Improved Genetics - ***(applies to all CAFs)***

A publication prepared for use in the United Kingdom includes genetic selection of useful traits to improve animal health and fertility as a potential mitigation measure to increase the efficiency of animals and reduce environmental impacts. Farmers select animal breeds that have improved genetics that increase efficiency as feasible to reduce overall costs and increase yield. The publication notes that use of animals with improved genetics "*is generally good in the poultry, dairy and pig industries*." Improvements in genetics and management practices to increase efficiency have already significantly reduced the environmental footprint of production from animal agriculture compared to previous years. As a result of genetic selection and improved diets, milk production per cow has increased and feed usage has decreased by 77 percent and water use has decreased by 65%.[196] GHG emissions from California dairy cattle per amount of milk produced have also decreased by over 45 percent in the 50 years from 1964 to 2014.[197] For poultry, it is estimated that genetic selection and the current feed practices have reduced nitrogen excretion by poultry by up to 55 percent, primarily due to the reduced time from egg to market age.[198]

Farmers are expected to continue to use animals with improved genetics that will increase efficiency and reduce production costs. However, there are several issues that cause this measure to be unsuitable as a requirement in a regulation. The study does not specify the genetic traits that need to be improved. The measure is largely theoretical and requires extensive research and funding to develop new breeds with the desired traits. It would take generations of each breed to evaluate the effectiveness of the breeds as it pertains to reducing ammonia emissions and any potential adverse impacts on the environment. There are also potential ethical concerns regarding if animals were to be genetically modified to accelerate selection of specific traits. Therefore, the District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Planting a Tree Shelter Belt - ***(applies to all CAFs)***

This measure involves planting tree shelterbelts around livestock housing and manure slurry storage facilities to disrupt airflow around these sites. The effectiveness of tree shelterbelts as a measure to reduce particulate matter from facilities depends on the shelterbelt height, canopy density, and the prevailing environmental conditions. While some evidence demonstrates effectiveness for PM2.5 emissions reductions, there is little to no evidence for

[196] McCabe, C. (2021). How Dairy Milk Has Improved its Environmental and Climate Impact. Clarity and Leadership for Environmental Awareness and Research at UC Davis. Retrieved from: *https://clear.ucdavis.edu/explainers/how-dairy-milk-has-improved-its-environmental-and-climate-impact*

[197] Naranjo A., Johnson A., Rossow H., Kebreab E. (2020) Greenhouse Gas, Water, and Land Footprint per Unit of Production of the California Dairy Industry Over 50 years. J Dairy Sci. 2020 Apr;103(4):3760-3773. doi: *10.3168/jds.2019-16576*. Epub 2020 Feb 7. PMID: 32037166.

[198] United States Department of Agriculture - Natural Resources Conservation Service. (2020). Feed and Animal Management for Poultry. Nutrient Management Technical Note No. 190-NM-4. Retrieved from: *https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=45569.wba*

ammonia emissions reductions. Effective tree shelterbelts are expensive and difficult to establish due to the large size of the facilities, severe water limitations, soil conditions, and the number of trees needed to protect these areas.

Irrespective of the lack of available data on the potential ammonia emissions reductions, implementation of this measure requires additional consideration with respect to animal health. Cattle facilities in the Valley depend on natural airflow to cool cattle and provide them with fresh air. Disrupting natural airflow can adversely affect cattle that depend on the natural flow of air, particularly during summer months where large numbers of heat-related animal mortalities occur in the San Joaquin Valley. Tree shelterbelts also require sufficient space to be effective, thus, dairies would need either to remove crops or acquire additional land for a shelterbelt. Furthermore, a shelterbelt of sufficient height to be effective would take a number of years to establish. In many cases in the Valley, where the soil has high salinity, conditions are unsuitable for planting tree shelterbelts.

In several cases, permitted CAFs proposed to grow shelterbelts to satisfy District BACT requirements, however, the shelterbelts were not sustainable. Agronomic land surveys of the facilities confirmed the poor soil quality would not sustain the tree shelterbelts. As a result, the District eliminated this option as a BACT requirement for these specific CAFs and allowed an alternative mitigation measure to be implemented.

For the reasons listed above, it is infeasible to require planting tree shelterbelts at animal facilities; however, the trees and plants in the agricultural fields and orchards that surround Valley animal facilities already capture a portion of emissions from these facilities and remove some of the ammonia by deposition. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Using Plants with Improved Nitrogen Use Efficiency - ***(applies to all cattle)***

This measure involves developing new plant varieties with improved genetic traits for the capture of soil nitrogen, which would allow reduced fertilizer application. New plant varieties could also be developed with improved nutritional characteristics. This measure is theoretical and requires extensive research and funding to develop new plant varieties with the desired traits. Years of testing would be required to evaluate the effectiveness of new plant varieties for reducing ammonia emissions and any adverse impacts of the new plant varieties. Furthermore, capturing additional soil nitrogen would primarily benefit water quality rather than reducing ammonia emissions. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Changing Land Use from Arable to Woodland - ***(applies to all CAFs)***

This measure involves changing land use from agricultural land to permanent woodland. However, many areas in the Valley are dry and often affected by droughts, and thus not suitable for the establishment of permanent woodlands. The District does not have authority to require that agricultural land be converted to forests. Moreover, conversion of agricultural land to farmland would result in total loss of income for the farmers and an associated loss in tax revenue. The District has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Reduced consumption of meat and eggs by humans by 63 percent - ***(applies to all CAFs)***

The District does not have authority to regulate what people eat and has concluded that the measure discussed is not a viable mitigation option to include in Rule 4570.

Evaluation of Potential Emissions Reductions from CAFs

As demonstrated in the evaluation above, the District has only identified a few measures that have the theoretical potential to reduce additional ammonia emissions beyond the practices currently enforced through Rule 4570. These measures are reducing CP content in feed for beef finishing cattle, incorporation of solid manure within 24 hours, and acidifying amendments for poultry litter and manure. Despite the technological and economic feasibility issues of these mitigation measures, the District evaluated the potential emission reductions and the impact they might have on the Valley's total ammonia emissions inventory if these measures were to be implemented. This was calculated as follows.

- Control efficiency of reducing CP content in feed for beef finishing cattle, applied to beef cattle emissions inventory:

  18.9% x 16.2 tpd = 3.1 tpd

- Control efficiency of incorporation of solid manure within 24 hours, applied to beef and dairy cattle emissions inventory:

  0.48% x 141.5 tpd = 0.7 tpd

- Control efficiency of acidifying amendments for poultry litter and manure, applied to broiler and layer emissions inventory:

  35% x 7.9 tpd = 2.8 tpd

The emissions reductions from the measures above total 6.6 tpd, which would be reduced from the total ammonia emissions inventory of 324.9 tpd:

6.6 tpd ÷ 324.9 tpd = 2.0%

Overall, ammonia emissions from CAFs in the Valley can only be reduced by 2 percent by implementing the mitigation measures above. This demonstrates that additional reductions in the EPA-recommended range of 30-70 percent are infeasible.

Fertilizers

Ammonia emissions from agricultural fertilizers are 111.2 tpd in 2023. Emissions growth from agricultural fertilizers are estimated by farmland acreage projection data developed by the Farmland Mapping & Monitoring Program (FMMP) of the California Department of Conservation.

The California Department of Food and Agriculture (CDFA) Feed, Fertilizer and Livestock Drugs Regulatory Services (FFLDRS) Branch primary focus is to ensure in every way possible a clean and wholesome supply of meat and milk, and to promote environmentally safe and agronomically sound use and handling of fertilizer materials. This is performed through regulating manufacturing, labeling, and use of fertilizing materials, feed and livestock drugs.

The CDFA Fertilizer Research and Education Program (FREP) funds and facilitates research to advance the environmentally safe and agronomically sound use and handling of fertilizing materials. FREP is voluntary and serves growers, agricultural supply and service professionals, extension personnel, public agencies, consultants, and other interested parties.

The Fertilizer Inspection Advisory Board (FIAB) is a statutory body that is advisory to the CDFA secretary on matters pertaining to fertilizer issues, including FREP activities. The Board consists of nine persons appointed by the secretary of agriculture, one of whom shall be a public member and eight of whom shall be licensed with CDFA to manufacture or distribute fertilizing materials, including organic inputs. The FIAB established the Technical Advisory Subcommittee (TASC) to advise the FIAB on matters related to the funding of FREP projects. The TASC serves as an expert scientific panel on matters concerning plant nutrition and on environmental effects related to fertilizing materials use. TASC assists in setting research priorities, reviews research proposals, and makes recommendations on projects for funding.

The composition of the TASC is determined by the FIAB. There should be at least nine members representing the major segments of the fertilizer industry, certified crop advisors, technical experts, farming community, public, and governmental agencies. Members have to demonstrate knowledge, technical and scientific expertise in the fields of fertilizing materials, agronomy, plant physiology, principles of experimental research, production agriculture, and environmental issues related to fertilizing materials use. One member can satisfy more than one of the criteria stated above. At minimum, one member shall be appointed from the membership of the FIAB, and one member on the TASC shall be from CDFA.

The TASC meets at least two times per year-once in spring to evaluate concept proposals and once in summer to evaluate full proposals. Additional meetings are necessary for special initiatives. Meetings typically last all day and alternate between Sacramento and other locations throughout the State. Serving on the TASC requires a time commitment in addition to participating in meetings. Members must read and critically evaluate all concept proposals (typically around 35 two-page proposals) and full proposals (typically at least ten 15-page proposals). In addition, TASC members are responsible for reviewing final research reports for FREP funded projects and may be asked to participate in conferences and special initiatives.

CARB has not found an ammonia emission reduction measure for fertilizers that meets EPA requirements for SIP submittal. CARB staff reached out to the National Association of Clean Air Agencies (NACAA) to ascertain whether other air pollution control agencies across the United States had any experience or regulations reducing ammonia emissions from fertilizers. NACAA reached out to all of their members and CARB staff did not receive any existing rules or regulations controlling ammonia emissions from fertilizers. CARB staff also reached out to

EPA Region 9 staff whether they were aware of any rules or regulations controlling ammonia emissions from fertilizers and they were not aware of any. EPA Region 9 staff did ask CARB to review some practices per Table 12.

Mitigation Measures

Table 13: Fertilizer Mitigation Measures Evaluated

Method	Measure	Reference
Fertilizer	Optimizing or minimizing use of fertilizer	Guthrie
	Adding a Urease Inhibitor	Guthrie
	Mixing and injecting fertilizer into the soil quickly	Guthrie and Eory
	Applying fertilizer during optimal weather conditions	Guthrie and Eory

Optimize or minimize use of fertilizer

The San Joaquin Valley is a part of Central Valley Water Board of the California Water Board, which is an expansive region extending south from the Oregon border to the northernmost portion of Los Angeles County. The California Legislature passed Senate Bill 390 in 1999, which required Water Boards to develop programs that regulate agricultural lands in accordance with the Porter-Cologne Water Quality Control Act (California Water Code Division 7). In 2003, the Central Valley Irrigated Lands Regulatory Program (ILRP) was established, regulating agricultural discharges to surface waters. The Central Valley Water Board extended the regulations in 2012 to include discharges to ground waters. With the exclusion of lands that are never-irrigated or are covered under a separate Central Valley Water Board program, all commercial irrigated lands are required to obtain regulatory coverage under the ILRP.[199] In accordance with the ILRP, growers are required to prepare farm management plans – which includes an Irrigation Nitrogen Management Plan Summary Report – that comply with the approved upon Waste Discharge Requirements (WDR). Using information from the Reports, inferences can be made about nitrogen management based on estimates that compare nitrogen applied (A) to the nitrogen removed (R) from a field: A/R ratio and A-R difference. Included in the nitrogen fraction is any nitrogen proactively added

[199] Central Valley Water Board. *Irrigated Lands Regulatory Program (ILRP) FAQs*. Available at: *https://www.waterboards.ca.gov/centralvalley/water_issues/irrigated_lands/ilrp_faq.pdf*

to a field such as organic amendments, synthetic fertilizers, manure, and irrigation water, whereas nitrogen removed refers to the nitrogen in the materials removed from the field.[200]

Though growers do not have an immediate requirement under ILRP to use nitrogen efficient strategies, growers that are deemed outliers in A/R ratio and A-R difference would be required to employ enhanced strategies to lower these estimates. CDFA FREP offers an Irrigation and Nitrogen Management training program[201] for this purpose among others. A subset of the Irrigation and Nitrogen Management training program is dedicated to nitrogen efficiency, including overviews of the "4 R's" of nitrogen management, and of efficient nitrogen practices.[202] The 4 R's principles are founded on applying the "Right source" of nitrogen at the "Right rate", "Right time", and "Right place". The right rate principle is with the identified measure, as it promotes strategies for providing nitrogen in rates that do not go beyond the crop demand for nitrogen. Examples of how this can be accomplished include adjusting the rate of application based on expected crop yield and adjusting season application rates based on soil and plant-tissue testing.

Guthrie et al. (2018) describe how minimizing the amount of fertilizer applied to an level that is optimal for crop can reduce ammonia emissions.[203] This measure and associated findings were not well described by both Guthrie et al. (2018) and the publications they referenced, nor were any specific regulations identified.[204,205,206,207] Additionally, the viewpoints of Guthrie et al. (2018) were prepared in the context of Europe and United Kingdom. There is therefore

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[200] California State Water Resources Control Board. *State of California State Water Resources Control Board, Order WQ 2018-0002.* Available at: *https://www.waterboards.ca.gov/board_decisions/adopted_orders/water_quality/2018/wqo2018_0002_with_data_fig1_2_appendix_a.pdf*

[201] CDFA. *Fertilizer Research and Education Program*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/*

[202] CDFA. *Irrigation and Nitrogen Management Training for Grower Self-Certification*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/pdfs/training/inmtp_workbook.pdf*

[203] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). Impact of ammonia emissions from agriculture on biodiversity: An evidence synthesis. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[204] UNECE. 2015. United Nations Economic Commission for Europe Framework Code for Good Agricultural Practice for Reducing Ammonia Emissions. United Nations Economic Commission for Europe Convention on Long-range Transboundary Air Pollution. *https://unece.org/environment-policy/publications/framework-code-good-agricultural-practice-reducing-ammonia*

[205] Zhang, Y., A.L. Collins, J.I. Jones, P.J. Johnes, A. Inman, J.E. Freer. (2017). The potential benefits of on-farm mitigation scenarios for reducing multiple pollutant loadings in prioritised agri-environment areas across England. Environmental Science & Policy 73, 100-114. *https://doi.org/10.1016/j.envsci.2017.04.004*

[206] Collins, A.L., Y.S. Zhang, M. Winter, A. Inman, J.I. Jones, P.J. Johnes, W. Cleasby, E. Vrain, A. Lovett, L. Noble. (2016). Tackling agricultural diffuse pollution: What might uptake of farmer-preferred measures deliver for emissions to water and air? Science of The Total Environment 547, 269-281. *https://doi.org/10.1016/j.scitotenv.2015.12.130*

[207] Dalgaard, T., J. F. Bienkowski, A. Bleeker, U. Dragosits, J. L. Drouet, P. Durand, A. Frumau, N. J. Hutchings, A. Kedziora, V. Magliulo, J. E. Olesen, M. R. Theobald, O. Maury, N. Akkal, P. Cellier. (2012). Farm nitrogen balances in six European landscapes as an indicator for nitrogen losses and basis for improved management. Biogeosciences 9, 5303–5321. *https://doi.org/10.5194/bg-9-5303-2012*

a probability that the conditions and farming practices described by Guthrie et al. (2018) are consistent with those present and employed in California. This, combined with the lack in strong evidence demonstrating the emission reduction potentials, demonstrates the need for additional research be completed under conditions consistent with those of the San Joaquin valley before this measure can be considered.

Urease Inhibitor

When combined with urease enzyme present in plants, urea present in urea-based fertilizers can be converted into ammonia, which can then volatilize. Urease inhibitors are a class of nitrogen stabilizer designed to minimize volatilization from applied nitrogen sources by inhibiting the action of the urease, thereby reducing the formation of ammonia.

Nitrogen stabilizers are regulated by federal and State regulatory agencies. At the federal level, The Federal Insecticide, Fungicide, and Rodenticide Act requires that nitrogen stabilizers sold and distributed in the United States be registered with U.S. EPA.[208] At the state level, both the California Department of Pesticide Regulations (DPR) and CDFA maintain regulatory authorities over nitrogen stabilizers. While DPR requires all nitrogen stabilizers to be registered,[209] CDFA regulates licensing, registration, labeling, tonnage reporting, and inspection of only a subset of commercial nitrogen stabilizers.[210] In coordination with 4R Nutrient Stewardship and UC Davis Land and Water Resources, CDFA FREP also encourage growers to use enhanced-efficiency sources such as Urease Inhibitors, identifying these sources as possible "Right Source" through their 4 R's principles.[211]

Although urease inhibitors have shown tremendous promise in reducing ammonia emissions, some studies indicate potential occurrences of pollution swapping through increasing of NOx emissions which must be critically considered and explored prior to further considering the measure.[212,213] Additionally, although there are numerous identified benefits associated with the use urease inhibitors, there is little existing knowledge about their potential to enter the

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[208] US EPA. *Nitrogen Stabilizer Products that Must Be Registered under FIFRA*. Available at: https://www.epa.gov/pesticide-registration/nitrogen-stabilizer-products-must-be-registered-under-fifra

[209] CDPR. *A Guide to Pesticide Regulation in California 2017 Update*. Available at: https://www.cdpr.ca.gov/docs/pressrls/dprguide/dprguide.pdf

[210] CDFA. *California Fertilizer Laws and Regulations*. Available at: https://www.cdfa.ca.gov/is/docs/Fertilizer_Law_and_Regs.pdf

[211] CDFA FREP. *California Crop Fertilization Guidelines.* Available at: https://www.cdfa.ca.gov/is/ffldrs/frep/FertilizationGuidelines/Adjustments.html#h11

[212] Drury, C.F., X. Yang, W.D. Reynolds, W. Calder, T.O. Oloya, A.L. Woodley. (2017). Combining Urease and Nitrification Inhibitors with Incorporation Reduces Ammonia and Nitrous Oxide Emissions and Increases Corn Yields. Journal of Environmental Quality 46:5, 939-949. https://doi.org/10.2134/jeq2017.03.0106

[213] Mirkhani, R., C. Resch, G. Weltin, L. K. Heng, J. Mitchell, R. Clare Hood-Nowotny, G. Dercon. (2023). Effect of urease inhibitor and biofertilizer on nitrous oxide emission, EGU General Assembly 2023, Vienna, Austria, 24–28 Apr 2023, EGU23-11242, https://doi.org/10.5194/egusphere-egu23-11242

food chain and impact food safety.[214] Further research is needed which demonstrates that there are no food safety-related issues prior to this measure being viable for consideration.

According to Guthrie et al. (2018), the addition of a urease inhibitor has the potential to reduce ammonia emissions by 40-70 percent.[215] Though this has the potential to hold remarkable mitigation potential, their estimates along with those of the original experiments, were prepared under European and United Kingdom conditions. As these findings were based outside of California where environmental and climatic conditions may differ, further research is needed that explores the reduction potentials of urease inhibitors in conditions consistent with those of the San Joaquin Valley. In addition to this, Guthrie et al. (2018) merely identified the measures but did not reference or identify any specific regulations.

Quick mixing and injecting into soil

The identified measure would involve rapid incorporation of fertilizers into soils after the fertilizers have been applied. As previously described, with the implementation of ILRP and WDRs by the Central Valley Water Board growers are required to prepare and management plans. The 4 R's of nitrogen management serve as guiding nitrogen efficiencies principles that growers are recommended to follow when developing their management plans. The identified measure is addressed through two of the four principles. The "Right time" principle refers to timed application of nitrogen to ensure availability to the plant during periods of greatest demand. The measure is also addressed through the "Right place" principle, which considers targeted application of fertilizer in the crop's effective rootzones to facilitate and enhance the uptake of nitrogen by the crop.

As described by Guthrie et al. (2018), ammonia emissions can be reduced by 50-90 percent through this measure, should the fertilizer be mixed in or injected into the soil within 4-6 hours of their application.[216] Though they do not touch on the speed of the process, Eory et al. (2016) likewise identified fertilizer injection as a candidate ammonia emission mitigation measure.[217] However, the publications referenced in Guthrie et al. (2018) and Eory et al. (2016) focus solely on manure application methods and do not provide estimates for

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[214] Byrne M.P., J.T. Tobin, P.J. Forrestal, M. Danaher, C.G. Nkwonta, K. Richards, E. Cummins, S.A. Hogan, T.F. O'Callaghan. (2020). Urease and Nitrification Inhibitors—As Mitigation Tools for Greenhouse Gas Emissions in Sustainable Dairy Systems: A Review. Sustainability 12:15, 6018. *https://doi.org/10.3390/su12156018*

[215] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). Impact of ammonia emissions from agriculture on biodiversity: An evidence synthesis. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[216] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). Impact of ammonia emissions from agriculture on biodiversity: An evidence synthesis. *Rand Europe, The Royal Society.* Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[217] Eory, V., Rees, B., Topp, K., Dewhurst, R., et al. ClimateXChange, "On-farm technologies for the reduction of greenhouse gas emissions in Scotland," March 2016. Retrieved from: *https://www.climatexchange.org.uk/media/1927/on-farm_technology_report.pdf*

commercial fertilizers. [218,219] We cannot assume the mitigation potential of fertilizers to be consistent with that of manure sources. We therefore proceed with caution with the identified measure and will not be considering it at this moment. In addition to this, research from a California-context is profoundly limited,[220] resulting in uncertainty regarding the ammonia reduction potentials under California-specific conditions. Consistent with the previously mentioned fertilizer measures, Guthrie et al. (2018) and Eory et al. (2016) merely identify the measure, and do not reference any specific regulations.

Application during optimal weather conditions

Weather conditions (i.e., air temperature, precipitation, and wind speed) have a demonstrated effect on ammonia fluxes.[221] The identified measure would involve rapid incorporation of fertilizers into soils after the fertilizers have been applied. The 4 R's "Right time" principle covers the issue that this measure aims to address. The principle is based on timed nitrogen application in order to ensure the availability of nitrogen to the plant during the more nutrient demanding periods. This period is during vegetative growth in annual crops, and during early fruit and nut development in mature trees and vines.[222]

While describing the fertilizer injection measure, Eory et al. (2016) convey that additional work is needed to determine the emission benefits related to fertilizer application with respect to weather.[223] They however do not provide any additional or specific information regarding a measure or identify the reduction potential of its application. Guthrie et al. (2018) identified weather as affecting ammonia emissions by up to 5 percent and provided the recommendation that growers refrain from using urea-based fertilizers during warm, dry, and

[218] Loyon, L., C.H. Burton, T. Misselbrook, J. Webb, F.X. Philippe, M. Aguilar, M. Doreau, M. Hassouna, T. Veldkamp, J.Y. Dourmad, A. Bonmati, E. Grimm, S.G. Sommer. (2016). Best available technology for European livestock farms: Availability, effectiveness and uptake. Journal of Environmental Management 166, 1-11. *https://doi.org/10.1016/j.jenvman.2015.09.046*

[219] Webb, J., B. Pain, S. Bittman, J. Morgan. (2010). he impacts of manure application methods on emissions of ammonia, nitrous oxide and on crop response—A review. Agriculture, Ecosystems & Environment 137:1-2, 39-46. *https://doi.org/10.1016/j.agee.2010.01.001*

[220] Krauter, C., D. Goorahoo, C. Potter, S. Klooster. (2014). *Ammonia Emissions and Fertilizer Applications in California's Central Valley*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/pdfs/completedprojects/00-0515Krauter2006.pdf*

[221] Li, Q., X. Cui, X. Liu, M. Roelcke, G. Pasda, W. Zerulla, A.H. Wissemeier, X. Chen, K. Goulding, F. Zhang. (2017). A new urease-inhibiting formulation decreases ammonia volatilization and improves maize nitrogen utilization in North China Plain. Scientific Reports 7, 43853. https://doi.org/10.1038/srep43853, *https://doi.org/10.1038/srep43853*

[222] CDFA. *Irrigation and Nitrogen Management Training for Grower Self-Certification*. Available at: *https://www.cdfa.ca.gov/is/ffldrs/frep/pdfs/training/inmtp_workbook.pdf*

[223] Eory, V., Rees, B., Topp, K., Dewhurst, R., et al. ClimateXChange, "On-farm technologies for the reduction of greenhouse gas emissions in Scotland," March 2016. Retrieved from: *https://www.climatexchange.org.uk/media/1927/on-farm_technology_report.pdf*

windy conditions.[224] After reviewing the two publications referenced in Guthrie et al. (2018) for this measure, Zhang et al. (2017)[225] and Newell et al. (2011)[226], no information regarding concerning weather-related conditions was found. Other publications have demonstrated a link between weather conditions and ammonia emissions, though it is unclear which environmental factors are most appropriate for the various fertilizer types.[227,228] It is particularly important for further research to address the impact of weather and fertilizer application timing under conditions specific to the San Joaquin Valley. Lastly, as has been described previously, Guthrie et al. (2018) and Eory et al. (2016) do not refer to any specific regulations when identifying the measure.

Ammonia emissions from agricultural fertilizers are 111.2 tpd in 2023. Emissions growth from agricultural fertilizers are estimated by farmland acreage projection data developed by the

CARB has not identified effective mechanisms within its authority to regulate air emissions of ammonia from livestock, which overwhelmingly come from the decomposition of manure, or from fertilizers, the second largest category of emissions in the Valley. CARB's main source of authority is the California Health and Safety Code. CARB's authority is primarily over mobile sources, consumer products, and air toxics, as well as methane from livestock (see Cal. Health & Saf. Code §§ 43013, 39666, 39730.7, 41712).

Estimated feasible reductions in ammonia from this emissions source in the Valley are zero tons.

Composting and Other Sources

The District already regulates ammonia emissions from composting operations through District Rules 4565 and 4566. Based on the mitigation measures in practice at facilities

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[224] Guthrie, S., Giles, S., Dunkerley, F., Tabaqchali, H., Harshfield, A., Ioppolo, B., Manville, C. (2018). The Impact of Ammonia Emissions from Agriculture on Biodiversity. *Rand Europe, The Royal Society*. Retrieved from: *https://www.rand.org/pubs/research_reports/RR2695.html*

[225] Zhang, Y., A.L. Collins, J.I. Jones, P.J. Johnes, A. Inman, J.E. Freer. (2017). The potential benefits of on-farm mitigation scenarios for reducing multiple pollutant loadings in prioritised agri-environment areas across England. Environmental Science & Policy 73, 100-114. *https://doi.org/10.1016/j.envsci.2017.04.004*

[226] Newell Price, J.P., D. Harris, M. Taylor, J.R. Williams, S.G. Anthony, D. Duethmann, R.D. Gooday, E.I. Lord, B.J. Chambers, D.R. Chadwick, T.H. Misselbrook. "An Inventory of Mitigation Methods and Guide to their Effects on Diffuse Water Pollution, Greenhouse Gas Emissions and Ammonia Emissions from Agriculture," December 2011. Retrieved from: *https://repository.rothamsted.ac.uk/download/942687eab7ec4b83751c7e241d62f0fa8472d72adcd25a149bb891b7c30d55d0/1595300/MitigationMethods-UserGuideDecember2011FINAL.pdf*

[227] V Venterea, R.T., A.D. Halvorson, N. Kitchen, M.A. Liebig, M.A. Cavigelli, S.J. Del Grosso, P.P. Motavalli, K.A. Nelson, K.A. Spokas, B. Pal Singh, C.E. Stewart, A. Ranaivoson, J. Strock, H. Collins. (2012). Challenges and opportunities for mitigating nitrous oxide emissions from fertilized cropping systems. Frontiers in Ecology and the Environment 10:10, 562-570. *https://doi.org/10.1890/120062*

[228] Grahmann, K., N. Verhulst, A. Buerkert, I. Ortiz-Monasterio, B. Govaerts. (2013). Nitrogen use efficiency and optimization of nitrogen fertilization in conservation agriculture. Cabi Reviews 8:053. *https://doi.org/10.1079/PAVSNNR20138053*

subject to Rule 4565 and 4566, ammonia emissions are already being reduced by 44 percent. With these controls in place, composting accounts for only 2 percent of the District's ammonia emissions; therefore, the District will not be further evaluating this source category at this time.

The other source category consists of ammonia emissions primarily from mobile sources and fuel combustion, which are heavily controlled. Therefore, the District will not be further evaluating this source at this time.

Estimated feasible reductions in ammonia from these emissions sources in the Valley are zero tons.

4. Research

CARB is working to fill knowledge gaps on feasible and effective ammonia controls. Development of effective air pollution mitigation strategies for ammonia requires additional spatiotemporal understanding of atmospheric ammonia emissions that are currently lacking as a result of limited data. CARB is conducting research, both in-house and with external partners, to characterize gaseous ammonia emissions from agricultural activities in the San Joaquin Valley. The results of these studies will help future development of CARB's ammonia emission inventory, SIP, Short-Lived Climate Pollutant Reduction Strategy, and community air protection program (AB 617). Findings from these research projects will help CARB better characterize ammonia emissions in the Valley, as a necessary prerequisite to identifying potential effective measures to achieve additional emissions reductions.

Ammonia emissions in general are not well quantified Statewide and further focused study is needed to facilitate quantification and potential further control strategies that are effective and cost-effective. As an example of the agency's work in this area, CARB's Research Division has developed a new mobile measurement platform equipped with a state-of-the-science ammonia analyzer and other advanced analytical instruments to improve the understanding of various ammonia sources in California. In September and October 2018, CARB staff collaborated with researchers from the University of California, Davis, to quantify emissions from several dairies in the Valley as part of the ongoing projects funded by the California Department of Food and Agriculture, CARB, and industry. Methane, oxides of nitrogen, and other air pollutants and meteorological parameters were measured at or near dairies in addition to ammonia. The major objective is to evaluate the effectiveness of various alternative manure management practices (AMMP) with respect to emission reductions as CARB staff will revisit these dairies after they implement the selected AMMP technologies. This effort is a direct response to Senate Bill 1383 requirements and goals. The AMMP is designed to identify air pollution sources and estimate their emission rates. Its mobility makes it ideal for field measurements that require large spatial coverage, such as mapping ammonia mixing ratios with an emphasis on determining the magnitude of emissions, characterizing spatial variability of emissions, and identifying dominant sources of emissions.

In addition, CARB is undertaking a suite of projects that address research needs. Many projects focus on emissions from dairies, while others, including those with a satellite or remote sensing component, can offer insight into ammonia emissions in the Valley from all source categories. CARB staff is also working with academic researchers and industry representatives to explore potential opportunities to reduce the emissions of ammonia and other air pollutants from dairy manure lagoons which are one of the largest contributors to ammonia in California. Preliminary experiments have been conducted, and further investigation is underway at some Valley dairies with the support from farmers. Additionally, CARB staff is planning to analyze existing satellite data to refine the spatial resolution and allocation of ammonia in California. This may also help evaluate the impact of major wildfires on surface ammonia levels in recent years, and can be used to compare with the estimation methodology in the current ammonia emission inventory associated with wildfires.

Due to research which indicates California is underestimating ammonia emissions in the air, CARB is reviewing and will reassess ammonia estimates in recognition of this research. This effort will help us update our understanding about modeled sensitivity of PM2.5 formation to changes in ammonia emissions.

5. Conclusion

While EPA guidance recommends modeling emissions reductions of PM2.5 precursors of between 30 and 70 percent to evaluate if precursor emissions reductions have a significant impact on PM2.5 levels, CARB and the District have determined that the 30 percent reduction in ammonia emissions is not achievable Moreover, CARB and the District have not identified methods within its authority to control air emissions of ammonia that achieve an overall 30 percent reduction in ammonia emissions. In practice, the District has implemented the best available control measures on livestock operations that have already achieved approximately 25 percent reduction from this source. CARB is not aware of controls that would achieve greater reductions on the order needed to achieve an overall 30 percent reduction of ammonia emissions in the Valley; nevertheless, CARB is pursuing further research specific to California and the Valley to improve our understanding of ammonia emissions from various sources as a necessary prerequisite to identifying potential effective measures to achieve additional emissions reductions.

The District and CARB analyzed potential control measures to reduce ammonia emissions from key source categories in order to evaluate whether a 30 percent reduction in emissions is feasible. Specific to the confined animal facility category, the District conducted a new, extensive evaluation of potential measures to control sources of ammonia emissions. EPA provided the list of measures to CARB and the District and requested that the measures and studies referenced be addressed specifically for the Valley. In this evaluation, the District has identified only a few measures that have the theoretical potential to reduce additional ammonia emissions beyond the practices currently enforced through District Rule 4570 (Confined Animal Facilities). These measures are reducing crude protein content in feed for beef finishing cattle, incorporation of solid manure within 24 hours, and acidifying amendments for poultry litter and manure. Despite the technological and economic feasibility issues of these mitigation measures, the District evaluated the potential emission reductions and the impact they might have on the Valley’s total ammonia emissions inventory if these measures were to be implemented. Overall, ammonia emissions in the Valley can only be reduced from the confined animal facilities source category by 2 percent by implementing these mitigation measures. For the fertilizer category, CARB has not identified effective mechanisms within its authority to regulate air emissions of ammonia from livestock, which overwhelmingly come from the decomposition of manure, or from fertilizers. Furthermore, CARB and the District are unaware of any other jurisdictions with rules for the source. In addition, CARB and the District did not identify feasible control measures for composting or other emissions sources.

Based on the extensive evaluation which identified feasible reductions of only approximately 2 percent, as summarized below in Table 14, CARB and the District conclude that a 30 percent reduction in ammonia emissions is not achievable.

Table 14. Estimated Feasible Emission Reductions

Emissions Category	Emissions (tpd, 2023)	Identified Controls	Feasible Ammonia Reductions
Confined Animal Feeding	186.5	• Reducing crude protein content in feed for beef finishing cattle • Incorporation of solid manure within 24 hours • Acidifying amendments for poultry litter and manure	6.6 tpd
Fertilizers	111.2	No authority or feasible controls identified	0
Composting	6.7	No feasible controls identified	0
Other sources	20.5	No feasible controls identified	0
Total Ammonia	324.9		6.6 tpd

A 2 percent reduction is consistent with the national trend identified in EPA guidance which stated that ammonia changes ranged nationally from an increase of six percent to a decrease of nine percent.[229] Moving forward, updated national guidance on ammonia emission reductions achievable in practice is needed, as well as guidance on available and feasible control measures.

CARB has followed EPA guidance to evaluate whether ammonia contributes significantly to PM2.5 levels that exceed the 15 µg/m3 annual standard NAAQS. Considering relevant contextualizing information including available controls, CARB determined that emissions of ammonia do not contribute significantly to PM2.5 levels that exceed the annual 15 µg/m3 standard in the San Joaquin Valley. Therefore, CARB has excluded ammonia from control requirements in the SIP.

[229] EPA. *PM2.5 Precursor Demonstration Guidance*. May 2019. *https://www.epa.gov/sites/production/files/2019-05/documents/transmittal_memo_and_pm25_precursor_demo_guidance_5_30_19.pdf*

ATTACHMENT T

APPENDIX E

California Environmental Quality Act

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Functional Equivalent Document

Renewable Electricity Standard

Prepared by:

California Air Resources Board

Prepared by:

Ascent Environmental, Inc.
455 Capitol Mall, Suite 210
Sacramento, CA 95814

June 2010

Functional Equivalent Document

Renewable Electricity Standard

Prepared by:
California Air Resources Board
1001 I Street
Sacramento, CA 95812

With Assistance From:

Ascent Environmental, Inc.
455 Capitol Mall, Suite 210
Sacramento, CA 95814

Contact:

Sydney Coatsworth
Project Manager
916/930-3185

June 2010

Ascent - 10010017.01 / 06.01.10

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This Functional Equivalent Document has been prepared by and under the direction of the California Air Resources Board (ARB), Energy Section. Ascent Environmental, Inc., Sacramento, California, served as the prime consultant assisting ARB. Consultants involved in the document preparation are:

Ascent Environmental, Inc.
Sydney B. Coatsworth, AICP, Project Principal
Amanda Olekszulin, Project Manager
Curtis E. Alling, AICP
Honey Walters
Linda Leeman
Kristen Stoner
Amber Giffin

Remy, Thomas, Moose, and Manley
James Moose, JD
Laura Harris
Jeannie Lee

POWER Engineers
Mike Strand

Synapse
Jeremy Fisher, Ph.D.

The Sanberg Group
Dale Schneeberger, PG, REA

Robertson-Bryan, Inc.
Michael Bryan, Ph.D.
Jeff Lafer

Applied Earthworks
M. Colleen Hamilton, RPA

Geografika Consulting
Megan Gosch

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ACRONYMS AND ABBREVIATIONS

AADT	average annual daily traffic
AB	Assembly Bill
ACEC	Area of Critical Environmental Concern
ACHP	Advisory Council on Historic Preservation
AICUZ	Department of Defense Air Installations Compatible Use Zones
ALUC	Airport Land Use Commission
amsl	above mean sea level
APE	area of potential effect
APEFZ	Alquist-Priolo Earthquake Fault Zone
ARB	California Air Resources Board
BAAQMD	Bay Area Air Quality Management District
BACT	best available control technology
BLM	U.S. Bureau of Land Management
BMPs	best management practices
bmsl	below mean sea level
BOR	U.S. Bureau of Reclamation
CAA	Clean Air Act
CAL FIRE	California, Department of Forestry and Fire Protection
Cal ISO	California Independent System Operator
CAL Recycle	State of California, Department of Resources Recycling and Recovery
Cal/EPA	California Environmental Protection Agency
Caltrans	California Department of Transportation
CBC	California Building Code
CCCT	closed circuit cooling tower
CCNM	California Coastal National Monument
CCP	comprehensive conservation plans
CCR	California Code of Regulations
CDCA	California Desert Conservation Area
CDPA	California Desert Protection Act
CEC	California Energy Commission

CEQA	California Environmental Quality Act
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CFCP	California Farmland Conservancy Program
CFR	Code of Federal Regulations
CGS	California Geological Survey
CHP	combined heat and power
CI	Circulation and Infrastructure
CNEL	Community Noise Equivalent Level
CNRA	California Natural Resources Agency
CO	Conservation
CPUC	California Public Utilities Commission
CREZ	competitive renewable energy zones
CRHR	California Register of Historical Resources
CT	simple cycle cooling tower
CUPA	Certified Unified Program Agency
CVMSHCP/NCCP	Coachella Valley Multi-Species Habitat Conservation Plan/Natural Communities Conservation Plan
CVP	Central Valley Project
CWA	Clean Water Act
dB	decibel
dBA	A-weighted sound levels
Delta	Sacramento-San Joaquin Delta
DFG	Department of Fish and Game
DOGGR	California Division of Oil, Gas, and Geothermal Resources
DPR	Department of Parks and Recreation
DTSC	Department of Toxic Substances Control
DWR	California Department of Water Resources
E3	Energy and Environmental Economics, Incorporated
EDCs	endocrine disrupting compounds
EIRs	Environmental Impact Reports
EIS	environmental impact statement
EPA	U.S. Environmental Protection Agency

EPCRA	Environmental Planning and Community Right-to-Know Act
FAA	Federal Aviation Administration
FED	functionally equivalent document
FEMA	Federal Emergency Management Agency
FHA	Federal Highway Administration
FHWA	Federal Highway Administration
FLPMA	Federal Land Policy and Management Act
FMMP	Farmland Mapping and Monitoring Program
FPPA	Farmland Protection Policy Act
FRA	Federal Rail Administration
FTA	Federal Transit Administration
g	gravity
GC	Government Code
GHG	greenhouse gases
H	Housing
HCP	habitat conservation plan
HLRs	Hydrologic landscape regions
IEPR	Integrated Energy Policy Report
in/sec	inches per second
IOUs	investor owned utilities
ISEGS	Ivanpagh Solar Electric Generating Systems
kW	kilowatts
lb/MWh	pound per megawatt hour
L_{dn}	Day-Night Noise Level
LEA	local enforcement agencies
L_{eq}	Equivalent Noise Level
L_{max}	Maximum Noise Level
L_{min}	Minimum Noise Level
LOS	level of service
LU	Land Use
mg/L	milligrams per liter
Moyer program	ARB's Carl Moyer Program
MPOs	metropolitan planning organizations

MPS	modular pumped storage
MRDS	USGS Mineral Resource Data System
MRZ	Mineral Resource Zones
MUC	Multiple-Use Class
MW	megawatts
MWh	megawatt-hour
mya	million years ago
NAAQS	National Ambient Air Quality Standards
NAGPRA	Native American Graves Protection and Repatriation Act of 1990
NCAs	National Conservation Areas
NCCP	natural communities conservation plan
NCP	National Contingency Plan
NCPA	Northern California Power Agency
NECO	Northern and Eastern Colorado Desert
NEPA	National Environmental Policy Act [
NFMA	National Forest Management Act
NFS	National Forest System
NHPA	National Historic Preservation Act
NLCS	National Landscape Conservation System
NPDES	National Pollution Discharge Elimination System
NPL	National Priority List
NPS	National Park Service
NRHP	National Register of Historic Places
NRPA	Archaeological Resources Protection Act of 1979
O_2	oxygen
O&M	operation and maintenance
OAQPS	Office of Air Quality Planning and Standards
OHMVR	off-highway motor vehicle recreation
OS	Open Space
OTC	once through cooling
OWTS	onsite wastewater treatment systems
oxide	aluminum
PA	Programmatic Agreements

PCBs	polychlorinated biphenyls
PEIS	Programmatic Environmental Impact Statement
PM	Particulate matter
POUs	publicly owned utilities
ppmv	parts per million by volume
PPV	peak particle velocity
PRC	Public Resources Code
PV	Photovoltaic
RCRA	Resource Conservation and Recovery Act
REC	renewable energy credit
RES	Renewable Electricity Standard
RETI	Renewable Energy Transmission Initiative
RMPs	Resource Management Plans
RMS	root-mean-square
ROWD	Report of Waste Discharge
ROWs	right-of-ways
RPS	Renewables Portfolio Standard
RWQCB	Regional Water Quality Control Board
SARA	Superfund Amendments and Reauthorization Act
SBE	State Board of Education
SCAQMD	South Coast Air Quality Management District
Scoping Plan	AB 32 Climate Change Scoping Plan
SCPPA	Southern California Public Power Authority
SCS	Sustainable Communities Strategy”
SDAPCD	San Diego Air Pollution Control District
SDWA	Safe Drinking Water Act
SERCs/TERCs	state/tribe emergency response commissions
SIC	Standard Industrial Classification
SIP	State Implementation Policy
SJVAPCD	San Joaquin Valley Air Pollution Control District
SMARA	California Surface Mining and Reclamation Act
SMUD	Sacramento Municipal Utility District
solar DG	distributed solar generation

SVRA	State Vehicular Recreation Area
SWAMP	Surface Water Ambient Monitoring Program
SWP	State Water Project
SWPPP	Storm Water Pollution Prevention Plan
SWRCB	State Water Resources Control Board
TAC	toxic air contaminant
TDS	Total dissolved solids
TMDL	Total Maximum Daily Load
tpy	tons per year
TRI	Toxics Release Inventory
TSCA	Toxic Substances Control Act
U.S. EPA	U.S. Environmental Protection Agency
UBC	Uniform Building Code
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USFS	U.S. Forest Service
USFWS	U.S. Fish and Wildlife Service
UXO	unexploded ordnance
V/C	volume-to-capacity ratio
VC	Vehicle Code
VdB	vibration decibels
VOCs	volatile organic compounds
VRI	Visual Resource Inventory
VRM	Visual Resource Management
WAPA	the Western Area Power Administration
WDRs	waste discharge requirements
WECC	Western Electricity Coordinating Council
WECO	Western Colorado
WEMO	West Mojave Habitat Conservation Plan
WSA	water supply assessment

I. INTRODUCTION AND BACKGROUND

A. INTRODUCTION

The California Environmental Quality Act (CEQA) and California Air Resources Board (ARB) policy require an analysis to determine any potentially significant adverse environmental impacts of ARB's regulations. The Renewable Electricity Standard (RES) is proposed to be adopted as a regulation. If adopted, it would advance the standard for the proportion of electricity generation by eligible renewable sources from 20 percent, as established in 2002 by the California Renewables Portfolio Standard (RPS), to 33 percent. The proposed 33 percent RES would modify other provisions contained in the existing RPS, as described in Chapter II.

RES is identified as one of the measures proposed in the Climate Change Scoping Plan (Scoping Plan), which was developed for the purpose of reducing emissions of greenhouse gases (GHG) in California, as directed by the California Global Warming Solutions Act of 2006 (AB 32, Chapter 488, Statutes of 2006). One of the key elements of the Scoping Plan recommendations is "Achieving a statewide renewables energy mix of 33 percent." As described in the Scoping Plan recommendations, "increasing the 20 percent RPS to 33 percent is designed to accelerate the transformation of the electricity sector, including investment in the transmission infrastructure and system changes to allow integration of large quantities of intermittent wind and solar generation," and other eligible renewable sources.

B. THE CALIFORNIA ENVIRONMENTAL QUALITY ACT AND FUNCTIONAL EQUIVALENCY

In PRC Section 21080(a) CEQA states, "Except as otherwise provided in this division, this division shall apply to discretionary projects proposed to be carried out or approved by public agencies, including but not limited to the enactment and amendment of zoning ordinances, the issuance of zoning variances, the issuance of conditional use permits, and the approval of tentative subdivision maps, unless the project is exempt from this division. " ARB determined that adoption and implementation of the proposed 33 percent RES constitutes a "project" as defined by Public Resources Code Section 21000 et seq. The CEQA Guidelines, Section 15378, define a project as:

(a) "Project" means the whole of an action, which has a potential for resulting in either a direct physical change in the environment, or a reasonably foreseeable indirect physical change in the environment, and that is any of the following:

(1) An activity directly undertaken by any public agency including but not limited to public works construction and related activities clearing or grading of land, improvements to existing public structures, enactment and amendment of zoning ordinances, and the adoption and amendment of

viewsheds of State Routes 14 and 58. For wind farms that would be sited along ridgelines and open plains, the wind turbines would be more prominent and would further increase the contrast between the natural and artificial visual environment, potentially damaging the visual character of the area. Views of construction and operation activities may be visible to some viewer groups in the area, including motorists along State Routes 14 and 58, residents in nearby communities, and recreationists using the Pacific Crest Trail. Residents and recreationists would be expected to experience a longer duration of views as opposed to motorists who would be passing through the Tehachapi area at higher speeds. However, the visual impact of wind turbines and associated facilities depends on several variables, including viewing distance, angle of view, and structure placement in the landscape. Because the Tehachapi Wind Resource Area already includes wind farms, it is possible that wind energy development in this area would not substantially exacerbate scenic impacts of State Routes 14 and 58. However, because specific locations are unknown, it is possible that wind turbines could be constructed in more pristine areas, resulting in significant scenic impacts.

Out of State – Low and High Load Conditions
Under the 20 percent low and high load conditions, implementation of the same degree of wind energy resource projects in Montana, the Pacific Northwest, Utah, Southern Idaho, and Wyoming may result in significant adverse effects on scenic vistas, scenic resources, and visual character in these areas. Some of these projects may occur on federal lands, which would subject such projects to environmental review of aesthetic impacts under NEPA. In some cases, renewable energy resource projects may also occur in states where such projects would be subject to the state's environmental review process. In any case, however, implementation of renewable energy resource projects in out-of-state locations may have significant effects primarily because such projects are typically located in areas of undeveloped, uninhabited land and would result in substantial alteration of the visual landscape. Implementation of Mitigation A-1 through A-10 would reduce scenic impacts, but it is uncertain whether mitigation would be sufficient to reduce the impact to a less than significant level.

Scenic impacts of wind energy development under the 20 percent RPS low and high load conditions would be potentially significant. This impact would be expected to occur even without adoption of the RES.

33 Percent Renewable Electricity Standard

Distributed Statewide – Low and High Load Conditions
No additional distributed wind energy is anticipated under the 33 percent RES over and above the 20 percent RPS, so no additional impact would occur from approval of the 33 percent RES.

Tehachapi – Low and High Load Conditions
Under the 33 percent RES, wind energy and transmission development in the Tehachapi area would be the same under both low and high load conditions, and the same as the high load condition under the 20 percent RPS. As such, scenic impacts of

some locations, the visible changes to these scenic resources may be potentially significant.

Out of State – Low and High Load Conditions
Out-of-state scenic impacts under the 33 percent RES, high and low load, for solar thermal would be identical to the 20 percent RPS, high and low load, described above.

Scenic impacts of solar thermal and transmission line development under the 33 percent RES low and high load conditions would be significant.

Solar Photovoltaic

20 Percent Renewable Portfolio Standard

Distributed Statewide – Low and High Load Conditions
Development of solar photovoltaic energy would occur in various locations throughout the State under the 20 percent RPS low and high conditions. Construction and operation of solar photovoltaic panels, access roads, and associated facilities would introduce new elements that have the potential to substantially degrade the existing quality of sites, particularly those in undeveloped areas. While specific locations of distributed solar photovoltaic energy development are unknown, such development may occur in areas with national, state, or county designated scenic vistas, other scenic resources, and State scenic highways. Solar photovoltaic development has the potential to substantially damage scenic resources.

Tehachapi – Low and High Load Conditions
Under the 20 percent RPS solar photovoltaic energy and transmission development is expected to occur in the Tehachapi area under both low and high load conditions. High load conditions under the RPS would require approximately three times the solar photovoltaic generation from this area. Although there are no officially designated State scenic highways in the Tehachapi area, portions of State Routes 14 and 58, which intersect near the Tehachapi Mountains, are eligible for designation. Depending on the locations of solar photovoltaic development, they may extend into the viewsheds of State Routes 14 and 58. Construction of solar photovoltaic facilities would create temporary, adverse changes in the visual character of the Tehachapi area and permanent facilities have the potential to create substantial changes in the visual quality and character of the flat desert areas south of the Tehachapi Mountains. Facility elements may be visible from public vantages, particularly State Routes 14, 58, and 138, which pass directly through the area where solar photovoltaic development would occur. Residents in the community of Rosamond may be affected by construction and operation activities near State Route 14. Some recreationists in the Sierra Pelona Mountains to the south of the Tehachapi area may be affected by the change in visual character, but this would largely depend on where the recreationist is located. Because specific locations of solar photovoltaic projects are unknown, it is possible that facilities could be constructed in pristine areas, resulting in significant scenic impacts.

Out of State – Low and High Load Conditions

Under the 20 percent low and high load conditions, implementation of the same degree of solar photovoltaic energy projects in Arizona/Southern Nevada—though modest—may result in significant adverse effects on scenic resources in these areas. Projects may occur on federal lands, in which case they would be subject to environmental review of aesthetic impacts under NEPA, and projects may also be subject to state environmental policies, rules, and regulations. In any case, however, implementation of solar photovoltaic projects in out-of-state locations may have significant effects primarily because such projects are typically located in areas of undeveloped, uninhabited land. Scenic impacts of solar photovoltaic development under the 20 percent RPS low and high load conditions would be significant. This impact would be expected to occur even without adoption of the RES.

33 Percent Renewable Electricity Standard

Distributed Statewide – Low and High Load Conditions

No additional distributed solar photovoltaic energy is anticipated under the 33 percent RES over and above the 20 percent RPS, so no additional impact would occur from approval of the 33 percent RES.

Tehachapi – Low and High Load Conditions

The amount of solar photovoltaic and transmission development in the Tehachapi area under 33 percent RES low and high load conditions is expected to be the same as under the 20 percent RPS high load scenario, discussed above.

Mountain Pass – Low and High Load Conditions

As with solar thermal, the level of solar photovoltaic energy and transmission development in the Mountain Pass area is anticipated to remain the same under both the 33 percent low and high scenarios. Construction activities and introduction of new solar photovoltaic energy facilities into the desert landscape may impair scenic vistas, resources, and aesthetic character. These visual elements would be visible primarily to motorists traveling on Interstate 15, which passes through the Mountain Pass project area and is a popular route for travelers to Las Vegas, and recreationists at the Primm Valley Golf Course. While not a State-designated scenic highway, San Bernardino County has designated portions of Interstate 15 that pass through the area as having scenic character of visual importance. Motorists are considered to have a low sensitivity to change of existing visual character because of their distance, angle, and duration of views in this area. Construction and operation activities may also be visible to residents in the nearby community of Primm, Nevada, although views may be minimal because of the community's distance from the area.

Although some transmission lines already pass through the Ivanpah Valley, the solar thermal energy facilities would introduce new artificial elements that would contrast photovoltaic with the existing natural environment as well as strong spatial and scale dominance. The proposed project would result in a significant visual change in the site and its surroundings.

Riverside East – Low and High Load Conditions

As with solar thermal, a similar amount of solar photovoltaic energy and transmission development is expected to occur in the Riverside East area under the 33 percent RES low and high load conditions. Construction activities would create a temporary, adverse change in the visual character of the area due to the introduction of heavy equipment in addition to site clearing and grading activities. Operation would introduce new solar photovoltaic energy facilities into the largely undeveloped desert landscape. These visual elements would be visible primarily to motorists traveling on Interstate 10, which passes through the project area, but which is not listed as a State scenic highway. The proposed project would introduce prominent solar photovoltaic structures into the foreground of motorists and into the background of residents in the nearby City of Blythe. Some recreationists at Joshua Tree National Forest to the west of the Riverside East area may also be affected by the substantial visual change in the desert landscape. Construction and operation of solar photovoltaic development would substantially degrade the Riverside East area and its existing natural surroundings by changing the environment to an industrial landscape. This would be a significant impact.

Fairmont –Low and High Load Conditions

Under the 33 percent RES low and high load conditions, development of solar photovoltaic energy and transmission is expected to occur in the Fairmont area. Construction activities would create a temporary, adverse change in the visual character of the Fairmont area due to the introduction of heavy equipment, access roads in addition to site clearing and grading. Construction activities may also alter naturally vegetated areas. Operation of the proposed project would introduce new solar photovoltaic facilities into areas that are largely undeveloped or used for agricultural purposes. These visual elements may be visible to motorists traveling on State Route 138, and to a much lesser extent, on State Route 14 although views from State Route 14 may be indiscernible. The proposed project would introduce prominent structures with an industrial character into the foreground of motorists and into the background of some residents in the nearby cities of Palmdale and Lancaster and the community of Little Rock, As a result, construction and operation of solar photovoltaic facilities would substantially degrade the Fairmont area and its existing natural surroundings.

Out of State – Low and High Load Conditions

Out-of-state scenic impacts under the 33 percent RES, high and low load, for solar photovoltaic would be identical to the 20 percent RPS, high and low load, described above.

Scenic impacts of solar photovoltaic and transmission line development under the 33 percent RES low and high load conditions would be significant.

III.B. AIR QUALITY

This section includes a general description of existing conditions (e.g., types of sensitive land uses and sources located out-of-state), a summary of applicable regulations, and evaluation of potential short-term and long-term air quality impacts associated with the out-of-state implementation of the proposed renewable energy development scenarios. Mitigation is recommended, as necessary, to reduce significant impacts.

As described in the Project Description, the RES Calculator was used to identify out-of-state electricity generation by resource type for: 2008 conditions; 20 percent RPS in 2020 under low and high load conditions; and 33 percent RES in 2020 under low and high load conditions. Tables II-1 and II-2 illustrate comparative data for 2008 (existing conditions for purposes of analysis), RPS and RES under low and high load conditions, respectively. Tables II-3 through II-6 illustrate electricity generation by resource type, by CREZ, for each scenario. Figure II-1 illustrates CREZ locations.

It is important to note that while the RES Calculator output represents the best available data to represent the results of the proposed regulation and a reasonable set of assumptions upon which to assess impacts, the manner in which renewable energy projects would actually come on line cannot be known with certainty. The number of potential future combinations of renewable resource mix, location, and timing, and degree that would satisfy RES requirements is nearly infinite and would depend upon myriad economic, political, and environmental factors. The plausible compliance scenarios identified by ARB and modeled using the RES Calculator represent a reasonable characterization of the way in which the future could unfold; analysis of additional potential future scenarios would not meaningfully add to the body of evidence necessary for ARB to make an informed decision with regard to the proposed regulation.

In addition, as with all of the environmental effects and issue areas, the precise nature and magnitude of impacts would depend on the types of projects authorized, their locations, their aerial extent, and a variety of site-specific factors that are not known at this time but that would be addressed by environmental reviews at the project-specific level.

1. ENVIRONMENTAL SETTING

Note to Reader: The evaluation of the in-State air quality impacts resulting from the renewable energy projects necessary for compliance with the RES is provided in Chapter IX of the RES Staff Report. Based on that analysis, implementation of new in-State renewable energy projects would not generate levels of emissions that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, result in a cumulatively considerable net increase in non-attainment areas, or expose sensitive receptors to substantial pollutant concentrations or odors with mitigation (e.g., compliance with applicable regulations). Thus, in-State air quality impacts from operation of renewable energy facilities is expected to result in beneficial effects. Generally, it is important to note that renewable electricity generation produces fewer pollutants per unit of electricity output than the fossil-fuel generation it would displace and less total electricity would be generated in-State in comparison to existing conditions.

Construction of any new facilities would be subject to site-specific mitigation imposed by local and potentially federal lead agencies and local air districts. Mitigation for construction related air quality impacts is expected to be the same or similar to those detailed below in Mitigation B-1. Please refer to the RES Staff report for additional information.

The following presents an evaluation of the potential out-of-state air quality impacts that could occur with implementation of the 33 percent RES.

(a). EXISTING OUT-OF-STATE SOURCES AND SENSITIVE LAND USES

Out-of-state renewable energy resources are projected by the RES Calculator to be developed in the following general areas: Alberta, Arizona/Southern Nevada, British Columbia, Montana, New Mexico, Northwest, Reno/Dixie Valley, Utah/Southern Idaho, and Wyoming.

The existing air quality environment in the proposed out-of-state areas is influenced by stationary, area, and mobile sources. According to EPA, there are areas within those mentioned above where out-of-state renewable energy resources are projected by the RES Calculator to be developed that are currently designated as nonattainment areas for ozone (8-hour), PM_{10}, $PM_{2.5}$, CO, SO_2, and lead) (EPA 2010). Sensitive land uses in such areas may include residences (e.g., single- and multi-family), schools, hospitals, nursing homes, and other uses that may include segments of the population that are sensitive to poor air quality.

2. REGULATORY SETTING

The following provides a brief description of the Federal and State regulations that could be applicable to an out-of-state renewable energy project. Local regulations may also apply; however, because the specific siting of the renewable energy facilities is not known at this time it would be speculative to present a discussion of applicable local regulations.

Table III.B-1. Applicable Laws and Regulations for Air Quality

Regulation	Description
Federal	
40 Code of Federal Regulations (CFR) (National Environmental Policy Act [NEPA])	NEPA requires all federal agencies to consider environmental factors through a systematic interdisciplinary approach before committing to a course of action. The NEPA process is an overall framework for the environmental evaluation of federal actions.

Table III.B-1. Applicable Laws and Regulations for Air Quality	
Regulation	**Description**
Clean Air Act and 40 CFR, Part 50	The Clean Air Act, which was last amended in 1990, requires EPA to set National Ambient Air Quality Standards (NAAQS) (40 CFR, Part 50) for pollutants considered harmful to public health and the environment. The Clean Air Act established two types of NAAQS. Primary standards set limits to protect public health, including the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary standards set limits to protect public welfare, including protection against decreased visibility, damage to animals, crops, vegetation, and buildings. EPA Office of Air Quality Planning and Standards (OAQPS) has set NAAQS for six principal pollutants, which are called "criteria" pollutants.
Other Applicable Federal-Level Regulations	This includes all other applicable regulations at the federal level for portions of the project area that are outside of the U.S. (e.g., Canada).
State	
Other Applicable State-Level Regulations	This includes all other applicable regulations at the state level for portions of the project area that are outside of California (e.g., Arizona, Nevada).

3. PROJECT IMPACTS

This section describes the project's out-of-state effects on air quality for the 20 percent RPS and 33 percent RES. The discussion includes the criteria for determining the level of significance of the effects and a description of the methods and assumptions used to conduct the analysis.

As with all of the impacts, the precise magnitude and extent of the impact would depend on the type of renewable energy project authorized, its specific location, its total length and size, and a variety of site-specific factors that are not known at this time. All of these issues would be addressed through project-specific environmental reviews that would be conducted by local land use agencies (e.g., cities, counties) or other regulatory bodies at such time the projects are proposed for implementation. ARB would not be the agency responsible for conducting the project-specific environmental review because it is not the agency with authority for making land use decisions.

(a). METHODOLOGY

Potential out-of-state impacts to air quality were assessed based on the potential for the 33 percent RES to exceed the thresholds of significance identified below. The analysis that is presented below evaluates the change from existing conditions to the 33 percent RES in 2020. However, an incremental portion of these impacts would occur regardless of whether the 33 percent RES is implemented. The CPUC approved the 20 percent RPS and this regulation would be implemented by 2020. The 33 percent RES would further the renewable energy objective and would be added to the 20 percent RPS. Therefore, the analysis below describes the impacts that would occur under the 20 percent RPS, the total impacts that would occur under the 33 percent RES (i.e., existing conditions to 33 percent RES), and the incremental impacts from 20 percent RPS to 33 percent RES. For each of these alternatives, a high and low load scenario is also evaluated (see Section II, Project Description, for additional details).

For some impacts below, the same type and magnitude would occur under each scenario and each alternative. Where this occurs, a combined analysis is presented to streamline the presentation of environmental impacts to avoid unnecessary repetition.

(b). THRESHOLDS OF SIGNIFICANCE

For purposes of this analysis, the following applicable thresholds of significance were used to determine whether implementing the 33 percent RES would result in a significant air quality impacts. The project would result in a significant impact if it would:

- conflict with or obstruct implementation of the applicable air quality plan;
- violate any air quality standard or contribute substantially to an existing or projected air quality violation;
- Result in a cumulatively considerable net increase of any criteria air pollutant for which the project region is non-attainment under an applicable federal or state ambient air quality standard;
- Expose sensitive receptors to substantial pollutant concentrations; or
- Create objectionable odors affecting a substantial number of people.

IMPACT B-1	**Short-Term Construction Impacts to Air Quality from Out-of-State Project-Generated Emissions of Criteria Air Pollutants and Precursors. Because the specific air quality impacts of the 33 percent RES cannot be identified with any certainty, and construction activities associated with these projects could generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas, this impact is considered *potentially significant* for all renewable energy types under the 33 percent RES (high and low load).**

All Renewable Energy Project Types

All renewable energy projects no matter their size, out-of-state location, or type would be required to seek local land use approvals prior to their implementation. Part of the land use entitlement process requires that each of these projects undergo environmental review consistent with Federal environmental review requirements (e.g., NEPA) or other applicable state requirements. The environmental review process for all renewable project types under either the 20 percent RPS or 33 percent RES would assess whether project implementation would result in short-term construction air quality impacts.

At this time, the specific location, type, and number of renewable energy projects constructed out-of-state is not known and would be dependent upon a variety of market factors that are not within the control of ARB including: economic costs, energy demands, environmental constraints, and other market constraints. Nonetheless, the analysis provided herein provides a reasonable accounting of the types of environmental impacts that would occur with implementation of the 33 percent RES plausible compliance scenarios (high or low load conditions) as discussed below for short-term construction emissions. Further, subsequent environmental review would be conducted at such time that a renewable energy project is proposed and land use entitlements are sought.

During construction of renewable energy projects out-of-state, criteria air pollutant and precursor emissions could be generated from a variety of construction activities and emission sources. These emissions would be temporary and occur intermittently depending on the intensity of construction on a given day. Site grading and excavation activities would generate fugitive PM dust emissions, which is the primary pollutant of concern during construction. Fugitive PM dust emissions (including PM_{10} and $PM_{2.5}$) vary as a function of parameters such as soil silt content and moisture, wind speed, acreage of disturbance area, and the intensity of activity performed with construction equipment. Exhaust emissions from off-road construction equipment, material delivery trips, and construction worker-commute trips could also contribute to short-term increases in PM emissions, but to a lesser extent. Exhaust emissions from construction-related mobile sources also include ROG and NO_x emissions. These emission types and associated levels fluctuate greatly depending on the particular type, number, and duration of usage for the varying equipment. Criteria air pollutants that are also associated with localized concerns (e.g., CO) are discussed under Impact B-3 below.

The site preparation phase typically generates the most substantial emission levels because of the on-site equipment and ground-disturbing activities associated with grading, compacting, and excavation. Site preparation equipment and activities typically include backhoes, bulldozers, loaders, and excavation equipment (e.g., graders and scrapers). Although detailed construction specific information is not available at this time, based on the types of renewable energy projects listed in the Section II, Project Description it would be expected that the primary sources of construction-related emissions include soil disturbance- and equipment-related activities (e.g., use of backhoes, bulldozers, excavators, and other related equipment). Based on typical emission rates and default parameters for above mentioned equipment and activities, construction of a out-of-state renewable energy project could result in hundreds of pounds of daily NO_x and PM_{10}, which may exceed general mass emissions limits depending on the exact location of generation. Thus, because the specific air quality impacts of renewable energy projects necessary to comply with the 33 percent RES cannot be identified with any certainty, and construction activities associated with these projects could generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas, this impact is considered potentially significant for all renewable energy types under the 33 percent RES (high and low load). It is important to note that there is no difference in the impacts that would occur under the 20 percent RPS versus the 33 percent RES, as, based on the modeling, the magnitude of electricity generated from new out of-state renewable projects is relatively similar (e.g., approximately 9,500 GWh versus 10,900 GWh under both low and high load scenarios). Additionally, the magnitude of this impact is influenced more by the how (e.g., size of project footprint and types of construction activities required) and the where (e.g., whether located in a nonattainment area) of the new renewable projects, more so than the total amount of electricity generated.

IMPACT B-2

Long-Term Operational Impacts to Air Quality from Out-of-State Project-Generated Emissions of Criteria Air Pollutants and Precursors. Because renewable generation produces lower levels criteria air pollutants per unit of electricity output than fossil-fuel generation it would displace and less total electricity would be generated out-of-state in comparison to existing conditions, these projects would not be anticipated to result in significant environmental impacts (e.g., generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas). This impact is considered *less than significant* for all renewable energy types under the 33 percent RES (high and low load).

All Renewable Energy Project Types

All renewable energy projects no matter their size, location out-of-state, or type would be required to seek local land use approvals prior to their implementation. Part of the land use entitlement process requires that each of these projects undergo environmental review consistent with Federal environmental review requirements (e.g., NEPA) or other applicable state requirements. The environmental review process for all renewable project types under either the 20 percent RPS or 33 percent RES would assess whether project implementation would result in long-term operational air quality impacts.

At this time, the specific location, type, and number of renewable energy projects constructed out-of-state is not known and would be dependent upon a variety of market factors that are not within the control of ARB including: economic costs, energy demands, environmental constraints, and other market constraints. Nonetheless, as discussed with regards to the in-state projects, renewable generation produces less criteria air pollutants per unit of electrical output than fossil-fuel generation it would displace with implementation of the 33 percent RES plausible compliance scenarios (high or low load conditions). Additionally, in comparison to existing conditions less total electricity would be generated out-of-state under the 33 percent RES (e.g., approximately 98,000 GWh versus 60,000 under the low load scenario and 86,000 under the high load scenario). Further, subsequent environmental review would be conducted at such time that a renewable energy project is proposed and land use entitlements are sought. Thus, project-generated long-term operational emissions of criteria air pollutants would not be anticipated to result in significant environmental impacts (e.g., generate levels that conflict with applicable air quality plans, violate or contribute substantially to an existing or projected violation, or result in a cumulatively considerable net increase in non-attainment areas). It is important to note that there is no difference in the impacts that would occur under the 20 percent RPS versus the 33 percent RES (e.g., in comparison to existing conditions less total electricity would be generated out-of-state under both the low and high load scenarios). This impact is considered less than significant for all renewable energy types under the 33 percent RES (high and low load).

IMPACT B-3	**Impacts to Sensitive Receptors in the Project Area from Exposure to Substantial Pollutant Emissions (e.g., localized criteria air pollutants, toxic air contaminates) and Odors. Because the specific out-of-state air quality impacts of the 33 percent RES cannot be identified with any certainty, and these projects could potentially expose sensitive receptors to substantial localized criteria air pollutants, toxic air contaminants , or odors, this impact is considered *potentially significant* for all renewable energy types under the 33 percent RES (high and low load).**

All Renewable Energy Project Types

As discussed above under Impact B-1, all renewable energy projects no matter their size, location out-of-state, or type would be required to seek local land use approvals prior to their implementation. Part of the land use entitlement process requires that each of these projects undergo environmental review consistent with Federal environmental review requirements (e.g., NEPA) or other applicable state requirements. The environmental review process for all renewable project types under either the 20 percent RPS or 33 percent RES would assess whether project implementation would result in the exposure of sensitive receptors to air quality impacts.

At this time, the specific location, type, and number of renewable energy projects constructed out-of-state is not known and would be dependent upon a variety of market factors that are not within the control of ARB including: economic costs, energy demands, environmental constraints, and other market constraints. Nonetheless, the analysis provided herein provides a reasonable accounting of the types of environmental impacts that would occur with implementation of the 33 percent RES plausible compliance scenarios (high or low load conditions) as discussed below for the exposure of sensitive receptors to substantial emissions. Further, subsequent environmental review would be conducted at such time that a renewable energy project is proposed and land use entitlements are sought.

The primary criteria air pollutant of localized concern is CO. Local mobile-source CO emissions near roadway intersections are a direct function of motor vehicle activity, particularly during peak commute hours, including traffic volume, speed, and delay. Transport of CO is extremely limited because it disperses rapidly with distance from the source under normal meteorological conditions. Under specific meteorological conditions, CO concentrations near roadways and/or intersections may reach unhealthy levels with respect to local sensitive land uses, such as residential areas, schools, playgrounds, childcare facilities, and hospitals. Consequently, CO emissions are typically analyzed at a local rather than a regional level. Additionally, because increased CO concentrations are usually associated with roadways that are congested and with heavy traffic volume, the criteria to determine if project-generated emissions would result in the exposure of sensitive receptors to substantial pollutant concentrations is tied the project’s effect on the delay times and LOS of local intersections.

As discussed in Section M, Transportation and Traffic, although detailed information is not currently available, renewable energy projects would be anticipated to result in short-term construction and long-term operational traffic from worker commute-, maintenance/operation-, and material delivery-related trips. The amount of construction activity would fluctuate depending on the particular type, number, and duration of usage for the varying equipment; and the phase of construction (e.g., demolition, construction, erection). These variations would affect the amount of project-generated traffic for both worker commute trips and material deliveries. The amount of operational traffic would also vary depending on the size and type of renewable energy project. Thus, depending on the amount of trip generation and the location of the renewable energy project, implementation could conflict with applicable programs, plans, ordinances, or policies, specifically the degradation of delay times and LOS of local intersections, which are tied as discussed above to localized CO impacts. Long-term operation of stationary sources could also result in localized CO emissions at sensitive receptors if located at close distance to new renewable energy projects.

During construction of renewable energy projects out-of-state, toxic air contaminants (TACs) could be generated from a variety of construction activities, but primarily composed of exhaust emissions from off-road construction equipment, material delivery trips, and construction worker-commute trips. Construction activities could be located in areas where naturally occurring substances are present in the soil, thatif These emission types and associated levels fluctuate greatly depending on the particular type, number, and duration of usage for the varying equipment. The amount of TAC’s and associated unit risk factors from operational activities would also vary depending on the size and type of renewable energy project. Even though project implementation would be anticipated to produce less TACs overall due to the fact renewable energy production produces less TAC’s per unit of electricity output than the fossil-fuel generation it would displace under the plausible compliance scenarios, the exposure of sensitive receptors is highly dependent on the their distance from the source.

With regards to both project-generated construction and operational TAC emissions, the dose to which receptors are exposed is the primary factor used to determine health risk. Dose is a function of the concentration of a substance or substances in the environment, which is positively correlated with distance from the source, and the duration of exposure to the substance. Thus, a new renewable energy project could be located in an area where sensitive receptors are currently located and no current sources exist, resulting in a net increase in exposure from project implementation.

Lastly, though the types of renewable energy projects listed in the Project Description would not be anticipated to result in any construction-related odor emissions, long-term operational activities could depending on the exact type of stationary sources on-site. Even diesel emissions at a close distance could be considered an objectionable odor source.

In summary, the specific location, type, and number of renewable energy projects constructed out-of-state is not known at this time. However, construction and operational activities could result in the generation of localized CO emissions, TACs, and odors. Thus, because the specific air quality impacts of new renewable projects needed to comply with the 33 percent RES cannot be identified with any certainty, and activities associated with these projects, depending on the exact location of the renewable energy projects in relation to existing sensitive receptors, could result in the exposure thereof to substantial pollutant concentrations or odors, this impact is considered potentially significant for all renewable energy types under the 33 percent RES (high and low load). It is important to note that there is no difference in the out-of-state impacts that would occur under the 20 percent RPS versus the 33 percent RES.

4. MITIGATION

Mitigation is required for the following significant or potentially significant impacts.

Mitigation Measure B-1

- **Proponents for the proposed renewable energy project shall coordinate with local land use agencies to seek entitlements for development of the project including completing all necessary environmental review requirements (e.g., NEPA). The local land use agency or governing body shall certify that the environmental document was prepared in compliance with applicable regulations and shall approve the project for development.**

- **Based on the results of the environmental review, proponents shall implement all mitigation identified in the environmental document to reduce or substantially lessen the environmental impacts of the project.**

- **Comply with local plans, policies, ordinances, rule, and regulations regarding air quality-related emissions and associated exposure.**

- **Apply for, secure, and comply with all appropriate air quality permits for project construction and operations from the local agencies with air** quality jurisdiction and from other applicable agencies (e.g., EPA), if appropriate, prior to construction mobilization.

- Prepare and comply with a dust abatement plan that addresses emissions of fugitive dust during construction and operation of the project.

The proponents and local land use agencies can and should be the parties responsible for the approval and implementation of the renewable energy project and its mitigation. ARB is not a land use agency and would not be responsible for ensuring that this mitigation is implemented. Implementation of the above mitigation would reduce this impact to a less-than-significant level

for all renewable energy types under the 33 percent RES plausible compliance scenarios (high and low load conditions).

Mitigation Measure B-2

- Implement Mitigation M-1 above.

The proponents and local land use agencies can and should be the parties responsible for the approval and implementation of the renewable energy project and its mitigation. ARB is not a land use agency and would not be responsible for ensuring that this mitigation is implemented.

Implementation of the above mitigation would reduce this impact to a less-than-significant level for all renewable energy types under the 33 percent RES (high and low load conditions).

ATTACHMENT U

BEFORE THE BOARD OF SUPERVISORS
COUNTY OF KINGS, STATE OF CALIFORNIA

* * * * * *

IN THE MATTER OF AMENDING THE LOCAL CEQA GUIDELINES FOR THE PREPARATION, EVALUATION AND PROCESSING OF ENVIRONMENTAL DOCUMENTS FOR THE COUNTY OF KINGS.	))))))	**RESOLUTION NO. 16-001** **RE: Local Guidelines for the Implementation of CEQA**

WHEREAS, pursuant to Section 21082 of the Public Resources Code of the State of California all public agencies are required to adopt by ordinance, resolution, rule or regulations, objectives, criteria, and procedures for the evaluation of projects, and the preparation of environmental impact reports and negative declarations under the provisions of the California Environmental Quality Act (hereinafter referred to as "CEQA", and found at Public Resources Code Section 21000 et seq; all generic "Section" references are to the Public Resources Code); and

WHEREAS, Section 21082 further requires that the objectives, criteria, and procedures adopted by a public agency shall be consistent with the provisions of CEQA and with the State CEQA Guidelines adopted by the Secretary of the Resources Agency pursuant to CEQA (as found in the California Code of Regulations, Title 14, Division 6, Chapter 3, and hereinafter referred to as the "CEQA Guidelines"); and

WHEREAS, the purpose of this Resolution is to further streamline the local CEQA process by rescinding in its entirety Resolution No. 09-001, adopted January 27, 2009, entitled "Amending the Local CEQA Guidelines for the Preparation, Evaluation and Processing of Environmental Documents for the County of Kings", and replacing it with the local guidelines for the implementation of CEQA set forth in Attachment A.

NOW, THEREFORE, BE IT RESOLVED AS FOLLOWS:

1. This action is exempt pursuant to Section 15061(b)(3) of the *Guidelines* for *California Environmental Quality Act* (*CEQA Guidelines*). This section states that a project is exempt from *CEQA* if the activity is covered by the general rule that *CEQA* applies only to projects, which have the potential for causing a significant effect on the environment. Where it can be seen with certainty that there is no possibility that the activity in question may have a significant effect on the environment, the activity is not subject to *CEQA*. The CEQA Implementation procedures are technical changes concerning general policy for the implementation of CEQA and there is no possibility that adopting these procedures will have a significant effect on the environment..

2. Except as otherwise expressly provided herein, the provisions of CEQA and the CEQA Guidelines are hereby referred to, adopted and made part of this Resolution and a part of the Local Guidelines as hereinafter defined, with the same effect as if fully set forth herein, and all the provisions thereof shall apply to projects proposed to be carried out or given discretionary review and approval by the County of Kings or any organizational subdivision thereof.

3. Resolution No. 09-001 entitled "Amending the Local CEQA Guidelines for the Preparation, Evaluation and Processing of Environmental Documents for the County of Kings" is hereby rescinded in its entirety.

4. The local guidelines in Attachment A of this Resolution are hereby enacted to implement the provisions of the California Environmental Quality Act in the County of Kings (such local guidelines are herein referred to as the "Local CEQA Guidelines").

The foregoing Resolution was passed and adopted on a motion by Supervisor Fagundes, seconded by Supervisor Neves, by said Board of Supervisors at a regular meeting held on the 5th day of January, 2016, by the following vote:

AYES:	**Supervisors Fagundes, Neves, Valle, Pedersen, Verboon**
NOES:	**None**
ABSENT:	**None**

Doug Verboon

Chairman of the Board of Supervisors
County of Kings, State of California

WITNESS my hand and seal of said Board of Supervisors this 5th day of January, 2016.

Melanie Curtis

Melanie Curtis
Deputy Clerk of said Board of Supervisors

ATTACHMENT A

LOCAL GUIDELINES FOR THE PREPARATION, EVALUATION AND PROCESSING OF ENVIRONMENTAL DOCUMENTS IN THE COUNTY OF KINGS, CALIFORNIA

Section 1. Purposes.

These Local Guidelines implement the provisions of the California Environmental Quality Act (CEQA) as contained in Division 13 (commencing at Section 21000) of the Public Resources Code of the State of California and the State CEQA Guidelines, as contained in Chapter 3 (commencing at Section 15000), Division 6, Title 14 of the California Code of Regulations, as adopted by the Secretary of the Resources Agency of the State of California. These Local Guidelines do not apply to ministerial projects, or to those projects which are statutorily exempt or excluded from CEQA review requirements, as set forth in Public Resources Code sections 21080 through 21080.35, or to those projects which are categorically exempt under the provisions of Article 19 (commencing at Section 15300) of the State CEQA Guidelines, or to those projects which are emergency projects under the provisions of Section 15269 of the State CEQA Guidelines.

Section 2. Definitions.

Whenever the following words or phrases are used in these Local Guidelines, unless otherwise defined, they shall have the meaning ascribed to them in this Section. These definitions are intended to clarify but not to replace or negate the definitions used in CEQA or in the State CEQA Guidelines, beginning at Section 15350, which are included herein by reference.

a. Consultant. An individual consultant or a consulting firm with expertise in environmental sciences and the preparation of environmental documents.

b. County or County Department. County or County Department means Kings County and any organizational subdivision thereof.

c. EAC - Environmental Advisory Committee - Committee. An informal committee appointed by the Board of Supervisors to advise County boards, commissions, committee, and departments on environmental matters, associated with their individual areas of expertise, concerning the implementation of CEQA, made up of the following members:

Kings County Health Officer,
Kings County Community Development Agency Director,
Kings County Director of Public Works,
Kings County Agricultural Commissioner and Sealer of Weights and Measures,
U.C. Cooperative Extension Services Farm Advisor, and
The Manager of the Kings Mosquito Abatement District.

d. Professional Services Agreement. An agreement between the County and a consultant which specifies the work that will be performed for the preparation of environmental documents and the cost of preparing such a document.

e. Reimbursement Agreement. An agreement between the County and the project proponent to reimburse the County for the actual cost to prepare the environmental documents for the project, including the cost of the "Agreement for Professional Services" and administrative costs incurred by County staff in processing the project.

f. Indemnification Agreement. An agreement between the County and the project proponent to reimburse the County's actual cost associated with challenges to the environmental documents prepared by, or under the direction of, the County for the project and to defend and indemnify the County against any and all challenges to the County's review, consideration, processing or approval of the project application.

g. Faithful Performance/Payment Bond. A performance bond, payment bond, cash deposit, letter of credit, or other suitable financial instrument approved by the County that is convertible to cash, or any combination of the above,, provided by the applicant to ensure the faithful performance of the project proponent's obligations, and/or the payment of amounts due, under a Reimbursement Agreement and/or an Indemnification Agreement entered into between the County and the Project Proponent under the terms and provisions of these Local Guidelines.

Section 3. Kings County Environmental Advisory Committee (EAC).

a. The Kings County Environmental Advisory Committee EAC shall consist of the following six members:

   Kings County Health Officer,
   Kings County Community Development Agency Director,
   Kings County Director of Public Works,
   Kings County Agricultural Commissioner and Sealer of Weights and Measures,
   U.C. Cooperative Extension Services Farm Advisor, and
   The Manager of the Kings Mosquito Abatement District.

b. The EAC shall be advisory only and will not hold public meetings. Each EAC member may provide written comments determined by the member to appropriately reflect that member's general and specific environmental concerns related to his or her area of expertise.

c. Duties of the Members of the EAC: The principal duty of the members of the EAC shall be to review initial studies which are submitted by County Departments during the 20-day public review period for proposed negative declarations and the 30-day or 45-day public review period for draft EIRs required by CEQA Section 21091. Committee members may make any of the following recommendations:

   1) Recommend approval of the initial study as a negative declaration, if, based upon the initial study, the Committee member determines that the project will not have a significant effect on the environment. Failure to notify the Planning Division of the Community Development Agency within the specified review period, indicates acceptance of the initial study as submitted; or

   2) In writing, request specific changes to the draft initial study, and with those specified changes recommend that the decision maker adopt a negative declaration; or

   3) In writing, recommend the preparation of an environmental impact report if, based upon the initial study, the Committee member believes that the project will have a significant adverse effect on the environment. The committee member shall specify, in writing, what effects on the environment he or she believes will be significant and why.

d. Each EAC member shall also be responsible for recommending to the Board of Supervisors' requests for additions to, or deletions from, the list of classes or projects that are exempt from environmental review pursuant to Sections 21084 through 21086, inclusive, of CEQA.

e. Limitations of Review by Environmental Advisory Committee: The review of negative declarations and environmental impact reports by the members of the EAC shall be advisory in nature and shall be limited to a determination of the objectivity and adequacy of the environmental documents submitted to its members, and shall ensure that the decision maker has sufficient information about the possible impacts to the environment, in the judgment of the committee member, that the project may cause. Committee members shall not consider the value of the project itself or whether the project should be approved or denied. Such determination is solely the responsibility of the decision maker for the project.

Section 4. Ministerial Projects and Actions in Kings County

Section 21080(b)(1) of CEQA provides that the Act does not apply to ministerial projects proposed to be carried out or approved by public agencies. Section 15268 of the State CEQA Guidelines states that the determination of what is "ministerial" can most appropriately be made by the public agency involved, and that each public agency should identify or itemize those projects and actions which are deemed ministerial.

The following is a non-exclusive list of types of projects that are ministerial and therefore exempt from CEQA review requirements:

a. Sheriff-Animal Control

1. Dog Licenses

b. Agricultural Commissioner-Sealer

1. Agricultural crop moving permits

c. Building Division of the Community Development Agency

1. Plan check reviews
2. Building Permits (including Electrical, Plumbing, and Mechanical Permits)
3. Demolition Permits
4. Mobile Home Installation Permits
5. Relocation Inspections and Permits
6. Utility Service Connections and Disconnections
7. Compliance Inspections and Reports
8. Water well permits

d. County Clerk

1. Marriage Licenses

e. Fire Department

1. Fireworks Sales Permits
2. Weed Abatement Program

f. Health Department

1. Food Vendor's Permits
2. Water Supply Permits (small public water systems and state small water systems)
3. Underground Storage Tank Permits, Authority to Construct, and Authority to Abandon
4. Hazardous Materials Business Plan and Inventory approvals
5. Risk Management and Prevention Program approvals
6. Medical Waste Management Registrations
7. Limited Quantity Medical Waste Hauler Exemptions
8. Registration of businesses engaged in the cleaning of septic tanks, chemical toilets, cesspools, and seepage pits
9. Reserved.
10. Plan approval for construction, modification, or remodeling of food facilities, public swimming pools and spas, on site sewage disposal systems, small public water systems, state small water system and/or underground storage tanks (including piping)
11. Occupational health and safety consultation services
12. Body art registrations

g. Planning Division of the Community Development Agency

1. Site Plan Reviews conducted by the Zoning Administrator under the provisions of Article 16 of the Kings County Development Code.
2. Land divisions exempted by Sections 2306 and 2308.I of Article 23 of the Kings County Development Code.
3. Certificates of Compliance
4. Lot Line Adjustments
5. Annual Fire Arms Dealers Reviews
6. Code enforcement investigations and orders for abatement of nuisances and violations
7. Abandoned Vehicle Abatement Program investigations and orders for abatement
8. Certificates of Voluntary Parcel Merger
9. Temporary Use Permits

h. Public Works Department

1. Encroachment Permits
2. Moving permits
3. Traffic control activities

i. Tax Collector
1. Dance, explosive, gun, and solicitors licenses
2. Rubbish disposal operator's license

A notice of exemption shall be filed for all projects determined to be statutorily, categorically or otherwise exempt from CEQA environmental review.

Section 5. Initial Study.

The initial study process shall be conducted according to the procedures outlined in the State CEQA Guidelines, Article 5, beginning with Section 15060.

The County department initiating a public project or receiving an application for discretionary approval of a private project may prepare its own initial study, or submit a description of the project to the Planning Division of the Community Development Agency for environmental review. If a project description is submitted to the Planning Division, the Planning Division shall conduct an initial study pursuant to Section 15063 of the State CEQA Guidelines and these Local Guidelines to determine if the project may have a significant effect on the environment. The County department or the applicant shall provide any additional information the Planning Division may require in preparing the initial study. Failure to provide the requested information in a timely manner may cause the application not to be certified as complete, and delay the development of the required environmental documents.

Section 6. Time Limits for the Certification of Environmental Documents.

Pursuant to Section 21151.5 of CEQA and Article 8 of the State CEQA Guidelines, the County of Kings hereby establishes one year as the time limit for the completion and certification of environmental impact reports, and 180 days for the completion and adoption of negative declarations, for projects which require environmental review. The commencement and running of these time periods shall be governed by CEQA and the CEQA Guidelines.

Extensions of Time for EIR's: Extensions of time for the processing of EIR's may be approved once, for an additional period not to exceed 90 days, by the Lead Agency provided that it finds that compelling circumstances justify the extension of time and that the project applicant consents to the specified extension, pursuant to Government Code Section 65957 and State CEQA Guidelines Section 15108. Extensions exceeding 90 days may be approved where the law expressly otherwise provides for such additional extensions.

Section 7. Deposit and Accounting on Private Project.

All applications for the discretionary review of private projects by the County shall include a fee, subject to Section 21089 of CEQA, in an amount set by Ordinance of the Kings County Board of Supervisors, at the time the project application is filed with the Planning Division of the Community Development Agency to cover the cost of preparation of the initial study.

If it is determined that an EIR should be prepared, the applicant shall be required to pay the cost of preparing the EIR (see Section 2 d, e, f, and g above). The Planning Division shall ensure the EIR is prepared according to the procedures described in Article 7 (Section 15084 through 15097) of the CEQA Guidelines.

The Planning Division may prepare the required documents, with Board of Supervisors approval, by engaging the services of a consultant with expertise in preparing environmental documents, based on a detailed work plan approved by the Planning Department staff, and made a part of the "Agreement for Professional Services", shall be submitted to the project applicant who shall enter into a *Reimbursement Agreement* with the County and deposit in an interest bearing account in the County Treasury the amount of the cost shown in the detailed work plan (agreement), plus an administrative fee determined by the Community Development Agency Director to be necessary to defray the cost of administering the agreement with the consultant and the staff time necessary to process the project to its completion.

As an alternative the applicant may submit detailed information in any form, including the form of a draft EIR. The Planning Division, with Board of Supervisors approval, may engage at the expense of the applicant the services of a consultant with expertise in preparing environmental documents, to advise the County on the adequacy of the information submitted, including, but not limited to, a draft EIR, if any is submitted. Reimbursement for the costs of the County's consultant shall be the same as described above.

An accurate accounting shall be kept by the Planning Division, with assistance from the County Department of Finance, of the actual cost of preparing and administering the EIR and shall be made available to the applicant at his request. Upon the completion of the project, after the decision maker's final action, the Planning Division shall refund to the applicant any money remaining in the account, including interest that was earned and not used.

Section 7.5. Indemnification and Bonding.

In its sole and absolute discretion, the County may determine that it has exposure to potential extraordinary costs and require an applicant to provide the county indemnification against extraordinary costs associated with the review and processing of a development application. The extraordinary costs the County may incur associated with the review and processing of a development application, may include, but are not limited to, applications for development entitlements requiring preparation of environmental impact reports, specific plans, and major general plan amendments, large urban development projects, project decisions that are appealed or challenged through law suits, etc. In addition, if it is determined that an Indemnification Agreement is required, the applicant will be required to provide a bond in an amount sufficient to ensure that the applicant's indemnification of the County is sufficient to protect the public interest in case of challenges to the process or action of the County related to the project, or failure of the applicant to provide the County with required reimbursements for the cost of the application review and processing under the terms of the Reimbursement Agreement. In its sole and absolute discretion, the County may determine that the Reimbursement Agreement and the Indemnification Agreement be combined as one document. The form, nature and amount of the bond and/or bonds or other suitable financial instrument, required under the terms of these Local Guidelines and in the light of any risks associated with a particular project shall be in the sole and absolute discretion of the County.

Section 8. Action by the Decision-Maker.

(a) When a proposed negative declaration has been forwarded to the decision-maker, the decision-maker shall, prior to making a decision on the project, either approve the negative declaration based upon a finding that the project will not have a significant effect on the environment, or shall refer the matter to the Planning Division of the Community Development Agency for preparation of an EIR, or mitigated negative declaration, based upon a finding that the project may have a significant effect on the environment. If the matter is referred for additional review, the decision maker shall take no further action on the project until a final EIR, or mitigated negative declaration, has been prepared as required by law.

(b) When a final EIR has been prepared and processed according to Article 7, beginning with Section 15080 of the State CEQA Guidelines, the decision-maker shall, prior to making a decision on the project, certify that the final EIR has been completed in compliance with CEQA and the State CEQA Guidelines, and shall review and consider the information contained in the final EIR. Based upon information contained in the final EIR, when the decision-maker finds that the project will have a significant effect on the environment, the decision-maker shall state in writing reasons to support its decision to approve or carry out the project based upon information contained in the final EIR or other information contained in the record.

Section 9. Mitigation Reporting and Monitoring Program.

When approving projects for which mitigation measures are required and adopted, the decision maker shall adopt as part of the approval action a "Mitigation Reporting and Monitoring Program", pursuant to Section 21081.6 of CEQA and Section 15097 of the State CEQA Guidelines, for the changes to the project. The "Mitigation Reporting and Monitoring Program", then becomes a condition of approval to mitigate or avoid significant effects on the environment. Failure of the project applicant to comply with the reporting requirements and mitigation measures are grounds for permit revocation or correcting the effects on the environment at the project applicant's cost.

The decision maker may require the applicant to deposit an amount of money estimated to offset the cost of monitoring the development and operation of the project into an interest bearing account in the Kings County

Treasury. Upon completion of the monitoring program any unused money in the account shall be returned to the applicant.

Section 10. Notice of Determination.

After making a decision on a project, the decision-maker shall cause to be filed a Notice of Determination, pursuant to Section 21080.4 of CEQA and 15094 of the State CEQA Guidelines. Such notice shall include a brief description of the project, the decision of the decision-maker to approve (carry out) or disapprove (not carry out) the project, the determination of the decision-maker whether the project will or will not have a significant effect on the environment, and a statement whether an environmental impact report has been prepared. The Planning Division of the Community Development Agency shall ensure that such notices are filed.

Section 11. Duties of the County Clerk.

All notices submitted to the County Clerk pursuant to CEQA shall posted by the County Clerk at the place designated by the County Clerk for the posting of all official notices. Members of the general public requesting copies of said notices shall be charged for the actual cost of reproducing that copy. The County Clerk shall prepare and maintain a list of the names and mailing addresses of all persons requesting review of a particular notice.

Section 12. Severability.

If any provision of these Local Guidelines or the application thereof to any person or circumstances is held invalid, such invalidity shall not affect other provisions or applications of these Local Guidelines which can be given effect without the invalid provision of application thereof, and to this end the provisions of these Local Guidelines are severable.

END OF GUIDELINES

ATTACHMENT V

Notice of Exemption

TO: ☐ Office of Planning and Research

For U.S. Mail
P.O Box 3044, Room 113
Sacramento, CA 95812-3044

Street Address
1400 Tenth St.
Sacramento, CA 95814

☒ County Clerk
County of Kings
Kings County Government Center
Hanford, California 93230

FROM: Kings County Community Development Agency
Kings County Government Center
Hanford, CA 93230

ORIGINAL
FILED
DEC 07 2023
KRISTINE LEE
KINGS COUNTY CLERK

PROJECT TITLE:
Site Plan Review No. 23-14 (Felicita Dairy)

PROJECT APPLICANT:
4-Creeks, Cole Martin, 324 S. Santa Fe St., Visalia, CA 93292
(559) 802-3052

PROJECT LOCATION - Specific:
22154 4th Ave.

PROJECT LOCATION - City
Hanford

PROJECT LOCATION - County:
Kings

DESCRIPTION OF PROJECT:
The applicant is proposing to construct a new anaerobic digester and ancillary equipment at the existing Felicita Dairy, located at 22154 4th Ave., Hanford, Assessor's Parcel Number 028-280-011. The proposed application includes the installation of a 360' L x 175' W x 25' D anaerobic digester and ancillary equipment. The biogas produced by the digester is proposed to be transported through a low-pressure pipeline to an onsite biogas conditioning pad for cooling and compression prior to entering the biogas collection line. It will then be transported to a centralized biogas upgrading facility, located on Assessor's Parcel Number 228-090-009 in Tulare County (Tulare County Special Use Permit No. PSP 18-015), for conditioning and electrical generation.

NAME OF PUBLIC AGENCY APPROVING PROJECT:
Kings County Community Development Agency, 1400 W. Lacey Blvd., Building 6, Hanford, CA 93230, (559) 852-2670

NAME OF PERSON OR AGENCY CARRYING OUT PROJECT:
Gerrit DeJong, Felicita Dairy, 22154 4th Ave., Hanford, CA 93230, (559) 992-3272

EXEMPT STATUS: *(check one)*
- ☒ Ministerial (Section 21080(b)(1); 15268);
- ☐ Declared Emergency (Section 21080(b)(4); 15269(a));
- ☐ Emergency Project (Section 21080(b)(4); 15269(b)(c));
- ☐ Categorical Exemption. State type and section number: ____________
- ☐ Statutory Exemptions. State code number: ____________

REASONS WHY PROJECT IS EXEMPT:
Section 4.G.1. of the *Kings County Local Guidelines to Implement CEQA* lists Site Plan Review as a Ministerial Project pursuant to Section 15268 of the *Guidelines for California Environmental Quality Act.*

CONTACT PERSON:
Noelle Tomlinson

TELEPHONE NUMBER:
(559) 852-2697

Signature: Noelle Tomlinson
Title: Planner
Date: 12/7/23

Clerk/Recorder,, Kristine Lee Date: 12/07/2023 09:09 AM

Kings County

Receipt Detail

Receipt Information

Receipt Time:	12/7/2023 9:08:18 AM	**Receipt #:**	19471		
Location:	MAIN OFFICE	**Department:**	REAL ESTATE	**Device:**	VIRGINIA DENKER
Effective Date:		**User:**	R069		
Customer:	4-CREEKS COLE MARTIN				
Address1:					
Address2:					
City:		**State:**		**Zip:**	
Phone:		**Email Address:**			
Remarks:					
Change Issued:	$0.00	**Refund:**	$0.00	**Surplus:**	$0.00
Cash Total:	$0.00	**Check Total:**	$70.00	**Escrow Total:**	$0.00
VoucherTotal:	$0.00	**Credit Card Total:**	$0.00	**Legalease Total:**	$0.00

Revenue Information

Seq #	No Fee	Voucher	Reference #	Transaction Type	# Pages	Amount	SubSystem Id
1	N	N	NA-15560147	Noe	1	$70.00	CASHADMIN

Payment Information

#	Type	Payment ID #	Amount	NSF
1	CHECK	5001	$70.00	

Revenue Detail Information

Seq #	GL Seq	Revenue Account #	Amount	Payment #	Payment Type	Amount Paid	Amount Remaining
1	1	DFW CLERK FILING FEE	$70.00	1	CHECK		

Account Transaction Information

Account #	Revenue #	GL Seq	Amount	Transaction Type	Reference #	Transaction Time

ATTACHMENT W

Notice of Exemption

TO: ☐ Office of Planning and Research

For U.S. Mail	Street Address
P.O Box 3044, Room 113	1400 Tenth St.
Sacramento, CA 95812-3044	Sacramento, CA 95814

☒ County Clerk
County of Kings
Kings County Government Center
Hanford, California 93230

FROM: Kings County Community Development Agency
Kings County Government Center
Hanford, CA 93230

ORIGINAL
FILED
MAY 15 2023
KRISTINE LEE
KINGS COUNTY CLERK

PROJECT TITLE:
Site Plan Review No. 22-16 (Countryside Dairy)

PROJECT APPLICANT:
Lauren Duggan, 2711 Meadow View Dr. suite 100 Redding CA 96002

PROJECT LOCATION - Specific:
21256 4th Ave

PROJECT LOCATION - City
Corcoran

PROJECT LOCATION - County:
Kings

DESCRIPTION OF PROJECT:
The applicant is proposing to establish a covered anaerobic digester and ancillary biogas cleanup equipment incidental to an existing dairy facility, Countryside Dairy, located at 21256 4th Ave, Corcoran Assessor's Parcel Number 028-280-018. There are two proposed options for the cleanup equipment – Option A (Trucking Biogas) and Option B (Piping Biogas).

NAME OF PUBLIC AGENCY APPROVING PROJECT:
Kings County Community Development Agency

NAME OF PERSON OR AGENCY CARRYING OUT PROJECT:
David & Arlene Bakker, Lauren Duggan, Maas Energy, 2711 Meadow View Dr. suite 100 Redding CA 96002 (530) 710-8545

EXEMPT STATUS: (*check one*)

- ☒ Ministerial (Section 21080(b)(1); 15268);
- ☐ Declared Emergency (Section 21080(b)(4); 15269(a));
- ☐ Emergency Project (Section 21080(b)(4); 15269(b)(c));
- ☐ Categorical Exemption. State type and section number: ____________
- ☐ Statutory Exemptions. State code number: ____________

REASONS WHY PROJECT IS EXEMPT:
Section 4.G.1. of the *Kings County Local Guidelines to Implement CEQA* lists Site Plan Review as a Ministerial Project pursuant to Section 15268 of the *Guidelines for California Environmental Quality Act.*

CONTACT PERSON:
Alex Hernandez

TELEPHONE NUMBER:
(559) 852-2679

Alex Hernandez

Signature: Alex Hernandez
Title: Deputy Director - Planning
Date: 05/15/23

KINGS COUNTY CLERK-RECORDER
1400 W. LACEY BLVD.
HANFORD, CA 93230
(559) 582-3211 X2470

Receipt Time: 05/15/2023 12:26:35 PM   Receipt #: 8153
Issued To: LAUREN DUGGAN

Documents

#	Type	# Pages	Quantity	Reference #	Book / Page	Amount
1	NOTICE OF EXEMPTION	1	1	NA-15413505		$65.00
					Total :	$65.00

Payments

#	Type	Payment #		Amount	NSF
1	CHECK	11123		$65.00	
			Total Payments:	$65.00	

SITE PLAN REVIEW NO. 22-16 (COUNTRYSIDE DAIRY)

THANK YOU!
R066

Clerk-Recorder,, Kristine Lee
Kings County
Receipt Detail

Date: 05/15/2023 12:36 PM

Receipt Information

Receipt Time:	5/15/2023 12:26:35 PM	**Receipt #:**	8153		
Location:	MAIN OFFICE	**Department:**	REAL ESTATE	**Device:**	ALEJANDRA ESPINOZA
Effective Date:		**User:**	R066		
Customer:	LAUREN DUGGAN				
Address1:	2711 MEADOW VIEW DR				
Address2:	SUITE 100				
City:	REDDING	**State:**	CA	**Zip:**	96002
Phone:		**Email Address:**			
Remarks:	SITE PLAN REVIEW NO. 22-16 (COUNTRYSIDE DAIRY)				
Change Issued:	$0.00	**Refund:**	$0.00	**Surplus:**	$0.00
Cash Total:	$0.00	**Check Total:**	$65.00	**Escrow Total:**	$0.00
VoucherTotal:	$0.00	**Credit Card Total:**	$0.00	**Legalease Total:**	$0.00

Revenue Information

Seq #	No Fee	Voucher	Reference #	Transaction Type	# Pages	Amount	SubSystem Id
1	N	N	NA-15413505	Noe	1	$65.00	CASHADMIN

Payment Information

#	Type	Payment ID #	Amount	NSF
1	CHECK	11123	$65.00	

Revenue Detail Information

Seq #	GL Seq	Revenue Account #	Amount	Payment #	Payment Type	Amount Paid	Amount Remaining
1	1	DFW CLERK FILING FEE	$65.00	1	CHECK		

Account Transaction Information

Account #	Revenue #	GL Seq	Amount	Transaction Type	Reference #	Transaction Time

ATTACHMENT X

So. Tulare Biogas Gathering Line

Summary

SCH Number
2020080277

Public Agency
Tulare County

Document Title
So. Tulare Biogas Gathering Line

Document Type
NOE - Notice of Exemption

Received
8/18/2020

Posted
8/18/2020

Document Description
CalBioGas South Tulare LLC proposes to construct 8.8 miles of a pressurized underground gas pipeline within portions of the County of Tulare rights-of-way of Roads 96, 128, 132 and 152; Avenues I84, 192 and 208; and Spacer Drive D 134), south of the City of Tulare. The intent of the project is to transport dairy biogas from participating dairies to a Southern California Gas Company mainline tie-in facility. The scope of the project consists of the installation of HDPE PE4710 SDR 11 gas pipeline and concomitant safety equipment along the 8.8-mile alignment. On August 18, 2020, the Tulare County Board of Supervisors approved an indemnification agreement to allow some segments of the underground pipeline to utilize County rights-of-way within easements along or across public roadways. All of Tulare County will benefit as the Project would recover manure methane at dairies and using the methane as a renewable source of natural gas thereby reducing greenhouse gas emissions.

Contact Information

Name
Hector Guerra

Agency Name
Tulare County Resource Management Agency

Contact Types
Lead/Public Agency

Address

5961 South Mooney Blvd
Visalia, CA 93277

Phone

(559) 624-7000

Email

hguerra@co.tulare.ca.us

Name

Agency Name

CalBioGas South Tulare LLC

Contact Types

Project Applicant

Location

Counties

Tulare

Township

21,20S

Range

24,25E

Section

multi

Other Location Info

Section Various, Township 21 and 20 S, Range 24 and 25 E of the Lake View School, Tipton, Tulare, and Cairn's Corner USGS 7 ½ minute quadrangles

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Notice of Exemption

Exempt Status

Categorical Exemption

Type, Section or Code

Sec. 15301, Class 1, and Sec. 15303, Class 3

Reasons for Exemption

The Project will not involve any new developments or changes to existing land uses, nor are any proposed, there will be no additional vehicular trips generated as a result of the proposed Activity/Project. The Activity/Project will result in no adverse impact to the environment including aesthetics, air quality, agriculture, biology, cultural, greenhouse gases, hazards/hazardous materials, land use/planning, noise, public services, traffic, or utilities/service systems. Furthermore, the proposed Project site will be required to comply with applicable San Joaquin Valley Unified Air District rules and regulations, including but not limited to, Rule 2010 (Permits Required), Rule 2201 (New and Modified Stationary Source Review), and Rule

9510 (indirect Source Review). The Activity/Project will result in reduction of methane-related GHG by using methane gas emissions from the dairies as an alternative/renewable fuel source, is consistent with draft Tulare County Dairy Climate Action Plan (which incorporates strategies to promote the use of renewable energy sources, including digesters for energy-production), and is also consistent with and implements the California Environmental Protection Agency Air Resources Board's Short-Lived Climate Pollutant Reduction Strategy March 2017; Methane Emissions Reductions from Dairy Manure. As the equipment modification will occur at an existing site and pipelines for this Activity/Project will remain within County of Tulare Rights-of-Way, this action is consistent with 14 Cal. Code Regs. Section 15301 (b) Existing facilities or both investor and public owned utilities used to provide electric power, natural gas, sewerage, or other public utility services and; 14 Cal. Code Regs. Section 15303(d) Water main, sewage, electrical gas, and other utility extensions, including street improvements, or reasonable length to serve such construction. Therefore, the use of CEQA Guidelines Sections 1530l (b) and 15303 (d), as noted above, are applicable and appropriate for this Activity/Project.

Attachments

Notice of Exemption

NOE_S Tulare Biogas Gathering Line_ocr PDF 464 K

ATTACHMENT Y

SB 535 Disadvantaged Communities

California Climate Investments to Benefit Disadvantaged Communities

Disadvantaged communities in California are specifically targeted for investment of proceeds from the state's Cap-and-Trade Program. These investments are aimed at improving public health, quality of life and economic opportunity in California's most burdened communities, and at the same time, reducing pollution that causes climate change. The investments are authorized by the California Global Warming Solutions Act of 2006 (Assembly Bill 32, Nunez, 2016).

In 2012, Senate Bill (SB) 535 (De León, Chapter 830, Statutes of 2012) established initial requirements for minimum funding levels to "Disadvantaged Communities" (DACs). The legislation also gives CalEPA the responsibility for identifying those communities, stating that CalEPA's designation of disadvantaged communities must be based on "geographic, socioeconomic, public health, and environmental hazard criteria".

In 2016, Assembly Bill (AB) 1550 (Gomez, Chapter 369, Statutes of 2016) directed CalEPA to identify DACs and also established the currently applicable minimum funding levels:

- At least 25 percent of funds must be allocated toward DACs
- At least 5 percent must be allocated toward projects within low-income communities or benefiting low-income households
- At least 5 percent must be allocated toward projects within and benefiting low-income communities, or low-income households, that are outside of a CalEPA-defined DAC but within ½ mile of a disadvantaged community.

Final Designation of Disadvantaged Communities (May 2022)

English | En Español

After receiving public input at workshops and in written comments, in May 2022, CalEPA released its updated designation of disadvantages communities for the purpose of SB 535. In this designation, CalEPA formally designated four categories of geographic areas as disadvantaged:

1. Census tracts receiving the highest 25 percent of overall scores in CalEnviroScreen 4.0 (1,984 tracts).
2. Census tracts lacking overall scores in CalEnviroScreen 4.0 due to data gaps, but receiving the highest 5 percent of CalEnviroScreen 4.0 cumulative pollution burden scores (19 tracts).
3. Census tracts identified in the 2017 DAC designation as disadvantaged, regardless of their scores in CalEnviroScreen 4.0 (307 tracts).
4. Lands under the control of federally recognized Tribes. For purposes of this designation, a Tribe may establish that a particular area of land is under its control even if not represented as such on CalEPA's DAC map and therefore should be considered a DAC by requesting a

consultation with the CalEPA Deputy Secretary for Environmental Justice, Tribal Affairs and Border Relations at TribalAffairs@calepa.ca.gov.

The designation takes into account the latest and best available data and considers factors related to data unavailability. This designation will go into effect on July 1, 2022, at which point programs funded through California Climate Investments will use the designation in making funding decisions.

Disadvantaged Communities Map

[Click to open this map in a new window]

CalEPA California Environmental Protection Agency

SB 535 Disadva

State's Cap-and-Trade Program specifically targeted for investment in disadvantaged communities in California. These funds must be used for programs that further reduce emissions of greenhouse gases.

Senate Bill 535 (De León, Statutes of 2012) directed that at least a quarter of the proceeds go to projects that provide a benefit to disadvantaged communities and at least 10 percent of the funds go to projects located within those communities. The legislation gives CalEPA the responsibility for identifying those communities.

How to use this map

- Use your mouse or touchpad to pan around.
- Zoom in/out with a mouse wheel or the +/- icons.
- Search by location or census tract number with the **search icon**.
- Click on a census tract to view additional information in the pop-up window.
- Dock the pop-up window to the side of the screen by clicking the **dock** icon.
- Export a map view that includes the legend and popup using the **screenshot** widget.
- Click the links in the header to view additional resources related to SB 535 Disadvantaged Communities.

SB 535 Disadvantaged Communities 2022 (Census Tracts and Tribal Areas)

Download SB 535 CalEnviroScreen Data

In addition to the interactive map above, SB 535 disadvantaged communities data is available for download in other formats:

- [SB 535 Excel Spreadsheet and data dictionary (May 2022)]. There are two files in this zipped folder. 1) a spreadsheet showing the list of census tracts identified as disadvantaged communities, a list of the Federally recognized tribal areas identified as disadvantaged communities, and the raw data and calculated percentiles for individual indicators and combined CalEnviroScreen scores for census tracts identified as disadvantaged communities. 2) a pdf document including the data dictionary.
- [SB 535 ArcGIS Geodatabase (May 2022)]: A zipped file which can be unzipped, then opened using ArcGIS software to view the results. (ArcGIS is a paid subscription)

Service URL: ArcGIS feature service:
https://services1.arcgis.com/PCHfdHz4GlDNAhBb/arcgis/rest/services/SB_535_

Additional information as well as the previous identification of disadvantaged communities from 2017 using CalEnviroScreen 3.0 is available on the CalEPA page.

For questions, please contact CalEnviroScreen@oehha.ca.gov or (916) 324-7572.

Documents

- SB 535 List of Disadvantaged Communities (2022) Spreadsheet and Data Dictionary
- SB 535 List of Disadvantaged Communities (2022) Geodatabase

Cal EPA

- Air Resources Board
- Cal Recycle
- Department of Pesticide Regulation
- Department of Toxic Substances Control
- State Water Resources Control Board

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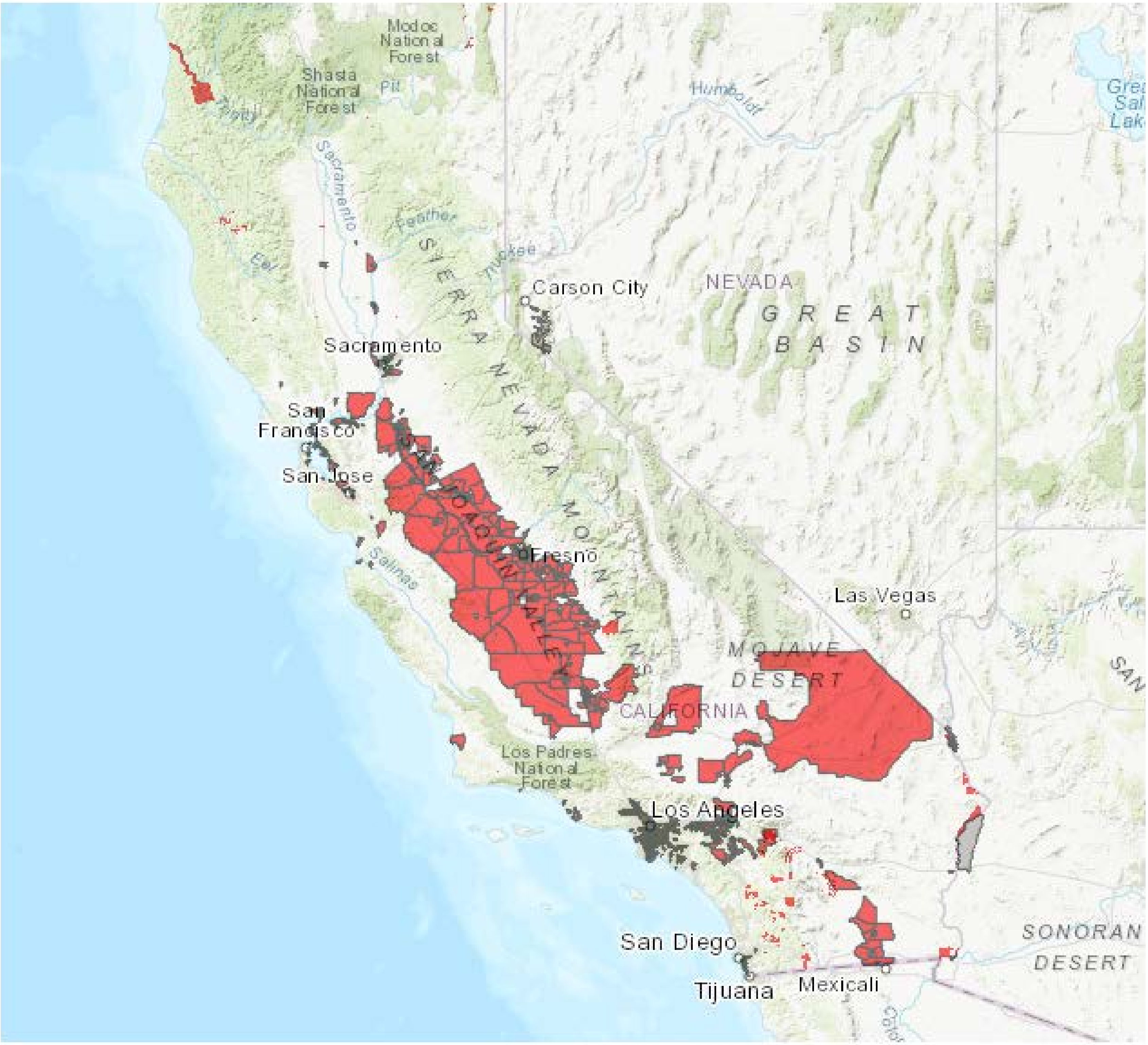

SB 535 Disadvantaged Communities 2022 (Census Tracts and Tribal Areas)

ATTACHMENT Z

Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target

Final

March 2022

CALIFORNIA AIR RESOURCES BOARD

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Executive Summary

California took a major step toward reducing greenhouse gas (GHG) emissions and combatting climate change when the Legislature enacted Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006), which requires the State to reduce GHG emissions to 1990 levels by 2020. California achieved this target in 2016, four years earlier than mandated. To achieve deeper reductions, the Legislature enacted Senate Bill (SB) 32 (Pavley, Chapter 249, Statutes of 2016), which requires the State to further reduce GHG emissions to 40 percent below 1990 levels by 2030. In the same year, the Legislature enacted SB 1383 (Lara, Chapter 395, Statutes of 2016), which recognizes the immediate climate benefits of reducing short-lived climate pollutants (SLCP). In the 2017 Scoping Plan Update, the plan for achieving GHGs reductions in the State, the California Air Resources Board) CARB describes that short lived climate pollutant (SLCP) reductions account for about one-third of the cumulative GHG emissions reductions the State is relying on to achieve the statewide 2030 GHG emissions target established under SB 32.

Short-lived climate pollutants, including methane, are powerful climate forcers that have a relatively short atmospheric lifetime, but a high global warming potential compared to other GHGs such as carbon dioxide. SB 1383 establishes SLCP reduction targets and requires CARB to implement a Short-Lived Climate Pollutant Reduction Strategy (Strategy) to achieve these targets. The law sets a 2030 methane emissions reductions target for the dairy and livestock sector (2030 target), which produces more than half of the State's methane emissions. This target is a reduction of 40 percent below 2013 levels, or a reduction of 9 million metric tons carbon dioxide equivalent ($MMTCO_2e$)[1] by 2030. SB 1383 also requires CARB, in consultation with the California Department of Food and Agriculture (CDFA), to analyze the progress that the sector has made toward achieving the 2030 reduction target and achieving the goals identified in the SLCP Strategy, including progress made in overcoming technical and market barriers to implementing methane emissions reductions measures identified in the Strategy. This Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target (Analysis) is responsive to that mandate.

Dairy and livestock methane emissions originate from two primary sources, manure management and enteric fermentation. Manure methane emissions can be reduced through two primary methods—installation of an anaerobic digester and alternative

[1] This emissions reduction estimate is calculated using the 100-year global warming potential (GWP) for methane (IPCC, 2007: Climate Change 2007: Synthesis Report; Contribution of Working Groups I, II and III to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, Pachauri, R.K and Reisinger, A. (eds.)]; IPCC, Geneva, Switzerland, 104 pp (AR4)). The Short-Lived Climate Pollutant Reduction Strategy estimated emissions using the 20-year GWP (AR4).

manure management practices. Anaerobic digesters capture methane-rich biogas for beneficial uses, including in electricity generation and fossil natural gas displacement. Alternative manure management practices reduce manure methane emissions in ways that do not involve an anaerobic digester. Examples include solid separation, conversion to dry scrape, and pasture-based management. Both digester and alternative manure management practices reduce GHG emissions and can improve water quality and nutrient management. Enteric methane emissions can be reduced through genetic selection, diet modification, and feed additives.

This Analysis shows that the dairy and livestock sector is projected to achieve just over half of the annual methane emissions reductions necessary to achieve the target by 2030 through modifications to manure management systems—primarily using anaerobic digesters—and additional reductions through decreases in animal populations. Figure ES-1 shows significant emissions reductions through 2030 absent additional funding after fiscal year 2019-20.[2]

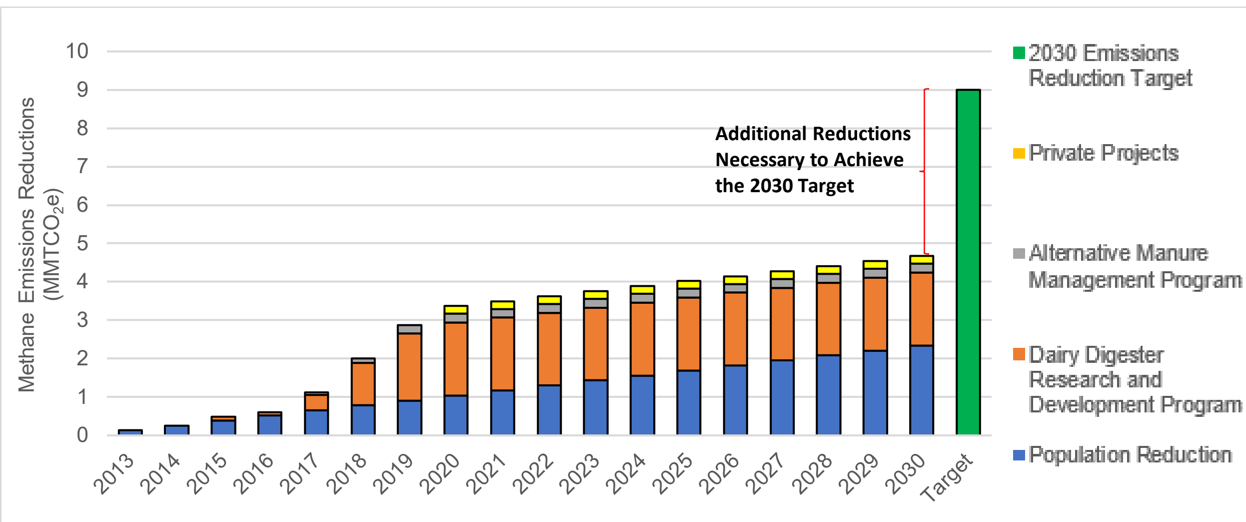

Figure ES-1. Projected Annual Methane Emissions Reductions through 2030 without Additional Funding beyond FY 2020-21

To meet the 2030 target, the dairy and livestock sector will need to achieve considerable emissions reductions from additional manure management projects, proven enteric mitigation strategies, or a combination of both over the next few years.

To understand what level of resources are needed to achieve the target, CARB staff looked at existing dairy methane emissions reduction efforts, including both grant

[2] This does not include $32 million in FY 2021-22 appropriations because it is uncertain how these appropriations will be allocated.

programs that fund the initial capital costs and market-based programs that incentivize GHG emissions reductions or low carbon fuel production.

Over the past six years, California Climate Investments (CCI)—the program that utilizes the State's Cap-and-Trade Program auction proceeds to facilitate GHG emissions reductions—has offset some capital costs through two CDFA grant programs to reduce manure methane emissions: the Dairy Digester Research and Development Program and the Alternative Manure Management Program. An approximate appropriation of $289 million in CCI funds has facilitated the construction of 233 dairy and livestock GHG emissions reduction projects. Many of these manure methane reduction projects are also generating environmental credits through CARB's Cap-and-Trade Program, Low Carbon Fuel Standard (LCFS) Program, and the federal Renewable Fuel Standard (RFS) Program. These projects, cumulatively funded through FY 2019-20, are expected to deliver the 2.0 $MMTCO_2e$ in annual methane emissions reductions noted above from manure management systems by 2030, or about 22 percent of the reductions necessary to achieve the 2030 target.

New or expanded local, State, or federal incentives or funding mechanisms could potentially accelerate the capture and beneficial use of California biomethane, provide additional revenue necessary to ensure that California's dairy manure methane emissions are captured, and direct the biogas to difficult-to-decarbonize sectors. Replacing fossil natural gas with upgraded dairy biogas (biomethane) or other alternatives is important for California's near and longer-term climate goals, but the cost to procure biomethane can be six to ten times more expensive than fossil natural gas. This cost disparity is almost entirely associated with the cost of bringing biomethane to market and will likely persist into the future. This is one of the primary reasons incentives are needed for California's dairy and livestock sector to adopt methane reduction strategies that also support the transition away from fossil natural gas supplies. Additional funding could also accelerate the adoption of alternative manure management projects. These projects provide climate benefits through avoided methane production and environmental co-benefits including water quality improvements and conservation, reduction of synthetic fertilizer usage and improvement of nutrient management, as well as groundwater protection.

Through coordinated State, industry, and utility efforts, the dairy and livestock sector has made meaningful progress in overcoming technical barriers to digester projects, interconnecting to utility electrical grids and pipeline networks, and meeting biomethane pipeline injection standards. Improved environmental credit certainty has also reduced the most considerable market barriers to digester projects by helping project developers obtain funding and financing. Challenging sector economics, insufficient availability of public funds, and underdeveloped markets for value-added manure products are persistent market barriers for both digester and alternative manure management projects. There has been limited progress in overcoming technical barriers to alternative manure management practices because emissions reductions vary based on site-specific factors. There has also been limited progress in overcoming both technical and market barriers to enteric reductions. Enteric methane-reducing feed additives may achieve considerable near-term emissions reductions. There are two commercially available products that were developed for enteric methane mitigation, with potential emissions reductions up to 10-20 percent. Additional feed additives are under development that may provide larger enteric methane emissions reductions.

Despite progress in overcoming barriers, there is more to do to ensure that the State meets the 2030 target. Remaining barriers may be overcome through multiple reasonable efforts, including allocation of additional local, State, or federal funding or incentives. If the remaining reductions needed to achieve the 2030 target are met through a mix of California dairy projects in which half are dairy digesters and half are alternative manure management projects, then at least 420 additional projects may be necessary. This approach would cost an amount between $0.8 and $3.7 billion, which could be supported by local, State, and federal funding, or other financial mechanisms, such as the pilot financial mechanism outlined in SB 1383.[3] If, going forward, only digester projects were developed to achieve the target, approximately 230 additional digesters may be needed, at a cost between $0.7 and $3.9 billion depending on the types of technologies selected. For example, prioritizing deploying digesters with internal combustion engines is the lowest-cost option ($0.7 billion) to achieve the 2030 target, but this would result in on-site criteria pollutant emissions. Alternatively, deployment of digesters that utilize fuel cell technology may avoid these emissions, but at a significantly higher cost ($3.9 billion). Finding 1-6 of this Analysis describes project types, technologies, and cost ranges. With respect to alternative manure management practices, based on currently funded projects and reduction trends observed to date, staff's analysis indicates that the State would be unable to achieve the 2030 dairy and livestock sector target through deployment of alternative manure management practices alone. A combination of dairy digesters, alternative manure management, enteric strategies, and dairy herd size population decreases will be needed to meet the 2030 target.

[3] On February 24, 2022, the California Public Utilities Commission approved Decision 22-02-025 adopting biomethane procurement standards pursuant to SB 1440 (Hueso, Chapter 739, Statutes of 2018), including procurement of biomethane from the California dairy and livestock sector.

Regardless of the project and technology mix used, the most important factors for achieving the 2030 target are ongoing capital funding for new methane emissions reduction projects, continued revenue streams that incentivize dairy biogas capture and beneficial use, and an available and accepted means of reducing enteric methane emissions. Even with considerable progress toward achieving the target since the enactment of SB 1383, the statute requires CARB to adopt a regulation to meet the target, provided that certain conditions are met. Further, CARB is only authorized to implement regulations to meet the 2030 target after January 1, 2024, provided that CARB, in consultation with CDFA, determine the regulations are technologically and economically feasible, cost-effective, include provisions to minimize and mitigate potential leakage, and include an evaluation of the achievements made by incentive-based programs. In designing a regulation for methane emission reductions, CARB staff will consider reasonable strategies to support the sector in meeting the 2030 target, which may include strategies that further support biogas capture and end-uses needed to advance the State's carbon neutrality efforts.

While the California dairy and livestock sector has made significant progress, it must still achieve considerable methane emissions reductions to meet the 2030 target. This will require implementation of additional methane emissions reductions strategies, and continued collaboration among agencies and other stakeholders. In addition, CDFA plans to convene a working group to address market development barriers for facilitate value-added manure products. CARB will continue to track progress of methane emission reductions project funding and outcomes, manure management and enteric methane reduction options, and will evaluate progress in the 2022 Scoping Plan Update.

Introduction

California has long championed environmental protection, and the State has made significant investments and efforts to decarbonize its economy. In 2006, the Legislature passed and the Governor signed the California Global Warming Solutions Act. Assembly Bill (AB) 32 (Núñez, Chapter 488, Statutes of 2006) requires the State to reduce greenhouse gas (GHG) emissions to 1990 levels by 2020. It also tasked the California Air Resources Board (CARB or Board) with developing a climate change scoping plan that details how the State will achieve its climate target and requires CARB to periodically update the plan. The Board adopted the first Climate Change Scoping Plan in December 2008 and updated this plan in 2013 and 2017.

Through aggressive pursuit of regulatory and voluntary GHG emissions reduction measures across economic sectors, California GHG emissions fell below 1990 levels in 2016, 2017, 2018, and 2019. Acknowledging the need to make deeper GHG emissions reductions to help slow climate change, the Legislature passed Senate Bill (SB) 32 (Pavley, Chapter 249, Statutes of 2016), which requires the State to reduce GHG emissions to 40 percent below 1990 levels by 2030. Figure 1 shows these GHG emissions reduction targets as well as the State's additional goal to reduce GHG emissions by 80 percent below 1990 levels by 2050.[4] Meeting these emissions reduction targets will be critical as California strives to achieve another goal – reaching carbon neutrality by 2045.[5] The Intergovernmental Panel on Climate Change (IPCC) has acknowledged carbon neutrality as necessary to limit global warming to 1.5 degree Celsius or less, the goal set by the international Paris Agreement on climate.

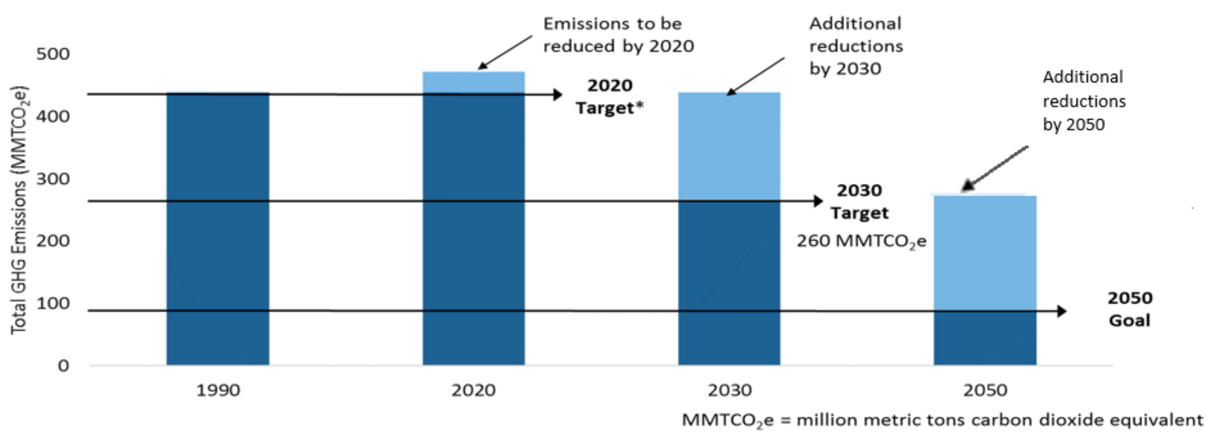

Figure 1. California GHG Emissions Reduction Targets and Goal through 2050

[4] Executive Order S-3-05.
[5] Executive Order B-55-18.

The Legislature also took action to limit emissions of short-lived climate pollutants (SLCP), which are powerful climate forcers that have relatively short atmospheric lifetimes but high global warming potentials (GWP). As a result, SLCP emissions reductions achieved now can have an immediate beneficial impact on climate change. Methane, a powerful SLCP, stays in the atmosphere for approximately a decade before being converted to carbon dioxide.[6] The effect of methane on climate change is 25 times stronger than that of carbon dioxide using the 100-year GWP (GWP 100), and 75 times stronger than carbon dioxide using the 20-year GWP (GWP 20).

CARB uses GWP 100 to quantify statewide methane emissions for inventory and regulatory purposes. GWP 100 is the standard for inventory development and aligns with IPCC and US Environmental Protection Agency (EPA) methods, allowing for comparison of the state inventory with other sub-national and international inventories through common methodologies and requirements for accuracy.

In 2014, the Legislature passed SB 605 (Lara, Chapter 523, Statutes of 2014), which requires CARB to develop a strategy to reduce SLCP emissions in the State. In response, staff developed and the Board approved a comprehensive Short-Lived Climate Pollutant Reduction Strategy (Strategy). In 2016, the Legislature passed SB 1383 (Lara, Chapter 395, Statutes of 2016), which requires CARB to approve and begin implementing the Strategy, and establishes a requirement, among others, for different SLCPs[7] to meet methane emissions reduction targets. More specifically, SB 1383 requires the California dairy and livestock sector to reduce methane emissions from enteric fermentation and manure management to 40 percent below 2013 levels by 2030. It also requires CARB, in consultation with the California Department of Food and Agriculture (CDFA), to adopt regulations to achieve this mandate if certain conditions are met. Specifically, SB 1383 intends to prioritize the use of voluntary and incentive-based measures to achieve those reductions before regulations are implemented. To achieve that end, the law calls for several specific efforts to incentivize reductions, including requiring CARB to work with stakeholders to identify and address technical, market, regulatory, and other challenges and barriers to development of dairy methane emissions reduction projects. Further, CARB is only

[6] While methane itself is not considered a toxic air contaminant, it is a large component of biogas, which may contain a mixture of gases including some toxic air contaminants like hydrogen sulfide. Removing these toxic air contaminants can reduce potential health impacts associated with the processing, transportation, and use of biogas streams.

[7] SB 1383 requires the reduction in the statewide emissions of methane by 40 percent, hydrofluorocarbon gases by 40 percent, and anthropogenic black carbon by 50 percent below 2013 levels by 2030. Additionally, the bill requires a 50 percent and 75 percent reduction in the level of the statewide disposal of organic waste from the 2014 level by 2020 and 2025, respectively. SB 1383 also sets a goal that not less than 20 percent of edible food that is currently disposed of is recovered for human consumption by 2025.

authorized to implement the regulations to meet the 2030 target after January 1, 2024, provided that CARB and CDFA determine the regulations are technologically and economically feasible, cost-effective, include provisions to minimize and mitigate potential leakage, and include an evaluation of the achievements made by incentive-based programs.

The Strategy put forward a path to achieve the SLCP emissions reduction goals established in SB 1383 in a way that provides both environmental and economic benefits to the State. Using the latest scientific and emissions information on SLCPs, it outlines the emissions reduction progress for specific SLCPs, potential options for additional reductions of these SLCPs, and strategies to achieve the respective emissions reduction targets. SLCP reductions are necessary to achieve the State's 2030 GHG emissions target, as described in the 2017 Scoping Plan Update, as well as the mid-century carbon neutrality goal. Notably, while some State programs incentivize dairy and livestock methane emissions reductions, no existing California programs directly require them or incentivize a sector-wide implementation of reduction measures. For example, CARB's Low Carbon Fuel Standard (LCFS) program provides some incentive for dairy operations to develop digesters and receive credits for biomethane production. However, on its own this program does not require operators to develop projects and through its credit system may not support statewide implementation of anaerobic digesters at dairies, and thus these emissions will not decrease without additional targeted programs or other interventions. In contrast, for the electricity and transportation sectors, the Cap-and-Trade Program acts as a backstop to ensure that GHG emissions reductions are achieved.

The Strategy describes a variety of manure management options that can provide the greatest methane emissions reduction potential, recognizing that not every option is feasible for each facility. The Strategy also recommends additional research to evaluate potential enteric methane emissions reduction options as well as the acceleration of early project development through incentives and market development. Prior to implementing regulations, incentives like California Climate Investments (CCI) allocations using Cap-and-Trade Program auction proceeds will encourage voluntary methane emissions reductions at dairies. The Strategy recognizes that implementing a variety of mitigation measures is necessary to achieve the 2030 target and will deliver significant reductions from the dairy and livestock sector while providing a variety of environmental and economic benefits.

Upon adoption of the Strategy and in compliance with SB 1383, CARB convened an interagency Dairy and Livestock Greenhouse Gas Emissions Working Group (Working Group) consisting of CARB, CDFA, California Energy Commission (CEC), and California

Public Utilities Commission (CPUC) principals. At the initial meeting in May of 2017, the Working Group convened three stakeholder subgroups composed of representatives and subject matter experts from State agencies, industry, academia, and the environmental justice community. The objective of these subgroups was to comply with SB 1383's requirement for CARB to work with stakeholders to identify and address barriers to dairy and livestock methane emissions reductions projects, and to develop actionable recommendations that State agencies could implement to help overcome these barriers.

Subgroup 1 provided recommendations to the Working Group to overcome barriers to non-digester manure management practices that focused on available and potential incentives, and developing value-added manure product markets. Subgroup 2 provided recommendations to the Working Group to overcome barriers to implementing livestock digester projects in California, along with a dairy digester emissions matrix that shows potential GHG and criteria pollutant emissions from dairy biogas use. Subgroup 3 focused on research needs related to dairy and livestock methane emissions reductions including enteric fermentation, and published a comprehensive Dairy Research Prospectus to Achieve California's SB 1383 Climate Goals, which outlines research concepts and needs to guide future funding of research projects in California. Over 18 months, the subgroups developed a set of Final Recommendations to the Dairy and Livestock Greenhouse Gas Reduction Working Group and presented them to the Working Group in December 2018. These recommendations outline potential solutions to overcome barriers to methane emissions reduction projects at California dairy and livestock operations and highlight innovative research on methane emissions reductions.

SB 1383 includes additional requirements on CARB to help provide market and environmental credit certainty to biogas-capturing anaerobic digester projects. These requirements, which CARB staff have fulfilled, include developing a white paper describing a potential pilot financial mechanism that, if implemented, could improve market stability for environmental credits from dairy digester projects. CARB, CDFA, and CPUC collaborated in selecting six dairy biomethane pipeline injection pilot projects to receive rate-recoverable infrastructure funding. Evaluating the factors that affect the cost and technical feasibility of these projects will help the State better understand and refine future incentives and regulatory measures. CARB staff also developed a frequently asked questions document discussing the potential impact that a dairy and livestock methane emissions reduction regulation would have on environmental credits generated under the LCFS Program and Cap-and-Trade Program.

Finally, SB 1383 requires CARB, in consultation CDFA, to analyze the progress that the sector has made toward achieving the 2030 target. This Analysis discusses the expected methane emissions reductions through 2022 and the estimated number of additional projects necessary to achieve the 2030 target. It also explores progress made in overcoming the technical and market barriers to implementing dairy and livestock methane emissions reductions projects.

Dairy and Livestock Sector Methane Emissions

In 2013, methane accounted for 40 million metric tons carbon dioxide equivalent ($MMTCO_2e$),[8] or approximately nine percent[9] of the State's GHG emissions (Figure 2). The dairy and livestock sector has been and continues to be the largest source of methane emissions in California, producing approximately 22 $MMTCO_2e$, or about 55 percent, of statewide methane emissions (Figure 3). Eighty percent of these emissions are from manure management and enteric fermentation at more than 1,300 dairies throughout the State. These dairies house more than 1.7 million milking cows and a similar number of replacement stock.[10]

Methane emissions at dairy and livestock operations come from two main sources—the animals themselves through enteric fermentation and manure management operations, especially at dairies. Enteric and manure emissions are both functions of cattle population, meaning that that more head of cattle there are, the higher the methane emissions. As a result, market dynamics such as changes in cost, revenue, or product demand can lead to fluctuations in methane emissions.

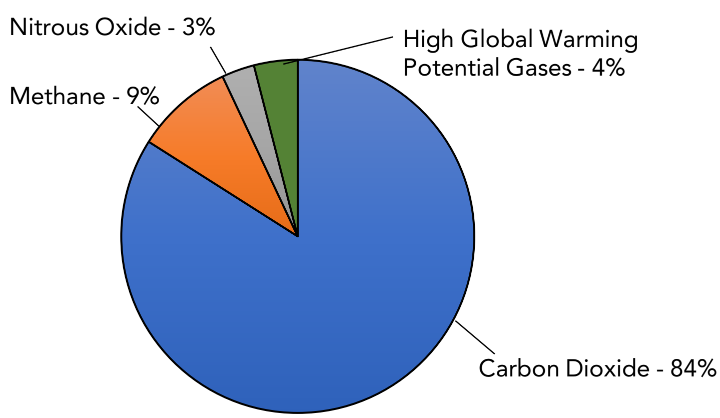

Figure 2. 2013 California GHG Emissions by Gas (Total 2013 Emissions~460 $MMTCO_2e$)

[8] 100-year GWP from IPCC AR4.
[9] California Greenhouse Gas Emissions for 2000 to 2017.
[10] California Agricultural Statistics Review 2018 to 2019.

The dairy and livestock sector has the potential to achieve significant methane emissions reduction from manure management operations at relatively low cost compared to other CCI-funded programs. Projects average $29 and $70 per $MMTCO_2e$ including both public and private funding for dairy digester and alternative manure management projects, respectively.[11,12] Enteric methane mitigation strategies also have important methane mitigation potential, but there is limited cost information available since only a few products are scientifically proven and commercially available.

Enteric fermentation is a natural digestive process that occurs within the digestive tract of ruminant animals such as cattle, sheep, and goats. In 2013, enteric fermentation emissions represented about 30 percent of California's total methane emissions (Figure 3), with two-thirds from dairy cows and the remaining one-third from other animal types. During the digestive process, microbes in the rumen decompose and ferment plant matter, which produces methane that ruminants subsequently emit, mostly through eructation (burping). A variety of factors influence enteric fermentation emissions including breed, diet, and the presence of feed additives, with the latter offering significant potential methane emissions reductions. In general, methane emissions from enteric fermentation can potentially be reduced through selective breeding, dietary modifications that improve milk production efficiency, and the introduction of methane-reducing feed additives.

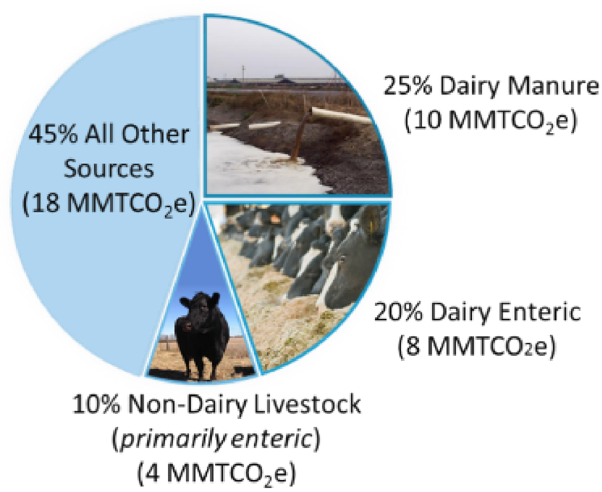

Figure 3. 2013 California Methane Emissions by Source

Anaerobic manure management and storage comprise the other main source of methane emissions at California dairy and livestock operations, accounting for about 25 percent of California's total methane emissions. Manure management systems that

[11] Dairy Digester Research and Development Report of Funded Project from 2015 to 2019.
[12] Alternative Manure Management Program Webpage.

treat or store manure under anaerobic conditions (i.e., those common to liquid manure management lagoons) are a large source of methane emissions. Anoxic manure treatment and storage conditions, common in manure settling basins and storage lagoons, are conducive to methanogenic bacteria producing methane from volatile solids. Methane emissions from anaerobic manure management can be mitigated through capture and destruction, or through avoidance of production.

Two types of projects—dairy digesters and alternative manure management projects—effectively reduce a significant amount of methane emissions from dairy and livestock operations. Dairy digesters involve installation of an anaerobic digester to capture biomethane produced from dairy waste for beneficial end-uses including but not limited to onsite electricity generation to offset facility needs, or delivery to the electrical grid. Upgraded biomethane that meets utility pipeline specifications set by the California Public Utilities Commission (CPUC) can also be injected into the natural gas pipeline network to offset use of fossil natural gas in multiple sectors. Use of upgraded biomethane in vehicles in place of diesel also provides the additional co-benefit of reducing nitrogen oxides (NOx) emissions. Dairy biomethane can also be used as a heat source in industrial application, or as a feedstock for low carbon fuels including renewable hydrogen and dimethyl ether. The biomethane produced is eligible for credits in CARB's LCFS program, the Federal Renewable Fuels Standard, or CARB's Cap-and-Trade offsets program, which act as an ongoing revenue stream for facilities to help offset the initial high capital costs of development as well as support the ongoing operational costs of the digester.

Alternative manure management practices reduce the amount of manure (and volatile manure solids) managed or stored under anaerobic conditions; the goal of these practices is to limit methane production and emissions. Examples of effective alternative manure management practices include conversion to "solid," "dry," or "scrape" manure management; installation of a compost-bedded pack barn; increase in the time animals spend on pasture; or implementation of solid-liquid separation technology into flush manure management systems (e.g., various types of mechanical separators and weeping walls). Other alternative manure management strategies that may result in methane emissions reductions include but are not limited to acidification, which involves the application of acid(s) to animal manure to reduce emissions; vermifiltration, which is an aerobic decomposition process that produces worm castings; and chemical flocculation, which involves using polymers to increase the solid separation rate from animal manure streams. A more detailed overview of these and other alternative manure management practices is available in the Newtrient technology catalog—a source of information on manure management practices that can reduce environmental impacts.[13]

These practices can also provide important environmental co-benefits including improved water quality and nutrient management, and more easily exportable manure solids. For example, dairies can contribute to groundwater pollution through nitrate and salt leaching when overapplying manure to cropland, however, these components may replace synthetic fertilizer or improve soil health in other regions. Exporting excess nutrients and solids may also help dairy and livestock operations comply with water quality requirements. In California, dairy manure is largely managed in liquid form, making it difficult and cost-prohibitive to export without solid-liquid separation. Certain alternative manure management practices can remove manure solids, nitrogen, and salt from the manure stream and concentrate them in the solids that can be more readily exported as organic fertilizer or converted them into environmentally benign end products such as nitrogen gas. Manure solids may be further processed into value-added manure products like compost or soil amendments that can provide additional revenue, though market development remains a barrier. Alternative manure management strategies also provide flexibility to operations seeking to reduce methane emissions where a digester may be infeasible.

Through the strategies described above, the dairy and livestock sector can make considerable progress toward achieving the target of reducing methane emissions to 40 percent below 2013 levels by 2030. This Analysis describes progress the sector has already made toward achieving the target through manure methane emissions reduction projects. It also assesses progress that may occur based on various funding scenarios, reductions in animal populations, or commercial availability of a methane-reducing feed additive. Additionally, it discusses technical and market barriers to methane emissions reductions strategies that must be overcome to achieve the 2030 target.

[13] Newtrient provides information about manure management strategies and associated environmental impacts to dairy producers through an online technology catalog. Newtrient participated in CARB's Dairy and Livestock GHG Emissions Workgroup but does not have a formal relationship to CARB. Reference to that material does not constitute an endorsement of that catalog, or any associated strategies, technologies, etc., included therein.

Analysis and Findings

Analysis Item 1: California's Dairy and Livestock Methane Emissions Reduction Progress and Projected Annual Emissions Reductions through 2030

Finding 1-1: The Sector Has Made Significant Progress, But Will Not Meet the 2030 Target without Almost a Doubling of Emissions Reductions Projects

The California dairy and livestock sector has predominantly relied on manure management strategies to achieve the methane emissions reductions directed by the Legislature. Even with limited enteric methane mitigation options, the sector is on course to achieve significant emissions reductions. Through private investments and public incentive funding programs, approximately 278 manure methane emissions reduction projects have been completed or are under construction at California's dairy farms. Of these, CCI funded 233 projects through CDFA's Dairy Digester Research and Development Program (DDRDP) and Alternative Manure Management Program (AMMP), which have been instrumental in driving manure methane emissions reduction projects at California dairy operations. DDRDP provides up to half of the capital cost of construction, and AMMP encourages private matching funds. Both programs are consistently over-subscribed, with requested funds usually about twice the amount available.

As of December 2020, 22 DDRDP and 61 AMMP projects were complete and operational. An additional 96 DDRDP and 54 AMMP projects are under construction, with expected completion by the end of 2022. The latest round of CCI funding in fiscal year (FY) 2019-20 funded 12 DDRDP and 13 AMMP projects; all are expected to be operational by the end of 2022. Aggregating the emissions reductions expected from all 233 CCI projects yields an estimated annual methane emissions reduction of 2.0 $MMTCO_2e$[14] by the end of 2022.[15] The emissions reductions counted toward the 2030 target represent over 20 percent of the 9 $MMTCO_2e$ required to achieve that target. Stated differently, CCI funded dairy and livestock projects are expected to

[14] Emissions reduction estimates are in 100-year GWP (AR4). Estimated emissions reductions using 20-year GWPs can be calculated by multiplying 100-year GWP figures in this Analysis by 2.88.

[15] These estimates do not include the anaerobic digestion projects receiving Aliso Canyon Mitigation Settlement funds, which will result in an estimated additional 0.3 $MMTCO_2e$ in annual methane emissions reductions. Since these projects count toward natural gas sector mitigation, they do not count toward the 2030 target.

reduce total methane emissions from the sector to about 9 percent below 2013 levels by the end of 2022.

CARB, in collaboration with air districts and dairy and livestock industry groups, identified as many as 45 additional manure management projects implemented or under development using only private funding throughout the State since January 1, 2013. Of these, 40 involve installation of a solid-liquid separation system, and the remaining five involve installation of an anaerobic digester. Solid separation systems reduce the amount of volatile solids that are managed anaerobically by diverting a fraction of these solids to a dry management system to produce compost, soil amendment, and bedding, preventing them from producing significant methane emissions. To estimate reductions from these projects, CARB staff used average methane emissions reductions for DDRDP and AMMP projects, respectively. The combined annual methane emissions reductions amount to 0.2 $MMTCO_2e$ from these projects, with 0.1 $MMTCO_2e$ each from digester and alternative manure management projects.

Changes in animal populations are an additional driver of methane emissions reductions, caused by factors including reduced product demand, increased costs, insufficient revenue, greater out-of-State competition, and land use changes. For example, consumer preferences may change, reducing the demand for animal-based products. Increased out-of-State competition and decreased national and international demand may also result in oversupply of products and animal population reductions. Increases in production costs for commodities like animal feed, electricity, and fuel can also have significant impacts on the financial viability of animal operations, especially when coupled with low commodity prices. In other cases, competing land uses like conversion to high-value crops or urban encroachment may lead to facility closures and animal population reductions.

Every five years, the U.S. Department of Agriculture (USDA) conducts a Census of Agriculture (Ag Census), which provides the most consistent and reliable population data available in absence of state-level activity data. As part of the Ag Census, USDA reports the number of animals by type on each farm in the U.S., allowing for state-specific population tracking, including for California's GHG Emission Inventory. USDA's two most recent Ag Census reports, from 2012 and 2017, cover dairy and livestock population changes between 2008 and 2017, and provide a basis for estimating methane emissions reductions from average annual population changes. The 2012 Ag Census also provides a reasonable 2013 baseline because it quantifies dairy and livestock populations in California by animal type as of December 31, 2012. Based on the 2012 and 2017 Ag Census reports, CARB staff calculated an average annual decline of 0.5 percent in animal populations from the sector between 2008 and 2017. Assuming that this population change trend will remain constant, methane emissions reduction attributable to sector population decreases will be ~0.13 $MMTCO_2e$ annually or 1.3 $MMTCO_2e$ total through 2022.

Adding methane emissions reductions expected from State- and privately funded manure management projects with those from expected animal population decreases yields a total methane emissions reduction in 2022 relative to 2013 of ~3.5 $MMTCO_2e$, as shown in

Table 1 below.[16] Assuming that the animal population will continue to decrease at approximately 0.13 $MMTCO_2e$ annually,[17] and not taking into account any additional funding that may be available for manure methane reduction projects beyond FY 2019-20, the total estimated 2030 methane emissions reductions would be approximately 4.6 $MMTCO_2e$. This would be just over half of the 9 $MMTCO_2e$ emissions reductions needed to meet the 2030 target – with about 4.4 $MMTCO_2e$ reductions remaining (Figure 4).

[16] Due to the time required to construct dairy methane emissions reductions projects—especially anaerobic digesters pipeline injecting biomethane (between 18 and 24 months)—a limited number of projects have been completed to date.

[17] Starting in March of 2020, California enacted shelter-in-place orders and temporary closures of public and private gathering spaces due to the global pandemic. Resulting closures of schools and restaurants likely exacerbated dairy sector economic challenges and may have lasting impacts, including accelerated facility closures and decreases in animal population. However, due to uncertainty about net long term impacts the pandemic may have on the dairy and livestock sector, this Analysis assumes that recent trends in animal population trends observed in USDA's 2012 and 2017 Ag Census change will remain consistent through 2030.

Table 1. Estimated California Dairy and Livestock Methane Emissions Reduction by the End of 2022

Reduction Type		**Number of Projects Funded through FY 2019-20**	**Expected Emissions Reductions Through 2022 ($MMTCO_2e$)**
Population Change		Not Applicable	1.3
Anaerobic Digester	State-funded (DDRDP)	118	1.8
	Privately funded	5	0.1
Alternative Manure Management Practices	State-funded (AMMP)	115	0.2
	Privately funded	40	0.1
Total		**278**	**3.5**

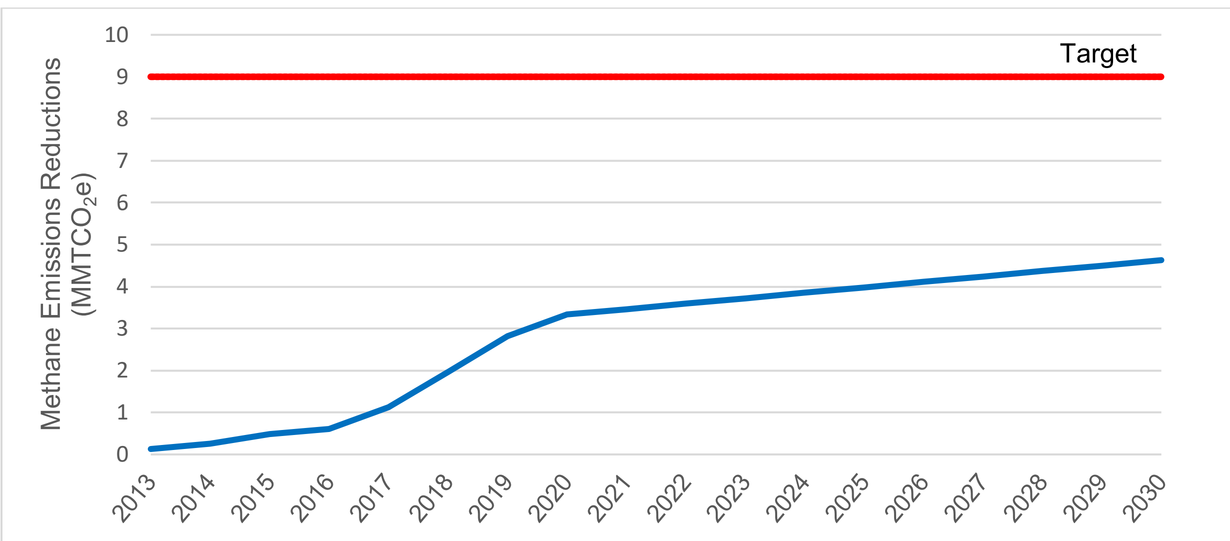

Figure 4. Projected Annual Methane Emissions Reductions through 2030 without Additional CCI Funding beyond FY 2020-21

The remaining 4.4 $MMTCO_2e$ in emissions reductions are expected to be achieved through manure management strategies but may be advanced by widespread adoption of effective enteric methane mitigation strategies. To estimate additional manure methane emissions reductions projects needed to reach the target, CARB staff used average reductions from DDRDP and AMMP projects. Staff calculated average project-level methane emissions reductions by program using figures reported by CDFA through DDRDP and AMMP. Based on the average emissions reductions, staff determined the number of additional projects necessary to achieve the 2030 target. This assumes that distribution of project types will remain roughly equal between digesters and alternative manure management projects, consistent with past practice. Based on this approach, at least 210 anaerobic digestion and 210 alternative manure management projects are necessary to achieve the remaining 4.4 $MMTCO_2e$ in methane emissions reductions. However, future project types may vary dependent upon available incentives and operator preference. If only dairy digester projects were implemented—which are about ten times as effective at reducing emissions than alternative manure management projects—over 230 projects would be necessary to achieve this level of emissions reductions. With respect to alternative manure management practices, based on currently funded projects and reduction trends observed to date, staff's analysis indicates that the State would be unable to achieve the 2030 dairy and livestock sector target through deployment of alternative manure management practices alone. A combination of dairy digesters, alternative manure management, enteric strategies, and dairy herd size population decreases will be needed to meet the 2030 target.

Finding 1-2: Public and Private Funding Support Methane Emissions Reduction Projects

Significant allocations of CCI funding have enabled the sector to make progress toward the 2030 target. From 2014 through 2020, the Legislature appropriated approximately $289 million in CCI funds for dairy methane emissions reduction projects. These funds, administered through CDFA's DDRDP and AMMP, have been effective in leveraging private capital investment and achieving cost-effective methane emissions reductions. With local, State, and federal funding, the dairy and livestock sector will be able to implement additional projects to help meet the 2030 target. Table 2 (below) shows that dairy methane projects constructed using CCI funds through the DDRDP and AMMP have successfully leveraged over $1.60 in match funding for each CCI dollar invested.[18]

[18] DDRDP eligibility requirements include a mandatory private match contribution of at least 50 percent of initial project cost estimates. AMMP does not require private match contributions.

Table 2. Private Funding Contributions per CCI Dollar Invested

Funding Sources	Programs		Total Funding
	AMMP	DDRDP	
CCI ($ million)	$67.8	$195.5	$263.3
Private Match ($ million)	$9.9	$413.1	$423.0
Private Match per CCI Dollar Invested ($)	$0.15	$2.11	-

In addition to DDRDP and AMMP, additional State programs, including the Cap-and-Trade Program, the LCFS Program, CPUC's Bioenergy Market Adjusting Tariff (BioMAT), CPUC's Renewable Gas Pipeline Interconnection Incentive Program and CPUC's SB 1383 Biomethane Pipeline Injection Pilot Project Program, have supported dairy and livestock methane emissions reduction projects through credit generation and grants, and other bioenergy and biofuel incentives. To date, more than $1 billion in combined public and private funding has supported approximately 280 anaerobic digester and alternative manure management projects. Additionally, public funds have supported rate-recoverable programs for biomethane pipeline interconnection infrastructure, which help deliver biomethane to end users.

The Strategy recommended a minimum funding amount[19] of at least $100 million per year for five years as necessary to accelerate significantly project development by offsetting capital costs and economic risks for manure management methane emissions reduction projects. CARB and CDFA, working with industry stakeholders and project developers during public development of the Strategy, estimated that $500 million would greatly increase the deployment rate of manure management projects within the State, though that amount was not estimated to be sufficient to achieve the 2030 target. To date, CDFA's DDRDP has awarded approximately $200 million in CCI funds for 118 dairy digesters, nearly an eightfold increase over the number of digesters operating prior to the availability of CCI funds. Similarly, CDFA's AMMP has awarded approximately $68 million for 115 alternative manure management projects and has greatly accelerated adoption of those practices. CARB staff estimates an additional $600 million in privately matched CCI funds, or similar public incentives, is necessary to achieve the emissions reductions still needed to meet the 2030 target through dairy digester projects. Despite considerable State investment and private match funding, incentives have not been sufficient to achieve

[19] In the Strategy, CDFA estimated that at least $100 million in the form of grants, loans, or other incentives would be needed for five years to support the development of necessary methane emissions reducing manure management projects including digesters and alternative manure management projects, as well as associated infrastructure.

the 2030 target. The FY 2019-20 CCI allocation of $34 million was considerably lower than the $99 million available in FY 2017-18 and FY 2018-19, falling $66 million short of annual funding needs. The proposed FY 2020-21 appropriation of $20 million did not materialize because of State budget cuts. The FY 2021-22 budget includes an appropriation of $32 million for CDFA's livestock methane reduction program, with priority given to AMMP.

CDFA's DDRDP projects have been the primary driver of GHG emissions reductions in the dairy and livestock sector since FY 2014-15. Prior to the availability of CCI funds, about 15 digesters were operating in California—far short of the 799 candidate dairies identified by the USDA AgSTAR program and 543 dairies identified in the Strategy[20] as necessary to achieve the 2030 target.[21] Most of the digesters installed prior to the start of CCI (2006-2013) relied heavily on public funding from CEC's Dairy Power Production Program. Emissions reductions resulting from these projects are not counted towards the target because they were online prior to the 2013 baseline year. Figure 5 below shows the number of digesters in place prior to the baseline year, the number of digesters resulting from CCI funding, and the number of additional digester projects necessary to achieve the 2030 target.

[20] The Strategy was adopted prior to the opening of the Alternative Manure Management Program and assumed that most of the necessary methane emissions reductions would result from digester installations.

[21] Noted in Table 17: Sector-wide implementation assumptions, and upfront capital costs of the Strategy.

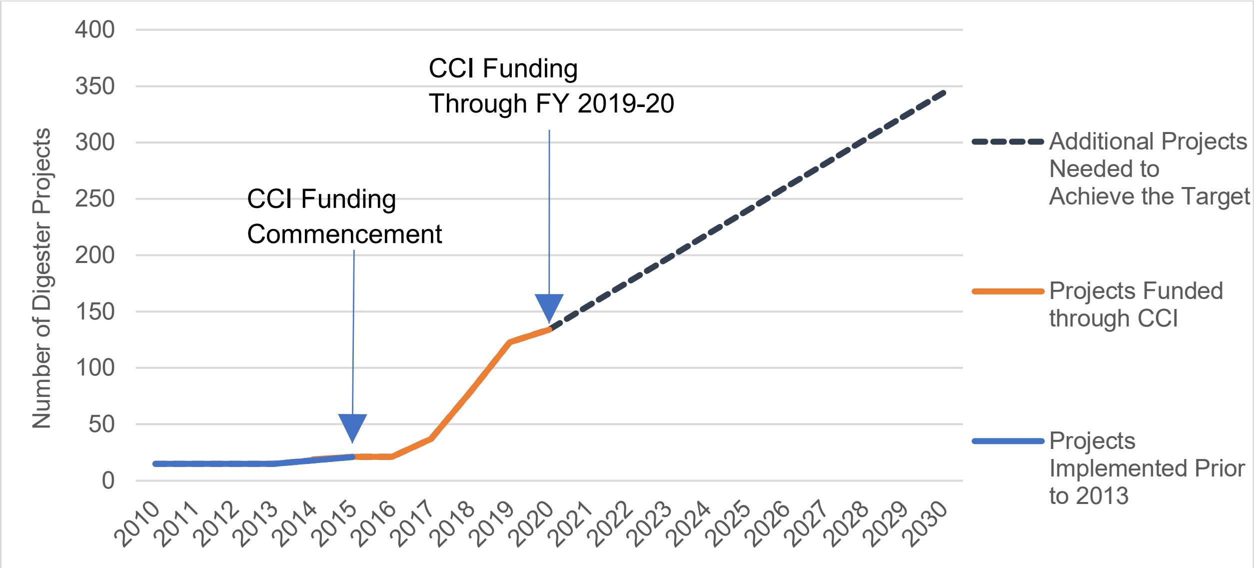

Figure 5. Number of Dairy Digesters in California[22]

Similarly, CDFA's AMMP is a primary source of funds for alternative manure management projects, which also rely heavily on public funds. Project developers are generally smaller dairies that are often not well suited to a digester because of limited financial resources, insufficient herd sizes, or other operational characteristics. While less expensive than a digester, alternative manure management projects on average cost about $600,000 per project. Unlike a digester project, alternative manure management projects do not produce bioenergy or biofuels and are not eligible to generate revenue from environmental credits. Some project developers realize cost savings from bedding purchases or sales of value-added manure products, while others—especially smaller pasture-based operations—are unable to capture any savings or revenue at all.

Infrastructure costs for digester systems producing onsite electricity from biogas including the cost to construct and install an anaerobic digester, construct conditioning facilities to upgrade biogas to necessary specifications, and either convert it to electricity using a reciprocating engine, a microturbine, or a fuel cell. These costs range from approximately $3 million to $17 million depending on the configuration and biomethane utilization option chosen, with average costs between $4 million and $7 million. Infrastructure costs to produce onsite electricity at the lower end assume that a project uses a reciprocating engine generator to produce onsite electricity, while upper end costs (~$17 million) assume the use of a solid oxide fuel cell. Infrastructure costs for digester systems that produce biomethane for pipeline

[22] Numbers shown in Figure 5 do not include the five privately funded dairy digester projects implemented since 2013.

injection (or trucking to injection point or fueling station) including the cost to install an anaerobic digester and a biogas upgrading facility. These costs range from $3 million to $16 million. Project variables include distance to the pipeline and whether the project is on a single dairy or part of a cluster of dairies.

According to CCI reports published to date, DDRDP and AMMP have delivered some of the most cost-effective GHG emissions reductions on a per-metric ton CO_2e basis compared to other CCI funded programs. Table 3 details State, private, and total investments into dairy manure methane emissions reduction projects.

Table 3. Estimated Cost Effectiveness of California Dairy and Livestock Methane Emissions Reductions through 2022

Program	State Investment ($/MTCO$_2$e)	Private Investment ($/MTCO$_2$e)	Total Investment ($/MTCO$_2$e)
DDRDP	$9	$20	$29
AMMP	$61	$9	$70

Alternative manure management projects can be further subdivided into three project types, including compost bedded pack barns, flush-to-scrape conversions, and solid-liquid separation systems. Methane emissions reduction potential and cost-effectiveness varies across these project types. Table 4 shows the average methane emissions reductions and cost-effectiveness of these alternative manure management project types. According to the table, solid-liquid separation projects have the highest per-project average methane emissions reductions and the lowest implementation costs among these alternative manure management practices. Importantly, site-specific conditions affect methane reductions potential and cost-effectiveness across all project types.

Table 4. Estimated Methane Emissions Reduction Potential and Cost-Effectiveness of Alternative Manure Management Projects through 2022

AMMP Practices	Reduction per Project (MTCO$_2$e)	Cost-effectiveness ($/MTCO$_2$e)	
		State Investment	Total Investment
Compost Bedded Pack Barn	1,880	$73	$91
Flush-to-Scrape Conversion	1,420	$78	$88
Solid-Liquid Separation	2,120	$54	$58

In addition to public funding of digester construction costs, incentive funds and other mechanisms are available to provide ongoing support to project developers. This includes the BioMAT, the Cap-and-Trade Program, and the LCFS Program. The Cap-and-Trade Program allows dairy digester developers to quantify the methane emissions reductions resulting from the installation of a digester using the CARB Compliance Offset Protocol for Livestock Projects. These methane emissions reductions can generate carbon offset credits that developers can sell to capped entities. The Cap-and-Trade Program is designed to encourage capped entities to reduce their GHG emissions while providing flexibility in how those reductions are achieved. The LCFS Program is designed to reduce the average carbon intensity of transportation fuels[23] in California by incentivizing the production and use of low carbon fuels. Alternative fuels like biomethane generate credits in the LCFS program that can be sold to entities generating deficits for supplying high carbon fuels for sale in California.

Dairy digester projects are increasingly participating in the LCFS credit market,[24] where credit prices averaged $192 in 2019.[25] A hypothetical 3,000 milking cow dairy supplying transportation fuel could generate approximately $3.5 million in annual LCFS credit value.[26] Equivalent emissions reductions from the same dairy project might generate $250,000 in annual compliance offset credit value through the Cap-and-Trade Program, using the weighted average price for livestock offset credit transfers.[27,28] However, these potential credit revenue values do not include project-specific variations in additional revenue streams or costs, which may be considerable, even among projects with similar sizes and designs. While dairy digesters offer significant and cost-effective methane emissions reductions, without large-scale public incentives, the rate of adoption would likely decrease greatly. Incentives such as the

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[23] Information on current fuel pathways can be obtained through the CARB Current Fuel Pathways Spreadsheet, which is searchable and sortable, by feedstock, fuel, classification, and/or facility name. Accessed in December 2020.

[24] Anaerobic digester projects cannot simultaneously generate both LCFS and Cap-and-Trade credits.

[25] Monthly LCFS Credit Transfer Activity Reports. Accessed in August 2020.

[26] The LCFS credit value represents potential gross revenue from sale of LCFS credits in 2020; this does not include revenues from the sale of fuel, nor the potential revenue from sale of Renewable Identification Numbers (RIN) under the federal EPA Renewable Fuel Standard (RFS). Project development costs are not included in these estimates due to significant variability; costs may include but are not limited to project feasibility, design, and interconnection studies, digester and gas upgrading equipment and installation, and pipeline interconnection infrastructure construction.

[27] Cap-and-Trade Compliance Offset Credits from livestock projects were valued at $13.67 on average per metric ton for transactions occurring in 2019. Summary of Market Transfers Completed in 2019.

[28] Offset credit revenue from livestock projects may vary considerably, even across similarly sized and designed projects resulting from variations in project costs, location, and additional revenue streams. The gross revenue values provided in this Analysis are intended to illustrate potential offset credit revenue for programmatic comparison but may not accurately describe actual net project revenues.

Cap-and-Trade Program, LCFS Program, or RFS Program significantly improve the attractiveness of investment in digester projects.

Finding 1-3: The 'Social Cost of Methane' Metric Cannot be Used to Determine the Net Societal Benefits or Disbenefits of Methane Emissions Reduction Projects Comprehensively; Methane Reduction Benefits or Disbenefits Vary by Project Type

In addition to mandating SLCP emissions reductions, the Legislature passed AB 197 (Garcia, Chapter 250, Statutes of 2016), which directs CARB to consider the social costs associated with GHG emissions mitigation rules and regulations. The social cost of methane is a measure of the long-term damages caused by emitting one ton of methane in a given year. Using the methodology developed in 2009 by a federal interagency working group convened by the U.S. Council of Economic Advisors and the Office of Management and Budget, CARB staff estimated the potential range in the social cost of methane emissions from 2015 through 2030 in the 2017 Climate Change Scoping Plan.[29] The current analysis focuses on the social costs of methane emissions in 2030 using different discount rates[30] in 2020 dollars[31]—or the value today of preventing environmental damages in the future (Table 5).

The social cost of methane is a metric that can contribute to understanding the societal benefits or disbenefits that accrue from reducing methane emissions. The social cost of methane accounts for damages that occur from the release of methane, including damages due to changes in human health, changes in net agricultural productivity, property damages from increased flood risk, changes in energy system costs, non-market amenities (based on outdoor recreation), and changes to human settlements and ecosystems. Importantly, the models used to estimate the social cost of methane emissions cannot assess the monetary value of all physical, ecological, or economic impacts of climate change. As such, actual societal benefits or disbenefits could differ considerably from the calculated values used in this analysis.

Furthermore, when conducting a complete cost benefit analysis, net societal benefits from a specific project may accrue despite an estimated project disbenefit (negative values shown in Table 5) associated solely with the social value of reducing methane

[29] More information is available in Table 8 in the 2017 Climate Change Scoping Plan.

[30] Discount rate is the rate at which society is willing to trade present benefits for future benefits. Discount rate affects decision making parameters including net present value, cost-effectiveness ratio, internal rate of return, return on investment.

[31] All social cost values have been adjusted to 2020 dollars using the U.S. Bureau of Labor Statistics Historical Consumer Price Index for All Urban Consumers. Accessed in December 2020.

emissions. A methane emissions reduction project may yield a social disbenefit when only accounting for methane emission reductions but may result in substantial improvements to air quality and water quality that are not quantified or monetized by only looking at the social cost of methane. For example, for the dairy and livestock sector, manure management projects such as anaerobic digesters have been successful at reducing methane emissions. The captured methane from digesters can be converted to an energy product, such as renewable electricity produced through fuel cells and internal combustion engine generators, resulting in potential net societal benefits or disbenefits associated with methane emissions reductions before considering other environmental and socioeconomic co-benefits.

Staff used the social costs of methane in Table 5 to estimate the societal benefits and disbenefits of various methane mitigation projects, including fuel cells and internal combustion engine generators at discount rates of 2.5, 3.0, and 5.0 percent. Subtracting the project investment costs from the social cost of methane estimates the net societal benefits or disbenefits of reducing methane emissions by investing in specific manure methane emissions reduction projects, solely from a methane mitigation perspective.[32] Depending on project types, societal benefits or disbenefits from reducing one metric ton of methane vary, ranging from a societal disbenefit of $2,806 to a societal benefit of $1,878. However, as previously noted, this methodology does not fully assess the monetary value of all environmental and socioeconomic co-benefits that may result from establishing these projects, nor does it fully assess any additional societal disbenefits that may arise from non-methane emissions. For example, implementing such strategies may offer improved nutrient management to farms through more precise application of manure solids to crop lands at agronomic rates and potential reductions in synthetic fertilizer use. Conversely, adoption of other methane emissions reductions strategies such as converting biogas to electricity using internal combustion engine generators may increase NOx and other air pollutant emissions, resulting in societal disbenefits. Given that most California dairies are in or near disadvantaged communities that may be disproportionately exposed to air quality impacts, ensuring air quality and other environmental benefits in these communities to the extent feasible is important, independent of the limitations to current social cost of methane estimates.

[32] The overall societal value of a project maybe positive even if a methane emissions reduction project has a social cost of methane disbenefit. Without conducting a comprehensive cost analysis of all environmental and socioeconomic factors, actual net societal benefits of a project remain unknown.

Table 5. Social Cost and Societal Benefits or Disbenefits of Reducing One Metric Ton of Methane Emissions in 2030

Discount Rate	Social Cost of Methane ($/MT CH_4)	Methane Emissions Reduction Cost ($/MT CH_4)		Net Societal Disbenefits (-) or Benefits (+)‡ ($/MT CH_4 Reduced)
		Fuel Cell	IC Engine	
5.0%	$949	$3,755	$773	$-2,806 to $176
3.0%	$1,997	$3,145	$648	$-1,148 to $1,349
2.5%	$2,496	$3,002	$618	$-506 to $1,878

Methane emission reduction scenarios shown in Table 5 assume methane is captured using a dairy digester and destroyed using either fuel cell or an internal combustion engine. These examples provide upper and lower bound estimates for net social benefits and disbenefits. (While pipeline injection projects are the most frequently implemented project types, they are not shown here because costs are highly variable based on project site. However, they would fall within the range shown.)

‡Net societal benefits or disbenefits of reducing one metric ton of methane emissions do not account for all environmental and socioeconomic co-benefits resulting from that reduction.

Finding 1-4: Feed and Manure Additive Methane Mitigation Strategies Could be Scaled to Help Achieve the 2030 Target

In addition to the manure management practices described above, additional strategies are under development to achieve further reductions from the sector. For example, certain markets have begun using additives that reduce methane emissions from enteric fermentation in ruminants, though use in North America is limited due to pending regulatory approval. Additives to reduce methane emissions from manure management are also under development. Such additives may potentially achieve important, cost-effective methane emissions reductions from dairy and livestock operations while offering increased flexibility and avoiding the significant upfront capital investment associated with installing a digester or implementing an alternative manure management practice.

Animal Feed Additives

Methane emissions from enteric fermentation in dairy and livestock account for about 30 percent of statewide methane emissions, or approximately 12 $MMTCO_2e$ annually. This presents an opportunity to achieve significant methane emissions reductions, potentially at a cost of approximately $50 per metric ton on a carbon dioxide equivalent basis.[33] Potential strategies to reduce emissions from the digestion process

[33] Assumes use of a product with a ten percent enteric methane emissions reduction effectiveness at an annual cost of approximately $48 per ton ($0.05 per cow per day) on a carbon dioxide equivalent basis.

include diet modifications, feed additives, feed efficiency improvements, and selective breeding of low methane producing animals. Of these, feed additives offer the greatest potential for sector-wide methane emissions reductions because they potentially deliver considerable methane emissions reductions shortly after adoption. In comparison, strategies like diet modifications, feed efficiency improvements, and selective breeding require a relatively long time to achieve significant emissions reductions. Unlike the manure management strategies described above, these strategies can be implemented at existing operations with minimal need to modify facility design and without significant upfront capital requirements. This makes these strategies potentially attractive for dairy and livestock operations, especially rented or leased operations.

Research suggests that certain feed additives may have promising methane emissions reduction potential. For example, 3-Nitrooxypropanol (3-NOP under the commercial name of Bovaer®),[34] has shown an emissions reduction potential between 20 and 40 percent across multiple ruminant species under various testing conditions.[35,36,37] The additive 3-NOP has undergone both laboratory-scale and on-farm testing for effectiveness in reducing methane emissions safely, and for potential impacts on animal health, reproduction, and productivity. It is a chemical product that is currently undergoing US Food and Drug Administration (FDA) approval and may become available within the next few years.[38] Nitrate is another feed additive that has shown an

[34] Mention of trade names or commercial products does not constitute or imply CARB endorsement or recommendation.

[35] Kim, S., Lee, C., Pechtl, H. A., Hettick, J. A., Campler, M. R., Pairis-Garcia, M. D. Beauchemin, K. A., Celi, P., Duval, S. M. (2019). Effects of 3-nitrooxypropanol on enteric methane production, rumen fermentation, and feeding behavior in beef cattle fed a high-forage or high-grain diet. *Journal of Animal Science*, 97(7), 2687–2699.

[36] Gonzalo, M., Stephane, D., Kindermann, M., Schirra, H, J., Denman, S. E., McSweeney C. S. (2018). 3-NOP vs. Halogenated Compound: Methane Production, Ruminal Fermentation and Microbial Community Response in Forage Fed Cattle. *Frontiers in Microbiology*, 9, 1582.

[37] Van Wesemael, D., Vandaele, L., Ampe, B., Cattrysse, H., Duval, S., Kindermann, M., Fievez, V., De Campeneere, S., Peiren, N. (2019). Reducing Enteric Methane Emissions from Dairy Cattle: Two Ways to Supplement 3-Nitrooxypropanol. *Journal of Dairy Science*, 102(2), 1780-1787.

[38] Mitloehner, F. M., Kebreab, E., Tricarico, J., Wallace, J., Gooch, C., Gibbs, C. (2020). Dairy Feed Additives to Reduce Enteric Methane Emissions. Newtrient.

emissions reduction potential between 10 and 20 percent.[39,40,41,42,43] However, existing research is insufficient to conclude that microbes in the rumen will acclimate to increased nitrate without causing adverse animal health impacts. Agolin® Ruminant,[44] an essential oil mix, has shown methane reduction potential between 10 and 20 percent for dairy cows without impacting milk yield and composition. Mootrol® Ruminant, a pelleted product made from garlic and orange extract, has also shown methane mitigation potential in both *in vitro* and *in vivo studies* [45,46] and researchers are currently investigating its long-term effectiveness in beef cattle. Both Agolin® Ruminant and Mootral® Ruminant are commercially available and are Generally Regarded As Safe (GRAS)[47] by the FDA. Novel additives, such as lemongrass and seaweed[48] have also shown emissions reduction potential but lack sufficient *in vivo* (animal) studies to demonstrate long-term effectiveness and potential impacts on

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[39] Alemu, A. W., Romero-Pérez, A., Araujo, R. C., Beauchemin, K. A. (2019). Effect of Encapsulated Nitrate and Microencapsulated Blend of Essential Oils on Growth Performance and Methane Emissions from Beef Steers Fed Backgrounding Diets. *Animals (Basel)*, 9(1), 21.

[40] Klop, G., Hatew, B., Bannink, A., Dijkstra, J. (2016). Feeding nitrate and docosahexaenoic acid affects enteric methane production and milk fatty acid composition in lactating dairy cows. *Journal of Dairy Science*, 99(2), 1161-1172.

[41] Raleng, A. O. (2008). The Potential of Feeding Nitrate to Reduce Enteric Methane Production in Ruminants.

[42] Meller, R. A., Wenner, B. A., Ashworth, J., Gehman, A. M., Lakritz, J., Firkins, J. L. (2019). Potential roles of nitrate and live yeast culture in suppressing methane emission and influencing ruminal fermentation, digestibility, and milk production in lactating Jersey cows. *Journal of Dairy Science*, 102(7), 6144-6156.

[43] Zijderveld, S. V., Gerrits, W., Dijkstra, J., Newbold, J., Hulshof, R., & Perdok, H. B. (2011). Persistency of methane mitigation by dietary nitrate supplementation in dairy cows. *Journal of dairy science*, 94(8), 4028-38.

[44] Carrazco, A. V., Peterson, C. B., Zhao, Y., Pan, Y., McGlone, J. J., DePeters, E. J., Mitloehner, F. M. (2020). The Impact of Essential Oil Feed Supplementation on Enteric Gas Emissions and Production Parameters from Dairy Cattle. Sustainability, 12(24), 10347

[45] Eger, M., Graz, M., Riede, S., Breves, G. (2018). Application of Mootral™ reduces methane production by altering the Archaea community in the rumen simulation technique. Frontier in microbiol, 9, 2094. doi: 10.3389/fmicb.2018.02094

[46] Roque, B. M., Van Lingen, H. J., Vrancken, H., Kebreab, E. (2019). Effect of Mootral—a garlic- and citrus-extract-based feed additive—on enteric methane emissions in feedlot cattle. Translational Animal Science, 3(4), 1383–1388

[47] "GRAS" is an acronym for the phrase Generally Recognized As Safe by the FDA. Under sections 201(s) and 409 of the Federal Food, Drug, and Cosmetic Act (the Act), any substance intentionally added to food is a food additive, that is subject to premarket review and approval by FDA, unless the substance is generally recognized, among qualified experts, as having been adequately shown to be safe under the conditions of its intended use, or unless the use of the substance is otherwise excepted from the definition of a food additive (https://www.fda.gov/food/food-ingredients-packaging/generally-recognized-safe-gras).

[48] Abbott, D. W., Aasen, I. M., Beauchemin, K. A., Grondahl, F., Gruninger, R., Hayes, M., Huws, S., Kenny, D. A., Krizsan, S. J., Kirwan, S. F., Lind, V., Meyer, U., Ramin, M., Theodoridou, K., von Soosten, D., Walsh, P. J., Waters, S., Xing, X. (2020). Seaweed and Seaweed Bioactives for Mitigation of Enteric Methane: Challenges and Opportunities. *Animals*, *10*, 2432.

productivity and human or animal health.

To better understand the potential contribution of feed additives in achieving the 2030 target, staff evaluated six potential enteric methane emissions reduction scenarios that focused on the use of feed additives. These scenarios shown in Figure 6 (below) illustrate potential annual methane emissions reductions resulting from the use of feed additives with methane mitigation effectiveness of 10, 30, and 50 percent,[49] representing the low, medium, and high potential of different feed additives, at adoption rates of 50 and 75 percent. The 2030 target is shown as a red dotted line at the top of the graph. At the bottom of the graph, a solid red line shows the methane emissions reductions attributed to dairy and livestock population change and manure methane emissions reduction projects already completed or under construction. It assumes that no additional projects will be implemented.[50] As the figure shows, if solely enteric feed additives are utilized beyond 2022 and no additional manure methane projects are implemented, a feed additive with a methane emissions reduction effectiveness of at least 50 percent would need to be adopted by at least 75 percent of ruminants in the sector to achieve the 2030 target.

[49] These values represent the enteric methane mitigation effectiveness of various feed additives. Ten percent represents a conservative estimate of mitigation effectiveness for currently available products; thirty percent represents a median estimated effectiveness for 3-NOP, which shows mitigation potential between 20-40 percent, and is expected to become commercially available in the near future; fifty percent represents a conservative estimate for the most effective emerging approaches, such as seaweed.

[50] Additional manure methane emissions reduction projects are expected to be developed but have been omitted from Figure 6 to illustrate the potential of feed additive-based enteric methane emissions reductions.

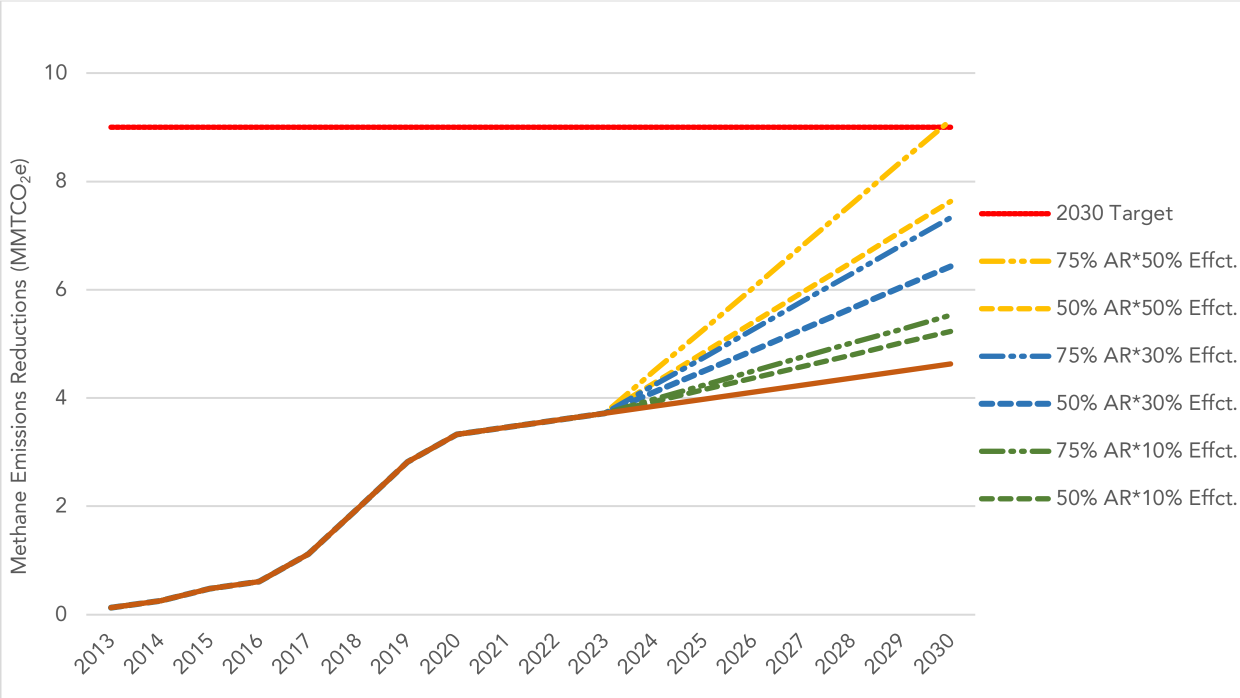

Figure 6. Projected Annual California Dairy and Livestock Sector Enteric Methane Emissions Reductions through 2030 Under Various Feed Additive Adoption Rates (AR) and Methane Mitigation Effectiveness (Effct.)

Manure Additives to Reduce Methane Emissions

Most of California's manure methane emissions originate from anaerobic manure treatment and storage lagoons. Manure additives can potentially modify environmental conditions in manure treatment and storage facilities, including but not limited to pH, redox potential, and microbial composition, to levels that are less conducive to methane production. Examples of potential manure additives include incorporation of biochar or proprietary lagoon additives, as well as the use of manure acidification. However, these strategies require additional investigation of their methane emissions mitigation effectiveness, applicability to California dairy and livestock manure management systems, and potential unintended impacts to air or water quality. For example, biochar has been shown to reduce methane emissions through incorporation into manure slurry; however, it may not be practical or effective in liquid manure management systems that are predominant on California dairy operations. Similarly, acidification of manure slurry may be effective at reducing methane emissions but may be impractical for California operations due to the need for large acid volumes that require special handling and safety equipment. CARB will continue tracking developments in manure additives as they become available, especially those with long-term studies that detail potential methane emissions mitigation effectiveness and environmental co-benefits.

Finding 1-5: Dairy and Livestock Sector May Fall Short of the 2030 Target absent an Enteric Strategy and Sufficient Public Funds[51]

To estimate potential emissions reductions from manure management projects under various public funding scenarios, CARB staff developed scenarios to extrapolate funding outcomes through 2030. These projections are based on project development costs and emission reductions described above, and do not account for environmental credit values on project costs. The impact of LCFS and RFS environmental credit prices on project economics is discussed in the following section. Figure 7 (below) illustrates potential methane emissions reductions achievable through the combination of an available enteric strategy, changes in animal populations, and from manure management projects at different levels of CCI funding assumptions.52 The 2030 target is shown as a red dotted line at the top of the graph. Potential methane emissions reductions from average animal population changes (discussed in Finding 1-1) are shown as a dark blue dashed line at the bottom of the graph.

[51] Trends discussed in this section are based on publicly available data wherever possible. In instances where available information was incomplete or insufficient, CARB staff used reasonable and conservative assumptions based on existing trends and available information.

[52] Funding projections assume that DDRDP and AMMP will fund an approximately equal number of projects, consistent with past practice.

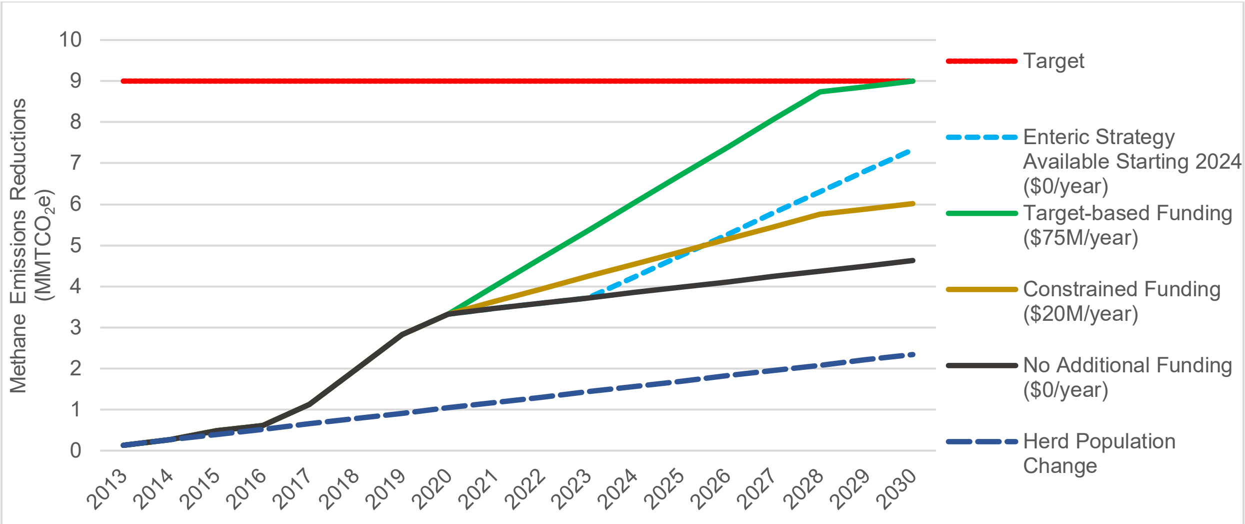

Figure 7. Projected Annual California Dairy and Livestock Sector Methane Emissions Reductions through 2030[53][54]

Additionally, Figure 7 shows methane emissions reductions expected under three different funding scenarios from FY 2020-21 through FY 2027-28 (green, brown, and dark gray solid lines).[55] It also shows potential emissions reductions from herd population changes and a potential enteric strategy (dark and light blue dashed lines, respectively). The funding scenarios assume that the observed decline in animal populations will continue at a constant rate through 2030. While emissions reductions attributable to a potential enteric strategy are shown in the figure, those emissions reductions are not accounted for in any of the funding scenarios above.

Each scenario includes emissions reductions expected from changes in population through 2030 as well as reductions expected from DDRDP and AMMP projects funded through FY 2019-20.

Incentive Funding Scenario 1: No Additional Funding

This scenario assumes that no additional appropriations of local, state, and federal funds are available for DDRDP and AMMP beyond FY 2019-20. Methane emissions reductions expected under Scenario 1 are shown in Figure 7 by the gray line labeled "No Additional Funding." This scenario assumes that funding is the limiting factor in new projects coming online. The y-axis difference between this line and the population

[53] Funding levels identified in Figure 7 do not reflect potential revenue from the generation of Cap-and-Trade, LCFS, or RFS RIN credits.
[54]Funding levels identified in Figure 7 do not reflect potential revenue from the generation of Cap-and-Trade, LCFS, or RFS RIN credits.
[55] Funding levels do not reflect private match funding that is required for DDRDP projects.

change line represents emissions reductions attributed mostly to State funds, emphasizing their importance in achieving the methane emissions reductions through 2022. Staff estimates this scenario will achieve 4.6 $MMTCO_2e$ of methane emissions reductions by 2030, falling 4.4 $MMTCO_2e$ short of the 2030 target.

Incentive Funding Scenario 2: Constrained Funding

This scenario assumes that consistent annual appropriations of $20 million for DDRDP and AMMP from FY 2020-21 through FY 2027-28. Methane emissions reductions expected under Scenario 2 are shown by the yellow line in Figure 7. This scenario assumes that allocations between DDRDP and AMMP will fund an approximately equal number of projects, consistent with past practice. With constrained funding through FY 2027-28, all funded projects will likely be operational by 2030. Staff estimates this scenario will achieve 6.0 $MMTCO_2e$ of methane emissions reductions by 2030, falling 3.0 $MMTCO_2e$ short of the 2030 target.

Incentive Funding Scenario 3: Target-Based Funding

This scenario assumes annual appropriations of $75 million for DDRDP and AMMP beyond FY 2019-20 through FY 2027-28—a level sufficient to achieve the 2030 target through manure emissions mitigation projects. This scenario accounts for a 20 percent project cost increase over current levels due to projects with smaller cattle populations and increased distances to the nearest natural gas pipeline with sufficient capacity. Methane emissions reductions expected under Scenario 3 are shown by the green line in Figure 7. Staff estimate that this scenario will achieve the 2030 target of 9.0 $MMTCO_2e$.

Enteric Strategy Scenario

Staff also estimated that a scientifically proven, cost-effective, safe, and consumer-accepted enteric methane mitigation strategy may be commercially available within the next three to five years to help achieve the 2030 target, shown by the light blue dashed line near the top of Figure 7. This assumes adoption of a feed additive with 30 percent enteric methane mitigation potential across ruminant species in California starting in 2024, and a linear annual adoption rate of approximately 11 percent through 2030, totaling 75 percent of the ruminant population.

For simplicity, the target-based funding scenario assumes that no enteric strategy will be available before 2030. Similarly, the enteric strategy scenario described below assumes that no public funding will be available beyond FY 2019-20. While both scenarios are based on reasonable estimates and are illustrative of potentially achievable methane emissions reductions, actual methane emissions reductions may vary.

While these scenarios focus on the outcomes of public investments and required private match funding to meet the 2030 target, revenue available through the California Cap-and-Trade Program and LCFS Program, as well as the federal RFS Program, can substantially reduce or eliminate the need for public funding of these projects. These revenue streams have become strong drivers of anaerobic digestion projects, helping ensure their long-term operation and financial stability.

Alternative Manure Management Practice Scenarios

Staff also evaluated the potential for different adoption rates of alternative manure management practices at California dairies to help achieve the 2030 target. As above, staff used average methane emissions reduction values to calculate potential reductions from various numbers of additional projects at California dairies. Staff also assumed that the approximately 280 dairy operations that had already implemented a manure methane strategy would not incorporate additional manure or implement enteric methane reduction strategies, leaving approximately one thousand dairies available for project implementation. Staff evaluated potential annual methane emission reductions resulting from alternative manure management project adoption under three different scenarios with 250, 500, and 750 additional dairies.

The estimated annual emissions reductions for each scenario are shown in Figure 8 (below). The 2030 target is shown as a red dotted line at the top of the graph. At the bottom of the graph, a solid red line shows the methane emissions reductions attributed to dairy and livestock population change and manure methane emissions reduction projects already completed or under construction. It assumes that no additional digesters projects and no enteric methane reduction strategies are implemented, showing the potential impact of alternative manure management projects on progress towards the 2030 target. The blue, yellow, and gray lines show expected annual emissions reductions from implementing new alternative manure management practices on 250, 500, and 750 additional dairies, respectively. On their own, none of these scenarios are estimated to provide sufficient methane emissions reduction to achieve the 2030 target.

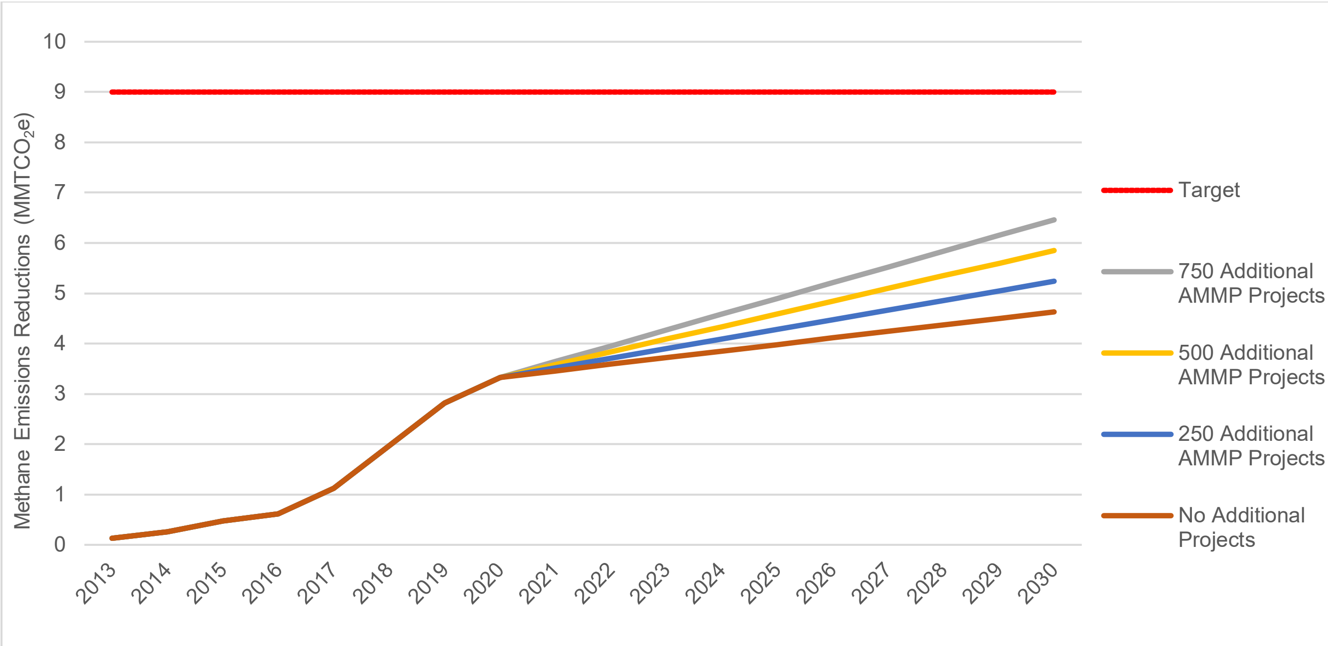

Figure 8. Projected Annual California Dairy and Livestock Sector Methane Emissions Reductions through 2030 Resulting from Implementing Additional Alternative Manure Management Projects

However, alternative manure management practices are important strategies that may provide significant additional environmental co-benefits. First, these practices may be more broadly implemented across the sector, including at small- and medium-sized dairies due to reduced upfront capital and maintenance costs compared to digesters. They may also provide flexibility to dairies with configurations that make digester implementation infeasible. Second, implementing certain alternative manure management practices alone or in combination with practices incentivized by other programs such as State Water Efficiency and Enhancement Program may provide additional water conservation and GHG benefits. These practices include conversion to scrape manure management, use of sub-surface drip irrigation, or pasture dairy conversion. Third, alternative manure management practices may improve solids and nutrient management, reduce nitrate leaching and improve water quality, reduce chemical fertilizer use, increase crop yield, and provide cost savings to dairy and livestock operations.

In addition to solid-liquid separation, compost bedded pack barns, conversion to scrape manure management, and pasture dairy conversion, stakeholders have proposed eligibility for other alternative manure management practices. These practices include but are not limited to manure acidification, vermifiltration, advanced chemical flocculation, and dissolved air flotation. Given the emergent nature of these strategies, additional research or observation at California dairy and livestock operations is necessary to evaluate methane reduction potential, long-term effectiveness, and potential unintended environmental impacts. Staff will continue monitoring deployment of these and other promising alternative manure management practices as they become available.

In some cases, alternative manure management practices can be combined with digesters to achieve greater emissions reductions than either strategy might on its own. Solid-liquid separators are commonly installed in conjunction with covered lagoon digesters to remove coarse solids, potentially reducing digester maintenance needs. These separated solids can be used for animal bedding, providing cost savings to the farmer. These same solids and nutrients can also be further processed into compost or soil amendment for onsite land application or export offsite, potentially generating additional revenue or cost savings while reducing chemical fertilizer needs. Stricter control of solids and nutrients can also help minimize water quality impacts by reducing nutrient leaching to groundwater.

Finding 1-6: Dairy Digester Development Will Need Significant Policy and Incentive Support, Providing Additional Methane Emissions Reduction Potential and Biomethane Supply

Generating environmental credits through the California Cap-and-Trade Program, LCFS Program, and federal RFS Programs can provide important revenue streams to dairy operators and project developers. As a result, these credit values are likely to drive additional dairy digester project development, methane emissions reductions, and increases in-State biomethane supply.

To estimate statewide dairy biomethane supply and production cost, staff reviewed existing literature and reports[56,57,58] as well as recent dairy population data from Regional Water Quality Control Board permits and annual reports. As part of that evaluation, and to refine supply estimates, staff adjusted underlying datasets to reflect facilities that had implemented an alternative manure management practice[59] or had closed. Staff assume that the remaining dairies can implement a digester project and

[56] Jaffe, A. M. (2016). Final Draft Report on The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute.

[57] Jaffe, A. M., Dominguez-Faus, R., Ogden, J., Parker, N. C., Scheitrum, D., McDonald, Z., Fan, Y., Durbin, T., Karavalakis, G., Wilcock, G., Miller, M., Yang, C. (2017). The Potential to Build Current Natural Gas Infrastructure to Accommodate the Future Conversion to Near-Zero Transportation Technology.

[58] Parker, N., Williams, R., Dominguez-Faus, R., & Scheitrum, D. (2017). Renewable natural gas in California: An assessment of the technical and economic potential. *Energy Policy*, *111*, 235-245.

[59] Facilities with alternative manure management practices implementation are less likely to divert animal waste to anaerobic digesters for biomethane production.

estimate that at least an additional 210 digester projects are necessary to achieve the target (in addition to 210 alternative manure management projects).

The six project technology options below describe potential pathways to use methane captured in a digester. These options include onsite electricity production using a reciprocating engine, a microturbine, or a solid oxide fuel cell, as well as direct injection into a natural gas pipeline from a single dairy, cluster of dairies, or through trucking to an existing interconnection point where it can displace fossil natural gas. While these technology options may result in similar methane emissions reductions, criteria pollutant performance, potential carbon intensities, project costs, and project revenues may vary considerably. Staff assume that project developers will select the digester technology option that is most suitable for their facility.

Anaerobic Digestion Technology Option 1: Reciprocating Engine Generator for Electricity Generation

This technology option involves using a reciprocating engine generator to generate electricity on site using biogas and offset fossil fuel-derived electricity for a variety of end uses, including but not limited to electric vehicle charging.[60] However, reciprocating engine generators also result in new sources of air pollutant emissions that adversely impact regional air quality, attainment of ambient air quality standards, and public health outcomes. For example, the San Joaquin Valley is home to the majority of the State's dairy and livestock operations, it has among the worst air quality in the country and is home to many of the State's most disadvantaged and low-income communities. Given the potential for further impacts, utilizing even the cleanest reciprocating engine generator is the least desirable option.

Anaerobic Digestion Technology Option 2: Microturbine for Electricity Generation

This technology option involves using a microturbine certified under the CARB Distributed Generation (DG) Certification Program to generate electricity using biogas. The DG Certification Program requires manufacturers of electrical generation technologies that are exempt from air district permit requirements to certify their technologies to specific criteria pollutant emission standards before selling products in California. Common DG technologies certified under this program include fuel cells and microturbines. Microturbines have higher costs compared to reciprocating engine generators but produce fewer air pollutant emissions, and therefore have fewer associated impacts on regional air quality and public health. As with all onsite

[60] The LCFS Program includes three California dairies projects that use reciprocating engine generators, one of which received a -630.92 g/MJ carbon intensity score, the lowest LCFS carbon intensity score to date.

electricity generation projects, microturbines do not require pipeline interconnection, improving their locational flexibility compared to pipeline projects.

Anaerobic Digestion Technology Option 3: Fuel Cell for Electricity Generation

This technology option involves using a fuel cell to generate onsite electricity using biogas to support electric vehicle charging.[61] Fuel cells generate onsite electricity with very low air pollutant emissions, especially when compared to emissions associated with reciprocating engine generators. These projects provide electricity using biogas that avoids up to 90 percent of the NOx and up to 80 percent of the particulate matter emissions resulting from other combined heat and power technologies on a life-cycle basis.[62] Fuel cells installed at dairies have the potential to be certified for ultra-low carbon intensity scores, and the potential LCFS credit revenue may make them competitive in the long-term. As with all onsite electricity generation projects, fuel cells do not require pipeline interconnection, improving their locational flexibility compared to pipeline projects.

Anaerobic Digestion Technology Options 4a & 4b: Onsite Injection of Biomethane into a Natural Gas Pipeline

These technology options include either single dairy or cluster pipeline interconnection projects. These are the most common options and involve biogas capture, upgrading to pipeline biomethane specifications, and injection into a natural gas pipeline. These projects reduce GHG emissions further when they replace fossil natural gas. They also avoid onsite combustion for electricity generation and the associated onsite air pollutant emissions and public health impacts. As a result, these projects are preferable to onsite combustion projects but may not be feasible due to factors including distance to the nearest natural gas pipeline with enough capacity, and whether the facility is part of a cluster. Project cost between these two categories differ notably, with single dairy projects costing considerably more compared to cluster projects due to lack of ability to share upgrading facility and pipeline extension costs.

Anaerobic Digestion Technology Option 5: Trucking Biomethane to an Existing Interconnection Point for Injection into Natural Gas Pipeline

This technology option involves trucking biomethane to the closet injection point or natural gas vehicle refueling station. This option assumes that biomethane is

[61] Two DDRDP projects use Bloom Energy solid oxide fuel cells.
[62] An Assessment of Energy Technologies and Research Opportunities: Chapter 4: Advancing Clean Electric Power Technologies September 2015.

transported by a zero-emissions electric or natural gas heavy duty truck with few criteria pollutant (including oxides of nitrogen) and particulate matter emissions compared to a diesel heavy-duty truck. Using natural gas or electric heavy-duty trucks reduces criteria pollutant emissions and avoids emissions of harmful diesel particulate matter from biomethane transport, with negligible impact on project cost compared to using a diesel truck. Trucking biogas, referred to as a "virtual pipeline," may reduce project costs and provide flexibility compared to construction of dedicated pipelines. It also mitigates the risk of stranded infrastructure in the event of reduced demand from a site-specific large downstream consumer (e.g., milk processing operation). Trucking biomethane to existing injection points may be a cost-effective delivery option that results in fewer emissions than reciprocating engine generator and microturbine projects. However, it will also increase vehicle miles traveled, likely in disadvantaged communities, so incentives or regulatory approaches should encourage facilities to reduce reliance on trucking where feasible and use of zero emission vehicles or natural gas heavy-duty trucks when necessary.

Potential Biomethane Supply from Anaerobic Digestion

The preceding anaerobic digestion technology options describe potential pathways to deliver biomethane to market through electricity generation or pipeline injection. This section illustrates the potential biomethane supplied to market and associated costs under each of these options in a baseline scenario, and under various environmental credit price scenarios. Figure 9 below shows potential biomethane supply and market delivery cost under a baseline scenario, which is absent any State or federal financial incentives. The dashed red line shows expected biomethane supply by 2022, approximately 4.7 trillion British thermal units (Btu). The dashed black line indicates the estimated amount of biomethane supply (~13.5 trillion Btu) needed to achieve the 2030 target. Without State or federal financial incentives like the State's LCFS Program or the federal RFS Program, none of the technology options described above (Figure 9) are financially viable.

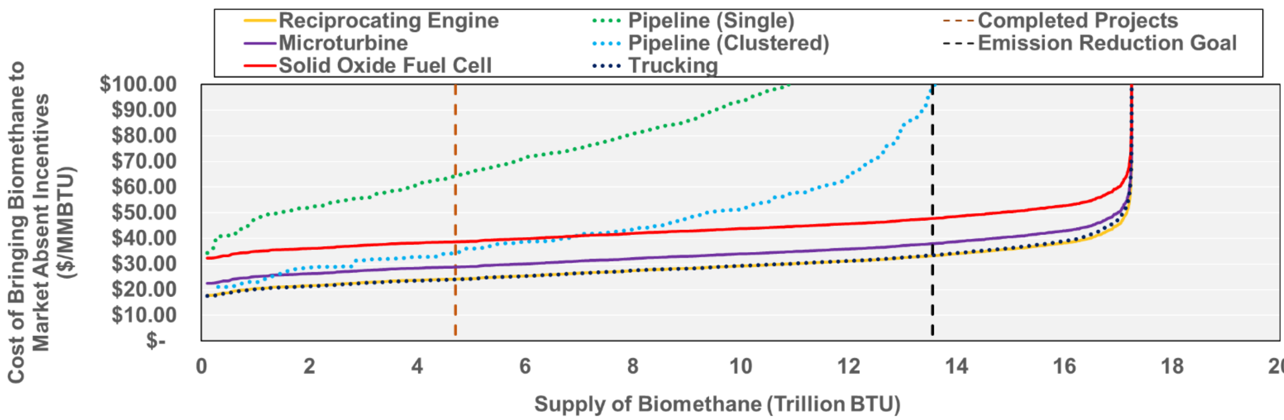

Figure 9. Biomethane Supply and Market Delivery Cost under Different Technology Options absent Federal and State Incentives

Figure 9 illustrates the cost of bringing biomethane to market under each technology option absent any public incentives (e.g., CCI funds, Cap-and Trade Program compliance offset credits, LCFS credits, RFS RIN credits). The costs portrayed for this curve and the subsequent supply curves in Figures 10 through 12 show levelized cost, and therefore includes financing assumptions for the digester projects as well as the additional capital and operating expenses associated with the technology that uses the dairy gas produced through anaerobic digestion. For instance, the levelized cost of pipeline projects is inclusive of the covered lagoon and anaerobic digestion system, upgrading the gas, building the pipeline, and injecting the gas into the pipeline. For the other technologies, the costs include any upgrading costs, as well as any additional equipment costs (e.g., solid oxide fuel cell) required to bring the gas to market.

In general, the supply curves for pipeline-based technologies have a substantially greater upward slope. Pipeline interconnection distances vary for each facility, and facilities that are further away from pipelines will have higher costs to build the network relative to facilities that are closer to pipeline interconnection points. Additionally, facilities that produce more biomethane (i.e., larger facilities) will be able to recoup fixed pipeline costs by distributing these costs over larger quantities of produced biomethane over time. As such, the lowest cost pipeline projects will generally be for large facilities that are closer to pipeline interconnections. The other technologies largely scale linearly with the size of the facility. As such, the slope for non-pipeline technologies is generally more gradual.

The cost to deliver biomethane to market may be as low as $30 per MMBtu if trucked to an existing pipeline interconnection or used to produce onsite electricity using a reciprocating engine generator. In contrast, delivering biomethane to market may cost as much as $100 per MMBtu for pipeline injection at a cluster of dairies—the costliest option with sufficient capacity to achieve the 2030 target. For comparison, in October 2020 wholesale fossil natural gas prices on Henry hub were approximately $3 per MMBtu, but has increased to approximately $5 per MMBtu in October 2021. Given that the price of fossil natural gas is approximately one tenth to one sixth that of biomethane, it is uneconomic to utilize biomethane without incentives beyond sale price.

Staff used biomethane delivery costs and volumes from Figure 9 to estimate potential costs for implementing at least 210 additional digester projects necessary to achieve the 2030 target. To be conservative, staff developed estimates using expected biomethane delivery costs from the 2030 target line to reduce potential underestimation of the total cost to achieve the target for feasible scenarios. Project costs on this line are expected to be the highest over time and assumes that more financially feasible projects have already been implemented.

To bound the potential total cost of achieving the 2030 target, staff used the solid oxide fuel cell scenario costs as an upper bound and costs associated with trucking biomethane to an existing interconnection point and producing onsite electricity using a reciprocating engine generator as the lower bound value. Though cluster pipeline projects may also potentially deliver sufficient biomethane to meet the 2030 target, this scenario is unlikely to be implemented at enough facilities to achieve the target. The costs associated with constructing additional pipelines to supply enough biomethane to achieve the target make it increasingly unlikely that the more costly projects would be implemented. Instead, it is more likely that these facilities will choose the lower cost options of generating onsite electricity or trucking biomethane to an existing interconnection point. As such, it is inappropriate to use direct pipeline injection as an upper cost bound.

Staff also assumed, as previously discussed in Finding 1-1, that at least 210 alternative manure management projects may be implemented at an assumed per project cost of $0.6 million, resulting in a total cost of $0.1 billion. Staff added this $0.1 billion to the total costs associated with the lower and upper bound cost of implementing the additional 210 digester projects. Based on these assumptions, the estimated total cost to achieve the 2030 target range from $0.8 to $3.7 billion absent any public incentives. The 2030 target may also be achieved solely through implementation of as few as 230 additional digester projects costing between $0.7 and $3.9 billion.

With public incentives like LCFS credits and RFS RINs, the need for upfront public investment in digester projects[63] may be reduced or even eliminated, assuming project developers will have access to debt financing for upfront project construction cost. These incentives can be sufficient to offset project development, operational, and financing costs in some cases depending on the level of incentive available, providing a positive project revenue stream and making the project financially viable.

Staff evaluated the same methane emissions reduction technology options used in the baseline scenario above to estimate biomethane supply and cost under various combinations of LCFS and RFS RIN credit prices.[64,65,66] These credit value scenarios range from $150-$200 per credit for LCFS and $0-$2 per RIN. Table 6 shows potential credit values from delivering one MMBtu of biomethane to market at these price ranges under different technology options. Potential credit values at such levels may make these projects competitive with fossil natural gas and with other sources of biomethane.

Table 6. Potential Environmental Credit Value ($) from Producing One MMBtu of Biomethane under Different Technology Options at Various LCFS and RIN Credit Prices[67]

Biomethane Delivery Option	LCFS $150			LCFS $200		
	RIN $0	RIN $1	RIN $2	RIN $0	RIN $1	RIN $2
Reciprocating Engine	$41	$41	$41	$55	$55	$55
Microturbine	$55	$55	$55	$74	$74	$74
Solid Oxide Fuel Cell	$64	$64	$64	$85	$85	$85
Pipeline (Single or Cluster)	$49	$62	$75	$66	$79	$92
Trucking	$44	$57	$70	$59	$72	$85

63 Alternative manure management projects are not eligible for State and federal biomethane incentive programs because, while they do reduce dairy methane emissions, they do not produce biomethane.

64 Assumes D3 cellulosic RIN

65 Electricity generation projects are not currently able to generate RFS RIN credits and have been assigned a $0.00 RIN price across all evaluated credit price scenarios.

66 Offset credits are not evaluated because the LCFS credits value is considerably more than the Cap-and-Trade program.

67 The assumed carbon intensities, energy efficiency rating (EER), and percent efficiency rating for the identified biomethane delivery options are as follows:

- Reciprocating Engine: -490 grams per mega Joule (g/MJ), 3.4 EER, 32% efficiency
- Microturbine: -490 g/MJ, 3.4 EER, 44% efficiency
- Solid Oxide Fuel Cell: -400 g/MJ, 3.4 EER, 57% efficiency
- Pipeline (Single or Cluster): -230 g/MJ, 0.9 EER, 100% efficiency
- Trucking: -230 g/MJ, 0.9 EER, 100% efficiency

Figure 10 through Figure 12 below illustrate the potential biomethane supply and market delivery cost under three different combinations of LCFS and RIN credit prices. These scenarios illustrate a potential lower bound, a potential upper bound, and a scenario with medium credit values. They are described in greater detail below. Values below $0.00 on the y-axis provide positive revenue to projects making them financially viable because revenues exceed project costs. Conversely, values above $0.00 indicate that revenues are insufficient to offset project costs, making the projects infeasible because supply costs are too high.

Environmental Credit Price Scenario 1: $150 LCFS and $0 RIN

This scenario estimates biomethane supply and production cost assuming values of $150 for LCFS credits and $0 for RIN credits (Figure 10). Under this scenario, single dairy pipeline projects can supply approximately 1 trillion Btu of biomethane to the market, falling far short of the required volume to meet the 2030 target. Previously funded projects exceeded this capacity, which suggests that future single pipeline injection projects are not viable at these prices.

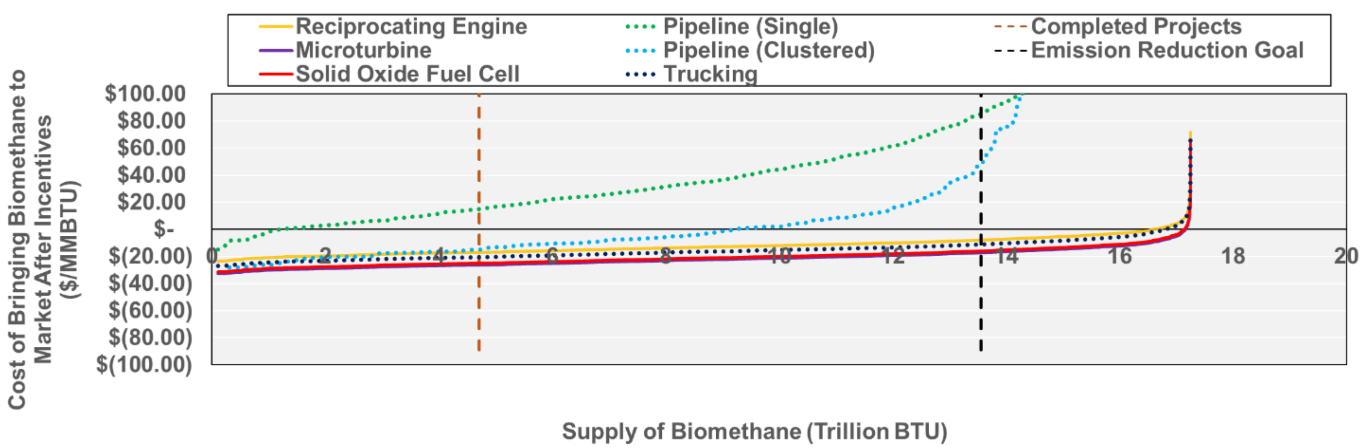

Figure 10. Biomethane Supply and Market Delivery Cost at LCFS and RIN Credit Prices of $150 and $0, Respectively

For comparison, clustered pipeline projects can supply approximately 9 trillion Btu. While a significant increase over the single pipeline projects, this still falls short of the volume required to meet the target. Under Scenario 1, both the single and cluster pipeline injection options are unable to bring sufficient dairy biomethane to market to meet the target without additional incentives.

However, biomethane-to-electricity projects and trucking biomethane to existing interconnection points may provide enough biomethane volume to the market to meet the 2030 target. In this scenario, the solid oxide fuel cell technology option generates the highest revenue with an LCFS environmental credit value of $64 per

MMBtu. Biogas-to-electricity projects that use reciprocating engines and microturbines result in less revenue but cost less than solid oxide fuel cell projects.

Environmental Credit Price Scenario 2: $200 LCFS and $1 RIN

This scenario estimates biomethane supply and production cost assuming values of $200 for LCFS and $1 for RIN (Figure 11). Under this scenario, single-dairy pipeline projects can cost-effectively supply approximately 8 trillion Btu of biomethane to the market, which is a considerable increase over Scenario 1, but still more than 5 trillion Btu short of the 2030 target. Cluster pipeline injection projects will not be able to cost-effectively supply sufficient biomethane to achieve the target either, falling short by approximately 1 trillion Btu. Consistent with Scenario 1, biogas-to-electricity, solid oxide fuel cell projects, and biomethane trucking projects can supply sufficient biomethane to achieve the 2030 target, with the latter two offering the considerably higher credit revenue. Under this scenario, only dairy pipeline injection projects would require additional incentives to achieve the target.

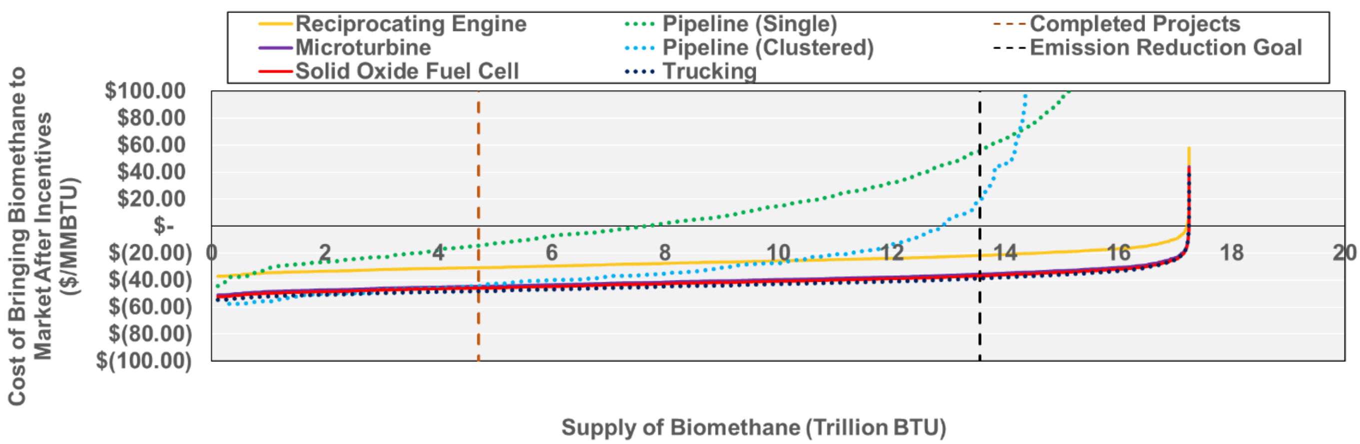

Figure 11. Biomethane Supply and Market Delivery Cost at LCFS and RIN Credit Prices of $200 and $1, Respectively

Environmental Credit Price Scenario 3: $200 LCFS and $2 RIN

This scenario estimates biomethane supply and production cost assuming values of $200 for LCFS and $2 for RIN (Figure 12). In this scenario, single-dairy pipeline injection projects can cost-effectively bring about 10 trillion Btu of biomethane to market, the highest volume across scenarios but still fall short of the target by 3 trillion Btu. Cluster pipeline injection projects can cost-effectively bring over 13 trillion Btu of biomethane to market, nearly achieving the target. Trucking projects are the most cost-effective overall resulting from credit revenue available and relatively low project development costs. Solid oxide fuel cell projects are another cost-effective option given the estimated credit value. Under this scenario, all but pipeline injection projects can cost effectively bring enough biomethane to market without the need for additional incentives.

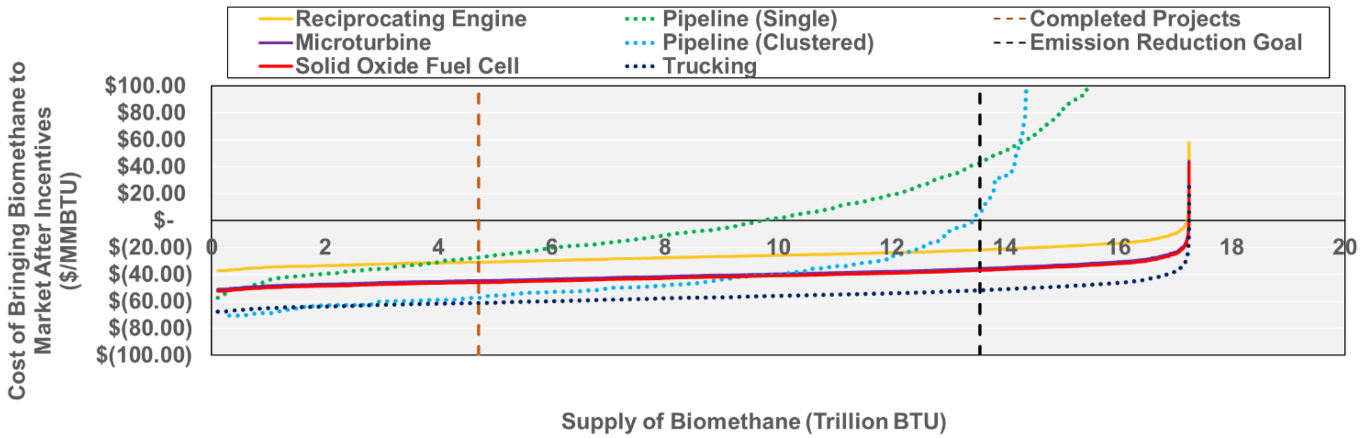

Figure 12. Biomethane Supply and Market Delivery Cost at LCFS and RIN Credits Prices of $200 and $2, Respectively

Current Federal and State Environmental Credits, Combined with Project Development Incentives, May Be Sufficient to Support Dairy Biomethane Projects

As the scenarios above illustrate, LCFS and RFS RIN credit prices are significant drivers of economic feasibility for anaerobic digestion projects at California dairy and livestock operations. This is especially true for projects that do not receive public funding. It is also clear that, given sufficient and sustained credit prices, most of these project types can cost-effectively supply sufficient biomethane to achieve the 2030 target with no additional public incentive funding, potentially reducing the need for those resources.

While each of these anaerobic digestion scenarios can potentially generate revenue or even profits to support construction and operation of digester projects, LCFS and RFS credit markets may be perceived as relatively uncertain as compared to conventional project financing options. Developers unable to obtain debt financing will need additional equity, assets, or public funding like that available through CCI to avoid delays in project implementation, or foregoing projects altogether. In these cases, local, state, and federal funding can ensure that projects will continue to move forward.

State law requires DDRDP expenditures funded by CCI to prioritize projects based on criteria pollutant emissions reduction benefits. While environmental credit prices may be sufficient to drive and sustain projects without additional public funds, the absence of these incentives may result in less desirable projects. For example, projects that use a reciprocating engine generator to produce electricity from biogas are often lower cost than other options but result in criteria pollutant impacts, potentially in some of California's most disadvantaged communities.

Similarly, trucking of biomethane to existing interconnection points may be a lower-cost option but may result in increased criteria pollutant emissions and vehicle miles traveled throughout the State. Reducing or eliminating CCI or other public funding for dairy and livestock methane emissions reduction projects may eliminate prioritization of projects that deliver important environmental and public health co-benefits.

Alternative Manure Management Projects Are Unlikely to be Implemented Without Incentives

Alternative manure management practice projects are not eligible to generate environmental credits because it is difficult to quantify methane emissions reductions relative to facility baseline emissions. This results from site-specific project variations that influence methane emissions mitigation. Variability in outcomes is a barrier to develop an offset quantification protocol for alternative manure management practices, so these projects are currently ineligible to generate carbon offset credits under CARB's Cap-and-Trade Program. As a result, financial viability is dependent on public funding, cost savings, and potential sales of value-added manure products like soil amendments and compost. In many cases, these combined savings and revenues are insufficient to offset project development costs, so public investments are critical. Without them, it is unlikely that a large number of projects will be implemented, which may impede the sector's ability to maximize its contribution to the target. These projects also provide important environmental and economic co-benefits through production of high-quality soil amendments, destruction of pathogens, reduction in nitrates and salts that threaten water quality, and production of a product that can be cost effectively transported to replace chemical fertilizer across the State.

Additional State Policies and Incentives Can Support Dairy Biomethane Projects

Long-term policies and incentives can play critical roles in supporting ongoing capture and use of biomethane from the dairy sector to achieve the 2030 target and the State's broader carbon neutrality goals. For example, a funding mechanism that incentivizes the capture of biomethane in California could expand to advance the production and use of biomethane and could provide market certainty to help project developers obtain project financing. While dairy biomethane is currently directed to the transportation fuel market through the LCFS Program, other market-based programs could play a role in directing the biomethane to alternative end uses, including towards industries that are difficult to electrify and otherwise decarbonize.

As described in the 2017 Scoping Plan Update, California must prioritize electrification wherever possible to in order to achieve its GHG emissions reduction goals. The State's electricity sector has already made considerable progress in moving toward zero- or low-GHG emissions generation, but other sectors including transportation, residential, and commercial still offer significant potential to decarbonize using electricity from sources like wind and solar. Some sectors, however, are difficult to electrify so directing dairy and livestock biomethane to these sectors can help decarbonize them, contributing to State carbon neutrality goals. The Scoping Plan Update will discuss additional policies to diversify dairy biomethane use and ensure long-term success of these projects to contribute to State's climate targets.

Analysis Item 2: Progress Made in Overcoming Technical and Market Barriers to Dairy and Livestock Methane Emissions Reductions Projects

The Strategy identifies barriers to methane emissions reductions measures that the dairy and livestock sector must overcome to achieve the 2030 target. These include technical barriers that impede project development based on various factors including technology limitations, incomplete development, or lack of standardized information. Market barriers impede project development based on factors including cost, availability of financing, environmental credit uncertainty, consumer acceptance, cost-effectiveness, and sector economics. This section will provide a short summary description of how to understand the technical and market barriers in this sector, followed by findings regarding the identified technical barriers and market barriers. Ultimately, the findings support that investment by the State and successful collaborations between agencies, developers, and stakeholders have largely overcome previously significant barriers.

Technical Barriers

Technical barriers impede both manure management methane emissions reduction projects and enteric mitigation strategy development. Specific to manure management, technical barriers impact both anaerobic digestion and alternative manure management projects. As described in the Strategy, technical barriers to anaerobic digestion include difficulties interconnecting with utility electrical grids and natural gas pipeline networks.

Technical barriers to alternative manure management projects result from inconsistent methane emissions reductions across project types and the resultant difficulty with accurately quantifying methane emissions reductions. In some cases, technical barriers may reinforce market barriers, making them even harder to overcome. For example, challenges in quantifying alternative manure management projects impedes the development of offset protocols or other market mechanisms that could improve their financial viability.

Market Barriers

Like the technical barriers discussed above, market barriers also impede both anaerobic digestion and alternative manure management projects. As detailed in the Final Recommendations to the Dairy and Livestock Greenhouse Gas Reduction Working Group, existing market barriers for manure methane reduction projects include project development costs, perceived lack of environmental credit certainty, out-of-State RNG competition, and underdeveloped markets for manure-based products. In addition to competition from out-of-State RNG, electricity and biofuels from California dairy waste faces competition from other sources of in-State renewable electricity such as solar and wind electricity, and competition from other sources of biomethane like landfills. As a result, dairy project developers rely on incentive funding or environmental credit revenues to make projects feasible. However, demand for incentives has consistently outpaced supply, especially for grant funding. Table 7 summarizes the status of progress for each technical and market barrier discussed in this section.

Table 7. Technical and Market Barriers to Implementing Manure Management and Enteric Fermentation Methane Emissions Reductions Projects

	Technical Barriers	**Market Barriers**
Manure Management	Alternative manure management projects ✗ Inconsistent reductions ✗ Difficulty quantifying reductions Anaerobic Digesters ✓ Grid and pipeline interconnection ✓ Biomethane quality standards	✓ Project development costs and financing ✓ Environmental credit certainty ✗ Sector economics ✗ Insufficient public funds ✗ Undeveloped markets for value-added manure products
Enteric Fermentation	✗ Transient effect/rumen adaptation ✗ Potential animal health impacts Limited availability ✓ Limited products with commercial availability ✗ Seasonal products	? Consumer acceptance ? Cost-effectiveness

✓ = Progress made ✗ = Persistent barrier? = Limited information available

Finding 2-1: Technical Barriers: Progress Has Been Made on Grid and Pipeline Interconnection and Biomethane Quality Standards, but Other Technical Barriers Remain

Technical Barriers to Anaerobic Digestion Projects

The dairy and livestock sector has made progress in overcoming certain technical barriers of manure methane emissions reductions projects, including access to pipeline networks and utility electrical grids. Project developers and utilities collaborated to understand technological and cost requirements for pipeline and electricity grid interconnection to reduce project development timelines.

Specific to pipeline injection projects, state agencies, utilities, project developers, and suppliers of biomethane upgrading equipment collaborated to identify technology immediately available for dairy operations to upgrade biomethane onsite.[68] Raw biogas from dairy and livestock facilities is mostly comprised of methane and carbon dioxide, with traces of many other constituents including oxygen, nitrogen, hydrogen sulfide, and water. To be injected into the utility pipeline, it must be upgraded, conditioned, and compressed to required pressures. Since the adoption of the Strategy, in Proceeding R.13-02-008, CPUC lowered the minimum heating value required for biomethane injected into natural gas pipelines. Prior to this change, achieving minimum heating value standards was a significant technical challenge and cost barrier for biomethane injection projects. This change resulted in decreased upgrading costs and removed the technical barrier without endangering public health or pipeline integrity.

In 2008, Pacific Gas and Electric Company (PG&E) interconnected the first dairy biomethane pipeline injection project, the first of its kind in California. PG&E continues to allow biomethane producers like dairy and livestock operations to interconnect to the natural gas pipeline system within their coverage area where sufficient capacity and downstream demand within the local pipeline exists. Interconnecting to the PG&E natural gas pipeline network consists of three steps. The first step involves an interconnection screening study which PG&E uses to determine the closest pipeline that can accept a producer's pipeline quality biomethane supply. Step two involves a preliminary engineering study where PG&E reviews the safest, most efficient interconnection route before developing a preliminary cost estimate for the

[68] Online Article. Xebec Enters California Dairy RNG Market with Maas Energy Works. Accessed on December 05, 2019.

interconnection. The final step consists of a detailed engineering study followed by construction of the interconnection.

In 2015, Southern California Gas Company (SoCalGas) began offering the Biogas Conditioning/Upgrading Services Tariff to allow the utility to plan, design, procure, construct, own, operate, and maintain biogas conditioning and upgrading equipment on customer premises. This optional fee service can further assist customers in their coverage area to overcome technical difficulties associated with interconnecting to the natural gas pipeline system. These potential biogas upgrading options help facilities achieve biomethane quality standards necessary for pipeline injection.

PG&E and SoCalGas are also working with dairy biomethane producers to engineer and construct pipeline infrastructure for six dairy biomethane pilot projects pursuant to SB 1383. These projects will help producers, utilities, and the State better understand the technical and economic factors affecting biomethane injection while ensuring and demonstrating successful biomethane delivery into the pipeline network. Additionally, three in-State projects that currently inject biomethane to the utility pipeline system have consistently met SoCalGas biomethane delivery specifications. In 2019, one of these projects completed construction of a digester cluster in Pixley, California and began delivering biomethane to the SoCalGas natural gas pipeline network. While costly, achieving pipeline quality specifications is technically feasible and no longer considered a technical barrier. In fact, in response to CARB's May 2020 webinar on this Analysis, SoCalGas submitted comments clarifying that the utility no longer views achieving pipeline quality specifications for biomethane injection a significant technical barrier.

Project developers and electric utilities have also overcome financial and technical barriers to accessing utility electrical grids. Interconnecting to utility electrical grids requires initial feasibility studies, which can cost several hundred thousand dollars, to outline site-specific technology requirements. Equipment and installation costs for system upgrades can be up to $1 million or more. While the costs and timelines associated with interconnections have not decreased considerably, experience from initial projects has helped to improve understanding of the processes and technical requirements and increased the deployment rate of electricity generation at dairy facilities. Three in-State dairy operations currently have certified LCFS pathways to deliver renewable electricity to the grid for electric vehicle charging with additional facilities—including two solid oxide fuel cell projects under development—that will pursue similar electric vehicle charging pathways to capitalize on potential LCFS credit revenue.

Technical Barriers to Alternative Manure Management Projects

Methane emissions reductions from alternative manure management practices vary substantially based not only on the technology chosen, but also on project-specific implementation variables. For example, a properly operated single stage slope screen solid-liquid separation system might reduce total and volatile solids sent to anaerobic storage by 17 percent. That same separation system operating in exceedance of its throughput capacity may process the same manure stream but with a reduced separation efficiency, allowing manure solids to bypass separation and proceed directly to anaerobic storage, eliminating the benefits intended by the system. Similarly, the composition of manure streams may affect the solid-liquid separation efficiency of the system with some manure streams being more readily separated than others. Such factors can cause considerable variability in solids removal and overall methane emissions reduction effectiveness, making it difficult to quantify reductions accurately and with certainty. In conclusion, alternative manure management practices have great methane emissions reduction potential, but many operational factors can affect their efficiencies, resulting in difficulties to quantify with appropriate certainty the methane emissions reductions benefits. CDFA and CARB have invested in the following research projects consistent with Dairy and Livestock Subgroup 1 Recommendations to better understand the methane emissions reduction potential of various alternative manure management practices:

- **Evaluation of Dairy Manure Management Practices for Greenhouse Gas Emissions Mitigation in California**
  In 2015, CDFA funded this University of California (UC), Davis study to measure the efficiency of various solid-liquid separation technologies. Results showed high variability across technologies resulting from factors including project design, operational capacity, and material throughput, and the associated report recommended additional research, particularly on weeping walls. This study also included an economic analysis to evaluate the cost-effectiveness of methane mitigation strategies on California dairy farms.

- **Characterize Physical and Chemical Properties of Manure in California Dairy Systems to Improve Greenhouse Gas Emission Estimates**
  In 2016, CARB funded this UC Davis research to characterize the physical and chemical properties of manure in California dairy systems.

- **Research and Technical Analysis to Support and Improve the Alternative Manure Management Program Quantification Methodology**
  In 2017, CARB funded this UC Davis literature review to assess methane emissions reduction potential of various alternative manure management practices, including solid-liquid separation and weeping walls. Results found all studied technologies had variable performance and the associated report recommended additional research on factors affecting performance of these systems.

- **Benchmarking of Pre- and Post-Alternative Manure Management Program Dairy Emissions and Prediction of Related Long-Term Airshed Effect**
  Between 2016 and 2018, CARB and CDFA collaborated to fund these complementary studies to monitor GHG and air pollutant emissions before and after implementation of various alternative manure management practices at six AMMP-funded dairies. In a separate but complementary effort, CARB installed flux towers to measure methane emissions on three of the six AMMP-funded dairies.

- **Development of the California Dairy Emissions Model**
  In 2019, CARB funded UC Davis to develop a California dairy emissions model to evaluate the effectiveness of potential mitigation strategies and to estimate GHG and other air pollutant emissions from California dairies.

Technical Barriers to Enteric Methane Mitigation Strategies

Enteric strategies, especially feed additives, hold considerable methane mitigation potential from all ruminant species. However, limited commercial availability and seasonal availability of effective feed additives, a lack of long-term effectiveness, and the potential for adverse impacts on animal health for certain products remain persistent technical barriers.

A few methane reducing feed additives with proven long-term effectiveness and no adverse impacts on animal or human health have become commercially available, indicating progress towards overcoming that barrier. However, limited availability of proven strategies remains a barrier for enteric mitigation strategies. For example, the most well-studied potential feed additive, 3-NOP, is expected to become commercially available in the United States in 2024.[69] There is a significant body of evidence to support the effectiveness of 3-NOP in reducing enteric methane emissions by approximately 30 percent. 3-NOP is currently undergoing long-term trials as part of

[69] Mitloehner, F., Kebreab, E., Tricarico, J., Wallace, J., Gooch, C., Gibbs, C. (2020). Dairy Feed Additives to Reduce Enteric Methane Emissions. Newtrient.

the FDA evaluation and approval process before final approval for commercial distribution.

Grape pomace is another additive that may reduce emissions and may not require FDA approval. However, it is only available in late summer and early fall during grape harvest, limiting its feasibility for year-round emissions reductions. Some novel additives such as seaweed also show methane emissions mitigation potential, but with limited *in vivo* (animal) studies to evaluate their long-term effectiveness and potential impacts on animal health, productivity, and product safety. For example, *Asparagopsis,* a special species of seaweed, shows mitigation potential of up to 90 percent during *in vitro* (non-animal studies using rumen simulation technologies) studies,[70] while *in vivo* studies show a mitigation potential of approximately 50 percent during enteric fermentation.[71] However, this additive is still under development, with many unaddressed technical barriers including the potential risk of elevated bromide residues in milk (a food safety concern), palatability concerns causing decreased feed intake and milk production, and low availability and high cost for the product.

Another persistent technical barrier for enteric methane mitigation strategies is limited long-term information about product effectiveness for most available or emerging options. There are a variety of products in various stages of commercial development that face barriers mentioned above. For example, some additives may impact animal health and productivity. Others may have limited long-term effectiveness due to rumen adaptation leading to rapid additive breakdown.[72] While some additives show great mitigation potential, their long-term impacts on animal health, availability, and cost-effectiveness are not well known. In short, feed additives offer promising potential as a mitigation strategy, but require further research and development before being required for use as part of any CARB regulation. SB 1383 requires that only incentive-based mechanisms are authorized for enteric emissions reductions until CARB, in consultation with CDFA, determines that another mechanism is cost-effective, considering the impact on animal productivity and must be scientifically proven to reduce enteric methane emissions, and that adoption of the enteric

[70] Machado, L., Magnusson, M., Paul, N., Kinley, R., de Nys, R., Tomkins, N. (2015). Dose-response effects of Asparagopsis taxiformis and Oedogonium sp. on in vitro fermentation and methane production. *Journal of Applied Phycology*, 28(2).

[71] Roque, B. M., Salwen, J. K., Kinley, R., Kebreab, E., (2019). Inclusion of Asparagopsis armata in lactating dairy cows' diet reduces enteric methane emission by over 50 percent. *Journal of Cleaner Production*, 234: 132-138.

[72] Hook, S.E., André -Denis G.W., McBride, B.W. (2010). Methanogens: Methane Producers of the Rumen and Mitigation Strategies. Archaea, 11 pages.

emissions reduction method would not damage animal health, public health, or consumer acceptance.

Additional Research to Address Technical Barriers

The California legislature appropriated $5 million for research grants for FY 2021-22 to measure and verify emissions reductions associated with dairy livestock methane emissions reduction projects. Specifically, the Legislature requires additional research in the following areas:

- Assessment of the cost-effectiveness of various dairy and livestock methane mitigation strategies on a per ton basis including a comparison of projects funded under AMMP and DDRDP
- Assessment of the cost-effectiveness of enteric methane mitigation strategies
- Additional research on value-added manure-based products development
- Measurement of greenhouse gases and criteria pollutants before and after livestock methane reduction projects are implemented

These research projects will further the State's understanding of the effectiveness of anaerobic digestion and alternative manure management projects at achieving methane emissions reductions and environmental co-benefits. In addition, these studies will allow further investigation of the efficacy and cost-effectiveness of enteric strategies, should additional strategies become available.

Finding 2-2: Market Barriers: The State and Federal Incentive Programs Have Helped Achieve Progress with Project Funding and Incentives

Similar to the technical barriers detailed above, the State, along with others, have made considerable progress in overcoming market barriers to implementing methane emissions reductions projects. Improved understanding of project development costs and significant allocations of CCI funding for manure methane emissions reduction projects have contributed to progress in overcoming barriers related to project funding (Table 8).

Table 8. State Investment in Manure Methane Emissions Reduction Projects

State Investment Program	Investment ($ million)
DDRDP	$196
AMMP	$68
Pilot pipeline construction	$319
Renewable Gas Pipeline Incentive Program	$40
Total	**$623**

This Analysis has already discussed the critical role that market-based programs like Cap-and-Trade and LCFS, RFS, and grant programs like DDRDP and AMMP, have played in driving manure management project development. In addition to those programs, with year-over-year funding to support project development, the Legislature also enacted other initiatives to reduce market barriers for anaerobic digestion projects. Through SB 1383, the Legislature directed CPUC, along with CARB and CDFA, to select six pilot projects to demonstrate biomethane injection into the common carrier pipeline network. This pilot program committed $319 million in rate-recoverable funding to 45 dairies for pipeline infrastructure and operational expenses over 20 years with no private match funding requirement.[73] These projects will provide valuable information on pipeline interconnection processes and the associated costs.

CPUC also administers BioMAT, which provides long-term power purchase agreements with a guaranteed price to projects that generate onsite electricity from certain biogenic feedstock and deliver that electricity to the grid. This market program allows three utilities (Pacific Gas and Electric Co., San Diego Gas & Electric Co., and Southern California Edison) to offer favorable rates to onsite generation projects using a market adjusting mechanism that periodically increases the rate until there are enough market participants. BioMAT has funded two projects for a cumulative total of $8 million, with eight additional projects pending. To date, dairy electricity generation projects have filled nearly 19 megawatts (MW) of the 90 MW available. Another program administered by CPUC is the Renewable Gas Pipeline Interconnection Incentive Program, which provides cost share for dairy biomethane pipeline injection projects. The Legislature appropriated $40 million for pipeline interconnection projects, with up to $3 million in infrastructure cost share available for single-dairy projects, and up to $5 million for dairy cluster projects. Although these programs predate SB 1383, both have seen increased interest since it was enacted.

These incentive programs have been critical to funding the upfront costs of anaerobic digesters, and have also been consistently oversubscribed, which shows an unmet need for additional local, state, and federal investment. However, the availability of incentives coupled with environmental credit revenue has led to increased private investment. Private equity firms and companies have invested in anaerobic digesters, creating additional opportunities for project developers and financers. Increased private funding may result in projects that are financially solvent without upfront incentives, but these funding sources are limited. Sustained environmental credit

[73] California Public Utilities Commission. (December 3, 2018). CPUC, CARB, and Department of Food and Agriculture Select Dairy Biomethane Projects to Demonstrate Connection to Gas Pipelines.

revenue can further reduce risk to lenders and deliver quicker returns on investments, making these projects increasingly attractive to private capital.

One important consideration about the role of public funding is its ability to prioritize multiple benefits. For instance, private capital will pursue biomethane or electricity options that minimize costs and maximize revenue available through environmental credits. In contrast, the State can require funded projects to meet multiple goals. For example, CDFA prioritizes DDRDP projects that minimize environmental impacts including NOx and air pollutants and maximize the environmental co-benefits and community benefits as required by the Legislature when it passed SB 859 (Chapter 368, Statutes of 2016). Implementation of SB 859 has resulted in widespread implementation of pipeline injection projects due to their lower air quality impact compared to relatively lower-cost onsite combustion or trucking projects.

Alternative manure management practices and enteric methane mitigation strategies have not seen similar progress in project funding; without additional local, State, and federal funding, these project types are unlikely to move forward.

Finding 2-3: Market Barrier: Clarity from the State Has Improved Environmental Credit Certainty

California's Cap-and-Trade Program and LCFS Program, and the federal RFS Program, are the primary policy and programmatic mechanisms that provide environmental credit revenue for dairy digesters. To improve market certainty of the Cap-and-Trade Program and LCFS Program for dairy digesters, CARB developed the following two documents:

- Credit Generation for Reduction of Methane Emissions from Manure Management Operations helps project developers better understand potential impact to environmental credit generation that a methane emissions reduction regulation may have, to provide greater market certainty.

- The SB 1383 Pilot Financial Mechanism Paper describes a potential pilot financial mechanism that, if implemented, could improve stability and certainty around LCFS credits generated from anaerobic digestion at dairy operations. The white paper describes two potential approaches—put options and contracts for differences—to ensure that participating facilities can receive a set minimum LCFS credit price. Increasing revenue certainty helps project developers access private financing, potentially reducing or eliminating the need for long-term public support. For the mechanism to be implemented, however, it would need an administrator and initial funding. The white paper notes that CARB should not administer this program because of a conflict of interest as the LCFS Program administrator.

Finding 2-4: Market Barriers Remain for Value-Added Manure Products, Alternative Manure Management Projects, and Enteric Methane Mitigation Strategies

Despite progress, persistent market barriers for alternative manure management projects and enteric methane mitigation strategies create an enduring need for funding to support these methane emissions reduction strategies.

Market Barriers for Value-Added Manure Products

Underdeveloped markets for value-added manure products is a persistent market barrier that, if addressed, could improve the financial viability of manure management projects and provide a variety of environmental co-benefits. Most alternative manure management practices produce compost that could be further commodified to provide an additional revenue stream for dairy operators. Improved markets for such products may also drive additional upstream or downstream GHG emissions reductions. For example, manure compost typically contains fewer contaminants and has higher nutrient content than municipal green waste. Similarly, dairy-based organic fertilizers avoid the upstream GHG emissions resulting from manufacture and distribution of synthetic, fossil-based fertilizers. As a result, value-added manure products can potentially provide an important revenue stream to dairy and livestock operations that could reduce reliance on public funding.

Additionally, these products can provide important environmental co-benefits, including soil health, water retention, and potential displacement of petrochemical fertilizers. Market maturation would offer more opportunity to export nutrient-rich manure solids and reduce potential for water quality impacts from land application of manure. These benefits may be especially important in the San Joaquin Valley, where representative groundwater monitoring shows widespread water quality impacts.[74]

Despite considerable potential benefit to producers and consumers, there is limited information available about the demand for value-added manure products or the quantity that can be cost effectively delivered to the market. To help overcome market barriers and facilitate value-added manure products market development, CDFA is

[74] Shrestha, A. & Luo, W. (2017). An assessment of groundwater contamination in Central Valley aquifer, California using geodetector method. *Annals of GIS*, 23(3), 149-166.

planning to convene a focused working group to address these obstacles and improve financial viability of alternative manure management projects.

Market Barriers to Alternative Manure Management Projects

In many cases, adopting alternative manure management practices at dairies may not be cost-effective due to the lack of revenue streams to generate attractive rates of return to farmers and developers. Additionally, many of the dairies that implement these practices may not have the have the resources to diversify their operations to take advantage of new or expanded market opportunities. In the absence of public funding, these operations—often smaller and less able to capitalize on economies of scale—will need to rely on cost savings and revenue from the sale of value-added manure products (e.g., compost and soil amendment). However, the limited financial benefits of these projects are often insufficient to offset project costs. Additionally, ineligibility for environmental credits and underdeveloped markets for value-added manure products present additional market barriers. As a result, the availability of debt financing is limited.

Market Barriers to Enteric Methane Mitigation Strategies

Limited information is available for a comprehensive analysis of market barriers for enteric mitigation strategies, though market barriers may arise as options become available. However, to be viable, the market requires potential products to gain consumer acceptance and be cost-effective. SB 1383 requires cost-effectiveness of products, among other requirements, prior to requiring their use. Additives that fail to meet these requirements are unlikely to be adopted as effective enteric methane mitigation strategies.

Next Steps

Moving forward, the dairy and livestock sector must still achieve considerable methane emissions reductions to meet the 2030 target. Achieving the target will require careful consideration of potential methane emissions reductions strategies and coordination with other agencies, the dairy and livestock sector, and the public, including environmental justice and disadvantaged communities. Implemented strategies must not only reduce methane emissions from the sector sufficient to achieve the 2030 target but should also be consistent (to the extent feasible) with other State objectives. These objectives include reduced impacts to air and water quality, improved soil health, reduced impacts to environmental justice communities, and maximized GHG emissions reductions while minimizing emissions leakage. This will require coordinated action between the State and the dairy and livestock sector to overcome barriers to implementing proven methane emissions reduction projects and emerging mitigation options, especially for enteric fermentation. Improved accuracy in tracking and quantifying methane emissions reductions achieved by operational manure management projects or expected from future projects—especially alternative manure management projects and emerging enteric methane reducing feed additives—is also critical to evaluating progress toward the 2030 target. These improvements will help identify effective incentives and policies in the near-term and will aid in the design of potential regulations should that be necessary for achieving the 2030 target. The 2022 Scoping Plan Update will further assess and describe the role that the dairy and livestock sector can play to help achieve carbon neutrality.

CARB staff will continue to monitor the dairy and livestock sector's methane emissions reductions progress and refine its understanding of emissions sources, emissions reduction potential, and the achievements of incentives. CARB will continue to research additional technology options and management practices that can achieve methane emissions reductions, as well as research the effectiveness of practices used today. CARB will consider potential options to improve quantification of methane emissions reductions from manure management projects as well as ways to refine GHG emissions accounting for the sector. In order to comply with the statutory direction, CARB will consider regulation development to ensure that the 2030 target is achieved, assuming the conditions outlined in the statute are met. These next steps are described in greater detail below.

Continue Tracking Progress of Methane Emissions Reduction Projects and Funding

The State's appropriation of $289 million in CCI funds for manure methane emissions reductions to date has resulted in 233 dairy manure management projects that will achieve an estimated 2.0 $MMTCO_2e$ in annual reductions by 2022. This funding delivers some of the most cost-effective SLCP emissions reductions to date. CARB staff will continue to track the availability of local, State, and federal incentive funding, the progress of existing projects, and future projects implemented using both public and private funds. Additionally, CARB staff will continue to monitor market developments for value added manure products, and CDFA will convene a working group to reduce market barriers and improve the financial viability of alternative manure management projects.

Continue Tracking Manure Management Methane Emissions Reduction Options

CARB staff will track advancements in manure methane emissions reductions. Specifically, staff will continue to monitor the results of ongoing research including the monitoring emissions at AMMP project sites pre- and post-implementation, CPUC pilot pipeline infrastructure projects, methane emissions flux monitoring, literature reviews, and the development of a dairy emissions model to better understand changes from manure management methane emissions reduction projects. CARB, in collaboration with CDFA, will also continue to evaluate the potential for additional alternative manure management practices.

Continue Tracking Enteric Methane Emissions Reduction Options

There are limited commercially available animal feed for mitigating enteric methane emissions reductions additives in the United States. Some regions, including Brazil, Chile, and Europe have recently approved the use of 3-NOP.[75,76] CARB staff will continue to track the progress of these enteric methane emissions mitigation strategies, analyze their cost-effectiveness, and assess consumer acceptance.

Address GHG Emission Inventory Challenges

In addition to tracking enteric and manure methane emissions reductions options, CARB staff is evaluating options to improve the accuracy of the annual GHG Emission Inventory. Gathering operational or "activity data"[77] from facilities within the sector is an important first step to refining inventory models and associated assumptions to be more California-specific. These refinements would improve GHG Emission Inventory accuracy and inform incentive planning and regulatory development efforts.

Detailed facility activity data on the parameters that affect methane emissions should be collected annually. Specific data may include animal breed, population, production stage, diet composition, animal housing type, and the manure collection rate, storage conditions and length, treatment methods, and land application rates of manure. A more accurate accounting of these parameters can help assess methane mitigation strategies and calibrate emission models.

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[75] https://www.bloomberg.com/news/articles/2021-09-09/world-s-top-beef-supplier-approves-methane-busting-cow-feed

[76] https://www.dsm.com/corporate/news/news-archive/2022/dsm-receives-eu-approval-Bovaer.html

[77] Activity data refers to important factors that can impact emissions from dairy and livestock operations. Some example factors include animal population size, breed, age, lactation status, diet, and type of manure management.

CARB recommends a collaborative effort including public agencies and industry to gather activity data from dairy and livestock operations. Specifically, it may evaluate leveraging or modifying existing reporting structures like annual water quality reports to gather additional activity data from the sector. This approach may increase the likelihood of a high response rate, reduce resources needed to develop a new reporting structure, and reduce the reporting burdens to dairy and livestock operations. A voluntary survey of the sector could also provide useful activity data if a new or modified reporting structure is infeasible.

If these efforts are infeasible or are unsuccessful, a recordkeeping and reporting regulation developed pursuant to SB 1383[78] could provide a mechanism to obtain the necessary activity data. Reported information would be used to improve inventory accuracy, evaluate methane emissions reduction progress, and inform design of potential emissions reduction regulations, should that be necessary.

[78] Section 39730.7(h).

ATTACHMENT AA

CALIFORNIA
AIR RESOURCES BOARD

December 2022

2022 Scoping Plan for Achieving Carbon Neutrality

CARB's mission is to promote and protect public health, welfare, and ecological resources through effective reduction of air pollutants while recognizing and considering effects on the economy. CARB is the lead agency for climate change programs and oversees all air pollution control efforts in California to attain and maintain health-based air quality standards.

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Abbreviations

°F	Fahrenheit
°C	Celsius
AB	Assembly Bill
AQMD	Air Quality Management District
AR5	IPCC Fifth Assessment Report
BECCS	bioenergy with carbon capture and storage
CAISO	California Independent System Operator
CalEPA	California Environmental Protection Agency
CalGEM	California Geologic Energy Management Division
CalSTA	California State Transportation Agency
CAP	climate action plan
CARB	California Air Resources Board
CCR	California Code of Regulations
CCS	carbon capture and sequestration
CCUS	carbon capture, utilization, and storage
CDFA	California Department of Food and Agriculture
CDPH	California Department of Public Health
CDR	carbon dioxide removal
CE	common era
CEC	California Energy Commission
CEQA	California Environmental Quality Act
CES	CalEnviroScreen
CH_4	methane
CMAQ	Community Multiscale Air Quality
CNRA	California Natural Resources Agency
CO_2	carbon dioxide
COPD	chronic obstructive pulmonary disease

CORE	Clean Off-Road Equipment
CPUC	California Public Utilities Commission
CVM	Climate Vulnerability Metric
DAC	direct air capture
DPR	Department of Pesticide Regulation
Draft EA	Draft Environmental Analysis for this Scoping Plan
EA	Environmental Analysis
ED	emergency department
EIA	U.S. Energy Information Administration
EJ	environmental justice
EJ Advisory Committee	Environmental Justice Advisory Committee
EO	executive order
EV	electric vehicle
F-gas	fluorinated gas
FCEV	fuel cell electric vehicle
GCF	Governors' Climate and Forests Task Force
GDP	gross domestic product
GHG	greenhouse gas
GSP	gross state product
GW	gigawatt
GWh	gigawatt-hour
GWP	global warming potential
HDV	heavy-duty vehicle
HD ZEV	heavy-duty zero-emission vehicle
HFC	hydrofluorocarbon
IBank	Infrastructure and Economic Development Bank
ICE	internal combustion engine
IPCC	Intergovernmental Panel on Climate Change

IPT	incidence-per-ton
IWG	Interagency Working Group
LCFS	low-carbon fuel standard
LDV	light-duty vehicle
MDV	medium-duty vehicle
MMT	million metric tons
$MMTCO_2e$	million metric tons of carbon dioxide equivalent
MOU	memorandum of understanding
MRR	Mandatory Reporting of GHG Emissions
$MTCO_2e$	metric tons of carbon dioxide equivalent
MW	megawatt
N_2O	nitrous oxide
NEMS	National Energy Systems Model
NF_3	nitrogen trifluoride
NOAA	National Oceanic and Atmospheric Administration
NOx	nitrogen oxides
NRDC	National Resources Defense Council
NWL	Natural and Working Lands
OEHHA	Office of Environmental Health Hazard Assessment
OGV	Ocean-Going Vessel
OPR	Governor's Office of Planning and Research
OTC	once-through cooled
PFC	perfluorocarbon
PHMSA	Pipelines and Hazardous Materials Safety Administration
PM	particulate matter
$PM_{2.5}$	fine particulate matter
PPP	public-private partnership
RFS	renewable fuel standard

ROG	reactive organic gases
RPS	Renewables Portfolio Standard
SB	Senate Bill
SC-CH_4	social cost of methane
SC-CO_2	social cost of carbon
SC-GHG	social cost of greenhouse gases
SC-N_2O	social cost of nitrous oxide
SF_6	sulfur hexafluoride
SGIP	Self-Generation Incentive Program
SLCP	short-lived climate pollutant
TSD	Technical Support Document
UC	University of California
UCLA	University of California, Los Angeles
UNFCCC	United Nations Framework Convention on Climate Change
U.S. EPA	United States Environmental Protection Agency
VMT	vehicle miles traveled
WUI	wildland-urban interface
ZEV	zero-emission vehicle

Executive Summary

This Scoping Plan lays out the sector-by-sector roadmap for California, the world's fifth[1] largest economy, to achieve carbon neutrality by 2045 or earlier, outlining a technologically feasible, cost-effective, and equity-focused path to achieve the state's climate target. This is a challenging but necessary goal to minimize the impacts of climate change. There have been three previous Scoping Plans. Previous plans have focused on specific greenhouse gas (GHG) reduction targets for our industrial, energy, and transportation sectors—first to meet 1990 levels by 2020, then to meet the more aggressive target of 40 percent below 1990 levels by 2030. This plan, addressing recent legislation and direction from Governor Newsom, extends and expands upon these earlier plans with a target of reducing anthropogenic emissions to 85 percent below 1990 levels by 2045. This plan also takes the unprecedented step of adding carbon neutrality as a science-based guide and touchstone for California's climate work. The plan outlines how carbon neutrality can be achieved by taking bold steps to reduce GHGs to meet the anthropogenic emissions target and by expanding actions to capture and store carbon through the state's natural and working lands and using a variety of mechanical approaches.

Greenhouse gases ↓85% | Air pollution ↓71% | Petroleum demand ↓94%

What this means for California is an ambitious and aggressive approach to decarbonize every sector of the economy, setting us on course for a more equitable and sustainable future in the face of humanity's greatest existential threat, and ensuring that those who benefit from this transformation include communities hardest hit by climate impacts and the ongoing pollution from the use of fossil fuels. The combustion of fossil fuels has polluted our air—particularly in low-income communities and communities of color—for far too long and is the root cause of climate change. This Scoping Plan helps us chart the path to a future where race and class are no longer predictors of disproportionate burdens from harmful air pollution and climate impacts.

The major element of this unprecedented transformation is the aggressive reduction of fossil fuels wherever they are currently used in California, building on and accelerating carbon reduction programs that have been in place for a decade and a half. That means rapidly moving to zero-emission transportation; electrifying the cars, buses, trains, and trucks that now constitute California's single largest source of planet-warming pollution. It also means phasing out the use of fossil gas used for heating our homes and buildings. It means clamping down on chemicals and refrigerants that are thousands of times more powerful at trapping heat than carbon dioxide (CO_2). It means providing our communities with sustainable options for walking, biking, and public transit to reduce reliance on cars and their associated expenses. It means continuing to build out the solar arrays, wind turbine capacity, and other resources that provide clean, renewable energy to displace fossil-fuel fired electrical generation. It also means scaling up new options such as renewable hydrogen for hard-to-electrify end uses and biomethane where needed. Successfully achieving the outcomes called for in this Scoping Plan would reduce demand for liquid petroleum by 94 percent

1 In October 2022, California was poised to become the world's fourth largest economy.

and total fossil fuel by 86 percent in 2045 relative to 2022.[2] Despite these world-leading efforts, some amount of residual emissions will remain from hard-to-abate industries such as cement, internal combustion vehicles still on the road, and other sources of GHGs, including high global warming chemicals used as refrigerants.

The plan addresses these remaining emissions by re-envisioning our natural and working lands—forests, shrublands/chaparral, croplands, wetlands, and other lands—to ensure they play as robust a role as possible in incorporating and storing more carbon in the trees, plants, soil, and wetlands that cover 90 percent of the state's 105 million acres while also thriving as a healthy ecosystem. Modeling indicates that natural and working lands will not, on their own, provide enough sequestration and storage to address the residual emissions. For that reason, it is necessary to research, develop, and deploy additional methods of capturing CO_2 that include pulling it from the smokestacks of facilities, or drawing it out of the atmosphere itself and then safely and permanently utilizing and storing it, as called for in recent legislation. Carbon removal also will be necessary to achieve net negative emissions to address historical GHGs already in the atmosphere.

This is a plan that aims to shatter the carbon status quo and take action to achieve a vision of California with a cleaner, more sustainable environment and thriving economy for our children. This ambitious plan will serve as a model for other partners around the world as they consider how to make their transition. As we have so often in the past, California can continue to serve as a leader in innovation that has produced not only the fifth largest economy on the planet, but ultimately one of the most energy-efficient economies, with a track record of demonstrating the ability to decouple economic growth from carbon pollution. This plan also builds upon current and previous environmental justice efforts to integrate environmental justice directly into the plan, to ensure that all communities can reap the benefits of this transformational plan. Specifically, this plan identifies a path to keep California on track to meet its SB 32 GHG reduction target of at least 40 percent below 1990 emissions by 2030.

2 See *CARB's energy demand reductions*.

- Identifies a technologically feasible, cost-effective path to achieve carbon neutrality by 2045 and a reduction in anthropogenic emissions by 85 percent below 1990 levels.
- Focuses on strategies for reducing California's dependency on petroleum to provide consumers with clean energy options that address climate change, improve air quality, and support economic growth and clean sector jobs.
- Integrates equity and protecting California's most impacted communities as driving principles throughout the document.
- Incorporates the contribution of natural and working lands (NWL) to the state's GHG emissions, as well as their role in achieving carbon neutrality.
- Relies on the most up-to-date science, including the need to deploy all viable tools to address the existential threat that climate change presents, including carbon capture and sequestration, as well as direct air capture.
- Evaluates the substantial health and economic benefits of taking action.
- Identifies key implementation actions to ensure success.

The path forward is informed by robust science. The recent Sixth Assessment Report (AR6) of the Intergovernmental Panel on Climate Change (IPCC) summarizes the latest scientific consensus on climate change. It finds that atmospheric concentrations of CO_2 have increased by 50 percent since the industrial revolution and continue to increase at a rate of two parts per million each year.[3] By the 2030s, and no later than 2040, the world will exceed 1.5°C warming unless there is drastic action. While every tenth of a degree matters — every incremental increase in warming brings additional negative impacts — climate-related risks to human health, livelihoods, and biodiversity are projected to increase further under 2°C warming, compared to 1.5°C.[4] For example, at 1.5°C of global warming, we would experience increasing heat waves, longer warm seasons, and shorter cold seasons, but at 2°C of global warming, heat extremes would more often reach critical tolerance thresholds for human health and agriculture.[5] We are already seeing unprecedented climate change impacts, such as continued sea level rise, that are "irreversible" for centuries to millennia, and we are dangerously close to hitting 1.5°C in the near term.[6] To avoid climate catastrophe and remain below 1.5°C with limited or no overshoot of that threshold, global net anthropogenic CO_2 emissions need to reach net zero by 2050.

3 *IPCC. 2021. Climate Change 2021: The Physical Science Basis. Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change. [Masson-Delmotte, V., P. Zhai, A. Pirani, S. L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M. I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J. B. R. Matthews, T. K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. Cambridge University Press. In Press.*

4 *IPCC. 2018. Global Warming of 1.5°C. World Meteorological Organization. Geneva, Switzerland. 32 pp.*

5 *IPCC. 2021. Climate change widespread, rapid, and intensifying – IPCC. August.*

6 *United Nations. 2021. IPCC report: 'Code red' for human driven global heating, warns UN chief. August 9.*

It has been 16 years since the Global Warming Solutions Act of 2006 was passed and signed into law. In 2017, the second update to the Assembly Bill (AB) 32 Climate Change Scoping Plan[7] (2017 Scoping Plan) laid out a cost-effective and technologically feasible path to achieve the 2030 GHG reduction target. At the time, many characterized the plan and the AB 32 target as unachievable, citing that it would lead to massive business and job loss, and excessive costs. Those predictions proved to be incorrect as California achieved its AB 32 target years ahead of schedule, all the while growing our economy, with the state distinguishing itself as a hub for green technology investment. This Scoping Plan draws on a decade and a half of proven successes and additional new approaches to provide a balanced and aggressive course of effective actions to achieve carbon neutrality in 2045, if not before, in addition to the 2030 goal.

California's economy is projected to grow vigorously in the coming years and decades. In 2045, under a Reference Scenario, the gross state product would be $5.1 trillion, nearly $2 trillion more than in 2021, and allow growth that would add hundreds of thousands of jobs. Under the Scoping Plan scenario, impacts to economic and job growth would be negligible in both 2035 and 2045, while delivering $199 billion of benefits in the form of reduced hospitalizations, asthma cases, and lost work and school days due to the cleaner air supported by this plan. This should come as no surprise given the tremendous growth of California's economy since the Great Recession of 2007–2009, even as the state has taken drastic measures to lower emissions. As noted, the savings associated with ambitious climate action are extensive, both in terms of avoided climate impacts and health costs. As described in Chapter 1, the health costs of climate and air pollution in the U.S. are well over $800 billion today and will continue to grow in the coming years[8] without robust action. Similarly, the costs of delayed or insufficient climate action could cost the U.S. upwards of $14.5 trillion over the next 50 years.[9] We can either take action now or pay the cost of inaction, both now and later.

Grows CA's economy to $5.1 trillion by 2045

New jobs ↑ 4 million

Health costs ↓ $200 billion

We cannot take on this unprecedented challenge alone. Collaboration with the federal government, other U.S. states, and other jurisdictions around the world will continue to be fundamental for California to succeed in achieving its climate targets, especially as the pace of our efforts increases in the coming years. We believe this collaboration and coordination also creates a race to the top, encouraging and enabling other jurisdictions to achieve climate and air quality goals as well, and often providing lessons for national action.

One example of fruitful collaboration is California's longstanding vehicle emissions standards programs, which have repeatedly been freely adopted by other states, consistent with the federal Clean Air Act. California's programs frequently pioneer more rigorous standards or new technologies—such as the now-standard catalytic converter and the rules that led directly to the nation-leading numbers of zero-emission vehicles on our roads today. From initial standards for cars

7 *CARB. 2017. California's 2017 Climate Change Scoping Plan.*

8 *Alwis, D. D., and V. S. Limaye. No date. The Costs of Inaction: The Economic Burden of Fossil Fuels and Climate Change on Health in the United States. NRDC, The Medical Society Consortium on Climate and Health, and WHPCA.*

9 *Deloitte. 2022. The Turning Point: A New Economic Climate in the United States.*

and trucks decades ago to the world-leading Advanced Clean Trucks program currently helping to electrify heavy-duty vehicles, this partnership continues to offer regulatory options and spread innovative technologies. A major example of future work is the Advanced Clean Cars II program, which lays out California's legally binding path to achieving 100 percent zero emission vehicle (ZEV) sales in 2035.[10] The California Air Resources Board (CARB) continues to work closely with many other states that also see zero-emission vehicles as critical to their climate and public health goals and expects many states to choose to adopt this regulation as well. This partnership with other states also creates market certainty for automakers, which in turn helps to ensure that California consumers have access to a variety of ZEVs at multiple price points.

The Scoping Plan Process

Four scenarios were extensively modeled to develop this Scoping Plan, with the objective of informing the most viable path to remain on track to achieve our 2030 GHG reduction target: a reduction in anthropogenic emissions by 85% below 1990 levels and carbon neutrality by 2045. All four have their merits and are informed by stakeholder input. The scenario ultimately chosen as the basis of this Scoping Plan is the alternative that most closely aligns with existing statute and Executive Orders. It was selected because it best achieves the balance of cost-effectiveness, health benefits, and technological feasibility.

For the first time, this Scoping Plan includes modeling and quantification of GHG emissions and carbon sequestration in natural and working lands (NWL). To date, the focus has been only on reducing the emissions of GHGs from our transportation, energy, and industrial sectors. The state's 2020 and 2030 GHG reductions targets only include these sources, as they are the primary drivers of climate change and disproportionate harmful air pollution in our vulnerable communities. This Scoping Plan, through the lens of carbon neutrality, expands the scope to more meaningfully consider how our NWL contribute to our long-term climate goals. For the first time, new and cutting-edge modeling tools allow us to estimate the quantitative ability of our forests and other landscapes to remove and store carbon under different scenarios. These cutting-edge tools were developed through a stakeholder process and in coordination with other agencies for the purpose of this update and will continue to be refined over time and made available to others seeking to do similar work.

10 *Executive Department. State of California. Executive Order N-79-20.*

As recent data and Scoping Plan modeling shows, our NWL also can act as a source of emissions, principally in the form of wildfires. California's forests are experiencing a deadly combination of drought and heat combined with a century of misguided fire suppression management. Scoping Plan modeling shows that, at this time and until our forests reach a balance through appropriate treatments, California's NWL will act as a net source of emissions, not a sink. As such, the Scoping Plan includes policy direction and actions intended to quickly move the sector toward being a net sink and a more natural state, where wildfires will continue to be an important part of the healthy forest cycle but not at the intensity and frequency observed in recent years.

Development of this Scoping Plan also includes careful consideration of, and coordination with, other state agencies, consistent with Governor Gavin Newsom's whole-of-government approach to tackling climate change. State agency plans and regulations, including the SB 100 Joint Agency Report,[11] State Implementation Plan, Climate Action Plan for Transportation Infrastructure,[12] AB 74 Studies on Vehicle Emissions and Fuel Demand and Supply,[13,14,15] Short-Lived Climate Pollutant Strategy (SLCP Strategy),[16] CARB's Achieving Carbon Neutrality Report,[17] Climate Smart Lands Strategy,[18] Natural Working Land Implementation Plan,[19] and the California Climate Insurance Report: Protecting Communities, Preserving Nature, and Building Resiliency,[20] among others, provided critical inputs and data points for this plan. This Scoping Plan is the product of work by multiple agencies across the Administration, including dozens of public workshops and years of rigorous analysis and economic modeling by California's leading institutions. This cooperation on planning lays the foundation for even closer coordination among and between state agencies to put the plan into effect.

The plan is also the product of tireless efforts of, and recommendations from, the AB 32 Environmental Justice Advisory Committee (EJ Advisory Committee). The EJ Advisory Committee, created by statute, plays a critical role to inform the development of each Scoping Plan and helps to ensure environmental justice is integrated throughout the plan. CARB reconvened the EJ Advisory Committee in early 2021 to advise on the development of this Scoping Plan. In their advisory role, the EJ Advisory Committee has worked together to provide inputs to CARB to inform the development of scenarios and the associated modeling. And in April 2022, the EJ Advisory Committee provided draft preliminary recommendations in advance of the Draft 2022 Scoping Plan to help ensure the draft plan meaningfully addresses environmental justice. The CARB Board and EJ Advisory Committee held a joint board hearing on September 1, 2022, where the EJ Advisory Committee presented their final recommendations on the Scoping Plan. Over five dozen of the recommendations are reflected in the Scoping Plan. Going forward, as this plan is ultimately acted on by the Board, ongoing input from the EJ Advisory Committee will be essential to address environmental justice and achieve the ambitious vision outlined in the plan throughout its implementation in the coming years.

11 *California Public Utilities Commission (CPUC), California Energy Commission (CEC), and CARB. 2021. SB 100 Joint Agency Report.*

12 *California State Transportation Agency (CalSTA). 2021. Climate Action Plan for Transportation Infrastructure.*

13 *California Environmental Protection Agency (CalEPA). 2021. Carbon Neutrality Studies.*

14 *Brown, A. L., et. al. 2021. Driving California's Transportation Emissions to Zero. University of California Institute of Transportation Studies.*

15 *Deschenes, O. 2021. Enhancing equity while eliminating emissions in California's supply of transportation fuels. University of California Santa Barbara.*

16 *CARB. Short-Lived Climate Pollutants.*

17 *Energy and Environmental Economics, Inc. 2020. Achieving Carbon Neutrality in California: PATHWAYS Scenarios Developed for the California Air Resources Board. October.*

18 *California Natural Resources Agency (CNRA). 2021. Draft Climate Smart Lands Strategy.*

19 *CARB. 2019. Draft California 2030 Natural and Working Lands Climate Change Implementation Plan.*

20 *California Department of Insurance. 2021. Protecting Communities, Preserving Nature, and Building Resiliency.*

Importantly, per legislative direction, the Scoping Plan development includes modeling and analyses of emissions, economics, air quality, health, jobs, and public health. This work is important to inform the discussion around trade-offs and how to balance the various legislative direction in identifying a path to achieve the state's climate goals. The technical work serves as a backdrop to what this means to Californian's daily lives—to how they will work, play, and live as we act to eliminate fossil fuel combustion and achieve the many public health and environmental benefits that will result from that action.

Ensuring Equity and Affordability

The state has a long history of public health and environmental protection. However racist and discriminatory practices such as redlining have resulted in low-income communities and communities of color being disproportionately exposed to health hazards and pollution burdens.[21] These communities are often located adjacent to major roadways and large stationary sources that not only emit GHGs, but also harmful localized air pollution. The plan delivers on the promise to transform the way we move, live, and work by nearly eliminating our dependence on fossil fuels. It includes effective actions to move with all possible speed to clean energy, zero-emission cars and trucks, energy-efficient homes, sustainable agriculture, and resilient NWL. And it prioritizes working with the communities most impacted to ensure that these strategies address their needs.

An important part of our equity consideration is ensuring the transition to a zero-emission economy is affordable and accessible, and that it uplifts disadvantaged, low-income communities and communities of color. Some aspects of the transition will have associated costs (e.g., escalating efforts to retrofit existing homes and businesses to support electric appliances and vehicles and increased costs of insurance). The state must ensure that these costs do not disproportionately burden consumers. In addition, the state has an important role to play in providing financial incentives, especially to low-income consumers, to allow for uptake of clean technologies. The Department of Community Services and Development's Low Income Weatherization Program is a prime example of this approach, enabling low-income Californians to be part of the zero-emission transition, all while lowering energy bills. The program provides low-income households with solar

21 *CalEPA. 2021. Pollution and Prejudice: Redlining and Environmental Injustice in California. August 16.*

photovoltaic systems and energy efficiency upgrades at no cost to residents, helping cushion the impact of climate change on vulnerable communities.

With this Scoping Plan, the state also adds another tool to help identify and close climate change impact gaps that will emerge over time. As California invests in climate mitigation and adaptation, it is essential to understand the relative impact of climate change across the state's diverse communities. We know not all communities are equally resilient in the face of climate impacts due to persisting health and opportunity gaps. We also know that a global metric such as the Social Cost of Carbon cannot adequately capture the incremental additional impact faced by overly burdened communities. The Climate Vulnerability Metric (CVM) is specifically focused on quantifying the community-level impacts of a warming climate on human welfare.

Energy and Technology Transitions

To support the transformation needed, we must build the clean energy production and distribution infrastructure for a carbon-neutral future. The solution will have to include transitioning existing energy production and transmission infrastructure to produce zero-carbon electricity and hydrogen, and utilizing biogas resulting from wildfire management or landfill and dairy operations, among other substitutes. In almost all sectors, electrification will play an important role. That means that the grid will need to grow at unprecedented rates and ensure reliability, affordability, and resiliency through the next two decades and beyond. It also means we need to keep all options on the table, as it will take time to fully grow the electricity grid to be the backbone for a decarbonized economy. We also know that electrification is not possible in all situations. As such, this plan systematically evaluates and identifies feasible clean energy and technology options that will bring both near-term air quality benefits and deliver on longer-term climate goals.

4x
solar & wind generation

1,700x
renewable hydrogen

100%
ZEV sales by 2035

This transition will not happen overnight. It will take time and planning to ensure a smooth transition of existing energy infrastructure and deployment of new clean technology. And while this Scoping Plan has the longest planning horizon of any Scoping Plan to date, this 25-year horizon is still relatively short in terms of transforming California's economy. We must avoid making choices that will lead to stranded assets and incorporate new technologies that emerge over time. Importantly, given the pace at which we must transition away from fossil fuels, we absolutely must identify and address market and implementation barriers to be successful. The scale of transition includes adding four times the solar and wind capacity by 2045 and about 1,700 times the amount of current hydrogen supply.

As we transition our energy systems, we must also rapidly deploy the clean technologies that rely on a decarbonized grid. As called for in Executive Order N-79-20, all new passenger vehicles sold in California will be zero-emission by 2035, and all other fleets will have transitioned to zero-emission as fully possible by 2045. This means the percentage of fossil fuel combustion vehicles will continue to rapidly decrease, becoming a fading vision of the past. Successful implementation of this Executive

Order (EO) and other zero-emission priorities will have to be attractive to consumers. As an example, electric and hydrogen transportation refueling must be readily accessible, and active transportation and clean transit options must be cheaper and more convenient than driving.

Cost-Effective Solutions Available Today

Ultimately, to achieve our climate goals, urgent efforts are needed to slash GHG emissions. Fortunately, cost-effective solutions are available to do so in many cases. In short, this plan relies on existing technologies—it does not require major technological breakthroughs that are highly uncertain.

For example, targeted action to reduce methane emissions can be achieved at low or negative cost, and with significant near-term climate and public health benefits. In many cases, renewable energy and energy storage are cheaper than polluting alternatives, and are already firmly part of our business-as-usual approach; modeling related to the most recent integrated resource planning process at the California Public Utilities Commission (CPUC) has shown that scenarios associated with the best emissions outcomes had the lowest average rates. As another example, research from Energy Innovation shows that the U.S. can achieve 100 percent zero-carbon power by 2035 without increasing customer costs.[22]

The same is either already true, or soon to be true, for zero-emission vehicles as well. Myriad studies show cost parity for light-duty and heavy-duty ZEVs being achieved by mid-decade or shortly thereafter. A carbon neutrality study conducted by the University of California (UC) Institute of Transportation Studies and funded by the California Environmental Protection Agency (CalEPA) shows that achieving carbon neutrality in the transportation sector will save Californians $167 billion through 2045.[23] Similar research from the Goldman School of Public Policy at UC Berkeley finds that achieving 100 percent light-duty ZEV sales nationwide would save consumers $2.7 trillion through 2050; equivalent to $1,000 per household, per year, for 30 years.[24]

22 *Phadke, A. et al. 2020. "Illustrative Pathways to 100 Percent Zero Carbon Power by 2035 Without Increasing Customer Costs, Energy Innovation." September.*

23 *Brown, A. L., et al. 2021. Driving California's Transportation Emissions.*

24 *Goldman School of Public Policy. 2021. 2035: The Report: Transportation. UC Berkeley. April.*

Many of these outcomes are a direct result of California's vision and policy development to advance clean energy and climate solutions, including through the Renewables Portfolio Standard, Advanced Clean Cars II regulations, SLCP Reduction Strategy, and others. While the world collectively has not yet fully deployed clean energy and climate solutions at the scale needed to adequately address climate change, California has made tremendous progress—even since the last Scoping Plan update in 2017. Continued ambition, leadership, and climate policy development from California will help the state achieve the scale of emissions reductions needed from technologies and strategies that are already cost-effective or close to it today, and will move additional technologies and strategies to that point in the near future. Achieving those outcomes and reducing costs for the entire array of climate solutions needed to achieve carbon neutrality and then maintain net-negative emissions will prove the true measure of California's success. This will enable California to not just meet our own climate targets, but to ultimately develop the replicable solutions that can scale globally to address global warming.

Continue with a Portfolio Approach

Over the past decade and a half, the state has undertaken a successful three-pronged approach to reducing GHGs: incentives, regulations, and carbon pricing. The 2017 Scoping Plan leveraged existing programs such as the Renewables Portfolio Standard, Advanced Clean Cars, Low Carbon Fuel Standard, Short-lived Climate Pollutant Strategy, mobile source measures to achieve federal air quality targets, and a Cap-and-Trade Program, among others, to lay out a technologically feasible and cost-effective path to achieve the 2030 GHG reduction target. When looking toward the 2045 climate goals and the deeper GHG reductions needed across the AB 32 GHG Inventory sectors, all of the existing programs must be evaluated and, as necessary, strengthened to support the rapid production and deployment of clean technology and energy, as well as the increased pace and scale of actions on our natural and working lands.

The challenge before us requires us to keep all tools on the table. Given the climate mitigation co-benefits, critical actions to deliver near-term air quality benefits, such as those included in the State Implementation Plan to achieve the federal air quality standards, are incorporated into this Scoping Plan, as are new legislative mandates to decarbonize the electricity and cement sectors. And, if additional gaps are identified, new programs and policies must be developed and implemented to ensure all sectors are on track to reduce emissions. Opportunities to leverage these programs to address ongoing air quality disparities must also be considered, along with targeted environmental justice policies such as the AB 617 Community Air Protection Program and the investments made possible through the California Climate Investments Program.

Conclusion

California has never undertaken such a comprehensive, far-reaching, and transformative approach to fighting climate change as that called for in this plan. Once implemented, it will place every aspect of how we live, work, play, and travel in California on a more sustainable footing, with a focus on directly benefitting those communities already most burdened by pollution. This comprehensive approach reflects how climate change is already changing life in California. We have all experienced the impacts of devastating wildfires, extreme heat, and drought. Despite much progress, California still has some of the worst air pollution in the nation, especially in the San Joaquin Valley and the Los Angeles Basin, which is driven by the continued use of fossil fuel-powered trucks and cars.

This Scoping Plan provides a solution; a way forward and a vision of a California where we can and will address those impacts. This plan is fundamentally based on hope. It is a hope grounded in experience and science that we can fundamentally improve the California we leave to future generations. The plan is built on the legacy of effective actions and on the conviction that we can effectively marshal the combined capabilities of California—from state, regional, tribal, and local governments to industry to our research institutions, and most importantly, to the nearly 40 million Californians who will benefit from the actions laid out in the plan. It addresses the challenge of our generation by laying out a pathway and guideposts for action across three decades. But the Scoping Plan is only that: a plan. The hard work—and hopeful work—is putting its recommendations into action. And there is no time to waste.

Post-adoption of the Scoping Plan

As with previous Scoping Plans, CARB Board approval is the beginning of the next phase of climate action. Specifically, approval of this plan catalyzes a number of efforts, including the development of new regulations as well as amendments to strengthen regulations and programs already in place, not just at CARB but across state agencies. The unprecedented rate of transition will also require the identification and removal of market and implementation barriers to the production and deployment of clean technology and energy. All of these actions and more will be needed if we are to achieve our climate goals.

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Chapter 1: Introduction

"The debate is over around climate change. Just come to the state of California. Observe it with your own eyes."

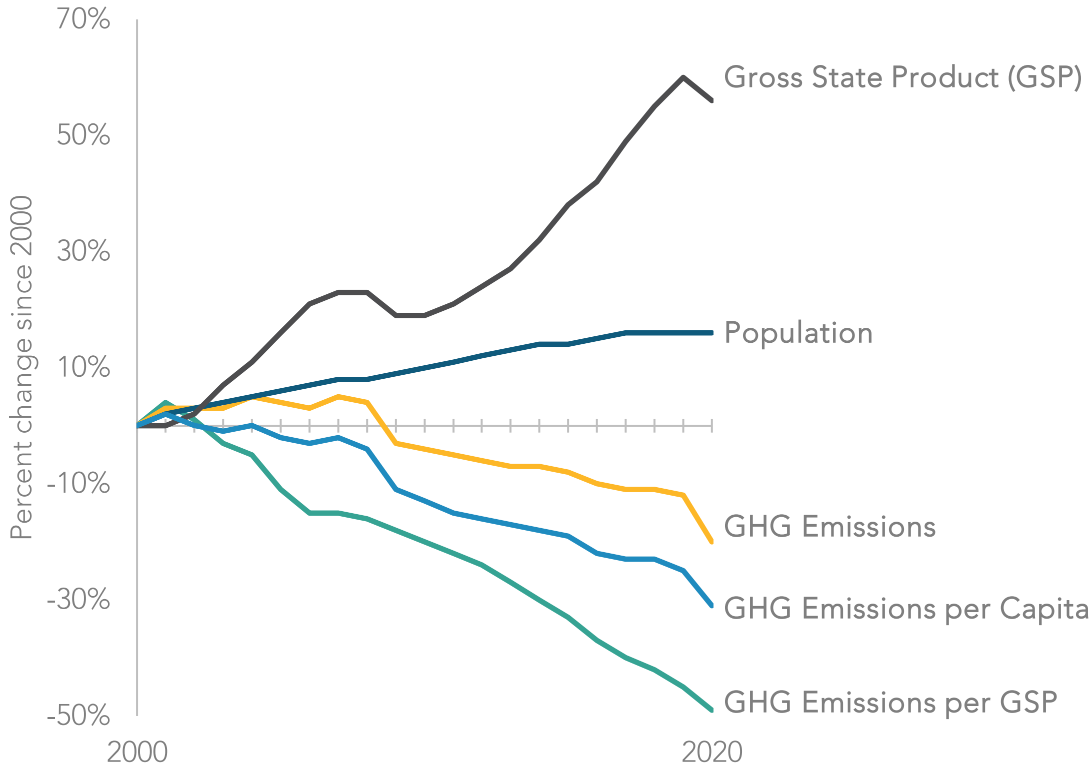
- California Governor Gavin Newsom in September 2020 after surveying the devastation caused by catastrophic wildfires

The impacts of climate change are no longer a distant threat on the horizon—they are right here, right now, with a growing intensity that is adversely affecting our communities and our environment, here in California and across the globe. The science that, decades ago, predicted the impacts we are currently experiencing is even stronger today and unambiguously tells us what we must do to limit irreversible damage: we must act with renewed commitment and focus to do more and do it sooner. That science is indisputable. Unless we increase ambition, we will be faced with more fire, more drought, more temperature extremes, and deadly, choking air pollution. The future of our state—our communities, economy, and ecosystems—is inextricably tied to the way we respond in this decade and the partnerships we forge along the way.

The impacts of climate change fall most heavily on frontline communities that bear the brunt of extreme heat, drought, wildfires, and other effects. Low-income communities and communities of color are also disproportionately impacted by fossil fuel combustion-related air pollution and related health problems. The continued phaseout of fossil fuel combustion will advance both climate and air quality goals and will deliver the greatest health benefits to the most impacted communities.

As it has responded to this climate crisis, California has established itself as a global leader in science-based, public health-focused climate change mitigation and air quality control. The California Legislature has worked with both Republican and Democratic governors to advance action on public health and environmental protections—and California has made progress on addressing climate change during periods of both Republican and Democratic federal administrations. Since the passage of Assembly Bill 32 (AB 32) (Núñez and Pavley, Chapter 488, Statutes of 2006), California has developed bold, creative, and durable policy solutions to protect our environment and public health, all while growing our economy. In fact, California met the target established in AB 32—a return of greenhouse gas (GHG) emissions to 1990 levels by 2020—years ahead of schedule, even as the state established itself as the one of the largest economies in the world. As Figure 1-1 below shows, California's emissions and economic growth have continued to decouple, and California is now the fifth largest economy in the world.

Figure 1-1: California total and per capita GHG emissions[25]



Recognizing both California's early successes in achieving GHG emissions reductions while growing the economy, as well as the worsening impacts of climate change, our governors and legislators have continued to enact ambitious goals. California's unwavering commitment to address climate change is based on indisputable science and data. This commitment is also informed by our collective efforts to address environmental justice and advance racial equity, such that race will no longer be a predictor for disproportionate environmental burdens faced by low-income communities and communities of color. As the Office of Environmental Health Hazard Assessment's

[25] Due to the global pandemic, 2020 is an outlier year and should not be considered indicative of a trend; emissions are likely to increase as economies recover from the impacts of the pandemic.

(OEHHA's) recent analysis of race/ethnicity and air pollution vulnerability and CalEnviroScreen 4.0 scores demonstrate, much work remains to be done.[26]

Many of California's environmental policies have served as models for similar policies in other U.S. states, and at national and international levels. Moving forward, California will continue its pursuit of collaborations and advocacy for action to address climate change at all levels of government. While California is responsible for just one percent of global GHG emissions, and we must do our part, we also play an important role in exporting both political will and technical solutions to address the climate crisis globally.

Today, we have a chance to re-envision California's future and set the state on a path to be carbon neutral no later than 2045 while advancing equity, addressing environmental justice, and continuing to grow our economy. This Scoping Plan provides a roadmap outlining key policies we can implement to achieve our climate goals while improving the health and welfare of Californians and addressing disparities in health outcomes to create a more equitable future. It will enable us to turn the corner in our efforts to protect and preserve our critical natural and public resources, all while providing unparalleled opportunities for clean, pollution-free economic growth.

Severity of Climate Change Impacts

With the increasing severity and frequency of drought, wildfire, extreme heat, and other impacts, Californians just have to look out their windows to know that climate change is real and rapidly getting worse. The impacts we thought we would see in the decades to come are happening now. We must act decisively to both reduce our GHG emissions and build resilience to these impacts for ourselves, future generations, and our iconic landscapes.

Wildfires

Of the twenty largest wildfires ever recorded in California, nine occurred in 2020 and 2021. The worst wildfire season in California's recorded history was in 2018, with over 24,226 structures damaged or destroyed and over 100 lives lost. The largest wildfire season ever recorded in state history was in 2020, where more than 4.3 million acres burned, albeit at different intensity and with varying ecological impacts, and over 112 million metric tons of

[26] OEHHA and CalEPA. 2021. Analysis of Race/Ethnicity and CalEnviroScreen 4.0 Scores. https://oehha.ca.gov/media/downloads/calenviroscreen/document/calenviroscreen40raceanalysisf2021.pdf.

carbon dioxide (CO_2) emitted into the atmosphere.[27] The economic damage of these fires was estimated to be over $10 billion in property damage and over $2 billion in fire suppression costs.[28] The Camp Fire, which destroyed much of Paradise, California, was the world's costliest natural disaster in 2018, with overall damages of $16.5 billion.[29] It was also the deadliest fire in California history, with 85 civilian fatalities. Wildfires have always been part of California's natural ecology and will continue to be. However, changes to the state's climate and precipitation expands the footprint of wildfire threat, severity, and intensity, with one quarter of California—more than 25 million acres—now classified as being under very high or extreme fire threat.[30]

The impacts of wildfire smoke have been linked to respiratory infections, cardiac arrests, low birth weight, mental health conditions, and exacerbated asthma and chronic obstructive pulmonary disease.[31] In 2020, with all of California covered by wildfire smoke for over 45 days—and 36 counties for at least 90 days—maximum fine particulate ($PM_{2.5}$) levels persisted in the "hazardous" range of the Air Quality Index for weeks in several areas of the state.[32,33]

Catastrophic wildfire damages extend beyond human health and the economy. The Castle Fire in 2020 and the KNP Complex and Windy Fires in 2021 led to the loss of an unprecedented number of giant sequoias: an estimated 13 to 19 percent of the giant

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27 CARB. 2020. Public Comment Draft Greenhouse Gas Emissions of Contemporary Wildfire, Prescribed Fire, and Forest Management Activities. *https://ww3.arb.ca.gov/cc/inventory/pubs/ca_ghg_wildfire_forestmanagement.pdf*.

28 News18. 2021. San Francisco Bay Area Receives its First Wildfire Warning of 2021, After California Concludes its Driest Year. *https://www.news18.com/news/buzz/san-francisco-bay-area-receives-its-first-wildfire-warning-of-2021-after-california-concludes-its-driest-year-3722897.html*.

29 Munich RE. 2019. Extreme Storms, Wildfires and Droughts Cause Heavy Nat Cat Losses In 2018. *https://www.munichre.com/en/company/media-relations/media-information-and-corporate-news/media-information/2019/2019-01-08-extreme-storms-wildfires-and-droughts-cause-heavy-nat-cat-losses-in-2018.html#-1808457171*.

30 CARB. No date. Wildfires. *https://ww2.arb.ca.gov/our-work/programs/wildfires/about*.

31 Reid, C. E., M. Brauer, F. H. Johnston, M. Jerrett, J. R. Balmes, and C. T. Elliott. 2016. "Critical Review of Health Impacts of Wildfire Smoke Exposure." *Environmental Health Perspectives* *http://dx.doi.org/10.1289/ehp.1409277*.

32 Vargo J. A. 2020 (updated in 2021 using the *NOAA Hazard Mapping System*). "Time Series of Potential US Wildland Fire Smoke Exposures." *Frontiers in Public Health* *https://doi.org/10.3389/fpubh.2020.00126*.

33 CalFire. 2020 *Fire Siege Report*. *https://www.fire.ca.gov/media/hsviuuv3/cal-fire-2020-fire-siege.pdf*.

sequoia population in the Sierra Nevada. An iconic species, giant sequoias are the largest trees on earth, with exceptional longevity outside of climate extremes.[34,35]

It is clear that we must take drastic measures to prepare for future wildfires, which is why California invested $2.7 billion in wildfire resilience from fiscal years 2020 to 2023. The exponential increase in funding launched more than 552 wildfire resilience projects in less than a year, and CAL FIRE met its 2025 goal of treating 100,000 acres a full three years ahead of schedule. Since Fiscal Year 2019–20, treatment work has significantly increased, and CAL FIRE has averaged 100,000 acres treated each fiscal year.

Although we are making progress, we have a lot more work to do in order to achieve our goal of treating one million acres annually by 2025. The Governor's Wildfire and Forest Resilience Strategy details 99 actions needed to address the key drivers of catastrophic wildfires, ramp up the pace and scale of forest management, and make threatened communities more resilient to catastrophic fires. It is also important to note that natural wildfire cycles are a part of a sustainable forest ecosystem and will continue to play a role in a healthy forests' future. We should not expect wildfires to cease, but we must manage our lands to address catastrophic wildfires that result from buildup of carbon stocks due to our interventions to suppress wildfires and from climate change resulting from fossil fuel combustion.

Drought

Drought is a recurring feature of the California climate that has been intensified by increasingly warmer average temperatures. Anthropogenic climate trends have exacerbated drought conditions; human-caused climate change accounts for 19 percent of drought severity and 42 percent of the soil moisture deficit in this region since 2000. The governor declared a drought state of emergency in October 2021, and as of September 2022, 94 percent of California was in severe drought, and 99.8 percent[36] of the state was in at least moderate drought. The first three months of 2022 were the driest January, February, and March on record in California.[37] The harsh drought conditions affecting California are part of a larger megadrought—a drought lasting more than two

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[34] Shive, K., C. Brigham, T. Caprio, and P. Hardwick. 2021. 2021 Fire Season Impacts to Giant Sequoias. The Nature Conservancy and National Park Service. https://www.nps.gov/articles/000/2021-fire-season-impacts-to-giant-sequoias.htm.

[35] Shive, K. L., A. Wuenschel, L. J. Hardlund, S. Morris, M. D. Meyer, and S. M. Hood. 2022. "Ancient Trees and Modern Wildfires: Declining Resilience to Wildfire in the Highly Fire-adapted Giant Sequoia." *Forest Ecology and Management* 511, 120110. https://doi.org/10.1016/j.foreco.2022.120110.

[36] Drought.gov. California. National Oceanic and Atmospheric Administration (NOAA) and the National Integrated Drought Information System. https://www.drought.gov/states/california.

[37] Drought.ca.gov. September 26, 2022. California Drought Update. https://drought.ca.gov/media/2022/09/Weekly-CA-Drought-Update-09262022-FINAL.pdf.

decades—that has been ongoing in the Southwestern region of North America since 2000. The past 22 years have been the region's driest period since at least 800 CE.[38]

While large urban water districts with diversified sources of water supply have maintained water deliveries to customers through the drought, hundreds of individual well owners and some small water systems have suffered disruption. The state is providing funding for water system consolidation and modernization projects in small communities, emergency repairs and replacements for dry wells, and bottled and hauled water deliveries. A 2021 law requires small suppliers to create drought contingency plans. During the drought of the last three years the state has delivered emergency drinking water assistance to nearly 10,000 households and 150 water systems.

California agriculture is responsible for more than half of all U.S. domestic fruit and vegetable production, and in 2021 drought resulted in the fallowing of nearly 400,000 acres of fields.[39] Direct crop revenue losses were approximately $962 million, and total economic impacts were more than $1.7 billion, with over 14,000 full- and part-time job losses.[40] During the 2011–2017 drought, California's agricultural industry suffered at least $5 billion in losses.[41] The 2022–23 budget includes $100 million to support agricultural water conservation practices, provide on-farm technical assistance, and provide direct relief to small farm operators.

Though native California species are adapted to drought, human engineering has altered most streams and wetlands in the state, making drought increasingly stressful to fish and wildlife. The state has conducted hundreds of fish and amphibian rescues in this drought to move creatures from diminished habitat, upgraded hatcheries, and boosted hatchery production, and has hauled millions of young hatchery salmon to San Francisco Bay to avoid adverse river conditions. State biologists monitor dozens of streams statewide and have negotiated voluntary agreements with landowners and water users to improve stream flows and temperatures.

California has started to implement major policies to build resilience to combat drought—such as the Sustainable Groundwater Management Act of 2014, the governor's Water Resilience Portfolio (2020), the governor's Water and Supply Strategy (August 2022), and

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[38] Williams, A. P., B. I. Cook, and J. E. Smerdon. 2022. "Rapid Intensification of The Emerging Southwestern North American Megadrought in 2020–2021." *Nature Climate Change* https://doi.org/10.1038/s41558-022-01290-z.

[39] Medellín-Azuara, J. 2022. *Economic Impacts of the 2021 Drought on California Agriculture.* University of California Merced. https://wsm.ucmerced.edu/wp-content/uploads/2022/02/2021-Drought-Impact-Assessment_20210224.pdf.

[40] Medellín-Azuara. *Economic Impacts of the 2021 Drought*.

[41] National Resources Defense Council (NRDC). 2019. Climate Change and Health in California. Issue Brief. https://www.nrdc.org/sites/default/files/climate-change-health-impacts-california-ib.pdf.

new standards for indoor, outdoor, and industrial water use. However, it is crucial that we take further actions to minimize the impacts of drought in the years to come.

Extreme Heat

California's hottest summer on record was 2021.[42] Death Valley recorded the world's highest reliably measured temperature (130°F) in July 2021, breaking its own record (129°F) from summer 2020.[43] Meanwhile, Fresno also broke one of its own records, with 64 days over 100°F in 2021.[44] This is part of a trend: the daily maximum average temperature, an indicator of extreme temperature shifts, is expected to rise 4.4°F–5.8°F by 2050 and 5.6°F–8.8°F by 2100.[45] Heat waves that result in public health impacts are also projected to worsen throughout the state. By 2050, these heat-related health events are projected to last two weeks longer in the Central Valley and occur four to ten times more often in the Northern Sierra region.[46]

Heat ranks among the deadliest of all climate hazards in California, and heat waves in cities are projected to cause two to three times more heat-related deaths by mid-century.[47] Climate vulnerable communities[48] will experience the worst of these effects, as heat risk is associated and correlated with physical, social, political, and economic factors. Aging populations, infants and children, pregnant people, and people with chronic illness are especially sensitive to heat exposure.[49,50] Combining these characteristics and existing health inequities with additional factors such as poverty, linguistic isolation,

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[42] NOAA. 2022. Climate at a Glance. https://www.ncdc.noaa.gov/cag/statewide/time-series/4/tavg/3/8/1895-2021?base_prd=true&firstbaseyear=1901&lastbaseyear=2000.

[43] Masters, J. 2021. Death Valley, California, breaks the all-time world heat record for the second year in a row. Yale Climate Connections. https://yaleclimateconnections.org/2021/07/death-valley-california-breaks-the-all-time-world-heat-record-for-the-second-year-in-a-row/.

[44] NOAA. Climate Data Online Search. Accessed on 16 March 2022. https://www.ncdc.noaa.gov/cdo-web/search.

[45] Governor's Office of Planning and Research (OPR), CEC, and CNRA. 2018. *California's Fourth Climate Change Assessment*. Page 23. https://www.energy.ca.gov/sites/default/files/2019-11/Statewide_Reports-SUM-CCCA4-2018-013_Statewide_Summary_Report_ADA.pdf.

[46] OPR, CEC, and CNRA. *California's Fourth Climate Change Assessment - Statewide Summary Report.* https://www.energy.ca.gov/sites/default/files/2019-11/Statewide_Reports-SUM-CCCA4-2018-013_Statewide_Summary_Report_ADA.pdf.

[47] Ostro, B., S. Rauch, and S. Green. 2011. "Quantifying the health impacts of future changes in temperature in California." National Library of Medicine. https://pubmed.ncbi.nlm.nih.gov/21975126/.

[48] CARB. Priority Populations. California Climate Investments. https://www.caclimateinvestments.ca.gov/priority-populations.

[49] Basu, R. 2009. "High Ambient Temperature and Mortality: A Review of Epidemiologic Studies from 2001 to 2008." National Library of Medicine. https://pubmed.ncbi.nlm.nih.gov/19758453/.

[50] Basu, R., and B. Malig. 2011. "High Ambient Temperature and Mortality in California: Exploring the Roles of Age, Disease, and Mortality Displacement." National Library of Medicine. https://pubmed.ncbi.nlm.nih.gov/21981982/.

housing insecurity, and the legacy of racist redlining practices, can put individuals at a disproportionately high risk of heat-related illness and death.[51,52] Rising temperatures will also speed up smog-forming chemical reactions, leading to worse asthma, reduced lung function, cardiac arrest, and cognitive decline. African American, American Indian/Alaskan Native, and Puerto Rican Californians are particularly sensitive to smog, as they are between 28.6 and 132.5 percent more likely to be diagnosed with asthma than white Californians.[53]

In addition to the dangers to public health, California's September 2022 heat wave is particularly illustrative of how more frequent extreme heat strains the state's infrastructure we depend on to adapt to a changing climate. For example, as all-time high temperature records were broken in Sacramento, San Jose, Santa Rosa and Fairfield, electricity demand for air conditioning threatened to overwhelm the state power supply.[54]

California has taken major steps to protect communities from the impacts of extreme heat. Our recent budgets invest $800 million to cool our schools and neighborhoods, including projects to reduce urban overheating. The Extreme Heat Action Plan, released in April 2022, outlines the all-of-government approach California is taking to reduce urgent risks and build long-term resilience to the impacts of extreme heat. In September 2022, Governor Newsom signed multiple bills addressing extreme heat, including AB 2238 (Rivas, Chapter 264, Statutes of 2022), which will create the nation's first extreme heat advance warning and ranking system to better prepare communities ahead of heat waves. The Administration is committed to addressing extreme heat, but we still have a lot of work to do.

Wildfires, drought, and extreme heat are some of the most pronounced climate impacts California is experiencing, but they are not the only ones. Sea level rise, rising ocean temperatures, ocean acidification, and inland flooding are also already having devastating impacts on our communities, ecosystems, and economy, and will continue to do so in the years and decades to come. The decisions and actions that we take today will determine how strongly we will feel the impacts of climate change in the future.

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[51] Hoffman, J. S., V. Shandas, and N. Pendleton. 2020. "The Effects of Historical Housing Policies on Resident Exposure to Intra-Urban Heat: A Study of 108 US Urban Areas." MDPI. https://www.mdpi.com/2225-1154/8/1/12/htm.

[52] U.S. Climate Resilience Toolkit. No date. Heat and Social Inequity in the United States. https://toolkit.climate.gov/tool/heat-and-social-inequity-united-states.

[53] NRDC. 2019. Climate Change and Health. Issue Brief. https://www.nrdc.org/sites/default/files/climate-change-health-impacts-california-ib.pdf.

[54] Samenow, Jason. 2022. No September on record in the West has seen a heat wave like this. *The Washington Post.* September 9. https://www.washingtonpost.com/climate-environment/2022/09/08/western-heatwave-records-california-climate/.

Imperative To Act

Consequences of Further Warming

The Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6) found that it will not be possible to keep global warming within the threshold of 1.5ºC to avoid the most severe impacts of climate change unless we make immediate and large-scale reductions in GHG emissions. It finds that atmospheric concentrations of CO_2 have increased by 50 percent since the industrial revolution, and that they continue to increase at a rate of two parts per million each year.[55] Without immediate action, the world will exceed 1.5ºC (or 2.7ºF) warming by the 2030s, and no later than 2040.

While every tenth of a degree matters—every incremental increase in warming brings additional negative impacts—climate-related risks to human health, livelihoods, and biodiversity are projected to increase further under 2ºC (or 3.6ºF) warming, compared to 1.5ºC.[56] To remain below 1.5ºC with limited or no overshoot of that threshold, global net anthropogenic CO_2 emissions need to be cut by about half by 2030 and reach net-zero by 2050.

If we fail to make rapid changes, we may not be able to limit global warming to 2ºC,[57] and the consequences of inaction would be catastrophic. Our planet is already 1.2ºC warmer than pre-industrial times due to human-induced warming, and many impacts we are already experiencing, such as sea level rise, are "irreversible" for centuries to millennia.[58] Californians with the fewest resources, who are disproportionately low-income communities and communities of color, are the most vulnerable to the impacts of climate change. While the human costs associated with health impacts can never be fully monetized, a recent report finds that the health costs of climate and air pollution in the U.S. are well over $800 billion today and will continue to grow in the coming years.[59]

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[55] IPCC. 2021. *Climate Change 2021: The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.

[56] IPCC. 2018. *Special Report: Global Warming of 1.5°C.* World Meteorological Organization. https://www.ipcc.ch/sr15/.

[57] IPCC. 2021. Summary for Policymakers. In: *Climate Change 2021: The Physical Science Basis.* Contribution of Working Group I to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Masson-Delmotte, V., P. Zhai, A. Pirani, S. L. Connors, C. Péan, S. Berger, N. Caud, Y. Chen, L. Goldfarb, M. I. Gomis, M. Huang, K. Leitzell, E. Lonnoy, J. B. R. Matthews, T. K. Maycock, T. Waterfield, O. Yelekçi, R. Yu, and B. Zhou (eds.)]. In Press. https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_SPM_final.pdf.

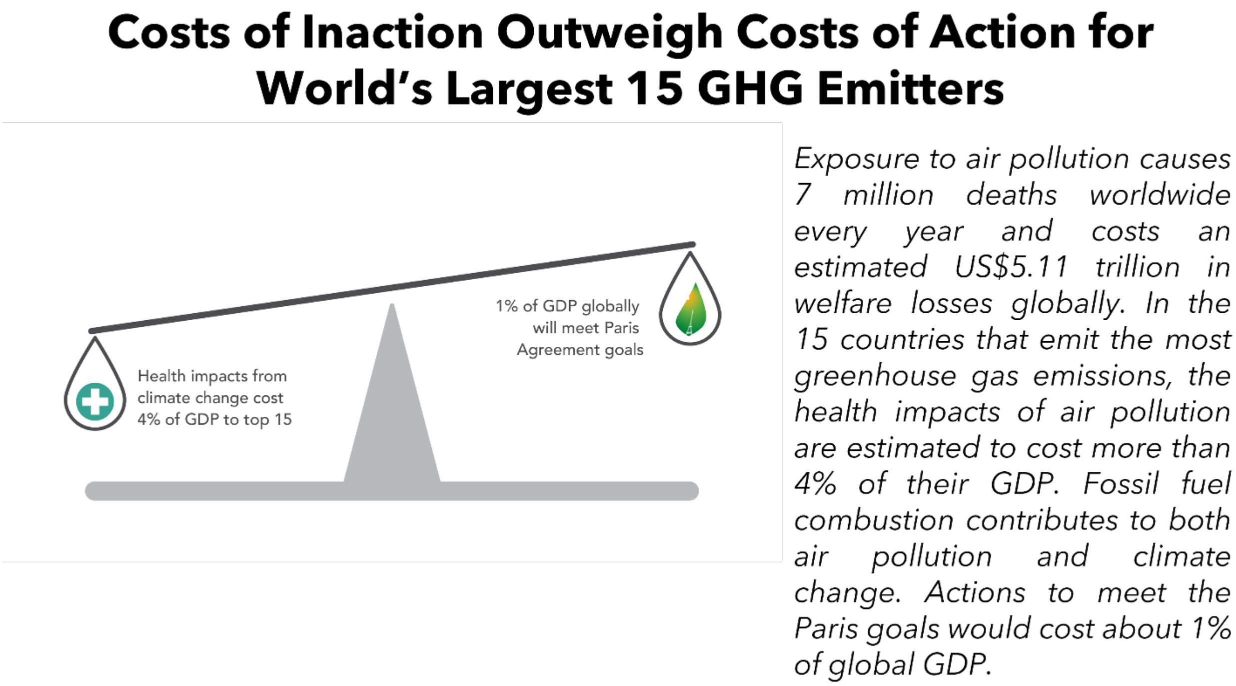
[58] United Nations. 2021. IPCC report: 'Code red.' https://news.un.org/en/story/2021/08/1097362#:~:text=%27Code%20red%20for%20humanity%27&text=We%20are%20at%20imminent%20risk,%2C%20to%20keep%201.5%20alive.%22.

[59] Alwis, D. D., and V. S. Limaye. No date. *The Costs of Inaction*. https://www.nrdc.org/sites/default/files/costs-inaction-burden-health-report.pdf.

Any delays in action or insufficient action are a threat to public health and the environment. The impacts to our economy would be devastating as well. While not specific to California, a 2022 report from Deloitte Economics Institute finds that failing to take sufficient action to reduce emissions could result in economic losses to the U.S. of more than $14.5 trillion over the next 50 years.[60] On a hopeful note, however, the report finds that if the country invests now and in the coming years in a net-zero economy, $3 trillion could be added to the economy over the next 50 years. The U.S. annual gross domestic product (GDP) would be 2.5 percent higher in 2070 in this fast-action scenario than in the delayed action scenario. The lessons for California from these analyses are clear: invest now or pay the price later. As shown in Figure 1-2, inaction can lead to negative consequences for individuals, communities, the economy, and society as a whole. As discussed later, Governor Newsom and the Legislature have accepted this imperative and made significant investments in climate action. This Scoping Plan combined with the historic investments and policy direction from the governor and Legislature, will result in unprecedented action to address the climate crisis.

[60] Deloitte. 2022. *The Turning Point.* https://www2.deloitte.com/content/dam/Deloitte/us/Documents/about-deloitte/us-the-turning-point-a-new-economic-climate-in-the-united-states-january-2022.pdf?id=us:2el:3dp:wsjspon:awa:WSJSBJ:2021:WSJFY22.

Figure 1-2: The real costs of inaction[61]



Scoping Plan Overview

Previous Scoping Plans

The Scoping Plan is a strategy the California Air Resources Board (CARB) develops and updates at least one every five years, as required by AB 32. It lays out the transformations needed across our society and economy to reduce emissions and reach our climate targets. This Scoping Plan is the third update to the original plan that was adopted in 2008. The initial Scoping Plan laid out a path to achieve the AB 32 2020 limit of returning to 1990 levels of GHG emissions, a reduction of approximately 15 percent below business as usual.[62] The 2008 Scoping Plan included a mix of incentives, regulations, and carbon pricing, laying out the portfolio approach to addressing climate change and clearly making the case for using multiple tools to meet California's GHG targets. The 2013 Scoping Plan assessed progress toward achieving the 2020 limit and made the case for addressing

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[61] Katowice, P. 2018. *Health benefits far outweigh the costs of meeting climate change goals.* WHO. https://www.who.int/news/item/05-12-2018-health-benefits-far-outweigh-the-costs-of-meeting-climate-change-goals.

[62] CARB. 2008. *Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/document/adopted_scoping_plan.pdf.

short-lived climate pollutants (SLCPs).[63] The most recent update, the 2017 Scoping Plan,[64] also assessed the progress toward achieving the 2020 limit and provided a technologically feasible and cost-effective path to achieving the Senate Bill 32 (SB 32, Pavley, Chapter 249, Statutes of 2016) target of reducing GHGs by at least 40 percent below 1990 levels by 2030.

Overview of this Scoping Plan

It is paramount that we continue to build on California's success by taking effective actions and doubling down on implementation of the strategies outlined here. As such, this Scoping Plan builds on and integrates efforts already underway to reduce the state's GHG, criteria pollutant, and toxic air contaminant emissions by identifying the clean technologies and fuels that should be phased in as the state transitions away from combustion of fossil fuels. By selecting and pursuing a sustainable and clean economic path, the state will continue to successfully execute existing programs, work to eliminate air pollution inequities, demonstrate the coupling of economic growth and environmental progress, and enhance new opportunities for engagement within the state to address and prepare for climate change.

The 2022 Scoping Plan for Achieving Carbon Neutrality (Scoping Plan) is the most comprehensive and far-reaching Scoping Plan developed to date. It identifies a technologically feasible and cost-effective path to achieve carbon neutrality by 2045 while also assessing the progress California is making toward reducing its GHG emissions by at least 40 percent below 1990 levels by 2030, as called for in SB 32 and laid out in the 2017 Scoping Plan.[65] The 2030 target is an interim but important stepping stone along the critical path to the broader goal of deep decarbonization by 2045. Modeling for this Scoping Plan shows that this decade must be one of transformation on a scale never seen before to set us up for success in 2045.

The relatively longer path assessed in this Scoping Plan incorporates, coordinates, and leverages many existing and ongoing efforts to reduce GHGs and air pollution, while identifying new clean technologies and energy. Given the focus on carbon neutrality, this Scoping Plan also includes discussion for the first time of the Natural and Working Lands (NWL) sectors as both sources of emissions and carbon sinks. Chapter 2 of this document

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[63] CARB. 2014. *First Update to the Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

[64] CARB. 2017. *California's 2017 Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/scoping_plan_2017.pdf.

[65] CARB. 2017. *California's 2017 Climate Change Scoping Plan.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/scoping_plan_2017.pdf.

includes a description of a suite of specific actions to drastically reduce GHGs across all sectors. Chapter 3 provides the air quality and economic evaluations of the actions. Chapter 4 provides a broader description of the many actions needed across all sectors to achieve carbon neutrality. Chapter 5 provides an overview of the next steps and partnerships needed to implement this Scoping Plan. Guided by legislative direction, the actions identified in this Scoping Plan reduce overall GHG emissions in California and deliver policy signals that will continue to drive investment and certainty in a low carbon economy. This Scoping Plan builds upon the successful framework established by the Initial Scoping Plan and subsequent updates while identifying new, technologically feasible, and cost-effective strategies.

Principles That Inform Our Approach to Addressing the Climate Challenge

California has decades of experience addressing the climate challenge. Through this experience, and based on extensive engagement with stakeholders through our regulatory and program development processes, we have developed a set of principles to inform our approach.

Unprecedented Investments in a Sustainable Future

The scale of transformation needed over this decade to avoid the worst impacts of climate change and meet our ambitious climate goals is extraordinary. This is why Governor Newsom and the Legislature invested over $15 billion in climate action through the 2021–2022 California Comeback Plan, and why the 2022–2023 budget marks the beginning of the California Climate Commitment—the governor’s multi-year plan to invest $54 billion in climate action. The enacted budgets (Figure 1-3) and the California Climate Commitment represent investments of a historic scale and will advance precisely the type of all-of-government approaches necessary to create the whole-of-society changes described in this Scoping Plan that will enable us to avert the worst impacts of climate change.

Figure 1-3: Comprehensive California climate change investments

The *California Climate Commitment* includes the following game-changing elements:

- $10 billion for zero-emission vehicles (ZEVs), including $1.5 billion for electric school buses to protect students' health and $3 billion to build an accessible charging network. ZEV investments will particularly focus on programs such as heavy-duty vehicle and port electrification that will reduce emissions and protect public health in low-income communities.
- $2.1 billion for clean energy investments, such as long duration storage, offshore wind, green hydrogen,[66] and industrial decarbonization.
- $13.8 billion for programs that reduce emissions from the transportation sector, such as improving public transportation while also funding walking, biking, and adaptation projects.
- Over $720 million for California's higher education institutions and research that will support the next generation of climate innovations.

[66] For the purposes of this Scoping Plan, "renewable hydrogen" and "green hydrogen" are interchangeable and are not limited to only electrolytic hydrogen produced from renewables.

- Nearly $1 billion to build sustainable, affordable housing and over $1 billion to help low-income Californians realize energy cost savings through building decarbonization.
- Nearly $9 billion for wildfire risk reduction, drought mitigation, extreme heat resilience, and nature-based solutions.

These investments are incredibly important in the context of this Scoping Plan in that they accompany and help support implementation of the many policies and regulations that will continue to be necessary to achieve our 2030 and carbon neutrality targets. In addition, these incentive programs jump-start emission reduction strategies for priority sectors, sources, and technologies, leveraging private-sector investment and building sustainable, growing markets for clean and efficient technologies. Many of California's incentive programs work in concert with federal and other state programs to drive emission reductions. As an example, as California pushes to move to 100% sales of new zero emission-vehicles, including plug-in hybrid vehicles, the Newsom Administration continues to invest heavily in incentive programs that allow families, communities, and businesses to choose zero-emission vehicles. This is done while simultaneously working with the federal government, other states, and jurisdictions around the world to align policies, regulations, and incentives, creating market certainty for the automakers that serve our markets.

Centering Equity

Prioritizing equity is just as important as the magnitude of the climate investments California is making. Addressing climate change and advancing our equity and economic opportunity goals cannot be decoupled. In line with the governor's Executive Order[67] to take additional actions to embed equity analysis and considerations, this plan works to center equity by addressing disparities for historically underserved and marginalized communities. California strives to ensure that our climate and air research, regulations, investments, and plans include provisions that specifically address and advance equity. This includes reducing and eliminating air pollution disparities, removing barriers that can prevent frontline communities from accessing benefits, lowering costs for low-income Californians, and promoting high-quality jobs. CARB's incentive programs regularly surpass their mandated equity targets, and CARB has incorporated equity-focused provisions in our research, planning, and regulatory efforts. For instance, statute requires that a minimum of 35 percent of California Climate Investments benefit low-income households along with disadvantaged and low-income communities (referred to as *priority*

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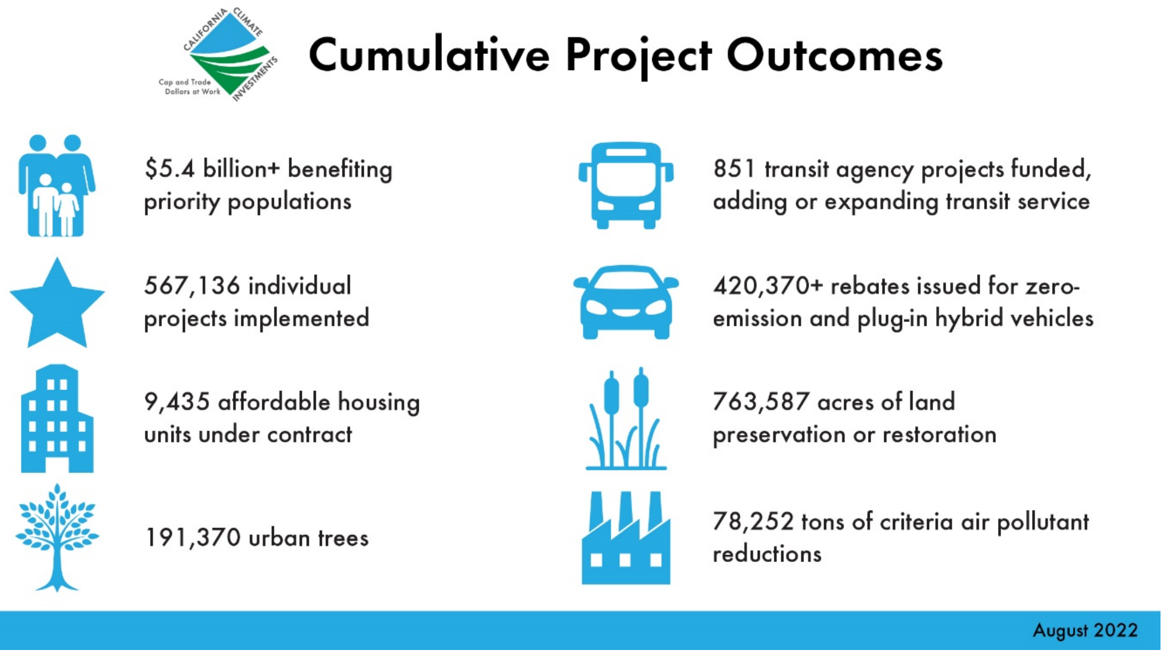
[67] Executive Department. State of California. 2022. Executive Order N-16-22. GSS_9320_2-20220912152941 (ca.gov).

populations). However, 48 percent—over $5.4 billion—of implemented California Climate Investments project funding is benefiting priority populations, greatly exceeding the statutory minimums (see Figure 1-4). Senate Bill 535 (De León, Chapter 830, Statutes of 2012) and AB 1550 (Gomez, Chapter 369, Statutes of 2016) direct state and local agencies to make significant investments using auction proceeds to assist California's most vulnerable communities. Under these laws, a minimum of 25 percent of the total investments are required to be located within and provide benefits to disadvantaged communities, and at least 10 percent of the total investments must benefit low-income communities and households. Moving forward, the state will continue to devote a greater share of incentive funding to priority populations, with the light-duty vehicle incentive program as just one example. We can simultaneously confront the climate crisis and build a more resilient, just, and equitable future for all communities.

Figure 1-4: California climate investments cumulative outcomes[68,69]



Role of the Environmental Justice Advisory Committee

To inform the development of the Scoping Plan, AB 32 calls for the convening of an Environmental Justice Advisory Committee (EJ Advisory Committee) to advise CARB in developing the Scoping Plan, and any other pertinent matter in implementing AB 32. It requires that the Committee be comprised of representatives from communities with the most significant exposure to air pollution, including communities with minority populations and/or low-income populations. On January 25, 2007, CARB appointed the first

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[68] CARB. 2022. California Climate Investments program implements $10.5 billion in greenhouse gas-reducing programs, expected to reduce 76 million metric tons of emissions. April 11. https://ww2.arb.ca.gov/news/california-climate-investments-program-implements-105-billion-greenhouse-gas-reducing-projects.

[69] SB 535 and AB 1550 require investments located in and benefiting low-income communities and households, which are termed *priority populations. Disadvantaged communities* are currently defined by CalEPA as the top 25 percent of communities experiencing disproportionate amounts of pollution, environmental degradation, and socioeconomic and public health conditions according to the Office of Environmental Health Hazard Assessment's *CalEnviroScreen tool,* plus certain additional communities including federally recognized Tribal Lands. Low-income communities and households are defined by statute as those with incomes either at or below 80 percent of the statewide median or below a threshold designated as low-income by the Department of Housing and Community Development.

Environmental Justice Advisory Committee to advise it on the Initial Scoping Plan and other climate change programs.

For this Scoping Plan, CARB reconvened the EJ Advisory Committee in May 2021. The committee is currently comprised of 14 environmental justice and disadvantaged community representatives, including the EJ Advisory Committee's first tribal representative, who was appointed in February 2022. In October 2021, the EJ Advisory Committee formally created eight workgroups. These workgroups are a space for EJ Advisory Committee members to better understand specific sectors of the Scoping Plan and to assist the EJ Advisory Committee in the development of recommendations on this Scoping Plan. In December 2021, the EJ Advisory Committee provided scenario input responses to help shape the modeling for this Scoping Plan. In February 2022, San Joaquin Valley EJ Advisory Committee members hosted their first community workshop, with over 100 attendees. In March 2022, the CARB Board held a joint public meeting with the EJ Advisory Committee to discuss their draft preliminary recommendations for this Scoping Plan. In June 2022, over 165 attendees participated in a statewide community workshop held by EJ Advisory Committee members. The full schedule of EJ Advisory Committee Meetings and meeting materials are available on CARB's website.[70] This Scoping Plan includes references where EJ Advisory Committee Final Recommendations[71] are included in the document. The final recommendations were discussed at a joint CARB and EJ Advisory Committee Hearing on September 1, 2022.

The integration of environmental justice is critical to ensure that certain communities are not left behind. The AB 32 EJ Advisory Committee provided recommendations on September 30 in advance of the final Scoping Plan. There are footnotes to indicate where there is alignment between the AB 32 EJ Advisory Committee's recommendations and this Scoping Plan. While the language in the text may not fully incorporate the specific EJ Advisory Committee's recommendation, the footnotes do acknowledge the places in the text where there is general alignment with the spirit of the EJ Advisory Committee's recommendation.

Partnering with Tribes

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[70] CARB. Environmental Justice Advisory Committee Meetings and Events. https://ww2.arb.ca.gov/environmental-justice-advisory-committee-meetings-and-events.

[71] Environmental Justice Advisory Committee. September 30, 2022. 2022 Scoping Plan Recommendations. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/090122/finalejacrecs.pdf.

There are 109 federally recognized tribes and over 60 non-federally recognized tribes in California. [72] In 2011, Governor Brown issued Executive Order B-10-11, recognizing and reaffirming the inherent right of tribes to exercise sovereign authority over their members and territory and directing state agencies to engage in government-to-government consultation with tribe and to work to develop partnerships and consensus.[73] In 2019, Governor Newsom issued Executive Order N-15-19, which acknowledges and apologizes on behalf of the state for the historical "violence, exploitation, dispossession and the attempted destruction of tribal communities."[74] Establishing partnerships with tribal leaders to incorporate their priorities, traditional expertise, and knowledge will be important to achieving California's climate goals. The Scoping Plan includes actions that tribal partners can voluntarily implement for sources under their jurisdiction (e.g., transitioning to zero emission fleets, installing infrastructure and control technologies, conducting climate smart land management). The Scoping Plan also uplifts the importance of having our tribal partners help guide actions that may impact tribal cultural resources and of benefitting from tribal input.

We also need alignment between state and local partners and tribes on actions related to land-use decisions. This means respecting and reinforcing tribal sovereignty and self-determination. As tribes do not always draw clear lines between the "natural" and "cultural" resources of a place, taking a holistic perspective will result in positive impacts in ability to address the complex issues of land management and regulatory undertakings.

Tribes have an intimate and historical knowledge of places and should be engaged early on to inform planning and future management related to activities that may impact tribal resources and areas including potential funding opportunities, technical assistance, and capacity building, where appropriate. Additionally, tribes should be involved in the identification of their own significant resources and areas of use. As decisions are made related to Scoping Plan undertakings, agencies should recognize and appropriately consider cultural resources and management from the beginning, not as an afterthought; and consider how the project could impact tribes.

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[72] These numbers are subject to change depending on determinations made by the Bureau of Indian Affairs (BIA) and the Native American Heritage Commission (NAHC). Please consult the most current Federal Register for a list of federally recognized tribes and the NAHC for a list of non-federally recognized tribes in California. As of the date of the Scoping Plan, the current list for federally recognized tribes is located at 87 Fed. Reg. 4636 (Jan. 28, 2022).

[73] Executive Order B-10-11. https://www.ca.gov/archive/gov39/2011/09/19/news17223/index.html#:~:text=EXECUTIVE%20ORDER%20B-10-11%20Published%3A%20Sep%2019%2C%202011%20WHEREAS,and%20affirmed%20in%20state%20and%20federal%20law%3B%20and.

[74] Executive Order N-15-19. https://tribalaffairs.ca.gov/wp-content/uploads/sites/10/2020/02/Executive-Order-N-15-19.pdf.

Finally, to the extent allowed by law, traditional ecological knowledge and culturally sensitive information should be protected, as this is information that may not be common knowledge and may not be known outside the tribe, as each tribe is unique and influenced by its local environment and cultural practices. Protection of this information will help foster productive relationships with tribes and should be included as part of the process. CARB and other agencies should continue to foster relationships with tribal partners.

Maximizing Air Quality and Health Benefits

The state has over 50 years of experience successfully cleaning the air in California by addressing criteria pollutants and toxic air contaminants from mobile and stationary sources. CARB has been a leader in measuring, evaluating, and reducing sources of air pollution that impact public health. Its air pollution programs have been adapted for national programs and emulated in other countries. Significant progress has been made in reducing diesel particulate matter (PM), which is a designated toxic air contaminant, and many other hazardous air pollutants. CARB partners with local air districts to address stationary source emissions and adopts and implements state-level regulations to address sources of criteria and toxic air pollution, including mobile sources. CARB also collaborates with federal agencies to address air pollution from sources primarily under federal jurisdiction. In many instances, actions to reduce fossil fuel combustion and achieve federal air quality standards also help to reduce GHG emissions.

However, air pollution disparities still exist, and more must be done to ensure the most vulnerable populations have safe air to breathe. California must continue to evaluate opportunities to harmonize our climate and air quality programs through innovative policymaking and by building on existing programs like the Low Carbon Fuel Standard (LCFS) and Community Air Protection Program. The LCFS includes a provision that allows electric utilities to opt-in and generate residential electric vehicle (EV) charging credits, where some of the revenues are invested back into rebate programs that address air quality and climate pollution.[75] The Community Air Protection Program[76] is the first of its kind in the country and brings together diverse stakeholders, including CARB, local air districts, and residents of environmental justice communities to increase local air monitoring and develop community-led plans to improve air quality in the communities most impacted by air pollution.

This Scoping Plan identifies actions that will deliver near-term air quality benefits to communities with the highest exposures and provide long-term GHG benefits. Many of the actions in this Scoping Plan are key elements of the 2022 State Strategy for the State

[75] CARB. LCFS Utility Rebate Programs. https://ww2.arb.ca.gov/resources/documents/lcfs-utility-rebate-programs.
[76] CARB. Community Air Protection Program. https://ww2.arb.ca.gov/capp.

Implementation Plan to meet federal air quality standards,[77] which has a primary focus of reducing harmful air pollution and achieving federal air quality targets. California's approach of leveraging air quality and GHG policies together has yielded results. A 2022 report by the Office of Environmental Health and Hazard Assessment (OEHHA)[78] that evaluated GHG and harmful air pollution emissions from the heavy-duty vehicle (HDV) and large stationary source sectors found declines in emissions in both sectors, with the greatest declines in disadvantaged communities. Both sectors are subject to state GHG and air quality policies, in addition to federal and local rules on harmful air pollution. Because of historically racist and discriminatory practices such as redlining, both types of sources are disproportionately located adjacent to vulnerable communities, which are predominantly communities of color.[79] The key findings from the OEHHA report are as follows:

- Both HDVs and facilities subject to the Cap-and-Trade Program have reduced emissions of co-pollutants, with HDVs showing a clearer downward trend when compared to stationary sources. These emission reductions have major health benefits, including a reduction in premature pollution-related deaths.
- The greatest beneficiaries of reduced emissions from both HDVs and facilities subject to the Cap-and-Trade Program have been in communities of color and in disadvantaged communities in California, as identified by CalEnviroScreen (CES). This has reduced the emission gap between disadvantaged and non-disadvantaged communities, but a wide gap still remains.
- The transition to zero-emission HDVs will expedite further emissions reductions.
- While the progress observed is encouraging, inequities persist, and federal, state, and local climate and air quality programs must do more to reduce emissions of GHGs and co-pollutants to reduce the burden of emissions on disadvantaged communities and communities of color.

It will take all tools at all levels of government, with robust enforcement, to ensure that vulnerable communities continue to see improvements in air quality until no disparities exist in air pollution across the state.

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[77] CARB. 2022 State Strategy for the State Implementation Plan. https://ww2.arb.ca.gov/resources/documents/2022-state-strategy-state-implementation-plan-2022-state-sip-strategy.
[78] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits within Disadvantaged Communities: Progress Toward Reducing Inequities.* https://oehha.ca.gov/environmental-justice/report/ab32-benefits.
[79] CalEPA. 2021. Pollution and Prejudice. https://storymaps.arcgis.com/stories/f167b251809c43778a2f9f040f43d2f5.

Economic Resilience

The state's efforts to tackle the climate crisis will create economic and workforce development opportunities in the clean energy economy in communities across the state. Transitioning existing skills and expanding workforce training opportunities in climate-related fields are critical for reducing harmful emissions and supporting workers in transitioning to new, high-quality jobs. The Administration's recent budgets acknowledge the challenges facing workers in industries most affected by the state's response to climate change—especially those in the fossil fuel industry. It will invest $1 billion in regional partnerships and economic diversification to create new jobs and support a local tax base and workforce transition and development once opportunities are identified. It also will invest in safety nets to protect, and support impacted communities as part of the transition to a carbon neutral economy. Specifically, the Community Economic Resilience Fund Program[80] (CERF) supports communities and regional groups in producing regional roadmaps for economic recovery and transition that prioritize the creation of accessible, high-quality jobs in sustainable industries. The budget investments create the opportunity to future-proof and increase economic resilience in the face of more frequent climate impacts and shifting economic conditions. For these investments and implementation of the Scoping Plan to be successful in supporting the transition to a carbon neutral economy, workers and affected communities must be included in ongoing dialogue to ensure a high-road transition for regional economies.

That state also recognizes it can play a more direct role in supporting a sustainable work force through its incentive programs. In 2021, Assembly Bill 680 (AB 680) (Burke, Chapter 746, Statutes of 2021) was signed into law, requiring CARB to work with the California Labor and Workforce Development Agency to update the Funding Guidelines to include new workforce standards. CARB's Funding Guidelines currently include requirements for administering agencies to, wherever possible, foster job creation within California, provide employment opportunities or job training tied to employment, and target these opportunities to priority populations. The Funding Guidelines also recommend administering agencies prioritize investments in projects that directly support jobs or a job training and placement program, and that they report the estimated employment benefits and employment outcomes for projects that meet specified criteria. These new requirements apply to agencies administering certain California Climate Investments

[80] Office of Planning and Research. Community Economic Resilience Fund. https://opr.ca.gov/economic-development/cerf/.

programs that receive continuous appropriations from the Greenhouse Gas Reduction Fund and fall into the following six categories of standards:

- fair and responsible employer standards,
- inclusive procurement policies,
- prevailing wage for construction work,
- community workforce agreements for construction projects over one million dollars,
- preference for projects with educational institutions or training programs, and
- creation of high-quality jobs. CARB will be updating the Funding Guidelines through a public process over the next year to operationalize these new requirements.

Partnering Across Government

The Scoping Plan is an actionable plan to identify and align programs and policies to achieve California's climate targets. To realize the outcomes and deliver results in any Scoping Plan, action is critical. For this Scoping Plan, there are also actions that rely on our federal partners to take on sources primarily under their jurisdiction (such as aviation, and federally owned/managed lands) while they also continue to develop national programs for GHG reductions. The federal government is already taking major steps to advance these types of programs. The Inflation Reduction Act of 2022[81] includes $369 billion for domestic energy production and manufacturing and is expected to lead to U.S. GHG emission reductions of roughly 40 percent by 2030. Direct incentives will include those for clean vehicles and ENERGY STAR appliances, as well as improving transportation and clean energy in underserved communities.

We also need our local partners to align on actions related to land-use decisions that support sustainable, resilient, low-carbon communities and permitting for clean energy production facilities and infrastructure; diversion of organics from landfills; and other climate-related projects. State agencies also should use the Scoping Plan to review and update their own programs and policies to support the actions identified in this Scoping Plan. Importantly, the Scoping Plan also can serve as a resource as the Legislature considers new legislative direction and funding to support the state's path to carbon neutrality and continue action to address near-term air pollution disparities.

Partnering with the Private Sector

Government cannot achieve our climate targets alone. The scale of investment needed requires both private-sector investment and partnerships with philanthropies. Public

[81] Pub.L. No. 117-169 (August 16, 2022).

sector dollars, accompanied by strong and steady policy signals, must be a catalyst for deeper and broader investments by the private sector in both reducing emissions and building the resilience of our communities. Governor Newsom is committed to working collaboratively with businesses, including small businesses, to deploy the technologies, capital, and ingenuity that are hallmarks of the private sector.

California structures our climate policies and regulations to create market signals and certainty that spur private sector investment. For example, the Governor's Executive Order on Zero-Emission Vehicles[82] set 2035 as the target year for 100 percent zero-emission vehicle sales, creating a time horizon that allows automakers to scale up zero-emission fleets and sending a clear signal to the companies and utilities that would deploy charging infrastructure. The Executive Order has been followed by development and adoption of the Advanced Clean Cars II regulation. CARB convened auto manufacturers, environmental justice groups, labor organizations, and many other stakeholders to provide input into development of the regulation in a robust and transparent manner; again, with the aim of providing certainty for producers and consumers.

California also pursues public-private partnerships (PPP) as a mechanism to advance our collective climate goals. We know these vehicles can be effective at increasing the impact of public sector dollars and helpful in moving markets in a direction aligned with state policy. A new PPP the Administration is advancing is the Climate Catalyst Revolving Loan Fund, housed at the state's Infrastructure and Economic Development Bank (IBank). The fund offers a range of financial instruments—including flexible credit and credit support—to help bridge financing gaps currently preventing advanced climate solutions from scaling in the marketplace. The Catalyst Fund's initial areas of investment include forest biomass management and utilization (unlocking innovation to reduce wildfire threats), climate-smart agriculture, and clean energy transmission. The fund leverages public sector investments by mobilizing private finance for shovel-ready projects that are stuck in the deployment phase. As such, IBank is ideally positioned as the state's all-purpose "Green Bank," with increasing connection to federal financing programs such as US DOE's Loan Programs Office and the United States Environmental Protection Agency's (U.S. EPA) Greenhouse Gas Reduction Fund.

The Catalyst Fund builds from existing IBank financing programs that are themselves increasingly focused on the climate imperative. The IBank's Infrastructure State Revolving Fund provides supportive capital to climate-aligned projects promoted by local governments and certain nonprofit entities, and will be refining its criteria and market outreach strategies to increase its level of service. IBank's bonds program has supported

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[82] Executive Department. State of California. Executive Order N-79-20. *https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf*.

multiple large environmental projects, including more than $2 billion in “green bonds,” and is poised to help expand access to the state’s deep and liquid bond capital market. Within IBank’s Small Business Finance Center, the new Climate Tech Loan Guarantee program encourages commercial banks to back climate-focused small businesses, leveraging federal capital to insure a portion of the private bank’s loan. And through IBank’s Expanding Venture Capital Access Fund program, the state is promoting greater diversity in the venture capital community, including climate equity and climate justice.

All of these financing programs exist to leverage private capital in support of the state’s climate goals, and to partner with state policy agencies driving the transition. IBank will also continue to collaborate closely with the State Treasurer’s Office in its provision of capital support to climate solutions, ensuring that funding flows to programs best positioned to deliver success. This partnership of public and private capital, responsive to and in communication with the climate policy community, will ensure that California gets the maximum possible benefit from its allocation of scarce resources.

Supporting Innovation

Reaching our ambitious, deep decarbonization goals will require continued technological innovation. Investment in research, development, and deployment of clean technologies has never been more critical. Sending clear and sustained market and policy signals will encourage large and small companies alike to pursue innovation that can be scaled up and deployed here and beyond our borders. The full suite of AB 32 policies[83] has touched nearly every sector of California’s economy and spurred technology innovation in the state, including the growth of technology developers, manufacturers, processors, and assemblers in many areas. Specifically, AB 32 policies and programs support both the supply side and the demand side to build new markets in California. On the supply side, AB 32 policies support businesses to demonstrate and refine technologies, and to help establish critical supply chains. On the demand side, AB 32 policies and programs provide outreach, education, and incentives—as well as disincentives—to motivate everyone from consumers to institutional purchasers to utility planners to adopt new, climate smart technologies. Innovations resulting directly from the state’s climate policies include the following:

- In the past 10 years, a growing market for heavy-duty zero-emission vehicles (HD ZEVs) was established in California, and this market now represents the largest single share of North American supply and demand for HD ZEVs. Vehicle

[83] CARB. Climate Change Programs. *https://ww2.arb.ca.gov/our-work/topics/climate-change*.

and component manufacturers are making long-term investments to develop and produce HD ZEVs within California.

- Total consumption of renewable diesel in the California LCFS market has skyrocketed from approximately 1.8 million gallons in 2011 to nearly 589 million gallons in 2020. The LCFS is a key driver of market development for renewable diesel and its coproducts. While the federal renewable fuel standard (RFS) and blenders tax credit also benefit producers, an analysis of their respective contributions to market development, and interviews with industry representatives and independent experts, point to LCFS as a more important factor in market development, at least in recent years.
- In the past five years, a market for small-scale energy storage in California was created where none previously existed. As of 2020, 185 megawatts (MW) of small-scale energy storage projects have been interconnected to the grid. The significant increase in deployment in the last five years is a result of the Self-Generation Incentive Program (SGIP), which significantly reduces the upfront costs to purchase and install small-scale energy storage devices, and of growing customer interest in disaster resiliency in the face of increasing risk from wildfire and related utility outages. These systems have already provided disaster resiliency benefits for residential and non-residential customers.

We have seen how quickly market barriers can be overcome in response to strong policy signals, as occurred in the solar panel and electric vehicle battery space. Government-stated priorities have a significant role in guiding private and public research, development, and deployment. This Scoping Plan unequivocally puts the marker down on the need for innovation to continue in non-combustion technologies, clean energy, CO_2 removal options, and alternatives for SLCPs. The five-year update to the Scoping Plan allows for a periodic evaluation of new tools to add to the state's toolkit.

Engagement with Partners to Develop, Coordinate, and Export Policies

California works closely with other states, tribal governments, the federal government, and international jurisdictions to identify the most effective strategies and methods to reduce GHGs, manage GHG control programs, and facilitate the development of integrated and cost-effective regional, national, and international GHG reduction programs. For example, the state's Cap-and-Trade Program has been linked with Québec's since 2014, and CARB staff regularly engage with jurisdictions throughout the world on the design features of our Cap-and-Trade Program through memoranda of understanding (MOUs) and venues such as the International Climate Action

Partnership.[84] Low carbon fuel mandates similar to California's LCFS have been adopted by the U.S. EPA and by other jurisdictions, including Oregon, Washington, British Columbia, the European Union, and the United Kingdom. Many other jurisdictions from Japan to New Zealand, Australia, and the European Commission also continue to seek information and technical experience on our LCFS. California has and will continue to share information and encourage ambitious emissions reductions with interested jurisdictions, with a focus on China, India, Mexico, Canada, and the European Union. California's early action to reduce super-pollutants such as methane and other SLCPs was reaffirmed by the 2021 Global Methane Pledge signed by the U.S. and over 100 other countries at the 26th Conference of the Parties to the United Nations Framework Convention on Climate Change (UNFCCC).[85]

In addition, under the Clean Air Act, the federal government is authorized to allow California to set more stringent vehicle emissions regulations than federal standards. California's goals and regulations to transition to 100 percent sales of new zero-emission passenger vehicles by 2035 (including plug-in hybrid vehicles), to drayage trucks by 2035, and other trucks and buses where feasible by 2045 are being emulated by partner states across the U.S. and in jurisdictions around the world. CARB's Advanced Clean Cars II regulation, [86] which codifies these targets, was approved in August 2022, and already at least four other states have announced their plans to adopt this regulation. Earlier in June 2020 CARB adopted the Advanced Clean Truck regulation, which requires truck manufacturers to meet increasing sale targets of zero-emission trucks in California through 2035. Since adoption, at least five other states—20 percent of the U.S. truck market—have adopted this regulation. These kinds of coordinated policies help signal to vehicle manufacturers a widespread and growing demand for zero-emissions technology, which in turn helps scale production and lower costs for consumers.

With the Mexican Secretariat for Environment and Natural Resources (SEMARNAT), California has engaged in a technical exchange on clean vehicle policies and helped to establish Mexico's Emissions Trading System (being piloted in 2022). A 2019 MOU signed between California and Environment and Climate Change Canada enables in-depth collaboration on policies and programs to decarbonize vehicles, engines, and fuels. This partnership has led to tangible emissions reductions, from aligning vehicle emissions targets and policies to collaborating on emissions testing and research critical to enforcing

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[84] International Carbon Action Partnership (ICAP). Homepage. https://icapcarbonaction.com/en?msclkid=dac30cb7b4f511ec94ccd0f1ae323e98.

[85] Global Methane Pledge. Homepage. https://www.globalmethanepledge.org/.

[86] Cal. Code Regs., tit. 13, §§ 1900,1961.2, 1961.3, 1962.2, 1962.3, 1962.4, 1962.5, 1962.6, 1962.7, 1962.8, 1965, 1968.2, 1969, 1976, 1978, 2037, 2038, 2112, 2139, 2140, 2147, and 2903; and Test Procedures located here: https://ww2.arb.ca.gov/rulemaking/2022/advanced-clean-cars-ii.

emissions limits for vehicle manufactures. At the national level, China has looked to California for cutting-edge requirements for car diagnostics and policies that promote zero-emissions vehicles. At a local level, Beijing has adopted California's vehicle emissions standards and several other progressive environmental regulations. California will continue and renew such efforts across China, including through a 2022 MOU signed with China's Ministry of Ecology and Environment.

Between 2021 and 2023, California also will serve as president of the Transport Decarbonisation Alliance, a global network of countries, regions, cities, and companies that come together to share experiences and technical expertise, and to increase the ambition and accelerate the deployment of targeted transportation decarbonization policies across freight, electric vehicle infrastructure, and active mobility. Throughout its presidency, California will focus its leadership on decarbonizing the cross-jurisdiction network of medium- and heavy-duty vehicles, both to ensure cleaner air in freight-adjacent communities and to stem the effects of climate change.

Over the years, California has also asserted the importance of and supported the ongoing efforts of state and local clean air and climate leadership. Through our participation in the Pacific Coast Collaborative alongside British Columbia, Washington, and Oregon,[87] the Under2 Coalition,[88] the U.S. Climate Alliance,[89] the International ZEV Alliance,[90] the Transportation Decarbonisation Alliance, and many more organizations, California has and will continue to build climate partnerships with state and local governments.

California also recognized the need to address the substantial emissions caused by the deforestation and degradation of tropical and other forests, and continues its work alongside other subnational governments as part of the Governors' Climate and Forests Task Force (GCF).[91] Founded in 2008, there are currently 39 GCF members, including states and provinces in Brazil, Colombia, Ecuador, Indonesia, Ivory Coast, Mexico, Nigeria, Peru, Spain, and the United States—all of whom are considering or operating programs to reduce emissions from deforestation, land-use, and rural development, and to benefit local and indigenous communities. CARB's California Tropical Forest Standard provides a rigorous methodology to assess jurisdiction-scale programs that reduce deforestation and to incentivize responsible action and investment.[92] The standard

[87] Pacific Coast Collaborative. Homepage. https://pacificcoastcollaborative.org/.
[88] Under2 Coalition. Homepage. https://www.theclimategroup.org/under2-coalition.
[89] United States Climate Alliance (USCA). Homepage. https://www.usclimatealliance.org/.
[90] ZEV Alliance. Homepage. Accelerating the Adoption of Zero-Emission Vehicles. https://zevalliance.org/.
[91] Governors' Climate and Forests Task Force. University of Colorado Boulder: Colorado Law. https://www.gcftf.org/.
[92] CARB. California Tropical Forest Standard. https://ww2.arb.ca.gov/our-work/programs/california-tropical-forest-standard.

provides a strong signal to value the preservation of tropical forests over continued destructive activities such as oil exploration and extraction and ensures rigorous social and environmental safeguards for indigenous peoples and local communities.

Working Toward Carbon Neutrality

To date, California and many other regions have focused on reducing GHG emissions from the industrial, energy, and transportation sectors. As defined in statute, the state's 2020 and 2030 targets include all in-state sources of GHG emissions—and those emissions associated with imported power that is consumed in the state. By moving to a framework of carbon neutrality, the scope for accounting is expanded to include all sources and sinks. As such, carbon neutrality is achieved when the GHG fluxes are at equilibrium—when sources equal sinks. Figure 1-5 depicts the sources included in the AB 32 GHG Inventory and the new sources and sinks added in this Scoping Plan under the framework of carbon neutrality. Natural and working lands are able to sequester carbon and therefore play an increasingly important role in this framework. However, modeling for this plan shows that carbon sequestration in our natural and working lands alone will be insufficient to achieve carbon neutrality no later than 2045. Therefore, this plan also considers the role of carbon capture and sequestration, as well as biological and mechanical carbon sequestration processes that are included in the IPCC Sixth Assessment Report,[93] as necessary tools for climate change mitigation.

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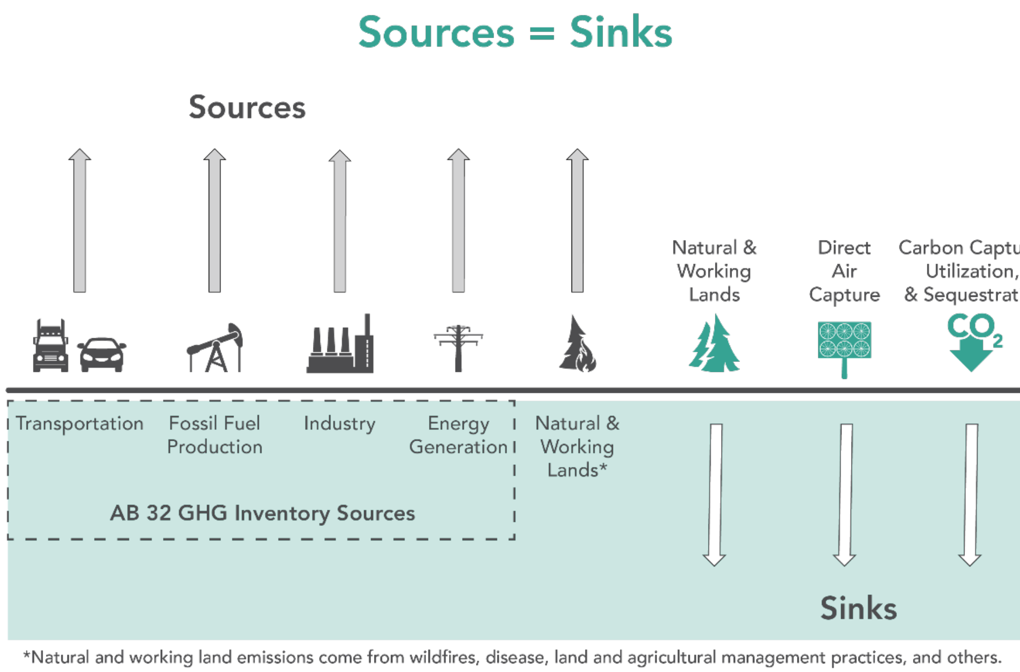
[93] IPCC. 2021. *Climate Change 2021: The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.

Figure 1-5: Carbon neutrality: Balancing the net flux of GHG emissions from all sources and sinks



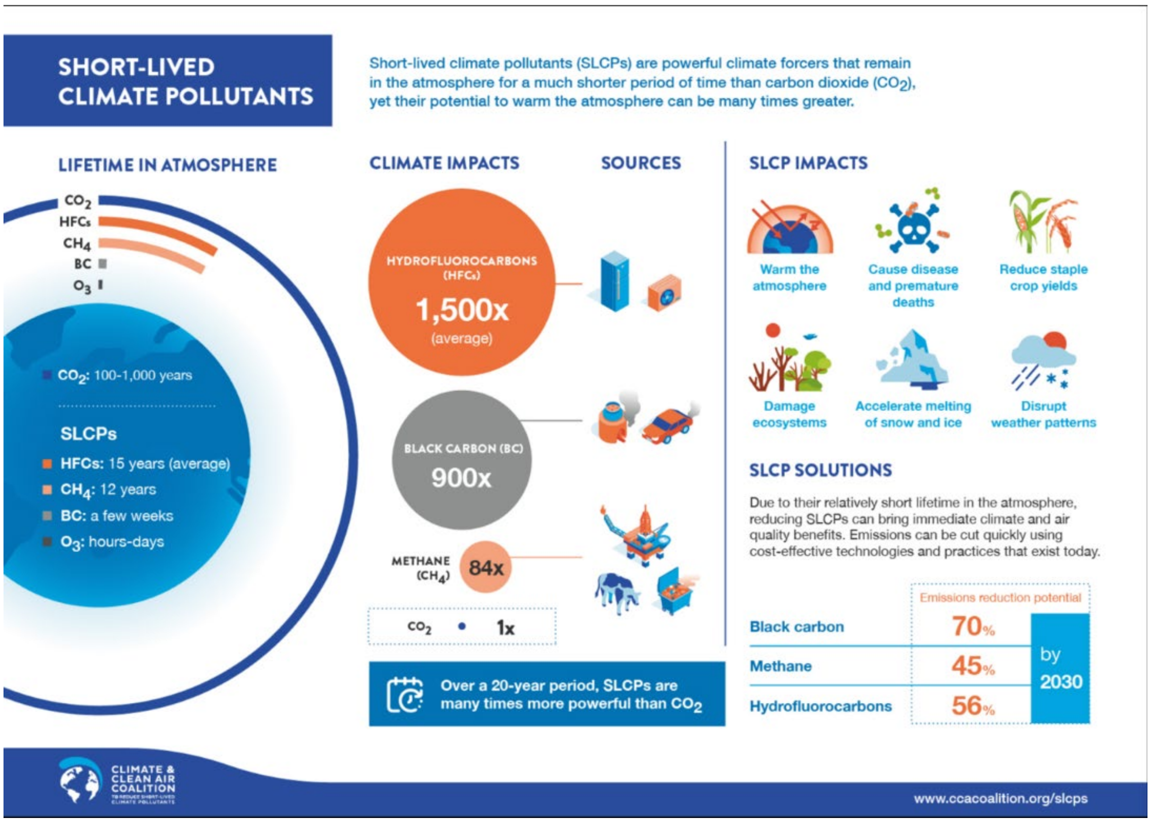
Supporting Healthy and Resilient Lands

Our natural and working lands are an important piece in California's fight to achieve carbon neutrality and build resilience to the impacts of climate change. Healthy land can sequester and store atmospheric carbon dioxide in forests, grasslands, soils, and wetlands. Healthy lands can also reduce emissions of powerful short-lived climate pollutants, limit the release of future GHG emissions, protect people and nature from the impacts of climate change, and build our resilience to future climate risks. Unhealthy lands have the opposite effect—they release more GHGs than they store and are more vulnerable to future climate change impacts. Through climate smart land management that focuses on supporting healthy living systems, we can support our carbon neutrality goals, reduce emissions, advance sequestration, and support healthy and more climate-resilient lands.

Maintaining the Focus on Methane and Short-Lived Climate Pollutants

Given the urgency of climate change, the often-disproportional impacts already being felt by underserved populations across California and the world, and the need to rapidly decarbonize and avoid climate tipping points as identified in the most recent IPCC assessment, efforts to reduce short-lived climate pollutants are especially important. SLCPs include methane (CH_4), black carbon (soot), and fluorinated gases (F-gases, including hydrofluorocarbons, or HFCs), and they are among the most harmful pollutants to both human health and the global climate. SLCPs are more potent than CO_2 in terms of their impact on climate change (and subsequently, global warming) and have a much shorter lifetime in the atmosphere than CO_2 does. That means they have an outsized impact on climate change in the near term—they are responsible for up to 45 percent of current climate forcing. It also means that targeted efforts to reduce short-lived climate pollutant emissions can provide outsized climate and health benefits, within weeks to about a decade (see Figure 1-6).

Figure 1-6: Short-lived climate pollutant impacts[94]



California has been a leader in addressing SLCP emissions. As part of the 2014 Scoping Plan,[95] CARB committed to developing a dedicated strategy to reduce SLCP emissions.

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[94] Climate and Clean Air Coalition. Short-Lived Climate Pollutants (SLCPs). https://www.ccacoalition.org/en/content/short-lived-climate-pollutants-slcps.

[95] CARB. 2014. *First Update.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

The resulting SLCP Reduction Strategy,[96] adopted by CARB in 2017, implements targets codified in SB 1383 (Lara, Chapter 395, Statutes of 2016) to reduce methane and HFC emissions by 40 percent by 2030 and anthropogenic black carbon emissions by 50 percent. California worked with several other states through the U.S. Climate Alliance to establish a similar goal to reduce SLCP emissions in line with the requirements of the Paris Agreement,[97] identifying the potential to reduce SCLPs by 40 to 50 percent by 2030 across the U.S. Climate Alliance.[98]

Process for Developing the Scoping Plan

This Scoping Plan was developed in coordination with the Governor's Office and state agencies, in accordance with direction from the Chair and Members of CARB, through engagement with the Legislature, with advice from the EJ Advisory Committee, in consultation with tribes, and with open and transparent opportunities for stakeholders and the public to engage in workshops and other meetings. Appendix A (Public Process) includes details of the public workshops, and Chapter 5 includes details of the EJ Advisory Committee's role in the Scoping Plan update process.

Guidance from the Administration and Legislature

This Scoping Plan reflects existing and recent direction in the Governor's Executive Orders and Statutes. Table 1-1 provides a summary of major climate legislation and executive orders issued since the adoption of the 2017 Scoping Plan.

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[96] CARB. 2017. *Short-Lived Climate Pollutant Reduction Strategy.* https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.
[97] UNFCCC. 2015. Paris Agreement. https://unfccc.int/sites/default/files/english_paris_agreement.pdf.
[98] USCA. 2018. *From SLCP Challenge to Action: A Roadmap for Reducing Short-Lived Climate Pollutants to Meet the Goals of the Paris Agreement.* http://www.usclimatealliance.org/slcp-challenge-to-action.

Table 1-1: Major climate legislation and executive orders enacted since the 2017 Scoping Plan

Bill/Executive Order	Summary
Assembly Bill 1279 (AB 1279) (Muratsuchi, Chapter 337, Statutes of 2022) *The California Climate Crisis Act*	AB 1279 establishes the policy of the state to achieve carbon neutrality as soon as possible, but no later than 2045; to maintain net negative GHG emissions thereafter; and to ensure that by 2045 statewide anthropogenic GHG emissions are reduced at least 85 percent below 1990 levels. The bill requires CARB to ensure that Scoping Plan updates identify and recommend measures to achieve carbon neutrality, and to identify and implement policies and strategies that enable CO_2 removal solutions and carbon capture, utilization, and storage (CCUS) technologies. This bill is reflected directly in this Scoping Plan.
Senate Bill 905 (SB 905) (Caballero, Chapter 359, Statutes of 2022) *Carbon Capture, Removal, Utilization, and Storage Program*	SB 905 requires CARB to create the Carbon Capture, Removal, Utilization, and Storage Program to evaluate, demonstrate, and regulate CCUS and carbon dioxide removal (CDR) projects and technology. The bill requires CARB, on or before January 1, 2025, to adopt regulations creating a unified state permitting application for approval of CCUS and CDR projects. The bill also requires the Secretary of the Natural Resources Agency to publish a framework for governing agreements for two or more tracts of land overlying the same geologic storage reservoir for the purposes of a carbon sequestration project. The Scoping Plan modeling reflects both CCUS and CDR contributions to achieve carbon neutrality.
Senate Bill 846 (SB 846) (Dodd, Chapter 239, Statutes of 2022) *Diablo Canyon Powerplant: Extension of Operations*	SB 846 extends the Diablo Canyon Power Plant's sunset date by up to five additional years for each of its two units and seeks to make the nuclear power plant eligible for federal loans. The bill requires that the California Public Utilities Commission (CPUC) not include and disallow a load-serving entity from including in their adopted resource plan, the energy, capacity, or any attribute from the Diablo Canyon power plant. The Scoping Plan explains the emissions impact of this legislation.
Senate Bill 1020 (SB 1020) (Laird,	SB 1020 adds interim renewable energy and zero carbon energy retail sales of electricity targets to California end-use customers set at 90 percent in 2035 and 95 percent in 2040.

Chapter 361, Statutes of 2022) *Clean Energy, Jobs, and Affordability Act of 2022*	It accelerates the timeline required to have 100 percent renewable energy and zero carbon energy procured to serve state agencies from the original target year of 2045 to 2035. This bill requires each state agency to individually achieve the 100 percent goal by 2035 with specified requirements. This bill requires the CPUC, California Energy Commission (CEC), and CARB, on or before December 1, 2023, and annually thereafter, to issue a joint reliability progress report that reviews system and local reliability. The bill also modifies the requirement for CARB to hold a portion of its Scoping Plan workshops in regions of the state with the most significant exposure to air pollutants by further specifying that this includes communities with minority populations or low-income communities in areas designated as being in extreme federal non-attainment. The Scoping Plan describes the implications of this legislation on emissions.
Senate Bill 1137 (SB 1137) (Gonzales, Chapter 365, Statutes of 2022) *Oil & Gas Operations: Location Restrictions: Notice of Intention: Health protection zone: Sensitive receptors*	SB 1137 prohibits the development of new oil and gas wells or infrastructure in health protection zones, as defined, except for purposes of public health and safety or other limited exceptions. The bill requires operators of existing oil and gas wells or infrastructure within health protection zones to undertake specified monitoring, public notice, and nuisance requirements. The bill requires CARB to consult and concur with the California Geologic Energy Management Division (CalGEM) on leak detection and repair plans for these facilities, adopt regulations as necessary to implement emission detection system standards, and collaborate with CalGEM on public access to emissions detection data.
Senate Bill 1075 (SB 1075) (Skinner, Chapter 363, Statutes of 2022) *Hydrogen: Green Hydrogen: Emissions of Greenhouse Gases*	SB 1075 requires CARB, by June 1, 2024, to prepare an evaluation that includes: policy recommendations regarding the use of hydrogen, and specifically the use of green hydrogen, in California; a description of strategies supporting hydrogen infrastructure, including identifying policies that promote the reduction of GHGs and short-lived climate pollutants; a description of other forms of hydrogen to achieve emission reductions; an analysis of curtailed electricity; an estimate of GHG and emission reductions that could be achieved through deployment of green hydrogen through a variety of scenarios; an analysis of the potential for opportunities to integrate hydrogen production and applications with drinking water supply treatment needs; policy recommendations for regulatory and permitting processes

	associated with transmitting and distributing hydrogen from production sites to end uses; an analysis of the life-cycle GHG emissions from various forms of hydrogen production; and an analysis of air pollution and other environmental impacts from hydrogen distribution and end uses. This bill would inform the production of hydrogen at the scale called for in this Scoping Plan.
Assembly Bill 1757 (AB 1757) (Garcia, Chapter 341, Statutes of 2022) *California Global Warming Solutions Act of 2006: Climate Goal: Natural and Working Lands*	AB 1757 requires the California Natural Resources Agency (CNRA), in collaboration with CARB, other state agencies, and an expert advisory committee, to determine a range of targets for natural carbon sequestration, and for nature-based climate solutions, that reduce GHG emissions in 2030, 2038, and 2045 by January 1, 2024. These targets must support state goals to achieve carbon neutrality and foster climate adaptation and resilience. This bill also requires CARB to develop standard methods for state agencies to consistently track GHG emissions and reductions, carbon sequestration, and additional benefits from natural and working lands over time. These methods will account for GHG emissions reductions of CO_2, methane, and nitrous oxide related to natural and working lands and the potential impacts of climate change on the ability to reduce GHG emissions and sequester carbon from natural and working lands, where feasible. This Scoping Plan describes the next steps and implications of this legislation for the natural and working lands sector.
Senate Bill 1206 (SB 1206) (Skinner, Chapter 884, Statutes of 2022) *Hydrofluorocarbon gases: sale or distribution*	SB 1206 mandates a stepped sales prohibition on newly produced high- global warming potential (GWP) HFCs to transition California's economy toward recycled and reclaimed HFCs for servicing existing HFC-based equipment. Additionally, SB 1206 also requires CARB to develop regulations to increase the adoption of very low-, i.e., GWP < 10, and no-GWP technologies in sectors that currently rely on higher-GWP HFCs.
Senate Bill 27 (SB 27) (Skinner, Chapter 237, Statutes of 2021)	SB 27 requires CNRA, in coordination with other state agencies, to establish the Natural and Working Lands Climate Smart Strategy by July 1, 2023. This bill also requires CARB to establish specified CO_2 removal targets for 2030 and beyond as part of its Scoping Plan. Under SB 27, CNRA is to establish and maintain a registry to identify projects in the state

Carbon Sequestration: State Goals: Natural and Working Lands: Registry of Projects	that drive climate action on natural and working lands and are seeking funding. CNRA also must track carbon removal and GHG emission reduction benefits derived from projects funded through the registry. This bill is reflected directly in this Scoping Plan as CO_2 removal targets for 2030 and 2045 in support of carbon neutrality.
Senate Bill 596 (SB 596) (Becker, Chapter 246, Statutes of 2021) *Greenhouse Gases: Cement Sector: Net-zero Emissions Strategy*	SB 596 requires CARB, by July 1, 2023, to develop a comprehensive strategy for the state's cement sector to achieve net-zero-emissions of GHGs associated with cement used within the state as soon as possible, but no later than December 31, 2045. The bill establishes an interim target of 40 percent below the 2019 average GHG intensity of cement by December 31, 2035. Under SB 596, CARB must: • Define a metric for GHG intensity and establish a baseline from which to measure GHG intensity reductions. • Evaluate the feasibility of the 2035 interim target (40 percent reduction in GHG intensity) by July 1, 2028. • Coordinate and consult with other state agencies. • Prioritize actions that leverage state and federal incentives. • Evaluate measures to support market demand and financial incentives to encourage the production and use of cement with low GHG intensity. The Scoping Plan modeling is designed to achieve these outcomes.
Executive Order N-82-20	Governor Newsom signed Executive Order N-82-20 in October 2020 to combat the climate and biodiversity crises by setting a statewide goal to conserve at least 30 percent of California's land and coastal waters by 2030. The Executive Order also instructed the CNRA, in consultation with other state agencies, to develop a Natural and Working Lands Climate Smart Strategy that serves as a framework to advance the state's carbon neutrality goal and build climate resilience. In addition to setting a statewide conservation goal, the Executive Order directed CARB to update the target for natural and working lands in support of carbon neutrality as part of this Scoping Plan, and to take into consideration the NWL Climate Smart Strategy.

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Executive Order N-82-20 also calls on the CNRA, in consultation with other state agencies, to establish the California Biodiversity Collaborative (Collaborative). The Collaborative shall be made up of governmental partners, California Native American tribes, experts, business and community leaders, and other stakeholders from across the state. State agencies will consult the Collaborative on efforts to:

Establish a baseline assessment of California’s biodiversity that builds upon existing data and can be updated over time.
Analyze and project the impact of climate change and other stressors in California’s biodiversity.
Inventory current biodiversity efforts across all sectors and highlight opportunities for additional action to preserve and enhance biodiversity.

CNRA also is tasked with advancing efforts to conserve biodiversity through various actions, such as streamlining the state’s process to approve and facilitate projects related to environmental restoration and land management. The California Department of Food and Agriculture (CDFA) is directed to advance efforts to conserve biodiversity through measures such as reinvigorating populations of pollinator insects, which restore biodiversity and improve agricultural production.
The Natural and Working Lands Climate Smart Strategy informs this Scoping Plan.
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<tr><td>Executive Order N-79-20</td><td>
Governor Newsom signed Executive Order N-79-20 in September 2020 to establish targets for the transportation sector to support the state in its goal to achieve carbon neutrality by 2045. The targets established in this Executive Order are:

100 percent of in-state sales of new passenger cars and trucks will be zero-emission by 2035.
100 percent of medium- and heavy-duty vehicles will be zero-emission by 2045 for all operations where feasible, and by 2035 for drayage trucks.
100 percent of off-road vehicles and equipment will be zero-emission by 2035 where feasible.

The Executive Order also tasked CARB to develop and propose regulations that require increasing volumes of zero-electric passenger vehicles, medium- and heavy-duty
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	vehicles, drayage trucks, and off-road vehicles toward their corresponding targets of 100 percent zero-emission by 2035 or 2045, as listed above. The Scoping Plan modeling reflects achieving these targets.
Executive Order N-19-19	Governor Newsom signed Executive Order N-19-19 in September 2019 to direct state government to redouble its efforts to reduce GHG emissions and mitigate the impacts of climate change while building a sustainable, inclusive economy. This Executive Order instructs the Department of Finance to create a Climate Investment Framework that: • Includes a proactive strategy for the state's pension funds that reflects the increased risks to the economy and physical environment due to climate change. • Provides a timeline and criteria to shift investments to companies and industry sectors with greater growth potential based on their focus of reducing carbon emissions and adapting to the impacts of climate change. • Aligns with the fiduciary responsibilities of the California Public Employees' Retirement System, California State Teachers' Retirement System, and the University of California Retirement Program. Executive Order N-19-19 directs the State Transportation Agency to leverage more than $5 billion in annual state transportation spending to help reverse the trend of increased fuel consumption and reduce GHG emissions associated with the transportation sector. It also calls on the Department of General Services to leverage its management and ownership of the state's 19 million square feet in managed buildings, 51,000 vehicles, and other physical assets and goods to minimize state government's carbon footprint. Finally, it tasks CARB with accelerating progress toward California's goal of five million ZEV sales by 2030 by: • Developing new criteria for clean vehicle incentive programs to encourage manufacturers to produce clean, affordable cars. • Proposing new strategies to increase demand in the primary and secondary markets for ZEVs. • Considering strengthening existing regulations or adopting new ones to achieve the necessary GHG reductions from within the transportation sector.

	The Scoping Plan modeling reflects efforts to accelerate ZEV deployment.
Senate Bill 576 (SB 576) (Umberg, Chapter 374, Statutes of 2019) *Coastal Resources: Climate Ready Program and Coastal Climate Change Adaptation, Infrastructure and Readiness Program*	Sea level rise, combined with storm-driven waves, poses a direct risk to the state's coastal resources, including public and private real property and infrastructure. Rising marine waters threaten sensitive coastal areas, habitats, the survival of threatened and endangered species, beaches, other recreation areas, and urban waterfronts. SB 576 mandates that the Ocean Protection Council develop and implement a coastal climate adaptation, infrastructure, and readiness program to improve the climate change resiliency of California's coastal communities, infrastructure, and habitat. This bill also instructs the State Coastal Conservancy to administer the Climate Ready Program, which addresses the impacts and potential impacts of climate change on resources within the conservancy's jurisdiction.
Assembly Bill 65 (AB 65) (Petrie-Norris, Chapter 347, Statutes of 2019) *Coastal Protection: Climate Adaption: Project Prioritization: Natural Infrastructure: Local General Plans*	This bill requires the State Coastal Conservancy, when it allocates any funding appropriated pursuant to the California Drought, Water, Parks, Climate, Coastal Protection, and Outdoor Access For All Act of 2018, to prioritize projects that use natural infrastructure in coastal communities to help adapt to climate change. The bill requires the conservancy to provide information to the Office of Planning and Research on any projects funded pursuant to the above provision to be considered for inclusion into the clearinghouse for climate adaption information. The bill authorizes the conservancy to provide technical assistance to coastal communities to better assist them with their projects that use natural infrastructure.
Executive Order B-55-18	Governor Brown signed Executive Order B-55-18 in September 2018 to establish a statewide goal to achieve carbon neutrality as soon as possible, and no later than 2045, and to achieve and maintain net negative emissions thereafter. Policies and programs undertaken to achieve this goal shall: • Seek to improve air quality and support the health and economic resiliency of urban and rural communities, particularly low-income and disadvantaged communities. • Be implemented in a manner that supports climate adaptation and biodiversity, including protection of the state's water supply, water quality, and native plants and animals.

	This Executive Order also calls for CARB to: • Develop a framework for implementation and accounting that tracks progress toward this goal. • Ensure future Scoping Plans identify and recommend measures to achieve the carbon neutrality goal. This Scoping Plan is designed to achieve carbon neutrality no later than 2045 and the modeling includes technology and fuel transitions to achieve that outcome.
Senate Bill 100 (SB 100) (De León, Chapter 312, Statutes of 2018) *California Renewables Portfolio Standard Program: emissions of greenhouse gases*	SB 100 mandates that the CPUC, CEC, and CARB plan for 100 percent of total retail sales of electricity in California to come from eligible renewable energy resources and zero-carbon resources by December 31, 2045. This bill also updates the state's Renewables Portfolio Standard (RPS) to include the following interim targets: • 44% of retail sales procured from eligible renewable sources by December 31, 2024. • 52% of retail sales procured from eligible renewable sources by December 31, 2027. • 60% of retail sales procured from eligible renewable sources by December 31, 2030. Under SB 100, the CPUC, CEC, and CARB shall use programs under existing laws to achieve 100 percent clean electricity. The statute requires these agencies to issue a joint policy report on SB 100 every four years. The first of these reports was issued in 2021. This Scoping Plan reflects the SB 100 Core Scenario resource mix with a few minor updates.
Assembly Bill 2127 (AB 2127) (Ting, Chapter 365, Statutes of 2018) *Electric Vehicle Charging Infrastructure: Assessment*	This bill requires the CEC, working with CARB and the CPUC, to prepare and biennially update a statewide assessment of the electric vehicle charging infrastructure needed to support the levels of electric vehicle adoption required for the state to meet its goals of putting at least 5 million zero-emission vehicles on California roads by 2030 and of reducing emissions of GHGs to 40% below 1990 levels by 2030. The bill requires the CEC to regularly seek data and input from stakeholders relating to electric vehicle charging infrastructure. This bill supports the deployment of ZEVs as modeled in this Scoping Plan.

Senate Bill 30 (SB 30) (Lara, Chapter 614, Statutes of 2018) *Insurance: Climate Change*	This bill requires the Insurance Commissioner to convene a working group to identify, assess, and recommend risk transfer market mechanisms that, among other things, promote investment in natural infrastructure to reduce the risks of climate change related to catastrophic events, create incentives for investment in natural infrastructure to reduce risks to communities, and provide mitigation incentives for private investment in natural lands to lessen exposure and reduce climate risks to public safety, property, utilities, and infrastructure. The bill requires the policies recommended to address specified questions.
Assembly Bill 2061 (AB 2061) (Frazier, Chapter 580, Statutes of 2018) *Near-zero-emission and Zero-emission Vehicles*	Existing state and federal law sets specified limits on the total gross weight imposed on the highway by a vehicle with any group of two or more consecutive axles. Under existing federal law, the maximum gross vehicle weight of that vehicle may not exceed 82,000 pounds. AB 2061 authorizes a near-zero-emission vehicle or a zero-emission vehicle to exceed the weight limits on the power unit by up to 2,000 pounds. This bill supports the deployment of cleaner trucks as modeled in this Scoping Plan.

Consideration of Relevant State Plans and Regulations

Development of this Scoping Plan also included careful consideration of, and coordination with, other state agency plans and regulations, including the SB 100 Joint Agency Report,[99] the 2022 State Strategy for the State Implementation Plan,[100] Climate Action Plan for Transportation Infrastructure,[101] AB 74 Studies on Vehicle Emissions and Fuel Demand and Supply,[102,103,104] Short-Lived Climate Pollutant Strategy (SLCP Strategy),[105]

[99] CPUC, CEC, and CARB. 2021. *SB 100 Joint Agency Report.* https://www.energy.ca.gov/sb100.
[100] CARB. January 31, 2022. Draft 2022 State Strategy for the State Implementation Plan. https://ww2.arb.ca.gov/sites/default/files/2022-01/Draft_2022_State_SIP_Strategy.pdf.
[101] CalSTA. 2021. *Climate Action Plan.* https://calsta.ca.gov/subject-areas/climate-action-plan.
[102] CalEPA. 2021. Carbon Neutrality Studies. https://calepa.ca.gov/climate/carbon-neutrality-studies/.
[103] Brown, A. L., et. al. 2021. *Driving California's Transportation Emissions.* https://escholarship.org/uc/item/3np3p2t0.
[104] Deschenes, O. 2021. *Enhancing equity*. https://zenodo.org/record/4707966#.YKPiaKhKi73.
[105] CARB. Short-Lived Climate Pollutants. https://ww2.arb.ca.gov/our-work/programs/slcp.

CARB's Achieving Carbon Neutrality Report,[106] Climate Smart Strategy,[107] and draft Natural and Working Lands Implementation Plan,[108] among others.

Input from Partners and Stakeholders

CARB also collaborated with other state agencies, held consultations with tribes, and solicited comments and feedback from affected stakeholders, including labor organizations and the public. The process to update the Scoping Plan began with kickoff workshops in early June 2021,[109] followed by over a dozen public workshops, including engagement with tribes,[110] and featured a series of EJ Advisory Committee and environmental justice community meetings.[111] The June 2021 workshop and several others were a joint agency effort, as there are many agencies with direct authority or jurisdiction over different sectors of the economy. Consultation with agencies also included bi-weekly, monthly, and weekly meetings.

During the summer of 2022 CARB held three community listening sessions, hosted by the CARB Chair and Board, in communities around the state, along with one virtual community listening session and one tribal listening session specifically for tribes. Many tribes provided written feedback, which was incorporated into this Scoping Plan. In addition, CARB respects tribal sovereignty and also engaged in a consultation campaign with tribes, which resulted in government-to-government consultations, and this Scoping Plan is reflective of this process.[112]

Emissions Data That Inform the Scoping Plan

Greenhouse Gas Emissions

AB 32 includes which GHGs are to be regulated, reduced, and included in the state's targets and goals. That list includes seven GHGs: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs),

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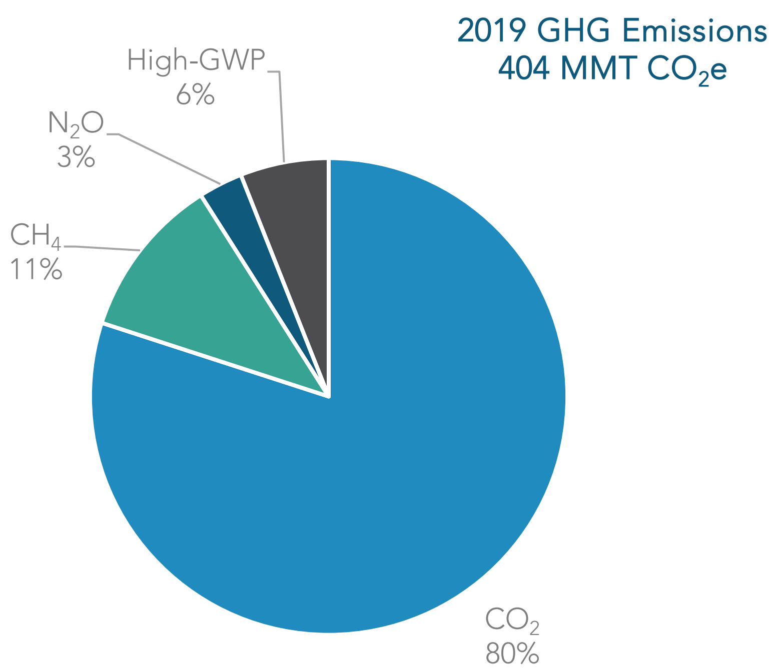
[106] Energy and Environmental Economics, Inc. 2020. *Achieving Carbon Neutrality.* https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf.
[107] CNRA. 2022. Natural and Working Lands Climate Smart Strategy. https://resources.ca.gov/Initiatives/Expanding-Nature-Based-Solutions.
[108] CARB. 2019. *Draft California 2030 Natural and Working Lands Climate Change Implementation Plan.* https://ww2.arb.ca.gov/resources/documents/nwl-implementation-draft.
[109] Appendix A (Public Process).
[110] CARB. Scoping Plan Meetings & Workshops. https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/scoping-plan-meetings-workshops.
[111] CARB. Environmental Justice Advisory Committee Meetings and Events. https://ww2.arb.ca.gov/environmental-justice-advisory-committee-meetings-and-events.
[112] CARB. 2018. Tribal Consultation Policy. October. https://www.arb.ca.gov/regact/nonreg/2018/california_air_resources_board_tribal_consultation_policy.pdf.

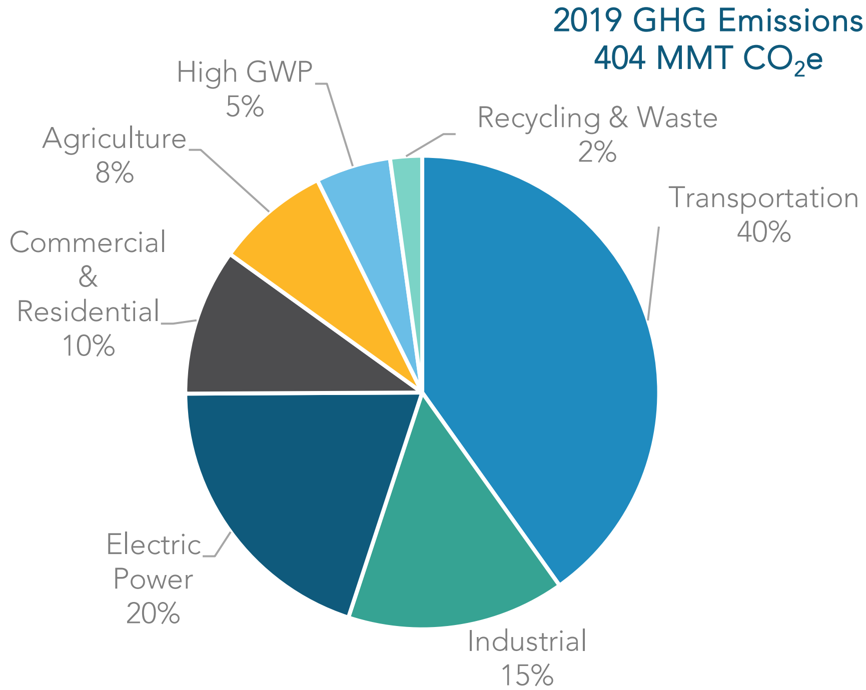
perfluorocarbons (PFCs), and nitrogen trifluoride (NF_3). Carbon dioxide is the primary GHG emitted in California, accounting for 83 percent of the total GHG emissions in 2019, as shown in Figure 1-7 below. Figure 1-8 illustrates that transportation (primarily on-road travel) is the single largest source of CO_2 emissions in the state. Upstream transportation emissions from the refinery and oil and gas sectors are categorized as CO_2 emissions from industrial sources and constitute about 50 percent of the industrial source emissions. When including these emissions, the transportation sector accounts for approximately half of statewide GHG emissions. Other significant sources of CO_2 include electricity production, industrial sources like refineries and cement plants, and residential sources like fossil gas. Figures 1-7 and 1-8 show state GHG emission contributions by GHG and sector based on the 2020 Greenhouse Gas Emission Inventory; GHG emissions for 2019 are shown because 2020 was an outlier due to the global pandemic. Emissions in Figure 1-8 are depicted by Scoping Plan sector, which includes separate categories for high-global warming potential (GWP) and recycling/waste emissions that are otherwise typically included within other economic sectors.

Figure 1-7: 2019 State GHG emission contributions by GHG[113]



[113] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020: Trends of Emissions and Other Indicators.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

Figure 1-8: 2019 State GHG emission contributions by Scoping Plan sector[114]



The scope of the AB 32 GHG Inventory encompasses emission sources within the state's borders, as well as imported electricity consumed in the state. This construct for the inventory is consistent with IPCC practices to allow for comparison of statewide GHG emissions with those at the national level and with other international GHG inventories. Statewide GHG emissions calculations use many data sources, including data from other state and federal agencies. However, a significant source of data comes from reports submitted to CARB through the Regulation for the Mandatory Reporting of GHG Emissions (MRR). The MRR requires facilities and entities with more than 10,000 metric tons of carbon dioxide equivalent ($MTCO_2e$) of combustion and process emissions, all facilities belonging to certain industries, and all electric power entities to submit an annual GHG emissions data report directly to CARB. Furthermore, this regulation requires that reports from entities that emit more than 25,000 $MTCO_2e$ be verified by a CARB-

[114] The High GWP sector includes high global warming potential gas emissions from releases of ozone depleting substance (ODS) substitutes, SF_6 emissions from the electricity transmission and distribution system, and gases that are emitted in the semiconductor manufacturing process. ODS substitutes, which are primarily HFCs, are used in refrigeration and air conditioning equipment, solvent cleaning, foam production, fire retardants, and aerosols.

accredited third-party verification body. More information on MRR emissions reports can be found at CARB's Mandatory Greenhouse Gas Emissions Reporting website.[115]

All data sources used to develop the GHG Emission Inventory are listed in CARB's inventory supporting documentation.[116]

Natural and Working Lands

For natural and working lands, the 2018 ecosystem carbon inventory (NWL Inventory)[117] shows there are approximately 5,340 million metric tons (MMT) of carbon in the carbon pools[118] (reservoirs of carbon that have the ability to both take in and release carbon) that CARB has quantified (see Figure 1-9). For purposes of comparison, 5,340 MMT of ecosystem carbon stock is equivalent to 19,600 MMT of atmospheric CO_2. Forests and shrublands contain the majority of California's carbon stock because they cover the majority of California's landscape and have the highest carbon density of any land cover type. All other land categories combined comprise over 35 percent of California's total acreage, but only 15 percent of carbon stocks. Roughly half of the 5,340 MMT of carbon resides in soils and half in plant biomass.

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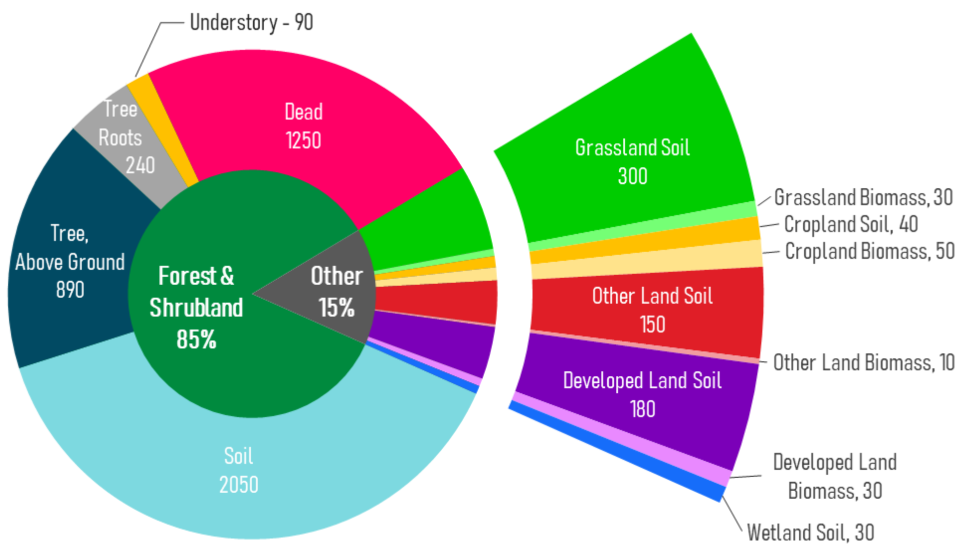
115 CARB. Mandatory Greenhouse Gas Emissions Reporting. https://ww2.arb.ca.gov/our-work/programs/mandatory-greenhouse-gas-emissions-reporting.

116 CARB. Current California GHG Emission Inventory Data. www.arb.ca.gov/cc/inventory/data/data.htm.

117 CARB. 2018. *An Inventory of Ecosystem Carbon in California's Natural and Working Lands.* https://ww3.arb.ca.gov/cc/inventory/pubs/nwl_inventory.pdf.

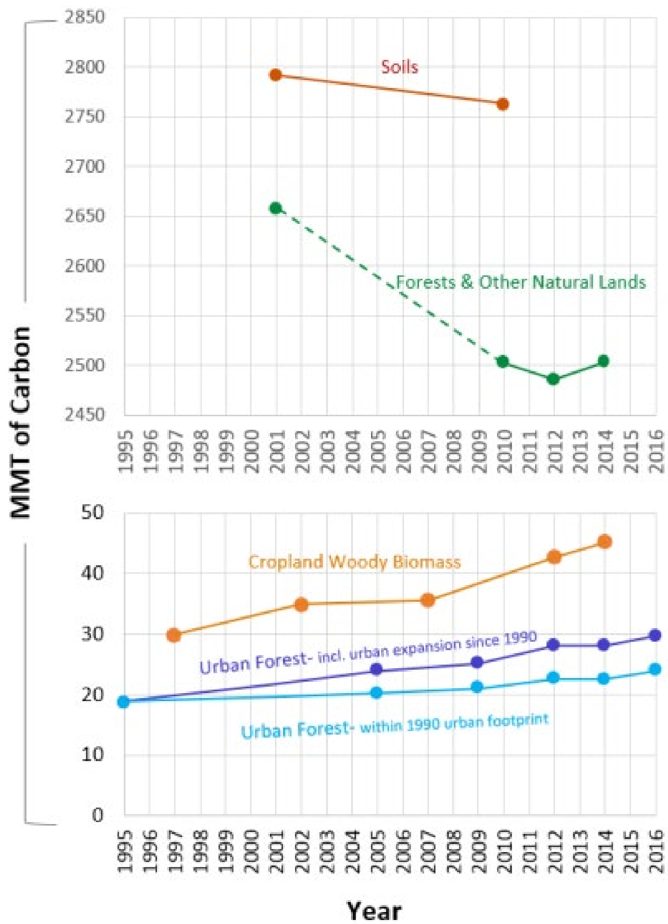
118 "Carbon pools" are Above-Ground Live Biomass (boles, stems, and foliage in shrubs, trees, grasses, and herbaceous vegetation), Below-Ground Live Biomass (roots in shrubs, trees, grasses, and herbaceous vegetation), Dead Organic Matter (standing or downed dead wood and litter), Harvested Wood Products (all wood and bark material that leaves harvest sites regardless of whether it is eventually incorporated into merchandisable products), and Soil Organic Matter (organic carbon in the top 30 centimeters of soil).

Figure 1-9: Carbon stocks in natural and working lands (MMT carbon)



In addition to providing an estimate of the ecosystem carbon that exists on California's landscape, the NWL Inventory also shows how those carbon stocks are changing (see Figure 1-10). The inventory attributes stock change to human activity, such as land use change, or to disturbances, such as wildfire. CARB's inventory shows these lands were a source of GHG emissions from 2001 to 2011, releasing more carbon than they stored, and then they returned to be a slight carbon sink from 2012 to 2014. These trends highlight the interannual and interdecadal variability of lands and their ability to be both a source and a sink of carbon.

Figure 1-10: Changes in carbon stock by landscape type



For natural and working lands, California's inventory is also based on IPCC methods for tracking ecosystem carbon over time, providing for comparability with other national and subnational inventories and carbon accounting. As such, the NWL Inventory is an important tool for tracking both carbon stock changes in California over time and the impacts that interventions such as those identified in this Scoping Plan, actions identified in the Climate Smart Land Strategy, and others have on NWL carbon stocks.

All data sources used to develop the NWL Inventory are listed in the technical support documentation at CARB's California Natural & Working Lands Inventory website.[119]

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[119] CARB. California Natural & Working Lands Inventory. https://ww2.arb.ca.gov/nwl-inventory.

Black Carbon

In addition, CARB has developed a statewide emission inventory for black carbon in support of the SLCP Strategy. The inventory is reported in two categories: non-forestry (anthropogenic) sources and forestry sources.[120] The black carbon inventory is calculated using existing $PM_{2.5}$ emission inventories combined with speciation profiles that define the fraction of $PM_{2.5}$ that is black carbon. The black carbon inventory helps support implementation of the SLCP Strategy, but it is not part of California's GHG Inventory that tracks progress toward the state's climate targets under AB 32 or SB 32. The state's major anthropogenic sources of black carbon include off-road transportation, on-road transportation, residential wood burning, fuel combustion, and industrial processes. CARB estimated 2017 black carbon emissions to be approximately 8 $MTCO_2e$.[121] The majority of anthropogenic sources come from transportation—specifically, heavy-duty vehicles. The share of black carbon emissions from transportation is dropping rapidly and is expected to continue to do so between now and 2030 as a result of California's air quality programs. The remaining black carbon emissions will come largely from woodstoves/fireplaces, off-road applications, and industrial/commercial combustion. The forestry category includes non-agricultural prescribed burning and wildfire emissions.

Tracking Life-Cycle and Out-of-State Emissions

In recent years there has been increased interest in the embedded carbon in products, also known as *life-cycle emissions.* A life-cycle accounting framework refers to all of the GHG emissions generated from the sourcing, production, and transportation of products to an endpoint. In doing such assessments for a product, emissions may be associated with sourced materials and production activity outside a jurisdiction's borders. While life-cycle emissions can provide a more comprehensive picture of the emissions associated with the goods we consume and ongoing demand, life-cycle inventories are inconsistent with IPCC standards, as they would result in double counting of emissions across jurisdictions. Other countries and regions do produce their own inventory reports consistent with IPCC methods and are taking action to reduce emissions within their jurisdictions. In addition, jurisdictions often lack legal authority to regulate sources outside of their borders. Finally, it is difficult to obtain accurate data for sources and production activities outside of a region's border that would impact the accuracy of such an inventory. For these reasons, the inventory used in the Scoping Plan does not use a life-cycle

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[120] SB 1383. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB1383.

[121] This is a preliminary estimate developed for this Scoping Plan. Official Black Carbon emissions estimates are provided in the SLCP inventory here: https://ww2.arb.ca.gov/ghg-slcp-inventory.

approach and remains consistent with international accounting standards and consistent with how other countries and regions track emissions within their jurisdictions.

However, GHG mitigation action may cross geographic borders as part of subnational and international collaboration, or as a natural result of implementation of regional policies. In addition to the state's existing GHG inventory, CARB will develop an accounting framework that reflects the benefits of our policies accruing outside of the state. This accounting framework will be important to better understand the true impact of the state's policies on what is emitted into the atmosphere. For example, the LCFS incentivizes GHG reductions along the entire supply chain for the production and delivery of transportation fuel imported for use in the state. However, our inventory only captures the change in emissions from the tailpipe of when that fuel is used in California and does not capture any GHG reductions that occur in the production process if the fuel is produced out of state.

Natural and working lands forestry actions are another example, where California's policies are inspiring forest management actions in other states that result in increased permanent carbon sequestration. California's NWL inventory does not capture the increased carbon stocks resulting from forestry projects happening outside of California, and the CO_2 removals resulting from these projects are not applied in either CARB's NWL inventory or CARB's AB 32 GHG Emissions Inventory. For GHG reductions outside of the state to be attributed to our programs, those reductions must be real, quantifiable, verifiable, and permanent.

It also will be important to avoid any double counting (including claims to those reductions by other jurisdictions) and to transparently indicate whether any extra-jurisdictional emissions reductions might be included in another region's inventory. CARB is collaborating with other jurisdictions to ensure GHG accounting rules are consistent with international best practices, as robust accounting rules instill confidence in the reductions claimed and maintain support for joint action across jurisdictions. The policy goals of consistency and transparency are critical as we work together with other jurisdictions on our parallel paths to achieve our GHG targets with real benefits to the atmosphere.

Tracking Progress

Historically, the AB 32 GHG Inventory has been the primary metric to track progress toward achieving climate targets.[122] However, we must now deploy clean technology at unprecedented rates. The emissions modeling underpinning this Scoping Plan and

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[122] Starting with the 2022 Edition of the AB 32 GHG inventory, the inventory development now relies more directly on the annually reported and third-party verified emissions from the Regulation for the Mandatory Reporting of Greenhouse Gas Emissions.

targets for clean technology in statute can serve as leading indicators across the economy on how our actions compare to the pace of action needed to be on track to achieve carbon neutrality. The California Climate Dashboard[123] was launched in 2022 and provides high-level metrics for clean energy production and technology deployment. Statistics such as the deployment of zero emission vehicles and clean electricity generation are just some of the examples of metrics across the economy that can be tracked, in addition to GHG emissions, to understand if the state is on track to meet its climate goals. A key indicator to track will be building of new energy infrastructure and deployment of clean technology as evaluated in the uncertainty analysis in Chapter 2. CARB will coordinate with state agencies to establish and make public similar metrics across all economic sectors to help provide transparency on the state's progress in deploying clean technology at the pace and scale needed to achieve carbon neutrality no later than 2045.

[123] CalEPA. California Climate Dashboard. https://calepa.ca.gov/climate-dashboard/.

Chapter 2: The Scoping Plan Scenario

This chapter describes the Scoping Plan Scenario, which for the first time includes sources in both the AB 32 GHG Inventory and Natural and Working Lands (NWL). It begins with a short description of the alternatives evaluated. Four scenarios for the AB 32 GHG Inventory and NWL were considered separately and helped to inform the Scoping Plan Scenario. Each of the alternatives were considered in terms of the important criteria and priorities that the state's comprehensive climate action must deliver, including the need for GHG reductions that are not only technologically feasible and cost-effective, but also can deliver health and economic benefits for the state. All the scenarios were set against what is called the *Reference Scenario*—that is, what the GHG emissions would look like if we did nothing at all beyond the existing policies that are required and already in place to achieve the 2030 target of at least 40 percent below 1990 levels, or those expected with no new actions in the NWL sector. For this Scoping Plan, two sets of modeling tools were used to evaluate the AB 32 GHG Inventory and NWL sectors because no single model can assess both AB 32 sectors and NWL together. As a result, two different sets of scenarios were developed for each sector type. While this chapter breaks out discussion separately for the two sector types, the Scoping Plan Scenario reflects the combined actions across both sectors by choosing an alternative from each sector type. The modeling provides point estimates; however, that does not imply precision. As discussed in the uncertainty section, several types of uncertainties are associated with any outcomes projected by the modeling results. There will be ranges of estimates associated with each point that are not shown in the graphs or results.

Scenarios for the AB 32 GHG Inventory Sectors

The Reference Scenario for the AB 32 GHG Inventory sectors shows continuing but modest GHG reductions beyond 2030 that level off toward mid-century. The comprehensive analysis of all four alternatives indicates that the Scoping Plan Scenario is the best choice to achieve California's climate and clean air goals while balancing the legislative direction on prioritizing direct emissions reductions, reducing anthropogenic emissions by at least 85 percent by 2045, being technologically feasible, and being cost-effective. It also protects public health, provides a solid foundation for continued economic growth, and drastically reduces the state's dependence on fossil fuel combustion and does not disproportionately impact disadvantaged communities. Each of the alternative scenarios was the product of a process of development informed by public input, the governor,[124] CARB, legislative direction, and input by the EJ Advisory Committee.[125,126] Future updates to the Scoping Plan may consider new clean technologies and fuels beyond those included in this Scoping Plan.

The four scenarios evaluated shared many similarities. They each embodied the following characteristics:

- Drastic reduction in fossil fuel dependence, with some remaining in-state demand for fossil fuels for aviation, marine, and locomotion applications, and for fossil gas for buildings and industry
- Ambitious deployment of efficient non-combustion technologies such as zero emission vehicles and heat pumps
- Rapid growth in the production and distribution of clean energy such as zero carbon electricity and hydrogen
- Progressive phasedown of fossil fuel production and distribution activities as part of the transition to clean energy
- Remaining emissions of fugitive SLCPs such as refrigerants and fugitive methane
- Strong consumer adoption of clean technology and fuel options
- Removal of remaining CO_2 emissions to achieve carbon neutrality
- Some reliance on carbon capture and sequestration (CCS)

While the four scenarios had a lot in common, they also had some differences:

- Year in which carbon neutrality is achieved (2035 or 2045)
- Rate of deployment of clean technology and production and distribution of zero carbon energy
- Remaining amount of demand for fossil energy in the year carbon neutrality is achieved
- Constraints on technology and fuels deployed in certain sectors
- Consumer adoption rates of clean technologies and fuels
- Degree of reliance on CO_2 removal
- Degree of reliance on CCS

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[124] Newsom, Gavin. July 22, 2022. Letter from Governor Newsom to CARB Chair Liane Randolph. Retrieved from *https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf*.

[125] EJ Advisory Committee. December 2, 2021. EJ Advisory Committee Responses for the CARB Scenario Inputs. *https://ww2.arb.ca.gov/sites/default/files/2021-12/EJAC%20Final%20Responses%20to%20CARB%20Scenario%20Inputs_12_2_21.pdf*.

[126] CARB. January 25, 2022. Update on PATHWAYS Scenario Modeling Assumptions. *https://ww2.arb.ca.gov/sites/default/files/2022-01/Scenario%20Slides%20for%20Jan25%20EJAC%20Mtg_01242022.pdf*.

The summary below provides an overview of the alternatives designed and considered for the energy and industrial sectors in this update. Full details of each scenario considered can be found in the *Draft 2022 Scoping Plan Update*

Scoping Plan Scenario (modeling scenario Alternative 3 from the Draft): carbon neutrality by 2045, deploy a broad portfolio of existing and emerging fossil fuel alternatives and clean technologies, and align with statutes, Executive Orders, Board direction, and direction from the governor

Alternative 1: carbon neutrality by 2035, nearly complete phaseout of all combustion, limited reliance on carbon capture and sequestration and engineered carbon removal, and restricted applications for biomass-derived fuels

Alternative 2: carbon neutrality by 2035 and aggressive deployment of a full suite of technology and energy options, including engineered carbon removal

Alternative 4: carbon neutrality by 2045, deployment of a broad portfolio of existing and emerging fossil fuel alternatives, slower deployment and adoption rates than the Scoping Plan Scenario, and a higher reliance on CO_2 removal

Other considerations for the AB 32 GHG Inventory sectors include the following:

- To what extent does an alternative meet the statewide targets and any sector targets, and also deliver clean air benefits (especially in the near term) to address ongoing healthy air disparities, prioritize reductions for mobile and large stationary sources, and emphasize continued investment in disadvantaged communities?
- Does an alternative support California in building on efforts to collaborate with other jurisdictions and include exportable policies based on robust science?
- Does an alternative provide for compliance options and a cost-effective approach to reduce GHG emissions?
- Does the alternative present a realistic and ambitious path forward consistent with statute and science, and support economic opportunities, particularly in anticipated growth sectors?

Scenarios for Natural and Working Lands

For the natural and working lands sector, the Reference Scenario shows that NWL will continue to emit GHGs and lose carbon stocks into the future as the combined effects of past unhealthy management practices and climate change impact our lands. Relative to the Reference Scenario, the four NWL scenarios represent different scales of land management on seven landscapes (forests, shrublands/chaparral, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands) to support carbon neutrality.

The analysis of the four NWL scenarios shows that the Scoping Plan Scenario is the preferred choice because it prioritizes sustainable land management to sequester carbon over the long term, GHG and air pollution reductions, ecosystem health and resilience, and implementation and technological feasibility and cost-effectiveness. The Scoping Plan Scenario reduces catastrophic wildfire risk to the state; increases the health and resilience of California's forests, shrublands, and grasslands; increases soil health; and protects, restores, and enhances California's natural and working lands for future generations. The Scoping Plan Scenario takes into consideration the priority landscapes and nature-based strategies identified in California's Climate Smart Strategy[127] and reflects the state's priorities to manage lands in ways that support the multiple benefits they provide. The Scoping Plan Scenario, as well as each of the alternative NWL scenarios, were informed by input from other agencies, the public, and the EJ Advisory Committee. Additional landscapes and land management activities will be added and evaluated in future Scoping Plan updates and in response to AB 1757.

Each of the NWL scenarios have several similarities, including the following:

- Prioritizing NWL management actions on forests, shrublands, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands. These actions can reduce GHG emissions from these lands, protect ecosystems against future climate change, protect communities, and enhance the ecosystem benefits they provide to nature and society.
- Exploring the potential impacts of different levels of NWL management actions that are designed to achieve the objective associated with each scenario.
- Analyzing the carbon impacts of land management actions, climate change, wildfire, and water use on California's diverse natural and working lands through 2045.

There are also differences across the four NWL scenarios. These include:

- The level of NWL management actions taken on each landscape, such as varying the acres of healthy soils practices for croplands.
- The types of NWL management actions taken on each landscape, such as prescribed burning or thinning for forests, grasslands, and shrublands.

[127] CNRA. 2022. Natural and Working Lands Climate Smart Strategy. https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/CNRA-Report-2022---Final_Accessible_Compressed.pdf.

The summary below provides an overview of the alternatives designed and considered for the NWL sectors in this Scoping Plan. Full details of each scenario considered can be found in the *Draft 2022 Scoping Plan Update*.

Scoping Plan Scenario (NWL Alternative 3 from the Draft): land management activities that prioritize restoration and enhancement of ecosystem functions to improve resilience to climate change impacts, including more stable carbon stocks

NWL Alternative 1: land management activities that prioritize short term carbon stocks in our forests and through increased climate smart agricultural practices on croplands

NWL Alternative 2: land management activities representative of California's current commitments and plans

NWL Alternative 4: land management activities that prioritize reducing catastrophic wildfires in forests, shrublands, and grasslands

Evaluation of Scoping Plan Alternatives

CARB staff solicited feedback from topical experts, affected stakeholders, and the EJ Advisory Committee, including a tribal representative, at public meetings to assemble input assumptions for four carbon neutrality scenarios to model using PATHWAYS. Revisions to the Draft Scoping Plan were informed by direction in statute, the Governor's Executive Orders, public comments, and the recommendations of the EJ Advisory Committee. The three alternative scenarios were designed to explore the potential speed, magnitude, and impacts of transitioning California's energy demand away from fossil fuels. The modeling assumptions listed below identify the primary fossil fuel alternative that is commercially available and technically feasible for widespread use by 2045 for each sector. CARB assumes that any energy demand that remains after the alternative technology or fuel is applied—such as on-road internal combustion engines, industrial processes, and gas use in existing buildings that have not yet decarbonized—will continue to be met by fossil fuels, resulting in residual GHG emissions.

NWL Scoping Plan Alternatives

For the NWL sectors, staff significantly expanded the scale of the scientific analysis for NWL from previous Scoping Plan efforts. CARB staff utilized modeling tools for this expanded analysis to assess both the carbon and other ecological, public health, and economic outcomes of management actions on forests, shrublands, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands. CARB staff aligned the scenarios with both the landscape types and actions identified in other efforts called for in Governor Newsom's Executive Order N-82-20 (e.g., California's Climate Smart Strategy and Pathways to 30x30). As part of this Scoping Plan, CARB staff modeled as many of the management actions identified in the Natural and Working Lands Climate

Smart Strategy as were feasible. The management actions that were included in the model were selected because of the State of California's previous work to quantify these actions' impacts. It was not feasible to model every land management strategy for NWL, and so it is possible that larger volumes of sequestration (e.g., in soils or in oceans) could result from additional non-modeled activities. California's Natural and Working Lands Climate Smart Strategy includes a more comprehensive listing of priority nature-based solutions and management actions. It is important to note that the absence of a particular management action or its climate benefit in the modeling is not an indication of its importance or potential contributions toward meeting the target or toward supporting the carbon neutrality target for California.

Forests: Management strategies were modeled for forests: biological/chemical/herbaceous treatments (e.g., herbicide application), clearcut, various timber harvests (e.g., variable retention, seed tree / shelterwood, selection harvesting), mastication, other mechanical treatments (e.g., piling of dead material, understory thinning), prescribed burning, and thinning. Avoided land conversion to another land use was also included in the modeling. Wildfire was modeled and is responsive to management strategies and climate conditions.

Shrublands and chaparral: Management strategies were modeled for shrublands and chaparral: biological/chemical/herbaceous treatments, prescribed burning, mechanical treatment (e.g., mastication, crushing, mowing, piling), and avoided conversion from shrubland to another land use. Wildfire was modeled and is responsive to management strategies and climate conditions.

Grasslands: Management strategies were modeled for grasslands: biological/chemical/herbaceous treatments, prescribed burning, and avoided land conversion from grasslands to another land use. Wildfire was modeled and is responsive to management strategies and climate conditions.

Croplands: Management strategies were modeled for row crops: cover cropping, no till, reduced till, compost amendment, transition to organic[128] farming, avoided conversion of annual crop agricultural land through easements, establishing riparian forest buffers, alley cropping, establishing windbreaks/shelterbelts, establishing tree and shrubs in croplands, and establishing hedgerows. For perennial crops, windbreaks/shelterbelts, hedgerows, conversion from annual crops to perennial crops, and avoided conversion to other land uses were modeled.

[128] Note: N_2O reductions from decreases in synthetic fertilizer application in organic farming were not modeled.

Developed lands: Management strategies were modeled for developed lands: Increasing tree canopy cover through planting trees and improved management of existing trees, and removing vegetation surrounding structures in accordance with the CAL FIRE Defensible Space PRC 4291.

Wetlands: Management strategies were modeled for wetlands: Restoring wetlands through submerging cultivated land in the Sacramento-San Joaquin Delta and avoided land conversion in the Sacramento-San Joaquin Delta.

Sparsely vegetated lands: Management strategies were modeled for sparsely vegetated lands: Avoided conversion of sparsely vegetated lands to another land use.

Scoping Plan Scenario

The Scoping Plan Scenario achieves GHG emission reductions that exceed the levels expected based on existing policies represented in the Reference Scenario, keeping California on track to achieve the SB 32 GHG reduction target for 2030 and become carbon neutral no later than 2045. Actions that reduce GHG emissions and transition AB 32 GHG Inventory sources away from fossil fuel combustion affect each economic sector. Actions that lead to improved carbon stocks affect each landscape.

AB 32 GHG Inventory Sectors

The AB 32 GHG Inventory Sector Reference scenario is the forecasted statewide GHG emissions through mid-century, with existing policies and programs but without any further action to reduce GHGs beyond those needed to achieve the 2030 limit. The Reference Scenario was developed based on other projections of business-as-usual conditions. Sources of data and policies included are:

- California Energy Demand Forecast[129]
- The two transportation carbon neutrality studies required by AB 74[130]
- The Mobile Source Strategy[131]
- SB 100 60 percent Renewables Portfolio Standard
- A Low Carbon Fuel Standard carbon intensity reduction target of 20 percent

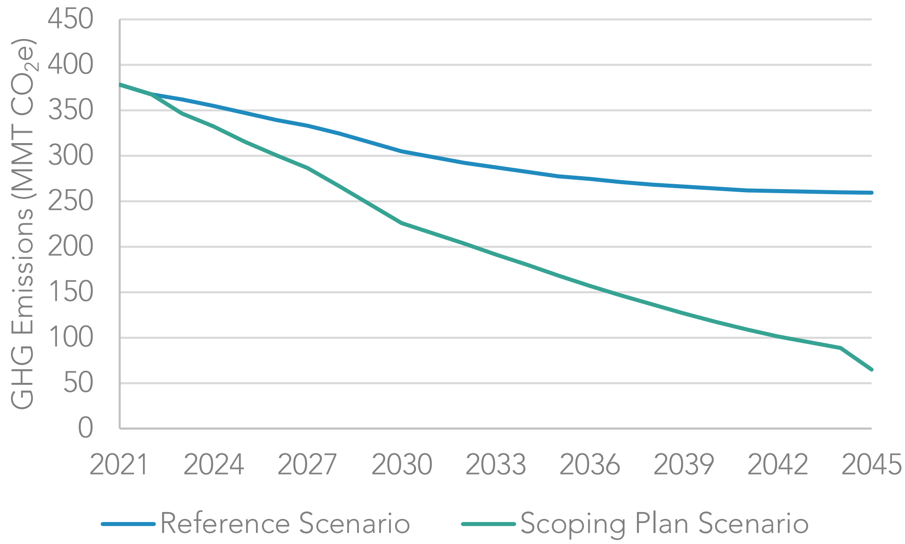
Policies that are under study or design, such the Advanced Clean Fleets regulation, are not included. The Reference Scenario reflects current trends and expected performance of policies identified in the 2017 Scoping Plan—some of which are performing better (such as the RPS and LCFS) and others that may not meet expectations (such as vehicle miles traveled [VMT] reductions and methane capture). Figure 2-1 provides the modeling results for a Reference Scenario for the AB 32 GHG Inventory sectors compared to the Scoping Plan Scenario.

[129] California Energy Commission (CEC). 2020. *2019 Integrated Energy Policy Report.* https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report.

[130] Brown et al. 2021. *Driving California's Transportation Emissions.* https://escholarship.org/uc/item/3np3p2t0 and Deschenes et al. 2021. *Enhancing equity.* https://zenodo.org/record/4707966#.YI72RNrMKUn.

[131] CARB. 2021. 2020 *Mobile Source Strategy.* https://ww2.arb.ca.gov/sites/default/files/2021-12/2020_Mobile_Source_Strategy.pdf.

Figure 2-1: Reference and Scoping Plan Scenario GHG emissions[132]



The Scoping Plan Scenario is summarized in Table 2-1. The table shows the types of technologies and energy needed to drastically reduce GHG emissions from the AB 32 Inventory sectors. It also includes references to relevant statutes and Executive Orders, although it is not comprehensive of all existing new authorities for directing or supporting the actions described. Each action is expected to both reduce GHGs and help improve air quality, primarily by transitioning away from combustion of fossil fuels. The Scoping Plan Scenario achieves the AB 1279 target of 85 percent below 1990 levels by 2045 and identifies a need to accelerate the 2030 target to 48 percent below 1990 levels.

[132] The drop in emissions in 2045 reflects both the need to achieve an 85% reduction below 1990 levels in anthropogenic emissions per AB 1279 and Governor Newsom's request for a 100 MMT CO2e carbon removal and capture target in 2045. This was modeled by extending CCS to electric sector emissions.

Table 2-1: Actions for the Scoping Plan Scenario: AB 32 GHG Inventory sectors

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
GHG Emissions Reductions Relative to the SB 32 Target[133]	40% below 1990 levels by 2030	SB 32: Reduce statewide GHG emissions. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Smart Growth / Vehicle Miles Traveled (VMT)	VMT per capita reduced 25% below 2019 levels by 2030, and 30% below 2019 levels by 2045	SB 375: Reduce demand for fossil transportation fuels and GHGs, and improve air quality. In response to Board direction and EJ Advisory Committee recommendations
Light-duty Vehicle (LDV) Zero Emission Vehicles (ZEVs)	100% of LDV sales are ZEV by 2035	EO N-79-20: Reduce demand for fossil transportation fuels and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory 2035 target aligns with the EJ Advisory Committee recommendation.

[133] While the SB 32 GHG emissions reduction target is not an Action that is analyzed independently, it is included in this table for reference.

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Truck ZEVs	100% of medium-duty (MDV)/HDV sales are ZEV by 2040 (AB 74 University of California Institute of Transportation Studies [ITS] report)	EO N-79-20: Reduce demand for fossil transportation fuels and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Aviation	20% of aviation fuel demand is met by electricity (batteries) or hydrogen (fuel cells) in 2045. Sustainable aviation fuel meets most or the rest of the aviation fuel demand that has not already transitioned to hydrogen or batteries.	Reduce demand for petroleum aviation fuel and reduce GHGs. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory In response to Governor Newsom's July 2022 letter to CARB Chair Liane Randolph
Ocean-going Vessels (OGV)	2020 OGV At-Berth regulation fully implemented, with most OGVs utilizing shore power by 2027. 25% of OGVs utilize hydrogen fuel cell electric technology by 2045.	Reduce demand for petroleum fuels and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Port Operations	100% of cargo handling equipment is zero-emission by 2037. 100% of drayage trucks are zero emission by 2035.	Executive Order N-79-20: Reduce demand for petroleum fuels and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Freight and Passenger Rail	100% of passenger and other locomotive sales are ZEV by 2030. 100% of line haul locomotive sales are ZEV by 2035. Line haul and passenger rail rely primarily on hydrogen fuel cell technology, and others primarily utilize electricity.	Reduce demand for petroleum fuels and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Oil and Gas Extraction	Reduce oil and gas extraction operations in line with petroleum demand by 2045.	Reduce GHGs and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Petroleum Refining	CCS on majority of operations by 2030, beginning in 2028 Production reduced in line with petroleum demand.	Reduce GHGs and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Electricity Generation	Sector GHG target of 38 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) in 2030 and 30 $MMTCO_2e$ in 2035 Retail sales load coverage[134] 20 gigawatts (GW) of offshore wind by 2045 Meet increased demand for electrification without new fossil gas-fired resources.	SB 350 and SB 100: Reduce GHGs and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory In response to Governor Newsom's July 2022 letter, Board direction, and EJ Advisory Committee recommendation
New Residential and Commercial Buildings	All electric appliances beginning 2026 (residential) and 2029 (commercial), contributing to 6 million heat pumps installed statewide by 2030	Reduce demand for fossil gas and GHGs, and improve ambient and indoor air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory In response to Governor Newsom's July 2022 letter

[134] SB 100 speaks only to retail sales and state agency procurement of electricity. The *2021 SB 100 Joint Agency Report* reflects the agency authors' understanding that other loads—wholesale or non-retail sales and losses from storage and transmission and distribution lines—are not subject to the law.

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Existing Residential Buildings	80% of appliance sales are electric by 2030 and 100% of appliance sales are electric by 2035. Appliances are replaced at end of life such that by 2030 there are 3 million all-electric and electric-ready homes—and by 2035, 7 million homes—as well as contributing to 6 million heat pumps installed statewide by 2030.	Reduce demand for fossil gas and GHGs, and improve ambient and indoor air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory In response to Governor Newsom's July 2022 letter
Existing Commercial Buildings	80% of appliance sales are electric by 2030, and 100% of appliance sales are electric by 2045. Appliances are replaced at end of life, contributing to 6 million heat pumps installed statewide by 2030.	Reduce demand for fossil gas and GHGs, and improve ambient and indoor air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory In response to Governor Newsom's July 2022 letter
Food Products	7.5% of energy demand electrified directly and/or indirectly by 2030; 75% by 2045	Reduce demand for fossil gas and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Construction Equipment	25% of energy demand electrified by 2030 and 75% electrified by 2045	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Chemicals and Allied Products; Pulp and Paper	Electrify 0% of boilers by 2030 and 100% of boilers by 2045. Hydrogen for 25% of process heat by 2035 and 100% by 2045 Electrify 100% of other energy demand by 2045.	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Stone, Clay, Glass, and Cement	CCS on 40% of operations by 2035 and on all facilities by 2045 Process emissions reduced through alternative materials and CCS	SB 596: Reduce demand for fossil energy, process emissions, and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Other Industrial Manufacturing	0% energy demand electrified by 2030 and 50% by 2045	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Combined Heat and Power	Facilities retire by 2040.	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Agriculture Energy Use	25% energy demand electrified by 2030 and 75% by 2045	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions
Low Carbon Fuels for Transportation	Biomass supply is used to produce conventional and advanced biofuels, as well as hydrogen.	Reduce demand for petroleum fuel and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory
Low Carbon Fuels for Buildings and Industry	In 2030s biomethane[135] blended in pipeline Renewable hydrogen blended in fossil gas pipeline at 7% energy (~20% by volume), ramping up between 2030 and 2040 In 2030s, dedicated hydrogen pipelines constructed to serve certain industrial clusters	Reduce demand for fossil energy and GHGs, and improve air quality. AB 197: direct emissions reductions for sources covered by the AB 32 Inventory

[135] *Biomethane* is also known as renewable natural gas (RNG).

Sector	Action	Statutes, Executive Orders, Other Direction, Outcome
Non-combustion Methane Emissions	Increase landfill and dairy digester methane capture. Some alternative manure management deployed for smaller dairies Moderate adoption of enteric strategies by 2030 Divert 75% of organic waste from landfills by 2025. Oil and gas fugitive methane emissions reduced 50% by 2030 and further reductions as infrastructure components retire in line with reduced fossil gas demand	SB 1383: Reduce short-lived climate pollutants.
High GWP Potential Emissions	Low GWP refrigerants introduced as building electrification increases, mitigating HFC emissions	SB 1383: Reduce short-lived climate pollutants.

Natural and Working Lands

The Reference Scenario for NWL represents the amount of land management that occurred between 2001 and 2014, and projects the outcomes from maintaining the 2001–2014 levels of land management until 2045. The management and land use practices that occur within the Reference Scenario were derived from empirical data used by staff. For forests, shrublands/chaparral, and grasslands, the Reference Scenario constitutes approximately 250,000 acres of annual statewide treatments. For croplands, the Reference Scenario represents no healthy soil practices because during this period the healthy soil program did not yet exist. For land use change within all land types that consider land use change, historical rates of land conversion from 2001–2014 also were taken from empirical data and modeled into the future for the Reference Scenario.

Table 2-2 summarizes the Scoping Plan Scenario. The table also includes references to relevant statutes and Executive Orders where available.

Table 2-2: Actions for the Scoping Plan Scenario: NWL sectors

Sector	Action	Statutes, Executive Orders, Outcome
Natural and Working Lands	Conserve 30% of the state's NWL and coastal waters by 2030. Implement near- and long-term actions to accelerate natural removal of carbon and build climate resilience in our forests, wetlands, urban greenspaces, agricultural soils, and land conservation activities in ways that serve all communities—and in particular low-income, disadvantaged, and vulnerable communities.	EO N-82-20 and SB 27: CARB to include an NWL target in the Scoping Plan. AB 1757: Establish targets for carbon sequestration and nature-based climate solutions. SB 1386: NWL are an important strategy in meeting GHG reduction goals.

Sector	Action	Statutes, Executive Orders, Outcome
Forests and Shrublands	At least 2.3 million acres[136] treated statewide annually in forests, shrublands/chaparral, and grasslands, comprised of regionally specific management strategies that include prescribed fire, thinning, harvesting, and other management actions. No land conversion of forests, shrublands/chaparral, or grasslands.	Restore health and resilience to overstocked forests and prevent carbon losses from severe wildfire, disease, and pests. Improve air quality and reduce health costs related to wildfire emissions. Improve water quantity and quality and improve rural economies. Provide forest biomass for resource utilization. EO B-52-18: CARB to increase the opportunity for using prescribed fire. AB 1504 (Skinner, Chapter 534, Statutes of 2010): CARB to recognize the role forests play in carbon sequestration and climate mitigation.

[136] The 2.3 million acre target is what the Scoping Plan modeling shows would be needed to realize the carbon stock target called for in this Scoping Plan by 2045.

Sector	Action	Statutes, Executive Orders, Outcome
Grasslands	At least 2.3 million acres[137] treated includes increased management of grasslands interspersed in forests to reduce fuels surrounding communities using management strategies appropriate for grasslands. No land conversion of forests, shrublands/chaparral, or grasslands.	Help to achieve climate targets, improve air quality, and reduce health costs.
Croplands	Implement climate smart practices for annual and perennial crops on ~80,000 acres annually. Land easements/ conservation on annual crops at ~5,500 acres annually. Increase organic agriculture to 20% of all cultivated acres by 2045 (~65,000 acres annually).	Reduce short-lived climate pollutants. Increase soil water holding capacity. Increase organic farming and reduce pesticide use. SB 859: Recognizes the ability of healthy soils practices to reduce GHG emissions from agricultural lands. Target increased in response to Governor Newsom's direction to prioritize sustainable land management.

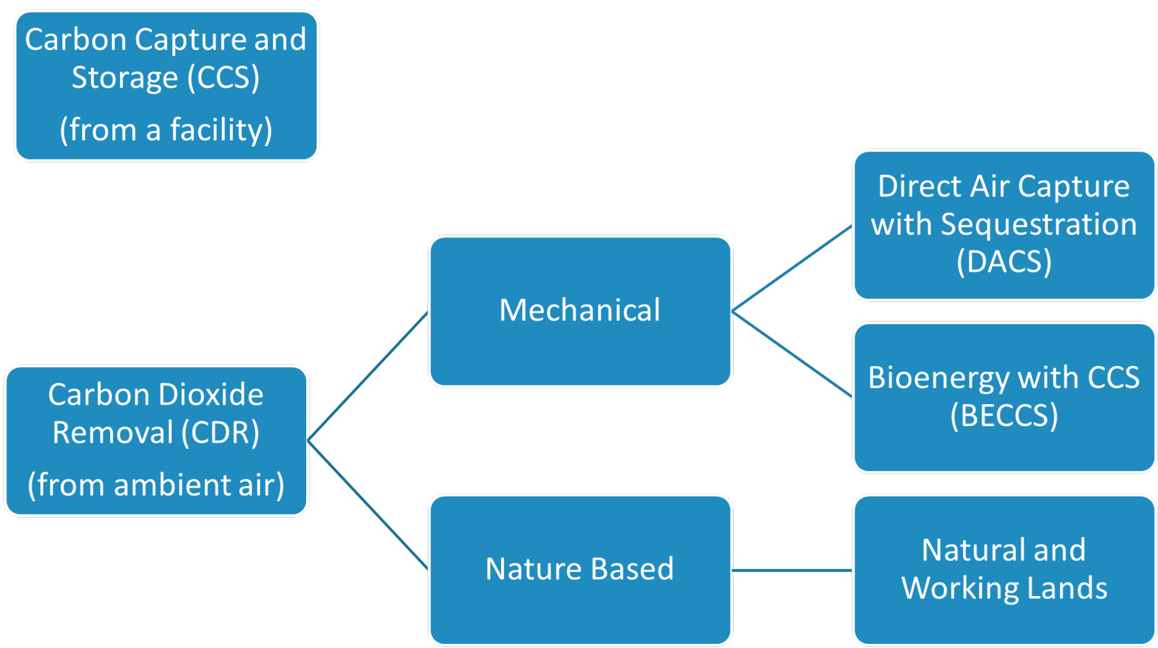
[137] The 2.3 million acre target is what the Scoping Plan modeling shows would be needed to realize the carbon stock target called for in this Scoping Plan by 2045.

Sector	Action	Statutes, Executive Orders, Outcome
Developed Lands	Increase urban forestry investment by 200% above current levels and utilize tree watering that is 30% less sensitive to drought. Establish defensible space that accounts for property boundaries.	Increase urban tree canopy and shade cover. Reduce heat island effects and support water infrastructure. Reduce fire risk via defensible space. AB 2251 (Calderon, Chapter 186, Statutes of 2022): Increase urban tree canopy 10% by 2035. Target increased in response to AB 2251 and Governor Newsom's direction on CO_2 removal targets in his July 2022 letter.
Wetlands	Restore 60,000 acres of Delta wetlands.	Increase carbon sequestration and reduce short-lived climate pollutants. Helps to reverse land subsidence while improving flood protection and providing critical habitat.
Sparsely Vegetated Lands	Land conversion at 50% of the Reference Scenario land conversion rate.	Reduce the rate of land conversion to more GHG-intensive land uses.

Strategies for Carbon Removal and Sequestration

To achieve carbon neutrality, any remaining emissions must be compensated for using carbon removal and sequestration tools. The following discussion presents more detail on the options available to capture and sequester carbon. Carbon removal and sequestration will be an essential tool to achieve carbon neutrality, and the modeling clearly shows there is no path to carbon neutrality without carbon removal and sequestration. Governor Newsom also recognized the importance of CO_2 removal strategies and directed CARB to establish CO_2 removal and carbon capture targets of 20 $MMTCO_2$ and 100 $MMTCO_2$ by 2030 and 2045, respectively, as well as signing 2022 legislation on carbon removal and sequestration, including: AB 1279, SB 905, SB 1137, and AB 1757. Carbon removal and sequestration can take different forms. Figure 2-2 illustrates the types of carbon removal and sequestration included in this Scoping Plan. There are numerous other carbon removal options undergoing research, development, and pilot deployment. As these options mature and new approaches emerge, they can be considered in future Scoping Plan updates.

Figure 2-2: Forms of carbon removal and sequestration considered in this Scoping Plan



The Role of Carbon Capture and Sequestration

Carbon capture and sequestration (CCS) will be a necessary tool to reduce GHG emissions and mitigate climate change while minimizing leakage and minimizing emissions where no technological alternatives may exist. CCS is a process by which large amounts of CO_2 are captured, compressed, transported, and sequestered. CCS projects are paired with a source of emissions, as the CCS project captures CO_2 as it leaves a facility's smokestack. CCS projects are often paired with large GHG-emitting facilities such as energy, manufacturing, or fuel production facilities. The sequestration component of CCS includes CO_2 injection into geologic formations (such as depleted oil and gas reservoirs and saline formations), as well as use in industrial materials (e.g., concrete). CCS is distinct from biological sequestration, which is typically accomplished through NWL management and conservation practices that enhance the storage of carbon or reduce CO_2 emissions with nature-based approaches. CCS is also distinct from mechanical CO_2 removal technologies, where CO_2 is removed directly from the atmosphere using mechanical and/or chemical processes.

CARB adopted a CCS Protocol in 2018 as part of amendments to the Low Carbon Fuel Standard.[138] At this time, no CCS projects have been implemented or have generated any credits under that protocol. However, CCS projects have been implemented elsewhere since the 1970s, largely on coal-fired power plants, with over two dozen projects operational around the world. Over 100 are at the stages of advanced or early development and are expanding beyond coal-fired plants to fossil gas, fuel production, and electricity generation facilities.[139] CCS projects are in development for addressing emissions from fuel, gas, energy production, and chemical production. As of November 2019, more than half of global large-scale CCS facilities (representing approximately 22 $MMTCO_2$/yr in capacity[140]) were in the U.S., mostly as a result of sustained governmental support for these technologies.[141] This support includes the federal 45Q tax credit for CCS[142,143] and research and deployment grants from federal agencies.[144,145] California's deep sedimentary rock formations in the Central Valley represent world-class

[138] CARB. 2022. Carbon Capture & Sequestration. https://ww2.arb.ca.gov/our-work/programs/carbon-capture-sequestration.

[139] Global CCS Institute. 2021. *Global Status of CCS 2021.* https://www.globalccsinstitute.com/wp-content/uploads/2021/11/Global-Status-of-CCS-2021-Global-CCS-Institute-1121.pdf.

[140] IHS Markit. August 2021. Carbon Removal Potential: An Overview. https://ww2.arb.ca.gov/sites/default/files/2021-08/ihsmarkit_presentation_sp_engineeredcarbonremoval_august2021.pdf.

[141] Beck, Lee. 2019. *Carbon capture and storage in the USA: The role of US innovation leadership in climate-technology commercialization.* https://academic.oup.com/ce/article/4/1/2/5686277.

[142] Congressional Research Service. 2021. Carbon Storage Requirements in the 45Q Tax Credit. IF11639. https://crsreports.congress.gov/product/pdf/IF/IF11639.

[143] The Inflation Reduction Act of August 2022 expands and enhances the 45 Q tax credit for CCS. Pub.L. No. 117-169 (August 16, 2022).

[144] U.S. Department of Energy. 2020. U.S. Department of Energy Announces $131 Million for CCUS Technologies. https://www.energy.gov/articles/us-department-energy-announces-131-million-ccus-technologies.

[145] U.S. Department of Energy. 2021. Funding Opportunity Announcement 2515, Carbon Capture R&D for Natural Gas and Industrial Point Sources, and Front-End Engineering Design Studies for Carbon Capture Systems at Industrial Facilities and Natural Gas Plants. https://www.energy.gov/fecm/articles/funding-opportunity-announcement-2515-carbon-capture-rd-natural-gas-and-industrial.

CO_2 storage sites that would meet the highest standards, with storage capacities of at least 17 billion tons of CO_2.[146,147]

In this Scoping Plan, CCS is included to address emissions from limited sectors, including electricity generation, cement production facilities, and refineries, to ensure anthropogenic emissions are reduced by at least 85 percent below 1990 levels in 2045, as directed in AB 1279. While the modeling outputs show CCS not being applied to the electricity sector until 2045, CCS could be implemented earlier on the electricity sector with a similar ramp up over time as that for refineries and cement plants. An earlier application of CCS in the electricity sector would yield additional reductions in years prior to 2045. In addition, CCS can support hydrogen production until such time as there is sufficient renewable power for electrolysis and an abundant water source.

Cement plants have emissions associated with combustion and process-related activities. Combustion emissions account for approximately 40 percent of the total emissions at cement plants. The remaining emissions are related to process-related activities. Due to the high heat content needed to produce cement, there is currently no technically feasible alternative to combustion. SB 596 calls for a 40 percent reduction in GHG intensity in cement emissions from 2019 levels by 2035, and then net zero emissions by 2045. To meet in-state demand, the state relies on cement both produced in state and imported. There are seven cement plants operating in California.[148] To minimize emissions leakage and address emissions from cement plants, the Scoping Plan Scenario includes CCS for cement plants. Additional reductions will need to be pursued and considered as part of implementation of SB 596, which calls for CARB to develop a comprehensive strategy by July 1, 2023, for the state's cement sector to achieve net-zero emissions of GHGs associated with cement used within the state as soon as possible, but no later than December 31, 2045. This effort began in the summer of 2022 and included sector specific workshops.

Even with implementation of EO N-79-20, and despite all of the ambitious efforts in the Scoping Plan Scenario, there will remain some demand for petroleum fuels for legacy vehicles on road applications, and in aviation, rail, and marine applications. Petroleum refineries will need to implement technology to decarbonize their operations and reduce their emissions. This Scoping Plan also assumes CCS at petroleum refineries as one of those potential strategies. Currently, there are seventeen petroleum refineries operating

[146] For comparison purposes, California's emitted 418.2 million metric tons of CO_2e in 2019.
[147] Lawrence Livermore National Laboratory. 2020. *Getting to Neutral: Options for Negative Carbon Emissions in California.* Revision 1. https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf.
[148] CARB. Mandatory GHG Reporting – Reported Emissions. https://ww2.arb.ca.gov/mrr-data

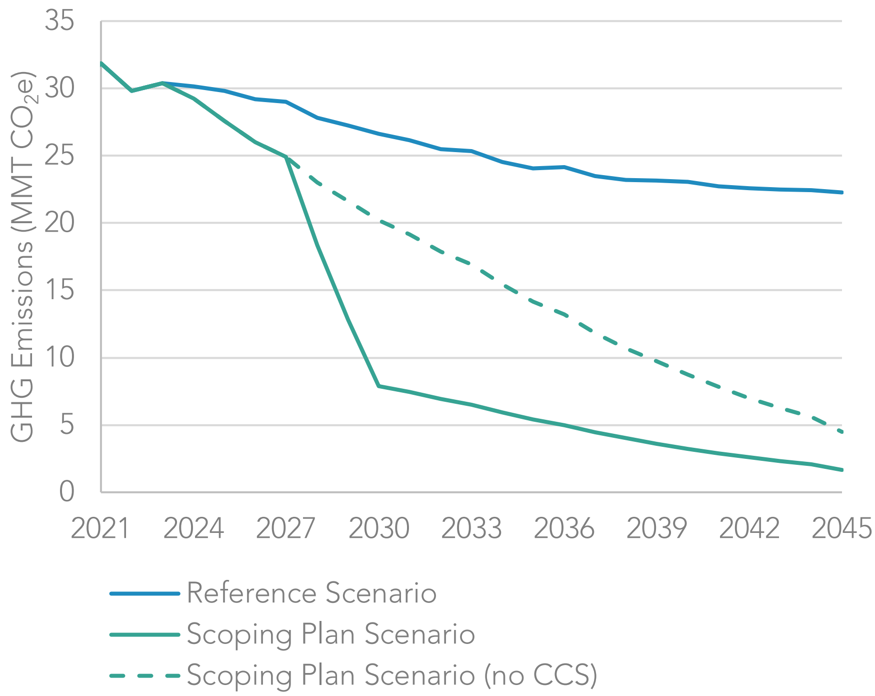
in the state.[149] On the supply side, the modeling assumes all in-state demand is met through some very limited refining activities in California. Figure 2-3 shows the emissions from the refining sector with and without CCS. If CCS is not deployed, the emissions would be directly emitted into the atmosphere, and CO_2 removal by NWL or direct air capture would need to increase to compensate for the sector's emissions.

Refineries can have a variety of point sources that emit CO_2—such as steam methane reformers for producing hydrogen, combined heat and power units, and catalytic crackers—that are best suited for CCS. Each configuration of a refinery can be unique to its footprint, onsite operations, and the types of crude oils processed. There are newer technologies with smaller footprints[150] that can be deployed in modular configurations to capture CO_2 in space-constrained and multiple-point-source facilities such as refineries. CCS can provide a path to reducing GHG emissions from these facilities to meet petroleum demand while avoiding leakage and until such time as some refineries can be transitioned to produce clean energy to support the transition away from fossil fuels.

While the Scoping Plan modeled deployment of CCS on refineries and identifies significant emissions reductions that can be achieved, the refineries in California are large and complex. The actual deployment of CCS at these facilities as modeled in the Scoping Plan is uncertain. It will be important to closely monitor the evolution of CCS deployment in the refinery sector and, in the next Scoping Plan update, to evaluate the progress toward use in this sector to determine whether the projected reductions will be achieved.

[149] CARB. Mandatory GHG Reporting. https://ww2.arb.ca.gov/mrr-data.
[150] Carbon Clean. Modular Carbon Capture Systems for Industry. https://www.carbonclean.com/modular-systems?hsLang=en.

Figure 2-3: Petroleum refining emissions with and without carbon capture and sequestration



This Scoping Plan also calls for accelerating the transition from combustion of fossil fuels to hydrogen. Hydrogen can be produced through electrolysis with renewable electricity or through steam methane reformation of biomethane. There is a high degree of uncertainty around the availability of solar to support both electrification of existing sectors and the production of hydrogen through electrolysis. Producing hydrogen required under the Scoping Plan Scenario with electrolysis would require about 10 gigawatts (GW)[151] of additional solar capacity. If steam methane reformation is paired with CCS, the hydrogen produced could potentially be low carbon. Additionally, the biomethane used to generate hydrogen could be sourced from gasification of forest or agricultural waste resulting from forest management and other NWL management practices, which could also lead to net negative carbon outcomes. Steam methane reformation paired with CCS can thus ensure a rapid transition to hydrogen and increase hydrogen availability until such time as

[151] The Draft Scoping Plan included an estimate for solar capacity (40 GW) to support only electrolysis to produce all hydrogen in the Proposed Scenario. The Scoping Plan now includes steam methane reformation of biomethane and biomass gasification with CCS to produce hydrogen, along with electrolysis from off-grid solar. See Appendix H (AB 32 GHG Inventory Sector Modeling) for additional details.

electrolysis with renewables can meet the ongoing need, assuming there is also sufficient water supply. Additional background and next steps for CCS can be found in Chapter 4.

The EJ Advisory Committee has raised multiple concerns related to the inclusion of CCS and mechanical CDR in the Scoping Plan. Concerns range from potential negative health and air quality impacts in communities from operation of facilities utilizing CCS that continue to emit other emissions, to safety concerns related to potential leaks, to the viability of the current technology. Additionally, the EJ Advisory Committee has policy concerns about the strategy and wants to ensure that engineered carbon removal is not used as a substitute for strategies to achieve emissions reductions onsite and that it does not result in delays in phasing out fossil fuel use. Given these and other concerns and the importance of building public awareness, CARB recognizes the need for a multi-stakeholder process including other state, federal, and local agencies; tribes; independent experts; and community residents to further understand and address community concerns related to CCS. CARB hosted a CCS Symposium with U.S. EPA Region 9 and the Stanford Doerr School of Sustainability to discuss some of these critical issues with community members and other participants. As CARB begins the process of implementing SB 905 in 2023, that will provide an opportunity for further engagement.

In the context of CCS deployment, the Council of Environmental Quality (CEQ) also highlighted the need to further assess and quantify potential impacts on local criteria air pollutants and other emissions resulting from carbon capture retrofits at industrial facilities in response to concerns regarding potential cumulative emissions from single and/or multiple sources.[152] An October 2020 Stanford report[153] discussed how the potential post-combustion capture for CO_2 could also reduce emissions of criteria air pollutant emissions from certain facilities. Exploring these potential outcomes will be important to ensure deployment of CCS does not exacerbate air pollution impacts in communities and maximizes any air pollution benefits. The need for these types of evaluations is also included in SB 905.

The Role of Natural and Working Lands Emissions and Sequestration

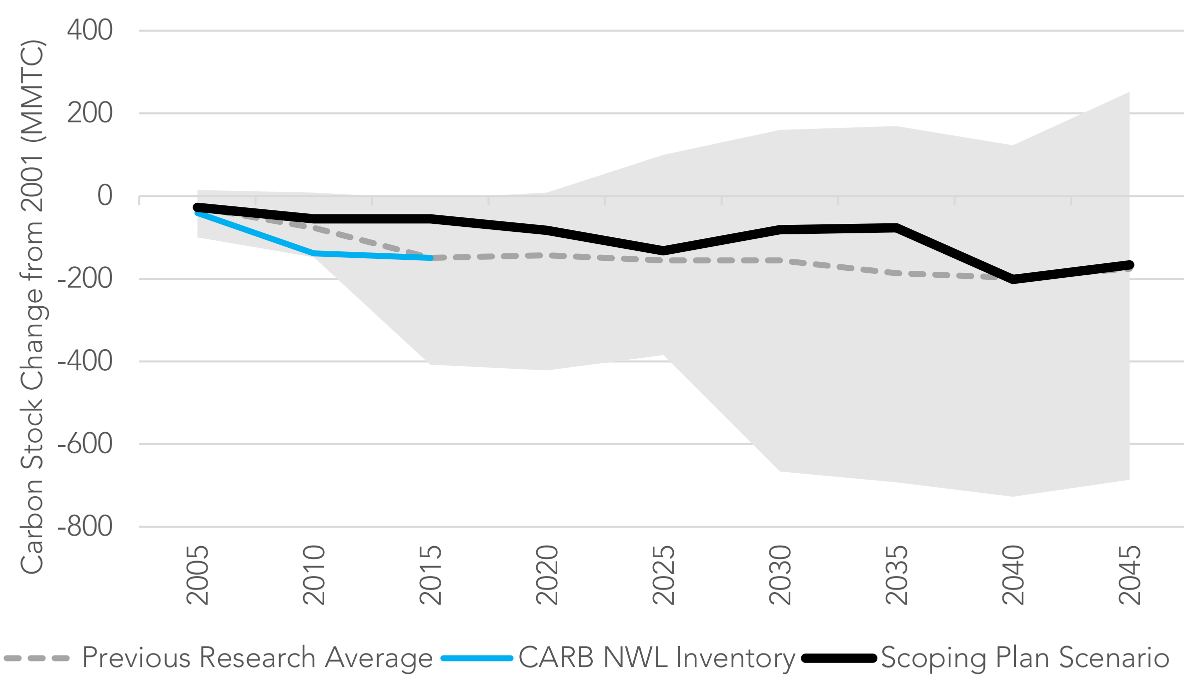
California's NWL assessments highlight the importance of increasing the pace and scale of NWL actions to ensure that our ecosystems are better equipped to withstand future climate change so they continue to provide the benefits that nature and society depend

[152] Carbon Capture, Utilization, and Sequestration Guidance. 87 Fed. Reg. 8808 (Feb. 16, 2022), [2022-03205.pdf (govinfo.gov)].

[153] Stanford Center for Carbon Storage. 2020. *An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions.* October. https://sccs.stanford.edu/ccs-in-ca/full-report-form?msclkid=6f9177f6c57811ecbebc473e75203b21.

upon for survival. As climate change increases the likelihood of extreme wildfires, drought, heat, and other impacts, carbon stocks in California's NWL will face increased risks and impacts. We know from previous climate change and Scoping Plan work[154] that lands can be a net source of GHG emissions or a net sink, and that the magnitude of carbon stock changes and GHG emissions and sequestration from NWL are dependent on the effects of climate change and land management. The expanded modeling conducted for this Scoping Plan shows that NWL are projected to be a net source of emissions through 2045 and indicates a probable decrease of carbon stocks into the future. This projection is further corroborated by previous, independent research that has reached the same conclusion, showing a range of varying levels of carbon stock loss. Figure 2-4 shows the modeling results of the Scoping Plan Scenario overlaid with the NWL inventory and findings from independent research.

Figure 2-4: Comparison of the Scoping Plan Scenario (NWL) with existing research



The modeling indicates that immediate and aggressive climate action can reduce the environmental impacts that would occur in the absence of this action. The results of the modeling demonstrate that regular NWL management over the next two decades can

[154] CARB. 2019. January 2019. *Draft California 2030 Natural and Working Lands Climate Change Implementation Plan*. https://ww2.arb.ca.gov/sites/default/files/2020-10/draft-nwl-ip-040419.pdf.

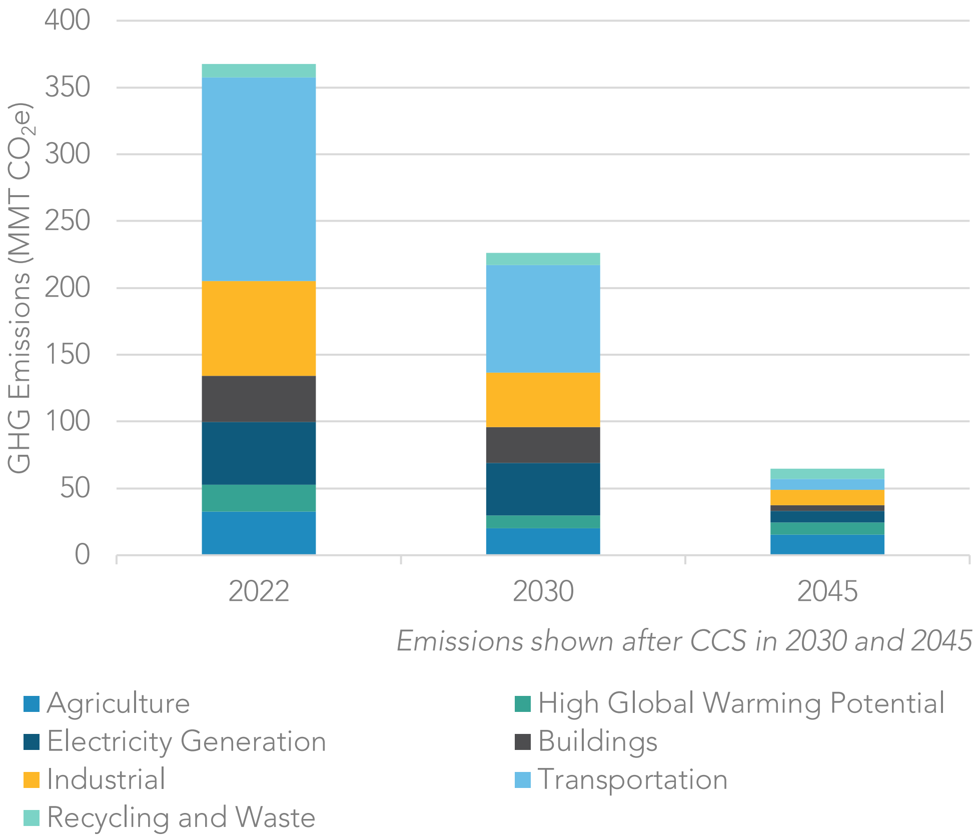
increase carbon stocks from the Reference Scenario trajectory, reduce GHG emissions from lands, and improve ecosystem and public health. This effort is the most comprehensive scientific effort taken by any government to include NWL within its overall climate strategy. Even so, we know that uncertainty exists about future climate and economic forces and the impacts they may have on our ecosystems, so it is important that the state take decisive and aggressive action to improve and diversify ecosystem structures and management.

The effects of climate change, including increased drought, wildfire, and extreme heat, play a significant role in determining the future of California's carbon stocks. And while management actions will help to reduce the impact that climate change will have on California, it is clear from the analysis that NWL sinks and sources are highly variable from year to year, and short time frames do not adequately demonstrate the impact that climate and management are having on ecosystems. For the purposes of climate planning, therefore, it is best to focus on carbon stock changes over longer periods rather than focusing on sequestration or emissions on shorter time frames. The Scoping Plan Scenario is estimated to result in additional NWL emissions of 7 million metric tons of carbon dioxide equivalent ($MMTCO_2e$) annually from 2025–2045. The Reference Scenario is estimated to result in annual emissions of 9 $MMTCO_2e$ over the same time period, and so the Scoping Plan Scenario slows the rate of emissions and provides an approximate 2 $MMTCO_2e$ in additional annual sequestration relative to the Reference Scenario. Because NWL are projected to be a net emissions source, the annual NWL emissions of approximately 7 $MMTCO_2e$ from the Scoping Plan Scenario will need to be compensated by additional CO_2 removal approaches to ensure California can achieve carbon neutrality by 2045.

The Role for Carbon Dioxide Removal (Direct Air Capture)

Even if anthropogenic emissions are reduced to at least 85 percent below 1990 levels by 2045 as called for by AB 1279, there will still be residual emissions in the AB 32 GHG Inventory sectors in 2045 that must be addressed in order to achieve the California's carbon neutrality target. Figure 2-5 includes the emissions by sector for the AB 32 GHG Inventory Sectors in 2022, 2030, and 2045 for the Scoping Plan Scenario.

Figure 2-5: Residual emissions in 2022, 2030, and 2045 for the Scoping Plan Scenario[155]



To achieve carbon neutrality, mechanical CDR will therefore need to be deployed. Because NWL management is not estimated to be a significant carbon removal path in the near term, additional CDR options will be needed. *Mechanical CDR* refers to a range of technologies that capture and concentrate ambient CO_2. Direct air capture (DAC) is one available option that is under development today and could be widely deployed. Note that, unlike CCS, DAC technologies are not designed to be attached to a specific source or smokestack. These technologies include chemical scrubbing processes that capture CO_2 through absorption or adsorption separation processes. Another carbon removal

[155] The High GWP sector includes high global warming potential gas emissions from releases of ozone depleting substance (ODS) substitutes, SF_6 emissions from the electricity transmission and distribution system, and gases that are emitted in the semiconductor manufacturing process. ODS substitutes, which are primarily hydrofluorocarbons (HFCs), are used in refrigeration and air conditioning equipment, solvent cleaning, foam production, fire retardants, and aerosols.

option that involves rapid mineralization of CO_2 at the Earth's surface is called *mineral carbonation.*[156] As is the case with CCS, mechanical CDR technologies will need governmental or other incentive support to overcome technology and market barriers. In the United States, the U.S. Department of Energy announced financing specifically for DAC in March 2020[157] and March 2021.[158] Additionally, almost $9 billion in CCS support was included in the $ 1 trillion Infrastructure Investment and Jobs Act of 2021.[159] This includes funding to establish four DAC hubs. The Inflation Reduction Act of 2022[160] increases the value of the 45Q tax credit to USD 85 per metric ton of CO_2 captured and stored in geologic formations from some industrial applications and USD 180 per metric ton for DAC with storage in geologic formations. In 2021, there were approximately 19 DAC facilities globally.[161]

Ultimately, the role for mechanical CDR will depend on the success of reducing emissions directly at the source in the AB 32 GHG Inventory sectors and the ability of the NWL to sequester carbon. However, mechanical CDR also provides an opportunity to not just achieve carbon neutrality, but also remove legacy GHG emissions from the atmosphere. As such, increased deployment of DAC can help achieve net negative emissions. This would further help avoid the most damaging impacts of climate change. While the federal incentives for DAC provide some support for this technology, the only California program that recognizes this technology is the LCFS program. Permitting must also happen across different levels of government and across multiple state agencies. Energy availability must also be addressed if DAC is to be implemented in remote areas. Additional information and next steps on DAC can be found in Chapter 4.

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[156] The National Academies Press. 2018. Direct Air Capture and Mineral Carbonation Approaches for Carbon Dioxide Removal and Reliable Sequestration: Proceedings of a Workshop–in Brief. *https://nap.nationalacademies.org/catalog/25132/direct-air-capture-and-mineral-carbonation-approaches-for-carbon-dioxide-removal-and-reliable-sequestration#:~:text=National%20Academies%20of%20Sciences%2C%20Engineering%2C%20and%20Medicine%3B%20Division,concentrate%20carbon%20dioxide%20%28CO%202%29%20from%20ambient%20air*.

[157] U.S. Department of Energy. 2020. Department of Energy to Provide $22 Million for Research on Capturing Carbon Dioxide from Air. *https://www.energy.gov/articles/department-energy-provide-22-million-research-capturing-carbon-dioxide-air*.

[158] U.S. Department of Energy. 2021. DOE Invests $24 Million to Advance Transformational Air Pollution Capture. *https://www.energy.gov/articles/doe-invests-24-million-advance-transformational-air-pollution-capture*.

[159] Pub.L. No. 117-58 (November 15, 2021). *https://www.congress.gov/bill/117th-congress/house-bill/3684/text*.

[160] Pub.L. No. 117-169 (August 16, 2022). *https://www.congress.gov/bill/117th-congress/house-bill/5376/text*.

[161] International Energy Agency (IEA). 2022. Direct Air Capture – Analysis. *https://www.iea.org/reports/direct-air-capture*.

Carbon Dioxide Removal and Capture Targets for 2030 and 2045

Recognizing the importance of CO_2 removal, Governor Newsom and the Legislature identified the need for targets to send policy and regulatory signals to pilot, deploy, and scale action for those efforts. Governor Newsom requested that CARB set a CO_2 removal and capture target of 20 MMT for 2030 and 100 MMT for 2045, first prioritizing sequestration in NWL. And while this Scoping Plan prioritizes and recommends significant increased climate-smart action on all NWL to support carbon neutrality and healthy and resilient lands, the modeling indicates that, across all NWL, lands will be a net source of emissions when accounting for both carbon sequestration and GHG (CO_2, CH_4, and N_2O) emissions from lands.

Some landscapes, however, are projected to have a net increase in carbon stocks under the Scoping Plan Scenario between 2025 and 2045 relative to the reference case, indicating that NWL actions can help California achieve Governor Newsom's CO_2 removal targets. Carbon stocks in urban forests and grasslands are projected to increase relative to historical levels from implementation of the 2022 Scoping Plan. To support the governor's CO_2 removal targets, CARB estimates that lands would contribute an average of 1.5 MMT of CO_2 removals each year between 2025 and 2045. Any carbon sequestration contributions from lands need to reflect both long-term storage and an overall net increase in carbon stocks over time to ensure these NWL actions are contributing toward California's achievement and maintenance of carbon neutrality over time.

CARB will work to update and revise these estimates as part of implementation of AB 1757, which was signed by the governor in September 2022 and requires that CARB and the California Natural Resources Agency (CNRA) work with an expert advisory committee to determine an ambitious range of carbon sequestration targets by January 1, 2024, for the years 2030, 2038, and 2045.

For the AB 32 GHG Inventory sectors, the Scoping Plan Scenario modeling indicates that the scenario would meet or exceed the 2030 SB 32 target through GHG reduction policies without the need for CDR. CDR will, however, be necessary to increase ambition for an accelerated 2030 target and in increasing amounts over the following decades to achieve carbon neutrality by 2045.[162] Given the likelihood of NWL to be a net source of emissions, and the need for CDR to compensate for residual emissions to achieve carbon neutrality

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[162] The modeled scenarios assume that residual emissions will be compensated using DAC technologies by including the direct cost in terms of dollars per ton CO_2 removed. The energy source for DAC is not modeled, but renewable electricity and/or hydrogen produced from electrolysis are zero carbon options consistent with the carbon neutrality targets in this Scoping Plan.

by 2045, California will need increasing deployment of mechanical CDR over the coming decades. In the immediate future, scaling nature-based CDR approaches also can help to provide some CO_2 removal quickly while mechanical CDR is scaled up between now and 2045. Table 2-3 provides estimates of CO_2 removal and capture needed in 2030[163] and 2045.

[163] As identified in Chapter 1, SB 27 (Skinner, Chapter 237, Statues of 2021) directed CARB to "establish carbon dioxide removal targets for 2030 and beyond" as part of this Scoping Plan. CARB is establishing these targets to satisfy both the requirements of SB 27 and the directive from Governor Newsom to establish CO_2 removal targets for 2030 and 2045.

Table 2-3: GHG emissions and removals needed to achieve carbon neutrality and meet the 20 $MMTCO_2$ removal and capture target in 2030 and the 100 $MMTCO_2$ removal and capture target in 2045.[164]

	2030 ($MMTCO_2e$)	2045 ($MMTCO_2e$)
GHG Emissions	233	72
AB 32 GHG Inventory Sector Emissions	226	65
Net NWL GHG Emissions Across All Landscapes (annual average from 2025–2045)	7	7
Carbon Capture and Sequestration (CCS): Avoided GHG Emissions from Industry and Electric Sectors	(13)	(25)
Carbon Dioxide Removal (CDR) including natural and working lands carbon sequestration,[165] Direct Air Capture, and Bioenergy with CCS (BECCS).	(7)	(75)
Net Emissions (GHG Emissions + CDR)	226	(3)

In 2030, the CO_2 removal and capture target is 20 MMT, but because the SB 32 target only encompasses the AB 32 GHG Inventory sectors, only CCS that reduces GHG emissions on AB 32 sources count toward achieving more ambitious GHG emission reductions in 2030. In 2045, the CO_2 removal and capture must compensate for any residual emissions from the AB 32 Inventory sectors and NWL emissions to support achieving carbon neutrality while also totaling at least 100 MMT. It is important to note that NWL, particularly forests, need a natural wildfire cycle to remain healthy. While the modeling projected wildfires, and implementing the Scoping Plan will result in a reduction in future wildfire emissions, getting to zero wildfires in the sector is not the goal, nor the

[164] Modeled estimates from the Scoping Plan Scenario indicate the relative quantity of emissions and removals to achieve carbon neutrality and meet carbon removal and capture targets. These estimates are not intended to imply precision, as the required policies are yet to be implemented and all models have some uncertainty in their forecasts.

[165] For the purposes of quantifying how to achieve the governor's 20 MMT and 100 MMT CO_2 removal and capture target, CARB included 1.5 $MMTCO_2e$ sequestration from NWL, which is the sequestration from urban forests. This is included as CO_2 removal because it is this sequestration that CARB can consider as having some permanence. Permanence is necessary for incorporating NWL into carbon neutrality. The net NWL emissions of 7 $MMTCO_2e$, identified in the second row of Table 2-3, includes *all* emissions and sinks from all NWL landscapes, which is inclusive of the 1.5 $MMTCO_2e$ sequestration. CARB will develop an accounting framework to accommodate NWL carbon stocks.

right approach to a sustainable forestry sector. In contrast in 2045, the reductions from programs and policies are estimated to reduce emissions by 169 $MMTCO_2e$ from business as usual.

The 2030 target for engineered CDR also provides a near term milestone for California and can serve as an important marker for progress in deploying CDR to support California's carbon neutrality goal. Preliminary estimates indicate that, globally, capacity from already announced projects will range from about 2 million metric tons per year ($MMTCO_2$/y) to 8 $MMTCO_2$/y from bioenergy paired with CCS, and from about 2,000 metric tons per year ($MTCO_2$/y) to 1 $MMTCO_2$/y from DACs by 2027,[166] which indicates that California's 2030 target is an ambitious, but achievable, goal.

Scenario Uncertainty

Greenhouse Gas Emissions Modeling

Several types of uncertainty are important to understand in both forecasting future emissions and estimating the benefits of emission reduction actions. In developing this Scoping Plan we forecasted a reference scenario and estimated the GHG emissions outcome of the AB 32 GHG Inventory sectors using the PATHWAYS[167] model. Inherent in the reference scenario modeling is the expectation that many of the existing programs will continue in their current form, and that the expected drivers for GHG emissions, such as energy demand, population growth, and economic growth, will match our current projections.

However, there is also the expectation that each of the policies included and implemented to achieve the 2030 target in the 2017 Scoping Plan will deliver their exact outcomes. It is unlikely the future will precisely match our projections, and this will lead to uncertainty in the forecast. For example, we never could have foreseen and forecasted economic and emissions impacts related to the extended disruptions from the COVID-19 pandemic. Thus, the single "reference" or "forecast" line should be understood to represent one possible future in a range of possible predictions. For this Scoping Plan, PATHWAYS utilized inputs that reflect technically feasible levels of deployment or adoption of low- or zero-carbon fuels and technologies. Each of the input assumptions provided to PATHWAYS has some uncertainty, which also contributes to uncertainty in the resulting reference scenario.

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[166] IHS Markit. August 2021. Carbon Removal Potential. https://ww2.arb.ca.gov/sites/default/files/2021-08/ihsmarkit_presentation_sp_engineeredcarbonremoval_august2021.pdf.
[167] See Appendix H (AB 32 GHG Inventory Sector Modeling).

Similarly, for the NWL modeling, CARB used a mix of individual modeling tools[168] to estimate the carbon and other ecological, public health, and economic outcomes. The Reference scenario assumes that the level of land management actions that occurred between 2001 and 2014 for forests, shrublands, grasslands, croplands, developed lands, wetlands, and sparsely vegetated lands continues into the future. Alternative scenarios assessed the effect of increasing levels of management actions from the reference scenario beginning in 2025. There is a great deal of uncertainty about exactly how lands are currently managed, and a larger uncertainty about how they may be managed in the future. For NWL, it is unlikely that the future will precisely match the carbon stock outcomes CARB has projected, particularly given the uncertainties around current and future land management and the effects climate change will have on our lands. For any modeling exercise these uncertainties exist; however, this modeling effort brings together the best available science, data, and models to quantify the impact our actions may have on the landscape under an unknown future.

Implementation

As this Scoping Plan is designed to chart a path to achieving carbon neutrality, additional work will be required to fully design and implement any policies and actions identified in this plan. During the subsequent development of policies, the Legislature, CARB, and other state agencies will learn more about the technologies and their costs, as well as how each industry works, as a more comprehensive evaluation is conducted in coordination with stakeholders, including community engagement. Significant areas of uncertainty include permitting wait times[169] and local ordinances that might limit or slow the build-out of utility scale renewables.[170,171] In another example, times to reach commercial operations for solar projects after securing an interconnection agreement also have increased in recent years, to 3.5 to 5.5 years.[172]

The level of natural and working lands climate action identified in this Scoping Plan is ambitious. Achieving the level of action needed to result in the quantified carbon,

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[168] See Appendix I (Natural and Working Lands Technical Support Document).

[169] CEC. 2021. *SB 100 Joint Agency Report.* https://www.energy.ca.gov/sb100#anchor_report.

[170] Roth, Sammy. 2019. "California's San Bernardino County slams the brakes on big solar projects." *Los Angeles Times.* https://www.latimes.com/business/la-fi-san-bernardino-solar-renewable-energy-20190228-story.html?fbclid=IwAR2qHGq3bahHme6SFErLsnyFi9UPIfBHIhvnOh3dU3OM7kUTMcEqYfN3pQA.

[171] Chediak, Mark. 2021. "California NIMBYs Threaten Biden's Clean Energy Goals." *BNN Bloomberg.* https://www.bnnbloomberg.ca/california-nimbys-threaten-biden-s-clean-energy-goals-1.1634351?msclkid=668c9ae9c11311ec92e34035ea157ad4.

[172] Rand, Joseph, et al. 2022. Queued Up: Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2021. Power Point Presentation. Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/default/files/queued_up_2021_04-13-2022.pdf.

emissions, health, and economic outcomes within this Scoping Plan requires coordination, investment, and partnerships across all levels of government and sectors of the economy. It is possible that not all of the actions at the identified level will begin in 2025. This uncertainty will result in diminished levels of beneficial outcomes quantified in the Scoping Plan Scenario. The levels of NWL action identified in this Scoping Plan represent CARB's assessment of the pace and scale of action needed to achieve the carbon stock targets and CO_2 removal targets identified in this Scoping Plan.

The Scoping Plan Scenario identifies that 2.3 million acres of forests, shrubland, and grassland management annually would achieve substantial levels of fire emissions reductions and the concomitant health and economics benefits. Currently, 1 million acres of forest treatment annually is the joint federal and state government goal (500,000 acres each). This target of one million acres annually by 2025 is for the purposes of increasing forest health and wildfire resilience in the near term, whereas the 2.3 million acre target is what the Scoping Plan modeling shows would be needed to realize the carbon stock target called for in this Scoping Plan by 2045. By identifying 2.3 million acres of climate action annually in forests, shrublands, and grasslands, this Scoping Plan emphasizes the importance of that 1 million acre annual goal as a milestone on the way to even more action and improved fire and air quality outcomes. The modeling indicates that substantial improvements to statewide fire emissions will occur at levels of action greater than 1 million acres per year. If these levels of action do not occur starting in 2025, the Scoping Plan has quantified climate benefits that will still occur, but to a lesser extent. In terms of fire emissions, compared to the Reference Scenario, 2.3 million acres of forest, shrubland and grassland management will result in a 10% reduction in wildfire emissions. At 1 million acres per year, this decreases to a 2.5% reduction. If 1 million acres per year is also not accomplished, then the emissions and health benefits are even lower.

Climate action in other NWL sectors also generates many co-benefits. Climate action identified in this Scoping Plan is aimed at not only fighting climate change but also improving air quality and public health. The climate action identified in the agricultural sector, for example, should result in decreased pesticide and synthetic fertilizer use. This decrease of synthetic chemical use in agriculture across California also should result in improved public health, especially for communities that work and live in and around agricultural lands. However, as with the forestry sector, the benefits of climate action in agricultural lands and in any other land are dependent on how much implementation takes place. Ramping up increased healthy soils practices and increasing organic agriculture in California will require continued and sustained implementation by private industry and public agencies. For example, achieving the carbon stock outcomes for the annual crops called for in this Scoping Plan would require deployment and maintenance of healthy soils practices on 80,000 additional acres of croplands in California every year between 2025 and 2045. For context, CDFA's Healthy Soils Program, which is an incentive program supporting healthy soils practices, took almost four years of sustained funding to achieve approximately 50,000 acres total under healthy soils practices.[173]

Given the uncertainty around the modeling assumptions, and performance uncertainty as specific policies are fully designed and implemented, estimates associated with the Scoping Plan Scenario are certain to be different than what is ultimately implemented. One way to mitigate for this is to develop policies that can adapt and increase certainty in GHG emissions reductions. Periodic reviews of progress toward achieving the 2030 target and longer term deeper decarbonization, as well as performance of specific policies, also provide opportunities for the state to consider any changes to ensure we remain on course to achieve the 2030 target and carbon neutrality. The need for this periodic review process was anticipated in AB 32, as it calls for updates to the Scoping Plan at least once every five years. For this Scoping Plan, the metrics provided on the rate of deployment of clean fuels and technologies, along with the annual AB 32 GHG Inventory, provide additional information that can be used to assess progress on sectors and aggregate emissions. This is also true of CARB's NWL carbon inventory. An uncertainty analysis for achieving an accelerated 2030 target is provided toward the end of this chapter.

Targeted Evaluations for the Scoping Plan: Oil and Gas Extraction and Refining

To achieve California's air quality and climate goals, we must end our dependence on petroleum. This will not happen overnight. There are about 28 million combustion engine heavy- and light-duty trucks and passenger vehicles in California, and these are almost always replaced at their end of life. The ZEV Executive Order (EO N-79-20) calls for 100 percent new ZEV car sales beginning in 2035 and a 100 percent ZEV medium- and heavy-duty fleet sales by 2045 where feasible. The result is an ongoing, albeit shrinking, pool of vehicles that will continue to require petroleum fuels. To avoid leakage, as called for in AB 32, and to meet that remaining demand for petroleum fuel, a complete phaseout of oil and gas extraction and refining is not possible by 2045. This Scoping Plan assumes a phasedown in both oil and gas extraction as well as petroleum refining in line with the reduction in demand for in-state on-road petroleum fuel demand. Since the transportation sector is the largest source of GHG emissions and harmful local air pollution, we must continue to research and invest in efforts to deploy zero emissions technologies and clean fuels, and to reduce VMT. An assessment of ongoing progress and efforts to reduce

[173] California Department of Food and Agriculture. 2021. *Incentives Program 2017–2020 Summary by the Numbers.* https://www.cdfa.ca.gov/oefi/healthysoils/docs/HSP_Incentives_program_level_data_funded_projects.pdf.

demand for petroleum fuels and of opportunities to phase down oil and gas extraction and refining will be included in the next Scoping Plan update.

In addition to supplying in-state demand, California is a net exporter of gasoline, diesel, and jet fuel. California pipelines supply the Nevada and Arizona regions[174] with approximately 87 million barrels gasoline equivalent of refined products annually.[175] California pipelines deliver approximately 85% of Nevada's and 40% of Arizona's refined product. Most finished fuels flowing from California to Nevada and Arizona are currently produced by California refineries. To manage the phasedown of oil and gas extraction and petroleum refining in California, exports of finished fuels must be considered and factored into that process, in addition to the declining in-state demand. The authorities and considerations related to supply and demand of petroleum fuels span federal, state, and local agencies. If supply of fossil fuels is to decline along with demand, a multi-agency discussion is needed to systematically evaluate and plan for the transition to ensure that it is equitable.

This inter-agency work should also consider related topics, such as the following:

- Direct and indirect job and economic impacts
- Demand for other liquid fuel types such as renewable fuels, and expected volumes
- Legal considerations
- Public health benefits
- Demand and supply strategies for petroleum fuels, including how to avoid short term supply constraints that may impact low-income consumers

Some of these topics were also discussed as part of two studies[176] supported by the California Environmental Protection Agency, which can serve as a starting point for a working group to analyze these questions and develop policy recommendations.

Oil and Gas Extraction

On April 23, 2021,[177] Governor Newsom directed CARB to evaluate the phaseout of oil and gas extraction no later than 2045 as part of this Scoping Plan. As noted above, this Scoping Plan still has some California demand for finished fossil fuels (gasoline, diesel,

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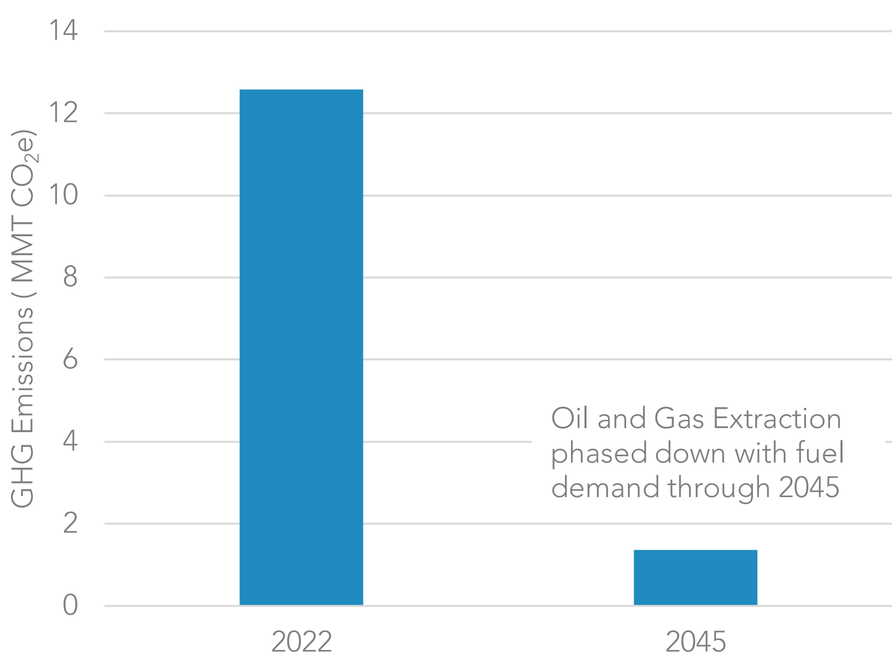
[174] CEC. August 2021. A Primer on California's Pipeline Infrastructure. *Petroleum Watch.* https://www.energy.ca.gov/sites/default/files/2021-08/August_Petroleum_Watch_ADA.pdf.
[175] CEC. March 2020. *Petroleum Watch.* https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.
[176] CalEPA. 2021. Carbon Neutrality Studies: https://calepa.ca.gov/climate/carbon-neutrality-studies/.
[177] Governor Newsom. April 23, 2021. Governor Newsom Takes Action to Phase Out Oil Extraction in California. Press Release. https://www.gov.ca.gov/2021/04/23/governor-newsom-takes-action-to-phase-out-oil-extraction-in-california/.

and jet fuel) in 2045. This demand is primarily for transportation, including for sectors that are directly regulated by the state and some that are subject to federal jurisdiction, such as interstate locomotives, marine, and aviation. As discussed more fully below, while significant GHG reductions from oil and gas extraction could be achieved as demand for fossil fuels is reduced due to strategies in this Scoping Plan, it is not feasible to phase out oil and gas production fully by 2045 given this remaining demand.

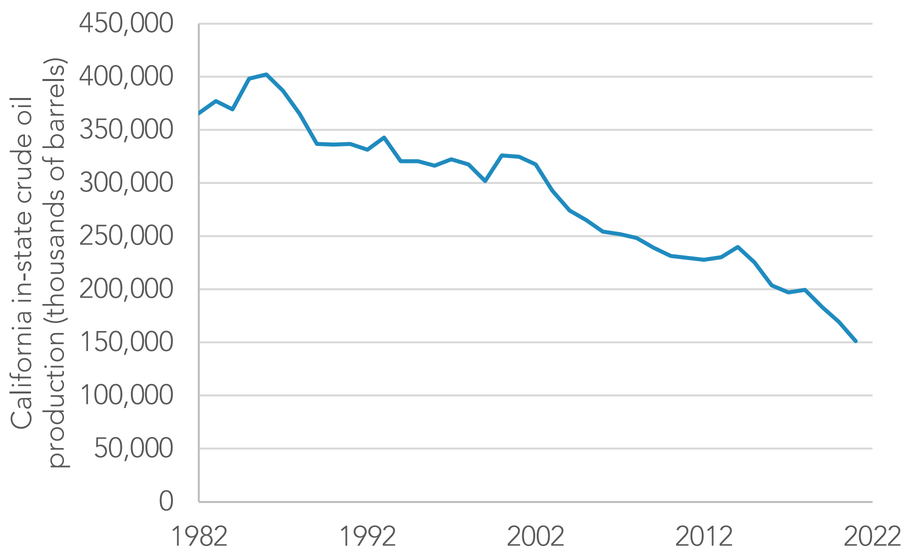
In the Scoping Plan Scenario, with successful deployment of zero carbon fuels and non-combustion technology to phase down petroleum demand, GHG emissions from oil and gas extraction could be reduced by approximately 89 percent in 2045 from 2022 levels if extraction decreases in line with in-state finished fuel demand. If in-state extraction were to be phased out fully, the future petroleum demand by in-state refineries would be met through increased crude imports to the state relative to the Scoping Plan Scenario. AB 32 defines leakage as, “a reduction in emissions in greenhouse gases within the state that is offset by an increase in emissions of greenhouse gases outside the state.” AB 32 also requires any actions undertaken to reduce GHGs to “minimize leakage.” Increases in imported crude could result in increased activity outside California to extract and transport crude into California. Therefore, our analysis indicates that a full phaseout of in-state extraction could result in GHG emissions leakage and in-state impacts to crude oil imported into the state. Figure 2-6 compares the 2022 emissions from this sector with the modeled results when the sector is phased down with in-state petroleum demand.

Figure 2-6: Oil and gas extraction sector GHG emissions in 2022 and 2045 when activity is phased down with in-state fuel demand



According to California Energy Commission (CEC) data used in Figure 2-7, the total oil extracted in California peaked at 402 million barrels in 1986. Since then, California crude oil production has decreased by an average of 6 million barrels per year, to about 200 million barrels in 2020. This steadily decreasing production of crude in California is expected to continue as the state's oil fields deplete.

Figure 2-7: California in-state crude oil production[178]



A UC Santa Barbara report estimated that, under business-as-usual conditions, California oil field production would decrease to 97 million barrels in 2045.[179] The business-as-usual model assumed no additional regulations limiting oil extraction in California.

Any crude oil demand by California refineries not met by California crude oil will be met by marine imports of Alaskan and foreign crude.[180] As shown in Figure 2-8, approximately 99 percent of crude imports into California are delivered by marine transportation. The

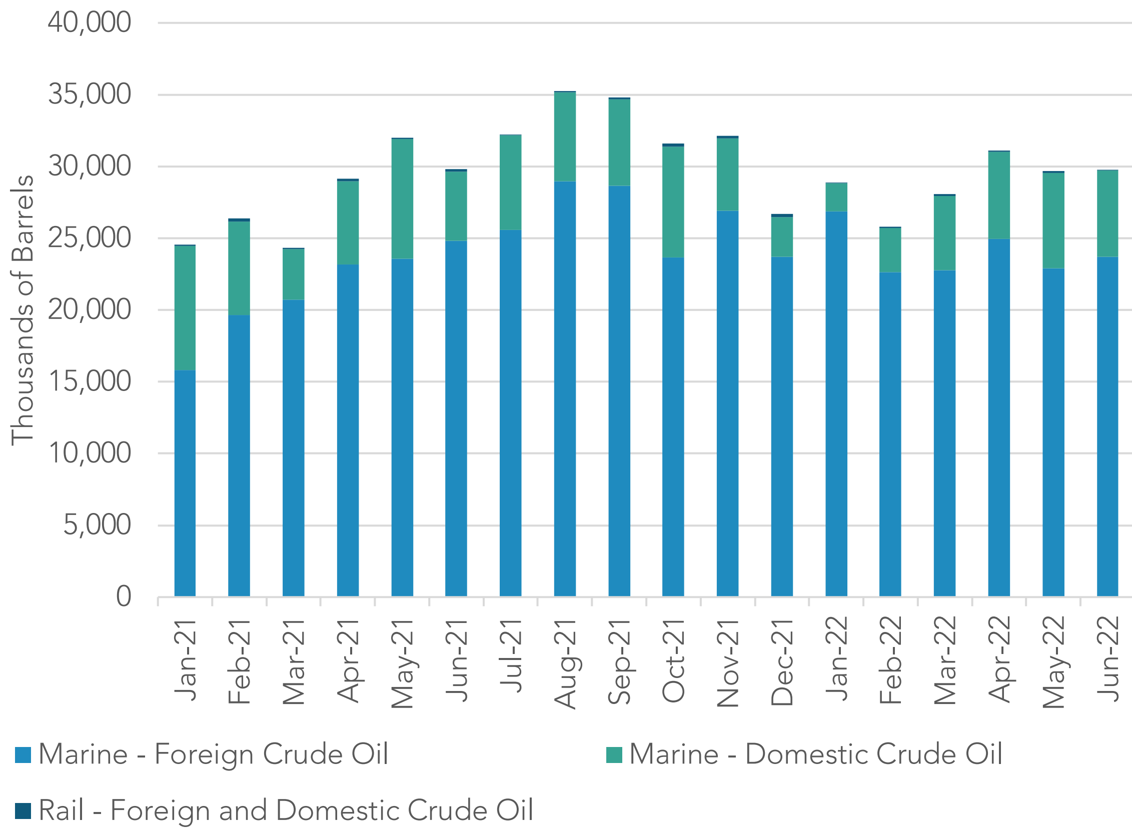
[178] CEC. No date. Oil Supply Sources to California Refineries. Accessed April 21, 2022. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/oil-supply-sources-california-refineries.

[179] University of California, Santa Barbara. 2021. Enhancing Equity While Eliminating Emissions in California's Supply of Transportation Fuels.

[180] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf, and CEC. 2020. *Petroleum Watch: What Types of Crude Oil Do California Refineries Process?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.

remaining imports occur by rail.[181] There are no pipelines that bring crude oil into California from out of state.[182]

Figure 2-8: Crude oil imports by transportation type[183]



Crude oil delivered by marine tankers is delivered to onshore storage tanks and subsequently to refineries via pipeline. Most crude oil produced in California is delivered to California refineries by pipeline. Using historical trends, any increases in imported crude above historic levels would result in increased deliveries through the marine ports. This increased activity could require more infrastructure to store and move larger volumes of crude to the refineries in state.

[181] CEC. June 2021. Crude Oil Imports by Transportation Type. Accessed March 16, 2022. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/crude-oil-imports-source.

[182] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.

[183] CEC. June 2021. Crude Oil Imports. https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/crude-oil-imports-source.

California refineries import a variety of crude oils to meet refinery needs. California petroleum refineries are generally designed to process relatively heavy crude relative to other U.S. refineries. In 2018, crude inputs to California refineries had an average American Petroleum Institute (API) gravity of 26.18 and an average sulfur content of 1.64 percent. Processing significantly lighter or heavier crude blends would require significant changes to a refinery.[184] Most crude imported from Alaska and the Middle East is relatively light (API gravity > 30) compared to California crude (API gravity < 20).[185] If California crude production is insufficient to meet the demand at California refineries, then California refineries will need access to a similarly heavy source of crude so that the average API gravity of crude remains within their established operating window. South American crude oil imports into California are the heaviest relative to other regions, and therefore they may be the most likely to replace decreased California crude oil supply.[186]

In summary, the modeling indicates that demand for petroleum will persist due to legacy fleets that will not be replaced until end of life. The modeling also shows what the GHG emissions reductions would be if oil and gas extraction activities were phased down in line with the reduction of in-state petroleum demand. Trend data shows that oil and gas extraction already has been on the decline and will continue to decline. It is possible to anticipate the likely regions and types of crude that would be imported to meet in-state petroleum demand if in-state extraction was fully phased out by 2045. Importantly, activity at the ports would increase, and new infrastructure would be needed to store and deliver crude to in-state refineries. And while GHG emissions from this sector would go to zero in our AB 32 GHG Inventory with a full phaseout, emissions related to the production and transport of crude to California might increase elsewhere, resulting in emissions leakage.

As the state continues to reduce demand for petroleum, efforts to protect public health for communities located near oil and gas extraction sites must also continue. In October 2021, Governor Newsom directed action to prevent new oil drilling near communities and

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[184] CEC. 2020. *Petroleum Watch: What Types of Crude?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.
[185] CEC. 2020. *Petroleum Watch: What Types of Crude?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.
[186] CEC. 2020. *Petroleum Watch: What Types of Crude?* February. https://www.energy.ca.gov/sites/default/files/2020-02/2020-02_Petroleum_Watch_ADA_0.pdf.

expand health protections.[187,188] In 2022, the Legislature passed, and the governor signed, SB 1137 to protect communities from existing and any new oil and gas extraction activities through 3,200 foot setbacks.

Petroleum Refining

In the Scoping Plan Scenario CARB modeled a phasedown of refining activity in line with petroleum demand. Meeting petroleum demand means sufficient availability of finished fuel (gasoline, diesel, and jet fuel). Crude is processed at in-state refineries to produce finished fuel. In response to stakeholder requests,[189] this evaluation focuses on the Scoping Plan Scenario, but with an evaluation of a complete phasedown of refinery operations in state.

The Scoping Plan Scenario results in California petroleum refining emissions of 4.5 $MMTCO_2e$ in 2045; a reduction of approximately 85 percent relative to 2022 levels, which is in line with the decline in in-state finished fuel demand.[190] Emissions from refining can be reduced further through the application of CCS technology, as shown in Figure 2-9. If in-state refining is phased down to zero and the demand for the finished fuels produced by that refining persists, imported finished fuels may be needed to meet the remaining in-state demand.[191] The current data shows unmet demand for liquid petroleum transportation fuels would most likely be met by marine imports. A CEC report notes, "The only way for California to receive large amounts of crude and refined products is by marine."[192]

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[187] Office of Governor Gavin Newsom. 2021. California Moves to Prevent New Oil Drilling Near Communities, Expand Health Protections. https://www.gov.ca.gov/2021/10/21/california-moves-to-prevent-new-oil-drilling-near-communities-expand-health-protections-2/?msclkid=6c0da86bc58e11ecb81cf596d4d8a735.

[188] California Department of Conservation Geologic Energy Management Division. October 2021. Draft Rule for Protection of Communities and Workers from Health and Safety Impacts from Oil and Gas Production Operations. https://www.conservation.ca.gov/calgem/Pages/Public-Health.aspx?msclkid=45660232cf2511ecb1c56119097e3b0c.

[189] California Environmental Justice Alliance. October 22, 2021. Comment on 2022 Scoping Plan Update - Scenario Inputs Technical Workshop. https://www.arb.ca.gov/lists/com-attach/68-sp22-inputs-ws-WzhdPlI5AjACW1Qx.pdf.

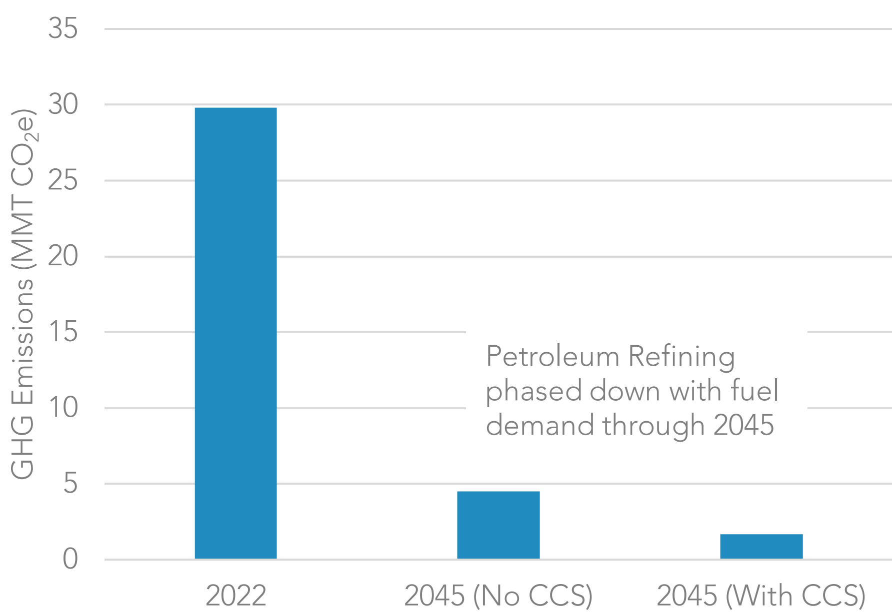
[190] This reduction in demand does not assume any need for ongoing operations to support exports to neighboring states.

[191] If demand assumes an ongoing need to support exports to neighboring states, the residual demand would require a five-fold increase in finished fuel imports.

[192] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.

There are currently no pipelines capable of bringing refined products to the state, and rail imports of refined products have historically made up less than 1 percent of all imports.[193] Significant increases in marine imports would likely require significant reconfiguring, retrofitting, or replacement of crude pipelines and storage tanks at current marine terminals, and possible reconfiguring of existing finished fuel infrastructure to account for changes in volumes and locations of supply points.

Figure 2-9: Petroleum refining sector GHG emissions in 2022 and 2045 (with and without CCS) when activity is phased down with fuel demand



If California's finished fuel demand is not met by continued refining activity in California, the state would need to import finished fuels to meet the ongoing demand. This would likely result in a two- to five-fold increase in the number of finished fuel ship deliveries to marine terminals. Marine tankers delivering refined products are often much smaller than crude oil tankers, so changes in fuel use and emissions cannot be easily estimated from the change in both the type and the number of ship deliveries.[194]

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[193] CEC. 2020. *Petroleum Watch: How Petroleum Products Move.* March. https://www.energy.ca.gov/sites/default/files/2020-03/March_2020_Petroleum_Watch.pdf.

[194] Personal communication with CEC staff, March 2022; U.S EIA. 2017. *World Oil Transit Chokepoints*. 3. https://www.eia.gov/beta/international/regions-topics.php?RegionTopicID=WOTC.

If refining ceased in California, the rail and marine deliveries currently needed to support both refining processes and the export of waste products, such as petroleum coke, would cease.

In summary, the modeling indicates that demand for petroleum will persist through 2045. The modeling also shows what the GHG emissions reductions would be if refining activities were phased down in line with the reduction in in-state petroleum demand. CCS can further reduce emissions for this sector. Importantly, activity at the ports would increase, and new infrastructure would be needed to store and deliver finished fuel across the state, if in-state refining were fully phased down by 2045. And while GHG emissions from this sector would go to zero in our AB 32 GHG Inventory with a full phaseout, emissions related to the refining and transport of finished fuel to California might increase elsewhere, resulting in emissions leakage.

Progress Toward Achieving the Accelerated 2030 Target

The 2017 Scoping Plan laid out a path to achieving the SB 32 target of at least a 40 percent reduction of GHG emissions below 1990 levels by 2030 that focused on reducing emissions in the state and was technologically feasible and cost-effective, reflecting statutory direction. Many of the programs to achieve the 2030 target increased in stringency beginning January 1, 2021. However, the 2030 target must be increased to help achieve the deeper reductions needed to meet the state's statutory carbon neutrality target specified in AB 1279 and Executive Order B-55-18.

Starting in 2020 and extending into 2022, the COVID-19 pandemic impacts reverberated across the globe in a multitude of ways, including the devastating loss of millions of lives. The pandemic also had a significant impact on GHG emissions by virtue of its impact on global economies and lifestyle changes for Californians, with extended work and school disruptions. Thus, assessing our progress toward meeting our SB 32 target is confounded by the unprecedented nature of the pandemic. Nevertheless, an assessment of progress toward the 2030 target is critical, in particular the accelerated 2030 target called for in this Scoping Plan, since achieving the accelerated 2030 target would make the state well positioned to achieve its carbon neutrality goals and bring critical near-term air quality benefits to address historical and ongoing disparities in access to healthy air. Because there is only one year of data available for this decade, the analysis takes a prospective look using projected emissions over the remainder of this decade.

Estimating GHG emissions in 2030 requires projecting the effect of policies or measures that are currently deployed and undergoing implementation. Table 2-4 shows three distinct estimates of GHG emissions in 2030 that were created at different times and used different modeling approaches.

Table 2-4: Estimates of 2030 GHG emissions

Scenario Description	2030 GHG Emissions ($MMTCO_2e$)
2017 Scoping Plan: the projected outcome from implementing policies identified in the 2017 Scoping Plan that was approved by the CARB Board in December 2017.	320
Reference Scenario: the assessment of current trends and expected performance of policies identified in the 2017 Scoping Plan, as of February 2022, using the PATHWAYS model (E3).	305
Reference Scenario (Rhodium): the analysis of projected emissions from 2021 to 2030 from state and federal policies implemented as of July 2022, including the estimated impact of the Inflation Reduction Act and Advanced Clean Cars II using RHG-NEMS and other Rhodium Taking Stock 2022 methods (https://rhg.com/wp-content/uploads/2022/07/Taking-Stock-2022_US-Emissions-Outlook.pdf).	324

These three estimates of 2030 GHG emissions differ, which is expected. The estimates reflect different outcomes of the current and future impact of policies and measures. They also vary due to fundamental differences in the way these models work. For example, PATHWAYS is an economy-wide, scenario-based GHG accounting tool that tracks energy demands and supplies in line with scenario assumptions and is benchmarked to historical values. RHG-NEMS optimizes both the supply and demand sides of the energy system while factoring in consumer constraints and dynamic economic and energy systemwide feedback. Importantly, while these point estimates give the appearance of certainty and accuracy, there is significant uncertainty in future emissions projections that is documented thoroughly in each of the three emissions scenarios described above. No model can predict the future given unforeseen factors such as notable economic swings and implementation delays for programs. However, the range of emissions estimates provides a useful indication of possible outcomes from successful implementation of policies and measures.

An important source of uncertainty is the impact of delayed implementation of policy measures and market actions. The successful rate of deployment of clean technology and fuels—including consumer adoption patterns, economic recovery from the pandemic, and the permitting and build-out of necessary new assets and reuse of existing assets to produce and deliver clean energy—is essential to reach GHG emission reduction targets. Any delays will only increase GHG emissions in 2030.

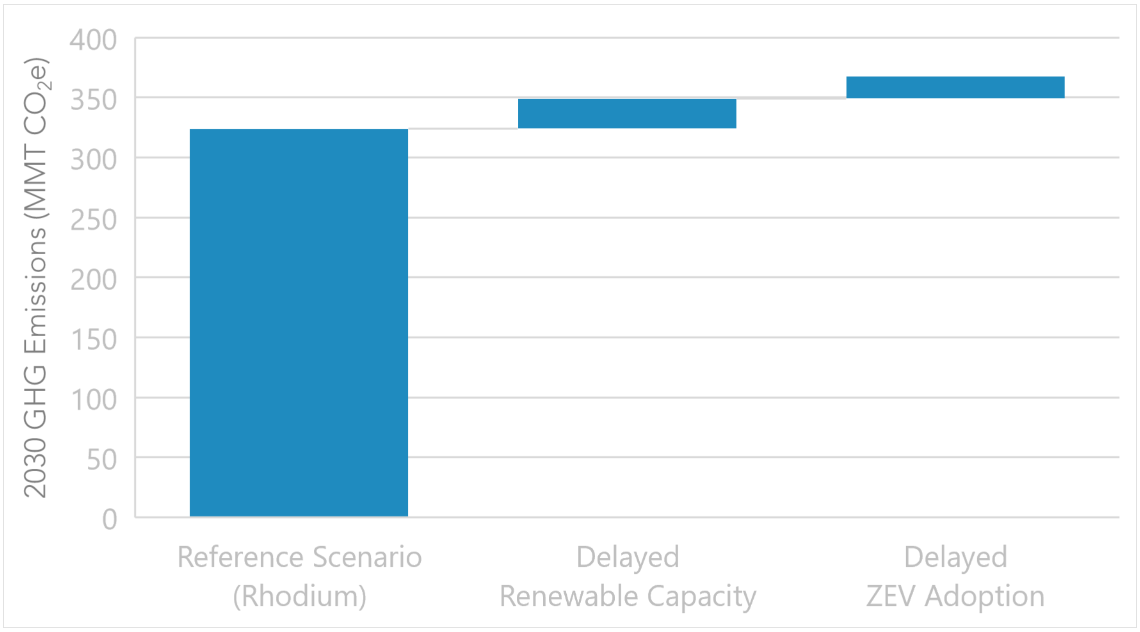
It is important to note that incentives, carbon pricing, and regulations all can result in similar types of responses including, but not limited to:

- Build-out of clean energy and infrastructure
- Deployment of clean technology
- Reduced demand for fossil energy
- Efficiency improvements

As such, the uncertainty analysis discussion focuses on implementation (technology and infrastructure deployment), and not any specific programs or policies. It is successful implementation that must ultimately happen for emissions reductions to be realized.

The uncertainty analysis described in Appendix J (Uncertainty Analysis) quantifies the impact of delayed permitting and building of renewable generation and transmission in the power sector and delayed adoption of ZEVs across all vehicle fleets in the transportation sector. The Reference Scenario (Rhodium) estimates emissions in 2030 to be 324 MMTCO2e. A five-year delay in renewable capacity would increase emissions by 8 percent in 2030 (25 MMTCO2e) relative to the Reference Scenario. If similar delays in clean energy production and deployment occur in other sectors, a larger increase in emissions relative to the reference scenario would be expected, jeopardizing the state's ability to achieve the 2030 target. Similarly, a delay in consumer adoption of zero emission vehicles (LDV, MDV, HDV) would increase emissions by 6 percent in 2030 (19 MMTCO2e) relative to the Reference Scenario. Delays in transitioning to electric equipment and appliances in homes and businesses would also lead to increased emissions in 2030. Figure 2-10 illustrates the impact on projected emissions in 2030 associated with delayed renewable capacity and delayed transportation vehicle electrification.

Figure 2-10: Impact of delayed implementation on 2030 GHG emissions[195]



Appendix J (Uncertainty Analysis) includes additional details on the assumptions and model used for the uncertainty analysis and the risks to achieve the emissions reductions from 2022 to 2030 that are anticipated in the Scoping Plan Reference Scenario. While the analysis focuses on renewable capacity and transportation, the analysis identifies a common set of themes that can impact emissions reductions across economic sectors, including permitting, technology availability, and consumer adoption. The impact of delayed emissions reductions will vary by sector and by the specific policy at risk of delay.

We give these quantitative examples of the impact implementation delays can have on GHG reductions, but almost every economic sector will have the need for permitting to enable at least a 40 percent reduction below 1990 levels. If we consider the increased ambition of the Scoping Plan Scenario, which identifies an accelerated 2030 target, the same types of uncertainty manifest themselves in successful implementation of the Scoping Plan Scenario, with the added need for CCS and CDR and a need to grow other energy sectors such as hydrogen.

[195] The implementation delay scenarios were modeled separately and do not necessarily reflect the combined impact of delayed renewable capacity and transportation vehicle electrification.

Cap-and-Trade Program Update

Since the adoption of the first Scoping Plan in 2008, carbon pricing in the form of a Cap-and-Trade Program has been part of the portfolio to achieve the state's GHG reduction targets, and it will remain critical as we work toward carbon neutrality. This section provides an update on the program and its role in achieving the 2030 target.

The Cap-and-Trade Program first came into effect in 2012, under AB 32, and included declining allowance caps through 2020. In 2017, AB 398[196] was passed by a supermajority in the Legislature and included prescriptive direction on the design of the program from 2021 through 2030. The AB 398 Cap-and-Trade Program came into effect on January 1, 2021, and it included the following changes:

- Doubling of stringency with an annual cap decline of 4 percent per year from 2021–2030
- AB 398 price ceiling
- AB 398 redesigned allowance price containment reserve with two tiers
- AB 398 100 percent leakage assistance factor for industry
- AB 398 lower offset limits: Usage limit cut from 8 percent to 4 percent, and half of offsets must provide direct benefits to California

The reduction in the role of offsets in the program was in recognition of ongoing concerns raised by environmental justice advocates regarding the ability of companies to use offsets for compliance instead of investing in actions on site to reduce GHG emissions that could also potentially reduce criteria or toxic emissions.[197,198] Note that data show the relationship between facility emissions of GHGs and co-pollutants is highly variable by sector and pollutant.[199] Changes to the allowance price containment reserve and the addition of the price ceiling were included to ensure protections against price spikes in the program, while the changes to the leakage assistance factors were to ensure the maximum protection against leakage in the program. The original design of the program included an auction floor price that increases by 5 percent plus inflation each year, and

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[196] Assembly Bill 398 (Garcia, Chapter 135, Stats. of 2017). California Global Warming Solutions Act of 2006: market-based compliance mechanisms: fire prevention fees: sales and use tax manufacturing exemption. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398.

[197] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits Within Disadvantaged Communities*. https://oehha.ca.gov/media/downloads/environmental-justice/impactsofghgpoliciesreport020322.pdf.

[198] The OEHHA report also found that companies that use the most offsets often own the facilities that contribute to local $PM_{2.5}$ exposure. However, there was no causal relationship found to indicate that implementation of the Cap-and-Trade Program was contributing to increases in local air pollution. Also see: CARB. FAQ Cap-and-Trade Program. https://ww2.arb.ca.gov/resources/documents/faq-cap-and-trade-program.

[199] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits Within Disadvantaged Communities*. https://oehha.ca.gov/media/downloads/environmental-justice/impactsofghgpoliciesreport020322.pdf.

that escalation factor is retained in the post-2020 program and is also applied to the allowance price containment reserve and price ceiling. These features, combined with the self-ratcheting mechanism for unsold allowances at auctions,[200] help to ensure the program is able to handle periods of high and low demand for allowances while continuing to ensure a steadily increasing price signal for regulated entities to invest in GHG reduction technologies.

As a result of achieving the 2020 target several years earlier than mandated by law, there are unused allowances in circulation. CARB estimated the amount to be approximately 310 million allowances after the conclusion of the third compliance period (2018–2020).[201] AB 398 had also called for a similar analysis, which was completed in 2018.[202] This bank represents approximately 5 percent of the total number of vintage 2013–2030 allowances issued within the joint market. This bank of allowances can only remain banked if year-over-year the covered emissions are declining by 14 MMT. If the annual decline in actual emissions is less than 14 MMT, regulated entities will need to use the banked allowances to cover their compliance obligations. It is likely that the existing bank of 310 million allowances will be needed over the early part of this decade and will be exhausted by the end of the decade. During the same period, prices for allowances will continue to increase at least 5 percent plus inflation year-over-year, sending a steadily increasing price signal to spur investment in onsite reductions for covered entities.

With the passage of AB 1279, the state has a statutory target to achieve carbon neutrality no later than 2045. This Scoping Plan demonstrates that planning on a longer time frame for the new carbon neutrality target means we must accelerate our near-term ambition for 2030 in order to be on track to achieve our longer-term target. CARB will use the modeling for this Scoping Plan to assess what changes may be warranted to the Cap-and-Trade or other programs to ensure we are on track to achieve an accelerated 2030 target. Since the original adoption of the Cap-and-Trade regulation, the program has been amended eight times through a robust public process. Moreover, then-California Environmental Protection Agency Secretary Jared Blumenfeld testified at a Senate hearing in 2022 that CARB will report back to the Legislature by the end of 2023 on the status of the allowance supply with any suggestions on legislative changes to ensure the number of allowances

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[200] The self-ratcheting mechanism temporarily removes unsold allowances from the market until either sufficient demand manifests for two consecutive auctions and they are incrementally reintroduced at future auctions, or they are permanently removed from general circulation if demand remains low.
[201] CARB. 2022. BR 18-51 Cap-and-Trade Allowance Report. Attachment A. *https://ww2.arb.ca.gov/sites/default/files/cap-and-trade/Allowance%20Report_Reso18_51.pdf*.
[202] CARB. 2018. Staff Report: Initial Statement of Reasons: Proposed Amendments to the Cap on Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation. September 4. *https://www.arb.ca.gov/regact/2018/capandtrade18/ct18398.pdf?_ga=2.134288305.1735610122.1664813952-1100516233.1657841496*.

is appropriate to help the state achieve its 2030 target of at least 40% below 1990 levels. As part of that status update, CARB will also provide information on any potential program changes that may be needed to allowance supply to help achieve an accelerated target for 2030 identified in this Scoping Plan as necessary to achieve carbon neutrality no later than 2045. Engaging in this process in 2023 will allow for the consideration of this Scoping Plan, inclusion of additional data points for the second year of operation of the AB 398-designed program (which only came into force in January 2021), and an opportunity to hold public workshops.

It is also worth noting that the COVID-19 pandemic had significant impacts on economic activity in California and elsewhere.[203] Emissions were significantly lower in 2020 due to the impacts of the global pandemic. There is an expectation that emissions will increase as the economy recovers and behaviors continue to shift from the impacts of the ongoing pandemic. As a result, 2020 should be regarded as an outlier in the emissions trends. This scenario of increasing emissions is similar to what happened in the first compliance period for Cap-and-Trade, where the state economy was recovering from the Great Recession and does not correlate to a problem with the structure of this program or other programs that cover emissions related to the manufacturing or transportation sectors. In any assessment of this and other programs, it is essential to consider external factors such as economic activity and availability of zero carbon energy such as hydropower, among others.

To better understand the role of the Cap-and-Trade Program in achieving the 2030 target, Table 2-5 compares the 2030 GHG emissions estimates from the three reference scenarios described in Table 2-4. The 2017 Scoping Plan projection is from the PATHWAYS model for the Scoping Plan Scenario approved by the Board in late 2017. It excludes the contribution of the Cap-and-Trade Program, without any consideration of uncertainty factors (i.e., a characterization of the uncertainty that a given GHG reduction measure included in the 2017 Scoping Plan will actually achieve the GHG reductions it is projected to deliver). The Reference Scenario represents what GHG emissions would look like if we did nothing beyond the existing policies that are required and already in place to achieve the 2030 target; this scenario is based on the recent PATHWAYS modeling, excluding the contribution of the Cap-and-Trade Program, and without any consideration of uncertainty factors. It indicates that GHG emissions will be lower over this decade than originally projected when the 2017 Scoping Plan was approved. The

[203] CARB. November 4, 2021. Mandatory Greenhouse Gas Reporting - 2020 Emissions Year Frequently Asked Questions. https://www.arb.ca.gov/cc/reporting/ghg-rep/reported-data/2020mrrfaqs.pdf?_ga=2.264251343.1760432228.1650736660-1644197524.1577749754.

Reference Scenario (Rhodium) which also does not include uncertainty bounds, is the modeling used for the uncertainty analysis above.

Importantly, PATHWAYS is not able to explicitly model a carbon pricing policy, and therefore the Cap-and-Trade Program is not represented in the 2017 Scoping Plan or the Reference Scenario. Carbon pricing is included in RHG-NEMS, which reflects state and federal policies included in the U.S. Energy Information Administration (EIA) Annual Energy Outlook 2022 and the National Energy Systems Model (NEMS), which is the basis for RHG-NEMS.[204]

As detailed in EIA's documentation, California's Cap-and-Trade Program is represented through increased energy prices, which flow across economic sectors.[205] However, many of the emissions covered by the California Cap-and-Trade Program are not energy- and fuel-related emissions. Given that, the energy systems model RHG-NEMS was used to model the impact of California Cap-and-Trade on the energy system. However, RHG-NEMS does not explicitly model the entire program, which includes non-energy related emissions from the industrial, agricultural, waste, and transportation sectors.

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[204] U.S. EIA. 2022. *Summary of Legislation and Regulations Included in the Annual Energy Outlook 2022.* March. https://www.eia.gov/outlooks/aeo/assumptions/pdf/summary.pdf.

[205] U.S. EIA. 2022. Electricity Market Module. https://www.eia.gov/outlooks/aeo/assumptions/pdf/electricity.pdf.

Table 2-5: Comparison of 2017 Scoping Plan and two Reference Scenarios

	2030 GHG Emissions ($MMTCO_2e$) (2017 Scoping Plan)	2030 GHG Emissions ($MMTCO_2e$) (Reference Scenario)	2030 GHG Emissions ($MMTCO_2e$) (Reference Scenario-Rhodium)
Reference Scenarios	320	305	324
Gap to Accelerated 2030 Target under the Scoping Plan Scenario (226)[206]	94	79	98

Under the Scoping Plan Scenario, in 2030 California emissions are anticipated to be 48% below 1990 levels. This represents an acceleration of the current SB 32 target of a 40% reduction below 1990 levels. Table 2-5 includes the gap between the different reference scenarios and the accelerated 2030 target achieved under the Scoping Plan Scenario. It also shows that depending on the modeling, there are a range of potential emissions levels in 2030 prior to accounting for the full impact of the Cap-and-Trade Program on emissions. That range is from 305 to 324 $MMTCO_2e$ in 2030. That represents a 19 $MMTCO_2e$ spread, or about 8.4 percent of the accelerated 2030 target of 226 $MMTCO_2e$. Importantly, none of these scenarios includes all of the actions identified in the Scoping Plan Scenario for this Scoping Plan; many of those actions, such as SB 596, CCS, and a more stringent LCFS program, will only begin to happen in this decade, and their contributions toward meeting the accelerated 2030 target are therefore not included in the reference scenarios. The actual emissions for the remainder of this decade will therefore likely be lower than in each of the scenarios in Table 2-5 once policies and regulations are in place to support an accelerated 2030 target. However, the degree of this difference between actual and projected emissions will differ across the modeled reference scenarios.

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[206] Table 3 from the 2017 Scoping Plan included a range of 34 to 79 $MMTCO_2e$ for reductions needed from the Cap-and-Trade Program to achieve a 2030 target of 40 percent below 1990 levels.

Regardless of the uncertainty and differences in the models, it is clear additional GHG reductions must happen over this decade to achieve an accelerated 2030 target. This will require an evaluation of all major programs to assess the need to increase their stringency between now and 2030. As the actual reductions from non-Cap-and-Trade Program measures increase, California will be less reliant on the Cap-and-Trade Program to "fill the gap" to meet an accelerated 2030 reduction target. For example, CARB is developing a proposal to increase the stringency of the LCFS program for 2030, the recently adopted Advanced Clean Cars II regulation is more stringent than modeled for the 2030 40 percent target in the 2017 Scoping Plan, and SB 596 requires specific reductions in the cement sector over this decade and beyond. However, we also know we are not on track to achieve the VMT reduction called for in the 2017 Scoping Plan and will need to double down to achieve the even more ambitious target called for in the Scoping Plan Scenario. Also, we will need additional actions over the coming years to reduce short-lived climate pollutants to meet the emission reductions called for in SB 1383.

Collectively, any additional legislation or prescriptive policies for sectors, delays in successful implementation of non-Cap-and-Trade programs and policies, increases in incentive program funding, and delays in economic recovery from the pandemic will continue to affect the role the Cap-and-Trade Program will need to play over this decade to meet the state's GHG reduction obligations. In summary, the Cap-and-Trade Program must continue to be able to scale across a range of possibilities. With passage of AB 1279 and the need to accelerate the 2030 target, CARB will initiate a public process to utilize the modeling results from this Scoping Plan, specifically the Scoping Plan Scenario, to evaluate and potentially propose changes to the design of the Program, including the annual caps. This process will ensure that the Program supports an increased ambition for 2030 while retaining the ability to scale as other factors, such as changing economic conditions and implementation of non Cap-and-Trade programs, impact the actual emissions at the sources covered by the Program. Any changes to the Program must continue to support a well-designed system that continues to send a steadily increasing price signal, minimizes for leakage, reduces emissions in the covered sectors toward the state's targets, is cost-effective and technologically feasible, and avoids energy rate spikes. Importantly, the Program should support air quality benefits, especially in overly burdened communities, and not exacerbate existing air quality disparities.

Chapter 3: Economic and Health Evaluations

This chapter provides two approaches for quantifying the economic and health outcomes of the Scoping Plan Scenario. One approach is to consider the combined impact of all measures[207] in a scenario. The other approach is required by AB 197, where each measure within a scenario is evaluated independently. In addition to these two evaluation approaches, this chapter also includes a discussion of the Public Health implications for the Scoping Plan Scenario, an overview of the Climate Vulnerability Metric, and the Environmental Analysis conducted in accord with the California Environmental Quality Act (CEQA).

It is important to note that all of the analyses in this chapter use a variety of data sources, but because the modeling is economy-wide at the state level, none of them produce community specific detail outputs. The AB 32 GHG Inventory Sector analysis relies on PATHWAYS data at the state level that is proportionally applied across all regions of the state to translate changes in state level fuel combustion to local level changes. The NWL analysis similarly utilizes a variety of data sources and a suite of models that produce data that are scaled up to the statewide level. All of the models, except the Wildland Urban Interface (WUI) defensible space model, which is conducted at the county level, create aspatial projections that are not applicable at the community level.

Economic Analysis

As part of the process to develop this Scoping Plan, alternative scenarios that transition energy needs away from fossil fuels and achieve carbon neutrality no later than 2045 were developed. Alternative scenarios that assess the impact of different land management strategies on carbon stocks in NWL were also developed. These alternatives are described in Appendix C (AB 197 Measure Analysis). The following sections describe the Scoping Plan Scenario in terms of direct cost, the economy, employment, and health outcomes.[208]

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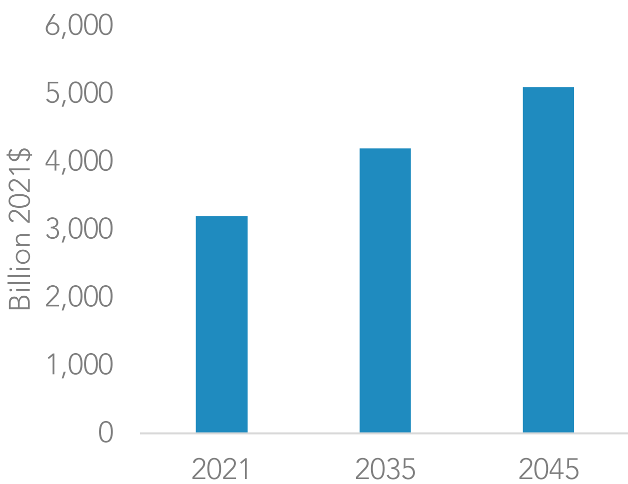
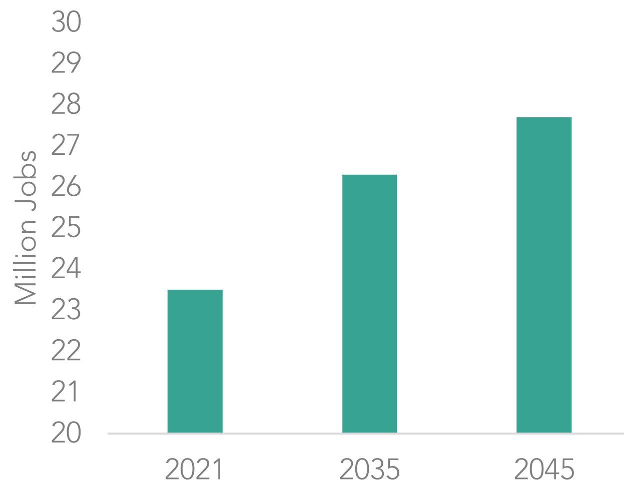
[207] AB 197 calls for the evaluation of "measures." This Scoping Plan treats each action and its variants on stringency as measures for the purposes of this chapter. Appendix C (AB 197 Measure Analysis) lists the measures and corresponding modeling assumptions for each alternative and the Scoping Plan Scenario. The modeling assumptions for the Scoping Plan Scenario are summarized in Table 2-1.

[208] For the Draft 2022 Scoping Plan Update, achieving carbon neutrality in 2035 and 2045 was evaluated. The AB 32 GHG Inventory sector direct cost, the economy, employment, and health outcomes were assessed in those years. Similarly, the Scoping Plan Scenario assessments that are presented in this chapter were made for years 2035 and 2045.

The California economy is growing, and it is projected to continue to grow about 2 percent each year, from $3.2 trillion in 2021 to $5.1 trillion in 2045, as shown in Figure 3-1. Similarly, employment in California is anticipated to grow 0.7 percent per year, from 23.5 million jobs in 2021 to 27.7 million jobs in 2045. It is in this context, termed the *Reference Scenario,* that CARB evaluates the Scoping Plan Scenario in terms of its impact on economic growth and employment. The projections shown in Figure 3-1 were produced by CARB to evaluate the incremental impact of regulations.

Figure 3-1: Projected California gross state product (left) and employment growth (right) from 2021 to 2035 and 2045





Source: California Air Resources Board

Transitioning away from fossil fuels to alternatives and increasing action on NWL will affect employment opportunities, household spending, businesses, and other economic aspects of our lives. Sectors expected to see growth include renewable electricity and hydrogen production, while other sectors may shrink. The deployment of clean technology may require higher upfront costs for things like heat pumps and induction stoves, but those could be offset by energy efficiency savings. Employment and economic development in NWL-related industries and sectors are expected to increase as land management actions increase, especially for the Forestry sector (in which a significant increase is called for under the Scoping Plan Scenario). The net impact of these actions on employment and jobs is presented in this chapter.

Estimated Direct Costs

One key metric is the direct cost, or net investment, reflecting any savings that result from actions. Similar approaches were used to estimate direct costs for the AB 32 GHG Inventory sectors and for the NWL, as described in this section.

AB 32 GHG Inventory Sectors

Transitioning away from fossil fuels requires investment in new equipment and infrastructure throughout the economy. It involves developing the capacity to produce fuels and electricity from renewable sources rather than producing fossil energy. This transition also takes time. One approach is to eliminate combustion of fossil fuels by replacing all equipment in a specified year. Another approach is to establish a future point at which all sales of new equipment rely on alternative energy sources and allow the transition to occur over time as equipment is replaced upon its end of life.

To evaluate the investment required through 2045, the PATHWAYS model was used to represent equipment stock and its turnover to non-fossil fuel alternatives over time. The annualized, incremental cost of infrastructure in excess of the annualized cost of the Reference Scenario[209] was computed for each year from 2022 through 2045. These costs were computed by first taking the absolute cost in each year—which includes both new equipment investment and also expenditures on energy, operations, and maintenance in each year—and then levelizing the costs (in the same way car or house payments are annualized or spread out over time) to arrive at an annualized cost. Fuel savings, and resulting cost savings, associated with changing energy demand—from gasoline to electricity for vehicles, for example—are included as a result of this methodology. Carbon dioxide removal includes DAC technology powered primarily by off-grid solar, BECCS to produce hydrogen or other fuels, and NWL sequestration, as discussed in Chapter 2.[210]

Figure 3-2 shows the stock investment cost, fuel/efficiency savings, and CDR cost. The Scoping Plan Scenario allows end-of-life transition of equipment. The cost of investing in new equipment is partially offset by savings associated with efficiency gains and reduced demand for fuels like gasoline. This is particularly relevant in the transportation sector, which leads to the majority of savings in 2045 in the Scoping Plan Scenario, which models near complete electrification of transport relying only on end-of-life replacement of vehicles. Appendix H (AB 32 GHG Inventory Sector Modeling) includes additional detail on direct costs in each sector and how costs change over time.

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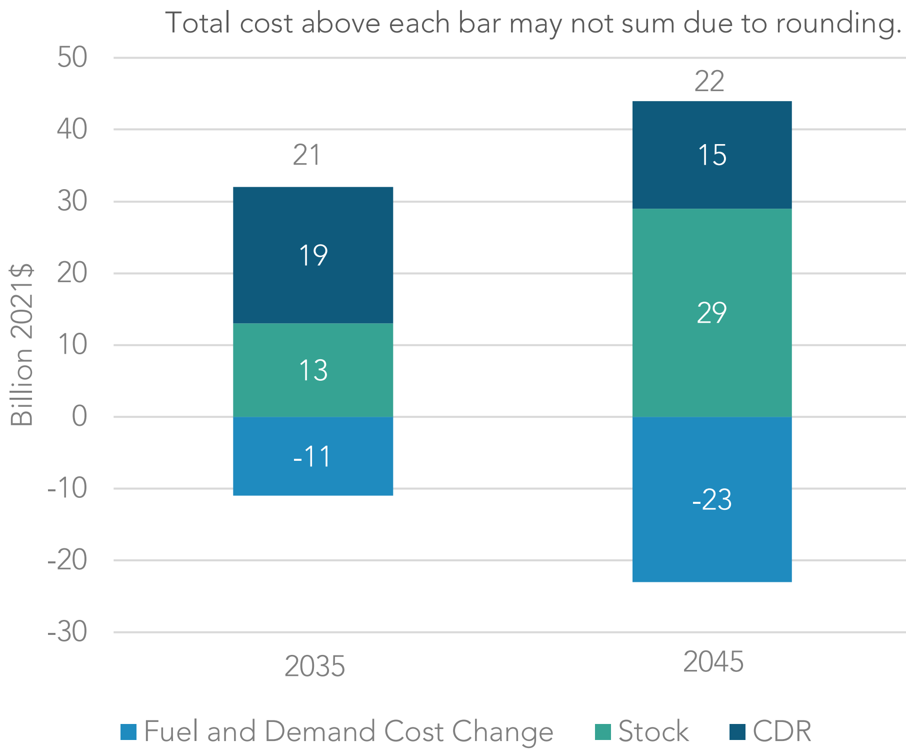
[209] The Reference Scenario described in Chapter 2 and in Appendix H (AB 32 GHG Inventory Sector Modeling) was the basis for the direct cost comparison.

[210] The energy source for DAC is not modeled, but renewable electricity and/or hydrogen produced from electrolysis are zero-carbon options consistent with the carbon neutrality targets in this Scoping Plan. The economic analysis associated the investment in DAC with the solar industry for consistency with the carbon neutrality targets.

Figure 3-2: Cost and savings relative to the growing California economy for the Scoping Plan Scenario in 2035 and 2045 (AB 32 GHG Inventory sectors)



Natural and Working Lands

For NWL, the direct costs of each management strategy were estimated using available academic literature, monitoring and reporting data, survey data, and cost data from existing subsidy programs on the per acre cost of implementing the management strategy. These cost data, in combination with the acreage of each management strategy under the scenarios, provided estimates of the overall direct cost to either the government or the private sector. The direct costs are independent of the policy lever used to implement the action and do not include many important benefits and externalities of the actions. They are assumed to be constant for each scenario and into the future. Avoided or secondary costs, such as those from reductions in wildfire suppression expenses, are not included. Appendix I (NWL Technical Support Document) includes additional direct cost details.

Table 3-1 includes the direct cost estimates for the Scoping Plan Scenario compared to the Reference Scenario.[211] Direct costs for the NWL sector are expected to be significant due to the ambitious level of action for each land type.

Table 3-1: Cost and savings relative to a growing California economy for the Scoping Plan Scenario (NWL)

Measure	Scoping Plan Scenario: Average Direct Annual Cost, 2025–2045 (millions $/year)
Forests / Shrublands / Grasslands	1,780
Annual Croplands	284
Perennial Croplands	4
Urban Forest	4,230
Wildland Urban Interface (WUI)	114
Wetlands	28
Sparsely Vegetated Lands	4
Totals	6,460
Note: Table values may not add to total due to rounding.	

CARB estimates that all jurisdictions, including private landowners, currently spend approximately $4 billion dollars annually on planting, maintenance, sidewalk repair, tree removal, and other expenses related to urban forests, and that reaching the theoretical maximum tree cover would require increasing that spending by a factor of 20. The cost of the Scoping Plan Scenario is predominantly a mix of urban forests and forests, shrubland, and grasslands spending.

[211] The Reference Scenario described in Chapter 2 and in Appendix I (NWL Technical Support Document) was the basis for the direct cost comparison.

Economy and Employment

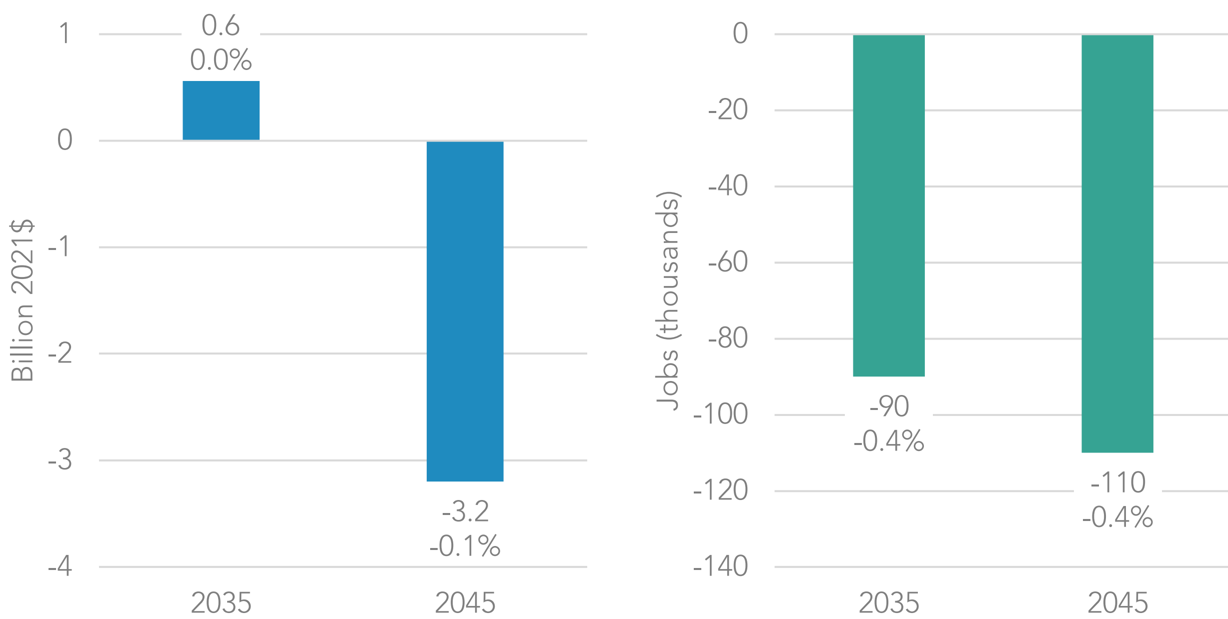
Two different models were used to estimate the overall impact that investing in a transition away from fossil fuels and in our NWL may have on the growing California economy. The transition away from fossil fuels was evaluated using the IMPLAN economic analysis model. The NWL investments were evaluated using the REMI PI+ economic model. These models provide similar outputs relative to the same economic and employment forecasts used to develop a Reference Scenario for use in each model.

AB 32 GHG Inventory Sectors

To estimate the overall impact that investing in a transition away from fossil fuels may have on the California economy, CARB used the IMPLAN model. Additional detail regarding the model, assumptions, and methodology are included in Appendix H (AB 32 GHG Inventory Sector Modeling). The IMPLAN model is a multisector representation of private industries in the U.S. economy that maps economic relationships across industries, households, and governments. This model translates direct costs and savings associated with transitioning away from fossil fuels with indirect effects such as wages, purchases of goods and services, business tax impacts, and supply chain effects. In addition, the induced effects of household purchases, local and import purchases, wages paid, and household tax impacts are estimated. This comprehensive assessment of the interactions between capital investment in fossil fuel alternatives and household purchases provides an indication of the response of the California economy to the Scoping Plan Scenario.

The Scoping Plan Scenario results in a small impact on the Gross State Product (GSP) and employment relative to the Reference Scenario, as shown in Figure 3-3. Economic growth is largely unaffected by the Scoping Plan Scenario in 2035 and slowed by 0.1 percent in 2045. Employment growth is also slowed a small amount, 0.4 percent in 2035 and in 2045, and employment still grows. Assuming annual growth rates of 0.7 percent means there would be more than 193,000 additional jobs in 2045.

Figure 3-3: Gross state product (left) and employment (right) relative to a growing California economy for the Scoping Plan Scenario in 2035 and 2045 (AB 32 GHG Inventory sectors)



California households will see increased costs from the purchase of new capital stock and savings from reduced spending on fuel, as shown in Figure 3-2. Households also will face increased costs associated with CDR, costs associated with energy efficiency measures, and commercial stock purchases—all of which are assumed to be passed directly to consumers. The impact to California households, however, is not limited to these direct costs, as changes in relative prices, employment, and wages can affect household well-being. Personal income, which captures the direct, indirect, and induced impacts, is a metric commonly used to evaluate the impact of policies on households.

Personal income in California is projected to grow from $2.7 trillion in 2021 to $3.6 trillion in 2035 and $4.4 trillion in 2045. Household projections are based on California Department of Finance population projections, which estimate the state's population to grow an average of 0.3 percent each year from 2021 to 2045.[212] California households are projected to increase from 13.3 million in 2020 to 14.6 million in 2035 and 15.0 million in 2045.

[212] California Department of Finance. Population Projections (Baseline 2019). https://dof.ca.gov/forecasting/demographics/projections/.

While the transition away from combustion of fossil fuels will improve air quality for all Californians (and even, more so in overly burdened communities), the economic impacts of the Scoping Plan Scenario are unlikely to be equal among Californians. Table 3-2 presents the change in income by household income group relative to the Reference Scenario in 2035 and 2045. While in 2035 there is a net decrease in personal income of $600 million, total income for households that make less than $100,000 per year is estimated to decline by $4.1 billion dollars, and the total income for households that make more than $100,000 per year will increase by $3.5 billion under the Scoping Plan Scenario. In 2045, although there is no net change in personal income across all California households, results vary by income level. Total income for households that make less than $100,000 per year are estimated to decline by $5.3 billion dollars, while the total income for households that make more than $100,000 per year will increase by $5.3 billion under the Scoping Plan Scenario.

Table 3-2: Income Impacts by California household income group in 2035 and 2045 for the Scoping Plan Scenario (AB 32 GHG Inventory Sectors)

Household Income Group ($2021)	Percentage of 2021 California Households[213]	Change in Income (Billion $2021)	
		2035	2045
Less than $50,000	30	-2.9	-3.9
$50,000 to $100,000	27	-1.2	-1.4
$100,000 to $200,000	28	2.5	4.0
More than $200,000	15	1.0	1.3
Total	100	-0.6	0.0

[213] U.S. Census Bureau. 2021. Household Income. California. https://data.census.gov/cedsci/table?q=california%20income.

In addition to income level, there is likely to be an impact to California personal income that varies based on race/ethnicity.[214] Table 3-3 shows the percentage of households within each income group based on eight race/ethnicity categories identified in the American Community Survey 2021. As shown in Table 3-2, households in lower income groups are anticipated to see negative impacts, while households in higher income groups are anticipated to see positive impacts from the Scoping Plan Scenario in both 2035 and 2045. Because more than 60% of households in the race/ethnicity categories of Hispanic, Black alone, Native Hawaiian (HI) or Pacific Islander, American Indian or Alaskan Native, Other, and Two or More make less than $100,000 per year, these populations generally are likely to experience reduced income. White and Asian households will generally experience both increased and decreased income because these households are distributed more evenly across all four income groups.

The state recognizes the need to ensure that accessibility to clean technology and energy do not further exacerbate health and opportunity gaps for low-income households and communities of color. The Climate Change Investments program exceeds the statutory minimums to invest in projects to benefit disadvantaged communities.[215] Utilities implement programs for reduced energy bills for qualifying low-income customers.[216] There are also resources for waste and water bills that leverage federal funds.[217] CARB also coordinated with the CPUC to ensure that the Climate Credit[218] funded from the sale of Cap-and-Trade allowances provided to utilities on behalf of ratepayers is credited equally to households and not based on how much energy is used. These are just a few examples of how the state is designing and implementing programs to avoid increasing existing disparities. The state must continue to find ways to relieve economic burdens on low-income households.

[214] The number of households in each bracket and the race/ethnicity categories are from American Community Survey 2021 results. Population changes through 2035 and 2045 are not forecast. U.S. Census Bureau. 2021. Household Income. California. https://data.census.gov/cedsci/table?q=california%20income.
[215] CARB. Priority Populations — California Climate Investments. https://www.caclimateinvestments.ca.gov/priority-populations.
[216] CPUC. CARE/FERA Program. https://www.cpuc.ca.gov/lowincomerates/.
[217] California Department of Community Services and Development. Low Income Household Water Assistance Program. https:/www.csd.ca.gov/lihwap.
[218] CPUC. California Climate Credit - FAQ. https://www.cpuc.ca.gov/industries-and-topics/natural-gas/greenhouse-gas-cap-and-trade-program/california-climate-credit/california-climate-credit---faq.

Table 3-3: Percentage of households in each race/ethnicity category by household income group

Household Income Group ($2021)	Households in Income Group (%)							
	White Not Hispanic	Hispanic	Black Alone	Asian Alone	Native HI or Pacific Islander	American Indian or Alaskan Native	Other	Two or More
Less than $50,000	26	35	45	25	30	35	37	32
$50,000 to $100,000	25	32	27	21	31	33	33	30
$100,000 to $200,000	29	25	21	30	30	26	24	27
More than $200,000	19	7	7	24	9	7	5	11

Natural and Working Lands

The macroeconomic impact of the NWL scenario was evaluated separately in the REMI PI+ model. For the Scoping Plan Scenario, the macroeconomic impact was modeled by assuming that economic activity in the relevant industries grows in proportion to the proposed implementation spending in that industry. All funds for implementing the actions were assumed to be sourced from within the state. For urban forests, the funds were modeled as being sourced from a combination of state government and private property owners in proportion to the current estimated private/public spending ratio. For all other actions, funds were assumed to be sourced from the state government. In each modeled scenario, government spending and income to property owners were reduced relative to the Reference Scenario in proportion to the annual costs of implementation. None of the proposed spending was modeled as being sourced from increased taxes. Additional details on the methodology for evaluating macroeconomic impacts are in Appendix I (NWL Technical Support Document).

While the macroeconomic model does count the increased economic activity in the affected industries as part of GSP, it does not quantify many of the important economic, health, and environmental benefits that would occur if these actions were implemented. While these benefits—like the reduced use of pesticides, value of urban trees, and increased recreational opportunities—would be very significant, they are outside the scope of the macroeconomic model.

The macroeconomic model also makes projections about the total level of employment in the state. The model forecasts that the Scoping Plan Scenario, which greatly increases the level of NWL management actions, channels economic activity toward related industries and would lead to a slight increase in total employment. (Table 3-4). While the model does aim to accurately represent many labor market dynamics, including adjustments of wages and migration rates, it does not account for many costs that might be associated with dramatically scaling up employment in a particular industry, such as the cost of job training.

Table 3-4: Gross state product and employment relative to a growing California economy for the Scoping Plan Scenario in 2035 / 2045 (NWL)

	Scoping Plan Scenario (%)
Gross State Product	0.00 / 0.01
Employment	0.12 / 0.10
Personal Income	-0.04 / -0.04
Personal Income per Capita	-0.04 / -0.14

Health Analysis

Air quality is affected by pollutant emissions from various processes associated with energy systems, including the combustion of fossil fuels, as well as the combustion of vegetation biomass from NWL during wildfires. Pollutants that are important contributors to degraded air quality in California include nitrogen oxides (NO_x), particulate matter (PM), reactive organic gases (ROG), and others. Further, in the atmosphere these pollutants are transported away from the locations of the emissions by wind and other phenomena, and undergo chemical reactions that result in the formation of new pollutants such as ground-level ozone and fine particulate matter ($PM_{2.5}$). Both primary (emitted) and secondary (formed) pollutants are important from a public health standpoint and contribute to the incidence of air pollution-related mortality and disease within California populations. Measures focused on GHGs do not incorporate specific targets to reduce emissions of $PM_{2.5}$ or air toxics like benzene. These co-pollutants, which are emitted from many of the same pollution sources as GHGs, affect local air quality and pose known risks to public health, such as the risk of asthma and cardiovascular disease. Generally, for stationary sources, certain harmful pollutants are regulated via local rules and regulations that are reflected in permits for stationary sources and are enforced by local air districts, with CARB also regulating air toxics contaminants from stationary sources with the air districts.

AB 32 GHG Inventory Sectors

To assess health impacts for the AB 32 GHG Inventory sectors, an integrated modeling approach was used to quantify and value the air pollution-related public health benefits of the Scoping Plan Scenario relative to the Reference Scenario. Additional details about the models, assumptions, and methodology are included in Appendix H (AB 32 GHG Inventory Sector Modeling). Using output from the PATHWAYS model, projections of pollutant emissions to 2045 were developed for stationary, area, and mobile source emissions using a detailed base year CARB pollutant emissions inventory. Further, the emissions are processed, including for where and when they occur in California, using the Sparse Matrix Operator Kernels Emissions (SMOKE) model. For example, on-road vehicle emissions were allocated along existing roadways, and refining emissions were assigned to the locations of existing refineries. It should be noted that the emissions projections represent statewide average reductions associated with high-level assumptions about alternative fuels and technologies. For example, emissions occurring from refineries to produce liquid fuels are reduced in line with petroleum demand. This reduction is applied equally to all refineries in the Scoping Plan Scenario and does not specify individual facility responses to changing demand. Similarly, the Scoping Plan Scenario does not specify which refineries transition to biofuel production or where new electricity generation facilities are built.

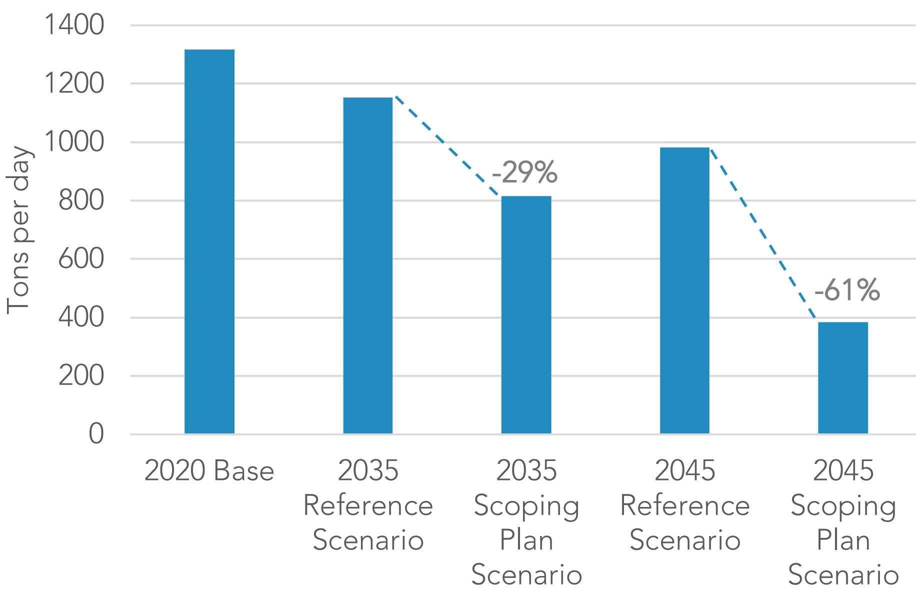
Next, emission changes were translated into impacts on atmospheric pollution levels, including ground-level ozone and $PM_{2.5}$, via an advanced photochemical air quality model called the Community Multiscale Air Quality (CMAQ) model, which accounts for atmospheric chemistry and transport. A comprehensive assessment of how pollutant concentrations are impacted throughout the year was achieved by simulating all months in 2035 and 2045 for the Scoping Plan Scenario.[219] Health benefits were estimated using the U.S. EPA's environmental Benefits Mapping and Analysis Program (BenMAP) model to translate pollutant changes into avoided incidence of mortality, hospital admissions, emergency room visits, and other outcomes as a result of reduced exposure to ozone and $PM_{2.5}$. These outcomes are associated with an economic value in order to aggregate health impacts.

The Scoping Plan Scenario shows a substantial reduction in pollutant emissions relative to the Reference Scenario, including NO_x, $PM_{2.5}$, and ROG. Reductions in NO_x are shown in Figure 3-4. Even under a business-as-usual trajectory, emissions are reduced from present levels by 26 percent in 2045 in the Reference Scenario, demonstrating the impact of current regulations and trends in energy sectors. The Scoping Plan Scenario further reduces NO_x

[219] This annual approach differs from the episodic modeling approach applied to the Proposed Scenario and Alternatives in the Draft 2022 Scoping Plan Update. Appendix H (AB 32 GHG Inventory Sector Modeling) describes both approaches.

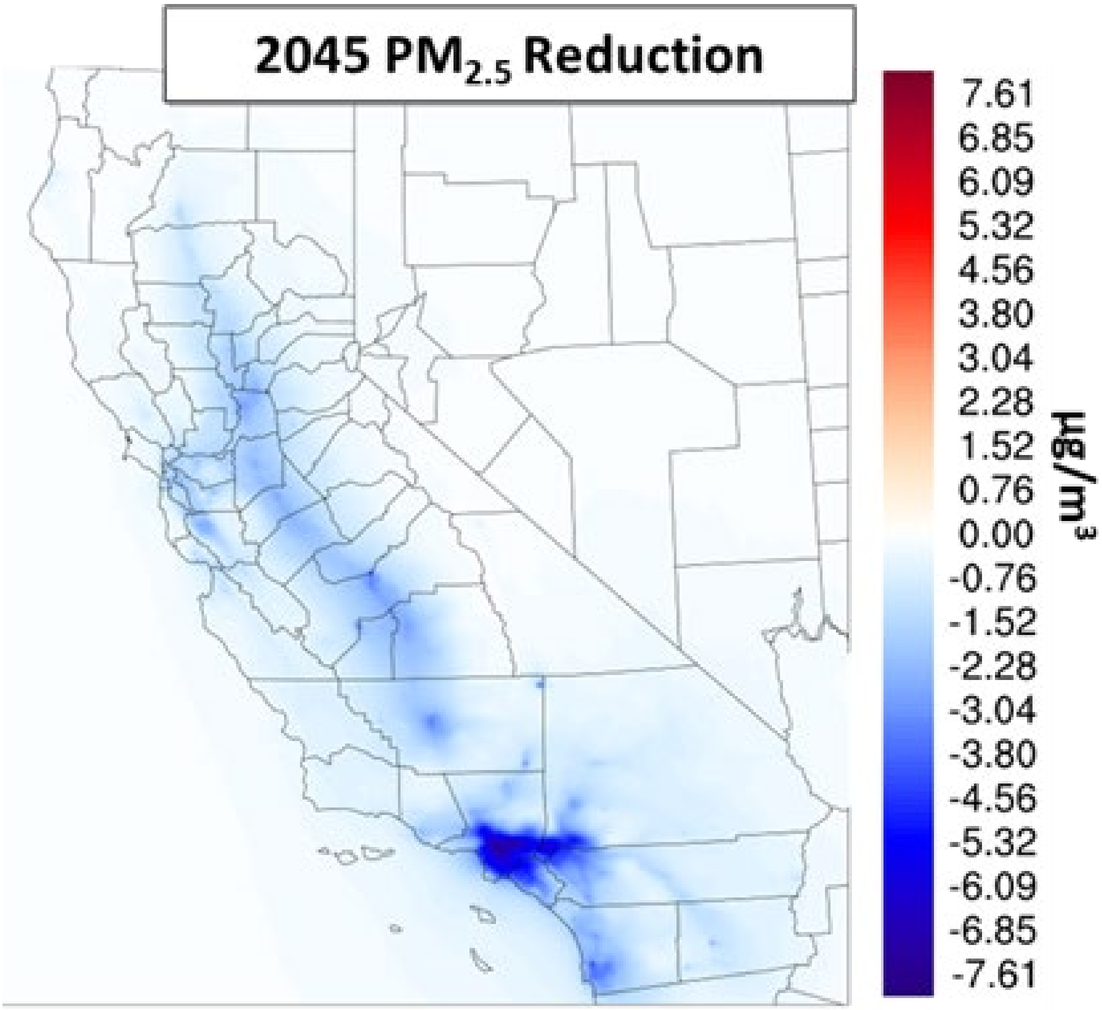
emissions from the Reference Scenario by 29% in 2035 and 61% in 2045. Emission reductions occur throughout the state with particular prominence in urban areas, including the South Coast Air Basin, due to the large presence and activity of emission sources. Appendix H (AB 32 GHG Inventory Sector Modeling) contains additional information about the pollutant emissions modeling and results.

Figure 3-4: Illustration of NOx emission reductions from current levels for the Reference Scenario and the Scoping Plan Scenario (AB 32 GHG Inventory sectors)



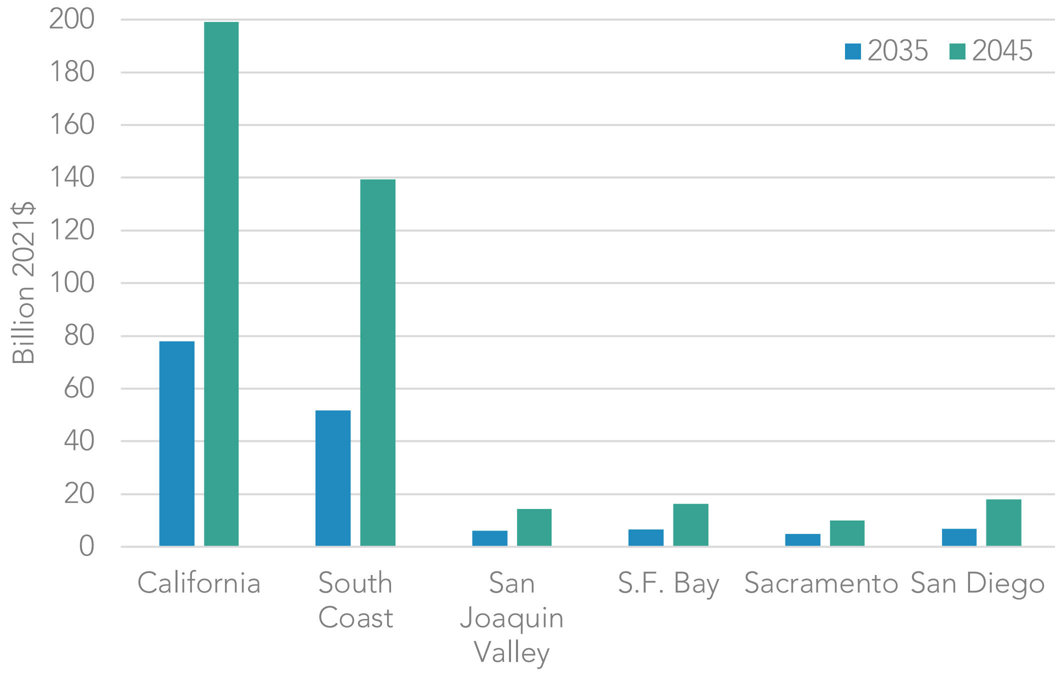
The emission reductions achieve important improvements in air quality throughout California, including reductions in the levels of ozone and $PM_{2.5}$. Reductions in annual $PM_{2.5}$ levels are shown in Figure 3-5. The greatest reductions are evident in Southern California, the San Joaquin Valley, the San Francisco Bay area, and the Greater Sacramento area due to the large presence and activity of emission sources, meteorology, topography, and others. To highlight the extent of the air quality improvements: reductions reach nearly 8 micrograms per cubic meter (μg/m^3) in 2045 and lead to 76% fewer exceedances of the health-based National Ambient Air Quality $PM_{2.5}$ standard of 12 μg/m^3. Similarly, ozone improvements reach 19 parts per billion (ppb) and yield 62% fewer exceedance events. Furthermore, the locations of improvements carry important implications for human health as these areas support large urban populations and generally experience the most degraded ozone and $PM_{2.5}$ pollution. Appendix H (AB 32 GHG Inventory Sector Modeling) provides details regarding the atmospheric modeling and results, including differences in ozone and $PM_{2.5}$.

Figure 3-5: Difference in annual average $PM_{2.5}$ ($\mu g/m^3$) in the Scoping Plan scenario relative to the Reference scenario in 2045 (AB 32 GHG Inventory sectors)



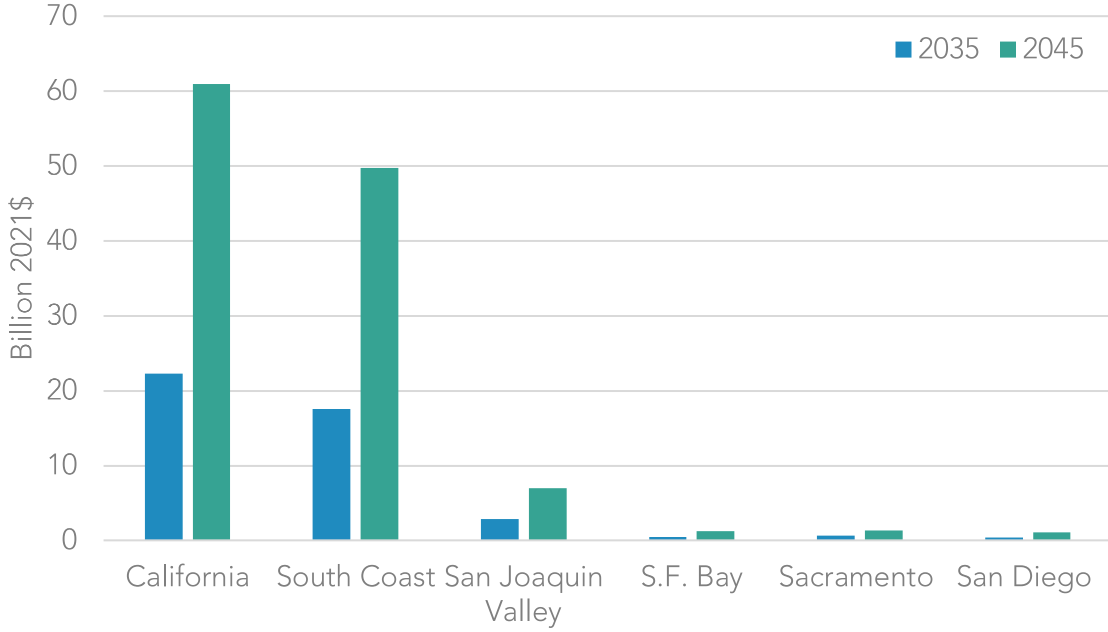
Notable health benefits representing the economic value of the avoided incidence of health effects are associated with the Scoping Plan Scenario. In total, the benefits reach $78 billion in 2035 and $199 billion in 2045, as shown in Figure 3-6. Populations in Southern California benefit the most due to preexisting air quality challenges, significant emission sources and activity, and the presence of a large, dense urban population. Additional details regarding the health impact assessment are provided in Appendix H (AB 32 GHG Inventory Sector Modeling).

Figure 3-6: Total health benefits estimated from air quality improvements in the Scoping Plan Scenario (AB 32 GHG Inventory sectors)



Furthermore, these benefits accrue within socially and economically disadvantaged communities identified by CalEnviroScreen, where they are most needed. Total health benefits within census tracts identified as disadvantaged communities using CalEnviroScreen 4.0 reach $22 billion in 2035 and $61 billion in 2045, as shown in Figure 3-7. Similarly to the statewide health benefits, the largest share of benefits occurs within disadvantaged communities in Southern California. Additional information on the health benefits within disadvantaged communities can be found in Appendix H (AB 32 GHG Inventory Sector Modeling).

Figure 3-7: Disadvantaged community health benefits relative to the Reference Scenario for the Scoping Plan Scenario (AB 32 GHG Inventory sectors)

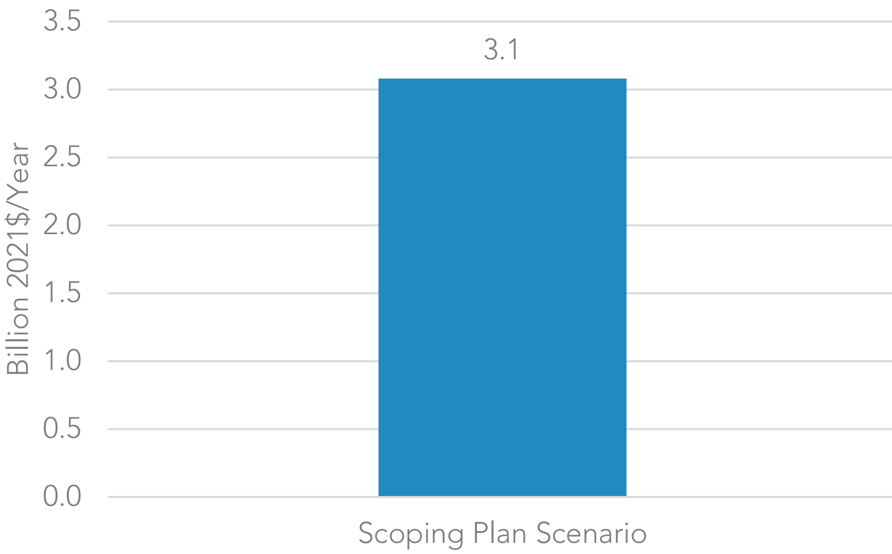


Natural and Working Lands

For NWL, health benefits were evaluated based on projected $PM_{2.5}$ wildfire emissions on forests, shrublands, and grasslands, discussed in the AB 197 Measure Analysis section of the chapter that follows.[220] The health endpoints for the Scoping Plan Scenario and in Appendix I (NWL Technical Support Document) for the alternative scenarios were the basis for the estimated health benefits shown in Figure 3-8. Health benefits were derived from the preliminary University of California, Los Angeles (UCLA) study that estimated annual health impacts and associated costs from California's wildfires from 2008–2018. Additional details are included in Appendix I (NWL Technical Support Document). These costs were applied to the health endpoints discussed in the AB 197 Measure Analysis section of the chapter.

[220] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11, N14. *finalejacrecs.pdf (arb.ca.gov)*.

Figure 3-8: Total average annual health benefits relative to the Reference Scenario for the Scoping Plan Scenario (NWL)



As health impacts analyzed here are driven by wildfire emissions, the health benefits for the Scoping Plan Scenario are directly related to the amount of forest, shrubland, and grassland management action. These management actions reduce vegetation fuels and, as a result, wildfire activity. The Scoping Plan Scenario increases the amount of these management actions, reducing wildfire emissions and avoiding incidence of emission-related health effects. The health benefits, or economic value of the avoided incidence of health effects, correspondingly increase with an increasing management implementation rate. Additional details are included in Appendix I (NWL Technical Support Document).

Estimated health benefits do not include the direct impact of wildfires on injuries, deaths, or mental health, nor the indirect costs of lost ecosystem benefits to wildfire. Additional direct health costs may result from wildfire that would likely increase the health benefits from increased forest, shrubland, and grassland management to reduce wildfire activity. Nonetheless, the conservative health benefits under the Scoping Plan Scenario are estimated to be $3.1 billion per year relative to the Reference Scenario for all NWL actions identified in the Scoping Plan Scenario.

AB 197 Measure Analysis

This section provides estimates for information associated with GHG emissions reduction measures evaluated in this Scoping Plan.[221] These estimates, which were developed as part of the process for meeting the requirements of AB 197 (E. Garcia, Chapter 250, Statutes of 2016), provide information on the relative impacts of the evaluated measures when compared to each other. To support the design of a suite of policies that result in GHG reductions, air quality co-benefits, and cost-effective measures, it is important to understand if a measure will increase or reduce criteria pollutants or toxic air contaminant emissions, or if increasing stringency at additional costs yields few additional GHG reductions. To this end, AB 197 requires the following for each potential emissions reduction measure evaluated in any Scoping Plan update:

- The range of projected GHG emissions reductions that result from the measure;
- The range of projected criteria pollutant emission reductions that result from the measure; and
- The cost-effectiveness, including avoided social costs, of the measure.

The following sections describe the evaluation of measures for the AB 32 GHG Inventory sectors and NWL. For the purposes of this Scoping Plan, the identified emissions reduction measures for the analysis required by AB 197 are actions grouped by sectors where several policies and programs are expected to overlap. This approach reflects the most granular feasible analysis given the modeling tools available,[222] the overlap and interaction effects among policies and incentive programs, the longer planning horizon used for this Scoping Plan compared to previous efforts, and the scale of transition needed to achieve carbon neutrality. To implement this Scoping Plan, dozens of individual regulations, policies, and incentive programs are anticipated that work together to drive down emissions across all economic sectors and support actions. Every specific policy or incentive program that could contribute to the deployment of clean technology and energy called for in this plan may overlap in ways that make it infeasible to tease out those policies and programs' individual effects with any reasonable degree of certainty. For example, in the transportation sector, deploying ZEVs and reducing driving demand may be achieved through a combination of the implementation of new or existing regulations, fuels programs, incentive programs, and VMT reduction initiatives that can each contribute to reductions in emissions for the sector. It is not feasible to isolate each sub action from each other at this time in terms of the share of contribution to total reductions. The estimated emission

[221] AB 197 calls for the evaluation of "emission reduction measures." This Scoping Plan treats each action and its variants on stringency as emission reduction measures for the purposes of this chapter. Appendix C (AB 197 Measure Analysis) lists the measures and corresponding modeling assumptions for each alternative.
[222] See Appendix H (AB 32 GHG Inventory Sector Modeling and Appendix I (NWL Technical Support Document).

reductions, health endpoints, and costs by measure for the Scoping Plan Scenario are presented in this chapter, and the corresponding estimates for the Proposed Scenario and Alternatives 1, 2, and 4 are included in Appendix C (AB 197 Measure Analysis).

Because many of the measures and underlying assumptions interact with each other, isolating the GHG emission reductions, corresponding changes to fuel combustion, and associated cost of an individual measure is analytically challenging. Each measure is evaluated by examining the change in fuel combustion, cost, and emissions associated with just that measure using the PATHWAYS model. The difference between the Scoping Plan Scenario and the Reference Scenario is estimated for each measure. Starting from the Scoping Plan Scenario, the modeling assumptions for an individual measure are reverted to the Reference Scenario values, resulting in GHG reductions, changes to fuel combustion, and costs (or savings). This approach does not reflect interactions between sectors in PATHWAYS that influence the results for each complete alternative, presented earlier. As such, the values associated with each measure should not be added to obtain an overall scenario estimate.

To arrive at the 2045 target for NWL, CARB modeled the ecological impact that climate smart land-based management strategies (suites of on-the-ground actions, or *treatments,* that are used across the landscape to manipulate an ecosystem) will have on ecosystem carbon; and whenever possible, additional co-benefits from those actions. The Scoping Plan Scenario incorporates a set of land management actions at varying scales of implementation for each land type to achieve the GHG emission reductions. Each land type, and its associated management actions, was considered a measure for this analysis. For modeling individual landscapes and management actions, CARB used a suite of models. The complexity of these models varies by land type, depending on the existing science, data, and availability of existing models to use. Appendix I (NWL Technical Support Document) provides detailed modeling assumptions for each NWL type. The estimated emission reductions, health endpoints, and costs by measure under the Scoping Plan Scenario for each NWL type are presented in this chapter, and the corresponding estimates for the Proposed Scenario and NWL Alternatives 1, 2, and 4 are included in Appendix C (AB 197 Measure Analysis).

Estimated Emissions Reductions

Both GHG emissions reductions and emissions of criteria air pollutants were evaluated for the AB 32 GHG Inventory sectors and for NWL. The methods and results are described in this section.

AB 32 GHG Inventory Sectors

In the absence of having direct modeling results for criteria pollutant estimates from PATHWAYS, CARB estimated criteria pollutant emissions impacts by using changes in fuel combustion in units of exajoules from PATHWAYS and emission factors in units of tons per exajoule to estimate the change in emissions in tons per year. Emission factors from a variety of sources for each sector were utilized, including but not limited to CARB's mobile source emissions models,[223] U.S. EPA's AP 42 Emissions Factors,[224] and the South Coast Air Quality Management District's (AQMD's) District Rules.[225] These emission factors were applied to fuel burn change by fuel type, sector, equipment type, and process, where applicable. Statewide annual average emissions were estimated for three criteria pollutants: NO_x, $PM_{2.5}$, and ROG.

Table 3-5 provides the estimated GHG and criteria pollutant emission reductions for the measures in the Scoping Plan Scenario in 2035 and 2045. The other alternatives are presented in Appendix C (AB 197 Measure Analysis). Based on the estimates below, these measures are expected to provide air quality benefits. The estimates provided in this chapter and Appendix C (AB 197 Measure Analysis) are appropriate for comparing across alternatives considered for the development of this Scoping Plan, but they are not precise estimates.

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[223] CARB. MSEI - Modeling Tools. https://ww2.arb.ca.gov/our-work/programs/mobile-source-emissions-inventory/msei-modeling-tools.

[224] U.S EPA. AP-42: Compilation of Air Emissions Factors. https://www.epa.gov/air-emissions-factors-and-quantification/ap-42-compilation-air-emissions-factors.

[225] South Coast AQMD. South Coast AQMD Rule Book. https://www.aqmd.gov/home/rules-compliance/rules/scaqmd-rule-book.

Table 3-5: Estimated GHG and criteria pollutant emission reductions relative to the Reference Scenario for the Scoping Plan Scenario in 2035/2045 (AB 32 GHG Inventory sectors)

Measure	GHG Reductions ($MMTCO_2$)	NOx Reductions (Short Tons/Year)	$PM_{2.5}$ Reductions (Short Tons/ Year)	ROG Reductions (Short Tons/Year)
Deploy ZEVs and reduce driving demand	-46 / -84	-51,620 / -122,806	-2,008 / -6,506	-18,967 / -30,410
Coordinate supply of liquid fossil fuels with declining California fuel demand	-25 / -30	-1,601 / -2,707	-978 / -1,705	-747 / -1,323
Generate clean electricity	-8 / -31	-92 / -1,555	-177 / -1,382	-41 / -425
Measure	**GHG Reductions ($MMTCO_2$)**	**NOx Reductions (Short Tons/Year)**	**$PM_{2.5}$ Reductions (Short Tons/ Year)**	**ROG Reductions (Short Tons/Year)**
Decarbonize industrial energy supply	-9 / -22	-21,172 / -34,876	-1,188 / -2,527	-3,710 / -6,298
Decarbonize buildings	-14 / -35	-8,105 / -94,455	-826 / -6,877	-1,093 / -8,109
Reduce non-combustion emissions[a]	-0.41 / -0.52 ($MMTCH_4$)	N/A	N/A	N/A
Compensate for remaining emissions	-25 / -64	N/A	N/A	N/A

[a] Methane emissions reductions are reported for this measure.

The measures related to reducing non-combustion emissions and compensating for the remaining emissions do not include changes to fuel combustion, and therefore are not associated with changes to air pollutants. Biomethane combustion is captured in measures that reduce combustion of fossil gas, such as decarbonizing industrial energy supply and buildings.

Natural and Working Lands

NWL ecosystems naturally vary between being a source and a sink for carbon over time. The NWL ecosystem carbon stock changes projected through mid-century by the suite of models were used to estimate net emissions or emissions reductions relative to the Reference Scenario. These changes in carbon stocks were affected by projected climate change, the implementation of management actions under the various scenarios, land conversion, and (for forests, shrublands, grasslands) wildfire. Each NWL type was evaluated, and an overview of all NWL is presented in Table 3-6. More detailed results for each NWL type can be found in Appendix C (AB 197 Measure Analysis).

Table 3-6: Estimated average annual GHG and criteria pollutant emission reductions relative to the Reference Scenario for the Scoping Plan Scenario from 2025–2045 (NWL)

Measure	GHG Reductions ($MMTCO_2e$/year)	$PM_{2.5}$ Reductions (MT/Year)
Forests/Shrublands/Grasslands	-0.12	-17,500
Annual Croplands	-0.25	N/A
Perennial Croplands	-0.01	N/A
Urban Forest	-1.29	N/A
Wildland Urban Interface (WUI)	0.75	N/A
Wetlands	-0.43	N/A
Sparsely Vegetated Lands	<-0.01	N/A

Fine particulate wildfire emissions were evaluated for forests, shrublands, and grasslands only. Wildfire emissions decreased under the Scoping Plan Scenario compared to the Reference Scenario. The Scoping Plan Scenario's higher level of management actions that reduce tree or shrub densities, protect large trees, reintroduce fire to the landscape, and diversify species and structures result in greater reductions in wildfire emissions.

Estimated Health Endpoints

Climate change mitigation will result in both environmental and health benefits. This section provides information about the potential health benefits of the Scoping Plan Scenario. Health benefits are primarily the result of reduced $PM_{2.5}$ pollution, both from stationary and mobile sources, as well as wildfire in forests, shrublands, and chaparral.

AB 32 GHG Inventory Sectors

CARB used the criteria pollutant emissions in Table 3-5 to understand potential health impacts. Similar to the air quality estimates, this information should be used to understand the relative health benefits of the various measures and should not be taken as absolute estimates of health outcomes. CARB used the incidence-per-ton (IPT) methodology to quantify the health benefits of emission reductions. The IPT methodology is based on a methodology developed by the U.S.

EPA.[226,227,228,229] Under the IPT methodology, changes in emissions are approximately proportional to the resulting changes in health outcomes. IPT factors are derived by calculating the number of health outcomes associated with exposure to $PM_{2.5}$ for a baseline scenario using measured ambient concentrations and dividing that number by the emissions of $PM_{2.5}$ or a precursor. To estimate the reduction in health outcomes, the emission reductions are multiplied by the IPT factor. For future years, the number of outcomes is adjusted to account for population growth. IPT factors were computed for the two types of $PM_{2.5}$: primary $PM_{2.5}$ and secondary $PM_{2.5}$ of ammonium nitrate aerosol formed from precursors.

For this AB 197 analysis, CARB calculated the health benefits associated with the five key measures that are represented by changes to fuel combustion. The health benefits associated with emission reductions for the Scoping Plan Scenario were estimated for each air basin and then aggregated for the entire state of California. CARB assumed that the statewide emission reductions distribution among the air basins is proportional to the baseline emissions in that air basin.

Calculated health endpoints include premature mortality, cardiovascular emergency department (ED) visits, acute myocardial infarction, respiratory ED visits, lung cancer incidence, asthma onset, asthma symptoms, work loss days, hospitalizations due to cardiopulmonary illnesses, hospitalizations due to respiratory illnesses, hospital admissions for Alzheimer's disease, and hospital admissions for Parkinson's disease.[230,231,232] These health endpoints were calculated using the IPT method for estimated emission reductions. Table 3-7 compares the health benefits of emission reductions associated with each measure for the Scoping Plan Scenario in the year

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[226] CARB. CARB's Methodology for Estimating the Health Effects of Air Pollution. Retrieved February 9, 2021. *https://ww2.arb.ca.gov/resources/documents/carbs-methodology-estimating-health-effects-air-pollution*.

[227] Fann, N., C. M. Fulcher, and B. J. Hubbell. 2019. "The influence of location, source, and emission type in estimates of the human health benefits of reducing a ton of air pollution." *Air Quality, Atmosphere & Health* 2:169–176. *https://www.ncbi.nlm.nih.gov/pmc/articles/PMC2770129/*.

[228] Fann, N., K. R. Baker, and C. M. Fulcher. 2012. "Characterizing the $PM_{2.5}$-related health benefits of emission reductions for 17 industrial, area and mobile emission sectors across the U.S." *Environ Int*. 49:141–51. November 15. *https://www.sciencedirect.com/science/article/pii/S0160412012001985*.

[229] Fann, N., K. Baker, E. Chan, A. Eyth, A. Macpherson, E. Miller, and J. Snyder. 2018. "Assessing Human Health $PM_{2.5}$ and Ozone Impacts from U.S. Oil and Natural Gas Sector Emissions in 2025." *Environ. Sci. Technol.* 52 (15), 8095–8103. *https://pubs.acs.org/doi/abs/10.1021/acs.est.8b02050*.

[230] CARB. CARB's Methodology. *https://ww2.arb.ca.gov/resources/documents/carbs-methodology-estimating-health-effects-air-pollution*.

[231] CARB. 2022. Updated Health Endpoints in CARB's Health Benefits Methodology. *Evaluating New Health Endpoints for Use in CARB's Health Analyses*.

[232] Cardio-pulmonary mortality, hospitalizations due to cardiopulmonary illnesses, and hospital admissions due to respiratory illnesses endpoints utilize studies documented in CARB's methodology document. For future assessments, CARB will use more recent studies to estimate cardiovascular hospital admissions and respiratory hospital admissions, as documented in CARB's updated health endpoints memo.

specified (2035 or 2045). The other alternatives are presented in Appendix C (AB 197 Measure Analysis).

Table 3-7: Estimated avoided incidence of mortality, cardiovascular and respiratory disease onset, work loss days and hospital admissions relative to the Reference Scenario for the Scoping Plan Scenario (AB 32 GHG Inventory sectors)

Measure	Mortality	Cardiovascular ED Visits	Acute Myocardial Infarction	Respiratory ED Visits	Lung Cancer Incidence	Asthma Onset	Asthma Symptoms	Work Loss Days	Hospital Admissions, Cardiovascular	Hospital Admissions, Respiratory	Hospital Admissions, Alzheimer's Disease	Hospital Admissions, Parkinson's Disease
Deploy ZEVs and reduce driving demand in 2035	635	170	70	400	45	1,475	128,930	92,510	95	115	245	40
Deploy ZEVs and reduce driving demand in 2045	1,820	475	200	1,115	135	3,995	343,095	255,800	295	350	745	125
Coordinate supply of liquid fossil fuels with declining CA fuel demand in 2035	115	30	15	70	10	275	23,530	16,880	20	20	50	10

Measure	Mortality	Cardiovascular ED Visits	Acute Myocardial Infarction	Respiratory ED Visits	Lung Cancer Incidence	Asthma Onset	Asthma Symptoms	Work Loss Days	Hospital Admissions, Cardiovascular	Hospital Admissions, Respiratory	Hospital Admissions, Alzheimer's Disease	Hospital Admissions, Parkinson's Disease
Coordinate supply of liquid fossil fuels with declining CA fuel demand in 2045	215	55	25	130	15	490	40,860	30,445	35	40	95	15
Generate clean electricity in 2035	20	5	0	10	0	45	3,930	2,820	5	5	10	0
Generate clean electricity in 2045	170	45	20	105	15	385	32,065	23,890	25	30	75	10
Decarbonize industrial energy supply in 2035	300	80	35	190	20	695	60,660	43,520	45	55	115	20
Decarbonize industrial energy supply in 2045	595	155	65	365	45	1,310	111,925	83,435	95	115	245	40

Measure	Mortality	Cardiovascular ED Visits	Acute Myocardial Infarction	Respiratory ED Visits	Lung Cancer Incidence	Asthma Onset	Asthma Symptoms	Work Loss Days	Hospital Admissions, Cardiovascular	Hospital Admissions, Respiratory	Hospital Admissions, Alzheimer's Disease	Hospital Admissions, Parkinson's Disease
Decarbonize buildings in 2035	155	40	15	95	10	360	31,130	22,335	25	30	60	10
Decarbonize buildings in 2045	1,610	420	175	985	120	3,550	303,830	226,500	260	310	665	115

Note: All values are rounded to the nearest 0 or 5.

The measures related to reducing non-combustion emissions and compensating for remaining emissions do not include changes to fuel combustion and therefore are not associated with changes to air pollutants or health endpoints. Biomethane combustion is captured in measures that reduce combustion of fossil gas, such as decarbonizing industrial energy supply and buildings.

Although the estimated health outcomes presented are based on a well-established methodology, they are subject to uncertainty. For instance, future population estimates are subject to increasing uncertainty as they are projected further into the future, and baseline incidence rates can experience year-to-year variation. Also, the relationship between changes in pollutant concentrations and changes in pollutant or precursor emissions is assumed to be approximately proportional.

In addition, emissions are reported at an air basin level and do not capture local variations. These estimates also do not account for impacts from global climate change, such as temperature rise, and are only based on the scenarios in this Scoping Plan.

The fuel changes for each AB 197 measure are estimated based on the impact of each measure compared to the Reference Scenario for the years 2035 and 2045. Therefore, aggregating the effect of each measure would overestimate the impacts of the Scoping Plan Scenario because the implementation of each measure would affect the level of benefits of the other measures. This measure-by-measure analysis uses a different methodology for calculating health endpoints than does the health analysis for the complete Scoping Plan Scenario provided earlier.

Natural and Working Lands

Implementation of NWL management strategies to mitigate and adapt to climate change will result in both environmental and health benefits. This section provides information about the potential health benefits of measures evaluated for the Scoping Plan Scenario. For this analysis, health benefit estimates were focused on increases or decreases to $PM_{2.5}$ resulting from wildfire emissions on forests, shrublands, and grasslands.[233] Other health benefits resulting from NWL management actions in the Scoping Plan Scenario are not quantified here but are important for all Californians. This includes, but is not limited to, reductions in exposure to synthetic pesticides when switching to organic agricultural systems, improvements in shade availability and mental health with increasing urban forest cover, improved mental health from opportunities for recreation in resilient and healthy environments, and protection from floods and rising sea levels.

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[233] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11, N14. finalejacrecs.pdf (arb.ca.gov).

These examples are by no means exhaustive, as our natural and working lands provide immense health benefits to everyone.

For this analysis, CARB used the $PM_{2.5}$ emissions in Table 3-6 to understand potential health impacts. This information should be used to understand the relative health endpoints of the various measures and should not be taken as absolute estimates of health outcomes of this Scoping Plan statewide or within a specific community. The IPT methodology was used to calculate health endpoints, similar to the AB 32 GHG Inventory Sector analysis. CARB calculated the annual health endpoints associated with the wildfire emissions changes resulting from the implementation of management strategies on forests, shrublands, and grasslands under each alternative. The annual health endpoints associated with emission reductions for the Scoping Plan Scenario were estimated for the entire state. Calculated health endpoints include emissions-caused mortality, hospital admittance, and emergency room visits from asthma; hospital admittance from chronic obstructive pulmonary disease; and emergency room visits from respiratory and cardiovascular outcomes. Table 3-8 compares the average annual health endpoints of wildfire emission reductions associated with the Scoping Plan Scenario over the period 2025–2045. The other alternatives are presented in Appendix C (AB 197 Measure Analysis).

Table 3-8: Estimated average annual avoided incidence of hospital admissions, emergency room visits, and mortality relative to the Reference Scenario for the Scoping Plan Scenario resulting from forest, shrubland, and grassland wildfire emissions (NWL)

Health Endpoints from Forest, Shrubland, and Grassland Wildfire Emissions	Average Annual Avoided Incidence
Hospital admissions from asthma	22
Hospital admissions from chronic obstructive pulmonary disease without asthma	19
Hospital admissions from all respiratory outcomes	63
Emergency room visits from asthma	155
Emergency room visits from all respiratory outcomes	419
Emergency room visits from all cardiovascular outcomes	156
All causes of mortality	394

Estimated Social Cost

Social costs are generally defined as the cost of an action on people, the environment, or society and are widely used to understand the impact of regulatory actions. One tool, the social cost of greenhouse gases (SC-GHG), is an estimate of the present value of the costs associated with the emission of GHGs in future years. It combines climate science and economics to help understand the benefits of reducing GHG emissions. The estimates of the social cost of carbon (SC-CO_2) and social cost of methane (SC-CH_4), two types of SC-GHGs presented here, estimate the value of the net harm to society associated with adding GHGs to the atmosphere in a given year; they do not represent the cost of actions taken to reduce GHG emissions (known as the *cost of abatement*) nor the cost of GHG emissions reductions. In principle, the SC-GHG includes the value of climate change impacts, including but not limited to, changes in net agricultural productivity, human health effects, property damage from increased flood risk and other natural disasters, disruption of energy systems, risk of conflict, environmental migration, and the value of ecosystem services. It reflects the societal value of reducing emissions of the gas in question by one metric ton.[234] Many of these damages from GHG emissions today will affect economic outcomes throughout the next several centuries.

In 2008, federal agencies began incorporating SC-CO_2 estimates into the analysis of their regulatory actions. U.S. EPA has used various models and discount rates to determine the value of future impacts. Generally, these models begin with assumptions to predict economic activity over time, along with projected GHG emissions. The modeled emissions are input into a model of the global climate system, which then translates into estimates of surface temperature, sea level rise, and other impacts. These outputs are used to estimate economic damages per ton of GHG emitted in a given year in the future. Since the models are calculating the present value of future damages, a discount rate is applied. For example, the SC-CO_2 for the year 2045 represents the value of climate change damages from a release of CO_2 in 2045 discounted back to today. The present value is significantly affected by the discount rate used; a higher discount rate results in a lower present value. For example, in 2021 dollars the SC-CO_2 in 2045 is $31 using a 5 percent discount rate, $88 using a 3 percent discount rate, and $122 using a 2.5 percent discount rate. Additional detail is included in Appendix C (AB 197 Measure Analysis).

The 2017 Scoping Plan utilized SC-CO_2 and SC-CH_4 Obama Administration-era values developed by the Council of Economic Advisors and the Office of Management and Budget-convened Interagency Working Group on the Social Cost of Greenhouse Gases (IWG)[235] to consider the social costs of actions to reduce GHG emissions. The Biden Administration reinstated these values in February 2021,[236] after they had been rescinded and significantly revised by the Trump Administration. The reinstatement was considered an interim step, and the Biden Administration also reconvened the IWG to continue its work to evaluate and incorporate the latest climate science and economic research and

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[234] U.S. Government. Interagency Working Group on Social Cost of Greenhouse Gases. February 2021. Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide – Interim Estimates under Executive Order 13990. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[235] Originally titled the "Interagency Working Group on the Social Cost of Carbon," the IWG was renamed in 2016. 82 Fed. Reg. 16093, 16095-96 (Mar. 28, 2017). https://www.govinfo.gov/content/pkg/FR-2017-03-31/pdf/2017-06576.pdf.

[236] Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis, Executive Order 13990 (Jan. 20, 2021), 86 Fed. Reg. 7037 (Jan. 25, 2021). https://www.energy.gov/sites/default/files/2021/02/f83/eo-13990-protecting-public-health-environment-restoring.pdf. IWG, Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990 (February 2021), https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf See also, The White House. 2021. A Return to Science: Evidence-Based Estimates of the Benefits of Reducing Climate Pollution. https://www.whitehouse.gov/cea/written-materials/2021/02/26/a-return-to-science-evidence-based-estimates-of-the-benefits-of-reducing-climate-pollution/.

respond to the National Academies' recommendations from 2017 as it develops a more complete revision of the estimates.

It is important to note that the models used to produce SC-GHG estimates do not include all of the important physical, ecological, and economic impacts of climate change recognized in the climate literature. There are additional costs to society, including the costs associated with changes in co-pollutants and costs that cannot be included due to modeling and data limitations. The IWG has stated that the range of the interim SC-GHG estimates likely underestimates societal damages from GHG emissions.[237] The revised estimates were originally slated to be released in early 2022 but were stalled.[238] CARB staff is applying the interim values presented in the IWG February 2021 Technical Support Document (TSD), which reflect the best available science in the estimation of the socioeconomic impacts of GHGs.[239] This Scoping Plan utilizes the TSD standardized range of discount rates, from 2.5 to 5 percent, to represent varying valuation of future damages.

AB 32 GHG Inventory Sectors

Table 3-9 presents the estimated social cost, in terms of avoided economic damages, for each measure of the Scoping Plan Scenario. For each measure, Table 3-9 includes the range of the SC-CO_2 and SC-CH_4 that results from the GHG emissions reductions in 2035 and 2045 at 2.5 and 5 percent discount rates. Additional background on the SC-GHG and methodology for calculating the SC-CO_2 and SC-CH_4 estimates in this Scoping Plan, as well as estimates for the alternatives, are provided in Appendix C (AB 197 Measure Analysis).

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[237] Interagency Working Group on Social Cost of Greenhouse Gases. 2021. Technical Support Document. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[238] See *Louisiana v. Biden* (W.D. La. 2022) 585 F.Supp.3d 840, stayed pending review (5th Cir. Mar. 16, 2022) 2022 WL 866282. A federal district court ruling issued in early February 2022 had granted a preliminary injunction blocking the Biden Administration from using the interim IWG SC-GHG estimates. However, a federal appeals court overturned the lower court's preliminary injunction in March 2022, which allows the Biden Administration to continue using the policy as legal proceedings continue. CARB will continue to monitor the litigation. However, the federal action does not prohibit CARB from using social cost of carbon and CARB will use the best available science regardless of politics. A separate federal appeals court upheld the Biden administration's use of the IWG SC-GHG estimates in October 2022. *Missouri v. Biden* (8th Cir. 2022) ____ F.4th ____.

[239] Interagency Working Group on Social Cost of Greenhouse Gases. 2021. Technical Support Document. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

Table 3-9: Estimated social cost (avoided economic damages) of measures considered in the Scoping Plan Scenario (AB 32 GHG Inventory sectors)

Measure	Social Cost of Carbon in 2035, 5%–2.5% Discount Rate Billion USD (2021 dollars)	Social Cost of Carbon in 2045, 5%–2.5% Discount Rate Billion USD (2021 dollars)
Deploy ZEVs and reduce driving demand	1.12–4.87	2.64–10.23
Coordinate supply of liquid fossil fuels with declining California fuel demand	0.61–2.63	0.95–3.67
Generate clean electricity	0.20-0.88	0.97–3.75
Decarbonize industrial energy supply	0.23–1.01	0.69–2.67
Decarbonize buildings	0.35–1.52	1.11–4.32
Reduce non-combustion emissions	0.51–1.29 (SC-CH_4)	0.86–2.01 (SC-CH_4)
Compensate for remaining emissions	0.61–2.66	2.03–7.84
Scoping Plan Scenario SC-CO_2 **Scoping Plan Scenario SC-CH_4** **Scoping Plan Scenario (Total)[a]**	2.4–10.4 0.51–1.3 2.9–11.7	5.6–21.9 0.86–2.0 6.5–23.9

[a] CARB staff could not precisely separate some CO_2 and CH_4 from other GHGs from PATHWAYS outputs, but the contribution is believed to be small for purposes of calculating the social cost of carbon. The approach used to estimate GHG emissions reductions for individual measures in PATHWAYS does not reflect cross-sector interactions. Therefore, the GHG values for each measure do not sum to the overall scenario total. The total GHG emissions reduction used in this calculation is 97 $MMTCO_2e$ in 2035 and 180 $MMTCO_2e$ in 2045.

Natural and Working Lands

The SC-CO_2 estimates for the NWL measures shown in Table 3-10, in terms of avoided economic damages, reflect 2021 IWG interim values, updated for inflation, similar to the AB 32 GHG Inventory Sector analysis. This analysis utilizes the 2.5 percent and 5 percent discount rate and the average annual emissions reductions from each NWL type from 2025–2045. Estimates for all alternatives are included in Appendix C (AB 197 Measure Analysis).

Table 3-10: Estimated social cost (avoided economic damages) of measures considered in the Scoping Plan Scenario (NWL)

Measure	Social Cost of Carbon in 2035, 5%–2.5% Discount Rate Billion USD (2021 dollars)	Social Cost of Carbon in 2045, 5%–2.5% Discount Rate Billion USD (2021 dollars)
Forests/Shrublands/Grasslands	0.003–0.012	0.004–0.014
Annual Croplands	0.006–0.027	0.008–0.031
Perennial Croplands	<0.001–0.001	0.000–0.001
Urban Forest	0.032–0.138	0.041–0.157
Wildland Urban Interface (WUI)	(0.018) – (0.080)[a]	(0.023) – (0.090)
Wetlands	0.011–0.046	0.014–0.053
Sparsely Vegetated Lands	<0.001	<0.001

[a] Parentheses indicate an increase in estimated social cost, i.e., an increase in economic damages. This is only the case for WUI measures where emissions are increased, shown in Table 3-6. The estimated social cost does not account for the decrease in wildfire risk or decrease in wildfire damages resulting from the WUI measures.

Social Costs of GHGs in Relation to Cost-Effectiveness

AB 32 includes a requirement that rules and regulations "achieve the maximum technologically feasible and cost-effective" greenhouse gas emissions reductions.[240] Under AB 32, *cost-effectiveness* means the relative cost per metric ton of various GHG reduction strategies,[241] which is the traditional cost metric associated with emission control. In contrast, the SC-CO_2, SC-CH_4, and social cost of nitrous oxide (SC-N_2O), because they are estimates of the cost to society of additional GHG emissions, can be used to estimate of the economic benefits of reducing emissions, but do not take into account the cost of the actions that must be taken to achieve those GHG emissions reductions.

There may be technologies or policies that do not appear to be cost-effective when compared to the SC-CO_2, SC-CH_4, and SC-N_2O associated with GHG reductions. However, these technologies or policies may result in other benefits that are not reflected in the IWG social costs. Examples include the evaluation of social diversification of the portfolio of transportation fuels (a goal outlined in the Low Carbon Fuel Standard) and reductions in criteria pollutant emissions from power plants (as in the Renewables Portfolio Standard). Additionally, costs for new technology may be higher early on in a technology's development cycle and may drop over time as use of the technology is scaled up.

Estimated Cost per Metric Ton

AB 197 requires an estimation of the cost-effectiveness of the measures evaluated for this Scoping Plan. The cost (or savings)[242] per metric ton of CO_2e reduced for each measure is one metric for comparing the performance of the measures. Additional factors beyond the cost per metric ton that could be considered include continuity with existing laws and policies, implementation feasibility, contribution to fuel diversity and technology transformation goals, and health and other benefits to California. These considerations are not reflected in the cost per metric ton estimates presented below. It is important to understand the relative cost-effectiveness of individual measures as presented in this section. However, the economic analysis presented earlier in this chapter, in Appendix H

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[240] AB 32 Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006. (AB 32, Nuñez, Chapter 488, Statutes of 2006). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.

[241] Health & Saf. Code § 38505(d).

[242] Similarly, to the direct costs reported earlier, the cost per metric ton of a measure reflects the stock costs and any fuel or efficiency savings associated with a measure divided by the GHG emission reduction achieved by the measure. Costs are reported as positive values, and savings are reported as negative values.

(AB 32 GHG Inventory Sector Modeling), and in Appendix I (NWL Technical Support Document) provides a more comprehensive analysis of how the Scoping Plan Scenario and alternative scenarios affect the state's economy and jobs.

AB 32 GHG Inventory Sectors

The cost per metric ton for the AB 32 GHG Inventory sectors was computed for each measure independently relative to the Reference Scenario using the sensitivity calculations based on PATHWAYS and RESOLVE outputs. The difference in the annualized cost between the Scoping Plan Scenario and the Reference Scenario was computed for each measure in 2035 and in 2045. The incremental cost was divided by the incremental GHG emissions impact to calculate the cost per metric ton in each year. To capture the fuel and GHG impacts of investments made from 2022 through 2035, or from 2022 through 2045, CARB computed an average annual cost per metric ton. The incremental cost in each year was averaged over the period. This value is divided by the corresponding annual, incremental GHG impact averaged over the same period.

The cost metric includes the annualized incremental cost of energy infrastructure, such as zero-emission vehicles, electric appliances, and required revenue to support all electric assets. A residual value for equipment such as vehicles or appliances that are retired early is included. The annual fuel cost or avoided fuel cost that results from efficiency improvements or changes to demand for fuels associated with transitioning to alternative fuels is included. Not included in this cost metric are costs that represent transfers within the state, such as incentive payments for early retirement of equipment.

It is important to note that this cost per metric ton does not represent an expected market price value for carbon mitigation associated with these measures. In addition, the values do not capture fuel savings or GHG reductions associated with the full economic lifetime of measures that have been implemented by the target date of 2035 or 2045 but whose impacts extend beyond the target date.

Table 3-11 includes the cost per metric ton and annual average cost per metric ton estimates for the Scoping Plan Scenario. The other alternatives are presented in Appendix C (AB 197 Measure Analysis). Measures that are relatively less costly in 2035 or 2045 are also less costly over the extended period. As noted earlier, incremental costs of new vehicles are generally offset by gains in efficiency and avoided fuel consumption resulting in negative cost per metric ton.

Table 3-11: Estimated cost per metric ton of reduced CO_2e relative to the Reference Scenario for measures considered in the Scoping Plan Scenario (AB 32 GHG Inventory sectors)

Measure	Annual Cost, 2035 ($/ton)	Average Annual Cost, 2022–2035 ($/ton)	Annual Cost, 2045 ($/ton)	Average Annual Cost, 2022–2045 ($/ton)
Deploy ZEVs and reduce driving demand	-171	-99	-103	-122
Coordinate supply of liquid fossil fuels with declining CA fuel demand	60	109	-50	39
Generate clean electricity[a]	101	156	145	161
Decarbonize industrial energy supply	290	217	257	274
Decarbonize buildings	235	230	112	213
Reduce non-combustion emissions	93	94	106	99
Compensate for remaining emissions	745	823	236	485

[a] Note: The denominator of this calculation (2045) does not include GHG reductions occurring outside of California resulting from SB 100. If these reductions were included, this number would be lower.

Natural and Working Lands

The cost per metric ton for NWL measures were computed for the Scoping Plan Scenario relative to the Reference Scenario using the projected carbon stock/sequestration data from the NWL modeling and the direct cost estimates for each management action, described earlier. Direct costs represent the cost of implementing a certain management action. The projected emissions reductions take into account the loss of carbon that results from the management action, such as fuels reduction treatments in forests, as well as climate change effects on growth. The direct cost for each NWL measure was divided by the average annual emission reductions presented in Table 3-6 to produce the cost per metric ton. The increasing effect of climate change on diminished future growth reduces the ability of the land to sequester or store carbon, driving up the cost per ton.

It is important to note that this cost per metric ton does not represent an expected market price value for carbon mitigation associated with these measures. In addition, emissions benefits of NWL management actions often take longer time periods to accrue, and these values only capture GHG reductions up to 2045.

Table 3-12 includes the average cost per metric ton estimates for the average annual CO_2e reductions from 2025 through 2045 for the Scoping Plan Scenario. The other alternatives are presented in Appendix C (AB 197 Measure Analysis).

Table 3-12: Estimated average cost per metric ton of reduced CO_2e relative to the Reference Scenario for measures considered in the Scoping Plan Scenario (NWL)

Measure	Average Cost per Reduced Ton CO_2e ($/Ton)
Forests/Shrublands/Grasslands	15,500
Annual Croplands	1,100
Perennial Croplands	412
Urban Forest	3,270
Wildland Urban Interface (WUI)	N/A
Wetlands	64
Sparsely Vegetated Lands	451,000

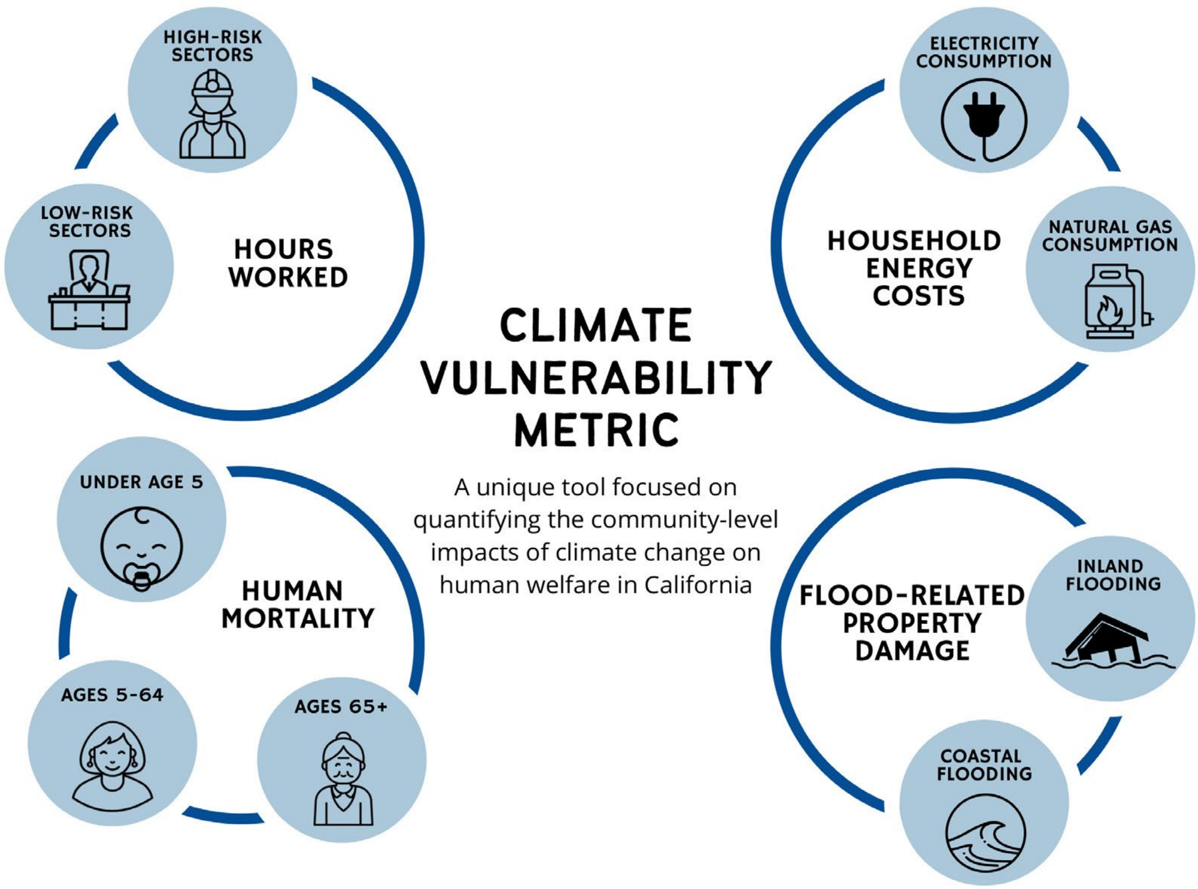
Climate Vulnerability Metric

As California invests in climate mitigation and adaptation, it is essential to understand that the relative impact of climate change will vary across the state's communities. Due to persisting health and opportunity gaps, not all communities are equally resilient in the face of climate impacts. A global metric such as the Social Cost of Carbon cannot adequately capture the incremental additional economic impact faced by overly burdened communities. The Climate Vulnerability Metric (CVM) is specifically focused on quantifying the community-level impacts of a warming climate on human welfare and the additional costs. Additional details and results are included in Appendix K (Climate Vulnerability Metric).

The CVM aggregates the impacts of climate change that can be quantified at the census tract level using robust and currently available research. The CVM includes the projected impacts of climate change on human welfare across four categories (hours worked, household energy costs, human mortality, and flood-related property damage) through midcentury. The CVM identifies nine components of the four climate impacts as shown in Figure 3-9 and aggregates the data to generate a total CVM result for each census tract. To ensure that the CVM represents the diversity of California communities, it is reported as the aggregate monetized impact of climate change as a percentage of census tract-specific incomes.[243] For example, a CVM value of 3 implies that by 2050, a census tract is projected to experience human welfare impacts of climate change that amount to 3% of annual income in that tract.

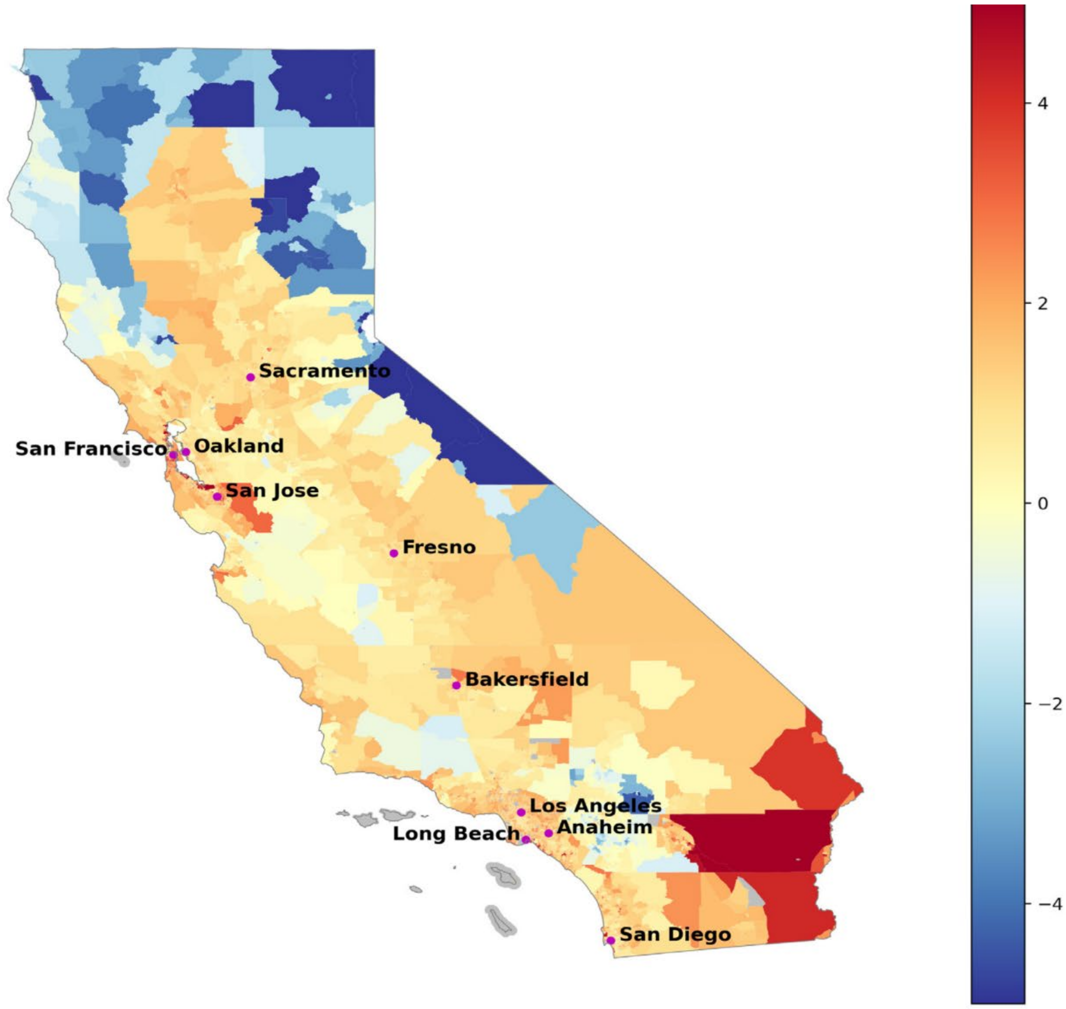
[243] Per capita income in 2019 for census tracts across California ranges from $633 to $176,388, with a median of $32,181 ($2019). Source: American Community Survey.

Figure 3-9: Categories of climate change impacts on human welfare included in the Climate Vulnerability Metric.



The CVM shows that climate change will have highly unequal impacts across California. While some southeastern regions of California are estimated to suffer damages that exceed 5% of annual income, other high-elevation northeastern regions of California are estimated to see benefits of up to 10%. Some low-lying urban areas, such as the San Francisco Bay Area, are estimated to be particularly vulnerable, while much of the Central Valley is estimated to suffer at least moderate economic damages relative to the rest of the state. It is important to note that the CVM does not set a threshold for vulnerability. Instead, it shows relative impacts across census tracts. The CVM is limited to the impacts that can currently be quantified at the census tract level.

Figure 3-10: Combined impacts of climate change in 2050 under a moderate emissions scenario; damages as share of 2019 tract income (%)



The map shows combined impacts of climate change in 2050 under a moderate emissions scenario (RCP 4.5), reported as a share of 2019 census tract income. For example, a CVM value of 3 implies that by 2050, a census tract is projected to experience human welfare impacts of climate change that amount to 3% of annual income. Impacts are combined across the categories shown in Figure 3-9. The higher the CVM for a given census tract, the more damaging the projected impacts of climate change on human welfare. Census tracts with high CVMs are represented by positive percentages in orange and red. A lower CVM is associated with lower projected impacts of climate change, shown in yellow, while a negative CVM value represents a projected beneficial impact of climate change (e.g., through reductions in deaths caused by extremely cold winter weather). Negative CVMs are represented by negative percentages in blue.

By providing information about how climate vulnerability varies across California (Figure 3-10), the CVM results can be used to direct resources to enhance resiliency in the state's most vulnerable communities based on the specific impacts, such as heat or flooding, they are experiencing. The CVM may be used in combination with existing screening tools, such as CalEnviroScreen 4.0, to identify communities that face environmental and health hazards that contribute to disproportionate economic impacts in addition to climate vulnerability. The CVM can become an essential source of information to implement this Scoping Plan and build a more resilient, just, and equitable future for all communities.

Public Health

Health Analysis Overview

This section focuses on a broader evaluation of public health and climate change. Science demonstrates that taking action to address climate change presents one of the most significant opportunities to improve public health outcomes.[244] Transitioning to clean energy and technology and improving land and ecosystem management will lead to a much healthier future. Many actions to reduce GHG emissions also have health co-benefits that can improve the health and well-being of populations across the state, as well as address climate change. This section and the accompanying Appendix G (Public Health) provide a qualitative analysis of health benefits to accompany the quantitative health analysis included in this chapter, in Appendix C (AB 197 Measure Analysis), and in Appendix H (AB 32 GHG Inventory Sector Modeling). Together the qualitative and quantitative analyses of benefits are demonstrating the many ways that climate action and health improvements go hand in hand.

Climate change can lead to a wide range of direct health impacts such as increased heat-related illnesses (i.e., heat exhaustion and heat stroke), and injuries and deaths from extreme weather events or disasters (e.g., severe storms, flooding, wildfires). Indirect impacts include:

- more air pollution-related exacerbations of cardiovascular and respiratory diseases (e.g., due to increased smog, wildfire smoke)
- increased vector-borne and fungal diseases due to changes in the distribution and geographic range of disease-carrying species (e.g., mosquitoes, ticks, fungi in dust)
- negative nutritional consequences related to decreases in agricultural food yields
- stress and mental trauma due to extreme weather-related catastrophes
- anxiety, depression, and other mental health impacts associated with gradual changes in the climate (e.g., prolonged drought or temperature shifts affecting jobs and industries) that result in unemployment and income loss

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[244] Watts, N., W. N. Adger, P. Agnolucci, et al. 2015. "Health and climate change: Policy responses to protect public health." *Lancet* 386, 1861–1914.

- residential displacement and home loss (e.g., sea level rise impacting coastal communities)

Wildfires and wildfire smoke are one area where we have already seen and expect to see even further drastic impacts on the health of Californians. According to CalFire, since 1932 the top eight largest wildfires in California have occurred in the past five years (2017–2022), with 151 deaths due directly to fires during that period.[245] Researchers estimate that wildfire smoke during fall 2020 may have led to as many as 3,000 excess deaths, with at least 95% of Californians suffering unhealthy levels of particle pollution due to wildfires in 2020.[246] Continued climate change is projected to further increase smoke exposure from wildfires through the end of the century.[247] Wildfires also create a high-risk environment for outdoor workers, including agricultural workers. While the direct medical and physical health impacts are often most noticeable, the psychological impacts can develop and persist well after the event. Estimates indicate that 20%–65% of survivors of extreme weather events have mental health issues following the event.[248]

Extreme heat, drought, and associated worsened air quality impacts are among the most serious climate-related exposures affecting the health of Californians. Numerous studies find a wide range of adverse health effects accompanying extreme heat, including heat stroke and adverse birth outcomes, and find that extreme heat can harm most body systems. Climate change exacerbates air pollution problems that cause difficulty breathing and can lead to serious illness and death in many parts of California. Increasing temperatures cause increases in ozone and other pollution concentrations, including for California's most polluted regions, and heighten health risks for the vulnerable and marginalized populations living in these areas.[249] In 2020, there were 157 ozone polluted days across Los Angeles, Orange, Riverside, and San Bernardino Counties—the most days since 1997. In addition, particulate matter exposure is a heightened problem during

[245] California Department of Forestry and Fire Protection (CAL FIRE). "Stats and Events." *Cal Fire Department of Forestry and Fire Protection*, https://www.fire.ca.gov/stats-events/.
[246] G-FEED. 2020. Indirect mortality from recent wildfires in CA. http://www.g-feed.com/2020/09/indirect-mortality-from-recent.html.
[247] M. D. Hurteau, A. L. Westerling, C. Wiedinmyer, and B. P. Bryant. 2014. "Projected effects of climate and development on California wildfire emissions through 2100." *Environ. Sci. Technol.* 48, 2298–2304.
[248] American Public Health Association. 2019. Addressing the Impacts of Climate Change on Mental Health and Well-Being. Policy No: 20196. https://www.apha.org/policies-and-advocacy/public-health-policy-statements/policy-database/2020/01/13/addressing-the-impacts-of-climate-change-on-mental-health-and-well-being.
[249] American Lung Association. State of the Air 2021. https://www.lung.org/research/sota.

droughts, which are expected to increase over this century.[250,251] Worse air quality leads to illnesses, emergency room visits, and hospitalizations for chronic health conditions, including chronic obstructive pulmonary disease (COPD), asthma, chronic bronchitis, and other respiratory and cardiovascular conditions, as well as increased risk for respiratory infections, which all result in greater health costs to the state.[252,253,254] These and other climate-related health impacts are discussed in more detail in Appendix G (Public Health).

Health Analysis Components

This Scoping Plan health analysis focuses on the contrast between a California that is still dependent on a fossil fuel-based economy and a California that is transitioned to a carbon-neutral, clean energy future. This qualitative analysis evaluates and demonstrates the broad range of benefits of a dramatic reduction in fossil fuels by 2045 combined with healthier ecosystem management, comparing health outcomes for a "no-action" scenario (Reference) to a "take-action" decarbonization scenario. As this is a qualitative analysis, it looks more broadly at the public health benefits of a drastic reduction in fossil fuel combustion. While this analysis provides scientific evidence for Scoping Plan benefits based on achieving carbon neutrality by 2045, it does not analyze a specific scenario.

The key areas of focus for the analysis are: heat impacts, children's health and development, economic security, food security, mobility and physical activity, urban greening, wildfires and smoke impacts, and housing affordability. For each area of focus, the analysis covers the scientific evidence and compares expected health effects between the Reference and decarbonization scenarios. This analysis looks at the major health outcomes, provides directional effects for each health outcome, and where possible provides information on the strength and scale of health impacts. Some areas include quantitative information where tools are available to measure health outcomes. While the analysis is focused on health outcomes statewide, it also includes discussion

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[250] Cvijanovic, I., B. D. Santer, C. Bonfils, et al. 2017. "Future Loss of Arctic Sea-ice Cover Could Drive a Substantial Decrease in California's Rainfall." 8 *Nat. Commun.* 1947. https://doi.org/10.1038/s41467-017-01907-4.

[251] Williams, A. P., R. Seager, J. T. Abatzoglou, B. I. Cook, J. E. Smerdon, and E. R. Cook. 2015. "Contribution of anthropogenic warming to California drought during 2012–2014." *Geophysical Research Letters* 42(16), 6819–6828.

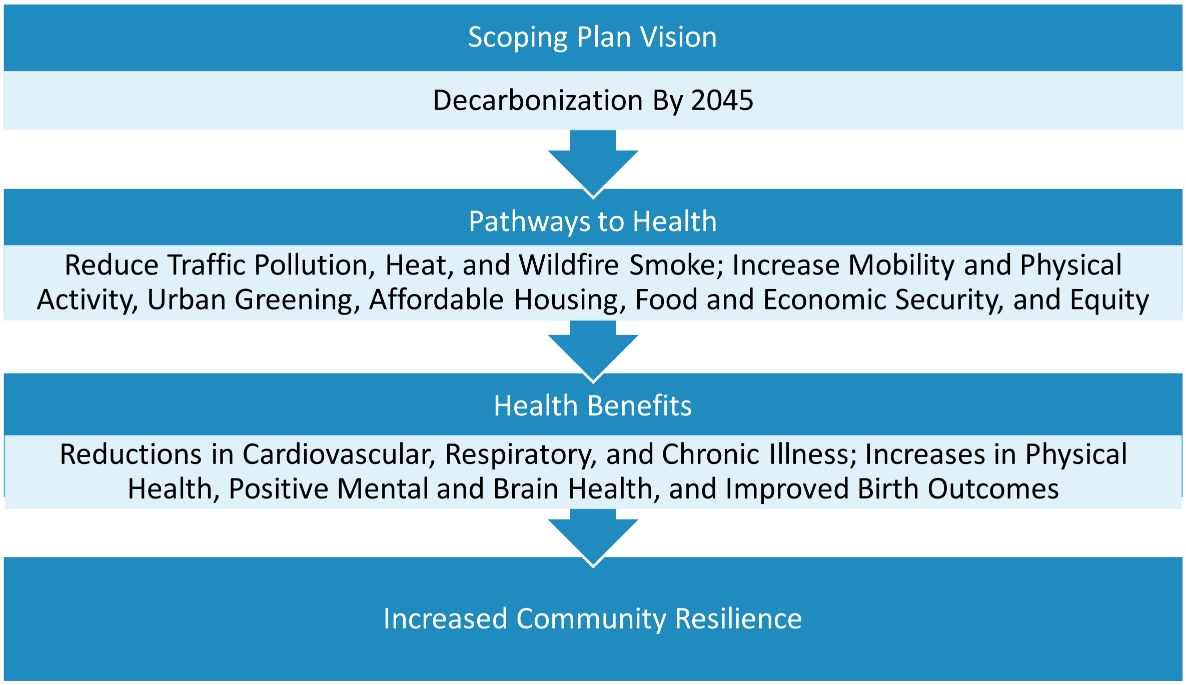
[252] Romley, J. A., A. Hackbarth, and D. P. Goldman. 2010. Cost and Health Consequences of Air Pollution in California. Santa Monica, California. RAND Corp. https://www.rand.org/pubs/research_briefs/RB9501.html.

[253] Wang, M., C. P. Aaron, J. Madrigano, E. A. Hoffman, E. Angelini, J. Yang, A. Laine, et al. 2019. "Association between long-term exposure to ambient air pollution and change in quantitatively assessed emphysema and lung function." *JAMA* 322(6), 546–556.

[254] Inserro, A. 2018. "Air Pollution Linked to Lung Infections, Especially in Young Children." *Am. J. Managed Care* (May 6). https://www.ajmc.com/view/air-pollution-linked-to-lung-infections-especially-in-young-children.

of benefits to community health and climate resilience, as well as potential inequities experienced at a community level. Figure 3-11 shows the co-benefit areas covered in this Scoping Plan and the path to health improvements and increased community resilience.

Figure 3-11: Scoping Plan outcome and the path to health improvements



Social and Environmental Determinants of Health Inequities

Communities across the state do not experience exposure to pollution sources and the resulting effects equally. Low-income communities and communities of color (including Black, Latino and Indigenous communities) consistently experience significantly higher rates of pollution and adverse health conditions than others due to factors including historic marginalization rooted in systemic racism. As shown in Figure 3-12, the most impacted neighborhoods according to CalEnviroScreen (CES) are home to very high percentages of people of color while the least impacted neighborhoods are predominantly white. Recent findings show that Black Californians have 19% higher $PM_{2.5}$ exposure from vehicle emissions than the state average, and the census tracts with the highest $PM_{2.5}$ pollution burden from vehicle emissions have a high proportion of people of color.[255] Air pollutant emissions from mobile sources have disproportionate impacts on low-income communities and communities of color due to their proximity.[256] Diesel-fueled vehicles traveling on California's freeways and major roads expose nearby residents to pollution that is linked to lung cancer, hospitalizations and emergency department visits for chronic heart and lung disease, and premature death.[257,258] A combination of historical and social inequities are evident in communities of color disproportionately living close to freeways and other major sources of vehicle pollution. Environmental exposures and contaminants are one component of a broader set of social, economic, and environmental factors that can amplify health conditions, and the combination of all these factors can compound the health effects of individual exposures. This broader set of community factors can be referred to as "cumulative impacts." In addition, specific populations are more sensitive to pollution and face greater susceptibility. This includes young children, older adults, and individuals with existing health conditions.

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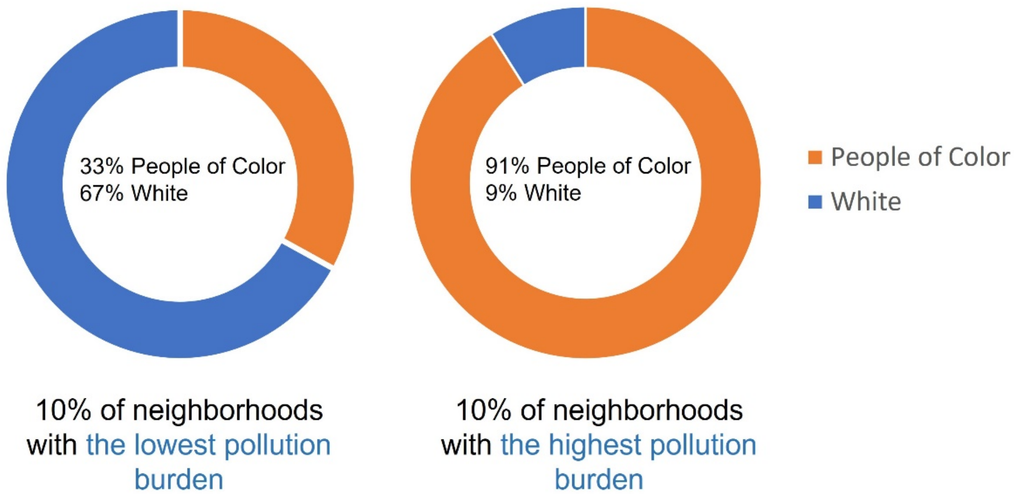
[255] Reichmuth, D. 2019. *Inequitable exposure to air pollution from vehicles in California.* https://www.ucsusa.org/resources/inequitable-exposure-air-pollution-vehicles-california-2019.

[256] CARB. 2017. *California's 2017 climate change scoping plan.* https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf.

[257] CARB. 2020. Overview: Diesel exhaust & health. https://ww2.arb.ca.gov/resources/overview-diesel-exhaust-and-health.

[258] Kagawa, J. 2002. "Health effects of diesel exhaust emissions—a mixture of air pollutants of worldwide concern." *Toxicology* 181–182:349–353.

Figure 3-12: Least and most impacted neighborhoods from CalEnviroScreen[259]



Social Determinants of Health Inequities

The physical and mental health of individuals and communities is shaped, to a great extent, by the social, economic, and environmental circumstances in which people live, work, play, and learn. According to the World Health Organization, these same circumstances—or social determinants of health—are "mostly responsible for health inequities: the unfair and avoidable differences in health status seen within and between countries." In fact, a strong body of research demonstrates that more than 50 percent of long-term health outcomes are the result of social determinants affecting an individual.[260] Race/ethnicity and socioeconomic status, for example, have been found to amplify impacts from long- and short-term environmental exposures for several health outcomes,

[259] The figure represents the top and bottom decile scoring of CalEnviroScreen census tracts for pollution burden. This chart is modified from Figure 2. Race in the Least and Most Impacted Census Tracts of CalEnviroScreen 4.0 in the Office of Environmental Health Hazard Assessment, California Environmental Protection Agency. Analysis of Race/Ethnicity and CalEnviroScreen 4.0 Scores. 2021. https://oehha.ca.gov/media/downloads/calenviroscreen/document/calenviroscreen40raceanalysisf2021.pdf.

[260] California Department of Public Health (CDPH). 2015. *The Portrait of Promise: The California Statewide Plan to Promote Health and Mental Health Equity.* A Report to the Legislature and the People of California by the Office of Health Equity. Sacramento, California. California Department of Public Health, Office of Health Equity.

such as mortality and birth outcomes.[261,262,263,264] Social factors combine in low-income communities and communities of color to create levels of toxic chronic stress and limit opportunities for healthy food and healthy lifestyles. Social factors also can cause health disparities through psychosocial pathways such as discrimination and social exclusion.[265] While the importance of social determinants is well known, measuring the specific and cumulative impacts of social determinants is challenging.

There are several important tools to evaluate and map cumulative impacts and factors contributing to the results of historical practices such as redlining, and these tools have been used for air quality and climate planning, community protection, and investments. CalEnviroScreen is a tool that maps cumulative pollution burdens and vulnerabilities on a statewide basis and ranks census tracts based on environmental, exposure, population, and socioeconomic indicators. An analysis using CES shows a direct, persistent relationship between exposure to environmental burdens and socioeconomic and health vulnerabilities affecting communities of color and historical redlining practices. OEHHA has evaluated health impacts of certain climate change policies on disadvantaged communities and communities of color utilizing CES rankings.[266] The Healthy Places Index (HPI) maps indicators that affect life expectancy on a statewide basis. In the future, these and other tools can be helpful to prioritizing investments and informing implementation efforts for GHG emission reductions policies.

Environmental Determinants of Health Inequities

Communities with large percentages of Black and other socially vulnerable and marginalized groups are disproportionately located near pollution sources, such as traffic

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[261] O'Neill, M. S., M. Jerrett, I. Kawachi, J. I. Levy, A. J. Cohen, N. Gouveia, et al. 2003. "Health, wealth, and air pollution: Advancing theory and methods." *Environ Health Perspect.* 111 (16): 1861–70.
[262] Ponce, N. A., K. J. Hoggatt, M. Wilhelm, and B. Ritz. 2005. "Preterm birth: The interaction of traffic-related air pollution with economic hardship in Los Angeles neighborhoods." *Am J Epidemiol.* 162 (2): 140–8.
[263] Morello-Frosch, R., B. Jesdale, J. Sadd, and M. Pastor. 2010. "Ambient air pollution exposure and full-term birth weight in California." *Environ Health.* 9: 44.
[264] Finkelstein, M. M., M. Jerrett, P. DeLuca, N. Finkelstein, D. K. Verma, K. Chapman, et al. 2003. "Relation between income, air pollution, and mortality: A cohort study." *CMAJ.* 169 (5): 397–402.
[265] Clougherty, J., and L. Kubzansky. 2009. "A framework for examining social stress and susceptibility in air pollution and respiratory health." *Environ Health Perspect.* 117 (9): 1351–8.
[266] OEHHA. 2022. *Impacts of Greenhouse Gas Emission Limits Within Disadvantaged Communities.* https://oehha.ca.gov/media/downloads/environmental-justice//impactsofghgpoliciesreport020322.pdf.

and freight facilities, industrial facilities, and hazardous waste sites.[267,268,269,270] Research shows large disparities in exposure to pollution between white and non-white populations in California, and between low-income and communities of color (Figure 3-13). The research also shows Black and Latino populations experience significantly greater air pollution impacts than white populations in California.[271] Additionally, Native Americans are disproportionately impacted by air pollution with high rates of exposure to industrial, diesel, and residential pollution sources and higher rates of diseases linked to air pollution.[272, 273]

[267] Mohai. P., P. M. Lanz, J. Morenoff, J. S. House, and R. P. Mero. 2009. "Racial and socioeconomic disparities in residential proximity to polluting industrial facilities: Evidence from the Americans' Changing Lives Study." *Am J Public Health.* 99 (Suppl 3): S649–56.

[268] Mohai, P., and R. Saha. 2007. "Racial inequality in the distribution of hazardous waste: A national-level reassessment." *Soc Probl.* 54 (3): 343–70.

[269] Morello-Frosch, R., M. Pastor, C. Porras, and J. Sadd. 2002. "Environmental justice and regional inequality in southern California: Implications for future research." *Environ Health Perspect.* 110 (Suppl 2): 149–54.

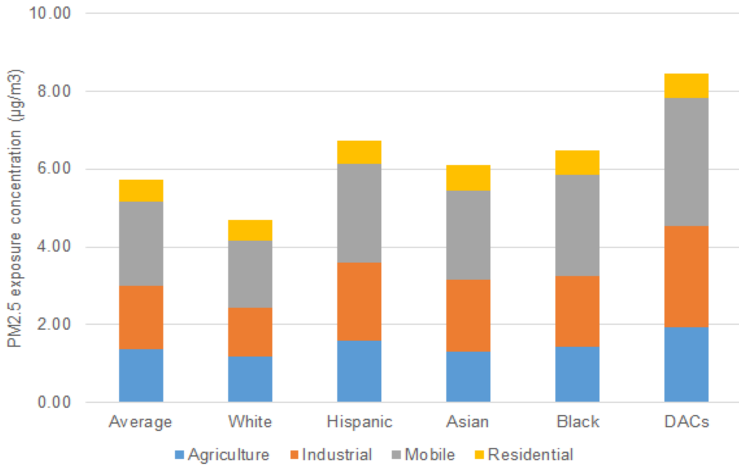
[270] Gunier, R. B., A. Hertz, J. von Behren, and P. Reynolds. 2003. "Traffic density in California: Socioeconomic and ethnic differences among potentially exposed children. *J Expo Anal Environ Epidemiol.* 13 (3): 240–6.

[271] Apte, J. S., S. E. Chambliss, C. W. Tessum, and J. D. Marshall. 2019. *A Method to Prioritize Sources for Reducing High $PM_{2.5}$ Exposures in Environmental Justice Communities in California.* CARB Research Contract Number 17RD006.

[272] Indigenous People and Air Pollution in the United States. A Report from the National Tribal Air Association and Moms Clean Air Force. 2021. https://7vv611.a2cdn1.secureserver.net/wp-content/uploads/2021/04/indigenousairpollution_041421.pdf

[273] National Tribal Air Association. 2022. Status of Tribal Air Report. Pg. 66. https://7vv611.a2cdn1.secureserver.net/wp-content/uploads/2022/10/2022-NTAA-Status-of-Tribal-Air-Report.pdf.

Figure 3-13: Top sources of $PM_{2.5}$ and their contribution to $PM_{2.5}$ exposures by race and in disadvantaged communities



These disparities in exposure to pollution sources generate health inequities. Communities located near major roadways are at increased risk of asthma attacks and other respiratory and cardiac effects. Studies consistently show that mobile source pollution exposure near major roadways or freight sources contributes to and exacerbates asthma, impairs lung function, and increases cardiovascular mortality.[274] The exposure to mixtures of gaseous and particulate pollutants in mobile sources (including PM, NO_x, and benzene) is associated with higher rates of heart attacks, strokes, lung cancer, autism, and dementia.[275]

Environmental hazards found in communities also can include exposures to toxic substances and emissions, as well as occupational exposures. Due to historical inequities, under-resourced communities and communities of color are often located close to sources of toxic pollution, including chrome platers; metal recycling facilities; oil and gas operations; agricultural burning; railyards; facilities transporting, managing, or disposing of hazardous waste; and areas impacted by pesticides, among others. Some populations may be at increased risk of exposure to pollutants, both at work and home.

Children are more susceptible to environmental pollutants for many reasons, including the ongoing development of their nervous, immune, digestive, and other bodily systems. Moreover, children eat more food, drink more fluids, and breathe more air relative to their

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[274] U.S. Environmental Protection Agency website. How Mobile Source Pollution Effects Your Health. https://www.epa.gov/mobile-source-pollution/how-mobile-source-pollution-affects-your-health.
[275] USC Environmental Health Centers. 2018. Living Near Busy Roads or Traffic Pollution. https://envhealthcenters.usc.edu/wp-content/uploads/2016/10/living-near-bus_19696172.pdf.

body weight, as compared to adults.[276] Exposure to high levels of air pollutants, including indoor air pollutants, increases the risk of respiratory infections, heart disease, and asthma.[277] Children living in low-income communities near industrial operations, rail yards, and heavily trafficked freeways and streets in urban areas are at especially high risk of chronic respiratory conditions. Black children are four times more likely to be hospitalized for asthma compared with white children, and urban Black and Latino children are two to six times more likely to die from asthma than white children.[278] Native American children also experience more impacts from asthma and Native American children, along with Black children, have the highest prevalence of asthma.[279]

For older adults, increased vulnerability is linked to respiratory, cardiovascular, and immune systems weakened by aging.[280] Preexisting health conditions interact with environmental pollutants to enhance risks of adverse health outcomes.[281,282] The recent COVID-19 pandemic has highlighted the heightened vulnerability of older adults as well as communities of color to respiratory disease, as hospital admissions and mortality data linked to COVID-19 cases for these groups have been higher than other groups. Research has also underscored the important link between COVID-19 mortality and morbidity and air pollution, demonstrating significantly higher mortality and morbidity for COVID-19 in areas of elevated $PM_{2.5}$ pollution.

Climate Vulnerabilities

Climate change is expected to exacerbate the existing disparities of health conditions and worsen climate vulnerability, which is the degree to which natural systems and people or

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[276] Blaisdell, R. J. Air Toxics Hot Spots Program Risk Assessment Guidelines. 2012. Technical Support Document for Exposure Assessment and Stochastic Analysis. Oakland, California: California Environmental Protection Agency, Office of Environmental Health Hazard Assessment. August.

[277] Woodruff, T. J., D. A. Axelrad, A. D. Kyle, O. Nweke, and G. G. Miller. 2003. *America's Children and the Environment: Measures of Contaminants, Body Burdens, and Illness.* 2nd ed. Washington, D.C.: United States Environmental Protection Agency. February.

[278] California Department of Public Health. Asthma Inequities in California Children. 2021. https://www.cdph.ca.gov/Programs/CCDPHP/DEODC/EHIB/CPE/CDPH%20Document%20Library/CA_Asthma_Inequities_Children_2021-Infographic.pdf.

[279] Meng, Y., S. H. Babey, T. A. Hastert, and E. Brown. 2007. California's Racial and Ethnic Minorities More Adversely Affected by Asthma. UCLA: Center for Health Policy Research. Retrieved from https://escholarship.org/uc/item/4k45v3xt.

[280] Sandström, T., A. J. Frew, M. Svartengren, and G. Viegi. 2003. "The need for a focus on air pollution research in the elderly." *Eur Respir J Suppl.* 40: 92s–5s.

[281] Zanobetti, A., and J. Schwartz. 2001. "Are diabetics more susceptible to the health effects of airborne particles?" *Am J Respir Crit Care Med.* 164 (5): 831–3. https://www.atsjournals.org/doi/pdf/10.1164/ajrccm.164.5.2012039.

[282] Zanobetti, A., J. Schwartz, and D. Gold. 2000. "Are there sensitive subgroups for the effects of airborne particles?" *Environ Health Perspect.* 108 (9): 841–5.

communities are at risk of experiencing the negative impacts of climate change.[283] A report from the California Climate Change Center warned that the impacts of climate change will likely create especially heavy burdens on low-income and other vulnerable populations: "*Without proactive policies to address these equity concerns, climate change will likely reinforce and amplify current as well as future socioeconomic disparities, leaving low-income, minority, and politically marginalized groups with fewer economic opportunities and more environmental and health burdens*."[284]

In the U.S. Environmental Protection Agency's "Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts,"[285] investigators analyzed risks of six primary climate change impacts disproportionately affecting communities across income, educational attainment, race/ethnicity, and age groups. Four socially vulnerable populations—low income, communities of color, no high school diploma, and age 65 and older—were identified as having a higher likelihood of experiencing the greatest impacts of a changing climate (according to the projected 2°C of global warming or 50 centimeters of global sea level rise). Disproportionate impacts were projected for climate events, including air quality, extreme temperature, coastal flooding, and other impacts, leading to increased risk of health and other adverse outcomes. The study projected significant health impacts for low-income communities, certain racial and ethnic subgroups, and those with lower educational attainment.

Several climate vulnerability tools have been developed or are under development to better understand and map areas at higher risk of climate impacts. The Climate Change and Health Vulnerability Indicators (CCHVIs) for California helps state and local health officials prepare for and reduce adverse health impacts due to a changing climate.[286] For example, Los Angeles County shows higher than state average climate vulnerability overall, particularly for those who are linguistically isolated (more than twice the state average).

In summary, there are many environmental, social, individual, and economic factors affecting health and equity in California and contributing to worsening health outcomes from climate change impacts. This section and Appendix G (Public Health) reference a substantial and growing body of research documenting the different social and

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[283] OPR. 2018. Defining Vulnerable Communities in the Context of Climate Adaptation. https://opr.ca.gov/docs/20180723-Vulnerable_Communities.pdf.

[284] Shonkoff, S., R. Morello-Frosch, M. Pastor, and J. Sadd. 2011. "The climate gap: environmental health and equity implications of climate change and mitigation policies in California—A review of the literature." *Climatic Change* 109 (Suppl 1): S485–S503.

[285] U.S. EPA. 2021. Climate Change and Social Vulnerability in the United States: A Focus on Six Impacts. U.S. Environmental Protection Agency. EPA 430-R-21-003.

[286] CDPH. 2022. Climate Change and Health Vulnerability Indicators for California. California Department of Public Health. https://www.cdph.ca.gov/Programs/OHE/Pages/CC-Health-Vulnerability-Indicators.aspx.

environmental factors affecting health outcomes and the many groups that are vulnerable to increased effects or that experience health inequities in California (see Table 3-13).

Table 3-13: Examples of vulnerable groups due to socioeconomic, environmental, developmental, and climate change factors

Examples of Vulnerable Groups Due to Socioeconomic, Environmental, Developmental, and Climate Change Factors		
Older People	People with Existing Chronic Illness	People Impacted Due to Working Conditions
Tribal Groups	Infants and Children	Low-Income People
People with Disabilities	People Experiencing Homelessness	Pregnant People
Communities of Color	Marginalized People	Immigrants/Refugees
People with Less Educational Options	Linguistically Isolated Households	People Impacted Due to Poor Housing Conditions

Summary of the Qualitative Health Analysis

CARB has developed a detailed health analysis that covers eight social and environmental co-benefit areas that impact public health (listed below). These co-benefit areas were selected due to ongoing research in these areas as well as discussion in a public workshop on climate change and health impacts held in summer 2018. For each social and environmental area, the analysis includes:

- a discussion of health impacts and disparities,
- key health metrics or epidemiological research on this topic,
- a discussion of how these areas would be affected by "no-action" (i.e., Reference) scenario compared to a "take-action" (i.e., Scoping Plan) scenario
- a discussion of where there are actions to consider for further success, and
- the types of mitigation actions that can help reduce or eliminate disparities and promote greater health equity and resilience.

All co-benefit areas are interconnected, and pursuing benefits in all areas has the potential to multiply positive results and further support building community resilience. *Community resilience* is the ability of a community to reduce harm and maintain an acceptable quality of life in the face of climate-induced stresses, which vary depending on that community's circumstances and location. Below is a brief description of the areas evaluated for public health co-benefits. The specific health outcomes impacted by each area, as well as the directional health benefits, are included in the Summary of Health Benefits section of the chapter and covered in more detail in Appendix G (Public Health).

Heat Impacts

Globally, increased GHG concentrations in the atmosphere are causing a continuing increase of the planet's average temperature. California temperatures have risen since records began in 1895, and the rate of increase is accelerating. Recent heat waves have broken heat records and caused serious illness across the state, and these events are becoming more frequent. Heat waves have a particularly high impact in Southern California, where they have become more intense and longer lasting. In the past two years, Los Angeles recorded 121°F, and the Coachella Valley had its hottest year ever, with temperatures reaching 123°F. Heat island effects in urbanized areas can elevate heat effects and disproportionately affect low-income communities and communities of color. Heat events exacerbate respiratory and cardiac illness and cause emergency room visits to soar. Strategies that reduce the impacts of heat exposure promote improved health outcomes.

Wildfires and Smoke

California's NWL cover more than 90 percent of California and include rangeland, forests, woodlands, grasslands, and urban green space. They provide biodiversity and ecosystem benefits, including their ability to sequester carbon from the atmosphere. Protecting and managing California's forests and other natural lands and maintaining their ecosystem health are key practices for maximizing GHG benefits and minimizing negative climate change impacts. Vegetation plays an important role in storing carbon; however, it can also release CO_2 back into the atmosphere when it dies or is burned by fires. California's wildfires are getting worse with increased fire risks, higher frequency of occurrence, larger burn areas, more costly damage, and a longer fire season due to climate change. Strategies that promote healthy ecosystem management of natural and working lands and increased urban greening promote improved health outcomes. Healthy ecosystems provide many health and environmental benefits and can maximize carbon sequestration.

Children's Health and Development

There are a wide range of interconnected environmental, social, biological, and community factors associated with climate change that are adversely affecting children's health. This section focuses on air pollution and near-roadway or traffic pollution as environmental impacts that have a profound effect on children's health. Children's bodies and lungs are still developing, and they take in more air per body weight than adults do. Many low-income communities and communities of color in California experience disproportionately high levels of air pollution, as well as high levels of traffic and freight that impact children. This excess exposure harms children's development and predisposes them to increased risk of illness throughout their lives. Strategies that reduce air pollution and traffic emissions promote improved health outcomes for children.

Economic Security

Climate change is expected to result in serious adverse socioeconomic effects across many sectors. Economic factors, such as income inequality (among geographic regions), poverty, wealth, debt, unemployment rate, and job security are among the strongest determinants of health. Along the entire income spectrum, higher income is associated with increased life expectancy and improved health outcomes in the United States. Additionally, economic insecurity and negative health impacts are more pronounced in low-income communities and communities of color. Economic strategies, such as the promotion of clean energy and other green jobs and investments in low-income communities and communities of color, and promoting a transition to high road jobs in economic sectors tied to the current fossil fuel economy, can promote improved health outcomes.[287]

Food Security

The food system is under pressure from numerous factors, and climate change is a key concern. Climate change can affect food production and agricultural yield, impact culturally significant plants and animals for Native American tribes, and exacerbate factors that limit food availability, such as supply chain disruption. Food security is defined as stable access to affordable, sufficient food for an active, healthy life. Many Californians routinely experience food insecurity, and while that impacts Californians of all races and groups, low-income communities and communities of color and children are disproportionately affected by food insecurity. Many Native Americans depend on resources from the land, such as animals and plants for consumption and cultural practices. Strategies that promote sustainable agriculture, access to healthy foods, and reduced organic food waste promote improved health outcomes.

Mobility and Physical Activity

Physical activity is one of the most important factors for a healthy lifestyle, and lack of activity increases the risk of chronic illness and premature death. Research shows that regular physical activity improves health in people of all ages by improving heart and lung

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[287] According to the California Labor and Workforce Development Agency's High Road Training Partnership program, high road jobs are considered "Quality jobs [that] provide family-sustaining wages, health benefits, a pension, worker advancement opportunities, and collective worker input and are stable, predictable, safe and free of discrimination." https://cwdb.ca.gov/wp-content/uploads/sites/43/2020/08/OneSheet_Job-Quality_ACCESSIBLE.pdf.

function, muscle fitness, mental health and brain function, and sleep quality. A sedentary lifestyle contributes to chronic illnesses, including obesity, heart disease, and Type 2 diabetes among other chronic illnesses. Promoting community design that supports sustainable patterns of land use and transportation enables active transportation choices like walking, biking, and public transit over driving, and can significantly increase physical activity, leading to many valuable health benefits.

Affordable Housing

Housing is an important social determinant of health. The stability of housing, housing quality, conditions inside and outside the home, the cost of housing, and the environmental and social characteristics of the places people live all affect health (including energy efficiency and insulation, cooler building material, tree canopy, home size). Housing affordability is a key factor, and this section highlights how housing affordability supports not only improved health but also more sustainable land use and transportation patterns. A lack of affordable housing is increasing commute distances for low-income renters and creating health burdens. Strategies that support sustainable transportation and housing patterns, together with increased housing affordability, promote improved health outcomes.

Urban Greening

Urban Greening is well recognized as an important amenity, but the inherent health benefits are not always well understood. Under-resourced and vulnerable areas consistently show a lack of urban greening and higher percentages of concrete, asphalt, and impervious surfaces. Under-resourced communities have a greater proportion of concrete and heat-trapping surfaces and a lower amount of tree cover in the neighborhoods in which they live. Areas with reduced urban greening have the potential to create areas of higher temperatures as heat is reflected from pavements and buildings. By contrast, increasing urban greening can provide air pollution buffers and promote physical activity. Strategies that preserve and create urban parks, green space, natural infrastructure, and sustainable agricultural practices support improved physical and mental health outcomes.

No Action Scenario (Reference)

In a no-action scenario, California would remain dependent on fossil fuels and other GHG emitting technologies. Fossil-fuel powered mobile sources including cars, trucks, trains, tractors, and a myriad of other on-road and off-road vehicles and equipment are the largest source of criteria pollutants and toxic air contaminants that directly affect community health and contribute the largest portion of GHG emissions.[288] Other key GHG emission sources include buildings, natural and working lands, and power production and industry. The no-action scenario reflects a continued reliance on fossil fuels in mobile and stationary sectors, including buildings. The continued production and use of fossil fuels; ongoing dependence on gasoline and diesel cars, trucks, buses, and equipment; continued releases of short-lived climate pollutants; and decreased emphasis on forest and ecosystem health will impact communities by reducing climate resilience and health benefits. Green space will likely remain at the same levels or degrade, and urban heat islands will likely increase. With continued growth of vehicle miles traveled, physical activity and the accompanying health benefits will not increase.

Exposure to wildfire smoke will increase, and air quality is expected to worsen as rising temperatures will increase levels of harmful air pollution. Jobs and economic security will be affected by the continuing potential for price spikes in fossil fuels, impacts to the economy from climate change, and fewer job opportunities in green technologies such as solar and electric vehicles. Food security in California will decrease due to the effects of accelerating climate impacts to agriculture; and without increased recovery of organic waste, including food products, food security will continue to decline under a no action scenario. All these impacts can be linked to worse health outcomes. Adverse health impacts are often most felt by Black, Latino, Native American, and other people of color and in low-income communities. These groups are affected more intensely by the physical stress of environmental pollution, social inequities, and the psychological stress of extreme weather events and food and economic insecurity.

Take Action Scenario

In the Take Action scenario, California will drastically reduce reliance on fossil fuels for motor vehicles, freight, buildings, electricity, or other sectors. This scenario is not a specific scenario within this Scoping Plan but examines the broad outcomes of actions to achieve carbon neutrality in 2045. Implementation of this Scoping Plan would achieve a transition to ZEVs, with 100% sales of light-duty ZEVs by 2035 and 100% sales of zero emission trucks by 2040, along with 30% VMT reductions below 2019 levels by 2045. State and local action that supports sustainable land use and transportation patterns and enables more transit and active transportation will lead to substantial health benefits from physical activity, including reduced illness and deaths.

[288] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

The economic benefits of improved health through active transportation can be modeled using the Healthy Mobility Options Tool (HMOT).[289] In order to demonstrate the important health and economic benefits of VMT reduction, CARB and CDPH used the HMOT to analyze an illustrative trip reduction scenario for 2050 from the California Transportation Plan (CTP). The CTP has a goal of increasing active modes of travel and transit from the current level of 13 percent to a level of 23 percent of all travel trips. While the CTP goal of 23 percent for active modes of travel is not a VMT reduction target, the scenario increases active transportation through a mix of changes in land use planning for increased transportation options, including increases in biking, walking, and transit use, and it helps to show the health benefits of increased active transportation. By achieving the CTP 2050 goals, nearly 8,000 deaths would be avoided in 2050 alone (see Figure 3-14), along with significant reductions in chronic diseases. Achieving this would rank among the top public health accomplishments (see Appendix G [Public Health] for additional modeling results and detailed discussion).

The dramatic reduction in fossil fuel combustion, combined with reductions in VMT and freight and traffic emissions projected in this Scoping Plan will significantly reduce air pollution and its associated health impacts on a statewide basis and in communities near freight sources. Coordinated action strategies will emphasize natural and working lands management changes, including healthy forests, increased vegetative cover, and increased organic farming. Wildfire smoke exposure will reduce significantly with healthy ecosystem management strategies. Since many communities in California are disproportionately impacted by high levels of traffic pollution, the reduction in petroleum fueled vehicles will reduce the additional impacts of living or going to school near historically highly polluting sources. Indoor air quality is also likely to improve through a shift to non-fossil fuel appliances. Concerted state and local action to support sustainable land use and transportation patterns can enable more active transportation with health benefits from physical activity.

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[289] ITHIM California. 2020. Transportation Planning for Health, Equity, and Climate Change. *https://skylab.cdph.ca.gov/HealthyMobilityOptionTool-ITHIM/*.

Figure 3-14: Quantified health benefits of active transportation from increased physical activity

*Calculated by the Healthy Mobility Options Tool, active transportation (including walking, rolling, cycling, and taking public transit) from the California Transportation Plan 2050 compared to business as usual for 2050.

Overall community resilience is expected to increase as physical activity and green space increases—potentially decreasing urban heat islands. Efforts to support VMT reduction will include coordination across state agencies on affordable housing measures. Reduced fossil fuel dependence will reduce economic pressure from wildfires, droughts, and price spikes in fossil fuels, especially as more jurisdictions implement plans with similar actions. Investment in sustainable agriculture, healthy forests, urban greening, and clean energy technologies will add sustainable jobs and further promote economic security. More sustainable agriculture and food recovery efforts will add to food security. All these impacts can be linked to wide ranging health benefits, including positive respiratory and cardiovascular effects, healthier birth and brain outcomes, improved mental health indicators, improved life expectancy, reductions in chronic illness and cancers, improved children's health and development, reduced depression, and other benefits. The magnitude of the possible co-benefits is extremely large, especially in areas that are currently the most affected.

Summary of Health Benefits

Below, Tables 3-14 and 3-15 show overall summaries of the directional benefits by co-benefit area estimated for this Scoping Plan. The supporting epidemiological studies used for qualitative or quantitative analysis of each co-benefit area are included in Appendix G (Public Health). Another section of Chapter 3, together with Appendix C (AB 197 Measure Analysis) and Appendix H (AB 32 GHG Inventory Sector Modeling), also includes the quantitative analysis of air pollution related health impacts, including recently added health endpoints for CARB's ongoing analysis.

Table 3-14: Scoping Plan directional benefits for health co-benefit areas (heat, affordable housing, food security, economic security, and urban greening)

	Health Co-benefit Areas*				
Quantitative vs. Qualitative	**Reduced Heat Impacts**	**Increased Affordable Housing**	**Increased Food Security**	**Increased Economic Security**	**Increased Urban Greening**
Research was used for Qualitative Analysis	↓ Mortality ↓ Emergency Room Visits for cardiovascular and respiratory causes and intestinal infections ↓Hospitalization for cardiovascular, respiratory causes ↓ Preterm Birth ↓ Mental Illness	↓ Infectious Disease ↓ Chronic Illness ↓ Asthma ↓ Injuries ↓ Mental Illness ↑ Children's Performance in Schools ↑ Children's Health ↓ Children's Behavioral Problems	↓ Mental Illness ↓ Iron Deficiency ↓ Chronic Diseases ↑ Life Expectancy ↓ Children's Mental Illness ↓ Children's Cognitive Problems ↓ Children's Behavioral Health Problems ↓ Children's Iron Deficiency ↓ Children's Oral Health Problems	↑ Life Expectancy ↑ Health Status ↑ Mental Health	↓ Mortality ↓ Asthma Prevalence ↓ Depression ↓ Adverse Birth Outcomes including low birth weight and small for gestational age ↑ Life Expectancy

*See Appendix G (Public Health) for a table with references to research for each health outcome listed.

Table 3-15: Scoping Plan directional benefits for health co-benefit areas (traffic pollution, wildfire, and active transportation)

Health Co-benefit Areas*			
Quantitative vs. Qualitative	**Reduced Traffic Pollution**	**Reduced Wildfire Smoke**	**Increased Active Transportation**
Research was used for Quantitative Analysis	↓ Children's Respiratory Outcomes, Hospital Admissions ↓ Children's Respiratory Outcomes, Emergency Room Visits ↓ Children's Asthma Onset ↓ Children's Asthma Symptoms	↓ All-Cause Mortality ↓ Asthma, Hospital Admissions ↓ COPD, Hospital Admissions ↓ All Respiratory Outcomes, Hospital Admissions ↓ Asthma, Emergency Room Visits ↓ All Respiratory Outcomes, Emergency Room Visits ↓ All Cardiac Outcomes, Emergency Room Visits	↓ Cardiovascular Diseases ↓ Colon Cancer ↓ Breast Cancer ↓ Diabetes ↓ Dementia ↓ Lung Cancer ↓ Respiratory Disease ↓ Depression ↑ Traffic Accidents
Research was used for Qualitative Analysis	↑ Children's Lung Function Growth ↓ Children's Bronchitic Symptoms ↓ Children's Impaired Cognitive Development ↓ Children's Adverse Birth Outcomes, including low birth weight and preterm birth		

*See Appendix G (Public Health) for a table with references to research for each health outcome listed.

In summary, the qualitative health analysis of the No-Action versus Take-Action scenarios for this Scoping Plan shows an overwhelming benefit for the state by taking action to move forward to carbon neutrality while continuing efforts to increase health equity and resilience in individual communities. Taking action can improve physical and mental health for adults and children, reduce a range of chronic illnesses, and promote improvements in life expectancy. Development and implementation of actions to achieve the outcomes called for in this Scoping Plan should consider how to engage affected communities in implementation, address the existing health and opportunity gaps, and pursue equitable implementation statewide and locally. This Scoping Plan deployment of clean technology and fuels, together with improved land management, will reduce GHGs and air pollution and create more resilient communities that are better able to prepare for and recover from extreme climate events.

Environmental Analysis

In May 2022, CARB, as the lead agency for the Scoping Plan, released for public review the Draft Environmental Analysis (Draft EA) for this Scoping Plan; it assessed the potential environmental impacts of implementing the Scoping Plan. CARB circulated the Draft EA for public review and comment for a period of 45 days that began on May 10, 2022, and ended on June 24, 2022. CARB held a public hearing on June 23, 2022 to provide the opportunity for public comment. During the review period, written and oral comments were received on the Draft EA. CARB reviewed the comments to identify environmental topics and began preparation of responses to those comments.

After the end of the Draft EA public review period, CARB identified potential revisions to certain aspects of this Scoping Plan that merit revisions to the project description. This new information results from, among other things, revisions to the project description regarding energy sector goals (including offshore wind), revised carbon removal targets, and additional strategies for natural and working lands. CARB released a Recirculated Draft EA for a written public comment period that started September 9, 2022, and ended on October 24, 2022. See Chapter 2 of the Recirculated Draft EA[290] for further information regarding the changes. The Recirculated Draft EA assesses the potential for significant adverse and beneficial environmental impacts associated with all proposed actions in this Scoping Plan, and provides a programmatic environmental analysis of the reasonably foreseeable compliance responses that could result from implementation of the Scoping

[290] CARB. 2022. Recirculated Draft EA. *https://ww2.arb.ca.gov/sites/default/files/2022-09/2022-draft-sp-appendix-b-draft-ea-recirc.pdf*.

Plan.[291] The Recirculated Draft EA concluded implementation of this Scoping Plan could result in the following:

- Beneficial impacts to: air quality (long-term operational-related) and GHG emissions (short-term construction-related and long-term operational-related)
- Less than significant impacts to: energy demand, mineral resources, population and housing, public services, recreation (short-term construction-related), and wildfire (short-term construction-related)
- Potentially significant and unavoidable adverse impacts to: aesthetics, agriculture and forest resources, air quality (construction-related and operational odors), biological resources, cultural resources, geology and soils, hazards and hazardous materials, hydrology and water quality, land use and planning, noise, recreation (long-term operational-related), transportation and traffic, tribal cultural resources, utilities and service systems, and wildfire (long-term operational-related

Before the public meeting at which the Board will consider this Scoping Plan Update, CARB will publish the Final EA as Appendix B (Final Environmental Analysis) to this Scoping Plan, along with written responses to timely submitted comments raising significant environmental issues received on the Draft EA and the Recirculated Draft EA, which will be presented to the Board for consideration.

[291] The Recirculated Draft EA is available at *https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents*.

Chapter 4: Key Sectors

Chapter 4 provides an overview of the major energy sources and technology in use today, and of alternative clean technology and fuels to support decarbonization based on the latest information available. Every sector of the economy will need to begin to transition in this decade to meet our GHG reduction goals and achieve carbon neutrality no later than 2045. AB 32 requires climate change mitigation policies to be considered in the context of the sector's contribution to the state's total GHG emissions. The transportation, electricity (in-state and imported), and industrial sectors are the largest contributors of GHGs in the state and present the largest opportunities for GHG reductions. Actions to reduce fossil fuel combustion in these sectors also can provide critical air pollution reductions in low-income communities and communities of color, which are often located adjacent to these sources. A carbon neutrality framework also elevates the role of CO_2 removal through natural and working lands and mechanical capture and storage. Actions that support energy efficiency, reduced VMT, alternative fuels, and renewable power also can provide benefits by reducing both criteria and toxic air pollutants.

What sets this plan apart from previous Scoping Plans is the focus on the accelerated rate of deployment of clean technology and energy within every sector. As a result, specific actions, including accelerated rates of deployment of clean technology and fuels identified within this Scoping Plan, will need to be translated into both new and amended regulations, policies, and incentive programs. State agencies will need to evaluate current authority to align existing policies or develop new ones to achieve outcomes called for in this Scoping Plan. Legislative support may be needed in some cases to ensure authority and funding is sufficient to ensure this Scoping Plan is translatable to action on the ground. Most regulations, or change to existing regulations, ultimately considered by the Board or other state agencies for adoption will be subject to administrative procedure requirements. Accordingly, they must rely on specific subsequent supporting analysis and extensive public processes and consultations with interested tribes to develop and identify appropriate proposals for effective implementation. For example, any proposal to strengthen the LCFS regulations through amendments increasing the stringency of the carbon intensity (CI) targets would be considered on the basis of a public process, including workshops, and focused environmental, economic, and public health analyses.

Policies that ensure economy-wide investment or program decisions that incorporate consideration of GHG emissions are particularly important. As we pursue GHG reduction targets, we must acknowledge the manner in which built and natural environments are connected, how changes in one may impact the other, and how policy choices in one sector can and do impact other sectors. For example, fostering more compact, transportation-efficient development in infill areas and increasing transportation choices with the goal of reducing VMT not only reduces demand for transportation fuel but also requires less energy for buildings and helps to conserve natural and working lands that sequester carbon. Therefore, the multiple and often interwoven actions that reduce VMT both reduce emissions from the transportation sector and support reductions needed in other sectors.

Legislation, such as SB 350[292] (De León and Leno, Chapter 457, Statutes of 2015), has recognized the need for CARB, the CEC, and the CPUC to work together to ensure the state's energy and climate goals are integrated in procurement decisions by load serving entities as part of Integrated Resource Plans. Moving forward, it is especially critical that similar approaches are adopted to break down silos across state agencies to ensure policies and programs are aligned with multiple state priorities outlined in this plan. Finally, supportive legislative direction, such as SB 905 that requires CARB to create the Carbon Capture, Removal, Utilization, and Storage Program, may also benefit emerging areas of policy to provide express agency authority and roles for these nascent efforts, including streamlining of permitting, while ensuring that protections for communities are in place.

Unlike previous Scoping Plans that separated out individual economic sectors, this Scoping Plan approaches decarbonization from two perspectives: (1) managing a phasedown of existing energy sources and technology and (2) ramping up, developing, and deploying alternative clean energy sources and technology over time. This approach supports a more comprehensive consideration of our energy infrastructure, the ability to repurpose existing assets, and the need to build new assets. It also provides multiple metrics beyond just the annual AB 32 GHG Inventory to better enable tracking progress. For example, it clearly demonstrates the production and distribution rates of specific types of clean energy, such as adding 4.3 GW of utility solar and 2.5 GW of storage year-over-year between now and 2035 to be on track to achieve carbon neutrality no later than 2045, and does the same for technology deployment, such as 11 million ZEVs in 2035.

The sections below include key actions to support success in the necessary transition away from fossil combustion, which is an overriding goal of this plan. The wide array of complementary and supporting actions being contemplated or to be undertaken across state government are detailed here. The broad view of actions described in this chapter thus provides context for the specific deployment of clean technology and fuels identified in the Scoping Plan Scenario described in Chapter 2. Actions identified in this Scoping Plan are based on currently known options and the latest science. As part of future Scoping Plan updates, additional clean technology and fuels may be identified and added to the mix of needed tools to continue to reduce the state's GHG emissions, support air quality co-benefits, and remove carbon from the atmosphere.

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[292] California Air Resources Board. SB 350 Electricity Sector Greenhouse Gas Planning Targets. https://ww2.arb.ca.gov/our-work/programs/sb350.

Transportation Sustainability

The transportation sector has long relied on liquid petroleum fuels as the primary energy source for internal combustion engine (ICE) vehicles, including cars, trucks, locomotives, marine equipment, and aircraft. Combustion of fossil fuels in vehicles emits significant amounts of GHGs, criteria pollutants, and toxic air contaminants. In 2019,[293] the transportation sector accounted for approximately 50 percent of statewide GHG emissions[294] and thus was by far the single largest source of carbon pollution in the state. In addition, the transportation sector accounted for over 80 percent of statewide NOx emissions and 30% of fine particulate matter emissions, including toxic diesel particulate matter.[295]

Communities adjacent to congested roadways, including ports and distribution centers, are exposed to the highest concentration of toxic pollutants from vehicles and equipment consuming fossil fuels, leading to a number of demonstrated health impacts such as respiratory illnesses, higher likelihood of cancer development, and premature death. In addition, communities located near oil extraction operations or crude oil refineries often experience higher exposure to poor air quality. While CARB's programs, along with local action, have made substantial progress over the past few decades, it is clear that California must transition away from fossil fuels to zero-emission technologies with all possible speed and pursue policies that result in less driving, in order to meet our GHG and air quality targets.

The transportation sector can be divided into three general categories: Technology, Fuels, and Vehicle Miles Traveled.

- *Technology* refers to the vehicles themselves, as well as the associated refueling infrastructure for those vehicles.
- *Fuels* refers to the energy source used to power vehicles and the facilities that produce them.
- Vehicle travel is measured as *vehicle miles traveled* (VMT), and is a product of development patterns and available transportation options.

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[293] In 2020 the state experienced shelter-in-place orders in response to the COVID-19 pandemic. The orders, and the effects of the pandemic, led to a significant year-over-year decline in transportation emissions in 2020. This means 2019 is likely a more representative year for overall transportation emissions and 2020 a likely outlier in the historical transportation emissions trend data.

[294] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf. This includes upstream oil extraction and refining emissions.

[295] CARB. California Greenhouse Gas Emission Inventory Program. https://ww2.arb.ca.gov/our-work/programs/ghg-inventory-program.

Sector Transition

Technology

Vehicles must transition to zero emission technology to decarbonize the transportation sector. Executive Order N-79-20[296] reflects the urgency of transitioning to zero emission vehicles (ZEVs) by establishing target dates for reaching 100 percent ZEV sales or fleet transitions to ZEV technology. The primary ZEV technologies available today are battery-electric and hydrogen fuel cell electric vehicles (FCEVs), both of which emit zero tailpipe GHGs, criteria pollutants, and toxic air contaminants, as they do not burn fuel. These vehicles are rapidly growing in performance, affordability, and popularity.[297] Plug-in hybrid electric vehicles also offer a limited but increasing range of zero emission operation and will play a role in the transition to ZEVs.

Light-duty passenger vehicles consume the majority of gasoline in the state—12.9 billion gallons in 2019[298]—and are well-suited for transitioning to ZEVs. EO N-79-20 calls for 100 percent ZEV sales of new light-duty vehicles by 2035, and this target is reflected in this Scoping Plan.[299] The Advanced Clean Cars II regulation fulfills the goal in the Executive Order and serves as the primary mechanism to help deploy ZEVs. A number of existing incentive programs also support this transition, including the Clean Cars 4 All Program.[300] Heavy-duty trucks are the largest source of diesel particulate matter, a toxic air contaminant that is directly linked to a number of adverse health impacts, and EO N-79-20 also sets targets for transitioning the medium- and heavy-duty fleet to zero emissions: by 2035 for drayage trucks and by 2045 for buses and heavy-duty long-haul trucks where feasible. Replacing heavy-duty vehicles with ZEV technology will significantly reduce GHG emissions and diesel PM emissions in low-income communities and communities of color adjacent to ports, distribution centers, and highways. The existing Advanced Clean Trucks regulation, paired with the proposed Advanced Clean Fleets regulation, are designed to transition a significant amount of the

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[296] Executive Department. State of California. Executive Order N-79-20. https://www.gov.ca.gov/wp-content/uploads/2020/09/9.23.20-EO-N-79-20-Climate.pdf.

[297] CARB. 2021. Public Workshop for Advanced Clean Cars II. May 6. https://ww2.arb.ca.gov/sites/default/files/2021-05/acc2_workshop_slides_may062021_ac.pdf.

[298] CARB. 2022. *Fuel Activity for California's Greenhouse Gas Inventory by Sector and Activity.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/fuel_activity_inventory_by_sector_all_00-20.xlsx.

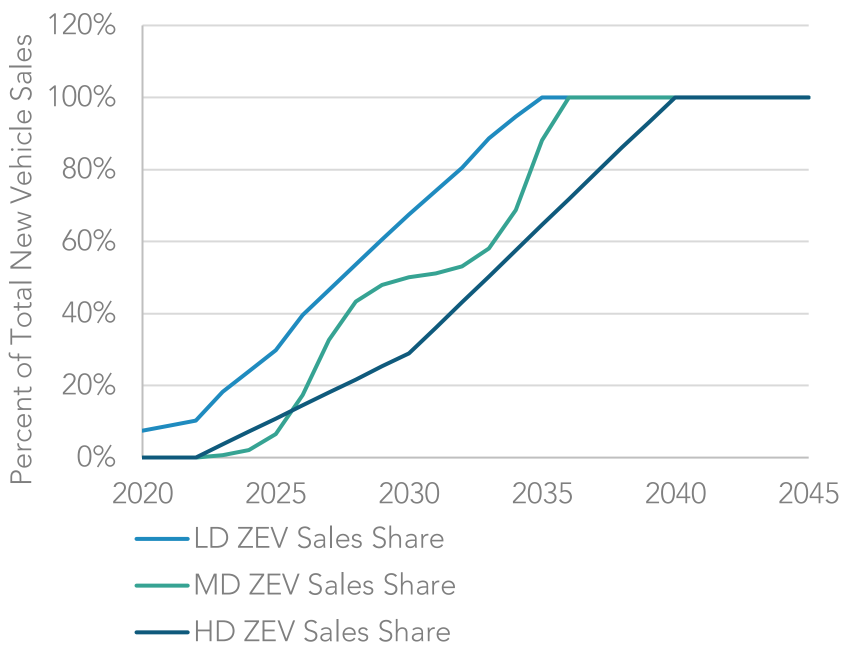
[299] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1A, with reference to the date at which all new vehicle sales are ZEVs. finalejacrecs.pdf (arb.ca.gov).

[300] CARB. Clean Cars 4 All. https://ww2.arb.ca.gov/our-work/programs/clean-cars-4-all. The Clean Vehicle Rebate Project (CVRP) also supports the transition to ZEVs. https://cleanvehiclerebate.org/en.

California truck fleet to ZEV technology. As with the LDV sector, a number of incentive programs support this transition, such as the Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP).[301]

Figure 4-1 below illustrates the pace of transition in vehicle technology needed to drastically reduce GHG emissions from vehicles. All vehicle classes reach 100 percent ZEV sales before 2045, with some achieving this well before. The ZEV technology across the vehicle classes is assumed to be primarily battery electric and hydrogen fuel cell (reflecting the primary ZEV technologies available today).[302]

Figure 4-1: Transition of on-road vehicle sales to ZEV technology in the Scoping Plan Scenario



Today, off-road vehicles also rely heavily on ICE technology. Executive Order N-79-20 sets an off-road equipment target of transitioning the entire fleet to ZEV technology by 2035, where feasible. There is a great need for both investment and innovation in the off-road space in order to develop and commercialize zero emission equipment types that meet or exceed the performance of existing equipment. A number of funding sources currently support this transition, including programs such as FARMER, Carl Moyer, and

[301] California HVIP. Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project. https://californiahvip.org/?msclkid=efaf65f2c26f11eca6bdd08ecc323864.

[302] The light-duty fleet includes more than 11 million battery electric and hydrogen fuel cell vehicles in 2035 and over 23 million battery electric and hydrogen fuel cell vehicles in 2045.

the Community Air Protection Incentives—as well as Low Carbon Transportation Incentives, including the Clean Off-Road Equipment (CORE) program. In addition, the 2021–22 California budget provided record-high allocations for funding ZEVs, including off-road equipment, and the 2022–23 budget is similarly ambitious.[303] Several regulations focused on transitioning to zero emission off-road equipment have recently been adopted or are in the works, and apply to locomotives,[304] forklifts, ocean-going vessels at berth,[305] commercial harbor craft,[306] small off-road engines,[307] and more.

Intrastate aviation relies on ICE technology today, but battery-electric and hydrogen fuel cell aviation applications are in development, along with sustainable aviation fuel. The Scoping Plan Scenario includes a transition of 20% of aviation fuel demand to ZEV technologies by 2045 and sustainable aviation fuel for the rest.

Refueling infrastructure is a crucial component of transforming transportation technology. Electric vehicle chargers and hydrogen refueling stations must become easily accessible for all drivers to support a wholesale transition to ZEV technology. Deployment of ZEV refueling infrastructure is currently supported by a number of existing local and state public funding mechanisms, the new National Electric Vehicle Infrastructure (NEVI) federal funding mechanism, California's electric utilities, the Electrify America initiative that was established in response the Volkswagen ZEV commitment, and by numerous companies, such as EVgo, ChargePoint, Tesla, Ford, FirstElement Fuel, Chevron, Shell, and Iwatani, who are investing substantial private resources into developing these networks. Private investment in reliable, affordable and ubiquitous refueling infrastructure must drive the transition as the business case for ZEVs continues to strengthen.

Strategies for Achieving Success

- Achieve 100 percent ZEV sales of light-duty vehicles by 2035[308] and medium-heavy-duty vehicles by 2040.
- Achieve a 20% zero emission target for the aviation sector.

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303 AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1C. CARB and the Administration are committed to increasing focus on transportation equity investment as was reflected in the governor's 2022–23 budget. *finalejacrecs.pdf (arb.ca.gov)*.

304 CARB. Reducing Rail Emissions in California. *https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california.*

305 CARB. Ocean-Going Vessels At Berth Regulation. *https://ww2.arb.ca.gov/our-work/programs/ocean-going-vessels-berth-regulation*.

306 CARB. CARB passes amendments to commercial harbor craft regulation. *https://ww2.arb.ca.gov/news/carb-passes-amendments-commercial-harbor-craft-regulation*.

307 CARB. Small Off-Road Engines (SORE). *https://ww2.arb.ca.gov/our-work/programs/small-off-road-engines-sore*.

308 AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1A. *finalejacrecs.pdf (arb.ca.gov)*.

- Develop a rapid and robust network of ZEV refueling infrastructure to support the needed transition to ZEVs.
- Ensure that the transition to ZEV technology is affordable for low-income households and communities of color, and meets the needs of communities and small businesses.[309]
- Prioritize incentive funding for heavy-duty ZEV technology deployment in regions of the state with the highest concentrations of harmful criteria and toxic air contaminant emissions.[310]
- Promote private investment in the transition to ZEV technology, undergirded by regulatory certainty such as infrastructure credits in the Low Carbon Fuel Standard for hydrogen and electricity[311] and hydrogen station grants from the CEC's Clean Transportation Program[312] pursuant to Executive Order B-48-18.[313]
- Evaluate and continue to offer incentives similar to those through FARMER,[314] Carl Moyer,[315] the Clean Fuel Reward Program,[316] the Community Air Protection Program,[317] and Low Carbon Transportation,[318] including CORE.[319] Where feasible, prioritize and increase funding for clean transportation equity programs.[320]
- Continue and accelerate funding support for zero emission vehicles and refueling infrastructure through 2030 to ensure the rapid transformation of the transportation sector.

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[309] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF6, in the context of communities. finalejacrecs.pdf (arb.ca.gov).
[310] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF7. finalejacrecs.pdf (arb.ca.gov).
[311] CARB. LCFS ZEV Infrastructure Crediting. https://ww2.arb.ca.gov/resources/documents/lcfs-zev-infrastructure-crediting.
[312] CEC. Clean Transportation Program. https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program.
[313] EO B-48-18 calls for 200 hydrogen refueling stations by 2025. https://www.library.ca.gov/wp-content/uploads/GovernmentPublications/executive-order-proclamation/39-B-48-18.pdf.
[314] CARB. FARMER program. https://ww2.arb.ca.gov/our-work/programs/farmer-program.
[315] CARB. Carl Moyer program. https://ww2.arb.ca.gov/our-work/programs/carl-moyer-memorial-air-quality-standards-attainment-program.
[316] California Clean Fuel Reward Program. https://cleanfuelreward.com/.
[317] CARB. Community Air Protection Program. https://ww2.arb.ca.gov/capp.
[318] CARB. Low Carbon Transportation Investments and Air Quality Improvement Program. https://ww2.arb.ca.gov/our-work/programs/low-carbon-transportation-investments-and-air-quality-improvement-program.
[319] Clean Off-Road Equipment (CORE) Voucher Incentive Program. https://californiacore.org/.
[320] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1C. finalejacrecs.pdf (arb.ca.gov).

- Evaluate and align with this Scoping Plan relevant CARB policies such as Advanced Clean Cars II,[321] Innovative Clean Transit,[322] Zero Emission Airport Shuttle,[323] California Phase 2 GHG Standards,[324] Advanced Clean Trucks, Advanced Clean Fleets, Zero Emission Forklifts,[325] In-use Locomotives,[326] the Off-Road Zero-Emission Targeted Manufacturer rule, Clean Off-Road Fleet Recognition Program, In-use Off-Road Diesel-Fueled Fleets Regulation,[327] Commercial Harbor Craft,[328] Off-Road Zero-Emission Targeted Manufacturer rule, Clean Off-Road Fleet Recognition Program, Amendments to the In-use Off-Road Diesel-Fueled Fleets Regulation,[329] carbon pricing through the Cap-and-Trade Program,[330] and the Low Carbon Fuel Standard.[331]
- Identify and address permitting and market barriers to successful rapid ZEV technology deployment while protecting public health and the environment.

Fuels

Transitioning away from conventional ICE vehicles is part of the solution, but we must ensure that an adequate supply of zero-carbon alternative fuel and distribution is available to power these vehicles. Electricity and hydrogen are currently the primary fuels for ZEVs,

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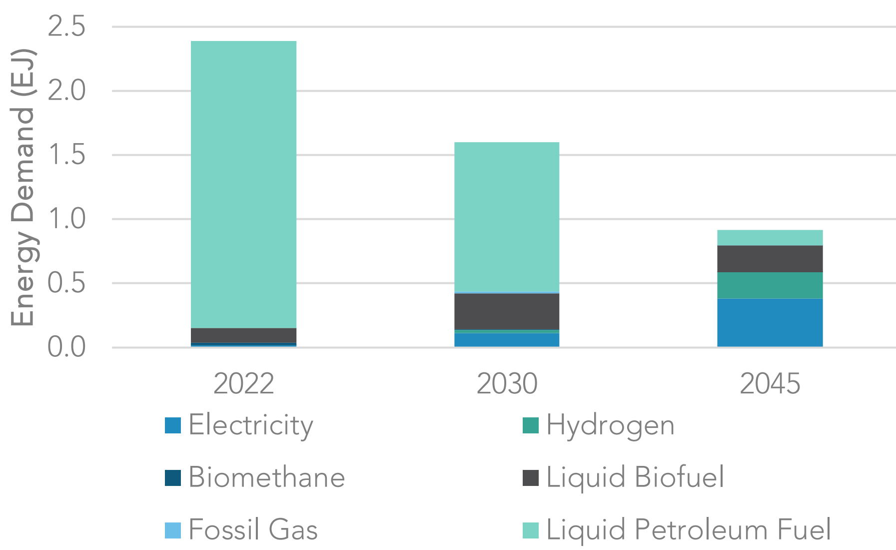
[321] CARB. Advanced Clean Cars Program. https://ww2.arb.ca.gov/our-work/programs/advanced-clean-cars-program. Cal. Code Regs., tit. 13, §§ 1900, 1961.2, 1961.3, 1961.4, 1962.2, 1962.3, 1962.4, 1962.5, 1962.6, 1962.7, 1962.8, 1965, 1968.2, 1969, 1976, 1978, 2037, 2038, 2112, 2139, 2140, 2147, 2317, 2903.
[322] CARB. Innovative Clean Transit. https://ww2.arb.ca.gov/our-work/programs/innovative-clean-transit. Cal. Code Regs., tit. 13, §§ 2023—2023.11.
[323] CARB. Zero-Emission Airport Shuttle. https://ww2.arb.ca.gov/our-work/programs/zero-emission-airport-shuttle. Cal. Code Regs., tit. 17, §§ 95690.1—95690.8.
[324] CARB. California Phase 2 Greenhouse Gas Standards. https://ww2.arb.ca.gov/our-work/programs/greenhouse-gas-standards-medium-and-heavy-duty-engines-and-vehicles/phase2. Cal. Code Regs., tit. 13, §§ 1956.8 and 2036; and Cal. Code Regs., tit. 17, §§ 95301, 95302, 95303, and 95663.
[325] CARB. Zero-Emission Forklifts. https://ww2.arb.ca.gov/our-work/programs/zero-emission-forklifts. Cal. Code Regs., tit. 17, §§ 95690.1—95690.8.
[326] CARB. Reducing Rail Emissions. https://ww2.arb.ca.gov/our-work/programs/reducing-rail-emissions-california. Proposed Cal. Code Regs., tit. 13, §§ 2478—2478.16.
[327] CARB. In-use Off-Road Diesel-Fueled Fleets Regulation. https://ww2.arb.ca.gov/our-work/programs/use-road-diesel-fueled-fleets-regulation. Cal. Code Regs., tit. 13, §§ 2449, 2449.1, 2449.2.
[328] CARB. Commercial Harbor Craft. https://ww2.arb.ca.gov/our-work/programs/commercial-harbor-craft. Cal. Code Regs., tit. 13, § 2299.5.
[329] CARB. In-use Off-Road Diesel-Fueled Fleets Regulation. https://ww2.arb.ca.gov/our-work/programs/use-road-diesel-fueled-fleets-regulation.
[330] CARB. Cap-and-Trade Program. https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program. Cal. Code Regs., tit. 17, §§ 95801 et seq.
[331] CARB. Low Carbon Fuel Standard. https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard. Cal. Code Regs., tit. 17, §§ 95480 et seq.

and both fuels must be produced using low-carbon technology and feedstocks to minimize upstream emissions.

The transition to complete ZEV technology will not happen overnight. Conventional ICE vehicles from legacy fleets will remain on the road for some time, even after all new vehicle sales have transitioned to ZEV technology. In addition, some equipment types are only now in the initial stages of development of ZEV technology for propulsion, such as commercial aircraft or ocean-going vessels. In addition to building the production and distribution infrastructure for zero-carbon fuels, the state must continue to support low-carbon liquid fuels during this period of transition and for much harder sectors for ZEV technology such as aviation, locomotives, and marine applications. Biomethane currently displaces fossil fuels in transportation and will largely be needed for hard-to-decarbonize sectors but will likely continue to play a targeted role in some fleets while the transportation sector transitions to ZEVs. Figure 4-2 provides the detail on fuels used in 2020 and the fuel mix under the Scoping Plan Scenario for 2035 and 2045.

Figure 4-2: Transportation fuel mix in 2022, 2030, and 2045 in the Scoping Plan Scenario[332]



Private investment in alternative fuels will play a key role in diversifying the transportation fuel supply away from fossil fuels. The Low Carbon Fuel Standard is the primary mechanism for transforming California's transportation fuel pool with low-carbon

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[332] See https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx for transportation fuels by year.

alternatives and has fostered a growing alternative fuel market. Partially as a result of the powerful market signals from the LCFS, fuels like renewable diesel, sustainable aviation fuel, biomethane, and electricity have all gained significant market shares and continue to displace gasoline and diesel in both on- and off-road vehicles. In addition, Executive Order N-79-20 calls on state agencies to support the transition of existing fuel production facilities away from fossil fuels and directs that this transition also protect and support workers, public health, safety, and the environment. In line with this direction, existing refineries could be repurposed to produce sustainable aviation fuel, renewable diesel, and hydrogen. This trend has already begun, and continuing to develop fuel production capacity in-state to support the energy transition while making the most efficient use of existing assets is critical to avoiding emissions leakage. If fuel demand persists after fuel production facilities have ceased operations, fuel demand will have to be met through imports.

As we transition or build new energy production facilities and infrastructure, it will be important to ensure low-income communities, tribes, and communities of color do not experience increases in existing air pollution disparities and continue to experience a reduction in the air pollution disparities that exist today. California must use the best available science to ensure that raw materials used to produce transportation fuels do not incentivize feedstocks with little to no GHG reductions from a life cycle perspective. A dramatic increase in alternative fuel production must not come at the expense of global deforestation, unsustainable land conversion, or adverse food supply impacts, to name a few examples. CARB will continue to monitor scientific findings on these topics to ensure that California policies, such as the LCFS, send the appropriate market signals and do not result in unintended consequences.[333]

Strategies for Achieving Success

- Accelerate the reduction and replacement of fossil fuel production and consumption in California.[334]
- Incentivize private investment in new zero-carbon fuel production in California.
- Incentivize the transition of existing fuel production and distribution assets to support deployment of low- and zero-carbon fuels while protecting public health and the environment.
- Invest in the infrastructure to support reliable refueling for transportation such as electricity and hydrogen refueling.

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[333] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1E. finalejacrecs.pdf (arb.ca.gov).

[334] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F3. finalejacrecs.pdf (arb.ca.gov).

- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Initiate a public process focused on options to increase the stringency and scope of the LCFS:
    - Evaluate and propose accelerated carbon intensity targets pre-2030 for LCFS.
    - Evaluate and propose further declines in LCFS post-2030 carbon intensity targets to align with this 2022 Scoping Plan.
    - Consider integrating opt-in sectors into the program.
    - Provide capacity credits for hydrogen and electricity for heavy-duty fueling.
- Monitor for and ensure that raw materials used to produce low-carbon fuels or technologies do not result in unintended consequences.[335]

Vehicle Miles Traveled

Transforming the transportation sector goes beyond phasing out combustion technology and producing cleaner fuels. Managing total demand for transportation energy by reducing the miles people need to drive on a daily basis is also critical as the state aims for a sustainable transportation sector in a carbon neutral economy. Though GHG emissions are declining due to cleaner vehicles and fuels, rising VMT can offset the effective benefits of adopted regulations.

Even under full implementation of Executive Order N-79-20 and CARB's Advanced Clean Cars II Regulations, with 100 percent ZEV sales in the light-duty vehicle sector by 2035, a significant portion of passenger vehicles will still rely on ICE technology, as demonstrated in Figure 4-2 above. Accordingly, VMT reductions will play an indispensable role in reducing overall transportation energy demand and achieving the state's climate, air quality, and equity goals. After a significant pandemic-induced reduction in VMT during 2020, passenger VMT has steadily climbed back up and is now closing in on pre-pandemic levels.[336] Driving alone with no passengers remains the primary mode of travel in California, amounting to 75 percent of the mode share for daily commute trips. Conversely, the transit industry, which was significantly impacted during

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[335] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1E. finalejacrecs.pdf (arb.ca.gov).

[336] U.S. Department of Transportation. 2021. December 2021 Traffic Volume Trends. Figure 3 - Seasonally Adjusted Vehicle Miles Traveled by Month. https://www.fhwa.dot.gov/policyinformation/travel_monitoring/21dectvt/figure3.cfm.

the lockdown months, and has struggled to recover; ridership only averages two-thirds of pre-pandemic levels,[337] [338] and service levels also lag behind.

Sustained VMT reductions have been difficult to achieve for much of the past decade, in large part due to entrenched transportation, land use, and housing policies and practices. Specifically, historic decision-making favoring single-occupancy vehicle travel has shaped development patterns and transportation policy, generating further growth in driving (and making transit, biking and walking less viable alternatives). These policies have also reinforced long-standing racial and economic injustices that leave people with little choice but to spend significant time and money commuting long distances, placing a disproportionate burden on low-income Californians, who pay the highest proportion of their wages on housing and transportation. While CARB has included VMT reduction targets and strategies in the Scoping Plan and appendices, these targets are not regulatory requirements, but would inform future planning processes. CARB is not setting regulatory limits on VMT in the 2022 Scoping Plan; the authority to reduce VMT largely lies with state, regional, and local transportation, land use, and housing agencies, along with the Legislature and its budgeting choices.

Appendix E (Sustainable and Equitable Communities) elaborates on reasons for reducing VMT and identifies a series of policies that, if implemented by various responsible authorities, could help to achieve the recommended VMT reduction trajectory included in this Scoping Plan (and related mode share increases for transit and active transportation). These policies aim to advance four strategic objectives:

1. Align current and future funding for transportation infrastructure with the state's climate goals, preventing new state-funded projects from inducing significant VMT growth and supporting an ambitious expansion of transit service and other multimodal alternatives.
2. Move funding for transportation beyond the gasoline and diesel taxes and implement fuel-agnostic pricing strategies that accomplish more productive uses of the roadway network and generate revenues to further improve transit and other multimodal alternatives.
3. Deploy autonomous vehicles, ride-hailing services, and other new mobility options toward high passenger-occupancy and low VMT-impact service models that complement transit and ensure equitable access for priority populations.
4. Encourage future housing production and multi-use development in infill locations and other areas in ways that make future trip origins and destinations

[337] U.S. Government Accountability Office. January 25, 2022. During COVID-19, Road Fatalities Increased and Transit Ridership Dipped. https://www.gao.gov/blog/during-covid-19-road-fatalities-increased-and-transit-ridership-dipped.
[338] American Public Transportation Association. APTA - Ridership Trends. https://transitapp.com/APTA.

closer together and create more viable environments for transit, walking, and biking.

The pace of change to reduce VMT must be accelerated. Certainly, structural reform will be challenging, but California has demonstrated time and again that it possesses the collective leadership and commitment to break away from ideas that no longer represent Californians' values and their aspirations for the many generations to come.

Strategies for Achieving Success

- Achieve a per capita VMT reduction of at least 25 percent below 2019 levels by 2030 and 30 percent below 2019 levels by 2045. [339]
- Reimagine new roadway projects that decrease VMT in a way that meets community needs and reduces the need to drive.
- Invest in making public transit a viable alternative to driving by increasing affordability, reliability, coverage, service frequency, and consumer experience.[340]
- Implement equitable roadway pricing strategies based on local context and need, reallocating revenues to improve transit, bicycling, and other sustainable transportation choices.[341]
- Expand and complete planned networks of high-quality active transportation infrastructure.[342]
- Channel the deployment of autonomous vehicles, ride-hailing services, and other new mobility options toward high passenger-occupancy and low VMT-impact service models that complement transit and ensure equitable access for priority populations.
- Streamline access to public transportation through programs such as the California Integrated Travel Project.
- Ensure alignment of land use, housing, transportation, and conservation planning in adopted regional plans, such as regional transportation plans (RTP)/ sustainable communities strategies (SCS), regional housing needs assessments (RHNA), and local plans (e.g., general plans, zoning, and local transportation plans), and develop tools to support implementation of these plans.

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[339] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1D. *finalejacrecs.pdf (arb.ca.gov)*.
[340] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1D. *finalejacrecs.pdf (arb.ca.gov)*.
[341] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1D. *finalejacrecs.pdf (arb.ca.gov)*.
[342] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1F. *finalejacrecs.pdf (arb.ca.gov)*.

- Accelerate infill development and housing production at all affordability levels in transportation-efficient places, with a focus on housing for lower-income residents.

Clean Electricity Grid

Much of the state's success to date in reducing GHGs is due to decarbonization of the electricity sector as a result of the RPS, SB 100 implementation, and the Cap-and-Trade Program. Moving forward, a clean, affordable, and reliable electricity grid will serve as a backbone to support deep decarbonization across California's economy. Under this Scoping Plan, the role of electricity in powering the economy will grow in almost every sector.

In 2021, 70 percent of California electricity demand was served by in-state power plants totaling about 82 GW, with the rest coming from out-of-state imports.[343] Additionally, approximately 8 GW of customer solar photovoltaic capacity has been installed to date to help with in-state demand.[344] Figure 4-3 shows the breakdown of in-state and imported sources of electricity.

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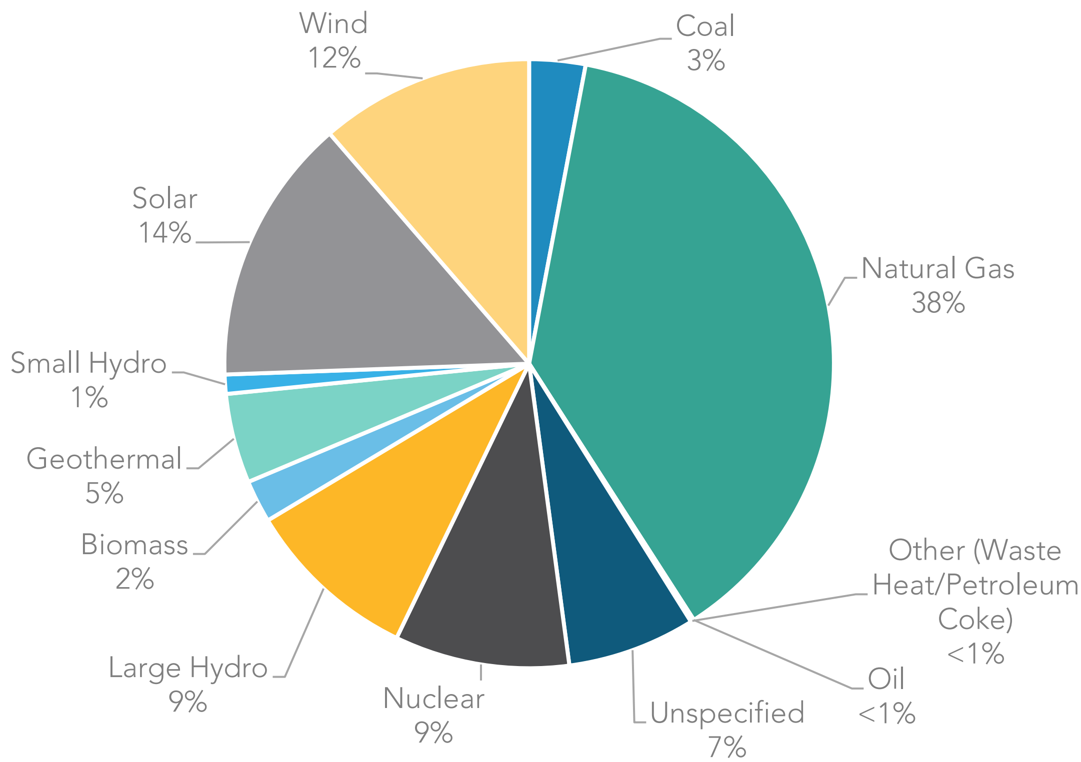
[343] CEC. 2021. Electric Generation Capacity and Energy. Data available at: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy and CEC. 2021. Total System Electric Generation. Data available at: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation. Capacity values are nameplate capacity from sources 1 MW and larger.
[344] CEC. 2021. *SB 100 Joint Agency Report Summary: Achieving 100% Clean Electricity in California, An Initial Assessment.* 10. https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity.

Figure 4-3: 2021 total system electric generation (based on GWh)[345]



Note: Imports contributing to total system generation are comprised of 58% zero-carbon energy and 42% non-renewable and unspecified energy. Percentages do not add to exactly 100 due to rounding.

In 2021, about 48 percent of electricity generation serving California came from non-renewable and unspecified[346] resources, while 52 percent came from renewable and zero-carbon resources. The state's Strategic Reliability Reserve, established in AB 205 to provide additional reliability insurance during extreme events, may make three of the fossil gas-fired OTC plants planned for retirement available to support the grid on a limited basis after 2023. The state also adopted legislation to facilitate extension of the Diablo Canyon Nuclear Power Plant for five years beyond its 2025 planned closure.[347] At the

345 *Total system generation* is the sum of all utility-scale, in-state generation, plus net electricity imports. CEC. 2021 Total System Electricity Generation. https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2021-total-system-electric-generation.
346 *Unspecified power* refers to electricity that is not traceable to a specific generating facility, such as electricity traded through open market transactions. It typically consists of a mix of resources and may include renewables.
347 In accordance with SB 846 (Dodd, Chapter 239, Statutes of 2022).

same time, the state continues to rapidly expand deployment of clean energy generation and storage resources and plan for increased electrification.[348] This is critical to reducing GHG emissions and addressing the long-term impacts of climate change.

Climate change is causing unprecedented stress on California's energy system—driving high demand and constraining supply. Heat, drought, and wildfires can both reduce electricity supply from reductions in hydropower generation and impacts on generation and transmission performance, and increase demand, especially in the evening hours when solar generation is declining.

California has experienced three straight years of energy reliability challenges, including a multi-day extreme heat event across the western United States with temperatures up to 20 degrees above normal in California, resulting in rotating outages in August 2020. In 2021, heat waves in June prompted a Grid Warning and the onset of emergency conditions, and the Bootleg Fire caused the loss of one transmission line, reducing import capability by 3,000 megawatts into the California Independent System Operator (CAISO) balancing authority area. And from August 31–September 9, 2022, a 10-day extreme heat event resulted in an unprecedented, sustained period of high peak loads in the CAISO system, averaging 47,000 MW and maxing at an all-time record of over 52,000 MW on September 6. The Western region also hit its record peak load on September 6, at 167.5 GW.

Reliable electricity service was maintained throughout the 10-day September 2022 heat wave in spite of the record breaking load levels. Factors that contributed to this outcome include the installation of over 3,500 MW of lithium-ion battery storage since summer 2020, enhanced coordination and communication within and outside of California, engagement with customer groups and other stakeholders, state actions to reduce load during critical times, and the additional capacity provided through the Strategic Reliability Reserve and other new state programs authorized in the 2022 Budget to provide load reduction and support the grid in extreme events. CEC, CPUC, CAISO, and the California Department of Water Resources will continue to build out strategies to enhance reliability in light of the increasing and compounding impacts of climate change on the electricity system.

[348] In June 2021, the CPUC adopted D.21-06-035 directing procurement of 11,500 MW of new capacity between 2023 and 2026 to ensure systemwide electric reliability as Diablo Canyon and several OTC facilities retire. It requires that, out of the 11,500 MW, 2,500 MW must be from zero-emission resources. Additionally, 2,000 MW must be long lead-time resources, with at least 1,000 MW of long-duration storage and 1,000 MW of firm capacity with zero on-site emissions or that qualifies under the RPS eligibility requirements.

While the electricity sector is using less fossil fuel due to increasing amounts of renewables,[349] existing fossil gas generation will continue to play a critical role in grid reliability until other clean, dispatchable alternatives can be deployed at scale. The integration of greater amounts of variable renewable generation resources[350] is changing power system planning and operations, and system operators need resources with flexible attributes to balance shifting supply and demand.

High levels of solar generation can lead to instances of oversupply during the middle of the day, when the sun is brightest.[351] In the evening hours, as the sun is setting, solar generation declines to zero and customers with solar generation shift back to the electric grid. In hot weather, customer demand remains high well into the summer evening period to power air conditioning, which can lead to reliability challenges.[352]

Figure 4-4 shows the energy sources used throughout one summer day in July. Renewable energy is consistent during the middle of the day, but it cannot meet all of the evening demand in the gray area. As illustrated in the figure, fossil gas generation is currently a resource that is typically ramped up to meet this evening demand as solar production begins to drop and electrical loads increase To help address this challenge, resource installations that pair solar with batteries, as well as a greater amount of battery build-out, are coming online currently and over the next five years. Nevertheless, the state's electricity grid is expected to be stressed further in the coming years by heat waves, drought, wildfires, and the growing intermittent power supply from renewables. California must accelerate deployment of diverse clean energy resources to maintain reliability and affordability in the face of climate change.

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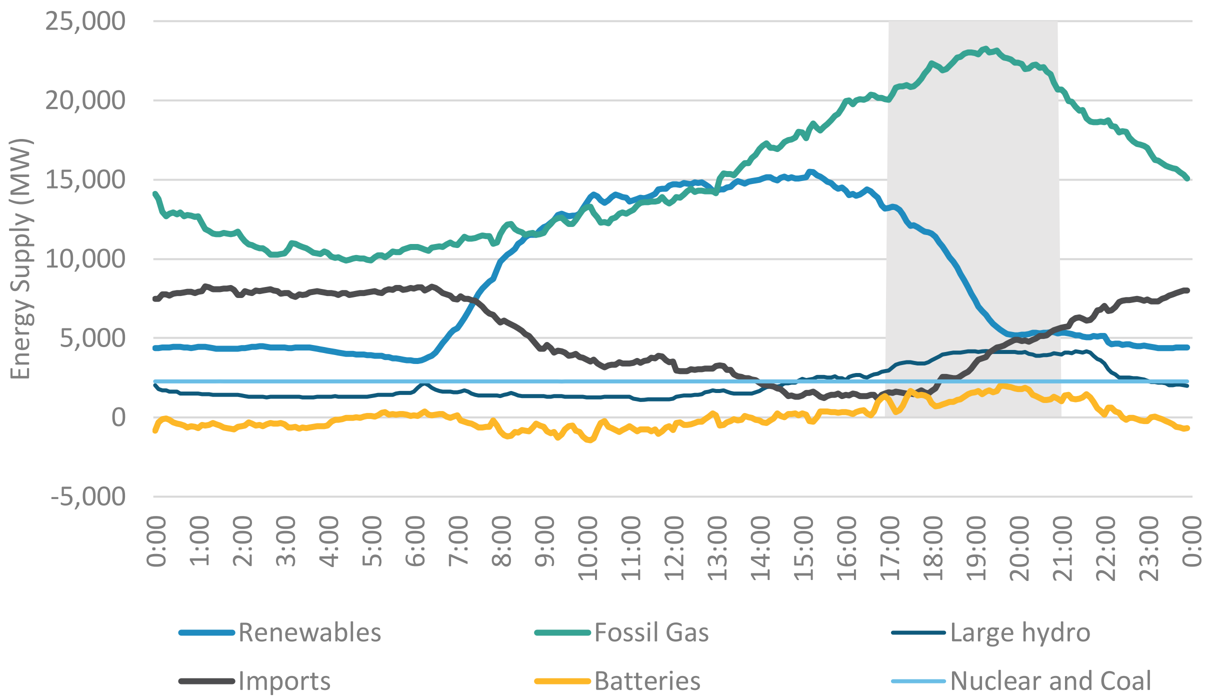
[349] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

[350] A *variable renewable generation resource* is a renewable source of electricity that is non-dispatchable due to its fluctuating nature and only produces electricity when weather conditions are right, such as when the sun is shining or the wind is blowing. Renewable resources that can be controlled and are dispatchable include geothermal, biomass, and dam-based hydroelectric power.

[351] *Brightness* is used colloquially here; solar energy depends on insolation (e.g., sun-hours), which is the measurement of cumulative solar energy that reaches an area over a period of time.

[352] CAISO, CPUC, and CEC. 2021. *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave.* http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

Figure 4-4: Electricity supply trend by resource for a California summer day, July 2022



Sector Transition

Decarbonizing the electricity sector is a crucial pillar of this Scoping Plan. It depends on both using energy more efficiently and replacing fossil-fueled generation with renewable and zero carbon resources, including solar, wind, energy storage,[353] geothermal, biomass, and hydroelectric power. The RPS Program[354] and the Cap-and-Trade Program continue to incentivize dispatch of renewables over fossil generation to serve state demand. SB 100 increased RPS stringency to require 60 percent renewables by 2030 and for California to provide 100 percent of its retail sales[355] of electricity from renewable and zero-carbon resources by 2045. Furthermore, SB 1020 has added interim targets to

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[353] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF1, NF2. *finalejacrecs.pdf (arb.ca.gov)*.

[354] The CEC estimates that 36 percent of California's 2019 retail electricity sales was served by RPS-eligible renewable resources (see CPUC. 2021. CPUC Perspectives on Electric Sector Decarbonization. *https://ww2.arb.ca.gov/sites/default/files/2021-11/CPUC-sp22-electricity-ws-11-02-21.pdf*).

[355] SB 100 speaks only to retail sales and state agency procurement of electricity. The *2021 SB 100 Joint Agency Report* interprets this to mean that other loads—wholesale or non-retail sales and losses from storage and transmission and distribution lines—are not subject to the law.

SB 100's policy framework to require renewable and zero-carbon resources to supply 90 percent of all retail electricity sales by 2035 and 95 percent of all electricity retail sales by 2040; the governor has asked the CEC to establish a planning goal of at least 20 GW of offshore wind by 2045; and the governor directed that state agencies plan for an energy transition that avoids the need for new fossil gas capacity to meet California's long-term energy goals.[356] In addition to grid-level resources, state efforts have supported rapid growth of the distributed solar industry through key actions like the California Solar Initiative (SB 1, Murray, Chapter 132, Statues of 2006).[357] Steps to commercialize microgrids powered by clean resources[358] are also being examined as part of SB 1339 (Stern, Chapter 566, Statutes of 2018).[359]

California also continues to advance its appliance and building energy efficiency standards to reduce growth in electricity consumption and meet the SB 350 goal to double statewide energy efficiency savings in electricity and fossil gas end uses[360] by 2030. In 2018, the CEC adopted a building energy efficiency code requiring most new homes to have solar photovoltaic systems[361] (or be powered by a solar array nearby) starting January 1, 2020. In 2019, California reached the milestone of 1 million solar rooftop installations.

Increased transportation and building electrification and continued policy commitment to behind-the-meter solar and storage will continue to drive growth of microgrids and other distributed energy resources (DER).[362] The CPUC's High-DER proceeding is examining how to prepare the electric grid for a high DER future by determining how to integrate

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[356] Newsom, Gavin. July 22, 2022. Letter from Governor Newsom to CARB Chair Liane Randolph. *https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf*.

[357] More information on the program, which closed in 2016, can be found on the CPUC website, including annual program assessment reports, at: *https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/demand-side-management/california-solar-initiative*.

[358] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, In part (NF2, NF13). *finalejacrecs.pdf (arb.ca.gov)*.

[359] CPUC. Resiliency and Microgrids. *https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/resiliency-and-microgrids*.

[360] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF1, ES1. *finalejacrecs.pdf (arb.ca.gov)*.

[361] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF2. *finalejacrecs.pdf (arb.ca.gov)*.

[362] Distributed energy resources include rooftop solar and other distributed renewable generation resources, energy storage, electric vehicles, time variant and dynamic electric rates, flexible load management, demand response, and energy efficiency technologies.

millions of DERs within the distribution grid to maximize societal and ratepayer benefits from DERs while ensuring grid reliability and affordable rates.[363]

SB 350 also aims to connect long-term planning for electricity needs with the state's climate targets. This is primarily accomplished through CARB's establishment of 2030 GHG emissions targets for the electricity sector in general and for each electricity provider, which inform the CPUC and publicly owned utilities' integrated resource planning. A GHG planning target range of 30 to 53 MMTCO_2e—informed by the 2017 Scoping Plan—was originally developed and adopted by CARB in 2018. In its 2021 IRP planning cycle, the CPUC adopted a 38 MMT GHG target for the electricity sector in 2030, which drops to 35 MMT in 2032.[364]

The Scoping Plan Scenario incorporates SB 350's energy efficiency doubling goal, aligns with the CPUC's IRP 2030 GHG target and latest GHG emissions benchmarks through 2035,[365] the governor's 20 GW offshore wind and no new gas generation[366] goals, and SB 100's 2030 RPS and 2045 zero-carbon retail sales targets to reduce dependence on fossil fuels in the electricity sector by transitioning substantial energy demand to renewable and zero-carbon resources.[367] As described in Chapter 2, CCS is applied in limited sectors, including on 16.7 MMT of CO_2 from existing fossil gas electricity generation in 2045, to ensure the state achieves the 85 percent reduction in anthropogenic emissions required by AB 1279. Continued transition to renewable and

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[363] The High-DER proceeding is one of four "anchor" proceedings in the CPUC's DER Action Plan 2.0 and is within the Action Plan's infrastructure track. Information on the High-DER proceeding is available at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning. The Action Plan can be accessed at: https://www.cpuc.ca.gov/about-cpuc/divisions/energy-division/der-action-plan.

[364] The February 10, 2022, Decision 22-02-004 by the CPUC adopts the 2021 Preferred System Plan, completing the 2019–21 IRP cycle. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M451/K412/451412947.PDF. The Decision requires load serving entities to submit plans in the next IRP cycle detailing how they will meet their proportionate share of a 30 MMT electric sector target, as well as a 38 MMT GHG target.

[365] June 15, 2022, Administrative Law Judge's Ruling for 2022 integrated resource plan filings specifies the need for GHG targets to plan for in 2035 to continue progress toward the 2045 goal. The ruling proposes a straight-line projection from the GHG planning target for 2030. Corresponding to the adopted Preferred System Plan in D.22-02-004, 38 MMT in 2030 leads to a target of 30 MMT in 2035. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M485/K625/485625915.PDF.

[366] The governor's July 22, 2022, letter specifies no new gas generation but does not place any constraints on existing gas resources. Therefore, for purposes of RESOLVE electricity sector modeling, existing gas capacity is an available resource that is able to be reduced over time based on announced retirements or if selected for retirement by the model.

[367] CARB. 2021. PATHWAYS Scenario Modeling: 2022 Scoping Plan Update – Attachment B: Generation Technologies to be included in Modeling. https://ww2.arb.ca.gov/sites/default/files/2021-12/Revised_2022SP_ScenarioAssumptions_15Dec.pdf.

zero-carbon electricity resources will enable electricity to become a zero-carbon substitute for fossil fuels across the economy.

Figure 4-5 shows the modeled resource capacity to meet the SB 100 retail sales target.[368] Energy efficiency moderates some of the need for additional electricity generation. However, that is quickly surpassed by growing electricity demand of 26 percent by 2030 and 76 percent by 2045 compared to today (2022) from increased population and electrification of other sectors, as shown in Figure 4-6. The estimated resource build needed to meet this level of demand amounts to approximately 72 GW of utility solar[369] and 37 GW of battery storage by 2045. Annual build rates (over the 2022–2035 period) for the Scoping Plan Scenario will need to increase by about 60 percent and over 700 percent for utility solar and battery storage, respectively, compared to historic maximum rates.[370] To reach the 2045 target, the state will need to quadruple its current level of wind and solar capacity. This does not include capacity associated with hydrogen production nor mechanical CDR, which was modeled off-grid; assuming hydrogen production via electrolysis, this would roughly be equivalent to an additional 10 GW[371] of solar generation needed in 2045, and an additional 64 GW of solar generation for direct air capture in 2045. The scale of solar and battery build rates needed could be reduced through the commercialization of new zero-carbon technologies.

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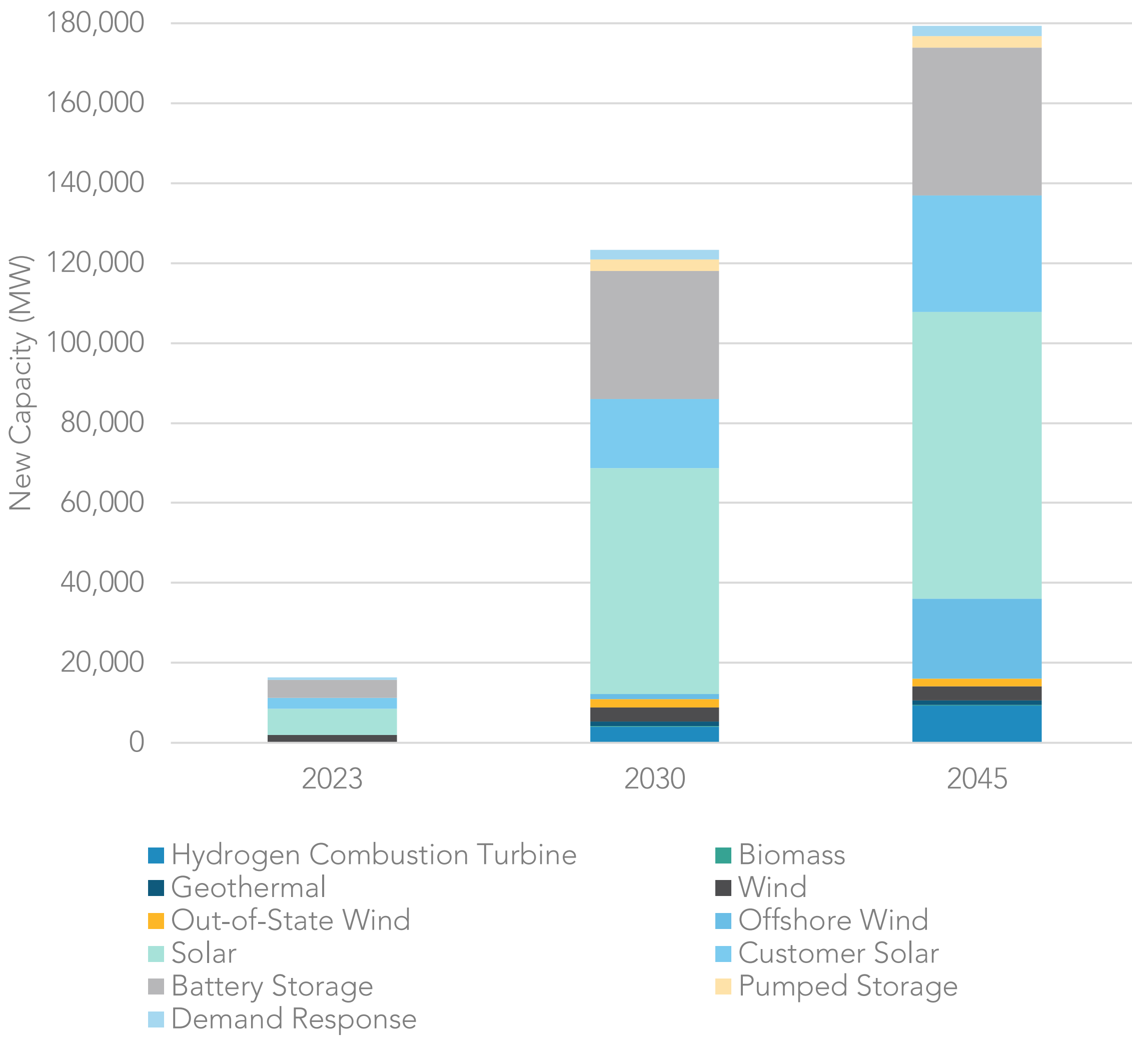
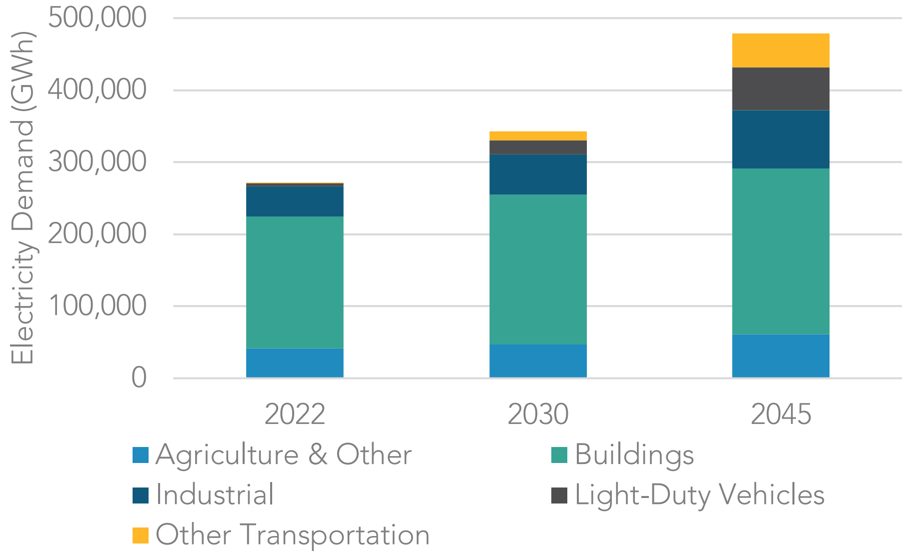
[368] SB 846 requires that load-serving entities exclude energy, capacity, or any attribute from the Diablo Canyon power plant in their resource plans. The Scoping Plan Scenario excludes energy, capacity, or any attribute from the Diablo Canyon power plant after the prior planned retirement date of 2025.
[369] The amount of additional customer solar included in the Scoping Plan Scenario is 29,208 MW by 2045.
[370] E3. 2022. CARB Scoping Plan: AB32 Source Emissions Final Modeling Results. PowerPoint. *https://ww2.arb.ca.gov/sites/default/files/2022-11/SP22-MODELING-RESULTS-E3-PPT.pdf*. Build rates are from EIA data historical builds in the 2011–2021 time frame.
[371] The estimate does not include hydrogen production assumed to be produced with bioenergy with carbon capture and storage (BECCS) and steam methane reforming (SMR).

Figure 4-5: Projected new electricity resources needed by 2045 in the Scoping Plan Scenario[372]



[372] See https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx for the capacity build-out by resource type.

Figure 4-6: Electric loads in 2022, 2030 and 2045 for the Scoping Plan Scenario[373]



This transformation will drive investments in a large fleet of generation and storage resources but will also require significant transmission to accommodate these new capacity additions. Transmission needs include high-voltage lines to access out-of-state resources and major in-state generation pockets. In consideration of typical 8- to 10-year lead times for many projects, the CAISO published its first 20-Year Transmission Outlook to inform transmission planning focused on meeting the needs identified through the 2021 SB 100 Joint Agency Report process. The outlook calls for significant transmission development to access offshore wind and out-of-state wind and reinforce the existing CAISO footprint at an estimated cost of $30.5 billion.[374]

Presently, fossil gas power plants provide about 75 percent of the flexible capacity for grid reliability as more renewable power enters the system. Moving forward, other resources such as storage and demand-side management are essential to maintain reliability with high concentrations of renewables. Hydrogen produced from renewable resources and renewable feedstocks can serve a dual role as a low-carbon fuel for existing combustion turbines or fuel cells, and as energy storage for later use. Reliability

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[373] *Other Transportation* includes all non-light-duty vehicles and reflects electrification of modes like passenger and freight rail, aviation, and ocean-going vessels.
[374] CAISO. 2022. *20 Year Transmission Outlook.* http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf.

also can be supported through increased coordination and markets in the interconnected western power grid; this is already helping to better integrate renewables.[375]

Strategies for Achieving Success

- Use long-term planning processes (Integrated Energy Policy Report, IRP, CAISO Transmission Planning Process, AB 32 Climate Change Scoping Plan) to support grid reliability and expansion of renewable and zero-carbon resource and infrastructure deployment.
- Complete systemwide and local reliability assessments across CAISO and other balancing authority areas, using realistic assumptions for land use, build rates, statewide and distribution system level constraints, and energy needs. Such assessments should be completed before state agencies update their electricity sector GHG targets.
- Prioritize actions to mitigate impacts to electricity reliability and affordability and provide sufficient flexibility in the state's decarbonization roadmap for adjustments as may be needed.
- Facilitate long lead-time resource development through the IRP and the SB 100 interagency process and through technology development and demonstration funding[376] that includes resources such as long-duration energy storage and hydrogen production.
- Continue coordination between energy agencies and energy proceedings to maximize opportunities for demand response.
- Continue to explore the benefits of regional markets to enhance decarbonization, reliability, and affordability.
- Address resource build-out challenges, including permitting, interconnection, and transmission network upgrades.
- Explore new financing mechanisms and rate designs to address affordability.[377]
- Per SB 350, double statewide energy efficiency savings in electricity and fossil gas end uses by 2030, through a combination of energy efficiency and fuel substitution actions.[378]
- Per SB 100 and SB 1020, achieve 90 percent, 95 percent, and 100 percent

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[375] CEC. 2021. *2021 SB 100 Joint Agency Report – Achieving 100 Percent Clean Electricity in California: An Initial Assessment.* Publication Number: CEC-200-2021-001.

[376] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, ES2. The committee recommendation speaks specifically to offshore wind production. *finalejacrecs.pdf (arb.ca.gov)*.

[377] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF30. *finalejacrecs.pdf (arb.ca.gov)*.

[378] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF1, NF2. *finalejacrecs.pdf (arb.ca.gov)*.

renewable and zero-carbon retail sales by 2035, 2040, and 2045, respectively.

- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Target programs and incentives to support and improve access to renewable and zero-carbon energy projects (e.g., rooftop solar, community owned or controlled solar or wind, battery storage, and microgrids) for communities most at need, including frontline, low-income, rural, and indigenous communities.[379]
- Prioritize public investments in zero-carbon energy projects to first benefit the most overly burdened communities affected by pollution, climate impacts, and poverty.[380]

Sustainable Manufacturing and Buildings

Fossil gas is the primary gaseous fossil fuel used to produce heat at industrial facilities, as well as in residential and commercial buildings. In buildings, space and water heating, cooking, and clothes drying all rely on gaseous fuels today. Industrial processes that require heat for conventional boilers and other processes also rely on gaseous fuels. Refineries rely on fossil gas and other gaseous fossil fuels, like liquefied petroleum gas and refinery fuel gas, and fossil gas is also used to generate electricity, as discussed earlier.

Gaseous fossil fuel use can be displaced by four primary alternatives: zero-carbon electricity, solar thermal heat, hydrogen, and biogas/biomethane. Displacing gaseous fossil fuel use can yield indoor air quality benefits, protect public health and property from unexpected fossil gas leaks, and reduce short-lived climate pollutants, which are many times more potent in affecting climate change than CO_2. The Scoping Plan Scenario reduces dependence on fossil gas in the industrial and building sectors by transitioning substantial energy demand to alternative fuels. Reducing fossil gas combustion also will help toward achieving our air quality and equity goals by reducing pollution in neighboring areas and communities. In addition, reduced dependence on gasoline and diesel in the transportation sector diminishes the need for gaseous fossil fuels to support oil and gas production and petroleum refining operations as those are phased down relative to the demand.

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[379] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF2, NF9, NF11, NF12, NF13. finalejacrecs.pdf (arb.ca.gov).

[380] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF14. finalejacrecs.pdf (arb.ca.gov).

Sector Transition

Industry

California's industrial sector contributes significantly to the state's economy, with a total output from manufacturing in 2019 of $324 billion (10.4 percent of the state total)[381] and employment of 1,222,000 manufacturing jobs (7.6 percent of the total state workforce).[382] California industry includes a diverse range of facilities, including cement plants, refineries, glass manufacturers, oil and gas producers, paper manufacturers, mining operations, metal processors, and food processors. Combustion of fossil gas, other gaseous fossil fuels, and solid fossil fuels provide energy to meet three broad industry needs: electricity, steam, and process heat. Non-combustion emissions result from fugitive emissions and from the chemical transformations inherent to some manufacturing processes. About 20 percent of the GHG emissions from the industrial sector are non-combustion emissions.

Decarbonizing industrial facilities depends upon displacing fossil fuel use with a mix of electrification, solar thermal heat, biomethane, low- or zero-carbon hydrogen, and other low-carbon fuels to provide energy for heat and reduce combustion emissions. Emissions also can be reduced by implementing energy efficiency measures and using substitute raw materials that can reduce energy demand and some process emissions. Some remaining combustion emissions and some non-combustion CO_2 emissions can be captured and sequestered. The strategy employed will depend on the industrial subsector and the specific processes utilized in production. The left side of Figure 4-7 illustrates the fuels used to meet industrial manufacturing energy demand in 2020. Industrial manufacturing energy demand needs to transition to the fuel mix shown for 2035 and 2045. The right side of Figure 4-7 illustrates the fuel mix needed to meet the energy demand of oil and gas extraction and petroleum refining operations for the same years. Energy demand in this portion of the industrial sector declines along with decreased demand for gasoline and diesel in the transportation sector. In both figures there is a continuing demand for fossil gas due to lack of non-combustion technologically feasible or cost-effective alternatives for certain industrial sectors. Policies that support decarbonization strategies like electrification, use of renewable energy, and transition to alternative fuels are needed.

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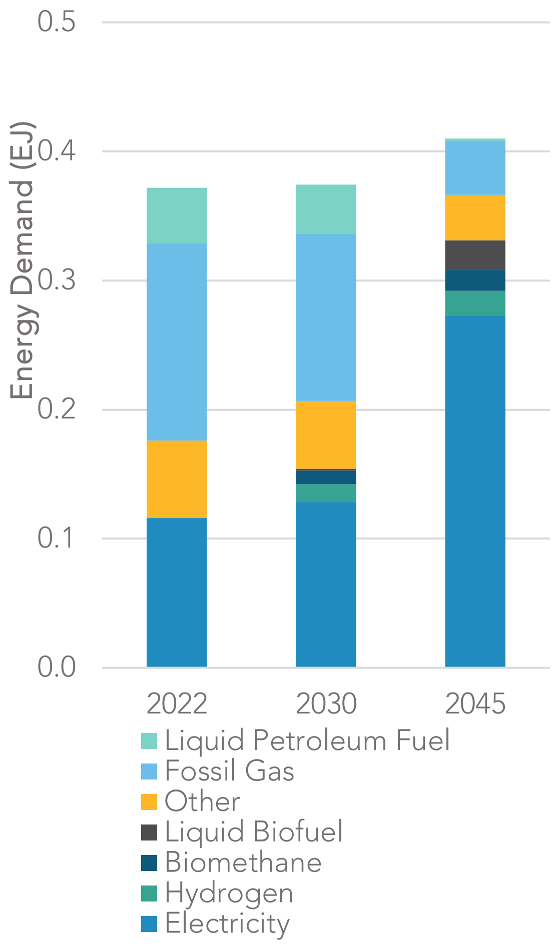
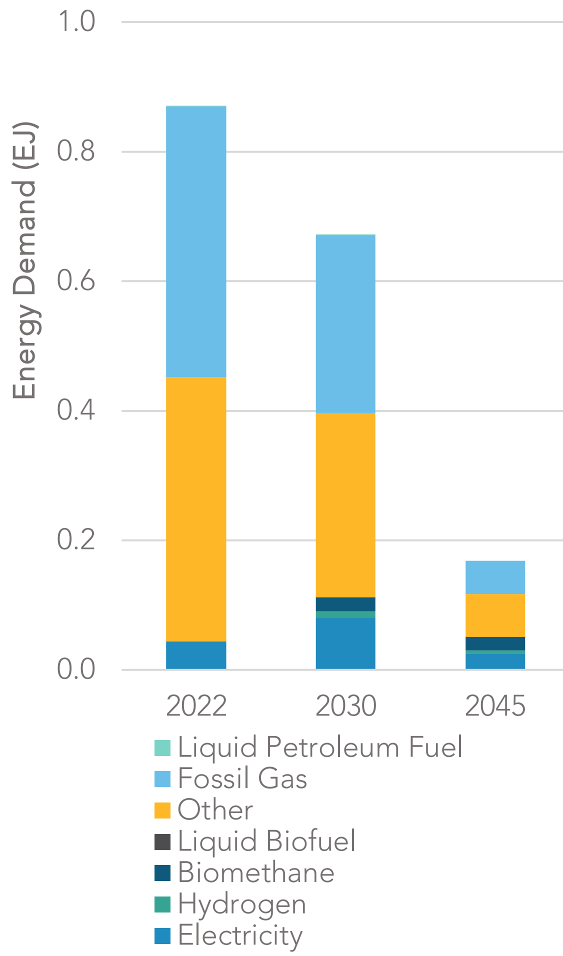
[381] National Association of Manufacturers (NAM). 2021 California Manufacturing Facts. https://www.nam.org/state-manufacturing-data/2021-california-manufacturing-facts/.

[382] NAM. 2021 California Manufacturing Facts. https://www.nam.org/state-manufacturing-data/2021-california-manufacturing-facts/.

Figure 4-7: Final energy demand in industrial manufacturing (left) and in oil and gas extraction and petroleum refining (right) in 2022, 2030, and 2045 in the Scoping Plan Scenario[383]





Electrification and solar thermal heat are best-suited to industrial processes that have relatively low heat requirements, such as food processors, paper mills, and industries that use low-pressure steam in their processes. Approaches could include replacing fossil gas boilers with electric boilers, process heaters with industrial electric heat pumps, steel forging furnaces with induction heaters, and implementing other sector-specific process electrification. Under current rate structures for industrial electricity and fossil gas in

[383] *Other* fuel in the industrial manufacturing sector is primarily coke and coal for cement production. *Other* fuel in the petroleum refining sector is primarily fossil gas associated with refining petroleum products.

California, most projects to electrify a fossil gas-powered industrial process will face operating cost barriers and potential reliability concerns. Microgrids powered by renewable resources and with battery storage are emerging as a key enabler of electrification and decarbonization at industrial facilities.

There are fewer commercially available and economically viable electrification options to replace industrial processes that require higher-temperature heat. For these processes, onsite combustion may continue to be needed, and decarbonization will require fuel substitution to hydrogen,[384] biomethane, or other low-carbon fuels. Fuel substitution and continued combustion will require monitoring and mitigation of any potential air quality impacts, especially in low-income and communities of color which already face disproportionate air pollution burdens. Industries in California with high heat needs include steel forging, glass manufacturing, and industries with calcination processes, such as manufacturing lime and cement.

Onsite emissions from cement manufacturing derive from two main sources: (1) fuel combustion to heat the kiln to a very high temperature and (2) process CO_2 emissions from the chemical transformation of limestone. Over 60 percent of emissions from the sector are process emissions unrelated to fuel use, and most emissions related to fuel use are from coal and petroleum coke combustion. Process emissions from cement manufacturing are significant and will continue even if the sector were to operate using only zero-carbon fuels; thus carbon capture and use/sequestration will be a likely component of any strategy to fully decarbonize cement manufacturing. There are additional opportunities to reduce GHG emissions from cement manufacturing via the combination of fuel-switching to low-carbon fuels (e.g., biomethane, municipal solid waste, biochar), increased blending of non-clinker materials, and efficiency improvements. High technological and economic barriers exist to electrifying kiln process heat at cement plants, as clinker production requires temperatures in excess of 1,500°C. There are potential decarbonization opportunities throughout the value chain of cement use, including in cement manufacturing, concrete mixing, and construction practices.[385] SB 596 (Becker, Chapter 246, Statutes of 2021), which was signed by Governor Newsom in September 2021, requires CARB to develop a comprehensive strategy for cement use in California to achieve a GHG intensity 40 percent below 2019 levels by 2035, and net-zero emissions by 2045.

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[384] Griffiths, Steve, Benjamin K. Sovacool, Jinsoo Kim, Morgan Bazilian, and Joao M. Uratani. 2021. "Industrial decarbonization via hydrogen: A critical and systematic review of developments, socio-technical systems and policy options." *Energy Research & Social Science* 80. 102208, ISSN 2214-6296. *https://doi.org/10.1016/j.erss.2021.102208*.

[385] California Nevada Cement Association. Achieving Carbon Neutrality in the California Cement Industry. *https://cncement.org/attaining-carbon-neutrality*.

Oil and gas extraction and refining make up over half of California's industrial GHG emissions. Reduced demand for transportation fossil fuels corresponds to reduced supply of fossil gas and other gaseous fossil fuels for refineries to produce these fuels. Some refining operations will continue to operate to produce fossil fuel for the remaining transportation energy demands, along with renewable diesel and sustainable aviation fuel, as discussed in the Transportation Sustainability section of this chapter.

Across industrial subsectors and processes, California facilities also could realize significant reductions in GHG emissions and energy-related costs by implementing advanced energy efficiency projects and tools.[386] While enhanced operation and maintenance practices are typical at industrial facilities, additional strategic energy management practices offer greater efficiency gains by focusing on setting goals, tracking progress, and reporting results.

Strategies for Achieving Success

- Maximize air quality benefits using the best available control technologies for stationary sources in communities most in need, including frontline, low-income, disadvantaged, rural, and tribal communities.[387]
- Prioritize alternative fuel transitions first in communities most in need, including frontline, low-income, disadvantaged, rural, and tribal communities.[388]
- Invest in research and development and pilot projects to identify options to reduce materials and process emissions along with energy emissions in California's industrial manufacturing facilities, leveraging programs like the CEC's Electric Program Investment Charge (EPIC).[389]
- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Support electrification with changes to industrial rate structures.
- Develop infrastructure for CCS and hydrogen production to reduce GHG emissions where cost-effective and technologically feasible non-combustion alternatives are not available.
- Implement SB 905.

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[386] Therkelsen, Peter, Aimee McKane, Ridah Sabouini, and Tracy Evans. 2013. *Assessing the Costs and Benefits of the Superior Energy Performance Program.* U.S Department of Energy. https://www.osti.gov/servlets/purl/1165470.
[387] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT14. *finalejacrecs.pdf (arb.ca.gov)*.
[388] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT15. *finalejacrecs.pdf (arb.ca.gov)*.
[389] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, M20. *finalejacrecs.pdf (arb.ca.gov)*.

- Establish markets for low-carbon products and recycled materials using Buy Clean California Act and other mechanisms relying on robust data
- Develop a net-zero cement strategy to meet SB 596 targets for the GHG intensity of cement use in California.
- Continue to leverage energy-efficiency programs, including the U.S. DOE's ENERGY STAR program,[390] U.S. DOE's Superior Energy Performance program,[391] and ISO 50001.[392]
- Evaluate and continue to offer incentives to install energy efficiency and renewable energy technologies through programs such as CPUC decisions as part of rulemaking R.19-09-009[393] and the CEC's Food Production Investment Program (FPIP) and EPIC programs.[394]
- Leverage low-carbon hydrogen programs, including the Bipartisan Infrastructure Law, for regional hydrogen hubs, hydrogen electrolysis, and hydrogen manufacturing and recycling.
- Evaluate the role of hydrogen in meeting GHG emission reductions, including policy recommendations regarding the use of hydrogen in California as required by SB 1075.
- Address cost barriers to promote low-carbon fuels for hard-to-electrify industrial applications.

Buildings

Buildings have cross-sector interactions that influence our public health and well-being and affect land use and transportation patterns, energy use, water use, and indoor and outdoor environments.[395] There are about 14 million existing homes and over 7.5 billion square feet of existing commercial buildings[396] in California. Fossil gas supplies about half of the energy consumed by end uses in these buildings. In addition to GHG emissions, fossil gas usage in buildings also produces CO_2, NOx, $PM_{2.5}$, and

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[390] ENERGY STAR. ENERGY STAR Guidelines for Energy Management. https://www.energystar.gov/buildings/tools-and-resources/energy-star-guidelines-energy-management.

[391] Energy.gov. Superior Energy Performance 50001. https://www.energy.gov/eere/amo/superior-energy-performance.

[392] ISO. ISO 50001 Energy Management. https://www.iso.org/iso-50001-energy-management.html.

[393] CPUC. January 14, 2021. CPUC Adopts Strategies to Help Facilitate Commercialization of Microgrids Statewide. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M360/K370/360370887.PDF.

[394] Bailey, Stephanie, David Erne, and Michael Gravely. 2021. *Final 2020 Integrated Energy Policy Report Update, Volume II: The Role of Microgrids in California's Clean and Resilient Energy Future, Lessons Learned From the California Energy Commission's Research.* California Energy Commission. Publication Number: CEC-100-2020-001-V2-CMF.

[395] See Appendix F (Building Decarbonization).

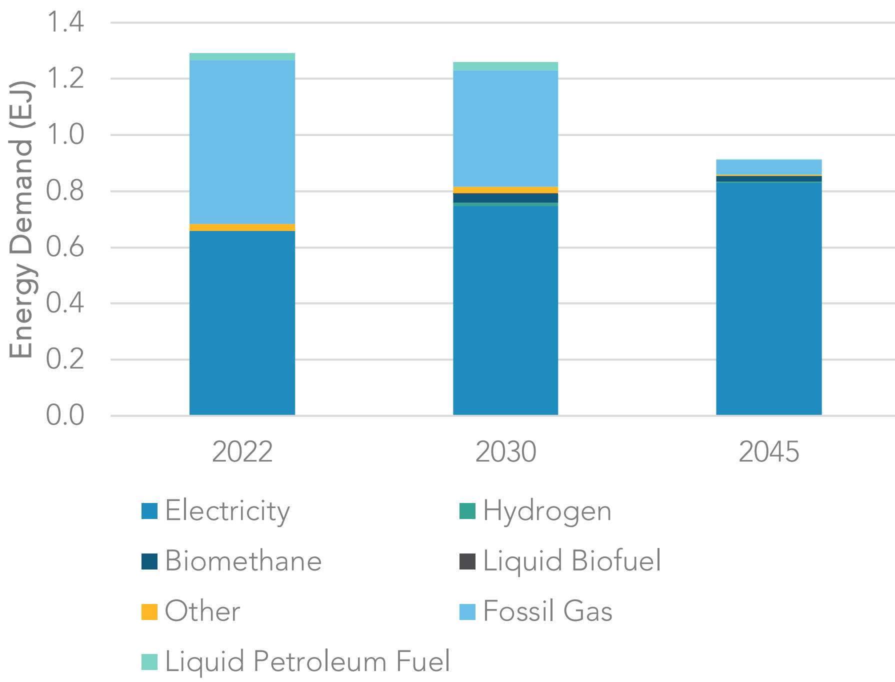
[396] CEC. 2021. California Building Decarbonization Assessment. https://efiling.energy.ca.gov/GetDocument.aspx?tn=239311&DocumentContentId=72767.

formaldehyde.[397] Each year, about 120,000 new homes[398] and more than 100 million-square feet[399] of commercial buildings are newly constructed across California. These new buildings will represent between a third to half of the total building stock by mid-century.

Achieving carbon neutrality must include transitioning away from fossil gas in residential and commercial buildings, and will rely primarily on advancing energy efficiency while replacing gas appliances with non-combustion alternatives. This transition must include the goal of trimming back the existing gas infrastructure so pockets of gas-fueled residential and commercial buildings do not require ongoing maintenance of the entire limb for gas delivery. Blending low-carbon fuels such as hydrogen and biomethane into the pipeline further displaces fossil gas. Pipeline safety and reliability must be evaluated to accommodate low-carbon fuels. Figure 4-8 illustrates the energy Californians use in buildings at present compared with the Scoping Plan Scenario, which introduces alternatives to fossil gas. In that scenario almost 90 percent of energy demand is electrified by 2045, and the remaining energy demand is met with combustion of hydrogen, biomethane, and fossil gas.

[397] Zhu, Yifang, et al. 2020. *Effects of Residential Gas Appliances on Indoor and Outdoor Air Quality and Public Health in California.* UCLA Fielding School of Public Health Department of Environmental Health Sciences.
[398] Construction Industry Research Board. 2018. Annual Building Permit Summary. http://www.cirbreport.org.
[399] Delforge, Pierre. August 11, 2021. California Forging Ahead on Zero Emission Buildings. Blog. NRDC. https://www.nrdc.org/experts/pierre-delforge/california-forging-ahead-zero-emission-buildings.

Figure 4-8: Final energy demand in buildings in 2022, 2030, and 2045 in the Scoping Plan Scenario[400]



This transition is achieved when all new buildings constructed include non-combustion appliances, and appliances in existing buildings are replaced at the end of their useful life with non-combustion alternatives. Currently, electric alternatives, combined with the decarbonizing of California's grid, are the most effective alternatives, and the Scoping Plan Scenario modeled these alternatives. The Scoping Plan Scenario assumes three million all-electric and electric-ready homes by 2030 and seven million by 2035. Figure 4-9 illustrates the pace at which electric space heating appliance sales increase and gas space heating appliance sales decrease in residences in the Scoping Plan Scenario, such that by 2035 100 percent of residential home appliance sales are electric. By 2030 over six million electric heat pumps are installed statewide. The residential electric space heating appliance sales increases rapidly in the near term as new all-electric buildings are constructed and as existing buildings are renovated to utilize electric appliances. A similar transition is envisioned for other home appliances. Commercial buildings also will undergo a transition away from gas appliances to electric appliances, achieving 80 percent sales of all-electric appliances by 2035 and 100 percent by 2045. Appendix F (Building Decarbonization) describes a holistic policy approach to rapidly grow the

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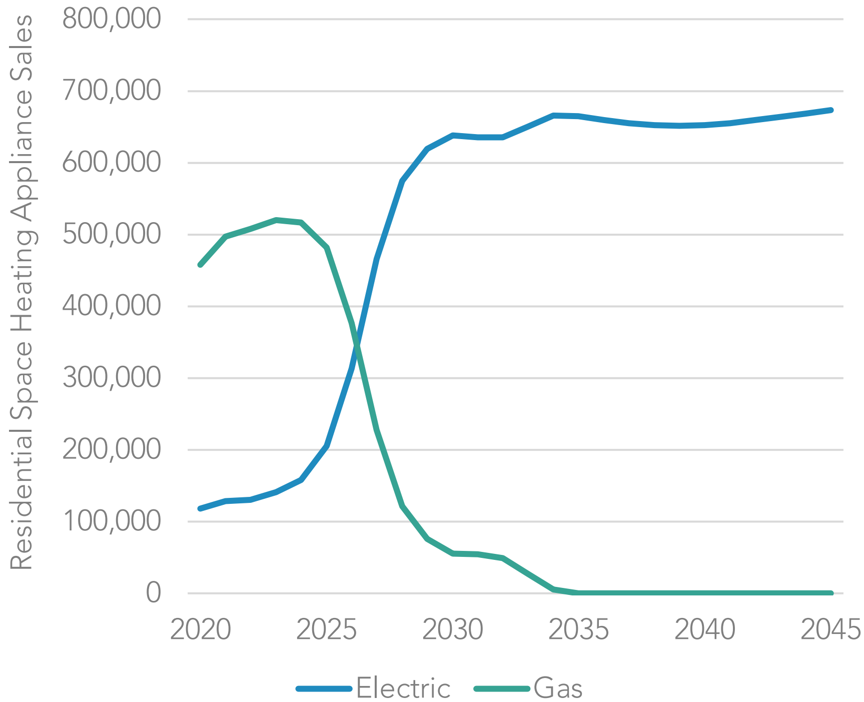
[400] *Other* fuel in the buildings sector is primarily liquid petroleum gas and waste heat.

number of zero emission appliances and buildings, to surmount the market barriers, and to prioritize an equitable transition for vulnerable communities.

Figure 4-9: Residential space heating appliance sales in the Scoping Plan Scenario



Strategies for Achieving Success

- Prioritize California's most vulnerable residents with the majority of funds in the new $922 million Equitable Building Decarbonization program, created through the 2022–2023 state budget. This would include residents in frontline, low-income, disadvantaged, rural, and tribal communities. This program is dedicated to a statewide direct-install building retrofit program for low-income households to replace fossil fuel appliances with electric appliances, energy-efficient lighting, and building insulation and sealing while also coordinating reductions in gas infrastructure in specific geographic areas.
- Achieve three million all-electric and electric-ready homes by 2030 and seven million by 2035 with six million heat pumps installed statewide by 2030.
- Expand incentive programs to support the holistic retrofit of existing buildings, especially for vulnerable communities.
- Ensure that incentive programs prioritize energy affordability and tenant protections, promote affordable and low-income household retrofits that improve habitability and reduce expenses, protect and empower small landlords and homeowners, address overlooked consumer groups, and pair decarbonization

with other critically needed renovation efforts to ensure that buildings support human health and are climate- and weather-resistant.[401]

- End fossil gas infrastructure expansion for newly constructed buildings.[402]
- Evaluate and propose, as needed, changes to strengthen the Cap-and-Trade Program.
- Strengthen California's building standards to support zero-emission new construction.
- Develop building performance standards for existing buildings.
- Adopt a zero-emission standard for new space and water heaters sold in California beginning in 2030, as specified in the 2022 State Strategy for the State Implementation Plan.
- Expand use of low-GWP refrigerants within buildings.
- Support electrification with changes to utility rate structures and by promoting load management programs.
- Increase funding for incentive programs and expand financing assistance programs focused on existing buildings and appliance replacements.
- Expand consumer education efforts to raise awareness and stimulate the adoption of decarbonized buildings and appliances, especially in vulnerable communities.
- Implement biomethane procurement targets for investor-owned utilities as specified in SB 1440 (Hueso, Chapter 739, Statutes of 2018) to reduce GHG emissions in remaining pipeline gas and reduce methane emissions from organic waste.

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[401] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF23, NF24, NF25, NF26, NF28. *finalejacrecs.pdf (arb.ca.gov)*.

[402] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF22. *finalejacrecs.pdf (arb.ca.gov)*.

Carbon Dioxide Removal and Capture

Climate Change 2022: Mitigation of Climate Change,[403] a report by the IPCC released in early 2022, states "The deployment of CDR to counterbalance hard-to-abate residual emissions is unavoidable if net zero CO_2 or GHG emissions are to be achieved. The scale and timing of deployment will depend on the trajectories of gross emission reductions in different sectors. Upscaling the deployment of CDR depends on developing effective approaches to address feasibility and sustainability constraints especially at large scales." In line with that report, this Scoping Plan considers CDR as a complement to technologically feasible and cost-effective GHG emissions mitigation, and the size of its role will depend on the degree of success in reducing GHG emissions at the source across the economy.[404] The modeling shows that emissions from the AB 32 GHG Inventory sources will continue to persist even if all fossil related combustion emissions are phased out. These residual emissions must be compensated for to achieve carbon neutrality. Options for CDR include both sequestration in natural and working lands and mechanical approaches like direct air capture. Chapter 2 provides estimates on how much CO_2 removal is possible by our natural and working lands and how much must be removed by mechanical CDR.

CCS, which is carbon capture from anthropogenic point sources, is described in Chapter 2 and involves capturing carbon from a smokestack of an emitting facility. Direct air capture, on the other hand, captures carbon directly from the atmosphere. Direct air capture technologies, unlike CCS, are not associated with any particular point source.

For this section, *carbon management* refers to the capture, movement, and sequestration of CO_2 through mechanical solutions for both capture at point sources and direct removal from the atmosphere through direct air capture.[405] Enabling policies and regulations across each of these steps are necessary for individual projects, and on a broader scale, for delivering reductions in support of the state's carbon neutrality and long-term carbon-negative goals. Figure 4-10 provides a graphic of the typical carbon management infrastructure.

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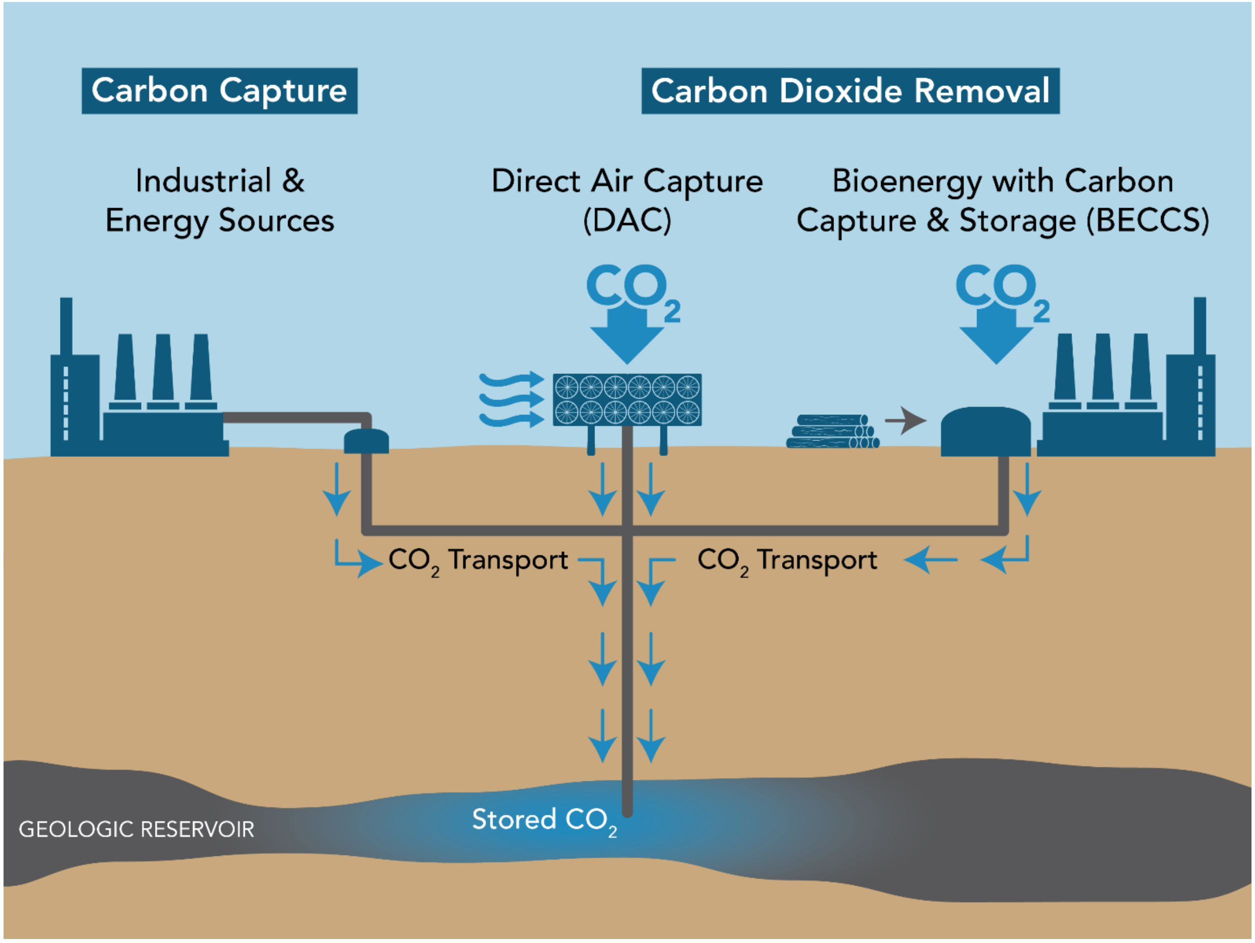
[403] IPCC. 2022. *Climate Change 2022: Mitigation of Climate Change.* https://www.ipcc.ch/report/sixth-assessment-report-working-group-3/.
[404] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.7. finalejacrecs.pdf (arb.ca.gov).
[405] CDR through natural and working lands is discussed in Chapter 2 and later in this chapter.

Figure 4-10: Carbon management infrastructure



Carbon dioxide removal directly from the atmosphere itself refers to a suite of carbon negative technologies that can be used to draw down ongoing and historical carbon emissions already in the atmosphere. Some CO_2 removal technologies leverage the abilities of both natural photosynthesis and mechanical removal by using biomass wastes as inputs to make low- or zero-carbon energy or fuels, all while capturing and storing produced CO_2.

Captured CO_2 from point sources or from the atmosphere is permanently stored in specialized geologic formations, typically half a mile or more underground. A recent Stanford University study estimated the state's commercial storage potential is nearly 70,000 million metric tons of CO_2, even when excluding oil and gas reservoirs.[406] California is well-positioned because few other places on the West Coast are suitable for

[406] Stanford Center for Carbon Storage. Opportunities and Challenges for CCS in California. https://sccs.stanford.edu/california-projects/opportunities-and-challenges-for-CCS-in-California.

geologic storage at scale. To inform discussion around CO_2 removal, CARB held two full-day workshops exploring the types of options for carbon capture and geologic storage and utilization in products.[407,408,409]

The modeling results provided in Chapter 2 demonstrate the targeted need for CCS on large facilities such as refineries and cement. The CCS numbers do not include the potential additional applications for producing hydrogen with biomethane, other manufacturing, electricity, or other bioenergy. If CCS is not deployed, those emissions would be released directly into the atmosphere and instead need to be addressed through CDR to achieve carbon neutrality. Although a study finds California has 76 existing electricity and industrial facilities that are suitable candidates for CCS retrofit,[410] this Scoping Plan proposes a targeted role for this technology such that it would only be used to address sectors where non-combustion options are not technologically feasible or cost-effective at this time, to the extent needed to achieve the 85 percent reduction in anthropogenic emissions as called for in AB 1279. In future updates to the Scoping Plan, there may be additional options for technologically feasible or cost-effective technologies that may be deployed, which would further reduce the need for CCS and CDR except in situations to address historical GHG emissions.

Recognizing the need for carbon capture and utilization sequestration and removal, the Legislature passed, and the governor signed, SB 905. It includes several key requirements in the development of the state's Carbon Capture Removal, Utilization, and Storage Program. The following is a summary of the work to be completed to establish and administer this program. Many of these steps will address the need to evaluate the safety and efficacy of actions to support carbon removal, sequestration, and transfer via pipelines. Note that not all of these actions are under CARB's authority.

- Review technology to evaluate efficacy, safety, viability of CCUS/CDR methodologies.
- Develop monitoring and reporting requirements and schedules.
- Develop a unified permit application.
- Develop financial responsibility requirements.
- Develop a centralized public database for project status.

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[407] CARB. December 11, 2019. Carbon Neutrality Meetings & Workshops. *https://ww2.arb.ca.gov/our-work/programs/carbon-neutrality/carbon-neutrality-meetings-workshops*.
[408] CARB. August 2, 2021 Scoping Plan Meetings & Workshops. *https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/scoping-plan-meetings-workshops*.
[409] *Carbon utilization* refers to the use of captured carbon to produce products such as plastics and concrete.
[410] Glenwright, Kara. 2020. *Roadmap for carbon capture and storage in California.* Precourt Institute for Energy. *https://earth.stanford.edu/news/roadmap-carbon-capture-and-storage-california#gs.ysj78q.*

- Consult with CNRA on pore space requirements as CNRA develops a framework for pore space governing agreements.
- Establish a Geologic Carbon Sequestration Group to identify suitable injection well locations, subsurface monitoring, and potential hazards that may require suspension of injection.

SB 905 also has requirements for project developers such as to develop monitoring plans and to avoid any adverse health and environmental impacts at the carbon capture location—or mitigation of unavoidable impacts as required under existing requirements. For the site of injection, there are requirements for site stability, monitoring, and reporting plans. SB 905 also bans CCS with enhanced oil recovery in California and prohibits the transfer of CO_2 via pipeline until the U.S. Department of Transportation's Pipelines and Hazardous Materials Safety Administration (PHMSA) completes its current rulemaking to update existing CO_2 pipeline safety requirements.

An often-cited example of pipeline concerns involves a CO_2 pipeline in Mississippi. On February 22, 2020, a CO_2 pipeline operated by Denbury Gulf Coast Pipelines LLC (Denbury) ruptured in proximity to the community of Satartia, Mississippi. The rupture followed heavy rains that resulted in a landslide, creating excessive axial strain on a pipeline weld (DOT 2022). The combination of weather and topography resulted in a slower dissipation of the gas. The pipeline was also carrying hydrogen sulfide, a flammable and toxic gas. The pipeline failed on a steep embankment, which had recently subsided. Heavy rains are believed to have led to a landslide, which created axial strain on the pipeline and resulted in a full circumferential girth weld failure. The PHMSA investigation also revealed several contributing factors to the accident, including but not limited to: Denbury not addressing the risks of geohazards in its plans and procedures, underestimating the potential affected areas that could be impacted by a release in its CO_2 dispersion model, and not notifying local responders to advise them of a potential failure.

As the Satartia example highlights, appropriate pipeline safety and environmental standards in California are critical to minimize any risks from CO_2 transport in the future. As such, SB 905 also tasks CNRA, in consultation with the Public Utilities Commission, to, no later than February 1, 2023, provide a proposal to the Legislature to establish a state framework and standards for the design, operation, siting, and maintenance of intrastate pipelines carrying CO_2 fluids of varying composition and phase to minimize the risk posed to public and environmental health and safety. The recommended framework shall be designed to minimize risk to public health and environmental health and safety, to the extent feasible. Because SB 905 prohibits the transfer of CO_2 via pipeline until the PHMSA completes its current rulemaking to update existing CO_2 pipeline safety requirements, CCS or CDR projects that would require a pipeline to transfer CO_2 are not feasible at this time within California.

Ultimately, and in accordance with SB 905, the merits of each CCS or CDR project must be evaluated on a case-by-case basis.[411] Deployment of CCS and CDR could support skilled jobs and workforces, including those in traditional fossil energy communities. Other co-benefits could include criteria air pollutant reductions and water production. It will be important to design projects that do not exacerbate community health impacts, include early and ongoing community engagement, and are in compliance with local, state, and federal public health and environmental protection laws. It also should be noted that, as these types of projects are an emerging area of governance, additional coordination and discussion will be needed among the various levels of authorities involved. SB 905 has already initiated this process by assigning specific agencies with tasks related to their expertise and authority.

Chapter 2 includes a more detailed discussion about the proposed role of CO_2 removal in this Scoping Plan.

Sector Transition

State,[412] national,[413,414] and global decarbonization analyses[415] indicate a significant role for carbon management infrastructure, yet relatively few projects are operational. Around the world, about two dozen large CCS projects are capturing tens of millions of metric tons of CO_2 each year, with about a dozen operating in the United States.[416] The vast majority of capacity is at industrial facilities, such as ethanol and fertilizer plants, that would otherwise vent nearly pure CO_2 into the atmosphere as a by-product of normal, non-combustion processes. Future research, development, and demonstration projects must refine and commercialize capture systems for more complex applications, especially

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411 AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.5. finalejacrecs.pdf (arb.ca.gov).

412 E3. October 2020. Achieving Carbon Neutrality in California Report: Final Presentation. https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_presentation_oct2020_2.pdf.

413 World Resources Institute. January 31, 2020. CarbonShot: Federal Policy Options for Carbon Removal in the United States. Working paper. https://www.wri.org/research/carbonshot-federal-policy-options-carbon-removal-united-states.

414 C2ES. No date. Getting to Zero: A U.S. Climate Agenda — Center for Climate and Energy Solutions. https://www.c2es.org/getting-to-zero-a-u-s-climate-agenda-report/.

415 IPCC. Mitigation Pathways Compatible with 1.5°C in the Context of Sustainable Development. Chapter 2. https://www.ipcc.ch/sr15/chapter/chapter-2/. All analyzed pathways limiting warming to 1.5°C with no or limited overshoot use CDR to some extent to neutralize emissions from sources for which no mitigation measures have been identified and, in most cases, also to achieve net negative emissions to return global warming to 1.5°C following a peak (high confidence). The longer the delay in reducing CO_2 emissions toward zero, the larger the likelihood of exceeding 1.5°C, and the heavier the implied reliance on net negative emissions after mid-century to return warming to 1.5°C (high confidence).

416 Congressional Research Service. 2021. Carbon Capture and Sequestration (CCS) in the United States. R44902. https://crsreports.congress.gov/product/pdf/R/R44902?msclkid=e45e0012c25911ec8085ca575cb61e82.

for those with limited decarbonization options. It has only been in the last few years that attention has seriously turned to mechanical CDR. As new information and modeling on climate change have been made available, the science has become clearer that avoiding the most catastrophic impacts of climate change requires both reducing emissions and deploying mechanical CDR.

California is paving a path forward on a science-based carbon management infrastructure policy that can serve as an example for other jurisdictions. The LCFS, which reduces the carbon intensity of transportation fuels, includes a protocol for select carbon management projects to become certified and generate LCFS credits.[417] CCS is not a new concept or technology. Twenty years of CCS testing show it is a safe and reliable tool.[418] As mentioned in Chapter 2, while no new CCS projects have been implemented or generated any credits under the CARB CCS protocol, CCS projects have been implemented elsewhere since the 1970s. Moreover, there has been a U.S. Department of Energy CCS research program underway for more than two decades. These all form a foundation of information for future efforts. Certified projects must successfully demonstrate adherence to rigorous pre-construction, operational, and site closure standards designed to strengthen environmental performance, as described in CARB's CCS Protocol. The protocol is designed to layer on top of existing federal carbon sequestration regulations designed to protect the environment. The protocol would need to be reevaluated if CCS were to be more broadly applied across sectors beyond transportation fuel production.

Direct air capture and carbon mineralization have high potential capacity for removing carbon, but direct air capture is currently limited by high cost. Carbon mineralization may also have high potential for removing carbon from the atmosphere, but understanding of the technology is still limited.[419] Direct air capture could also be deployed at higher rates to remove legacy GHG emissions from the atmosphere. Chapter 2 contains additional information on the current status of CCS and mechanical CDR projects globally, as well as federal support of such technologies.

Strategies for Achieving Success

- Implement SB 905.

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[417] CARB. 2018. Carbon Capture and Sequestration Protocol under the Low Carbon Fuel Standard. August 13. *https://ww2.arb.ca.gov/sites/default/files/2020-03/CCS_Protocol_Under_LCFS_8-13-18_ada.pdf*.

[418] National Energy Technology Laboratory. Permanence and Safety of CCS. *https://netl.doe.gov/coal/carbon-storage/faqs/permanence-safety*.

[419] Aines, Roger. No date. Options for Removing CO_2 from California's Air. Lawrence Livermore National Laboratory. *https://ww2.arb.ca.gov/sites/default/files/2021-08/llnl_presentation_sp_engineeredcarbonremoval_august2021.pdf*.

- Convene a multi-agency Carbon Capture and Sequestration Group comprised of federal, state, and local agencies to engage with environmental justice advocates, tribes, academics, researchers, and community representatives to identify the current status, concerns, and outstanding questions concerning CCS, and develop a process to engage with communities to understand specific concerns and consider guardrails to ensure safe and effective deployment of CCS.[420]
- Iteratively update the CARB CCS Protocol with the best available science and implementation experience.
- Incorporate CCS into other sectors and programs beyond transportation where cost-effective and technologically feasible options are not currently available and to achieve the 85 percent reduction in anthropogenic sources below 1990 levels as called for in AB 1279.
- Evaluate and propose, as appropriate, financing mechanisms and incentives to address market barriers for CCS and CDR.
- Evaluate and propose, as appropriate, the role for CCS in cement decarbonization (SB 596) and as part of hydrogen production pathways (SB 1075).
- Support carbon management infrastructure projects through core CEC research, development, and demonstration (RD&D) programs.
- Continue to explore carbon capture applications for producing or leveraging zero-carbon power for reliability needs as part of SB 100.
- Consider carbon capture infrastructure when developing hydrogen roadmaps and strategy, especially for non-electrolysis hydrogen production.
- Evaluate and streamline permitting barriers to project implementation while protecting public health and the environment.
- Explore options for how local air quality benefits can be achieved when CCS is deployed.
- Explore opportunities for CCS and CDR developers to leverage existing infrastructure, including subsurface infrastructure.
- Explore permitting options to allow for scaling the number of sources at carbon sequestration hubs.

Short-Lived Climate Pollutants (Non-Combustion Gases)

Short-lived climate pollutants (SLCPs) include black carbon (soot), methane (CH_4), and fluorinated gases (F-gases, including hydrofluorocarbons [HFCs]). They are powerful climate forcers and harmful air pollutants that have an outsized impact on climate change

[420] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.9. finalejacrecs.pdf (arb.ca.gov).

in the near term, compared to longer-lived GHGs, such as CO_2. According to the IPCC's *Climate Change 2021: The Physical Science Basis,* in the near-term (i.e., 10- to 20-year time scale) the warming influence of all SLCPs combined will be at least as large as that of CO_2.[421] The United Nations Environment Programme's Global Methane Assessment[422] advises that achieving the least-cost pathways to limit warming to 1.5°C requires global methane emission reductions of 40–45 percent by 2030 alongside substantial simultaneous reductions of all climate forcers, including CO_2 and SLCPs. Action to reduce these powerful emissions sources today will provide immediate benefits—both to human health locally and to reduce warming globally—as the effects of our policies to transition to low carbon energy systems and achieve carbon neutrality further unfold.

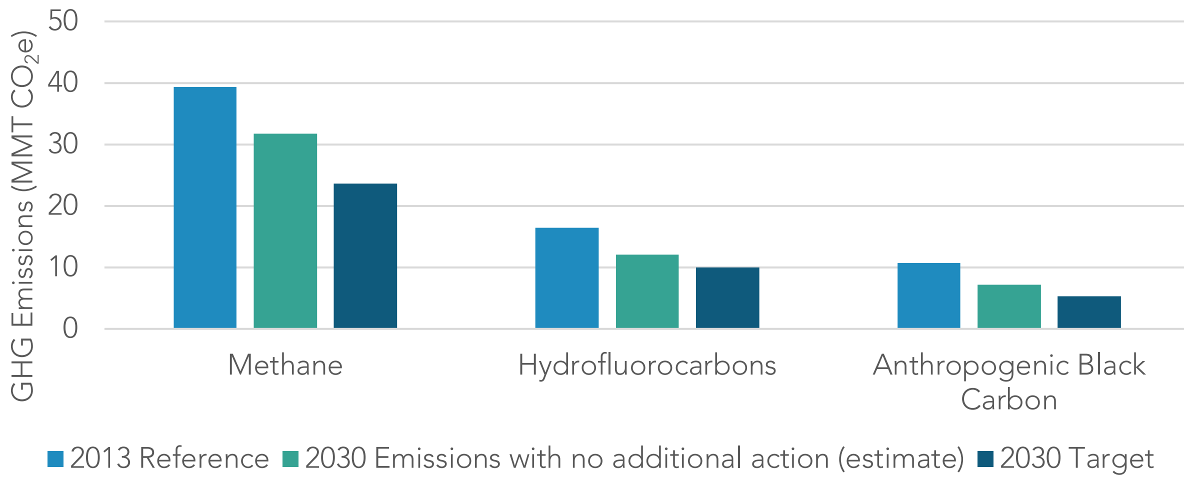
In 2017, the Board approved the comprehensive Short-Lived Climate Pollutant Reduction Strategy (Strategy).[423] This strategy explained how the state would meet the following SB 1383-established targets:

- 40 percent reduction in total methane emissions[424] (including a separate 40 percent reduction in dairy and livestock emissions)
- 40 percent reduction in hydrofluorocarbon gas emissions
- 50 percent reduction in anthropogenic black carbon emissions
- 50 percent reduction of organic waste disposal from 2014 levels by 2020, and 75 percent by 2025, including recovery of at least 20 percent of edible food for human consumption

The state is expected to achieve roughly half of the SB 1383 targeted emissions reductions by 2030 through strategies currently in place (See Figure 4-11). As directed by the Legislature under SB 1383, state agencies focused on voluntary, incentive-based mechanisms to reduce SLCP emissions in the early years of implementation to overcome technical and market barriers. Under this "carrot-then-stick" strategy, incentives are replaced with requirements as the solutions become increasingly feasible and cost-effective. To meet legislated targets, more aggressive action is needed.

[421] IPCC. 2021. *Climate Change 2021:The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.
[422] United Nations. Global Methane Assessment. Summary for Policymakers. https://wedocs.unep.org/bitstream/handle/20.500.11822/35917/GMA_ES.pdf.
[423] CARB. 2017. Short-Lived Climate Pollution Reduction Strategy. https://ww2.arb.ca.gov/sites/default/files/2020-07/final_SLCP_strategy.pdf.
[424] All SB 1383 emissions reductions are mandated to be realized by 2030 and are relative to 2013 levels.

Figure 4-11: Expected progress toward SB 1383 targeted emissions reductions by 2030 through strategies currently in place



While the state's overall GHG emissions have declined by 9 percent over the past decade, SLCP emissions reductions have not kept pace with broader progress toward decarbonization. After growing steadily in the preceding decade, methane emissions have remained relatively flat since 2013.

HFCs are the fastest growing source of GHG emissions, primarily driven by their use to replace ozone-depleting substances and an increased demand for cooling and refrigeration.[425] Since 2005, statewide HFC emissions have more than doubled. While the rate of increase has slowed in recent years due to the state's measures, HFC emissions are still on the rise in California, and have grown by over 50 percent since 2010.[426] Globally, as temperatures rise, adoption of cooling technologies (and refrigerants) is increasing rapidly. If no measures are taken, it is estimated that HFCs will account for 9 to 19 percent of the total global GHG emissions by 2050.[427]

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[425] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020: Trends of Emissions and Other Indicators.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

[426] CARB. 2022. *California Greenhouse Gas Emissions for 2000 to 2020.* https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/2000-2020_ghg_inventory_trends.pdf.

[427] Velders, G. J., D. W. Fahey, J. S. Daniel, M. McFarland, and S. O. Andersen. 2009. "The large contribution of projected HFC emissions to future climate forcing." *Proceedings of the National Academy of Sciences* 106(27), 10949–10954.

Methane

Human sources of methane emissions are estimated to be responsible for up to 25 percent of current warming.[428] Fortunately, methane's short atmospheric lifetime of ~12 years[429] means that emissions reductions will rapidly reduce concentrations in the atmosphere, slowing the pace of temperature rise in this decade. Further, a substantial portion of the targeted reductions can be achieved at low cost and will provide significant human health benefits. For example, the UN's *Global Methane Assessment* (2021)[430] found that over half of the available targeted measures have mitigation costs below \$21/MTCO_2e, and that each million metric tons of methane reduced would prevent 1,430 premature deaths annually due to ozone pollution caused by methane.

Following the Twenty Sixth Conference of Parties (COP26) (the United Nations Convention on Climate Change in 2021), over 110 nations have signed onto the Global Methane Pledge (Pledge)[431] to limit methane emissions by 30 percent relative to 2020 levels. The Pledge covers countries that emit nearly half of all methane and make up 70 percent of global GDP. The UN's Global Methane Assessment[432] shows that human-caused methane emissions can be reduced by up to 45 percent this decade, which would avoid nearly 0.3°C of global warming by 2045.

As shown in Figure 4-12, the three largest sources of California's methane emissions are the dairy and livestock industry, landfills, and oil and gas systems.

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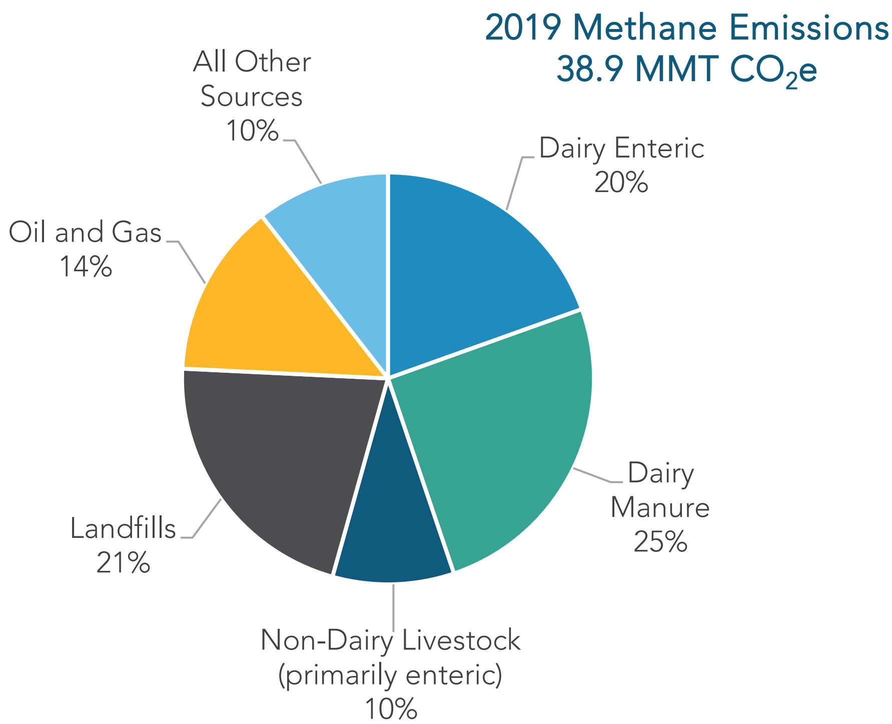
[428] IPCC. 2021. *Climate Change 2021:The Physical Science Basis.* https://www.ipcc.ch/report/ar6/wg1/.
[429] In contrast, the lifetime of CO_2 is hundreds of years. The IPCC Third Assessment Report concluded that no single lifetime can be defined for CO_2 because of the different rates of uptake by different removal processes. According to IPCC Fourth Assessment Report, the majority of an increase in CO_2 will be removed from the atmosphere within decades to a few centuries, while the remaining 20 percent may stay in the atmosphere for many thousands of years.
[430] United Nations. 2021. Global Methane Assessment. https://wedocs.unep.org/bitstream/handle/20.500.11822/35917/GMA_ES.pdf.
[431] Global Methane Pledge. https://www.globalmethanepledge.org/.
[432] United Nations Environment Programme. 2021. Global Methane Assessment: Benefits and Costs of Mitigating Methane Emissions. https://www.unep.org/resources/report/global-methane-assessment-benefits-and-costs-mitigating-methane-emissions?msclkid=00661370c85811eca078eb8fdbd603d1.

Figure 4-12: Sources of California methane emissions (2019)



Emissions from dairy and livestock operations come from two main sources: (1) enteric fermentation and (2) manure management operations, especially at dairies that employ open anaerobic lagoons that allow methane to escape into the atmosphere. Landfills, the second largest source of methane emissions, produce methane from the decomposition of organic waste. Although approximately 95 percent of all the waste that has been disposed of in the state has been deposited in a landfill that is equipped with a gas collection and control system, as required by California's Landfill Methane Regulation,[433] a portion of the methane still escapes into the atmosphere. Fugitive methane emissions can be intermittent and highly variable, both seasonally and spatially, particularly at landfills. Research has shown that landfills are complex systems and a wide range of conditions (e.g., atmospheric, operational, biological, chemical, and physical) may contribute to variability in rates of organic waste degradation, methane generation, and capture efficiency, so reducing the amount of organics deposited in landfills is critical to reducing overall landfill methane emissions. And despite the variability in individual landfill emissions, landfill gas collection and control systems remain the most effective strategy

[433] CARB. Landfill Methane Regulation. https://ww2.arb.ca.gov/our-work/programs/landfill-methane-regulation.

for reducing methane emissions from waste once it is placed in a landfill. Non-combustion methane emissions from the oil and gas sector are the third largest source of methane emissions in California. Almost three-quarters of the methane emissions from this sector come from leaks and venting from fossil gas transmission and distribution pipelines and equipment.

Hydrofluorocarbons

HFCs are synthetic GHGs that are powerful climate forcers. They are used mainly as refrigerants or heat transfer fluids in refrigeration, space conditioning, and heat pump equipment. Refrigerants are ubiquitous and are used everywhere from supermarkets, convenience stores, cold storage warehouses and wineries, to vending machines and residential and motor vehicle air-conditioners. Additionally, HFCs are also used as foam-blowing agents, solvents, aerosol-propellants, and fire suppressants. While HFCs remain in the atmosphere for a much shorter time than CO_2, the relative global warming potential (GWP) values of HFCs can be hundreds to thousands of times greater than CO_2. The mix of HFCs currently in use in California, weighted by usage (tonnage), have an average 100-year GWP of 1,700.[434] The average atmospheric lifetime of the mix of HFCs in use is 15 years.[435] Given the short average lifetimes, rapid reductions in HFC emissions can translate into near-term reductions in climate change effects.

As the global temperatures increase, the demand for cooling and refrigerants will continue to grow, as will the use of electric heat pumps to replace conventional fossil gas heating options. Unless addressed, continued use of high-GWP HFCs will perpetuate a feedback loop, where the cooling agents themselves cause additional warming.

In 2016, representatives from 197 nations signed the Kigali Amendment, which amended the existing Montreal Protocol (to reduce ozone-depleting substance production and consumption) to include a global phasedown in the production and consumption of HFCs beginning in 2019.[436] As of September 2022, 137 nations have either accepted, approved, or ratified the Kigali Amendment. On September 21, 2022, the U.S. Senate approved ratification of the Kigali Amendment, and it is expected that the United States

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[434] CARB. 2020. *Initial Statement of Reasons: Public Hearing to Consider the Proposed Amendments to the Prohibitions on Use of Certain Hydrofluorocarbons in Stationary Refrigeration, Chillers, Aerosols-Propellants, and Foam End-Uses Regulation.* October 20. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2020/hfc2020/isor.pdf?_ga=2.164659835.592460318.1646664679-912670513.1542398285.

[435] Zhongming, Z., et al. 2011. *HFCs: A Critical Link in Protecting Climate and the Ozone Layer: A UNEP Synthesis Report.*

[436] United Nations Treaty Collection. Chapter XXVII, Amendment to the Montreal Protocol on Substances that Deplete the Ozone Layer. https://treaties.un.org/Pages/ViewDetails.aspx?src=IND&mtdsg_no=XXVII-2-f&chapter=27&clang=_en.

will soon join the 137 nations that have already ratified.[437] In the United States, Congress enacted the federal *American Innovation and Manufacturing (AIM) Act* in December 2020.[438] The AIM Act authorizes the U.S. EPA to address HFCs in several ways, including a national HFC phasedown that nearly mirrors the schedule of the global phasedown under the Kigali amendment.[439]

Nearly 90 percent of HFC emissions in California come from their use as refrigerants in the commercial, industrial, residential, and transportation sectors. The timescales over which the HFC emissions occur vary, depending on the type of application. Thus, strategies to reduce HFC emissions must be tailored by equipment type. CARB has several measures in place to tackle HFC emissions from the various sources shown in Figure 4-13 below. This includes the Refrigerant Management Program[440] that tracks and manages emissions from large commercial, industrial, and cold storage refrigeration facilities in the state. CARB has adopted regulations to reduce HFC emissions from consumer product aerosol propellants, semiconductor manufacturing, and small cans of automotive refrigerant.[441]

In 2018, California adopted HFC prohibitions via regulation and legislation for several sectors, including stationary refrigeration and foam end uses to backstop the partially vacated federal Significant New Alternatives Policy (SNAP) program.[442] Most recently, in 2020, CARB adopted additional measures that place GWP limits on refrigerants used in refrigeration and air conditioning equipment, which are the largest sources of HFC emissions, and are commonly used in residential, commercial, and industrial buildings. Additionally, CARB adopted a unique pilot program requiring the use of reclaimed refrigerant: the Refrigerant Recovery, Reclaim, and Reuse (R4) Program. The newly adopted HFC rules for the refrigeration and air conditioning sectors are the first of their kind in the nation.

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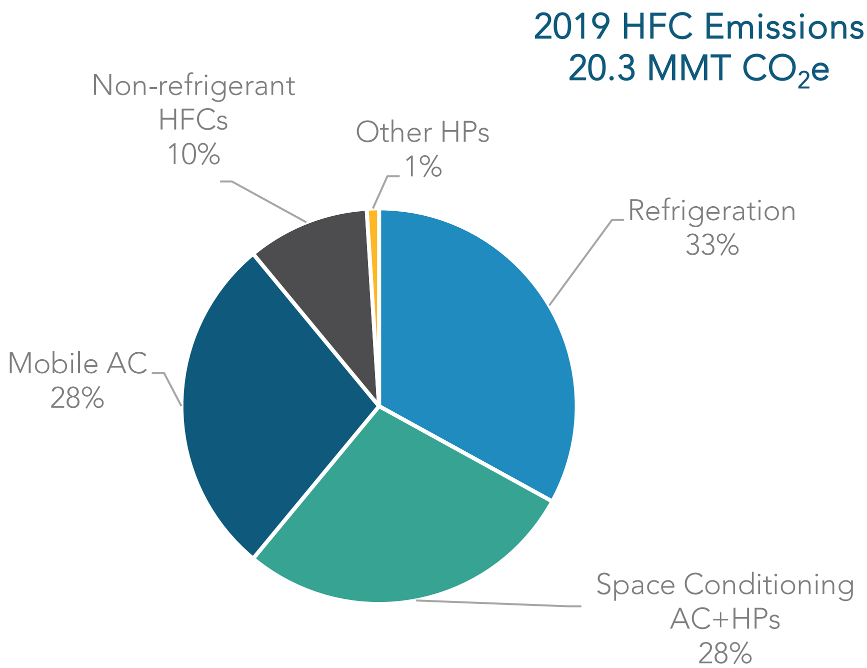
[437] U.S. Ratification of the Kigali Amendment - United States Department of State. https://www.state.gov/u-s-ratification-of-the-kigali-amendment/.
[438] 42 U.S.C § 7675, Pub. L. 116-260, § 103. https://www.epa.gov/sites/default/files/2021-03/documents/aim_act_section_103_of_h.r._133_consolidated_appropriations_act_2021.pdf.
[439] 42 U.S.C § 7675, Pub. L. 116-260, § 103.
[440] Cal. Code of Regs., tit. 17, §§ 95380, et seq.
[441] Contained in various sections, commencing with Cal. Code of Regs., tit. 13, §§ 1900 et seq.
[442] Cal. Code of Regs., tit. 17, §§ 95371, et seq.; California Cooling Act, Senate Bill 1013 (Lara, Stats. of 2018, Ch. 375, Health & Saf. Code § 39764).

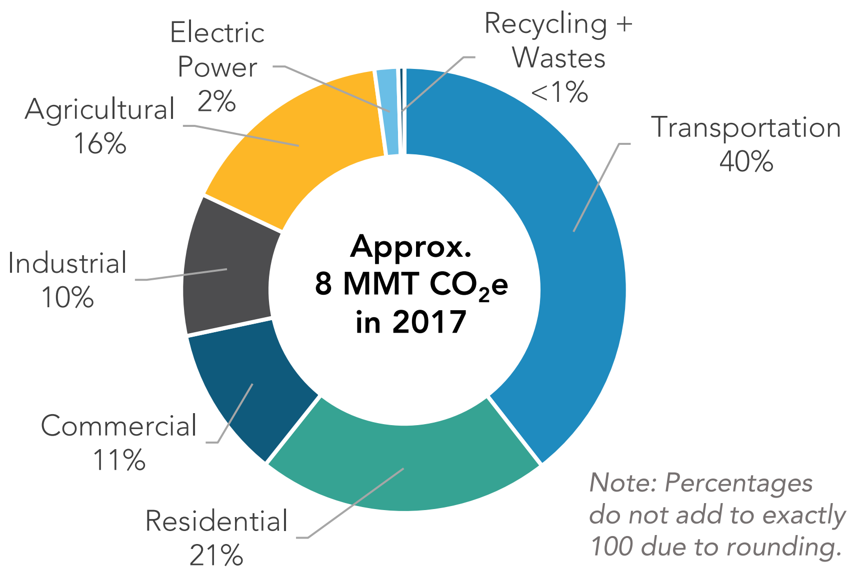
Figure 4-13: Sources of hydrofluorocarbon (HFC) emissions (2019)



Anthropogenic Black Carbon

Black carbon is not included in AB 32 or the state's AB 32 GHG inventory that tracks progress toward the state's climate targets; however, it has been identified as a powerful climate forcer and is included California's Short-Lived Climate Pollutant Reduction Strategy. The majority of anthropogenic black carbon emissions come from transportation, specifically heavy-duty vehicles, and they have decreased since 2013 due to engine certification standards and in-use rules for on-road and off-road fleets, along with clean fuel requirements and incentives, including California Climate Investments and LCFS credits. Additionally, fuel combustion for residential, commercial, and industrial applications contribute significantly to overall black carbon emissions. Approximately 95 percent of residential black carbon emissions are due to wood combustion; these emissions are being reduced through programs like the Woodsmoke Reduction Program established by SB 563 (Lara, Chapter 671, Statutes of 2017). Alternatives to agricultural burning and policies that phase out agricultural burning will also result in agricultural black carbon emissions reductions. In 2021 CARB provided a preliminary estimate of 2017 black carbon emissions (Figure 4-14).[443] This estimate will be finalized as part of a future update to the Short-Lived Climate Pollutant Inventory.

Figure 4-14: Sources of anthropogenic black carbon (preliminary 2017 estimates; AR5 100-yr GWP 900)



Sector Transition

California has long recognized the importance of mitigating non-combustion SLCPs and took several early action measures as part of a comprehensive, ongoing program to reduce in-state GHG emissions under AB 32. The early action measures included CARB's Landfill Methane Regulation,[444] Refrigerant Management Program,[445] and Oil and Gas Methane Regulation.[446]

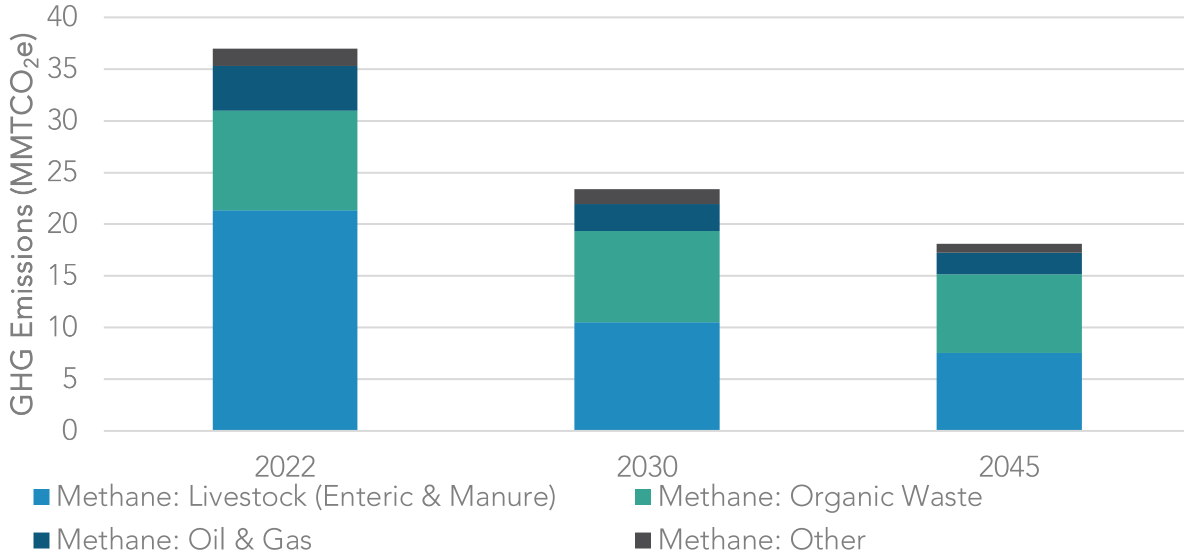
Methane

The methane abatement strategies currently in place are projected to achieve half of the methane emissions needed to meet the overall methane reduction target of SB 1383 (40 percent reduction by 2030). The reduction target translates to a limit of less than 24 $MMTCO_2e$ in 2030 (Figure 4-15). It is anticipated that, since some sectors have fewer

[443] CARB. 2021. 2022 Scoping Plan Update – Short-Lived Climate Pollutants Workshop Presentation, September 8. https://ww2.arb.ca.gov/sites/default/files/2021-09/carb_presentation_sp_slcp_september2021_1.pdf.
[444] Cal. Code of Regs., tit. 17, §§ 95460, et seq.
[445] Cal. Code of Regs., tit. 17, §§ 95380, et seq.
[446] Cal. Code of Regs., tit. 17, §§ 95665–77.

strategies that can be implemented to reduce methane in the near-term, other sectors will need to go beyond the 40 percent reduction to meet the target.

Figure 4-15: Methane emissions in 2022, 2030, and 2045 in the Scoping Plan Scenario[447]



Dairy and Livestock Methane

California is the largest dairy-producing state, home to one in five U.S. dairy cows. To date, methane emissions reductions from the dairy and livestock sector have mainly been driven by a decreasing animal population and the growing adoption of manure management strategies, including anaerobic digesters and conversion to dry manure systems and pasture systems. CARB recently completed a detailed analysis of the emission reductions expected by 2030 and the estimated additional investment needed to reach the dairy and livestock sector methane reduction target. [448]

Assuming no adoption of additional manure management and enteric mitigations strategies beyond the projects that have committed funding, and a continued annual animal population decrease of 0.5 percent per year through 2030, further reductions of approximately 4.4 $MMTCO_2e$ will be needed to achieve the 2030 methane emissions reduction target for the sector set by SB 1383. If the remaining reductions are met through

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[447] The *Organic Waste* category includes methane from landfills, wastewater treatment, and compost facilities.

[448] CARB. 2021. Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target. June. https://ww2.arb.ca.gov/sites/default/files/2021-06/draft-2030-dairy-livestock-ch4-analysis.pdf.

a mix of dairy projects in which half are dairy digesters and half are alternative manure management projects, then it is estimated that at least 420 additional projects will be necessary. Additional emissions reductions beyond this level will likely be necessary to ensure that the overall state methane emissions reduction targets are met.

Despite the considerable methane emissions mitigation potential of enteric strategies like feed additives, little progress has been made, as few products with proven mitigation potential have become commercially available, and unlike manure management strategies, there is a lack of financial incentives for their adoption.

Market conditions favoring farm consolidation and improved production efficiencies have driven reductions in the California and U.S. dairy population over the past decade. [449] These efficiency gains have allowed California to maintain production levels despite the decreasing population. If demand for dairy and beef products remains steady or increases, continued improvements in production efficiency and adoption of effective manure management and enteric mitigation strategies will be important to support dairy and livestock methane emission reductions.

Strategies for Achieving Success

- Install state of the art anaerobic digesters that maximize air and water quality protection, maximize biomethane capture, and direct biomethane to sectors that are hard to decarbonize or as a feedstock for energy.
- Increase alternative manure management projects, including but not limited to conversion to "solid," "dry," or "scrape" manure management; installation of a compost-bedded pack barn; an increase in the time animals spend on pasture; and implementation of solid-liquid separation technology into flush manure management systems.
- Implement enteric fermentation strategies that are cost-effective, scientifically proven, safe for animal and human health, and acceptable to consumers, and that do not impact animal productivity. Provide financial incentives for these strategies as needed.
- Accelerate demand for dairy and livestock product substitutes such as plant-based or cell-cultured dairy and livestock products to achieve reductions in animal populations.
- In consideration of pace of deployment of methane mitigation strategies and the scale of complimentary incentives, consider regulation development to ensure that the 2030 target is achieved, assuming the conditions outlined in SB 1383 are met.

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[449] MacDonald, James M., Jonathan Law, and Roberto Mosheim. 2020. *Consolidation in U.S. Dairy Farming.* ERR-274. July. https://www.ers.usda.gov/webdocs/publications/98901/err-274.pdf.

Landfill Methane

Achieving the 75 percent organic waste disposal reduction target[450] of SB 1383, and maintaining that level of disposal in subsequent years, would bring annual landfill emissions in 2030 to just below the 2013 baseline. Annual methane emissions will be higher through 2030 than originally anticipated by the SLCP Strategy because the state did not achieve the anticipated reductions in organic waste disposal of 50 percent below 2014 levels by 2020. SB 1383 prohibited the organic disposal regulations from taking effect until 2022,[451] and, as a result, emissions have continued to increase.

Due to the multidecadal time frame required to break down landfilled organic material, the emissions reductions from diverting organic material in one year are realized over the course of several decades. For example, one year of waste diversion in 2030 is expected to avoid 8 $MMTCO_2e$ of landfill emissions, cumulatively, over the lifetime of that waste's decomposition.[452] Near-term diversion efforts are critical to avoid locking in future landfill methane emissions.

CalRecycle's 2020 report, *Analysis of the Progress Toward the SB 1383 Waste Reduction Goals,*[453] estimated that 8 million short tons of composting and anerobic digestion capacity will be needed to manage organic wastes, above the existing and new capacity expected to be available by 2025. The 2019 report, *Co-Digestion Capacity in California,*[454] from the State Water Resources Control Board estimated that at least 2.4 million tons of digester capacity is available at urban wastewater treatment plants if sufficient incentives or funding for collection, receiving, and processing operations are provided to enable utilization of this capacity. The CPUC approved a decision in February 2022 implementing the biomethane procurement program, which will require investor-owned utilities by 2025 to procure 17.6 billion cubic feet (BCF) of biomethane produced from organic wastes to support the landfill disposal reduction and SLCP target and reduce fossil gas reliance for

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[450] The target is from 2014 levels by 2025.
Public Resources Code, § 42652.5. CalRecycle approved the SLCP: Organic Waste Reductions regulations (*https://calrecycle.ca.gov/organics/slcp/*) in 2020 and began implementing them in January 2022. These regulations are designed to achieve the 2025 disposal reduction and edible food recovery targets.

[452] The life cycle emissions reduction is based on anticipated diversion of 27 million short tons of organic waste from CalRecycle (2020) Analysis of the Progress Toward the SB 1383 Organic Waste Reduction Goals (*https://www2.calrecycle.ca.gov/Publications/Details/1693*). Under CalRecycle's SLCP regulations, an alternative to landfill disposal must achieve a life cycle GHG reduction of 0.3 $MTCO_2e$ per short ton of waste diverted.

[453] CalRecycle. 2020. *Analysis of the Progress Toward the SB 1383 Waste Reduction Goals.* *https://www2.calrecycle.ca.gov/Publications/Details/1693*.

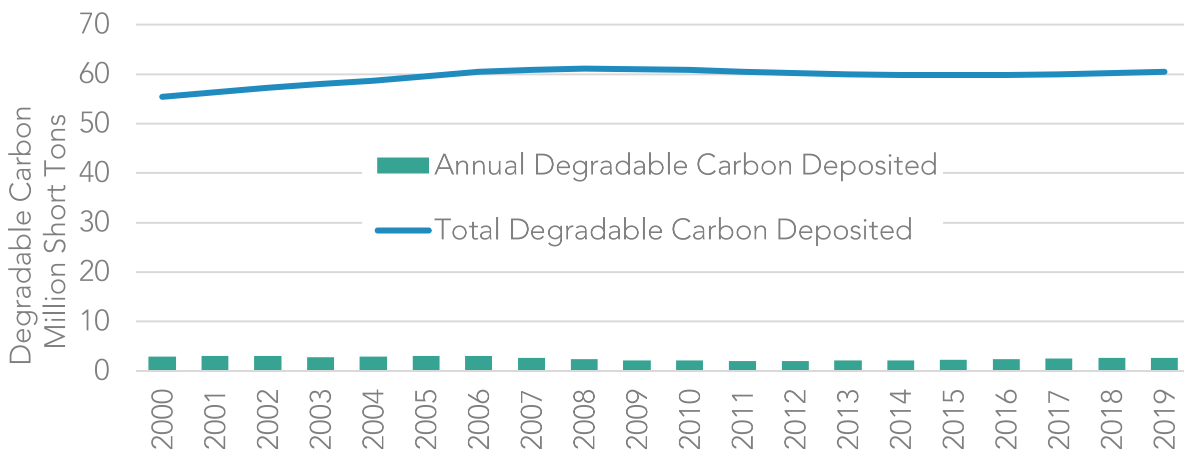
[454] State Water Resources Control Board. 2019. *Co-Digestion Capacity in California.* *https://www.waterboards.ca.gov/water_issues/programs/climate/docs/co_digestion/final_co_digestion_capacity_in_california_report_only.pdf*.

residential and commercial customers.[455] Additionally, the organic waste stream includes more than one million tons of edible food that could be recovered before it enters the waste stream through food rescue programs that combat hunger in communities throughout California.

While reducing organic waste disposal is the most effective means of achieving reductions in waste sector methane, strategies to reduce emissions from waste already in place in landfills also will play a role in achieving near-term reductions. As Figure 4-16 shows, the total degradable carbon (a measure of the amount of waste with potential to generate methane) that is accumulated from waste deposited in previous years is over 20 times greater than the amount added each year. This illustrates that even if we were able to entirely phase out landfilling of organic waste today, the existing waste in place at landfills would continue to generate methane for decades into the future.

Through a combination of improvements in operational practices, use of lower permeability covers, advanced landfill gas collection systems, and increased monitoring to detect and repair leaks, it is estimated that a direct emission reduction of 10 percent is achievable across the state's landfills by 2030. Technologies to utilize landfill gas efficiently can contribute further emission reductions in the energy sector.

Figure 4-16: Degradable carbon deposited in landfills



Strategies for Achieving Success

- Maximize existing infrastructure and expand it to reduce landfill disposal, with strategies including composting, anaerobic digestion, co-digestion at wastewater treatment plants, and other non-combustion conversion technologies.

[455] CPUC. 2022. Decision 22-02-025.

- Expand markets for products made from organic waste, including through recognition of the co-benefits of compost, biochar, and other products.[456]
- Recover edible food to combat food insecurity.
- Invest in the infrastructure needed to support growth in organic recycling capacity.
- Utilize existing digesters at wastewater treatment facilities to rapidly expand food waste digestion capacity.
- Direct biomethane captured from landfills and organic waste digesters to sectors that are hard to decarbonize.
- Implement improved technologies and best management practices at composting and digestion operations.
- Reduce emissions from landfills through improvements in operational practices, lower permeability covers, advanced collection systems, and technologies to utilize landfill gas.
- Leverage advances in remote sensing capabilities to quickly pinpoint large methane sources and mitigate leaks, improve understanding of the factors that lead to better capture efficiency, and explore new technologies and practices that can reliably improve methane control at landfills.

Upstream Oil and Gas Methane Reduction

For oil and gas production, processing, and storage, California is currently on track to achieve a 41 percent reduction in methane emissions by 2025 relative to 2013. The additional reductions needed to meet the 2030 target may be achieved by implementing additional regulatory requirements to further reduce intentional venting of fossil gas from equipment. If necessary, additional reductions from transmission and distribution facilities may be achieved by requiring the utilities to increase inspection and repair activities or further reduce emissions from pipeline blowdowns by implementing methods such as using portable compressors, using plugs to isolate sections of pipelines, flaring vented gas, routing gas to fuel gas systems, and installing static seals on compressor rods. Advances in methane detection technologies (e.g., satellites equipped to detect large methane sources) may also help to identify and mitigate methane emissions quickly across the oil and gas sector.

As California transitions away from fossil fuels, in-state oil and gas production will likely decline. This could result in an increase over time in the number of long-term idle and orphan wells (idle wells lacking a financially solvent, responsible owner) in the state. While California has regulations aimed at helping ensure operators manage their idle wells,

[456] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F4.4. *finalejacrecs.pdf (arb.ca.gov)*.

there could likely be an increase in California's orphan well population. Plugging all orphan wells, of which there are currently over 5,000, could take decades due to the limited resources California has for orphan well plugging. The benefits from plugging wells include methane emission reductions and job creation; employment gains from well plugging and site remediation activities could help temporarily offset job losses from the oil and gas industry. The California Council on Science and Technology's 2018 report on orphan wells, *Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells,*[457] found that the potential cost to the state of plugging current orphan wells could be approximately $500 million, and the cost of plugging all active and idle wells could total over $9.1 billion. As oil and gas production in California declines due to reduced demand for fossil fuels, additional funding will likely be needed to cover the costs of plugging wells that have no viable operator.

Strategies for Achieving Success

- Mitigate emissions from leaks by regular leak detection and repair (LDAR) surveys at all facilities.
- Replace high emitting equipment with zero emission alternatives wherever feasible.[458]
- Have CARB and CalGEM lead a Task Force to identify and address methane leaks from oil infrastructure near communities.
- Pursuant to SB 1137, develop leak detection and repair plans for facilities in health protection zones, implement emission detection system standards, and provide public access to emissions data.
- Minimize emissions from equipment that must vent fossil gas by design (e.g., fossil gas powered compressors).
- Install vapor collection systems on high emitting equipment.
- Phase out venting and routine flaring of associated gas (gas produced as a by-product during oil production).
- Continuous ambient monitoring at fossil gas underground storage facilities to quickly detect large methane sources.
- Reduce pipeline and compressor blowdown emissions.

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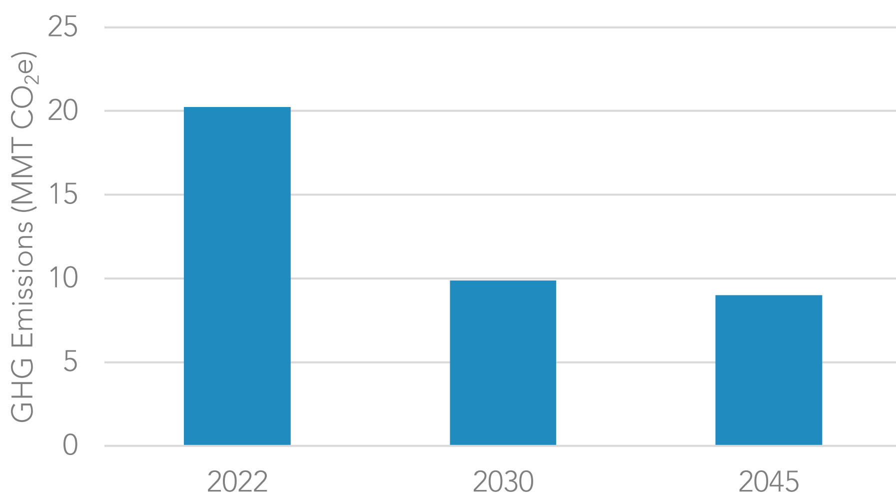
[457] The California Council on Science and Technology. 2018. *Orphan Wells in California: An Initial Assessment of the State's Potential Liabilities to Plug and Decommission Orphan Oil and Gas Wells.* https://ccst.us/wp-content/uploads/CCST-Orphan-Wells-in-California-An-Initial-Assessment.pdf.
[458] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, P5. finalejacrecs.pdf (arb.ca.gov).

- Leverage advances in remote sensing capabilities to quickly pinpoint large methane sources and mitigate leaks.[459]

Hydrofluorocarbons

In California, all the HFC measures currently in place will help achieve more than 70 percent of the reductions needed to achieve the 2030 HFC goal and provide very significant emissions reductions by 2045 and beyond. However, new targeted measures will be needed to maintain the pace of reductions, as demand for technologies that currently predominantly use high-GWP refrigerants is anticipated to grow. Despite decarbonization efforts, high-GWP HFCs are expected to be among the last remaining persistent GHG emission sources, as shown in Figure 4-17.[460]

Figure 4-17: Hydrofluorocarbon emissions in 2022, 2030, and 2045 in the Scoping Plan Scenario



HFC emissions from new and existing sources should be addressed in tandem with building decarbonization efforts to maximize reductions.[461] As buildings are electrified in an effort to decarbonize them, the use of heat pumps for space conditioning, water heaters, and clothes dryers is expected to increase significantly. Heat pumps, while using

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[459] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, CC17. finalejacrecs.pdf (arb.ca.gov).

[460] Energy and Environmental Economics, Inc. 2020. *Achieving Carbon Neutrality.* https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf.

[461] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF26. finalejacrecs.pdf (arb.ca.gov).

electricity, not fossil gas, currently rely predominantly on high-GWP refrigerants. Very low- or no-GWP technologies and solutions are either available or emerging for various heat pump technologies, and likely to develop further as international efforts to mitigate HFCs continue. However, most of these technologies are still nascent in the United States. In addition, some of the alternatives cannot be used until California building codes are updated, which is currently expected at the earliest in mid-2024 for some technologies based on the recently adopted provisions in AB 209[462] requiring the California Building Standards Commission to adopt the latest safety standards for refrigerant containing equipment into California's building codes. The current updates to the building codes will allow the use of many refrigerants with lower GWPs than HFCs currently in use. However, additional building code updates are needed to expand the choices of ultra-low-GWP alternatives, and that will need to happen in the next few years. The adoption of low-GWP refrigerants must occur in parallel with building decarbonization efforts; without such efforts, the vast GHG benefits of the latter will be partially offset, and the proportion of HFC emissions from buildings will continue to grow.

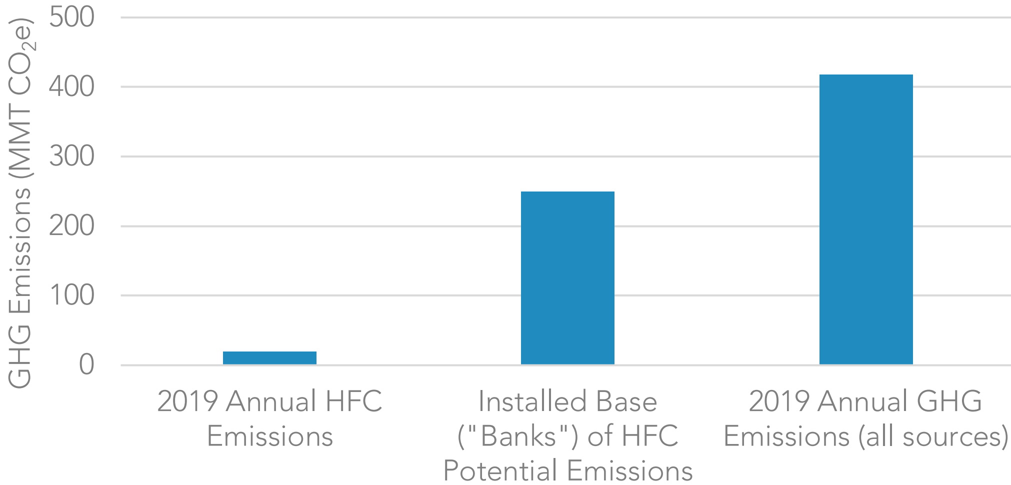
Leaks from existing air conditioning and refrigeration equipment are a major source of statewide and global HFC emissions. Once installed, refrigeration and air conditioning equipment can stay in place for decades, while leaking refrigerants into the atmosphere. This makes it very important that new installed equipment use refrigerants with a GWP as low as possible. The refrigerants inside existing equipment are sometimes collectively referred to as the *installed base* or *banks* of potential HFC emissions. If released spontaneously, the existing HFC banks would equal 60 percent of all annual statewide GHG emissions in California, as illustrated in Figure 4-18.[463]

The sales prohibitions on newly produced refrigerants set forth in SB 1206 (2022) and the national/international HFC phasedown will help in reducing HFC emissions from existing equipment by restricting the supply of and increasing the value of existing high-GWP HFCs, thus enabling a circular economy. In the 2022–2023 state budget, CARB received $45 million in incentive funding for climate-friendly refrigerant technologies; this funding will be critical in shifting the market toward the best available refrigerant technologies in various sectors.

[462] AB 209: Energy and climate change. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB209.

[463] CARB. 2021. 2022 Scoping Plan Update – Short-Lived Climate Pollutants Workshop Presentation. September 8. https://ww2.arb.ca.gov/sites/default/files/2021-09/carb_presentation_sp_slcp_september2021_1.pdf.

Figure 4-18: Potential emissions from refrigerants in existing equipment



Strategies for Achieving Success

- Expand the use of very low- or no-GWP technologies in all HFC end-use sectors, including emerging sectors, like heat pumps for applications other than space conditioning, to maximize the benefits of building decarbonization.[464]
- Convert large HFC emitters such as existing refrigeration systems to the lowest practical GWP technologies.[465]
- Prioritize small-scale and independent grocers serving priority populations in addressing existing "banks" of high-GWP refrigerants.[466]
- Improve recovery, reclamation, and reuse of refrigerants by limiting sales of new or virgin high-GWP refrigerants and requiring the use of reclaimed refrigerants where appropriate.[467]
- Assist low-income and disadvantaged communities in obtaining low-GWP space conditioning units to protect vulnerable communities from heat stress and wildfire smoke.[468]

[464] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF26. finalejacrecs.pdf (arb.ca.gov).
[465] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF22. finalejacrecs.pdf (arb.ca.gov).
[466] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT5 and JT6. finalejacrecs.pdf (arb.ca.gov).
[467] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, JT1. finalejacrecs.pdf (arb.ca.gov).
[468] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, NF28, JT5, and JT6. finalejacrecs.pdf (arb.ca.gov).

- Accelerate technology transitions in California and the U.S. overall by collaborating with international partners committed to taking action on HFCs under the Kigali Amendment to the Montreal Protocol; this includes addressing barriers to adoption of very low- or no-GWP refrigerant technologies such as high upfront costs, shortage of trained technicians, and lag in updating safety standards and building codes.

Anthropogenic Black Carbon

Significant progress has been made since 2013 to reduce anthropogenic black carbon emissions, primarily from decreased combustion of distillate fuels in the agricultural sector, as well as improvements to provide cleaner, on-road combustion technologies. Under current strategies, anthropogenic black carbon from transportation is expected to be reduced by over 60 percent in 2030. Continued reductions in combustion emissions across all sectors from both the state's climate and air quality programs will also help reduce anthropogenic black carbon emissions going forward.

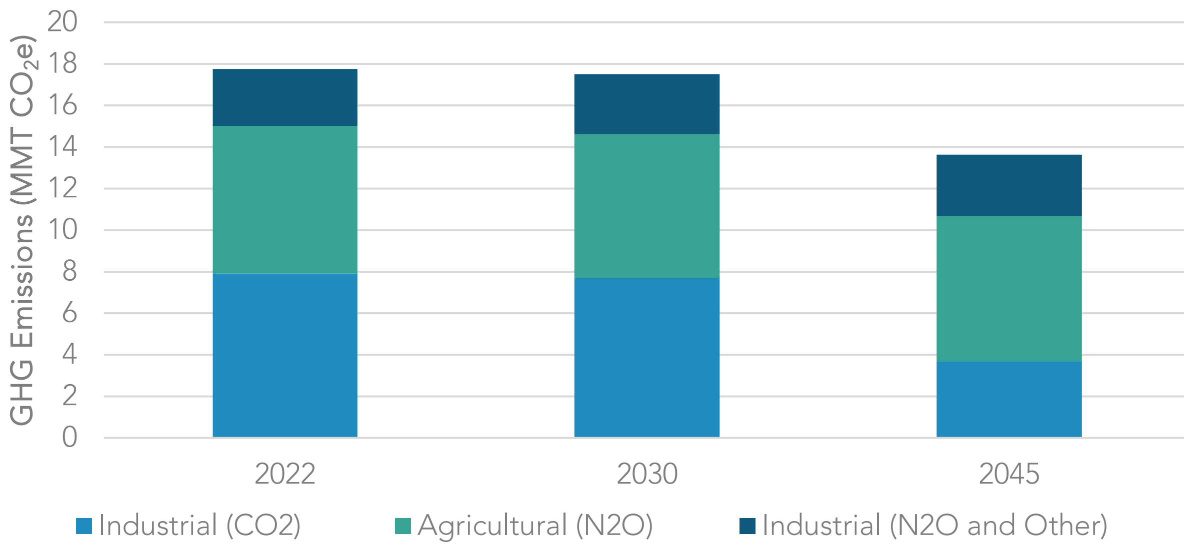
Strategies for Achieving Success

- Reduce fuel combustion commensurate with state's climate and air quality programs, particularly from reductions in transportation emissions and agricultural equipment emissions.[469]
- Invest in residential woodsmoke reduction.

In addition to SLCP emissions, some remaining non-combustion emissions are anticipated to persist in the coming decades, as shown in Figure 4-19. These include CO_2 from industrial processes such as cement manufacturing, oil and gas extraction, and geothermal electric power; N_2O from wastewater treatment, fertilizers, and livestock manure applied to agricultural soils; and other industrial, non-HFC GHG emissions.

[469] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, F1A and Appendix A (Table Summary of Direct Emission Reduction Strategies). "Emissions reductions from energy consumed by California's agricultural sector, including post-harvest processing, use of tractors and other farm equipment, and water import and irrigation." *finalejacrecs.pdf (arb.ca.gov)*.

Figure 4-19: Remaining non-combustion emissions in 2022, 2030, and 2045 in the Scoping Plan Scenario



Natural and Working Lands

California's natural and working lands (NWL) cover approximately 90 percent of the state's 105 million acres,[470] and include forests, grasslands, shrublands and chaparral, croplands, wetlands, sparsely vegetated lands, and the green spaces in urban and built environments. These lands include California Native American tribes' ancestral and cultural lands, parks and green spaces in our cities and communities, and the waters and the iconic landscapes we know and love. The diverse landscapes and biodiversity found throughout California's NWL provide a multitude of benefits to the people of California, including clean water, clean air, biodiversity, food, economic prosperity, recreational opportunities, continuation of traditional tribal ways of life, mental health benefits, and many others.

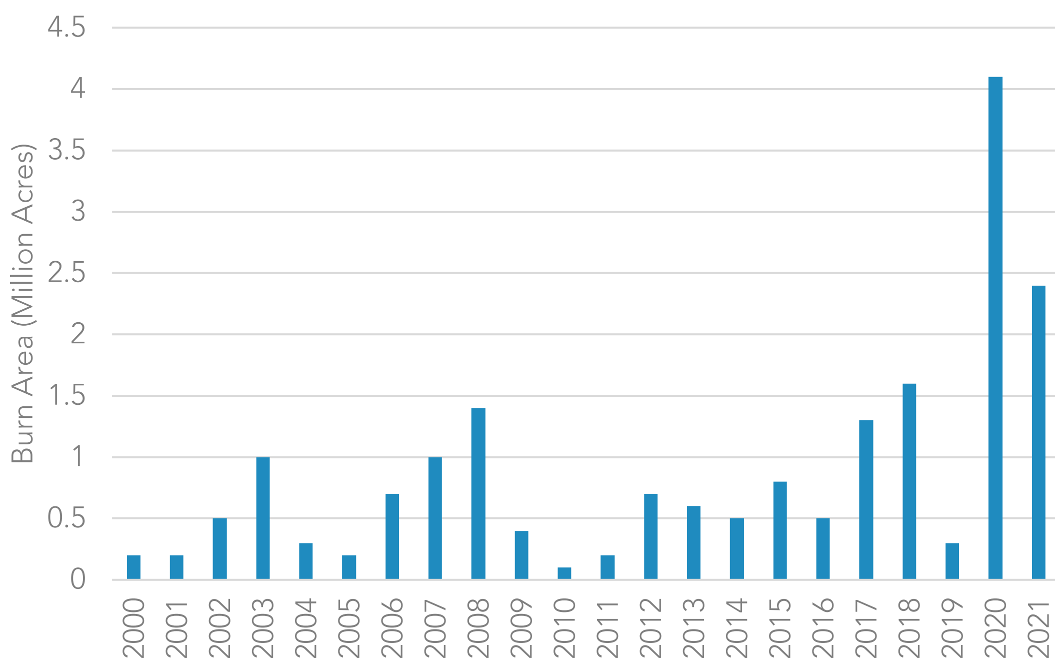
Our lands are a critical sector in California's fight to achieve carbon neutrality and build resilience to the impacts of climate change. Healthy land can sequester and store atmospheric CO_2. Healthy lands also can reduce emissions of powerful SLCPs, limit the release of future GHG emissions, protect people and nature from the impacts of climate change, and build our resilience to future climate risks. Creation of healthy lands through

[470] CNRA. 2022. Natural and Working Lands Climate Smart Strategy. https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/CNRA-Report-2022---Final_Accessible_Compressed.pdf.

multi-benefit and mitigation measures can also support tribal and local traditional lifeways. Unhealthy lands have the opposite effect—they release more GHGs than they store and are more vulnerable to future climate change impacts.

Climate change impacts have become more apparent in recent years and are having significant effects on communities throughout the state. One of these impacts is the much more frequent occurrence of unusually large, high-severity wildfires, which are being driven by climate change and by a recent history of fire-exclusion and land management practices that have resulted in forests with high levels of biomass. These recent large and high-severity wildfires have resulted in a significant amount of burned acreage and emissions in California (Figure 4-20).[471]

Figure 4-20: Acreage of burned wildland vegetation area



These wildfires deviate from the lower-severity fires that previously occurred at frequent intervals, around which California's forests evolved. As climate change accelerates, these large, uncharacteristic wildfires are likely to become more common and impact more of our landscapes. Climate change is also expected to have other significant effects on our lands, including more extreme droughts, floods, extreme heat, and the spread of invasive aquatic and terrestrial species, pests, diseases, and parasites. These impacts can lead

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[471] CARB. 2022. Wildfire Emission Estimates for 2021. https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/Wildfire%20Emission%20Estimates%202000-2021.pdf.

to negative feedback loops on human and ecological health; for example, increasing the spread of invasive species can lead to increases in pesticide use, if not managed through regulation or mitigation, which can pose risks to human health and the environment.

California's approach to climate action in the NWL sector is not solely focused on maximizing carbon stocks but instead on supporting carbon management that holistically fosters ecosystem health, resilience, provision of overall climate function, and other co-benefits.

Natural systems operate on a longer timescale than the energy and industrial sectors, and benefits from climate action on our lands can take decades to accrue. Scaling climate smart land management in California requires taking action now and playing the "long game" by establishing and maintaining consistent, patient approaches and programs.

Landscapes

For the first time, this Scoping Plan includes modeling for the NWL sector. The focus of the initial modeling is limited to seven land types that align with the those in the NWL Climate Smart Strategy.[472] Work will continue to incorporate more landscapes and management practices into the modeling over time. The initial landscapes included in the modeling for this Scoping Plan are:

- Forests
- Shrublands and Chapparal
- Grasslands
- Croplands
- Wetlands
- Developed Lands
- Sparsely Vegetated Lands

Each of these land types are a key component to the state's approach to increasing climate action in the NWL sector, as called for in Executive Order N-82-20 and AB 1757.[473] The Executive Order directs CARB to update the target for this sector in support of carbon neutrality by 2045 as part of this Scoping Plan, and to take into consideration the NWL Climate Smart Strategy. AB 1757 calls for the development of an

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[472] CNRA. 2022. *Natural and Working Lands Climate Smart Strategy. Appendix B.* *https://resources.ca.gov/-/media/CNRA-Website/Files/Initiatives/Expanding-Nature-Based-Solutions/Appendix-B_04132022_ada.pdf*.

[473] AB 1757 California Global Warming Solutions Act of 2006: Climate Goal: Natural and Working Lands. *https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220AB1757*.

ambitious range of targets for the NWL sector to be integrated into the Scoping Plan and other state policies. It directs CARB and CNRA to work closely together to update the NWL Climate Smart Strategy, and establish an expert advisory committee to inform and advise on NWL modeling, targets, and implementation strategies.[474] Additionally, in 2021, the governor signed SB 27[475] (Skinner, Chapter 237, Statutes of 2021) into law. It directed CARB to establish CO_2 removal targets for 2030 and beyond and take into consideration the NWL Climate Smart Strategy. The governor's Executive Order, AB 1757, and SB 27 go beyond previous direction from the Legislature and past administrations. These directives emphasize the importance of quantifying land-based carbon both statewide,[476] and in programs and policies,[477] setting targets[478] for NWL to support the state's climate objectives, and advancing land management actions[479] that support the health and resiliency of these lands.

Blue carbon (also known as carbon captured and held in coastal vegetation and soils, such as seagrasses, seaweeds, and wetlands)—is also important to consider as we look at long-term climate goals. While this landscape is not currently covered by IPCC inventory guidelines or included in California's NWL Inventory, the United States was the first nation to include blue carbon in its national GHG emissions inventory. California's Ocean Protection Council and San Francisco Estuary Institute are partnering to create a new coastal wetlands, beaches, and watersheds inventory. CARB staff will utilize information from this effort and assess other available data to evaluate how this landscape may be integrated into our efforts in the future as more data become available.[480]

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474 AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N20. finalejacrecs.pdf (arb.ca.gov).
475 SB 27 Carbon sequestration: state goals: natural and working lands: registry of projects. https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220SB27.
476 SB 859 Public resources: greenhouse gas emissions and biomass (SB 859, Committee on Budget and Fiscal Review, Chapter 368, Statutes of 2016). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB859.
477 SB 1386. Resource conservation: working and natural lands. (SB 1386, Chapter 545, Statutes of 2016). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1386.
478 CARB. 2017. 2017 Climate Change Scoping Plan Update. Board Resolution 17-46. https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2017/res17-46.pdf.
479 Executive Department. State of California. EO B-52-18. https://www.ca.gov/archive/gov39/wp-content/uploads/2018/05/5.10.18-Forest-EO.pdf.
480 AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N2. finalejacrecs.pdf (arb.ca.gov).

Trends of Carbon on Landscapes

CARB currently tracks the carbon stock changes though the Inventory of Ecosystem Carbon in California's Lands[481] (NWL Inventory), which is summarized in Chapter 1. The NWL Inventory is a key tool for tracking changes in carbon stocks across the state, and it will serve as the inventory of record for this sector, tracking sector-wide progress toward the target. The NWL Inventory provides a retrospective snapshot of the status of California's lands, and captures the gains or losses of carbon stocks that occur over time. In addition to tracking carbon stock changes, the NWL Inventory is an important tool for understanding the impacts of our efforts to increase climate action in this sector (such as those identified in this Scoping Plan and the NWL Climate Smart Strategy) on NWL carbon stocks. The inventory is also used as the foundation for Scoping Plan scenario modeling and target setting.

CARB's inventory shows that carbon stocks decreased in NWL lands from 2001 to 2011, releasing more carbon than they were storing, and then increased slightly from 2012 to 2014.[482] These trends highlight the interannual and interdecadal variability of lands and their ability to be both a source and a sink of carbon, and the importance of looking at NWL data and trends over multiyear and multidecadal time periods, as opposed to looking only at annual changes. This movement is part of the Earth's carbon cycle, where carbon transfers between the land, ocean, and atmosphere. As part of the carbon cycle, over decades or centuries, fire and plant respiration and decomposition move carbon from the land to the atmosphere, while plant growth and other processes move carbon from the atmosphere to the land. Emissions from fossil-fuel combustion are contributing to putting this cycle out of balance.

Additionally, some historic land management practices that have resulted in the loss of carbon from the soil are also contributing to the atmospheric rise of CO_2 while simultaneously exacerbating the imbalance of the water cycle, which is influenced by and linked to the carbon cycle. These emissions are also contributing to a feedback loop for California's lands: as CO_2 emissions accumulate in the atmosphere—and California experiences more warming, extreme heat events, and droughts—the risk and intensity of carbon losses also increases, which in turn transfers more carbon from the land to the atmosphere. And because forests and shrublands comprise approximately 85 percent of the carbon stocks in California, management strategies and disturbances in forest and

[481] CARB. *An Inventory of Ecosystem Carbon in California's Natural & Working Lands.* 2018 Edition. nwl_inventory.pdf (ca.gov). Accessed 3/2/2022.

[482] These trends are consistent estimates in the most recent AB 1504 reporting period.

shrubland carbon play an important role in determining whether California's lands are providing either net carbon sequestration or net emissions on an annual basis.

The gains and losses of carbon on our lands will fluctuate in the future; what is important is to restore carbon in places where it has been lost and reduce large carbon losses on our NWL through active, attentive, and adaptive management. For additional details on the nexus between NWL and GHGs, see pages 5–6 of the NWL Climate Smart Strategy.

Goals and Accelerating Nature-Based Solutions

The state's climate mitigation targets are traditionally identified by individual years, (i.e., tons of GHG emissions in 2020 or 2030). However, because NWL processes fluctuate year to year and because it can sometimes take decades for climate action to fully impact carbon in NWL, it is important to consider the statewide, long-term trends of carbon stock change when identifying how this sector contributes to California's pathway to achieving carbon neutrality. Tracking carbon stock change over a multi-decadal period is the best way to assess the full direct impact climate action has on carbon storage. Such an approach filters out fluctuations from year-to-year weather variations and multi-year natural climate cycles, such as El Niño patterns.

Current data sources and methods allow us to track only certain carbon stocks that exist on NWL. For target tracking to be successful, each carbon pool must be inventoried using a methodology that can detect changes due to management and climate change. Certain carbon pools lack the scientific data and methodologies necessary for target-setting and tracking. For example, soils in forests, shrublands, and grasslands are not included in the Scoping Plan carbon stock target because, currently, there is no way to track statewide soil carbon through time in a way that would capture the effects of increased climate action and climate change.

When considering how NWL contribute to the state's goal of carbon neutrality, all lands' carbon stock gains and losses must be considered, and the Scoping Plan target is set in these terms. It is not sufficient to aggregate climate benefits only within areas where projects, management, or climate action occur. Much of the state does not receive active or quantifiable management, but these areas still contribute to the state's overall carbon stock change and GHG emissions. To incorporate the entire carbon balance toward true carbon neutrality, the Scoping Plan target is set in terms of carbon stock change across the entire state. This incorporates all lands that both receive and do not receive active management, and includes the end result of all sequestration, emissions, and other changes to carbon on the landscape.

However, carbon stock change is not equivalent to emissions. Currently, the data and emission quantification science is not sufficient to enable inventories to comprehensively track all NWL emissions in a way that would enable us to set an NWL target in terms of statewide emissions and sequestration. There is a great need, across the entire NWL sector statewide, for more empirical data, science, and tools to track all carbon stocks across each carbon pool, and to begin to track emission and sequestration rates. As California implements AB 1757, there is an opportunity to update the data, science, and tools to enable this level of tracking and target setting in the future.

As outlined in Chapter 2, California is projected to lose carbon stocks over the coming decades, but this Scoping Plan analysis also shows that increasing the pace and scale of climate smart land management in California will reduce the carbon stock losses and GHG emissions from the NWL sector. In response to EO N-82-20 and AB 1757, the proposed target for NWL is shown in Table 4-1.

Table 4-1: Scoping Plan modeled target for NWL, based on increasing action on NWL

	Total Carbon Stock % Change from 2014
2045	-4

Achieving this target will require significant expansion of the pace and scale of climate action on California's NWL, including the following:

- Increasing climate smart forest, shrubland, and grassland management to at least 2.3 million acres a year—an approximate 10x increase in management from current levels.
- Increasing climate smart agricultural practices by at least 78,000 acres adopted a year, annually conserving at least 8,000 acres a year of croplands, and increasing organic agriculture to comprise at least 20 percent of cultivated acres in California by 2045—an approximate 7.5x increase in healthy soils practices from previous levels and a 2x increase in total acres of organic agriculture.
- Increasing annual investment in urban trees in developed lands by at least 200 percent above historic levels and establishing defensible space on all parcels by 2045.
- Restoring at least 60,000 acres, or approximately 15 percent of all Sacramento–San Joaquin River Delta (Delta) wetlands, by 2045.
- Cutting land conversion of deserts and sparsely vegetated landscapes by at least 50 percent annually from current levels, starting in 2025.

If the carbon stock target above is met, and the management actions above are implemented, the modeling for NWL indicates that California's lands will be a net source of emissions, producing approximately 7 $MMTCO_2e$ of average annual emissions.

Additional climate smart management practices and additional landscapes, such as those included in the Climate Smart Strategy and discussed below in Additional Management Strategies, have the potential to increase carbon stocks and reduce GHG emissions from NWL beyond the levels modeled for this Scoping Plan.

The purpose of the NWL target and the above estimated outcomes is to provide a numerical guide that can support the state's efforts to accelerate both near-term and long-term climate action on California's lands, prioritizing durable solutions that deliver multiple outcomes. Taking these actions over the coming decades will reduce the potential carbon losses from NWL, reduce GHG emissions from some landscape types (such as croplands and Delta wetlands), and support sequestration of GHGs from NWL between 2025 and 2045. These actions will also deliver significant benefits to Californians beyond advancing our climate goals, such as reducing wildfire emissions and their associated health impacts, increasing habitat for biodiversity, reducing urban heat island effects, reducing harmful pesticide exposure, expanding economic opportunities, and others. Additional information on several economic and health outcomes from the Scoping Plan Scenario is included in Chapters 2 and 3.

Statewide planning and target setting for the NWL sector will only create meaningful change if followed by effective on-the-ground implementation. State government cannot accomplish this implementation alone. Effective large scale climate action is dependent on partnerships among tribal, federal, state, regional, and local partners, and across governmental, private, nonprofit, and commercial sectors. The NWL sector of the Scoping Plan sets a carbon target with climate action recommendations that can be used to achieve the quantified carbon, health, and economic outcomes. Implementation of these actions must be led by local or regional partnerships that plan and execute projects appropriate to the specific conditions. The technical expertise and local knowledge of land managers and stewards in all sectors must be elevated to ensure relevant, efficient, and effective climate action.

Implementation of climate action should contribute to state targets, maximize local benefits, and alleviate environmental injustices and other social inequities. On-the-ground action is largely executed and managed by local and regional actors, but state government agencies must support communities across the state in implementing nature-based climate solutions that address statewide objectives, such as the Scoping Plan carbon target. This includes providing resources and developing frameworks, while greatly increasing capacity and technical assistance to assist and empower local partners. Examples of how this can be done are the Regional Forest and Fire Capacity Program within the forestry sector, the UC Cooperative Extension in the agricultural and forestry sectors—as well as the work of the state's 10 regional Conservancies. These programs provide strong examples to emulate as they facilitate statewide coordination, and information and resource transfer from the state to the regional and local levels. The Regional Forest and Fire Capacity Program provides funding for local and regional groups to build their organizational capacity to plan and implement wildfire and forest management projects that are informed by their own local expertise. The UC Cooperative Extension is an example of how the state provides technical assistance to local landowners and community organizations, helping them apply the latest science-based management strategies to their lands. California's regional Conservancies play a pivotal role in implementing regional conservation, restoration, and land management efforts through activities such as grant funding, science generation, and planning assistance.

The state also has identified the need to incorporate and elevate traditional indigenous knowledge into climate action on the regional and local scales. Accomplishing this requires close partnerships with tribes for mutual knowledge and resource sharing, while protecting culturally sensitive knowledge and resources. As Tribes are sovereign nations with specialized cultural knowledge and experience in managing lands, climate action on these lands that contribute to the State of California's climate targets can only be accomplished with the full participation and under the leadership of the Tribes that govern those lands.

Strategies for Achieving Success: Crosscutting Items for all NWL

- Implement AB 1757 and SB 27.
- Implement the Climate Smart Strategy.
- Accelerate the pace and scale of climate smart action, consistent with the management levels identified above, as part of a collective effort between federal, state, private, nonprofit, and individual land managers.
- Prioritize and practice equity, including through meaningful community engagement and prioritizing implementation of nature-based solutions that benefit the communities most vulnerable to climate change.[483]
- Advance multi-benefit, collaborative, landscape-level approaches that engage communities and landowners, and incorporate adaptive managements.
- Consult and partner with California Native American tribes to increase co-management and tribal management authority; restore, protect, and enhance natural cultural resources, traditional foods, and cultural landscapes; respect tribal sovereignty; and support tribes' implementation of tribal expertise and Traditional Ecological Knowledge and cultural easements.[484]

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[483] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N8. *finalejacrecs.pdf (arb.ca.gov)*.

[484] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N1, N6, N16, N17, N18. *finalejacrecs.pdf (arb.ca.gov)*.

- Leverage existing innovative financial and market mechanisms, and explore new ones, between the public, private, and philanthropic sectors to secure funding of climate smart land management.
- In partnership with communities, tribes, and the private sector, expand and develop new infrastructure for manufacturing and processing of climate smart agricultural and biomass products.
- Leverage and support technical assistance providers: such as the UC Cooperative Extension and California's 98 Resource Conservation Districts, that have track records of providing technical assistance to local landowners and implementing agriculture, forestry, natural resource management, and restoration projects across the state.
- Establish and expand mechanisms that ensure NWL are protected from land conversion and parcelization (e.g., conservation easements or Williamson Act), in line with the strategies outlined in CNRA's Pathways to 30x30 California.[485,486] Pair land conservation projects with management plans that increase carbon sequestration, where feasible.
- Increase opportunities for private and philanthropic investments in nature-based climate solutions, utilizing existing voluntary and compliance carbon markets, existing state and local programs, and the California Carbon Sequestration and Climate Resiliency Project Registry established pursuant to SB 27.
- Expand monitoring and tracking of management actions and outcomes consistent with the tracking and monitoring recommendations of the Climate Smart Strategy.

Forests, Shrublands, and Chaparral

At roughly 29 million acres, forests cover 27 percent of California. Shrublands and chaparral cover 31 percent of the state; roughly 33 million acres. Both types are distinct, with their own ecological dynamics and management strategies, and are modeled within a single model that is calibrated to treat them uniquely.

Together, forests, shrublands, and chaparral support a high biodiversity of plants and animals, in addition to high levels of carbon stocks. They provide important air and water quality benefits to all Californians, as well as recreational opportunities and, for forests, harvested wood products for the state. These landscapes are fire-adapted, and historical tribal management of these lands has fostered ecosystem health and resilience. Over the past century, these lands have been impacted severely by fire exclusion, including

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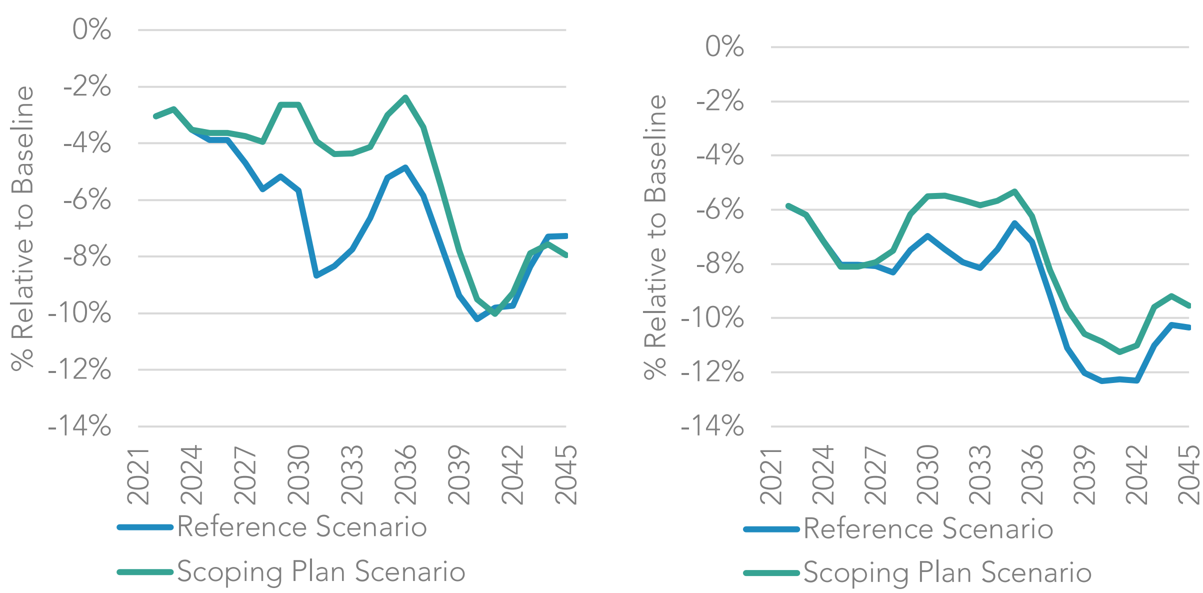
[485] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N5, N26, N27. finalejacrecs.pdf (arb.ca.gov).
[486] CNRA. 2022. *Pathways to 30x30 California*. https://www.californianature.ca.gov/pages/30x30.

exclusion of indigenous people's management and past management practices, which has resulted in less resilient ecosystems and communities and more destructive wildfires today. This, along with drought induced stress and mortality, has changed these landscapes from a carbon sink to a carbon source. Climate smart management can help make forests more resilient to climate change and less prone to catastrophic wildfire. Climate-smart management in shrublands and chaparral face additional challenges and uncertainty, but can still provide protection for threatened communities and natural resources. This management, if conducted on a regular basis to maintain forest health, can help reduce emissions from forests, shrublands, and chaparral, and help strengthen and maintain the co-benefits that Californians experience from them.

Under all management levels, forests and shrublands are expected to lose carbon over the next two decades due to climate change and wildfire (Figure 4-21).

Figure 4-21: Forest (left) and shrubland (right) carbon stocks by 2045[487,488]



While this decrease in carbon stocks may be inevitable, forest management under the Scoping Plan Scenario can help direct where and how carbon loss occurs. By proactively managing forests and shrublands, the loss of carbon from wildfire can be lessened as the risk of high severity fire is decreased, with the removed biomass going toward a more

[487] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N13. finalejacrecs.pdf (arb.ca.gov).
[488] This analysis is the aggregation of all forests and shrublands from all ownerships across the entire state of California.

useful purpose such as harvested wood products, bioenergy, and engineered carbon removal. Managing for a diverse and resilient forest landscape also can help forests recover more quickly so that when climate change and wildfire impacts occur, forests will be less affected and can continue to thrive and sequester carbon. Additional details on the climate benefit potential of forests and shrublands/chapparal can be found in Section 2 of the NWL Climate Smart Strategy.

Strategies for Achieving Success

- Accelerate the pace and scale of climate smart forest management to at least 2.3 million acres annually by 2025, in line with the climate smart management strategies identified in this Scoping Plan, the NWL Climate Smart Strategy, and the Wildfire and Forest Resilience Action Plan.[489]
- Establish and expand mechanisms that ensure forests, shrublands, and grasslands are protected from land conversion and that support ongoing, rather than one-time, management actions.
- In collaboration with state and local agencies, accelerate the deployment of long-term carbon storage from waste woody biomass residues resulting from climate smart management, including storage in durable wood products, underground reservoirs, soil amendments, and other mediums.
- Expand infrastructure to facilitate processing of biomass resulting from climate smart management.
- Expand permit streamlining in collaboration with state and local agencies to accelerate implementation of climate smart forest management while protecting natural resources.

Grasslands

Grasslands cover 9 percent of California, roughly 10 million acres, and are found throughout the state in various landscapes, with concentrations in the foothills surrounding the Sacramento and San Joaquin Valleys. In addition to carbon storage (primarily in the soil), grasslands provide open space, wild habitat, grazing land, and important water filtration and recharge benefits. The protection of grasslands provides an opportunity to reduce sprawl and complement VMT reduction strategies. As grasslands are susceptible to invasive species, climate smart strategies can increase grassland

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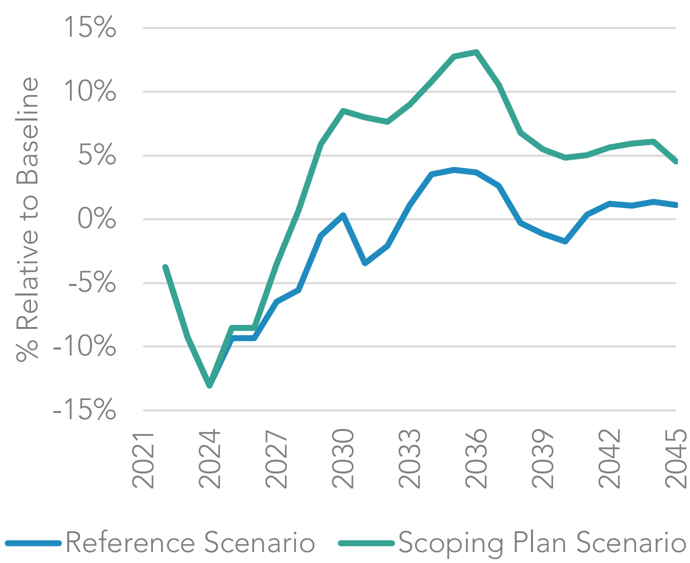
[489] Forest Management Task Force. 2021. *California's Wildfire and Forest Resilience Action Plan: Recommendations of the Governor's Forest Management Task Force.* https://www.fire.ca.gov/media/ps4p2vck/californiawildfireandforestresilienceactionplan.pdf.

resilience to climate change by improving species diversity and maintaining or increasing soil carbon stocks.

Modeling results show that increased fuels treatments and avoided land conversion can increase carbon stocks on grasslands by 2045, but sequestration rates fluctuate annually. Grasslands are capable of high carbon sequestration rates but are susceptible to carbon losses from wildfire and land conversion. Soil carbon is the major carbon pool on these lands, and continued future improvement of the monitoring and modeling of soil carbon is needed. Similar to forests and shrubland/chaparral, modeling alternatives that include fuels treatments resulted in greater carbon stocks compared to no management, and had lower wildfire emissions. Unlike forests and shrubland/chaparral, which have a general declining carbon stocks trend, the modeling results (Figure 4-22) show grasslands can maintain or increase carbon stocks with active management. Details on the climate benefit potential of grasslands can be found in Section 2 of the NWL Climate Smart Strategy.

Figure 4-22: Grassland carbon stocks by 2045



Strategies for Achieving Success

- Establish and expand mechanisms that ensure grasslands are protected from land conversion/parcelization and that support ongoing, rather than one-time, management actions that improve carbon sequestration.
- Deploy grassland management strategies, like prescribed grazing, compost application, and other regenerative practices, to support soil carbon sequestration, biodiversity, and other ecological improvements.

- Increase adoption of compost production on farms and application of compost in appropriate grassland settings for improved vegetation and carbon storage, and to deliver waste diversion goals through nature-based solutions.

Croplands

Croplands cover 9 percent of the state, roughly 9.5 million acres. This land is some of the most productive agricultural land in the world, and enables California to be a global leader in agriculture. Aside from developed lands, croplands are the most intensively managed landscapes in the state, and are closely tied to society through the food they produce and the constant, direct contact that people have with croplands through the course of management. In addition to food security, croplands provide considerable carbon storage in the soil and, in perennial croplands, in aboveground biomass. Climate smart practices can improve public health; for example, by reducing synthetic fertilizer and pesticide use. They also help to maintain or increase the climate resilience of cropland productivity through improved soil conditions and increased pollinator habitat.

There is also significant potential to transform this sector to increase soil carbon storage, reduce GHG emissions (Figure 4-23), and reduce pesticide exposure and health impacts. Moving to an agricultural system that improves soil health and water holding capacity reduces over-application of nitrogen, reduces the use of pesticides and fumigants, and increases biodiversity and pollinator habitat, supporting California's pathway to carbon neutrality while simultaneously improving the lives of those who live and work in the agricultural community. Croplands are intricately tied to people, communities, and their health, and through climate smart practices and cropland conservation, these lands have the potential to contribute more to society than just food.[490] The implementation of climate smart agricultural practices and diversified organic agriculture can help California achieve social and environmental benefits, like improving water use efficiency, increasing pollinator habitat, and reducing synthetic fertilizer and pesticide use.[491] Additional details on the climate benefit potential of croplands can be found in Section 2 of the NWL Climate Smart Strategy.

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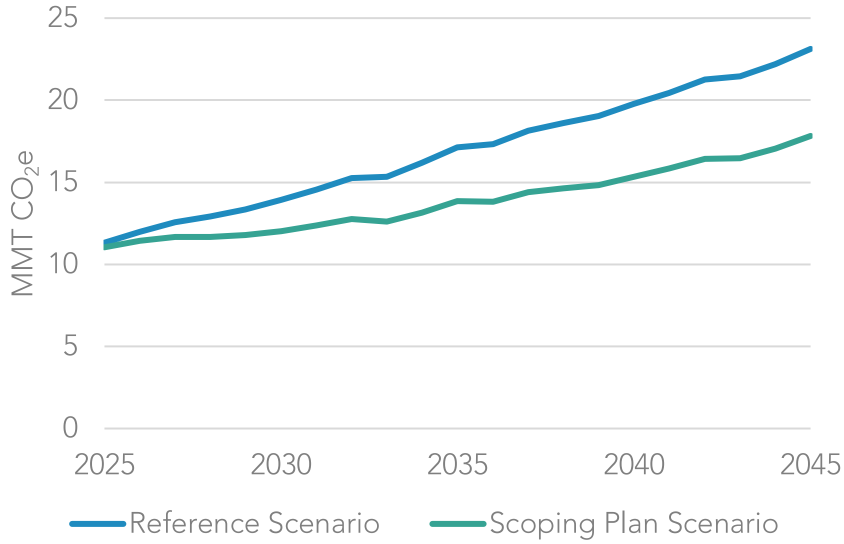
[490] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations In-part (N3, N4, N22), N5, N21. *finalejacrecs.pdf (arb.ca.gov)*.
[491] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11. *finalejacrecs.pdf (arb.ca.gov)*.

Figure 4-23: Cumulative CO_2e emissions from annual croplands in 2045[492]



CARB recognizes the complex nature of croplands, cross-sector relationships, and the need to build on this analysis to further our understanding of cropland dynamics. Many more aspects of cropland management need to be explored for potential climate benefits, such as water and nutrient use management, pest control methods, crop rotations, and other management practices. The impacts of climate change on water availability, annual/perennial crop growth, and future carbon sequestration trends are uncertain, and recent policies such as the Sustainable Groundwater Management Act may also influence cropland management in unforeseen ways. Nonetheless, it is clear that greater climate smart practice implementation can prepare California for the future and yield tangible benefits for the state.

Strategies for Achieving Success

- Accelerate the pace and scale of healthy soils practices to 80,000 acres annually by 2025, conserve at least 8,000 acres of annual crops annually, and increase organic agriculture to 20 percent of all cultivated acres by 2045.

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[492] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11. *finalejacrecs.pdf (arb.ca.gov)*.

- Utilize the recommendations included in CDFA's Farmer and Rancher-Led Climate Change Solutions[493] report to accelerate deployment of healthy soils practices, organic farming, and climate smart agriculture practices.
- Establish or expand financial mechanisms that support ongoing deployment of healthy soils practices and organic agriculture.[494]
- Support strategies that achieve co-benefits of safer, more sustainable pest management practices and the health and preservation of ecosystems, such as implementing the California Department of Pesticide Regulation's (DPR's) Sustainable Pest Management Work Group recommendations.[495]
- Conduct research on the intersection of pesticides, soil health, GHGs, and pest resiliency via a multi-agency effort with DPR, CDFA, and CARB.[496]
- Conduct outreach and education to develop and facilitate the increased adoption of safer, more sustainable pest management practices and tools; reduce the use of harmful pesticides; promote healthy soils; improve water and air quality; and reduce public health impacts.
- In collaboration with state and local agencies, accelerate the deployment of alternatives to agricultural burning that increase long-term carbon storage from waste agricultural biomass, including storage in durable wood products, underground reservoirs, soil amendments, and other mediums.
- Work across state agencies to reduce regulatory and permitting barriers around some healthy soils practices (e.g., composting), where appropriate.
- Utilize innovative agriculture energy use and carbon monitoring and planning tools to reduce on-farm GHG emissions from energy and fertilizer application or to increase carbon storage, as well as to promote on-farm energy production opportunities.

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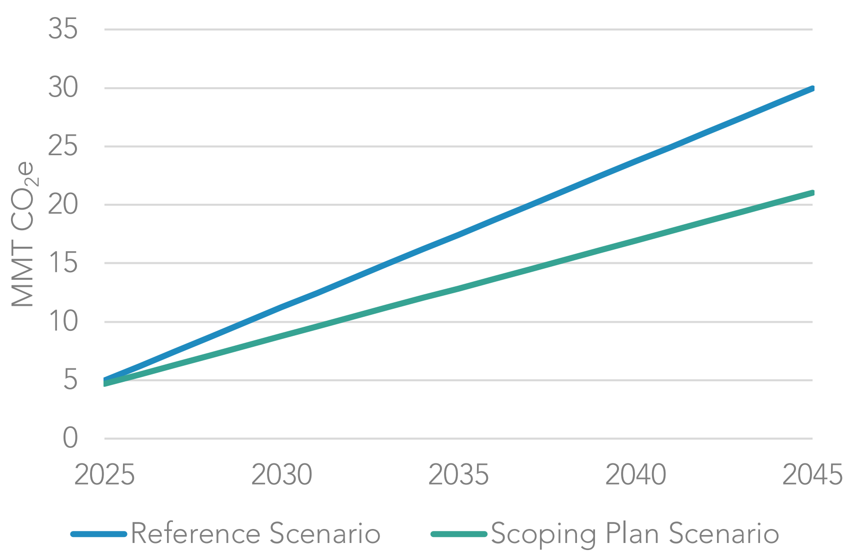
[493] California Department of Food and Agriculture. 2021. Farmer and Rancher Led Climate Change Solutions. https://www.cdfa.ca.gov/oefi/climate/docs/cdfa_farmer_and_rancher-led_climate_solutions_meetings_summary.pdf.
[494] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N5, N7. finalejacrecs.pdf (arb.ca.gov).
[495] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations N3, N4, N5, N7, N22. finalejacrecs.pdf (arb.ca.gov).
[496] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N11. finalejacrecs.pdf (arb.ca.gov).

Wetlands

Wetlands cover 2 percent of the state (roughly 1.7 million acres) and include inland and coastal wetlands, such as vernal pools, peatlands, mountain meadows, salt marshes, and mudflats. These lands are essential to California's communities as they serve as hotspots for biodiversity, contain considerable carbon in the soil, are critical to the state's water supply, and protect upland areas from flooding due to sea level rise and storms. Wetlands have been severely degraded through reclamation, diking, draining, and dredging practices in the past, resulting in the emissions of the carbon stored in the soils and the loss of ecosystem benefits. Climate smart strategies to restore and protect all the types of wetlands can reduce emissions while simultaneously improving the climate resilience of surrounding areas and improving the water quality and yield for the state. Restored wetlands also can reduce pressure on California's aging water infrastructure. These benefits beyond emissions reductions will help in the future, as climate change is predicted to negatively affect water supply.

Avoided conversion and restoration of Delta wetlands reduces CO_2 and methane emissions from wetlands, with GHG reductions scaling with implementation rates (Figure 4-24). Expansion of conservation and restoration efforts will generate benefits such as the conservation of biodiversity, improved water quality and supply, and reduced flood risk. Additional details on the climate benefit potential of wetlands can be found in Section 2 of the NWL Climate Smart Strategy.

Figure 4-24: Cumulative CO_2e emissions from Delta wetlands by 2045



Strategies for Achieving Success

- Restore 60,000 acres of Delta wetlands annually by 2045 to reduce methane emissions from wetlands and reverse the resulting subsidence.

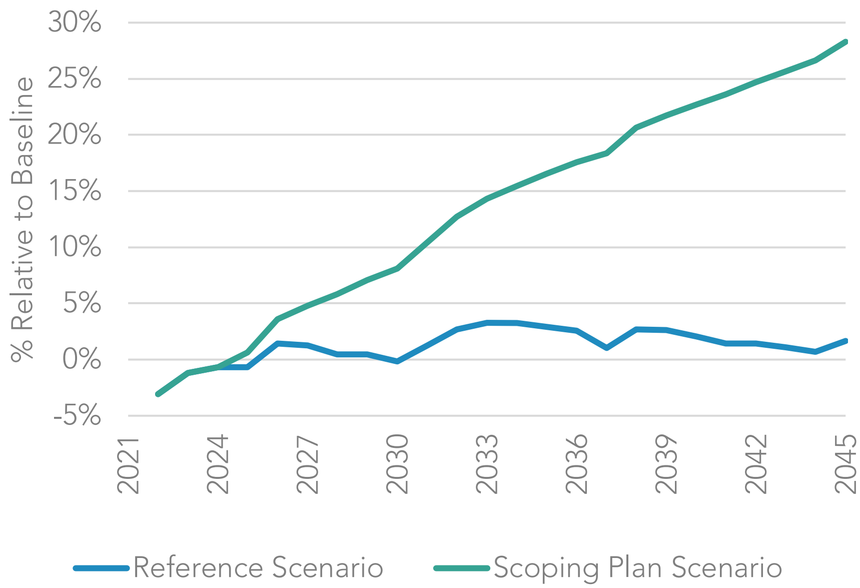
- Identify and prioritize wetland restoration efforts around climate vulnerable communities.
- Leverage other funding and institutions to support wetland restoration projects, including land trusts, local funding (e.g., San Francisco Measure AA), federal funding, and private and philanthropic funding to support wetlands restoration projects.
- Work across state agencies to reduce regulatory and permitting barriers around wetland restoration projects, where appropriate.

Developed Lands

Developed lands cover 6 percent of the state (roughly 6.8 million acres) and include urban, suburban, and rural areas, as well as transportation and supporting infrastructure throughout California. This area encapsulates the land on which the vast majority of Californians reside and call home. The vegetation within cities and communities, and along infrastructure, are all part of developed lands. This vegetation provides numerous benefits to surrounding areas, including carbon storage, air and water filtration, reduced urban heat island effect, and access to nature, aesthetics, and mental health, among others. These areas are susceptible to climate change as well, and climate smart strategies to protect and expand the urban forests, landscaping, green spaces, parks, and associated vegetation can increase their climate resilience and the benefits Californians derive from them. These strategies also have a significant opportunity to benefit disadvantaged communities, who may not have equitable access to these practices or the benefits they provide. Additional details on the climate and equity benefit potential of developed lands can be found in Section 2 and the Introduction of the NWL Climate Smart Strategy.

Urban forests have a significant potential to sequester carbon (Figure 4-25). They are vastly different from wildland forests, as they require investments to maintain and irrigate. This results in the need for a significant increase in investment to increase urban forest carbon. As urban forests become denser and management difficulty increases, the carbon stock returns on investment diminish, making it expensive to maximize carbon in urban forests. Water availability and irrigation efficiency are also an important consideration for increasing urban forest cover. As water becomes scarcer, the prioritization of irrigating trees over lawns or gardens may be required to achieve increases in urban forest carbon.

Figure 4-25: Carbon stocks in urban forests by 2045



Within wildland-urban interface (WUI) areas, defensible space can protect urban and rural communities from wildfire. Analysis results show that 48 percent of parcels are currently fully compliant with defensible space requirements. This highlights how much work needs to be done to protect communities and homes. Defensible space results in a decrease in carbon stocks, as expected when reducing fuels for wildfire.

Strategies for Achieving Success

- Increase urban forestry investment annually by 200 percent, relative to business as usual.
- Increase public awareness of urban forest benefits and, where appropriate, prioritizing irrigation of trees over lawns.
- Provide technical assistance and resources to disadvantaged communities to implement community urban greening projects to provide equitable access to the benefits of urban greening projects.[497]
- Work with state and local agencies to expand technical assistance for and enforcement of the defensible space requirements of PRC 4291 to reduce wildfire risk to homes and structures.

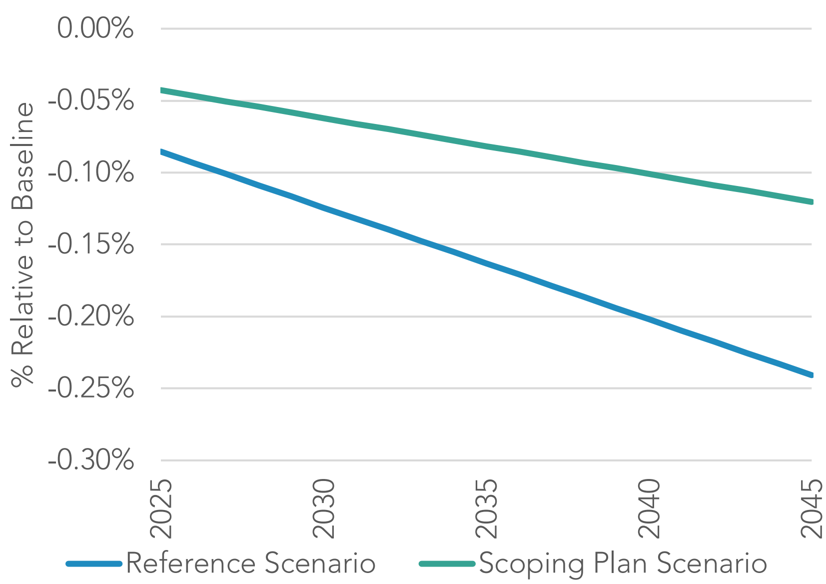
[497] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N8. *finalejacrecs.pdf (arb.ca.gov)*.

Sparsely Vegetated Lands

Sparsely vegetated lands cover 10 percent of the state, roughly 10.2 million acres, primarily in the east and southern parts of California. These lands include deserts, beaches, dunes, bare rock, and areas covered in ice and snow (e.g., higher mountain elevations). The limited carbon storage of these lands varies from bare rock and mineral soil to more vegetated areas, though severe climate limits the amount of biomass. Nonetheless, sparsely vegetated lands are important for open space and provide rare and unique habitats for endemic species and a diversity of wildlife. These lands present important recreational opportunities for Californians and serve as important protective buffers in coastal and low-lying areas. Land use change threatens these lands, and conservation efforts are important for protecting these unique areas of California.[498]

Avoided conversion of sparsely vegetated lands reduces the organic carbon lost from the soil, which is the major carbon pool in this land type (Figure 4-26). In identifying the outcomes for sparsely vegetated lands, CARB modeled avoided land conversion to another land use.

Figure 4-26: Carbon stocks in sparsely vegetated lands by 2045



Strategies for Achieving Success

- Establish and expand mechanisms that ensure sparsely vegetated lands are

[498] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N26. finalejacrecs.pdf (arb.ca.gov).

protected from land conversion, prioritizing those areas most vulnerable to climate change and loss.

Additional Management Strategies

Additional nature-based climate solutions beyond those management strategies modeled for this Scoping Plan are available for implementation, but either cannot currently be modeled and/or affect carbon and the landscape in ways that cannot currently be tracked. Nevertheless, it is important to take action even where these technical gaps exist. Some of these actions, such as cultural burning and indigenous farming practices, have been used on large scales for decades or even centuries, while others are relatively new concepts. The state nevertheless recommends implementing the additional solutions listed here to achieve potential additional climate benefits, as well as other co-benefits. These additional solutions were drawn from the NWL Climate Smart Strategy and stakeholder, tribal government, and interagency feedback.[499]

Considerations

Although these practices are recommended, because of the lack of in-depth modeling and analysis available, several considerations must be addressed when implementing them. These considerations also apply to the management strategies included in the Scoping Plan Scenario.

- Future climate change impacts are uncertain: The negative impact that climate change can have on the ability of these practices to maintain expected climate benefits is uncertain and may significantly change in the future. Climate change is expected to further diminish the already constricting growing conditions in California, with increasing droughts, more extreme weather events, and expanding disturbances from fire, insects, and disease. It is estimated that suitable habitat for many native plant and animal species could shift, creating novel ecosystems without historical precedent. Close monitoring of all practices, including no management, across our NWL will be critical to understand if and how future climate change affects outcomes and how to adapt management to meet the needs of the system under climate change.[500]

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[499] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N24. *finalejacrecs.pdf (arb.ca.gov)*.
[500] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N15. *finalejacrecs.pdf (arb.ca.gov)*.

- Local conditions: Not every practice is applicable, feasible, or even desirable in every location across California. Implementation of these practices should account for local conditions and needs that may affect the appropriateness of that practice.
- Long-term carbon storage: The ability to sequester additional carbon into NWL is only beneficial to the climate if that carbon stays out of the atmosphere. Many of the additional practices listed here may require continual incentives or interventions to ensure permanence of carbon storage in the soil and biomass. For example, in croplands, it is difficult to estimate how much of the carbon stored by no-tillage can be released by a single subsequent tillage, but a return to conventional tillage would usually be expected to erase most gains.[501,502]
- Scaling actions: There are uncertainties on how these practices may impact both the environment and communities when significantly expanded. For this reason, it is best to take a cautious and measured approach to ramping up actions to a larger scale.
- Infrastructure and operational needs: Scaling up the implementation of some of these practices demands transformational change in the supporting infrastructure and operational frameworks. For example, increasing forest management to the degree included in the Scoping Plan Scenario will require significant changes to wood-processing infrastructure, workforce capacity, permitting processes, technical assistance, and other operational constraints. The increased application of compost to croplands, and potentially to rangelands, will require a significant increase in organic waste and dairy manure collection to increase compost supply, in line with SB 1383. This will also require additional compost production facilities as well as compost/organic waste transportation and application methods.
- Co-benefits: Many co-benefits from these practices exist beyond the climate benefits. These co-benefits include improved public and worker health; improved microbial, insect, and wildlife habitat; enhanced biodiversity; greater labor demand in the nature-based economy; and improved climate resilience.
- Labor and Economics: Many of these practices require additional labor, and an evaluation of how many more jobs are needed to carry out many of these practices

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[501] Muñoz-Romero, V., R. J. Lopez-Bellido, P. Fernandez-Garcia, R. Redondo, S. Murillo, and L. Lopez-Bellido. 2017. "Effects of tillage, crop rotation and N application rate on labile and recalcitrant soil carbon in a Mediterranean Vertisol." *Soil Tillage Res.* 169, 118–123.
[502] Mitchell, J. P., A. Shrestha, W. R. Horwath, R. J. Southard, N. Madden, J. Veenstra, and D. S. Munk. 2015. "Tillage and cover cropping affect crop yields and soil carbon in the San Joaquin Valley." *California. Agron. J.* 107, 588–596.

is currently unknown. There will also be the need to explore the costs and economic benefits of implementing these additional practices.

- Retreatments: All of these practices have limits on how long they can enhance carbon sequestration. Many of these practices need to be periodically repeated, followed by complementary practices, or maintained through time. This increases costs and requires diligence and long-term stewardship.

Additional NWL Actions and Strategies

Below is a set of additional actions that should be taken on California's natural and working lands. Again, these practices were not modeled for this Scoping Plan, and all of the considerations listed above should be taken into account before implementing the following actions.

- Conservation of all NWL types (in line with the NWL Climate Smart Strategy and CNRA's Pathways to 30x30 California) is critical to ensuring continued carbon sequestration and provision of co-benefits from these lands for all Californians.[503]
- Reforestation following disturbance, using appropriate species, is an impactful practice that can help prevent conversion away from forestland and establish new trees to sequester carbon. The number of acres that may need reforestation following high severity wildfires is estimated to continue to increase into the future.
- Restoration of shrublands, chaparral, riparian zones, and oak woodlands across California includes a variety of practices to alter their structure and return endemic species to the areas. These unique habitats provide multiple co-benefits to the state, such as clean water, reduced wildfire risk, and biodiverse habitats for flora and fauna.
- Conservation and restoration of wetlands, beyond the Delta wetlands included in the NWL modeling, can protect these unique habitats and the climate benefits they provide. These wetland types can include but are not limited to coastal wetlands, mountain meadows, vernal pool complexes, alkali sinks and meadows, and floodplains.
- Conservation and restoration of seagrasses and seaweeds provide a number of benefits, including carbon storage and sequestration, habitat provision for many culturally and commercially important species of fishes and invertebrates, shoreline protection, and tourism opportunities.[504]

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[503] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N26, N27. *finalejacrecs.pdf (arb.ca.gov)*.

[504] AB 32 EJ Advisory Committee. 2022 Scoping Plan Recommendations, N2. *finalejacrecs.pdf (arb.ca.gov)*.

- Prescribed herbivory utilizes various livestock to consume vegetation to reduce fuel loads across an area. This fuel management practice can be used in forests, grasslands, and shrublands as an effective alternative to herbicide use, and should be considered wherever local conditions allow.
- Urban and community greening efforts such as green schoolyards, urban farms, rain gardens, community gardens, community composting, and many more provide numerous health benefits to communities.
- Additional Healthy Soils Program practices on annual croplands such as conservation cover and crop rotation, biomass planting for borders, wind barriers, riparian areas, and improved nutrient management can improve soil health, water retention, and increase carbon stocks.
- Healthy Soils Program practices on perennial croplands and rangelands, such as compost application and alley cropping/cover cropping to improve soil health, water retention, erosion control, and biomass growth.[505]
- Stacking of these Healthy Soils Program practices, where appropriate, in perennial and annual systems, can synergistically improve soil health and provide multiple benefits.
- Mulching adds high carbon materials to croplands or fallowed lands to reduce competing vegetation and retain moisture. This practice can support other benefits such as reduced water use and reduced synthetic pesticide and fertilizer use, as well as provide a use for suitable forest and agricultural waste biomass.
- Reductions in the use of synthetic fertilizers in cropland management, generally supported by the implementation of new management tools or technologies, can lead to reductions in GHG emissions from the production and application of fertilizers. This benefit is in addition to the co-benefits of reduced chemical runoff into waterways and reduced exposure of human populations to their harmful effects.

[505] Various types of organic amendments are being researched for application to particular landscape types. For example, compost application to rangelands is a relatively new practice that has been shown to improve soil health and increase carbon sequestration in the short term, though the science on the long-term impacts of this practice is still developing and the supply of available compost may be limiting.

Chapter 5: Challenge Accepted

This chapter provides an overview of the next steps and partnerships that will be needed to successfully implement this Scoping Plan. The path forward is not dependent on one agency, one state, or even one country. It will take action on a global level to address the threat climate change poses. But, the work begins at home.[506] The state can lead by engaging Californians and demonstrating how action at the state, regional, and local levels of government, as well as action at community and individual levels, can contribute to addressing the challenge before us. We must build partnerships with academic institutions, private industry, and others to support and accelerate the transition to carbon neutrality. Ultimately, the success of this Scoping Plan will be measured by our ability to implement the actions modeled in the Scoping Plan Scenario at all levels of government and society. This will depend on a mix of legislative action, regulatory program development, incentives, institutional support, workforce and business development, education and outreach, community engagement, and research and development and deployment. Optimizing this mix will help to ensure that clean energy and other climate mitigation strategies are clear, winning alternatives in the marketplace and in communities—to promote equity, drive innovation, and encourage consumer adoption. Bold institutional action will catalyze continued research and push private investment to create jobs and bring innovative ideas to reality.

State-level Action

Achieving the targets described in this Scoping Plan will require continued commitment to and successful implementation of existing policies and programs and identification of new policy tools and technical solutions to go further, faster. California's Legislature and state agencies will continue to collaborate to achieve the state's climate, clean air, equity, and broader economic and environmental protection goals. It will be necessary to maintain and strengthen this collaborative effort, and to draw upon the assistance of the federal government, regional and local governments, tribes, communities, academic institutions, and the private sector to achieve the state's near-term and longer-term emission reduction goals and a more equitable future for all Californians.

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[506] This "polycentric" approach to climate challenges, engaging many levels of government, was articulated in leading papers by Nobel laureate Elinor Ostrom. See, for example, Ostrom, E. 2014. "A Polycentric Approach to Coping with Climate Change." *Annals of Economics and Finance* 15-1, 97–134.

Regulations and Programmatic Development

Meeting the AB 32 2020 GHG emissions reduction target several years earlier than mandated demonstrated that developing mitigation strategies through a public process, where all stakeholders have a voice, leads to effective actions that address climate change and yields a series of additional economic and environmental co-benefits to the state. Following adoption of this Scoping Plan, state agencies will continue to update and implement new and existing programs to align with the outcomes in the plan. Community, tribal, and stakeholder engagement will be a critical part of this work. Several state agencies, including CARB, the CEC, the California State Transportation Agency (CalSTA), the CPUC, and others will need to be part of various subsequent rulemaking processes. Each of these agencies' leadership and technical staff will engage with the public through public meetings, written and oral comment, and other methods of engagement. This work will be informed by evaluations of the health, air quality, environmental, equity, and economic benefits and impacts of regulations, including an assessment of the societal cost of carbon, as required under AB 197.

Incentive Programs

As described in Chapter 1, incentive programs are one of the most important tools the state has in advancing our low carbon future, especially for climate vulnerable communities. The programs ensure clean technology and energy are accessible and are critical to closing ongoing opportunity gaps. These programs also leverage private-sector investment and build sustainable, growing markets for clean and efficient technologies, and they are particularly necessary to support GHG emission reduction strategies for priority sectors, sources, and technologies. Clean technologies are often already the best and lowest cost option over their lifetimes but incentive funding is critical to ensure that they are broadly available, especially in climate vulnerable communities. Incentives also build on California's long track record of driving innovative technology developments, and creating new industries, with targeted investment. The Inflation Reduction Act also provides a new source of funding and tax incentives that must be leveraged to help achieve the state's climate goals.

Many state funding programs are designed to achieve multiple objectives simultaneously: reduce emissions from GHGs, criteria pollutants, and toxic air contaminants; manage natural and working lands for carbon sequestration; and address health and opportunity gaps in disadvantaged communities. California's incentive programs focused on jump-starting the transition to a zero emission transportation future are a good example of this "stacked" approach. The state is investing billions of dollars through programs such as the On-Road Heavy-Duty Voucher Incentive Program and Clean Cars 4 All in order to replace the light- and heavy-duty vehicles most responsible for the state's GHG emissions and poor air quality, all while bolstering the nascent ZEV market. Further strategies aid in developing new technologies, in ramping up access for all, and in shifting to cleaner modes of transport; for instance, by supporting investments in walkable, bikeable communities and transit, as well as in vehicles. This funding strategy is, of course, paired with the regulatory approach described above.

Local Action

Local action by cities can support and amplify efforts to reduce GHGs. For example, the City of Oakland requires all new construction to be all-electric and is currently working on electrifying existing buildings.[507] In addition, starting in 2023, the City of Sacramento will require all new buildings under three stories to be all-electric, and it extends the mandate to all new construction by 2026 with some limited exemptions. The City of Sacramento also requires levels of EV charging infrastructure in new construction starting in 2023, higher than the minimum state requirements, and provides parking incentives for zero-emission carsharing and EV charging.[508] Local governments asserting this type of leadership are critical partners in supporting state-level measures to contain the growth of GHG emissions associated with the transportation system and the built environment.

California must accommodate population and economic growth in a far more sustainable and equitable manner than in the past. Good climate policy can and should create affordable and pleasant places to live, with effective transport and clean air for all—a future in which local governments and communities are central partners. Local governments have the primary authority to plan, zone, approve, and permit how and where land is developed to accommodate population growth, economic growth, and the changing needs of their jurisdictions. They also make critical decisions on how and when to deploy transportation infrastructure, and can choose to support transit, walking, bicycling, and neighborhoods that do not force people into cars. Local governments also have the option to adopt building ordinances that exceed statewide building code requirements, and play a critical role in facilitating the rollout of ZEV infrastructure. As a result, local government decisions play a critical role in supporting state-level measures to contain the growth of GHG emissions associated with the transportation system and the built environment—the two largest GHG emissions sectors over which local governments have authority.

Local governments are also frequently the source of innovative and practical climate solutions that can be replicated in other areas. Their efforts to reduce GHG emissions within their jurisdictions are vital to achieving the state's near-term air quality and long-term climate goals. Local governments must continue to take action that affirmatively

[507] City of Oakland. Building Electrification. *https://www.oaklandca.gov/projects/building-electrification*.
[508] City of Sacramento. Electrification of New Construction. *http://www.cityofsacramento.org/SacElectrificationOrdinance*.

builds the projects and expend the funds needed to further the state's collective path toward equitable emissions reductions. As such, aligning local jurisdiction action with state-level priorities to tackle climate change and the outcomes called for in this Scoping Plan is critical to achieving the statutory targets for 2030 and 2045. Local governments can implement climate strategies that can effectively engage residents by addressing local conditions and issues that also deliver local economic benefits.

Local Climate Action Planning and Permitting

California encourages local jurisdictions to take ambitious, coordinated climate action at the community scale; action that is consistent with and supportive of the state's climate goals.[509] As discussed in more detail in Appendix D (Local Actions), local jurisdictions can do much to enable statewide priorities, such as taking local action to help the state develop the housing, transport systems, and other tools we all need. Indeed, state tools—such as the Cap-and-Trade Program or zero-emission vehicle programs—do not substitute for these local efforts. Multiple legal tools are open to local jurisdictions to support this approach, including development of a climate action plan (CAP), sustainability plan, or inclusion of a plan for reduction of GHG emissions and climate actions within a jurisdiction's general plan. Any of these can help to align zoning, permitting, and other local tools with climate action.

Once adopted, the GHG emissions reductions plans detailed in CAPs can provide local governments with a valuable tool for coordinated climate planning in their community. When a local CAP complies with CEQA requirements, individual projects that comply with the CAP are allowed to streamline the project-specific GHG analysis.[510,511] Effectively, local governments that adopt a CEQA-compliant CAP enable project developers to use this streamlined approach. This saves time and resources and provides more consistent expectations for how GHG reduction measures are applied across projects in the jurisdiction. While the state encourages local governments to follow this approach, we acknowledge not all jurisdictions have the resources to develop a CAP that meets the CEQA requirements.

In addition to being required for a local CAP to comply with CEQA, local GHG reduction targets have long been recommended as part of the process of developing a climate

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[509] This plan provides more detailed guidance and tools to local governments in Appendix D (Local Actions).

[510] Cal. Code of Regs., tit. 14, § 15183.5.

[511] California Governor's Office of Planning and Research. n.d. "General Plan Guidelines - Chapter 8 Climate Change."

action plan.[512] One challenge local jurisdictions have faced is how to evaluate and adopt quantitative, locally appropriate goals that align with statewide goals. An effective response to this challenge is to focus on goals that can help implement overall state priorities—enabling the key transformations California needs.

There are many ways that local governments can make key contributions to this transformation, depending on the characteristics of their jurisdiction and community. For example, some jurisdictions will inherently have more land capacity to remove and store carbon, whether through natural and working lands or by other means. Other jurisdictions will be host to GHG-emitting facilities that serve necessary functions and will take time to transition to clean technology (e.g., municipal wastewater treatment plants, landfills, and energy generation and transmission facilities). It is important to recognize that we will need to build new energy production and distribution infrastructure, and repurpose existing ones, for clean technology and energy before we are able to phase down existing fossil sources. There also will be a need to handle the significant amount of biomass resulting from sustainable forest management for catastrophic wildfire prevention, agricultural waste, and landfill diversion.

Regional efforts can support change too: energy and transportation systems that serve Californians do not stop at jurisdictional boundaries, and some local decisions can have ramifications for other communities. For instance, Metropolitan Planning Organizations (MPOs) can help to integrate local efforts by planning consistent with the Scoping Plan and Climate Action Plan for Transportation Infrastructure, including by removing polluting roadway capacity expansions from project pipelines and instead focusing on climate-friendly solutions. These varied capabilities and needs should be taken into account in setting targets for local climate plans. For instance, although net zero targets can often be valuable and achievable, and mitigation is important, targets should be considered in the larger context of these goals. This all means any GHG targets on a local scale should take into consideration the actions and outcomes included in this Scoping Plan. Jurisdictions considering "net zero" targets should carefully consider the implications such targets may have on emissions in neighboring communities and the ability of the state to meet our collective targets.

Jurisdictions without formal CAPs also have important opportunities within this context. These jurisdictions can still take actions that effectively translate key state plans, goals, and targets, including those articulated in this Scoping Plan for local action. For instance, state ZEV targets can advance local efforts to promote broad and equitable access to charging and fueling. Similarly, local jurisdictions can enable reduced dependence on

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[512] Climate Smart Communities. 2014. Climate Action Planning Guide. https://cdrpc.org/wp-content/uploads/2015/05/CAP-Guide_MAR-2014_FINAL.pdf.

single-occupancy vehicles by supporting dense infill housing and transit, among other actions. Such actions can be reflected in particular project plans, in general plans, or through other local policies. Regional partnerships among these jurisdictions can also help tap resources and provide for more effective overall action.

Unlocking CEQA Mitigation for Local Success

The California Environmental Quality Act also provides important tools for lead agencies to support the achievement of the state's GHG and VMT reduction goals. Although many climate-friendly local government actions already fall into categories that may not require a full CEQA analysis, thanks to streamlining or other tools, and although certain product types (such as affordable infill housing) are generally clearly consistent with state climate goals, CEQA analyses may still sometimes be required. CEQA can be a powerful and useful tool to engage the public, identify additional opportunities to support climate efforts, and localize change. It is important that lead agencies look for ways to use CEQA to support these core purposes, ensuring that these processes do not become sources of delay but instead unlock more opportunities. The uncertainty analysis in Chapter 2 evaluates how project implementation delays can lead to missed state climate targets and continued dependence on fossil energy. Mitigation measures applied in the communities affected by projects subject to CEQA have the added benefit of improving health, social, and economic resiliency as climate impacts worsen.

Appendix D (Local Actions) explores the role of local government action and CEQA in detail. As discussed there, an important CEQA-related tool is mitigation—which can be used to further drive local action consistent with state climate goals. When a lead agency determines that a proposed project would result in potentially significant GHG impacts due to its GHG emissions or a conflict with state climate goals, the lead agency must impose feasible mitigation measures to minimize the impact. Appendix D (Local Actions) provides suggestions for prioritizing the various types of mitigation, starting with on-site GHG-reducing design features[513] and mitigation measures, such as methods to reduce VMT and support building decarbonization, access to shared mobility services or transit, and EV charging. After exhausting all the on-site GHG mitigation measures, CARB recommends prioritizing local, off-site GHG mitigation measures, including both direct investment and voluntary GHG reduction or sequestration projects, in the neighborhoods impacted by the project. This could include, for example, development of a neighborhood green space, investment in street trees, or expansion of transit services. Implementing GHG mitigation measures in the project's vicinity would allow the project proponent and the lead agency to work directly with the affected community to identify and prioritize the

[513] Cal. Code of Regs., tit. 14, § 15126.4(c)(2) and (3).

mitigation measures that meet their needs while minimizing multiple environmental and societal impacts.

Once all potential on-site and local off-site GHG mitigation measures have been incorporated to the extent feasible, Appendix D (Local Actions) provides further suggestions for prioritizing other mitigation types, including non-local off-site mitigation, and voluntary offsets issued by a recognized and reputable voluntary carbon registry (as listed on CARB's website[514]) may be appropriate. Additional in-state mitigation also may be available in the upcoming SB 27[515] (Skinner, Chapter 237, Statues of 2021) registry, which will serve as a database of projects in the state that drive climate action on natural and working lands. Lead agencies should use substantial evidence to demonstrate that the project proponent explored and prioritized investments in feasible, local mitigation prior to moving mitigation to a geography located farther away from the project.

Communities and Environmental Justice

As noted in Board Resolution 20-33,[516] it is incumbent on CARB to function as an agent of responsible social change, especially when it is clear that environmental injustices continue to persist for low-income communities, tribes, and communities of color.

State law defines *environmental justice* as the fair treatment of all people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies.[517] Government Alliance for Race and Equity (GARE)[518] defines *racial equity* as when race can no longer be used to predict life outcomes and outcomes for all groups are improved.

For this Scoping Plan to be successful, it must address environmental justice and advance racial equity. Implementation of the plan needs to address the needs of those communities that are disproportionately burdened by climate impacts and continue to face significant health and opportunity gaps. Now, we need to ensure our actions allow these communities to not only have a seat at the table, but also inform and shape the policies

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[514] CARB. 2022. Offset Project Registries. https://ww2.arb.ca.gov/our-work/programs/compliance-offset-program/offset-project-registries.

[515] SB 27. Carbon sequestration: state goals: natural and working lands: registry of projects. (SB 27, Skinner, Chapter 237, Statutes of 2021). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220SB27.

[516] CARB. 2020. Resolution 20-33: A Commitment to Racial Equity and Social Justice. October 22. https://ww2.arb.ca.gov/sites/default/files/barcu/board/res/2020/res20-33.pdf.

[517] Gov. Code, § 65040.12, subd. (e).

[518] Local and Regional Government Alliance on Race and Equity. 2015. *Advancing Racial Equity and Transforming Government: A Resource Guide to Put Ideas into Action.* Page 9. https://racialequityalliance.org/wp-content/uploads/2015/02/GARE-Resource_Guide.pdf.

to ensure their communities thrive. With this Scoping Plan, the state also adds a new tool to identify which communities will be the least resilient in the face of selected climate impacts and will see disproportionate economic impacts as a result. As described in Chapter 3, the CVM will enable the state to target programs and policies to build resiliency in the specific regions that will feel climate impacts more acutely due to existing health and opportunity disparities leading to disproportionate economic impacts. This tool will be critical in the state's efforts to address climate impacts while accounting for environmental injustices and racial inequities. CARB will incorporate the CVM into its work as it moves forward and will share this new tool with other agencies to align our efforts. The goal is to keep expanding the CVM to incorporate additional climate impacts to better identify disproportionate economic impacts as community level data becomes available.

AB 617 is another important tool for both Air Districts and CARB to bring resources to communities that have long been disproportionately burdened by poor air quality. While AB 617 does not require local agencies to participate in the Community Air Protection Program, several AB 617 communities are finding ways to bring local land use agencies to the table to respond to community priorities. We look forward to more opportunities to foster relationships with local authorities and continued collaboration between state and air district programs.

In alignment with AB 32, and to ensure environmental justice and racial equity were integrated into this Scoping Plan, CARB reconvened the AB 32 Environmental Justice Advisory Committee (EJ Advisory Committee) to advise CARB on the development of this Scoping Plan. Since reconvening in May 2021, the EJ Advisory Committee has engaged in the following activities:

- In October 2021, the EJ Advisory Committee sent a letter to the governor requesting a timeline extension for the Scoping Plan process. In response to the EJ Advisory Committee's letter, CARB modified this Scoping Plan process[519] and committed to an active engagement with the EJ Advisory Committee following the approval of this Scoping Plan. The EJ Advisory Committee also presented to the CARB Board[520] at its October 2021 Board meeting, reiterating its request for a timeline extension, as well as sharing additional concerns about process.

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[519] Randolph, L. M. 2021. LMR October 19 response to Environmental Justice Advisory Committee Letter. https://ww2.arb.ca.gov/sites/default/files/2021-10/LMR%20October%2019%20response%20to%20EJAC%20Letter%20Final.pdf.

[520] Argüello, M. D., K. Hamilton, S. Taylor, and P. Torres. 2021. EJ Advisory Committee Co-Chair Informational Presentation to CARB Board. October 28. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2021/102821/21-11-4pres.pdf.

- In December 2021, the EJ Advisory Committee shared its responses to Scenario Input Questions,[521] as well as a narrative document outlining their concerns[522] around the process, the need for evaluation, and the need for a tribal representative. In response to the EJ Advisory Committee Scenario Input Questions, CARB incorporated the EJ Advisory Committee responses into the Scenario Assumptions document,[523] and modeled results from PATHWAYS.[524] In response to the EJ Advisory Committee's concerns, CARB worked diligently to appoint a tribal representative[525] in February 2022, and to outline additional opportunities for the EJ Advisory Committee to engage in the Scoping Plan process.[526]
- In March 2022, the EJ Advisory Committee presented at the joint EJ Advisory Committee / CARB Board meeting[527] and walked through their preliminary draft recommendations to inform this Scoping Plan. In April, the EJ Advisory Committee shared its revised preliminary draft recommendations[528] to inform this Scoping Plan.
- In September 2022, the EJ Advisory Committee presented at the joint EJ Advisory Committee / CARB Board meeting[529] and engaged in discussion about priority items as they relate to incorporating environmental justice into the Scoping Plan. By the end of September, the EJ Advisory Committee shared its final

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[521] EJ Advisory Committee. 2021. EJ Advisory Committee Final Responses to CARB Scenario Inputs. December 2. *https://ww2.arb.ca.gov/sites/default/files/2021-12/EJAC%20Final%20Responses%20to%20CARB%20Scenario%20Inputs_12_2_21.pdf*.

[522] EJ Advisory Committee. 2021. EJ Advisory Committee Responses to Scenario Input Questions. EJ Advisory Committee narrative document regarding scenario input recommendations. December 1. *https://ww2.arb.ca.gov/sites/default/files/2021-12/EJAC%20Narrative%20Document%20re%20Scenario%20Input%20Recommendations%2012_1_2021.pdf*.

[523] CARB. 2021. PATHWAYS Scenario Modeling. *https://ww2.arb.ca.gov/sites/default/files/2021-12/Revised_2022SP_ScenarioAssumptions_15Dec.pdf*.

[524] E3. 2022. CARB Draft Scoping Plan AB32 Source Emissions Initial Modeling Results. March 15. *https://ww2.arb.ca.gov/sites/default/files/2022-03/SP22-Model-Results-E3-ppt.pdf*.

[525] CARB. AB32 EJ Advisory Committee Meeting, February 28, 2022 CARB Update. *https://ww2.arb.ca.gov/sites/default/files/2022-02/CARB%20EJAC022822presentation.pdf*.

[526] Fletcher, C. 2021. CARB Response to EJ Advisory Committee Narrative. CARB. December 15. *https://ww2.arb.ca.gov/sites/default/files/2021-12/CARB%20response%20to%20EJAC%20Narrative.pdf*.

[527] EJ Advisory Committee. 2022. EJ Advisory Committee Presentation: Preliminary Draft Recommendations. March 10. *https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/031022/ejacpres.pdf*.

[528] AB 32 EJ Advisory Committee. Draft Recommendations. *https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/031022/ejacrecsrevised.pdf*.

[529] EJ Advisory Committee. 2022. EJAC Presentation. September 1. *https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/090122/ejacpres.pdf*

recommendations[530] to inform this Scoping Plan. To the extent possible, CARB has incorporated and cited these recommendations through this Scoping Plan.

In addition to the activities listed above, Central Valley EJ Advisory Committee members hosted a successful community engagement workshop[531] in San Joaquin Valley in February 2022 with over 100 attendees. Members of EJ Advisory Committee hosted a statewide community engagement workshop[532] in June 2022 with more than 165 attendees. Throughout the EJ Advisory Committee's process, members of the Committee continued to work with their communities to ground truth their recommendations to inform the development of the Scoping Plan. The EJ Advisory Committee worked hard to ensure the voices of those communities most burdened by climate impacts were reflected in the plan. The EJ Advisory Committee will continue to play an ongoing role in the implementation of this Scoping Plan to ensure environmental justice and racial equity are prioritized in our effort to address the climate challenge before us.

To the extent possible, the EJ Advisory Committee's recommendations were integrated throughout the plan. This plan directly cites instances where there is alignment between the plan and the EJ Advisory Committee recommendations. This approach seeks to ensure there is more transparency and identify consensus that exists, as well as relevant ways equity and environmental justice are addressed in this plan and in the planning for future related implementation activities. CARB is dedicated to its efforts to ensure this plan does not leave communities behind.

As this Scoping Plan moves into the implementation phase, there will be a need to better understand how to address EJ Advisory Committee recommendations on the following topics:

- Actions under the jurisdiction of other agencies: there are certain EJ Advisory Committee recommendations that are outside of CARB's jurisdiction. As the EJ Advisory Committee continues to convene, it would be helpful to understand the

[530] EJ Advisory Committee. 2022. EJAC 2022 Scoping Plan Recommendations. September 30. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/090122/finalejacrecs.pdf

[531] San Joaquin Valley Climate Justice & the Scoping Plan. 2022. https://ww2.arb.ca.gov/sites/default/files/2022-07/SJV%20Climate%20Justice%20%26%20the%20Scoping%20Plan%20Workshop%20Report%20out%20%26%20Recommendations_5.2022.pdf

[532] EJAC. 2022. *EJAC/Community Engagement Synthesis Report '22.* https://ww2.arb.ca.gov/sites/default/files/2022-07/EJAC-CommunityEngagement-SynthesisReport-2022-English%26Spanish.pdf.

role that CARB can play as it relates to the EJ Advisory Committee's recommendations for actions outside CARB's jurisdiction and coordinates with sister agencies.

- Actions that require legislative direction: there are certain EJ Advisory Committee recommendations that would require legislative action. As the EJ Advisory Committee continues to convene, it will be helpful to understand how CARB can work with the EJ Advisory Committee to share these recommendations with the appropriate members of the Legislature.
- Actions directly tied to implementation activities: This Scoping Plan is not an implementation document; it is a plan to chart a course to continue to reduce GHG emissions and achieve carbon neutrality. Once the Scoping Plan is approved, there will be follow-up action at CARB, as well as at other agencies. In these follow-up efforts, there will be a role for ongoing EJ Advisory Committee engagement.
- Actions to implement recent legislation, such as SB 905.

CARB proposes to continue to work with the EJ Advisory Committee to better understand how to move forward on EJ Advisory Committee recommendations that fall into the topics listed above and any other recommendations that were not included in this plan. It is also important to note that there are numerous recommendations where CARB shares the goals of the EJ Advisory Committee and can assist in implementation steps. Examples include the following:

- CARB shares the goal of prioritizing non-fossil energy generation and supports non-fossil projects and opportunities to locate behind-the-meter clean resources in communities of concern in programs such as the Solar on Multifamily Affordable Housing program.
- CARB will engage with agencies and academic institutions to further workforce development.
- Many other recommendations related to financial support for various energy projects, such as microgrids, are within the purview of the CPUC or local publicly owned utilities. Similarly, utility scale projects are within the jurisdiction of other agencies. However, CARB supports strategies identified in the recommendations such as offshore wind to reduce the reliance on fossil fuel generation.
- CARB is supportive of rooftop solar, although it is not within CARB's jurisdiction to determine how incentives for those projects are structured.
- CARB is supportive of strong energy decarbonization goals, recognizing that increased reliance on electrification in transportation and other sectors will create significant demand for electricity, and therefore ensuring reliability of a decarbonized grid is a critical need for the state.
- In the transportation sector, CARB is supportive of the EJ Advisory Committee's recommendations to maintain aggressive zero emission vehicle goals consistent

with its statutory mandate to ensure regulations are technologically feasible and in alignment with Governor Newsom's ZEV Executive Order (EO N-79-20). CARB looks forward to continued engagement on rulemakings that will implement these goals.

- As noted elsewhere in this plan, CARB is supportive of the Caltrans California Transportation Plan 2050 and the California Climate Action Plan for Transportation Infrastructure.
- CARB is supportive of additional public support for transit. CARB is supportive of locating EV charging in low-income communities and communities of color.
- CARB is supportive of prioritizing funding incentives for transit and heavy- and medium-duty vehicles, although CARB does believe there is an important role for incentives that support adoption of light-duty vehicles for the time being. CARB will also be opening a rulemaking on the Low Carbon Fuel Standard to ensure it continues to support clean fuels that will displace petroleum fuels and will consider the EJ Advisory Committee recommendations on this program.
- In the industrial sector, in addition to the strategies discussed more fully in this Scoping Plan, CARB continues to work with the Legislature, local agencies, and air districts to support, implement, and enforce effective reductions in emissions of GHGs and air pollutants in stationary sources. The air districts have the authority to directly issue permits addressing a facility's criteria pollutant and toxics emissions levels. These levels are set after careful permit review, under district regulation and statute. However, AB 617 directs and authorizes CARB to take several actions to improve data reporting from facilities, air quality monitoring, and pollution reduction planning for communities affected by a high cumulative exposure burden. CARB will continue to implement AB 617 and look for ways to strengthen the Community Air Protection Program.
- Considerations around the phaseout of oil and gas extraction and refining, and the role of carbon capture are discussed more thoroughly in Chapter 2.

As CARB continues to engage with the EJ Advisory Committee—in addition to the EJ Advisory recommendations that have been integrated throughout this plan—below are the following commitments that CARB is making to ensure that environmental justice is integrated in this plan and its implementation:

- Building decarbonization is a pillar of this Scoping Plan and CARB commits to working closely with state and local agencies to implement the EJ Advisory Committee recommendations that call for prioritization for residents in low-income communities and communities of color in this transition.
- CARB commits to sharing the EJ Advisory Committee's recommendations with the CEC, CPUC, and other agencies administering funds to support building

decarbonization, and to work closely with those agencies as they engage in public processes to further building decarbonization.

- CARB has committed to review the Cap-and-Trade program and determine what potential legislative or regulatory amendments could be necessary to ensure the program continues to deliver GHG reductions needed to achieve the statutory climate goals. In that process, CARB will consider the recommendations of the EJ Advisory Committee[533] and Independent Emissions Market Advisory Committee,[534] as well as others.

Critically, the EJ Advisory Committee makes numerous recommendations centered around tracking progress of the various strategies in this Scoping Plan. Currently, progress is tracked and reported in numerous ways, including the annual GHG inventory and reports to the Legislature. Part of the ongoing work of implementation, however, will include consideration of ways to provide more data and information to the public, such as rates of deployment of clean energy and technology as described in Chapter 1. CARB will also continue to collaborate with CDPH and OEHHA on health metrics to track cumulative benefits of air pollution and climate programs, especially in low-income communities and communities of color.

As noted earlier in this document, the EJ Advisory Committee will continue to play a vital role in the Scoping Plan and its implementation to ensure environmental justice and racial equity are prioritized in our effort to address the climate challenge before us. This includes ongoing EJ Advisory Committee engagement to advise CARB on the development of the Scoping Plan and any other pertinent matters in implementing AB 32. The ongoing EJ Advisory Committee will help to ensure integration of environmental justice in implementation efforts as it relates to AB 32, and also help CARB as we work toward a future where race is no longer a predictor for life outcomes.

Academic Institutions and the Private Sector

Academic institutions produce and present the latest science on both the impacts of, and actions to reduce, climate change damages. They are also leading the way by

[533] California Legislative Information. Bill Text – AB 32. Air pollution: greenhouse gases: California Global Warming Solutions Act of 2006. (AB 32, Nuñez, Chapter 488, Statutes of 2006). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=200520060AB32.

[534] California Legislative Information. Bill Text – AB 398. California Global Warming Solutions Act of 2006: market-based compliance mechanisms: fire prevention fees: sales and use tax manufacturing exemption. (AB 398). https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180AB398.

establishing their own climate goals and GHG emissions reductions targets.[535, 536, 537] They are incubators for innovation and knowledge in clean energy and technology and play an important role in adding to the wealth of robust information to inform policies and programs. Academic institutions have the ability to fill knowledge gaps and push us toward new frontiers. As we move forward, we will continue to see these institutions as partners and resources that can help CARB look for ways to accelerate and introduce actions to reduce GHG emissions and remove and store carbon.

As such, it will be important to maintain and enhance relationships with academic institutions, including community colleges. Community colleges are more likely to have a large proportion of first generation students or students that come from low-income communities or communities of color. The perspective of this diverse student body will be critical to inform discussions on climate change damages and mitigation efforts. This student body is also a future workforce, and courses to teach the skills for a sustainable economy are a chance to close historical opportunity gaps. Importantly, many of the students at community colleges are local residents and community members. This engagement provides another way to invest in communities across our state. The Foundation for California Community Colleges is already leading the way through innovate programs such as their Good Jobs Challenge - California Resilient Careers in Forestry.[538] These types of programs could be replicated across other sectors. CARB will evaluate how to leverage the requirements in AB 680 on workforce development in the California Climate Investments programs with the work at the Foundation for California Community Colleges.

As noted in Chapter 1, public and private partnerships will be important as we move forward in the great energy transition. But the private sector is also important in the context of research and development and deployment. Many of these companies have the resources and expertise to build and produce the clean technology and energy we will need. It was through the efforts of several private companies (Bell, Exxon, Telecom

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[535] University of California. Our Commitment. https://www.universityofcalifornia.edu/initiative/carbon-neutrality-initiative/our-commitment.

[536] California State University. Energy, Sustainability, & Transportation. https://www.calstate.edu/csu-system/doing-business-with-the-csu/capital-planning-design-construction/operations-center/Pages/energy-sustainability.aspx.

[537] California Community Colleges Chancellor's Office. Climate Action and Sustainability. https://www.cccco.edu/About-Us/Chancellors-Office/Divisions/College-Finance-and-Facilities-Planning/Facilities-Planning/Climate-Action-and-Sustainability?msclkid=4a72350ec4f511ecaf292c6b14ac9a4f.

[538] Foundation for California Community Colleges. 2022. Good Jobs Challenge. Developing Resilient Careers in Forestry for Californians. https://foundationccc.org/What-We-Do/Workforce-Development/Good-Jobs-Challenge.

Australia) that the photovoltaic solar panels in use today were developed.[539] Similarly, it was companies such as General Electric and Texas Instruments that contributed to the development of hydrogen fuel cells.[540] This Scoping Plan includes the known and emerging clean technologies and fuels available today. The private sector spirit of invention, improvement, and innovation must continue to deliver new tools in the fight against climate change.

Individuals

This Scoping Plan not only projects ambitious availability of clean technology and energy, but also includes aggressive assumptions about consumer adoption of ZEVs, heat pumps, and other energy efficiency practices, among others. When it comes to climate change mitigation, the sum of the parts matters. Only when we add up the impacts of the choices we make do we understand the true impact on GHG emissions. Today, many Californians have opportunities to choose between driving a car, taking a bus, biking, or walking. Many can choose to install a heat pump or buy an electric cooktop. Together, we can increase these opportunities and pick the future we want. We can start or transform businesses that create clean jobs, innovate new technologies, or introduce new systems. We can engage with fellow workers to support durable paths for labor in a clean economy. And we can choose to engage with our community, tribes, and our governments to advocate for change, call out challenges, and propose solutions. Our choices will help determine California's climate future. Down one path is a future of climate impacts that will continue to worsen and further increase disparities across communities. Down the other is a future that avoids the worst impacts of climate change, improves air quality—especially for the most burdened communities—and fosters new economic and job opportunities to support a sustainable economy.

Importantly, we must acknowledge that historical decisions have resulted in health and opportunity gaps for residents in low-income communities and communities of color. Not everyone has the resources or access to make these choices—to buy a ZEV, install a heat pump, or use public transit to get to work. It is here that government can help. Government, at multiple levels, can fund programs and structure policies to provide consumers with more choice and to support them in adopting cleaner technology options. Whether through affordable energy rates or assistance in purchasing zero emission vehicles and appliances, we can use the transition to a carbon neutral economy as an opportunity to close some of these persisting opportunity gaps. By acting now, we can

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[539] Californiasolarcenter.org. Passive Solar History. *http://californiasolarcenter.org/old-pages-with-inbound-links/history-pv/*.
[540] Fuel Cell Store. History of Fuel Cells. *https://www.fuelcellstore.com/blog-section/history-of-fuel-cells?msclkid=04a19450c50211ec8d20f2afff4039fe*.

change our planet's fate and build a more resilient, healthier, and equitable future for all Californians.

Comment Log Display

Here is the comment you selected to display.

Comment 318 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Karen
Last Name	Huggard
Email Address	khuggard@nata.aero
Affiliation	National Air Transportation Association
Subject	Opposition to CARB Proposal to Regulate Jet Fuel
Comment	The attached letter of opposition to the California Air Resources Board (CARB) proposal to regulate jet fuel under its Low Carb Fuel Standard (LCFS) Program is submitted on behalf of the following aviation industry associations and stakeholders: Airlines for American, Airbus, Aerospace Industries Association, Boeing, California Manufacturers & Technology Association, General Aviatio Manufacturers Association, National Air Transportation Association National Business Aviation Association, and RTX Corporation.
Attachment	www.arb.ca.gov/lists/com-attach/6989-lcfs2024-VDVAZVYpWWoCaM0d.pdf
Original File Name	Aviation Industry letter on CARB LCFS proposal - Final - 02-20-2024[18].pdf
Date and Time Comment Was Submitted	2024-02-20 16:47:19

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Submitted electronically at:
https://ww2.arb.ca.gov/lispub/comm/bclist.php

February 20, 2024

Clerks' Office
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: Opposition to California Air Resources Board Proposal to Regulate Jet Fuel

Dear Chair Randolph,

As members of the aviation industry, we are writing to share our serious concern and opposition
to the recent California Air Resources Board (CARB) proposal to regulate jet fuel under its Low
309.1 Carb Fuel Standard (LCFS) Program. We believe the CARB proposal will raise the cost of jet
fuel without inducing additional Sustainable Aviation Fuels (SAF) production or use in California,
an objective the aviation industry shares with CARB. And further, the proposal to regulate jet
309.2 fuel is pre-empted by federal authority. We encourage CARB to withdraw the proposal to
309.3 regulate jet fuel and instead establish a joint CARB-industry working group to explore alternative
solutions to increase SAF production and use.

The aviation industry is committed to reducing its climate impact and achieving net zero carbon emissions by 2050, and transitioning to SAF is core to this commitment. We have long recognized that scaling up the supply of SAF and achieving net-zero carbon emissions by 2050 can only happen by working collaboratively with governments and other stakeholders across sectors. Achieving this ambition for SAF will require new and additional policy incentives, streamlined permitting processes, and close collaboration among governments, the aviation industry, the fuels industry, environmental organizations and others.

Aviation accounts for 2.6% of the U.S. greenhouse gas emissions but 5% of U.S. Gross Domestic Product (GDP) and 4.1% of California's GDP, thus exerting outsize economic impact relative to its share of emissions. U.S. civil aviation firms employ more than 380,000 California-based employees, with an overall economic impact of $194 billion.[1] Aviation is critical to driving California's economy and its rank as the 5th largest economy in the world, enabling $114 billion in annual trade flows and underpinning many of California's other significant economic drivers such as agriculture, tourism, manufacturing, banking, technology and small business.

California has established itself as an early leader in attracting investment, production, and use of SAF through the existing LCFS Program, which provides an opt-in credit for SAF that helps reduce the price difference between SAF and conventional jet fuel. Ensuring a healthy and vibrant aviation industry is essential to California's future, and leveraging CARB's early leadership on SAF can enable California leadership in the emerging SAF production industry, creating new jobs and economic development opportunities.

With this context, we express our serious concern with the proposal by CARB to regulate jet fuel
used for flights within California as an obligated fuel under the LCFS Program. This proposed
309.1 change would be unlikely to result in increased SAF production, availability, or use in California,
but would lead to higher jet fuel prices and slow down, rather than accelerate, efforts to increase

[1] The Economic Impact of Civil Aviation on the U.S. Economy, State Supplement, US Department of Transportation, November 2020

the state's SAF production and use. The primary impediment to increased SAF production and availability in California remains the higher cost of SAF for producers and buyers relative to conventional jet fuel and renewable diesel. The CARB proposal would not address this fundamental challenge or otherwise meaningfully increase SAF supply or use.

309.2 In addition to not being an effective policy tool to increase SAF production, the proposal seeks to regulate jet fuel and reduce emissions from aviation, both of which are preempted under federal law, a fact that CARB recognized when it exempted jet fuel from the LCFS in 2018.[2] Aviation, unlike many other industries, is uniquely situated in that other factors such as the safe operation and maintenance of aircraft are of great importance, which the federal government has recognized in the jurisdiction of the FAA and the EPA's Clean Air Act.

309.3 Our mutual interest is to increase SAF production, availability, and use, and the most effective way to accomplish this is to continue the positive, collaborative approach represented by the existing "opt-in" mechanism developed by CARB and the aviation community. We urge CARB to reconsider and withdraw the proposal to remove the exemption for jet fuel for intrastate flights, preserve the existing opt-in approach for SAF, and establish a joint CARB-industry working group with stakeholders across the emerging SAF ecosystem to explore alternative policy and voluntary proposals to rapidly increase SAF production, availability and use in California. We look forward to working with CARB on such measures to accelerate SAF deployment.

Sincerely,

Airlines for America® We Connect the World

AIRBUS

AIA AEROSPACE INDUSTRIES ASSOCIATION

BOEING

CMTA CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION

GAMA General Aviation Manufacturers Association

NATA

NBAA NATIONAL BUSINESS AVIATION ASSOCIATION

RTX

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[2] CARB stated that "[s]ubjecting aircraft fuels to annual carbon intensity standards would raise federal preemption issues" *available at* https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/isor.pdf?_ga=2.259407882.1202437490.1641231788-253234234.1573227006

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Comment 319 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Graham
Last Name	Noyes
Email Address	graham@noyeslawcorp.ccom
Affiliation	Low-CI Power Coalition
Subject	Low-CI Power Coalition Comments on Proposed LCFS Amendments
Comment	Dear CARB, On behalf of the Low-CI Power Coalition, please find attached our comments in response to the proposed Low Carbon Fuel Standard Amendments. Sincerely, Graham Noyes
Attachment	www.arb.ca.gov/lists/com-attach/6990-lcfs2024-ATMGNAQ1AmNRZVNj.pdf
Original File Name	240220_Low CI Power Comments FINAL (00627570xBA8E1).pdf
Date and Time Comment Was Submitted	2024-02-20 16:54:13

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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NOYES LAW CORPORATION
FUEL & CARBON LAW

February 20, 2024

Liane Randolph
Chair, California Air Resources Board

Steven Cliff
Executive Officer, California Air Resources Board

1001 I Street
Sacramento, CA 95814

Comment submitted electronically

RE: Low-CI Power Coalition's Comments on Proposed Low Carbon Fuel Standard Amendments.

Dear Chair Randolph and Executive Officer Cliff:

Our diverse group of low carbon fuel producers and developers, including Blue Arrow, Eco Energy, Fulcrum BioEnergy, Growth Energy, the Renewable Fuels Association, POET, Velocys, and World Energy (collectively, the "Low-CI Power Coalition") offers the following comments on the proposed amendments to the Low Carbon Fuel Standard ("LCFS") ("Proposed Regulation Order"). As reflected in the attached Appendix 1, these leading-edge companies utilize a diverse range of low carbon feedstocks and advanced process technologies to produce the low carbon fuels of the future including ethanol, renewable diesel, renewable naphtha, and sustainable aviation fuel.

These comments respond to the proposed revisions to Section 95488.8(i)(1)(C), which would allow wholesale power contracting as part of a narrow set of fuel pathways (certain hydrogen pathways and direct air capture projects). These comments explain why the proposal should apply to a broader set of low carbon intensity ("Low-CI") alternative fuels, and why excluding these fuels is arbitrary and contravenes the California Air Resources Board's ("CARB's") own policy seeking to accelerate rates of deployment of clean technology and fuels identified in the scoping plan.[1] While we are broadly supportive of many aspects of the Proposed Regulations, we are deeply concerned that the Regulation will not achieve all cost-effective emission reductions and will leave federal money that could be directed to clean energy
310.1 development in California on the table. For reasons discussed in our pre-rulemaking comments, CARB should amend Section 95488.8 to ensure that all alternative fuels can achieve incremental

[1] 2022 Scoping Plan Update, at 182.

310.1 cont. emission reductions when their alternative fuel source leads to new electricity demand.[2] This approach (the "Low-CI Proposal") is workable and consistent with CARB's objectives and stated policies supporting the optimal use of Low-CI resources to help meet California's climate goals.

DISCUSSION

I. CARB Should Expand Low-CI Power Provisions in Section 95488.8(i)(1)(C) to include a Broader Set of Tier 2 Applications.

The Low-CI Proposal is straightforward, designed to avoid any concerns about resource shuffling, and is simple to implement. As described in our June 6, 2023, comments, the Low-CI Proposal would allow for review of eligible new Low-CI power sources that are contracted by fuel pathway holders and delivered via the grid. The fuel pathway holder would be required to submit documentation as part of a Tier 2 application that it has contracted for one or more new Low-CI power sources under a power purchase agreement ("PPA") or ownership agreement.

Significantly, the contract or ownership agreement would have to meet three essential threshold requirements to ensure additionality, including a showing through the Tier 2 application process that the facility providing Low-CI electricity is not contracted with another buyer or included in a utility resource plan, a showing that the commercial online date of the facility occurs after execution of the PPA or ownership agreement, and a showing that the environmental attributes of the facility cannot be contracted, sold or transferred to any other buyer. The Low-CI Proposal did not include restrictions as to the alternative fuel because the benefits of the proposal can accrue from a range of Low-CI alternative fuels, including renewable hydrogen, renewable diesel and naphtha, ethanol, and sustainable aviation fuel. As described in our comments, the Low-CI Proposal would create additional flexibility for the sourcing of Low-CI power, and thus enable real, additional, quantifiable, verifiable, permanent, and enforceable greenhouse gas ("GHG") emission reductions. It would directly address obstacles that currently restrict pathway holders from reducing their emissions through contracting for Low-CI power sources to meet demand. The net result of integrating the Low-CI Proposal into LCFS regulation would be to achieve additional and permanent CI reductions from the same quantity of alternative fuel, thereby further decarbonizing California's transportation fuel market.

Instead of recommending adoption of the Low-CI Proposal across all alternative fuels, the Proposed Regulation Order includes only a very limited proposal to allow for the use of PPAs for Low-CI electricity for production and processing of hydrogen used directly as a transportation fuel.[3] The Initial Statement of Reasons ("ISR") acknowledges the need to support and encourage renewable and Low-CI hydrogen production to meet demand for decarbonization

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[2] See Low CI Power Coalition comment letter submitted by Noyes Law Corporation in LCFS Pre-Rulemaking workshop (June 6, 2023), available at: https://ww2.arb.ca.gov/system/files/webform/public_comments/3666/Low%20CI%20Power%20ARB%20LCFS%20Comments%20w%20Appendices%206%20June%202023.pdf.

[3] Proposed Regulation Order at 148.

310.1 cont. in transportation and hard-to-electrify end uses.[4] It further recognizes that concerns about resource shuffling and additionality can be addressed by restricting eligibility to new or expanded capacity, delivery to the local balancing authority, and resource matching.[5] But there is no discussion justifying or explaining why the modified Tier 2 application process should be limited to hydrogen and direct air capture projects.

As there are clear benefits to be achieved through adoption of the Low-CI Proposal, and no identified justification for the Proposed Regulation Order's narrowing it to address only hydrogen and direct air capture projects, the Board should adopt the broader version proposed in the Low-CI Proposal.

a. <u>Low CI Power achieves CARB's fundamental policy goal of carbon neutrality by 2045 and will lead to material, additional emission reductions irrespective of the type of fuel that claims LCFS credit.</u>

i. Electricity demand (load) from alternative fuel producers will grow irrespective of whether the LCFS regulation allows book-and-claim for Low-CI power.

In the absence of an explanation, it is difficult to understand why the Proposed Regulation Order would forego a clear opportunity to enable incremental emission reductions that can be provided by eligible, available Low-CI alternative fuels. Under the existing LCFS procurement limitations, low carbon fuel production facilities have no practical alternatives other than to source power from a utility or other load-serving entity ("LSE"), which is likely to increase GHG emissions on a marginal basis. Direct connection of Low-CI energy (under existing regulations), is severely limiting and negates cost effective emission reductions that are otherwise available through wholesale contracting.

Marginal emission rates vary by market and are generally the greatest during peak conditions. Allowing a fuel pathway holder to enter into contracts for new, additional Low-CI power sources that are not already contracted for other purposes provides additional emission reductions regardless of the type of fuel that claims the LCFS credit. By restricting the current proposed amendments to hydrogen used as a transportation fuel, the Proposed Regulation Order is limiting potential emissions reductions, since electricity demand from alternative fuel production facilities will grow in any event, and the substantial majority of that demand will be met by system power instead of Low-CI Power.

This outcome directly contravenes the statutory requirements governing the program. Section 38510 of the California Health and Safety Code charges CARB with the responsibility for monitoring and regulating GHG emissions. Section 38560 is the primary statute that provides authority to CARB to implement the LCFS. That section provides that "[t]he state

[4] ISOR at p. 34.

[5] Id.

310.1 cont. board shall adopt rules and regulations in an open public process to achieve the maximum technologically feasible and cost-effective greenhouse gas emission reductions from sources or categories of sources, subject to the criteria and schedules set forth in this part." The proposed narrow application of the Low-CI power rules contravenes this statute because the LCFS regulation would not maximize emission reductions that are cost effective.

The purpose of the LCFS regulation is to reduce the carbon intensity of transportation fuels used in California and to "incentivize the production of low-carbon and renewable alternatives, such as low-CI electricity and renewable hydrogen, and biofuels to displace fossil fuels and allow more energy security in the transportation sector."[6] While renewable hydrogen used in fuel cell electric vehicles ("FCEVs") is without question a key resource to be supported through the LCFS, there is no need to forego opportunities to support other Low-CI alternative fuel sources. The 2022 Scoping Plan does not only call for scaling up hydrogen production, but more broadly for the "aggressive reduction of fossil fuels *wherever they are currently used in California*, building on and accelerating carbon reduction programs that have been in place for a decade and a half."[7]

The Low-CI Proposal was designed specifically to address market barriers that are currently limiting the integration of new, additional clean energy resources. It is aimed at achieving additional incremental emissions reductions at a time when accelerating climate change demands that we do so immediately, and at scale.

b. <u>A Broader Scope of Low-CI Power Rules Would not Disrupt the Availability of Clean Energy and Capacity for Other Demands.</u>

We appreciate the state has ambitious low-CI power targets and there are concerns about the ability of the state to keep up with demand for low-CI power. This Low-CI Proposal has been designed to protect power markets and to ensure availability of new power for other decarbonization strategies, such as vehicle electrification. These concerns are adequately addressed by the power contracting requirements already proposed for hydrogen and DAC. Among other requirements, the Proposed Regulation Order for Low-CI power contracting would set a quarterly balancing requirement of electricity demand from the fuel production and generation from the Low-CI power source. By proposing a quarterly balancing requirement, the proposed regulations make a fundamental distinction in how Low-CI power would be contracted under the LCFS. The proposed revisions to Section 95488.8(i) would require the fuel pathway holder to purchase energy and match that energy to load over a reporting period (i.e., a quarter). The fuel pathway holder would not need to ensure that power is "deliverable" during peak conditions. As explained below, deliverability requirements are the primary driver of delays in the power sector.

Power plants generate two products that are frequently purchased pursuant to PPAs: energy and capacity. Under the proposed revisions to Section 9588.8(i), CARB would require

[6] ISR at 6.

[7] 2022 Scoping Plan Update, Executive Summary at 1.

310.1 cont. energy matching, not capacity. Because the Proposed Regulation Order only requires energy matching, the power plants retain the ability to supply capacity to load serving entities that may need the capacity to satisfy their reliability objectives and load growth. In recent years, the timely development of new network upgrades needed to transact capacity for reliability requirements has contributed to concerns about the ability of the state to develop sufficient new power plants to meet the pace and scale of Low-CI power development contemplated in the 2022 Scoping Plan. Power plants that only require "energy-only" status are generally not affected by the same delays as projects seeking FCDS. While these "energy-only" projects must still meet interconnection requirements, these projects are generally only reliant on the interconnection facilities required for the project itself, not for network upgrades that are shared with many other interconnection customers all trying to sell capacity for reliability.

As this discussion highlights, concerns that enabling broader Low-CI power sourcing authorities to alternative fuel producers would create material risks of disrupting the market for capacity are not grounded in the details of CARB's own proposal for quarterly matching of energy. Nothing in Section 95488.8(i) requires a Low-CI power contract to provide fully deliverable capacity. Rather, the pathway applicant simply must demonstrate that over the course of a quarter, the power plant generated enough electricity to match the demand of the fuel production facility. It is anticipated that energy-only projects would be procured under the Low-CI Proposal without affecting the supply of capacity that LSEs need to meet their reliability obligations or negatively impacting known load forecasting requirements for transportation electrification.

c. <u>Power-plant Development in California Is Subject to Extensive Planning Requirements, Which Help Ensure that New Sources of Demand do Not Compete for Power at the Wholesale Level.</u>

As noted above, fuel-related electricity demand was extensively evaluated in the 2022 Scoping Plan Update and in prior iterations of the Scoping Plan process. CARB has evaluated the displacement of fossil fuels, driven by the growth of a variety of alternative fuels with varying timelines. The Scoping Plan process sets a high-level trajectory for various planning processes, including GHG target setting for the Integrated Resource Planning ("IRP") and also informs the California Energy Commission ("CEC") load forecasting process. Utilities must also account for their own projected load growth in the context of their load forecast filings to the CEC. These forecasts in turn inform the utilities' procurement of power plant capacity. The load forecasting feeds into the CPUC's IRP and the SB 100 process to ensure the utilities are planning for adequate capacity reserve margins. The load forecasting process also informs the pace and scale of new power plant development needed to meet the state's climate targets. In other words, the state has processes in place to ensure that LSEs are planning to meet various reliability and clean energy objectives, including supplying a sufficient amount of new capacity to reliably meet the state's electricity demand. As discussed above, incentivizing incremental Low-CI power demand for energy-only projects will not disrupt the state's clean energy build out

310.1 cont. because the state's load forecasting and capacity procurement processes are already designed to keep pace with the state's power needs.

d. **Broader Low-CI Power Sourcing Would Drive Clean Energy Development in Other States with Shorter Interconnection Queues, Particularly MISO Where Most of California's Low Carbon Fuels Are Produced.**

As part of its oversight of the LCFS program, CARB tracks the share of liquid biofuels produced in-state by volume and displays annual information on the LCFS Data Dashboard.[8] Over the reported years from 2011-2022, the share of in-state biofuel production has remained relatively stable at approximately 9-15%. For 2022, the share of in-state production was 14.72%. While the CARB data does not provide more granular data, it is well-known in the industry that most of the ethanol and biodiesel production in the US is concentrated in the Midwestern states while substantial renewable diesel production is located in these states but also in Texas and Singapore where Neste's renewable diesel production facility that serves the western U.S. markets is located. With reference to electricity markets, the largest concentration of US biofuels production overall is located in MISO. According to recent analysis by RMI, clean repowering-deploying clean power using existing fossil fuel power plants' interconnections- can accelerate and reduce costs for the interconnection of renewables. Overall, RMI determined that clean repowering is a 250 GW opportunity concentrated in MISO, PJM and the Southeast.[9]

Because nearly 85% of the liquid biofuel development driven by the LCFS occurs in other electricity markets (e.g., MISO, PJM, ERCOT, etc.), and while there are delays in many interconnection queues across the country, there is no evidence that creating incremental demand for Low-CI energy will exacerbate those delays in the longer term. To the contrary, encouraging incremental Low-CI power in these markets will ensure that grid operators have a broader pool of renewable energy to serve load. Moreover, there are processes in place and underway at the Federal Energy Regulatory Commission and elsewhere to ensure that utilities are meeting the demand for energy and capacity across the country. The LCFS has the potential to send long term investment signals to maximize emission reductions and expand renewable energy production to other electricity markets. CARB should not presume that interconnection delays will persist, that interconnection delays are necessarily applicable to the Low-CI energy-only projects contemplated in Section 95488.8(i), or that the concerns about competition for Low-CI power are uniform across the country. To the contrary, CARB should send positive market signals to incentivize the production of alternative fuels with Low-CI power to the greatest extent possible.

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[8] See CARB, "LCFS Data Dashboard," Figure 10a (Share of Liquid Biofuels Produced In-State by Volume 2022), at https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard.

[9] RMI, Clean Repowering: How to Capitalize on Fossil Grid Connections to Unlock Clean Energy Growth, January 2024, Research and Analysis Summary at slide 29, available for download at https://rmi.org/insight/clean-repowering/.

Conclusion

The Low-CI Power Coalition appreciates the opportunity to comment on CARB's proposed amendments to the LCFS. We look forward to working with CARB to further tailor and ultimately implement amendments to the LCFS regulations.

Sincerely,

Graham Noyes
Noyes Law Corporation

APPENDIX 1

Low-CI Power Coalition member companies:

Blue Arrow is the exclusive technology licensee in Mexico, Brazil and elsewhere of Fulcrum Bioenergy, Inc. Blue Arrow's and Fulcrum's plants combine multiple proven and established industrial processes into a patented system that converts waste into zero-carbon synthesis crude. The syncrude is then upgraded at a refinery to zero-sulfur SAF.

Eco Energy is a leading clean energy solutions company for over three decades, focuses on reducing emissions through the promotion of low-carbon renewable fuels and products. The Eco-Energy Solar team is the trusted advisor in achieving sustainability goals for our partners by offering custom projects, including solar design and engineering. In an evolving, climate-conscious economy, Eco-Energy is leveraging its core businesses in marketing, trading, and logistics of ethanol and natural gas across the US, Canada, and abroad.

Fulcrum BioEnergy is a clean energy company pioneering the creation of renewable, drop-in transportation fuels from landfill waste, and is currently commissioning a facility in Reno, Nevada.

Growth Energy represents producers and supporters of biofuels who are working to bring consumers better choices at the fuel pump, grow America's economy, and improve the environment for future generations.

POET is the world's largest producer of biofuel and a global leader in sustainable bioproducts, creating plant-based alternatives to fossil fuels that unleash the regenerative power of agriculture and cultivate opportunities for America's farm families.

Renewable Fuels Association is a national trade association for America's ethanol industry, driving growth in sustainable renewable fuels and bioproducts for a better future.

Velocys is an international Sustainable Aviation Fuel (SAF) technology company with offices in the US and UK. Velocys' technology enables the conversion of various cellulosic feedstocks, including woody biomass residues and municipal solid waste, into low or negative carbon intensity transportation fuels. Velocys broadly offers its technology to the marketplace, and is developing the Bayou Fuels project in Natchez, MS as a commercial reference plant. Velocys has secured offtake commitments for 100% of the SAF from Southwest Airlines and IAG (parent of British Airways) with plans to supply this fuel for uplift in California.

World Energy is a low-carbon solutions provider focused on helping the world's leading companies make their net-zero commitments real. World Energy's solutions include sustainable aviation fuel, renewable diesel, and renewable naphtha, with plans to create renewable propane and green hydrogen.

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Comment 320 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Matthew
Last Name	Rutherford
Email Address	mrutherford@peninsulacleanenergy.com
Affiliation	
Subject	LCFS Regulations Amendments to Support MFR EV Charging
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6991-lcfs2024-VjxSO1I6WGVWJAhX.pdf
Original File Name	Joint CCA Comments - LCFS Regulations Amendments to Support MFR EV Charging_20240220.pdf
Date and Time Comment Was Submitted	2024-02-20 16:58:07

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February 20, 2024

Chair Liane Randolph and
Members of the Board
California Air Resources Board
1101 I Street
Sacramento, CA 95814

Re: Proposed Low Carbon Fuel Standard Amendments To Improve Support For EV Charger Access at Multi-Family Residences

Dear Chair Randolph,

In accordance with the Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments dated January 2, 2024, Ava Community Energy (Ava) and Peninsula Clean Energy Authority (PCE) (collectively, the "Joint CCAs") submit the following comments and recommendations to the California Air Resources Board (CARB).

The Joint CCAs were encouraged to learn that CARB intends to provide more robust support for EV charging at multi-family residences (MFRs). The Staff Report: Initial Statement of Reasons (ISOR) proposed that CARB reclassify MFR EV charging as non-residential. This reclassification, in theory, is consistent with post-workshop comments submitted by CCAs during the public engagement phase of the rulemaking.[1] However, the proposed amendments to the LCFS Regulation ("Amended Regulation") are limited in nature and do not go far enough to encourage robust EV infrastructure development at MFR in California.

As default Load Serving Entities (LSE) in our respective service territories and local public agencies, the Joint CCAs are tasked with reducing GHG emissions associated with the electricity we provide to the communities we serve. The Joint CCAs' mandate to advance climate action also lends itself to a shared transportation electrification (TE) philosophy that centers around

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[1] Joint CCAs, "Comments of the Joint CCAs on Potential Future Changes to the LCFS Program," January 7, 2022, https://www.arb.ca.gov/lists/com-attach/110-lcfs-wkshp-dec21-ws-UjFSO1Q4VmhXNFU7.pdf; Joint CCAs, "Post-workshop Comments of the Joint CCAs on Potential Changes to the LCFS Program," August 8, 2022, https://www.arb.ca.gov/lists/com-attach/91-lcfs-wkshp-jul22-ws-AHAAaVIgACcAKwdw.pdf.

broad access to TE solutions, especially for those facing significant barriers to adoption, by minimizing the cost to adopt TE technologies.

PCE's EV Ready program is a $28 million infrastructure program that offers free, no obligation technical assistance for PCE customers, $24M+ in project incentives, access to preferred pricing on EV chargers, and a trained Trade Ally network of contractors.[2] The program provides support for the design of an EV charging project from inception through installation. EV Ready also has a particular focus on supporting MF residents. Of the 1,000 charge ports installed so far, roughly 2/3 of these are in apartment buildings or condos. And another 3,000 are in process.[3]

Despite the CCAs' efforts, as well as incentives and programs offered by various other actors such as the EDUs, and agencies at the state, regional, and local level, California is not on track to hit our EV targets. And in Q4 2023, EV sales growth in California dipped for the first time in several years, challenging the assumption that consumer acceptance and continued growth of the EV market is a given.[4]

According to the California Energy Commission (CEC), "As of mid-2023, California has installed more than 91,000 public and shared chargers, including nearly 10,000 direct current fast chargers."[5] A recent analysis by the CEC identifies a need for aggressive new development of Level 1 and Level 2 MFR chargers in order to meet California's EV goals. Their recent *Assembly Bill 2127 Second Electric Vehicle Charging Infrastructure Assessment* "projects 1.01 million public and shared private chargers are needed to support 7.1 million passenger plug-in electric vehicles in 2030, and 2.11 million public and shared private chargers are needed to support 15.2 million passenger plug-in electric vehicles in 2035."[6] The CEC modeled the combined number of Level 1 and Level 2 MFR chargers needed to meet these goals and their findings are stark. They

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2 "EV Ready Incentives." Peninsula Clean Energy. https://www.peninsulacleanenergy.com/ev-ready-incentives/.

3 Angueira, Gabriela Aoun. "Why the Slowest EV Chargers May Be the Fastest Way to Get People into Evs." Grist, January 30, 2024. https://grist.org/transportation/why-the-slowest-ev-chargers-may-be-the-fastest-way-to-get-people-into-evs/.

4 Mitchell, Russ. "California EV Sales Are Falling. Is It Just Temporary, or a Threat to State Climate Goals?" Los Angeles Times, February 15, 2024. https://www.latimes.com/environment/story/2024-02-15/falling-ev-sales-raise-worries-over-california-climate-plan.

5 California Energy Commission. "Electric Vehicle Charging Infrastructure Assessment - AB 2127." Accessed February 15, 2024. https://www.energy.ca.gov/data-reports/reports/electric-vehicle-charging-infrastructure-assessment-ab-2127.

6 *Ibid.*

estimate that California will need 313,000 new MFR chargers in MFR by 2030, and 264,000 more by 2035, for a total of 577,000 multi-family chargers.[7] This is or roughly equal to a rate of 24,000 MFR charger installations a year, every year through 2035. And according to CEC's assessment, the number of new MFR chargers needed to meet California's EV goals is larger than almost any other use case.[8]

CARB's LCFS Rulemaking presents a timely opportunity to modify an existing program to better address a growing need identified by its sister agency. The LCFS, if amended appropriately, could provide strong support for MFR EV adoption. It has the prospect of encouraging MF infrastructure development to maximize charging access for residents. It can also help alleviate cost concerns as EV fueling savings are continually eroded by increasing electric rates. As written, the Amended Regulations do not go far enough. The CCAs provide the following recommendations.

311.1
1. The Amended Regulation should be further modified to classify all multi-family EV charging as "non-residential" to provide the strongest incentive to develop EV charging access at multi-family residences;

311.2
2. The registration process for EV Fuel Supply Equipment ("FSE") should be updated to allow low-cost smart Level 1 and Level 2 EV charging outlets to generate LCFS credits; and

311.3
3. The LCFS should require that credit claimed from MF EV charging should be used to lower the cost of driving for those drivers and counter cost pressures from rising electricity rates.

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[7] Davis, Adam, Tiffany Hoang, Thanh Lopez, Jeffrey Lu, Taylor Nguyen, Bob Nolty, Larry Rillera, Dustin Schell, Micah Wofford. 2023. Assembly Bill 2127 Second Electric Vehicle Charging Infrastructure Assessment: Assessing Charging Needs to Support Zero-Emission Vehicles in 2030 and 2035. *Figure 1 - Chargers Needed for Light-Duty Plug-In Electric Vehicles in 2030 and 2035*. Page 4. California Energy Commission. Publication Number: CEC-600-2024-00, available at: https://www.energy.ca.gov/publications/2024/assembly-bill-2127-second-electric-vehicle-charging-infrastructure-assessment.

[8] The Report forecasts that the need for Multi-Family (L1 + L2) chargers is greater than all 5 of the use case categories analyzed, except for Shared Private Workplace. Shared Private Workplace charger installation need is less than 2% higher than Multi-Family (L1 + L2). The Report forecasts that California must install the following numbers of new chargers by use case in order to meet the goal of supporting 15.2 million plug-in electric vehicles by 2035 (in descending order): Shared Private (at work) – 587,000; Multi-family (L1 + L2) – 577,000; Public (at work) – 392,000; Other Public – 475,000; DCFC – 83,000. Page 4.

1. Classifying All Multi-Family EV Charging As Non-Residential Will Make The LCFS Program More Equitable And Provide the Strongest Incentive To Develop EV Charging That Benefits Californians Living In Multi-Family Residences

As the Joint CCAs have argued in prior comments to the CARB, classifying MFR EV charging as residential under the LCFS rules, and subjecting it to the associated data reporting and registration requirements, effectively prevents entities from claiming credits generated by MFR EV charging, which in turn prevents the LCFS from being fully leveraged to support MFR EV infrastructure development.[9] Therefore the Joint CCAs were encouraged when reviewing the ISOR as it suggested that the Amended Regulation would address this issue. The ISOR includes a table which serves as a summary of the proposed amendments in the Amended Regulation. In that Table, there is a statement the Amended Regulation will "Include Multi-Family residences as non-residential."[10] However, when reading the draft language, the change is far more limited and in effect is inconsistent with the stated rationale behind the change: to provide a strong incentive to develop more MFR EV charging infrastructure.

The reason the Amended Regulation falls short is because it fails to recognize that MFR charging at assigned parking spaces needs to be a central part of the solution and incentivized by
311.1 the LCFS. According to the Amended Regulation, the only charging at MFR that will be classified as non-residential under Sections 95483(c)(1) and 95483(c)(2) is charging in shared parking spaces. Shared EV charging is suboptimal due to several practical operational, project design, and cost barriers that cannot be overcome by simply increasing LCFS incentives. As such, it will not provide meaningful support to install the number of MFR chargers the CEC forecasts that California needs. Instead, the Amended Regulation's MFR reclassification does not do enough to support MFR EV charging projects designed to maximize charging access to MF residents. To achieve this, the final Amended Regulation should classify <u>all</u> MFR EV charging as non-residential to ensure that the LCFS Program provides the strongest support possible to expand EV adoption among California's MFR communities.

Appendix E of the ISOR speaks to the purpose and rationale behind the proposed language in the Amended Regulation. Staff reasoned that "chargers at multi-family residences

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[9] Joint CCAs, *supra* note 1.

[10] California Air Resources Board, "Staff Report: Initial Statement of Reasons," *Table 2: Summary of Proposed Regulatory Amendments to the LCFS Regulation,* December 19, 2023, page 20, https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf

(MFR) should generate LCFS credits as nonresidential charging in order to more strongly incentivize the development of and availability of charging at MFRs."[11] Appendix E continues, "[t]his change will allow EV supply equipment owners and developers to generate credits from deployment at multi-family residences, which has been identified as a sector requiring further investment."[12] Appendix E also correctly identify that the issue presented by classifying MFR charging as residential is that it designates crediting for residential charging to the Electric Distribution Utilities (EDUs) instead of EV service providers (EVSPs), meaning that currently, "the latter may not have as strong and direct an incentive to develop more EV supply equipment at MFRs *as could be most optimal and impactful"* (emphasis added).[13]

However, the Amended Regulation only provides a "strong and direct incentive" for
311.1 developing MFR EV supply equipment that is installed in a manner that is both not optimal for
encouraging MFR residents to adopt EVs, or optimal for the MFR property owners. As a result, the Amended Regulation's support for EV supply equipment at MFRs is not the most impactful. Programs like PCE's EV Ready emphasize project designs that encourage as many charging ports as possible, most of which are installed in reserved tenant parking, while limiting the need for grid or service upgrades. This design philosophy of "right-sizing" the project to suit charging needs and capacity constraints has several key advantages. It allows the MFR charging project to maximize charging access to provide the greatest incentive to consider purchasing or leasing an EV. Current and prospective tenants are given certainty they will always have charging access at home if they choose to purchase or lease an EV, a powerful motivator to adopt an EV as it is estimated that 80% of charging takes place at home. But projects that follow this design philosophy to maximize charging access will remain ineligible to claim LCFS credits under the Amended Regulation.

Right-sizing also addresses several typical concerns of MFR property owners considering
an EV charging project for their tenants. One is that EV charging will require time-consuming
311.1 and expensive grid studies and upgrades, or costly panel work. But right-sizing the project allows

[11] ISOR, Appendix E: Purpose and Rationale of Proposed Amendments for the Low Carbon Fuel Standard Requirements, *Amendments to Sections 95483(c)(1) and 95483(c)(2). Fuel Reporting Entities for Residential Electrical Vehicle Charging*, January 2, 2024, page 16, available at: https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appe.pdf

[12] *Ibid.*

[13] *Ibid*.

property owners to offer EV charging access to as many current and future tenants as possible while avoiding these pitfalls. And as MFR charging often occurs in parking lots and garages available to all the MF tenants, rather than near the existing individual tenants' utility meters, it is often the most cost-effective approach to install the electrical work so that the new EV load is served under a common meter and the usage is billed by the LSE directly to the property owner, not the individual tenants. This design approach allows the property owner to preserve their flexibility to reassign parking spaces to tenants as needed. Conversely, reassigning limited shared parking spaces, like guest parking, to limit it to only EV charging can be a point of friction between tenants and a property owner, especially for those tenants who do not drive an EV. Installing EV charging in shared parking spaces also creates friction opportunities between residents such as disagreements over the use of the equipment, moving vehicles to make sure that everyone who needs to charge their vehicle can, and so forth. The installation of EV charging in shared parking also triggers ADA requirements that can lead to significant delays and cost increases for the project. These are the costs and types of issues property owners simply don't want to deal with and could lead them to install a limited number of chargers that would provide limited incentive for tenants, or turn them off from pursuing an EV charging project entirely. But many of these issues are avoided if each tenant has their own charging port in their assigned parking space. But the Amended Regulation only "strongly incentivizes the development of and the availability of charging at MFRs" if the property owner decides to pursue an EV charging
311.1 project that will serve fewer tenants, is more likely to cause operational headaches, and will cost more per charging port. Therefore, the Amended Regulation should reclassify all MFR charging as non-residential to in order to strongly incentivize EVSPs to design MFR charging projects that maximize charging access for tenants and keep project costs down.

The ISOR makes it clear that the intention is to amend the LCFS to incentivize the development and availability of charging at MFRs. However, the draft Amended Regulation, by reclassifying EV charging as non-residential only if it is located in shared parking, will only provide incentives for MFR charging projects that are more costly, more time consuming to complete, and provide a weaker overall incentive for tenants to adopt purchase or lease an EV. If CARB's true intention is to provide a "strong and direct an incentive to develop more EV supply
311.1 equipment at MFRs *as could be most optimal and impactful* [emphasis added]", then the Joint CCAs propose that the final Amended Regulation must reclassify all EV charging at MFR as

non-residential. If it does not, CARB will miss an opportunity to adopt truly impactful the amendments to the LCFS program that would support level of MFR charging development that California needs to meet its EV goals.

2. Low-cost EV charging equipment should be permitted to register as Fuel Supply Equipment to generate non-residential LCFS credits

311.2 Another simple change to the LCFS regulations that the ARB should adopt to promote equitable benefit among MFR EV drivers is to allow smart Level 1 and Level 2 outlets to be registered as non-residential FSE and generate credits. There are many examples of this type of EV charging equipment on the market today that provide low-cost charging equipment options compared to standard L2 EVSE.[14] These smart outlets are also still networked, allowing the equipment to collect the data fuel reporting entities need to claim LCFS credits. Permitting these charging ports to register as FSE would also provide a strong incentive for MFR property owners to pursue EV charging projects that maximize charging access for residents while minimizing the cost of the project and the per port cost.

PCE's EV Ready program has designed 200 EV charging projects, many with smart Level 1 and Level 2 outlets for several reasons. A primary reason is that the number of MFR charging ports needed is so large that it cannot be met only with traditional Level 2 EVSE. Smart Level 1 and Level 2 outlets are a much more cost-effective and widely scalable solution. In order to provide enough charging to encourage the significant community of Californians living in MFRs to consider adopting EV technology, PCE realized designed the EV Ready guidelines to: (1) provide as much charging as possible at people's residences, particularly at their assigned parking spaces (2) provide enough charging capacity to meet their typical driving needs, and (3) avoid costly service upgrades. PCE discovered that, per day, most drivers across the state drive about 40 miles and leave their cars parked for almost 12 hours. And those EV drivers that were using Level 2 charging would leave their cars plugged in all night but only draw electricity for less than three hours. So, while Level 2 charging is still appropriate for many use cases, it is an overbuilt solution considering the low daily miles and the long dwell times, such as at MFRs. Instead, L1 and low-power L2 ports allowed PCE to design MFR projects that are much less

[14] *See* GoPowerEV, https://gopowerev.com/; Orange Charger, https://www.orangecharger.com/; Pando Electric, https://www.pandoelectric.com/; Plugzio, https://www.plugzio.com/.

likely to trigger service upgrades or utility studies, provide more charging ports for lower cost, and still provide enough charging power to meet the daily driving needs of residents.

311.2 Unfortunately, current registration restrictions do not allow owners of EV charging equipment to register smart Level 1 and Level 2 ports as non-residential EV FSE.[15] Therefore projects that utilize these EV charging options to limit project costs are unable to generate LCFS credits and leverage the program to further expand EV charging access. This highlights a disconnect between the charging options the LCFS incentivizes vs charging options available on the market that appeal to property owners for reasons of operational simplicity and lower project cost. The Joint CCAs encourage CARB to permit smart Level 1 and Level 2 ports to register as non-residential FSE to incentivize the charging options on the market today that are best positioned to encourage EV adoption among MFR communities.

3. The LCFS should require that credit claimed from MFR EV charging should be used to lower the cost of driving for those drivers to counter increasing electric rates and maintain EV cost savings.

EVs are assumed to offer a cost savings for the driver compared to an internal combustion engine (ICE) vehicle as they have lower maintenance costs and typically lower fueling costs. But as electric rates continue to rise, EVs' value proposition will continue to erode. Depending on a given ICE vehicle's fuel efficiency, there may be little or even no operational cost savings to be gained by switching to an EV. But to meet California's ZEV and climate goals, the rate of EV adoption must increase. This is especially true among MF residents who have typically faced more significant barriers to EV adoption.[16] And once they do have an EV, MF drivers also often face higher charging rates compared to SFH drivers, meaning that the value proposition was already less attractive. MFR charging on networked equipment typically includes additional fees, fees that SFH EV drivers do not have to pay to use a charger in their

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[15] LCFS Guidance 19-04: Fueling Supply Equipment Registration. See section 4, *Non-residential EV Charging* which specifies that only Level 2 chargers with attached SAE J1772 plugs can be registered. (September 2022), available at: https://ww2.arb.ca.gov/sites/default/files/2022-09/lcfsguidance_19-04_093022.pdf

[16] Hsu, Chih-Wei and Fingerman, Kevin, "Public Electric Vehicle Charger Access Disparities Across Race and Income in California" Transport Policy, Vol. 100 at 59-67 (Jan. 2021), available at: https://www.sciencedirect.com/science/article/pii/S0967070X20309021.

home. It is important that the value proposition is not eroded further to ensure that MF residents who adopt EV technology can continue to save money on their transportation costs.

The Joint CCAs propose that the LCFS should require that the credit entities claim from
311.3 MFR EV charging projects should be allocated, at least in part, back to the EV drivers to reduce the cost of fueling. As all LCFS-eligible FSE are networked, this could be implemented by charging providers by simply crediting the accounts of drivers who live in one of the provider's MFR projects. The Joint CCAs also want to emphasize that any change to this effect must strike a balance between returning LCFS credit to EV drivers and allowing providers to retain enough of the credit to incentivize them to continue to develop MFR EV projects.

4. Conclusion

As noted above, the Joint CCAs fully support the goals and objectives of the LCFS program to reduce the carbon content of the transportation fuels in California. The Joint CCA request that CARB reclassify <u>all</u> MFR charging as "non-residential" will encourage more
311.1 equitable deployment of EV chargers where MF residents live which will provide a strong incentive for residents to consider purchasing or leasing an EV. CARB should also permit networked Level 1 and Level 2 charging ports to register as EV as they provide a lower-cost
311.2 option for MF property owners to provide charging to their tenants. The Joint CCAs also
311.3 encourage CARB to require that entities who claim credits from MFR charging use a portion of that credit to reduce the residents' fueling costs to counter the impact of rising electricity rates.

The Joint CCAs thank the ARB for taking the time to consider its recommendations and look forward to continuing to work together to advance ZEV adoption among Californians.

/s/ Matthew DS Rutherford
Matthew DS Rutherford
Manager of Regulatory Policy
Peninsula Clean Energy Authority
2075 Woodside Road
Redwood City, CA 94061
E-mail: mrutherford@peninsulacleanenergy.com

/s/ Michael Quiroz
Michael Quiroz
Regulatory Analyst
Ava Community Energy
1999 Harrison Street, Suite 2300
Oakland, CA 94612
E-mail: mquiroz@avaenergy.org

Comment Log Display

Here is the comment you selected to display.

Comment 321 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Stefan
Last Name	Unnasch
Email Address	unnasch@lifecycleassociates.com
Affiliation	Life Cycle Associates
Subject	Temporary Fuel Pathway Code for Ethanol with CCS
Comment	Please see our attached comment letter on a Temporary Fuel Pathway Code for Ethanol with CCS.
Attachment	www.arb.ca.gov/lists/com-attach/6992-lcfs2024-VDhQNVAwAw8FZQF0.pdf
Original File Name	LCA_Fuel Pathway Code for Ethanol with CCS_LCFS Comments Feb 20 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 17:00:18

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Life Cycle Associates

Stefan Unnasch
1.650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

February 20, 2024

Liane M. Randolph
Chair, California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject**:** Letter of Comment on Temporary Fuel Pathway Code for Ethanol with CCS for Proposed Amendments to the LCFS, posted December 19, 2023

Dear Chair Randolph:

Life Cycle Associates would like to take this opportunity to provide our comments on the Proposed Amendments to the Low Carbon Fuel Standard Regulation, posted on December 19, 2023. This letter is focused on the development of a Temporary Fuel Pathway Code for Ethanol with Carbon Capture and Sequestration (CCS) technology.

LCFS regulation text defines the CCS technology as follows: *"Carbon capture and sequestration (CCS) project" means a project that captures CO_2 by an eligible entity specified in section 95490(a) of this subarticle, transports the captured CO_2 to an injection site, and injects and permanently sequesters the captured CO_2 pursuant to the Carbon Capture and Sequestration Protocol and as specified by section 95490 of this subarticle.*

CCS is an emerging technology in the U.S. ethanol industry. We believe that CCS technology, combined with existing and newly developing alternative fuel production facilities, offers significant environmental benefits while supporting the overall goals of the California Air Resources Board (CARB). Numerous production plants, many of which already have certified fuel ethanol pathways under LCFS for corn, corn fiber, and sorghum feedstocks, have signed agreements to develop and utilize the technology. The production facilities are pursuing CCS technology in part to further reduce their GHG emissions and meet the increasingly stringent carbon intensity (CI) reduction targets under the LCFS.

The current certification process for a CCS pathway takes multiple years, resulting in a considerable loss of potential credits during the certification period even after beginning to sequester CO_2. We understand the necessity for a thorough evaluation and approval process to ensure compliance with regulatory standards, but the extended duration can hinder the timely realization of the benefits associated with such projects.

With the expectation that CCS will become commonplace for ethanol, and potentially many other fuel production technologies destined for the California market, we ask
312.1 CARB to consider developing a temporary fuel pathway code for ethanol with CCS. The LCFS program already offers multiple temporary pathways to allow alternative fuel producers to generate a limited value from their low-CI fuel. A temporary pathway for CCS with ethanol would further encourage ethanol producers to develop CCS technology and supply even lower CI ethanol to California.

Stefan Unnasch
1.650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

The amount of CO_2 captured and sequestered at an ethanol facility can be easily calculated due to a strong stoichiometric basis as demonstrated by the equation below.

$$\underset{\text{Starch}}{(C_6H_{10}O_5)_x} \xrightarrow{\text{enzymes}} \underset{\text{Glucose}}{C_6H_{12}O_6} \xrightarrow{\text{enzymes}} \underset{\text{Ethanol}}{2CH_3CH_2OH} + 2CO_2$$

Each molecule of ethanol produced via fermentation process also co-produces one molecule of CO_2, which is roughly equivalent to about 30 g CO_2/MJ reduction in the ethanol CI. However, the addition of CCS adds a marginal electricity usage for compression and transport of CO_2. This stoichiometric relationship can be utilized by CARB to determine a conservative CI for the requested temporary pathway(s), subject to verification. Following the temporary pathway, the applicant will be required to measure and monitor the quantity of CO_2 captured and sequestered as required per the provisions of the LCFS and CCS protocol. Our expectation is that this will expedite compliance with the LCFS regulation and set a standard for the industry.

We firmly believe that creation of such a temporary pathway for ethanol with CCS would contribute to meeting CARB's emissions reduction targets and serves as a model for encouraging and fostering technological advancements in the CCS technology itself. We are committed to working closely with CARB throughout the process and are ready to provide any additional information or clarification that may be required.

Thank you for your consideration in reviewing our comments and incorporating them into the final regulation. If you have any questions, please reach out to me directly.

Sincerely,

Stefan Unnasch
Managing Director
Life Cycle Associates, LLC

Love Goyal
Sustainability Project Manager
Life Cycle Associates, LLC

Comment Log Display

Here is the comment you selected to display.

Comment 322 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Stefan
Last Name	Unnasch
Email Address	unnasch@lifecycleassociates.com
Affiliation	Life Cycle Associates
Subject	Comments on Proposed Tier 1 Calculators
Comment	We propose minor changes to the proposed Tier 1 calculators, including addressing N2O emissions and aligning with CA GREET4.0 livestock categories. Our detailed feedback is attached. Thank you for your time and consideration
Attachment	www.arb.ca.gov/lists/com-attach/6993-lcfs2024-BWlRNAdnUV1WfQRb.pdf
Original File Name	LCA_-_Biogas_Tier_1_comments.pdf
Date and Time Comment Was Submitted	2024-02-20 16:58:18

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

The Honorable Liane M. Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Comment on Draft Amendments to the Low Carbon Fuel Standard (LCFS) Tier 1 Calculators

Dear Chair Randolph,

Thank you for the opportunity to comment on the Proposed Low Carbon Fuel Standard (LCFS) Amendments and updated Life Cycle Analysis (LCA) and Documentation. As a California-based consulting firm with over 10 years of experience in life cylce analysis for biofuels and alternative energy, Life Cycle Associates has actively participated in the LCFS program since its inception. We bring extensive experience in fuel life cycle anaylsis, having supported a wide variety of biofuel and alternative energy developers. Our work has been instrumental in securing government funding and approvals for numerous fuel pathways, and we have collaborated with agencies like CARB, EPA, and the states of Oregon and Washington to establish low-carbon fuel programs.

Drawing on this experience, we recommend the following minor changes to the proposed Tier 1 calculators. We believe our insights can help refine the calculators to better serve a broad range of fuel developers and accelerate the growth of alternative fuels in California.

Our specific comments and recommendations are summarized below.

Recommendation for Tier 1 Organic Waste (OW) Calculator: Recognize Diversity and Address N_2O Emissions in all Waste Treatments

It is critical that CARB recognize the complexity of organic waste management in California. The state's most recent waste characterization studies reveal a variety of organic materials ending up in landfills, from over 6 million tons of paper products to 4 million tons of food waste, over 2 million tons of wood products, more than a million tons of textiles, and over 200,000 tons of manure[1]. Moreover, the landscape of composting in California has evolved significantly since the inception of SB 1383, encompassing materials such as soiled paper products, bio-plastics, agricultural residues, and food processing wastes. These materials not only contribute to the state's compost production but are also an important part of its waste management strategy.

We support the recently added category of Recovered Organics (RO) in the Tier 1 OW calculator. However, there remains room for better accounting for emissions across all waste streams in California. Presently, only food scraps qualify for diverted N_2O credit, leaving other waste streams

[1] California Department of Resources Recycling and Recovery. (2022, November). 2021 Disposal Facility-based Waste Characterization Data Tables. Retrieved from https://calrecycle.ca.gov/wcs/dbstudy/

largely unaddressed despite their potentially significant N_2O emissions. It's worth noting that while methane holds about 30 times the potency of CO_2 over a century, N_2O is roughly 300 times more potent than CO_2 over the same period. Unlike methane, which dissipates relatively quickly, N_2O persists in the atmosphere for over a century, amplifying its long-term warming impact.

To accommodate the diverse nature of waste and the myriad waste management systems across California, the Organic Waste calculator would benefit from minor adjustments. We suggest:

313.1

- Introducing options to indicate the percentage of Other Organic Waste (OOW) diverted from composting, in addition to landfilling.
- Incorporating user inputs for site-specific baseline CH_4 emissions.
- Including user inputs for site-specific baseline N_2O emissions.

Figure 1 illustrates a potential layout for integrating these user-defined inputs.

Section 3: Static Operational Data	
3.1 Electricity Grid Region	
3.2 Grid Electricity EF (gCO_2e/kWh)	
3.3 Low-CI Electricity EF (gCO_2e/kWh)	
3.4 Distance to CNG Station (miles)	
3.5 LNG Facility ID	
3.6 Distance to LNG Facility (miles)	
3.7 Liquefaction EF (gCO_2e/gallon)	
3.8 Bio-LNG Trucking Distance (miles)	
3.9 Bio-LNG Truck Type	
3.10 OOW - % Diverted from Landfill	
OOW - % Diverted from Composting	
OOW - % Diverted from Other Treatment	
OOW - Baseline Site Specific CH_4 Emissions (g/wet kg feedstock)	
OOW - Baseline Site Specific N_2O Emissions (g/wet kg feedstock)	
OOW - % Diverted from other Treatment	
3.11 OOW - TDOC (% dry basis)	
3.12 OOW - DANF (%)	
3.13 OOW - Decay Rate (k)	

Figure 1. Proposed location of additional user defined and site specific inputs is outline in red.

Recommendation: Align Tier 1 Calculators with CA GREET4.0 Livestock Categories

313.2 In the CA GREET4.0 RNG tab, livestock categories include Beef, Dairy Cow, Dairy Heifer, Swine, Layer, and Broiler and Turkey (refer to Figure 2). However, the Tier 1 calculator for animal manure (tier 1 DSM) presently covers only dairy cow, heifer, and swine categories. We suggest minor changes to align the tier 1 DSM with CA GREET4.0: CARB should incorporate beef and poultry manure categories into the DSM, using corresponding baseline manure management emissions described in CAGREET4.0 (Figure 3). To reflect these changes, we propose renaming the Tier 1 Dairy and Swine Manure Calculator to the Tier 1 Livestock Manure calculator.

1.3) Assumptions for Anaerobic Digestion of Animal Waste

Source of Assumptions: U.S.

U.S.

	Beef	Dairy Cow	Dairy Heifer	Swine	Layer	Broiler and Turkey
Share of Livestocks	0.0%	100.0%	0.0%	0.0%	0.0%	0.0%

Figure 2. Snapshot of CA GREET4.0 RNG Tab showing livestock categories

	Beef Feedlots [2]		Layer Operation		Broiler and Turkey Operation	
	Dry Lot	Liquid/Slurry	Anaerobic La	Poultry w/o	Pasture	Poultry w/o Litter
Manure Region Management System Usage (MS%)						
U.S. Average	100.0%	0.7%	12.9%	87.1%	1.0%	99.0%
Manure Management System MCFs						
U.S. Average	1.2%	30.4%	71.5%	1.5%	1.2%	1.5%
Direct N2O Emission Factors (kg N2O N/kg N)	0.02	0.005	0	0.001	0	0.001
N Loss Factors through Volatilization of NH3	23%	26%	54%	34%	0%	34%

Figure 3. Snapshot of CA GREET4.0 RNG Tab showing livestock categories

We also note that livestock manures, and especially poultry manure, emit significant amounts of N_2O under traditional management systems. These emissions are amplified by the increasing concentration of modern livestock and poultry operations. This concentration leads to an overabundance of nutrients, exceeding the capacity of nearby crops to absorb them. Without effective manure management solutions to distribute these excess nutrients, they accumulate in concentrated areas, creating "hotspots" with devastating environmental consequences. These consequences include, but are not limited to, the eutrophication of water bodies and the proliferation of harmful algal blooms[2].

Livestock manure-to-RNG pathways, including beef and poultry manure pathways, offer a promising solution. RNG facilities transform manure through anaerobic digestion, generating renewable natural gas (RNG) and valuable fertilizer byproducts. Distributing these byproducts efficiently addresses nutrient needs in areas beyond the immediate vicinity of the operation, reducing N_2O emissions and mitigating the impacts of nutrient concentration on watersheds.

[2] Bryant, Ray B., et al. "Poultry manureshed management: Opportunities and challenges for a vertically integrated industry." Journal of Environmental Quality 50.4 (2021): 1201-1213. https://doi.org/10.1002/jeq2.20273

Therefore, we urge CARB to consider included avoided N_2O emissions and fertilizer displacement benefits in all manure-to-RNG pathways. This would ensure accurate accounting of the environmental benefits associated with manure-to-RNG pathways, ultimately incentivizing their development and adoption.

We appreciate your attention to these comments and recommendations. Thank you for considering our input.

Sincerely,

Anna Redmond

Anna Redmond
Project Manager
Life Cycle Associates, LLC

Stefan Unnasch

Stefan Unnasch
Managing Director
Life Cycle Associates, LLC

Comment Log Display

Here is the comment you selected to display.

Comment 323 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Stefan
Last Name	Unnasch
Email Address	unnasch@lifecycleassociates.com
Affiliation	Life Cycle Associates
Subject	Dairy and Swine RNG Proposal
Comment	Please see our attached comment letter on Dairy and Swine RNG Proposal.
Attachment	www.arb.ca.gov/lists/com-attach/6994-lcfs2024-WjZWMwdnUFwCYFc2.pdf
Original File Name	LCA_Dairy RNG Proposal_LCFS Comments Feb 20 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 17:03:46

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Stefan Unnasch
1. 650.461.9048 direct
1.484.313.9504 facsímile
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

February 20, 2024

Liane M. Randolph
Chair, California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Letter of Comment on Dairy and Swine RNG for Proposed Amendments to the LCFS, posted December 19, 2023

Dear Chair Randolph:

Life Cycle Associates would like to take this opportunity to provide our comments on the Proposed Amendments to the Low Carbon Fuel Standard Regulation, posted on December 19, 2023. This letter is focused on the proposed amendments for Dairy and Swine based RNG.

Diary and Swine RNG are potentially important feedstocks for hydrogen production. The avoided methane results in a low CI which helps to finance these facilities and support the supply of low-CI hydrogen either directly to market or as a process fuel for alternative fuel producers. While CARB is evaluating numerous comments about the generosity of
314.1 such credits, we recommend that CARB also evaluate the alignment of dairy RNG credits with the high value credit opportunities under the Hydrogen Refueling Infrastructure (HRI) provision.

Just like the HRI provides an incentive to build hydrogen stations that otherwise could not support financing of their construction, the avoided methane credits are intended to provide a financial incentive to install equipment to eliminate methane emissions that otherwise would not be regulated. Following such an intention, the HRI incentive is capped to the capital spent to build the hydrogen dispensing infrastructure. CARB should recognize the high costs for installing and operating manure Biogas Control
314.2 Systems (BCS) and not eliminate methane avoidance credits abruptly and develop an incentive (utilizing avoided methane) for dairy farms to install a BCS system to regulate their uncontrolled methane emissions in-line with the capital and operational expenditures for such BCS system(s).

Thank you for your consideration in reviewing our comments and incorporating them into the final regulation. If you have any questions, please reach out to me directly.

Sincerely,

Stefan Unnasch
Managing Director
Life Cycle Associates

Comment Log Display

Here is the comment you selected to display.

Comment 324 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Rock
Last Name	Zierman
Email Address	rock@cipa.org
Affiliation	CIPA
Subject	CIPA Comments
Comment	See attached.
Attachment	www.arb.ca.gov/lists/com-attach/6995-lcfs2024-AmFdMgFwBDYDWghk.pdf
Original File Name	CIPA LCFS Comments 2-20-24-final.pdf
Date and Time Comment Was Submitted	2024-02-20 17:06:07

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

California Independent Petroleum Association
1001 K Street, 6th Floor
Sacramento, CA 95814
Phone: (916) 447-1177
Fax: (916) 447-1144

CIPA

California Independent Petroleum Association Comments on the Proposed LCFS 45-day Regulatory Package

Chair Liane Randolph
Board Members
California Air Resources Board

February 20, 2024

Via electronic submittal to: regulatory docket

Thank you for the opportunity to comment on this important regulatory update on behalf of the members of the California Independent Petroleum Association (CIPA)[1]. CIPA represents nearly 300 crude oil and natural gas producers, royalty owners, and service and supply companies who all operate in California under the toughest regulations on the planet.

The LCFS regulatory package released in early January contains the complete package of material for the pending amendments[2]. The materials include a proposed updated LCFS regulation and appendices, including an update Table 9—*Carbon Intensity Lookup Table for Crude Oil Production and Transport*. The proposed regulation also solidifies the role of the Innovative Crude crediting program to incent the reduction of greenhouse gases (GHGs) from in-state production activities.

CIPA is appreciative of the staff recommendation to retain the Innovative Crude credit provisions through 2040. This regulatory signal allows for significant capital flows to occur in the near-term and GHG reductions to occur continually for the next 16 years, while assisting the retention of high-value jobs within the State. We are however disappointed to see the results of the latest OPGEE model as provided in the proposed Table 9, as they do not seem to reflect stakeholder input on the differences with in-state production as compared to other less regulated jurisdictions. CIPA is also discouraged by the lack of real transparency in that process.

The 2022 Update to the AB 32 Scoping Plan clearly shows that, even in 2045, California will continue to consume significant volumes of crude oil to fuel the legacy fleet of ships, planes, trains and vehicles that remain in California, even with the State's all-in push for zero-emission technology[3]. California in-state crude, produced under the State's Cap-and-Trade, Low Carbon Fuel, and Oil/Gas Methane regulations should be prioritized as the primary feedstock of choice. The results of the latest update, do not accomplish this anti-leakage approach to the LCFS. CIPA remains strongly opposed to any LCFS amendments in which in-state crude is replaced with

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[1] The mission of CIPA is to promote greater understanding and awareness of the unique nature of California's oil and natural gas resources, and the independent producers who contribute actively to California's economy, employment and environmental protection.
[2] https://ww2.arb.ca.gov/rulemaking/2024/lcfs2024
[3] https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp_1.pdf

imported crude either by direct regulation or indirect impact such as inaccurate values for crude carbon intensity scores. A true and successful LCFS would not shift emissions, tax-base and jobs to other jurisdictions.

Stability of the Innovative Crude Program

315.1 CIPA doesn't see the need to end LCFS crediting, as is proposed in the amendment package, of large capital projects that are built to meet the goals of the Program by continually reducing GHG emissions year-after-year, thus reducing a key economic feedstock's carbon intensity. Nonetheless, the staff proposal to retain the Innovative Crude credits option under the LCFS is an important policy signal to the market. The Scoping Plan's approach to allow the demand for fuels lead the market rather than attacking local supply, allows for the transportation and byproduct feedstocks to not be relied up only through increased imports.

We have supported our members in these GHG-reducing endeavors for years. As long as there is demand for liquid fuels, California should be promoting GHG reduction projects for in-state oil and gas extraction given it is the only crude oil that is compliant with California's climate program.

CIPA members are actively deploying carbon reduction strategies including renewable energy to replace both electricity and thermal loads, in addition to, carbon capture and sequestration, which is rightly not subject to the deadline assigned other Innovative Crude credits. Replacing thermal loads, as allowed under the Regulation, has significant direct local air quality benefits in the state's most impacted communities, and if properly designed, permitted and built, can reduce costs and strain on the state's electrical grid.

OPGEE and Table 9 Updates

The OPGEE scores for California produced crude have moved higher on average, even though
315.2 CARB has claimed success for reducing industry emissions on several fronts, including implementation of the Oil/Gas Methane rule. This is incongruent, especially given that foreign CI scores have proportionally decreased compared to in-state production even though it can't be shown that new or additional emission controls have been enacted.

The OPGEE model continues to use of foreign default values that are not enforceable or verifiable, two hallmarks of California's climate regulations—Cap-and-Trade and the LCFS. Additionally, the California oil/gas methane rule has been shown to reduce in-state fugitive methane emissions from local producers.[4]

CIPA has been actively engaged in this process and previously submitted comments to the OPGEE model update under earlier LCFS workshops. Those comment go into great detail about the need to get the science right BEFORE policy decision are made, and describe a model in which the regulatory framework of California is ignored.[5,6] We incorporate those comments by reference and provide these additional thoughts.

We have requested a transparent analysis evaluating the *global* impact of replacing California crude, with its methane monitoring rules, flaring rules, vapor recovery rules and short pipeline transport distances with the equivalent volume of less regulated, long-distance transported

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[4] https://ww2.arb.ca.gov/resources/documents/ldar-analysis-paper-published-environmental-challenges
[5] https://www.arb.ca.gov/lists/com-attach/53-lcfs-wkshp-oct20-ws-WjldMgBxUmACWwVp.pdf
[6] https://www.arb.ca.gov/lists/com-attach/4-opgee-general-ws-AGMBbgNyVmQAWVI9.pdf

foreign crude. Such an analysis needs to consider all the emission reduction efforts highlighted in the previous CIPA OPGEE letters to CARB

The OPGEE model overestimates the CI of California crude oil, and underestimates the CI of foreign crudes, most notably those from Saudi Arabia and Ecuador, the two largest suppliers of oil to California. The data support the common-sense conclusion that California's demand for oil is best met by locally produced, locally regulated, and lesser greenhouse gas emitting oil than those foreign sources which require long transport distances in addition to non- or under-reported greenhouse gas emissions and environmental protections.

Summary

As shown in the State's officially adopted climate planning document, California will need petroleum and natural gas fuels for many years. During this time, California should not only prioritize in-state supply but incent its carbon intensity reduction.

The last barrel of oil used in California, should be produced in-state with all the local, regional and statewide environmental, health and safety and labor standards ensured to be used. California environmental and worker leadership cannot include looking the other way through direct or indirect promotion of foreign crude supplies.

Thank you.

Sincerely,

Rock Zierman
Chief Executive Officer
California Independent Petroleum Association

Comment Log Display

Here is the comment you selected to display.

Comment 325 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Colleen
Last Name	Liang
Email Address	cliang@portoakland.com
Affiliation	Port of Oakland
Subject	Comments on Proposed LCFS Amendments
Comment	Please see attached letter.
Attachment	www.arb.ca.gov/lists/com-attach/6996-lcfs2024-Uj5TNlYxBycDWlcn.pdf
Original File Name	LCFS Port Comments 2024.02.20.pdf
Date and Time Comment Was Submitted	2024-02-20 17:06:26

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

PORT OF OAKLAND

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Port of Oakland Comments on Proposed Amendments to Low Carbon Fuel Standard

Dear California Air Resources Board Staff:

The Port of Oakland (Port) appreciates the opportunity to review and comment on California Air Resources Board's (CARB) amendments to the Low Carbon Fuel Standard (LCFS). The Port is a public enterprise agency, operating a seaport, an airport (Oakland International Airport (OAK)), and commercial properties along the Oakland waterfront. The Seaport and the Airport are both essential transportation infrastructure serving the San Francisco Bay Area, the State of California, and the nation. The Port is also a public utility, providing electricity to both the Seaport and Airport.

OAK is in East Oakland, which has a mix of residential neighborhoods, heavy industrial land uses, and major transportation infrastructure. California's CalEnviroScreen tool identifies East Oakland as a pollution-burdened area with elevated levels of diesel particulate matter and other toxic air contaminants. In addition, the Council of Environmental Quality's Climate and Economic Justice
316.1 Screening tool identifies East Oakland as a disadvantaged community. The Port requests that CARB include electric ground support equipment (eGSE) as a lookup pathway in the LCFS program. This would accelerate airport electrification, support the Port's transition to zero emission program, and further the goals of the LCFS program.

The Port incorporates zero emissions operations and climate resiliency considerations into its planning, management, development, and operations to support its zero emission goals, reducing air quality impacts to the environment and adjacent communities. The LCFS program allows entities that provide low carbon intensity fuel to generate credits and sell to high carbon intensity fuel producers and then invest the proceeds into projects that further reduce the carbon intensity of transportation fuel.

The Port has been participating in the LCFS program since 2019, generating credits for ocean-going vessel shore power, electric cargo handling equipment

PORT OF OAKLAND

(eCHE), and electric light-duty, medium-duty, and heavy-duty vehicles at the Seaport and electric light-duty vehicle charging at the Airport. The Port generates about 5,800 credits per quarter.

316.1 cont. In 2019, the Port initiated discussions with CARB on including eGSE in the LCFS program as a lookup pathway. Following recommendations from CARB, OAK and other California airports sponsored the California Airports Council (CAC) Environmental Working Group in hiring a consultant to develop an Energy Economy Ratio (EER) for eGSE using the same methodology that CARB used to develop the EER value for eCHE. CAC's consultant developed the EER and submitted the report to CARB in 2021 (see Attachment 1). Following multiple correspondences and meetings, CARB decided not to include an eGSE category in 2022 and encouraged individual airports to apply through the Tier 2 pathway process. However, the Tier 2 pathway process is long and labor intensive and requires annual verification. This has proven to be a barrier, which in turn has slowed the adoption of eGSE at airports.

It is noteworthy that Oregon's Department of Environmental Quality included eGSE in its LCFS equivalent, Clean Fuel Program using the data developed by California airports. Oregon Clean Fuel Program has similar goals of reducing fuel carbon intensity. More information can be found here: https://www.oregon.gov/deq/ghgp/cfp/pages/cfp-overview.aspx#:~:text=DEQ%20gradually%20lowers%20the%20amount,meet%20the%20annual%20reduction%20goal.&text=The%20Clean%20Fuels%20Program%20encourages,reduction%20goals%20for%20that%20year.

The Port respectfully requests that CARB reconsider including eGSE into the LCFS Program as a lookup pathway using the EER value that has already been developed and submitted. Inclusion of eGSE aligns with CARB's objectives to promote investment in disadvantaged communities and incentivizes more electric infrastructure and electric equipment. Including eGSE as a lookup pathway would further Port and State decarbonization goals and accelerate infrastructure upgrades that will continue improving air quality for the East Oakland community and other communities located near California airports.

We appreciate the opportunity to provide comments. Please contact me at 510-627-1198 if you have any questions.

Thank you,

Colleen Liang
Director of Environmental Programs and Planning

PORT OF OAKLAND

Attachment 1

CAC Development of EER Values for eGSE
In the California LCFS Program

530 Water Street ■ P.O. Box 2064 ■ Oakland, California 94604-2064

www.portofoakland.com

February 5, 2021

TO:	Arpit Soni, California Air Resources Board
	Jordan Ramalingam, California Air Resources Board
FROM:	Sarah Johnson, California Airports Council
SUBJECT:	Development of EER Values for eGSE in the California LCFS Program

Energy Economy Ratios for Electric Ground Support Equipment in the Low Carbon Fuel Standard

The California LCFS program allows owners of charging infrastructure or electric equipment to generate credits for many different equipment categories, including forklifts, on-road trucks, yard tractors, cargo handling equipment, and shore power for marine vessels. Electrified airside ground support equipment (eGSE) is not precluded from participation in the program. However, because no energy economy ratio (EER) for this equipment category exists in the LCFS regulation, there are only two mechanisms by which eGSE can generated credits; 1) use of a site-specific EER-adjusted Tier 2 pathway, or 2) use of an EER of 1.0 in lieu of an equipment-specific EER. Both options introduce burdens to eGSE fleets, limiting participation in the LCFS program. In fact, no eGSE currently generates LCFS credits. Given the sustainability efforts and commitments by airports and airlines in California, eGSE represent an important equipment category for further electrification of California's transportation sector.

The most effective way to include eGSE in the LCFS program is to establish one or more defensible EER values that can be added to the LCFS regulatory text and/or used in an EER-adjusted Tier 2 pathway without requiring site-specific data collection and verification of the EER on an ongoing basis.

Previous analyses have established EERs in one of two ways:

1. Predicting emissions based on the average speed of the equipment. This is the basis of EER values for electric on-road trucks and yard tractors.
2. Correlating average activity and engine loads to CO_2 emissions and fuel consumption. This is the methodology used to calculate EER values for the electric cargo handling equipment (eCHE) and electric ocean-going vessel (eOGV) categories. It is used for applications where average speed does not properly characterize engine performance because of significant changes in engine load at low- or zero-speed.

The approach to developing EERs for eGSE follows the same basic methodology as used by CARB staff for these other categories. The approach for eCHE and eOGV EER development is described in CARB Staff's Attachment D to the "Notice of Public Availability of Modified Text and Availability of Additional

Documents and Information," related to the 2018 Proposed Amendments to the Low Carbon Fuels Standard Regulation and to the Regulation on Commercialization of Alternative Diesel (Attachment D). These prior analyses referenced emissions inventories developed for the Port of Long Beach as the source of equipment activity data. The source of equipment activity data for this analysis is CARB's OFFROAD model.

A. Methods

1. eGSE Power Requirements

The OFFROAD model provides data on populations, fuel consumption, engine work, and load factors, for a wide range of GSE types. For this analysis, the engine efficiency for each GSE type and fuel combination is calculated from the OFFROAD model data as follows:

$$Efficiency_{type,fuel} = CF * \left(\frac{E_{fuel} * \sum_{ModelYear} \sum_{HP\ Bin} FuelUse}{LF_{type,fuel} * \sum_{ModelYear} \sum_{HP\ Bin} HPhr} \right)^{-1}$$

Equation 1. Calculation of Engine Efficiency for GSE by Equipment Type and Fuel

Where:

E_{fuel} is the energy density of the base fuel type (diesel, gasoline, or natural gas) in MJ/gallon on a lower heating value basis

FuelUse is the annual fuel consumption for each model year and HP bin combination in gallons/year

LF is the load factor for a particular combination of GSE type and fuel

HPhr is the total horsepower hour per year of activity reported by the OFFROAD model for each model year and HP bin combination, before applying the load factor. The OFFROAD model reports this value as "Horsepower_Hours_hhpy"

CF a conversion factor of 2.6845 MJ per hp-hr

Efficiency is the average thermodynamic efficiency of the engine

Currently, CARB's EER calculation methods assume no energy loss during battery charging or conversion of energy to useful work. To be consistent with prior calculation methods, it is similarly assumed that no losses occur for eGSE. Therefore, the inverse of conventional engine efficiency can be used to estimate EERs for each equipment type and fuel.

To: California Air Resources Board
Subject: Development of EER Values for eGSE in the California LCFS Program
Date: February 5, 2021

2. Application to Specific Ground Support Equipment

Table 1 presents the fuel consumption, activity, and load factors for each GSE type and fuel combination, as reported by the CARB OFFROAD model[1]. Note that the OFFROAD model data presented in ORION2017 does not contain data for portable diesel equipment (e.g., pre-conditioned air units, ground power units, generators). The OFFROAD2007 model does include information on portable diesel GSE, so average horsepower, activity, and load factors from OFFROAD2007 were used to calculate estimated EER values for these portable diesel equipment categories.

Table 1. Fuel Consumption (MJ/yr), HP-hr per year, and Load Factors for eGSE Types

	Fuel (MJ/yr)			Total hp-hr/yr (LF not included)			Load Factors		
GSE Category	Gasoline	Diesel	Nat Gas	Gasoline	Diesel	Nat Gas	Gasoline	Diesel	Nat Gas
Aircraft Tug - Narrow Body	55,227,686	57,906,380	-	6,476,925	15,522,087	-	0.800	0.536	
Aircraft Tug - Wide Body	58,025,218	60,547,877	-	7,053,625	16,225,558	-	0.800	0.536	
Baggage Tug	535,547,053	35,645,686	82,486,005	88,920,205	13,816,546	16,767,370	0.550	0.369	0.550
Cargo Tractor	732,057,079	50,482,215	11,061,473	115,388,344	19,992,594	2,337,073	0.540	0.362	0.540
Belt Loader	127,667,994	19,316,500	7,850,987	23,263,275	8,218,157	1,763,607	0.500	0.335	0.500
Cargo Loader	40,238,884	61,869,997	8,030,818	7,333,617	26,532,597	1,774,959	0.500	0.335	0.500
Deicer	922,082	-	-	86,899	-	-	0.950		
Other GSE	13,741,179	137,540,964	10,200,874	2,254,423	58,122,833	2,367,755	0.500	0.335	0.500
Sweeper	1,175,750	-	214,934	204,078	-	51,082	0.510		0.510
Lift	45,515,173	19,211,856	1,224,001	8,257,030	8,161,388	268,275	0.500	0.335	0.500
Passenger Stand	16,601,705	664,036	32,226	2,656,129	236,128	-	0.590	0.395	0.590
Air Conditioner	16,911	47,290,564	-	-	8,204,232		0.750	0.750	0.750
Ground Power Unit	106,319,743	391,507,327	-	13,453,718	68,018,311	-	0.750	0.750	
Generator	5,996,704	588,458,336	-	649,485	98,545,126	-	0.780	0.780	
Air Start Unit	2,914,642	175,225,060	-	292,292	25,367,845	-	0.900	0.900	

[1] See attached supporting spreadsheets detailing OFFROAD model values and analysis.

EER values for eGSE were estimated by applying the values in Table 1 to the function in Equation 1. The EER for each equipment type and fuel is the inverse of the engine efficiency resulting from Equation 1. Combined EERs for each fuel type are calculated by weighting each GSE category EER based on Operating Hours per year, following the eCHE methodology.

GSE were grouped into two categories: Mobile and Portable, based on the primary fuel and type of GSE. Gasoline and spark-ignited natural gas and propane are the dominant fuel types for Mobile equipment while diesel is the dominant fuel type for Portable equipment. Consequently, the proposed EER for Mobile equipment is 4.2 and based on EERs for gasoline equipment. The proposed EER for Portable equipment is 2.9 and based on EERs for diesel equipment.

Table 2. Fuel Consumption and Calculated EER for eGSE Types

Group	GSE Category	Total Fuel Consumed (gal/yr)			EER		
		Gasoline	Diesel	Nat Gas	Gasoline	Diesel	Nat Gas
Mobile	Aircraft Tug - Narrow Body	476,800	430,627	-	4.0	2.6	n/a
Mobile	Aircraft Tug - Wide Body	500,952	450,271	-	3.8	2.6	n/a
Mobile	Baggage Tug	4,623,561	265,083	1,046,378	4.1	2.6	3.3
Mobile	Cargo Tractor	6,320,099	375,416	140,321	4.4	2.6	3.3
Mobile	Belt Loader	1,102,201	143,649	99,594	4.1	2.6	3.3
Mobile	Bobtail	664,424	54,966	22,159	4.1	2.6	3.4
Mobile	Cargo Loader	347,396	460,103	101,875	4.2	n/a	n/a
Mobile	Deicer	7,961	-	-	4.5	2.6	3.2
Mobile	Other GSE	118,632	1,022,838	129,403	4.2	n/a	3.1
Mobile	Sweeper	10,151	-	2,727	4.1	2.6	3.4
Mobile	Lift	392,948	142,871	15,527	3.9	2.7	n/a
Mobile	Passenger Stand	143,328	4,938	409	n/a	2.9	n/a
Portable	Air Conditioner	146	351,681		3.9	2.9	n/a
Portable	Ground Power Unit	917,895	2,911,485	-	4.4	2.9	n/a
Portable	Generator	51,772	4,376,131	-	4.1	2.9	n/a
Portable	Air Start Unit	25,163	1,303,079	-	4.0	2.6	n/a
				Mobile (Operating Hour Weighted)	**4.2**	2.6	3.3
				Portable (Operating Hour Weighted)	4.0	**2.9**	n/a

3. Alternative Data Source Considered

Data from the Airport Cooperative Research Program, Report 149 (ACRP 149)[2] were also considered as an source of information to estimate EERs. ACRP 149 is "a guidance document that provides a potential update to the current set of default ground support equipment (GSE) fleet and activity data used for passenger and cargo aircraft and a protocol to improve the accuracy and consistency of data collection for airport GSE activity."[3] However, while ACRP 149 provides recommended load factors for emissions inventories, it does not provide values for equipment activity, rated engine horsepower, or fuel consumption. To implement the same methodology as described in Attachment D, values for rated engine horsepower and annual operating hours for each GSE type and fuel were taken from the OFFROAD model. Composite horsepower ratings for each GSE category were calculated on a population weighted basis across all fuel types using OFFROAD population values.

The relationship between CO_2 emissions factors and engine brake horsepower presented in Figure 1 of the Attachment D document was then used to calculate CO_2 emissions, implied diesel fuel consumption, and the resulting EERs. Results of this analysis are summarized in Table 3.

This approach is limited because the relationship between CO_2 and engine brake horsepower developed for diesel engines is applied to a composite of all fuel types described in the OFFROAD model. However, the resulting EERs for Mobile and Portable equipment are 4.1 and 2.9, respectively, and are nearly identical to the results from the previously described approach. This suggests that the EER values of 4.2 and 2.9 for Mobile and Portable equipment presented previously are reasonable, robust when using different approaches and data sources.

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[2] National Academies of Sciences, Engineering, and Medicine 2015. Improving Ground Support Equipment Operational Data for Airport Emissions Modeling. Washington, DC: The National Academies Press. https://doi.org/10.17226/22084

[3] ibid

Table 3. Inputs and resulting EERs using ACRP 149 data combined with Attachment D methodology

Group	GSE Category	ACRP 149 Avg Load Factor	Rated HP - OFFROAD Composite	Avg HP	CO2 Emissions (g/bhp-hr)	Diesel Energy Consumption (MJ/kWh)	EER	Activity (hrs/year)
Mobile	Aircraft Tug - Narrow Body	0.43	132	57	706	12.7	3.5	166,868
Mobile	Aircraft Tug - Wide Body	0.43	279	120	560	10.1	2.8	80,594
Mobile	Baggage Tug	0.36	96	34	825	14.8	4.1	1,242,303
Mobile	Cargo Tractor	0.38	99	38	802	14.4	4.0	1,442,453
Mobile	Belt Loader	0.29	64	19	999	17.9	5.0	528,970
Mobile	Cargo Loader	0.29	105	30	857	15.4	4.3	356,627
Mobile	Deicer	0.54	93	50	733	13.2	3.7	934
Mobile	Other GSE	0.42	96	40	785	14.1	3.9	630,700
Mobile	Sweeper	0.51	51	26	899	16.2	4.5	4,964
Mobile	Lift	0.34	97	33	834	15.0	4.2	171,518
Mobile	Passenger Stand	0.32	104	33	834	15.0	4.2	24,628
Portable	Air Conditioner	0.55	172	95	602	10.8	3.0	47,570
Portable	Ground Power Unit	0.45	160	72	655	11.8	3.3	506,726
Portable	Generator	0.82	214	176	497	8.9	2.5	460,674
Portable	Air Start Unit	0.47	363	171	502	9.0	2.5	65,441
						Mobile (Operating Hour Weighted)	4.1	
						Portable (Operating Hour Weighted)	2.9	

B. Recommendations

The EERs shown in Table 2 represent a wide range of GSE types and fuels with contributions that vary in proportion to the overall activity and emissions. The dominant fuel and associated engine type combinations (spark-ignited vs compression-ignited) vary by group; defined here as Mobile and Portable groups. Thus, the final recommended EERs for eGSE are separated into the two equipment groups and weighted based on the operational hours reported in the OFFROAD model. Specifically, it is recommended that Mobile eGSE be assigned an EER of 4.2 and a gasoline baseline, while Portable eGSE be assigned an EER of 2.9 and a diesel baseline.

Finally, it should be noted that some airside equipment are already captured under other LCFS categories. For example, medium- and heavy-duty trucks, buses, light-duty cars and trucks, and forklifts already have established EERs. It is recommended that equipment in those categories continue to use the EERs already established.

980 Ninth Street, Suite 2000 • Sacramento, CA 95814
Telephone (916) 266-4575 • Facsimile (916) 266-4580

Comment Log Display

Here is the comment you selected to display.

Comment 326 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mahlon
Last Name	Aldridge
Email Address	emahlon@ecoact.org
Affiliation	Ecology Action
Subject	Ecology Action Comments LCFS Reg Ammendment
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/6998-lcfs2024-AGUHYgNtWGdVPFA3.docx
Original File Name	Ecology Action Comments LCFS Holdback Funds-2024-02-20.docx
Date and Time Comment Was Submitted	2024-02-20 17:11:11

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

Chair Lianne Randolph
California Air Resources Board
1001 "I" Street
Sacramento, CA 95812

Re: Use of LCFS Holdback funds in the Proposed 2024 Low Carbon Fuel Standard Amendments

Dear Chair Randolph and Members of the Air Resources Board:

Ecology Action is a 501(c)3 nonprofit based in Santa Cruz, California focused on reducing emissions at scale and has done extensive work with energy efficiency retrofits and EV infrastructure across California. Ecology Action specializes in developing equitable EV infrastructure deployment and EV demand generation approaches in hard-to-reach markets such as affordable multifamily and small business. Our most recent projects are “direct installation” of EV charging in affordable multifamily properties via the CEC REACH 1.0 and 2.0 grant programs and with PG&E on their Multi-Family Housing and Small Business Direct Install Pilot (MSDI) using LCFS holdback funds. Ecology Action is unique as we act as both a community-based organization (CBO) and a program implementer.

317.1 We strongly support the ARB staff’s proposal to increase the amount of hold back proceeds benefiting priority communities to 75% by January 2025. We support staff’s efforts to expand the scope of how LCFS holdback proceeds can address the unique barriers faced by disadvantage communities such as using holdback proceeds to fund managed charging and V2X applications. This will open new pathways for equity customers to tap into the emerging value stream from managed and bi-directional charging as a grid support service.

LCFS holdback funds create unique opportunities to design programs that better serve the equity market. This is in contrast to some other highly constrained and historically regulated EV funding sources. One example is the ability to create programs which pair vehicle incentives along with EV infrastructure delivering a complete solution. Another is providing of end-to-end technical assistance support for site hosts in priority communities. Ecology Action has learned from its more than 20,000 energy efficiency “direct installation” projects completed that even if 100% of the cost of an intervention is covered by incentives, hosts would not be able to realize the adoption without in-depth technical assistance to overcome other persistent barriers they face (e.g. lack of EVSE expertise, necessity for the property staff to not be distracted from their primary business imperatives). Direct installation is one example of a solution that provides additional support. It is a ‘one-stop shop’ approach much like that which CARB has used, but with the addition of technical assistance providing construction project management to assure project completion.

One of the key impediments to equitable deployment of EV infrastructure faced by the utilities is that current allocations for technical assistance under the Transportation Electrification Framework (TEF) appear to be extremely underweighted. While consumer incentives are extremely important in creating and expanding markets, right-sized technical assistance is critical to meet the staff’s proposed 75% equity benefit goal. To help cover this gap left by the TEF, we encourage CARB to assure that the Amendment language being considered now be crafted to assure that the following recommendations can be adopted.

317.2 1. Allow LCFS holdback proceeds to fund technical assistance that is directly paired with the TEF statewide incentive program dollars so that underserved participants can receive the end-to-end, vendor neutral technical assistance they need to electrify. This includes system design, business model and payment settlement selection, permitting, contractor selection, construction management services, activation and staff/driver training.

317.3 2. Allow the continued, and encourage the expanded, use of nonprofit and for-profit third-party implementers for deployment of holdback-funded initiatives. This is in compliment to the utilities own teams that are implementing a portfolio of very effective programs. Third party implementers have been used extensively for utility-funded energy efficiency and demand response program implementation for more than two decades and often bring essential nimbleness and innovation at costs that are often less than traditional approaches. The CPUC's energy efficiency and other DER programs implemented by IOUs and CCAs can be used as real-world benchmarks for setting the appropriate balance between technical assistance and incentive dollars required to reach the State's equity and scaling objectives.

317.4 3. Focus LCFS funds on electrification of small, essential EV fleets that serve priority communities. (e.g. foodbanks, paratransit, elder meal delivery, small business fleets in underserved communities). Holdback proceeds should fund, in a single offering, the triad of 1.) end-to-end vendor neutral technical assistance 2.) vehicle incentives and 3.) infrastructure incentives. This bundled offering is essential for scaling small equity fleets. Likewise, it is important that incentives for Class 1 & Class 2 vehicles are eligible for holdback proceeds, beyond the current Class 3-8 vehicles covered by CARB's ISEF program.

317.5 4. We encourage the Amendment to expressly state that a key purpose of LCFS proceeds is to demonstrate and pilot deployment innovations as a way to inform and shape future iterations of TEF funding.

The State of California has ambitious goals for equity, air quality improvement and GHG reduction. Ecology Action truly believes the State can make a meaningful contribution to all three with the thoughtful deployment of the LCFS holdback funds as outlined here.

If you have any questions regarding our comments, please don't hesitate to contact me.

Sincerely,

Mahlon Aldridge
Vice President
Ecology Action
c. 831-4265-9257
mahlon.aldridge@ecoact.org.

Comment Log Display

Here is the comment you selected to display.

Comment 327 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Stefan
Last Name	Unnasch
Email Address	Unnasch@lifecycleassociates.com
Affiliation	Life Cycle Associates LLC
Subject	Correction to Non-combistion VOC Emissions for Ethanol Pathways
Comment	Please see the attached letter for our comments. Thank you.
Attachment	www.arb.ca.gov/lists/com-attach/6999-lcfs2024-BWIcOVU1VVkHLABf.pdf
Original File Name	LCA_-_Corn Ethanol biogenic VOC 2024_V3.pdf
Date and Time Comment Was Submitted	2024-02-20 16:49:41

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Stefan Unnasch
1. 650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

February 20, 2024

Liane M. Randolph
Chair, California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject**:** Letter of Comment on Ethanol Pathway in GREET, Issue with Biogenic VOC for Proposed Amendments to the LCFS, posted December 19, 2023

Dear Chair Randolph:

318.1 Life Cycle Associates would like to take this opportunity to provide our comments on the dry mill corn ethanol pathway under CA LCFS. We wish to draw attention to an issue regarding the treatment of biogenic VOC emissions within the ethanol production and T&D phases, which have been incorrectly categorized as fully oxidized GHG emissions. Both the prior and current versions of GREET have incorporated fugitive VOC emissions as fully oxidized GHG emissions, thereby adding to the carbon intensity of corn ethanol's well-to-tank phase. Such miscalculation within GREET1 models has carried forward to CA-GREET models as well, permeating this issue to CA LCFS.

Given that the VOC's carbon source is inherently biogenic, it logically follows that it should be designated as carbon-neutral for the purposes of carbon intensity calculations, warranting a reevaluation of its current treatment within the model. The non-combustions VOC emissions at the production plant as well as during the T&D phase are calculated per the equation below:

Equation 1. Total VOC emissions Dry Milling Corn Ethanol w/o Corn Oil Extraction.

$$VOC \ \left(\frac{g\ CO2e}{MMBtu}\right) = \left(\frac{(\mathbf{2.239})}{76{,}330} \times 1.001 \times 1e^{6} \times 1.000\right) \times \frac{44}{14} + (6.667 + 13.082) \times \frac{44}{14} \times 0$$

Compared to its predecessor, the 2019 simplified sfe calculator correctly excluded the T&D VOC fugitive emissions as GHG emissions. However, the fugitive VOC emissions as GHG from the production phase were still incorrectly retained, resulting in a CI of about 0.087 g/MJ. The same calculation has been carried forward in the proposed simplified SFE calculator, as shown in Table 2 below.

Stefan Unnasch
1. 650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

Table 1. Corn Ethanol Evaporative Emissions

CA-GREET4.0 Emission Factors and Specifications				
Category	Sub-Category	Name	Value	Unit
Fuel Production	Process Fuel	Natural Gas Combustion in Boiler	75,496	gCO_2e/MMBtu NG (LHV)
	Chemicals and Enzymes	Chemicals	2.02	gCO_2e/MJ ethanol (LHV)
		Cellulosic Enzymes Used	525	gCO_2e/lb enzyme (normalized)
	Coproducts	Default Distiller's Oil Moisture Content	1%	%W/%W
	Evaporative Emissions	Standard Value	0.0867	gCO_2e/MJ EtOH
	Denaturant	Default Blend Value	2.5%	%V/%V

There are two key issues to be corrected in the above calculation and thus the ethanol CI calculator.

1. Incorrect oxidation of VOC
The fully oxidized conversion of the VOC from the production phase currently utilizes the standard factor of approximately 44/14, where 14 refers to the molecular weight of an average VOC molecule. However, the VOC fugitively emitted during ethanol production is essentially an ethanol molecule with a molecular weight of 46, not 14. Thus, the correct fully oxidized fugitive VOC emission should use the factor of (44/46) instead of (44/14).

2. It's all biogenic
Most importantly, the origin of carbon in these fugitive VOC emissions is strictly biogenic. As all other biogenic carbon flows are treated carbon neutral under the ethanol pathway, these fugitive emissions should also be zeroed out and not be included in the ethanol pathway altogether.

Overall, the correct equation to calculate the GHG emissions from the fugitive VOC emissions is as follows:

$$VOC\ \left(\frac{g\ CO2e}{MMBtu}\right) = \left(\frac{(2.239)}{76{,}330} \times 1.001 \times 1e^{6} \times 1.000\right) \times \frac{44}{\mathbf{46}} \times \mathbf{0} + (6.667 + 13.082) \times \frac{44}{14} \times 0 = \mathbf{0}\ \frac{\boldsymbol{g\ CO2e}}{\boldsymbol{MMBtu}}$$

Correcting for this reduces the corn ethanol pathway CI by about 0.087 g/MJ as shown in the Table *1*. This may seem like a small number, but it should be noted that this is a systematic error which affects each and every certified corn ethanol pathway and every gallon of corn ethanol sold in California, and it also affects the Inflation Reduction Act (IRA). Over the total volume of corn ethanol sold, such a small change in CI generates a significant impact for the LCFS program. It is also critical from a consistency perspective to treat the emissions from all biogenic sources equally.

Note that the same issue applies to other biofuel pathways including biodiesel and renewable diesel. CARB has already zeroed out the GHG impact of the transport VOC emissions for these pathways based on comments we provided several years ago. However, since the source of VOC in the ethanol plant is not clearly identified as biogenic ethanol, CARB has not acted on the ethanol production component, which clearly appears to be fugitive ethanol.

Life Cycle Associates has previously shared this comment with Argonne National Laboratory as well as with CARB. The response from ANL was in agreement with the comments, however owing to their priorities, ANL has deferred this change to future. Our previous comment letter to

Stefan Unnasch
1. 650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

CARB also describes in detail the exact calculation with references to the specific sheets and cells within the prevailing CA-GREET and GREET1 model.

More importantly, the GREET model defines the basis for GHG calculations under the LCFS. Scholars, students, analysts, and of course affected parties look to the model to define the methods for GHG analysis. So, simple math errors do not support confidence in the program and should be corrected to avoid misunderstandings.

Thank you for your consideration.

Best Regards,

Stefan Unnasch
Managing Director
Life Cycle Associates, LLC

Love Goyal
Sustainability Project Manager
Life Cycle Associates, LLC

Fabiola Camacho
Chemical Engineer
Life Cycle Associates, LLC

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Comment 328 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Stefan
Last Name	Unnasch
Email Address	unnasch@lifecycleassociates.com
Affiliation	Life Cycle Associates
Subject	Avoided Methane from Organic Materials and Renewable Power for Process Fuel
Comment	Please see our comment letter attached addressing Avoided Methane from Organic Materials and Renewable Power for Process Fuel.
Attachment	www.arb.ca.gov/lists/com-attach/7000-lcfs2024-WjZcOVU1VFhXPAh7.pdf
Original File Name	LCA_MSW and Power_LCFS Comments Feb 20 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 17:16:07

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

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Stefan Unnasch
1.650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

February 20, 2024

Liane M. Randolph
Chair, California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Letter of Comment on Avoided Methane from Organic Materials and Renewable Power for Process Fuel for Proposed Amendments to the LCFS, posted December 19, 2023.

Dear Chair Randolph:

Life Cycle Associates would like to take this opportunity to provide our comments on Proposed Amendments to the Low Carbon Fuel Standard Regulation, posted on December 19, 2023. This letter is focused on two key components of the proposed amendments: Avoided Methane from Organic Materials and Renewable Power for Process Fuel.

Organic Feedstocks

319.1 • CARB is considering that all U.S. landfills are capped and that all U.S. landfill methane emissions are capped up to 75% and that only 25% can be considered leaked and potentially avoided. According to the U.S. EPA, even capped landfills cannot capture more than 50% of its LFG, and that there are numerous landfills in CA and the U.S. which are NOT capped at all. Therefore, CARB's assumptions in the Tier1 OW calculator is conservative.

319.2 • The Tier1 OW calculator is limited to CNG production via anaerobic digestion. We recommend that the calculator should apply to all fuels including hydrogen, FT jet, and others and not be limited to CNG via anaerobic digestion. Digestate from AD systems also becomes CO_2 just like feedstock into gasification systems and CARB should not delay the adoption of these technologies.

319.3 • We recommend that CARB provide more clarity on the definition of material that was diverted from a landfill versus material that otherwise would be composted as the counterfactual will be difficult to prove. A methane avoidance emission factor that represents the potential alternative fates of landfilling and composting with decomposition to CO_2 will allow for greater clarity in defining the avoided emissions from organic materials.

Processing Power

319.4 • That the small amount of power used for processing includes energy used for pumps, compressors and electronic control systems, etc. We recommend that CARB allows the use of grid power with book and claim of RECs for process power used to make hydrogen. These loads do not require large grid drawdown and only use for plant controls, pumps and processing and should not receive any different treatment than power used for electrolysis, especially for projects located in California.

Stefan Unnasch
1.650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

Consequences of Biomass Disposal

I have seen the consequences of inaction on biomass some of them are well known. SB1383 has led the challenges in the handling of urban biomass including wood chips. I don't need to look far to see the consequences. Alongside the roads everywhere you see piles of wood chips, no doubt the consequence of SB1383 and landfill fees that have risen. Better enforcement cannot force the round wood chip into the square hole. Technologies such as the utilization of biomass need to be actively considered and cannot wait another decade. Organic material provides an ideal energy source for synthetic aviation fuel, hydrogen, and other fuels and this resource needs to be examined.

Figure 1. Slash piles from commercial lumber operations are not stored for long periods of time as new trees must be grown.

Stefan Unnasch
1.650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

Figure 2. Biofuel policies could eliminate illegally dumped woodchips which accumulate along CalTrans freeway interchanges. High tipping fees and the challenges associated with composting make biomass energy an attractive option. No integrated polies are in place to deal with the fire hazards such as the Eucalyptus tree that overlooks the scene.

Avoidance Credit for Recovered Organics

The proposed regulation and the associated Tier 1 calculators now allow recovered organics to also generate avoided methane credit similar to urban landscape waste diverted away from landfills. Such an inclusion can be seen in the instruction manual of the OW calculator as shown below:

Field Name	Instructions
2.1 Organic Waste Feedstocks	Select feedstock(s) used by the fuel pathway. "Food Scraps" (FS) is the organic portion of municipal solid waste (MSW) that consists of wastes derived from plants or animals for the explicit preparation for consumption by humans or other animals that is predominantly disposed by landfilling. This includes inedible waste from foods processed or consumed at residences, hospitality facilities (hotels, restaurants, amusement parks, stadiums, special events, etc.), institutions (hospitals, schools, prisons, etc.), and grocery stores. Food scraps do not include liquid wastes, fat/oil/grease (FOG) materials, or other by-products of industrial food processing, manufacturing, and distribution facilities. "Urban Landscaping Waste" (ULW) is organic MSW material collected from landscaping activities, including leaves, grass, branches, and stumps. "Recovered Organics" (RO) is the organic fraction of mixed MSW that is manually or mechanically separated from the waste stream, typically at a materials recovery facility or transfer station. Any other organic waste feedstocks may be modeled as "Other Organic Waste" (OOW).

Similar to the FS or OLW waste pathways, the RO waste pathway also earns an avoided fugitive emissions from landfilling. The RO represents the waste that is separated from the aggregate waste stream at a recovery facility.

Stefan Unnasch
1.650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

319.5 However, the regulatory text, particularly the section § 95488.9.(f) (2), does not clearly reflect the same. A simple reading of this provision seems not to include avoided methane credit generation for recovered organics. We propose modifying the language in the following section to accurately reflect inclusion of recovered organics towards generating avoided methane emissions from landfilling.

(2) A fuel pathway that utilizes an organic material may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary diversion from decomposition in a landfill and the associated fugitive methane emissions, provided that:

(A) The organic material that is used as a feedstock would otherwise have been disposed of by landfilling, and the diversion is additional to any legal requirement for the diversion of organics from landfill disposal.

(B) Any degradable carbon that is not converted to fuel is subsequently treated in an aerobic system or otherwise is prevented from release as fugitive methane. Upon request, the applicant must demonstrate that emissions are not significant beyond the system boundary of the fuel pathway.

(C) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the avoidance or capture and destruction of biomethane.

For additional consistency we also recommend addition of "recovered organics" in all places which specify or define "organic waste" for the purposes of methane credit generation. Few of such places are shown below as examples:

- Tier 1 Classification

GREET~~3~~4.0 model to calculate the pathway CI. The Tier 1 classification includes, but is not limited to, the following fuel pathways:

(1) Ethanol derived from starch or fiber in corn kernels or grain sorghum, and sugarcane;

(2) Biodiesel produced from feedstocks including but not limited to oilseed crop-derived oils; rendered animal fat, distiller's corn oil, distiller's sorghum oil, and used cooking oil;

~~(3)~~ Renewable ~~Diesel~~diesel, renewable naphtha, alternative jet fuel and renewable propane produced by hydrotreatment of feedstocks in a stand-alone reactor, including ~~but not limited to~~ oilseed crop-derived oils, rendered ~~tallow~~animal fat, distiller's corn oil, distiller's sorghum oil, and used cooking oil~~;~~

~~(4)~~(3) ~~LNG and L-CNG from North American fossil natural gas;~~, also known as Hydroprocessed Ester and Fatty Acid (HEFA) Fuels;

~~(5)~~(4) Biomethane from North American landfills, anaerobic digestion of wastewater sludge, dairy and swine manure, and food, urban landscaping waste, and other organic waste~~.~~; and

Life Cycle Associates

Stefan Unnasch
1.650.461.9048 direct
unnasch@LifeCycleAssociates.com
884 Portola Road, Suite A11
Portola Valley, CA 94028 USA

- Temporary Pathways Table

Fuel	*Feedstock*	*Process Energy*	*CI* (gCO_2e/MJ)
Alternative Jet Fuel	Distiller's Corn Oil	Grid electricity/solar and wind electricity and natural gas	65
Alternative Jet Fuel	Any other feedstock	Grid electricity/solar and wind electricity and natural gas	Baseline (2010) CI value for Fossil Jet Fuel
Fossil LNG	Petroleum Natural Gas	N/A	95
Fossil L-CNG	Petroleum Natural Gas	N/A	100
Biomethane CNG	Landfill gas or Municipal Wastewater Sludge	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	~~70~~65
Biomethane LNG	Landfill gas or Municipal Wastewater Sludge	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	~~85~~80
Biomethane ~~L-CNG~~LCNG	Landfill gas or Municipal Wastewater Sludge	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	~~90~~85
Biomethane CNG	~~Municipal Wastewater sludge,~~ Food Scraps, Urban Landscaping Waste, or Other Organic Waste	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	45
Biomethane LNG	~~Municipal Wastewater sludge,~~ Food Scraps, Urban Landscaping Waste, or Other Organic Waste	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	60
Biomethane ~~L-CNG~~LCNG	~~Municipal Wastewater sludge,~~ Food Scraps, Urban Landscaping Waste, or Other Organic Waste	Grid electricity/solar and wind electricity, natural gas, and/or parasitic load	65
Biomethane CNG, LNG	Dairy Manure and Swine	Grid electricity/solar and wind	

Thank you for your consideration in reviewing our comments and incorporating them into the final regulation. If you have any questions, please reach out to me directly.

Sincerely,

Stefan Unnasch

Stefan Unnasch
Managing Director
Life Cycle Associates

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Comment 329 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Chad
Last Name	Frahm
Email Address	chad.frahm@brightmark.com
Affiliation	Brightmark
Subject	Brightmark comments to CARB LCFS amendments
Comment	Please see Brightmark's comments to CARB LCFS amendments attached Thank you.
Attachment	www.arb.ca.gov/lists/com-attach/7002-lcfs2024-AGICdgNrAzcFa1Qg.pdf
Original File Name	Brightmark comments.CARB LCFS amendments.Feb 20 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 17:24:16

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BRIGHTMARK

1725 Montgomery Street, Floor 3
San Francisco, CA 94111
415-810-0448
Brightmark.com

Submitted via electronic submittal: https://ww2.arb.ca.gov/lispub/comm/bclist.php

February 20, 2024

The Honorable Liane Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Comments on Proposed Low Carbon Fuel Standard Amendments and associated Initial Statement of Reasons

Dear Chair Randolph:

Brightmark LLC ("Brightmark") appreciates the opportunity to submit comments on the Proposed Low Carbon Fuel Standard Amendments and associated Initial Statement of Reasons (ISOR) posted on December 19, 2023, and updated on January 2, 2024 ("Proposed LCFS Amendments"). We appreciate the California Air Resources Board (CARB) engaging with stakeholders regarding changes and updates to the Low Carbon Fuel Standard (LCFS) program.

California's leadership in climate action through aggressive reduction targets and corresponding programs, like the LCFS, accomplishes actual pollution reduction and public health benefit outcomes by establishing market certainty to drive private investment. The state's leadership and programs provide key solutions to the global climate challenge, however, more needs to be done.

The Proposed LCFS Amendments are **insufficient** to maintain and increase investment in the LCFS program and **risk stranding existing assets** that have relied on the program.

The credit market has shown, through price dips, not price increases, following the release of the Proposed LCFS Amendments in December 2023 that the proposed changes are insufficient. Current LCFS prices as of February 11, 2024, reached the lowest point in over a year, indicating that CARB has not gone far enough in the Proposed LCFS Amendments regarding Carbon Intensity (CI) targets, CI step-down, and the Auto Acceleration Mechanism (AAM). This trend in credit market decreases following CARB proposed rule announcements includes after the February 2023 workshop and after posting of the Standardized Regulatory Impact Assessment (SRIA) in September 2023. If the current prices were to continue, there is a real threat of stranded assets for current investments that limit, if not eliminate, future investment.

CARB needs to utilize the three main levers: (1) CI targets, (2) CI step-down, and (3) AAM to stabilize credit prices at a level that will sustain current investments and lead to future investments. Increased program ambition is critical for continued methane reduction and growth in all low-carbon fuels.

1725 Montgomery Street, Floor 3
San Francisco, CA 94111
415-810-0448
Brightmark.com

Based on the Proposed LCFS Amendments, Brightmark recommends the following policy changes:

- A 2030 CI target of 40%,
- A CI step-down of 10% from the current regulation of 12.5% to 22.5% in 2024 to address current oversupply issues and increases in the bank that will occur in 2024.
  - If not administratively possible, then a CI step-down of 10% from the current proposal of 13.75% to 23.75% in 2025.
  - Increases of credits in the bank in 2024, because of delayed rule implementation, are causing downward price pressure needing immediate attention.
- An AAM, using similar mechanics laid out by AJW at the May 23, 2023 Workshop (May Workshop), to help avoid future oversupply situations, with the following changes:
  - Allow for a cumulative Credit/Deficit (C/D) bank trigger, instead of waiting for annual C/D numbers, and adjust the C/D ratio from 1.0 to 0.8
  - Allow for the AAM to be triggered as early as 2025
- A full credit true-up process that includes both
  - a true up while generating credits using the temporary pathway and
  - an annual true-up during the annual fuel pathway report process.

Brightmark Overview

Brightmark was founded in 2016 with the mission of solving some of the greatest environmental challenges facing the United States. One of these solutions is capturing methane emissions from organic waste and producing biogas and digestate through the natural process of anaerobic digestion. Agricultural activities contribute approximately 30% to total U.S. greenhouse gas (GHG) emissions, a significant portion attributable to methane emissions from animal waste.[1]

Brightmark operates over 30 net-negative carbon intensity projects on dairy farms across the U.S., including in California. Through these projects, Brightmark derives RNG from biogas that has been captured from organic waste streams and is cleaned and conditioned to achieve the quality standards necessary to blend with or substitute for geologic natural gas. We work with dairy farmers to harness the energy potential of their dairy manure, provide them with solutions to meet their greenhouse gas reduction goals, and enhance farm profitability. We are committed to reimagining waste and building projects that benefit farms, their dairy, their communities, and the planet.

These facilities provide a win/win scenario for farmers and local communities; they help address methane emissions from organic waste produced locally and turn that waste into renewable energy and fertilizers. To date, our projects have offset over 850,000 metric tons of CO2eq.

[1] U.S. Department of Agriculture Economic Research Service, citing the U.S. Environmental Protection Agency *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021*, April 2023 (EPA 2023).

1725 Montgomery Street, Floor 3
San Francisco, CA 94111
415-810-0448
Brightmark.com

The LCFS program, and the certainty it provides to the market, is a key factor in the long-term success of projects like these in addressing environmental challenges. The CARB LCFS workshops throughout 2022 and 2023 highlighted the success of the LCFS, showing that the program is over-performing and helping California meet its reduction goals sooner than originally targeted.

California Leadership in Climate Solutions Should Lead to More Aggressive Targets

California has a long history of supporting aggressive actions to address environmental challenges, like climate change. Governor Newsom has called for an even more aggressive approach to achieve climate neutrality. As CARB has stated, "[s]ignificant reductions in transportation emissions are needed to achieve state's air quality and climate goals."

During the Oil Price Information Service LCFS & Carbon Markets Workshop, ICF presented a scenario analysis that included the current bank of credits with a step-down of 7.25% and found that a CI reduction target of 40% was achievable in 2030 without the credit bank going negative.

The credit bank is projected to reach 28-30 million credits through the end of 2024 reporting, with the bank projected to increase in size by up to 6-8 million credits in 2024 alone. The current proposed 5% CI step-down will still lead to an increase in the bank in 2025, but a step-down of 10% will offset most, if not all, of the bank increase in 2024. This will stabilize the size of the bank to maintain credit prices at levels that will sustain and increase investment in the LCFS.

We believe the reduction target should be 40% by 2030, combined with a step-down of 10% in 2024. Because of the delay in LCFS rule implementation, the credit bank increases through 2024 do not seem to be addressed in the CI targets and step-down proposals. If not administratively possible in 2024, then a 10% step-down in 2025 should be implemented. As with California's Renewable Portfolio Standard program, the industry rises to the occasion with aggressive targets.

According to the ISOR, the LCFS provides environmental and public health benefits. Appendix A shows that projected positive environmental and health benefits, on a 2021$/gallon basis in 2026 and 2030, are comparable to significantly higher credit prices than what we see now. And historically, the potential LCFS impact on gas prices is insignificantly less than other exogenous impacts on crude prices (the main driver of gas prices) and California refinery disruptions and issues, see Appendix B.

In addition to the environmental and public health benefits, an increasingly stringent target provides market and regulatory certainty. Participants in the LCFS program have already demonstrated the ability to invest in long-term assets that drive CI reduction targets that exceeded expectations. Brightmark supports higher targets to increase credit demand and maintain a diverse fuel and credit generation mix.

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1725 Montgomery Street, Floor 3
San Francisco, CA 94111
415-810-0448
Brightmark.com

An Auto Accelerator Mechanism Provides an Appropriate Guardrail Against Low Prices and Increases Investor Certainty

In addition to a near-term 2024 or 2025 adjustment to the range of 23-24% and tightening the stringency to achieve a minimum 40% reduction by 2030, CARB should adopt a target accelerator mechanism to reduce the likelihood of future oversupply scenarios. An accelerator mechanism is not a substitute for appropriate changes in the targets, but it does offer an attractive additional tool to CARB if they wish to minimize future minor target-adjustment rulemakings. The key term here is "future oversupply scenarios." The LCFS is already oversupplied, with that oversupply projected to increase by 30-40+% higher from now through 2024. It is important that a sufficient step-down is implemented where the AAM would not be triggered in the first year after the new amendments (2026).

The details of the accelerator mechanism mechanics proposed by AJW at the May Workshop are well thought out and administratively feasible. A high credit-to-deficit (C/D) ratio and a high bank-to-deficit (B/D) ratio are important signals indicating an imbalance in credit supply and demand fundamentals. We encourage CARB to allow for a cumulative Credit/Deficit (C/D) bank trigger instead of waiting for annual C/D numbers. Also, as proposed, the C/D ratio should be adjusted from 1.0 to 0.8. If the B/D ratio can be triggered, then the bank is too large. However, if a C/D ratio is between 0.8-1, then there will not be a significant enough decrease in the bank to impact prices and lead to future investment.

A dual trigger, consisting of both a C/D ratio and a B/D ratio, as proposed by AJW, will likely strike an appropriate balance and only activate when there is a high likelihood of systemic long-run oversupply. The proposed trigger values should be reassessed appropriately based on historical data from the CA LCFS system. Once the trigger conditions are met, responding with a jump ahead in compliance targets is a straightforward and transparent way to increase stringency. Aligning the timing of correction with the existing process to address significant undersupply (through the Credit Clearance Market) is appropriate and straightforward.

320.1
- **Policy recommendation:** To address current and anticipated credit oversupply that threatens the viability of RNG projects, a more aggressive carbon intensity target with an increase to at least 40%

320.2
- **Policy recommendation:** A CI step-down of 10% from the current regulation of 13.75% to 23.75% in 2025 to address current oversupply issues and increases in the bank that will occur in 2024. This level of ambition should also be implemented in Q3 or Q4 of 2024, if administratively possible.

320.3
- **Policy recommendation:** in the AAM,
  - allow for a cumulative Credit/Deficit (C/D) bank trigger, instead of waiting for annual C/D numbers, and adjust the C/D ratio from 1.0 to 0.8, and
  - allow for the AAM to be triggered as early as 2025.

1725 Montgomery Street, Floor 3
San Francisco, CA 94111
415-810-0448
Brightmark.com

Accurate Credit Accounting

A full credit true-up remains necessary to properly recognize the true environmental performance of all pathways. Brightmark appreciates the inclusion of a credit true-up process in the rule language and wants to clarify that it is a full credit true-up both during temporary pathway and annual true up process, consistent with the recommendations submitted by the RNG Coalition in September 2023.

This recommendation would incentivize RNG producers to continuously make improvements to, and find efficiencies in, their existing production processes to improve their carbon intensity score, thus resulting in the continued reduction of GHG, even from operational facilities (which, may yield the greatest value for the LCFS program). As to underperformance, which can be impacted by a variety of external factors separate and apart from the facility itself, a true-up mechanism will allow producers to make the required adjustments and disclosures without the need for CARB staff to generate and process Notice of Violations (NOVs).

320.4
- **Policy recommendation:** A full credit true-up process that includes both a true up while generating credits using the temporary pathway and an annual true up during the annual fuel pathway report process.

Focusing on Solving the Problem

The goal of the LCFS is to reduce the carbon intensity of transportation fuels through greenhouse gas emission reductions. The LCFS is currently the only market with the economic incentive to develop carbon negative projects, including dairy biomethane. Dairy digester projects, due to the low energy density feedstock and higher required residence time, among other reasons, result in higher costs per MMBtu produced.

320.5 The success and market certainty of the LCFS program should be based on increasing the demand for credits, not limiting fuels and credit generation. Increasing demand for credits will result in greater overall emission reductions and a more diverse and stable credit pool. Avoided methane crediting should continue in LCFS until a realistic and proven replacement policy is implemented. Significant investments have been made in existing and future projects based on the current rules and trust in the LCFS program that emission reductions from these projects would be valued for delivering positive outcomes.

320.6 Brightmark supports the continued alignment of deliverability requirements for RNG with that of the federal Renewable Fuel Standard program. Biomethane projects that theoretically have the ability to deliver to California should be included, as the program currently operates. Current rules require that a project's CI score measure the additional carbon impact of traveling further in the CI calculation. Gas pipelines, contrary to the transmission power grids, can deliver biomethane from the East Coast to the West Coast.

1725 Montgomery Street, Floor 3
San Francisco, CA 94111
415-810-0448
Brightmark.com

320.7 While Brightmark prefers the current rule mechanisms for avoided methane and book and claim deliverability continue as is, we can support the proposed rule language applying to projects that break ground after December 31, 2029, to phase out pathways for crediting biomethane used in CNG vehicles after December 31, 2040, and pathways for biomethane used to produce renewable hydrogen would be eligible to receive credits until December 31, 2045.

Market and Regulatory Certainty

The success of the LCFS to date shows the market's ability to deliver together in partnership with CARB. The LCFS, at its core, is a market-based, fuel-agnostic regulation that does not pick winners and allows for all fuels to compete.

Market and regulatory certainty are based on trust in California as a reliable place to sell low-carbon fuel and credits to meet and exceed climate goals. However, to continue to achieve aggressive targets, CARB must promote a long-term, stable environment to encourage investors and teams to create new and maintain existing CI-reducing projects. This requires that credit prices maintain a level for capital recovery of previous and future investments.

320.8 An unfounded concern is that LCFS credit prices will adversely impact fuel prices. Appendix A illustrates that projected environmental and public health benefits, on a 2021$/gallon basis in 2026 and 2030, are comparable to significantly higher credit prices than what we see now. Appendix B shows that historically the potential LCFS impact on gas prices is insignificantly less than other exogenous impacts on crude prices (the main driver of gas prices) and California refinery disruptions and issues.

The ultimate goal of California and the market participants, like Brightmark, is decarbonization and eventual carbon neutrality of not only transportation, but all sectors of the economy. To reach this goal, California needs negative CI fuels for transportation and negative CI biogas for other uses (power, thermal, etc.). In-state and out-of-state RNG production are connected, the same developers that develop instate projects develop out-of-state projects. Current RNG production's success will lead to developing additional RNG projects necessary to decarbonize the non-transportation sectors to achieve long-term goals.

Negative CI fuels require significant economic incentives and market certainty, which has eroded with current LCFS prices. Long-term depression of credit prices will lead to stranded assets and lack of private investment in decarbonizing California's economy. CARB should send a strong signal by dramatically increasing the LCFS reduction targets and help return certainty to the market.

1725 Montgomery Street, Floor 3
San Francisco, CA 94111
415-810-0448
Brightmark.com

We appreciate the opportunity to provide comments, please do not hesitate to reach out with any questions.

Respectfully Submitted,

Bob Powell,
Founder & CEO

BRIGHTMARK

1725 Montgomery Street, Floor 3
San Francisco, CA 94111
415-810-0448
Brightmark.com

Appendix A – Quantification of Environmental Benefits

The following values are taken directly from the ISOR for total emission reductions and annual monetized environmental benefits.

all in 2021$	2026	2030
CO2 Emission Reduced (MMT)	13	20
5% Discount Rate	$254	$438
3% Discount Rate	$852	$1,368
2.50% Discount Rate	$1,250	$1,997
CH4 Emissions Reduced (MT)	314,024	292,597
5% Discount Rate	$288	$304
3% Discount Rate	$601	$640
2.50% Discount Rate	$816	$800
Health Benefits Total Benefits	$141	$129

The table below shows the combined environmental and health benefits per metric tonne (MT) of CO2e reduced.

Per MT CO2e Reduced in 2021$	2026	2030
5% Discount Rate	$32.8	$31.9
3% Discount Rate	$76.4	$78.2
2.50% Discount Rate	$105.8	$107.1

With the proposed CI targets of 21% and 30% by 2026 and 2030, that results in 0.0024 and 0.0034 deficits generated per gallon of gasoline. The table below compares monetized environmental and health impact per gallon (in 2021$) with the LCFS credit price impact per gallon. The range of credit prices shown are $50, $100, and $150 in nominal dollars that are converted to 2021$ with a range of 2.5%, 3%, and 5% discount rates.

$/gallon Positive Environmental and Health Impact – 2021$		
	2026	2030
5% Discount Rate	$0.08	$0.11
3% Discount Rate	$0.18	$0.27
2.50% Discount Rate	$0.26	$0.37

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San Francisco, CA 94111
415-810-0448
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	$/gallon Credit Impact (2021$)					
	2026			2030		
Nominal $ Credit prices	2.50%	3%	5%	2.50%	3%	5%
$50	$0.11	$0.10	$0.09	$0.14	$0.13	$0.11
$100	$0.21	$0.21	$0.19	$0.28	$0.26	$0.22
$150	$0.32	$0.31	$0.28	$0.41	$0.40	$0.33

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1725 Montgomery Street, Floor 3
San Francisco, CA 94111
415-810-0448
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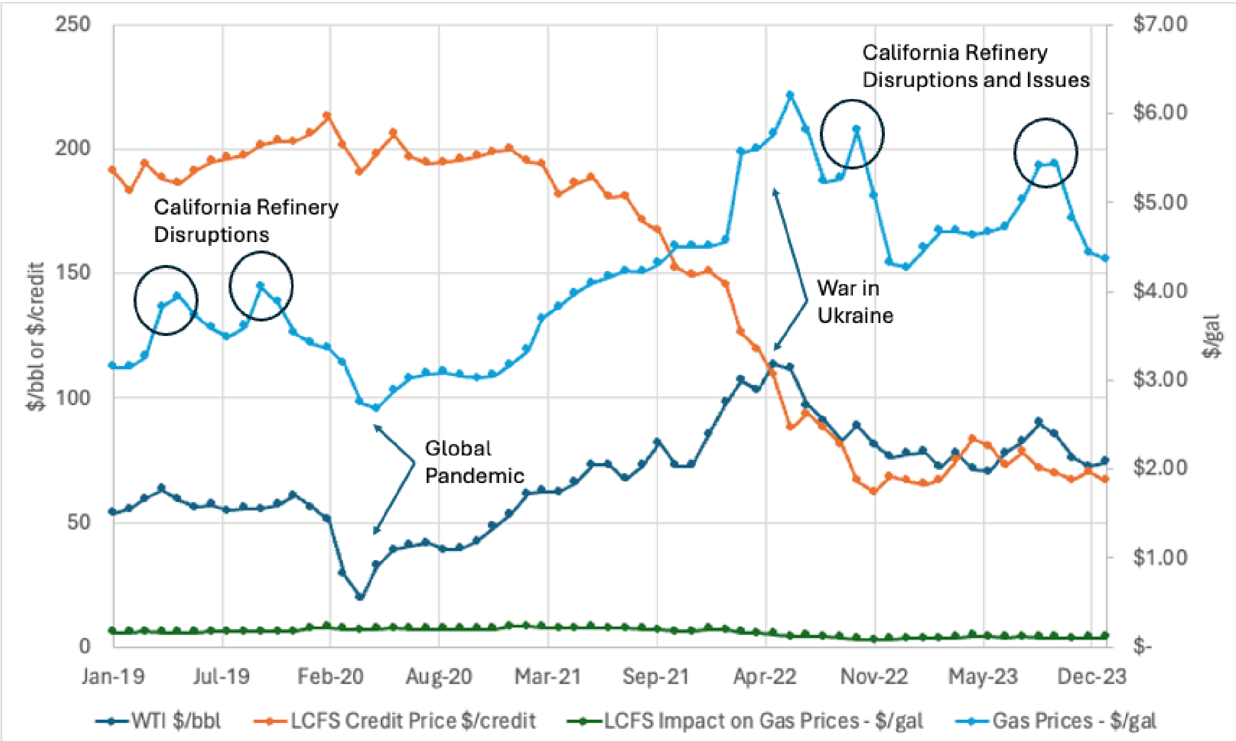
Appendix B – Historic Prices in Nominal Prices



Comment Log Display

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Comment 330 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Erin
Last Name	Cooke
Email Address	erin.cooke@flysfo.com
Affiliation	San Francisco International Airport
Subject	LCFS Missing Key Programs to Drive SAF Uplift to Reach CA's Climate and A Quality Goals
Comment	As you know San Francisco International Airport (SFO) is a global leader of sustainable aviation fuel (SAF) uplift, using ten millic gallons of neat SAF delivered last year. Receipt of this fuel was exclusively enabled by CARB's 2018 Low Carbon Fuel Standard Rulemaking that incentivized SAF beyond any other state or countr While SFO respects the bold decarbonization vision that CARB outlined in its 2022 Scoping Plan Update, we write today to humbl request that CARB team with key members of our aviation industry, as AB1322 requested, to develop a far broader playbook than that proposed in this 2024 LCFS Rulemaking to ensure the state meets Governor Newsom's 20% clean fuels adoption for the aviation secto estimated at 1.5 billion gallons of SAF by 2030.
Attachment	www.arb.ca.gov/lists/com-attach/7005-lcfs2024-USJWNgdpUFxQOlUh.pdf
Original File Name	SFO Ltr - LCFS Missing Key Programs to Drive SAF 2-20-24.pdf

Date and Time Comment Was Submitted	2024-02-20 17:26:51

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

SFO

San Francisco International Airport

February 20, 2024

The Honorable Liane M. Randolph
Chair, California Air Resources Board (CARB)
1001 I Street
Sacramento, CA 95814

TRANSMITTED VIA EMAIL
https://ww2.arb.ca.gov/lispub/comm/bclist.php

RE: Low Carbon Fuel Standard Missing Key Programs to Drive SAF Uplift as Key Components to Reach California's Climate and Regional Air Quality Goals

Dear Chair Randolph,

As you know San Francisco International Airport (SFO) is a global leader of sustainable aviation fuel (SAF) uplift, using ten million gallons of neat SAF delivered last year. Receipt of this fuel was exclusively enabled by CARB's 2018 Low Carbon Fuel Standard Rulemaking that incentivized SAF beyond any other state or country. Since this adoption, SFO and the Sustainable Aviation Fuel (SAF) Coalition we launched that is comprised of airlines, airports, conventional and alternative aviation fuel producers, and other nonprofit and government partners, has met with CARB staff and leadership to compel additional programs to sustain the state's SAF leadership. Further, the SAF Coalition teamed with the Speaker of the Assembly, Robert Rivas, to author the widely supported AB1322, which passed unanimously through the California Legislature, to gap analyze SAF programs that could ensure California's continued SAF competitiveness. While SFO respects the bold decarbonization vision that CARB outlined in its 2022 Scoping Plan Update, we write today to humbly request that CARB team with key members of our aviation industry, as AB1322 requested, to develop a far broader playbook than that proposed in this 2024 Low Carbon Fuel Standard (LCFS) Rulemaking to ensure the state meets Governor Newsom's 20% clean fuels adoption for the aviation sector, estimated at 1.5 billion gallons of SAF by 2030.

California and CARB must model a complete program that addresses the greenhouse gas and criteria air emissions across all sectors. Aviation efforts are falling short of our European
321.1 counterparts. SFO aligns with our industry peers to urge CARB to align LCFS policy across both hydrogen and SAF to allow for book and claim accounting for low-CI electricity and RNG inputs via the use of Power Purchase Agreements (PPAs). SAF and hydrogen are both nascent industries and the state should equally allow the indirect accounting for both technologies.

SFO continues to encourage CARB to consider LCFS and other levers that can materialize new markets to recognize SAF's non-CO2 benefits, as outlined in previous communications with CARB, the California Natural Resources Agency (CNRA), the Bay Area Air Quality Management District, and GoBiz. These positive externalities include improvements to air quality, economic development through green jobs, and wildfire risk reduction, and are detailed in industry studies and should be represented in the LCFS, Scoping Plan, further CARB

Rulemaking, GoBiz programs and/or CNRA incentive structures. A recent Airport Cooperative Research Program (ACRP), administered by the Transport Research Board of the U.S. National Academies of Sciences, found that a 50% SAF blend could reduce by nearly 40% oxides of sulfur and PM reductions of up to 65%. A more recent measurement campaign found that SAF produced via the alcohol-to-jet pathway could reduce non-volatile PM by up to 97%.

The California aviation sector utilizes four billion gallons of conventional jet fuel annually. By creating new programs that enable airlines to switch to SAF, California can reduce aviation GHG emissions by 50-80% on a lifecycle basis. If aircraft in California uplifted just 5% SAF by 2025, greenhouse gas emissions avoided from those flights would total up to 2 million metric tons of CO2. Without growing AJF use, aviation sector emissions are expected to grow to over 25% of California's emissions by 2040, as other sectors (e.g., buildings, road transport) have full decarbonization pathways.

SFO has set a goal of expanding SAF use by its airlines to 5% by 2025. And while we are on our way, hitting 1% last year, achieving this goal will require 200 million gallons of SAF per year (MGY) by 2025, or 16 new SAF plants. As this goal of 200 MGY represents only about one-third of California's 2019 renewable diesel supply, it requires a rapid scaling of SAF production to be achieved.

SAF is being commercialized and is scalable, but volumes are currently small, with roughly 15 million gallons used exclusively in California last year, compared to 2.5 billion gallons of biodiesel and renewable diesel consumption. The key factor limiting SAF growth is the total monetary value that SAF producers receive when compared to that available to producers of alternative fuels to serve the on-road market. This has been quantified and detailed in a 2020 submittal by Graham Noyes ("Cap and Rack Cost" + LCFS cost) and is recognized by the industry to be approximately $0.40 per gallon. To that end, we request that CARB further review LCFS through its Public Workshops and consider revising the regulations to overcome the disparity in policies between the production of renewable diesel and SAF. Doing so will send the price signal producers need to secure investment capital to expand their facilities and increase supply to airlines uplifting SAF in California. It also offers a lifeline to renewable diesel fuel producers that exclusively serve the on-road sector, which is now obligated to increasingly electrify through State Executive Order and regulation to retrofit and retool plants for a future of aviation fueled by SAF.

With quotas and targeted SAF incentives announced and growing in Canada, the United Kingdom, Sweden, Norway, and the European Union, we hope that CARB will consider expanding the LCFS credit for SAF. Doing so will help power aviation's contribution to California's continued post-COVID and wildfire recovery in a way that keeps our state climate-competitive and fuels our industry's energy transition. While other states are starting to develop more robust SAF tax credits and incentive programs, CARB must grow SAF's LCFS credit value, or pursue other programs that can scale (not hinder) SAF as a key waypoint in California's climate emergency response planning and create a lasting legacy for our state.

We stand ready to support CARB's leadership, side by side with our airline and SAF producer peers, through the development of a mutual and robust SAF campaign that we hope you'll take on through this LCFS Rulemaking.

Very truly yours,

Ivar C. Satero
Airport Director

Comment Log Display

Here is the comment you selected to display.

Comment 331 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	George
Last Name	Kivork
Email Address	george.kivork@jobyaviation.com
Affiliation	Joby Aviation
Subject	Joby's Comments on Proposed LCFS Amendments
Comment	Please see attached the Comments of Joby Aviation on the Proposed Amendments to the Low Carbon Fuel Standard.
Attachment	www.arb.ca.gov/lists/com-attach/7006-lcfs2024-UWMHMVdkB2RReQg4.pdf
Original File Name	2020.02.20 Joby LCFS Amendments Comments.pdf
Date and Time Comment Was Submitted	2024-02-20 17:11:20

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
[submitted electronically]

RE: Comments of Joby Aviation on the Proposed Amendments to the Low Carbon Fuel Standard

Joby Aviation appreciates the opportunity to provide comments on the California Air Resources Board's (CARB) Proposed Amendments to the Low Carbon Fuel Standard (LCFS).

About Joby Aviation

Joby's mission is to help the world connect faster and more easily with the people and places that matter most by delivering a new form of clean, quiet, electric vertical take-off and landing (eVTOL) aerial transportation. Building on recent advancements in energy storage, microelectronics, material science, and software, we are developing an all-electric aircraft with zero operating emissions that will transport a pilot and four passengers at speeds of up to 200 mph, while also having the ability to take off and land vertically.

Developing sustainable mobility solutions has never been more needed given the threat that climate change poses to our communities and to our planet. According to the U.S. Environmental Protection Agency (EPA), the top source of CO2 emissions in the U.S. is the transportation sector. We expect the electrification of transportation to accelerate and extend to the skies in the decade ahead, representing a bright spot where technology, economy, and sustainability converge. Applying electrification to small aircraft unlocks new degrees of freedom in aircraft design that were not possible with traditional, combustion engines.

Our aircraft has been specifically designed to achieve a considerably lower noise footprint than that of today's conventional aircraft or helicopters. It is quiet at takeoff and near silent when flying overhead, blending seamlessly into the environment. This will allow us to operate from new skyport locations nearer to where people live and work, in addition to utilizing the more than 5,000 heliport and airport infrastructure facilities already in existence in the U.S. alone.

Joby is headquartered in Santa Cruz, CA with over 1,400 employees across California. In 2022, we completed the construction of our pilot production lines in San Carlos and Marina, CA, and we began manufacturing our production prototype aircraft. We are excited to support the clean transportation and climate goals of our home state.

Zero-Emission Aviation is Key to Meeting California's Climate Goals

The combustion of aviation and other transportation fuels releases substantial amounts of greenhouse gasses into the atmosphere. The transportation sector has the highest dependency on oil over any other sector, with over 90% of energy coming from fossil fuels.[1] At the same time, the aviation industry is undergoing rapid expansion due to the increasing popularity and accessibility of flying. The rise of low-cost carriers and a growing middle-class population worldwide have fueled a surge in air travel demand. Joby strongly supports the broader accessibility of flying as a mode of transportation. We also believe that eVTOL will play an important role in replacing internal combustion vehicles on the road. However, there is a challenge in ensuring minimizing the environmental impacts while reaping the undeniable benefits of increased mobility and connectivity.

For this reason, California and CARB have already created goals to reduce emissions from aviation. These include:

1. 20% of aviation fuel demand met by electricity (batteries) or hydrogen (fuel cells) by 2045; and
2. Sustainable aviation fuel meeting most or the rest of 2045 fuel need.[2]

These goals are ambitious, but Joby and others in the aviation sector are working to ensure that zero-emission aviation becomes a reality in California. In order to advance these goals, CARB will need to utilize every tool available to unlock zero-emission and sustainable aviation technologies and fuels. This includes the LCFS, which will play an important role in incentivizing a less carbon-intensive aviation industry. CARB should seek to streamline the participation of the aviation sector in the LCFS, such as by creating Tier 1 or Lookup Table participation pathways for electric aviation. It is also important that CARB initiate a rulemaking process to implement its aviation goals.

Joby Supports a Stronger LCFS Program

[1] See Data from the International Energy Agency: https://www.iea.org/energy-system/transport
[2] CARB 2022 Scoping Plan at p.73. Available at: https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

322.1 Joby supports increasing the carbon intensity (CI) reduction target of the LCFS program to at least 30 percent by 2030 and also increasing stringency in later years. As emphasized in the 2022 Scoping Plan Update, the aviation sector holds an important role in California's ambitious journey toward carbon neutrality by 2045, and the LCFS program is a critical instrument in facilitating the decarbonization of aviation.

Beyond setting a more ambitious yet attainable CI target for 2030, it is imperative to structure the LCFS program to be adaptable to market dynamics, ensuring support for continued investments in the cleanest low-carbon technologies. The inclusion of a compliance target "auto-acceleration mechanism," capable of automatically adjusting to
322.2 expedite investments if the LCFS program surpasses expectations, serves as a strategic measure to maximize California's potential for emissions reduction in the transportation sector. This multifaceted approach aligns with Joby's commitment to sustainable aviation and complements the broader initiatives aimed at achieving California's environmental objectives.

Conclusion

Joby is excited to continue to work with CARB on achieving California's zero-emission aviation and larger climate goals.

Sincerely,

/s/ George Kivork
George Kivork
Head of U.S. State & Local Policy
Joby Aviation

Comment Log Display

Here is the comment you selected to display.

Comment 332 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Cassandra
Last Name	Farrant
Email Address	cfarrant@ampamericas.com
Affiliation	Amp Americas
Subject	Comments on the Proposed Low Carbon Fuel Standard Amendments
Comment	Amp America appreciates the opportunity to submit comments in response to the proposed Low Carbon Fuel Standard Amendments. Please see our comments attached.
Attachment	www.arb.ca.gov/lists/com-attach/7007-lcfs2024-UjNdNlEgUl4CdAFz.pdf
Original File Name	Amp Proposed LCFS Admendments Comment Letter.pdf
Date and Time Comment Was Submitted	2024-02-20 17:20:56

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Amp Americas

February 20, 2024

Matt Botill
Chief, Industrial Strategies Division
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: AMP AMERICAS COMMENTS ON PROPOSED LOW CARBON FUEL STANDARD AMENDMENTS

Dear Mr. Botill:

Thank you for the opportunity to comment on the Proposed Amendments to the Low Carbon Fuel Standard ("LCFS"). Amp Americas ("Amp") appreciates the California Air Resource Board's ("CARB's") leadership on addressing climate change and the significant success the LCFS program has had in decarbonizing transportation. Amp especially appreciates CARB staff's thorough and ongoing stakeholder engagement throughout the LCFS amendment process, and in particular on issues related to dairies and renewable natural gas ("RNG").

Amp strongly supports amending the LCFS to ensure its ongoing success as a driver of investment in a broad array of low carbon fuels, including dairy RNG. Accordingly, we offer the following comments, which are further elaborated upon below:

323.1
- Stronger near-term targets than proposed are necessary to address the ongoing accumulation of credits and drive additional investments in low carbon fuels projects in the near term. We recommend:

323.2
  - **A step down to at least 23%** carbon intensity reduction, to take effect as soon as the regulation takes effect in Q3 2024, rather than 2025. If the step down is not effective until 2025, we recommend a 25% step down effective January 1, 2025.

323.3
  - **A 2030 target of at least 35%,** in order to drive the outcomes laid out in the 2022 Scoping Plan. We note that approximately 3 percentage points of the target are required to counteract the change in diesel baseline, which without adjustment, effectively reduces program ambition by 3 percentage points.

323.4
- We support the addition of an auto acceleration mechanism (AAM) to the program, and encourage minor adjustments that would allow it to be more responsive to market conditions:

323.5
  - The **AAM should take effect as soon as the regulation does**, with the first test occurring in 2026 to evaluate 2025 performance.

323.6
  - The **AAM trigger should be 1x quarterly deficits**, rather than 3x, in recognition that 1) the LCFS is now a liquid and mature market, and 2) that liquid and mature markets are in surplus conditions when inventory is greater than 0.6x quarterly demand.

323.7
  - There should be **no limit to applying the AAM in consecutive years**.

323.8
- **We urge CARB to follow the deep and sound science and maintain avoided methane crediting for all RNG pathways.**

323.9 • We **support efforts to develop RNG pathways for zero emission vehicle ("ZEV") fuels and stationary sources**, and encourage CARB to **enable book-and-claim delivery for RNG-to-power plants** to further support this transition.

323.10 • We **support the proposed true-up provisions and recommend CARB allow true-ups during the Temporary CI period for any pathway using a Temporary CI.**

323.11 • We include various other technical comments and recommendations to bolster the ability of the program to continue driving investment in low carbon transportation fuels and greenhouse gas emissions reductions, including allowing the regulation to **automatically incorporate new carbon capture, removal, utilization and sequestration (CCRUS) pathways** if and when new CCS Protocols are developed pursuant to Senate Bill 905.

In addition to these recommendations on the proposed amendments, we appreciate the opportunity to comment on the proposed CA-GREET 4.0 model and revised Tier 1 calculators. We reiterate our comments shared previously on the calculator,[1] and specifically that:

323.12 • All biomethane pathway calculators should include the option to model biogas-to-electricity carbon intensity scores.

323.13 • Applicants should be allowed to account for actual fugitive methane performance.

323.14 • The avoided emissions boundary should include biogas flared during normal operations.

323.15 • The volatile solids table should be updated to include new technologies.

ABOUT AMP

Founded in 2011, Amp develops, owns, and operates RNG facilities that convert dairy waste into carbon-negative renewable energy. Over our history, Amp's projects have prevented over 1.7 million metric tons of carbon equivalent emissions. In 2022 alone, our projects abated approximately 480,000 metric tons of carbon equivalent emissions, and we plan to rapidly expand our impact over the next several years.

As a pioneer in the dairy RNG industry, Amp registered the first 5 dairy RNG-to-CNG pathways in California's LCFS program, and we were the RNG supplier for the first 11 dairy RNG-to-hydrogen pathways. Our experience developing, operating, and reporting on these and other assets gives us a unique perspective on the impact CARB policy has on investment and project development activity related to low carbon fuels. Our projects and resulting methane and carbon dioxide reductions have been made possible by CARB's leadership in decarbonizing transportation, and we encourage CARB to continue to support the policy decisions that have made it so successful.

LCFS CRITICAL TO ACHIEVING SB 1383 METHANE REDUCTION TARGETS

California is a global leader in efforts to slash potent super pollutants, including methane from dairies and other sources. Since the finalization of the *Short Lived Climate Pollutant ("SLCP") Reduction Strategy* in 2017, the state has seen significant investment in projects to mitigate methane emissions, notably from dairy manure management. For example, for decades prior to development of the SLCP Reduction Strategy, the state had only a handful of dairy digesters to mitigate methane emissions, but over the few

[1] https://www.arb.ca.gov/lists/com-attach/360-lcfscalculators23-ws-UTBVPgZ3U19QIgNq.pdf

years since the adoption and implementation of the SLCP Reduction Strategy, California now has over 200 dairy digesters built or under development. Hundreds more projects are under development nationally, delivering significant additional SLCP reductions and creating a broader supply of available RNG to replace fossil natural gas (virtually all of which is imported from out-of-state) and decarbonize California's transportation and other sectors in alignment with the state's strategy to achieve carbon neutrality under the *2022 Climate Change Scoping Plan Update*.

A key element driving this success has been the LCFS. The SLCP Reduction Strategy specifically highlights the LCFS and federal Renewable Fuel Standard as critical programs to enable ongoing development of dairy digesters in California.[2] Without credits generated under the LCFS and RFS programs, or other significant ongoing state incentives, additional dairy manure methane mitigation projects are unlikely to be developed in California.[3] This was a clear finding in the March 2022 review report, *Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target*. Among other takeaways, the report finds that the LCFS can ensure the long-term operation and financial stability of digester projects[4] and that alternative manure management projects are unlikely to be implemented without subsidies.[5]

This successful framework can continue driving investment in methane mitigation in order to meet our statutory emissions reduction targets, provided that the LCFS is strengthened to maintain a strong investment signal and continues to allow for methane mitigation projects to be developed by (1) increasing overall program ambition in line with the 2022 Scoping Plan, (2) preserving the science-based accounting for avoided methane associated with RNG pathways, and (3) preserving book-and-claim delivery for RNG so it can continue to reach its current transportation fuels markets and extending book-and-claim to allow RNG to serve other target end markets in transportation and stationary uses.

Maintaining current provisions for dairy RNG pathways maintains the investment case under which investors allocated capital to the LCFS program and avoids emissions backsliding. CARB engineered a program to draw private dollars rather than allocate public funds to its SLCP Strategy goals. In order to maintain trust with investors and continue to drive private investment, CARB cannot change the rules and strand investment in capital already deployed. Not only is preserving the rules for dairy digesters important for statewide carbon goals and the LCFS program, but investment in digesters is required to achieve the state's methane mitigation goals and supporting initiatives under SB 1383. The state's Renewable Gas Standard directs utilities to procure biogas from projects utilizing organics diverted from landfills in line with SB 1383 obligations, and explicitly relies on dairy biogas projects continuing to be supported by the LCFS.[6] Thus, several state priorities are at risk with the proposed changes to the dairy RNG rules and overly conservative proposal for overall program ambition by 2030.

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[2] For example, see the SLCP Reduction Strategy, pp. 68, 107.
[3] SLCP Reduction Strategy, pg. 121.
[4] For example, see the report, Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target, pp. 19, 29, 31, 40.
[5] Analysis of Progress toward Achieving the 2030 Dairy and Livestock Sector Methane Emissions Target, pg. 41.
[6] CPUC Decision 22-02-025, February 24, 2022.
https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M454/K335/454335009.PDF

STRONGER NEAR-TERM TARGETS NEEDED TO SUPPORT ONGOING INVESTMENT

The ongoing development and operation of low carbon fuel projects, including dairy RNG projects, requires programs like the LCFS to provide and maintain a strong and clear market signal sufficient to attract capital for new projects and to maintain operations at existing RNG facilities. In previous comments,[7] we have advocated for a step-down in CI average reductions to at least 19% in 2024, and CI reduction targets of at least 35% in 2030, and urged that targets be in-line with emissions reduction targets in statute or identified in the 2022 Scoping Plan Update (e.g., 40-48% reduction).

323.2 cont. While the proposed amendments include a step-down to about 19%, *the step-down as proposed wouldn't take effect until 2025.* During the third quarter of 2023, the credit bank grew by 2.25 million credits and ended the quarter with a balance of 20.4 million credits. With no change to targets in 2024, if credit supply and demand continue their current rate of growth, the bank could be 38 million by the end of 2024, almost 6 times quarterly deficit generation. If credit supply were to remain constant at Q3 2023 values, with no step down in 2024 (a wildly conservative scenario), the bank would still reach 30 million credits and represent more than 4 quarters' worth of deficits. These outcomes do not account for the recently revised diesel carbon intensity, which will lead to additional credit generation beginning in 2025. With a bloated credit bank to begin with, the market will be hopelessly saturated and getting worse by multiple percentage points and millions of additional banked credits.[8]

If the bank is allowed to reach these levels, prices will remain depressed for an extended time. Investment in new LCFS credit generating projects has already slowed or frozen, and while projects that were green-lit in a higher price environment continue to come to market, new projects are not starting. If low prices persist, new supply growth will stop. In several years, when targets accelerate, the market could snap to undersupply and squeeze prices past the cap. In order to prevent this situation, targets must reflect the market's ability to bring in new supply.

The proposed increase in stringency to 18.75% (growing program targets by 50% vs. 2023), if executed immediately for the full year 2024 (not an option proposed) would only balance the market for this year. However, in 2025, supply growth will once again outstrip demand growth as projects currently under construction are brought online. With surplus conditions continuing, the bank will continue to build, and we will remain in a low price environment – meaning no new investment will materialize.

Together, these trends demonstrate that a greater step down is necessary to maintain orderly functioning of the LCFS market, reverse the trend of accelerating growth in the credit bank, and to avoid further weakening the signal to invest in new projects and GHG reductions. **Accordingly, we encourage amendments that would have the step-down to 23% take effect in 2024 or alternatively, to increase the step down to ~25% if it were to take effect only in January 2025.** Our recommendation is in-line with the analysis presented by ICF, showing levels needed to return balance to the credit bank and stabilize prices**.** We also reiterate our call to set 2030 CI reduction targets of at least 35%, and align program goals with levels required to achieve the goals of the Scoping Plan.

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[7] For example, see: https://ww2.arb.ca.gov/system/files/webform/public_comments/3751/Amp%20LCFS%20May%202023%20Workshop%20Comment%20Letter%20vF.pdf

[8] ICF, *Analyzing Future Low Carbon Fuel Targets in California*, February 2024

We appreciate that CARB has evaluated three scenarios for program rules and targets, showing high prices and a leveling, declining bank in its proposed scenario. We do not have access to all of CARB's inputs to provide specific feedback, but it is clear that the market disagrees with the output of CARB's forecasts, as reflected in the price of credits since the ISOR was released. The market believes the LCFS market will remain in surplus for the foreseeable future, and credit prices have been trading down since the proposed amendments were released. At the current price level in the low $60s per ton, with the proposed program target levels, most capital providers have stopped investing and going forward will not allocate dollars for further investment in California low carbon fuels projects for at least the next few years.

ADJUSTMENTS TO THE AUTO ACCELERATION MECHANISM WILL MAKE IT MORE EFFECTIVE

323.5 cont. The demonstrated market response implies two things. First, and most importantly, the step-down quantum is insufficient to clear the current supply of available credits. If the market had confidence in the AAM, we might see some price recovery, rather than a continuing decline in credit prices. So the second implication of the market response is that the market believes the AAM as proposed will be insufficient to correct the for the low ambition in the targets. Accordingly, in addition to strengthening the step-down and pulling it forward to Q3 2024, Amp strongly encourages CARB to adjust the AAM, so that it takes effect sooner and is more responsive to changing market conditions.

323.4 cont. Amp strongly supports development of an AAM, which will help to strengthen the program and potentially help to avoid future potential market weakness driven by as-yet unforeseen trends in low carbon fuels supplies. While the market is currently overachieving its targets, there is a long way to go to reach 2045 goals. Ironically, when overachieving the targets in the near term leads to sustained price weakness, it will inevitably lead to sustained periods of underachievement and high prices. If the market subsequently swings from undersupply to oversupply, prices will be volatile, undermining public confidence in the program and jeopardizing long term goals. An AAM can help provide a clear, ongoing signal that there will be a market for low carbon fuels, providing greater certainty to investors and incentivizing continuous investments in clean fuels and ongoing greater emissions reductions, provided that it is designed appropriately.

323.5 cont. As noted above, however, together with the proposed step-down approach, the AAM is insufficient to reverse an accumulating credit bank over the next several years, and therefore stands to miss on its promise. Accordingly, Amp recommends adjusting the AAM as follows:

- The **AAM (and step-down) should take effect as soon as the regulation does (e.g. Q3 2024).** This would imply the first test would take effect in May 2025, and the first year the target could be accelerated would be 2026. If the regulation becomes effective in 2025, the first test should occur in May 2026.
- 323.6 The **AAM should be triggered when credits exceed one quarter of demand**, rather than 3x quarterly demand.
- 323.7 There should be **no limit to applying the AAM in consecutive years** if the specified thresholds are met.

323.6 cont. The AAM is by its nature conservative, requiring both a significant and growing credit bank in order to be triggered. Accordingly, there is no reason to wait an additional year after the step-down takes effect

323.6 cont. for the AAM to potentially apply, or for that matter, to introduce a year between periods when the AAM may potentially trigger again. If a significant credit bank persists and continues to grow – even during a year in which targets were accelerated by operation of the step-down or the AAM – that demonstrates that further acceleration of the targets is warranted.

A credit bank that is too large has a seriously detrimental effect on the market. Especially when a large number of credits is held by few players – as is the case now and for the last several years – those players can draw on their holdings and not buy or generate additional credits. This leads to price weakness and tells potential future suppliers not to invest. Even if the market were to supply fewer new credits than compliance obligations require (i.e., market balance is in deficit) the large bank can prevent prices from signaling to suppliers the need to invest. So, what is the right level? Drawing corollaries from similar markets, stores rarely exceed 15-25% of annual demand or 0.6-1.0x quarterly demand in U.S. grain[9] and energy markets (see data for crude oil and natural gas below). We note as well that the federal RFS program allows for an effective bank maximum of 0.8x quarterly demand in the form of its rule allowing 20% carryover of RIN balances (and deficits).

U.S. Crude Oil Storage as Share of Quarterly Demand 2008-2023[10,11,12,13]

	Ending Stocks of Crude Oil (Barrels)	Crude Oil + NGL Quarterly Production (Barrels)	Quarterly Supplied Petroleum Products (Barrels)	Quarterly Storage Divided by Next Quarter Demand
Max	1,208,001,846	1,832,932,500	1,937,512,923	0.72x
Median	1,055,914,615	1,139,179,000	1,801,268,000	0.59x
Mean	1,052,450,337	1,149,569,945	1,801,178,655	0.59x
Min	782,771,000	593,810,000	1,653,659,000	0.43x

[9] Zulauf, et al. University of Illinois. *Stock-to-Use Ratios of US Corn, Soybeans, and Wheat Since 1960.* June 2021.
[10] Crude oil inventory: http://www.eia.gov/dnav/pet/pet_stoc_wstk_dcu_nus_w.htm
[11] Crude production: http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm
[12] NGL production: https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=M_EPL2_FPF_NUS_MBBLD&f=M
[13] Crude consumption ("U.S. Weekly Product Supplied"): http://www.eia.gov/dnav/pet/pet_cons_wpsup_k_w.htm

323.6 cont. **U.S. Natural Gas Storage as Share of Quarterly Demand 2010-2023**[14,15,16]

	Lower 48 Natural Gas Inventory (Bcf)	U.S. Natural Gas Gross Withdrawals (Bcf)	U.S. Natural Gas Total Consumption (Bcf)	Quarterly Storage Divided by Next Quarter Demand
Max	3,864	11,626	9,433	0.51x
Median	2,750	8,255	6,951	0.39x
Mean	2,732	8,828	7,054	0.39x
Min	1,308	6,535	4,959	0.23x

Would a tighter allowance on the size of the bank present a risk to the operation of the LCFS program? We see little reason to believe so. The biggest quarterly deficit ever seen in the program was 13% of deficits for the quarter (Q2 2018). Were we to see this level of shortfall again, it would take almost 8 quarters of sustained deficit at this record level to draw down a bank balance of 1x quarterly deficits and it would take 23 quarters to draw a bank balance of 3x quarterly deficits. **Implementing a reasonable 1x quarterly deficits trigger would be a clear signal to the market of CARB's intent to reach its goals with very little risk to overall program effectiveness.**

AVOIDED METHANE AND BOOK AND CLAIM DELIVERY FOR BIOGAS CRITICAL TO ACHIEVING METHANE REDUCTION GOALS

323.8 cont. Avoided methane crediting is critical for both financing digester project development and long-term operating viability. Dairy digester projects cost tens to hundreds of millions of dollars and take 2-3 years to develop and construct, followed by up to two years to receive provisional pathway scores. Avoided methane crediting provides the source of revenue for these projects that pays for their beneficial impact and allows developers to invest. If in the future, farm methane emissions are regulated directly, milk buyers will foot the bill for reducing emissions through milk prices or government will directly subsidize digesters. Until then, avoided methane crediting is the only way to support digester development, ongoing operations, and associated emissions reductions. **We strongly encourage CARB to maintain avoided methane crediting for all RNG pathways, and to not phase out CNG or hydrogen pathways unless and until direct regulation renders avoided methane non-additional.**

As noted above, the LCFS has proven a successful model – likely the most successful in the world – in achieving methane reductions from the agricultural sector. This success stems directly from avoided methane crediting as part of lifecycle GHG emissions accounting for biomethane pathways. Methane crediting is both scientifically accurate and proven effective in supporting project development and driving significant methane reductions. Given this demonstrated success and scientific accuracy, a number of new programs are taking a similar approach to California's, including the Inflation Reduction Act and other programs based on the Argonne National Laboratory (ANL) Greenhouse gases, Regulated Emissions, and Energy use in Technologies (GREET) model.

[14] Natural gas storage: https://ir.eia.gov/ngs/ngs.html
[15] Natural gas production ("Natural Gas Gross Withdrawals") http://www.eia.gov/dnav/ng/ng_prod_sum_a_epg0_fgw_mmcf_m.htm
[16] Natural gas consumption: http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_nus_m.htm

323.8 cont. Still, project infrastructure and equipment have a finite life. If avoided methane crediting goes away, not only will new projects not be built, but existing projects will shut down because they cannot pay operating costs and costs to maintain and extend the life of equipment. If existing projects shut down, we will backslide to pre-LCFS methane emissions at dairies. Our existing projects and projects currently under construction prevent about 700,000 MT per year of carbon reduction that would revert to venting.

Backsliding has happened before. Some of Amp's largest projects were originally biogas-to-electricity projects that were shut down by prior owners due to failed economics. CARB should not assume that once a digester project is developed, methane emissions are permanently abated, and it should not change accounting for avoided methane emissions until clear mechanisms are in place to ensure avoided methane emissions remain avoided.

323.16 Additionally, as described in our previous comments,[17] California imports nearly all of its natural gas,[18] and any biomethane injected into the pipeline system under the LCFS serves to displace fossil natural gas that otherwise would be imported into the State. The North American natural gas system does not mirror the fractured and isolated electricity markets in the western U.S. Instead, the gas system is deeply interconnected, and long ago moved away from point-to-point service, instead creating trading hubs and flexible receipt and delivery points to give customers a variety of options in the market.

Fossil natural gas operates on a system very similar to book-and-claim, in which buyers of fossil gas do not buy the molecules injected by their supplier, but rather instantaneously take receipt of a pre-agreed amount of gas, based on a mass-balance corresponding to the amount their supplier injected elsewhere in the system. These systems already work well for natural gas supplies across the continent and in the LCFS, and they should continue to be leveraged to cost effectively and efficiently support decarbonizing California gas end uses. RNG under the LCFS should be treated no less preferentially than compared to fossil natural gas, and **book-and-claim eligibility should be maintained for all RNG pathways**.

AMP SUPPORTS DEVELOPING RNG FOR STATIONARY SOURCES, ZEV FUELS

The proposed phaseout of avoided methane crediting and book-and-claim eligibility for combustion-based or hydrogen-based pathways is counter-productive and not supported by science. Still, we appreciate that California is moving towards zero emission vehicles ("ZEVs"), as required by the Advanced Clean Cars II and Advanced Clean Fleets regulations, and the Scoping Plan highlights a priority to develop additional renewable gas supplies to help decarbonize stationary sources. Amp supports California's overall decarbonization goals and its efforts to develop RNG supplies to decarbonize stationary sources in all sectors of the economy. Provisions in the proposed amendments help support transitioning RNG to ZEV fuels and stationary sources, but we encourage additional steps to further assist the transition, specifically:

[17] https://www.arb.ca.gov/lists/com-attach/125-lcfs-wkshp-nov22-ws-VzZcN1EgAg5QOghr.pdf
[18] According to the California Energy Commission, "California continues to depend upon out-of-state imports for nearly 90 percent of its natural gas supply…" https://www.energy.ca.gov/data-reports/energy-almanac/californias-natural-gas-market/supply-and-demand-natural-gas-california

323.17
- **Do not phase out avoided methane crediting and book-and-claim eligibility for all RNG pathways, including RNG-to-hydrogen**.

323.18
- **Allow RNG book-and-claim eligibility for electricity production at power plants** to charge electric vehicles ("EVs").

323.19
- **Allow RNG book-and-claim eligibility for process energy for any transportation fuel pathway,** in order to align with the Scoping Plan and begin to shift RNG away from transportation to stationary sources.

323.20 Enabling book-and-claim delivery for RNG sourced from projects in North America to be eligible for both hydrogen production *and* electricity generation would align with state goals around ZEVs and maintain equal treatment among ZEV options – including both hydrogen and electricity. We recommend making this change in Section 95488.8(i)(2) to expressly allow book-and-claim delivery for biomethane used to produce electricity for transportation purposes.

323.21 We recommend making a similar change to Section 95488.8(h) to expressly allow book-and-claim delivery for biomethane used for process energy (e.g., in cement production). This will serve as another mechanism to promote shifting RNG from transportation to stationary applications.

A significant portion of the LCFS value generated from RNG flows to the stations that distribute fuel, and this same dynamic would apply to RNG-to-electricity-to-EV pathways, accelerating EV adoption by injecting additional LCFS value into the EV ecosystem.

AMP SUPPORTS AMENDMENTS RELATED TO CREDIT TRUE UP

323.10 cont. Amp strongly supports the proposed amendments regarding "credit true up after annual verification." For RNG pathways specifically, which encompass living, biological systems, several parameters are beyond the control of a pathway holder – including temperature, herd count, changes to the manure volatile solid content, unplanned equipment downtime, evolving energy efficiency due to equipment age, force majeure events, or other changes in dairy operations beyond the operator's control including manure collection practice, water usage, dairy feed – can impact a number of variables that affect the CI of a pathway. Due to these unpredictable and uncontrollable factors, verified pathways may deviate from provisional pathways through no fault of the project developer or operator. The true up provisions will protect the environmental integrity of the program and maintain rigorous accounting and verification, while allowing flexibility to accommodate reasonable uncertainties.

323.22 In addition, Amp supports credit true up between temporary CI and certified (e.g. provisional or non-provisional) CI values, as previously proposed by CARB staff. Essentially all dairy RNG pathways utilize a Tier 2 process today, which currently takes about 18-24 months for approval and means that dairy RNG projects use a Temporary CI score for about 2 years. The Temporary CI score is -150, where the average dairy RNG project is -313, meaning these projects fail to get credit for approximately 40%[19] of their emissions reductions for 2 years. This also reduces credit availability in the program, increasing the cost of compliance for regulated entities. By allowing a true up between temporary CI and certified CI values, CARB would help alleviate concerns related to pathway process delays, assist in avoiding complicated

[19] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/current-pathways_all.xlsx accessed 2/19/2024; simple average of Dairy Manure feedstock pathways; diesel baseline of 87 gCO2e/MJ in 2024

323.22 cont. storage agreements, provide reliable deliveries to fleets by avoiding buildup of stored gas inventory, allow more direct sales of RNG to smaller local fleets, and motivate additional project development. **CARB should allow true-up for the verified actual CI of projects during the pathway registration period.**

323.23 We applaud CARB's attempts to make the Tier 1 calculator more usable by dairy projects and to shorten the period during which a Temp CI would be required. Our comments stand even if this initiative is successful. There is simply no equitable argument to deny dairy RNG projects credit for their verified impact however long the Temporary CI period may last.

ADDITIONAL PROVISIONS TO SUPPORT AN ONGOING, SUCCESSFUL LCFS

Finally, Amp offers the following comments and questions on various provisions included in the proposed amendments:

<u>Less Intensive Verification</u>

323.24 We support the concept of "Less Intensive Verification" in Section 955011(h), given that the verification
323.25 process can often be completed remotely. However, we oppose applying the rules only to electricity transactions identified in section 95500(c)(1)(E). Amp recommends that less intensive verifications be applied for all quarterly fuel transaction reports ("QFTR") identified in Section 95500(c)(1). This would be consistent with the CARB Regulation for the Mandatory Reporting of Greenhouse Gas Emissions, Title 17 of the California Code of Regulations ("CCR") Section 95130(a)(1), while allows for less intensive verification services for the following two years if the less intensive verification criteria are met. Verification site visit for a QFTR primarily consists of a visit to an entity's headquarters or other location of central data management and comprises reviewing electronic records. The site visit can easily be done virtually, as we successfully observed during COVID. The third-party verifier could still have discretion to determine that a conventional verification is necessary if project-specific facts indicate a less intensive verification will not suffice. Allowing less intensive verifications for QFTRs will reduce travel requirements, costs and associated emissions.

<u>Deficit Obligation Calculation</u>

232.26 We support the deficit obligation concept in Section 95486.1(g), given the variability of biological carbon
323.27 intensity scores. We recommend that this starts with the 2024 fuel transaction year instead of the 2025 fuel transaction year. If the Regulation goes into effect at the start of 2025, the new provision can be easily implemented prior to verification being completed by August 2025.

<u>Measurement Accuracy</u>

323.28 The measurement accuracy section under Section 95488.8(j) was moved to Section 95491.2(a), however the old section is still cited three times in Sections 95481(a), 95491.1(c)(1)(K), and 95491.1(c)(1)(2)(E). This creates ambiguity that would be helpful to correct.

<u>Missing Data Provisions</u>

323.29 The proposed "Missing Data Provisions" in Section 95491.2(b)(2)(B) Table 13 are based on a data year, however data substitution is often required to be completed monthly to determine fuel allocations for Pathways with multiple fuel pathway codes. If missing data substitution is required to be completed annually instead of monthly, it will create issues with monthly fuel allocation and dispensing for

323.29 cont. pathways, as well as quarterly fuel transaction reporting, which will require quarters 1, 2, and 3 to be re-opened and re-reported every year.

Amp requests that the use of "reasonable temporary methods" continue to be allowed to address missing data, which allows for operational realities and engineering best practices to be used. As the majority of data being substituted is continuous data (e.g. 15-minute data), data substitution using data directly prior and after is likely to be more accurate than a 30-day average or highest/lowest value over a one- to two-year time period. As the reports that fall under 95491.2 are all required to undergo third party verification, it ensures that all "reasonable temporary methods" are deemed conservative and accurate.

Force Majeure Events

323.30 Section 95491.2(b)(3) provides updated force majeure event requirements, including a requirement to report operational data during force majeure events when submitting the quarterly or annual verification. Reporting entities already report operational data to the verification body during the verification process as well as to CARB upon request. Therefore, it is unnecessary to also provide this operating data for force majeure events during the quarterly and annual reporting process.

Carbon Capture Protocols

323.11 cont. We encourage CARB to allow additional carbon capture, removal, utilization and sequestration ("CCRUS") protocols to be utilized as they are developed, pursuant to SB 905 or if the CCS Protocol is updated otherwise. Enabling a wider array of CCRUS pathways to be deployed will help reduce industrial sector emissions and emissions associated with several different transportation fuel pathways, including biogas. However, the definition of a "carbon capture and sequestration project" and provisions in Section 95490 refer to geologic sequestration and transport of CO_2 to an injection site, which implies only geologic sequestration projects would be eligible. We encourage amendments to avoid limiting future eligibility of CCRUS projects, should new CCRUS protocols be developed.

Thank you again for your collaboration with stakeholders through this public process, the opportunity to comment on the proposed regulatory amendments. We appreciate your consideration of these comments and work to amend and strengthen this critical program.

Sincerely,

Cassandra Farrant

Cassandra Farrant
Head of Environmental Credit Compliance
Amp Americas

Comment Log Display

Here is the comment you selected to display.

Comment 333 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Claire
Last Name	Behar
Email Address	Claire.Behar@Hystorenergy.com
Affiliation	Hy Stor Energy
Subject	Hy Stor Energy's Comments on Proposed Low Carbon Fuel Standard Amendments
Comment	Dear California Air Resources Board, Thank you for the opportunity to provide comments on the proposed low-carbon fuel standard amendments. Hy Stor Energy LP respectful submits the following comments, which are intended to facilitate the adoption of clean hydrogen in low-carbon transportation fuels, which include sustainable aviation fuel (SAF), power-to-liquids, and renewable diesel, and would help scale up a low-carbon fuel industry that would supports the decarbonization of the U.S. economy. Sincerely, Hy Stor Energy LP
Attachment	www.arb.ca.gov/lists/com-attach/7008-lcfs2024-AmpRLgZYAiJRI1c4.pdf
Original File Name	Hy Stor Energy LCFS Comments Final.pdf

Date and Time Comment Was Submitted	2024-02-20 17:30:08

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

555 Tombigbee St
Suite 101
Jackson MS 39202
(888) 542-6074
www.hystorenergy.com

February 20, 2024

Ms. Liane Randolph
Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95864

Re: Hy Stor Energy Comments on Proposed 2024 Low Carbon Fuel Standard (LCFS) Regulation

Dear California Air Resources Board:

Thank you for the opportunity to provide comments on the proposed low-carbon fuel standard amendments. Hy Stor Energy LP respectfully submits the following comments, which are intended to facilitate the adoption of clean hydrogen in low-carbon transportation fuels, which include sustainable aviation fuel (SAF), power-to-liquids, and renewable diesel, and would help scale up a low-carbon fuel industry that would supports the decarbonization of the U.S. economy.

Hy Stor Energy, a company headquartered in Jackson, MS, was formed for the purpose of developing and advancing renewable hydrogen production, storage, and delivery at commercial scale in the United States. Pursuing a multi-regional platform strategy focused on critical locations with the right geography and geology uniquely suited to favorable renewable power generation, underground hydrogen storage, and distribution networks for regional and global market access. Hy Stor Energy's first major project, the Mississippi Clean Hydrogen Hub, is under active development. It will be centered on the development of world-scale underground hydrogen storage capability, with approximately 70,000 acres of land in sixteen Mississippi counties and two Louisiana parishes under Hy Stor Energy's control, seven salt domes, and nine salt caverns fully permitted for underground hydrogen storage. Hy Stor Energy will soon announce a second project in the western United States positioned to be the leading renewable hydrogen supply hub serving the U.S. West and California markets.

Renewable hydrogen is an essential tool for the energy transition and will play a significant role in enabling California to achieve its net-zero goal by 2045. Renewable hydrogen is both an important transportation fuel for fuel cell electric vehicles as well as a necessary feedstock for many low and zero-carbon transportation fuels including SAF, power-to-liquids, renewable diesel, renewable methanol, and renewable ammonia. Enabling the LCFS eligibility of renewable hydrogen as both a transportation fuel in FCEVs as well as a feedstock liquid transportation fuel will enable greater adoption of low-carbon liquid fuels and drive emissions reductions in both the near and long term.

Hy Stor Energy respectfully suggests that the California Air Resources Board (CARB) modify the LCFS amendments to make the following amendments to the LCFS staff draft.

555 Tombigbee St
Suite 101
Jackson MS 39202
(888) 542-6074
www.hystorenergy.com

I. Allow book-and-claim delivery of low-CI electricity for electrolytic hydrogen production used as a feedstock in liquid transportation fuels.

II. Allow book-and-claim delivery of low-CI hydrogen in dedicated hydrogen pipelines outside of California for transportation fuel sold into the California market.

III. Allow delivery of low-CI electricity via book-and-claim for electrolytic hydrogen production in the Renewable Hydrogen Refinery Credit Program.

324.1 **Allow book-and-claim delivery of low-CI electricity for electrolytic hydrogen production used as a feedstock in liquid transportation fuel.**

Allowing book-and-claim delivery for low-CI electricity would maximize the potential for renewable hydrogen adoption and emissions reductions. Low-CI hydrogen will support the production of low and zero-carbon liquid transportation fuels, which are critical to decarbonizing the hard-to-decarbonize markers of heavy-duty surface transportation, aviation, and maritime transportation.

Furthermore, permitting book-and-claim delivery for low-CI electricity will match the treatment CARB has extended to renewable natural gas (RNG), which allows for the utilization of book-and-claim delivery of RNG, including for RNG used in the production of liquid transportation fuels.

324.2 **Allow book-and-claim delivery of low-CI hydrogen in dedicated hydrogen pipelines outside of California for transportation fuel sold into the California market.**

Currently, there are no dedicated hydrogen pipelines in California. Our goal as a nation and Hy Stor Energy's goal as an early mover in the production and distribution of green hydrogen is to facilitate the build-out of a national clean hydrogen economy. This will necessarily include the buildout of a robust hydrogen pipeline backbone to support the scale up of low-CI hydrogen adoption and drive down costs across the entire hydrogen value chain. Limiting eligible dedicated hydrogen pipelines to the California state borders would dramatically stunt the development of the hydrogen market both within California and the region. The optimal policy would be to allow book-and-claim delivery of low-CI hydrogen in any dedicated hydrogen pipeline serving as a feedstock for any fuel being consumed in California. A robust book-and-claim system will allow the delivery of low-CI hydrogen to catalyze market adoption of low and zero-carbon liquid transportation fuels including sustainable aviation fuels, power-to-liquids fuels, and renewable diesel in the critical hard-to-decarbonize industries in California and nation-wide.

324.3 **Allow delivery of low-CI electricity via book-and-claim for electrolytic hydrogen production in the Renewable Hydrogen Refinery Credit Program.**

In order to decarbonize medium to large scale facilities GW scale electrolysis projects will be required. As the current program is designed, requiring onsite renewable generation restricts the program to small-scale projects due to land constraints where refinery facilities are currently located. Allowing for the

HY STOR ENERGY

555 Tombigbee St
Suite 101
Jackson MS 39202
(888) 542-6074
www.hystorenergy.com

delivery of low-CI electricity via book-and-claim for electrolytic hydrogen production would allow refineries to utilize this program to lower emissions. Without this amendment, this program will likely continue to be underutilized.

Conclusion

Hy Stor Energy is committed to catalyzing low and zero-carbon solutions to enable California to meet its climate goals. We appreciate the CARB staff's work on the development of the proposed rule and their commitment to improving the LCFS. We look forward to continuing to work with CARB staff on this critically important effort.

Sincerely,

Laura L Luce
Founder & CEO
Hy Stor Energy LP

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Comment 334 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Tyler
Last Name	Cole
Email Address	tyler.cole@tes-h2.com
Affiliation	
Subject	TES Comments on Proposed Amendments to the California LCFS Program
Comment	TES US Development LLC is pleased to submit the attached comment letter to share our company's perspective on key aspects of the Proposed Amendments to the Low Carbon Fuel Standard ("LCFS") regulation relevant to electrofuels (e-fuels) producers. TES respectfully requests the California Air Resources Board consider the referenced topics in the LCFS update, to advance California's transition to cleaner transportation fuels and in furtherance of California's climate goals.
Attachment	www.arb.ca.gov/lists/com-attach/7009-lcfs2024-Wi4GZV0vBAgAagdk.pdf
Original File Name	TES_LCFS Comments_Final-240219.pdf
Date and Time Comment Was Submitted	2024-02-20 17:28:29

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

TES Green energy, naturally.

1200 Smith Street, Suite 730
Houston, TX 77002

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Comments on Proposed LCFS Amendments to Sections 95481, 95482, 95483, 95483.2, 95483.3, 95484, 95485, 95486, 95487, 95486.1, 95486.2, 95488, 95488.1, 95488.2, 95488.3, 95488.5, 95488.6, 95488.7, 95488.8, 95488.9, 95488.10, 95489, 95490, 95491, 95491.1, 95495, 95500, 95501, 95502, 95503 of title 17, California Code of Regulations

Ladies and Gentlemen:

I am writing on behalf of TES US Development LLC ("TES") to share our company's perspective on key aspects of the Proposed Amendments to the Low Carbon Fuel Standard ("LCFS") regulation relevant to electrofuels (e-fuels) producers. TES respectfully requests the California Air Resources Board ("CARB") consider the following topics in the LCFS update, to advance California's transition to cleaner transportation fuels and in furtherance of California's climate goals:

1) **Definition of Biomethane and Synthetic Natural Gas:**

325.1 The current and proposed amendments to the LCFS regulation do not clearly define biomethane or renewable natural gas, specifically what CARB considers "synthetic natural gas derived from renewable resources" and whether synthetic natural gas derived from renewable resources of non-biogenic origin (e.g., industrial waste stream or captured CO_2) would be considered biomethane or renewable natural gas. The promotion of recycled carbon fuels is a key contributor towards energy diversification and decarbonization of the transportation sector, especially for drop-in fuels that can significantly reduce emissions in the near future with existing fleet and infrastructure. In addition, such fuels contribute to the avoidance of CO_2 emitted to the atmosphere due to the use of waste streams of non-biogenic origin which are unavoidable and an unintentional consequence of industrial processes.

The current and proposed amendments to the LCFS define Biomethane as "methane derived from biogas, or synthetic natural gas derived from renewable resources" but do not define "renewable resources." The proposed LCFS amendment also includes a new definition for Renewable Natural Gas, defined as "an alternate term for biomethane," so for the purposes of commenting, we will refer to the term biomethane.

TES recommends that LCFS include a standalone definition for "renewable resources" to clearly define the feedstocks that are allowed in low carbon fuel pathways and extend the scope to include a broader range of sources beyond the traditional "biogenic sources," in accordance with the established federal practices. As an example, the United States Department of Energy ("DOE") Office of Energy Efficiency & Renewable Energy defines renewable carbon resources as *"carbon-based resources that are regularly regenerated, either via photosynthesis (e.g., plants and algae), or through regular generation of carbon-based waste (e.g., the non-recycled portion of municipal solid waste, biosolids, sludges, plastics, and* CO_2 *and industrial waste gases)."* TES recommends expanding LCFS to adopt a similar approach towards the applicability of synthetic natural gas and other e-fuels.

TES would like to highlight the state, federal, and international level recognition of the importance of carbon capture, utilization, and storage ("CCUS") strategies in achieving climate goals and urges CARB to consider how limiting “renewable resources” to biogenic sources would exclude leveraging existing industrial waste streams via carbon capture to produce low carbon fuels.

2) **Book-and-Claim Eligibility**

325.2 TES recommends CARB expand the pathways that can apply book-and-claim accounting (“B&C”), which currently includes low-CI electricity, biomethane or low-CI hydrogen, to include any low-CI methane pathways. The current and proposed LCFS limits B&C accounting to biomethane based on feedstock rather than physical product characteristics or CI. Given the overarching intent of LCFS to support California’s transition to low carbon fuels and drive GHG emissions reductions, TES recommends CARB consider revising B&C restrictions to be feedstock agnostic, and instead limit B&C eligibility based on fuel product (e.g., electricity, methane or hydrogen pathways, where infrastructure exists to support indirect accounting, and use depends upon common carrier infrastructure) and pathway CI.

3) **Availability of Fuel Pathways**

325.3 TES would like to note that the current LCFS regulation does not include any Tier 1 or Temporary fuel pathways specific to synthetic natural gas or other e-fuels with CO_2 conversion. TES recommends CARB develop either a Temporary or Tier 1 pathway for synthetic fuels or e-fuels that convert CO_2 to common products (e.g., methane, methanol, liquid hydrocarbon fuels). This would help support technology developers and fuel producers to bring these low-CI, drop-in fuels to market, thereby accelerating California’s transition away from fossil fuels.

We appreciate your review and consideration of our recommendations, and we are ready to provide assistance as needed to support the development of e-fuels and the decarbonization of the transportation sector.

Sincerely,

Cynthia Walker
President
TES US Development

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Comment 335 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Alexandra
Last Name	Frumar
Email Address	monika@remoracarbon.com
Affiliation	Remora
Subject	Remora Comments on Proposed LCFS Amendments
Comment	Please see attached Remora's Comments on the Proposed Low Carbon Fuel Standard Amendments.
Attachment	www.arb.ca.gov/lists/com-attach/7010-lcfs2024-VGYANgEyUzRSelRk.pdf
Original File Name	2024.02.20 Remora Comments on LCFS Amendments.pdf
Date and Time Comment Was Submitted	2024-02-20 17:32:02

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

REMORA

CONTACT (734) 744-4862
HELLO@REMORACARBON.COM

ADDRESS ECHENEIDAE INC. DBA REMORA
13685 OTTERSON CT
LIVONIA, MI 48150

February 20, 2024

California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
[submitted electronically]

RE: Comments On Proposed Low Carbon Fuel Standard Amendments

Remora values the chance to share input on the Staff Proposed Amendments to the California Air Resources Board's (CARB) Low Carbon Fuel Standard (LCFS). Our commitment extends to collaborating with CARB, its State agency partners, and all stakeholders to contribute innovative climate solutions with broad-reaching benefits in California and beyond.

About Remora & Mobile Carbon Capture Technology

Remora designs and manufactures an **innovative engine exhaust technology that captures carbon dioxide (CO_2) directly from heavy, hard-to-decarbonize mobile sources**, including Class 8 heavy-duty vehicles (semi-trucks). Using Remora's mobile carbon capture and storage (MCCS) technology, semi-truck exhaust is diverted to a carbon capture unit, which aims to capture approximately 80% of CO_2 emissions generated by the semi-truck (as well as approximately 75% of nitrous oxide emissions), before the exhaust is released into the atmosphere. The captured CO_2 is compressed, stored onboard, and then offloaded at designated sites that are co-located at refueling or cargo-loading infrastructure sites. All captured CO_2 can be safely and permanently disposed of via underground sequestration or utilized within other products and industries.

Semi-trucks are essential to our economy, delivering over 70% of goods that Americans use. Unfortunately, semi-trucks are also extremely high greenhouse gas (GHG) emitters and difficult to decarbonize. The approximately two million semi-trucks in operation today emit approximately 340 million metric tons of CO_2 per year. In addition, these high-emitting semi-trucks will be on the roads for decades to come, given the investments made by companies to purchase these vehicles and the need for these vehicles to support supply chain needs across the United States. Remora's MCCS technology has the power to decarbonize existing trucks and, if coupled with the use of biofuels, can result in semi-truck operations with a negative carbon intensity score.

To date, Remora has partnered with numerous nationally significant companies, including three in the Fortune 10 and numerous in the Fortune 500, to install its carbon capture equipment on their semi-trucks. Market demand for Remora's technology is extremely high as companies seek to reduce their CO_2 emissions. Remora's MCCS technology, and that developed by other MCCS companies, is uniquely poised to offer major decarbonization benefits while also supporting the growth of small businesses, helping to remedy environmental justice injustices and inequalities, advancing further innovations in CCS technology, and more, as described further below:

- Air Quality Benefits: Remora's MCCS technology acts as a filter on engine exhaust. Along with capturing CO_2, it demonstrates the potential to drastically improve air quality by reducing toxic air pollutants like nitrogen oxides by approximately 75%. These benefits could immediately serve low-income and disadvantaged communities that are most affected by vehicle emissions due to their proximity, in many cases, to highways and other major roadways.

- Scalable Impact: The decarbonizing impact of Remora's technology has the potential to rapidly scale. Each Remora MCCS unit is equivalent to removing approximately 30 passenger vehicles from the road per year. Remora's carbon capture units can capture and store 1,000,000 metric tons of CO_2 annually just by installing MCCS units on about 7,500 semi-trucks. With millions of semi-trucks in the United States, the opportunity for MCCS is enormous and increases further when utilized for other mobile sources of CO_2 emissions.

Remora's device and other mobile carbon capture technologies can quickly address the most difficult sectors to decarbonize, including heavy-duty trucking, vessel shipping, and rail. Remora has signed on to group comments with the Mobile Carbon Capture Coalition, which shows the breadth of the industry and the additional work being done across the world.

Remora Supports a Strong LCFS

California's transportation sector is the State's largest source of both greenhouse gas emissions and air pollution, accounting for more than half of statewide GHG emissions.[1] Rapidly driving down these emissions is a critical element of California's strategy to achieve carbon neutrality. As described in the 2022 Scoping Plan Update, the transition to zero-emission technology will take time as internal combustion vehicles will remain on the roads in California for decades to

[1] See Draft 2022 Scoping Plan Update, pg. 147.

come. The modeling for the Scoping Plan indicates that even in 2045, significant volumes of liquid fuels, including fossil fuels, are likely to remain in California's transportation fuel mix.[2] Solutions that can significantly reduce—and even fully eliminate—greenhouse gas emissions from California's transportation sector will be key.

326.1 Remora supports CARB's accelerated carbon intensity (CI) reduction target of 30% by 2030 as proposed by Staff in these LCFS amendments. Remora encourages CARB to consider even more
326.2 ambitious CI targets to drive California towards its climate goals. For this reason, Remora also supports the inclusion of an auto-acceleration mechanism that will increase the stringency of
326.3 LCFS if the program over-performs. This mechanism will help to ensure that California will continue to achieve emissions reductions and will provide additional incentives for investment in clean transportation fuels and technologies.

LCFS should be positioned to incorporate Mobile Carbon Capture Technologies

Given the scale and scope of the challenge to meet California's GHG reduction targets, the State cannot afford to limit any approaches that can contribute to this effort. As CARB works to refine
326.4 LCFS, **Remora urges CARB to ensure that it optimally positions California to reap the benefits that innovative and proven technologies like MCCS can provide**.

Incorporating additional technologies into the existing CCS Protocol within the LCFS Regulation, which recognizes the role CCS can play in decarbonizing the production of transportation fuels, will be key.

By incorporating MCCS into the LCFS, California can work towards even more ambitious transportation decarbonization targets, which will provide climate, air quality, and public health benefits to Californians.

Remora appreciates the opportunity to submit comments, and we look forward to continuing to work with you and all stakeholders in California on this critically important effort.

Sincerely,

Alexandra Frumar

Alexandra Frumar
Chief Legal & Policy Officer

[2] See Draft 2022 Scoping Plan Update, pg. 153.

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Comment 336 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Katelyn
Last Name	Roedner Sutter
Email Address	kroedner@edf.org
Affiliation	Environmental Defense Fund
Subject	EDF comments re: potential changes to LCFS
Comment	Attached please find comments regarding potential changes to the Low Carbon Fuel Standard on behalf of Environmental Defense Fund.
Attachment	www.arb.ca.gov/lists/com-attach/7011-lcfs2024-BWBWNFE2BwsGYwdo.pdf
Original File Name	EDF Comments re Proposed Changes to LCFS 2.20.24.pdf
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If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

Ms. Liane Randolph
Chair, California Air Resources Board
1001 I Street Sacramento, CA 95814

Submitted Electronically

Re: Comments regarding proposed amendments to the Low Carbon Fuel Standard

Dear Chair Randolph,

Thank you for the opportunity to provide comments on the proposed amendments to California's Low Carbon Fuel Standard. Environmental Defense Fund (EDF) appreciates the work CARB staff has dedicated to amending the Low Carbon Fuel Standard. EDF looks forward to continuing to engage in this rulemaking and supporting the successful decarbonization of California's transportation sector.

As we have stated in previous comments during the informal workshop process, updating LCFS to increase the program's ambition and efficacy will be integral to ensuring California can deliver the outcomes and emissions reductions envisioned in the final Climate Change Scoping Plan, as well as achieve carbon neutrality by 2045.

327.1 We are pleased to see that this proposal strengthens the CI reduction benchmarks both pre- and post-2030. Alongside this increased rigor, EDF hopes to see amendments that will sustain the LCFS's role in promoting the use of lower carbon alternatives to petroleum fuels, thus bringing substantial health, economic, and environmental benefits. To that end, we offer the following comments regarding four aspects of the proposed LCFS amendments: 1) crediting for manure biogas, 2) hydrogen crediting and usage, 3) crediting for medium- and heavy-duty vehicle charging, and 4) sustainable decarbonization of the aviation sector.

1. Crediting for Manure Biogas

Agriculture, particularly the dairy industry, is a major source of California's methane emissions. Almost 25% of California's total methane emissions are estimated to come from dairy manure. Addressing dairy manure methane emissions is a key action needed to meet California's climate goals. We applaud the state for establishing a specific methane reduction for the dairy and livestock sectors in SB 1383 (Lara, 2016). California dairy farmers, as price takers, have little market power to pass costs associated with methane reduction solutions on to the consumer, we therefore also recognize the important role that programs such as the LCFS continue to play in incentivizing and supporting reductions in livestock methane sources.

327.2 We appreciate CARB's stance that capturing methane from landfills, dairies, and wastewater is critical to achieving climate targets, and we are aligned with CARB's preference for biomethane to be used to produce low-carbon intensity hydrogen and electricity. We agree that attention is needed to ensure methane capture projects are not abandoned as LCFS transitions away from combustion vehicles towards hard-to-decarbonize sectors.[1]

Manure biogas systems, when operated and installed in a responsibly maintained farm system, are a proven technology that can address existing sources of agriculture methane (from dairy manure storage systems) while replacing fossil fuel-derived methane. Given the large number of liquid manure systems that exist on California (and US) dairies, continuing to include manure biogas systems—as part of an environmentally comprehensive farm nutrient management system—in the LCFS is a powerful tool to drive agriculture methane reductions from existing sources. Continued eligibility is important to meet California's climate goals and drive further agriculture methane reductions across the US.

Today, the LCFS is the most impactful market-based tool to incentivize livestock farmers to adopt methane capture technologies. However, as with any program, it is not perfect. We cannot focus on solving methane, a global climate pollutant, without also ensuring meaningful improvement in the local environment and community.

Addressing Local Pollution

Sources of on-farm methane leakage need to be properly managed.

327.3 While they are an important tool for capturing methane, the leakage of methane and the resulting net methane emissions relative to the counterfactual must be considered. EPA acknowledges in its RNG Operations Guide that "fugitive emissions of methane, depending upon their magnitude, can negate the climate and environmental benefits of RNG projects." While methane's negative impact on climate is commonly discussed, methane can also be dangerous to human health at the local level, as a precursor to ozone.[2] Ozone, even at relatively low levels, can cause health effects including inflammation and damage of the airways and further aggravating lung diseases such as asthma, emphysema, and chronic bronchitis.[3]

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[1] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf
[2] https://unece.org/2010/presentations/Importance%20of%20Methane%20for%20Ozone.pdf
[3] https://www.epa.gov/ground-level-ozone-pollution/health-effects-ozone-pollution

One of the largest sources of methane leakage in digester biomethane production comes from improper digestate management.[4] Digestate is the effluent that comes out of the digester, which contains nutrients that can fertilize crops. It is common in the United States for digestate to be held in open storage pits or lagoons. Although the manure has been digested, and most of the biogas has been captured in the digester, digestate still produces some methane which is emitted if the digestate is stored in an open lagoon or storage tank. Residual methane emissions from the digestate are estimated to be between 0.2-5.9% of that captured in the digester.

Covering digester effluent storage captures this residual methane, which can be flared or added to the digester biogas, enhancing the carbon market value when it is used for energy. An impermeable cover on the digestate can reduce residual methane emissions by 90%.[4] There are also developing technologies that can capture the ammonia and concentrate it, making it easier to land apply or potentially be sold to generate additional revenue.[5,6]

Another large source of methane leakage is from the processing of biogas – to produce renewable natural gas sufficient to meet natural gas pipeline standards. Methane leakage from the processing of biogas is estimated to be in the 2 – 4% range up to as much as 15%.[7] Methane leakage in the transmission and distribution of natural gas has been estimated to be in the range of 0.4 - 0.9%.[8]

Local air quality impacts that result either directly or indirectly from anaerobic digestion must be addressed.

327.4

One of the most significant local air pollutants of concern surrounding biogas systems is ammonia. Approximately 80% of ammonia emissions in the United States, encompassing emissions from both natural sources and human activities, are from agricultural sources. Notably, around 60% of these national emissions stem from livestock manure.[9] Ammonia is a health concern, as it has the potential to form fine particulate matter (PM2.5), which can lead to respiratory and pulmonary issues in nearby communities.[10] Ammonia emissions also present an environmental risk contributing to soil acidification and/or eutrophication in downwind ecosystems.[11]

During anaerobic treatment or storage, manure organics decompose in an oxygen-free environment and produce methane, ammonia, and other gases. In open-system manure storage

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4 https://ecommons.cornell.edu/server/api/core/bitstreams/a725208d-82ba-4b17-aab4-b1305191c377/content
5 https://www.sciencedirect.com/science/article/abs/pii/S0048969721021689?via%3Dihub
6 https://www.mdpi.com/1996-1073/16/4/1643
7 https://iopscience.iop.org/article/10.1088/1748-9326/ab9335
8 https://www.wri.org/research/production-and-use-waste-derived-renewable-natural-gas-climate-strategy-united-states
9 https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data#doc
10 https://pubmed.ncbi.nlm.nih.gov/20458016/
11 https://www.sciencedirect.com/science/article/pii/S0301479722018588?via%3Dihub

or treatment lagoons, as the manure undergoes anaerobic decomposition, most of these compounds are lost to the atmosphere. If the anaerobic decomposition takes place in an enclosed environment (such as a covered lagoon or anaerobic digester), the methane degases from the liquid phase and is captured under the cover where it can be collected and flared or used as a fuel. However, the ammonia stays in the solution and hence the dissolved ammonia becomes concentrated inside the anaerobic digester, particularly relative to that remaining dissolved in an open lagoon.

Once the digestate from the anaerobic digester or covered lagoon is discharged from beneath the cover into an open lagoon or storage tank, the ammonia is lost to the atmosphere in the same quantity or perhaps somewhat higher quantities, relative to that lost in an open lagoon, presenting a serious health risk to downwind communities.

Any tax credit generated from biogas created from manure in covered lagoons or anaerobic digesters for hydrogen production should be predicated upon the management of the digestate to reduce ammonia losses. Keeping the digestate in an enclosed system would greatly reduce the loss of ammonia from the digestate as well as allow for the capture of the residual methane in the digestate. The residual methane could be added to the digester biogas and used as fuel. An impermeable cover on the digestate reduces ammonia losses by 55-100% and residual methane emissions by 90%[4] while a permeable cover is estimated to reduce ammonia by 40-80%.[12]

Crediting should be contingent upon meeting specific standards to further reduce local environmental impacts.

As discussed, farm systems can have a negative impact on local communities, specifically around air pollutants, odors, and other downwind ecosystem and water concerns. Producers of
327.4 biomethane from digesters should have a robust system in place to participate in LCFS to ensure the digester and its nutrients are managed properly. Third-party vetted Nutrient Management Plans (NMP) and Comprehensive Nutrient Management Plans (CNMP) are utilized in many states to reduce the environmental footprint of livestock operations. In New York State for instance, certified nutrient management planners help farmers create farm plans and verify they are followed throughout the year.[13] This standard goes beyond what EPA requires and adds assurance to communities that best management practices are followed, even in emergencies.

For farmers using digesters, compliance with relevant USDA NRCS standards, including both USDA NRCS Nutrient Management (Code 590)[14] to ensure digestate nutrients are well-managed and USDA NRCS Anaerobic Digester Conservation Practice Standard (CPS) for Anaerobic Digesters (Code 366) is paramount. This guidance outlines standard practices to improve air

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[12] https://extension.colostate.edu/topic-areas/agriculture/best-management-practices-for-reducing-ammonia-emissions-lagoon-covers
[13] http://nmsp.cals.cornell.edu/publications/extension/CAFOCNMPNY2023.pdf
[14] https://datcp.wi.gov/Documents/NM590Standard2015.pdf

quality by reducing greenhouse gas emissions and objectionable odors from manure or agricultural waste, and/or to reduce transport of pathogens to surface water.[15] These practices apply where biogas production and capture are components of a waste management system plan or a comprehensive nutrient management plan, and sufficient and suitable organic feedstocks are readily available. This practice outlines standards for system design, cover, etc., as well as gas collection, transfer, control, utilization, and monitoring/safety requirements, including criteria for maintenance of air quality, but does notably leave out the control of ammonia emissions, which should be addressed per earlier information.

Without these guardrails, programs like LCFS could encourage the build-out of additional digesters with no oversight into how they are managed – potentially leading to harmful methane leaks and other air pollutants, including ammonia, which can negatively affect local air, soil, and water quality and in turn, harm local communities.

Deliverability

Beyond accelerating the capture of manure methane emissions on California livestock farms, the LCFS, in its current form, has also helped address methane emissions from manure across the US. Under the current regulation, the LCFS allows for indirect accounting of biomethane injected into the North American natural gas pipeline without a deliverability requirement. This enables farm systems across the country to participate in supplying biomethane for the LCFS. However, CARB's proposed changes include new deliverability requirements for natural gas pipeline injection.

327.5 *Indirect accounting without a deliverability requirement should continue, provided that out-of-state biogas systems contribute to the overall improvement of the local environment and community.*

Continuing to allow indirect accounting of biomethane without a deliverability requirement, serves to lift the conversation on manure methane emissions across the country and push other states to engage in how to address agriculture methane emissions. Since methane emissions are a global pollutant, the current LCFS regulation helps reduce methane emissions in a broader context than just California.

As the supply of RNG from manure digestion represents less than 1.5% of current natural gas production, limiting deliverability will decrease the number of offset credits available for the LCFS.[16] Another implication of limiting delivery is the quenching effect it would have on

[15] https://www.nrcs.usda.gov/sites/default/files/2023-04/366-NHCP-CPS-Anaerobic-Digester-2023.pdf
[16] https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

livestock methane capture across large sections of the US as well as the amount of low CI hydrogen produced.[17]

As the market regulator, CARB has the ability and responsibility to ensure that out-of-state manure biogas systems are being implemented in a manner that protects local water quality and air quality, and meaningfully reduces the impact of livestock on local communities. It's imperative that CARB utilize its authority to ensure full compliance with LCFS regulations to not only ensure fraud is prevented in indirect accounting, but that biogas producers contributing to local pollution are held accountable. Biogas systems are complex operations and if farm systems are not currently meeting equivalent environmental regulations and expectations to those followed by California biogas systems, out-of-state biogas systems should not be eligible for participation in the LCFS.

There are numerous examples across the US of manure biogas systems that, upon reaching the current technology end-of-life, are no longer being used and manure methane emissions are again being released into the atmosphere. Without ongoing appropriate economic incentives, farms will not continue to operate manure biogas systems and will not reinvest in the technology. CARB needs to consider how best to address manure biogas systems when they reach the end of the ten-year avoided methane crediting period.

2. Hydrogen Crediting and Usage

Hydrogen is a short-lived, indirect greenhouse gas (GHG) that causes warming by increasing the concentrations of GHGs in the atmosphere.[18] At least 15 scientific publications over the past two decades, including two IPCC assessment reports, have cautioned about the climate impacts of hydrogen emissions in the context of a potential hydrogen economy.[19]

Around 30% of molecular hydrogen (H_2) emitted into the atmosphere chemically reacts with the naturally occurring hydroxyl radical after a few years. This reaction ultimately increases the amounts of short-lived greenhouse gases including methane, tropospheric ozone, and stratospheric water vapor. Recent advancements in chemistry-climate modeling have led to the quantification of hydrogen's full atmospheric warming effects using multiple models—leading to a doubling of earlier warming potency estimates. The latest science suggests that hydrogen emissions are 30-40 times more powerful at trapping heat over the following 20 years than carbon dioxide for equal mass, and 8-12 times more powerful over a 100-year period.[18]

Hydrogen is notoriously hard to hold onto given its small molecular size and is emitted throughout the value chain from both operational releases and leakage. Currently, sensors with

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[17] https://gasfoundation.org/wp-content/uploads/2019/12/AGF-2019-RNG-Study-Full-Report-FINAL-12-18-19.pdf
[18] https://acp.copernicus.org/articles/23/13451/2023/acp-23-13451-2023.html
[19] https://www.nature.com/articles/s41467-022-35419-7

the speed and sensitivity necessary to quantify emissions are not widely available; and in the absence of direct measurement data, several studies have estimated emissions from venting, purging, and leakage at various stages of the value chain and in total,[20] finding a wide range in emissions anywhere from <1% to 20%. Thanks to DOE funding, advanced sensor equipment is currently under development, with early models just entering the market this year. These sensors will enable empirical measurements of hydrogen emissions from existing infrastructure in the near future.

Operational and fugitive hydrogen emissions should be excluded from receiving LCFS credits.

327.6 Due to hydrogen's warming impacts, it is critical to exclude "wasted" gas from operational practices (i.e., vented or purged hydrogen) from being able to claim the LCFS credit. Similarly, detectable levels of unintentional emissions (i.e. leaks) should also be immediately excluded. These lost volumes can easily be determined by comparing the known inputs with their calculated outputs of hydrogen energy to be sold, and these loss rates should be reported alongside the claimed volumes to improve the data collection around hydrogen emissions. In the near future, as high-precision sensors become more readily available, hydrogen producers will be able to measure small leaks along with their calculated lost volumes. CARB can thus stipulate that all levels of fugitive emissions will eventually be excluded from receiving LCFS credits.

Hydrogen emissions should be factored into CA-GREET.

327.7 Because of its well-documented role as an indirect greenhouse gas, hydrogen must be factored into life cycle assessments through the CA-GREET model. Argonne has already been exploring the inclusion of hydrogen emissions into the GREET model. This can be done by using GWP values of 37 for GWP20 and 12 for GWP100.[21]

While the GREET model currently does not include hydrogen's warming effects, it does include estimated loss rates throughout the value chain. We recommend that hydrogen's GWPs be applied to the current loss rates, and then as empirical measurements become available, the loss rates should be updated regularly. Hydrogen producers can also account for hydrogen emissions via a mass balance calculation of what they expect to produce versus what they actually produce.

327.6 *Producers should be required to submit and comply with hydrogen emission management plans.*

To both verify the amount of wasted hydrogen gas and as an incentive to control hydrogen emissions, producers should be required to submit hydrogen emission management plans. These will likely include a commitment to using the best available sensor technology to detect

[20] https://www.frontiersin.org/articles/10.3389/fenrg.2023.1207208/full
[21] https://acp.copernicus.org/articles/23/13451/2023/

leaks, and operational best practices to mitigate leakage such as tightening valves and seals, establishing a leak detection and repair program, and incorporating technology to recombine vented, purged, and residual hydrogen with oxygen back into water. Management plans should also disclose whether you are using venting, flaring, and purging practices and state how a facility is verifying final volumes to ensure tax credit compliance.

Hydrogen should be deployed responsibly by targeting the hard-to-abate sectors.

Due to hydrogen's leakage risks combined with the relative energy intensity involved in its production, processing, and distribution, hydrogen use should be limited to hard-to-abate applications. The U.S. National Clean Hydrogen Strategy and Roadmap[22] states the importance of targeting "strategic, high-impact uses for clean hydrogen," including "the industrial sector (e.g., chemicals, steel, and refining), heavy-duty transportation, and long-duration energy storage."

Based on data from available scientific literature and hydrogen supply chain models, we know that light-duty vehicles can be more effectively decarbonized, with greater climate benefits, via EV batteries.[23] On average, powering a hydrogen fuel cell vehicle requires three to four times (and up to nine times) more energy than an electric battery.[24] In addition to the energy needed to convert renewable electricity into hydrogen fuel — and then back again through a hydrogen fuel cell — hydrogen also requires additional energy-intensive processes, such as compressing or liquefying hydrogen for transport and storage. In contrast, renewable electricity does not require conversions into a different state and is significantly less energy-intensive for transmission, distribution, and end use.

On the other hand, using hydrogen to produce fuels for aviation and maritime shipping – both
327.9 hard-to-abate end uses with limited opportunities for electrification – are clearly "no regrets"
opportunities that should be prioritized through the LCFS.

<u>3. Crediting for Medium- and Heavy-Duty Vehicle Charging</u>

Medium- and heavy-duty vehicles are responsible for a disproportionate amount of greenhouse gas (GHG) emissions and local pollution relative to the size of their population. In California, despite the fact that trucks are just seven percent of all vehicles in the state, they emit nearly 33% percent of particulate matter, 25% percent of nitrogen oxides (NOx), and nearly 9% percent of greenhouse gas emissions[25] from the transportation sector; electrifying these vehicles will therefore produce outsized climate and local air pollution benefits. This is particularly important in the state's disadvantaged communities, because while the health impacts, which can

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[22] https://ww2.arb.ca.gov/ghg-inventory-graphs
[23] https://blogs.edf.org/energyexchange/wp-content/blogs.dir/38/files//2023/01/Methodology-for-H2-Energy-Intensity-Blog.pdf
[24] https://blogs.edf.org/energyexchange/2023/01/30/rule-1-of-deploying-hydrogen-electrify-first/
[25] https://ww2.arb.ca.gov/ghg-inventory-graphs

negatively affect “every organ in the body,”[26] are experienced to some extent all across the state, “low-income and communities of color…are often disproportionately affected by emissions from freight movement due to their proximity to transportation infrastructure,”[27] such as ports, railyards, and freight corridors. Because of this disproportionate impact, there is an urgent need to electrify medium- and heavy-duty vehicles in these neighborhoods.

327.10 *The proposed expansion of the Clean Fuel Reward program will further incentivize and streamline the adoption of medium- and heavy-duty electric vehicles.*

EDF supports the proposal to change the scope of the statewide Clean Fuel Reward program from a light-duty rebate to a medium and heavy-duty rebate. The focus on new and used rebates for medium- and heavy-duty trucks that are exempted from the Advanced Clean Fleets regulation will chart a path towards electrification for the segments of the trucking sector that are most challenging to transition. This program will be particularly important for small fleets and independent owners/operators, for whom up-front purchase price can be a major barrier to electrification.

327.10 *LCFS crediting for medium- and heavy-duty vehicle charging will support the deployment of necessary infrastructure to help California realize the full benefits of the Advanced Clean Trucks and Advanced Clean Fleets rules.*

While the goals embedded in the Advanced Clean Trucks and Advanced Clean Fleet regulations – setting sales and purchase targets for zero-emission vehicles – are crucial components for a sustainable, equitable transportation future, the benefits will not be realized without adequate charging that is sufficient in number and well-designed to support the medium- and heavy-duty vehicles in the state. As such, EDF views the introduction of a new medium- and heavy-duty vehicle Fast Charging Infrastructure (MHD FCI) credit as critical for this effort. The operational variation of medium- and heavy-duty vehicles necessitates a wide diversity of charging equipment and capabilities. Given the diversity of charging needs, the 10 years of crediting will be one of many state-supported funding solutions necessary to transition fleets effectively and affordably throughout the state.

327.12 *CARB should remove the minimum nameplate power rating requirement for the MHD FCI program.*

EDF recommends that CARB modify the proposed eligibility requirements for participating in the MHD FCI program to remove the requirement that each charger (also referred to as Fueling Supply Equipment or FSE) “must have a minimum nameplate power rating of 250 kW.” While some electric trucks and buses will rely on direct current fast chargers (DCFCs) with nameplate capacities of 250 kW or greater, many will not need this level of charging. This is particularly

[26] https://www.ucsusa.org/resources/cars-trucks-buses-and-air-pollution#toc-effects
[27] https://ww2.arb.ca.gov/sites/default/files/2021-09/Proposed_2020_Mobile_Source_Strategy.pdf

true for fleets operating out of and charging at private depots which may have shorter duty cycles and can spread their charging overnight and/or several daytime blocks with lower-power DCFC or level-2 charging. Removing the 250 kW requirement would allow these fleets to optimize their charging based on their own operational needs, resulting in grid-beneficial charging behavior, while still remaining eligible for the program. Consistent with this recommendation, CARB should also remove or modify the limitation that no more than ten chargers per applicant per site would be eligible for credits. The proposed 10 MW cap per customer per site is a sufficient constraint on individual customers accumulating credits while retaining the flexibility for applicants to deploy chargers in number and capacity consistent with their needs. Otherwise, applicants would potentially be incentivized to oversize chargers' nameplate capacity to maximize credit eligibility.

4. Sustainable Decarbonization of the Aviation Sector

For almost a decade, EDF has been working to reduce harmful pollution from aviation to mitigate climate change and deliver public health benefits utilizing alternative fuels. This includes engagement in climate policy at the International Civil Aviation Organization (ICAO), leading and participating in expert working groups developing ICAO's Sustainability Framework for Sustainable Aviation Fuel (SAF) – an effort that builds heavily on California's Low Carbon Fuel Standard (LCFS). We were also deeply involved in the inclusion of SAF tax credits in the federal Inflation Reduction Act (IRA).

The proposed LCFS reforms include changes that will significantly impact California's efforts to decarbonize the aviation sector and warrant thorough consideration. Expanding the scope of the Low Carbon Fuel Standard (LCFS) program to include aviation fuels beyond the existing voluntary opt-ins for alternative jet fuels[28] is a necessary step towards achieving carbon neutrality in California by 2045 and will likewise support collective climate ambition. The structured deployment of sustainable aviation fuels (SAF) in California is crucial for the civil aviation sector to reach the International Civil Aviation Organization (ICAO)'s global goal of net-zero climate impact by 2050.

The following recommendations are relevant in evaluating how to sustainably transition from the uptake of conventional fossil jet fuel to the uptake of alternative jet fuel in the State.

327.13 *All fossil jet fuel provided in California should generate deficits under the LCFS, not only intrastate flight fuel burn.*

We respectfully encourage CARB to extend a reformed LCFS beyond the proposed amendment of CCR §95482(c)(1)(2), and instead, cover all fossil jet fuel uplifted in California to ensure the

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[28] Important to note, 'alternative jet fuels' denotes a broader category than does 'SAF.' Per definitions established at the federal and international levels, 'SAF' refers solely to fuels produced using renewable energy sources, wastes and residues and meet sustainability criteria.

greatest degree of climate benefits. Whereas the modified text makes conventional fossil jet fuel subject to LCFS regulation only for intrastate flights, we recommend instead that CARB delete altogether the exemption §95482(c)(1)(2), "Conventional jet fuel or aviation gasoline."

The broader coverage of all flights – whether intrastate, interstate, or international -- is consistent with the generally applicable language of Gov. Schwarzenegger's Executive Order S-01-07 establishing the LCFS applicable to all transportation fuel providers in California. It is also consistent with the authority CARB exercised in the 2018 LCFS reform when it included alternative jet fuel as an opt-in fuel entitled to generate credits, providing the necessary steppingstone towards more comprehensive action now.

Furthermore, an amended LCFS covering only intrastate flights could pose a serious risk of invalidation under federal law. CARB could easily sidestep this risk by removing the exemption language and thus treating fossil jet fuel as part of the general suite of transport fuels subject to LCFS regulation.

On this front, CARB needs to act now – and act prudently. Postponing the effective start date until 2028 would be a missed opportunity we cannot afford. Planning for intrastate-only aviation coverage – and with such a long delay - would be neither legally viable in the face of federal preemption nor commensurate with the climate emergency.

In terms of emissions quantities, intrastate flights represent a mere 10% of emissions from jet fuel uplifted in California, or around 6% of the total aviation emissions from flights to and from California.[29] In a scenario of LCFS coverage limited to intrastate flights, Governor Newsom's requested "aggressive 20% clean fuels target for the aviation sector" in 2030 translates to emissions reductions on the order of 1% of California's aviation emissions.[30] This is far too small a quantity to achieve meaningful benefits for climate action or for human health.

327.14 *CARB must protect workers' and airport-adjacent communities' health by regulating jet fuels' aromatic content and thus mitigating particulate matter pollution.*

Fuel-related emissions from landing and take-off operations disproportionately affect local communities as well as workers within the airport envelope. Communities living in proximity to

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[29] Based on 2020 inventory data available at: https://ww2.arb.ca.gov/sites/default/files/classic/cc/inventory/ghg_inventory_scopingplan_sum_2000-20.pdf
[30] https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf?emrc=1054d6

airports are exposed to elevated levels of ultrafine particles (UFP) and are at risk of adverse health effects, a critical issue upon which CARB needs to act without further delay.[31]

While alternative aviation fuel blends have the potential to reduce harmful aviation emissions by reducing aromatic content, such an outcome will not happen unless additional regulations are enforced. Furthermore, the gradual scale-up of alternative aviation fuels means that a fuel swap will help only marginally in the near term - if at all - which is insufficient to protect overburdened communities already suffering decades' worth of accumulated adverse health effects.

To deliver tangible near-term public health benefits, CARB should not only extend the scope of LCFS-covered jet fuel but, California should also undertake complementary action to regulate jet fuel composition. Jet fuel aromatic content could be reduced by hydrotreating conventional jet fuel while tapping on IRA's generous clean hydrogen subsidies to cushion price impacts and GHG emissions penalties.[32] This is a near-term measure that could slash PM2.5 emissions without adversely affecting safety, i.e., in a manner that would be fully compatible with existing federal airworthiness certifications.

327.15 *The prohibition on converting forested land into agricultural production should extend to also protect wetlands and grasslands.*

As noted in Appendix E: Rationale, section W(5), "It is vital that the LCFS program limit deforestation and land use change as a result of feedstock production as much as possible." The proposed new §95488.9(g), Sustainability Requirements for Crop-Based and Forestry-Based Feedstocks, takes a step toward installing the needed guardrails. Notably, the requirement that all domestic and imported feedstocks be traced to their point of origin has a more comprehensive coverage than any other domestic tracing requirement to date. However, the text is incomplete in fulfilling its purpose outlined in the ISOR(II)(F), "reduce the risk that rapid expansion of biofuel production and biofuel feedstock demand could result in deforestation or adverse land use change."

Direct land use change (DLUC) can occur on land cover types other than only forest. High-carbon-stock and high-biodiversity land types include grasslands and wetlands as well; bringing these lands into bioenergy feedstock cultivation is every bit as dangerous as bringing forests into

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[31] For a more detailed description, a literature review, and an overview of options on how to tackle $PM_{2.5}$ emissions from aviation see EDF's letter to the U.S. Environmental Protection Agency from April 4, 2022:
https://downloads.regulations.gov/EPA-HQ-OAR-2019-0660-0207/attachment_1.pdf

[32] In recent filings, EDF has underscored the vital importance of reducing climate and health harming pollution from hydrogen production. See: https://www.edf.org/sites/default/files/2023-09/Petition%20for%20Rulemaking%20-%20Hydrogen%20Production%20Facilities%20-%20CAA%20111%20and%20112%20-%20EDF%20et%20al.pdf

cultivation. These natural land conversion emissions are non-negligible: the soil carbon released from plowing alone can be greater than the entire lifecycle carbon intensity of fossil jet.[33]

Therefore, the first sentence of §95488.9(g), “Crop-based and forestry-based feedstocks must not be sourced from land that was forested after January 1, 2008,” should be modified to protect grasslands, wetlands, and peatlands in addition to forested land.

By removing the deficit-generating exemption for all fossil jet fuel provided in California, regulating jet fuels' aromatic content, and protecting a broad range of natural lands from agricultural conversion, CARB can deliver on deep decarbonization and public health goals now.

CARB’s upcoming decision on LCFS reform offers a golden opportunity to lay down the foundation for the high-integrity SAF needed to make real progress in transforming the aviation sector’s outlook for climate action in California. Including the aviation sector under the LCFS is urgent, and we can’t afford to miss this opportunity to deliver on deep decarbonization and public health goals.

Regulating fossil aviation fuels under the LCFS will ensure that the environmental attributes associated with the use of alternative jet fuels are claimed on California’s emissions ledger, rather than under other jurisdictions through indirect accounting systems. The emissions reduction benefits from the use of alternative aviation fuels take place upstream of fuel combustion, i.e., within sectors counted toward California’s GHG inventory (or equivalent inventory for imports).

Covering aviation fuels under the LCFS will also ensure that the aviation sector shares responsibility for a portion of the cost of deploying SAF in California, rather than leaving road transportation end-users to subsidize the aviation sector (a dynamic driven also by the federal Renewable Fuel Standard). Even so, the impact on airfare prices of expanding the scope of the LCFS to aviation should be modest because (1) generous federal subsidies are available to offset increased manufacturing expenses, and (2) air carriers have the ability to shield themselves against marginal price signal pass-throughs from jet fuel providers.

In parallel to striking out §95482(c)(1)(2), CARB would also need to recalibrate the increase in stringency of the LCFS carbon intensity targets to account for the uptick in aviation’s sectoral demand. This task is already under deliberation and should be relatively straightforward, though it is no less time-sensitive than the other components of LCFS analysis.

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[33] Estimates from Spawn et al, 2019, Environ. Res. Lett. 14 045009. There is a wide geographic variation in both the size and sensitivity of affected carbon stocks that would need to be evaluated on a case-by-case basis. Still, the primary source of land conversion in the United States is grassland to cropland, in which disruption of soil organic carbon stocks makes it a larger emissions source than conversion of the Brazilian Cerrado.
https://iopscience.iop.org/article/10.1088/1748-9326/ab0399/pdf

Thank you for your consideration of these comments. EDF looks forward to continuing to work with CARB to update the LCFS. If you have questions or would like to discuss any of these recommendations, please contact Katelyn Roedner Sutter at kroedner@edf.org.

Sincerely,

Katelyn Roedner Sutter
California State Director

Beth Trask
Vice President, Global Energy Transition

John Tauzel
Senior Director, Global Agriculture Methane

Dr. Pedro Piris-Cabezas
Senior Director, Global Transportation

Joe Rudek
Lead Senior Scientist

Glenda Chen
Senior Analyst, Global Transportation

Michelle Tynan
Manager, Global Agriculture Methane

Cole Jermyn
Attorney, Energy Transition

Mindi DePaola
Senior Manager, Community and Equity,
Agriculture Methane

Sara Noelani Olsen
Project Manager, California Political Affairs

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Comment 337 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Ryan
Last Name	Kenny
Email Address	ryan.kenny@cleanenergyfuels.com
Affiliation	Coalition of 51 Stakeholders
Subject	Comment Letter from 51 Stakeholders
Comment	Please find attached a comment letter on the proposed LCFS amendments from 51 stakeholders. Thank you for considering our views.
Attachment	www.arb.ca.gov/lists/com-attach/7013-lcfs2024-W2lAYwdyUnIQLM0d.pdf
Original File Name	Multi-Stakeholder LCFS Comment Letter Feb 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 17:33:11

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SOUTH SAN FRANCISCO SCAVENGER COMPANY, INC.

The Honorable Liane Randolph
Chair, California Air Resources Board
1001 I St, Sacramento, CA 95814
Sacramento, California 95814

February 20, 2024

Re: Low Carbon Fuel Standard

Dear Chair Randolph:

328.1 We, the 51 undersigned clean fuel businesses and related organizations, write to emphasize our support for the key proposed amendments to the Low Carbon Fuel Standard (LCFS) and urge adoption of several additional amendments that will allow the state of California to effectively achieve climate and clean air goals.

We stand ready to follow your leadership to address the dire threat of climate change. The LCFS drives reductions in greenhouse gases (GHG), supports a rapid phase-out of petroleum, and bolsters a transition to electrification everywhere feasible. Also, as partners in California's transportation decarbonization efforts, we strongly support the conclusions in the *Initial Statement of Reasons* supporting science-based analysis. By doing so, the LCFS is well positioned to encourage the billions of dollars of investment required to implement the California Air Resources Board's (CARB's) *2022 Scoping Plan for Achieving Carbon Neutrality* in the transportation sector.

There is no more effective and immediate step we can be taking to address climate change now than to aggressively and rapidly reverse emissions of fugitive methane from all sectors, including society's organic waste streams through renewable natural gas (RNG) projects.

Many RNG projects in planning and construction across North America currently rely on LCFS
328.2 revenues to be built, operated, and provide a return on investment for debt service. We are pleased that CARB, via the just-released *Proposed Amendments to the Low Carbon Fuel Standard Regulation,*[1] is proposing to allow projects that break ground by December 31, 2029 to
328.3 retain the current approach to book and claim and avoided methane accounting. We are also supportive of the proposal that for projects that break ground after December 31, 2029, deliverability rules won't be modified until January 1, 2041 for pathways which include biomethane used in CNG vehicles and January 1, 2046 for biomethane used for hydrogen production. While these existing accounting rules are well functioning and do not need to be deviated from, we look forward to working with CARB to increase stakeholder understanding on these topics and plan for new accounting rules once more implementation details are developed.

Outstanding Problem: Making LCFS a Functional Program Requires a Strong CI Curve

328.4 We remain concerned that the proposed carbon intensity (CI) compliance curve falls short of stimulating the market and needs to be significantly strengthened to draw down the Program's credit bank which recently hit a new high of over 20 million surplus credits, with ICF forecasting that the program will have a bank of about 29-30 million credits by the end of 2024.[2] In fact, ICF continued to state, "[T]he proposed [CARB] CI step-down will slow the bank build by about 50%

[1] "Appendix A-1; Proposed Regulation Order; Proposed Amendments to the Low Carbon Fuel Standard Regulation," California Air Resources Board, January 2, 2024
[2] "Analyzing Future Low Carbon Fuel Targets in California; Response to Staff Report," Page 3, ICF, February 2024

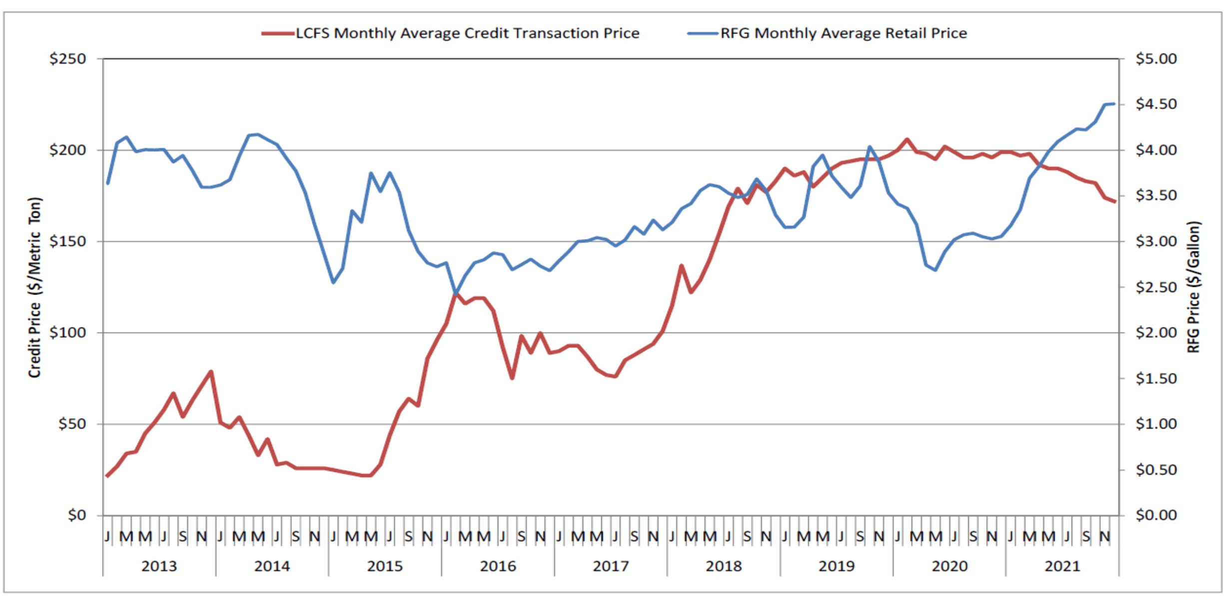
compared to previous years; however, the credit bank is still likely to grow by nearly 4 million credits by the end of 2025."

The primary reason for the substantial surplus in credits is the increasing supply of renewable diesel fuel due to additional projects coming online and various projects passing significant milestones. Without changes, this will continue to drive the credit bank up and keep LCFS prices depressed for multiple years. In fact, we are seeing the same occurrence in Oregon's program with a steady increase in renewable diesel going there, causing credit prices to fall as more credits are flowing into that market.

328.4c cont. The oversupply of credits in the market hurts existing and proposed projects, but additionally it sends a signal to investors that we should not invest. In fact, based on the spot and futures markets, Wall Street believes California has lost its urgency to decarbonize transportation. Investment banks are viewing credits as stranded assets over proactively investing in production projects that move California closer to its climate and clean air goals. And while the Program has been successful in driving down carbon intensity of transportation fuels, this situation also demonstrates the need to tighten the CI curve so that the market can move off its eight-year low credit price of $55, when the credit bank by the end of this year will have enough credits for nearly 2 years' worth of compliance and is still growing.

It is important to note that research[3] has concluded there is not a causal relationship between the LCFS and prices at the pump. Analysis of market prices demonstrates that the LCFS is not a significant driver of retail fuel prices in California, as the primary driver is the cost of crude oil. Lower carbon fuels are displacing Californians' exposure to foreign crude and delivering alternatives that bring home cost savings, in addition to the California jobs required to build low carbon fuel supply, clean fuel networks, and maintenance infrastructure of clean fuel vehicles. This conclusion is consistent with that in the ISOR on pages 82-83. This graph shows this lack of causal relationship over time:

Figure 1: LCFS Credit Price and Retail Gasoline Price[1]



[3] "Low Carbon Fuels Standards; Market Impacts and Evidence for Retail Fuel Price Effects," Bates White Economic Consulting, April 2022

In conclusion, the LCFS program must be fixed to be functional, but won't achieve California's climate goals if the CI curve is not effective.

Solution

328.4a cont. We urge CARB to set an ambitious compliance curve course that immediately draws down the credit bank and ensures a steady market to 2030. We support the ICF conclusion on the step-down for 2025 that "[A] CI [reduction] of 25% in 2025 is likely needed to ensure that the credit bank reverses and that the bank is drawn down to a level that is in line with a credit bank of only two quarters' worth of deficits. This level of stringency, while seemingly high, is likely what is needed to achieve CARB's stated intent of correcting for the 'near-term over-performance' of the program."[4] 328.4b We are also supportive of at least a 41% CI reduction target by 2030, which to our industry's extensive quantitative modeling[5] concludes that implementing the above strategy would increase the current approximate $55 credit price to $100-$120 by the end of 2025 and maintain at least that price through 2030.

Additional Amendments

Additional RNG-related changes are also needed to improve investor confidence and increase the pace of methane emissions abatement. We urge CARB to please consider:

328.5

- A full credit True-up remains necessary to properly recognize the true environmental performance of all pathways. Approvals take 18 months or more which puts financial hardship on a project and those in the entire value chain. A project would be able to apply its actual CI performance retroactively to the start of a project and thus eliminate the need to store gas. The project would be eligible to claim the full benefit of its project CI even when starting with the temporary pathway (also known as the project start up period);

328.6

- The Auto Acceleration Mechanism should be able to trigger as early as 2026. This would dynamically respond in the event of future sustained and significant underestimation of CI reduction targets by further tightening the stringency and complement the updated overall stringency of the program, complement existing mechanisms to avoid credit shortfalls, and better ensure that opportunities to deliver additional reductions of carbon and air pollutants are not foregone;

328.7

- We support the revised Tier 1 calculators and urge improving pathway processing times. The current review delay of over a year deters future investment and decreases return on investment of projects that California needs. For example, a multi-million dollar project built today must endure an 18-month administrative review on average to certify the project's LCFS pathway. Certification should be performed in less than a six-month window.

The success of the LCFS is due to the broad portfolio of clean fuels working together to achieve substantial emissions reductions. Unwinding these successful partnerships would strand billions

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[4] "Analyzing Future Low Carbon Fuel Targets in California; Response to Staff Report," Page 4, ICF, February 2024

[5] "Analyzing Future Low Carbon Fuel Targets in California; Initial Results for Accelerated Decarbonization, Central Case," ICF, June 2023

of dollars in clean technology investment, delay transportation decarbonization, and extend the period where petroleum is the dominant fuel in California.

328.8 The LCFS must remain fuel-neutral, driven by CARB's science-based analysis, capable of incentivizing real-world investment, and focused on performance-based GHG outcomes. Remaining true to these core concepts will ensure California leads the world in rapid transportation sector decarbonization.

Sincerely,

Arsen Sarkisian, President and Chief Executive Officer, NASA Services, Inc.

Chris Akers, Chief Executive Officer, Northern Biogas

Tom Bachman, Vice President, Mead & Hunt

Ashley P. Beaty, Vice President of Policy and Partnerships, Bridge To Renewables, Inc.

Nejteh Der Bedrossian, Operations Manager, Nationwide Environmental Services

Michael Boccadoro, Agricultural Energy Consumers Association

Doug Button, South San Francisco Scavenger Company

Todd R. Campbell, Vice President, Public Policy & Regulatory Affairs, Clean Energy

Will Charlton, CEO of Valkyrie Analytics, Inc.

Kurt Christensen, Vice President, Digester Doc LLC

Merissa Coello, Environmental Program Manager, Vespene Energy

Steve Compton, President, Sevana Bioenergy

Raphael Le Deley, Managing Director, North America, Prodeval

Clay Detlefsen, Esq., Senior Vice President, Environmental and Regulatory Affairs & Staff Counsel, National Milk Producers Federation

Johnny Duong, California Waste Solutions, Chief Operating Officer

David E. Fahrion, Chief Executive Officer, California Waste and Recycling Association

Bernard C. Fenner, Chief Executive Officer, Ductor Americas, Inc.

Andy Foster, President – Advanced Fuels, Aemetis, Inc.

Katrina M. Fritz, Executive Director, California Hydrogen Business Council

Daniel J. Gage, President, NGVAmerica

Gov Graney, Co-Founder, and Patrick Graney, Co-Founder, Nacelle

Tommy Gendal, Chief Operating Officer, Waste Resource Technologies, Inc.

Richard E. Hammond, Manager and Chief Operating Officer, Bio-Tronic Energy-CA, LLC

Mike Harrison, P.E., CPSWQ, Engineering Manager, E.J. Harrison & Sons, Inc.

Scott Hill, Project Executive, Swinerton Energy, Inc.

Derek Hundert, President, PlanET Biogas

David Kailbourne, CEO of these entities: REV Holdings, REV LNG LLC, REV H20, Marks RNG, Lincoln RNG, Renewable Operations Company, LLC

Joseph Kalpakoff, President, Mid Valley Disposal

Greg Kelley, General Manager / Managing Member, Napa Recycling & Waste Services and Northern Recycling, LLC

Charlie Ker, Senior Director, Business Development (North America), Westport Fuel Systems

Lauren Lamb, Environmental Attribute Manager, BerQ RNG

Greg Lammers, Vice President - Strategic Development, Athens Services

James Lavelle, Chief Executive Officer, US Renewable Energy Development Capital, Inc.

Robert Lems, CEO of HoSt Bioenergy Systems North America

Brent Lilienthal, Chief Executive Officer, LF Bioenergy

Daryl Maas, Chief Executive Officer, Maas Energy Works, Inc.

Erik Neandross, President, Chief Executive Officer, Gladstein, Neandross & Associates

Brad Petersen, Executive Vice President, NLC Energy

Bob Powell, Founder and Chief Executive Officer, Brightmark

Ashley Remillard, Senior Vice President, Legal and Government Affairs, Hexagon Agility

Nicole Rice, President, California Renewable Transportation Alliance

Gov Siegel, Co-Founder, Avolta

Jay Skiersch, Vice President, Interra Global Corporation

Sean Trambley, Senior Director, California Policy, SMART Policy Group

John A. Thornton, President, CleanFuture, Inc.

Chris Valbusa, General Manager, Alameda County Industries

Dan Valdez, Office Manager, Roberts Waste & Recycling

Sam Wade, Director of Public Policy, Coalition for Renewable Natural Gas

Brian Waters, Chief Operating Officer, Atlas Disposal

Ben Wilson, Executive Vice President, EFI USA

Patrick Wood, Founder and General Manager, Ag Methane Advisors, LLC

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First Name	Matt
Last Name	Miyasato
Email Address	matt.miyasato@firstelementfuel.com
Affiliation	FirstElement Fuel
Subject	FEF Comments on LCFS proposed changes
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/7015-lcfs2024-AmRRMlI1BAgLYQhr.pdf
Original File Name	FEF LCFS comments Feb2024.pdf
Date and Time Comment Was Submitted	2024-02-20 17:37:39

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

FirstElement Fuel Inc. | 5281 California Ave, Suite 260, Irvine, CA 92617 | 949-205-5553

February 20, 2024

Ms. Liane Randolph, Chairman
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Subject: Low Carbon Fuel Standard (LCFS) Comments

Dear Chair Randolph,

FirstElement Fuel (FEF) is pleased to provide these comments on the proposed changes to the LCFS program detailed in the Staff Report: Initial Statement of Reasons (December 19, 2023)[1]. FEF, as you may know, is the largest retail hydrogen refueling station (HRS) provider in California, due to the state's aggressive greenhouse gas emissions policies married to appropriate market incentives embodied in the Low Carbon Fuel Standard (LCFS) regulatory framework. We provide these comments not only as a market participant but also as an enabler of California's hydrogen transportation ambitions and as a business dependent on its success.

First and foremost, we commend you and your staff for the thoughtful proposal, which reflects a balance between strict regulatory goals and economic reasonableness. Due to the large scope of changes, however, some areas regarding hydrogen deserve further refinement to enable greater implementation. These areas are discussed below.

Increased Stringency and Step Down
329.1 We agree with staff's recommendation of the 30% reduction in carbon intensity (CI) by 2030
329.2 and a 90% reduction in CI by 2040. However, we are concerned that the historically low credit
prices[2] will continue through 2025, so urge bringing the one-time 5% CI step down forward
sooner (e.g., at rule adoption through OAL) as well as the auto acceleration mechanism (AAM).
329.3 The delay in hearing the rule and any further delays in implementation will further stifle any
329.4 private investments in cleaner transportation fuels, especially HRS. We request the Board
implement the 5% step down and AAM sooner than the proposed date of 2025.

Light-Duty (LD) Hydrogen Refueling Infrastructure (HRI) Pathway
The existing LD HRI program has been working as intended, with HRS development solving the chicken-or-egg dilemma of vehicle adoption or fuel availability coming first. The HRI program was meeting or exceeding all of its goals laid out by the CARB Board and LCFS Staff through 2021 while there was a healthy balance of LCFS credit deficits in the marketplace that in turn buoyed LCFS credit prices. The *Program Goals*, and concomitant positive results, are summarized below.

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[1] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf
[2] https://r.search.yahoo.com/_ylt=AwrgzbOD88tlcAQAl.ZXNyoA;_ylu=Y29sbwNncTEEcG9zAzIEdnRpZAMEc2VjA3Ny/RV=2/RE=1709074564/RO=10/RU=https%3a%2f%2fww2.arb.ca.gov%2fresources%2fdocuments%2fmonthly-lcfs-credit-transfer-activity-reports/RK=2/RS=yu36..J0ANG2sS86H065qyHr788-

329.5 1. *Accelerate the development of hydrogen refueling infrastructure capacity*.
The installed capacity of HRS in California more than doubled between 2019, when the HRI program was initially implemented and mid-2022 when LCFS credit prices dramatically fell.

329.6 2. *Unlock private investment as a greater share of hydrogen refueling station capital expenditures.*
The share of public funding for HRS fell from an average of ~70% of project capex *plus* Operation & Maintenance support to ~30% of project capex and an elimination of Operation & Maintenance support.

329.7 3. *Enable hydrogen station operators to retail hydrogen at a price more indicative of a full-fledged market.*
The average retail price of hydrogen fell to an all-time low in the months following the implementation of HRI, with FEF retailing hydrogen at $12/kg + tax, nearly price-parity with gasoline.

329.8 4. *Encourage the development of commercial-scale hydrogen stations with higher capacity, capable of supporting growth in the marketplace, including more vehicle classes (such as Medium-Duty hydrogen vehicles).*
As a result of the hydrogen station development spurred by the HRI program, California leads the world in higher-performing, higher-capacity hydrogen stations. Furthermore, setting the capacity cap at 1,200 kg/d in the LD HRI program has led to the development of stations that are robust enough to serve medium-duty (MD) fuel cell electric vehicles (FCEVs), such as large pickup trucks or delivery vans, thus enabling another vehicle segment.

329.9 5. *Encourage good performance of hydrogen refueling stations in the marketplace.*
The "uptime" requirement in the HRI program has incentivized FEF to make significant investments in R&D and engineering to improve equipment performance and uptime, which has also led to the creation of jobs and workforce training.

329.10 6. *Reduce the CI and increase the renewable content of hydrogen sold into the mobility sector.*
As a result of the LD HRI program, FEF increased the renewable content of our hydrogen on average from 33% to over 70% and reduced our CI to zero. CARB data suggests that other hydrogen station operators followed similar trends during the first several years of the LD HRI program.

The single factor that has caused the LD HRI program to fall short of its goals in recent months is the imbalance of LCFS credits in the marketplace which has depressed LCFS credit prices. Depressed LCFS credit prices have resulted in a near standstill of LD HRS development, a dramatic increase in retail hydrogen prices throughout the state, and a reduction in performance by several hydrogen refueling station operators (while FEF continues to make strides in improving hydrogen station performance, nearly every other hydrogen station operator in California has seen a reduction in performance).

Several historical outcomes of the LD HRI program performance and participation suggest that the program *as originally designed* is well-balanced and was extremely successful at achieving its targeted goals if there was a healthy balance of LCFS credits-to-deficits in the marketplace. For example:

- There was never a "gold rush" to develop HRS, suggesting that the incentive was appropriate and not overly generous;
- The program was effective in hitting all 6 of its goals very shortly after implementation (this can be tracked with data), suggesting that the program was effectively designed; and
- When LCFS credit prices fell dramatically in 2022, the program stopped incentivizing the development of HRS and the retail price of hydrogen rose, again suggesting that the incentive was appropriate and not overly generous.

329.11 So, we agree with the staff recommendation to extend the LD HRI program but urge elimination of the new constraints imposed on the program, namely the more restrictive 10-year crediting period, the 600 kg/d capacity cap, and crediting only if within low-income, rural and disadvantaged communities (DACs). The specific justifications for each are summarized below:

- Limiting LD HRI crediting to 10 years creates risk and uncertainty for the continued operation of LD/MD HRS and hydrogen fuel availability beyond 10 years that could inhibit FCEV adoption. This uncertainty will also further limit private investment in HRS. We urge the CARB to maintain the efficacy of the existing LD HRI program by keeping 15 years crediting duration.
- Reducing the station capacity eligible for LD HRI crediting from 1,200 kg/d to 600 kg/d will severely undersize stations at sub-economic size. The LD HRI Capacity Cap was originally established at 1,200 kg/d to support HRS with at least three (3) dispensers as the minimum viable size. As MD hydrogen trucks are introduced, these will typically fill at the neighborhood fueling stations established under the LD HRI program rather than HD HRS stations along freeways (i.e., truck stops). Each MD FCEV may fill with twice the amount of hydrogen as each LD FCEV, making HRS capacity established under the existing LD HRS program even *more* important today than ever. We urge the CARB to maintain the lasting benefits of the LD HRI program by keeping the station Capacity Cap at 1,200 kg/d.
- Supporting stations with HRI crediting only in low-income, rural and DACs will hinder the fueling network coverage that is essential to FCEV adoption. Many practical constraints already limit the viable locations for new HRS, so adding the additional location requirements will certainly cause gaps. Furthermore, environmental justice advocates have argued that HRS would not benefit but rather create *further burden* to these communities by enabling greater traffic, congestion and idling fossil-fueled vehicles in those areas due to a station. A better solution is to enable greater ZEV incentives for those communities rather than requiring infrastructure.

We urge the Board to simply extend the LD HRI program "as is" and revisit in a few years to ensure the program is operating as intended and serving disadvantaged communities. We also request grandfathering on-going CEC projects awarded under the existing LD HRI program since

329.11 cont. these projects have been delayed due to the pandemic, the recent financial crisis in California, and the historically low credit prices.

Heavy-Duty HRI

329.12 The hydrogen industry stakeholders have worked with staff to draft a workable HD HRI program, and for the most part, we agree with the resulting capacity credit outline. From our experience over 10 years as the largest developer and operator of LD HRS, now looking toward HD HRS, we expect the 6,000 kg/d station Capacity Cap and 2.5% HD HRI Market Cap to be sufficient and the CARB action to establish the HD HRI program to be similarly effective as the existing LD HRI program.

329.13 However, for the same reasons elaborated above, we urge staff to create the new HD HRI pathway incorporating the parameters proven effective in the existing LD HRI pathway rather than the more restrictive current proposal. In particular, we urge a 15-year HRI crediting period, rather than the proposed 10-year limitation, and the elimination of the location requirements.

329.14
- Limiting HD HRI crediting to 10 years creates risk and uncertainty for the continued operation of HD HRS and hydrogen fuel availability beyond 10 years, which could inhibit HD FCEV adoption, especially amongst commercial fleets operating HD FCEV seeking long-term certainty in their operations. With the higher cost of HD HRS and long-term investment horizon of commercial fleets, the need for at least 15-year HRI crediting period is even more essential for HD HRS. We urge the CARB to establish efficacy in the HD HRI program with a 15-year crediting duration.

329.15
- Limiting HD HRI to locations within one mile of a ready or pending FHA Alternative Fuel Corridor, next to truck parking, or having received funding from a state or federal competitive grant program are too restrictive, unnecessary and will hinder the fueling network coverage that is essential to commercial fleet adoption of HD FCEV. Many existing truck stops fueling diesel truck fleets are further than 1 mile from FHA Alternative Fuel Corridors and not adjacent to truck parking, and we know that there are existing HD HRS locations that will serve significant truck volumes that are also NOT within one mile of a FHA corridor (e.g., the 60 Freeway and warehousing centers in the Inland Empire). We urge the location restrictions be removed entirely, or at least increased to a more reasonable five (5) miles with exceptions that allow for local or regional funding (as opposed to only state or federal) programs since there are Air District grant programs that vet station locations in their grants.

329.16 We recommend the Board adopt the HD HRI with a 15-year crediting period and without the location constraints, or at least allow the Executive Officer case-by-case discretion in the location approval.

Decarbonizing Hydrogen Fuel: 80% Renewables by 2030

329.17 The LCFS policy with HRI pathways has proven effective for the rapid decarbonization of hydrogen fuel. Per LCFS reporting, the hydrogen sold for transportation in California was rapidly decarbonized after the HRI was established, to 33 gCO2e/MJ average in 2022[3]. In contrast, the electricity in the California grid in 2022, at 77 gCO2e/MJ, was more than double the carbon

[3] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

329.17 cont. intensity[4]. So, we know that reducing the *carbon intensity* of hydrogen fuel to mitigate climate change is an effective weapon, and we also recognize that renewable sources for hydrogen production will be the ultimate pathway for transportation. However, the needed scale and cost of renewable-source hydrogen feedstocks take time to develop, at the project level as well as at utility scale with renewable power generation. Requiring 80% renewable content by January 1, 2030 is too soon and may prove counter-productive to the primary intent of LCFS policy to decarbonize fuels. We urge the Board to keep the existing 40% requirement for renewable content and conduct periodic check-ins on the average renewable content before mandating an increase.

Station Capacity Modeling: HyCAP and HyScape

329.18 Although not addressed in the regulatory package, we understand and agree the modeling for HD HRS capacity using the HyCAP model is essential for determining the HD HRS capacity credits, while continued use of the HyScape model is appropriate for determining the LD HRS capacity credits. However, we urge staff to provide certainty in the LCFS regulation that multi-use stations serving LD/MD and HD FCEV will be eligible to certify into both the LD HRI and HD HRI pathways. Furthermore, we recommend this be implemented with an iterative approach using both HyScape (LD/MD) and HyCAP (HD) models to ensure consistent and equitable treatment. We are involved with the NREL working group for HyCAP, and are confident in the implementation of this approach.

Finally, we wish to thank the CARB Board and staff for allowing us to comment. The LCFS is the most important regulation for the hydrogen refueling infrastructure industry, and the HRI programs are the keys to our continued viability. We look forward to working through these issues with staff prior to Board adoption.

Sincerely,

Matt Miyasato, Ph.D.
Chief Public Policy & Programs Officer
FirstElement Fuel

[4] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/2022_elec_update.pdf

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Comment 339 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Holly
Last Name	Yanai
Email Address	hyanai@divertinc.com
Affiliation	
Subject	Divert Comments on The Proposed Low Carbon Fuel Standard Amendments
Comment	Good Afternoon - Please find Divert's comments regarding the Proposed Low Carbon Fuel Standard attached. Thank you, Holly Yanai
Attachment	www.arb.ca.gov/lists/com-attach/7016-lcfs2024-VTZQNwR3BTQLUlc7.pdf
Original File Name	CARB LCFS Amendments - Divert Comments.docx.pdf

Date and Time Comment Was Submitted	2024-02-20 17:45:56

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2023

VIA ELECTRONIC FILING

Matthew Botill
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: Proposed Low Carbon Fuel Standard Amendments

Dear Mr. Botill,

Divert is an impact technology company with a mission to protect the value of food. Based in Concord, Massachusetts with significant operations within California, we were founded in 2007 with the purpose of creating innovative and efficient solutions toward eliminating food waste. We are passionate about proving that environmental sustainability can be as good for business and consumers as it is for the planet. To that end, Divert is focused on decarbonizing unconsumed food through source reduction, food rescue, and recycling.

Divert operates 13 facilities across the U.S., and works with over 5,400 retail stores. Divert works across the retail food supply chain, implementing training protocols and technology to track food and gather data about what is wasted and why. Divert provides insights that enable our customers to change behaviors and ultimately reduce waste through source prevention and rescue programs. For inedible food, Divert created the first FDA Food Safety Modernization Act (FSMA)-compliant reverse logistics process to aggregate wasted food and transport it to one of Divert's anaerobic digestion facilities at no additional cost and with negative carbon intensity. At these anaerobic digestion facilities, before it's digested, wasted food is processed through a proprietary depackaging system to remove excess moisture and unwanted contaminants – such as wrappers, stickers and rubber bands – that make this commercially generated organic material unsuitable for composting. Divert's facilities capture the biogas naturally released during anaerobic digestion, which is captured and purified into renewable natural gas.

We work towards our purpose every day, and have achieved successes to:

- Use our technology platform to optimize the reduction of food waste generation for the retail food industry, which is the largest generator of food waste in the U.S.
- Cultivate partnerships with retailers and food banks to increase donations for unsold food that meets food donation guidelines but would otherwise be bound for the landfill.
- Establish ourselves as the largest processor of food waste in the U.S., converting food waste to renewable natural gas via proprietary liquefaction and anaerobic digestion.

Divert is committed to helping California reduce short-lived climate pollutants through the rescue, recovery, and recycling of food waste. As California continues to achieve its food waste reduction and carbon neutrality goals, Divert is:

- Partnering with Feeding America, local food banks, and a private retailer to service over 900 California based stores to identify and facilitate the rescue of unsold food to provide to local communities and families in need.
- Providing California food retailers access to Artificial Intelligence (AI) and Internet of Things (IoT) technology to maximize source reduction and improve the proper handling and freshness of perishable goods.
- Expanding food waste processing and anaerobic digestion capabilities with a new California food waste to energy facility that makes carbon negative renewable natural gas (RNG).

We are supportive of the efforts made by the California Air Resources Board (CARB) and the State of California to achieve its carbon-neutrality goals and offer comments to the Low Carbon Fuel Standard Amendment below.

330.1 **Avoided Methane Crediting Should Continue in LCFS and Remain Available to Those Addressing The goals set forth in SB 1383 or Until a Realistic and Proven Replacement Policy is Implemented**
SB 1383 requires the state to achieve a reduction in SLCP emissions, including a 40 percent reduction in methane, by 2030.[1] In its 2022 Scoping plan, CARB outlines its SLCP related emissions achievements, while noting that these reductions have not kept pace with the broader progress towards California's decarbonization goals.[2] The document states that "more aggressive action is needed" to meet the state's legislative goals.[3]

As CARB has acknowledged, the emission impacts of SLCP's are especially strong over the short term, and timely action on reducing these pollutants can have an immediate beneficial impact on climate change and public health.[4] Achieving reductions in SLCP's would help reduce ambient levels of ozone and particulate matter and the cardiovascular and respiratory effects associated with air pollution, and many of these benefits would accrue in disadvantaged communities, which are often located near sources of SLCP emissions.[5]

SB 1383 requires a 40 percent methane reduction target by 2030, but by 2025 the state is expected to remain roughly 8 million tons short of anaerobic digestion or composting capacity.[6] Scaling up California's organic waste recycling infrastructure is crucial to achieving the adopted goals and such infrastructure can be incredibly costly to local jurisdictions. Private businesses can help the state achieve these goals with project investments both inside and outside of California.

Despite the state's need to reduce short lived climate pollutants and to scale organics processing infrastructure, the Proposed Rule has outlined a plan to phase out the avoided methane crediting in the LCFS program. This phase out is premature and leaves an incredible amount of uncertainty for investors that are looking to scale organics processing solutions that promote decarbonization within the state. These types of projects are often reliant on LCFS crediting and it would be counterproductive to propose

[1] California State Legislature, "SB 1383 - Short-lived climate pollutants: methane emissions: dairy and livestock: organic waste: landfills" 2015
[2] California Air Resources Board, "Final 2022 Scoping Plan Update", Page 224
[3] ID
[4] California Air Resources Board, "Short-Lived Climate Pollutant Reduction Strategy", Page 1
[5] California Air Resources Board, "Short-Lived Climate Pollutant Reduction Strategy", Page 13
[6] Governing Magazine (March 10, 2022), "It's Time America stopped Throwing Out Food Waste"

an arbitrary phase out of avoided methane crediting without a detailed plan for developing a replacement policy or continuing to provide a similar credit to projects that are working to help the State achieve the goals set for in SB 1383. To continue with a phase out will lead to significant project uncertainty, an increased potential for stranded assets, and could discourage future investment within the state of California.

We continue to support CARB analyzing phase-out of avoided methane crediting once replacement policies are in place. However, we do not support the Proposed Amendment's *required* phase-out of avoided methane crediting *without* a suitable replacement policy. Divert would recommend that CARB work with industry stakeholders to determine what alternative incentives are needed to advance projects that directly achieve the state's SLCP emissions reduction goals.

330.2 **Tier 1 Calculator: Recognition of Methane Benefits of RNG Projects Diverting Organic Material from Landfills Should be Revisited and Expanded**

Both CARB and US EPA have mandatory emission control requirements for landfills that help reduce methane emissions, yet research literature suggests that many landfills still contribute methane emissions at rates that are much higher than previously estimated.[7] A 2019 study by NASA JPL estimates that landfills' contribution to the state's methane emissions is double current estimates – approximately 41% of all methane point source emissions in California.[8]

LCFS can help address methane from organic waste handling through better recognition of the benefits of RNG projects that divert organics from landfills and into dedicated digesters. Better quantification of the methane benefits of avoided landfilling and incenting such reductions in the LCFS should be a key focus for CARB, rather than considering arbitrary dates for eventual sunsetting of avoided methane crediting.

We support and appreciate the change for years 1-3 in the *Tier 1 Calculator Biomethane from Anaerobic Digestion of Organic Waste* acknowledging the fact that significant methane emissions occur from open face of the landfill. However, maintaining the 75% assumed capture rate for the remaining years is inaccurate and does not align with current science, most notably EPA's October 2023 EPA findings that 61% of methane from landfilled food waste escapes to the atmosphere (39% capture rate).[9]

Given that EPA was the source for prior capture rate assumptions (with the 75% capture coming from a 1997 EPA study), EPA's much more robust and up-to-date findings should be immediately adopted and the 2023 EPA findings of 39% capture rate incorporated into the Tier 1 calculator.

330.3 **Tier 1 Calculator: Adjust Calculation Innaccuracy Related to Fugitive Methane from Biogas Upgrading**

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[7] This fact should be noted by those that believe a mandate to control is the sole solution that should be employed for other sources of fugitive methane, such as agricultural manure methane emissions.

[8] Duren, R.M., Thorpe, A.K., Foster, K.T. et al. California's methane super-emitters. Nature 575, 180–184 (2019). https://doi.org/10.1038/s41586-019-1720-3

[9] United States Environmental Protection Agency, Office of Research and Development, October 2023, *Food Waste Management: Quantifying Methane Emissions from Landfilled Food Waste* https://www.epa.gov/system/files/documents/2023-10/food-waste-landfill-methane-10-8-23-final_508-compliant.pdf

330.3 cont. As written, the CI score Tier 1 Calculation for fugitive methane emissions from biogas upgrading potentially creates a significant amount of inaccuracy. The calculator estimates tail gas emissions, which is a very small number, by subtracting two very large numbers - the digester gas heating value and the RNG and flared gas heating value - from each other. This can mean that an error as small as 1% in the digestor gas flow or methane content can recreate calculation errors as large as or larger than the entire CI contribution from factors like tailpipe emissions, pipeline transport, or fuel station compression which have been meticulously calculated.

The intent to accurately measure fugitive methane emissions is understood and effort should be made to ensure knowledge of what these fugitive emissions are, but we believe that a static assumption for fugitive losses in the upgrader would lead to more accuracy over the long term. A static assumption would also create less of a need for true-ups against fully certified CI scores due to measurement fluctuations within typical device uncertainty. We would welcome the opportunity to work with CARB to determine how this static assumption can be created and suggest that it potentially be based on technology type or vendor documentation.

330.4 **A Full Credit True-up Remains Necessary to Properly Recognize the True Environmental Performance of RNG Pathways**

We support the Proposed Amendment's inclusion of a "Credit True Up" after Annual Verification. When implemented properly, such a concept can ensure that the LCFS program correctly accounts for the full GHG benefits all fuel pathways produce. However, we believe the Proposed Amendment's true up

330.5 language may be mis-drafted as it appears to *not* allow true ups during the temporary pathway period.

This is confusing because, at both October 2020 and August 2022 LCFS Workshops, CARB Staff proposed providing a credit true up to correct for under crediting to pathway holders *only* during the period where a project is using temporary CI scores at the outset of their credit generation. At the time, CARB workshop material stated that such a limited true up would help reduce the pressure on CARB from developers to process LCFS applications quickly.

330.4 cont. We continue to support a full true up to verified actual CI performance for all pathways (temporary, provisional, and fully certified).[10] As an anaerobic digester is going through its application period, it is often assigned a carbon intensity score that substantially underestimates the greenhouse gas benefit (and associated lost revenue) during the project's startup period. This will lead to increased pressure on CARB developers to process LCFS applications quickly - something that CARB was actively hoping to avoid - as digestor operators scramble to make their investments viable. If pathways were allowed to fully "true up" their LCFS credit generation to their actual CI score, once that score was able to be calculated based on actual greenhouse gas performance data, these problems can be resolved.

330.5 cont. The current LCFS regulation requires an annual verification to determine the true CI score, relative to the certified CI score. But the result of that annual verification is that pathway holders can only give up credits if their actual CI score goes up—they cannot also gain credits if their verified CI score goes down. We believe that, absent some manipulation or misrepresentation, the exchange should go both ways. With proper safeguards around the timing of the true up and potentially some requirement to hold credits in

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[10] See the Renewable Natural Gas Coalition's comment letters from prior workshops dated January 7, 2022, August 8, 2022, and September 18, 2022.

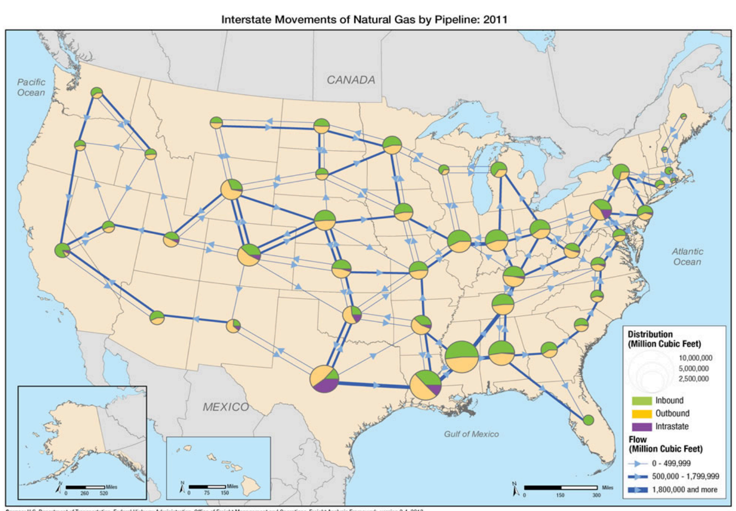
330.5 cont. reserve, this policy can serve to encourage very low carbon pathways whereas the current policy discourages very low carbon fuels in favor of less variable fuels.

330.6 **Because it is Physically Interchangeable with Fossil Natural Gas, Renewable Natural Gas can be Distributed in the Same, Longstanding Natural Gas Pipeline System that has Served California for Decades. This System Can Move Gas Across North America, therefore, a 50% Flow Requirement is Arbitrary and Unjustified.**

In the Proposed Rule, CARB staff is proposing a deliverability requirement on biomethane projects and is requiring projects to demonstrate that eligible biomethane is carried through common carrier pipelines that physically flow within California or toward end use in California 50% of the time on an annual basis. Divert understands that this requirement would be put in place to ensure that California is making progress on the State’s methane reduction targets, but the requirement would be detrimental to projects that are aimed at helping the state realize its short lived climate pollutant goals.

Natural gas currently flows throughout the United States depending on shifts in production, demand, weather, export pricing, and natural gas balancing. All major North American gas pipelines are interconnected, sharing gas flow and balancing, which can be contrasted with the power sector that is a more balkanized grid with limits on wheeling between regions—despite the efforts mentioned above to increase interconnection of the power grid.

When RPS limitations were developed, gas was just beginning to come from all over the country to California. The map below shows cross-country flows, dating back to 2011, illustrating the interconnectedness of the natural gas pipeline system in the United States.[11]



Since the RPS provisions were developed, the gas system has only grown more interconnected. For example, natural gas now flows from the Northeast region to all areas of the United States, from Texas to

[11] U.S. Department of Transportation Federal Highway Administration, *Interstate Movements of Natural Gas by Pipeline: 2011 Map*, https://ops.fhwa.dot.gov/freight/freight_analysis/nat_freight_stats/interstatenatgas2011.htm (last modified Mar. 23, 2020).

330.6 cont. California, and from the Rockies to California. The entire pipeline system in the United States is interconnected and in many cases is now bidirectionally flowing.

Natural gas has long been distributed through pipeline systems tracking volumes being injected and withdrawn throughout the entire system. These volumes are carefully tracked, as the pipeline system typically has state and federal oversight and third-party pipelines have metering throughout the system. Not only does this create a robust and liquid market for physical gas delivery across North America, that market already optimizes moving gas from supply to demand in a least cost (and lowest GHG)[12] fashion.

Given the interconnected nature of the US Gas pipeline, deliverability requirements can create a difficult burden on producers of natural gas to prove compliance. In addition, it will limit the production of biomethane for use in organics processing and in sectors that are hard to electrify. We strongly recommend that CARB avoid implementing deliverability requirements and instead maintain the status quo of the program to allow for book and claim for RNG Programs across North America. As California currently sets the precedent for the nation's decarbonization efforts, it is crucial that the state accept book and claim requests for projects across North America to better incentivize states to decarbonize. As new states adopt LCFS programs, it is important to consider what such a precedent would create as they adopt policies championed by CARB. Instead, Divert would welcome the opportunity to work with CARB to better explain the ramifications of such a policy move and discuss alternatives for a productive outcome.

330.7 **Increased Program Ambition as it is Critical for Continued Methane Reduction and Growth in All Low Carbon Fuels**

We support the effort that CARB staff has taken to outline future scenarios that set forth carbon intensity reduction goals for 2030 and beyond, however we feel that the biggest barrier to continued LCFS-driven methane reduction is the Proposed Rule's lack of overall ambition. Given the LCFS credit surpluses seen over the past two years and as CARB staff has highlighted in several of their recent workshops, the LCFS program has significantly exceeded expectations and low carbon fuels are coming to the market quicker and in greater volumes than previously anticipated. With this success, a significant step-down in the Annual Carbon Intensity (CI) Benchmarks is critical at this time. Based on all recent market information to date in 2024, the program will have produced many more credits than deficits. This will cause the bank to continue to build rapidly, prices to fall, and low-carbon investment to decline.

We urge CARB to adopt goals to reduce this trend and promote a healthy market. To accomplish this goal, CARB must adopt the appropriate stringency trajectory for the CI Benchmarks. Throughout this rulemaking process, a diverse group of clean fuel voices have contracted with the consulting firm ICF to independently prepare and submit an analysis of what program targets are feasible. In their analysis they are recommending that:

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[12] Moving gas requires additional energy and emissions from compression stations and potential methane leakage. These factors are already correctly accounted for in the LCFS CI modeling, which assumes physical gas flow from source to sink, regardless of the ability to trace actual molecule path. This provides a fair and appropriate disincentive that recognizes GHG disbenefits of moving gas from projects located farther from California, all else equal.

A 2025 Target of >25% is Needed to Address Current Oversupply Issues. This Level of Ambition Should also be Implemented in Q3 or Q4 of 2024, if Administratively Possible.

330.7a cont. The ICF work demonstrates that increasing the program's benchmarks to set a 25% CI reduction below the 2010 Baseline in 2025 would be sufficient to begin to draw down the credit bank, reestablish a demand for additional expansion in low carbon fuel supply, and therefore drive additional greenhouse gas
330.7b abatement. Further, starting the step-down as soon as possible and avoiding unnecessary bank build is crucial. We recommend that CARB target the step-down to occur on 7/1/2024 to a level of 25% below the 2010 baseline and maintain that level through 12/31/2025 (assuming CARB elects to retain the updated 2010 diesel baseline value).

330.7c *A 2030 Target of >30% can be Achieved with a Lower Credit Price Trajectory than Predicted in CARB's Modeling of the Primary ISOR Scenario*

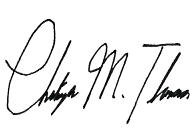
ICF's work shows significantly different LCFS credit price outcomes than CARB's ISOR analysis of the primary scenario. We believe that ICF's outlook is better informed by the true near-term supply outlook across all low carbon fuels and a better understanding of the potential other areas of public policy support (e.g., federal biofuel policy). Given that this deeper understanding demonstrates that it is possible to achieve greater mid-term reductions, we recommend that CARB continue to target at least a 30% CI reduction by 2030.

Conclusion
By considering the above recommendations, CARB staff has the opportunity to inspire further innovation in the low-carbon fuel sector while ensuring that the state does not prematurely reverse its historic emissions reduction accomplishments. These suggestions will strengthen the LCFS program by:

- Incorporating new innovations in emissions reduction and inspiring additional carbon reduction operational improvements.
- Ensuring that the LCFS program prioritizes the removal of short lived climate pollutants by keeping incentives in place to develop necessary organics infrastructure
- Creating opportunities for a cohesive and uniform RNG marketplace across North America

We would welcome an opportunity to discuss these suggestions further and additionally talk through our operations to provide further context to our suggestions. If you have any questions, please do not hesitate to contact me at cthomas@divertinc.com or at 202-421-1107. We are eager to collaborate further on this critical effort.

Sincerely,



Chris Thomas
Vice President of Public Affairs
Divert Inc.

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Comment 340 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jamie
Last Name	Katz
Email Address	jbkatz@leadershipcounsel.org
Affiliation	
Subject	Defensores Comments on LCFS ISOR
Comment	attached
Attachment	www.arb.ca.gov/lists/com-attach/7017-lcfs2024-B2MBYIM0V2FXP1Mg.pdf
Original File Name	Defensores Letter - LCFS 2.20.24 .pdf
Date and Time Comment Was Submitted	2024-02-20 17:46:41

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

DEFENSORES DEL VALLE CENTRAL
PARA EL AIRE Y AGUA LIMPIO

CENTRAL VALLEY DEFENDERS
FOR CLEAN AIR AND WATER

February 20, 2023

Liane M. Randolph, Chair
California Air Resources Board
1001 “I” Street
Sacramento, CA 95814

Submitted via CARB’s online Comment Submittal Form

Re: San Joaquin Valley Community Resident Opposition to the Proposed LCFS Amendments

Dear Chair Randolph and members of the CARB board,

We are Defensores del Valle Central para el Agua y el Aire Limpio (Central Valley Defenders for Clean Air and Water) a group of residents from the San Joaquin Valley who have come together out of the need to defend our right to healthy neighborhoods. Our mission is simple, to promote and enforce policies and practices that decrease pollution, degradation of the environment, and other negative impacts from dairies on vulnerable communities and the region.

For almost two years, our group has played an active role in ensuring the concerns of our communities, regarding the proliferation of factory farm gas and its harmful effects on our health, are addressed by CARB in the LCFS rulemaking update. Unfortunately at every turn, CARB staff ignores our concerns and blatantly tries to erase our lived experiences and the impacts we live with every day, from the expansion of factory farm gas infrastructure, like digesters and pipelines near our communities.

331.1 As Environmental Justice communities in a region with poor air quality, high levels of asthma and other respiratory illnesses, a lack of public health infrastructure, and many of us without clean and affordable drinking water, we demand that CARB eliminate avoided methane crediting and use the power the legislature gave them to initiate a rulemaking to directly regulate emissions from manure.

331.1 cont. Below you will find a collection of comments from a few members of Defensores urging you to think about how staff proposals, that did not mention any community concerns, must and should take those concerns into account in this rulemaking.

"I have lived in Pixley, CA for over 47 years. I have come to this body in Sacramento, over Zoom, the phone, and some of you have even visited Pixley to hear our stories. Unfortunately, it seems like you have not heard or listened to the yells from our community. One mile north of Pixley is a dairy digesters cluster where factory farm gas is being produced. The smell of ammonia and concentrated cow manure has only gotten worse in Pixley. We are surrounded by dairies and their digesters, the truck traffic in our community keeps getting worse, and people in our community are suffering from the air quality impacts. There are three generations of people in my family that use a CPAP machine, my 36-year-old son, my 11-year-old grandson, and myself, Sadly, this is not a unique story in my community, in fact respiratory illnesses have become a "normal" thing for us. This is why we need your leadership more than ever because our communities can not wait."

Maria Arevalo, Pixley

"I live in Santa Nella and was raised in the Central Valley. Since the inception of digesters, there has never been any intention of actually engaging communities in this process. In the past, meetings did not provide translation, outreach was not conducted, and materials were not accessible to non-English speakers. Now, you ask us to attend workshops and you meet with us, only to not mention our concerns in your documents at all. In addition to ignoring what the community has to say and trying to erase us from your record, there was not one mention of public health in your document and the already existing problems many SJV communities face. You are contaminating our air, water, and all for companies that are not even in our communities. We have needs in our communities to improve our local air quality and not line the pockets of investors who have never had to live with the smell day in and out. We ask the board to consider public health for all over profit for some."

Patricia Ramos-Anderson, Santa Nella

"CARB must regulate the dairy industry. We have to endure the flies, the odors, and the air quality impacts. Many people in my community live with Asthma. The dairy industry impacts our air and water quality. I worry about our safety and our health. CARB must have regulations on the dairies manure."

Josefa Gonzalez, Pixley

"I stand with my partners in community demanding justice for our communities that are already overburdened with pollution. We do not need more mechanisms in our communities to make us sick, you should be investing in community-identified measures to improve the health of our air."
Tere Ochoa, Los Banos

"I've been living here since 1960. Hillcrest arrived in 2002 with over 3,000 cows. In 2012 they

331.1 cont. *were out of compliance with Merced County with over 8,000 cows. Our Town population is only a little bit over 4,000. I've gone to the Board of Supervisors in Merced County to complain with a group of citizens as well but it goes and it falls on deaf ears. In January 2024, CARB could start a rulemaking for the regulation of methane, but to this day we have not heard any desire from staff of the board to begin this process. California Regulators have not adequately evaluated this program as to local air and small communities so we implore your help communities, just like Pixley and Planda and any other small town that just want to breathe."*

David Rodriguez, Planada

We thank you for your time and consideration and look forward to a better program that does not disproportionately impact our communities.

Sincerely,

Defensores del Valle Central Para el Aire y el Agua Limpio
Central Valley Defenders for Clean Air and Water

Comment Log Display

Here is the comment you selected to display.

Comment 341 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Trisha
Last Name	Delloiacono
Email Address	tdelloiacono@calstart.org
Affiliation	CALSTART
Subject	Support Proposed Amendments to the Low Carbon Fuel Standard Regulation
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/7018-lcfs2024-BmVcO1M+BCRRI1Ax.pdf
Original File Name	CALSTART Comments on Proposed Low Carbon Fuel Standard Amendments 2_20_24.pdf
Date and Time Comment Was Submitted	2024-02-20 17:47:54

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Clean Transportation Technologies and Solutions

www.calstart.org

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

SUBJECT: SUPPORT Proposed Amendments to the Low Carbon Fuel Standard Regulation

Dear Chair Randolph and Honorable Board Members,

CALSTART appreciates the opportunity to submit comments on the proposed amendments to the Low Carbon Fuel Standard (LCFS) program. Since its initial implementation in 2011, the LCFS program has allowed California to decrease carbon in the state's fuel pool and accelerated new technology and alternatives to petroleum fuel. The program has also served as a valuable incentive program in helping bring new companies and their ideas for zero-emission fuels and technology into the state's fuel market.

CALSTART and our Origins

CALSTART, headquartered in California, is a globally renowned 501(c)3 nonprofit organization dedicated to the advancement of zero emission vehicle and infrastructure technology. With a global member consortium of more than 300 technology, government, industry, and community partners, CALSTART has worked for 30+ years to accelerate the commercialization and deployment of advanced technologies and solutions. Through policy development, incentive program administration, and first-of-its-kind deployment partnerships, CALSTART has designed and managed programs that drive the market for clean transportation technologies needed to achieve critical greenhouse gas and criteria pollutant emission reduction goals.

Comments on the Proposed Amendments to the Low Carbon Fuel Standard

In July of 2022, Governor Newsom wrote a letter to California Air Resources Board (CARB) Chair Randolph[1] pushing for "greater opportunities to reduce our dependence on fossil fuels to achieve our air quality and climate targets," and continue the diversification of fuels away from petroleum in the transportation sector. Part of his ask was to evaluate and consider an increase in the stringency of the LCFS. Shortly thereafter the CARB Board approved the 2022 update to the Scoping Plan including increasing the stringency of the 2030 greenhouse gas (GHG) reduction target to 48 percent below 1990 emissions and putting the state on track to achieve carbon neutrality by 2045, or earlier. CALSTART strongly supports CARB's efforts to increase its ambition to deliver needed GHG reductions to help stave off the most serious impacts of climate change—impacts that disproportionately harm our most vulnerable populations.

Increased Stringency

To that end, CALSTART believes there are opportunities to improve the proposed amendments to deliver additional greenhouse gas emissions reductions. There are two key adjustments that CARB can make to the stringency as part of the 15-day change process. Specifically, by increasing the step-down and pulling forward the effective date for triggering the Auto Acceleration Mechanism (AAM) CARB can deliver additional reductions in GHG emissions. These reductions will be lost with the current proposal and by doing so will send a clear, and supportive market signal to continue investments in clean fuels.

332.1 The proposed 5% step-down in stringency does not go far enough considering the size of the cumulative credit bank, which is anticipated to increase its rate of growth as new clean fuels come to market. CALSTART strongly encourages the step-down must be increased by ***at least*** seven percent (7%), translating into a 2030 target of at least thirty-two percent (32%) reduction in the carbon intensity (CI) relative to the 2010 baseline. While a 7% step-down will likely leave many credits in the cumulative credit bank, this single adjustment will translate into millions of additional tons of greenhouse gas emission reductions and strengthen the market in the process.

332.2 As designed, the first year that the AAM could impact program stringency is 2028---which is far too long in the event the cumulative bank continues to grow. The concept and need for the AAM is to respond to clear overperformance of the program and to send an unambiguous signal to investors that the program will respond to opportunities to deliver additional GHG reductions. The AAM should be based on 2025 data with the trigger assessment occurring in May 2026, and the AAM being applied in 2027 providing the applicable conditions are met, thus increasing program stringency for 2027. Relying on 2025 as the first eligible year for triggering the AAM is appropriate as one of the main objectives of the step-down is to bring the program into balance. Therefore, assessing the impact of the step-down on the market based on 2025 data, including the cumulative bank and the rate of credit to deficit generation, is aligned with the principles of the program. With this approach, the AAM could potentially increase the stringency of the program in 2027 and 2029 (i.e., triggered twice prior to 2030), better ensuring that potential emission reductions are not left on the table in the event the program continues to overperform following the Board's adoption of the amendments. Furthermore, it is important to note that the 3:1 ratio (i.e., cumulative bank/average quarterly deficits) proposed by staff that would trigger the AAM is likely inadequate. For example, in 2022, a year where there is consensus that the LCFS was overperforming, the AAM would not have been triggered using CARB's current proposal.

Support Full Range of Medium/Heavy Duty Zero Emission Transportation

332.3 CALSTART strongly supports staff's proposal to change the Clean Fuel Reward program from a focus on new light-duty EV rebate, to rebates for new and used medium- and heavy-duty zero emission trucks that are exempted from the Advanced Clean Fleets regulation. CALSTART believes this will be hugely impactful in transitioning currently unregulated fleets. Additionally, CALSTART is appreciative of the proposal to expand ZEV infrastructure crediting to the medium- and heavy-duty sector to support ZEV infrastructure needed for medium- and heavy-duty ZEVs. However, there are areas where CALSTART believes the regulation needs additional consideration and
332.4 modification. CALSTART recommends that CARB create parity between how the Fast-Charging Infrastructure and Hydrogen Refueling Infrastructure credits are treated under the program. The proposed regulation gives preferential treatment to hydrogen stations over electric vehicle charging stations when assigning the CI for capacity credits. We

332.5

encourage CARB to harmonize hydrogen refueling and EV charging. Additionally, CALSTART recommends that the geographic restrictions be modified. ZEV charging behavior does not necessarily mirror conventional fueling, nor that of light duty charging infrastructure. Specifically, MHD ZEV charging can be located where vehicles are domiciled and used, which may not be within one mile of a highway corridor. While the current proposal will support regional and long-haul trucks by incentivizing infrastructure along freight corridors, CALSTART believes the LCFS should support the full range of truck vocations, including drayage and short haul.

Conclusion

The LCFS program continues to be one of the best drivers for reduction of carbon in fuel and opportunities to incentivize and promote investments in cleaner fuel and zero-emission infrastructure. It is a necessary program to ensure the reduction of carbon intensity in the transportation sector while adoption of ZEV is accelerated. The basis of the program should be adopted by other states in the country, and CALSTART will continue to push for multi-state adoptions based on California's LCFS program's successes.

Thank you for your time and consideration. Please feel free to reach out if there are any comments or questions.

Trisha Dellolacono
Head of Policy
CALSTART

Comment Log Display

Here is the comment you selected to display.

Comment 342 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Stefan
Last Name	Unnasch
Email Address	unnasch@lifecycleassociates.com
Affiliation	Life Cycle Associates

Subject	Low Carbon Fuels Coalition Working Group on Biomass Comments on Draft Amendments
Comment	On behalf of the Low Carbon Fuels Coalition Working Group on Biomass, we appreciate the opportunity to provide comments on the Draft Amendments to the LCFS Regulation. Our working group support the overall objectives of the LCFS program and would like to express our specific recommendations regarding the inclusion of biomass feedstocks in the regulation. These reccommendations are detailed in the attached letter. Thank you for your consideration of these comments.
Attachment	www.arb.ca.gov/lists/com-attach/7019-lcfs2024-UDxWM1I1VmYFXARn.pdf
Original File Name	LCFC_CALCFS_Biomass_Comments.pdf

Date and Time Comment Was Submitted	2024-02-20 17:54:52

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

The Honorable Liane M. Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Comment on Draft Amendments to the Low Carbon Fuel Standard (LCFS) Regulation

Dear Chair Randolph,

On behalf of the Low Carbon Fuel Coalition Working Group on Biomass, we appreciate the opportunity to provide comments on the Draft Amendments to the LCFS Regulation. Our working group supports the overall objectives of the LCFS program and would like to express our specific recommendations for enhancing the inclusion of biomass feedstocks in the regulation.

Expanding Forestry Waste Feedstocks for Emission Reductions:

We strongly support the inclusion of additional waste feedstocks (§95488.8.g), specifically focusing on forest residues removed for forest fire fuel reduction or forest stand improvement as included in *§95488.8.g:*

(1) Pathways Utilizing a Specified Source Feedstock. In order to be eligible for a reduced CI that reflects the lower emissions or credit associated with the use of a waste, residue, by-product or similar material as feedstock in a fuel pathway, fuel pathway applicants must meet the following requirements.

a. Specified Source feedstocks include:

3. Small -diameter, non-merchantable forestry residues removed for the purpose of forest fire fuel reduction or forest stand improvement and from a treatment where no-clear cutting occurred; Municipal solid waste that is diverted from landfill disposal;

While the proposed regulation includes some forestry residues, we propose expanding this section to encompass all materials generated from essential forest management practices to adequately respond to the urgency of California's wildfire crisis, the resulting threat to human life, and the massive GHG and criteria pollutant emissions from wildfires and open burning. California's 2021 Wildfire and Forest Resilience Action Plan underscores the critical need to dramatically expand intensive forest management to mitigate wildfire risks [1]. The plan emphasizes the role of large-scale thinning and other management activities in reducing long-term greenhouse gas (GHG) emissions and air pollution associated with catastrophic wildfires. This aligns with the ambitious goal of managing 2.3 million acres of Natural Working Lands (NWL) set by the CARB 2022 Scoping Plan[2]. Utilizing residues from these activities as biomass feedstocks not only supports wildfire prevention but also offers a lower-emission alternative to traditional fuels. However, the ambiguous language in the proposed regulation will inhibit or preclude biomass utilization.

The current language presents three challenges:

[1] California's Wildfire and Forest Resilience Action Plan. California Wildfire Task Force. April 2022. Retrieved from https://wildfiretaskforce.org/wp-content/uploads/2022/04/californiawildfireandforestresilienceactionplan.pdf
[2] California Air Resource Board - 2022 Scoping Plan for Achieving Carbon Neutrality, November 16, 2022

- **Ambiguity:** Vague terms like "small-diameter, non-merchantable" hinder feedstock evaluation and create uncertainty for developers.

333.1
- **Inconsistency:** Lack of alignment with established federal and international standards (RFS, RSB) represent a challenge for securing eligible feedstocks under multiple regulatory frameworks.
- **Rigidity:** Failure to recognize that California is experiencing a wildfire crisis that the State and Federal Governments have recognized requires massive fuel reduction activities that will result in increasing quantities of forest biomass that must be open burned if the material cannot be utilized in a beneficial manner.

For example of this ambiguity and inconsistency, please see the table below:

Standard	Thinnings description	Definition/Questions
Proposed California language	Small -diameter, non-merchantable forestry residues	How will "non-merchantable" be interpreted since thinnings can generally be sold albeit at a much lower value than saw timber.
RFS	Pre-commercial thinnings	Pre-commercial thinnings are trees, including unhealthy or diseased trees, removed to reduce stocking to concentrate growth on more desirable, healthy trees, or vegetative material that is removed to promote tree growth.
RSB	Early/non-commercial thinnings	Thinnings performed for sivacultural or ecological reasons; including pre-commercial thinnings (i.e., thinnings of trees with a typical breast height diameter (DBH) below 10 inches.)

To address the challenges and encourage necessary biomass utilization in California we propose:

1. **Expand eligible feedstocks:** Include all forestry residues from forest management practices approved by the authorized tribal, federal, state or local agency.

333.2
2. **Adopt clear, consistent definitions:** Align with established standards for terms like "thinnings" and "residues" where possible, while still allowing flexibility for site specific forest management practices.
3. **Stakeholder Engagement:** Gather input from diverse groups to refine definitions and implementation procedures that will maximize forest health.

Additional Considerations:

- **Clearcut materials:** We propose revising the total exclusion of clearcut-derived biomass wastes and residues. Tightly regulated clearcutting practices ensure sustainability[3], and utilizing these residues offers environmental benefits without encouraging further clearcutting. Furthermore, the rationale for this exclusion has not been supported by stakeholder interaction at CARB workshops.

---

[3] California Forest Practice Rules in Title 14 of the California Code of Regulations (CCR) Section 921.3(c)(1)

- **Pre-2008 plantations:** Similar to the 2015 Compliance Offset Protocol, consider including materials from pre-2008 plantations meeting California's Forest Practice Rules[4].

Inclusion of Agricultural Residues Under Waste Definition:

We strongly support the proposed inclusion of additional waste biomass under §95488.8.g. Additionally, we urge for the explicit definition and inclusion of agricultural residues such as crop residues including
333.3 corn stover, wheat straw, sugarcane trash and bagasse, orchard prunings, and vineyard prunings, and orchard trees.

CARB's website acknowledges the current practice of burning these residues, which contributes to GHG emissions and air pollution[5]. Burning leads to GHG emissions and air pollution. By utilizing these materials as fuel feedstocks, we can convert waste into a valuable resource while reducing emissions.

Therefore, we recommend explicitly defining agricultural residues as eligible waste feedstocks within the LCFS program. This clarity will facilitate their incorporation and promote investments in diverse fuel types.

Inclusion of Lumber Mill Residue Under Waste Definition:

333.4 We strongly urge CARB to support the inclusion of lumber mill waste as a waste feedstock. This prevents landfilling and aligns with the broader environmental goals of the LCFS program.

Attestation Requirements for Waste Feedstocks:

333.5 We appreciate the importance of maintaining a rigorous chain of custody for all waste feedstocks and support the amended text under §95488.8.g.D regarding supplier attestation letters:

> ***Requirements for Feedstock Attestation Letter***. *Each specified source feedstock supply chain entity must maintain a specified source feedstock supplier attestation letter. Supply chain entities supplying biogas or biomethane used as a feedstock must follow the requirements under section 95488.8(i)(2). The specified source feedstock supply chain entities include points of origin, collectors, aggregators, traders, distributors, and storage facilities that participate in the supply chain from point of origin to the fuel producer for specified source feedstocks. The attestation letter must attest to the veracity of the information supplied, declare that the information accurately represents the specified source feedstock(s), and conform to the requirements of this subsection. The specified source feedstock attestation letter must make the following specific attestations:*

However, we seek clarity and flexibility on the specific definitions introduced in this requirement. For example, regarding traceability to "point-of-origin", we suggest clarifying the language to define the point-of-origin for biomass wastes as the location where the waste or the residue was generated. In this case, forestry residues would be traced to the specific timber stand, and lumbermill waste to the lumbermill. Bills of lading, already used for chain of custody purposes, should be an acceptable verification method.

---

[4] Section 5.2.1(e)(1)(D)
[5] https://ww2.arb.ca.gov/our-work/programs/agricultural-burning

333.6 We recognize potential challenges in applying these requirements to certain feedstocks, like sawdust, where tracing the origin throughout the entire supply chain might be impractical or infeasible. Therefore, we urge CARB to consider a more flexible approach for such specific cases. This flexibility could involve:

- Alternative verification methods: Accepting alternative forms of documentation or verification mechanisms suitable for the specific feedstock type.
- Focus on key points: Prioritizing attestation requirements on critical stages of the supply chain, such as initial collection and final delivery, rather than demanding origin details for every intermediary step.
- Tiered approach: Implementing a tiered system where the level of detail required in the attestation letter varies depending on the feedstock type and potential risks associated with its origin.

By adopting a more nuanced approach, we can ensure the integrity of the program while also fostering the utilization of diverse and potentially important waste feedstocks.

Sustainability Requirements:

We acknowledge the importance of establishing sustainability requirements for crop-based and forestry-based feedstocks under §95488.9.g to safeguard environmental integrity within the LCFS program:

> *(g) Crop-based and forestry-based feedstocks must not be sourced on land that was forested after January 1, 2008. A forest is as defined in section 95481 or where they are protected by international or national law or by the relevant competent authority for nature protection purposes.*
>
> *All crop-based and forestry-based feedstocks used for LCFS fuel pathways must meet the following sustainability requirement:*
>
> (1) *Maintain continuous third-party sustainability certification under an Executive Officer approved certification system.*
>
> (A) *All feedstocks at the point-of-origin must be certified by January 1, 2028. Fuel quantities reported under fuel pathways utilizing feedstocks not certified by January 1, 2028 must be assigned the ULSD carbon intensity found in Table 7-1 of the LCFS regulation.*
>
> (B) *The Executive Officer will review and may approve certification systems based on the following criteria:*

However, we raise concerns regarding the potential impact of mandatory third-party certification on forestry residues essential for wildfire prevention, particularly those originating from unmanaged lands.

333.7 While we agree with the principle of ensuring sustainable sourcing, applying a uniform certification requirement might pose undue challenges for wildfire abatement efforts. Unlike residues from managed forests, those obtained from unmanaged lands often lack established management practices and readily available certification pathways. The prohibitive expense of acquiring individual certifications for each instance of wildfire fuel reduction could hinder critical activities essential for forest health and wildfire abatement.

Therefore, we urge CARB to consider a nuanced approach that acknowledges the unique circumstances surrounding wildfire abatement residues.

Inclusion of Biomass as a Process Fuel:

333.8 We advocate for the inclusion of biomass as a process fuel within the LCFS program, recognizing its potential to contribute to GHG emission reductions and energy diversification.

The omission of biomass derived process fuels creates several missed opportunities for utilizing biomass and decarbonizing California's transportation sector**.** Biomass can be a valuable source of process heat, power, and combined heat and power (CHP) in facilities like:

- Biomass gasification plants
- Corn ethanol facilities with CHP (utilizing corn stover or other biomass)
- Facilities requiring low-carbon intensity (CI) power

As a practical example, the current Tier 1 calculators for the sugarcane ethanol pathway only consider "externally sourced biomass," excluding the use of biomass within the production process itself. This narrow definition fails to capture the full potential for emission reductions and sustainable biomass utilization.

Therefore, we recommend explicitly including biomass process fuels within the LCFS program, and updating the proposed tier 1 calculators to include both internally and externally sourced biomass.

Urgency for Clear Biogenic Carbon Accounting Guidance for Biomass Feedstocks:

The proposed LCFS regulation lacks crucial details regarding how the carbon intensity (CI) of biomass feedstocks will be determined. This omission presents a significant hurdle for developers of biomass-to-fuel pathways.

Biogenic carbon accounting plays a vital role in calculating the overall CI of a pathway, which will ultimately determine a project's economic viability.

We urge CARB to urgently provide comprehensive guidance on biogenic carbon accounting for all biomass feedstocks within the LCFS program. Ideally, this guidance should:

333.9

- Establish categories of biomass: By establishing clear categories for biomass types, considering factors such as their origin, properties, and potential uses, CARB can streamline the process of biogenic accounting. For instance, forestry residues and agricultural wastes represent major biomass categories that can be further refined based on geographical sources and potential alternative fates. Categories of biomass should include thinnings and slash, wildfire risk removal material, agricultural residues, urban wood waste, and purpose grown biomass.

- Align with established federal policies: Harmonizing with existing biogenic carbon accounting frameworks under programs like the RFS, where GREET serves as the accepted modeling tool and biogenic carbon is treated as carbon neutral, would streamline processes and promote clarity for developers.
- Acknowledge wildfire abatement contributions: Recognize the unique context of forestry materials sourced for wildfire abatement. Thinning and utilizing these materials can significantly reduce uncontrolled wildfire emissions, leading to orders of magnitude greater CO_2 savings compared to the biogenic carbon sequestered in the feedstock itself due to the avoidance of collateral damage from catastrophic wildfires. A nuanced approach that factors in this mitigation potential is crucial.
- Offer flexible and practical pathways: Allow for flexibility for accommodate diverse feedstock types and projects.

Clear guidance will attract investment to biomass-to-fuel projects, accelerating California's transition to a lower carbon intensity transportation sector.

The Low Carbon Fuel Coalition Working Group on Biomass is committed to working collaboratively with CARB to refine and implement these recommendations. We look forward to discussing these recommendations with you further and working together to strengthen the LCFS program.

Sincerely,

ROBIN VERCRUSE
Executive Director
LOW CARBON FUELS COALITION

STEFAN UNNASCH
Managing Director
LIFE CYCLE ASSOCIATES

MICHAEL C. DARCY
Chairman & CEO
DG FUELS, LLC

CHRISTOPHER EFIRD
Chairperson and CEO
NXTCLEAN FUELS, INC.

JEFF MCDANIEL
VP New Projects
VELOCYS

OSCAR GARCIA
Regulatory Affairs Manager
NESTE

DAN SHAPIRO
CEO
FIDELIS NEW ENERGY, LLC

Comment Log Display

Here is the comment you selected to display.

Comment 343 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Judy
Last Name	Vaccaro-Fry
Email Address	jfry@avta.com
Affiliation	Antelope Valley Transit Authority
Subject	AVTA Comments on LCFS Proposed Amendments
Comment	Please find our comments attached. Thank you.
Attachment	www.arb.ca.gov/lists/com-attach/7021-lcfs2024-W2lUYlFiAGcAKwY2.pdf
Original File Name	2024-02 CARB response.pdf
Date and Time Comment Was Submitted	2024-02-20 18:01:51

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Antelope Valley Transit Authority

February 20, 2024

Rui Chen
California Air Resources Board (CARB)
1001 I Street
Sacramento, CA 95814

Re: Antelope Valley Transit Authority Comments on the Proposed Low Carbon Fuel Standard Amendments

Dear Mr. Chen:

Antelope Valley Transit Authority (AVTA) appreciates the opportunity to comment on the California Air Resources Board (CARB) proposed amendments for the Low Carbon Fuel Standard (LCFS). AVTA supports CARB's initiatives to advance California's climate change goals, including propelling the growth of the nascent heavy-duty charging infrastructure and zero emission vehicle (ZEV) market through
334.1 the LCFS. We encourage CARB to provide more specificity around requirements to receive DC Medium-and Heavy-Duty Fast Charging Infrastructure (MHD-FCI) credits, in order to ensure accuracy and allow for greater participation in the program.

About Antelope Valley Transit Authority

AVTA is a transit agency with 30 years of experience providing mobility and access to over 450,000 residents of the surrounding Antelope Valley region and northern Los Angeles County. AVTA operates a fleet of 100 buses for transit service with 83 fully electric buses dedicated for local service, 19 electric On Request Microtransit Ride Service (ORMRS) vans and 24 electric coaches dedicated to commuter service for over one million rides annually (post COVID ridership). AVTA is the first transit authority in the United States to achieve a 100% zero-emission fleet, and it accomplished this goal in 2022.

The Importance of MHD-FCI Credits and Specifications in Requirements

The LCFS is a critical program for advancing California's climate objectives, including the expansion of electric vehicle charging infrastructure. The funds generated from LCFS credits have had a powerful impact on AVTA's ability to operate and grow, and MHD-FCI credits will allow AVTA to further expand its DC charging network to accommodate its growing fleet and help the state meet its climate and transportation electrification goals.

42210 6th Street West | Lancaster, California 93534 | 661.945.9445 | avta.com

334.1 cont. The proposed amendments contain areas in which the language is ambiguous in regards to some aspects of the criteria for eligibility for MHD-FCI credits. In particular, § 95486.3(b)(1)(B)(2) states that proposed MHD-FCI chargers must be "located within one mile of a reading or pending electric vehicle Federal Highway Administration Alternative Fuel Corridor or on or adjacent to a property used for medium or heavy-duty vehicle overnight parking." It is unclear what form of measurement is used to determine the one-mile distance from an Alternative Fuel Corridor – options include a straight-line or "as the crow flies" distance (the length of the straight-line drawn from the station to the nearest exit on the Corridor), or a driving distance (the distance measured along the route a vehicle takes from the Corridor to the station). If a station is greater than one mile driving distance from a corridor due to road logistics, but it is less than a mile straight-line distance from the corridor, it is unclear whether the station would meet the criteria for MHD-FCI credits.

334.2 AVTA recommends that the one-mile requirement be measured using a straight-line distance and that this be explicitly stated in the language, both for clarity and accuracy, as well as to favor a slightly more inclusive policy with the added effect of promoting more heavy duty infrastructure development in the state. Heavy duty infrastructure is a nascent market that needs additional support in order to reach the state's transportation electrification and climate goals, and allowing for greater participation in this program is one way of providing such support.

It is for these reasons that we propose the following changes:

- Specify the means of measuring a one mile distance in § 95486.3 (b)(1)(B):

  "The proposed MHD-FCI chargers must be:
  1. Located in California; and
  2. Located within a one mile straight-line distance* of a reading or pending electric vehicle Federal Highway Administration Alternative Fuel Corridor or on or adjacent to a property used for medium or heavy-duty vehicle overnight parking, or has received capital funding from a State or Federal competitive grant program that includes location evaluation as criteria."
  *The length of the straight line from the charging station to the nearest exit on the Corridor.

We Appreciate the Transparent Amendment Process

We are grateful for your time and consideration of these comments. We look forward to working with you to support a renewed, strengthened LCFS that will keep the state on track to meet and exceed its climate goals. Please do not hesitate to reach out if you have any questions about AVTA or these comments.

Sincerely,

Judy Vaccaro-Fry, MBM, MPA
Chief Financial Officer
Antelope Valley Transit Authority

Comment Log Display

Here is the comment you selected to display.

Comment 344 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Don
Last Name	Schinske
Email Address	don@lcfcoalition.com
Affiliation	Low Carbon Fuels Coalition
Subject	Re-Upload of ICF Update
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/7022-lcfs2024-UWMAMlVkUTAKPQk9.pdf
Original File Name	240214 Analzying Low Carbon Fuel Targets .pdf
Date and Time Comment Was Submitted	2024-02-20 18:05:16

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Analyzing Future Low Carbon Fuel Targets in California

Response to Staff Report

February 2024

ICF Resources, L.L.C.
1902 Reston Metro Plaza
Reston, VA 20190
703-934-3000

Contact: Philip Sheehy, PhD
Phone: 415-385-4160
E-Mail: Philip.Sheehy@icf.com

Contact: Fang Yan, PhD, PE
Phone: 916-210-5906
E-Mail: Fang.Yan@icf.com

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Table of Contents

Executive Summary

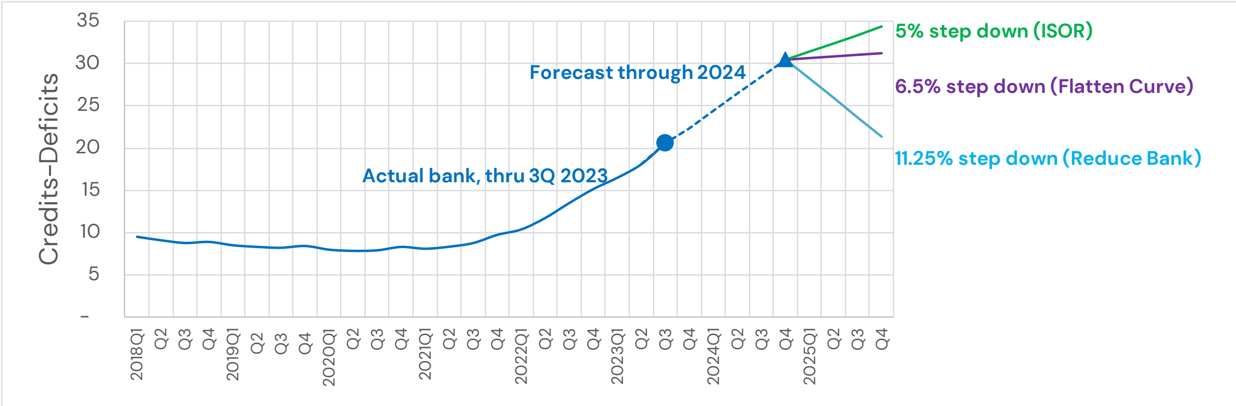
The California Air Resources Board staff released the Staff Report: Initial Statement of Reasons outlining many proposed amendments to the LCFS program in December 2023. The Staff Report identified three key areas of change with respect to carbon intensity targets: 1) increased stringency by 2030 (from 20% to 30% CI reduction), 2) a step down of 5% in the carbon intensity reduction required in 2025 (yielding an 18.75% carbon intensity reduction requirement compared to the 13.75% reduction scheduled), and 3) the introduction of an Automatic Acceleration Mechanism.

ICF previously reported that in an Accelerated Decarbonization *Central Case* a carbon intensity reduction target of 41-44% for 2030 is achievable for California's Low Carbon Fuel Standard program. ICF reached this conclusion based on expected fuel volumes and carbon intensity reductions for a wide array of low carbon fuel pathways. The work presented here, however, was prepared in direct response to the Staff Report and accompanying documentation published in December 2023. ICF modified and updated our analysis by focusing on a) an *ISOR Case*, b) the step down in 2025, c) the Automatic Acceleration Mechanism, and d) credit pricing.

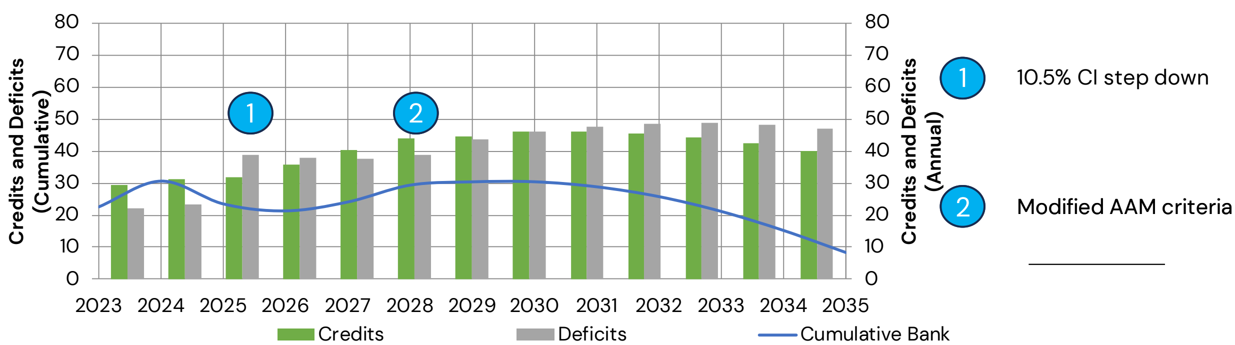
ICF developed the *ISOR Case* by modifying certain aspects of our modeling with the express intent of aligning more closely with the restrictions or constraints included in modeling done by Staff in support of the proposed amendments. ICF removed both the potential for a 15 percent blend of ethanol with gasoline and any pathways in the analysis that generated credits via the implementation of climate smart agriculture practices at the farm level. ICF also constrained renewable natural gas deployment in line with proposed changes to deliverability requirements and avoided methane emissions accounting. Lastly, ICF updated the carbon intensity value for ultra-low sulfur diesel in our analysis to align with the higher value published by Staff. ICF made other minor modifications to our analysis to reflect market developments that occurred over the course of the project.

335.1 ***ICF recommends a step down of 10.5% to 11.5% in 2025 to achieve a target credit bank equivalent of 2-3 quarters worth of deficits.*** This level of stringency is likely what is needed to achieve the stated intent of correcting for the "near-term over-performance" of the program. ICF's analysis indicates that the credit bank will likely continue to build significantly in 2025 if the step down is limited to 5%. ICF analysis suggests that a 6.5% step down is needed to ensure that the credit bank build is flattened in 2025.

335.1 cont.



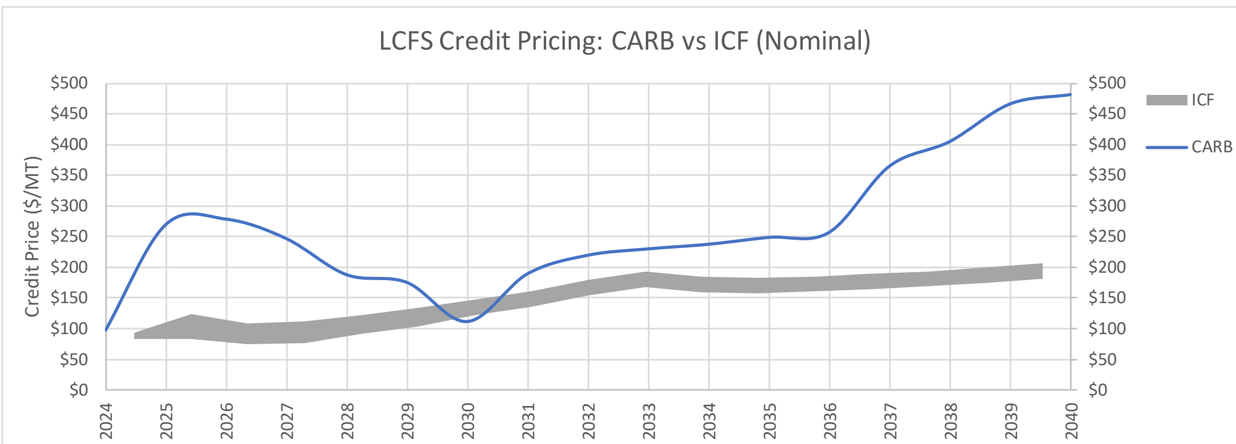
335.2 ***ICF recommends that the Automatic Acceleration Mechanism be considered for implementation as soon as 2026, rather than waiting until 2028. ICF also recommends that the first criteria for the Automatic Acceleration Mechanism be modified such that the mechanism is enacted when the credit bank is more than 2.5 times greater than the quarterly deficits generated in a given year*** (down from the proposed value of 3 times). The figure below shows the results of ICF's modeling using the *ISOR Case*.



The figure above has a shape and curve that ICF thinks is more in line with a successful Low Carbon Fuel Standard program i.e., one that maintains a tighter credit-deficit balance and is flexible enough to respond to market conditions in the near-term future (pre-2030), while enabling California to achieve its long-term GHG reduction targets. ICF's view of the market suggests that a focus on an "ideal" credit bank from pre-2021, quantified using a threshold of 3 quarters worth of deficits, is misguided and may lead to a market that "swings" up and down (as measured by the credit bank) more than necessary, thereby creating market uncertainty for active and would-be participants. Major investments by regulated parties in the last several years have likely improved their respective line of sight on credit generation, thereby reducing the need to carry such a large credit bank.

335.3 ***ICF recommends that Staff make more transparent the credit price modeling so that stakeholders can understand better what is driving the magnitude of credit pricing and the patterns emerging from the data.*** Staff used an internal estimate of credit pricing as

335.3 cont. one of the primary reasons for dismissing a higher carbon intensity reduction target in 2030. Staff claim that a higher target will lead to higher costs faced by consumers associated with pass-through compliance costs. However, Staff's forecasting is flawed and effectively implies that the Low Carbon Fuel Standard program will bear the entire cost of subsidizing low carbon fuel production. This analysis is overly pessimistic because it overlooks the substantial value of the Clean Fuel Production Credit via the Inflation Reduction Act, robust pricing from the federal Renewable Fuel Standard, moderate commodity pricing (e.g., for gasoline and diesel), and increasing California carbon allowance prices. The figure below shows a range of ICF forecasted credit prices in grey compared to the Staff credit price forecast in blue line.[1]



ICF makes three observations associated with the comparison between Staff's forecast and our forecast:

1. In the near-term future (by 2025), Staff is forecasting a four-fold increase in credit pricing. This forecasted credit price spike coincides with the introduction of the Clean Fuel Production Credit and other substantial Inflation Reduction Act incentives that will be flowing to the low carbon fuel market and reducing pressure on the Low Carbon Fuel Standard program.
2. In a post 2030 environment, though the two curves are showing similar patterns of increasing credit prices, Staff's forecast is still $60-65/ton higher than ICF.
3. Post-2035, Staff's forecasts are suggesting that a credit price of $250 to nearly $500/ton is needed to achieve program compliance. There is no reason that the credit price should ever need to be that high to induce the investments necessary to achieve compliance based on ICF modeling.

[1] Staff's credit price forecast has been adjusted to nominal dollars, as ICF has found this is how stakeholders tend to view the market (rather than adjusting pricing to some real-dollar basis).

1 Introduction

The California Air Resources Board (CARB) has proposed more ambitious carbon intensity (CI) targets to increase the stringency of the Low Carbon Fuel Standard (LCFS), with the intent of achieving more significant greenhouse gas (GHG) emission reductions in support of California's pursuit of economy-wide carbon neutrality no later than 2045. With respect to CI targets, CARB has proposed three key areas for change:

1. Increased CI stringency by 2030, increasing the target from 20% to 30% by 2030.
2. Additional 5% CI reduction in 2025 from the current CI target, also referred to as the step down. This step down in 2025 will yield an 18.75% CI target in 2025. The step down in 2025 is "in response to the near-term over-performance."
3. Introduction of an Automatic Acceleration Mechanism (AAM) that is designed to trigger a more stringent CI standard in the event of the market over-performing in the future (with over-performance measured by two criteria).

ICF is supporting a coalition of interested parties representing a diverse mix of low carbon fuel producers seeking to understand the potential carbon intensity reduction that could be achieved assuming the likely aggregate deployment of low carbon fuels and supporting technologies. Previously, in an Accelerated Decarbonization *Central Case*, ICF found that a carbon intensity target of 41-44% for 2030 is achievable based on expected fuel volumes and carbon intensity reductions for a wide array of fuel pathways.[2]

The initial stages of this project were focused on defining an ambitious CI target for 2030. However, the work presented here is in response to the Staff Report: Initial Statement of Reasons[3] and accompanying documentation published by CARB, and ICF has modified the analysis accordingly. The work presented here focuses on a) an *ISOR Case*, b) commentary on the step down in 2025 supported by ICF analysis, c) review of the AAM in light of likely low carbon fuel deployment to California out to 2030 (and beyond), and d) commentary on LCFS credit pricing.

As noted elsewhere, ICF's modeling differs from the modeling conducted by CARB staff using the California Transportation Supply (CATS) model. More specifically, CATS is described as a "transportation fuel supply optimization model" that "minimizes the cost of supplying fuel to meet demand in each year." In other words, given certain modeling constraints, namely a specific CI reduction trajectory and associated policy constraints, the

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[2] In a *High Case* reflecting updated science and analysis, additional cost effective GHG reduction opportunities, and alignment with proposed federal policies, ICF reported that a carbon intensity reduction of 43% to about 57% could be achieved by 2030.

[3] Available online at https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf.

CATS model optimizes compliance accordingly. The CATS model is designed to answer the question: *What is the least-cost compliance pathway associated with a CI target of X in year Y?* ICF notes that CARB has used scenario modeling in previous analysis supporting amendments to the LCFS program and has provided no rationale for switching to an optimization model. ICF maintains that an optimization model is not the right approach for target setting because it puts an out-sized impact on the modeling inputs that are used to solve for what is more likely to be a preconceived outcome. Scenario modeling, when done correctly is more useful to understand market outcomes as they might be, rather than how the author(s) wants them to be.

2 ICF Analysis of the Staff Report

Developing an ICF *ISOR Case*

After reviewing the Staff Report and engaging in a peer-exchange with CARB staff, ICF made several changes to our modeling approach with the intent of aligning more closely with the work done by CARB and the resulting proposed regulatory structure. ICF refers to this as an *ISOR Case*. As a reminder, ICF was previously focused on the CI reduction that was achievable by 2030. In this *ISOR Case*, ICF sought to focus on details that were not available prior to the Staff Report, including the 2025 CI step down and the implementation of the Automatic Acceleration Mechanism. While still standing behind the modeling and assumptions previously employed, ICF made the following changes to the supply-demand for low carbon fuels to more closely align with CARB's modeling approach:

- ***E15 Blending Removed.*** ICF removed the opportunities for E15 blending in the modeling. CARB has signaled that they did not include E15 consumption in their modeling because it is not yet approved as a fuel for sale in California. ICF maintains that E15 should be included in the modeling given the high likelihood of approval before 2030 and the interest in E15 to help reduce retail gasoline pricing in line with SB X1-2 ("discussion of methods to ensure an adequate, affordable, and reliable fuel supply"). However, for the purposes of evaluating the 2025 CI Step Down, E15 blending was excluded.
- ***Climate Smart Agriculture Removed***. ICF removed LCFS credit generation attributable to climate smart agriculture from our modeling because CARB has indicated that they did not include this in their modeling, and ICF's intent in the ISOR Case is to align initial assumptions or modeling boundary conditions to the extent feasible with CARB. This had an impact on credit generation associated with liquid biofuels, including ethanol, biodiesel, renewable diesel, and renewable jet fuel. ICF maintains that California will likely find itself as a disadvantage compared to other states considering incentivizing GHG emission reductions at the farm-level. However, although ICF believes climate smart agriculture has the potential to

provide significant additional CI reductions and will be implemented in the LCFS subsequent to 2028, this was removed from our modeling for this analysis.

- ***Constrained RNG Deployment.*** ICF constrained RNG deployment based on changes to deliverability and avoided methane emissions accounting consistent with the Staff Report. The constraints also account for lower credit pricing in the near-term future because of the over-supply of credits occasioned by the current LCFS targets, thereby restricting investment opportunities. [4]
- ***Updated CI value for ULSD.*** ICF updated the CI value for diesel in 2025 based on the revised value published by CARB--the CI of ULSD increased from 100.45 g/MJ to 105.76 g/MJ. ICF modeling suggests that this will have a material impact on the program because biomass-based diesel (i.e., biodiesel and renewable diesel) have displaced more than 50% of ULSD in California. Without a concomitant change in the CI of biodiesel or renewable diesel, ICF analysis suggests that this will yield substantially more credit generation than previously forecast.

ICF made other minor modifications to our analysis based on the market developments that occurred over the course of the project. For instance, ICF revised upward our renewable diesel projections as a result of additional projects coming online, various projects passing significant milestones, and data released by CARB related to deliveries to California through 3Q 2023. ICF also made modifications to the average carbon intensity of fuels based on data available for 2023, including for ethanol, biodiesel, renewable diesel, renewable jet fuel, renewable natural gas, and electricity.

2025 CI Step Down

ICF views the 2025 CI step down as a critical juncture for the program. In our modeling, we first evaluated the following:

1. What is the impact of the proposed 5% CI reduction step down, yielding an 18.75% CI target in 2025?

As of the end of 3Q 2023, the credit bank surpassed 20 million credits, with a bank build of 2.25 million credits in the most recent quarter for which data are available. ICF forecasts that the program will have a bank of about 29-30 million credits by the end of 2024. ICF analysis suggests that the proposed CI step down will slow the bank build by about 50% compared to previous years; however, the credit bank is still likely to grow by nearly 4 million credits by the end of 2025.

[4] Note that ICF's initial assessment indicates that this constraint may restrict California's ability to achieve its methane reduction targets included in SB 1383. It is conceivable that SB 1383 targets are still met; however, this would likely require changes to procurement rules under SB 1440.

335.1 cont. ICF then sought to determine two things with our analysis:

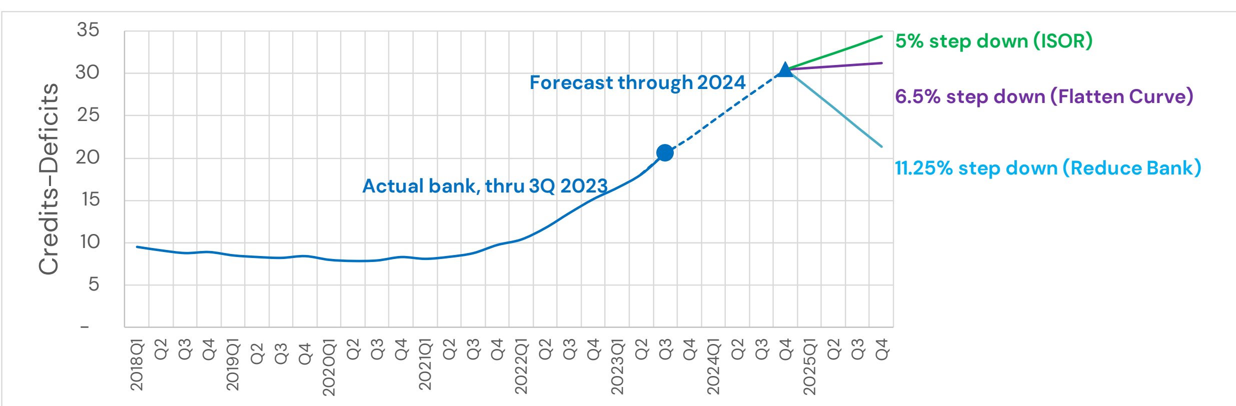
2. What CI step down is necessary to flatten the credit bank in 2025?
3. What CI step down is necessary to decrease the bank of credits to two quarters' worth of deficits?

With respect to the former, ICF modeling sought to identify the level of CI reduction that would be needed for the step down to *at least* flatten the curve of growing credits. ICF analysis shows that a CI of 20.25% in 2025 is likely needed to ensure that the credit bank does not continue to build.

With respect to the latter, ICF sought to identify the level of CI reduction that would be needed for the step down to reduce the bank of credits to about two quarters' worth of deficits in 2025. ICF analysis shows that a CI of 25% in 2025 is likely needed to ensure that the credit bank reverses and that the bank is drawn down to a level that is in line with a credit bank of only two quarters' worth of deficits. This level of stringency, while seemingly high, is likely what is needed to achieve CARB's stated intent of correcting for the "near-term over-performance" of the program.

The figure below illustrates the three aspects of the 2025 CI step down evaluated by ICF: the blue line shows the current credit bank inventory (20 million credits), the dotted blue line shows ICF forecasted credit bank by the end of 2024 (30 million credits), the green line shows the likely growth of the credit bank using CARB's proposed step down in 2025 (5% step down to 18.75% CI reduction), the purple line shows what ICF analysis indicates is needed to flatten the credit bank (6.5% step down to 20.25% CI reduction), and the light blue line shows that a CI step down of 11.25% to a 25% CI step down is needed to restore the program to an appropriate credit bank balance.

Figure 1. ICF analysis of the CI step down in 2025



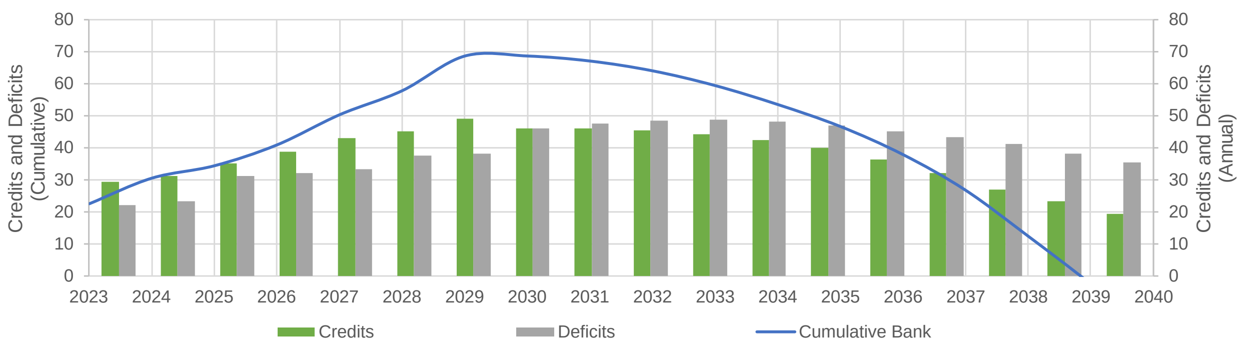
ICF recommends a step down of 10.5%-11.5% to reduce the cumulative bank of credits to the range of 2-3 quarters' worth of deficits by the end of 2025.

Automatic Acceleration Mechanism

The AAM is designed to accelerate the stringency of the LCFS program when certain criteria are met. CARB defined two criteria in the Staff Report: 1) when the credit bank is more than 3 times greater than the quarterly deficits generated in a given year and 2) when credit generation exceeds deficit generation. The Staff Report also indicates that the first year during which the CI reduction schedule can be impacted is in 2028, based on data from 2027.

Building on commentary regarding the CI step down in 2025, ICF's analysis indicates that if CARB keeps the 5% CI step down in 2025, that the credit bank will build in 2025, 2026, and 2027. In fact, by the end of 2027, ICF analysis suggests that the credit bank will reach 45-50 million credits. This will trigger the AAM in 2028 (based on 2027 data). ICF analysis suggests that the bank will be triggered again in 2030 (based on data for 2029)-getting the program to a 39% CI standard by 2030. The figure below shows the credit and deficit generation annually (green and grey bars, respectively) and the associated credit bank (blue line) using CARB's CI trajectory, including the CI step down in 2025, and the AAM as proposed.

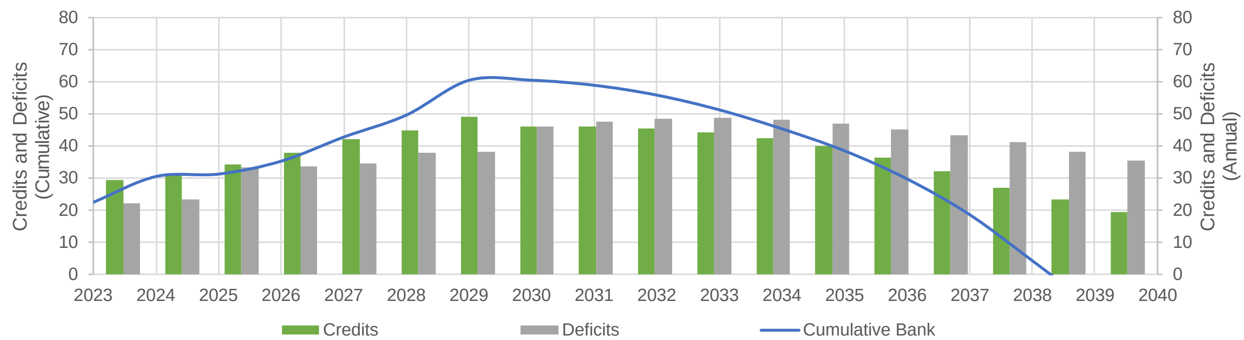
Figure 2. Credit-Deficit Balance in the ICF ISOR Case



In the long-term future, the AAM modifies the trajectory of the program post-2030. However, the short-term impact is muted-the CI step down does not achieve the objective of reversing the credit bank, and delaying the AAM until 2028 slows credit growth, but does not reverse the credit bank build until 2031. The shape of the curve in the figure above is appropriate, but the magnitude of the credit bank is too high to drive higher credit prices.

335.2 cont. Implementing a more stringent CI step down in 2025 will reduce credit generation but will still likely lead to credit generation post-2025, and the AAM will be inadequate to reverse the credit bank build until 2030.

335.2 cont. Figure 3. Credit-Deficit Balance in the ICF ISOR Case, with 6.5% CI stepdown in 2025

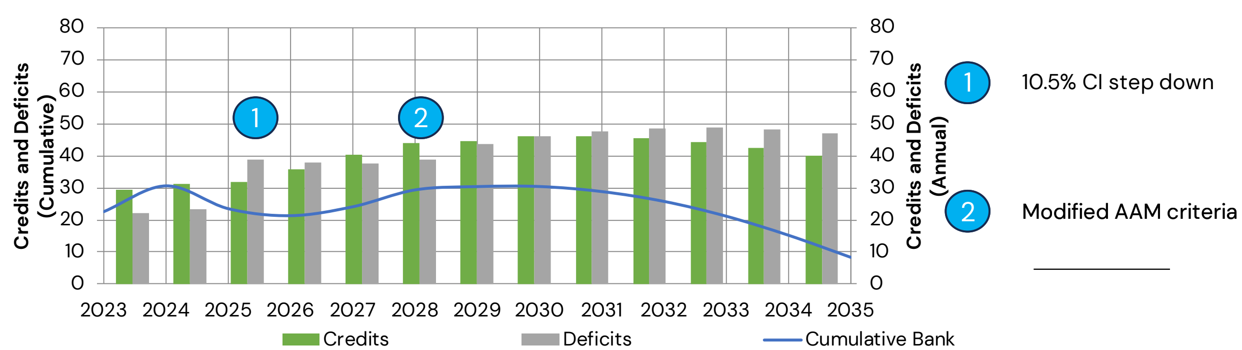


ICF analyzed the ISOR Case using the following assumptions:

- A CI stepdown of 10.5% in 2025 that would require a CI reduction of 24.25%. We adjusted the targets between 2026 and 2030 linearly while maintaining the 30% CI reduction in 2030 and post-2030 CI reduction schedule included in the Staff Report.
- An AAM that is implemented similarly as to what is used in the Staff Report, but adjusting the threshold to being triggered when the credit bank is more than 2.5 times greater than the quarterly deficits generated in a given year.

The figure below shows the results of the ISOR Case using the parameters described above.

Figure 4. ICF ISOR Case with larger CI step down and modified AAM



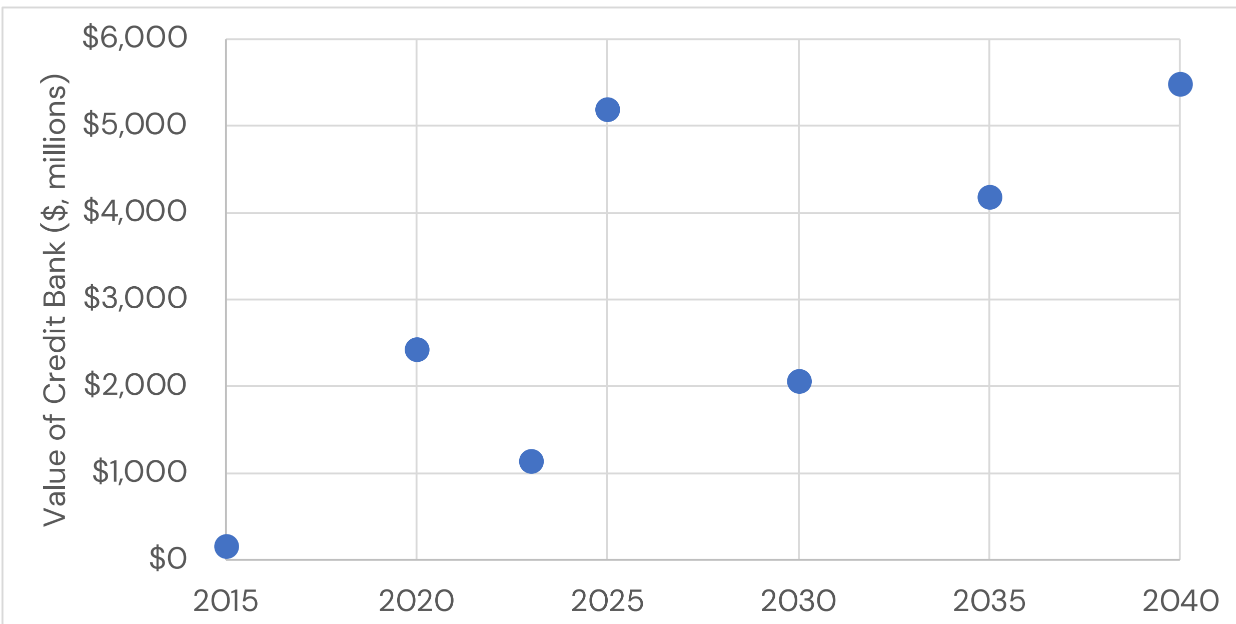
The figure above has a shape and curve that ICF thinks is more in line with a successful LCFS program i.e., one that maintains a tighter credit-deficit balance and is flexible enough to respond to market conditions in the near-term future (pre-2030), while enabling California to achieve its long-term GHG reduction targets. A similar trajectory can be achieved with a shallower step down in 2025, but with an AAM that comes into place in 2026 and an even lower threshold of the first criteria that would trigger the AAM (e.g., lowering the value from 2.5 to 2.0).

ICF recommends that the AAM be considered for implementation as soon as 2026, rather than waiting until 2028, regardless of the 2025 CI step down.

ICF Commentary on AAM Trigger Criteria 1

335.4 ICF disagrees with the underlying presumption that the AAM should be triggered at the proposed threshold i.e., when there are three quarters' worth of deficits in the bank. Based on information presented at the May 23, 2023 modeling discussion, the AAM design is looking to program data from prior to 2021 as an indicator of an "ideal" bank of credits. ICF views this as a critical mistake with respect to how the market is likely to unfold in the future. From a market perspective, if we consider the credit bank as a measure of the risk that regulated parties (i.e., refiners) bear in order to do business in California, then the credit bank should be measured in dollars, not credits/deficits. The figure below shows the estimated value of the credit bank in five-year increments from 2015 to 2040. The data for 2015 and 2020 are based on data reported by CARB for both deficits and credits; whereas the data for 2025 to 2040 is based on the deficit generation in ICF's analysis of the proposed CI reduction trajectory and the credit price reported by CARB in the Staff Report. All values are reported in real dollars using 2021 as the basis year ($2021).

Figure 5. Estimated value of LCFS credit bank as a proxy for refiner risk tolerance



A target credit bank of three quarters worth of deficits in 2015 would have been valued at $140 million; by 2020, the value of the bank grew to $2.4 billion. In 2023, ICF estimates that a credit bank with three quarters worth of deficits is valued at $1.1 billion. Based on CARB's forecasted credit price, the value of a credit bank of three quarters worth of deficits in 2025 would rise to $5.2 billion before collapsing back to $2.1 billion in 2030. The higher pricing reported by CARB in 2035 and 2040 yields an "ideal bank" valued at $4.2 billion and $5.5 billion. When viewed from the lens of dollars tied to risk, rather than risk tied to a specific credit bank, the target bank of three quarters worth of deficits does not make

335.4 cont. sense. By 2035, for instance, petroleum products will have decreased substantially due to efficiency gains, increased liquid biofuel blending, and transportation electrification. ICF estimates that gasoline consumption may decrease by up to 50% by 2035, while ULSD consumption could decrease by as much as 85% by 2035 (compared to 2022 consumption). Why would an industry that has lost so much market share increase the value of its risk burden by nearly a factor of four over that same time frame?

In line with ICF's hypothesis that the AAM should consider the "ideal credit bank" in terms of managed risk (as measured in dollars' worth of exposure), we also believe that the proposed AAM fails to recognize the evolution of the market post-2020. Consider that in 2018:

- The average CI of ethanol was nearly 70 g/MJ
- Biodiesel volumes were averaging around 5% blend rates in California
- There were 2-3 renewable diesel producers delivering product to California
- The first fuel pathway for RNG from animal manure was submitted and approved by CARB
- EVs represented just 7% of new light-duty vehicle sales
- Off-road electrification applications generated about 500,000 credits

Most of the refiners in the LFCS program had limited visibility with respect to LCFS credit generation and were forced into a position of purchasing LCFS credits from a limited market. As a result, refiners generally opted to build substantial credit banks as part of their compliance strategy. This strategy enabled other market participants to benefit via an increased credit price. However, in the interim years, refiners have made substantial investments that give them a clearer line of sight in their credit generation. The table below highlights the key investments that six refiners have made since 2018; these refiners represent what ICF estimates to be more than 90% of the obligation in the LCFS program. This is not meant to be an exhaustive list, rather it illustrates key investments that will impact LCFS credit generation moving forward.

335.4 cont

Obligated Party	Key Investment since 2018
Marathon	• Retrofitted Dickinson facility for RD production • Martinez Renewables joint venture with Neste in California • Acquired RNG platform (LF Bioenergy)
Chevron	• Acquired REG, largest biodiesel producer in US • Converting diesel hydrotreating unit for renewable diesel / renewable jet fuel production at El Segundo • Investments in RNG platforms including California Bioenergy, Brightmark Energy • Acquired natural gas fueling assets via deal with Mercuria
PBF[5]	• St. Bernard Renewables project in Louisiana producing RD
Valero	• Expanded Diamond Green Diesel (a joint venture with Darling Ingredients) at Norco, Louisiana • Commissioned Port Arthur project with expected completion in 2025
Phillips 66	• On the verge of completing Rodeo Renewed project at San Francisco Bay Area refining complex, converting to renewable fuels entirely
BP	• Expanded co-processing capabilities at Cherry Point • Purchased RNG platform via Archaea acquisition

It is clear from this table that there is a much clearer line of sight to LCFS credit generation for regulated parties today in 2024 than there was in 2018. The view of the credit-deficit balance from pre-2021 will not be a good indicator of how the market will evolve moving in 2025 and beyond.

ICF recommends that the first criteria for the AAM be modified such that the mechanism is enacted when the credit bank is more than 2.5 times greater than the quarterly deficits generated in a given year.

LCFS Credit Pricing

ICF views the LCFS credit price as part of a broader set of environmental commodities available to low carbon fuel producers. ICF models environmental commodities using an approach that assumes the marginal cost of compliance is determined by the value of subsidy needed to offset the difference between low carbon fuel production costs and the conventional fuels that they replace i.e., gasoline and diesel. The complicating factor related to determining marginal compliance costs is the multiple subsidies available and the

[5] Shell sold its Martinez Refinery and related logistics assets to PBF in 2021.

associated "loading order" of those subsidies with respect to various fuels. ICF's modeling assumes the value for low carbon fuel producers is generated via multiple streams, including federal tax credits or incentives, federal policies like the Renewable Fuel Standard, and then state level programs like California's LCFS program.

- ***Federal tax incentives***: ICF considers two types of tax incentives, the Blenders Tax Credit and the Clean Fuel Production Credit (CFPC) from the Inflation Reduction Act (IRA).
    - The BTC is available to blenders that blend biodiesel or renewable diesel into the transportation fuel supply and is valued at $1.00 per gallon of eligible fuel blended. The current version of the BTC will expire at the end of 2024. The BTC is not adjusted for inflation.
    - The CFPC is a carbon intensity-based production tax credit that replaces and expands upon the BTC. The CPFC is codified in the Inflation Reduction Act and is often referred to as the Sec 45z credit. It is valued at up to $1.00 per gallon of eligible fuel; however, in order to qualify, an eligible fuel must be produced in the United States and meet a maximum carbon intensity threshold of 50 kgCO2e/mmBtu. The CFPC is calculated as follows:[6]

$$CFPC = \$1.00\ x\ \left(1 - \frac{CI_{fuel}}{50}\right), (\max \$1.00)$$ [7]

- ***Renewable Fuel Standard***: Most transportation fuels generate value via the Renewable Fuel Standard and generate RINs (or Renewable Identification Numbers), the currency and compliance tracking mechanism for the federal program. There are several RIN buckets in the program: D6 RINs, D5 RINs, D4 RINs, and D3 RINs. The RIN designation is tied to two key factors: a) the feedstock used to produce the renewable fuel and b) the GHG emission reductions attributable to the fuel. <u>It is important to note that while there is a GHG emission reduction requirement or threshold within each RIN bucket, fuels are not differentiated by their carbon intensity score the way that they are in the LCFS program.</u>
- ***California Cap at the Rack (CAR)***: Renewable diesel producers to date have received some share of the value of displacing a gallon of ULSD in the Cap-and-

[6] Note that the GREET model referenced in the IRA is the version of the model developed by Argonne National Laboratory (ANL) and not the CA-GREET model used by CARB to regulate the LCFS program. The CI for renewable diesel in the CA-GREET model is *higher* than the CI for renewable diesel in the GREET model for several reasons, but most notably because CARB's model assumes a higher CI adder for land use change (LUC), specifically for soybeans.

[7] ICF assumes that the CI of the marginal gallon of eligible fuel will have a CI score of 35 kg/mmBtu, yielding an incentive of $0.30 per gallon of 30 cpg. The CFPC is adjusted for inflation from 2022 pursuant to the IRA.

Trade program, which is quantified as CAR. Generally speaking, renewable diesel is the only low carbon fuel that has benefitted significantly from California Carbon Allowance (CCA) pricing, which has helped to maintain profitability of renewable diesel production in light of falling LCFS credit prices.

- ***California LCFS Credit Price***: The LCFS credit price serves as a subsidy for low carbon fuel production, with the understanding that many low carbon fuels cost more to produce than their conventional counterparts. The value of the LCFS credit price can be represented by the cost per ton to deliver the last or marginal unit of low carbon fuel to California in any given year, after accounting for revenue from other subsidies.

ICF modeling calculates the LCFS credit price as the difference between the low carbon fuel cost of production (inclusive of any costs to deliver the fuel to California) minus any other revenue streams that the low carbon fuel would otherwise receive. For example, in the case of renewable diesel, the production costs, $C_{production}$, would include the feedstock costs associated with producing the fuel, the fixed and variable production costs, and any logistical costs associated with bringing the fuel to California.

$$C_{production} = C_{feedstock} + C_{fixed} + C_{variable} + C_{logistics}$$

The revenue streams, *R*, for renewable diesel exclusive of the LCFS credit price, including the commodity value of the fuel, the value of the D4 RIN, any tax credits (e.g., the Blenders Tax Credit, BTC), and some share (α) of the value of displacing a gallon of ULSD in the Cap-and-Trade program, which is quantifies as Cap at the Rack (CAR).

$$R = Commodity + Fed \quad al\ Tax\ In \quad ives + \quad RIN + \alpha \quad CAR$$

In this example, the LCFS credit price needed to bring that gallon of renewable diesel (*LCFS Credit Price*$_{RD}$) to California would be calculated as the difference between the production costs and the revenue streams:

$$LCFS \qquad Pri\ \ e_{RD}\left(\frac{\$}{ton}\right) = \frac{C_{production} - R}{}$$

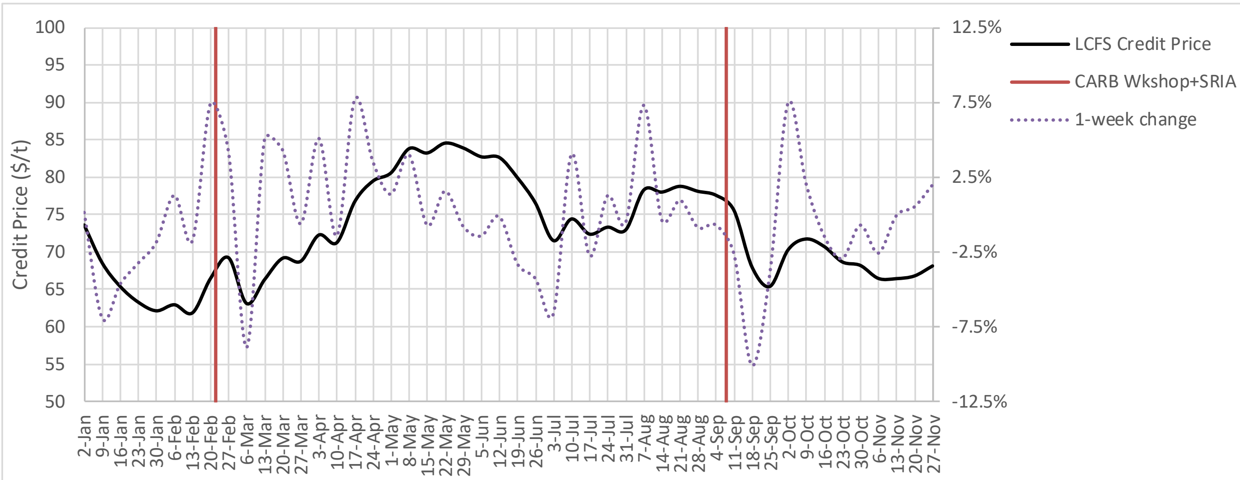
The LCFS credit price in any given year (t) can be approximated as the maximum LCFS credit price amongst low carbon fuels (fuels) delivered to California:

$$LCFS \qquad Pri\ \ e_{t}\left(\frac{\$}{ton}\right) \approx Max_t^{fuels}\{LCFS \qquad Pri\ \ e_{fuels}\}$$

LCFS Credit Pricing in response to CARB Proposals

Prior to the Staff Report, CARB staff had two significant opportunities to communicate to the market their intentions with respect to increasing the stringency of the LCFS program. The figure below shows the weekly LCFS credit price for Type 1 transfers reported by CARB from January to late November 2023 (black line), with a range of $60 to $85 per ton over that time frame. The dotted purple line shows the change from week to week on a percentage basis. The two largest week-over-week decreases in LCFS credit pricing for 2023 occurred after the February 22, 2023 LCFS workshop and when the Staff Regulatory Impact Assessment (SRIA) for the LCFS was made publicly available. In both cases, CARB signaled its intention to advance a proposal with a 30% CI standard in 2030.

Figure 6. ICF analysis of LCFS credit prices in response to CARB announcements



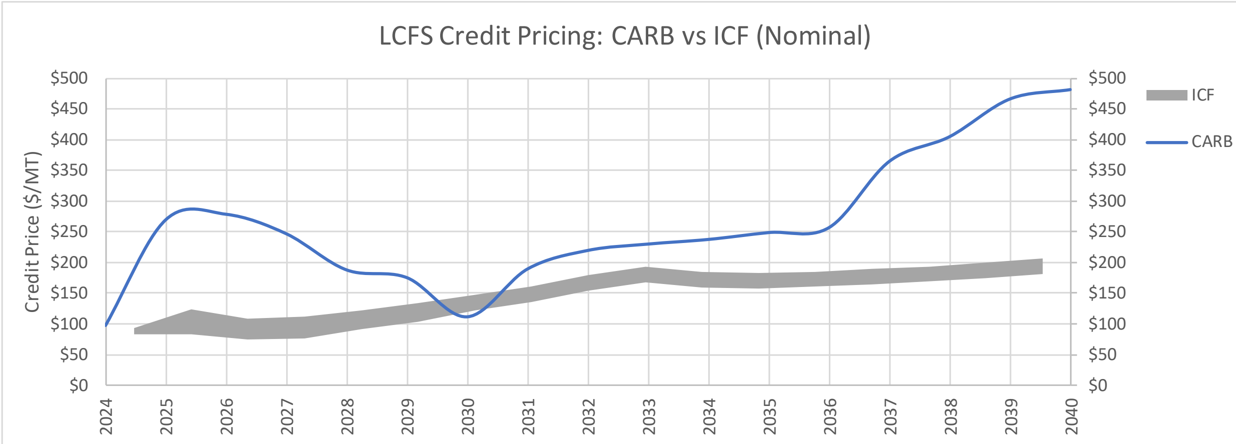
While ICF cautions against overreacting to spot price movements in any market, these movements can be a helpful indicator of market sentiment. In this case, the market was likely hoping for a more stringent standard. This conclusion is bolstered more forcefully in the market reaction after the Staff Report was issued, with credit prices in early 2024 decreasing to below $60/t for the first time in more than five years.

LCFS Credit Pricing: CARB vs ICF

335.3 cont. CARB's forecasted LCFS credit pricing has a variety of caveats associated with it; however, CARB staff use the LCFS credit pricing as one of the primary reasons for dismissing a higher CI reduction target in 2030 because of potential consumer impacts associated with pass-through compliance costs. However, the CARB forecasting is flawed and effectively implies that the LCFS will bear the entire cost of subsidizing low carbon fuel production. This is misaligned with market factors given the significant supplemental value of the Clean Fuel Production Credit via the IRA, robust RIN pricing, moderate commodity pricing (e.g., for gasoline and diesel), and increasing CCA prices.

The figure below shows a range of ICF forecasted LCFS credit prices in grey compared to the CARB LCFS credit price forecast in blue line. The CARB LCFS credit price forecast has been adjusted to nominal dollars, as ICF has found this is how stakeholders tend to view the market (rather than adjusting pricing to some real-dollar basis).

335.3 cont. Figure 7. Comparison of CARB and ICF LCFS credit pricing forecasts (nominal dollars)



ICF makes three observations associated with the comparison between CARB's forecast and our forecast:

4. In the near-term future (by 2025), CARB is forecasting a four-fold increase in LCFS credit pricing. This credit price spike coincides with the introduction of the CFPC and other IRA incentives flowing to the market. [8]
5. In a post 2030 environment, though the two curves are showing similar patterns of increasing credit prices, CARB's forecast is still $60-65/ton higher than ICF.
6. Post-2035, CARB's forecasts are suggesting that a LCFS credit price of $250 to nearly $500/ton is needed in order to achieve program compliance. There is no reason that the credit price should ever need to be that high in order to induce the investments necessary to achieve compliance based on ICF modeling.

[8] The CFPC will apply to a broader set of fuels than the BTC; however, many fuels that were receiving the $1.00 per gallon benefit of the BTC will be reduced to what ICF estimates is more like $0.30 per gallon. Historically, after the removal of the BTC (via expiration of the incentive based on some timeline defined in statute) the D4 RIN price has increased to accommodate the lost value. ICF analysis suggests that the RIN price has increased and helped to recover as much as 75% of the lost value. ICF assumes a similar dynamic will emerge for RIN pricing as the BTC transitions to the CFPC. The transition from the BTC to the CFPC will also likely reduce imports into the United States. Despite these potential changes, ICF analysis of available supply of low carbon fuels to California will not require such a dramatic increase in LCFS credit pricing, as highlighted in the text.

Appendix

Background on ICF Modeling

ICF models the CI reductions that could be achieved using the structure of the LCFS program. The modeling is driven by the demand for transportation fuel in California, which is a function of many variables including but not limited to economic growth, vehicle miles traveled (VMT), vehicle fleet turnover, and the expected compliance with complementary policies that impact transportation fuel demand. ICF's modeling is initiated using documentation associated with the EMissions FACtor model (EMFAC)[9] that is publicly available for download. The EMFAC model is "developed and used by CARB to assess emissions from on-road vehicles including cars, trucks, and buses in California." The EMFAC model enables ICF to characterize top-level transportation fuel demand in California given baseline consideration of the aforementioned key factors, like VMT and fleet turnover. Although EMFAC2021 incorporates expected compliance with several regulations that decrease fossil fuel demand, like the Advanced Clean Truck (ACT) Rule and the Innovative Clean Transit (ICT) Rule, it does not include expected compliance with Advanced Clean Cars II (ACC2) or Advanced Clean Fleet, which were adopted by the Board in 2022 and 2023, respectively. ICF has modified EMFAC2021 to ensure compliance with ACC2 and ACF. ICF then pairs the fleet turnover and fuel demand functions of EMFAC with supply-cost curves for low carbon fuels, including ethanol, biodiesel, renewable diesel, and renewable natural gas (RNG).

ICF previously modeled multiple scenarios for this project and framed each as *Accelerating Decarbonization* in the transportation sector using a diverse array of low carbon fuel strategies that are viable in the timeframe contemplated. Within this framework, ICF presented a Central Case and High Case(s).

- *Accelerating Decarbonization, Central Case*: ICF's primary focus is this case, whereby we limited our consideration of low carbon fuel strategies that require expanded deployment, reasonable technological advancement, and limited, if any, substantive policy changes.
- *Accelerating Decarbonization, High Case(s)*: In these cases, ICF considered additional strategies and/or policy changes that would lead to higher deployment of low carbon fuels and/or greater CI reductions over the course of the analysis. These included but were not limited to reductions in indirect land use change (ILUC) accounting, resumption of FFV manufacturing by OEMs, and relaxation of

[9] ICF is using the most recent version of EMFAC, EMFAC2021 (v1.0.2) as a starting point for our modeling. The EMFAC model is available for download online.

deliverability requirements for electricity used as a transportation fuel and as a processing fuel. Together, these represent a more expansive market and aggressive outlook for decarbonizing the transportation sector.

Stakeholder Outreach

ICF retains exclusive decision-making with respect to the parameters that are included in (or excluded from) the modeling in this project. However, as part of the development of our modeling, we sought (and will continue to seek) input and feedback from stakeholders that are uniquely positioned to characterize trends, constraints, and opportunities across various low carbon fuels. ICF conducted interviews with stakeholders from various low carbon fuel providers. Through these conversations, ICF introduced the broader project objectives and ICF's modeling approach to help stakeholders understand the key drivers for our analysis. ICF then led a discussion guided by the following questions:

- ***Deployment***. What are expected changes in the industry that will increase or decrease the deployment of a particular fuel or fuel/vehicle combination? These generally include supply and demand considerations and should account for opportunities and barriers to the extent feasible. What is the timeframe associated with any changes?
- ***Carbon intensity.*** What is the current and projected carbon intensity of the fuel under consideration? Are there any California-specific policy or regulatory changes that can be accommodated to help achieve these reductions? What is the rate at which these carbon intensity changes are likely to occur?
- ***Demand from Other Markets***. Where are the developments likely to occur? Are there any specific advantages or disadvantages associated with delivering these solutions to California that ICF needs to consider? To what extent will other (existing or potential) low carbon fuel markets be advantaged or disadvantaged as it relates to these solutions as a function of their corresponding geography?

Lastly, it is important to note that ICF developed the modeling framework used in this study based on publicly available tools and data—we have purposefully excluded any proprietary data or considerations as part of this analysis.

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About ICF

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Comment 345 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Robert
Last Name	Coviello
Email Address	robert.coviello@bunge.com
Affiliation	Bunge
Subject	Bunge Comments Regarding Proposed LCFS Amendments
Comment	Please find Bunge's comments attached.
Attachment	www.arb.ca.gov/lists/com-attach/7024-lcfs2024-UjBTIFE+V2MAY1QL.pdf
Original File Name	Bunge Comments Regarding Proposed LCFS Amendments (02.20.2024).pdf
Date and Time Comment Was Submitted	2024-02-20 18:08:51

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

1391 Timberlake Manor Parkway
Chesterfield, MO 63107
314.292.2000 | bunge.com

February 20, 2024

Hon. Liane M. Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: Proposed Low Carbon Fuel Standard Amendments

Dear Chair Randolph:

Bunge is the world's largest oilseed processor by crush volume capacity. Bunge buys and processes agricultural commodities, turning them into products used in the food industry, animal feed, and the renewable diesel industry. Bunge is also an industry leader in sustainability, embracing climate-focused decision making and setting ambitious goals. For instance, we are well on our way to meeting our commitment to eliminate deforestation and native vegetation conversion from our supply chain in 2025 and are helping to accelerate industry-wide progress through sector initiatives that seek to create common alignment and scalability on deforestation goals. Bunge's robust traceability and monitoring systems give us unprecedented insight into our supply chain. We achieved 82 percent traceability for soy in Brazil's high-risk areas in 2022, helping us achieve our 2025 commitment. Further, we have already achieved 100 percent traceability in our direct supply of soy in priority areas in South America. We are leveraging our experience working with farmers and incentivizing sustainable practices through the use of technology and data to scale our efforts across the wider agribusiness sector in many geographies where deforestation is a higher risk.

In general, Bunge supports the Low Carbon Fuel Standard ("LCFS") and the California Air Resources Board's ("CARB's") proposed 2024 amendments. Bunge recognizes the challenges that climate change poses to the world, as well as to Bunge's business and agriculture overall. The LCFS has addressed climate change by driving demand for lower-carbon fuels. Bunge applauds the success of CARB's LCFS implementation, which has increased volumes of low-carbon fuels such that California's overall petroleum fuel use has fallen by 1.3 billion gallons since 2019. Meanwhile, the carbon intensity ("CI") of the state's transportation fuels has declined 12.63 percent from 2010 levels.

Bunge appreciates the opportunity to comment on the amendments that CARB is proposing to update the LCFS in 2024. As a leader in renewable fuels and sustainable practices, Bunge broadly supports the proposed amendments. However, Bunge is concerned about aspects of CARB's proposed sustainability certification requirements. Bunge encourages CARB to clarify and/or modify the amendments to address these issues before finalizing the rule, as discussed further below.

Bunge Supports the LCFS, and CARB's Decision to Reject a Cap on Crop-Based Fuels

336.1 Bunge commends CARB for proposing amendments that generally maintain and strengthen the LCFS as a market-based system that drives emissions reductions by using science to identify the CI of various fuels. Specifically, Bunge supports CARB's decision to reject an arbitrary cap on crop-based fuels. An arbitrary cap would have run counter to CARB's science-based approach, as we underscored in our March 15, 2023 letter in response to CARB's February 2023 public workshop. Still, we understand and appreciate CARB's desire to further address indirect land use change in the program. Indeed, impacts on land use change are driving Bunge's existing efforts to guarantee its supply chains are deforestation free. We appreciate that CARB's proposal seeks to address sustainability concerns through efforts to demonstrate that crops used in the program are deforestation-free, rather than by adopting an arbitrary cap on crop-based fuels.

Bunge Encourages CARB to Adjust Its Sustainability Certification Rules for Feasibility

In general, Bunge echoes the comments of the National Oilseed Processors Association ("NOPA"), which represents Bunge and others in the industry. Like NOPA, Bunge is concerned about the details of CARB's proposed requirement that crop- and forestry-based feedstocks "maintain continuous third-party sustainability certification" to demonstrate they were not "sourced on land that was forested after January 1, 2008." *See* Proposed Regulation Order at § 95488.9(g).

In particular, Bunge has reservations about the feasibility of implementing certifications requiring high traceability with U.S. and Canada producers, for whom such certifications remain relatively foreign because deforestation risk is remote for these producers. U.S. Department of Agriculture data illustrates the low domestic deforestation risk: U.S. producers actually planted fewer acres of land as corn, soybeans, and wheat in 2022 than in 1980, as highlighted in NOPA's comment letter. If deforestation were a reality or risk, one would expect more acres of land planted in recent years, which would indicate that forested land had been cleared for crops. Instead, U.S. farmers today produce higher crop volumes on the same amount of land—or slightly less—than forty years ago. Programs like the federal Renewable Fuel Standard do not require third-party sustainability certification, recognizing the low deforestation risk in the U.S.
336.2 and Canada. Requiring low-risk U.S. and Canada feedstocks to undergo certifications that are

336.2(cont'd) suited to and designed for high-risk regions like South America could disadvantage some of the lowest-risk growers without attendant sustainability benefits.

We appreciate the value and utility of sustainability certifications. In fact, in our March 2023 letter, we suggested that CARB study certification options rather than pursue an arbitrary cap on crop-based fuels, reinforcing Bunge's commitment to sustainability. Still, Bunge believes such certifications are most useful and relevant in high deforestation risk contexts. For example, Bunge has found that certifications are valuable in parts of South America, such as Brazil, where the threat of deforestation has been an issue the industry has had to address. In these regions, Bunge has substantial experience tracing products from the point of origin to certify them as deforestation-free and thus compliant with sustainability requirements like the European Union's Renewable Energy Directive ("RED"). Specifically, Bunge has certified products in high-risk deforestation regions like South America using systems from the Round Table on Responsible Soy ("RTRS"), Biomass Biofuel Sustainability Voluntary Scheme ("2BSvs"), and International Sustainability and Carbon Certification ("ISCC"). Certifications that trace soy to the
336.2 (cont'd) farm level have clear value in the Gran Chaco in Argentina and Paraguay and the Cerrado in Brazil, where there is significant agricultural expansion pressure. But in the U.S. and Canada, tracing soy to the farm level has little to no sustainability benefit because there is very little expansion pressure caused by agriculture, meaning deforestation risk is low.

With this context in mind, Bunge is concerned that these full traceability systems are less workable in the North American context, particularly on the implementation timeline that CARB is proposing. CARB's proposal requires crop-based feedstocks be certified at the point of origin by January 1, 2028. For a certification system to be approved, it must have been recognized by a government for at least 24 months. In other words, market participants have less than four years to implement certifications, and any certification scheme used must be recognized by a government now or in the very near future due to the 24-month criterion. Based on the
336.3 European experience implementing RED, it is difficult to imagine development and implementation of a certification system that complies with CARB's proposed requirements within the proposed time frame. We are concerned that it will not be possible to develop new schemes that meet CARB's listed criteria on such a tight timeline and then implement those schemes. Factoring in the required two years of government recognition makes this even less feasible.

With these difficulties in mind, Bunge encourages CARB to consider workable solutions that guarantee LCFS feedstocks are deforestation free. For instance, CARB might consider altering
336.4 the timeline and governmental-recognition requirement to give industry, the agency, and growers time to advance certification systems that are feasible in the North American context. The industry needs time to develop a risk-based approach that does not over burden the supply

336.4(cont'd) chain with full traceability to the farm when the risk of deforestation in some areas of the world, such as the United States and Canada, is much lower than in others.

Bunge commends CARB's commitment to addressing climate change through its proposed LCFS amendments. Bunge also appreciates CARB's commitment to maintaining the science-based integrity of the LCFS, as demonstrated by the agency's rejection of an arbitrary cap on crop-based fuels. We look forward to working with CARB to make sure any sustainability certification requirements and timelines are feasible while also accomplishing the goal—which Bunge shares—of deforestation-free fuels.

Sincerely,

Robert Coviello
Chief Sustainability Officer and Government Affairs

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Comment 346 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Chelsea
Last Name	Lee
Email Address	chelsea@betterworldgroup.com
Affiliation	Coalition to Fix the LCFS

Subject	Fix the Low Carbon Fuel Standard - Prioritize Zero Emission Investments

Comment

On behalf of more than three dozen cross-sectoral organizations, w
respectfully submit the attached critical process and substantive
337.1 recommendations for CARB to fix the LCFS. We urge CARB to provide
non-voting, informational Board hearing, which will allow for more
time and the opportunity for meaningful public and Board
engagement. This need for more engagement opportunities is
underscored by the major deficiencies that remain in the current
proposal. We urge CARB to prioritize fixing the LCFS this year in
the following ways:

A. Reign in bogus credits that are depressing the credit price,
337.2 distorting markets, and harming people and ecosystems by:
 - Eliminating avoided methane crediting for fuel derived
from livestock manure.
337.3 - Capping the use of lipid biofuels.

B. Leverage the LCFS to achieve a zero-emissions future for all
337.4 Californians by:
 - Creating ZEV multipliers to boost electric school bus ar
electric public transit bus and rail system deployments.
 - Following through with the inclusion of intrastate jet
337.5 fuel as a deficit generator and starting to analyze the path towar
including California's share of the fuel used in interstate and
international flights.
 - Allowing credits for zero-emission transportation fuels
337.6 used for ocean-going vessels, and simplifying the process for
credits for shore power installations serving electrified harbor
crafts and for dispensing green hydrogen.

Attachment www.arb.ca.gov/lists/com-attach/7025-lcfs2024-UT0GY106ACAFXABq.pdf

Original File Name LCFS Joint Letter - 02.20.2024.pdf

Date and Time Comment Was Submitted 2024-02-20 17:22:56

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Chair Liane Randolph and
Members of the Board
California Air Resources Board
1101 I Street
Sacramento, CA 95814
cotb@arb.ca.gov

Re: Fix the Low Carbon Fuel Standard - Prioritize Zero Emission Investments

Dear Chair Randolph and Members of the Board,

On behalf of the undersigned advocates, we respectfully submit the following critical process and substantive recommendations that CARB must take to ensure the LCFS aligns with and truly advances our state's zero-emission transportation priorities.

The LCFS is an important financing component of private and public sector transportation electrification investments that California needs to achieve the successful implementation of its landmark clean transportation regulations, like the Advanced Clean Fleets, Advanced Clean Cars II, and Advanced Clean Trucks rules, which CARB itself developed and approved.

Despite its unique potential to support these life-saving regulations, the LCFS proposed by staff is misaligned with electrification goals, worsens environmental injustices, and will continue to founder from a glut of lipid-based biofuels and livestock biogas that will undercut the credit price. CARB must spend more time to ensure that the policy fulfills its unique role in helping secure California's zero-emission transportation future without further exacerbating harm to vulnerable communities. The April workshop must feature a robust discussion about these core program issues and not just focus on biofuels certification and auto adjustment mechanisms for credits. We also request a hybrid workshop format that allows in-person attendance and offers Spanish translation to ensure the discussion is accessible to impacted communities.

We request an informational Board hearing before a vote.

In previous regulation processes, the Board has followed the release of a staff proposal with a non-voting, informational Board hearing. Considering that the LCFS is a complex policy with long-lasting and far-reaching impacts, deviating from this standard practice will rob the public of the opportunity for meaningful engagement and the Board of the opportunity to give direction. In addition, many Board members are new to the role, and 10 of 16 Board members have not previously participated in a major update to the LCFS. The Board will reach a stronger decision if members are given an opportunity to ask questions and provide direction to staff in an informational meeting before they are asked to vote. A non-voting hearing will give also the Board and staff more time to meaningfully engage with the Environmental Justice Advisory Committee, whose eight recommendations rooted in environmental justice principles were not properly considered in staff's proposal. Providing one additional informational hearing for both the public and Board to analyze and engage is especially crucial given that staff's current proposal is vastly different from what they had presented in previous workshops and at the September 2023 Board meeting. Finally, holding a non-voting meeting this year will still meet the timing requirements of the Office of Administrative Law and enable 2025 implementation.

CARB has the opportunity to finally align the LCFS program with all of California's other zero-emission transportation laws, regulations, and investments. The Board needs more public engagement opportunities to ensure successful alignment, and getting it right in this rulemaking is critical.

Critical changes to the LCFS are needed in this rulemaking.

The need for more engagement opportunities is underscored by the major deficiencies in the staff proposal that the Board must fix in this rulemaking. On behalf of our diverse coalition of advocates, we urge CARB to prioritize fixing the LCFS this year in the following ways:

- Reign in bogus credits that are depressing the credit price, distorting markets, and harming people and ecosystems by:
  - Eliminating avoided methane crediting for fuel derived from livestock manure.
  - Capping the use of lipid biofuels.
- Leverage the LCFS to achieve a zero-emissions future for all Californians by:
  - Creating ZEV multipliers to boost electric school bus and electric public transit bus and rail system deployments.
  - Following through with the inclusion of intrastate jet fuel as a deficit generator and starting to analyze the path toward including California's share of the fuel used in interstate and international flights.
  - Allowing credits for zero-emission transportation fuels used for ocean-going vessels, and simplifying the process for credits for shore power installations serving electrified harbor crafts and for dispensing green hydrogen.

In conclusion, we request that CARB ensure the April workshop is comprehensive and accessible and that it hold an informational non-voting hearing to allow greater public and Board engagement before the vote. This will ensure appropriate Board direction, ultimately producing the best policy possible for achieving CARB's zero-emission transportation future with the greatest benefits for environmental justice communities.

Thank you for your consideration of our requests. We look forward to further collaborating with CARB on improving the LCFS and securing a zero-emission transportation future for all Californians.

Sincerely,

Daniel Chandler
Steering Committee Member
350 Humboldt

Faraz Rizvi
Policy & Campaign Manager
APEN

Michael Quiroz
Regulatory Analyst
Ava Community Energy

Marc Carrel
President and CEO
Breathe Southern California

Ruben Aronin
Director
California Business Alliance for a Clean Economy

Gracyna Mohabir
Clean Air and Energy Regulatory Advocate
California Environmental Voters

Gregory Stevens
Northern California Director
California Interfaith Power and Light

Scott Hochberg
Staff Attorney
Center for Biological Diversity

Marven Norman
Policy Coordinator
Center for Community Action and Environmental Justice

Dashel Murawski
Communications and Policy Coordinator
Center for Food Safety

Kyra Greene
Executive Director
Center on Policy Initiatives

Dan Ress
Senior Attorney
Center on Race, Poverty & the Environment

Kevin D. Hamilton, Senior Director
Government Affairs
Kimberly McCoy, Climate and Environmental Justice Associate
Central California Asthma Collaborative

Geoff Crook
Director, West State Policy
Ceres

Jason Anderson
President and CEO
Cleantech San Diego

Janet Cox
CEO
Climate Action California

Amelia Keyes
Attorney & Legal Fellow
Communities for a Better Environment

Jocelyn Del Real
Energy Policy Organizer
East Yard Communities for Environmental Justice

Kyle Heiskala
Policy Co-Director
Environmental Health Coalition

Daniel Gold, President
Tyler Galgas, Business Development Manager
Green Water and Power

Andrea Marpillero-Colomina
Sustainable Communities Program Director
GreenLatinos

Emily Gartenberg
Policy and Legislative Manager
Jobs to Move America

Phoebe Seaton
Co-Executive Director
Leadership Counsel for Justice and Accountability

Mary Leslie
President
Los Angeles Business Council

Eli Lipmen
Executive Director
Move LA

David Weiskopf
Senior Policy Advisor
NextGen Policy

Ilonka Zlatar
Climate Justice Organizer
Oil and Gas Action Network

Teresa Bui
Climate Policy Director
Pacific Environment

Andrea Vidaurre
Co-Founder & Policy Coordinator
Peoples Collective for Environmental Justice

Dieynabou Diallo
Climate Justice Manager
Powerswitch Action

Chelsea Hodgkins
Senior EV Policy Advocate
Public Citizen

Joel Ervice
Associate Director
Regional Asthma Management & Prevention

Pauline Seales
Organizer
Santa Cruz Climate Action Network

Jason John
Acting Director
Sierra Club California

Jack Eidt
Co-Founder
SoCal 350 Climate Action

Ellie Cohen
CEO
The Climate Center

Román Partida-López
Senior Legal Counsel for Transportation Equity
The Greenlining Institute

Kye Whitmore
Western States Campaign Coordinator
Union of Concerned Scientists

Sheheryar Kaoosji
Executive Director
Warehouse Worker Resource Center

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Comment 347 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Alexis
Last Name	Moch
Email Address	amoch@prologis.com
Affiliation	Prologis
Subject	Prologis Comments on Proposed Low Carbon Fuel Standard Amendments
Comment	Please see attached comment document. Thank you.
Attachment	www.arb.ca.gov/lists/com-attach/7026-lcfs2024-UCBUIF0zVmkKYwVi.pdf
Original File Name	Prologis LCFS Comments 02202024.pdf
Date and Time Comment Was Submitted	2024-02-20 18:07:43

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Board Comments Home

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95815

RE: Proposed Low Carbon Fuel Standard Amendments

Dear California Air Resources Board Members and Staff:

Thank you for the opportunity to provide comments and recommendations to the California Air Resources Board (CARB) on its proposed Low Carbon Fuel Standard (LCFS) Amendments. We recognize the significant undertaking of initiating revisions to a program with diverse stakeholders and critical importance to the State's ability to meet its zero-emissions transportation goals and regulatory deadlines, and commend CARB staff on their thoughtful and deliberative process since initiating this rulemaking.

Headquartered in San Francisco, CA, Prologis, is the global leader in logistics real estate, with a portfolio of over 1.2 billion square feet across four continents and approximately 2.8% of global GDP flowing through our properties each year. Prologis leases modern warehousing and distribution facilities to customers, which include manufacturers, retailers, transportation companies, third-party logistics providers, and other enterprises. Our large, flat rooftops have enabled us to build out commercial solar installations to serve onsite and offsite load with clean energy and battery storage, helping our customers reduce their emissions and placing us second in the U.S. for corporate on-site solar.

Prologis' Mobility business is helping transform the fleet and logistics industry and enabling our customers to transition to zero-emissions through industry-leading electric vehicle (EV) charging technology and solutions. With roughly 180 million square feet of industrial real estate across our California portfolio, the opportunity for us to help our customers with this transition is significant, and we are developing dedicated charging infrastructure at Prologis sites to support their medium- and heavy-duty (MHD) fleets across last mile, drayage, and other applications. In addition to providing charging solutions at our own properties, we offer electrification services at non-Prologis buildings and are developing multi-fleet charging hubs serving areas with dense concentrations of warehouses.

Prologis echoes the comments submitted by the Joint MHD EV Infrastructure Parties focused on the proposed amendments to the LCFS as they focus on MHD-FCI Shared charging sites or "hubs," of which we are a signatory. We believe that ensuring concurrent growth of both hub and MHD-FCI Private on-site "depot" models for fleet charging in California is integral to the successful electrification of the goods movement sector, and welcome the opportunity to submit Prologis' additional recommendations.

338.01

Remove the §95486.3(b)(3)(A)(2) 0.5% criterion to avoid unintended consequence of penalizing individual fleets for having common service providers and avoid creating conflicts with the regulatory framework of the South Coast Air Quality Management District's (SCAQMD) Indirect Source Rule (ISR).

Section §95486.3(b)(3)(A)(2) states "*If estimated potential MHD-FCI credits from an individual applicant's approved stations exceed 0.5 percent of deficits in the most recent quarter for which data is available, the Executive Officer will not approve additional MHD-FCI pathways or accept additional applications from* *that applicant until the applicant's estimated potential MHD-HRI credits are less than 0.5 percent of deficits."*

An individual applicant can be providing charging services at more than one private charging site for private fleets unrelated to each other, as is the case for Prologis and other industrial property owners that are investing in charging infrastructure on-site to serve their tenants' fleets. For example, Prologis leases warehousing and distribution space to a diverse customer base of 6,700 businesses across our global portfolio. In California alone, Prologis owns more than 900 buildings where, from one site to the other, different fleet operators lease real estate and assets, including charging infrastructure. It would not be fair to penalize one private fleet because of their association with other unrelated fleets through a common service provider. This creates an impediment for warehouse operators implementing mitigation measures in line with the ISR's requirements, such as EV fleet adoption and on-site charging infrastructure deployment, as well as fleet conversion towards Advanced Clean Fleets (ACF) deadlines.

338.02

Remove the Section §95486.3(b)(3)(A)(3) 1% criterion to avoid an unintended consequence of penalizing individual fleets for maximizing competitiveness and compliance efficiencies by charging their fleets at their natural domicile locations.

Section §95486.3(b)(3)(A)(3) states *"If estimated potential MHD-FCI credits from approved private MHD-FCI stations exceed 1 percent of deficits in the most recent quarter for which data is available, the Executive Officer will not approve additional private MHD-FCI pathways and will not accept additional applications for private MHD-FCI stations until private MHD-FCI stations' estimated potential MHD-HRI credits are less than 1 percent of deficits."*

Having different rules for Private vs. Shared will create operational and potentially SCAQMD ISR compliance inefficiencies for our customers who need to electrify at their "home" fleet domicile location.

Grant equitable access to book-and-claim accounting for EV charging microgrids.

Section §95488.8(i)(2)(A) states *"RNG injected into the common carrier pipeline in North America (and thus comingled with fossil natural gas) can be reported as dispensed as bio-CNG, bio-LNG, or bio-L-CNG, or as an input to hydrogen production, without regards to physical traceability."*

MHD charging projects are in a difficult position: they are extremely capacity and energy intensive, second only to data centers in light-industrial real estate,[1] making them time-consuming to connect to the grid, yet they require accelerated schedules to meet fleet electrification mandates and avoid stranding EV assets. Projects in this predicament look to on-site generation with energy storage as solution to meet fleet electrification objectives ahead of utility connections, with a coproduct of resiliency for critical fleet operations when the utility connection is eventually established in parallel. However, due to the exceptional energy intensity of industrial MHD charging projects on limited footprints, dispatchable power-dense on-site generation such as fuel cells or linear generators can sometimes be the only feasible technical solution remaining that can fit the available real estate and meet the energy demand.

This important EV charging pathway for biomethane (whether RNG or hydrogen in its final delivered form for on-site generation) is not only a more energy efficient pathway for biomethane, but also has

[1] According to Prologis benchmarks of typical alternative uses for comparable properties

significantly lower NOx emission profile than CNG vehicle application in sensitive disadvantaged communities around ports for example[2], yet only CNG vehicle fueling projects are incentivized with book-and-claim LCFS accounting from RNG energy sources.

338.03 As Prologis has recommended in prior comment letters, CARB should grant equitable access to biomethane book-and-claim LCFS accounting for MHD EV charging projects investing in on-site RNG/hydrogen generation that add resiliency and accelerate around transmission and distribution upgrade delays. We ask that CARB consider amending 95488.8(g)(1)(A)(2) to read as follows:

"Biomethane supplied using book-and-claim accounting pursuant to section 95488.8(i)(2) and is claimed as feedstock in pathways for bio-CNG, bio-LNG, bio-L-CNG, hydrogen via steam methane reformation, ***and electricity generation for co-located EV charging****;"*

Further, we suggest a revision of Section §95488.8(i)(2) to explicitly state:

"(2) Book-and-Claim Accounting for Pipeline-Injected Biomethane Used as a Transportation Fuel or to Produce Hydrogen ***or to generate Electricity****. Indirect accounting may be used for RNG used as a transportation fuel or to produce hydrogen* ***or to generate Electricity*** *for transportation purposes (including hydrogen that is used* ***either*** *in the production of a transportation fuel* ***or in the generation of electricity for transportation purposes****), provided the conditions set forth below are met:*

> *(A) RNG injected into the common carrier pipeline in North America (and thus comingled with fossil natural gas) can be reported as dispensed as bio-CNG, bio-LNG, or bio-L-CNG, or as an input to hydrogen production,* ***or as an energy source for electricity generation****, without regards to physical traceability. Entities may report natural gas as RNG within only a three-quarter time span. If a quantity of RNG (and all associated environmental attributes, including a beneficial CI) is pipeline-injected in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to natural gas sold in California as RNG no later than the end of the third calendar quarter. After that period is over, any unmatched RNG quantities expire for the purpose of LCFS reporting.*
>
> *(B) Biomethane reported under fuel pathways associated with projects that break ground after December 31, 2029, injected into the common carrier pipeline, and claimed indirectly under the LCFS program for use as bio-CNG, bio-LNG, or bio-L-CNG in CNG vehicles or as an input to hydrogen production* ***or as an energy source for electricity generation*** *for transportation purposes, must demonstrate compliance with the following requirements:*
>
> *1. Starting January 1, 2041 for bio-CNG, bio-LNG and bio-LCNG pathways, and January 1, 2046 for biomethane used as an input to hydrogen production* ***or electricity generation****, the entity reporting biomethane must demonstrate that the pipeline or pipelines along the delivery path physically flow from the initial injection point toward the fuel dispensing facility at least 50 percent of the time on an annual basis. Entities may report natural gas as RNG within only a three-quarter time span. If a quantity of RNG (and all associated environmental attributes, including a beneficial CI) is pipeline-injected in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to natural gas sold in California as RNG no later than the end of the third calendar*

[2] 0.059 gNOx/mile for a battery electric truck supported by linear generators vs. 0.317 gNOx/mile for a CNG truck per industry SME calculations provide to Prologis

quarter.

After that period is over, any unmatched RNG quantities expire for the purpose of LCFS reporting."

Prologis believes these recommendations will further enhance CARB's proposed improvements to the LCFS program to align with the State's transportation electrification goals and ensure they reflect the multiple use cases supporting logistics sector fleets, including both MHD-FCI Private and Shared charging, as well as address the realities of utility energization delays and resiliency risks for charging projects.

Thank you for considering our recommendations, and we welcome the opportunity to further discuss our views with the Board and staff. Please do not hesitate to contact me at amoch@prologis.com or 571-895-5763 for more information or to discuss our comments in further detail.

Respectfully submitted,

Alexis Moch
Director, Government Affairs
Prologis

Comment Log Display

Here is the comment you selected to display.

Comment 348 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Patty
Last Name	Lovera
Email Address	pattylovera20@gmail.com
Affiliation	Campaign for Family Farms and the Envt

Subject	End LCFS Support for Manure Digesters

Comment

February 20, 2024

Dear Governor Newsom and Members of the California Air Resources Board,

The Campaign for Family Farms and the Environment appreciates the opportunity to comment on the Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments. CFFE is a coalition of state and national organizations, including Dakota Rural Action Iowa Citizens for Community Improvement, Land Stewardship Project, Missouri Rural Crisis Center, Food & Water Watch and Institute for Agriculture and Trade Policy. Our organizations work together as CFFE to change policies that promote consolidation in animal agriculture at the expense of independent family farms, rural and urban economies, workers and an open, fair and competitive food system.

Our members have witnessed the shift in the structure of the livestock sector away from independent diversified farms to industrialized animal feeding operations in their communities. These factory farms concentrate animals and their waste, burdening surrounding communities with air and water pollution. A report by Food & Water Watch called Factory Farm Nation: 2020 Edition provides many examples of what happens to communities when livestock and their waste is concentrated in specific regions. Jus one example of FWW's findings illustrates the problem: hogs on factory farms in Duplin County, North Carolina produce the same weight in manure as residents of Boston. But unlike human sewage, hog and other livestock waste is not treated before being released into the environment. Around the country, neighbors of these facilities report odors and other health impacts, and losing the ability to spend time outdoors. Anaerobic digesters are touted by the industry as a win-win solution that creates usable energy whi reducing the environmental impact from the management of massive quantities of manure. But communities around the country know that this technology is far from a real solution. Instead, digesters allow factory farms to not only remain a burden on surrounding communities, but often to grow even larger.

Unfortunately, California's preference for manure-derived biogas the LCFS program is driving the expansion and entrenchment of factory farms and dirty biogas projects farm beyond California, including into our communities. The LCFS has become a lucrative financing tool for factory farm biogas. It is driving the construction of more factory farms and factory farm biogas projec in states far from California, causing severe harm to air, water, public health, rural economies, and overall quality of life.

The current flaws in the LCFS, such as "avoided methane crediting and inaccurate life cycle assessments, not only enable pollution but disproportionately harm low-income communities and communitie of color who live near factory farms and manure digesters. This i in stark contrast to the environmental justice commitment set by California.

CFFE believes that climate change is a serious challenge that requires a dramatic response. This crisis demands more than highl speculative market-based schemes that will allow polluters to kee polluting and let agribusiness pay farmers less for their crops a livestock. A serious plan to address agriculture and climate chan must address structural issues, not just attempt minor improvemen in environmental performance in a highly consolidated, industrialized factory farm system. Factory farms require huge quantities of feed, water, chemical inputs and energy and manage manure in a way that drives greenhouse gas emissions. California' climate programs must support a dramatic transition in how we rai animals for food that is centered on independent family farms and sustainably managed grazing systems.

Using California's climate programs, including the LCFS, to suppo expensive manure management projects on confinement operations fails to make this necessary structural change, and instead props up and expands the factory farm system. Prioritizing grazing over factory farm manure management would increase the sequestration o carbon in pastures, and also avoid the emissions from industrialized animal operations' feed production and liquid manu storage. Manure lagoons not only emit high amounts of methane and nitrous oxide, but they are also highly vulnerable to natural disasters such as hurricanes and floods. And confinement operatio decouple grazing animals from grasslands, requiring more syntheti fertilizers for feed production, which drives further emissions.

In addition to these overarching concerns about LCFS' support for manure digesters, we urge you to prioritize the following changes to the standard:

- Eliminate "avoided methane crediting"

- Address inaccuracies in the Life Cycle Assessment that ig associated up and downstream greenhouse gas emissions from factor farm gas production

- Remove the 10-year "grace period" for factory farm gas pr

- Stop double counting by allowing factory farm gas project for and claimed by other programs to sell LCFS credits as well.

For practices related to manure management, including anaerobic digesters, the LCFS calculation should evaluate not only the risk of increased ammonia emissions and water pollution from disposal digestate, but also the potential that the contract will lead to increase in the total number or density of livestock raised on the site. The potential for LCFS funding to lead to more animals bein raised on an operation with a digester, and the increase in enter emissions and carbon emissions from feed production related to th increase, should be incorporated into a new LCFS scoring system f manure-derived biogas.

The California Air Resources Board (CARB) has the opportunity to adopt new rules that would realign the LCFS with California's environmental justice commitments and stop rewarding factory farm around the country for their pollution. CARB's Environmental Justice Advisory Committee has presented a clear alternative that CARB should incorporate to align the LCFS with California's environmental justice commitments and end the state's support of environmental harm in communities across the country.

We appreciate the opportunity to comment on this critical subject

Sincerely,

Campaign for Family Farms and the Environment

Attachment	www.arb.ca.gov/lists/com-attach/7027-lcfs2024-VDdWNl06UmQGXwBj.pdf
Original File Name	CFFE comment LCFS 2023.pdf
Date and Time Comment Was Submitted	2024-02-20 18:10:13

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Dear Governor Newsom and Members of the California Air Resources Board,

The Campaign for Family Farms and the Environment appreciates the opportunity to comment on the Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments. CFFE is a coalition of state and national organizations, including Dakota Rural Action, Iowa Citizens for Community Improvement, Land Stewardship Project, Missouri Rural Crisis Center, Food & Water Watch and Institute for Agriculture and Trade Policy. Our organizations work together as CFFE to change policies that promote consolidation in animal agriculture at the expense of independent family farms, rural and urban economies, workers and an open, fair and competitive food system.

339.1

Our members have witnessed the shift in the structure of the livestock sector away from independent diversified farms to industrialized animal feeding operations in their communities. These factory farms concentrate animals and their waste, burdening surrounding communities with air and water pollution. A report by Food & Water Watch called *Factory Farm Nation: 2020 Edition* provides many examples of what happens to communities when livestock and their waste is concentrated in specific regions. Just one example of FWW's findings illustrates the problem: hogs on factory farms in Duplin County, North Carolina produce the same weight in manure as residents of Boston. But unlike human sewage, hog and other livestock waste is not treated before being released into the environment. Around the country, neighbors of these facilities report odors and other health impacts, and losing the ability to spend time outdoors. Anaerobic digesters are touted by the industry as a win-win solution that creates usable energy while reducing the environmental impact from the management of massive quantities of manure. But communities around the country know that this technology is far from a real solution. Instead, digesters allow factory farms to not only remain a burden on surrounding communities, but often to grow even larger.

Unfortunately, California's preference for manure-derived biogas in the LCFS program is driving the expansion and entrenchment of factory farms and dirty biogas projects farm beyond California, including into our communities. The LCFS has become a lucrative financing tool for factory farm biogas. It is driving the construction of more factory farms and factory farm biogas projects in states far from California, causing severe harm to air, water, public health, rural economies, and overall quality of life.

The current flaws in the LCFS, such as "avoided methane crediting" and inaccurate life cycle assessments, not only enable pollution but disproportionately harm low-income communities and communities of color who live near factory farms and manure digesters. This is in stark contrast to the environmental justice commitment set by California.

CFFE believes that climate change is a serious challenge that requires a dramatic response. This crisis demands more than highly speculative market-based schemes that will allow polluters to keep polluting and let agribusiness pay farmers less for their crops and livestock. A serious plan to address agriculture and climate change must address structural issues, not just attempt minor improvements in environmental performance in a highly consolidated, industrialized factory farm system. Factory farms require huge quantities of feed, water, chemical inputs and energy and manage manure in a way that drives greenhouse gas emissions. California's climate programs must support a dramatic transition in how we raise animals for food that is centered on independent family farms and sustainably managed grazing systems.

Using California's climate programs, including the LCFS, to support expensive manure management projects on confinement operations fails to make this necessary structural change, and instead props up and expands the factory farm system. Prioritizing grazing over factory farm manure management would increase the sequestration of carbon in pastures, and also avoid the emissions from industrialized animal operations' feed production and liquid manure storage. Manure lagoons not only emit high amounts of methane and nitrous oxide, but they are also highly vulnerable to natural disasters such as hurricanes and floods. And confinement operations decouple grazing animals from grasslands, requiring more synthetic fertilizers for feed production, which drives further emissions.

In addition to these overarching concerns about LCFS' support for manure digesters, we urge you to prioritize the following changes to the standard:

- Eliminate "avoided methane crediting"

339.2
- Address inaccuracies in the Life Cycle Assessment that ignore associated up and downstream greenhouse gas emissions from factory farm gas production

339.3
- Remove the 10-year "grace period" for factory farm gas producers

339.4
- Stop double counting by allowing factory farm gas projects paid for and claimed by other programs to sell LCFS credits as well.

339.5 For practices related to manure management, including anaerobic digesters, the LCFS calculation should evaluate not only the risks of increased ammonia emissions and water pollution from disposal of digestate, but also the potential that the contract will lead to an increase in the total number or density of livestock raised on the site. The potential for LCFS funding to lead to more animals being raised on an operation with a digester, and the increase in enteric emissions and carbon emissions from feed production related to the increase, should be incorporated into a new LCFS scoring system for manure-derived biogas.

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We appreciate the opportunity to comment on this critical subject. If you have questions or need more information, please contact Patty Lovera at pattylovera20@gmail.com.

Sincerely,

Campaign for Family Farms and the Environment

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Comment 349 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Gary
Last Name	Hughes
Email Address	garyhughes.bfw@gmail.com
Affiliation	Biofuelwatch
Subject	CARB push for liquid biofuels endangers global forests
Comment	Please see the attached document as comment on the proposed Low Carbon Fuel Standard Amendments.
Attachment	www.arb.ca.gov/lists/com-attach/7028-lcfs2024-B2VdMlA+AjcFdlA1.pdf
Original File Name	Biofuelwatch_LCFSRulemaking_2024.pdf
Date and Time Comment Was Submitted	2024-02-20 18:20:26

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

biofuelwatch

February 20, 2024

Governor Gavin Newsom
California State Capitol
Sacramento, CA 95814

Liane Randolph, Chair
Members of the Board
Dr. Steven Cliff, Executive Officer
California Air Resources Board
1001 "I" Street
Sacramento, CA 95814

Submitted electronically via
https://www.arb.ca.gov/lispub/comm/iframe_bcsubform.php?listname=lcfs2024

Re: Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments (lcfs2024)

To Esteemed Responsible Officials:

Our organization Biofuelwatch appreciates the opportunity to submit this brief letter to the California Air Resources Board (CARB) as comment on the Notice of Public Hearing to Consider Proposed Low Carbon Fuel Standard Amendments (LCFS Rulemaking)[1]. Biofuelwatch[2] is an international organization that works to increase public understanding and civic engagement on the land-use implications of climate policy. We have a particular focus on the environmental harms and social inequities of large-scale industrial bioenergy projects, and we work extensively on addressing the negative ecological and social outcomes of policy and actions that are justified as being beneficial to the global climate, yet carry with them risks and threats to public health and safety, economic stability and natural resources. Due to circumstance, more than an innate desire, we have developed extensive experience with the negative real-world outcomes due to the Low Carbon Fuel Standard (LCFS). In particular, over the last nearly four years our
340.1 organization has been deeply engaged on what we assess to be the extremely irregular governance of the conversion of two refineries in the San Francisco Bay Area to manufacturing liquid biofuels, the Phillips 66 Rodeo Renewed Project (Phillips 66 Project)[3] being one of those controversial refinery conversion projects and the Marathon-Neste biofuel refinery joint venture in Martinez (Marathon-Neste Project)[4] being the other.

The California Air Resources Board (CARB) has unfortunately played a key role in the irregular governance of the refinery conversions, not only as a regulator but as a political player. For all intents and purposes

[1] https://ww2.arb.ca.gov/rulemaking/2024/lcfs2024
[2] http://www.biofuelwatch.org.uk/
[3] https://www.contracosta.ca.gov/RodeoRenewed
[4] https://www.marathonmartinezrenewables.com/

CARB has acted to protect the stranded assets of large transnational energy corporations, and has put aside local community and global climate justice concerns about the refinery conversions. Our organization has arrived at the harsh conclusion that in doubling down on climate false solutions like liquid biofuels CARB is failing in the objective of reforming the LCFS in order that the mechanism effectively be a tool for mitigating climate change. Unfortunately, there are numerous and severe harms arising from the LCFS mechanism that CARB staff have refused to recognize throughout the discussions regarding the current LCFS Rulemaking effort.

Though the postponement of the scheduled March 21 board hearing on the LCFS Rulemaking may have been in response to public concern about the LCFS in concept and deed, not the least of which are the inadequate current amendments to the LCFS requirements, we are attentive to how the agency may be once again working to dilute public participation in a significant rulemaking process.

We hope that the board will hear what has been shared over the last several years of workshops and processes around the LCFS. We also know that the board heard a great deal about the problems with the LCFS as the 2022 Scoping Plan was developed, and that current deliberations around cap-and-trade have also exposed major problems with the incentive mechanism. The unfortunate truth is that fatal flaws are embedded within the LCFS. The current amendments do not address these fatal flaws. For our organization and for the communities we work with around the state, the nation and around the world, it is horrifying to us that a high-profile markets-based mechanism, one that California authorities celebrate as an example of global climate leadership to be emulated by other jurisdictions, is in many instances not actually helping, and is instead making the climate situation worse faster.

Purpose and Rationale for LCFS Amendments Addressing the Evidence That Increased Production of Crop-based Liquid Biofuels Presents to Global Forests Fails to Meet the Moment

This comment letter will remain within the relatively limited handrails of the nexus between forests and bioenergy. This can include many topics related to the LCFS, but for the most part this letter will address **liquid biofuels**, and the related LCFS credit pathways currently in effect, such as the Phillips 66 pathway for making '*renewable diesel*' specifically with a feedstock of soy oil from Argentina that is imported by ocean tanker to their refinery in Rodeo, California.

340.2 It is obvious to anyone with experience in the manufacture of liquid biofuels that these energy products present serious threats to forest ecosystems and the communities dependent on them. It has long been understood that any increase in demand for high deforestation risk commodities for use in feed, food, or for fuel will drive deforestation. This most certainly includes liquid biofuels.

Actually, CARB goes so far as to admit that these types of concerns need to be addressed. In the description of the Purpose and Rationale of Proposed Amendments[5], staff go so far as to emphasize the need to "mitigate the concerns regarding deforestation and other unintended environmental impacts."

This is not the only effort of CARB staff to try to assuage the concerns about the well-known fact that increasing demand for high deforestation risk feedstocks such as soy to make liquid biofuels is a driver of land use change, biodiversity loss and environmental degradation. The Purpose and Rationale goes on to explain that "(T)he growing demand for crop- and forest-based feedstocks for use in the LCFS program produce an increasing risk of deforestation and use of land with a high biodiversity value to meet this

[5] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appe.pdf

demand. It is vital that the LCFS program limit deforestation and land use change as a result of feedstock production as much as possible."

Though some might be relieved to see that CARB is showing so much concern about these critical matters,
340.3 the problem is that CARB is out of touch with current understanding of the imperative to stop deforestation. Limiting deforestation is simply not enough. CARB is so completely out of touch with global efforts on these matters that this failing needs to be addressed in this comment letter.

For instance, even though the statement is considered anodyne and toothless by many experts with experience addressing the drivers of deforestation and working to halt the loss of primary forest globally, the Glasgow Leaders Declaration on Forest and Land Use[6] that was signed during COP 26 in Scotland in 2021 is explicit in describing the need to "**halt and reverse forest loss and land degradation**." The objective is not to 'limit' deforestation. This is not just a semantical difference. Halting and reversing forest loss is the global standard, whereas simply aspiring to limit deforestation and land use change is by simple definition allowing for the loss of forest to continue. Earth living systems cannot afford more forest loss.

Thus, from the outset CARB has failed global forests with the description of these matters in the Purpose and Rationale for the amendments. This is inexcusable for an agency that has in many instances claimed to have expertise over tropical forest-based climate mitigation strategies, even though California is not host to tropical forests.

Prohibiting Palm Oil Based Fuels Is Long Overdue and Is Simply Not Enough

Our organization noted that CARB has finally taken steps to more explicitly prohibit the use of palm oil or palm derivative fuels in the LCFS program. However, we still take issue with the assignment of higher Carbon Intensity (CI) scores as a disincentive. First and foremost, the reliance of the LCFS on CI is essentially a case study in the manner in which CARB obfuscates climate science, as the concept of CI ignores the climate science fundamental that emissions are cumulative. Just like with cap-and-trade CARB embarks upon technocratic carbon accounting formulas that fail to take into account the most basic underpinnings of the climate problem: that emissions are cumulative and that we are working with a rapidly diminishing carbon budget. The LCFS still fails to pass the climate science smell test.

That said, CARB has long relied on disincentives in the market-based mechanism. It is actually quite remarkable that after all this time CARB is offering to clearly ban palm oil and palm derivative based fuels. Congratulations! However, this is not enough. The global policy debate has already moved on from palm to discuss the imperative of also banning soy as a feedstock for making liquid biofuels. As it can be said, *soy is the new palm*. But CARB is as behind the times on this matter, just as it is in aspiring to 'limit' deforestation as opposed to rising to the global standard to 'halt and reverse deforestation.' The prohibition of palm oil-based liquid biofuels is long overdue, and it is simply not enough.

Sustainability Certification Systems Are Proven Ineffective

In answer to concerns about the LCFS incentivizing global deforestation by incentivizing demand for high deforestation risk feedstocks, CARB decides to play a card from several decades ago: require certification to guarantee 'sustainability.' Unfortunately, CARB has apparently failed to look at what is happening with certification standards globally, much less at home in California.

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[6] https://webarchive.nationalarchives.gov.uk/ukgwa/20230418175226/https://ukcop26.org/glasgow-leaders-declaration-on-forests-and-land-use/

The fact is that certification has not helped companies meet commitments to keep deforestation out of their supply chains.

As a window into this dynamic regarding the failures of certification schemes to guarantee sustainability, which is not a new phenomenon, Greenpeace International published a report in March 2021, nearly three years ago now, titled Destruction: Certified[7].

340.4 The purpose of the report is to assess the effectiveness of certification for land-based commodities as an instrument to address deforestation, land degradation and other ecosystem conversion and human rights abuses. **The analysis in the report shows that certification is a weak tool to address global forest and ecosystem destruction**.

Among the certification schemes evaluated in the report are the International Sustainability and Carbon Certification, the Round Table on Responsible Soy, and the Forest Stewardship Council (FSC). Though CARB does not name any of these specific schemes, experienced stakeholders can predict exactly where this proposal for certification will lead. This without even beginning to address the total lack of regulation of the certifying entities that would be responsible for the implementation of any certification scheme.

340.5 With decades of experience working on the development and implementation of certification schemes our organization is adamant in our position that the plan to require certification of high deforestation risk commodities for qualification for the LCFS is not only inadequate, it is bound to fail.

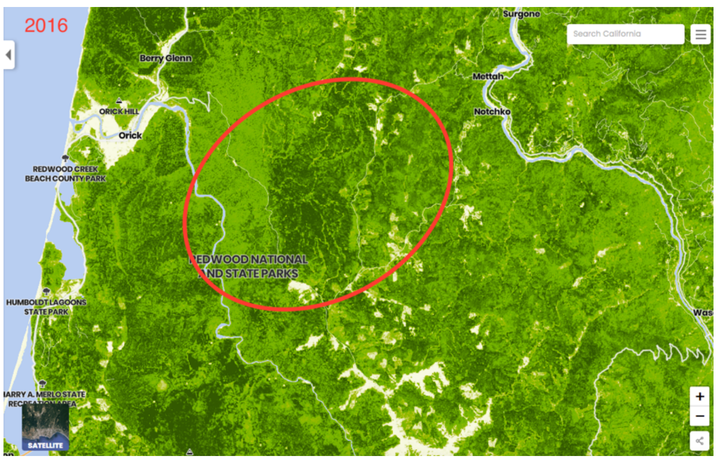
Forest Stewardship Council Weakened Standards to Certify Clearcutting in the Redwoods as Sustainable
As an example of why certification standards have failed as an instrument for addressing sustainability challenges with land-based commodities one has to travel no further than the redwood temperate rainforest ecosystem, Northern California's own globally important forest. In 2012, the FSC, in the face of strong community opposition, and after weakening their standards to allow clearcutting, certified Green Diamond Resource Company (GDRC). Interestingly enough, the GDRC clearcuts are visible from space.

This image above is of the southern boundary of the Redwood National and State Park system and the clearcut holdings of Green Diamond Resource Company in Humboldt County. The National Park, to the

[7] https://www.greenpeace.org/international/publication/46812/destruction-certified/

right side of the frame in dark green, is a UNESCO World Heritage site, ostensibly subject to the management protocols of the Man and Biosphere framework, which would normally include a significant buffer zone between the industrially managed holdings and the globally relevant protected area. Yet, as can be seen with the review of the image, the clearcutting is happening right up to the boundary of the Redwood National Park/World Heritage site. Despite a rhetorical emphasis on the importance of protecting forests as a climate mitigation tool CARB has remained silent about the intensive logging right up to the boundary of a World Heritage site in California. FSC certifies this logging as 'sustainable.'

Another set of maps, 'before and after,' from the California Forest Observatory[8], focused on Green Diamond Resource Company holdings to the north of the Redwood National Park, shows how clearcut logging can be certified sustainable. You can see the circle in the 2016 map below, highlighting an area of mostly intact second growth forest that is/was in the immediate vicinity of the Redwood National and State Park matrix. There can be no questioning the biological and climate value of this forest.



Unfortunately, as the 2020 map below shows, this area was aggressively logged by GDRC in the space of five years, leaving clearcuts visible from space. The products from this logging were certified and marketed as 'sustainable' by FSC. This is not the first time that CARB staff have received this evidence. CARB arguments that certification is a solution for avoiding forest loss and ecosystem degradation ignore reality.

[8] https://forestobservatory.com/

340.6 ***The Carbon Intensity, Environmental Repercussions and Climate Impacts of the Soy Oil Feedstock from Argentina Specified in the Phillips 66 Credit Pathway Are Grossly Underestimated***

It is unfortunate that when the imperative of halting global deforestation has become more acute than ever that such a grossly inadequate fuel pathway Life Cycle Analysis[9] was submitted with the Phillips 66 Application for an LCFS credit pathway for making 'renewable diesel' from soy imported from Argentina.

The assessment of Indirect Land Use Change (ILUC)[10] tried to apply a methodology from the Midwest United States to Argentina, though the quality of the assessment is so poor it is hard to discern exactly how the methodology was applied. This assessment of Indirect Land Use Change failed completely to address the most contemporary science when it comes to calculating ILUC.

The conclusion in the Application materials that deforestation from the expansion of the agriculture frontier is no longer an issue of concern for the soy sector in Argentina flies in the face of common knowledge. Indeed, this facile conclusion is refuted by simple and easy to find studies[11] from the Environment Ministry of the Government of Argentina that make it clear that the expansion of soy agriculture, which is closely related to the cattle industry, remains one of the major drivers of deforestation in the country. The assessments of the feedstock climate impacts as provided in the Application were woefully deficient.

Considering the urgency of the situation, an item that would serve CARB staff and leadership to take into consideration is the recently published report from the European organization Transport and Environment titled "Halt Deforestation-Driving Soy Biofuels Before it is Too Late."[12]

In this report clear arguments are made that soy must be considered a high-ILUC risk feedstock (something that the recent LCFS Rulemaking fails to do) and that **in order to protect global forests an aggressive**
340.7 **phase out of palm and soy-based biofuels is needed immediately**. There are many lessons to be learned from the European experience on these matters of global deforestation and biofuels, and CARB staff and leadership need to take measures to update the approach to assessing the climate impacts from high deforestation risk feedstocks like soy.

Much more research and analysis need to be done about the viability and environmental repercussions of granting a special climate value to making liquid biofuels from soy. The available evidence shows that this is not a climate solution. By rushing forward with these credit pathways for making liquid biofuels from commodities like soy CARB is running the risk of elevating California climate policy to become a driver of global deforestation.

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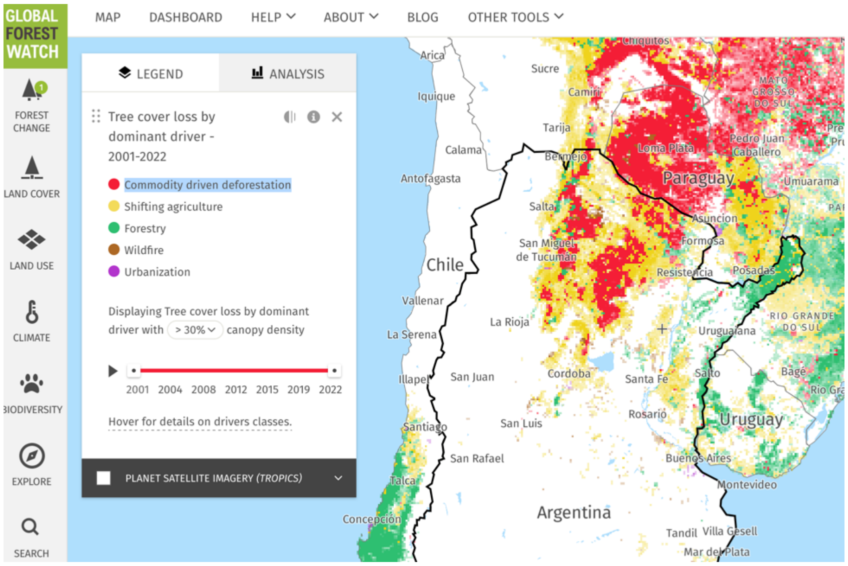
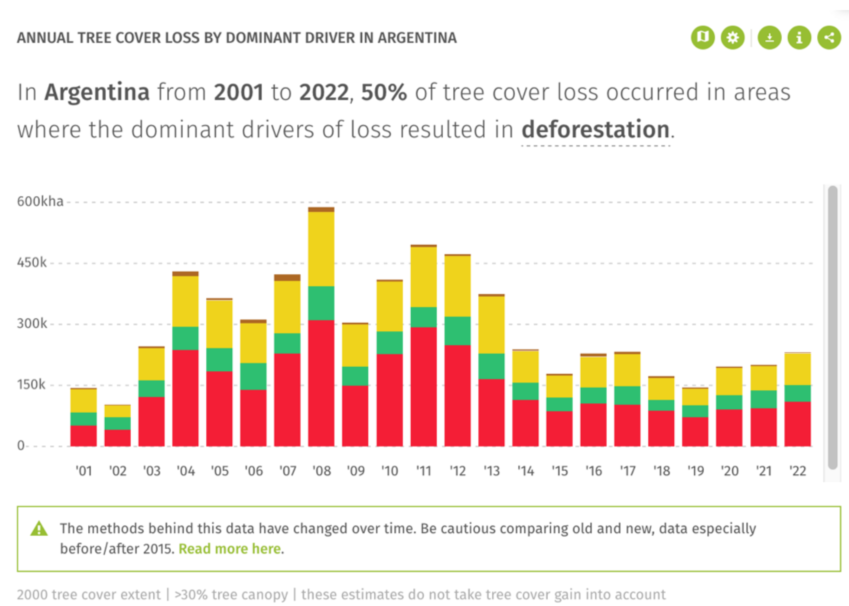
[9] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0520_report.pdf
[10]https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0520_attachment_b.pdf
[11] https://www.argentina.gob.ar/sites/default/files/desmontes_y_alternativas-julio27.pdf
[12] https://www.transportenvironment.org/wp-content/uploads/2023/12/Halt-deforestation-driving-soy-biofuels-before-it-is-too-late.pdf

Global Forest Watch Data Describes Commodity Driven Deforestation in Argentina



This data is easily accessible from the Global Forest Watch portal[13]. The map image above shows in red the tree cover loss attributable to 'commodity driven deforestation since the year 2001 until 2022, the last year for which data is currently available. In the graph below commodity driven deforestation is again shown in red. The year 2022 saw the greatest amount of annual deforestation in Argentina since 2013.



Clearly the issue of deforestation in Argentina remains acute, despite the facile treatment of the matter by CARB in the Phillips 66 LCFS credit pathway application. The recently proposed amendments are also completely inadequate. The hard and sad truth is that by falsely characterizing liquid biofuels as a climate solution California climate policy is contributing to the market dynamics that drive global deforestation.

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[13] https://www.globalforestwatch.org/dashboards/country/ARG/

340.8 ***The Public Health Disaster Resulting from the Expansion of the Soy Agroindustry Is Being Ignored***

Over the last decades the soy agroindustry has expanded in Argentina at a breathtaking rate. This expansion has extended throughout Southern South America more broadly, especially in the region reaching north from Argentina into Paraguay, Bolivia and Brazil. This industrial monoculture model has relied almost exclusively on varieties of soy that are genetically modified organisms that are engineered to be resistant to pesticides, namely the "Round Up Ready" varieties, which are engineered to confer tolerance to glyphosate and dicamba, both of which are associated with a host of serious human health hazards and environmental risks. Unprecedented amounts of these pesticides have been applied across the region, sprayed by hand, by vehicle and by airplane. This has resulted in a tragic and intensifying public health crisis across the area that has hosted this exponential expansion of the soy agroindustry model.

The situation has gotten so desperate that communities that self-identify as "*los pueblos fumigados*" – the fumigated peoples – have begun to organize to address the indiscriminate use of toxic pesticides across the region, and to free themselves from an industrial model that is poisoning their families and their environment[14]. This public health crisis is totally ignored by the LCFS and the formulas used to give a CI value to different feedstocks. The LCFS design discriminates against affected communities; in the rush to put a price on carbon and to protect the stranded assets of multi-billion-dollar transnational energy corporations, California is embracing known false solutions like liquid biofuels. The externalities of these resource intensive high emissions feedstocks are thrust on rural and indigenous communities, which are forced to shoulder the burden of a climate mechanism that fails to take their well-being into account.

Once again it is marginalized communities that are paying the price of California's climate hubris.

Why is this happening? Is it disinterest? Or ignorance? Why is the State of California doubling down on the promotion of liquid biofuels as a climate solution? The status quo is untenable and the expansion of the production and use of these energy products is climate suicide.

The board of directors of CARB must take responsibility for the monster they are unleashing on the world. To turn a blind eye to the evidence that is being presented regarding the real-world impacts of these crop-based liquid biofuel products, whether it be '*sustainable aviation fuel*' or '*renewable diesel*,' is immoral. Doubling down on a poorly designed incentive mechanism to avoid publicly having to admitt to the defects of these failed technologies would be worse than irresponsible. The time to correct course is now.

We demand extensive reformulation and redesign of California's failing markets-based approach to climate, the LCFS being first up for review, revision and reframing. We remain available to meet with board members that are looking for more information about these matters of global relevance and local significance.

Sincerely,

Gary Graham Hughes

Gary Graham Hughes
Americas Program Coordinator, Biofuelwatch
garyhughes.bfw@gmail.com / +1-707-223-5434

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[14] https://agenciatierraviva.com.ar/encuentro-de-pueblos-fumigados-por-un-pais-y-un-continente-con-soberania-alimentaria/

Comment Log Display

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Comment 350 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Jessi
Last Name	Davis
Email Address	jdavis6@socalgas.com
Affiliation	SoCalGas
Subject	SoCalGas Comments on Proposed Amendments to the Low Carbon Fuel Standard
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/7029-lcfs2024-WyhcNVU3VGYBa1M0.pdf
Original File Name	SoCalGas Comments on Proposed Amendments to the Low Carbon Fuel Standard.pdf
Date and Time Comment Was Submitted	2024-02-20 18:26:07

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Kevin Barker
Senior Manager
Energy and Environmental Policy
555 West 5th Street
Los Angeles, CA 90013
Tel: (916) 492-4252
KBarker@socalgas.com

February 20, 2024

Cheryl Laskowski
Transportation Fuels Branch Chief
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812-2815

Subject: Comments on the California Air Resources Board Proposed Amendments to the Low Carbon Fuel Standard

Dear Dr. Laskowski:

Southern California Gas Company (SoCalGas) values the opportunity to provide feedback on the Proposed Amendments (Proposed Amendments) to the Low Carbon Fuel Standard (LCFS). The LCFS has played a critical function in decarbonizing the transportation sector and will continue to serve a crucial role in promoting the adoption of lower carbon transportation fuels to reduce greenhouse gas (GHG) emissions. To meet California's ambitious GHG reduction targets outlined in the 2022 Scoping Plan, CARB should foster a stable, long-term environment that encourages investment in methane capture projects essential for reducing emissions from sources including landfills, dairies, and wastewater. As highlighted in the Staff Report's Initial Statement of Reasons, "Capturing methane from California's sources is critical for achieving climate targets, including those set by SB 32, SB 1383, and AB 1279."[1]

We commend CARB for thoughtfully incorporating a smooth transition to fuels supporting zero-emission vehicles while maintaining support for clean fuels that have driven the emission reductions thus far in the program. Without additional support and direction for new programs, however, the proposed incentive adjustments may not be sufficient to encourage investments in biomethane and the infrastructure necessary to achieve carbon neutrality by 2045.

341.1 As such, SoCalGas's comments highlight the following: 1) CARB should establish a complimentary policy such as an industrial clean fuels standard to promote the growth of the biomethane market for use in hard-to-electrify sectors; and 2) the proposed deliverability requirements support rapid buildout of biomethane capture projects.
341.2

[1] Proposed Amendments to the Low Carbon Fuel Standard Staff Report: Initial Statement of Reasons; (ISOR) at 30.

341.1 cont.

1) CARB should establish a complimentary policy such as an industrial clean fuels standard to promote the growth of the biomethane market for use in hard-to-electrify sectors

SoCalGas appreciates that the Proposed Amendments recognize the need for more methane capture projects in California to reduce short-lived climate pollutants (SLCP) emissions.[2] We agree with CARB staff that immediate action to curtail these potent emissions will yield local health benefits and mitigate global warming as we transition to low-carbon energy systems and pursue carbon neutrality.[3]

More specifically, the proposed modifications to avoided methane crediting maintain a pathway for projects established before 2030 to recover initial capital costs of methane capture. These projects constitute some of the most cost-effective investments for carbon reduction in the state and merit fortification.[4] A complementary program to advance the deployment of biomethane beyond the transportation sector is essential to the sustainability of methane capture projects post-crediting phase-out.

We support the policy direction outlined in CARB's 2022 Scoping Plan for the long-term deployment of biomethane for hydrogen production and its expanded use in stationary sources. To sustain this momentum, the State should establish a clear pathway with concrete milestones and appropriate offramps before the complete phase-out of avoided methane credits. Since California's industrial sector is a significant contributor to natural gas consumption and greenhouse gas emissions, incentivizing biomethane use in sectors beyond transportation becomes crucial.[5] CARB could achieve this by opening the current LCFS program to stationary sources or using the current LCFS program as a model to create a new Industrial Clean Fuel Standard program. This new standard would aim to institute a set of gradually declining emissions-based targets for regulated entities, empowering the industrial sector to reduce emissions through diverse approaches including electrification, procuring low and zero-carbon fuels, carbon capture and sequestration, and enhancing energy efficiency. CARB should also evaluate pathways to utilize other programs such as the Cap-and-Trade Program to support the transition of biomethane into other sectors.

The ongoing success of the LCFS program is pivotal to fortifying the biomethane market, especially as its applications extend beyond transportation. To support a robust biomethane market with competitive pricing and a consistent supply, SoCalGas recommends expediting discussions on potential initiatives, such as an Industrial Clean Fuel Standard or expanding the utilization of

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[2] DRAFT ENVIRONMENTAL IMPACT ANALYSIS for the Proposed Low Carbon Fuel Standard Regulation (Draft EIA) at 17.
[3] ISOR at 29.
[4] CARB, California Climate Investments 2022 Mid-Year Data Update, September 2022, indicates that investments in dairy digesters and diverted organic waste cut carbon emissions by approximately $9 and $10 per ton, respectively. CARB's 2021 Annual Report on Climate Investments also showed that investments in organic waste to energy were the most cost-effective of the State's climate investments; at 119.
[5] California Industrial Energy Efficiency Market Characterization Study, XENERGY Inc., December 2001, available at http://www.calmac.org/publications/California%20Ind%20EE%20Mkt%20Characterization.pdf; at 3-22.

341.1 cont. other program funds like Cap-and-Trade for biomethane procurement. The proposed amendments to the avoided methane crediting underscore the need for establishing a complementary policy before 2030. This proactive measure not only incentivizes the market to lower prices but also provides clear guidance and procedures for funding opportunities, encouraging businesses to invest in biomethane projects.

As championed by CPUC-supported programs[6], the benefits of biomethane procurement are based on the avoided costs of well gas, encompassing upstream interstate transmission, and the avoided social cost of methane. Hence, it is crucial for CARB, as a regulatory body, to adopt programs that equally incentivize multiple cost-effective means of decarbonization to more rapidly achieve net-zero goals, benefiting society at large.

341.2 cont.

2) The proposed deliverability requirements support rapid buildout of biomethane capture projects

SoCalGas appreciates that CARB's proposed revisions to deliverability requirements acknowledge the importance of sustaining existing procurement agreements with out-of-state biomethane projects. The Proposed Amendments will encourage and expedite the expansion of biomethane capture projects throughout this decade, aligning with the imperative to reduce methane emissions.[7] California will need both in-state and out-of-state supplies of biomethane to decarbonize hard-to-abate sectors, including cement and steel manufacturing, as well as promoting methane capture and GHG emissions throughout the west, since GHG emissions are a global pollutant rather than a local pollutant. An uninterrupted flow of biomethane into California is a strategic imperative that fosters its adoption across diverse economic sectors over time.

Furthermore, the Book-and-Claim (B&C) deliverability approach not only supports the production of clean fuel sources that mitigate global pollutants but facilitates the cost-effective procurement of biomethane in support of California's clean energy policies and prioritization of energy security for all Californians. This is crucial for maintaining affordability while decarbonizing challenging sectors. As biomethane phases out of the LCFS, its limited availability for hard-to-abate sectors underscores the need for current policies to concentrate on boosting both production and demand. Allocating funds for developer incentives and consumer programs can drive greater end-use applications, bolstering production. Hence, it is critical for CARB to maintain biomethane B&C provisions in future policies supporting biomethane. Such a measure is essential to maintaining the positive momentum and success attained in the realm of affordable and reliable procurement thus far.

Conclusion

SoCalGas is grateful for the chance to offer feedback and to participate in discussions with CARB and stakeholders during the LCFS Program regulatory update. We are dedicated to a unified and

[6] Decision 22-02-025, Finding of Fact 16 at 53.
[7] Draft EIA at 18.

collaborative shift towards cleaner energy and acknowledge CARB's thoughtful consideration given to all stakeholders throughout this process. We eagerly anticipate continued engagement with staff to collaboratively establish a framework for expeditiously transitioning biomethane for use in other sectors.

Respectfully,

/s/ Kevin Barker

Kevin Barker
Senior Manager
Energy and Environmental Policy

Comment Log Display

Here is the comment you selected to display.

Comment 351 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Graham
Last Name	Noyes
Email Address	graham@noyeslawcorp.com
Affiliation	Noyes Law Corporation
Subject	The Importance to California's Climate Goals of Power-to-Liquid Fuels

Comment

```
Please find the attached comment submit jointly by Infinium,
Twelve, Air Company, Arcadia eFuels, Dimensional Energy, Boom and
the International Airlines Group. A brief summary of the comment i
included below.  Please contact me regarding any issues or
questions relating to the comment.

Thank you for your assistance.

Best Regards,
Graham Noyes
Noyes Law Corporation

Comment Summary:
The signatories of this letter are pleased to submit comments
recommending a modification to the California Air Resources Board
("CARB") proposed amendments to the Low Carbon Fuel Standard
("LCFS"). We support CARB's LCFS program, as it sends a market
signal to decarbonize the transportation sector, is performance
based, and provides long-term policy stability that supports
investment. However, we respectfully request that CARB maintain
LCFS policy stability for the clean fuels industry and preserve th
eligibility of facilities that produce Power-to-Liquid ("PtL")
fuels to source low-carbon intensity electricity ("Low-CI
Electricity") via book-and-claim accounting. PtL fuels, also known
as eFuels, electrofuels or synthetic fuels, are drop-in replacemen
fuels for use in airplanes, ships and motor vehicles that do not
trigger the costs or delays inherent to engine or infrastructure
changes. Specifically, we
request that CARB preserve the current renewable energy certificat
("REC") system for electrolytic hydrogen and enable the sourcing o
energy for PtL fuel production via book-and claim accounting.
```

Attachment www.arb.ca.gov/lists/com-attach/7030-lcfs2024-VD4AaQRsU25SIABf.pdf

Original File Name Joint eFuel LCFS Comment FINAL.pdf

Date and Time Comment Was Submitted	2024-02-20 18:28:37

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

The Honorable Liane M. Randolph
Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

(Comment submitted electronically)

RE: The Importance to California's Climate Goals of Enabling Power-to-Liquid Fuel Producers to Source Low-Carbon Intensity Electricity via Book-and-Claim Accounting

Dear Chair Randolph,

The signatories of this letter are pleased to submit comments recommending a modification to the California Air Resources Board's ("CARB") proposed amendments to the Low Carbon Fuel Standard ("LCFS"). We support CARB's LCFS program, as it sends a market signal to decarbonize the transportation sector, is performance based, and provides long-term policy stability that supports investment. However, we respectfully request that CARB maintain LCFS policy stability for the clean fuels industry and preserve the eligibility of facilities that
342.1 produce Power-to-Liquid ("PtL") fuels to source low-carbon intensity electricity ("Low-CI Electricity") via book-and-claim accounting. PtL fuels, also known as eFuels, electrofuels or synthetic fuels, are drop-in replacement fuels for use in airplanes, ships and motor vehicles that do not trigger the costs or delays inherent to engine or infrastructure changes. Specifically, we request that CARB preserve the current renewable energy certificate ("REC") system for electrolytic hydrogen and enable the sourcing of energy for PtL fuel production via book-and-claim accounting.

342.2

CARB's proposed LCFS regulatory amendments are highly damaging to the nascent PtL industry in that the new proposed regulatory structure would require that PtL facilities source grid mix power both for PtL hydrogen and for their other energy needs. This structure would inhibit the growth of PtL fuels and the expansion of new sources of renewable power. One of the key benefits of PtL fuels is their deep reduction in carbon intensity (over 90%) compared to fossil fuel incumbents. The deep CI reduction hinges on reliance on carbon-free electricity. CARB's LCFS regulations, if they fail to allow book-and-claim mechanisms for PtL fuel producers' electricity procurement, will undercut the tremendous potential of PtL fuels to contribute to the decarbonization of internal combustion vehicles ("ICVs") and, importantly, the aviation sector. Indeed, the proposed LCFS regulatory change impedes fulfillment of the goals of CARB's 2022 Scoping Plan to dramatically decarbonize transport and power and reduces the likelihood that California will achieve its goal to displace 80% of its fossil jet fuel supply with sustainable aviation fuel ("SAF"). It also makes it very challenging to achieve the on-road and jet fuel CI reduction target of 90% by 2045 that CARB has proposed.

PtL has the potential to be an ultra-low carbon fuel alternative to petroleum derived transportation fuels and to scale rapidly - ***but only to the extent that PtL producers are allowed to source Low-CI Electricity***. PtL fuel producers do not use biomass feedstocks for production

342.2 cont but instead utilize carbon dioxide (CO_2) that would otherwise be emitted as waste and water as their only feedstocks to produce PtL transportation fuels. To convert water to hydrogen via electrolysis, PtL facilities require a substantial amount of power, which needs to come from carbon-free sources in order for the resulting fuels to achieve deep CI reductions. Due to this electricity demand, the proposed regulatory changes would dramatically increase the CI of PtL fuels (i.e., to a level at or above the petroleum baseline CI value) and perpetuate the use of fossil jet fuel and other petroleum-based fuels in the broader transportation sector. This will effectively stunt the innovative PtL industry, the importance of which has already been recognized in the road, aviation and maritime sectors and in other jurisdictions such as the European Union and United Kingdom (i.e. ReFuelEU Aviation, FuelEU Maritime, EU RED, and UK RTFO programs).

<u>CARB's Proposed Change to the Existing LCFS Regulation</u>
342.1 cont **<u>Is Highly Detrimental to PtL Fuels</u>**

Under §95488.8(i)(1)(A)-(B) of the existing LCFS Regulation, book-and-claim accounting is authorized for Low-CI Electricity supplied as a transportation fuel or to produce hydrogen through electrolysis if that hydrogen is used either as a transportation fuel or in the production of another transportation fuel (e.g., SAF). Through these provisions, PtL facilities are explicitly authorized to source Low-CI Electricity from the grid to produce hydrogen that is used in the production of PtL fuels. Under these existing LCFS provisions, Low-CI electricity can be sourced flexibly through the use of RECs or via a qualifying Green Tariff program.

The proposed LCFS regulatory revisions that CARB released on December 22, 2023, would dramatically narrow the power-sourcing landscape for PtL producers. The proposed amendments would revoke the current authorization to source Low-CI Electricity for electrolysis through the REC mechanism. To source Low-CI Electricity, the proposed regulations would instead require a PtL facility to construct a wind, solar or other renewable generation project and directly connect that power generation source behind the utility meter to the PtL fuel facility, which is typically impractical. CARB's regulatory proposal will severely inhibit the growth of a liquid fuel technology that holds great promise for scaling and, as noted above, is not dependent upon biomass feedstocks. By changing its policy this significantly with no notice to the industry or delayed phase-in, CARB will also undermine investor confidence in the continuity of its policy structure and thereby deter investment in ***all clean fuel facilities and technologies***, including game-changing fuels like PtL fuels.

<u>Policy Support for Expanding Power Sourcing Flexibility within the LCFS</u>

We appreciate that other considerations have informed CARB's development of the proposed LCFS amendments. In particular, we recognize that CARB is seeking to adhere to a strategy of aggressive electrification to reduce GHG emissions from the transportation sector and is seeking to support the growth of hydrogen fuel cell electric vehicles (FCEVs) through this regulatory proposal. By this comment letter, we do not seek to detract from CARB's electrification strategies and for the reasons discussed herein, we consider our proposed revision to the proposed LCFS amendments to be fully consistent with these strategies. However, we do think it important to bring to CARB's attention the difficulty of decarbonizing the aviation sector
342.2 cont without enabling PtL fuel producers to access Low-CI Electricity via the grid. It is only through

the ability to source zero-emission electricity from renewable energy resources that PtL facilities will be able to obtain ultra-low CI scores (e.g., < 10 gCO_{2e}/MJ) for their fuels, substantially reduce GHG emissions on a lifecycle basis and generate LCFS credits.

This past November, The International Council on Clean Transportation ("ICCT") published a white paper assessing the feasibility of meeting the targets in the Biden Administration's SAF Grand Challenge based on "resource availability, production costs, technology readiness level, and policy support."[1] ICCT's white paper emphasized the importance of PtL SAF in meeting the 2050 SAF Grand Challenge goal of 35 billion gallons, as follows:

> *We find that the near-term 2030 production target can be met with sustainable resources, but the 2050 target will be far more challenging to reach. In the longer-term, biomass volumes will need to be supplemented with a combination of other fuel sources or fuel burn reduction to meet the energy needs of the entire U.S. aviation sector. . . .*
>
> *E-fuels, or synthetic aviation fuels produced from renewable electricity, could help to bridge the supply gap in later years. . . .Though the technology remains in the demonstration phase, e-fuels have gained significant interest in Europe and other markets due to their 'drop-in' advantages and theoretically unlimited supply. For example, the EU has adopted an e-fuel mandate of 1.2% of aviation fuel, averaged over 2030 and 2031, and 5% of aviation fuel volumes by 2035 (European Commission, 2023). These e-fuels are estimated to be costlier than most biomass-derived SAFs in the near-future, but their costs could rapidly come down as electrolyzer technology matures and the cost of renewable electricity declines (Zhou et al., 2022). . . . With the use of policy incentives, including the IRA's 10-year production tax credits for hydrogen and carbon capture, utilization, and storage (CCUS), e-fuels will likely become cost-competitive within a much shorter timeframe.*[2]

Conclusion

Due to the importance of Low-CI Electricity to the production of PtL fuels, and the importance of PtL fuels to meeting both California's 2045 carbon neutrality goal and California's specific goals to displace fossil jet fuel with SAF, we respectfully recommend that CARB modify the proposed LCFS amendments such that PtL facilities are authorized to procure Low-CI Electricity for electrolytic hydrogen production and their other energy needs via book-and-claim accounting.

Thank you for the opportunity to provide comments on this important topic.

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[1] O'Malley, J., Pavlenko, N., & Kim, Y.H. (2023). Meeting the SAF Grand Challenge: Current and Future Measures to Increase U.S. Sustainable Aviation Fuel Production Capacity. International Council on Clean Transportation. Available at https://theicct.org/wp-content/uploads/2023/11/ID-37-%E2%80%93-SAF-Grand-Challenge-white-paper-letter-40036-v3.pdf.

[2] *Id.* at 21.

Sincerely,

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Comment 352 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Alex
Last Name	Menotti
Email Address	alex.menotti@lanzajet.com
Affiliation	
Subject	Aviation and the CA LCFS
Comment	Please find attached comments from a coalition of SAF producers ar stakeholders including Advanced Biofuels Canada, Blue Arrow, Comstock Fuels, Darling Ingredients, Fulcrum Bioenergy, Green Plains, LanzaJet, LanzaTech, Raizen, SkyNRG, and Velocys. We appreciate the opportunity to comment. Please do not hesitate t reach out with any questions.
Attachment	www.arb.ca.gov/lists/com-attach/app-zip/7031-lcfs2024-WyhcO1A3Ag5RMAV3.zip
Original File Name	SAF group comments on LCFS Rulemaking 2024.zip

Date and Time Comment Was Submitted	2024-02-20 18:26:52

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Submitted Electronically via https://ww2.arb.ca.gov/lispub/comm/bclist.php

Re: Proposed Low Carbon Fuel Standard Amendments

Dear Board Members,

As a broad coalition of clean fuel producers committed to building a robust alternative jet fuel industry and decarbonizing aviation, we appreciate the opportunity to comment on the proposed changes to the California Low Carbon Fuel Standard (LCFS). We strongly support the CA LCFS program and applaud CARB's proposal to better align the program with the bold vision outlined in the 2022 Scoping Plan Update. Here, we comment specifically to express our strong support for CARB's proposal to eliminate the exemption for intrastate fossil jet fuel use under the LCFS, which is a critical step to enhance the market signal for sustainable aviation fuel (SAF).

Our organizations recognize and appreciate the state's continued leadership in the adoption of clean fuels in the aviation sector—one of the most difficult to decarbonize. In the 2018 LCFS rulemaking, CARB initiated inclusion of SAF in the program on an opt-in, credit-generating basis, which has since been replicated in other LCFS jurisdictions.[1] Unfortunately, while a helpful first step in providing some value for SAF under the LCFS, a stronger market signal is needed. The slow uptake of SAF in California can be traced, in part, to state regulatory rules, including the lack of an obligation on fossil jet fuel under the LCFS.[2]

California has rightfully set ambitious targets for aviation and for SAF specifically: Governor Newson recently called for 20% clean fuels adoption in the aviation sector,[3] the state legislature has estimated a need for at least 1.5 billion gallons of SAF blending by 2030,[4] and the 2022 CARB Scoping Plan states that 80% of all aviation fuel demand will need to come from SAF by 2045.[5] Given California's aggressive goals in the aviation sector and its recognition in the proposal that the LCFS should actively encourage transitioning the use of low carbon fuels to hard-to-decarbonize sectors in the coming decades, we urge CARB to better align the aviation provisions with the ambition that will be needed to achieve the state's goals.

Accordingly, we ask that CARB significantly strengthen the signal for SAF in the proposal provisions that would impact the aviation sector. Specifically, we suggest that CARB consider the following revisions to the proposal:

343.1
343.2

1. Include all fossil jet fuel as a deficit generator under the LCFS.
2. Accelerate the obligation to begin in 2025, rather than 2028.

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[1] Both [Oregon Clean Fuels Program]() and [Washington Clean Fuels Standard]() currently exempt fossil jet fuel from generating deficits and allow SAF to generate credits on an opt-in basis.
[2] *See* Bay Area Air Quality Management District, Sustainable Aviation Fuel: Greenhouse Gas Reductions from Bay Area Commercial Aircraft (October 2020) *available at* https://www.baaqmd.gov/news-and-events/page-resources/2020-news/121120-saf-report. *See also* https://stillwaterassociates.com/saf-in-the-ira-era-how-do-the-incentives-stack-up/.
[3] *See* California Office of the Governor, Governor's Letter to Chair Randolph. July 22, 2022. https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf?emrc=1054d6
[4] *See* AB1322 (Rivas) *available at* https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB1322. AB 1322was passed by the California assembly in 2022 and later vetoed by Governor Newsom, who, in his veto letter, supported the legislature's intent with the bill and ordered CARB to develop a "plan to reduce greenhouse gas emissions through the production and use of sustainable aviation fuels by July 1, 2024". Governor Newsom's veto letter *available at* https://www.gov.ca.gov/wp-content/uploads/2022/09/AB-1322-VETO.pdf?emrc=7598b6
[5] *See* CARB, 2022 Scoping Plan for Achieving Carbon Neutrality. December 2022. https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp_1.pdf. Page 73. The Scoping Plan scenario envisions 20% of aviation fuel demand met by electricity (batteries) or hydrogen (fuel cells) in 2045, with sustainable aviation fuel meeting the remaining 80%.

343.3 3. Allow for book-and-claim accounting of low-CI electricity and RNG for SAF production, a regulatory approach that is already in place for electric vehicle charging.

343.4 4. Utilize the LCFS to encourage long term adoption of SAF in the aviation sector by adopting provisions that will help realize the additional air quality and climate benefits SAF can provide the state, including by developing mechanisms to credit the non-CO2 climate benefits of SAF.

343.5 5. Finally, we offer new legal analysis, attached, to show that California enjoys ample authority to obligate all jet fuel uplifted in California, in line with its treatment of other transportation fuels[6]

Please see our detailed comments and rationale for each below.

1. Include all jet fuel as a deficit generator under the LCFS.

The current proposal to remove the exemption only for intrastate jet fuel is an important step in the right direction but is far from sufficient to meet state goals for the aviation sector. Removing the exemption for intrastate jet fuel SAF will help by partially eliminating the LCFS rack fee benefit that currently applies to replacements for obligated fuels but not for SAF, thereby increasing the market signal for SAF production.[7] However, an obligation on roughly 10% of the jet fuel pool cannot be expected to close the gap between current uptake and the state's goals. Indeed, CARB's own modeling suggests that SAF blending could reach about 100 million gallons in 2030 and about 200 million in 2045 as a result of the current proposal.[8] While these volumes represent encouraging growth from today's volumes, they still fall far short of state goals, which would require roughly 800 million gallons of SAF to meet Gov. Newsom's 20% clean fuels adoption target, 1.5 billion gallons in 2030 to meet the AB 1322 goal, and 3.2 billion gallons by 2045 to meet the 2022 Scoping Plan target. As noted by the International Council on Clean Transportation (ICCT), obligating only intrastate jet fuel would have "a minimal impact on the program due to the small size of this fuel pool and would fail to meaningfully promote aviation decarbonization."[9]

343.1 To boost the impact of the aviation provisions and put California on a path to achieving its aviation decarbonization goals, we encourage CARB to remove the exemption for all jet fuel uplifted in California. While anything that closes the incentive gap under the LCFS between jet and diesel substitutes (including obligating only a portion of jet fuel as proposed) will be directionally helpful in increasing SAF supply by reducing the opportunity cost for producers who choose to make SAF, obligating all jet fuel uplifted in CA will have a much more significant impact in sending an investment signal for SAF and driving SAF use in the state.

If CARB maintains a focus on obligating only intrastate jet fuel use, we suggest that CARB obligate all jet fuel combusted in California, as outlined in the September 20, 2023 Board meeting, when CARB staff stated that intrastate jet fuel would include not only flights within California, but also the portion of jet fuel combusted in California from other flights that start or end in California. Such a provision need not be overly precise or require direct regulation of or reporting from aircraft operators. Rather, existing data and tools could be used to develop a rough estimation of intrastate fuel use.[10]

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[6] *See* Attachment to our comments (Attachment_Legal Analysis_CARB LCFS Authority to Obligate Jet Fuel.pdf)

[7] SAF credit generation under the LCFS has consistently been less than 1% of credit generation for very similar renewable diesel. This is in part because of regulatory disincentives to SAF, such the LCFS rack fee and the state Cap-at-the-Rack cost under the Cap-and-Trade program, both of which increase the cost of fossil diesel, and the federal RFS program which awards 1.7 RINs per gallon of renewable diesel compared to just 1.6 per gallon of SAF. While the total size of the incentive gap varies, the BAAQMD analysis estimated it in 2020 at about $0.42 per gallon advantage for producing renewable diesel versus SAF, of which the LCFS represented about $0.14. An obligation only on intrastate jet fuel—a small fraction of the total pool—would reduce the LCFS disparity only marginally. New federal incentives under the Inflation Reduction Act, such as the SAF Blender's Tax Credit (40B) and the Clean Fuels Production Credit (45Z) can in theory make up much of that difference, but given that those expire in 2025 and 2027, respectively, they do not send a robust investment signal for needed SAF production. *See* CA LCFS Data Dashboard, Figure 2 at https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard; *See also* Bay Area Air Quality Management District (BAAQMD), Sustainable Aviation Fuel: Greenhouse Gas Reductions from Bay Area Commercial Aircraft. October 2020. *available at* https://www.baaqmd.gov/news-and-events/page-resources/2020-news/121120-saf-report.

[8] CARB, Appendix C-1 Standardized Regulatory Impact Assessment, September 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appc-1.pdf. Figure 4, page 18.

[9] Stephanie Searle, International Council on Clean Transportation Comments on the November 2022 LCFS Workshop. December 21, 2022. https://www.arb.ca.gov/lists/com-attach/84-lcfs-wkshp-nov22-ws-B2lQOVAnVVkEMAc3.pdf.

[10] *See* Graver, Rutherford, and Zheng, CO_2 Emissions from Commercial Aviation. ICCT, 2020. https://theicct.org/wp content/uploads/2021/06/CO2-commercial-aviation-oct2020.pdf. The methods used by Graver et al. could be extended with a simple additional calculation to attribute fuel burn from either takeoff or landing (whichever occurs in California) plus a fraction of the cruising fuel burn equal to the fraction of the route's distance that lies within the state.

2. **Accelerate the obligation to begin in 2025, rather than 2028.**

343.2 CARB states that the proposal to delay the elimination of the exemption for fossil fuel jet fuel until 2028 is meant to provide "sufficient time for potential producers of alternative jet fuel to add capacity for the anticipated increased demand of alternative jet fuel"[11] However, such a delay is unnecessary, and we urge CARB to consider an earlier implementation date. We note that British Columbia has already added an obligation for all fossil jet fuel beginning in 2026, coupled with a volumetric SAF mandate beginning in 2028.[12] In addition, the proposal trails the ambition of both the ReFuel EU SAF mandate beginning in 2025 as well as the recently announced SAF mandate in Singapore beginning in 2026.[13]

Given that CARB is only proposing an obligation for jet fuel and not an actual SAF requirement, consistent with the LCFS, there is technically no need for lead time to increase SAF production capacity because the structure of the LCFS program allows for compliance via credits generated outside of aviation—credits which are readily available today.[14] In addition, CARB has already provided a five-year window for growth since making SAF an opt-in credit generator in 2019, during which time SAF volumes recorded under the LCFS have increased five-fold, despite a global pandemic and the continued regulatory disadvantages for SAF producers under both the LCFS and the Cap and Trade program.[15] Nevertheless, SAF continues to lag far behind similar ground transportation fuels under the LCFS. This gap should not be misinterpreted as a signal that the SAF market or SAF technologies are insufficiently mature to support an obligation for aviation, but rather should serve as evidence that the lack of an LCFS obligation for aviation has steered producers toward more lucrative opportunities serving road transportation.[16]

In any event, our organizations are confident that there will be enough production capacity to meet demand beginning in 2025. In the last year alone, global SAF capacity has increased by over 300 million gallons from a single producer and the International Air Transport Association estimates 2024 SAF production to triple to over 500 million gallons, or 1.5 million metric tonnes.[17] In the U.S., SAF production capacity has expanded by at least 70 million gallons, with new facilities including LanzaJet's Freedom Pine Fuels[18] and Montana Renewables Great Falls plant[19] coming online. Additional expansions are in the pipeline, including concrete, near-term plans for expansions from Diamond Green Diesel,[20] Montana Renewables,[21] and California's own World Energy.[22] Most importantly, there are roughly 3 billion gallons of renewable diesel consumed in the U.S. each year, 80% of which is produced domestically,[23] and half of which could easily be transitioned to SAF production—where it would produce additional benefits to both climate and local air quality— if additional policy incentives were put in place under the LCFS to level the playing field for SAF. In sum, there is sufficient SAF production capacity and CARB need only send an appropriate market signal.

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[11] *See* CARB, Appendix E: Purpose and Rationale for Low Carbon Fuel Standards Amendments. January 2, 2024. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appe.pdf. Page 12.

[12] *See* https://www.bclaws.gov.bc.ca/civix/document/id/oic/oic_cur/0699_2023.

[13] *See https://www.consilium.europa.eu/en/press/press-releases/2023/10/09/refueleu-aviation-initiative-council-adopts-new-law-to-decarbonise-the-aviation-sector; See also https://www.reuters.com/sustainability/singapore-require-departing-flights-use-sustainable-fuel-2026-2024-02-19/*

[14] As further detailed in Section 5 below, the ability to comply by means other than SAF further demonstrates that CA is not preempted from obligating jet fuel under the LCFS.

[15] *See* CA LCFS Data Dashboard, Figure 2 at https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard

[16] On regulatory disincentives, see footnote 8. On technology and market maturity, several SAF pathways have already been commercialized. A total of 8 pathways for SAF production have been approved under ASTM 7566, and 3 additional coprocessing pathways have been approved under ASTM D1655. *See* https://www.caafi.org/focus_areas/fuel_qualification.html.

[17] *See* https://www.neste.com/products-and-innovation/sustainable-aviation/questions-and-answers-about-saf ; https://www.iata.org/en/pressroom/2023-releases/2023-12-06-02/

[18] *See* https://www.prnewswire.com/news-releases/lanzajet-celebrates-grand-opening-of-the-worlds-first-ethanol-to-sustainable-aviation-fuel-production-facility-302052431.html.

[19] *See* https://www.prnewswire.com/news-releases/montana-renewables-begins-sustainable-aviation-fuel-deliveries-to-shell-301820679.html.

[20] *See* https://worldbiomarketinsights.com/valero-energy-and-darling-ingredients-on-time-with-saf-plant-in-texas/#:~:text=Valero%20Energy%20and%20Darling%20Ingredients%20on%2Dtime%20with%20SAF%20plant%20in%20Texas,-by%20Daniela%20Castim&text=Valero%20Energy%20and%20Darling%20Ingredients%20have%20announced%20that%20their%20joint,the%20first%20quarter%20of%202025.

[21] *See* https://www.ogj.com/energy-transition/article/14296189/calumet-provides-operational-update-on-montana-renewables-great-falls-plant.

[22] *See* https://www.prnewswire.com/news-releases/world-energy-secures-permits-will-completely-convert-its-southern-calif-refinery-to-create-north-americas-largest-worlds-most-advanced-sustainable-aviation-fuel-hub-301531135.html.

[23] *See* https://ethanolproducer.com/articles/epa-2375-billion-rins-generated-in-2023. RIN data, which measure consumption of renewable diesel, underestimate domestic production capacity because a fraction of domestically produced fuels are exported.

We urge CARB to maintain its role as a leader in LCFS policy by accelerating its fossil jet fuel obligation to 2025.

3. Allow for book-and-claim accounting of low-CI electricity and RNG for SAF production.

343.3 We are supportive of the existing policy to allow book-and-claim accounting for low-CI electricity and RNG inputs to the production of low-CI hydrogen, and we applaud CARB's proposal to expand access through the use of power purchase agreements (PPAs) for low-CI electricity. However, we strongly believe that the same access should be expanded to SAF. At minimum, we urge CARB not to eliminate the existing allowance for indirect accounting for low-CI electricity to produce hydrogen that is used in the production of fuels, including SAF.

CARB's arguments for providing additional flexibility to low-CI hydrogen when directly used as a transportation fuel apply equally to SAF. Both low-CI hydrogen and SAF are young technologies with nascent markets that displace hard-to-electrify end uses like powering aircraft. The 2022 CARB Scoping Plan calls for significant growth in the use of both and, in the aviation sector, envisions even greater growth for SAF—from less than 1% of jet fuel consumption today to 80% in 2045.[24]

Despite these parallels, current and proposed LCFS rules for indirect accounting of low-CI energy systematically disadvantage SAF relative to hydrogen. Hydrogen producers have access to emissions reductions from process energy—low-CI electricity and RNG—that SAF cannot access. This is counter to state goals for SAF uptake and aviation decarbonization. We urge CARB to promote equity between future fuels like SAF and hydrogen and allow indirect accounting of RNG and low-CI electricity—both as a direct
343.3 input to SAF and as an input to hydrogen for use in SAF.

4. Utilize the LCFS to encourage long term adoption of SAF by adopting provisions that will help realize the additional air quality and climate benefits SAF can provide the state, including by developing mechanisms to credit the non-CO2 climate benefits of SAF.

We applaud CARB for thinking dynamically about alternative fuels and their impacts on climate, environment, and society. We urge CARB to acknowledge the additional, uncounted positive externalities that come from substituting fossil jet fuel with SAF and consider ways to better account for them under the LCFS.

First, while both light and medium/heavy-duty transportation are expected to electrify over the coming decades (although on different timetables), aviation will take much longer to transition to decarbonize, and SAF is expected to be the chief decarbonization lever for the foreseeable futures. The 2022 Scoping Plan scenario envisions 100% sales of zero emissions vehicles for light duty transport by 2035 and for medium/heavy duty transport by 2040, but for aviation sees only 20% alternative propulsion by 2045.[25]

343.4 Second, SAF provides additional air quality benefits that have not been fully considered by CARB. CARB notes that the current proposal would result in reductions in oxides of nitrogen (NO_x) and fine particulate matter (PM 2.5).[26] In addition, a recent synthesis of emissions measurement campaigns by the Airport Cooperative Research Program (ACRP), administered by the Transport Research Board of the U.S. National
343.4 Academies of Sciences, found that a 50% SAF blend could reduce by nearly 40% oxides of sulfur,[27] which are known to have significant negative effects on exposed populations, and which are present in greater proportions in fossil jet fuel than other transportation fuels like diesel. Additionally, other studies have found greater reductions in PM than the 55% cited in the SRIA. The ACRP study found PM reductions of

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[24] *See* CARB, 2022 Scoping Plan for Achieving Carbon Neutrality. December 2022. https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp_1.pdf. Page 73.
[25] *See* CARB, 2022 Scoping Plan for Achieving Carbon Neutrality. December 2022. https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp_1.pdf. Page 72-73.
[26] *See* CARB, Staff Report: Initial Statement of Reasons (ISOR). December 19, 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf. Page 57.
[27] Airport Cooperative Research Program, Alternative Jet Fuels Emissions Quantification Methods Creation and Validation Report. August 2019. Page 10. *Available at* http://www.trb.org/Publications/Blurbs/179509.aspx

up to 65%, and a more recent measurement campaign found that SAF produced via the alcohol-to-jet pathway could reduce non-volatile particulate matter by up to 97%.[28]

343.4 Third, California's environmental justice communities have explicitly asked CARB to support displacement of fossil jet fuel with SAF, both in the formal recommendations to CARB of the Environmental Justice Advisory Committee[29] and in person, at the September 28th, 2023 Board meeting. Communities that live near and work at airports are some of the most vulnerable in California — of the ten busiest airports in the state, four are located within SB 535 designated disadvantaged communities, and another four are immediately adjacent.[30] These communities have long borne the disproportionate health impacts of unmitigated fossil jet fuel combustion.

Fourth, jet fuel causes unique contributions to global climate change that are unrecognized by the LCFS—harms that SAF can mitigate. Emerging research indicates that particulate matter reductions from SAF reduce aviation's non-CO_2 climate impact, specifically the climate forcing from "contrail cirrus" impacts (the combined warming from contrails and contrail-induced cirrus). The current best estimate from the most recent comprehensive study is that the climate impact from contrail cirrus is nearly twice the impact from CO_2.[31] Even the low end of current estimates–which show that contrail cirrus causes roughly half the total warming of CO_2– warrants consideration of potential mitigation opportunities from SAF.[32] One recent study cited found that a 50% SAF blend could reduce contrail cirrus climate impacts by over 20%. An eventual shift to 100% SAF could reduce the climate impact of contrail cirrus by 50%.[33] While continued scientific uncertainty around the size of the non-CO_2 climate impacts makes them difficult to precisely quantify, the direction of those impacts—less warming when SAF is used—is known.

We strongly believe that these additional benefits—which align closely with state goals and priorities and accrue only to SAF—justify action by CARB to prioritize the use of SAF. And as CARB has noted, transitioning fuels to other sectors in the long term requires that market signals transition first.[34] Under the current proposal, the market signal improves marginally, but is not likely to be enough to meet the state's goals. Accordingly, we encourage CARB to consider additional measures to credit those benefits. For example, CARB should consider applying a credit multiplier for SAF on the basis of the most conservative estimates of non-CO_2 climate benefits of SAF. (The European RED II program, currently provides a multiplier of 1.2x for SAF.) Alternatively, CARB might develop a "CO_2 equivalent" metric to account for these benefits in terms of carbon intensity and incorporate them into the CA-GREET model, as has been suggested by the European Commission in its recent study on how to address the non-CO_2 climate impacts of aviation.[35]

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[28] Tran, Brown and Olfert. Comparison of Particle Number Emissions from In-Flight Aircraft Fueled with Jet A1, JP-5 and an Alcohol-to-Jet Fuel Blend. *Energy Fuels* 34, 6, 7218–7222 (2020). https://doi.org/10.1021/acs.energyfuels.0c00260.

[29] *See* AB 32 EJAC DRAFT Recommendations to the CARB on the Low Carbon Fuel Standard Regulation Updates. August 24, 3023. https://ww2.arb.ca.gov/sites/default/files/2023-08/EJAC%20Low%20Carbon%20Fuel%20Standard%20Recommendations%20Version%201%20082423.pdf *and* EJAC, Environmental Justice Advisory Committee 2022 Scoping Plan Recommendations: NF54. Page 16. September 30, 2022. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/090122/finalejacrecs.pdf.

[30] *See* https://oehha.ca.gov/calenviroscreen/sb535. LAX, OAK, BUR, and ONT are within disadvantaged communities. SFO, SMF, SNA, and LGB are adjacent.

[31] D.S. Lee, et al. The contribution of global aviation to anthropogenic climate forcing for 2000 to 2018. *Atmospheric Environment* 244, 117834 (2021). https://doi.org/10.1016/j.atmosenv.2020.117834.

[32] *Id*.

[33] *See* European Union Aviation Safety Agency, Updated Analysis of the non-CO_2 Climate Impacts of Aviation and the Potential Policy Measures Pursuant to EU Emissions Trading System Directive Article 30(4) (synthesizing research on SAF non-CO_2 climate benefits and suggesting further consideration of SAF policy measures to mitigate aviation climate impacts); *available at* https://www.easa.europa.eu/sites/default/files/dfu/201119_report_com_ep_council_updated_analysis_non_co2_climate_impacts_aviation.pdf.

[34] *See* CARB, Staff Report: Initial Statement of Reasons (ISOR). December 19, 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf. Page 30.

[35] *See* European Union Aviation Safety Agency, Updated Analysis of the non-CO_2 Climate Impacts of Aviation and the Potential Policy Measures Pursuant to EU Emissions Trading System Directive Article 30(4) (synthesizing research on SAF non-CO_2 climate benefits and suggesting further consideration of SAF policy measures to mitigate aviation climate impacts); *available at* https://www.easa.europa.eu/sites/default/files/dfu/201119_report_com_ep_council_updated_analysis_non_co2_climate_impacts_aviation.pdf.

5. <u>California Enjoys Ample Authority to Obligate All Jet Fuel Uplifted in CA</u>

While some stakeholders have long asserted that CARB does not have legal authority to include jet fuel as an obligated fuel due to unarticulated claims of federal preemption in the sector, this claim has to date not been addressed on the merits and we hope this proposal catalyzes more detailed understanding among stakeholders of the scope of CARB's authority over aviation. As further outlined in the attached legal analysis and summarized below, it is clear that CARB enjoys ample authority to obligate both intrastate and all jet fuel uplifted in California (interstate and international) under the LCFS program.[36] None of the statutes that have been cited by stakeholders—the Clean Air Act, the Federal Aviation Act, or the Airline Deregulation Act, serve as a source of preemption or a barrier to CARB promulgating an aviation obligation that is commensurate with the state's goals in the aviation sector.

Here, we address each of those statutes in turn.

a) Clean Air Act

The Clean Air Act does not preempt an obligation on jet fuel under the CA LCFS, whether applied to intrastate jet fuel use or to all fossil jet fuel uplifted in the state. Importantly, courts analyzing preemption are "highly deferential to state law in areas traditionally regulated by the states" such as air pollution prevention and related public health measures.[37]

While Section 233 of the Clean Air Act does give EPA explicit preemptive authority on the regulation of emissions **<u>from aircraft engines</u>**, this provision is simply not relevant to the regulation of fuels.[38] Notably, the Ninth Circuit interprets the preemptive scope to cover only regulation of aircraft or aircraft engines, and has not extended preemption beyond that scope to include the regulation of jet fuel.[39] Indeed, a reading that Section 233 preempts regulation of jet fuel would be contrary to the plain meaning of the statute, the structure of the Clean Air Act, and EPA's longstanding interpretation of its authority over aviation. By its terms, section 233 refers to engine and aircraft standards promulgated under Section 231, not to fuel standards. And the underlying structure of the Clean Air Act certainly distinguishes between engine and fuel standards, with separate provisions for engine/vehicle standards under Sections 202 (on road vehicles/engines), 213 (nonroad vehicles/engines) and Section 211 (fuels for use in on road and nonroad vehicles/engines). To read Section 233's preemption provisions as somehow applying to aircraft fuels would be wholly inconsistent with this statutory structure.

Such an interpretation would also be inconsistent with EPA's long-held interpretation of its authority as extending only to aircraft/engine standards, with the Federal Aviation Administration (FAA) then having authority to promulgate fuel standards for any pollutant for which EPA has made an endangerment finding under Section 231 of the Clean Air Act.[40] Indeed, just last year the EPA reiterated this position, noting in its final endangerment finding for leaded aircraft fuels that EPA's only role was to make an endangerment finding and promulgate an engine standard for lead. Aviation fuel standards, EPA reiterated, were left to FAA.[41] Simply put, the Clean Air Act cannot preempt California from issuing fuel standards for aviation that EPA itself lacks the authority to issue.

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[36] We note that, in the Canadian context, British Columbia has determined that any jet fuel sold in the province is subject to provincial regulation.

[37] 14 Exxon Mobil Corp. v. United States EPA, 217 F.3d 1246, 1255 (9th Cir. 2000).

[38] See 42 U.S.C. § 7573 (stating that" No State or political subdivision thereof may adopt or attempt to enforce any standard respecting emissions of any air pollutant from any aircraft or engine thereof unless such standard is identical to a standard applicable to such aircraft under this part.")

[39] See California v. Department of Navy, 624 F.2d 885, 888 (9th Cir. 1980); California ex rel. State Air Resources Bd. v. Department of Navy, 431 F. Supp. 1271, 1285 (N.D. Cal. 1977) (narrowly interpreting the "field" regulated as the "structure or performance of aircraft engines").

[40] *See* EPA, Advance Notice of Proposed Rulemaking on Lead emissions From Piston-Engine Aircraft Using Leaded Aviation Gasoline, 75 Fed. Reg. 22445-22446 (April 28, 2010) (explaining in EPA rulemaking that although EPA has authority under the Clean Air Act to regulate fuels used in motor vehicles and nonroad vehicles, fuels used exclusively in aircraft engines are regulated by FAA); see also EPA, Advance Notice of Proposed Rulemaking on Regulating Greenhouse Gas Emissions Under the Clean Air Act, 73 Fed. Reg. 44434 (July 30, 2008) ("Section 211(c) authorizes regulation of vehicle fuels and fuel additives (excluding aircraft fuel)…").

[41] *See* EPA, Finding That Lead Emissions From Aircraft Engines That Operate on Leaded Fuel Cause or Contribute to Air Pollution That May Reasonably Be Anticipated To Endanger Public Health and Welfare, 88 Fed. Red. 72372-72404 (October 20, 2023). (EPA states, "pursuant to 49 U.S.C. 44714, the FAA has a statutory mandate to prescribe standards for the composition or chemical or physical properties of an aircraft fuel or fuel additive to control or eliminate aircraft emissions which the EPA has found endanger public health or welfare under section 231(a) of the Clean Air Act.")

Further, even if EPA theoretically had authority to regulate jet fuel, the proposal does not run afoul of the preemption provisions under Section 233 of the Clean Air Act because the LCFS is not an "emission standard" applicable to aircraft and aircraft engines. Under the U.S. Supreme Court's definition of emission standard, the LCFS is not an emission standard because it does not restrict how much of a given pollutant an engine may emit, it does not require equipment of a certain pollution control device, or mandate emission control design features.[42] Further, as reinforced in a recent order from the U.S. District Court for the Central District of California, the LCFS is not an aviation emission standard because regulated entities (fuel suppliers) can comply by taking action unrelated to the purchase of SAF and the LCFS does not serve as an attempt to compel the purchase of SAF.[43]

b) Federal Aviation Act

The Federal Aviation Act grants broad authority to the FAA that has been generally held to "preempt the field" of aviation safety and airspace management.[44] However, the preemptive scope of the FAA Act is not limitless, and courts have determined that states may still regulate certain aspects of aviation operations that do not directly intrude on the FAA's domain.[45] With respect to fuels, the FAA's domain includes both the general authority to approve aviation fuels[46] and the specific statutory authority, under Section 44714[47], to prescribe "standards for the composition or chemical or physical properties of an aircraft fuel or fuel additive to control or eliminate aircraft emissions" which the Environmental Protection Agency (EPA) has determined endanger public health or welfare.[48]

The inclusion of jet fuel as an obligated fuel under the CA LCFS would not intrude on the FAA's regulatory domain. While the CA LCFS would establish standards for the lifecycle carbon intensity of jet fuel and incentivize the use of some fuels approved by FAA over others, it would **not mandate or prohibit the use of any particular jet fuel approved by the FAA**, nor would it set any of its own requirements on the composition of fuels. The FAA could—and should—exercise its own authority under Section 44714 to set a federal emissions standard on fossil jet fuel,[49] with which the LCFS obligation on fossil jet fuel would work in tandem. [50]

Importantly, an obligation on jet fuel is not equivalent to a mandate for SAF, and obligated upstream fuel providers are free to comply with LCFS credits from numerous sources. While we believe an obligation on fossil jet fuel—particularly all fossil jet fuel uplifted in the state—will meaningfully increase the market signal for SAF production and use in the state, the ultimate means of compliance with the LCFS is up to obligated parties, and aircraft operators will not be required to use SAF under the proposal.

c) Airline Deregulation Act (ADA)

Finally, some stakeholders have claimed that the ADA preempts California from obligating fossil jet fuel under the LCFS. The ADA expressly prohibits states from enacting or enforcing "a law, regulation, or other provision having the force and effect of law related to a price, route, or service of an air carrier that may provide air transportation . . . ."[51] However, although obligating jet fuel as a deficit generator under the LCFS may increase the cost of fuel uplifted by an airline, those impacts are likely outside the scope of ADA

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[42] *See Engine Mfrs. Ass'n v. S. Coast Air Quality Mgmt Dist.,* 541 U.S. 246, 253 (2004).
[43] *See* Order re: Plaintiff's Motion for Summary Judgment as to Plaintiff's Complaint for Declaratory Judgment and Injunctive Relief [Dkt. 65]; and Plaintiff-Intervenor Airlines for America's Motion for Summary Judgment [Dkt. 73], Docket No. 162 (holding that South Coast's Warehouse Indirect Source Rule is not a Clean Air Act emission standard because regulated entities may comply by taking actions unrelated to the purchase of zero emission trucks.)
[44] See *Montalvo v. Spirit Airlines*, 508 F.3d 464, 471-74 (9th Cir. 2007).
[45] *See Goodspeed Airport LLC v. East Haddam Inland Wetlands & Watercourses Comm'n,* F.3d 206, 209-12 (2d Cir. 2011); *Martin v. Midwest Express Holdings,* 555 F.3d 806, 812 (9th Cir. 2009); *Med-Trans Corp. v. Benton,* 581 F. Supp. 2d 721, 740 (E.D.N.C. 2008) ("Although the FAA has preemptive control of aviation safety measures, regulations regarding [emergency medical services] related equipment would not intrude on its domain.... [O]nly those regulations governing equipment or training directly related to aviation safety are preempted.").
[46] *See* 14 C.F.R. § 33.7 (engine operating limitations for fuel)
[47] 49 U.S.C. § 44714.
[48] EPA endangerment findings are authorized under Section 231 of the Clean Air Act (42 U.S.C. 7571)
[49] *See* Third Way, FAA's Existing Authority to Create a Low Carbon Aviation Fuel Standard, at 4 (June 2023), https://thirdway.imgix.net/Existing-Authority-for-a-Federal-LCFS.pdf.
[50] *See Rocky Mountain Farmers Union v. Corey*, 258 F. Supp. 3d 1134, 1152-53 (E.D. Cal. 2017) (holding LCFS was not preempted where and state efforts to reduce GHG emissions complemented and supported the EPA's efforts).
[51] 49 U.S.C. § 44713(b)(1). The exceptions do not apply to the proposal to include jet fuel in the LCFS

preemption,[52] impose such a tenuous burden on an air carrier's price or services that it would not trigger preemption,[53] or are simply too difficult to link causally to changes in carrier prices, routes or services, given the complexity of airline ticket and fuel pricing. Fundamentally, an LCFS obligation on jet fuel would not
343.5 entail any specific regulation of price, routes, or services, and is therefore not preempted by the ADA. Notably, the Central District of California recently held that the South Coast Air Quality Management District's Warehouse Indirect Source Rule does not run afoul of the ADA because it only has an indirect connection to carrier prices, services, or routes.[54]

To further insulate the aviation provisions from potential legal challenge, we recommend that CARB designate jet fuel suppliers as the reporting entity—as currently proposed. Designating fuel suppliers as the
343.5 reporting entity aligns with existing LCFS precedent for other fuel types and merely ensures that upstream aviation fuel suppliers are treated in the same fashion as all other transportation fuel suppliers in the California economy. This is significant, as case law around aviation preemption distinguishes between regulations targeted specifically at aviation and regulations that merely apply to upstream "inputs" to many sectors of the economy, including aviation.

d) Dormant Commerce Clause

In addition to preemption challenges, another potential challenge to the LCFS that could arise is the "dormant Commerce Clause" of the U.S. Constitution, which limits the state's authority to enact or enforce laws that burden interstate commerce. However, the LCFS has already been upheld against dormant Commerce Clause challenges.[55] Because the burden on jet fuel providers would not seem appreciably different from the burden imposed by the LCFS on other fuel providers, a court may be hard pressed to reach a different result if a dormant Commerce Clause challenge to the Proposal were brought.

Finally, we emphasize that CARBs attempt to avoid conflict with federal laws by isolating intrastate jet fuel is unnecessary. When Congress determines that a uniform national standard is needed, federal law preempts state regulation everywhere—including regulations internal to a state, such as obligating intrastate jet fuel under the LCFS. The proposal's limitation to intrastate jet fuel use offers only marginal protection from challenges, while dramatically weakening the impact of the obligation and threatening the achievement of the state's aviation decarbonization goals. Accordingly, we strongly suggest that CARB eliminate the distinction between intrastate and interstate jet fuel and obligate all jet fuel uplifted in California under the LCFS.

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Thank you for the opportunity to comment on this LCFS Rulemaking. Please don't hesitate to reach out if you have any questions.

Sincerely,

[52] 17 See Nat'l Federation of the Blind v. United Airlines, Inc., 813 F.3d 718, 727-28 (9th Cir. 2016) (noting that the Ninth Circuit has narrowly interpreted "service" to mean an air carrier's transportation service).
[53] *Supra*. Note 15
[54] *Supra*. Note 43 (noting that the rule is not preempted because it applies to all warehouses and not only air carrier warehouses, that potential increased costs for air carriers are not sufficient as increased costs do not interfere with the air carrier/customer relationship, and that the rule does not require specific prices or fundamentally differ from other generally applicable regulation that affects an air carrier's cost of compliance.)
[55] Rocky Mountain Farmers Union v. Corey, 730 F.3d 1070, 1107 (9th Cir. 2013); Rocky Mountain Farmers Union v. Corey, 913 F.3d 940, 948-54 (9th Cir. 2019).

Advanced Biofuels Canada
Biocarburants avancés Canada

Blue Arrow

CEMVITA

Green Plains

LanzaTech

raizen

Sugar VALLEY ENERGY

Bio

comstock FUELS

DARLING INGREDIENTS

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Comment 353 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Graham
Last Name	Noyes
Email Address	graham@noyeslawcorp.com
Affiliation	NLC on behalf of Infinium
Subject	Comment of Infinium RE: Electrofuels

Comment

Attached please find the comments of Infinium regarding the proposed Low Carbon Fuel Standard regulations. Below is a summar of the comments. Please contact me for any questions relating to the comments.

Best Regards,
Graham Noyes
Noyes Law Corporation

Infinium Operations, LLC ("Infinium") is pleased to submit comment recommending specific modifications to the California Air Resource Board's ("CARB") proposed amendments to the Low Carbon Fuel Standard ("LCFS"). We strongly support CARB's LCFS program. However, we respectfully request that CARB revisit its proposed power sourcing structure as applied to power-to-liquid fuels which are also known as eFuels". In the same way that electric vehicles must utilize zero carbon power to be carbon neutral, eFuels must b produced from zero carbon power to be carbon neutral. We respectfully recommend that CARB follow its own precedent by allowing eFuels to source low carbon intensity ("Low-CI") power in the future in the same manner as electric vehicles do today.

Attachment www.arb.ca.gov/lists/com-attach/7032-lcfs2024-VD1TO1UyUWsHb1Q9.pdf

Original File Name Infinium Only Letter FINAL.pdf

Date and Time Comment Was Submitted 2024-02-20 18:38:45

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Board Comments Home

INFINIUM™

February 20, 2024

The Honorable Liane M. Randolph
Chair
California Air Resources Board

(Comment submitted electronically)

RE: Infinium Operations, LLC's Recommendations that would Enable California to Harness the Profound Decarbonization Potential of eFuels

Dear Chair Randolph,

Infinium Operations, LLC ("Infinium") is pleased to submit comments recommending specific modifications to the California Air Resources Board's ("CARB") proposed amendments to the Low Carbon Fuel Standard ("LCFS"). We strongly support CARB's LCFS program as it sends a strong market signal to decarbonize the transportation sector, is performance based, and
344.1 provides long-term policy stability that supports investment. However, we respectfully request that CARB revisit its proposed power sourcing structure (the "Proposed Structure" or "Proposed Regulations") as applied to power-to-liquid fuels ("PtL Fuels") which are also known as eFuels. In the same way that electric vehicles must utilize zero carbon power to be carbon neutral, eFuels must be produced from zero carbon power to be carbon neutral. We respectfully recommend that CARB follow its own precedent by allowing eFuels to source low carbon intensity ("Low-CI") power in the future in the same manner as electric vehicles do today.

As further examined in this comment, the Proposed Structure precludes the recognition of greenhouse gas ("GHG") emission reductions that are achieved by sourcing Low-CI power that is delivered over the grid to produce eFuels. By effectively mandating that eFuel production facilities source only grid power that includes fossil-based power except in rare circumstances, the Proposed Structure prevents both the growth of the eFuel industry and the expansion of new sources of renewable power. These policy outcomes undercut the tremendous potential of eFuels to decarbonize internal combustion vehicles ("ICVs") and jet engines; run counter to the goals of CARB's 2022 Scoping Plan to dramatically decarbonize transport and power; and reduce the likelihood that California will achieve carbon neutrality by 2045.

Recommended Changes

Infinium respectfully requests the following modifications to the Proposed Structure:

344.2 1. Allow eFuel production facilities to utilize the book-and-claim power sourcing system that is currently authorized for battery electric vehicles and electrolytic hydrogen to source Low-CI power via book-and-claim to produce electrolytic hydrogen and to produce drop-in fuels from hydrogen and carbon dioxide.

344.3 2. Establish a book-and-claim accounting system for hydrogen pipelines that is applicable outside California.

344.4 3. Establish a book-and-claim accounting system for carbon dioxide pipelines that is applicable outside California.

344.5 4. Revise the proposed Alternative Fuel definition to account for drop-in eFuel alternatives for gasoline and diesel fuel.

About Infinium

Infinium's mission is to decarbonize the transportation sector through the production of eFuels, an ultra-low carbon fuel alternative to petroleum derived transportation fuels. Infinium eFuels are drop-in replacements for use in planes, ships and motor vehicles without the need for costly infrastructure changes. Infinium's proprietary technology utilizes carbon dioxide (CO_2) that would otherwise be emitted, renewable power, and water as feedstocks to produce transportation fuels (e.g. eSAF, eDiesel and eNaphtha), with substantial reductions in lifecycle GHG emissions as compared to fossil-based alternatives.

Infinium's strategic and financial investors, include affiliates of Amazon, NextEra Energy, Mitsubishi Heavy Industries, SK Ventures, and AP Ventures- leading companies that are interested in both reducing their carbon footprints and innovating solutions to current environmental issues.

Infinium operates the first commercial drop-in eFuel facility in the world from its plant in Corpus Christi, Texas which will provide eFuels to Amazon's middle mile trucking fleet. Infinium announced a second commercial eFuel facility in West Texas called Project Roadrunner, which will be the largest in the world when it begins production in 2026. Project Roadrunner will produce primarily Infinium eSAF and smaller volumes of eDiesel and eNaphtha. Anchor partners include American Airlines as a sustainable aviation fuel ("SAF") off-taker and Breakthrough Energy Catalyst providing project equity investment.

How Can eFuels Help California Achieve Carbon Neutrality?

eFuels are renewable transportation fuels that are unique in that none of the energy content of the fuel comes from the input raw materials such as crude oil or biological sources (i.e., fuel feedstocks). The raw materials to produce eFuels are water and carbon dioxide that have no accessible energy value. Instead, the energy content in eFuels originates from renewable electricity applied during production to create hydrogen via electrolysis and subsequently reacted with CO_2 to yield eFuels such as eSAF, eDiesel and eNaphtha. In this respect, eFuels provide a method to convert renewable energy into a drop-in replacement fuel for ICVs and long-haul jets without the need to extract energy or release additional carbon from fossil crude oil or biomass-derived feedstocks.

eFuels have been recognized as a foundational fuel pathway in the policy framework of many jurisdictions and have also been recognized as a vital solution by non-governmental organizations ("NGOs") and think tanks. eFuels (with lifecycle GHG emission reductions exceeding 90% if produced using zero CI energy) provide the most effective means to substantially decarbonize internal combustion vehicles ("ICVs") and long-haul jets, and the drop-in nature of eFuels allows harnessing the massive value and capabilities of existing vehicles and liquid fuel infrastructure (e.g. storage and distribution systems).

The underlying logic of utilizing eFuels has been demonstrated by analysis completed by the University of California Institute of Transportation Studies ("ITS") in a report that charted California's likely course to carbon neutrality in the transportation sector. As stated in the Executive Summary, "The purpose of this study is to provide a research-driven analysis of possible policy options that could, if combined, put the state on the pathway to a carbon-neutral transportation system by 2045."[1]

The ITS report's authors deployed an aggressive suite of policies to accelerate and maximize the speed and scale of the transportation electrification to create the scenario for their analysis. Nonetheless, the Driving California's Transportation Emissions to Zero report concluded that a significant number of ICVs will remain on the road beyond 2035 and even beyond 2045 and these vehicles will require a substantial continued supply of liquid fuels. The ITS report recognized the resiliency of ICVs in terms of vehicle life and reached the conclusion that while total energy demand for transportation would drop substantially due to the efficiency of electric vehicles, ***almost half of all transportation energy demand in California would still be met by liquid fuels in 2045 as is reflected by the following figure from the ITS report***.[2] Importantly, the methodology of the ITS report limited the demand for SAF to fuel uplifted for intrastate flights in California only,[3] thus the report's fuel demand forecast did not account for approximately 90% of aviation fuel demand in California.

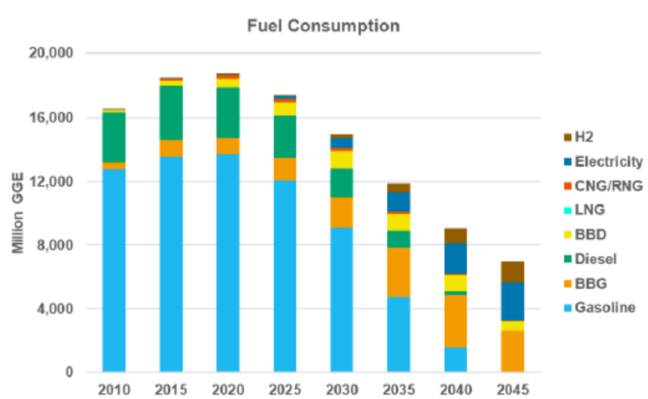

Figure EX-2. CO_2 emissions and fuel consumption projections in the LC1 scenario. The near-zero CO_2 emissions target is reached by 2045, with nearly all fossil fuels replaced by electricity, hydrogen, and biofuels at that date. (MMT, million metric tonnes; SAF, sustainable aviation fuel; H2, hydrogen; CNG/RNG, compressed natural gas/renewable natural gas; LNG, liquefied natural gas; BBD, bio-based diesel, including biodiesel and renewable diesel; BBG, bio-based gasoline, including ethanol blends and drop-in gasoline replacement fuels)

Driving California's Transportation Emissions to Zero

[1] See Institute of Transportation Studies, "Driving California's Transportation Emissions to Zero," (April 2021), available at https://escholarship.org/uc/item/3np3p2t0 , Executive Summary at p. 1, and Figure EX-2.
[2] Id.
[3] Id. at p. 395.

A close review of the ITS fuel forecasts for 2045 highlights the critical importance of low carbon liquid fuels to California's goal of achieving carbon neutrality:

- With reference to BBG (Bio-based Gasoline), ITS projected that the demand for this type of fuel would approximately double between 2025 and 2045 from 1.2 BGY to 2.4 BGY (in GGE, Gasoline Gallon Equivalent).
    - It is important to note that in the current market, ethanol is the only commercialized Bio-based gasoline and is restricted to a maximum blend level of 10%. Flex fuel vehicles can utilize blends of up to 85% but represent a small portion of the ICV fleet.
    - Thus, unless a drop-in Bio-gasoline is commercialized or eFuel is utilized, fossil-based gasoline would be the only fuel option and preclude achievement of California's carbon neutrality goal.
- With reference to BBD (Bio-based Diesel), the ITS report projects demand for this type of fuel will decline from approximately 930 MGY to 625 MGY (GGE).
    - However, as previously noted, the ITS report only evaluated demand for intrastate jet fuel in its analysis. If aviation fuel for interstate and international fuel is included, the demand for BBD in 2045 would increase to approximately 4.6 BGY or continued fossil jet fuel usage would be necessary to enable air travel.
    - Thus, if California considered all jet fuel uplifted in the State, it would be necessary to expand bio-based diesel usage by a factor of over 7x, a strategy that the ITS report deemed infeasible due to biomass feedstock supply constraints. eFuels will have a significant role in filling this void, given concerns regarding feedstock supply.

The European Union has Integrated eFuels into their Climate Policies

Consistent with the ITS analysis, the European Union ("EU") has determined eFuels to be an essential solution in the transport sector toward achieving the Union's carbon neutrality goals.

The EU RefuelEU Aviation program mandates steadily increasing blends of SAF for flights originating and departing in the EU with a sub-mandate for eFuels of 35% by 2045, as depicted in this chart.[4] In the road sector, under the Renewable Energy Directive ("RED"), eFuels must be blended to a minimum of 1% by 2030, with member countries planning to adopt higher quotas of up to 5.5%. In the marine sector, under the FuelEU Maritime program, eFuels are expected to play an outsized role in meeting the sector decarbonization mandate of 80% reduction in GHG emissions by 2050.

[4] See TOPSOE, "The Outlook for SAF," Timeline 3: The Course of Legislation, available at "https://www.topsoe.com/sustainable-aviation-fuel/saf-outlook".

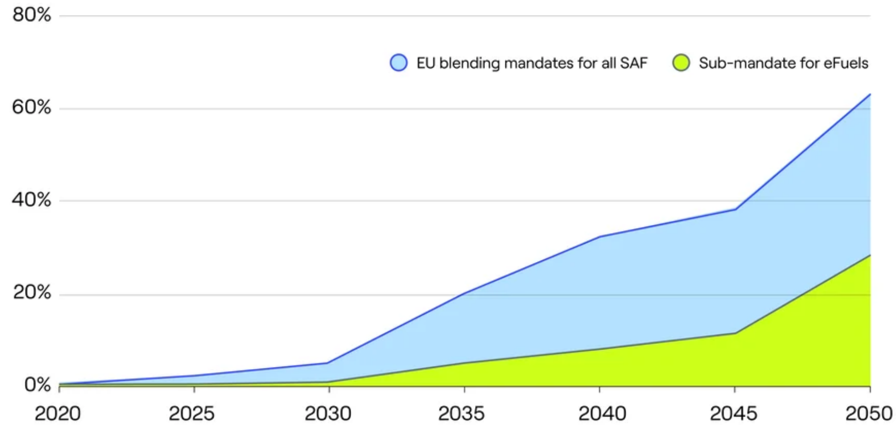

Chart: EU blending mandates for all SAF and sub-mandate for eFuels

The International Council on Clean Transportation has Recognized the Importance of eFuels

This past November, The International Council on Clean Transportation ("ICCT") published a white paper assessing the feasibility of meeting the targets in the Biden Administration's SAF Grand Challenge based on "resource availability, production costs, technology readiness level, and policy support."[5] ICCT's white paper emphasized the importance of eSAF in meeting the 2050 SAF Grand Challenge goal of 35 billion gallons, as follows:

> *We find that the near-term 2030 production target can be met with sustainable resources, but the 2050 target will be far more challenging to reach. In the longer-term, biomass volumes will need to be supplemented with a combination of other fuel sources or fuel burn reduction to meet the energy needs of the entire U.S. aviation sector. . . .*
>
> *E-fuels, or synthetic aviation fuels produced from renewable electricity, could help to bridge the supply gap in later years. . . .Though the technology remains in the demonstration phase, e-fuels have gained significant interest in Europe and other markets due to their 'drop-in' advantages and theoretically unlimited supply. For example, the EU has adopted an e-fuel mandate of 1.2% of aviation fuel, averaged over 2030 and 2031, and 5% of aviation fuel volumes by 2035 (European Commission, 2023). These e-fuels are estimated to be costlier than most biomass-derived SAFs in the near-future, but their costs could rapidly come down as electrolyzer technology*

[5] O'Malley, J., Pavlenko, N., & Kim, Y.H. (2023). Meeting the SAF Grand Challenge: Current and Future Measures to Increase U.S. Sustainable Aviation Fuel Production Capacity. International Council on Clean Transportation. Available at https://theicct.org/wp-content/uploads/2023/11/ID-37-%E2%80%93-SAF-Grand-Challenge-white-paper-letter-40036-v3.pdf.

matures and the cost of renewable electricity declines (Zhou et al., 2022). . . . With the use of policy incentives, including the IRA's 10-year production tax credits for hydrogen and carbon capture, utilization, and storage (CCUS), e-fuels will likely become cost-competitive within a much shorter timeframe.[6]

Low-CI Power Sourcing is Essential to the Success of eFuels

344.6 As noted by ICCT, eFuels are costlier than most biomass-derived SAF currently and in the near future. However, there is an opportunity to reduce the cost of eFuels as electrolyzer technology matures and the cost of renewable electricity further declines. Success in driving down the cost of both wind and solar power has been an enormous success story that has been led in the US by California policy. Similarly, California's 2022 Scoping Plan contained ambitious goals to expand supply and demand for hydrogen while driving down prices.

eFuels are uniquely well-situated to benefit from further reductions in the cost of renewable power and electrolyzers but the tremendous potential of this industry's growth will be stunted by the policy change in the Proposed Structure. Under §95488.8(i)(1)(A)-(B) of the existing LCFS Regulation, book-and-claim accounting is authorized for Low-CI Electricity supplied as a transportation fuel or to produce hydrogen through electrolysis if that hydrogen is used either as a transportation fuel or in the production of another transportation fuel (e.g., SAF). Through these provisions, eFuel production facilities are explicitly authorized to source Low-CI Electricity from the grid to produce hydrogen that is used in the production of eFuels. Under these existing LCFS provisions, Low-CI electricity can be sourced flexibly through the use of Renewable Energy Certificates ("RECs") or via a qualifying Green Tariff program.

The proposed LCFS regulatory revisions that CARB released on December 22, 2023, would dramatically narrow the power-sourcing landscape for eFuel producers. The proposed amendments would revoke the current authorization to source Low-CI Electricity for electrolysis through the REC mechanism. To source Low-CI Electricity, the proposed regulations would instead require an eFuel facility to construct a wind, solar or other renewable generation project and directly connect that power generation source behind the utility meter to the eFuel facility, which is typically impractical and infeasible. CARB's regulatory proposal will severely inhibit the growth of a liquid fuel technology that holds great promise for scaling and, as noted above, is not dependent upon biomass feedstocks. By changing its policy this significantly with no notice to the industry or delayed phase-in, CARB will also undermine investor confidence in the continuity of its policy structure and thereby deter investment in ***all clean fuel facilities and technologies***, including game-changing fuels like eFuels.

Book-and-Claim Power Sourcing Recommendation

Due to the importance of Low-CI Electricity to the production of eFuels, and the importance of eFuels to meeting both California's 2045 carbon neutrality goal and California's specific goals to displace fossil jet fuel with SAF, we respectfully recommend that CARB modify

[6] *Id.* at 21.

344.6 cont. the proposed LCFS amendments such that eFuel production facilities are authorized to procure Low-CI Electricity for electrolytic hydrogen production and their other energy needs via book-and-claim accounting.

344.7 Under existing LCFS provision §95488.8(i)(1)(A)-(B), Low-CI electricity supplied as a transportation fuel, e.g., used to power BEVs, can be sourced flexibly through the use of RECs or via a qualifying Green Tariff program. Under these provisions, it is also required that the electricity be supplied to the grid within the same balancing authority as where the EVs are charged or in compliance with CPUC §399.16, that all environmental attributes be retired with limited exceptions, and that the RECs be used within three quarters of when the RECs were generated.

As is currently the case for electrolytic hydrogen that can utilize RECs to obtain Low-CI power, CARB should restore and authorize this same power sourcing structure for eFuels that meets the requirements established by §95488.8(i)(1)(A)-(B). See Exhibit A for illustrative regulatory language that is aligned with this comment's recommendations.

344.8 Infinium also requests that the proposed definition for Alternative Fuel be revised to include the range of eFuel types including eDiesel, and eNaphtha / eGasoline. As drafted, the definition for Alternative Fuel includes fuels that are not CaRFG and 'diesel fuel'. However, for example, diesel fuel, as defined under California Code of Regulations, title 13, section 2281(b), includes any fuel that is commonly or commercially know, sold or represented as diesel fuel. As a result, any drop-in non-petroleum alternative such as eDiesel could be classified as 'diesel fuel' under this broad definition. See Exhibit A for illustrative regulatory language that is aligned with this comment's recommendations.

Infinium's Pipeline Recommendations

344.9 **Hydrogen:** Infinium supports CARB's proposal to provide a 'book-and-claim' accounting approach for low-CI hydrogen. To meet California's GHG reduction targets and support the eFuel industry, it is essential to utilize book-and-claim to preserve the CI attribute of hydrogen that is transported in multi-source/multi-use distribution systems, where Low-CI hydrogen is comingled with conventionally produced hydrogen. A robust book-and-claim system for hydrogen will ensure that the low-carbon attributes of the hydrogen are retained and applied to end-uses where the most environmental benefit can be derived. This sends the necessary long-term signal for low-CI hydrogen to play a meaningful role in decarbonizing transportation.

344.10 One key improvement to the LCFS proposal that Infinium supports is to eliminate the requirement that eligible hydrogen must be supplied to California in a dedicated pipeline as proposed in §95488.8(i)(3)(A). This requirement places an unnecessary constraint on a nascent market and will stifle investments at a time when massive capital outlays are needed to bring low-carbon hydrogen to scale. There are no dedicated interstate hydrogen pipelines to California. This requirement therefore favors only in-state hydrogen pipelines and fails to recognize the value of using hydrogen as a feedstock to produce eFuels out of state and imported for use in California. Section 95488.8(i)(3) specifically indicates the intention that the low-CI hydrogen book-and-claim approach should be applied to hydrogen used in "Alternative Fuel Production", but this proposed

344.10 cont. eligibility requirement precludes alternative fuel facilities out of state from realizing these benefits. We anticipate that eFuel production facilities will be located in fuel producing regions across North America, be connected to regional hydrogen pipelines, and must necessarily lower their CI by utilizing low-CI hydrogen. We urge CARB to adopt a wider worldview that acknowledges the need for a multi-jurisdictional supply chain for low-CI hydrogen.

We specifically request that CARB modify §95488.8(i)(3)(A) as follows:

> Low-CI hydrogen is injected into a dedicated hydrogen pipeline physically connected to ~~California~~ a distribution system or a production facility that provides transportation fuel to California.

344.11 **Carbon Dioxide:** Infinium recommends that book-and-claim be similarly established for carbon dioxide transported by pipeline with the following proposed regulation:

> *Book-and-Claim Accounting for Pipeline-Injected carbon dioxide Used in Alternative Fuel Production.* Indirect accounting may be used for carbon dioxide used to produce alternative fuel for transportation purposes provided the conditions set forth below are met:
>
> (i) Carbon dioxide is injected into a dedicated carbon dioxide pipeline physically connected to a production facility that provides alternative fuel to California
>
> (ii) To substantiate carbon dioxide quantities injected into the pipeline as an input to alternative fuel production, the pathway application and subsequent Annual Fuel Pathway Reports must include the following documents linking the environmental attributes of carbon dioxide in kg with corresponding quantities of carbon dioxide in kg withdrawn from the pipeline: monthly invoices showing the quantities of carbon dioxide (in kg) sourced and the unredacted contract by which the fuel pathway holder obtained the environmental attributes.

Thank you for the opportunity to provide comments. Should you have any questions or would like additional information, please feel free to contact me at dzaziski@InfiniumCo.com.

With kind regards,

David Zaziski, Ph.D.
Vice President, Policy & Government Affairs

The following proposed regulatory text is provided for illustrative purposes with deleted text as compared to the Proposed Regulations indicated by ~~strike-outs~~ and inserted text indicated by underlining.

344.12 **§ 95481. Definitions and Acronyms.**

(…)

"Alternative Fuel" means any transportation fuel that is not fossil CaRFG, fossil diesel fuel, or fossil jet fuel including those fuels specified in section 95482(a)(3) through (a)(13).

(…)

"PtL Fuel" means a synthetic hydrocarbon fuel that is produced from water, captured CO_2 and electricity, and that can replace or be blended into CARBOB, CaRFG, diesel fuel or jet fuel.

(…)

344.13 **§ 95488.8. Fuel Pathway Application Requirements Applying to All Classifications.**

(…)

(i) Indirect Accounting for Low-CI Electricity, Biomethane, PtL Fuel and Low-CI Hydrogen.

(1) *Book-and-Claim Accounting for Low-CI Electricity Supplied as a Transportation Fuel, Direct Air Capture projects, or Used to Produce PtL Fuel or Hydrogen.* Reporting entities may use indirect accounting mechanisms for low-CI electricity supplied as a transportation fuel, for PtL Fuel supplied as a transportation fuel, for hydrogen production and processing for transportation purposes (including hydrogen that is used in the production of a transportation fuel), or for direct air capture projects, provided the conditions set forth below are met:

(A) For electricity used as a transportation fuel, for PtL Fuel production, or as an input to hydrogen production delivered through the grid without regard to physical traceability if it meets all requirements of this subarticle. The low-CI electricity must be supplied to the grid within a California Balancing Authority (or local balancing authority for PtL Fuel or hydrogen produced outside of California) or alternatively, meet the requirements of California Public Utilities Code section 399.16, subdivision (b)(1). Such book-and-claim accounting for low-CI electricity may span only three quarters. If a low-CI electricity quantity (and all associated environmental attributes, including a beneficial CI) is supplied to the grid in the first calendar quarter, the quantity claimed for LCFS reporting must be matched to grid electricity used as a transportation fuel

344.13 cont.

or for hydrogen or PtL Fuel production no later than the end of the third calendar quarter. After that period is over, any unmatched low-CI electricity quantities expire for the purpose of LCFS reporting.

(B) Low-CI electricity used as a transportation fuel or used for hydrogen or PtL Fuel production for transportation purposes can be indirectly supplied through a green tariff program (including the Green Tariff Shared Renewables program described in California Public Utilities Code Section 2831-2833) or other contractual electricity supply relationship that meets the following requirements:

1. Electricity is generated by, or supplied under contract to, the pathway applicant for all environmental attributes of the claimed electricity. In order to substantiate low-CI electricity claims, the applicant must make contracts available to the Executive Officer, upon request, to demonstrate that the electricity meets the requirements of this subarticle. Generation invoices or metering records are required to substantiate the quantity of low-CI electricity produced from the renewable assets. Monthly invoices must be unredacted copies of originals showing electricity sourced (in kWh) and contracted price;

2. All electricity procured by any LSE for the purpose of claiming a lower CI must be in addition to that required for compliance with the California Renewables Portfolio Standard (described in California Public Utilities Code sections 399.11-399.32~~)~~ or, for hydrogen or PtL Fuel production for transportation purposes outside of California,) in addition to local renewable portfolio requirements;

3. Renewable energy certificates or other environmental attributes associated with the electricity, if any, are not issued credits or claimed under any other voluntary or mandatory program with the exception of the federal RFS, and the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800). Retirement of renewable energy credits for the purpose of demonstrating Green Tariff Shared Renewables procurement to the California Public Utilities Commission does not constitute a double claim.

(C) For direct air capture projects ~~or for hydrogen used as a transportation fuel~~, low-CI electricity must meet the following criteria:

344.13 cont.

1. The low-CI electricity must be supplied to the grid within the local balancing authority where the electricity is consumed or delivered to that local balancing authority without substitution consistent with the requirements of California Public Utilities Code section 399.16, subdivision (b)(1).

2. The pathway holder or the project operator must be the first contracted entity for procuring the low-CI electricity.

3. Low-CI electricity must be supplied by new or expanded low-CI electricity that begins new or expanded production on or after January 1, 2022, or within three years of the start of the hydrogen production facility or direct air capture project, whichever is later.

4. Such book-and-claim accounting for low-CI electricity may span only one quarter. If a low-CI electricity quantity (and all associated environmental attributes, including a beneficial CI) is supplied to the grid in the first calendar quarter, the quantity claimed for LCFS reporting in the same calendar quarter. After that period is over, any unmatched low-CI electricity quantities expire for the purposes of LCFS reporting.

5. Any renewable energy certificates or other environmental attributes associated with the energy are not issued credits or claimed produced, or are retired and not claimed under any other voluntary or mandatory program with the exception of the federal RFS, incentives under the Infrastructure Investments and Jobs Act or the Inflation Reduction Act, and the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800).

(…)

Comment Log Display

Here is the comment you selected to display.

Comment 354 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Brian
Last Name	Kee
Email Address	brian.kee@mn8energy.com
Affiliation	MN8 Energy
Subject	MN8 Energy Comments on Proposed Low Carbon Fuel Standard Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/7034-lcfs2024-Am8FbVZvV1tQMwln.pdf
Original File Name	MN8 Energy Comments on Proposed Low Carbon Fuel Standard Amendments.pdf
Date and Time Comment Was Submitted	2024-02-20 18:45:49

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

California Air Resources Board (CARB)
1001 I Street
Sacramento, CA 95814

RE: MN8 Comments on Proposed Low Carbon Fuel Standard Amendments

Dear CARB staff and board,

345.1 MN8 Energy LLC (MN8) appreciates CARB's ongoing effort to update the Low Carbon Fuel Standard (LCFS) regulation. MN8 is largely supportive of the Proposed Regulation Order (The Order) and appreciates the opportunity to offer these comments.

MN8 develops, owns, and operates renewable energy generation facilities, battery energy storage systems (BESS) and electric vehicle (EV) charging stations. Today, we provide clean, affordable energy to over 200 world-class enterprise customers, with an operating fleet of over 850 energy projects and approximately 3 gigawatts (GW) of solar photovoltaic (PV) and BESS capacity spread across 28 US states. We are also partnering with various customers, such as OEMs and fleet operators, to develop EV charging solutions with the goal of delivering a reliable and high-quality experience to EV drivers that will enable widespread EV adoption.

Strengthening the LCFS Carbon Intensity Targets

345.2 MN8 supports CARB's proposed amendments to increase California's LCFS carbon intensity (CI) benchmarks. California has not updated its LCFS annual CI benchmarks since 2018 and the state has made significant progress in technology development and Zero-Emission Vehicle (ZEV) infrastructure deployment since the last update. MN8 appreciates CARB staff's (Staff) in-depth analysis and engagement with stakeholders to determine appropriate benchmark updates. We agree with Staff's assessment that a reduction in the CI of transportation fuel of at least 30% by 2030 and 90% by 2045 is both achievable and necessary to meet the state's goal in transportation decarbonization and beyond. Increasing the stringency of the LCFS CI targets and implementing an automatic acceleration mechanism will provide the market with a strong incentive to make long-term investments in low carbon transportation infrastructure.

Proposed Amendments to the LCFS ZEV Infrastructure Crediting Program for Light-Duty Fast Charging Infrastructure (LD-FCI)

345.3 MN8 recommends that CARB delay implementing a requirement that stations be built in low-income (LIC) or disadvantaged communities (DAC), or at least ten miles away from the nearest fast charger, to be eligible for the LD-FCI pathway. There remain substantial

345.3 cont. additional infrastructure needs across the LD charging space – the state needs 39,000 public DCFCs by 2030, and 85,000 by 2035, and had installed around 10,000 as of the end of 2023 and just over 1,000 over the course of 2023[1]. This means that the average rate of public DCFC buildout needs to achieve approximately four times the rate realized in 2023 over the period spanning 2024-2030 to meet the state's goals; this will require a rapid acceleration of deployments. These infrastructure needs include but are not limited to LICs and DACs. FCI can serve an important role in achieving the rapid and widespread public DCFC infrastructure deployment needed by the state. CARB should therefore delay implementation of any locational constraints around LD-FCI eligibility until a later rulemaking, if and when it finds that the state is clearly on pace to meet its immense DCFC deployment needs.

345.4 MN8 also cautions against the proposed amendment to limit the maximum number of eligible chargers in the LD-FCI program to four per site. Limiting the number of eligible chargers at a participating site could discourage the build-out of larger charging hubs that will be needed in certain locations to provide a more accessible and reliable service to drivers. As EV adoption rises, public charging stations must have adequate charging capabilities to support current and future demand, which will require sites far larger than four charging ports in high-traffic locations.

Support of a new FCI program for medium- and heavy-duty EVs

345.5 MN8 supports CARB's proposed amendments to expand the ZEV Infrastructure Fueling Pathways for Medium- and Heavy-Duty (MHD) vehicles. Expanding LCFS ZEV credit generation to the MHD vehicle sector will complement existing policies in California including the Advanced Clean Truck (ACT) and Advanced Clean Fleet (ACF) rules to support a rapid transition to ZEVs in the MHD sector. MN8 appreciates CARB's willingness to consider stakeholder feedback in proposing that credits can be generated through both public and private ZEV refueling infrastructure, since both of these categories will be critical in enabling a rapid transition in the MHD space. Given the substantial capital costs of installing MHD ZEV refueling infrastructure, the state's objectives to achieve rapid fleet turnover from internal combustion engine vehicles to ZEVs, and because MHD ZEV adoption is only just beginning, it is important that FCI applies to all business models and use cases for MHD infrastructure.

345.6 MN8 opposes the proposed amendments to limit MHD FCI to sites located within one mile of a Federal Highway Administration Alternative Fuel Corridor (AFC) or on or adjacent to a property where medium- and heavy-duty vehicles are parked overnight, or which have received capital funding from a state or federal competitive grant program that included location evaluation as a criteria."[2] Various charging solutions are likely to be necessary to serve the MHD space that would not be covered by this rule – for

[1] Davis, Adam, Tiffany Hoang, Thanh Lopez, Jeffrey Lu, Taylor Nguyen, Bob Nolty, Larry Rillera, Dustin Schell, Micah Wofford. 2023. *Assembly Bill 2127 Second Electric Vehicle Charging Infrastructure Assessment: Assessing Charging Needs to Support Zero-Emission Vehicles in 2030 and 2035*. California Energy Commission. Publication Number: CEC-600-2024-003

[2] Proposed Low Carbon Fuel Standard Amendments, Appendix A-1: Proposed Regulation Order (Proposed Sections for Amendments), Section 95486.3(b)(1). Medium- and Heavy-Duty Fast Charging Infrastructure Pathway Eligibility

345.6 cont. example, off-site charging opportunities at cross docks and warehouse facilities where trucks do not park overnight but would benefit from “convenience charging” opportunities as they wait for their cargo to be loaded and/or unloaded, or public and private charging depots located near demand centers (e.g., warehouse clusters) but are not necessarily on or adjacent to premises where MHD vehicles park overnight. Excluding these sorts of infrastructure from FCI would remove an important incentive for the industry to build out critical charging infrastructure.

Thank you again for your leadership in implementing the LCFS in California. MN8 appreciates the opportunity to provide feedback on this important program.

Regards,

Brian Kee

Brian Kee
Manager, EV Charging Policy
MN8 Energy LLC
Brian.kee@MN8energy.com

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Comment 355 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Emily
Last Name	Carlton
Email Address	emily.carlton@lanzajet.com
Affiliation	LanzaJet
Subject	Aviation and the CA LCFS
Comment	Please find attached comments from LanzaJet regarding the propose changes to the CA LCFS. We appreciate the opportunity to comment. Please feel free to rea out with any questions.
Attachment	www.arb.ca.gov/lists/com-attach/7035-lcfs2024-BmpVMlc4ACIXMFc9.pdf
Original File Name	LanzaJet_Comments on LCFS Rulemaking 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 18:53:39

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

Submitted Electronically via https://ww2.arb.ca.gov/lispub/comm/bclist.php

Re: Proposed Low Carbon Fuel Standard Amendments

Dear Board Members,

346.1

LanzaJet thanks CARB for the opportunity to comment on the proposed changes to the California Low Carbon Fuel Standard (LCFS). As longtime supporters of the CA LCFS program, LanzaJet is encouraged by CARB's proposal to better align the program with the ambitious path laid out in the 2022 Scoping Plan. We echo parallel comments submitted by a broad coalition of sustainable aviation fuel (SAF) producers, including LanzaJet, in strongly supporting CARB's proposal to eliminate the exemption for intrastate fossil jet fuel under the LCFS.[1] We comment separately to stress the importance of that key next step in enhancing the market signal for SAF and also to provide insights on other key provisions in the proposal.

LanzaJet is an industry-leading SAF producer using a proprietary alcohol-to-jet (ATJ) process to convert any source of low-carbon, sustainable ethanol into ASTM-compliant SAF and renewable diesel. Following a decade of technology development and demonstration, LanzaJet was launched in 2020 with a clear mission—to scale the SAF market and enable meaningful decarbonization of the aviation sector. LanzaJet recently completed construction of a first-of-a-kind commercial scale SAF facility in Soperton, Georgia, U.S., and we are pursuing a pipeline of SAF projects to meet our goal of 1 billion gallons of domestic production by 2030. LanzaJet's equity investors include LanzaTech, Suncor, Mitsui, British Airways, and Shell, and financial support has been provided by ANA and Microsoft.

LanzaJet recognizes and appreciates California's continued leadership in the adoption of clean fuels in the aviation sector—one of the most difficult to decarbonize. In the 2018 LCFS rulemaking, CARB initiated inclusion of SAF in the program on an opt-in, credit-generating basis, which has since been replicated in other LCFS jurisdictions.[2] Unfortunately, while a helpful first step in providing some value for SAF under the LCFS, a stronger market signal is needed. The slow uptake of SAF in California can be traced, in part, to state regulatory rules, including the lack of an obligation on fossil jet fuel under the LCFS.[3]

California has rightfully set ambitious targets for aviation and for SAF specifically: Governor Newson recently called for 20% clean fuels adoption in the aviation sector,[4] the state legislature has estimated a need for at least 1.5 billion gallons of SAF blending by 2030,[5] and the 2022 CARB Scoping Plan states that

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[1] *See* SAF group comments on LCFS Rulemaking 2024.docx *submitted* February 20, 2024

[2] Both Oregon Clean Fuels Program and Washington Clean Fuels Standard currently exempt fossil jet fuel from generating deficits and allow SAF to generate credits on an opt-in basis.

[3] *See* Bay Area Air Quality Management District, Sustainable Aviation Fuel: Greenhouse Gas Reductions from Bay Area Commercial Aircraft (October 2020) *available at* https://www.baaqmd.gov/news-and-events/page-resources/2020-news/121120-saf-report. *See also* https://stillwaterassociates.com/saf-in-the-ira-era-how-do-the-incentives-stack-up/.

[4] *See* California Office of the Governor, Governor's Letter to Chair Randolph. July 22, 2022. https://www.gov.ca.gov/wp-content/uploads/2022/07/07.22.2022-Governors-Letter-to-CARB.pdf?emrc=1054d6

[5] *See* AB1322 (Rivas) *available at* https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=202120220AB1322. AB 1322 was passed by the California assembly in 2022 and later vetoed by Governor Newsom, who, in his veto letter, supported the legislature's intent with the bill and ordered CARB to develop a "plan to reduce greenhouse gas emissions through the production and use of sustainable aviation fuels by July 1, 2024". Governor Newsom's veto letter *available at* https://www.gov.ca.gov/wp-content/uploads/2022/09/AB-1322-VETO.pdf?emrc=7598b6

Corporate Headquarters: 520 Lake Cook Road, Suite 680, Deerfield, Illinois 60015
Tel: +1 (224) 369-0257 | www.lanzajet.com

80% of all aviation fuel demand will need to come from SAF by 2045.[6] Given California's aggressive goals in the aviation sector and its recognition in the proposal that the LCFS should actively encourage transitioning the use of renewable fuels to hard-to-decarbonize sectors in the coming decades, we urge CARB to better align the aviation provisions with the ambition that will be needed to achieve the state's goals.

Accordingly, we urge CARB to significantly strengthen the signal for SAF in the proposal provisions that would impact the aviation sector. Specifically, we suggest that CARB consider the following revisions to the proposal:

346.2 1. Include all fossil jet fuel as a deficit generator under the LCFS.
346.3 2. Accelerate the obligation to begin in 2025, rather than 2028.
346.4 3. Allow indirect accounting of low-CI electricity and RNG for SAF production, a regulatory approach that is already in place for electric vehicle charging.
346.5 4. Allow book-and-claim use of SAF as proposed for hydrogen used as a transportation fuel.
346.6 5. Further strengthen proposed increases to the stringency of the program.
346.7 6. Align the definition of renewable diesel with the definition used by the EPA Renewable Fuel Standard Program (RFS).
346.8 7. Adopt the proposed rules for feedstock traceability with provisions to avoid increasing administrative burdens.
346.9 8. Utilize the LCFS to encourage long term transition of biofuels into hard-to-decarbonize sectors like aviation.

Please see our detailed comments and rationale for each below.

1. Include all jet fuel as a deficit generator under the LCFS.

The current proposal to remove the exemption only for intrastate jet fuel is an important step in the right direction, but far from sufficient to meet state goals for the aviation sector. Currently, the LCFS provides a "rack fee" benefit that accrues to replacements for obligated fuels, like renewable diesel, but not to SAF.[7] This benefit, in conjunction with other state and federal regulatory rules, systematically disincentivizes SAF production, leading SAF credit generation under the LCFS to be consistently less than 1% of credit generation for very similar renewable diesel.[8] While removing the exemption for intrastate jet fuel SAF will help by partially eliminating the LCFS rack fee benefit, an obligation on roughly 10% of the jet fuel pool cannot be expected to fully close the gap nor to substantially increase the market signal for SAF production. Indeed, CARB's own modeling suggests that SAF blending could reach about 100 million gallons in 2030 and about 200 million in 2045 as a result of the current proposal.[9] While these volumes represent encouraging growth from today's volumes, they still fall far short of state goals, which would require roughly

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[6] *See* CARB, 2022 Scoping Plan for Achieving Carbon Neutrality. December 2022. https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp_1.pdf. Page 73. The Scoping Plan scenario envisions 20% of aviation fuel demand met by electricity (batteries) or hydrogen (fuel cells) in 2045, with sustainable aviation fuel meeting the remaining 80%.

[7] Under the LCFS, suppliers of obligated fuels like diesel face a compliance cost, part of which they pass through to purchasers of fuel "at the rack". This rack fee narrows the gap between the cost of fossil and renewable fuels, increasing the willingness to pay for the latter.

[8]. Besides the LCFS rack fee, additional regulatory disincentives to SAF include the state Cap-at-the-Rack cost under the Cap-and-Trade program, which similarly narrows the price gap between fossil and renewable diesel, and the federal Renewable Fuel Standard (RFS) program which awards 1.7 RINs per gallon of renewable diesel compared to just 1.6 per gallon of SAF. While the total size of the incentive gap varies, the BAAQMD analysis estimated it in 2020 at about $0.42 per gallon advantage for producing renewable diesel versus SAF, of which the LCFS represented about $0.14. An obligation only on intrastate jet fuel—a small fraction of the total pool—would reduce the LCFS disparity only marginally. New federal incentives under the Inflation Reduction Act, such as the SAF Blender's Tax Credit (40B) and the Clean Fuels Production Credit (45Z) can in theory make up much of that difference, but given that those expire in 2025 and 2027, respectively, they do not send a robust investment signal for needed SAF production. *See* CA LCFS Data Dashboard, Figure 2 at https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard; *See also* Bay Area Air Quality Management District (BAAQMD), Sustainable Aviation Fuel: Greenhouse Gas Reductions from Bay Area Commercial Aircraft. October 2020. *available at* https://www.baaqmd.gov/news-and-events/page-resources/2020-news/121120-saf-report.

[9] CARB, Appendix C-1 Standardized Regulatory Impact Assessment, September 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/appc-1.pdf. Figure 4, page 18.

800 million gallons of SAF to meet Gov. Newsom's 20% clean fuels adoption target, 1.5 billion gallons in 2030 to meet the AB 1322 goal, and 3.2 billion gallons by 2045 to meet the 2022 Scoping Plan target. As noted by the International Council on Clean Transportation (ICCT), obligating only intrastate jet fuel would have "a minimal impact on the program due to the small size of this fuel pool and would fail to meaningfully promote aviation decarbonization".[10]

To boost the impact of the aviation provisions and put California on a path to achieving its aviation decarbonization goals, we encourage CARB to remove the exemption for all jet fuel uplifted in California. While anything that closes the LCFS incentive gap between jet and diesel substitutes (including obligating only a portion of jet fuel as proposed) will be directionally helpful in increasing SAF supply, obligating all jet fuel uplifted in CA will have a much more significant impact in sending an investment signal for SAF and driving SAF use in the state.

346.2 If CARB maintains a focus on obligating only intrastate jet fuel use, we suggest that CARB obligate all jet fuel combusted in California, as outlined in the September 20, 2023 Board meeting, when CARB staff stated that intrastate jet fuel would include not only flights within California, but also the portion of jet fuel combusted in California from other flights that start or end in California. Such a provision need not be overly precise or require direct regulation of or reporting from aircraft operators. Rather, existing data and tools could be used to develop a rough estimation of intrastate fuel use.[11]

2. Accelerate the obligation to begin in 2025, rather than 2028.

CARB states that the proposal to delay the obligation for fossil fuel jet fuel until 2028 is meant to provide "sufficient time for potential producers of alternative jet fuel to add capacity for the anticipated increased demand of alternative jet fuel"[12] However, such a delay is unnecessary, and we urge CARB to consider an earlier implementation date. We note that British Columbia has already added an obligation for all fossil jet fuel beginning in 2026, coupled with a volumetric SAF mandate beginning in 2028.[13] Given that CARB is only proposing an obligation for jet fuel and not an actual SAF requirement, consistent with the LCFS, there is technically no need for lead time to increase SAF production capacity because the structure of the LCFS program allows for compliance via credits generated outside of aviation—credits which are readily available today. In addition, CARB has already provided a five-year window for growth since making SAF an opt-in credit generator in 2019, during which time SAF volumes recorded under the LCFS have increased five-fold, despite a global pandemic and the continued regulatory disadvantages for SAF producers under both the LCFS and the Cap and Trade program.[14] Nevertheless, SAF continues to lag far behind similar ground transportation fuels under the LCFS. This gap should not be misinterpreted as a signal that the SAF market or SAF technologies are insufficiently mature to support an obligation for aviation, but rather should serve as evidence that the lack of an LCFS obligation for aviation has steered producers toward more lucrative opportunities serving road transportation.[15]

346.3

In any event, LanzaJet is confident that there will be enough production capacity to meet demand beginning in 2025. In the last year alone, global SAF capacity has increased by over 300 million gallons from a single producer and the International Air Transport Association estimates 2024 SAF production to triple to over

[10] Stephanie Searle, International Council on Clean Transportation Comments on the November 2022 LCFS Workshop. December 21, 2022. https://www.arb.ca.gov/lists/com-attach/84-lcfs-wkshp-nov22-ws-B2lQOVAnVVkEMAc3.pdf.
[11] *See* Graver, Rutherford, and Zheng, CO_2 Emissions from Commercial Aviation. ICCT, 2020. https://theicct.org/wp content/uploads/2021/06/CO2-commercial-aviation-oct2020.pdf. The methods used by Graver et al. could be extended with a simple additional calculation to attribute fuel burn from either take-off or landing (whichever occurs in California) plus a fraction of the cruising fuel burn equal to the fraction of the route's distance that lies within the state.
[12] *See* CARB, Appendix E: Purpose and Rationale for Low Carbon Fuel Standards Amendments. January 2, 2024. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appe.pdf. Page 12.
[13] *See* https://www.bclaws.gov.bc.ca/civix/document/id/oic/oic_cur/0699_2023
[14] *See* CA LCFS Data Dashboard, Figure 2 at https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard
[15] On regulatory disincentives, see footnote 8. On technology and market maturity, several SAF pathways have already been commercialized. A total of 8 pathways for SAF production have been approved under ASTM 7566, and 3 additional coprocessing pathways have been approved under ASTM D1655. *See* https://www.caafi.org/focus_areas/fuel_qualification.html.

500 million gallons, or 1.5 million metric tonnes.[16] In the U.S., SAF production capacity has expanded by at least 70 million gallons, with new facilities including LanzaJet's Freedom Pines Fuels[17] and Montana Renewables Great Falls plant[18] coming online. Additional expansions are in the pipeline, including concrete, near-term plans for expansions from Diamond Green Diesel,[19] Montana Renewables,[20] and California's own World Energy.[21] Most importantly, there are roughly 3 billion gallons of renewable diesel consumed in the U.S. each year, 80% of which is produced domestically,[22] and half of which could easily be transitioned to SAF production—where it would produce additional benefits to both climate and local air quality— if additional policy incentives were put in place under the LCFS to level the playing field for SAF. In sum, there is sufficient SAF production capacity and CARB need only send an appropriate market signal. We urge CARB to maintain its role as a leader in LCFS policy by accelerating its fossil jet fuel obligation to 2025.

3. Allow indirect accounting of low-CI electricity and RNG for SAF production, a regulatory approach that is already in place for electric vehicle charging.

LanzaJet supports existing policy to allow indirect accounting for low-CI electricity and RNG inputs to the production of low-CI hydrogen, and we applaud CARB's proposal to expand access through the use of power purchase agreements (PPAs) for low-CI electricity.[23] However, we strongly believe that the same access should be expanded to SAF. At minimum, we urge CARB not to eliminate the existing allowance for indirect
346.4 accounting for low-CI electricity to produce hydrogen that is used in the production of fuels, including SAF.

CARB's arguments for providing additional flexibility to low-CI hydrogen when directly used as a transportation fuel apply equally to SAF. Both low-CI hydrogen and SAF are young technologies with nascent markets that displace hard-to-electrify end uses like powering aircraft. The 2022 CARB Scoping Plan calls for significant growth in the use of both and, in the aviation sector, envisions even greater growth for SAF—from less than 1% of jet fuel consumption today to 80% in 2045.[24]

Despite these parallels, current and proposed LCFS rules for indirect accounting of low-CI energy systematically disadvantage SAF relative to hydrogen. Hydrogen producers have access to emissions reductions from process energy—low-CI electricity and RNG—that SAF cannot access. This is counter to state goals for SAF uptake and aviation decarbonization. We urge CARB to promote equity between future fuels like SAF and hydrogen and allow indirect accounting of RNG and low-CI electricity—both as a direct input to SAF and as an input to hydrogen for use in SAF.

4. Allow book-and-claim use of SAF, as proposed for hydrogen used as a transportation fuel

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[16] *See* https://www.neste.com/products-and-innovation/sustainable-aviation/questions-and-answers-about-saf ; https://www.iata.org/en/pressroom/2023-releases/2023-12-06-02/

[17] *See* https://www.prnewswire.com/news-releases/lanzajet-celebrates-grand-opening-of-the-worlds-first-ethanol-to-sustainable-aviation-fuel-production-facility-302052431.html.

[18] *See* https://www.prnewswire.com/news-releases/montana-renewables-begins-sustainable-aviation-fuel-deliveries-to-shell-301820679.html.

[19] *See* https://worldbiomarketinsights.com/valero-energy-and-darling-ingredients-on-time-with-saf-plant-in-texas/#:~:text=Valero%20Energy%20and%20Darling%20Ingredients%20on%2Dtime%20with%20SAF%20plant%20in%20Texas,-by%20Daniela%20Castim&text=Valero%20Energy%20and%20Darling%20Ingredients%20have%20announced%20that%20their%20joint,the%20first%20quarter%20of%202025.

[20] *See* https://www.ogj.com/energy-transition/article/14296189/calumet-provides-operational-update-on-montana-renewables-great-falls-plant.

[21] *See* https://www.prnewswire.com/news-releases/world-energy-secures-permits-will-completely-convert-its-southern-calif-refinery-to-create-north-americas-largest-worlds-most-advanced-sustainable-aviation-fuel-hub-301531135.html.

[22] *See* https://ethanolproducer.com/articles/epa-2375-billion-rins-generated-in-2023. RIN data, which measure consumption of renewable diesel, underestimate domestic production capacity because a fraction of domestically produced fuels are exported.

[23] *See* CARB, Staff Report: Initial Statement of Reasons (ISOR). December 19, 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf. Page 34.

[24] *See* CARB, 2022 Scoping Plan for Achieving Carbon Neutrality. December 2022. https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp_1.pdf. Page 73.

LanzaJet also supports the proposal to allow book-and-claim accounting for low-carbon intensity hydrogen used as a transportation fuel. We agree with CARB's rationale for allowing hydrogen book and claim: that physical delivery is impractical for large scale production that is sent to several off-takers through shared
346.5 pipelines.[25] However, the same rationale also applies to SAF, and we strongly recommend that the offtake opportunities provided by book and claim should be available to all pipeline-fungible liquid and gaseous fuels.

All of the arguments given by CARB in the Initial statement of Reasons for extending book and claim to low-CI hydrogen also apply to SAF.[26] Like hydrogen, the SAF market is nascent, and relies on large scale production, pipeline deliveries, and multiple off-takers for economies of scale. In the aviation sector, both hydrogen and SAF serve the same end use—transportation fuel for aircraft.

The 2022 Scoping Plan sees SAF as the essential key to meaningful decarbonization of aviation through 2045—displacing 80% of the fossil fuels used by the sector. Despite that, current and proposed LCFS rules for book and claim that exclude SAF make it much more logistically difficult and carbon intensive for jet fuel suppliers to provide their customers with emissions reductions from SAF than it would be from hydrogen.

5. Further strengthen proposed increases to the stringency of the program.

LanzaJet supports the proposed measures to increase the stringency of the LCFS program and encourages CARB to boost stringency even more. We believe that near-term efforts to quickly boost LCFS prices back
346.6b to meaningful levels are essential, and we therefore urge CARB to 1) aim for a 6 or 7% stepdown in the CI
346.6c reduction target in 2025, rather than the proposed 5%, and 2) move implementation of the auto adjustment mechanism forward from 2028 to 2027. Additionally, we suggest that CARB increase the 2030 CI reduction
346.6d target—currently at 20%-- even beyond the proposed 30%. A recent study by ICF found that a 42% CI reduction by 2030 is both feasible and necessary to support progress toward the 2022 Scoping Plan goals.[27]

6. Align the definition of renewable diesel with the definition used by the EPA RFS program.

LanzaJet believes that the proposed definition of "renewable diesel" is unintentionally limited to certain production processes (hydrotreating or Fisher-Tropsch) and feedstocks (lipids, biocrudes, or gasified biomass).[28] The proposed definition would arbitrarily exclude renewable diesels produced via alcohol-to-fuels pathways as well as via other non-enumerated feedstocks. We urge CARB to let lifecycle analysis, guided by the latest science, determine eligibility for credit generation under the LCFS and broaden the definition to include objective criteria, as was the case with the former definition.

346.7 Specifically, we suggest that CARB expand the definition of renewable diesel to align with the EPA definition of a non-ester renewable diesel under the federal RFS program:

"A fuel or fuel additive that meets the Grade No. 1–D or No. 2–D specification in ASTM D975 (incorporated by reference, see § 80.12) and can be used in an engine designed to operate on conventional diesel fuel;"[29]

[25] *See* CARB, Staff Report: Initial Statement of Reasons (ISOR). December 19, 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf. Page 34.
[26] *See* CARB, Staff Report: Initial Statement of Reasons (ISOR). December 19, 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf. Page 30.
[27] *See* ICF, Analyzing Future Low Carbon Fuel Targets in California. June 2023. Submitted to CARB June 30, 2023.
[28] *See* CARB, Appendix A-1 Proposed Regulation Order (Proposed Sections for Amendments). January 2, 2024. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/lcfs_appa1.pdf. Page 22.
[29] *See* 40 C.F.R. § 80.2

7. Adopt the proposed rules for feedstock traceability with provisions to avoid duplicative administrative burdens.

In principle, LanzaJet supports the additional proposed guardrails on crop-based feedstocks—the sustainability of our SAF is paramount to us. However, we urge CARB to ensure that these requirements do not add additional undue administrative burden to reporting entities. SAF producers participate in a variety regulatory programs and incentives beyond the CA LCFS, including the federal Renewable Fuel Standard (RFS) program, incentives under the Inflation Reduction Act, the International Civil Aviation Organization's Carbon Offsetting Reduction Scheme for International Aviation (CORSIA), and others. As such, SAF producers, like other low carbon fuel producers, are already subject to multiple, separate sets of detailed regulations for tracking, verifying, and independently certifying the details of feedstock production and procurement. Given that we do not believe any producer would produce a biomass-based transportation fuel only for the LCFS market, we urge CARB to avoid adding a new, bespoke, and duplicative administrative burden under the LCFS. We strongly request that CARB explicitly allow for the new
346.8 feedstock tracking and certification requirements to be met by existing certification schemes, such as EPA Quality Assurance Plans under the RFS program, International Sustainability and Carbon Certification (ISCC) or the Roundtable on Sustainable Biofuels (RSB).

6. Utilize the LCFS to encourage long term transition of biofuels into hard-to-decarbonize sectors like aviation.

We applaud CARB for thinking dynamically about existing biofuel resources, and considering ways to encourage diversions into sectors where they will be most needed to meet 2022 Scoping Plan goals. A key example of this type of thinking is CARBs proposals aimed at pivoting biomethane from its current end-use as a road transportation fuel into hard-to-decarbonize applications like industry and flexible power generation.[30] We strongly urge CARB to apply the same thinking to the aviation sector and use the LCFS to encourage the diversion of biofuels from road transport—including both renewable diesel and ethanol—to aviation.

346.9 We believe there is ample justification for CARB to prioritize a long-term transition of biofuel resources to SAF:

First, while both light and medium/heavy-duty transportation are expected to electrify over the coming decades (although on different timetables), aviation will take much longer to transition to decarbonize, and SAF is expected to be the chief decarbonization lever for the foreseeable futures. The 2022 Scoping Plan scenario envisions 100% sales of zero emissions vehicles for light duty transport by 2035 and for medium/heavy duty transport by 2040, but for aviation sees only 20% alternative propulsion (hydrogen or electric) possible by 2045.[31] In short, SAF is California—and the world's—only viable option for meaningful decarbonization in the aviation sector before mid-century.

Second, SAF provides additional air quality benefits that have not been fully considered by CARB. CARB notes that the current proposal would result in reductions in oxides of nitrogen (NO_x) and fine particulate matter (PM 2.5).[32] In addition, a recent synthesis of emissions measurement campaigns by the Airport Cooperative Research Program (ACRP), administered by the Transport Research Board of the U.S. National Academies of Sciences, found that a 50% SAF blend could reduce by nearly 40% oxides of sulfur,[33] which are known to have significant negative effects on exposed populations, and which are present in greater

[30] *See* CARB, Staff Report: Initial Statement of Reasons (ISOR). December 19, 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf. Page 33.
[31] *See* CARB, 2022 Scoping Plan for Achieving Carbon Neutrality. December 2022. https://ww2.arb.ca.gov/sites/default/files/2022-12/2022-sp_1.pdf. Page 72-73.
[32] *See* CARB, Staff Report: Initial Statement of Reasons (ISOR). December 19, 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf. Page 57.
[33] Airport Cooperative Research Program, Alternative Jet Fuels Emissions Quantification Methods Creation and Validation Report. August 2019. Page 10. *Available at* http://www.trb.org/Publications/Blurbs/179509.aspx

proportions in fossil jet fuel than other transportation fuels like diesel. Additionally, other studies have found greater reductions in PM than the 55% cited in the SRIA. The ACRP study found PM reductions of up to 65%, and a more recent measurement campaign found that SAF produced via the alcohol-to-jet pathway could reduce non-volatile particulate matter by up to 97%.[34]

Third, California's environmental justice communities have explicitly asked CARB to support displacement of fossil jet fuel with SAF, both in the formal recommendations to CARB of the Environmental Justice Advisory Committee[35] and in person, at the September 28th, 2023, Board meeting. Communities that live near and work at airports are some of the most vulnerable in California: of the ten busiest airports in the state, four are located within SB 535 designated disadvantaged communities, and another four are immediately adjacent.[36] These communities have long borne the disproportionate health impacts of unmitigated fossil jet fuel combustion.

Fourth, jet fuel causes unique contributions to global climate change that are unrecognized by the LCFS—harms that SAF can mitigate. Emerging research indicates that particulate matter reductions from SAF reduce aviation's non-CO2 climate impact, specifically the climate forcing from "contrail cirrus" impacts (the combined warming from contrails and contrail-induced cirrus). The current best estimate from the most recent comprehensive study is that the climate impact from contrail cirrus is nearly twice the impact from CO2.[37] Even the low end of current estimates–which show that contrail cirrus causes roughly half the total warming of CO2– warrants consideration of potential mitigation opportunities from SAF.[38] One recent study cited found that a 50% SAF blend could reduce contrail cirrus climate impacts by over 20%. An eventual shift to 100% SAF could reduce the climate impact of contrail cirrus by 50%.[39] While continued scientific uncertainty around the size of the non-CO2 climate impacts makes them difficult to precisely quantify, the direction of those impacts—less warming when SAF is used—is known.

We strongly believe that these additional benefits—which align closely with state goals and priorities and accrue only to SAF—justify action by CARB to prioritize the production and use of SAF. As CARB has noted, transitioning fuels to other sectors in the long term requires that market signals transition first.[40] Under the current proposal, the market signal for SAF would improve marginally, but not nearly enough to overcome existing disincentives and pivot biofuel production toward SAF. Therefore, we encourage CARB to consider additional measures to credit the additional climate and air quality benefits. For example, CARB should consider applying a credit multiplier for SAF based on the most conservative estimates of non-CO_2 climate benefits of SAF. (The European RED II program, currently provides a multiplier of 1.2x for SAF.) Alternatively, CARB might develop a "CO_2 equivalent" metric to account for these benefits in terms of carbon intensity and incorporate them into the CA-GREET model, as has been suggested by the European Commission in its recent study on how to address the non-CO2 climate impacts of aviation.[41]

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[34] Tran, Brown and Olfert. Comparison of Particle Number Emissions from In-Flight Aircraft Fueled with Jet A1, JP-5 and an Alcohol-to-Jet Fuel Blend. *Energy Fuels* 34, 6, 7218–7222 (2020). https://doi.org/10.1021/acs.energyfuels.0c00260.

[35] *See* AB 32 EJAC DRAFT Recommendations to the CARB on the Low Carbon Fuel Standard Regulation Updates. August 24, 3023. https://ww2.arb.ca.gov/sites/default/files/2023-08/EJAC%20Low%20Carbon%20Fuel%20Standard%20Recommendations%20Version%201%20082423.pdf *and* EJAC, Environmental Justice Advisory Committee 2022 Scoping Plan Recommendations: NF54. Page 16. September 30, 2022. https://ww2.arb.ca.gov/sites/default/files/barcu/board/books/2022/090122/finalejacrecs.pdf.

[36] *See* https://oehha.ca.gov/calenviroscreen/sb535. LAX, OAK, BUR, and ONT are within disadvantaged communities. SFO, SMF, SNA, and LGB are adjacent.

[37] D.S. Lee, et al. The contribution of global aviation to anthropogenic climate forcing for 2000 to 2018. *Atmospheric Environment* 244, 117834 (2021). https://doi.org/10.1016/j.atmosenv.2020.117834.

[38] *Id.*

[39] *See* European Union Aviation Safety Agency, Updated Analysis of the non-CO2 Climate Impacts of Aviation and the Potential Policy Measures Pursuant to EU Emissions Trading System Directive Article 30(4) (synthesizing research on SAF non-CO2 climate benefits and suggesting further consideration of SAF policy measures to mitigate aviation climate impacts); *available at* https://www.easa.europa.eu/sites/default/files/dfu/201119_report_com_ep_council_updated_analysis_non_co2_climate_impacts_aviation.pdf.

[40] *See* CARB, Staff Report: Initial Statement of Reasons (ISOR). December 19, 2023. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2024/lcfs2024/isor.pdf. Page 30.

[41] *See* European Union Aviation Safety Agency, Updated Analysis of the non-CO2 Climate Impacts of Aviation and the Potential Policy Measures Pursuant to EU Emissions Trading System Directive Article 30(4) (synthesizing research on SAF non-CO2 climate

LANZAJET

346.10 We also urge CARB to consider carefully how to account for the lifecycle emissions involved in a pivot—rather than an expansion—of biofuels toward the aviation sector. As light and medium/heavy duty road transportation electrify, the 2022 Scoping Plan envisions a 94% reduction in demand for ethanol in California's transportation sector by 2045—an absolute decline of 1.6 billion gallons per year of biofuel.[42] This presents a key opportunity to expand SAF production; at the national level, the 17B of ethanol currently blended into gasoline each year could become 10 billion gallons per year of SAF—more than triple the amount envisioned in the 2022 Scoping plan and the SAF Grand Challenge—with no net new ethanol demand.[43] The emissions factors for land use change (LUC) under the LCFS are based largely on a shock in emissions from the initial land conversion, annualized over a project horizon of 30 years.[44] However, if there is no net new ethanol demand, there can be no new land use change. As long as ethanol production does not substantially increase, LanzaJet recommends CARB maintain consistency with the assumptions that underlie the current LUC carbon intensity values by phasing out LUC emissions once emissions are amortized over the full 30-year project horizon land use change emissions have been fully accounted for. With nearly half of that amortization period over and the current rulemaking extending to 2045, LanzaJet believes it would be appropriate for CARB to include provisions for phasing out ILUC emissions in 2040, 30 years after the 2010 rulemaking, particularly for feedstocks like ethanol where significant demand destruction is forecasted and the "demand shock" rationale for ILUC cannot be reasonably maintained.

****

Thank you for the opportunity to comment on this LCFS Rulemaking. Please don't hesitate to reach out if you have any questions.

Sincerely,

Alex Menotti
VP, Government Affairs, Policy, and Sustainability
LanzaJet
alex.menotti@lanzajet.com

Emily Carlton
SAF Policy Specialist
LanzaJet
emily.carlton@lanzajet.com

benefits and suggesting further consideration of SAF policy measures to mitigate aviation climate impacts); *available at* https://www.easa.europa.eu/sites/default/files/dfu/201119_report_com_ep_council_updated_analysis_non_co2_climate_impacts_aviation.pdf.

[42] *See* https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx.

[43] *See https://ethanol.org/ethanol-today/ethanols-flight-plan-to-sustainable-aviation-fuel*

[44] *See* CARB, Staff Report: Initial Statement of Reasons (ISOR). March 5, 2009. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2009/lcfs09/lcfsisor1.pdf. Page IV-21-26.

Comment Log Display

Here is the comment you selected to display.

Comment 356 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Claire
Last Name	Behar
Email Address	Claire.Behar@Hystorenergy.com
Affiliation	
Subject	Hy Stor Energy's Comments on Proposed Low Carbon Fuel Standard Amendments

Comment

Dear California Air Resources Board,

Thank you for the opportunity to provide comments on the proposed low-carbon fuel standard amendments. Hy Stor Energy LP respectful submits the following comments, which are intended to facilitate the adoption of clean hydrogen in low-carbon transportation fuels, which include sustainable aviation fuel (SAF), power-to-liquids, and renewable diesel, and would help scale up a low-carbon fuel industry that would supports the decarbonization of the U.S. economy.

Sincerely,

Hy Stor Energy LP

Attachment www.arb.ca.gov/lists/com-attach/7036-lcfs2024-UTkCfQFfVHRXJQVq.pdf

Original File Name	Hy Stor Energy LCFS Comments Final.pdf
Date and Time Comment Was Submitted	2024-02-20 18:58:34

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

HY STOR ENERGY

555 Tombigbee St
Suite 101
Jackson MS 39202
(888) 542-6074
www.hystorenergy.com

February 20, 2024

Ms. Liane Randolph
Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95864

Re: Hy Stor Energy Comments on Proposed 2024 Low Carbon Fuel Standard (LCFS) Regulation

Dear California Air Resources Board:

Thank you for the opportunity to provide comments on the proposed low-carbon fuel standard amendments. Hy Stor Energy LP respectfully submits the following comments, which are intended to facilitate the adoption of clean hydrogen in low-carbon transportation fuels, which include sustainable aviation fuel (SAF), power-to-liquids, and renewable diesel, and would help scale up a low-carbon fuel industry that would supports the decarbonization of the U.S. economy.

Hy Stor Energy, a company headquartered in Jackson, MS, was formed for the purpose of developing and advancing renewable hydrogen production, storage, and delivery at commercial scale in the United States. Pursuing a multi-regional platform strategy focused on critical locations with the right geography and geology uniquely suited to favorable renewable power generation, underground hydrogen storage, and distribution networks for regional and global market access. Hy Stor Energy's first major project, the Mississippi Clean Hydrogen Hub, is under active development. It will be centered on the development of world-scale underground hydrogen storage capability, with approximately 70,000 acres of land in sixteen Mississippi counties and two Louisiana parishes under Hy Stor Energy's control, seven salt domes, and nine salt caverns fully permitted for underground hydrogen storage. Hy Stor Energy will soon announce a second project in the western United States positioned to be the leading renewable hydrogen supply hub serving the U.S. West and California markets.

Renewable hydrogen is an essential tool for the energy transition and will play a significant role in enabling California to achieve its net-zero goal by 2045. Renewable hydrogen is both an important transportation fuel for fuel cell electric vehicles as well as a necessary feedstock for many low and zero-carbon transportation fuels including SAF, power-to-liquids, renewable diesel, renewable methanol, and renewable ammonia. Enabling the LCFS eligibility of renewable hydrogen as both a transportation fuel in FCEVs as well as a feedstock liquid transportation fuel will enable greater adoption of low-carbon liquid fuels and drive emissions reductions in both the near and long term.

Hy Stor Energy respectfully suggests that the California Air Resources Board (CARB) modify the LCFS amendments to make the following amendments to the LCFS staff draft.

555 Tombigbee St
Suite 101
Jackson MS 39202
(888) 542-6074
www.hystorenergy.com

I. Allow book-and-claim delivery of low-CI electricity for electrolytic hydrogen production used as a feedstock in liquid transportation fuels.

II. Allow book-and-claim delivery of low-CI hydrogen in dedicated hydrogen pipelines outside of California for transportation fuel sold into the California market.

III. Allow delivery of low-CI electricity via book-and-claim for electrolytic hydrogen production in the Renewable Hydrogen Refinery Credit Program.

Allow book-and-claim delivery of low-CI electricity for electrolytic hydrogen production used as a feedstock in liquid transportation fuel.

Allowing book-and-claim delivery for low-CI electricity would maximize the potential for renewable hydrogen adoption and emissions reductions. Low-CI hydrogen will support the production of low and zero-carbon liquid transportation fuels, which are critical to decarbonizing the hard-to-decarbonize markers of heavy-duty surface transportation, aviation, and maritime transportation.

Furthermore, permitting book-and-claim delivery for low-CI electricity will match the treatment CARB has extended to renewable natural gas (RNG), which allows for the utilization of book-and-claim delivery of RNG, including for RNG used in the production of liquid transportation fuels.

Allow book-and-claim delivery of low-CI hydrogen in dedicated hydrogen pipelines outside of California for transportation fuel sold into the California market.

Currently, there are no dedicated hydrogen pipelines in California. Our goal as a nation and Hy Stor Energy's goal as an early mover in the production and distribution of green hydrogen is to facilitate the build-out of a national clean hydrogen economy. This will necessarily include the buildout of a robust hydrogen pipeline backbone to support the scale up of low-CI hydrogen adoption and drive down costs across the entire hydrogen value chain. Limiting eligible dedicated hydrogen pipelines to the California state borders would dramatically stunt the development of the hydrogen market both within California and the region. The optimal policy would be to allow book-and-claim delivery of low-CI hydrogen in any dedicated hydrogen pipeline serving as a feedstock for any fuel being consumed in California. A robust book-and-claim system will allow the delivery of low-CI hydrogen to catalyze market adoption of low and zero-carbon liquid transportation fuels including sustainable aviation fuels, power-to-liquids fuels, and renewable diesel in the critical hard-to-decarbonize industries in California and nation-wide.

Allow delivery of low-CI electricity via book-and-claim for electrolytic hydrogen production in the Renewable Hydrogen Refinery Credit Program.

In order to decarbonize medium to large scale facilities GW scale electrolysis projects will be required. As the current program is designed, requiring onsite renewable generation restricts the program to small-scale projects due to land constraints where refinery facilities are currently located. Allowing for the delivery of low-CI electricity via book-and-claim for electrolytic hydrogen production would allow refineries to utilize this program to lower emissions. Without this amendment, this program will likely continue to be underutilized.

Conclusion

Hy Stor Energy is committed to catalyzing low and zero-carbon solutions to enable California to meet its climate goals. We appreciate the CARB staff's work on the development of the proposed rule and their commitment to improving the LCFS. We look forward to continuing to work with CARB staff on this critically important effort.

Sincerely,

Laura L Luce
Founder & CEO
Hy Stor Energy LP

Comment Log Display

Here is the comment you selected to display.

Comment 357 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Shiva
Last Name	Swaminathan
Email Address	shiva.swaminathan@cityofpaloalto.org
Affiliation	City of Palo Alto
Subject	Comments on the Amendments to the LCFS Regulation
Comment	City of Palo Alto would like to hereby earnestly request CARB to consider exempting smaller CNG stations operated by governmental entities from the verification process, as the cost for verification largely outweigh the benefit when applied to these small and not-for-profit entities dispensing standard fuel such as CNG.
Attachment	www.arb.ca.gov/lists/com-attach/7037-lcfs2024-UjFUMwd0U2JRCAll.pdf
Original File Name	CARB LCFS Regulation Comment Letter from Palo Alto - February 2024 v1.pdf
Date and Time Comment Was Submitted	2024-02-20 19:02:24

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

250 Hamilton Avenue. 3rd Floor
Palo Alto. CA 94301
650 329 2241

CITY OF PALO ALTO

February 20, 2024

Honorable Chair Liane Randolph and Honorable Board Members California Air Resources Board 1001 I Street
P.O. Box 2815
Sacramento, CA 95812

Re: City of Palo Alto Comments on California Air Resources Board's Amendments to the Low Carbon Fuel Standard Regulations

Dear Chair Randolph and Honorable Board Members:

The City of Palo Alto ("Palo Alto") respectfully submits these comments to the California Air Resources Board ("CARB") regarding amendments to the Low Carbon Fuel Standard ("LCFS") regulation as drafted in the Proposed Regulation Order posted on December 19, 2023.

City of Palo Alto provides a broad array of city services to the residents and businesses in Palo Alto, including the operation of a Compressed Natural Gas (CNG) fueling station that serves the community. This station is registered with the CARB under the LCFS regulation.

348.1 Even though it is small station, dispensing ~200,000 terms/year, the LCFS regulation requires Palo Alto to contract with a CARB accredited Verifier to provide verification of services for fuel dispensed by the CNG station. The cost of this verification services is ~$8,000, plus staff time to manage the verification process; we have received verifier quotes as high as $19,000. We believe this level of cost and effort is not commensurate with the value, especially for small station that is expected to receive just 40 LCFS credits in 2023, currently valued at ~$3,000. As such, we would like to request CARB consider exempting small CNG dispensers like Palo Alto from need for verification.

Palo Alto would like to hereby earnestly request CARB to consider exempting smaller CNG stations operated by governmental entities from the verification process, as the costs largely outweigh the benefit when applied to these small and not-for-profit entities dispensing standard fuel such as CNG.

We appreciate the Board's consideration of our request.

Respectfully submitted,

Shiva Swaminathan

Shiva Swaminathan
Senior Resource Planner
shiva.swaminathan@cityofpaloalto.org

Copy: Danitra Bahlman, Fleet Manager

Comment Log Display

Here is the comment you selected to display.

Comment 358 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Casey
Last Name	Coward
Email Address	casey.coward@seiu-usww.org
Affiliation	SEIU - United Service Workers West
Subject	Public Comment on Proposed LCFS Amendments - SEIU USWW
Comment	Please see the attached for SEIU USWW's comments on the proposed LCFS amendments.
Attachment	www.arb.ca.gov/lists/com-attach/7038-lcfs2024-VSZQMwdvACZQewJ3.pdf
Original File Name	SEIU-USWW_CARB_LCFS_Comment_2-20-24.pdf
Date and Time Comment Was Submitted	2024-02-20 19:04:03

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Via Electronic filing with the California Air Resources Board
2/20/2024

Re: SEIU-USWW Public Comments on Proposed Low Carbon Fuel Standard Amendments

Our Union & Member Communities

SEIU United Service Workers West (USWW) represents nearly 45,000 janitors, security officers, entertainment & stadium workers across California, including thousands of workers at LAX, SFO and other airports throughout the state. Our membership primarily consists of workers within low-wage industries, including aviation. Many of our members reside in communities near major airports and within their flight paths. For decades, these communities - largely Black and Brown - have endured exposure from an array of toxic pollutants produced by airport operations, adding on to the decades of environmental racism these cities and neighborhoods have faced from other sources.

SEIU USWW recognizes the detrimental health impacts on our membership and communities produced by commercial aviation's dependency on fossil fuel consumption. For years, we've fought to raise industry standards at the bargaining table, but more recently have been expanding our commitment to confronting the environmental racism and inequity that our members and their communities face as a result of this industry's continued and ever-expanding operations.

California's LCFS & Commercial Aviation's Immense Privilege

349.1 It is for these reasons that we are excited to see CARB taking steps to decarbonize aviation by finally ending the industry exemption and incorporating conventional jet fuel (CJF) into the Low Carbon Fuel Standard. This is long overdue: Sustainable Aviation Fuel (SAF)[1] has been a credit-generating fuel under the LCFS for years, but it's difficult to imagine airlines prioritizing a meaningful transition to more sustainable fuels while their older, polluting fuels continue to draw hundreds of millions of dollars worth of subsidies and savings from the state.

The carveout for CJF saves the airlines an estimated \$110 to \$360 million each year on the cost of that fuel.[2] The exemption from sales & use taxes for fuel used in international flights cost state and local governments nearly \$300 million last year[3], and the jet fuel exemption from excise taxes saves airlines about \$29 million a year.[4]

This heavily subsidized, minimally regulated dynamic for aviation will have to be changed in order to transition to a sustainable industry and meet California's ambitious climate goals. It's simply a matter of when and how.

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[1] Called "Alternative Jet Fuel" under the program
[2] State fuel use estimated using DoT T-100 data on available seat miles originating in state & DoT data on national airline fuel consumption for 2019
[3] CA Dept. of Tax and Fee Administration, Aircraft Jet Fuel - Frequently Asked Questions; CA Dept. of Finance, Tax Expenditure Reports, 2023-24
[4] CA Dept. of Finance, Tax Expenditure Reports, 2023-24

Intrastate Jet Fuel in the LCFS - A Great *First* Step

SEIU USWW is encouraged to see CARB continuing to move forward on a proposal to subject conventional jet fuel to the LCFS standards - a direction that our union has been on the record in support of for years now.[5] We know that the agency has been exploring the concept since at least 2021,[6] and are happy to see this idea move toward implementation. This is a great first step, but we do want to emphasize that it can't be the last one. The latest proposal will only cover fuel used in intrastate flights - flights that represent an extremely small portion of overall emissions from aviation activity: just 3% of emissions nationally, and less than 6% in California.

California's aviation sector accounted for about 34 million metric tonnes of CO_2 emissions in 2018, and only about 2 million were the result of intrastate flights.[7] Nationally, intrastate flights make up only about 3% of CO_2 emissions in the United States. Nearly two-thirds of domestic aviation's CO_2 emissions - 112 million metric tonnes in 2019 - come from domestic flights, but of that, only 6 million comes from intrastate flights.

We view any progress toward reckoning with aviation's climate impact on California residents and communities as both welcome and overdue, but this should be the beginning of a much more comprehensive effort that California is uniquely positioned to lead on. Intrastate flights are a drop in the bucket (though still a very important departure from the status quo), and ending there runs the risk of greenwashing the industry's outsized climate impact by focusing our state policy solutions for aviation on such a small fraction of fuel and emissions.

349.2 CARB needs to set a clear path toward bringing jet fuel used in any flights combusted over California into the LCFS, not just the flights that begin and end in our state. A policy that stops short of that needs to also include some kind of commitment toward obligating more of the fossil jet fuel as time goes on. Ongoing analysis of the supply of SAF and growth in the aviation sector needs to take place so that CARB can increase the obligated fuel beyond this current rulemaking. Without a plan to take on more than just intrastate flights, growth in overall aviation activity stands to outpace any gains made in discouraging the continued use of fossil jet fuel.

Implementation Delay to 2028 is Unnecessary

Currently, CARB is proposing a 2028 implementation date for the obligation of intrastate jet fuel under the
349.3 LCFS.[8] Given that the proposal has been scaled back significantly to just fuel used in intrastate flights, we feel that this kind of delay is excessive and unnecessary. The intrastate limitation means that over 90% of the industry's fossil jet fuel is still exempt from the LCFS, four years of additional grace period for the small share of fuel that will be obligated by the latest proposal is gratuitous. By 2028, SAF will have been eligible for LCFS credits for nearly a full decade - it is clear at this point that significant and urgent action is needed in order to encourage the industry to take their transition away from fossil fuels much more seriously.

Just a few years ago, the industry and the Biden administration both committed to SAF production goals of at least 3 billion gallons a year by 2030 - a figure that would total not even 7% of US jet fuel consumption in 2023, and stands to amount to an even smaller proportion of what that total would be in

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[5] SEIU USWW, "Re: CARB Draft 2022 Climate Change Scoping Plan Update," 6/23/2022

[6] CARB, Public Workshop: Potential Future Changes to the LCFS Program, 12/7/2021

[7] Zheng & Rutherford, ICCT, "Reducing aircraft CO_2 emissions: The role of U.S. federal, state, and local policies," February 2021

[8] CARB, Staff Report: Initial Statement of Reasons, 12/19/2023

2030.[9] If the scope of the LCFS' jet fuel obligation does not expand beyond intrastate flights, a delay to 2028 is unjustified. A policy that is no more ambitious than the industry's own plans and projections will do little to actually encourage a shift away from fossil fuels that wouldn't have occurred already.

SAF Needs Strong Guardrails

Given how far out we are from truly zero-emission solutions at commercial scale in aviation, the industry
will have to rely on Sustainable Aviation Fuel in the near term. But as supply ramps up, smart policy is
349.4 necessary to ensure that this short-term bridge fuel doesn't create long-term problems. The industry has
consistently worked to dilute sustainability standards for SAF[10], and there is a real possibility of the market
being flooded with SAF that fails to significantly reduce lifecycle greenhouse gas emissions. Taking on
SAF as a bridge fuel only makes sense when paired with strong guardrails. A cap on crop-based
feedstock would be ideal, as well as a strong framework for assessing the sustainability of SAF feedstock.
Even now, the industry has been pushing for changes at the federal level that would undermine the ways
in which the overall emissions impacts of SAF are assessed.[11] CARB's evolving policies on aviation must
ensure that we are not simply trading problematic fossil fuels for problematic SAF.

Next Steps

349.5 At SEIU USWW we strongly support efforts to incorporate conventional jet fuel into the LCFS program and will continue to advocate for this kind of policy - though we believe that CARB can and should still include the fuels used in interstate and international flights in current proposals. Falling short of that, CARB should reopen the LCFS rulemaking a couple years from now to chart that path. Within the current rulemaking though, we find the proposed 2028 implementation date excessively generous given the minimal share of flights affected by limiting the program's obligations to intrastate flights only, and are calling for this to be pulled back to 2025 or removed entirely. Finally, we believe a cap on crop-based SAF feedstock is warranted, and as clarity increases with respect to the supply chain for Sustainable Aviation Fuel we hope to see stronger sustainability criteria for SAF feedstock within the LCFS. It should be an ongoing concern for CARB to fight the industry's efforts to undermine the ways in which the emissions impact of different feedstock is assessed.

We believe that meeting California's ambitious climate goals will require a sober-minded view of the sources of carbon emissions, and that decarbonizing aviation is a necessary challenge that our state must overcome. We are encouraged by this policy as a first step and optimistic about the legal viability of this direction. We look forward to continued and increased collaboration with CARB in the years to come as we work to bring true accountability to an industry with so many stakeholders in our workplaces and communities.

Sincerely,

David Huerta
President - SEIU United Service Workers West & SEIU California

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[9] US DoT, Bureau of Transportation Statistics, Fuel Cost and Consumption, CY 2023
[10] *InfluenceMap*, "US Sustainable Aviation Fuel (SAF) Policies and Corporate Engagement," July 2023
[11] *International Council on Clean Transportation*, "How the long shadow of model inputs could dilute the ambition of the Biden Administration's SAF Grand Challenge," 11/6/2023

Comment Log Display

Here is the comment you selected to display.

Comment 359 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Virgil
Last Name	Welch
Email Address	virgil@caliberstrat.com
Affiliation	
Subject	CCSC_LCFS_2.20.24
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/7039-lcfs2024-UDNcOQByBTUCWwdr.pdf
Original File Name	CCSC_LCFS_02.20.24.pdf
Date and Time Comment Was Submitted	2024-02-20 19:05:08

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

CALIFORNIA CARBON SOLUTIONS COALITION

Building Climate Smart Solutions for California

February 20, 2024

California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812
[submitted electronically]

RE: Comments on the Proposed Amendments to the Low Carbon Fuel Standard Regulation

The California Carbon Solutions Coalition appreciates the opportunity to provide comments on the Proposed Amendments to the Low Carbon Fuel Standard.

350.1 The California Carbon Solutions Coalition is the state's leading business and labor organization working to support the rapid deployment of carbon capture, removal, utilization and sequestration (CCUS) technologies to reduce greenhouse gas emissions and deliver high-quality jobs for Californians.

California's 2022 Climate Change Scoping Plan identifies CCUS and direct air capture (DAC) technologies as critically needed tools to support achievement of California's climate goals. A number of industries across California are actively investing in CCUS and DAC projects and technologies. As recognized in the December 19, 2023 Initial Statement of Reasons, the LCFS is a key policy driver for the rapid deployment of these technologies.[1] As CARB proceeds with implementation of an updated LCFS program it is crucial to ensure the timely review and approval of applications submitted pursuant to the "Carbon Capture and Sequestration Protocol (CCS Protocol) under the Low Carbon Fuel Standard."

350.2 Additionally, the Coalition supports the proposal in § 95490 (a)(2)(A) of the proposed regulation that direct air capture projects must be physically located in the United States to be eligible under the CCS Protocol.[2] This proposal will effectively align the LCFS with national efforts currently underway, including major federal incentive funds, to capture the climate, economic and jobs benefits that these projects can deliver.

The Coalition appreciates the opportunity to comment on the Proposed Amendments to the Low Carbon Fuel Standard and looks forward to continuing to work with CARB to ensure that CCUS technologies can meaningfully contribute to the achievement of California's climate goals.

Sincerely,

Virgil Welch
Director

[1] See December 19, 2023 ISOR, pg. 16.

[2] See Proposed Regulation Order, pg. 217.

Comment Log Display

Here is the comment you selected to display.

Comment 360 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Mark
Last Name	Vincelli
Email Address	mark.vincelli@maasenergy.com
Affiliation	Maas Energy Works
Subject	Maas Energy Works Comment on Proposed LCFS Amendments
Comment	
Attachment	www.arb.ca.gov/lists/com-attach/7040-lcfs2024-BmtcP1UjWFRWIFci.pdf
Original File Name	MEW_Publlic Comment_2024.02 - DRM Signed.pdf
Date and Time Comment Was Submitted	2024-02-20 18:57:32

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

MAAS ENERGY WORKS

1730 South Street
Redding, CA 96001
www.maasenergy.com

February 20, 2024

VIA ELECTRONIC FILING

Chair Liane M. Randolph
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: Maas Energy Works Public Comments on the Notice of Public Hearing to Consider Proposed Low Carbon Fuels Standard Amendments

Dear Chair Randolph:

Maas Energy Works (MEW) is North America's largest developer of dairy manure digesters, and one of the two major such companies active in California. Our facilities generate renewable natural gas (RNG) and electricity use as carbon-negative vehicle fuel. Working with our partner families in the California dairy industry, Maas develops projects that support the California Air Resources Board's (CARB) goal of greenhouse gas (GHG) emission reductions. They also protect regional air and water quality, create local jobs, and provide a new revenue stream along with other meaningful benefits to the dairy.

351.1 Thank you for the opportunity to provide comments to CARB on the Proposed Low Carbon Fuel Standard Amendments as presented by CARB staff on December 19, 2023. We fully support the comments submitted by the Coalition for Renewable Natural Gas, which has provided a detailed and authoritative response to the full set of issues raised in this process.

We would like to bring particular attention to the following points in RNC Coalitions comment, using the numbering system from their letter.

351.2 **1.1 Target Setting** The market is oversupplied to a degree that the proposed rule changes will not sufficiently rebalance. The surplus credits will continue to build for years, even more so with the proposed CI change to ULSD. We request CARB refer to the excellent analysis prepared by ICF and described in the RNG Coalition's letter, with the accompanying recommendations regarding changes to the timing and degree of annual CI targets.

351.3 **2.1.1, 2.1.2, and 2.1.3. Avoided Methane** The US dairy RNG industry has been largely built upon capturing fugitive methane emissions and receiving credits for turning those emissions into transportation fuel. Without a way of monetizing those reductions, future investments in digesters are at risk. While we appreciate that the draft rule gives dairy RNG projects a long time before phasing out avoided methane crediting, CARB is still signaling that its goal is to end avoided methane crediting—even if those methane reductions remain additional, verifiable, and voluntary. We would prefer CARB communicate that avoided methane crediting will remain valid under the LCFS for as long as the reductions are additional—just like any other fuel. We note that the European Union's Renewable Energy Directive, Argonne-GREET, and many other leading protocols assign avoided methane benefits to RNG, and we ask CARB not to be the leader in tearing down an industry that CARB has done so much to build up.

351.4 **2.2 Credit True-Up** CARB's proposed true-up mechanism should be helpful in allowing RNG projects to claim the full value of the verified emissions reductions created the project at the end of each verification

MAAS ENERGY WORKS

1730 South Street
Redding, CA 96001
www.maasenergy.com

351.4 cont. cycle—but only at the risk of 4x penalties if the verified score comes in too high. By itself, this change will reduce or delay revenues to digester projects but is at least helpful in providing a way to avoid triggering Notices of Violation (NOVs) in the LCFS program. But the original intention of the credit true-up, as discussed in CARB workshops, was to allow for projects to receive the full value of their verified emissions reductions, full stop. We do not understand why CARB did not extend this same verified, science-based true-up logic to the startup period. Projects that are forced to use a Temporary Fuel Pathway Code should be automatically entitled to later the full value of their emission reductions if and when the underlying data has been validated or verified. As it is, the startup revenue delays, lost credits, risk of NOVs, and regulatory uncertainty are pushing our company and many other developers to question whether supplying carbon-negative RNG to the LCFS program is still a good investment. By making the Credit True Up apply to the initial startup period, CARB can solve one of these problems favorably and accurately. The 4x penalties might be tolerable if there was a full true up in place, but without full accounting for the emissions reductions that our projects generate, the 4x penalty is just punitive.

351.5 **2.3.3 Book and Claim** Book and claim accounting for natural gas deliveries is standard across the RNG industry in North America and much of Europe. We ask CARB not to create new obstacles to the delivery of RNG which will confuse and inhibit production or RNG and/or abatement of dairy methane. Again, the message coming from CARB in these kinds of proposed changes is that RNG should expect more regulatory downsides. Such messages make it very hard to take risks on future projects.

351.6 **3. Auto Accelerator Mechanism** We applaud the AAM as a needed tool to balance supply and demand in the LCFS market. Due to the large and rapidly growing oversupply in the market, we urge that the mechanism be triggered earlier. As proposed, it cannot be triggered earlier than 5/15/2027 and the impacts of this mechanism might not be felt for months or even years after that date. Our company is already needing to pause investments in this sector until demand is more certain.

351.7 **Review of Missing Data Substitution**. CARB, like many regulatory bodies, has previously recognized the use of "reasonable temporary methods" to address data gaps, noting operational realities result in varying gaps that can be reliably filled in reasonable ways that consider the context of each situation. RNG Coalition urges CARB to continue to allow those participating in the LCFS to be able to use "a reasonable temporary method," rather than prescribing the limited data substitution tactics specified under 95491.2(b)(2)(B)'s Table 13 or resorting to an "Executive Office approved alternate method."

We appreciate CARB's hard work and devotion to improving the LCFS program. We appreciate the dedication of CARB LCFS staff in preserving the integrity of the program. Thank you, again, for the opportunity to comment on the draft rule.

Warmly,

Daryl Maas

Daryl Maas, CEO

Comment Log Display

Here is the comment you selected to display.

Comment 361 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Eric
Last Name	Mintzer
Email Address	ekmintz@gmail.com
Affiliation	
Subject	RE: CARB Proposed 2024 LCFS Amendments
Comment	See Attached
Attachment	www.arb.ca.gov/lists/com-attach/7041-lcfs2024-BWIQNVE2UXFRCFU7.pdf
Original File Name	LCFS Note.pdf
Date and Time Comment Was Submitted	2024-02-20 19:06:53

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

California Air Resources Board

1001 I Street

Sacramento, CA 95814

RE: CARB Proposed 2024 LCFS Amendments

I'd like to voice my concerns with the Proposed 2024 LCFS Amendments and the associated rulemaking. These concerns revolve around an underestimation of the degree of tightening needed to drive higher credit prices, and a departure from the technologically neutral stance that formed the basis of the LCFS. I also have one question on the future of Electric Vehicle crediting which will be more pertinent in future years.

Proposed CI Targets

352.1 Overcompliance is clearly seen in recent data, with the credit bank set to increase to around 24mm MT by the end of 2023 and over 31mm MT by the end of 2024 (assuming no changes are made to 2024 targets). Data for the 3rd Quarter of 2023 demonstrated a 15.6% CI reduction, which exceeds the 2026 statutory reduction target. In just a few years, LCFS compliance has moved three years ahead of schedule.

In light of this data, the 2025 step change as proposed will not go far in rebalancing the market. The proposed 18.75% CI reduction target for 2025 would result in about equal credits and deficits assuming pretty conservative trends for biomass-based fuels, RNG, and electric vehicles. If this turns out to be true, the LCFS credit market will remain severely oversupplied due to the large credit bank until at least 2028, when the AAM can begin to respond. Until then, the credit bank will weigh on prices, decarbonization investments, and climate outcomes.

While these assumptions are far from a sure thing, history tells us that technology has adapted quickly to LCFS, and that overlapping local, state, and federal incentives for making this technology economical are quite powerful together. The biggest obstacle to accelerated technological progress seems to be underestimation of its potential. The rulemaking in 2018 seemed quite ambitious at the time but proved to be the opposite. The current rulemaking, on the other hand, feels conservative even at its onset.

The credit bank is in the process of reaching a full year's worth of deficits. The AAM is a fine instrument for automatically adapting to future developments, but CARB should act now to address current situation if it indeed seeks to support the market. A step change to 22.75% in 2025 would reduce the credit bank by approximately 28mm MT vs the current proposal. This is necessary if CARB seeks to reduce the LCFS credit bank by a meaningful amount before EV adoption begins shifting the market back into surplus before 2030, assuming the 30% target in 2030 remains in place. While I don't expect an

352.1 cont. AAM trigger would be necessary if such a move would be made, I also cannot predict what unexpected advances or setbacks in decarbonized transportation might surface.

If it is the desire of CARB to keep prices around current levels (between $50 and $80) I think the current proposal would be adequate. While the market will remain oversupplied, I believe the prospect of the AAM triggering in later years will draw in investor interest when credits drop significantly below this range, with the possibility of higher prices in the 2030's. This rulemaking strategy also has its merits, as it would help avoid rising compliance and fuel costs which could pose a political risk to the LCFS and other state-level environmental programs such as Cap-and-Trade and ACCII, among others. And to the extent that LCFS is meant to find least-cost pathways to low carbon transportation, this path would truly emphasize the 'least-cost' aspect, with competition likely to drive the cost of low-carbon fuels lower.

I'd be happy to share my model assumptions with CARB if requested.

Concern Regarding Existing Modeling

352.2 Regarding the CATS model, I'd like to highlight what I view to be an improper implementation of the credit bank. While the bank has nominally been included, banked credits are only made available at the price ceiling where the supply of credits is effectively unlimited already. This effectively means the CATS model ignores the entire bank. In reality, banked credits will be available at much lower prices, especially when considering the lack of ambition around this proposed rulemaking. Correcting this assumption would show much lower credit prices going forward, even leaving the rest of the CATS model unchanged.

I also believe the CATS model is showing a misunderstanding of the state of the renewable diesel market. California is already consuming more RD than the CATS long-term projections of RD supply. I don't have specific recommendations for fixing the model, but suggest interpreting the results with extreme caution in light of this.

Technological Neutrality

352.3 I find the moves to limit crediting to particular decarbonization technologies as concerning for the integrity of the program going forward. To preserve an efficient market, the rules must be clearly established and enforced. The developments needed to decarbonize transportation (or any industry) require long periods of time to fund, deploy, and operate to be financially viable. Inconsistent rules add economic and regulatory risk to that process, and will make investment more expensive and more short-term focused. I do not believe this is the intention of the CARB, but it is a likely consequence of proposed changes to RNG, biomass-based fuels, and electric forklifts.

LCFS and the CA-GREET model have effective and scientifically rigorous means for evaluating technology, and in many ways already address the criticism of various technologies. Adapting these methodologies to new science and evidence is entirely appropriate, but disregarding them or creating parallel, inconsistent methodologies is not.

352.3 cont. I urge ARB to eliminate its unscientific changes to its rules meant to favor some technologies over others, and instead strongly reaffirm its science-driven rules-based technological neutrality. To the extent that existing pathways do not properly reflect compliance with the LCFS CI targets, corrections for this should be made primarily through the established program mechanisms – updating CA-GREET and adjusting the annual CI reduction targets.

The Future of ZEV Crediting

352.4 Lastly, I have a question about Zero-Emission Vehicle crediting in the future with respect to ACCII. As the regulation goes into effect that requires a certain percentage of new car sales be Zero-Emission Vehicles, will LCFS crediting be adjusted to reflect the fact that each ZEV is not replacing an ICE vehicle? As soon as 2026, the status quo baseline alternative to purchasing and operating 100 new ZEVs will be purchasing and operating a fleet of 65 new ICE vehicles and 35 new ZEV vehicles. The overall fleet of vehicles will also shift more towards ZEV vehicles, making the concept that each ZEV displaces one ICE's worth of gasoline incorrect. How does LCFS plan to incorporate this into their crediting methodology, and is this consistent with other technologies?

Thank you for considering my comments. I greatly appreciate the hard work involved in managing this program, as well as the transparency which has allowed me to have and voice these reflections and opinions.

Sincerely,

Eric Mintzer

Comment Log Display

Here is the comment you selected to display.

Comment 362 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Thad
Last Name	Kurowski
Email Address	tkurowski@tesla.com
Affiliation	Tesla
Subject	Tesla Comments on CARB’s Proposed Low Carbon Fuel Standard Amendments (Dec. 19, 2023)
Comment	Please accept the attached comments on behalf of Tesla.
Attachment	www.arb.ca.gov/lists/com-attach/7042-lcfs2024-AjBdb1VkVjcLP1Rk.pdf
Original File Name	240220 Final Tesla LCFS Comments .pdf
Date and Time Comment Was Submitted	2024-02-20 18:52:18

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

1 Tesla Road, Austin TX 78725
www.tesla.com/contact

February 20, 2024

Submitted electronically via https://ww2.arb.ca.gov/applications/public-comments

Chair Liane Randolph and Board Members
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Tesla Comments on CARB's Proposed Low Carbon Fuel Standard Amendments (Dec. 19, 2023)

Dear Chair Randolph and Members of the Board:

Pursuant to the California Air Resources Board's (CARB's) Proposed Low Carbon Fuel Standards (LCFS) Amendments (Dec. 19, 2023), Tesla respectfully submits the following comments. Tesla incorporates by reference its written comments in response to previous 2022 Scoping Plan and LCFS workshops and presentations.[1] [2] [3]

Tesla continues to support CARB and the state of California in defending the state's authority to implement the LCFS. In response to the Proposed Regulation Order and Initial Statement of Reasons (ISOR) released on December 19, 2023, Tesla provides comments highlighting, inter alia, amendments that support the maintenance of programmatic stringency, enhance public benefits and infrastructure investments, modernize the program and ease administrability.

To provide an understanding of the level of importance of each of our suggested amendments, our comments are divided into three sections. The sections are: Section II) Essential Amendments (changes that Tesla believes to be essential to LCFS stabilization and success), Section III) High-priority Amendments (changes Tesla believes will significantly improve the adoption of EVs and result in emissions reductions sought), and Section IV (Amendments that should be included if time permits though could be completed in a future regulatory cleanup). These three levels of prioritization are based upon a view of where EV (all classes) adoption stands, economic influences, the influence CARB's programmatic decisions have on other US states, balancing the need to finalize new regulations with CARB Staff resource availability and other considerations.

I. Background

a. Tesla's Mission and its California Manufacturing Footprint

Tesla's mission is to accelerate the world's transition to sustainable energy. Moreover, Tesla believes the world will not be able to solve the climate change crisis without directly reducing air pollutant emissions

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[1] https://ww2.arb.ca.gov/form/public-comments/submissions/3796
[2] https://www.arb.ca.gov/lists/com-attach/4195-scopingplan2022-BmVcO1IMAyMGYwBv.pdf
[3] https://www.arb.ca.gov/lispub/comm2/iframe_bccomdisp.php?listname=lcfs-wkshp-feb23-ws&comment_num=111&virt_num=98

- including carbon dioxide and other greenhouse gases - from the transportation and power sectors.[4] To accomplish its mission, Tesla designs, develops, manufactures, and sells high-performance fully electric vehicles and energy generation and storage systems, installs, and maintains such systems, and sells solar electricity.[5] Consistent with this effort, in May, 2023, Tesla was ranked as the world leader in the transition to vehicle electrification.[6]

Tesla currently produces and sells four fully electric, zero emissions light-duty vehicles (ZEVs): the Model S sedan, the Model X sport utility vehicle (SUV), the Model 3 mid-sized sedan, and the Model Y mid-sized SUV. As an EV-only manufacturer, as the U.S. Environmental Protection Agency (EPA) recognized in its *2023 Automotive Trends Report*, Tesla had by far the lowest carbon dioxide emissions (0 g/mi) and highest fuel economy (120 miles per gallon) of all large vehicle manufacturers in MY 2022.[7] Additionally, in December 2022, Tesla initiated delivery of its Tesla Semi Class 8 day cab truck[8] and in December 2023, delivery of its electric pickup truck, the Cybertruck.[9]

Tesla is the largest manufacturing employer in California and employs more than 42,500 people in state. California is home to both Tesla's global design headquarters in Hawthorne, as well as its global engineering headquarters in Palo Alto. Tesla manufactures and assembles vehicles, advanced 4680 lithium-ion battery cells, and battery packs at its factories in Fremont, CA.[10] It also produces Megapack, a utility-scale grid storage battery, at its factory in Lathrop, CA.[11] In 2021 alone, Tesla's investment in California helped deliver $10.4 billion ($28.5 million per day) to California's gross state product.[12]

Importantly, Tesla is not only a manufacturer but is also continuing to grow its large network of retail stores, vehicle service centers, collision centers, and electric vehicle charging stations to accelerate and support the widespread adoption of electric vehicles (EV).[13] Tesla has over 60 stores and galleries and over 45 Service Centers in California. Tesla also operates the country's largest and most reliable public EV charging network. Since 2012, Tesla has invested heavily in siting, building, operating, and maintaining charging infrastructure. In 2013, Tesla had just eight Supercharger Stations in North

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[4] See, Tesla, Master Plan Part 3 (Apr. 5, 2023) *available at* https://www.tesla.com/ns_videos/Tesla-Master-Plan-Part-3.pdfhttps://www.tesla.com/ns_videos/Tesla-Master-Plan-Part-3.pdf

[5] See, Tesla, Impact Report 2022 (Apr. 24, 2023) *available at* https://www.tesla.com/ns_videos/2022-tesla-impact-report-highlights.pdf

[6] See, ICCT, The Global Automaker Rating 2022: Who Is Leading the Transition to Electric Vehicles? (May 31, 2023) *available at* https://theicct.org/publication/the-global-automaker-rating-2022-may23/

[7] EPA, The 2023 EPA Automotive Trends Report, Greenhouse Gas Emissions, Fuel Economy, and Technology Since 1975 (Dec. 2023) at 11-14, *available at* https://www.epa.gov/automotive-trends/download-automotive-trends-report#Full%20Report

[8] See, Tesla, Tesla Semi Delivery Event (Dec. 1, 2022) *available at* https://livestream.tesla.com/https://livestream.tesla.com/; See generally, Tesla, Semi: The Future of Trucking *available at* https://www.tesla.com/semihttps://www.tesla.com/semi

[9] Tesla, Cybertruck, *available at* https://www.tesla.com/cybertruck

[10] See, Inside EVs, Tesla 4680 Cell Production Ramping Quickly, Won't Impact Cybertruck (Oct. 20, 2022) *available at* https://insideevs.com/news/617588/tesla-4680-cell-ramp-wont-impact-cybertruck-other-models/

[11] Tesla, Megapack *available at* https://www.tesla.com/en_eu/megapack

[12] IHS Markit, The Economic Contributions of Tesla to the California Economy, 2018–2021 (October 2022) (detailing Tesla's positive economic impact in California) *available at* https://www.tesla.com/blog/teslas-california-footprint

[13] See, 86 Fed. Reg 43726, 43799 (Aug. 10, 2021) ("Electrification of the vehicle fleet is likely to affect both the number and the nature of employment in the auto and parts sectors and related sectors, such as providers of charging infrastructure.").

America. Today, Tesla owns and operates the largest DCFC network in the world, known as the Tesla Supercharging network.[14] In California, Tesla has 440 Tesla Supercharger locations with over 6,600 charging stalls.

b. Tesla's Class 8 Truck – the Tesla Semi

Tesla's first heavy duty vehicle, a Class 8 truck, is designed from the ground up to be the most efficient and safest truck on the market. The Tesla Semi will have an outsized impact on reducing GHG, particulate matter (PM), and (nitrogen oxides) NO_X emissions from goods movement and transportation. The Semi comes in two models with ranges of 300 and 500 miles respectively and demonstrates that an all-electric truck can meet virtually any duty cycle when paired with the Semi charging system that Tesla is developing.

Combination trucks – of which the vast majority are semi-trucks – account for just 1.1% of the total fleet of vehicles on the road in the U.S.. As EPA recognizes, because combination trucks have high fuel consumption due to their weight and heavy utilization, they account for approximately 25% of all U.S. vehicle GHG emissions.[15] Accordingly, rapidly electrifying the heavy-duty truck segment is an essential part of transitioning the world to sustainable energy.

On December 1, 2022, Tesla announced delivery of its first Semi trucks and has subsequently deployed a fleet of the vehicles with PepsiCo.[16] Since unveiling the Tesla Semi, a significant number of fleets with substantial freight needs have placed reservations for the truck, indicating broad industry demand for heavy-duty electric vehicles.[17] These fleets will be deploying the Tesla Semi in a wide range of applications, including but not limited to, manufacturing, retail, grocery and food distribution, package delivery, dedicated trucking, rental services, intermodal, drayage, and other applications. Companies with operations throughout North America representing every major trucking sector and category of the economy have reserved the Tesla Semi, ranging from food service to logistics to retail.[18]

The reason for this strong interest is clear – the economics of electrified heavy-duty vehicles are compelling for end-users, particularly sophisticated and economically rational operators. Tesla estimates that the time to recoup the investment in a Tesla Semi, given the operational savings it provides customers compared to a conventional Class 8 truck, will be approximately two to three years (Class 8 diesel trucks have a 15-year average lifetime). With the per mile operational costs being so much cheaper than diesel trucks, economic minded operators will maximize the use of their electric trucks and quickly expand the number of electric trucks in their fleets.

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[14] See, Tesla, Supercharger *available at* https://www.tesla.com/supercharger

[15] 88 Fed. Reg. at 25928.

[16] Freightwaves, Tesla delivers fleet of Semi trucks to Pepsi facility in California (April 13, 2023) *available at* https://www.freightwaves.com/news/tesla-delivers-fleet-of-semi-trucks-to-pepsi-facility-in-california

[17] See e.g., Yahoo Finance, Tesla Gets Order for 150 Semi Trucks from Canadian Company as It Prepares for 'Volume Production' (Nov. 5, 2020) *available at* https://finance.yahoo.com/news/tesla-gets-order-150-semi-072938525.html; The Street, Walmart Triples-Down on Tesla Semi Reservations (Sept. 29, 2020) *available at* https://www.thestreet.com/tesla/news/walmart-triples-down-on-tesla-semi-reservations; Business Insider, Tesla has a new customer for its electric Semi — here are all the companies that have ordered the big rig (Apr. 25, 2018) *available at* https://www.businessinsider.com/companies-that-ordered-tesla-semi-2017-12

[18] See EPA, Greenhouse Gas Emissions Standards for Heavy-Duty Vehicles: Phase 3, Draft Regulatory Impact Analysis (Draft RIA) (April 2023) at 52-59.

Tesla has set an annual Semi North American production goal of 50,000.[19] This production rate will represent a level of approximately 20% of 2022 Class 8 domestic annual sales.[20]

c. BEV Deployment Growth Necessitates Stringency and Continued Programmatic Support of All BEV Classes, including Light-Duty and Heavy-Duty

In the ISOR, CARB recognizes that the increasing deployment and market share of electric vehicles and the accompanying buildout of EV charging enable the ability to strengthen the CI reduction benchmarks of the LCFS.[21] Tesla believes the path of EV adoption can support even further reductions in both the CI reduction benchmarks and a greater near-term step down in 2025.

As the agency should be aware, numerous manufacturers have announced increased EV production goals that encompass rapid deployment between now at 2030.[22] These announcements have continued

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[19] See Canary Media, Elon Musk finally delivers on the long-awaited Tesla Semi truck (Dec. 1, 2022) *available at* https://www.canarymedia.com/articles/electric-vehicles/elon-musk-finally-delivers-on-the-long-awaited-tesla-semi-truck

[20] See Transport Topics, December Class 8 Sales Reach All-Time High (Jan. 13, 2023) (2022 Class 8 sales at 254,206 vehicles) *available at* https://www.ttnews.com/articles/december-class-8-truck-sales-reach-all-time-high#:~:text=They%20also%20were%20the%20highest,compared%20with%20221%2C889%20in%202021.

[21] See CARB, Staff Report: Initial Statement of Reasons (Dec, 19, 2023) at 14-17 *available at*

[22] See e.g., Reuters, At least 50% of Aston Martin car sales should be electric by 2030, says CEO (Oct. 19, 2021) *available at* https://www.reuters.com/business/autos-transportation/least-50-aston-martin-car-sales-should-be-electric-by-2030-says-ceo-2021-10-19/; Reuters, BMW investing $1.7 bln to build electric vehicles in U.S. (Oct. 19, 2022) *available at* https://www.reuters.com/business/autos-transportation/bmw-investing-17-bln-build-electric-vehicles-us-2022-10-19/; CNBC, Ford ups EV investments, targets 40% electric car sales by 2030 under latest turnaround plan (May 26, 2021) *available at* https://www.cnbc.com/2021/05/26/ford-ups-ev-investments-targets-40percent-electric-car-sales-by-2030-under-latest-turnaround-plan.html; Honda, Honda Announces Next Steps in Preparation for U.S. EV Production (March 15, 2023) *available at* https://global.honda/newsroom/news/2023/c230315aeng.html; Automotive Dive, Hyundai to invest $85B in EVs by 2030 (June 22, 2023) *available at* https://www.automotivedive.com/news/Hyundai-85-billion-Investor-Day-CEO-electric-vehicle-Ioniq-Kia-Genesis-batteries/653693/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202023-06-22%20Automotive%20Dive%20%5Bissue:51564%5D&utm_term=Automotive%20Dive; Reuters, Jaguar Land Rover boosts investment to catch up in EV race (Apr. 20, 2023) *available at* https://www.reuters.com/business/autos-transportation/jaguar-land-rover-plans-invest-15-bln-pounds-electric-push-2023-04-19/?utm_source=newsletter&utm_medium=email&utm_campaign=newsletter_axiosgenerate&stream=top; Reuters, Kia Corp to produce electric vehicles in the U.S. from 2024, reports say (Sept. 19, 2022) *available at* https://www.reuters.com/business/autos-transportation/kia-corp-produce-electric-vehicles-us-2024-reports-2022-09-20/; Mazda, Mid-Term Management Plan Update and Management Policy up to 2030 (Nov. 22, 2022) *available at* https://newsroom.mazda.com/en/publicity/release/2022/202211/221122a.html; Reuters, Mercedes-Benz foresees EV-only production lines within a few years (Feb 21, 2022) *available at* https://www.reuters.com/business/autos-transportation/mercedes-benz-foresees-ev-only-production-lines-within-few-years-board-member-2022-02-21/; Reuters, Mitsubishi Motors to sell only EVs, hybrids by mid-2030s (March 10, 2023) *available at* https://www.reuters.com/business/autos-transportation/mitsubishi-motors-electrify-100-its-fleet-by-2035-yomiuri-2023-03-10/?utm_source=newsletter&utm_medium=email&utm_campaign=newsletter_axiosgenerate&stream=top; Bloomberg, Nissan Speeds Up Electric Transition Plans With New Targets (Feb. 26, 2023) *available at* https://www.bloomberg.com/news/articles/2023-02-27/nissan-speeds-up-electric-transition-plans-with-new-

to expand with Toyota, Hyundai, JLR, and Subaru, among others, recently announcing new commitments on BEVs.[23] As of the fall of 2023, automakers and battery manufacturers had committed $115 billion to expand the production of EVs and batteries inside the U.S. and across North America.[24]

While some in the fossil fuel industry along with manufacturers struggling to efficiently produce electric vehicles have suggested a retrenchment on EV deployment, any such pronouncements have been flat wrong.[25] In late 2023, the U.S. Energy Information Administration's (EIA) figures reported EV sales were 17.7% of U.S. sales already outpacing the anticipated market share projected by EPA for MY 2026.[26] While the entire U.S. vehicle market was up 13% YoY over 2023, the EV market was up almost 50%

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targets?cmpid=BBD022723_hyperdrive&utm_medium=email&utm_source=newsletter&utm_term=230227&utm_campaign=hyperdrive#xj4y7vzkg; Quartz, Stellantis posted a record year driven by a 41% rise in electric vehicles sales (Feb 22, 2023) *available at* https://qz.com/stellantis-2022-results-electric-vehicles-fiat-new-500-1850144027?utm_source=cbnewsletter&utm_medium=email&utm_term=2023-02-23&utm_campaign=Daily+Briefing+23+02+2023; Automotive Dive, Subaru has a more aggressive EV plan (Aug. 3, 2023) *available at* https://www.automotivedive.com/news/subaru-aggressive-ev-plan-electric-vehicles-hybrid-2030/689807/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202023-08-03%20Automotive%20Dive%20%5Bissue:53237%5D&utm_term=Automotive%20Dive.

[23] See e.g., Toyota, Toyota Unveils New Technology That Will Change the Future of Cars (June 13, 2023) available at https://global.toyota/en/newsroom/corporate/39288520.html?utm_source=newsletter&utm_medium=email&utm_campaign=newsletter_axiosgenerate&stream=top; Reuters, Hyundai Motor Group to invest $18 bln in South Korean EV industry by 2030 (Apr. 11, 2023) (expanding annual EV production in Korea to 1.51 million units and global volume to 3.64 million units by 2030 *available at* https://www.reuters.com/business/autos-transportation/hyundai-motor-group-invest-18-bln-ev-industry-skorea-by-2030-2023-04-11/; Reuters, Jaguar Land Rover boosts investment to catch up in EV race (Apr. 20, 2023) (Investing $19 billion over the next five years in BEVs) *available at* https://www.reuters.com/business/autos-transportation/jaguar-land-rover-plans-invest-15-bln-pounds-electric-push-2023-04-19/?utm_source=newsletter&utm_medium=email&utm_campaign=newsletter_axiosgenerate&stream=top; Electrek, Subaru suddenly breaks electric following tripled annual profits, promises 4 crossover EVs in US (May 11, 2023*) available at* https://electrek.co/2023/05/11/subaru-electric-tripled-annual-profits-promises-4-crossover-ev-us/

[24] Alliance for Automotive Innovation, "Alliance for Automotive Innovation Reports New U.S. Electric Vehicle Data" (Sept. 25, 2023), *available at* https://www.autosinnovate.org/posts/press-release/2023-q2-get-connected-press-release; See also, Atlas Public Policy, U.S. Investments in Electric Vehicle Manufacturing (2023) (January 2023) (Projecting $210 billion to be invested in the United States by 2030, more than in any other country.) *available at* https://atlaspolicy.com/u-s-investments-in-electric-vehicle-manufacturing-2023/

[25] Bloomberg, Reports of an Electric Vehicle Slowdown Have Been Greatly Exaggerated (Dec. 5, 2023) *available at* https://www.bloomberg.com/news/articles/2023-12-05/reports-of-an-electric-vehicle-slowdown-have-been-greatly-exaggerated?cmpid=BBD120523_hyperdrive&utm_medium=email&utm_source=newsletter&utm_term=231205&utm_campaign=hyperdrive

[26] Energy Information Administration, Electric Vehicles and Hybrids Grow to a Record-High 18% of U.S. Light-duty Vehicle Sales (Nov. 27, 2023) *available at* https://www.eia.gov/todayinenergy/detail.php?id=61004#:~:text=Sales%20of%20hybrid%2C%20plug%2Din,to%20data%20from%20Wards%20Intelligence; See also, EPA, EPA Finalizes Greenhouse Gas Standards for Passenger Vehicles, Paving Way for a Zero-Emissions Future (Dec. 20, 2021) *available at* https://www.epa.gov/newsreleases/epa-finalizes-greenhouse-gas-standards-passenger-vehicles-paving-way-zero-emissions

YoY.[27] BloombergNEF predicts a 32% YoY growth rate for 2024.[28] These results are consistent with other projections of rapid EV sales growth. A recent study published in the Proceedings of the National Academies of Science (PNAS) found that consumer valuation of increased range and lower prices will lead EVs to being the majority of vehicles sold by 2030.[29] Some analysts predict that by 2026 60% of new models will be EVs.[30] Still other analysts project that EVs could even account for 90% of sales by 2027.[31]

Most importantly in terms of light-duty EVs, Veloz's Q4 2023 EV Market Report shows that in 2023,[32] California recorded the highest EV share of total car sales, with 25 percent of all vehicles sold being EVs – nearly three times the national average.[33] Further, California's recent adoption of the ACC II rule, setting a 100 percent ZEV sales standard by 2035, will also accelerate BEV adoption. Tesla also expects the deployment of medium- and heavy-duty EVs to scale rapidly. The depth and pace of electrification technology deployment that has already occurred and will be accelerated through market forces and numerous other state and federal policies is impressive. Electric truck deployment, like other technologies, will follow an S curve leading to a rapid pace of adoption in the next decade. Indeed, many manufacturers have rapidly placed innovative technology across major portions of their new vehicle offerings in only a few model years.[34] BEV technology will continue to follow similar paths, and deployment has already been shown to outperform the traditional S curve.[35]

The BEV market is dynamic and changing rapidly. One recent report published two months *before* passage of the Inflation Reduction Act (IRA) found that revenue from the electric truck market was growing at a compound annual growth rate of 54%.[36] In another example, NREL has found economics will drive much faster adoption with ZEV sales possibly reaching 42% of all medium- and heavy-duty trucks by 2030.[37] It even projects out a scenario where ZEV sales reach >99% by 2045, and 80% of the

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[27] BloombergNEF, Electrified Transport Market Outlook 4Q 2023: Growth Ahead (Jan. 4, 2024) *available at* https://about.bnef.com/blog/electrified-transport-market-outlook-4q-2023-growth-ahead/
[28] Id.
[29] Proceedings of the National Academies of Science, Technology advancement is driving electric vehicle adoption (May 30, 2023) available at https://www.pnas.org/doi/10.1073/pnas.2219396120
[30] Automotive News, Car Wars study: By 2026, 60% of new models will be EV, hybrid (June 30, 2022) (citing a Bank of America Merrill Lynch Car Wars study predicting automakers will launch roughly 245 new models over the next four years.) *available at* https://www.autonews.com/sales/car-wars-study-2026-60-new-models-will-be-ev-hybrid?utm_source=dont-miss&utm_medium=email&utm_campaign=20220630&utm_content=hero-headline
[31] Ark Invest, Sales of Gas-Powered Vehicles Could Collapse 85% In the Next Five Years (Nov. 21, 2022) *available at* https://ark-invest.com/newsletters/issue-343/
[32] See https://www.veloz.org/q4-2023-data-shows-a-29-percent-year-over-year-increase/
[33] InsideEVs, California Tops US EV Adoption: 25% EV Share Of Total Sales In H1 2023 (Sept. 27, 2023) *available at* https://insideevs.com/news/688779/california-tops-us-ev-adoption-25-percent-share-total-sales-h1-2023/
[34] See e.g. Hula, et al, Analysis of Technology Adoption Rates in New Vehicles, *SAE International* (April 1, 2014) *available at* https://www.epa.gov/sites/default/files/2016-10/documents/2014-01-0781_0.pdf
[35] Ark Investment, Electric Vehicles Are Outperforming the Traditional S-Curve Dynamics (July 2, 2019) *available at* https://ark-invest.com/articles/analyst-research/ev-growth-outperforming-the-traditional-s-curve-dynamics/
[36] Charged, New Reports Analyze US Electric Truck Market and Global Off-Highway EV Market (June 16, 2022) *available at* https://chargedevs.com/newswire/new-reports-analyze-us-electric-truck-market-and-global-off-highway-ev-market/?utm_source=ChargedEVs.com+Email+Newsletter+Opt-in&utm_campaign=c0d41568d2-Daily+Headlines+RSS+Email+Campaign&utm_medium=email&utm_term=0_6c05923d39-c0d41568d2-343935020
[37] NREL, Decarbonizing Medium- & Heavy-Duty On-Road Vehicles: Zero-Emission Vehicles Cost Analysis (March 8, 2022) *available at* https://www.nrel.gov/docs/fy22osti/82081.pdf

sector transitions to ZEVs by 2050, reducing CO2 emissions by 69% from 2019.[38] A new analysis views the heavy-duty haul market as 50% electrifiable right now.[39] Still other analyses have found that most "market segments have the potential to be fully mature by 2025, with EV models available from multiple companies, including the majority of major OEMs that currently have 90% market share of the in-use fleet."[40] Further, it is predicted the pace of electrification in the truck sector will increase rapidly over the next decade.[41] Recent sales suggest this pace of adoption is already occurring.[42]

These estimates do not take into account the BEV sales impacts that will result from California's newly adopted Advanced Clean Fleets (ACF) program. [43] ACF will require last mile delivery and yard trucks to transition to ZEVs by 2035, work trucks and day cab tractors must be zero-emission by 2039, and sleeper cab tractors and specialty vehicles must be zero-emission by 2042.[44] Moreover, the ACF rule has accelerated the rate of BEV deployment under the original ACT rule to embrace an end to combustion truck sales in 2036.[45] In California, the original ACT rule is estimated to require the deployment of 100,000 heavy-duty ZEVs in 2030 and 300,000 by 2035.[46]

353.1 Finally, CARB should consider the role that new federal incentives may play in deployment of heavy-duty electric vehicles. Federally, numerous heavy-duty electrification grants, demonstration programs, incentives, and infrastructure incentives were included in the Infrastructure Investment and Jobs Act of

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[38] Id.

[39] NACFE, Charting the Course for Early Truck Electrification (May 2022) *available at* https://rmi.org/insight/electrify-trucking/?mc_cid=09f3d727f2&mc_eid=544476f6c1 (Analysis shows that approximately 65 percent of medium-duty trucks and 49 percent of heavy-duty trucks — are regularly driving short enough routes that they could be replaced with electric trucks that are on the market today) ; See also, NACFE, Electric Trucks Have Arrived: The Use Case For Heavy-Duty Regional Haul Tractors (May 2022) *available at* . https://nacfe.org/heavy-duty-regional-haul-tractors/?mc_cid=09f3d727f2&mc_eid=544476f6c1

[40] MJ Bradley, Medium- & Heavy-Duty Vehicles: Market Structure, Environmental Impact, and EV Readiness (Aug. 11, 2022) at 6 *available at* https://www.mjbradley.com/reports/medium-heavy-duty-vehicles-market-structure-environmental-impact-and-ev-readiness

[41] See, Wood Mackenzie, US electric truck sales set to increase exponentially by 2025 (Aug. 10, 2020) *available at* https://www.woodmac.com/press-releases/us-electric-truck-sales-set-to-increase-exponentially-by-2025/ (finding there were just over 2,000 electric trucks on US roads at the end of 2019 and project this to grow to over 54,000 by 2025); BNEF, EV Outlook 2021 (heavy-duty electric trucks become economically attractive in urban duty cycles by the mid-2020s. Megawatt-scale charging stations and the emergence of much higher energy density batteries by the late 2020s result in battery electric trucks becoming a viable option for heavy-duty long-haul operations, especially for volume-limited applications.) *available at* https://bnefhttps://bnef.turtl.co/story/evo-2021/page/3/2?teaser=yes

[42] Fleet Owner, Pace of heavy EV sales quickens with two recent deals (Mar. 22, 2022) *available at* https://www.fleetowner.com/emissions-efficiency/electric-vehicles/article/21237583/pace-of-heavy-ev-sales-quickens-with-two-recent-deals

[43] 88 Fed. Reg. at 25973.

[44] California Air Resources Board, Advanced Clean Fleets Regulation Summary *available at* https://ww2.arb.ca.gov/resources/fact-sheets/advanced-clean-fleets-regulation-summary

[45] CARB, California approves groundbreaking regulation that accelerates the deployment of heavy-duty ZEVs to protect public health (April 28, 2023) *available at* https://ww2.arb.ca.gov/news/california-approves-groundbreaking-regulation-accelerates-deployment-heavy-duty-zevs-protect#:~:text=The%20Advanced%20Clean%20Fleets%20rule%20includes%20an%20end%20to%20combustion,accelerated%20benefits%20for%20California%20communities.

[46] CalMatters, California Mandates Zero-exhaust Big Rigs, Delivery Trucks (July 6, 2020) *available at* https://calmatters.org/environment/2020/06/california-zero-emission-trucks/

353.1 cont. 2021.[47] The IRA also has established programs, such as the Clean Heavy-Duty Vehicles Program, to address climate change by reducing GHG emissions and improve the air quality through the acquisition and use of zero-emission vehicles.[48] The program directs EPA to award a total of $1 billion through grants and rebates to eligible recipients (e.g., states and municipalities) to replace existing heavy-duty vehicles with clean zero-emission vehicles and develop zero-emission vehicle infrastructure. The funding can be applied to up to 100% of the incremental costs of replacing an eligible heavy-duty vehicle with a zero-emission vehicle. It can also be used for other activities such as purchasing, installing, operating, and maintaining infrastructure needed to fuel or maintain zero-emission vehicles. The federal government also recently launched its Commercial Clean Vehicle Credit providing up to $40,000 per truck in tax credits.[49]

CARB should ensure it utilizes the universe of manufacturers' significant public EV deployment commitments in implementing a stringent LCFS, and the agency can mitigate any retrenchment in those commitments by maintaining an adequate light-duty Clean Fuel Rewards program as discussed in Section II.c.i. below.

II. Essential Amendments to Reinvigorate the LCFS Program and Support Light through Heavy Duty BEV Deployments

353.2

a. Tesla Supports Strong Program Stringency (30% minimum by 2030)[50]

Tesla applauds CARB's long-term vision of setting a 90% reduction target by 2045. This cements California as the clear leader in the transportation decarbonization policy space, with the farthest-forward decarbonization target of any transportation decarbonization program globally. It also sets California on a path to reach Net Zero by 2045, as envisioned by Executive Order B-55-18.

The compliance curve, step change, and auto acceleration mechanisms must all work in unison, and Tesla encourages CARB to increase the stringency of the 2030 target beyond 30% if our below recommended changes to the step-change and auto acceleration mechanism are not implemented.

353.3

b. Correcting The Supply-Demand Imbalance Necessitates a Regulatory Step Change of at least 12%

As discussed earlier, the current LCFS market is not functioning in a sustainable manner. There is simply a glut of credits on the market that has driven down pricing, making the LCFS less supportive of electrification efforts in California. As a near term solution to address these issues, CARB should implement a step change of at least 12%, implemented as quickly as possible.

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[47] See, DOE, Alternative Fuel Data Center, Bipartisan Infrastructure Law (Infrastructure Investment and Jobs Act of 2021) *available at*. https://afdc.energy.gov/laws/infrastructure-investment-jobs-act
[48] Inflation Reduction Act of 2022, P.L. 117-169 (Aug. 16, 2022), Section 60101.
[49] https://www.irs.gov/credits-deductions/commercial-clean-vehicle-credit#:~:text=Businesses%20and%20tax%2Dexempt%20organizations,powered%20by%20gas%20or%20diesel)
[50] See UC Davis Updated fuel Portfolio Scenario Modeling to inform 2024 Low Carbon Fuel Standard Rulemaking here. Updated Fuel Portfolio Scenario Modeling to Inform 2024 Low Carbon Fuel Standard Rulemaking (escholarship.org)

353.3 cont. In the past year of reported data, the actual CI reduction has gone from -13.11% (against a -10% target) in Q4 2022 to -15.61% (against a -11.25% target) in Q3 2023, resulting in the differential between target and actual increasing from -3.11% to -4.36%. A simple linear extrapolation of this trend would result in a CI differential of -6.41% by Q1 of 2025.[51] However a response to adopt a 7% step change would not result in a declining credit bank or be reflected in a substantive credit price stabilization. The combination of continued EV adoption with the diesel pool approaching 100% justifies a significant step change of at least 12%.

The step change should be increased in stringency to adjust for the change being proposed by CARB in this rulemaking to the diesel benchmark from 100.45 gCO2e/MJ to 105.76 gCO2e/MJ. Because the diesel credit pool is now more than 50% renewable, an increase in the diesel benchmark results in more overall credit generation per gallon consumed in the whole pool. Going forward, in the absence of limits to first generation biofuels, it is widely expected that the renewable content of the diesel pool will continue increasing until it approaches 100%. This increase in renewable content will amplify the effects of this benchmark change. We recommend CARB model these effects and increase the step change stringency correspondingly.

Just as speed to implementation of the rule changes is critical to health of the program, so too is speed to implementation of the step change. The difference between a 2024 implementation and a 2025 implementation could result in a bank size growing millions of MT higher. Such a large bank increase could require years to rebalance, lowering demand for newly generated credits during that period. By allowing such a large supply and demand imbalance and the creation of such a large total bank, many smaller credit-generating companies who have been critical to the success of the program thus far could experience financial hardship, potentially resulting in lower credit generation in future years as they slow or cease operation. Further, delaying a step change, to use a BEV analogy, sends a message to participants that California is taking its foot off the accelerator, engaging regenerative breaking. This effectively implies that the state leading the climate fight in the U.S. feels it has done enough near-term and is willing to sacrifice additional emissions reductions and reinvestment when it is critically needed.

353.4

c. EV Automaker Contributions to Emissions Reductions Are Deserving of Base Credit Allocations to Revitalize the Clean Fuel Reward (CFR) Program as the CFR was Envisioned

In addition to Tesla's investments noted above in the introduction and Section II, it is expected that Automakers will invest more than $500B globally throughout the electrification value chain.[52] As similarly mentioned in a joint response filed by Tesla and others to the 2022 Scoping Plan, automakers enjoy comparatively strong relationships with consumers and act as primary distributors of information regarding the consumer and environmental benefits of EVs. Automakers also guide consumer preferences by providing compelling EV products, which are primarily responsible for the emissions reductions associated with EV adoption. Despite this significant and unique role in the transition to EVs,

[51] Using actual CI reduction calculation methodology from Figure 1 of the LCFS dashboard: https://ww2.arb.ca.gov/resources/documents/lcfs-data-dashboard;Using reported actual data from the LCFS Quarterly Data Spreadsheet: https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries

[52] See Auto OEMs to Invest US$515 Billion in EV-Related Technologies and Upgrades…here. https://www.prnewswire.com/news-releases/auto-oems-to-invest-us515-billion-in-ev-related-technologies-and-upgrades--but-supply-chain-challenges-remain-301550827.html

353.4 cont. EV automakers may only generate limited incremental LCFS credits, and only if other stakeholders have not already registered to generate such credits. Furthermore, the value of the incremental credits structurally depreciates as improvements are made to the carbon intensity of California's electric grid. This existing structure provides a weak and diminishing incentive for EV manufacturers to make additional allocations to- or investments in- California based on LCFS, and it does not reflect the relative contributions of EV manufacturers in the transition to EVs. As such, CARB should establish a structure that shifts base credit generation for residential EV charging to automakers for the purpose of implementing a functional CFR Program, creating a more inclusive program in which the roles of different stakeholders are more evenly balanced while still ensuring programmatic goals are met. Such a change would reward EV manufacturers for the use of their products—a powerful complement to the existing ZEV sales mandate and an incentive to invest in more capable and desirable EVs.

Tesla continues to support the reinvestment of LCFS electrification credit revenue back into the program to support further electrification. CARB LCFS regulations provide utilities a relatively diverse menu of base credit spending categories which historically included offering a light-duty (LD) Clean Fuel Reward (CFR) program. Far from "bankrupt," by Tesla's estimates, the CFR program has in excess of $420M[53] in LCFS credits intended for LD EV incentives held by utilities today. CARB should provide EV automakers with base credit allocations to revitalize the CFR program, touched upon further below. Lastly, CARB should consider requiring all clean fuel providers (E.G. hydrogen producers or Biofuels Producers) to reinvest funds generated through the sales of LCFS generated credits back into CA LCFS efforts as only electricity is required to reinvest and track today.

353.5

i. Revitalize the Light Duty California Clean Fuel Reward (CFR) Program with Efficient and Sustainable Modifications including EV Manufacturer Base Credit Allocations

CARB staff's proposal to fundamentally change the CFR program from one that supports on the hood incentives for LD vehicles to one focused on medium and heavy-duty vehicles was an unexpected change to the program that was not discussed in any of the preliminary workshops. It is fundamentally problematic to utilize base credits from residential light duty EV charging to fund medium and heavy-duty programs. While the CFR program was obviously flawed, Tesla believes that it can be salvaged, improved, and turned into a consistent pool of funds to support on the hood incentives for light duty electric vehicles. Automakers have decades of experience administering incentives. CARB should welcome EV manufacturers willing participation to create CFR programmatic efficiencies and recognize that the proposal to abandon the LD CFR and reallocate funding to MHD is premature, particularly with extensive existing MHD incentive support. Moving these funds into supporting medium and heavy-duty vehicles that are "exempted from Advanced Clean Fleets regulation"[54] as CARB intends, will essentially provide additional funds for the same pool of vehicles that are currently supported by CARB's HVIP Program, which currently has over $480M of funding available.[55] Further, these truck fleets (unlike California's light duty EV drivers), will already be getting base credits for fleet charging that will reduce their total cost of ownership.

[53] $450,540,222 in total program costs reported for 2020, 2021, and 2022: https://cleanfuelreward.com/reporting;
[54] Appendix E: Purpose and Rationale of Proposed Amendments for the Low Carbon Fuel Standard Requirements at 14.
[55] See https://californiahvip.org/funding/

353.5 cont. That said, the CFR program was not as effective as it could have been. Automakers know more about their delivery plans than anyone and can leverage that knowledge to plan ahead, creating a revitalized LCFS program. By granting base credit revenue to EV manufacturers, administrative efficiencies can be gained, creating a program that relies on lower administrative fees and provides on-the-hood incentives. Having completed substantive and ongoing analysis to understand why the CFR failed and how it could have succeeded (and can succeed) if established with EV manufacturers as the credit recipient, Tesla is confident that a revitalized program could remain solvent, support an incentive for all line makes, including new market participants, and continue to support consumer decisions to purchase LD EVs in pursuit of LCFS goals. Tesla supports the continuation of the LD Clean Fuel Rewards Program with EV manufacturers responsible for operationalizing the program through receipt of non-holdback credits similarly to how utilities are receiving those now.

Should CARB establish a similar CFR MHD program or reallocate funds intended for LDV to MHD as proposed, Tesla recommends that CARB provide the Executive Officer with the authority to adjust any MHD program including credit allocation. The challenging history of the CFR is long and creating flexibility to correct course when expectations and outcomes do not match is essential. CARB has presented no support or justification as to why a CFR for MHD vehicles will not face the same problems that the LD CFR experienced when funded simply through the utilities use of credits. In order for a MHD CFR focused program to succeed, the way this program is funded needs to be reimagined.

353.6

d. Implement Rule Changes in 2024, Being Careful to Not Sacrifice Stringency

With a supply and demand imbalance of over 6 million MT per year, as of the last reported data,[56] the speed in which CARB implements new rules is of vital importance to market participants. With actual reductions in carbon emissions exceeding 15%,[57] surpassing expectations since 2020, and seeing LCFS credit prices fall since that time from ~$200 to a low of $57 so far this year,[58] delaying a stringency increase and step-change will likely continue to suppress credit values, market confidence and investment in clean fuels in California. While every quarter delay matters, Tesla encourages CARB staff to continue to focus on rules that correct near-term credit pricing in support of reinvestment in emissions reducing efforts.

353.7

e. Improve the Automatic Acceleration Mechanism (AAM)

The inclusion of an Automatic Acceleration Mechanism (AAM) is an important and welcome step towards balancing the safeguards in the program. The program already includes multiple safeguards to help rebalance the program if it is underachieving its targets, including a Credit Clearance Market, Advanced Credits, Carryback Credits, and Accumulated Deficits. The AAM is an important counterbalance safeguard for times when the program is overachieving its targets.

During times of program overachievement, the AAM, as currently envisioned, requires two full years to take effect.

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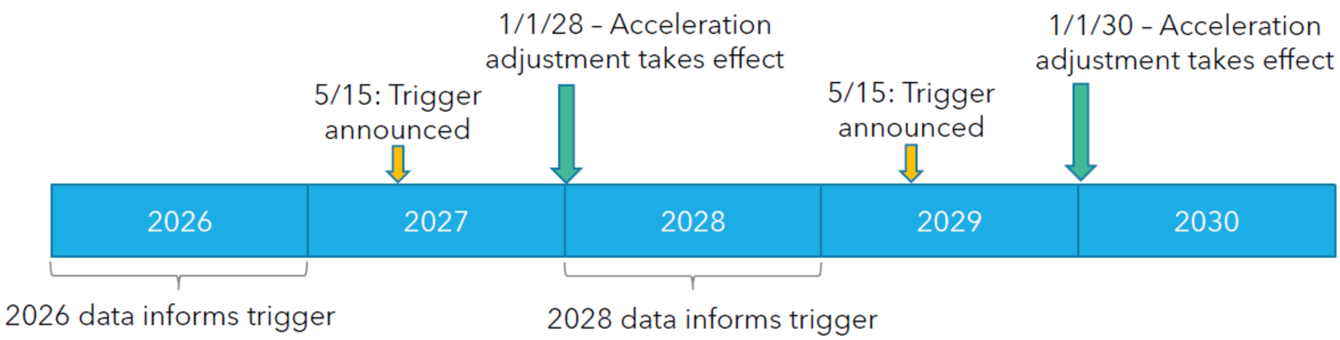
[56] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries
[57] https://ww2.arb.ca.gov/resources/documents/low-carbon-fuel-standard-reporting-tool-quarterly-summaries
[58] See California Low Carbon Fuel Standard Credit Price from July 2020 through February 13, 2024, https://www.neste.com/investors/market-data/lcfs-fuel-standard-credit-price

353.7 cont.



The current draft rule also sets the AAM's first year of implementation as 2027, with benchmark changes taking effect in 2028 at the earliest. Tesla's primary ask is for the first year of AAM implementation should be in 2026, using 2025 data for the trigger, with the changes to the benchmark being implemented in Q3 of 2026 if triggered.

III. High Priority Amendment Recommendations

353.8 **a. Update the Light Duty BEV Energy Efficiency Ratio (EER) and Provide a Pathway for OEM-Specific EERs**

CARB should also use this rulemaking as an opportunity to update the Energy Efficiency Ratio (EER) for Light Duty Battery Electric Vehicles (LD BEV). The current 3.4 EER was adopted by CARB in 2011 and has not been updated in the 13 years since. As described in the 2011 Initial Statement of Reasons (ISOR) (Appendix A, Page 67),[59] the 3.4 EER was an average of the EERs of two vehicle comparisons. The first was a PHEV-to-ICE comparison between a 2011 Chevy Volt compared to a 2011 Chevy Cruze (93 MPGe combined fuel economy / 28.3 MPG combined fuel economy = 3.29 EER). The second was a BEV-to-ICE comparison between a 2011 Nissan Leaf and a 2011 Nissan Versa (99 MPGe combined fuel economy / 28.4 MPG combined fuel economy = 3.49 EER). The fuel economy numbers can be viewed on www.fueleconomy.gov. The 28.3 MPG fuel economy for the Chevy Cruze was presumably a simple average of the automatic transmission versions of the three engine trims offered. The 28.4 MPG fuel economy for the Nissan Versa was presumably a simple average of the automatic transmission versions of the two engine trims offered. Given the immense change in EV adoption in recent years, and the remarkable improvements in the efficiency of EVs today, it is simply inappropriate to use an EER that is 13 years old. As an illustrative example, a 2024 Hyundai Ioniq 6 has a 140 MPGe, which is a 40% improvement on the 2011 Nissan Leaf.

If CARB were to keep the 2011 (existing) EER methodology and simply update the calculation using the most current version of the cars included in that calculation, the EER would rise from 3.4 to 3.8. However, for the first comparison between a PHEV and ICE vehicle, CARB chose the Chevy Volt and Chevy Cruze; unfortunately, General Motors ceased production of both vehicles in 2019.[60] In leu of

[59] https://ww3.arb.ca.gov/regact/2011/lcfs2011/lcfs2011.htm
[60] https://www.cbsnews.com/news/chevy-volt-discontinued-chevrolets-last-volt-rolls-off-the-assembly-line/

353.8 cont. these vehicles, CARB would need to add another comparison. A similar comparison can be done between the 2024 Prius Prime, which achieves a 127 MPGe combined fuel economy,[61] and the conventional ICE 2024 Toyota Corolla (both are classified as compact cars), which achieves a 28.5 MPG combined fuel economy across the simple weighted average of the automatic transmission versions of the two non-hybrid engine trims. This is a PHEV-to-ICE EER of 4.46. Nissan continues to sell the Leaf and the Versa. The Nissan Leaf energy efficiency has improved from 99 MPGe in 2011 to 111 MPGe for the 2024 model year.[62] The Nissan Versa energy efficiency has improved from 28.4 MPG in 2011 to 35 MPG for the automatic transmission version of the only engine trim.[63] This translates to an EER of 3.17 for BEV-to-ICE. Using the simple average of the BEV and PHEV EERs, we arrive at an overall Light Duty EER of 3.8. Another apt comparison would be the Hyundai Ioniq 6 and the Hyundai Elantra. As stated earlier, the Ioniq 6 gets 140 MPGe, while the Elantra's weighted average of the automatic transmission versions of the two non-hybrid engine trims is 35 MPG. This is a BEV-to-ICE EER of 4. Using a sales-weighted BEV-to-ICE ratio would likely result in an EER over 4.0.

California would not be alone in modernizing its EERs for LD BEVs. Canada's Clean Fuel Regulations use a 4.1 EER for light duty EV Charging. This was calculated based on the ratio of the sales-weighted average efficiencies of electric vehicles to the sales-weighted fuel efficiency of the ICEVs in the same class, with efficiency data came from the 5-cycle testing procedure.[64] The Netherlands' Energy Transport Regulation currently uses an EER of 4.0.[65] The European Union recently passed the third version of its Renewable Energy Directive (REDIII). This directive increases the targets for EU member states transportation GHG reductions and guides them to use a 4.0 EER.[66] Updating the EER is important to ensure that electric vehicle charging is properly credited and continues to be incentivized appropriately. Utilizing a higher EER can support a steeper step change and a steeper compliance curve for this program.

In addition, CARB should allow an OEM to submit an application for an EER based upon that OEM's real-world fleet. CARB has created a precedent for this by approving the Lime scooter Tier 2 pathway which included a company-specific EER factor.[67] Allowing OEMs to submit applications for company-specific EERs would better reflect the actual efficiency of electric vehicles in the market and allow those vehicles to be properly credited. This would also incentivize each OEM to focus on improving vehicle efficiency.

353.9

b. Update the Medium and Heavy-Duty BEV Energy Efficiency Ratio

[61] https://www.fueleconomy.gov/feg/Find.do?action=sbs&id=47501
[62] https://www.fueleconomy.gov/feg/Find.do?action=sbs&id=46973
[63] https://www.fueleconomy.gov/feg/Find.do?action=sbs&id=47236
[64] Page 86 of the Specifications for Fuel LCA Model CI Calculations, https://data-donnees.az.ec.gc.ca/data/regulatee/climateoutreach/carbon-intensity-calculations-for-the-clean-fuel-regulations/en/Resources/?lang=en
[65] https://www.rijksoverheid.nl/documenten/kamerstukken/2022/12/22/beantwoording-kamervragen-over-wijziging-van-de-stimuleringsfactoren-in-de-regeling-energie-vervoer
[66] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32023L2413&qid=1699364355105
See also, https://www.europarl.europa.eu/doceo/document/ITRE-AM-729929_EN.pdf
[67] https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0467_cover.pdf

353.9 cont. While not quite as dated, the current 5.0 EER for Heavy Duty battery electric vehicles is also due for an update. This EER was set during the 2018 rulemaking and the methodology for calculating this EER is described in the ISOR Appendix H, Section E.[68] Unlike the Light Duty EER calculation, which was based on just two vehicle comparisons, the MHD EER calculation is based on an analysis of a number of papers comparing the efficiency of transit buses, drayage trucks, parcel trucks, and many other MHD vehicle types. Tesla believes this more comprehensive EER methodology is preferable and encourages CARB to update the MHD EER based on the current state of vehicle efficiency research.

In the current EER table (Table 5) CARB has Light and Medium Duty electric vehicles lumped together into a single EER and Heavy Duty EERs as another single EER. Light Duty vehicles are defined as vehicles with a GVWR of 8,500 pounds or less, while Medium Duty Vehicles are defined as vehicles with a GVWR between 8,501 and 14,000 pounds. Anything over 14,001 pounds GVWR is classified as Heavy Duty. This combining of Light and Medium duty in the EER table conflicts with the combining of Medium and Heavy Duty in the Fast Charge Infrastructure (FCI) program. As part of the EER update, Tesla encourages CARB to either create a separate EER for Medium and Heavy Duty BEVs or allow for OEM-specific EERs.

353.10

c. Remove the Unnecessary Third Party Verification for Non-Residential EV Charging

Proposed section 95501 of the amendments includes a proposal to expand third party verification for EV charging transactions. While Tesla appreciates the intent of CARB staff's proposal, it is unnecessary to create a separate third-party verification program regime for non-residential electricity transactions related to EV charging. Commercial EV charging infrastructure transactions fall under the purview of the CA Department of Agriculture, Division of Measurement Standards (DMS), under its state weights and measures program. CA DMS is responsible for verifying the accuracy of commercial EV charging infrastructure in California. This includes both a field verification process carried out by the CA counties as well as type evaluation program. It is unnecessary for LCFS to add additional verification requirements given the accuracy of commercial EV charging transaction is already regulated and verified in CA. We therefore recommend that no additional third-party verification is necessary for EV charging transactions.

353.11

d. Amendments to the Medium and Heavy-Duty Fast Charge Infrastructure Program

Tesla agrees that medium and heavy duty FCI pathways are important for accelerating the transition of electrifying trucking in California. Tesla supports CARB's inclusion of a HD-FCI pathway in the proposed amendments and appreciates CARB's inclusion of depot charging as an eligible pathway. Initial Tesla Semi customers will initially be focused on charging infrastructure located in the internal depots. These trucks utilize "hub and spoke" operations or go through other internal depots during their operations. The cost of infrastructure is one of the main determining factors for how many trucks a customer is willing to purchase. The HD-FCI will incentivize customers to build out the necessary charging infrastructure to support their fleet transitioning to electric trucks on an expedited timeline.

353.12

i. Remove Geographic Restrictions for MHD FCI

[68] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2018/lcfs18/apph.pdf

353.12 cont. The geographic restrictions included in the proposed amendments for the HD FCI should be removed. There are limited locations in California with the power available to support truck charging at scale. Given the cost, and more importantly, the time constraints that come with bringing new capacity to power constrained locations, charging developers must be able to locate their locations where it makes the most sense from a business perspective. Alternatively, CARB should change the one mile from the corridor limit to five miles. This will at least expand the number of suitable charging locations to develop.

CARB's justification for including the restriction to within one mile of a major freight corridor is to "bring cleaner air for communities living adjacent to these areas currently heavily impacted by diesel truck pollution." Siting medium and heavy-duty chargers is a balancing act between land costs, availability of land near freeways, availability of land without zoning restrictions, and, perhaps most importantly, the challenge in finding 5 MW or more of grid capacity where the local utility is willing to install interconnects on a quick timeline. Because the Venn diagram overlap of these needs is already small, we do not believe CARB should be adding additional geographic restrictions to further limit the number of qualifying sites. Limiting eligible charging locations will only serve to slow down that process and subject all communities, including Environmental Justice communities to continued diesel pollution.

Different trucks have different driving patters – class 4 trucks might deliver milk to grocery stores early in the morning and then sit charging for the rest of the day; this would best be served by slower chargers in the location where these trucks are parked most of the time. Class 8 trucks might be traveling all day long, with multiple driving shifts between the ports and warehouses; this would best be served by fast chargers along a major freight corridor. Some trucks will be fleet vehicles while others will be driven by independent-owner operators. Trying to overlay a "one size fits all" geographic restriction on MHD-FCI will only serve to slow the deployment of these chargers.

353.13

ii. Eliminate or Increase the 10 Charger Per Site Limit for MHD FCI

For MHD-FCI sites, CARB is proposing limits of no more than 10 charging posts per site. This artificial limitation should be removed. Charging developers that are focused on the medium and heavy-duty truck sector are developing sites that are far bigger than 10 posts for good reason.[69] In order to support

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[69] See e.g., Bloomberg News, Tesla Wants to Build a Semi Truck-Charging Route From Texas to California (August 1, 2023), (describing a proposal for charging infrastructure that included at least 12 chargers per site) *available at* https://www.bloomberg.com/news/articles/2023-08-01/tesla-semi-truck-charging-route-pitched-at-100-million?embedded-checkout=true; Canary Media, Big electric-truck charging depots are coming soon to California (January 26, 2024) (an overview of three truck charging depots being built by WattEV, including two in the Central Valley which will have a combined 192 chargers and a third site in Blythe with 66 chargers),*available at* https://www.canarymedia.com/articles/ev-charging/big-electric-truck-charging-depots-are-coming-soon-to-california; (Forum announcing a new charging depot in Port of Long Beach with 25 chargers) Forum Mobility Announces New Charging Depot for Electric Drayage Trucks in the Port of Long Beach (November 30, 2023) *available at* https://www.prnewswire.com/news-releases/forum-mobility-announces-new-charging-depot-for-electric-drayage-trucks-in-the-port-of-long-beach-302001230.html; TerraWatt Infrastructure Accelerates Rollout of EV Fleet Charging Solutions Across Inland Empire (October 10, 2023), (Terrawatt announcing two sites capable of charging over 500 trucks utilizing 40MW of power) *available at* https://www.prnewswire.com/news-

353.13 cont. the transition to truck electrification being driven by policy and regulations in California, it is vitally important that there are large charging depots available to truck operators. These charging sites can support fast charging for regional and long-haul trucking but can also serve other truck operations where operators are able to sit and charge for longer periods of time. These charging locations will make electric trucking possible for companies looking to electrify longer routes, as well as smaller operators who are unable to accommodate charging in their depots. If CARB is unwilling to remove this limitation entirely, Tesla suggests increasing the charger post number to 100 or at least remove or increase the limitation for shared depots and fleet depots which will be the majority of initial charging developments in the coming years.

353.14

iii. Increase 10 MW Limit to 15 MW per Site with Exceptions up to 24 MW

For the same reasons stated above that the 10 charger per site limit should be removed, CARB should also remove the overall site capacity limit of 10 MW. 10 MW is simply not enough power to support the charging stations needed to meet California's electric truck deployment goals. CARB should increase the 10 MW cap for sites to at least 15 MW and allow an exception by the Executive Officer for up to 24 MW for sites.

353.15

iv. Raise 2.5% cap for MHD FCI to 5%

The MHD-FCI program is limited to 2.5% of the previous quarter deficits. At today's deficit levels, this would fall dramatically short of the charging requirements in the state. Additional support is needed to attract the scale of private capital required, particularly at this nascent stage of the market.

We suggest increasing the 2.5% cap, particularly in the early years of the program. As truck and charging infrastructure deployments grow, CARB might consider reducing the cap in a future rulemaking. Tesla supports increasing the cap to 5% to provide the support necessary to begin to build a charging network that will enable the market to take off. Solving the chicken-and-egg infrastructure problem by using FCI to provide assurances to MHD infrastructure developers in advance of vehicle adoption is critical to the success of ACF, ACT, and the Scoping Plan. Encouraging the early adopters (e.g., shared depots and some fleets) to build the infrastructure to accommodate full electrification is critical even if the initial vehicle deployments are lower. This will help expedite the time frame for increasing the fleet's adoption rate of electric trucks. In the near future, turnaround time for new electric truck orders will be measured in weeks and the lack of infrastructure will delay adoption. Helping fleets move early will allow them to quickly add to their fleet after gaining comfort with the technology.

353.16

i. Harmonize Hydrogen and EV Charging CIs for Capacity Credits

CARB currently gives preferential treatment to hydrogen stations, despite showing no signs of commercial success, over electric vehicle charging stations when assigning the CI for capacity credits. Hydrogen stations utilizing the HCI pathway receive a CI of the "Company-wide weighted average CI for dispensed hydrogen during the quarter or 0 g/MJ, whichever is greater" while electric vehicle charging

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releases/terawatt-infrastructure-accelerates-rollout-of-ev-fleet-charging-solutions-across-inland-empire-301951648.html

353.16 cont. stations utilizing the FCI receive a CI of the "California average grid electricity carbon intensity" regardless of whether the EV charging company is utilizing 0 CI RECs for the rest of their charging.

CARB should treat Hydrogen and EV charging equally by either giving hydrogen HRI capacity credits a CI of the last reported industry average, or by allowing EV charging FCI capacity credits to be generated off of a 0 CI if the company is using REC matching for the rest of their charging.

353.17 **ii. Ownership Clarification**

Tesla suggests that CARB clarify that "private MHD-FCI stations" includes fleets owned by entities in the government, private and non-profit sectors.

e. Amendments to the Light Duty Fast Charge Infrastructure (FCI) Program

353.18 The light duty FCI program has played an important role in driving the expansion of electric vehicle charging infrastructure throughout California. It has been key driver of making the economics of charging station development pencil out by providing developers with some incentives before utilization picks up. This has made certain charging locations economic to build months or years ahead of when they would have been built without this support. Importantly, as utilization grows at these locations, dependence on this program wanes as they move to base credit generation. As California seeks to dramatically expand its charging infrastructure to support its EV growth trajectory, it is critically important that this program remains robust and effective. Tesla offers the below comments on amendments to this program.

353.19 **i. CARB should Maintain a 2.5% Light Duty FCI Cap, Removing the 0.5% Cap Change**

CARB is proposing reducing the total amount of available FCI credits from 2.5% of deficits to 0.5%. Tesla believes that it is too early to declare "mission accomplished" on light duty electric vehicle charging. In the technology adoption life cycle, we are now past the early adopters and into the mainstream of car buyers. These buyers tend to be more risk-adverse and more concerned with the availability of reliable charging infrastructure. It is crucial that we continue to maintain a positive charging experience for these mainstream customers so that we can continue to advance the full electrification of the transportation sector. Light Duty FCI credits continue to play an important role in solving in the "chicken and the egg" problem of the tension between EV vehicle deployment and EV charger deployment. The CEC modeling of ACC2 shows a need for 83,000 DCFC in public locations by 2035 which is a daunting increase from the 10,000 public DCFC today and is significantly more than what a 0.5% cap can incentivize. CARB should keep the 2.5% cap in place to ensure continued incentives flow to charging infrastructure developers to build new chargers ahead of demand.

353.20 **ii. Remove Geographic Restrictions and Station Size Limitations**

CARB is proposing additional geographic restrictions for LD-FCI projects, where "station must be located in California in a low-income or disadvantaged community, or at least 10 miles from the nearest direct current fast charger open to the public with a nameplate capacity equal to or greater than 150 kW."[70]

[70] APPENDIX A-1 Proposed Regulation Order Proposed Amendments to the Low Carbon Fuel Standard Regulation at 105.

353.20 cont. CARB's logic for these geographic restrictions is to "help fill refueling gaps in the State."[71] However, these amendments effectively limit LD FCI stations to rural areas because there are very few non-rural locations that are not located ten miles from an existing DCFC station. This amendment is operationally unworkable, requiring real time checking of federal maps (e.g., Alternative Fuel Data Center) on a daily, monthly, or even quarterly basis to see if the planned station remains within ten miles of some other public DCFC station.

Given the need for charging throughout California, CARB should remove all geographic limitations on this program. If our recommendation for no geographic restrictions is not acceptable, we recommend the new LCFS use United States Treasury Department and Internal Revenue Service (IRS) guidance on station eligibility for the 30C alternative fuel vehicle fueling property tax credit, which was designed to support the deployment of EV charging infrastructure in non-urban (rural) communities across the US and updated in the Inflation Reduction Act.[72] The U.S. Department of Energy has also published a clear mapping tool that shows which census tracts meet IRS definition of non-urban census tracts.[73] Compared to having a 10 mile from existing DCFC as a way to encourage DCFC in rural areas, the federal definition of non-urban census tracts is easily understood, stable, and remains in effect through 2030 until the Census Bureau updates determinations of urban and non-urban areas.[74]

CARB is also proposing to reduce the maximum site limit from 6 MW to 1 MW and adding a cap on the number of charging posts at a site to 4. Tesla believes that CARB should not add these additional restrictions. Tesla's largest location in Coalinga, California has 168 charging posts with a capacity of 16 MW. Charging companies have the best data to make informed business decisions about where to deploy new chargers and often the optimal decision is to add new chargers to an existing location which customers already find convenient, rather than adding a new site somewhere else. Adding restrictions on the size of the site and number of posts will result in suboptimal charger placement. Charging providers should continue to be incentivized to identify where charging infrastructure will be needed and build ahead of the demand with the support of the capacity credits. If charging is only built when needed, it is the customer who suffers because they are forced to wait for charging at chargers that are busy while new relief charging is being developed.

The 6 MW cap was implemented because CARB was worried that charging companies would build "white elephant" projects where they deployed dozens of chargers in whatever location was the cheapest to build, rather than in locations that were convenient for drivers. This concern has proven to be unfounded, as thousands of chargers have been built all over California in locations that are best optimized for both cost and customer convenience. This policy has directly enabled California's charging infrastructure to have a fighting chance to stay ahead of demand and ensure California EV drivers are able to live, travel and work throughout California. It is, therefore, unnecessary to add additional size and geographic restrictions today.

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[71] Appendix E: Purpose and Rationale of Proposed Amendments for the Low Carbon Fuel Standard Requirements at 37.

[72] https://www.irs.gov/pub/irs-drop/n-24-20.pdf

[73] https://experience.arcgis.com/experience/3f67d5e82dc64d1589714d5499196d4f/page/Page/

[74] https://www.irs.gov/pub/irs-drop/n-24-20.pdf

353.21 Note: in the draft regulation CARB incorrectly listed the section for amendment as "Subsection 95486.2(b)(1)(E)1" – it should be "Subsection 95486.2(b)(2)(E)(1)".

353.22 **f. Tesla Supports Efforts to Protect Against Fraud in Biofuel Markets**

CARB is proposing additional guardrails to the use of crop-based feedstocks in the production of biofuels. Tesla supports efforts to remove palm oil as a qualifying feedstock and requirements to track crop-based and forestry-based feedstocks to their point of origin.

Tesla is involved in the European fuel credit markets, such as the German THG program and Netherlands HBE program, and has seen how the flood of allegedly fraudulent biofuels into the European Union has caused the prices of those programs to fall, harming companies who are producing actual carbon reductions. One study found that imported used cooking oil represented 80% of consumption and that "a large share of these imports could be fraudulent" sourced from "repurposed virgin palm oil."[75] With the European Union now investigating those allegedly fraudulent sources of biofuels, there are concerns that these feedstocks will flow to other biofuels markets with less stringent safeguards. California is a leader in transportation decarbonization and as such we hope CARB will work with EU regulators as well as other North American regulators with LCFS programs to harmonize biofuel feedstock verification and tracking requirements to prevent these allegedly fraudulent biofuels from flowing to whichever LCFS program has the most lax regulations.

353.23 **g. Book-and-Claim Accounting for Hydrogen Could be Catastrophic and Requires Further Analysis prior to Implementation**

CARB is proposing rules which would allow Book-and-Claim Accounting for hydrogen injected into pipeline systems. Tesla is concerned that CARB has not fully taken into account the potential detrimental effects on our climate from such a provision. Hydrogen itself is a greenhouse gas with a global warming potential 33 times that of carbon dioxide on a 20 year timeframe.[76] As opposed to simply putting renewable electrons directly into a battery electric vehicle for motive power, hydrogen production from electrolysis uses that renewable electricity to split water and produces hydrogen, a greenhouse gas, some of which inevitably leaks into the atmosphere, furthering climate change. Because hydrogen is the smallest molecule, it is more susceptible to leakage than any other greenhouse gas. Leakage of hydrogen into the atmosphere during production, storage, distribution, and dispensing counteracts some of the potential carbon reductions. We hope that CARB staff will further study this issue and release a full analysis of the impacts of such a decision before it is implemented.

IV. Technical Amendment Improvements to Modernize the Policy if Time Allows:

353.24 **a. Reduce Geofencing Radius for Incremental Credit for Residential Charging**

CARB Guidance Document 19-03 sets a geofencing radius of 220 meters (M) around all registered non-residential EV charging FSEs, using a 4 decimal point prevision. Within that 220 meter radius, automakers are not allowed to apply incremental crediting to home charging. This is an issue in dense

[75] https://www.transportenvironment.org/discover/biofuels-from-unsustainable-crops-to-dubious-waste/
[76] https://www.gov.uk/government/publications/atmospheric-implications-of-increased-hydrogen-use

353.24 cont. locations like cities where home charging takes place near registered non-residential EV chargers. With thousands of non-residential EV chargers deployed across the state, these geofencing radii have begun morphing into a patchwork that has nearly blotted out entire cities.

Tesla recommends CARB update the geofence radius from 220M to 20M at most. Improvements in GPS systems since adoption of the 220M radius provide assurance that double counting will not take place. A 2021, MIT Technology review revealed that "Once the signals are processed by a receiver, GPS is generally accurate to within five to 10 meters. Now the system is in the middle of a years-long upgrade to GPS III, which should improve its accuracy to one to three meters (see chart)."[77] The review goes on to recognize that additional accuracy, down to the centimeter, may be possible with the assistance of ground-based augmentation. Without fully knowing where ground-based augmentation may be in use to create higher accuracy, Tesla urges CARB to adopt a conservative radius of 20 meters at this time.

353.25 **b. Smart Charging Provision Modifications**

The current LCFS regulations include a pathway for generating incremental credits by using smart charging. This pathway is designed to incentivize shifting electricity use for EV charging to the times when marginal greenhouse gas emission rates of grid electricity are lower than the average emission rate. Tesla believes that this pathway is important for the continued acceleration of grid decarbonization. California has hit some key grid decarbonization milestones in the past few years, with the entire grid operating on 100% renewable electricity for brief periods throughout the day. As we ramp up renewables further, we will need companies to utilize the smart charging pathway to help flatten the Duck Curve.[78]

We encourage CARB to explore regulatory changes that would encourage more companies to utilize the Smart Charging pathway. One change could be to allow companies offering whole home renewable power systems with solar, storage, and EV charging to combine the systems to act as a virtual power plant, using the rooftop solar to charge the home storage battery during the day and discharging the home storage into the EV at night to lower grid pull during high emissions periods. We look forward to a future when more homes have such integrated systems and can be combined to provide grid services and time-shifting carbon reduction. Another change could be to allow for the use of hourly RECs, matched to offset specific carbon reductions against the hourly grid carbon intensity, rather than being matched against the yearly average carbon intensity. This would encourage the development of hourly RECs and would create a market that would put a price on hourly grid carbon intensity and incentivize investment in grid assets that reduce emissions during the highest intensity hours.

353.26 **c. Repayment of Accumulated Deficits with a 10% Interest Rate**

The current LCFS regulation[79] requires obligated parties to repay accumulated deficits with an interest rate of 5% applied. Given the higher interest rates we are seeing now, this low rate may incentivize

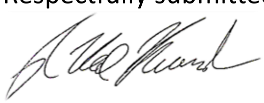
[77] See MIT Technology Review located here, https://www.technologyreview.com/2021/02/24/1017805/hyper-accurate-global-positioning-available-worldwide/#:~:text=Once%20the%20signals%20are%20processed,three%20meters%20(see%20chart).
[78] https://www.energy.ca.gov/sites/default/files/2022-10/CEC-500-2022-013.pdf
[79] §95485(c)(5)(A)

353.26 cont. some obligated parties to hold off on purchasing credits as the interest rate applied to these deficits would be below their cost of capital. Tesla recommends increasing this interest rate to 10%.

Conclusion

353.27 In conclusion, Tesla supports CARB adopting a stringent standard, at least 30% by 2030 with at least a
353.28 12% step change and an effective AAM in 2026 that limits implementation delays. Further, Tesla believes that the CFR Program should continue to support LD EV deployment and would remain solvent and create efficiency if base credits were allocated to EV automakers to support the program. While
353.29 Tesla supports alterations to LD through MHD FCI crediting, overall, FCI regulations for electrification
353.30 should generally mirror those provided to hydrogen producers. Lastly, we urge CARB to modernize the regulations through updates to EERs and others. Section IV changes are necessary to support scientific integrity however could be postponed should CARB have insufficient resources to make these changes while getting the regulations adopted and enforceable in 2024.

Respectfully submitted,



Thad Kurowski
Public Policy & Business Development

Comment Log Display

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Comment 363 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Cory-Ann
Last Name	Wind
Email Address	cwind@cleanfuels.org
Affiliation	Clean Fuels Alliance America
Subject	Comments on the Proposed LCFS Amendments
Comment	Thank you for the opportunity to submit these comments on behalf the Clean Fuels Alliance America and California Advanced Biofuels Alliance.
Attachment	www.arb.ca.gov/lists/com-attach/7043-lcfs2024-BWZRMQZmUmBXDlU2.pdf
Original File Name	CFAA Comments CARB LCFS.Final.pdf
Date and Time Comment Was Submitted	2024-02-20 19:10:54

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Re: Comments on the December 19th Initial Statement of Reasons

Submitted electronically

Chairwoman Liane M. Randolph
California Air Resources Board
1001 I Street
Sacramento, CA 95814

The Clean Fuels Alliance America (Clean Fuels)[1] and California Advanced Biofuels Alliance (CABA)[2] appreciate the opportunity to provide comments on the December 19th proposed changes to the Low Carbon Fuel Standard (LCFS) as presented in the Initial Statement of Reasons. Clean Fuels and CABA have been longtime supporters of the state's overall climate and air quality improvement goals and have collaborated frequently with CARB staff toward achieving those goals. We continue to support California's efforts to decarbonize its economy, especially the transportation sector, with a comprehensive all-of-the-above suite of measures.

Our California member producers and marketers support over 3,900 well-paying jobs in the state and about $960 million in economic activity each year. Further, the biodiesel, renewable diesel, and sustainable aviation fuel supplied to the state by our California and national members are collectively the single largest source of GHG reductions in the LCFS, providing nearly half[3] (about 45%) of the carbon reductions since 2017, more than any other fuel including electricity, and 42% since the start of the LCFS. Our fuels have grown to the point where nearly 60% of each gallon on average of diesel fuel consumed in the state in 2023 consisted of our industry's low-carbon fossil diesel replacement fuels.[4] Our sustainable replacements for petroleum diesel have been a major factor in driving California's continuing transformation towards being carbon neutral. In short, the LCFS would not be the success it is today, and one the state is looking to export to other jurisdictions, without the key role our diesel replacements have played. More to the point, our liquid

[1] Clean Fuels (formerly the National Biodiesel Board) is the U.S. trade association representing the entire supply chain for biodiesel, renewable diesel, and sustainable aviation fuel. The name change reflects our embrace of all the products Clean Fuels members and the U.S. industry are producing, which include biodiesel, renewable diesel, sustainable aviation fuel, and Bioheat® fuel for thermal space heating. Our membership includes over 100 farmers, producers, marketers, distributors, and technology providers, and many are members of environmental organizations supportive of state and local initiatives to achieve a sustainable energy future.
[2] California Advanced Biofuels Alliance is a not-for-profit trade association promoting the increased use and production of advanced biofuels in California. CABA represents biomass-based diesel (BMBD) feedstock suppliers, producers, distributors, retailers, and fleets on state and federal legislative and regulatory issues.
[3] Biodiesel and renewable diesel provided almost 60% of the LCFS credits in Q3 2023. See LCFS Quarterly Data Spreadsheet (dated January 31, 2024).
[4] Ibid.

Missouri Headquarters
605 Clark Ave
PO Box 104898
Jefferson City, MO 65110

800.841.5849

Washington, D.C., Office
1331 Pennsylvania Ave, NW
Suite 505
Washington, D.C. 20004

888.246.3437

cleanfuels.org

petroleum replacement fuels remain the only viable, large-scale, cost-effective alternatives for the next several decades to decarbonizing the most difficult-to-electrify sectors: heavy duty on- and off-road, marine, rail, and aviation.

Previous Comments

Clean Fuels and CABA have been keenly aware of how significant this rulemaking is to its members and the clean fuels industry as a whole. We have actively participated throughout the workshops in the pre-rulemaking process to provide information and perspective on how staff's proposal may impact the industry. In addition to this comment letter, please refer to our previous comments submitted for the May 31/June 2 virtual meeting, the May 23 workshop on Auto-Acceleration Mechanisms, and the February 22 workshop to discuss potential changes to the LCFS to address previous discussions that did not make it into the ISOR but are potentially still on the table as future modifications are considered.

Strengthen the CI Reduction Targets

354.1 Clean Fuels and CABA are generally supportive of CARB's proposal to strengthen the CI reduction
354.2 targets in 2030 and 2035 but we reserve comment on the feasibility of a 2045 target due to the lack of data to support a target that far out into the future. We are also generally supportive of the addition of the step-down and auto acceleration mechanisms to provide ways to firm up credit prices as quickly as possible. We further believe that additional adjustments can and should be made to maximize the GHG reductions and benefits provided by the LCFS and the credit prices that are necessary for the clean fuels market to thrive.

Request: As further discussed in the report submitted by ICF[5], Clean Fuels and CABA respectfully request that the Board direct CARB staff to establish:

354.3
- A Carbon Intensity (CI) reduction target between 41 – 44% for 2030.

354.4
- An initial step down of 10.5% to 11.5% in 2025 to achieve a target credit bank equivalent of two to three quarters worth of deficits.

354.5
- An Automatic Acceleration Mechanism (AAM) implementation that can be triggered in 2026, with a modification to enact the AAM when the credit bank is more than 2.5 times greater than the quarterly deficits generated in a given year.

354.6 In addition, we urge CARB to maintain the technology neutrality that has enabled the success of the LCFS program. Clean Fuels and CABA believe that this combination of revisions can further boost the effectiveness of the LCFS program.

Introduction of Sustainability "Guardrail" Provisions

Clean Fuels and CABA were surprised by the introduction of sustainability provisions in the ISOR,
354.7 especially since that was the first time anyone had seen them. At no time during the informal rulemaking process did anyone have a chance to vet, workshop, or provide feedback on these provisions, which is a far cry from how CARB typically engages with its stakeholders. It is especially concerning since the implementation of these provisions will have a significant negative impact to
354.8 our members as they are potentially burdensome, duplicative, and infeasible as proposed.

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[5] Analyzing Future Low Carbon Fuel Targets in California: Response to Staff Report, ICF Resources, February 2024.

Our members are eager to work with CARB staff to work through the many details surrounding this topic, including but not limited to – having a proper length of time to gather and submit information, considering similar certification programs that can be modified to streamline the verification process, and planning for any potential next steps once these provisions are complied with. There must be a collaborative and transparent process to produce sustainability provisions that will meet the interests of both CARB and the clean fuels industry.

Request:

354.9
- The Board should direct CARB staff to assemble a small workgroup of affected parties to develop the implementation guidance for these provisions.

354.10
- The Board should direct CARB staff to exempt any feedstocks that are grown on land that was already in production prior to 2007 from being subject to these sustainability provisions. Since they were already in agricultural production prior to 2007, those lands involve no deforestation whatsoever, the primary concern raised by CARB staff during the workshop process and ostensibly the reason the sustainability provisions were proposed. These domestic feedstocks already meet the qualification criteria to generate RINs in the federal Renewable Fuel Standards, which were established to address similar sustainability concerns. It makes complete sense that the LCFS align with these existing federal requirements that the clean fuels industry already understands and complies with.

354.11
- As an alternative to the previous bullet, the Board should direct CARB staff to draft implementation guidance for any feedstocks that are proven to be low deforestation risk and could be exempted, that considers:
  - the different environmental impacts of different feedstocks;
  - alignment with the certifications that are already required for producers selling into the Canadian or European markets to avoid expensive and unnecessary duplication of effort; and
  - using a mass balance approach or equivalent for feedstocks that are co-mingled prior to biofuel processing.

Exemption for Jet Fuel

354.12
Clean Fuels and CABA believe that prior to the availability of sustainable aviation fuel (SAF), exempting jet fuel from the LCFS program seemed logical. However, the landscape has dramatically shifted with new facilities coming online in the very near future. In light of this evolving reality, it is perplexing that the proposed amendments continue to exempt intrastate jet fuel until January 1, 2028. Such a delay would be severely counterproductive since urgent market signals are crucial for capitalizing on the momentum the industry is currently experiencing.

Request: The Board should direct CARB staff to advance the repeal of the exemption to January 1, 2025. This would offer essential support urgently needed to transition the aviation sector toward cleaner, more sustainable practices. Furthermore, we advocate for removing the exemption of all jet fuel, not solely intrastate, as continuing reliance on petroleum jet fuel amidst cleaner alternatives is entirely unnecessary, especially for years 2025, 2026, and 2027 when the industry has already announced projects that could fulfill the entire SAF obligation for all three years.

Update GTAP-BIO

Clean Fuels and CABA would like to re-emphasize that the ILUC model, GTAP-BIO, is not being updated during this rulemaking while all other key models used to calculate lifecycle emissions are being updated or are new (GREET 4.0, HyCap, OPGEE). Previous comments submitted by Clean Fuels and CABA throughout the workshop process highlight the many reasons why this gross inequity must be resolved during this rulemaking.

354.13 Despite many years of stakeholder requests, CARB has not revisited GTAP-BIO, electing to continue using the 2014 version of GTAP-BIO, which in turn uses nearly two decade old datasets, compared to the 2022 version that reflects the most updated and granular data available based on real-world observations developed over many years. The failure to use the latest science quite frankly puzzles our members and continues to be a significant point of frustration regarding the assignment of CIs for biofuel producers. An update to the ILUC modeling would be a welcome effort that can complement and inform the discussions about environmental impacts from biofuels and the design of the sustainability provisions as described above. Using the latest version, the ILUC impact from soy would be decreased from the current 29.1 g CO2e/MJ to less than 10, a 67% reduction from the current value and an 84% reduction from CARB's original value set in 2011. It is counter-intuitive and nonsensical that CARB propose guardrail sustainability provisions in this rulemaking without first making sure the regulation reflects the most current science available.

354.14 Request: The recent announcement to postpone the Board hearing from March to a future meeting provides a great opportunity for CARB to update the GTAP datasets in line with the above. The Board should direct CARB staff to update GTAP immediately to be incorporated into the current rulemaking..

Penalty for Underestimating a CI

354.15 Clean Fuels and CABA believe that the proposed changes to how CARB will treat a CI score that is verified to be higher than their approved value is overly punitive. CI scores are dependent on a multitude of feedstock assumptions and operating conditions and pathway holders make their best faith effort when they compile the pertinent model inputs for their pathway applications. They include the best data available to them, in addition to a reasonable margin of safety to cover fluctuations throughout the fuel's lifecycle.

354.15 Credits that were illegitimately generated due to having a higher CI at the time of verification compared to their approved value should absolutely be replaced, but at a one to one ratio, not at a four to one ratio. CARB provides no justification in the ISOR to warrant the additional penalty, and no justification has been provided by CARB that documents underestimation of CI scores is a rampant issue. If a pathway holder's underestimation is due to demonstrable misconduct, then CARB can use its existing enforcement and penalty authority to address that situation. But unintentional shortfalls made in good faith that are relatively minor should not be subject to this penalty.

Request: The Board should direct CARB staff to remove the quadrupling of the number of credits that need to be retired against the illegitimate credit generation due to an underestimation of a CI.

Incorrect Tallow value in CA-GREET

Clean Fuels and CABA are concerned that the proposed CA-GREET 4.0 model contains an incorrect value for emissions related to the energy inputs for beef tallow rendering process. This

354.16 error first appeared in GREET 2016 and was identified by the Argonne National Laboratory[6] and corrected in GREET 2017. The difference is about 8 gCO2e/MJ, about double what it should be. However, this correction was not made to CA-GREET 3.0 nor to CA-GREET 4.0.

GREET 2022 updated the energy use for rendering with data from another 46 rendering facilities. The values were broadly in line with the data from the original 25 plants that were used to generate the data in the GREET models from 2014 to 2021.

354.16 Request: The Board should direct CARB staff to update CA-GREET 4.0 with the correct energy inputs for the beef tallow rendering process as contained in GREET 2022.

Conclusion

Clean Fuels and CABA thank CARB staff for their continued efforts to strengthen the LCFS and provide the vision for the program to meet California's carbon neutrality goals. For this rulemaking, we support the proposed increases in the CI targets but feel that even more can be done to strengthen the program and the market by making additional adjustments to the step-down and automatic acceleration mechanisms. We are deeply concerned by the lack of transparency regarding the process to add sustainability provisions to the LCFS but stand ready to work with CARB to address those concerns in a collaborative way in the future. We support the repeal of the exemption of jet fuel as soon as possible. We strongly believe that the latest science should be used to estimate ILUC and to calculate the CI for tallow pathways and that updating GTAP and GREET will help. Finally, we would like to endorse and incorporate by reference the comments filed by members and affiliates of Clean Fuels and CABA, including but not limited to ADM, Darling Ingredients, and the National Oilseed Processors Association. Thank you for your consideration of these comments. We look forward to continuing our strong collaboration with CARB and staff.

Sincerely,

Cory-Ann Wind

Cory-Ann Wind
Director of State Regulatory Affairs
Clean Fuels Alliance America

Carlos Gutierrez
Executive Director
California Advanced Biofuels Alliance

[6] Updates on the Energy Consumption of the Beef Tallow Rendering Process and the Ratio of Synthetic Fertilizer Nitrogen Supplementing Removed Crop Residue Nitrogen in GREET, Argonne National Laboratory, October 9, 2017.

Comment Log Display

Here is the comment you selected to display.

Comment 364 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Michael
Last Name	Pimentel
Email Address	michael@caltransit.org
Affiliation	California Transit Association
Subject	California Transit Association - LCFS Comment Letter
Comment	Attached here.
Attachment	www.arb.ca.gov/lists/com-attach/7044-lcfs2024-AmFVJwRkBQlSOAhr.pdf
Original File Name	CTA LCFS Comment Letter.pdf
Date and Time Comment Was Submitted	2024-02-20 19:15:35

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

California Transit Association

Connecting us.

February 20, 2024

Liane Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Amendments to the LCFS Program

Chair Randolph:

355.1 On behalf of the California Transit Association, I write to you today to voice our support for the Low Carbon Fuel Standard (LCFS) amendments package released by the California Air Resources Board (CARB) on December 19, 2023 and to elevate the specific, but currently unaddressed, priorities of our transit and rail agency members. The Association represents over 230 member organizations from across California's transit industry, which includes 85 transit and rail agencies in the state.

Through our work to advance the implementation of the Innovative Clean Transit and In-Use Locomotive regulations and our steadfast support for federal and state investments in zero-emission transit vehicles across modes, the Association and our members have been consistent partners with CARB in promoting and accelerating the deployment of zero-emission vehicle (ZEV) technologies in public transportation
355.2 applications. In an era of significant financial constraints at state and local levels, we view the LCFS program as a vital incentive for encouraging transit and rail agencies to take early and expansive actions to further clean their fleets and as a critical funding source for offsetting the persistently high costs of zero-emission operations. We thank CARB for its efforts to continuously improve this program to the benefit of program participants and formally request a series of changes to the amendments package as
355.3 it moves forward. Additionally, we request that CARB continue to review options to further support transit and rail agencies that participate in the LCFS program. The specific changes we request would address current disparities in credit generation between pre-2011 fixed guideway systems and post-2010 fixed guideway systems, administrative challenges related to registration and reporting of electricity usage from the fuel service equipment (FSE), and the scope of reporting of electricity usage.

<u>Disparities in Credit Generation</u>

355.4 The LCFS program currently affords pre-2011 fixed guideway systems fewer credits

355.4 cont. for their electricity usage than post-2010 fixed guideway systems due to disparities in CARB's Energy Economy Ratio. We understand that this current disparity reflects modeling performed by CARB at the beginning of the LCFS program, which established a baseline that treated all rail in place at that time as existing, and rail constructed after as new. CARB posited then that new rail would reduce significantly more VMT than existing rail. We believe this distinction and justification is arbitrary and does not reflect the reality that rail – no matter when it was constructed – significantly reduces VMT and that the level of VMT reduction at any one point in time or segment of service may vary depending on a series of exogenous factors.

With rail agencies facing operations funding shortfalls and higher expenses, the Association implores CARB to increase the level of credit generation for pre-2011 fixed guideway systems to bring it into alignment with post-2010 fixed guideway systems. The additional credits generated from this change will be vital as rail agencies work to continue to provide service with diminished local funding sources.

Administrative Challenges in Reporting

355.5 The LCFS program currently requires non-residential EV charging industries and agencies generating credits from grid electricity to report the quantity of electricity (in kWh) from the FSE, or electric charger.

As an Association, we are concerned with the administrative constraints associated with registering and reporting from each individual FSE. Several transit agencies have designed for an overhead charging system that will implement power cabinets (power source), and depot pantographs (dispenser to conductively charge on top of buses). The overhead charging design is a 3-to-1 ratio (3 pantographs to 1 power cabinet or 3 buses connected to 1 charger). With this, we have concerns about how data will be reported from this type of design, and the need to register and report from each individual charger (power cabinet) and/or pantograph (dispenser). To manage this type of overhead charging system, several transit agencies are also planning to implement a charge management system (CMS) software to efficiently manage charging cycles optimally for getting buses ready for service each day and at its most cost effective. These CMS platforms are still in their infancy stages, with most vendors being third- party to charger manufacturers. It is currently unknown how a third-party vendor's CMS platform will manage multiple charger manufacturers (interoperability) data components and if proprietary parameters will impact data communication when exporting this data. At this time, to maximize credits using time-of-use energy consumption, our members would need to report from the meter/utility bill.

Loss of Credit (Energy Loss/Line Loss)

355.6 Since January 2022, several transit agencies have experienced an overall loss of energy or line loss from what's reported at the meters to what's been reported at the FSEs. At full deployment, this loss can equate to hundreds of thousands of dollars in credit loss per quarter and millions of dollars in credit loss annually. Reporting with an energy loss or line loss (consumption in kWh) also doesn't accurately reflect the well-to-wheel GHG analysis

355.6 cont. for running a battery electric bus in-service.

In closing, we greatly value our partnership with CARB in advancing the deployment of zero-emission vehicle technologies. We thank you for your consideration of our requested changes to the LCFS program.

If you have any questions, please feel free to contact me at (916) 446-4656 or michael@caltransit.org.

Sincerely,

Michael Pimentel
Executive Director

Comment Log Display

Here is the comment you selected to display.

Comment 365 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Russell
Last Name	Dyk
Email Address	russ.dyk@btr.energy
Affiliation	Bridge To Renewables, Inc.
Subject	Preliminary Staff Report Proposed LCFS Amendments - Dairy Biogas to Electricity
Comment	We are pleased to provide comments on proposed changes to biogas-based electricity crediting in response to the Preliminary Staff Report Proposed Low Carbon Fuel Standard ("LCFS") Amendments
Attachment	www.arb.ca.gov/lists/com-attach/7045-lcfs2024-VDcHYFYIWGlSCwRn.pdf
Original File Name	CARB Comment Letter_Biogas_Electricity_02.20.24_BTR.pdf
Date and Time Comment Was Submitted	2024-02-20 19:25:41

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

Bridge to Renewables, Inc.
1 Thomas Circle NW, Suite 700
Washington, DC 20005

VIA ELECTRONIC FILING

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Preliminary Staff Report Proposed Low Carbon Fuel Standard ("LCFS") Amendments

We are pleased to provide comments on proposed changes to biogas-based electricity crediting in response to the Preliminary Staff Report Proposed Low Carbon Fuel Standard ("LCFS") Amendments.

We commend ARB for recognizing the important role that dairy manure biogas-to-electricity fuel pathways play in decarbonizing California's transportation sector. We believe that there are several changes that ARB could make to reduce barriers for small biogas to electricity generators to participate in the program; and to adjust restrictions related to book-and-claim of renewable natural gas into an offsite generator and create a temporary pathway for all dairy biogas-to-electricity projects.

Adjust Requirements for Small Biogas-to-Electricity Facilities

As they are currently designed, annual verification requirements for dairy biogas to electricity fuel pathways are cost prohibitive to small electricity generators and effectively shut out a large portion of the state's small and medium dairy operations from participating in a program that could provide meaningful support to decarbonization efforts.

356.1 For facilities with a total nameplate capacity of less than 150 kW, we encourage ARB to consider the following changes to the LCFS program:

- **Simplified Lookup Table Pathway for dairy biogas-based electricity**
  For small facilities looking for a simple way to participate in the LCFS, CARB could offer a Lookup Table Pathway option, with a CI score set at the lower of the score of the highest currently approved dairy manure to electricity fuel pathway in the program or 0. After ensuring that facilities meet a minimum eligibility criteria, projects would then be able to be approved for immediate participation into the program.

356.2
- **Remove the Third-Party Verification Requirements**
  The requirement to have a third-party verifier review the AFP report is an excessive burden for small facilities and can often exceed the credit revenue available from the program, a problem exacerbated by the recent low level of LCFS prices. While low LCFS prices strain the economics for dairy biogas-to-electricity generators of all sizes, that dynamic combined with the cost burden of annual verification particularly disadvantages smaller farms.

356.3
- **Simplify the Annual Fuel Pathway Report**
  The data requirements of the Annual Fuel Pathway Report can be onerous for a small

operation. Specifically, the data requirements for raw biogas flow, methane content, and sub metered electricity usage are difficult to obtain and can be costly relative to the size and production of smaller facilities. WREGIS already certifies RECs based on exported electricity consumption. In combination with the recommendations above, more reasonable data requirements for small dairies for AFP reporting would go a long way to making the LCFS more viable for smaller dairy biogas-to-electricity facilities.

356.4 **Allow for Book & Claim of RNG to Off-Site Electric Generators**

ARB currently recognizes that "Low-CI electricity used as a transportation fuel can be indirectly supplied" through book-and-claim accounting, typically by pairing a renewable energy credit ("REC") with electric vehicle charging. ARB separately currently recognizes book-and-claim accounting for renewable natural gas ("RNG") injected into a commercial distribution pipeline and paired with compressed natural gas ("CNG") fueling in California.

Yet to generate RECs from low-CI electricity derived from dairy biogas, ARB requires that the generator of the electricity in California that consumes the biogas is co-located with the digester from which it is produced.

We re-iterate our proposal submitted in prior comments in June 2023, in response to ARB's May 2023 LCFS Workshop, encouraging ARB to enable book-and-claim accounting of RNG to be eligible for electricity generation. This approach not only aligns with CARB's existing book-and-claim accounting framework but is also consistent with ARB's objectives of supporting the transition to zero emission transportation.

356.5 **Establish a Temporary CI Pathway for Dairy Biogas-to-Electricity and a Credit True-Up Mechanism**

In contrast to other low carbon transportation fuels in the LCFS program, no Temporary CI Pathway exists for dairy biogas-to-electricity projects. Despite the fact that dairy biogas-to-electricity pathways fully reduce methane in the same manner as dairy biogas-to-RNG pathways, ARB treats them differently in this respect.

The lack of a Temporary CI Pathway prevents beneficial projects from receiving revenue until the Provisional CI is achieved, a process that can last from many months to a year or more. The extensive timeline for projects to receive even a Provisional CI means ARB in parallel should revise the true-up language to apply to Temporary CI scores.

We thank you again for the opportunity to provide these comments, and we look forward to continued engagement with ARB staff.

Sincerely,
Bridge To Renewables, Inc.

Comment Log Display

Here is the comment you selected to display.

Comment 366 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Scott
Last Name	Hedderich
Email Address	scott.hedderich@nuseed.com
Affiliation	Nuseed Americas
Subject	Proposed changes to the LCFS program
Comment	please see our attached comments
Attachment	www.arb.ca.gov/lists/com-attach/7046-lcfs2024-VDcHYABzAjMLUgRo.pdf
Original File Name	CARB LCFS comments.pdf
Date and Time Comment Was Submitted	2024-02-20 19:26:37

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Proposed amendments to the Low Carbon Fuel Standard Regulation under Division 3, Chapter 1, Subchapter 10, Article 4, Subarticle 7 (Low Carbon Fuel Standard) under Title 17, California Code of Regulations

California Air Resources Board Members and staff:

I am writing on behalf of Nuseed Americas, Inc.

Nuseed is a global agriculture innovator enabling the transformation of select crops into renewable and traceable sources of lower-carbon energy, and plant-based nutrition. Nuseed's proprietary solutions contribute to solving global challenges like food security, human nutrition, and climate change. By unlocking the intrinsic value and commercial potential of omega-3 canola, carinata, sorghum, sunflower, and energy cane to deliver VALUE BEYOND YIELD®, Nuseed empowers growers and end-use customers to rapidly scale today to meet current and emerging demand for generations to come.

Established in 2006, Nuseed has 10 locations in Australia, Europe, North America, and South America, including three proprietary innovation centers, more than 400 employees, and sales in more than 30 countries. Nuseed is the seed technologies platform of Nufarm Limited.

We appreciate and recognize the significant amount of time, energy and effort by all (staff and stakeholders) to develop the proposed changes to the LCFS program in accordance with the adopted scoping plan. This has been a significant undertaking and while some may wish to single out certain items or proposals as lacking and needing changes or adjustments, it is important to acknowledge how the overall proposal significantly improves air quality, reduces carbon loading and positively impacts climate change.

357.1 To that end, Nuseed applauds the increase in stringency of carbon intensity reductions from 20% below 2010 baselines to 30% by 2030 and a 90% reduction by 2045. Comparing this step to previous actions, from 2015, when the Board readopted the program, to 2018 when the 10% target was increased to 20% (and extended from 2020 to 2030), critics raised concerns about the availability of alternative fuels and its impact on the state's economy and derided the goals as unachievable.

Yet as CARB's own data shows, time and again biofuel manufacturers and suppliers were able to overachieve and deliver biofuel volumes at a rate faster than the agency required or predicted possible and at competitive pricing with existing fossil fuels. The renewable fuel industry has proven it can meet the targets CARB sets.

As a developer of carinata that is grown on fallow land between crop rotations and does not compete with existing food or feed crops, we are ready and eager to help the industry achieve the next set of targets, particularly as the state moves to phase in intrastate aviation fuel for compliance. Sustainable Aviation Fuel (SAF) is available today as a drop in fuel and has already been used in California as airlines were able to opt into the program. As the need for SAF grows, we can deliver new innovative feedstocks that add to the supply of existing sources of feedstocks already approved for use.

357.2 In addition to the increase in stringency, we also support the development of the Automatic Acceleration Mechanism (AAM). This addition to the program allows the state to more nimbly respond to the biofuel (and ZEV) industry's ability to "overcomply." As noted in the ISOR, the AAM would help bolster market stability in the event that transportation fuel decarbonization grows rapidly. This kind of market adjustment sends a strong signal to companies like ours that are putting significant resources into developing new feedstocks with low and ultra-low carbon intensities.

357.3 It is in that vein, that we note with interest the sustainability provisions added to §95488.8(g). Nuseed has been working with international sustainability standard setting bodies like RSB for sometime. While the section lays out in detail how the entities should be structured and the path for their approval by the Executive Officer, a number of details remain to be developed. We would welcome the opportunity to share our experiences in working with international sustainability groups on data collection and reporting. 357.4 We also believe there is a robust discussion to be had on the positive impacts crops like ours can have on soil retention and improvement and the potential in on-farm carbon sequestration. As CARB looks at innovative ways to sequester carbon, like direct air capture, the agency should also embrace data driven climate smart agriculture's ability to store carbon at the farm level.

Thank you again for your leadership and for the opportunity to provide comments.

Sincerely,

Scott R. Hedderich
North America Policy & Government Affairs Director

Comment Log Display

Here is the comment you selected to display.

Comment 367 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Graham
Last Name	Noyes
Email Address	graham@noyeslawcorp.com
Affiliation	Noyes Law Corporation for H Cycle

Subject	LCFS Comment of H Cycle

Comment	Attached please find the Low Carbon Fuel Standard comment of H Cycle. A short summary is included below. Thank you for the opportunity to provide this comment. Best Regards, Graham Noyes Noyes Law Corporation H Cycle, LLC ("H Cycle") is pleased to submit comments pertaining to the California Air Resources Board's ("CARB") proposed amendments to the Low Carbon Fuel Standard ("LCFS Proposal" or "Proposal"). We support CARB's LCFS program as it sends a powerfu market signal to decarbonize the transportation sector, is performance based, and provides long-term policy stability that supports investment. However, we respectfully encourage CARB to take advantage of this LCFS rulemaking to make regulatory changes that incentivize deployment of low carbon intensity ("Low-CI") waste-to-hydrogen production facilities that can simultaneously catalyze more organics diversion, reduce emissions of the short-lived climate pollutant ("SLCP") methane, create a distributed hydrogen production network and drive federal dollars to California to accelerate hydrogen production expansion.
Attachment	www.arb.ca.gov/lists/com-attach/7048-lcfs2024-Vz9WD1Y0UHoKbwdr.pdf
Original File Name	H Cycle LCFS Comment w Exhibits Final .pdf
Date and Time Comment Was Submitted	2024-02-20 19:40:33

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

The Honorable Liane M. Randolph
Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

(Comment submitted electronically)

RE: H Cycle's Recommendations to Leverage the Low Carbon Fuel Standard Program to Accelerate Achievement of SB 1383 Diversion, Reduce Methane Emissions, Rapidly Scale Distributed Hydrogen and Attract Federal Funding to California

Dear Chair Randolph,

H Cycle, LLC ("H Cycle") is pleased to submit comments pertaining to the California Air Resources Board's ("CARB") proposed amendments to the Low Carbon Fuel Standard ("LCFS Proposal" or "Proposal"). We support CARB's LCFS program as it sends a powerful market signal to decarbonize the transportation sector, is performance based, and provides long-
358.1 term policy stability that supports investment. However, we respectfully encourage CARB to take advantage of this LCFS rulemaking to make regulatory changes that incentivize deployment of low carbon intensity ("Low-CI") waste-to-hydrogen production facilities that can simultaneously catalyze more organics diversion, reduce emissions of the short-lived climate pollutant ("SLCP") methane, create a distributed hydrogen production network and drive federal dollars to California to accelerate hydrogen production expansion.

<u>LCFS Recommendations</u>

H Cycle has identified three modifications to the LCFS Proposal that will increase organics diversion, decrease methane emissions, accelerate development of distributed hydrogen production, and attract federal funding:

358.2

1. CARB should respond to the Little Hoover Commission's findings regarding the State's current failure to meet SB 1383 organic diversion targets by modifying LCFS regulations to support SB 1383 implementation by recognizing real-world methane emission reductions achieved by diverting additional organic waste from landfills to produce hydrogen. This recommended action also supports the goals outlined in the Advanced Clean Fleets Rule that will require availability of renewable hydrogen derived from waste feedstocks to supply the eventual zero emission fleets.

358.3

2. Given the massive scale of hydrogen ambition established by the 2022 Scoping Plan and the minimal hydrogen demand that exists from fuel cell electric vehicles ("FCEVs"), CARB should extend the eligibility of electricity book-and-claim to Low-CI hydrogen that is used in the production of an alternative fuel. Related to

358.3 cont. this, due to the importance of attracting federal funding to California including Inflation Reduction Act ("IRA") funds for Low-CI hydrogen, CARB should more closely align LCFS electricity book-and-claim accounting requirements with IRA Section 45V's utilization of environmental attribute certificates ("EACs"). This alignment would provide hydrogen producers with the flexibility to source Low-CI power utilizing Power Purchase Agreements ("PPAs") and/or unbundled Renewable Energy Certificates ("RECs").

358.4 3. CARB should clarify its intent under proposed LCFS §95488.8(i)(1)(C)(2) as this proposed provision states, "The pathway holder or the project operator must be the first contracted entity for procuring the low-CI electricity." Prior to adoption of the LCFS Proposal, CARB should revise the language to clearly indicate what is meant by the phrase "first contracted entity" and ensure that this provision does not establish an impossible condition in California or other markets.

The Critical Nature of Low-CI Hydrogen

The 2022 Scoping Plan recognized the critical role that new technologies and low carbon intensity ("Low-CI") hydrogen must play in California's drive to carbon neutrality and emphasized the need to identify and remove market and implementation barriers that impede California's transition away from fossil fuels:

> *We must avoid making choices that will lead to stranded assets and incorporate new technologies that emerge over time. Importantly, given the pace at which we must transition away from fossil fuels, we absolutely must identify and address market and implementation barriers to be successful. The scale of transition includes adding four times the solar and wind capacity by 2045 and about 1,700 times the amount of current hydrogen supply.*[1]

In addition to charting a course away from fossil fuels and toward massive hydrogen expansion, the 2022 Scoping Plan also identified the challenge of relying solely on electrolytic hydrogen to achieve California's goals. The Draft Scoping Plan included an estimate that 40 GW of solar capacity would be required to support only electrolysis to produce all hydrogen in the Proposed Scenario. The Final Scoping Plan substantially reduced the anticipated on-grid solar capacity down to 10 GW. This reduction was necessary due to a high degree of uncertainty as to whether this level of on-grid solar capacity expansion was feasible. The solution reached in the Final Scoping Plan was to integrate steam methane reformation of biomethane and biomass gasification with carbon capture and sequestration to produce hydrogen, along with off-grid solar.[2] As discussed in the following section of this comment, H Cycle's new technology is uniquely situated to produce additional and particularly beneficial hydrogen for California from landfill diversion on a distributed scale while at the same time reducing methane emissions.

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[1] California Air Resources Board, 2022 Final Scoping Plan, at p. 9.
[2] Id. at p. 88-89, and footnote 151.

H Cycle is the Leading Company in Organic/Biogenic Waste-to-Hydrogen

H Cycle is a California company based in Concord that was founded in 2021. H Cycle is a developer of low-cost, low-carbon hydrogen production facilities that deploy an advanced waste-to-hydrogen thermal conversion technology. H Cycle is currently developing multiple projects in California. H Cycle facilities will be capable of utilizing a diverse composition of waste feedstocks including post-separated organic fractions of municipal solid waste, agricultural residues, and woody biomass from wildfire risk reduction projects to produce Low-CI hydrogen. The successful development of these projects will reduce methane emissions from landfill disposal and other waste streams and facilitate achievement of California's waste diversion targets under Senate Bill 1383 ("SB 1383"). The H Cycle process delivers Low-CI hydrogen that can be used as a fuel for decarbonizing hard-to-abate sectors such as low-carbon fuel production, heavy-duty trucking, and sustainable aviation. H Cycle is excited to work with CARB and local communities to deploy our solution and support the State in meeting its climate, sustainability and air quality goals.

H Cycle is the first company to have received a favorable Article 2 determination from CalRecycle. The Short-Lived Climate Pollutants Waste Reduction Regulations ("SB 1383 Regulations") identify specific technologies that constitute recovery of organic waste and other technologies that are categorized as landfill disposal.[3] If a technology or activity is not specifically identified in either subsection (a) or (b) of 14 CCR Section 18983.1, an interested party may request CalRecycle to perform an evaluation of its technology to determine if it constitutes a reduction in landfill disposal, in accordance with the Article 2 requirements.[4] For a technology or recovery process to constitute a reduction in landfill disposal, it must reduce the physical presence of organic waste in landfills and reduce greenhouse gas ("GHG") emissions. Pursuant to the CalRecycle and CARB evaluation process, H Cycle's technology was determined to exceed the benchmark ERF for composting and also met other SB 1383 Requirements and was therefore determined to be "a reduction in landfill disposal" by CalRecycle on January 11, 2024.[5] See Attached Exhibit A for the H Cycle Article 2 determination.

H CYCLE'S ANALYSIS AND RECOMMENDATIONS

358.2 cont. ***Recommendation 1:***

CARB should utilize the findings and recommendations of the Little Hoover Commission regarding the current statewide shortfall and inability to meet organic diversion targets under SB 1383 to inform its LCFS regulatory amendments and to take remedial action to reduce methane emissions from organics that continue to be landfilled in the State.

Discussion:

The Little Hoover Commission is an independent state oversight agency. By statute, the Commission is a bipartisan board composed of five public members appointed by the governor,

[3] Recovery at 14 CCR Section 18983.1(b); landfill disposal at 14 CCR Section 18983.1(a).
[4] 14 CCR Section 18983.2.
[5] See CalRecycle, "Public Notice: Consideration of a Technology Determination for H Cycle Pursuant to Article 2 of the SB 1383 Regulations," at https://www2.calrecycle.ca.gov/PublicNotices/Details/5287, "Request for Action," download available at https://www2.calrecycle.ca.gov/PublicNotices/Documents/15520.

358.2 cont. four public members appointed by the Legislature, two senators and two assemblymembers. When the Commission was established in 1962, the Legislature declared its purpose to be:

> "… promoting economy, efficiency and improved services in the transaction of the public business (…) and in making the operation of all state departments, agencies and instrumentalities, and all expenditures of public funds, more directly responsive to the wishes of the people as expressed by their elected representatives…"[6]

In its letter presenting the report entitled "Reducing California's Landfill Methane Emissions: SB 1383 Implementation," to Governor Newsom and to members of the California Senate and Assembly, Chair Pedro Nava emphasized the following:

> *Combatting climate change is perhaps the defining issue of our era, and California has long been a leader in that fight. In 2016, the state enacted a landmark reform in this area by passing SB 1383, which required the state to reduce the amount of organic material deposited into landfills. The stakes could not be higher. As it decomposes, organic material produces methane, which is extraordinarily efficient at trapping heat and contributing to climate change. In the effort to constrain climate change, no short-term step is as important as reducing methane emissions. The livability of our planet depends on it.*
>
> *Yet California is falling short of its goals. The state missed its 2020 target, and is poised to miss its 2025 goal. Local governments – the front-line warriors in this fight – are struggling to implement the state's program.*
> *(…)*
> *The recommendations in this report present a critical opportunity to advance California's fight against climate change. We hope and believe you will consider this report in that light – as a plea to fix what is wrong in the pursuit of a noble and critical challenge.*[7]

The Little Hoover Commission 1383 report noted that the State completely failed to meet its target in 2020 of a 50% reduction below 2014 levels in that the amount of organic waste sent to landfills in 2020 actually increased by one million tons over the 2014 baseline. The report forecast that the 2025 target of a 75% reduction is unattainable and estimated that the State will fall short of the target by approximately 8 million tons per year.[8] (For reference, this would be the equivalent of approximately 54 one-unit H Cycle facilities. H Cycle is permitting its first one-unit facility in the City of Pittsburg.) The 2025 forecast in the report was based on CalRecycle's analysis of the amount of organic waste that would be received in 2025 and the testimony of CalRecycle's leadership to the Commission. The CalRecycle analysis found that the state would only have sufficient composting, anaerobic digestion, co-digestion, biomass electricity and mulching facilities to process 10 of the 18 million tons that would need to be processed by these types of facilities in 2025.[9]

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[6] Little Hoover Commission, "Reducing California's Landfill Methane Emissions: SB 1383 Implementation (Report #274, June 2023), at p. 2, available at https://lhc.ca.gov/sites/lhc.ca.gov/files/Reports/274/Report%20274.pdf
[7] Id. at p. 4.
[8] Id. at p. 5.
[9] Id. at p. 10; citing at Little Hoover 1383 Report to footnote 11: CalRecycle, "Analysis of the Progress Toward the SB 1383 Organic Waste Reduction Goals" (August 18, 2020). p. 7-15. https://www2.calrecycle.ca.gov/Publications/Download/1589.

358.2 cont. The Little Hoover 1383 report recommended that the State implement a temporary pause on SB 1383 and take a series of steps during the temporary pause to the get the organics diversion policy on track. The report noted that more than 100 local jurisdictions have sought an extension of the deadline for compliance.[10] The report examined Low-CI hydrogen and found that Low-CI hydrogen is not sufficiently commercialized in California to be deployed at scale or to play a significant role in meeting the SB 1383 target for 2025 and stated as follows:

> *Work on future use of hydrogen in California should and will continue. In 2022, the Legislature passed a bill requiring that by June 2024 the California Air Resources Board evaluate "the development, deployment, and use of hydrogen." But while low- carbon hydrogen has promising implications for the future, it would be unrealistic and unreasonable to expect even the state government to meet the procurement requirements with hydrogen by 2025 given the factors noted above. Presenting it as a feasible alternative for local governments to have in place by 2025 is setting them up to fail.*[11]

Given the centrality of hydrogen's role in the 2022 Scoping Plan and California's strategy to achieve carbon neutrality by 2045, CARB should take this LCFS rulemaking opportunity to accelerate technologies like H Cycle's that can both help California achieve the methane reduction goals that underlie SB 1383 and expand its Low-CI hydrogen production capacity. Because of the severe failure and current inability of the State to meet SB 1383 organics diversion targets, CARB should deviate from its standard approach to LCFS lifecycle analysis that utilizes California legal requirements to serve as baseline for analysis. The tremendous shortfall that has already occurred in landfill diversion of organics necessitates a different approach so that California's most potent transportation program can be leveraged to help reduce methane emissions immediately. The following proposed regulatory changes would institute a short-term program designed specifically to accelerate landfill diversion and commercialize technologies that can enable California to solve its methane crisis. To fulfill its obligations under SB 1383 and other statutes, CARB must acknowledge the reality that California is currently not capable of diverting 75% of organics from landfills for the litany of reasons detailed in the Little Hoover 1383 report that has caused over 100 jurisdictions to request compliance extensions.

Summary of Recommended LCFS Amendments under H Cycle Recommendation 1

CARB should make a number of targeted amendments to the LCFS Proposal to address the landfill methane crisis facing the State:

A. **Modify §95488.9(f) to authorize a technology that produces a transportation fuel determined by CalRecycle and CARB to meet the Article 2 standard to simultaneously receive a qualifying LCFS pathway score under the LCFS with a pathway CI score that is aligned with the Article 2 determination.**
B. **Modify §95488.9(f) so that new technologies can continue to receive LCFS pathway scores that are consistent with Article 2 determinations until California attains the SB 1383 statewide organics diversion target of 75%.**

[10] Id.
[11] Id. at p. 14-15.

358.2 cont. **C. Modify §95488.9(f) such that subsequent to California attaining the SB 1383 statewide organics diversion target of 75%, fuel pathways that are based on the diversion of organic waste will receive LCFS fuel pathways based on reductions achieved that are greater than the emissions reduction from composting organic waste (0.30 MTCO2e per short ton organic waste).**

H Cycle's proposed approach would be administratively efficient, would enhance the coordination between CalRecycle and CARB in the recognition of technologies that can enable California to bridge the 1383 organics diversion gap and would advance the commercialization of hydrogen. The attached **Exhibit B** provides recommended text to implement this recommendation.

H Cycle recognizes that the proposed revisions to the LCFS regulation would be exceptions to CARB's general approach to life cycle analysis modeling of carbon intensity reductions which is to only recognize GHG reductions that are additional to legal requirements. However, the findings of CalRecycle and the Little Hoover 1383 report conclusively establish that California is likely to miss its 2025 statewide target *by eight million tons of organics* and that the result of this landfilling of organics in excess of SB 1383 targets is that massive quantities of the powerful SLCP methane will be released into the atmosphere in 2025 and subsequent years. The Little Hoover 1383 report provides compelling evidence of the impact of persistent organics in California landfills in that 30 (of the state's 436) landfills and 2 compositing facilities are super-emitters, have persistent methane plumes, and are the source of almost half of landfill methane emissions.[12]

While consistency is the preferred general rule in regulatory development, there is no valid climate policy reason for CARB not to recognize real-world methane reductions from diverted landfill organics in its LCFS program that occur before SB 1383 organics diversion targets are achieved. Such SLCP reductions are additional reductions that California and the planet desperately need. If climate change is indeed the kind of existential crisis described in the Scoping Plan and a large body of California statutes, now is the time to leverage the LCFS program to incentivize H Cycle and other developers of technologies that can convert organic wastes into transportation fuels. It is certainly not the time to sunset crediting for qualified Article 2 technologies when municipalities are desperately searching for viable outlets for landfill-diverted organics and H Cycle is the only Article 2 approved technology that exists.

358.3 cont. ***Recommendation 2:***

Given the massive scale of hydrogen ambition established by the 2022 Scoping Plan and the extremely small market share of fuel cell electric vehicles ("FCEVs") CARB should extend the eligibility of electricity book-and-claim to Low-CI hydrogen that is used in the production of an alternative fuel. Related to this, due to the importance of attracting federal funding to California including Inflation Reduction Act ("IRA") funds for Low-CI hydrogen, CARB should more closely align LCFS electricity book-and-claim accounting requirements with IRA Section 45V's utilization of environmental attribute certificates ("EACs"). This would include allowing hydrogen producers the flexibility to source Low-CI power utilizing PPAs and/or unbundled RECs.

[12] Id. at p. 23-24.

358.3 cont. ***Discussion:***

H Cycle would like to first acknowledge and express its support and appreciation for CARB's decision to expand the eligibility of hydrogen to utilize Low-CI electricity beyond electrolytic hydrogen to Low-CI hydrogen that meets the requirements established by §95488.8(i)(3). We commend CARB for establishing a technology-neutral eligibility standard that recognizes the value of hydrogen derived from biogenic sources, including the derivation of hydrogen from organic waste diverted from landfills.

However, we must also express our concern that in the LCFS Proposal, CARB has severely restricted how hydrogen can be used as a fuel under the LCFS while maintaining eligibility for book-and-claim power sourcing. Under the existing regulations, book-and-claim can be utilized for qualifying hydrogen that is "for transportation purposes (including hydrogen that is used in the production of a transportation fuel)" under existing §95488.8(i)(1). Under the LCFS Proposal, book-and-claim can only be utilized for "hydrogen used as a transportation fuel" under proposed §95488.8(i)(1) and §95488.8(i)(1)(C).

We have raised this issue in discussions with CARB and have been advised that the rationale for the restriction is the concern that there is a limited amount of Low-CI power currently available in California and there are limits to the rate of Low-CI power supply expansion. Due to these concerns regarding Low-CI power scarcity, the LCFS Proposal is intended to ensure sufficient supply of Low-CI power for zero emission vehicles ("ZEVs") including battery-electric vehicles ("BEVs") and FCEVs. We respect this concern but in the current rulemaking, it is our perspective that the restriction to supplying FCEVs will preclude the massive growth of hydrogen supply (1,700x) that CARB is seeking to achieve by 2045 to meet California's climate and air quality goals.

The market reality is that by limiting Low-CI book-and-claim to neat/unblended hydrogen used in FCEVs, CARB has shrunk the addressable hydrogen market demand drastically. In order to develop multiple facilities in California during the 2020's, H Cycle and other hydrogen producers must raise sufficient capital to secure each site, comply with environmental reviews, permit the facility, procure necessary equipment, hire workers and build and commission the facility. The fundamental question from investors is, "What is the anticipated return on investment for the capital provided in the form of equity or debt to the project?" According to the scenario spreadsheet developed by E3 that underlies the 2022 Scoping Plan, in 2024 there will be a very small FCEV sector in California that includes 8,168 light-duty FCEVs; 410 medium-duty FCEVs, 1,230 heavy-duty FCEVs, and 53 FCEV buses.[13]

Returning to the vantage point of the investor, there is likely to be little interest in investing in new hydrogen production facilities that are forced to choose whether:

- To build in remote areas, far-removed from hydrogen demand, in order to co-locate with solar or wind power generation to reduce the CI of their energy input,
- To sell hydrogen only to the very small and distributed FCEV fleet that currently exists in California, or,

[13] See CARB Scoping Plan at p. 189, footnote 332 which provides the underlying information to Figure 4-2, "Transportation fuel mix in 2022, 2030, and 2045 in the Scoping Plan Scenario." The Scoping Plan footnote states, See https://ww2.arb.ca.gov/sites/default/files/2022-11/2022-sp-PATHWAYS-data-E3.xlsx for transportation fuels by year.

358.3 cont.

- To source grid-mix power that may result in a CI score that reduces their federal IRA 45V incentives and California LCFS crediting.

The same investor is likely to be substantially more interested in investing in a Low-CI facility that has the flexibility to supply hydrogen that is used in the production of an alternative fuel. We note that there is more expansive flexibility in the existing LCFS section 95488.8(i)(1) that allows Low-CI power sourcing for electrolytic hydrogen producers that supply "hydrogen that is used in the production of a transportation fuel." While we recognize that hydrogen supplied to produce transportation fuel extends to hydrogen used in petroleum refineries, we also recognize that CARB is working to phase down the supply of fossil fuels to speed the reduction of both GHG and criteria pollutant emissions.

We therefore limit our recommendation to "hydrogen that is used in the production of an alternative fuel." H Cycle's focus is on decarbonization and thus the company is focused on supplying hydrogen to the low carbon fuel market. This is a diverse and growing market that includes power-to-liquid ("PTL") fuels, renewable diesel and sustainable aviation fuel ("SAF"), and each of them has significant needs for hydrogen inputs to production.

Under existing LCFS provision §95488.8(i)(1)(A)-(B), Low-CI electricity supplied as a transportation fuel, e.g., used to power BEVs, can be sourced flexibly through the use of renewable energy certificates ("RECs") or via a qualifying Green Tariff program. Under these provisions, it is also required that the electricity be supplied to the grid within the same balancing authority as where the EVs are charged or in compliance with CPUC §399.16, that all environmental attributes be retired with limited exceptions, and that the RECs be used within three quarters of when the RECs were generated.

As is currently the case for electrolytic hydrogen that can utilize RECs to obtain Low-CI power, CARB should authorize this same power sourcing structure for Low-CI hydrogen that meets the requirements established by §95488.8(i)(3). Hydrogen producers must necessarily comply with the requirements of IRA Section 45V which, when finalized, will impose strict requirements on power sourcing for Low-CI hydrogen. Due to the substantial value that attaches to 45V crediting for hydrogen producers, and the associated potential inflow of federal funding to the State, CARB should authorize either the use of RECs pursuant to §95488.8(i)(1)(A)-(B), or environmental attribute certificates as authorized under Section 45V.

The expansion of low-CI power would facilitate California's receipt of federal funds that are available through the Inflation Reduction Act, Bipartisan Infrastructure Law, and other federal programs. These funding opportunities hinge upon CARB's continuing to enable the sourcing of Low-CI Power via RECs. If CARB instead limits Low-CI Power sourcing to neat hydrogen supplied to FCEVs, H Cycle will be required to source grid-mix power. The sourcing of grid mix power will substantially increase the H Cycle's CI score and correspondingly reduce H Cycle's ability to generate LCFS credits. Without the additional value derived from LCFS credits, H Cycle will have a more difficult time siting its facilities in California where permitting requirements cause substantial expense and time delays, and it is generally more expensive to site and operate a facility.

358.4 cont. ***Recommendation 3:***

CARB should clarify its intent under proposed LCFS §95488.8(i)(1)(C)(2) as this proposed provision states, "The pathway holder or the project operator must be the first contracted entity for procuring the low-CI electricity." Prior to adoption of the LCFS Proposal, CARB should revise the language to clearly indicate what is meant by the phrase "first contracted entity" and ensure that this provision does not establish an impossible condition in California or other markets.

Discussion:

CARB should clarify its intent under §95488.8(i)(1)(C)(2*)* regarding the use of PPAs for bundled Low-CI power sourcing for hydrogen production, with regard to the "first contracted entity" requirement, because California law does not allow "direct access" for manufacturers as end-use retail customers to procure competitive wholesale power supplies.[14] Other than direct hard-wiring of power supplies, entering into PPAs to source Low-CI power indirectly via community choice aggregators ("CCAs") or other load-serving entities represent hydrogen producers' only authorized opportunity to source Low-CI power from renewable generators at a competitive cost, versus procuring grid power from their utility plus unbundled RECs at enormous cost. If CARB's intent is to allow hydrogen producers to access this lower-cost, Low-CI power and thereby promote the development of more hydrogen production in the State, then the language should be modified to remove the first contracted entity requirement, so hydrogen producers can contract indirectly via CCAs and other load-serving entities to arrange such Low-CI power supplies.

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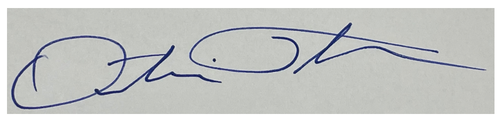
[14] See DIVISION 1. REGULATION OF PUBLIC UTILITIES [201 - 3297] *(Division 1 enacted by Stats. 1951, Ch. 764.);* PART 1. PUBLIC UTILITIES ACT [201 - 2120]; *(Part 1 enacted by Stats. 1951, Ch. 764.)*
CHAPTER 2.3. Electrical Restructuring [330 - 400.3] (Chapter 2.3 added by Stats. 1996, Ch. 854, Sec. 10.);
ARTICLE 6. Requirements for the Public Utilities Commission [360 - 380.5] (Article 6 added by Stats. 1996, Ch. 854, Sec. 10.).

Conclusion

358.5 Non-electrolytic hydrogen technologies and pathways have the potential to be a meaningful contributor to the State's and CARB's goals in the latest LCFS Proposal, and H Cycle believes the foregoing recommendations are strongly needed to ensure the projects have a fair shot at being financially viable to make such contributions. Supporting waste-to-hydrogen as a technology and commercial pathway, brings many benefits including a) supporting the State's current law in SB 1383; b) supporting the adoption of ZEVs in the CARB's Advanced Clean Fleets rules; c) achieving local air emissions reductions of NOx, particulate matter, etc. as a result of ZEV displacement of fossil-fueled vehicles; and d) job growth and investment tax base from new facilities. The LCFS Program and policies in the LCFS Proposal will play a key role in securing these benefits.

We appreciate the opportunity to submit these comments, and are available for further discussions on these important issues.

Sincerely,



Quentin Foster
VP, Policy and Government Affairs

EXHIBIT A

REQUEST FOR ACTION

To: Rachel Machi Wagoner
Director

From: Cara Morgan
Deputy Director, Materials Management and Local Assistance Division

Request Date: December 8, 2023

Decision Subject: Consideration of a Technology Determination for H Cycle Pursuant to Article 2 of the SB 1383 Regulations

Action By: January 16, 2024

Summary of Request
This Request for Action presents staff's analysis of a technology determination application pursuant to Article 2 of the SB 1383 Regulations (14 CCR Section 18983.2.), conducted in consultation with the California Air Resources Board (CARB). Action is needed to (1) determine whether the proposed technology, submitted by H Cycle and described below, constitutes a reduction in landfill disposal by reducing the physical presence of organic waste in landfills and reducing greenhouse gas (GHG) emissions and (2) to determine whether to publish a description of H Cycle's proposed technology on CalRecycle's website.

Background
The Short-Lived Climate Pollutants Waste Reduction Regulations (SB 1383 Regulations) identify specific activities and technologies that constitute recovery of organic waste (14 CCR Section 18983.1 (b)) and others that are considered landfill disposal (14 CCR Section 18983.1 (a)). If a technology or activity is not specifically identified in either subsection (a) or (b) of 14 CCR Section 18983.1, an interested party may request CalRecycle to perform an evaluation of its technology to determine if it constitutes a reduction in landfill disposal, in accordance with the Article 2 requirements (14 CCR Section 18983.2.).

For a technology or recovery process to constitute a reduction in landfill disposal, it must reduce the physical presence of organic waste in landfills and reduce greenhouse gas (GHG) emissions. To meet the requirements under Article 2 (14 CCR Section 18983.2 (a)(3)), the permanent lifecycle GHG emission reductions of a proposed technology or process must be equal to or greater than the emission reductions from composting organic waste (0.30 metric tons of carbon dioxide equivalents ($MTCO_2e$) per short ton organic waste), referred to herein as the "benchmark." The methodology used to calculate the permanent lifecycle GHG emission reductions from composting organic waste (or benchmark) is set out in Section 19883.2 and described in CARB's Calculation of the Lifecycle Greenhouse Gas Emission Reduction Benchmark for the Organic Waste Reductions Regulation.

To conduct the required lifecycle analysis of a technology or process, CalRecycle, in consultation with CARB staff, evaluates its GHG emission impacts as described in 14 CCR Section18983.2 (a)(1)-(a)(3). An applicant must submit a complete set of assumptions, data, and other information that is sufficient to estimate the GHG emissions and permanent lifecycle GHG emission reductions of their technology or process. CalRecycle staff, in consultation with CARB, must evaluate the information submitted in an application within 30 days of receipt and inform the applicant whether the application is complete. Upon receiving all required information and deeming an application complete, CalRecycle and CARB staff conduct an evaluation of the technology or process and determine, within 180 days, if it will permanently reduce GHG emissions by at least 0.30 $MTCO_2e$ per short ton of organic waste. As authorized by 14 CCR Section 18983.2 (a)(1)(I), CalRecycle may request additional information to clarify and validate the information provided in an application. If CalRecycle determines that a proposed technology or process constitutes a reduction in landfill disposal, Section 18983.2 (b) mandates that a description of the operation be posted on CalRecycle's website.

Applicability of the Article 2 Technology Determination

Under the SB 1383 regulations, jurisdictions are required to provide organic waste collection services to all residents and businesses to divert these materials away from landfills and to recycling and recovery activities such as composting, anaerobic digestion, animal feed, and land application. The regulations provide a pathway for processes that are not specified in the SB 1383 regulations, to be deemed a reduction in landfill disposal. An Article 2 technology determination allows a facility to count as a reduction in landfill disposal for purposes of the SB 1383 Regulations if it can show it achieves the required GHG emission reductions. The Article 2 technology determination is not a guarantee that a project can be built or meets other requirements of state or federal law. Further,

i) The Article 2 technology determination is not an endorsement of a technology or process. The determination is solely an evaluation of the lifecycle GHG emission impacts of a proposed operation, technology, or process using the methods and assumptions described in 14 CCR Section 18983.2.
ii) An Article 2 technology determination made by the department pursuant to 14 CCR Section 18983.2 is a factual determination and does not constitute a permit or a permit approval. Further, although a technology or process may constitute a reduction in landfill disposal under the criteria set out in Section 18983.2, the operation must still comply with all other statutory and regulatory requirements. A technology or process deemed to constitute a reduction in landfill disposal pursuant to Article 2 may still be considered landfill disposal under other laws, such as AB 939 (PRC Section 40120.1).
iii) An Article 2 technology determination does not serve any role in the permit approval process.
iv) An Article 2 technology determination is made on the basis of the information presented in the Article 2 application and clarifying information submitted at the request of the department. The determination is limited to the specific activities, operations, and assumptions presented in the Article 2 application. If the technology, activities, operations, or processes differ

from the application as described in herein and on the department's website, the determination is not applicable.

a. If a facility is found to be operating in a manner that differs from the description posted on the department's website and is not otherwise engaged in one of the activities specified in 14 CCR 18983.1(b), any organic waste processed by the facility does not constitute a reduction in landfill disposal.

Applicant: H Cycle

H Cycle is a developer that intends to build and operate multiple facilities in California to produce hydrogen from organic waste. H Cycle previously applied for an Article 2 technology determination in 2022. The previous application lacked information specifying the operational controls that would prevent a facility using H Cycle's technology from deviating from the feedstock scenarios and other operating assumptions, which could impact whether it permanently reduces greenhouse gas emissions by at least 0.30 MTCO2e per short ton of organic waste. Because CalRecycle is required to make a determination upon a "proposed operation," and requires operational controls demonstrating how a proposed technology will operate in practice to permanently reduce GHG emissions, CalRecycle found that the application did not sufficiently demonstrate permanent reductions in greenhouse gas emissions to warrant a finding that the operation described constituted a reduction in landfill disposal. Subsequently, H Cycle submitted an application on July 17, 2023, which included operational controls and monitoring and verification procedures to verify the greenhouse gas emission reductions are achieved.

Staff Analysis

Application Review Process

CalRecycle received an Article 2 application from H Cycle on July 17, 2023. In accordance with Section 18983.2 (a)(2), staff reviewed the application, in consultation with CARB, and performed a completeness review. After reviewing the application, in consultation with CARB, CalRecycle determined that it was complete at its August 15, 2023, Monthly Public Meeting. CalRecycle notified H Cycle of the completeness finding.

CalRecycle and CARB staff reviewed all the information and calculations provided by the applicant and confirmed that, under the specific processes and assumptions identified in H Cycle's application, the permanent lifecycle GHG emission reductions are equal to or greater than the emission reductions from composting organic waste (0.30 $MTCO_2e$/short ton organic waste). CalRecycle and CARB reviewed the methodology utilized to determine the emission reduction factor (ERF) of H Cycle's proposed process under the three feedstock scenarios described below. H Cycle provided key performance data based on its preliminary engineering design, which provides data on heat and mass balances, utility needs, product yields, and other key metrics utilized to calculate the life cycle greenhouse gas (GHG) emissions from the waste processing and hydrogen production process, the avoided fugitive methane emissions from landfilling, avoided emissions due to hydrogen production (i.e., the GHG emissions that do not occur because a conventional fossil fuel is replaced by waste-derived hydrogen), and emissions due to transportation. Below is CARB's technical summary.

Summary of Hydrogen Production Process

H Cycle's application proposed that facilities utilizing its technology will convert approximately 85,000 to 133,000 short tons per year of organic waste from material recovery facilities (MRFs) into hydrogen using Omni Conversion Technologies' thermal conversion process, a sour-gas-shift reactor, and a pressure swing adsorption system. The hydrogen is intended for use at refineries or in fuel cell electric vehicles. The process described in the application is organized into four units: the feedstock preparation unit, the waste conversion unit, the hydrogen production plant, and a utility and water unit.

At the feedstock preparation unit, the material is shredded; most inert materials and plastics are removed using manual sorting, screening, magnetic and eddy current separators and air classifier; and the material is dried to 10 percent moisture content using steam from a boiler and heat recovered from the process. At the waste conversion unit, the prepared feedstock will be transformed into syngas using a non-combustive thermal conversion process. The syngas (a mixture of primarily hydrogen, carbon monoxide, and some methane) goes through a second high-temperature conversion step to maximize yield. Particles are removed from the syngas and converted to a non-hazardous slag, which can be used as a recycled product or disposed.

The syngas is finally sent through a series of cleaning and scrubbing steps to remove chlorine and nitrogen species and remaining solids. The syngas is then compressed and fed into the hydrogen production unit, which uses a sour-gas-shift reactor where steam reacts with syngas forming a hydrogen-rich gas and converting carbon monoxide to carbon dioxide. The resulting gas is treated to remove sulfur species and purified in a pressure-swing adsorption system to generate hydrogen gas of at least 99.97 percent purity, the International Standards Organization (ISO) specification level for use in a hydrogen fuel cell.

A utility and water unit comprised of oxygen production, steam generation, and wastewater treatment supports various stages of the process. Condensate wastewater from the plant is cleaned and disposed to the local sewer. Offgas is recycled and combusted in a boiler equipped with emissions controls to generate additional steam for use on-site.

Feedstock Scenarios

H Cycle developed three illustrative feedstock scenarios, based on characterization and lab sampling of specific sources collected from MRFs. The three scenarios differ primarily by moisture content of the organic waste, which in turn impacts process energy demand. For each feedstock scenario, the application provides the quantity of each waste type, as-received, as-fed to the process, and the total annual throughput in tons.

1. Low-moisture scenario: the waste feedstock is composed of a mixture of construction and demolition waste and post-MRF non-recyclable fibers (15 percent moisture as-received).
2. Medium-moisture scenario: the waste feedstock is composed of residential black bin organics post primary processing at a MRF or transfer station, further processed by H Cycle to high organic content (39 percent moisture as-received).

3. High-moisture scenario: the waste feedstock is composed of material obtained from a high-diversion organic MRF containing the expected worst-case maximum 9 percent plastic (45 percent moisture as-received).

The life cycle GHG emissions analysis is based on the assumption that the feedstocks processed in H Cycle's projects will fall within the boundaries of these scenarios and do not exceed them in terms of moisture or plastic content.

Based on the as-fed composition, H Cycle used a process model to determine the anticipated throughput of the facility and resulting process energy demand, hydrogen and slag yields for each feedstock scenario. Key inputs and outputs are summarized in Table 1.

Table 1. Key Process Performance Metrics

Input or Output (per short ton of organic waste feedstock)	Feedstock 1 Low Moisture	Feedstock 2 Medium Moisture	Feedstock 3 High Moisture
Natural Gas Input (MMBtu/ton)	0.74	1.44	1.39
Electricity Input (MWh/ton)	0.93	0.63	0.59
Slag Output (kg/ton)	151.60	102.56	145.86
Hydrogen Output (kg/ton)	73.16	47.03	43.76

System Boundary and Emissions

The life cycle GHG emissions analysis includes the emissions reduction from avoided landfill disposal, the emissions reduction due to products displaced by hydrogen (i.e., the GHG emissions that do not occur because a conventional fossil fuel is replaced by waste-derived hydrogen), the process emissions from the waste processing and hydrogen production process, and the emissions due to transportation. Key assumptions, data sources, and calculations are summarized below:

1. Avoided landfill emissions
   H Cycle used the Landfill Emission Reduction Factor Tool developed by CARB to calculate avoided GHG emissions from landfilling each organic waste type. The weighted average was calculated for each feedstock scenario.

2. Avoided product displacement emissions
   H Cycle estimated the avoided GHG emissions that could result from displacing fossil fuels with hydrogen derived from conversion of organic waste. H Cycle estimates 30 percent of the product will be used in heavy-duty fuel cell electric vehicles to displace diesel and the remainder will be used at refineries to displace fossil gas-derived hydrogen.

3. Process emissions
   Energy use included fossil natural gas, grid electricity, and diesel used at the H Cycle facility, and at hydrogen vehicle fueling stations to compress, store, and dispense fuel. Process emissions also included the emissions associated with

the production of material and chemical inputs used at the H Cycle facility (e.g., catalysts, potassium carbonate, activated carbon, and zeolite). Life cycle emission factors were obtained from CA-GREET3.0. Fugitive, leaked, and vented emissions were calculated by assuming one percent of generated methane and carbon monoxide may leak from flanges, valves, or other parts of the processing equipment and emissions during the storage of post-processed waste for up to 3 days in aerobic conditions may be vented. Emissions from conversion of plastics were calculated using the emission factor from the U.S. EPA's Waste Reduction Model (WARM), 2.33 $MTCO_2e$ per short ton.

4. Transportation emissions for slag disposal and hydrogen product delivery
   H Cycle assumed a maximum distance of 200 miles per trip for both the disposal of slag material at a landfill or delivery of hydrogen product to an end use. H Cycle calculated the emissions from diesel in heavy-duty trucks to transport slag for disposal in 21-ton capacity trucks and to transport compressed hydrogen to a fueling station or refinery in 0.4-ton capacity tube trailers. Capacity and fuel economy factors used in the calculation are from CA-GREET3.0. Note that the system boundary does not include transport of organic waste from a MRF, under the assumption that the H Cycle facility will be the same distance or nearer to the organic waste supplier than the nearest landfill that would otherwise dispose of the organic waste feedstock.

Example calculation of avoided emissions from product displacement:

$$\text{Displacement} = CCCC_{\text{displaced fuel}} \times EEEEEE \times ww \times CC$$

Where, $CCCC_{dddddddddddddddddd\ ffffdddd}$ is the carbon intensity of the conventional fuel, e.g., diesel; $EEEEEE$ is the energy economy ratio, a ratio that represents the efficiency of a fuel as used in a powertrain as compared to a reference fuel; ww is the energy density of hydrogen; and CC is the unit conversion from metric tons (MT) to kilograms (kg) and grams (g) to MT. Values are from CA-GREET3.0. Displacement for hydrogen (H_2) that is used to displace diesel in a heavy-duty electric fuel cell vehicle is given by:

$$\text{Displacement} = 99.76\,\frac{gCCCC_2e}{\text{MJ}_{\text{diesel}}} \times 1.9\,\frac{\text{MJ}_{\text{diesel}}}{\text{MJ}_{\text{H2}}} \times 120\,\frac{\text{MJ}_{\text{H2}}}{\text{kg}_{\text{H2}}} \times \frac{1000\ \text{kg}_{\text{H2}}/\text{MJ}_{\text{H2}}}{10^{6}\text{g}CCCC_2\text{e}/\text{MT}CCCC_2\text{e}} = \mathbf{2222.77}\,\frac{\text{MT}CCCC_2\text{e}}{\text{MT}_{\text{hydrogen}}}$$

A similar calculation is performed to determine displacement for H_2 used in refineries, with $EEEEEE = 1$ and $CCCC_{dddddddddddddddddd\ ffffdddd} = 99.4$. Displacement resulting from use of 30% H_2 in vehicles and 70% in refineries is calculated by:

$$\text{Displacement} = (30\% \times 22.7) + (70\% \times 11.9) = \mathbf{1111.22}\,\frac{\text{MT}CCCC_2\text{e}}{\text{MT}_{\text{hydrogen}}}$$

This factor is then adjusted to the short ton organic waste basis for inclusion in the ERF.

Key Assumptions

- Waste feedstock is prepared within one day of delivery to the H Cycle facility.
- No additional pre-processing steps are required at the MRF or transfer station that supplies organic waste.

- No hazardous waste will be accepted, and organic material as received will have a maximum moisture content of 45 percent.
- Prepared organic feedstock is stored for no more than 3 days and contains no more than 9 percent plastic by mass.
- At least 30 percent of the hydrogen product will be used in fuel cell electric vehicles.
- Slag material will be transported for landfill disposal no more than 200 miles from the conversion facility.
- Hydrogen products will be transported for end use no more than 200 miles.
- Process energy demand does not exceed the values stated in the application.
- Product yields achieved are greater than or equal to the values stated in the application.

Final Emission Reduction Factor

The final ERF was determined by adding (a) the avoided methane emissions from not landfilling the waste and (b) the avoided GHG emissions associated with product displacement, and subtracting both (c) the process emissions and (d) transportation emissions. The resulting ERF reflects the life cycle GHG emissions reduction from processing one short ton of mixed organic waste versus depositing the same amount of material into a landfill. Note that while the total GHG emissions per year are accounted for in these calculations (including fossil CO2 emissions from plastic conversion), they are divided by the tons of organic waste processed only (i.e., excluding tons of plastic and other inert materials), as specified in the regulations.

A summary of the emissions by life cycle stage and final ERF for each feedstock scenario is provided in Table 2.

Table 2. Emission reductions and final ERF for each feedstock scenario, expressed in $MTCO_2e$/short ton of organic waste processed.

Feedstock Scenario	Avoided Landfill (a)	Product Displacement (b)	Process Emissions (c)	Transport Emissions (d)	Final ERF
1	0.20	1.08	(0.45)	(0.06)	**0.78**
2	0.26	0.69	(0.37)	(0.04)	**0.55**
3	0.06	0.65	(0.36)	(0.03)	**0.31**

*See references used for technical analysis below.

Monitoring and Verification Procedures

The H Cycle application includes “Feedstock Quality Control” and “Monitoring and Verification” sections that identify operational and contractual controls, recordkeeping and reporting procedures, and methods for CalRecycle to monitor and verify that a facility using the H Cycle technology is continually operating consistent with what is represented in this Article 2 application.

Without the following additional monitoring and verification procedures and controls, CalRecycle cannot validate that the technology described in H Cycle's application will continually achieve the permanent lifecycle reduction in greenhouse gas emissions equal to or greater than 0.30 $MTCO_2e$/short ton of organic waste that therefore constitutes a reduction in landfill disposal. Any finding by CalRecycle that the H Cycle technology as described in the application constitutes a reduction in landfill disposal is contingent upon these monitoring and verification procedures and controls being in place.

1. Conduct waste characterization analyses of each contracted source of municipal solid waste (MSW) feedstock and of as-fed feedstock materials, at least quarterly, using the following protocol:
    a. Collect and photograph 200-pound samples per ASTM[1] D5231 – 92.[2]
    b. Conduct a bulk density test of each sample per ASTM E11090 – 19.[3]
    c. Pass materials through a fine screen (screen size to be consistent with that which is utilized for as-fed feedstocks) and continue hand sorting overs into subcomponent categories listed in (d).
    d. Hand sort each sample into subcomponents categories including but not limited to, yard waste, food waste, paper products, plastics, glass, hazardous waste, and ferrous and non-ferrous metals. Photograph and weigh each subcomponent category and maintain records.
    e. Create laboratory samples for moisture content analysis by recreating a weighted average mixture of the subcomponent categories, properly storing the samples to not allow evaporation of water content prior to testing. The laboratory samples shall be prepared in a manner consistent with the standards of the independent laboratory utilized and shall not contain the fines removed via the fine screen unless fines are included in as-fed feedstock. These samples shall be sent to an accredited ISO/IEC 17025[45] laboratory to measure moisture content.
2. Maintain and make available to the department, upon request, records of all slag material and any other co-products or waste produced, including but not limited to residuals removed from feedstocks, liquids produced onsite, hazardous waste outputs, and any constituents removed from the hydrogen gas produced. Records shall include a description and quantity of each material produced, the name of the landfill(s) where each material is disposed, quantity of material transported for any other use, and distance transported for each of these uses.
3. For each quarter in operation when reporting in the Recycling and Disposal Reporting System pursuant to CCR Title 14, Section 18815.1 through 18815.13, upload a document to the Recycling and Disposal Reporting System that includes the following:

---

[1] ASTM International, formerly known as American Society for Testing and Materials.
[2] ASTM D5231-92(2016), *Standard Test Method for Determination of the Composition of Unprocessed Municipal Solid Waste*
[3] ASTM E1109-19, *Standard Test Method for Determining the Bulk Density of Solid Waste Fractions*
[4] International Organization for Standardization/International Electrotechnical Commission:
ISO/IEC17025:2017 general requirements for the competence of testing and calibration laboratories.

   a. The total quantity of feedstock as-received and the total quantity of feedstock as-fed to the reactor over the quarter.
   b. The results of waste characterization and moisture content analyses conducted, including the quantity of plastic contained in the as-fed feedstock.
   c. Total utility energy consumption reported in units of kWh/ton of organic waste as-fed.
   d. Total natural gas consumption reported in million British thermal units per ton of organic waste as-fed.
   e. Description, quantity, disposition, and location of disposition of all slag material and any other co-products or waste produced, including but not limited to residuals removed from feedstocks, liquids produced onsite, and any hazardous waste in as-received feedstock.
   f. The total quantity of hydrogen produced, the distance the hydrogen is transported to its destination, and the end use of the hydrogen.
4. The project proponent includes operational aspects to implement monitoring and verification procedures 1, 2 and 3, as identified above in this RFA, in the operating document required for a solid waste facilities permit.
5. Monitoring by the Local Enforcement Agency:
   a. CalRecycle to provide technical assistance to Local Enforcement Agency.
   b. If the operating document is altered, CalRecycle will be notified by the Local Enforcement Agency.
6. H Cycle will participate in CARB’s Low Carbon Fuel Standard (LCFS) Program and will be subject to annual reporting to CARB and third party verification of its carbon intensity (CI) score which includes:
   a. Feedstock quantity, moisture content, and amount of plastics contained in the as-fed feedstock materials.
   b. Energy consumption.
   c. Assessment of calibration procedures.
   d. Quantity of produced hydrogen used as transportation fuel.
7. If the facility utilizing the H Cycle technology, as described in the application, is operating outside the parameters identified in this application and RFA averaged over the reporting quarter, the facility shall notify CalRecycle within seven business days of submitting the quarterly RDRS report.

These additional monitoring and verification procedures will enable CalRecycle to validate that the technology as described in the application constitutes a reduction in landfill disposal on an ongoing basis for a specific operation. If these procedures are not followed, any determination that the technology does represent a reduction in landfill disposal will not be applicable as CalRecycle cannot be certain that the requisite GHG reductions are being met to constitute a reduction in landfill disposal. Any waste sent to such a facility likely will be deemed disposal.

Feedback from Interested Parties

As part of CalRecycle’s commitment to transparency in decision making and program development, the H Cycle application documents, with confidential and proprietary information redacted, were made available for public review and comment. An email message was sent via the SB 1383 Short-Lived Climate Pollutants listserv which provided instructions for submitting comments to CalRecycle. The 30-day public comment period was held from August 15, 2023, through September 16, 2023. All comments received are attached to this RFA (see attachments 3-20).

Summary of Staff Analysis

CalRecycle staff, in consultation with CARB, reviewed H Cycle's application and found the permanent lifecycle GHG emissions reduction is equal to or greater than the emissions reduction from composting organic waste (0.30 $MTCO_2e$ per short ton organic waste), and can be determined to be a reduction in landfill disposal under the analysis and methodology prescribed by regulation in 14 CCR Section 18983.2. The additional monitoring and verification procedures and controls identified above will allow CalRecycle to validate that the technology described in H Cycle's application will continually achieve the permanent lifecycle reduction in greenhouse gas emissions equal to or greater than 0.30 $MTCO_2e$/short ton of organic waste that therefore constitutes a reduction in landfill disposal.

Options

1. Find that the proposed H Cycle technology is a reduction in landfill disposal because the technology meets the benchmark reduction required by regulations to constitute a reduction in landfill disposal pursuant to 14 CCR Section 18983.2(a)(3). Staff is directed to publish a description of this technology on CalRecycle's website as required by 14 CCR Section 18983.2(b).
2. Find that the proposed H Cycle technology is not a reduction in landfill disposal because it fails to meet the benchmark reduction required by regulations to constitute a reduction in landfill disposal pursuant to 14 CCR Section 18983.2(a)(3).

Action

Based on the information and analysis provided in this Request for Action, including the above-noted monitoring and verification procedures, and as required by section 18983.2, I hereby determine that the proposed H Cycle technology is:

✓ Option 1: A reduction in landfill disposal and direct staff to publish a description of this technology on CalRecycle's website.

☐ Option 2: Not a reduction in landfill disposal.

Dated: 1/11/2024

Signed By: Rachel Machi Wagoner, Director

Attachments

Additional information and documents posted to CalRecycle's website can be accessed as indicated below.

1. Public Notice: Consideration of a Technology Determination for H Cycle Pursuant to Article 2 of the SB 1383 Regulations, https://www2.calrecycle.ca.gov/PublicNotices/Details/4942
2. Public Notice: Notice of Completeness Finding for H Cycle's SB 1383 Article 2 Application and 30-Day Public Comment Period, https://www2.calrecycle.ca.gov/PublicNotices/Details/5196

Public Comments: The following comments were received during the 30-day comment period which began on August 16, 2023, and concluded on September 15, 2023.

3. Lapis, N., Californians Against Waste (see attachment for list of 17 co-signers).
4. Adams, T., Green Waste Recovery LLC.
5. Bellafronte, S., City of Pittsburg.
6. Boyer, S., Hyzon Motors.
7. Clifford, G., Athens Services.
8. Edgar, E., Edgar & Associates.
9. Edgar, N., California Compost Coalition.
10. Evola, S., Mt. Diablo Resource Recovery.
11. Fornesi, T., South San Francisco Scavenger Company.
12. Forst, N., R2 Consulting Group, Inc.
13. Gatlin, J., NAACP Harbor Area Branch #1069.
14. Glover, F., Contra Costa County, Board of Supervisors District V.
15. Grayson, T., Assemblymember, 15th Assembly District.
16. Hughes, M., Industrial Association of Contra Costa County.
17. Levin, J., Bioenergy Association of California.
18. Orcutt, M., East Bay Leadership Council.
19. Pardo, V., Resource Recovery Coalition of California.
20. Whitney, B., Contra Costa Building and Construction Trades Council.

References:

1. California Air Resources Board. Calculation of the Lifecycle Greenhouse Gas Emission Reduction Benchmark for the Organic Waste Reductions Regulation (Revised January 2022) https://ww2.arb.ca.gov/sites/default/files/2022-01/Benchmark-Calculation.pdf
2. California Air Resources Board. Landfill Emission Reduction Factor Tool for Section 18983.2. Accessed December 13, 2022 https://ww2.arb.ca.gov/slcp-organic-waste-reduction
3. California Air Resources Board. CA-GREET3.0 Model and Documentation. Accessed December 13, 2022. https://ww2.arb.ca.gov/resources/documents/lcfs-life-cycle-analysis-models-and-documentation
4. U.S. Environmental Protection Agency. Documentation for Greenhouse Gas Emission and Energy Factors Used in the Waste Reduction Model (WARM) Management Practices Chapters, November 2020, Exhibit 5-1. https://www.epa.gov/sites/default/files/2020-12/documents/warm_management_practices_v15_10-29-2020.pdf.

Exhibit B

LCFS Proposed Amendments

(…)

§ 95488.9. Special Circumstances for Fuel Pathway Applications.

(…)

(f) Carbon Intensities that Reflect Avoided Methane Emissions from Dairy and Swine Manure or Organic Waste Diverted from Landfill Disposal.

(1) A fuel pathway that utilizes biomethane from dairy cattle or swine manure digestion may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the voluntary capture of methane, provided that:

(A) A biogas control system, or digester, is used to capture biomethane from manure management on dairy cattle and swine farms that would otherwise be vented to the atmosphere as a result of livestock operations from those farms.

(B) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the capture and destruction of biomethane.

(2) Prior to January 1, 2025, a fuel pathway that utilizes an organic material diverted from a landfill may be certified with a CI that reflects the reduction of greenhouse gas emissions determined in the approval of an Article 2 of the SB 1383 Regulations (14 C.C.R. 18983.2) technology determination by CalRecycle conducted in consultation with CARB if the permanent lifecycle GHG emissions reduction is equal to or greater than the emissions reduction from composting organic waste (0.30 $MTCO_2e$ per short ton organic waste).

(3) Until California attains its statewide organics diversion goal of 75% under SB 1383, ~~A~~a fuel pathway that utilizes an organic material may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by the ~~voluntary~~ diversion from decomposition in a landfill and the associated fugitive methane emissions, provided that:

(A) The organic material that is used as a feedstock would otherwise have been disposed of by landfilling~~, and the diversion is additional to any legal requirement for the diversion of organics from landfill disposa~~l.

(B) Any degradable carbon that is not converted to fuel is subsequently treated in an aerobic system or otherwise is prevented from release as fugitive methane. Upon request, the applicant must demonstrate that emissions are not significant beyond the system boundary of the fuel pathway.

(C) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the avoidance or capture and destruction of biomethane in a landfill.

~~(4)~~ Upon a determination that California has attained its statewide organics diversion goal of 75% under SB 1383, ~~A~~ a fuel pathway that utilizes an organic material may be certified with a CI that reflects the reduction of greenhouse gas emissions achieved by ~~the voluntary~~ mandatory diversion ~~to a~~ if the permanent lifecycle GHG emissions reduction is equal to or greater than the emissions reduction from composting organic waste

~~(A) The organic material that is used as a feedstock would otherwise have been disposed of by landfilling, and the diversion is additional to any legal requirement for the diversion of organics from landfill disposal.~~

~~(B) Any degradable carbon that is not converted to fuel is subsequently treated in an aerobic system or otherwise is prevented from release as fugitive methane. Upon request, the applicant must demonstrate that emissions are not significant beyond the system boundary of the fuel pathway.~~

~~(C) The baseline quantity of avoided methane reflected in the CI calculation is additional to any legal requirement for the avoidance or capture and destruction of biomethane.~~

(5) Carbon intensities that reflect avoided methane emissions from dairy and swine manure or organic waste projects are subject to the following requirements for credit generation:

(A) *Crediting Periods.* Avoided methane crediting for dairy and swine manure pathways as described in (f)(1) above, and for landfill-diversion pathways as described in (f)(2) above, is limited to three consecutive 10 years crediting periods, counting from the quarter following Executive Officer approval of the application. The pathway holder must formally request each subsequent crediting period for the project through the LRT-CBTS. The Executive Officer may renew crediting periods for fuel pathways certified before January 1, 2030, for up to three consecutive 10-year crediting periods. For pathways for bio-CNG, bio-LNG, and bio-L-CNG used in CNG vehicles associated with projects that break ground after December 31, 2029, the Executive Officer may only approve avoided methane crediting through December 31, 2040. For pathways for biomethane used to produce hydrogen that break ground after December 31, 2029, the Executive Officer may only approve avoided methane crediting through December 31, 2045.

(B) Notwithstanding (A) above, in the event that any law, regulation, or legally binding mandate requiring either greenhouse gas emission reductions from manure methane emissions from livestock and dairy projects or diversion of organic material from landfill disposal, comes into effect in California during a project's crediting period, then the project is only eligible to continue to receive LCFS credits for those greenhouse gas emission reductions for the remainder of the project's current crediting period. The project may not request any subsequent crediting periods.

(C) Notwithstanding (A) above, projects that have generated CARB Compliance Offset Credits under the market-based compliance mechanism set forth in title 17, California Code of Regulations Chapter 1, Subchapter 10, article 5 (commencing with section 95800) may apply to receive credits under the LCFS. However, the LCFS crediting period for such projects is aligned with the crediting period for Compliance Offset Credits, and does not reset when the project is certified under the LCFS.

(…)

Comment Log Display

Here is the comment you selected to display.

Comment 368 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Allie
Last Name	Wainer
Email Address	awainer1@jh.edu
Affiliation	Center for a Livable Future
Subject	Avoided methane crediting comment letter
Comment	The Center for a Livable Future submits the attached comment to CARB on the Low Carbon Fuel Standard, with particular attention to the avoided methane credits. We appreciate your consideration of our comments.
Attachment	www.arb.ca.gov/lists/com-attach/7049-lcfs2024-Am5VMFYxBCQDWgFi.pdf
Original File Name	LCFS Comment Letter 20240220.pdf
Date and Time Comment Was Submitted	2024-02-20 19:56:18

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

Re: Proposed Low Carbon Fuel Standard Amendments

Disclaimer: The opinions expressed herein are our own and do not necessarily reflect the views of The Johns Hopkins University.

Liane M. Randolph
Chair, California Air Resources Board
1001 I Street
Sacramento, CA 95814

Dear Chair Randolph:

We are researchers at the Johns Hopkins Center for a Livable Future (CLF) based at the Bloomberg School of Public Health in the Department of Environmental Health and Engineering. The Center for a Livable Future investigates the interconnections among diet, food production, public health, and the environment. Since 1996, the Johns Hopkins Center for a Livable Future has applied a public health lens to the ecological, economic, and social considerations across the food system.
359.1 While the Low Carbon Fuel Standard (LCFS) has potential to support environmental justice and a transition to renewable fuel sources in California's transportation sector, we are concerned that a specific element of the Proposed LCFS Amendments will negatively impact the health of Californians and Americans alike. Specifically, we believe that the inclusion of the avoided methane credits in the Proposed LCFS Amendments would threaten public health and deepen environmental injustices by incentivizing and further entrenching the industrial food animal production (IFAP) model.

We call on the California Air Resources Board (CARB) to eliminate avoided methane crediting, as recommended by its own Environmental Justice Advisory Committee (EJAC) (CARB 2023).

The avoided methane credits incentivize growth of and further entrench the industrialized model of food animal production, which has been demonstrated to threaten public health.

IFAP is a term referring to the predominant system of meat, milk, and egg production in the U.S., characterized by confining thousands of animals in small areas and the resulting concentration of massive quantities of manure. The Environmental Protection Agency (EPA) and Centers for Disease Control (CDC) have documented that these large animal operations pose significant public health and environmental risks, particularly in surrounding communities (US EPA 2013; CDC 2018). These facilities are disproportionately sited in low-income communities, as well as in non-white communities (US EPA 2013; CDC 2018). Public health concerns stem from human exposures to air pollution, as well as drinking water and soil contamination. EPA recently analyzed the literature documenting health effects of direct emissions from animal production facilities and found that residential proximity to them is linked to asthma, decreased lung function, mortality, odor annoyance, and gastrointestinal illness (US EPA 2023).

359.1 cont. The Proposed LCFS Amendments state that digester operators that join the program before 2030 can receive payment for the avoided methane credits until 2060, creating an enormous incentive for biodigester expansion in the next six years. Further, evidence suggests that the economic viability of these operations requires a significant number of animals (Anderson et al. 2013, Barbera et al. 2019; US EPA 2023). Given public health concerns related to the operation of these IFAP facilities, such an expansion may have implications for human exposures to IFAP related pollutants.

We are concerned that the avoided methane credits incentivize wet manure management systems, which pose known public health concerns. These systems use pits or tanks to store liquid waste and a connected system of pipes to transport it. The tanks and pipes are both susceptible to failures and breaches—now more common as heavy rainfall and flooding become more frequent and intense due to climate change. These failures and breaches may release pathogens, nitrates, and other pollutants into surface water and groundwater supplies (Burkholder et al. 2007). Exposure to these contaminants have been linked to an increased risk of cancer, diabetes, thyroid disease, and birth defects (Burkholder et al. 2007; Jones et al. 2016; Inoue-Choi et al. 2015; Temkin et al. 2019). Furthermore, wet manure management systems are associated with high levels of nitrous oxide and methane emissions, which contribute to climate change and are associated with increased asthma attacks (Glibert 2020).

Due to the water contamination and air pollution caused by wet manure management systems, the American Public Health Association (APHA) has called on federal and state governments to "prohibit the installation of new liquid manure handling systems, including waste lagoons" and to phase out existing wet manure management at IFAP facilities (APHA 2019). Unfortunately, the Proposed LCFS Amendments, through avoided methane crediting and the resulting negative carbon intensity for biogas, would do the opposite.

The avoided methane credits do not reduce burdens on environmental justice communities and workers.

The avoided methane credits run counter to one of the key intentions of the Proposed LCFS Amendments which is to promote investment and improve air quality in disadvantaged communities (CARB 2023). In a study of North Carolina counties with many IFAP operations, average ammonia concentrations, linked to the health effects listed above, have been found to be two and a half to three times higher in environmental justice communities compared to the entire study region (Quist et al. 2022). Additionally, IFAP operations are associated with declining infrastructure, property values, and sense of cohesion—all of which have the opposite impact of community investment (Donham et al. 2007).

The EJAC, whose membership comes from Many disadvantaged communities with significant exposure to air pollution, concluded that IFAP facilities do not promote investment or improved air quality in disadvantaged communities (EJAC 2023). CARB must honor the recommendations of EJAC in order to follow through with its own commitments to reducing pollution burdens in environmental justice communities.

359.1 cont. The practice of burning biogas on-site for electricity production poses safety and public health risks to workers. These can include explosions, asphyxiation, and disease from bacteria, viruses, and parasites in manure (Westenbroek and Martin II 2019). Many agriculture workers are not protected by US labor laws (Lydersen 2022); California has the opportunity to protect those workers from these risks by prohibiting the burning of biogas in its LCFS regulations.

In conclusion, the California Air and Resources Board must eliminate avoided methane crediting, included in the Environmental Justice Scenario, in order to mitigate the public health risks described above. CARB has stated its commitment to transition to clean fuels and to improve air quality in the transportation sector in California. We believe that a solution to improved air quality in the transportation sector cannot include regulations that harm air quality in the agricultural sector. Given that CARB does not have the authority to implement air quality mitigation measures, it should be particularly cautious about including any measures in the LCFS that pose a public health risk to air quality.

Sincerely,

Allie Wainer, MS
Program Officer | Center for a Livable Future
Johns Hopkins Bloomberg School of Public Health

Patti Truant Anderson, PhD, MPH
Senior Program Officer | Center for a Livable Future
Faculty Associate | Health Policy and Management
Johns Hopkins Bloomberg School of Public Health

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Comment Log Display

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Comment 369 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Dr. Rina
Last Name	Singh
Email Address	rina@altfuelchem.org
Affiliation	Alternative Fuels & Chemicals Coalition
Subject	Proposed Amendments to the Low Carbon Fuel Standard Regulation
Comment	Attached are the comments from AFCC.
Attachment	www.arb.ca.gov/lists/com-attach/7050-lcfs2024-BmdTMwFjBzdQCVAz.pdf
Original File Name	AFCC Comments to CARB LCFS Amendments Final.pdf
Date and Time Comment Was Submitted	2024-02-20 19:53:41

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

California Air Resources Board
Rajinder Sahota
Deputy Executive Officer
Climate Change and Research, CA Air
1001 1 St #2828
Sacramento, CA, 95814

Re.: Proposed Low Carbon Fuel Standard Amendments

Dear Rajinder Sahota,

Background

AFCC and its member companies welcome the opportunity to provide comments on the CARB proposed low carbon fuel standard amendments.

AFCC is a collaborative government affairs effort organized by the Kilpatrick Townsend & Stockton law firm and American Diversified Energy. AFCC was created to address policy and advocacy gaps at the federal and state levels with respect to renewable chemicals, bioplastics/biomaterials, cell-cultured food ingredients, alternative proteins, single cell protein for food and feed, enzymes, alternative fuels, biobased products and sustainable aviation fuels sectors. AFCC member companies work on food and fiber supply chain security and sustainability, renewable chemicals, industrial biotechnology, bioplastics and biomaterials, and biofuels.

Areas of Importance for Amending the LCFS

The amendments to the LCFS are focused on expanding the definition of renewable biomass to include woody biomass, forest residuals, sawdust, and ensuring these are treated in any LCA model as carbon neutral which is aligned with the enacted federal definition of carbon neutrality. Furthermore, amendment to the areas of risk of wildfire should be expanded and producers qualify for the LCFS for sustainable aviation biofuels, advanced biofuels, cellulosic biofuels, marine biofuels, hydrogen and ammonia. Innovation in these areas continues to grow, as such LCFS should account for these technologies correctly.

§ 95481. Definitions and Acronyms.

360.1 "California-modified Greenhouse Gases, Regulated Emissions, and Energy use in Transportation model (CA-GREET)" is a modified version of Argonne National Lab's Greenhouse Gases, Regulated Emissions, and Energy use in

Transportation (GREET) model used to evaluate well-to-wheel GHG emissions in the LCFS. The CA-GREET model is periodically updated, and includes a version number suffix, e.g., CA-GREET4.0.

360.1 cont

It is recommended to amend the definition as: Projects will occur in CA and developers should not be in a position to build a project with no GHG guidance.

360.2 Individual cases exist for developers such as: 1. Wildfire, there need to be details on areas with wildfire risk. 2. Thinnings to increase surrounding tree growth. 3. Agricultural residues. 4. Lumbermill and sugar mil waste. 5. Waste should have zero iLUC, similar to UCO. 5. Counterfactuals are consistent with carbon neutrality.

(20)"Biomass" means non-fossilized and biodegradable organic material originating from plants, animals, or micro-organisms, including: products, byproducts, residues and waste from agriculture, forestry, and related industries; the non-fossilized and biodegradable organic fractions of industrial and municipal wastes; and gases and liquids recovered from the decomposition of nonfossilized and biodegradable organic material.

It is recommended to amend the definition as: align with federal enacted law for the definition of carbon neutrality.
Expand CARB's definition of biomass to include: Federal use of GREET. Support CARB's efforts in supply chain tracking, consistent with RED, Federal requirements. Carbon neutrality is Federal law, align Carb with Federal definition.

360.3 **§ 95481. Definitions and Acronyms. Definition of Renewable Hydrogen**

Renewable Hydrogen" means hydrogen derived from

(1) electrolysis of water or aqueous solutions using renewable electricity;

(2) catalytic cracking, oxidation or steam methane reforming of biomethane or other renewable hydrocarbons; or

(3) thermochemical conversion of biomass, including the organic portion of municipal solid waste (MSW).

It is recommended to amend the definition as: Hydrogen derived from thermochemical conversion of biomass, including the bio-genic portion of municipal solid waste (MSW) or landfill diverted MSW which contains biogenic and non-biogenic/non-recyclable material.

§ 95481. Definitions and Acronyms. Definition of Biomethane

360.4 *It is recommended to have a distinct definition of renewable natural gas to include methane derived from other renewable sources, such as methane derived from renewable resources such as bio-genic and non-biogenic components in the landfill-diverted MSW.*

Methanation uses H2 and CO2 to create synthetic methane and becomes a method for bulk hydrogen storage and bulk hydrogen transportation via existing natural gas pipelines.

360.5 **§ 95488.1(c). Tier 1 calculator for hydrogen**

Proposal to include Tier 1 calculator for

1. Electrolysis

2. Steam methane reformation using RNG or North America Natural Gas

It is recommended to include thermochemical conversion of landfill diverted MSW (biogenic and non-biogenic component) with carbon capture in Tier 1 pathway for hydrogen.

Thermochemical conversion of organic component of MSW is well accepted technology for producing renewable hydrogen. Approval of CARB for landfill diverted MSW as feedstock for thermochemical conversion technology with carbon capture under Tier 1 pathway, will support rapid deployment of these projects.

360.6 **§ 95488.8. Fuel Pathway Application Requirements**

Applying to All Classifications. section (g) Specified Source Feedstocks (1) (A) subsection 3 be amended to read as follows:

~~Small-diameter, non-merchantable~~ Any forestry residues and byproducts removed as part of a forest fire fuel reduction, ~~last~~ stand improvement or slash/tops from a treatment (including harvests) ~~where no-clear cutting occurred;~~ from forest lands that meet applicable federal, state or local regulations; Municipal solid waste that is diverted from landfill disposal;

360.7 **§ 95488.8. Fuel Pathway Application Requirements Applying to All Classifications.**

It is recommended to amend as:

(4) Areas at risk of wildfire include: thinnings to increase surrounding tree growth, agriculture residues, lumber mill and sugar mill waste, wasts should have zero ILUC – similar to UCO, and counterfactuals are consistent with carbon neutrality. Carbon neutrality aligns with federal definition.

§ 95488.8(g). Specified Source Feedstocks
1. MSW diverted from landfills will be added under specified feedstock
360.8 sources.
2. Robust chain of custody documentation that traces MSW to the point of origin is required.

It is recommended that the definition of MSW diverted from landfill to include non-biogenic components/ non-recyclable components such as plastic. Considering 48% of landfill waste is non-biogenic (by mass, ref 2023 R&D GREET model), landfill diverted MSW represents a valuable untapped, sustainable, and renewable clean energy resource when carbon capture is implemented.

360.9 **§ 95488.8 (i)(1)(A)-(B).**
The proposed LCFS regulatory revisions that CARB released on December 22, 2023, would narrow the power-sourcing landscape for Power-to-Liquid (PtL) producers. We urge CARB to retain and expand the language which prescribes low-carbon intensity electricity (Low-CI electricity) can be sourced flexibility through the use of RECs or via a qualifying Green Tariff program. Therefore, AFCC and its member companies propose the following:
(i) add to the LCFS regulation a definition of the term "power-to-liquid fuel," with the term defined to mean transportation fuel that is produced from captured carbon dioxide, water, and low-carbon intensity (low-CI) electricity; and (ii) make low-CI electricity used in the production of such fuel, including power-to-liquid sustainable aviation fuel (PtL SAF), eligible for book-and-claim accounting. Indirect accounting mechanisms are warranted for the production of PtL SAF and other PtL fuels, and perhaps more importantly, would promote the scale-up of the PtL fuels industry. PtL SAF in particular has the potential to make a significant contribution to the decarbonization of California's aviation sector.

§ 95488.8(I)(3). Expanding Book and Claim to low CI Hydrogen used in FCVs and alternative fuel production for use in transportation
1. Book and claim for low CI hydrogen injected into dedicated pipelines of hydrogen, which are physically connected to California.
2. Such hydrogen can be used in direct transportation or in the further process of production of alternative fuel.
3. CI of hydrogen for Well to Wheel Analysis is defined as <= 55 gCo2e/MJ (CI-45) for gaseous H2 and <= 95 gco2e/MJ (CI-79) for liquid hydrogen if transported as liquid before pipeline injection.
4. All the projects operational post Dec 31, 2023 are eligible for book and claim.

360.10 *It is recommended that under Book and Claim for hydrogen the requirement of demonstration of deliverability to take effect from Jan 1st, 2041, similar to RNG criteria.*

360.11 **§ 95491 (d)(4)(D). Book and Claim accounting for Low-CI electricity used in production of Hydrogen and direct air capture projects**

1. Low-CI electricity supplied by new or expanded low-CI projects that begin production on or after January 1, 2024, or
2. Within three years of the start of the hydrogen production facility or direct air capture project, whichever is later.
3. Book and claim accounting at qtrly matching, any unmatched CI electricity quantities produced will expire for LCFS reporting.

It is recommend: The carbon intensity of grid-sourced electricity to be evaluated according to the generation portfolio of the PPA (power purchase agreement) without regard to the Three Pillars (Incrementality, Temporal matching, Deliverability).

Electric power requirement for thermochemical conversion pathway, including balance-of-plant, is substantially less than the power required for other pathways. Considering the energy of the product, hydrogen fuel, the majority comes from feedstock (MSW). GHG emissions associated with process energy inputs (grid power) shall be included in the lifecycle hydrogen CI. Technology improvements will result in further efficiencies including industrial heat recovery and sharing.

360.12 **Renewable Natural Gas (RNG) – Importance of the Transportation Market Segment to Avoid Phase Out for Biomethane and Hydrogen**

The CARB proposed amendments seek to phase out avoided emission pathways for projects that break ground after December 31, 2029, for biomethane used as a transportation fuel through 2040 and for biomethane used to produce hydrogen through 2045. While we understand that CARB's intention here is to begin to transition biomethane away from the transportation sector – this will have impact on both short term and long term investments, and the underlying rational is being construed by some as science-driven rather than a policy decision concerning the phase out of combustion in transportation. AFCC and its member companies do not support the phaseout of avoided emission credits. CARB should be explicit that the policy decision to discontinue recognition and eligibility of avoided methane emissions in vehicle pathways should not be interpreted as a departure from the established rigorous science of accounting for the benefits of avoiding methane emissions which continues to be appropriate for non-vehicle sectors. AFCC and its member companies recognize that avoided emission credits for biogas to electricity projects remain, and applaud CARB for recognizing the value of these projects by proposing to retain this aspect of the program.

Conclusion

360.2 cont AFCC and its member companies are requesting forest residuals or hazardous fuels to be treated as carbon neutral feedstocks for producers of biofuels. We respectfully ask CARB to have consistency in its regulatory development of standards to that of other states, federal agencies, and international policies, for ease of adoption, and not create market confusion.

Sincerely,

Rina Singh, PhD.
Executive Vice President, Policy
Alternative Fuels & Chemicals Coalition

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Comment 370 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Yaniv
Last Name	Lewis
Email Address	ylewis@xpansiv.com
Affiliation	
Subject	Clearing Service Provider Five Day Holding Requirement Amendment
Comment	See attached.
Attachment	www.arb.ca.gov/lists/com-attach/7051-lcfs2024-Bn4HcVw8VmtRJAJr.pdf
Original File Name	Xpansiv LCFS Comment Letter Feb 2024.pdf
Date and Time Comment Was Submitted	2024-02-20 19:26:04

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

Rajinder Sahota
Deputy Executive Officer – Climate Change and Research
California Air Resources Board
1001 I Street
Sacramento, CA 95814

Re: Clearing Service Provider Five-Day Rule Amendment

Xpansiv, through an affiliate, acts as an Account Administrator for Minneapolis Grain Exchange's Clearing Service Provider Account in the LCFS Program. Xpansiv is submitting these comments in its capacity as market operator for the CBL Platform, which provides a venue for participants to transact LCFS Credits.

Dear Ms. Sahota,

Xpansiv operates the market infrastructure to rapidly scale the world's energy transition. The company runs the largest spot exchange for environmental commodities, including carbon credits and renewable energy certificates. It is the premier provider of registry infrastructure for energy, power, and environmental markets and operates the largest independent platform for managing and selling solar renewable energy credits in North America.

Last year, Xpansiv partnered with the Minneapolis Grain Exchange ("MGEX"), an eligible Clearing Service Provider ("CSP") under § 95483.1(a)(3) in the LCFS Regulation, to launch the first exchange traded spot LCFS contract on the CBL Platform ("CBL"), where MGEX holds participants' LCFS credits in its LRT-CBTS account that are transacted on CBL. The contract launched in July 2023 and has been well received by the market with over 175,000 LCFS credits cleared across a diverse array of counterparties.

While the market has responded positively to the contract, Xpansiv has observed, in its role as operator of CBL, operational challenges that limit participation and create barriers to adoption.
361.1 As a result, Xpansiv would like to re-submit comments encouraging the ARB to reconsider the requirement that a clearing service provider only hold LCFS credits for up to 5 days in the LRT-CBTS for spot exchanges.

Provision § 95483.1(a)(3)(B) restricts CSPs to holding LCFS credits in an LRT-CBTS account for "up to five days". We believe that an extended holding period would provide participants with an increased opportunity to leverage an exchange to market their credits. In the 2018 Final Statement of Reasons, CARB noted, in response to CBL's comments, that "five days are sufficient to facilitate a transfer" and would "minimize the time period during which credits are locked out of a credit market". As a spot exchange where buyers and sellers transact credits, CBL provides a platform where market participants can access liquidity in the market, as

361.1 cont. opposed to getting "locked out" of it. Approved Participants log into CBL to actively market their LCFS credits. In many instances, the process of listing orders, negotiating, matching with a counterparty, settlement and delivery, takes longer than five days. The CSP account holding period not only covers "facilitation of transfer" of LCFS credits, but the entire lifecycle of a transaction. In addition, participants leverage the CBL LCFS spot contract to set and maintain active bid-ask spreads and hedge their LCFS credit positions in a transparent and efficient way. This requires LCFS credits to be held in a CSP account for longer than five days. The inability to do so has disrupted market participants' ability to make a consistent market during all trading hours, resulting in a less liquid marketplace.

We suggest amending § 95483.1(a)(3)(B) to read "A clearing service provider cannot own credits but can hold LCFS credits for up to thirty days for clearing purposes only." This maintains a reasonable time limit on credit holdings, but also gives participants flexibility in marketing LCFS credits through a spot exchange-based medium. We believe this adjustment will allow firms more flexibility to assess market conditions and utilize an open and competitive marketplace for trade execution and price discovery. This would result in a more liquid marketplace, which benefits all LCFS participants.

We appreciate the California Air Resources Board's ongoing efforts to continue to assess and improve this market-based mechanism. The proposed modification would help enhance an already successful program that is setting the standard for similar regulated low carbon fuel markets across the Americas.

Xpansiv respectfully submits these comments for consideration and thanks the California Air Resources Board for the opportunity. Please direct all follow-up questions and inquiries to policy@xpansiv.com.

Respectfully,

Yaniv Lewis

Yaniv Lewis
Senior Manager, North American Environmental Markets
Xpansiv Limited

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Comment 371 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Julia
Last Name	Tauszig
Email Address	julia.tauszig@unica.com.br
Affiliation	UNICA
Subject	UNICA Comments on LCFS Rulemaking
Comment	Thank you
Attachment	www.arb.ca.gov/lists/com-attach/7052-lcfs2024-BjRTZQc0VzBWYFdl.pdf
Original File Name	20240220_UNICAcomments_CARB.pdf
Date and Time Comment Was Submitted	2024-02-20 19:57:28

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: Rulemaking Regarding Amendments to LCFS

The Brazilian Sugarcane and Bioenergy Industry Association (UNICA) appreciates the opportunity to submit feedback on the proposed amendments to the Low Carbon Fuel Standard being considered later this year.

UNICA applauds California policymakers who have long led the nation on environmental conservation and climate change. The current deliberations over the future of the LCFS again reflect innovative thinking and continue the state's tradition of introducing change that can change the direction of the nation. It is in this spirit that we share our unwavering belief that our product is part of the carbon-reducing vision you seek. California was thoughtful in 2011 when it put biofuels to work. California's climate policy reach goes way beyond the west coast geographic limits, so today, perhaps more than ever, CARB's technical evaluation of biofuels needs to be fair for the different sources of energy, especially those willing to bring in scientific evidence to support their claims.

With this in mind, we only ask that in your deliberations that Brazilian ethanol is scored fairly and accurately so that California residents can continue to enjoy the environmental benefits derived from the world's more efficient, environmentally friendly biofuel. A careful review of the data will again demonstrate that Brazilian ethanol should continue contributing to the state's climate goals, not only in road transportation, but in hard to abate sectors, with the use of sugarcane advanced fuels for sustainable aviation fuels (SAFs) and hydrogen technologies.

As reflected in the staff report, there is a significant opportunity for emissions reduction in the aviation sector and UNICA is well positioned to supply this transition. Meeting this demand requires building out significant new supply capacity, and with appropriate LCFS incentivizes and collaboration among the world's largest ethanol producers we are confident that California can provide proof of concept and market leadership for the global economy.

362.1 We respectfully request that the update of the factors/ inputs presented below are included in the rulemaking process, not only because there is new data and scientific literature to support them but to give Brazilian biofuels a fair score in the LCFS program, which will help with the state's carbon neutrality goals. The items UNICA would like to request to be updated are summarized here. A detailed explanation along with supporting references follows below.

INPUT	ASK
Primary Farming Data	Update farming input values based on truly verified primary data
Farming Energy + Mechanized Harvesting	Update mechanization to a conservative 95% rate in all states of the Center- South region of Brazil
Straw Yield	Update straw yield to 140 kg (dry) per ton of sugarcane (fresh weighted), in line with re- cent literature
N2O from Applied N	Update values to 0.006 kg-N20-N/kg N-fert applied according to Tier2 evidence.
N2O and CH4 from vinasse transportation	Eliminate emissions of N2O and CH4 from vi- nasse transportation
Credits for electricity surplus	Credits from electricity surplus must con- sider the marginal (natural gas, diesel) in- stead of average of the grid
Logistical Routes	Allow Brazilian mills to register different routes with different CIs
Maritime Backhaul Penalties	Reduce or eliminate backhaul penalties, subjecting maritime logistics to the verification procedures
Regenerative Agriculture	Recognize climate-smart agriculture techniques for crop-based biofuels, including in Brazil
By Products Optimization	Establish credit values for displacement of natural gas by biomethane

Sugarcane Farming Data – update farming input values with thoroughly verified primary data, differentiating production patterns in the US and Brazil.

Inspired by LCFS the RenovaBio program developed the most complete and updated database on biofuels production patterns in Brazil. The RenovaBio Program is a national policy guided by three strategic axes: 1) Decarbonization Targets; 2) Efficient Biofuel Production Certification; and 3) Decarbonization Credit (CBIO). In the first axis, each year, the government sets national targets for ten years, which are cascaded down to the fuel distributors, who are the obligated party of
362.1 cont the policy. In the second axis, producers voluntarily certify their production and receive, as a result, energy-environmental efficiency scores (NEEA). These scores are multiplied by the volume of biofuel sold, which results in the amount of CBIOs that a given producer may issue and sell in the market, which is the third axis.[1]

The biofuel certification process follows several steps to ensure the reliability of the NEEA and of the program. First, the producers collect and organize information on agricultural and indus- trial phases to be ascribed into a GHG calculator (RenovaCalc) developed by the National Agency of Petroleum Biofuels and Natural gas (ANP). Each input data needs to be traceable and verifiable

[1] ANP. Renovabio - https://www.gov.br/mme/pt-br/assuntos/secretarias/petroleo-gas-natural-e-biocombustiveis/renovabio-1

(up to the farm level) since each value will be audited in a third-party verification process by companies registered and accredited by ANP[2]. A detailed certification protocol has been published by ANP to assure the reliability and homogeneity of the information. After that, the application is submitted to public consultation and then is verified by ANP before the NEEA is approved and the biofuel is certified.

The certified NEEA is valid for three years, after that the biofuel producer must submit a new certification process again. Also, to remain active and in compliance with the program, producers are required to update the calculator yearly.
It is important to clarify that for the biofuel to be considered eligible, the area of cultivation of the raw material that originated it must meet three criteria:

1. No deforestation of native vegetation after Dec/2017 (validated by satellite images).
2. The Rural Environmental Registry (CAR) must be valid.
3. The cultivated area is in a municipality listed in the Agroecological Zoning of the crop.

As for the reported information regarding the inputs used in the biomass production phase, these have two distinct origins, namely:

Primary data: areas where the raw material is cultivated, whose reported data on the inputs were confirmed through the presentation of documentation in the external audit process carried out by the inspection firm.

Standard penalized input: areas where the raw material is cultivated, which could not be proved through the presentation of documentation. These areas, as long as they meet the eli- gibility criteria, will have default input values assigned, which severely penalizes the final car- bon intensity of biofuels in relation to the primary data.

The information requirements are similar (and were inspired by) to GREET modeling approach and include farming inputs (fertilizers, energy by type), industrial inputs, and yields. . It is important to notice that cherry-picking is not allowed in RenovaBio; each producer must inform and verify the complete set of production indicators to be considered in the primary data.
As mentioned to staff during the August 18th workshop, UNICA has organized one of the most extensive database on production patterns in Brazil. The data presented in this database were collected directly from the 97 production units with the Biofuel Production Certification who agreed to share their annual monitoring spreadsheets, exposing their primary information. Thus, the values presented refer only to the portion of the cultivation areas whose proof was possible. These companies represent about 43% of ethanol production in Brazil in 2018 and 2019.
As CARB is aware, Brazil has also stated production of ethanol from multicropping. This production pattern is different from corn ethanol produced in the US, including using inputs. Cur- rently LCFS does not have such a production pattern registered in CA-GREET. We understand this is an important update in the CA-GREET tool as well.

362.2 **Mechanized Harvesting** – update the mechanization to a conservative rate of 95% in all states of center-south of Brazil.

Mechanization has significantly expanded in the last decade and now represents more than 95% of the total harvested area in the Center-south. This information is supported both by official governmental data and by RenovaBio primary data collected and audited (afore-mentioned database). CARB cannot keep ignoring such evidence. Mechanization has dramatically reduced emissions in sugarcane fields, and mills should be recognized for this progress. Brazilian biofuel

[2] ANP. List of the accredited inspection companies - https://www.gov.br/anp/pt-br/assuntos/renovabio/arq/firmas-inspetoras-credenciadas.xlsx/

producers who have made significant technological investments should not be penalized by lower default assumptions.

In the Tier1 sugarcane ethanol calculator, CARB offers two default values for sugarcane mechanization for Brazil: 80% for São Paulo state and 65% for other states in the Center-South region.

362.2 cont

According to Conab (Brazilian National Supply Company), during the 2022/23 in the Center- South region of Brazil, 2.73% of the sugarcane was manually harvested. This rate has been below 10% since 2015/16. The Center-South region supplies more than 85% of all the sugarcane produced in Brazil.

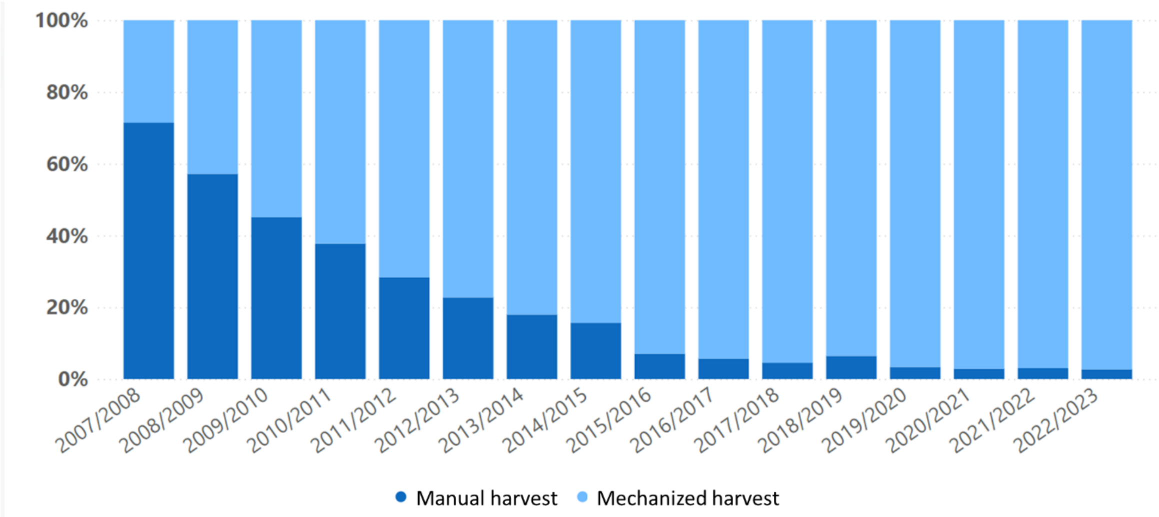

Figure 1: Ratio of manual and mechanized harvest in the Center-South region of Brazil.
Source: CONAB (Observatório da Cana)[3]

We again urge CARB to offer an option for self-declared mechanization percentage in the Tier 1 CI calculator. If for some reason this is not feasible, we respectfully ask staff to adjust the default
362.2 cont mechanization values for Center-South Brazil to a value no lower than 95%. By doing so, CARB will be scoring input more closely to actual practice and will most likely avoid Tier 2 application requests from Brazilian mills, saving time and financial resources for both the Agency and the mills.

Straw Yield –
The CA-GREET3.0 calculator (sheet: Fuel_Prod_TS cell: CI269) considers a straw yield of 0.28 wet ton straw per tonne cane; wet straw containing 15% moisture. Our specialists were unable to identify the source of this combination of values, which leads to a dry straw yield of 0.238 dry
362.3 ton straw per ton cane.
Scientific literature is consistently indicating the ratio of straw (tops and leaves) to cane stalks of about 140 kg (dry) per ton (fresh weight)[4,5], which is equivalent to 0.47 kg (dry) per kg (dry). More recent studies[6], on the other hand, have quantified the straw availability as 120 kg (dry) per ton (fresh), thus resulting in a 0.4 kg (dry) per kg (dry) ratio.

362.4 **N2O from applied N** – revise the Ratio of N2O – N ration from applied fertilizer to 0.6%, according to regional scientific evidence.

[3] CONAB. https://observatoriodacana.com.br/listagem.php?idMn=4
[4] S. J. Hassuani, M. R. L. V. Leal, and I. de C. Macedo (eds.), Biomass power generation: sugar cane bagasse and trash, (CTC ; PNUD, 2005).
[5] M. R. L. V. Leal, M. V. Galdos, F. V. Scarpare, J. E. A. Seabra, A. Walter, and C. O. F. Oliveira, 'Sugarcane straw availability, quality, recovery and energy use: A literature review', Biomass and Bioenergy, 53 (2013), 11–19.
[6] L. M. S. Menandro, H. Cantarella, H. C. J. Franco, O. T. Kölln, M. T. B. Pimenta, G. M. Sanches, S. C. Rabelo, and J. L. N. Carvalho, 'Comprehensive assessment of sugarcane straw: implications for biomass and bioenergy production', Biofuels, Bioproducts and Biorefining, 11/3 (2017), 488–504.

362.4 cont Currently CA-GREET 3.0 considers 0.01 kg-N2O-N/kg N-fert applied (IPCC recommendation). Independent studies found that the emission factors for regional-specific conditions (Tier 2) on the direct GHG emissions for sugarcane in Brazil are usually below the IPCC Tier 1 default value[7] due to the good drainage properties of the deep Oxisols, where sugarcane is commonly cultivated in Brazil. Carvalho et al. (2021)[8] developed an extensive work with field experiments combined with a thorough literature review. Its recommendation for the sugarcane ratoon, which receives most of the N application of the sugarcane areas and represents 4/5 of the sugarcane cycle, the average N2O–N EF from N fertilizer is 0.60%.

362.5 **N2O and CH4 from vinasse transportation** – eliminate such emissions.
CA-GREET 3.0 considers CH4 and N2O emissions from open channel transportation of vinasse, with an impact of approximately 0.24 gCO2e/MJ ethanol. Even though vinasse unlined tanks and open channels feature conditions that may lead to methane emissions (N2O emissions are very low), such transportation strategy does not reflect the regulatory conditions of vinasse logistics in Brazil. Regulations in the state of São Paulo, for example, have established back in 2005 schedules for impermeabilization of vinasse tanks and channels [9] . Furthermore, mills have also adopted systems based on closed tanks and pipes, which further reduce methane emissions during vinasse transportation[10]. Therefore, we recommend CARB to disregard CH4 and N2O emissions from open vinasse channels as a representative condition considered in CA-GREET as such conditions does not represent real practice.

362.6 **Credits for electricity surplus** –
One important revision is the value of electricity surplus credits kg CO2eq/MWh for sugarcane ethanol. The surplus electricity from sugarcane mills plays a fundamental role in the Brazilian electricity mix. Hydropower, which relies on water reservoirs and rainfall regimes, accounted for most of the electricity production in Brazil. Hydroelectric environmental restrictions often push the electric system to other sources (such as natural gas, or diesel) with much higher cost and emissions, but more reliability.
The periods of heaviest use of high-cost electricity sources are marked with “red flags,” as presented in figure 1. This occurs in the dry season (winter), when the reservoir levels of the hydro- electric plants are low, and the sugarcane harvesting is at its highest levels, avoiding the use of oil and natural gas power plants.

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[7] The default value for EF_1 has been set at 1% of the N applied to soils or released through activities that result in mineralization of organic matter in mineral soils. But in the 2019 Refinement to the 2006 IPCC Guidelines, alternative emission factors, disaggregated by climatic zone and fertilizer type, are provided. In wet climates, the default value has been set at 0.6% of organic N inputs and 1.6% of synthetic N inputs. For $Frac_{LEACH-(H)}$ and EF_5, the new aggregated default values are 0.24 and 0.011, respectively.
[8] J. L. N. Carvalho, B. G. Oliveira, H. Cantarella, M. F. Chagas, L. C. Gonzaga, K. S. Lourenço, R. O. Bordonal, and A. Bonomi, ‘Implications of regional N2O–N emission factors on sugarcane ethanol emissions and granted decarbonization certificates’, Renewable and Sustainable Energy Reviews, 149 (2021), 111423.
[9] CETESB, São Paulo. Portaria CTSA – 01, de 28 de novembro de 2005. Dispõe sobre os prazos e procedimentos para a impermeabilização de tanques de armazenamento de vinhaça e de canais mestres ou primários, já instalados, de uso permanente para a distribuição da vinhaça destinada à aplicação no solo. São Paulo, 2005, publicada no Diário Oficial do Estado de São Paulo de 29 de novembro de 2005. [10] Oliveira, et al.,2017. Methane emissions from sugarcane vinasse storage and transportation systems: Comparison between open channels and tanks. Atmospheric Environment. Volume 159, June 2017, Pages 135-146.

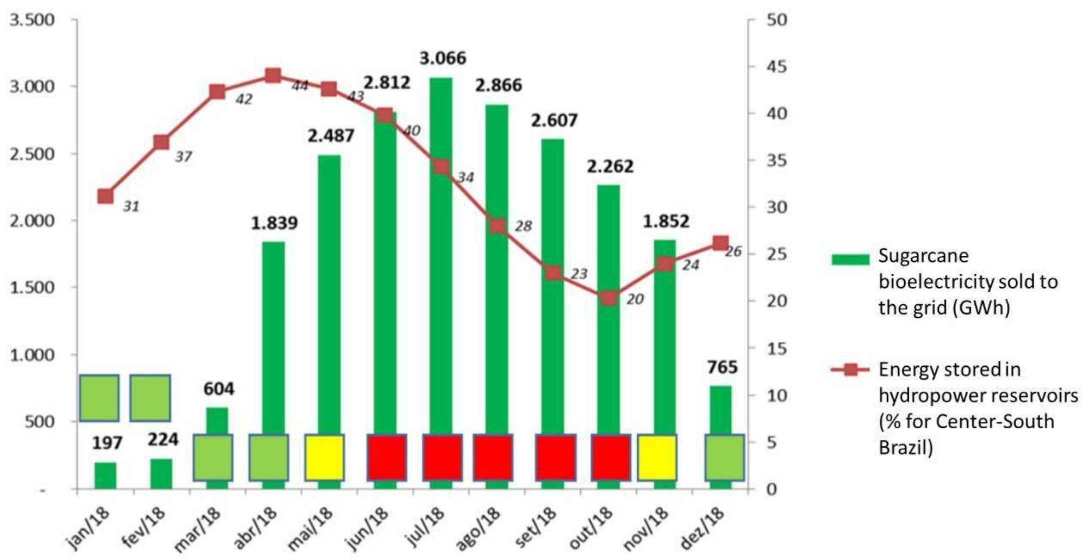

Figure 2: Production of bioelectricity versus hydroelectric reservoirs
Source: UNICA (2019)[11]

Therefore, the correct assumption to calculate electricity credits in Brazil is using electricity at the margin. This approach was taken by CARB in the initial regulation and should be reinstated.

362.6 cont

Further, in Tier1 applications CARB is excluding export electricity credits generated in the off-season months from sugarcane ethanol CI calculations. Mills in Brazil have the option to store their own bagasse to produce electricity to be used in the off-season months to be exported to the grid, avoiding other more polluting sources from being tapped for energy. Brazilian sugar-cane ethanol should not be penalized for this practice, and we urge CARB to reconsider this assumption and allow the use of these credits by Brazilian mills, especially considering that the calculator already backs out the electricity exports eventually generated from third party bio-mass, which excludes the possibility of gearing.

Allow optimization in international transport: Registration of more than a single logistical route for the same facility

Due to the geographical location of Brazil and some methodological choices made by CARB, logistics represent an important share of sugarcane ethanol emissions in the LCFS. The Tier 1 calculator does not allow for a mill to register more than one logistic route with different CIs. Due to this restriction, mills must register the most conservative logistical route.

362.7 As a result, there is no benefit in choosing the most optimized logistic with lower CI. This is an unnecessary burden for the LCFS program (and ultimately to Californians) and does not help to guide better decisions considering their environmental costs.

Further, we understand there is precedent for this pledge in the LCFS program, as one single mill can register more than one pathway. In at least one case, a single renewable diesel facility has different CIs depending on the origin of its feedstock. Similar flexibility seems to be granted for RNG from manure. We would very much welcome the opportunity to engage in this discus- sion with staff.

As we mentioned below, maritime and onshore logistics can be easily tracked, particularly now that LCFS has third party verification. This also applies to pipeline logistics, which represents

[11] UNICA, “A bioeletricidade da cana,” 2019, [Online]. Available: https://www.unica.com.br/wp-content/uploads/2019/07/UNICA-Bioeletricidade-julho2019-1.pdf.

362.7 cont much lower emission levels than the direct alternative in Brazil (trucks) but not currently captured in the modeling.

Maritime Transportation – backhaul

Evidence shows that back-haul penalties for maritime transportation of Brazilian ethanol to California is significantly overestimated. CARB’s assertion that ocean tankers bringing ethanol fuel from Brazil to California will return empty to Brazil lacks evidence. CARB made clear that back-haul emission penalty is due to an overly conservative approach in case such empty (unlikely) return trips happen in the future so it can treat all biofuels fairly.

362.8 As previously mentioned, different UNICA member companies have tracked the vessels that transport their fuel to California and verified that they do not return empty to Brazil. Those companies traced at least 20 vessels from 2019 and 2020 shipments. The information provided by vessel´s operators corroborate to our explanation about logistics regarding oil/chemicals ships discharging ethanol in California, that they do not travel back empty to Brazil in any circumstances. They normally reload in the same port or somewhere else around US West Coast. If no option there, they usually load Vegoils out of Vancouver, or even Gasoline and Diesel in Central America. In the last case, they move to the Golf Coast to load chemicals like Styrene, EDC, Caustic Soda and others.

As for the logistics before loading in Brazil, our country is a net oil products (derivates) importer, as our national refining capacity is much lower than the local demand for fossil fuels, mainly diesel and gasoline. Also, Brazil imports a significant amount of ethanol annually. This scenario results in an over-supply of ships available for loading ethanol to exportation in our main ports. The reason is that these ships bring much more oil products and ethanol to Brazil than the amount of fuel we export. The graphs below illustrate the Brazilian balance for the export and import of oil products and ethanol.

Figure 3: Brazil´s Import and Export of oil products derivates, in millions of liters, from 2010 to 2019.

Source: ANP 2020 (Oil and gas national agency)

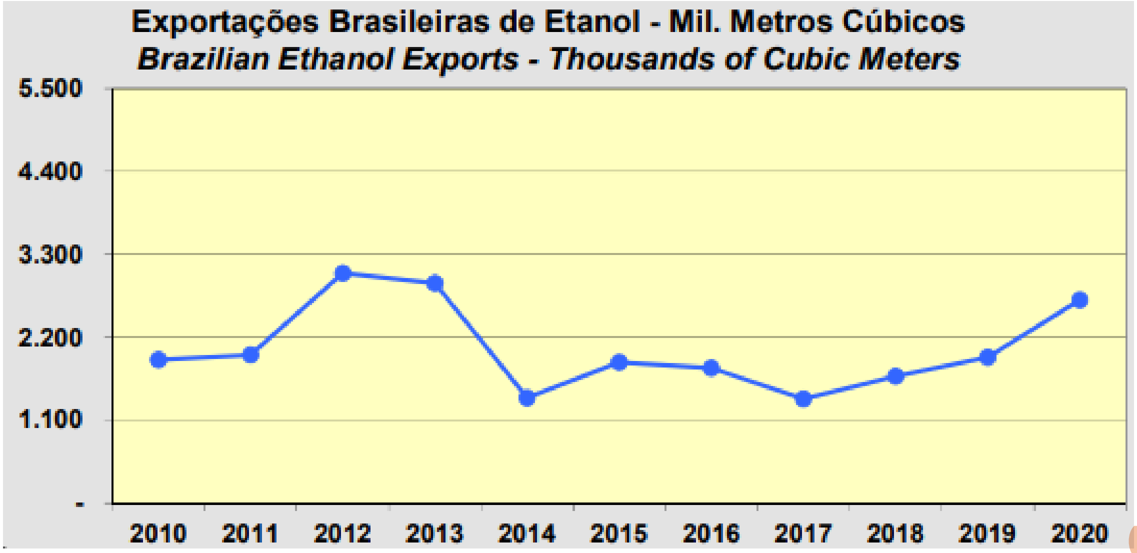

Figure 4: Brazilian Ethanol Exports, in millions of liters, from 2010 to 2020.
Source: UDOP 2020 – Bioenergy National Union

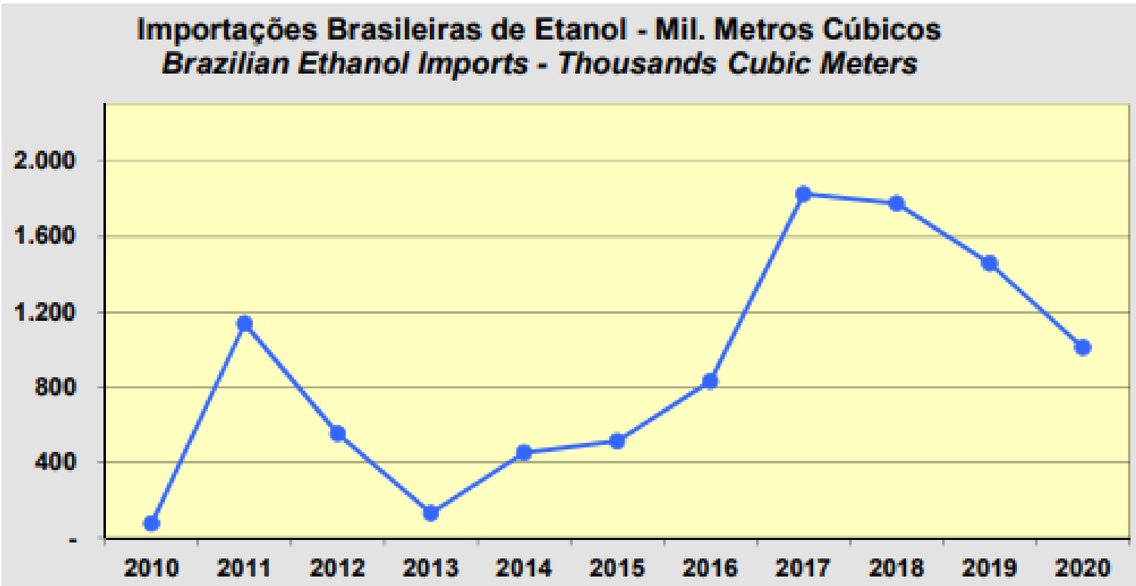

Figure 5: Brazilian Ethanol Imports, in millions of liters, from 2010 to 2020.
Source: UDOP 2020 – Bioenergy National Union

Taking the year of 2019 as reference, Brazil has imported 36.8 and exported 13.7 billion liters of oil products, resulting in a 23.1 billion liters deficit of oil products. Also, Brazil has imported around 1.5 and exported 1.77 billion liters of ethanol. This shows that a significantly higher volume of fuels (oil derivatives) arrives in Brazil rather than leave the country annually, corroborating to the scenario stated by our mill's shipping chartering team and vessels operators
362.8 cont that there is an over-supply of liquid fuel ships in Brazil.

It means that Brazilian fuel supplier companies do not need to hire empty vessels from overseas to export their products. These vessels are constantly available in our ports (mainly Santos port) and they have preference to load ethanol or oil products at the same port where they are discharged in Brazil than travel to another place to load again due to the simple fact that this is more economically attractive.

Assuming the energy consumption and associated emissions of the ocean tanker's round trip be attributed to sugarcane ethanol is speculative and arbitrary. This approach causes a tremendous damage to Brazilian ethanol competitiveness in the California market.

362.8 cont We urge staff not to impose backhaul penalties on Brazilian sugarcane ethanol, since these penalties are not supported by data or shipping practices. Maritime logistics can be easily tracked, particularly now that the LCFS has third party verification, and the agency should defer to verification bodies to make a decision on such penalty, based on their traced data.

362.9 **Recognize climate-smart agriculture practices in Brazil.** Allow for gains in Soil Organic Carbon (SOC) that are supported by scientific literature and verifiable.

From Agroecological Zonings to the current Sao Paulo state's Greener Ethanol Protocol, there are several initiatives to consolidate and advance sustainable management practices in the sugarcane sector in Brazil. We now have a far greater understanding of the changes in C stocks when climate-friendly management practices such as no till, crop rotation, conservation of riparian vegetation, sugarcane green harvesting, pasture recovery, and integrated systems are adopted. Unfortunately, most land use models (including the GTAP-AEZ_EF) didn't incorporate those improvements, nor did the LCFS. Although updated versions of those models should include scientific evidence in their structure, those gains can also be recognized at the field level using accurate indicators. Here we present evidence on the positive impacts of green harvesting compared to "burned fields" baseline and multicopying against "single cropping".

Sugarcane green harvesting

In areas previously occupied by sugarcane, changes in SOC for sugarcane depend on the harvesting technique. Sugarcane fields are replanted only after 5-6 years; thus, "perennial crop" is a better representation than "long-term cultivated crop" of all harvesting techniques. In contrast to traditional manual harvesting systems (where cane used to be burned in the pre-harvest), green harvest system can uptake as much as 1.02 to 1.87 Mg C ha-1 year-1 in topsoil when compared to areas under the traditional pre-harvest burning practices (La Scala Jr. et al., 2012[12]). Recent studies have shown a positive correlation between post-harvest straw maintenance and increased soil carbon content in Brazil (Cerri et al., 2014[13]; Ferreira et al., 2016[14]; Carvalho et al., 2017[15]; Bordonal et al., 2018[16]). According to a study developed by Ferreira et al. (2016), sugarcane absorbed 7.6 kg ha−1 of N (average of two sites) from the straw after 3 years of maintenance in the field Cerri et al. (2014) analyzed the impact of burning and unburned sugarcane straw on soil carbon content in two areas cultivated with sugarcane in the municipality of Ribeirão Preto-SP, one with clayey soil and another with sandy soil. The authors observed that in the clayey soil area, the unburned cane system stored 6.5 t C more than the burned cane system in the 0-20 cm layer. Even in the sandy soil environment, the increase was 4.87 t C/ha (Cerri et al., 2014). The authors conclude that preserving plant biomass makes it possible to sequester C in the studied soils. Carvalho et al. (2017) evaluated the impacts of sugarcane residue removal on soil C stocks in two areas of the state of São Paulo. In one of the sites, soil C stocks were reduced with the total removal of shoot residues, while the partial removal of sugarcane residues did not reduce soil C stocks in any of the areas (Carvalho et al. al, 2017).

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[12] La Scala N Jr, De Figueiredo EB, Panosso AR (2012) A review on soil carbon accumulation due to the management change of major Brazilian agricultural activities. Braz J Biol 72:775–785. https://doi.org/10.1590/S1519-69842012000400012

[13] Cerri et al., 2017. CARBON STOCK IN SOIL AND GREENHOUSE GAS FLOWS IN THE SUGARCANE AGRO-SYSTEM. p.203-216. In Luis Augusto Barbosa Cortez (Coord.). Sugarcane bioethanol — R&D for Productivity and Sustainability, São Paulo: Editora Edgard Blücher, 2014. http://dx.doi.org/10.5151/BlucherOA-Sugarcane-SUGARCANEBIOETHANOL_23

[14] Ferreira et al., 2016. Contribution of N from green harvest residues for sugarcane nutrition in Brazil. GCB Bioenergy, 8, 859–866, 2016. doi: 10.1111/gcbb.12292.

[15] Carvalho JLN, Hudiburg TW, Franco HCJ, DeLucia EH (2017) Contribuição de resíduos de culturas de bioenergia acima e abaixo do solo para o carbono do solo. Glob Change Biol Bioenergy 9:1333–1343. https://doi.org/10.1111/gcbb.12411

[16] Bordonal et al., 2018. Sustainability of sugarcane production in Brazil. A review. Agronomy for Sustainable Development (2018) 38: 13. https://doi.org/10.1007/s13593-018-0490-

Multicropping

La Scala et al. (2012) reviewed on the accumulation of SOC due to the change in the management of the main Brazilian agricultural activities[17]. The study review indicates that in soybean-corn and related rotation systems, there is significant soil carbon uptake throughout the year of conversion from conventional practices to no-till, with an average rate of 0.41 Mg C ha-1 yr-1. According to Dieckow et al. (2005, cited by La Scala et al., 2012), the main factors that contribute to the accumulation of C in the soil of annual crops are no-tillage and crop rotation with leguminous plants, which remove atmospheric nitrogen through a symbiotic interaction, leaving large amounts of dry matter on the soil surface. Petter et al. (2017) evaluated the effect of different agricultural management systems on carbon stocks in Latosols in southern Amazonia, in the Brazilian state of Mato Grosso[18]. The authors emphasize that the "management systems traditionally used in the Cerrado region characterized by the cultivation of soy monoculture and/or soybeans in the summer with second crop corn may not be sufficient to maintain C stocks in the Amazon", but the soybean-corn rotation system showed higher C stocks than the single soybean.

By-Products Optimization

362.10

The use of new technologies in the sugarcane industry has advanced significantly in recent years, especially regarding the potential to extract the energy content of its by-products, wastes and residues. A great example of this is the production of biogas from vinasse and filter cake, whose energy content of these residual raw materials can be extracted via the metagenesis process, without removing its nutritional characteristics, which are reused in sugarcane fields. In turn, the generated biogas can be purified and produce biomethane, a renewable gas that can directly replace natural gas in several industrial processes, or even diesel in automotive vehicles.

In this context, new investments for the energy reuse of sugarcane by-products can be unlocked with the support of decarbonization programs such as LCFS/CARB, and thus provide greater potential for reducing carbon emissions globally and support the program itself on reaching its carbon intensity reduction targets smoothly and within potential lower costs than other unproved technologies.

For that, we asked CARB to recognize the reduction of carbon emissions generated by sugarcane by-products when displacing a fossil fuel, through the sugarcane- ethanol CI´s reduction. In our understanding, this recognition is provided for in the life cycle analysis methodology through the expansion of the LCA system´s boundaries, based on the con- sequential approach used by LCFS/CARB

***

We appreciate the opportunity to submit this feedback and we look forward to discussing with CARB staff the improvements to the scoring methodology in this upcoming rulemaking pro- cess. You can count on our continued support.

Sincerely,

Julia Tauszig
International Relations Coordinator

[17] La Scala Júnior, N., De Figueiredo, EB. and Panosso, AR. A review on soil carbon accumulation due to the management change of major Brazilian agricultural activities. Braz. J. Biol., v. 72, n. 3 (suppl.), p. 775-785, 2012. https://doi.org/10.1590/S1519-69842012000400012

[18] Fabiano André Petter, Larissa Borges de Lima, Leidimar Alves de Morais, Renan Francisco Rimoldi Tavanti, Marcos Eusébio Nunes, Onã da Silva Freddi, Ben Hur Marimon, Carbon stocks in oxisols under agriculture and forest in the southern Amazon of Brazil, Geoderma Regional, Volume 11, 2017, Pages 53-61, ISSN 2352-0094, https://doi.org/10.1016/j.geodrs.2017.09.001.

Comment Log Display

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Comment 372 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Martina
Last Name	Simpkins
Email Address	msimpkins@anewclimate.com
Affiliation	Anew Climate
Subject	Comments on the Proposed LCFS Amendments
Comment	Please find enclosed comments from Anew Climate regarding the proposed amendments to the LCFS.
Attachment	www.arb.ca.gov/lists/com-attach/7053-lcfs2024-AGZUN1c0U19QZFdn.pdf
Original File Name	Feb 20 CARB LCFS ISOR comments.pdf
Date and Time Comment Was Submitted	2024-02-20 19:28:11

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Board Comments Home

February 20, 2024

VIA ELECTRONIC FILING

Matthew Botill
California Air Resources Board
1001 I Street
Sacramento, California 95814

Re: Anew Climate Comments Regarding the Proposed Amendments to the Low Carbon Fuel Standard as outlined in the Staff Report: Initial Statement of Reasons, published on January 5, 2024

Dear Mr. Botill:

Anew Climate, LLC ("Anew") is one of the largest climate solutions providers in North America and has an established track record of participating in California's various sustainability programs, including the Low Carbon Fuel Standard ("LCFS"). We commend the California Air Resources Board ("CARB") and its staff for its successful implementation of the LCFS, driving the decarbonization of California's transportation sector, and proposing amendments to the LCFS in response to the 2022 Scoping Plan Update. The LCFS has a significant role in helping California achieve its ambitious climate goals and we appreciate the opportunity to provide comments on the proposed amendments as outlined in the Initial Statement of Reasons ("ISOR").

Increased Program Ambition and Timely Implementation of a Step-Down in CI Targets Are Critical to the Success of the LCFS

Given the LCFS credit surpluses generated over the last two years, a significant and near-term step-down in the Annual Carbon Intensity (CI) Benchmarks is critical. Based on available market information to date, the LCFS credit bank will continue to grow in 2024 as more credits are being generated than are needed to meet the current CI benchmarks. This will cause the market to stall or even fall further, undermining a key goal of the program - to incentivize investment in low-carbon fuels and fuel technologies.

363.1 A significant step-down in CI benchmarks as soon as possible is the only feasible way in the near term to prevent continued building of the credit bank. In addition, we recommend a step-down of at least 7% to a level of at least 20.75% below the 2010 baseline.

In response to the recent over-performance in the LCFS market, staff proposed a one-time step-down in the form of a 5% reduction in carbon intensity beginning in 2025. In the ISOR, CARB noted accurately that "[a] step-down in stringency was strongly supported by feedback provided by stakeholders, particularly in response to February and May 2023 technical workshops. The step-down reflects the current effectiveness of the program, which suggests that the pace of CI reductions can be increased through the benchmarks."[1]

Given the ongoing overcompliance and related realities in the market, many groups initially urged CARB to target an implementation date of no later than January 2024. CARB subsequently invited comment on a potential mid-year 2024 implementation date, which we supported in our previous comments and still support today to the extent feasible. We understand the complexities involved with modeling revisions to the LCFS program and developing proposed amendments and appreciate CARB's continued efforts to conclude this process in the near future. Given the dramatic oversupply in the market, implementation of a step-down as soon as possible is critical to the integrity of the market going forward. Near-term action by CARB would send a strong signal that California remains committed to rapid decarbonization of its transportation sector and that investments in low-carbon fuels continue to be adequately rewarded and incentivized in California.

We agree with other stakeholders that a **step-down of at least 7% to a CI reduction level of at**
363.1 **least -20.75% in 2025 over the 2010 baseline** is appropriate and necessary to create the desired
market response for market impact. We believe this is one of the most consequential and important steps CARB could take in this rulemaking process and it is vital to the future of the LCFS program.

We Support a 30% or Greater Reduction in Carbon Intensity by 2030

While we would also support a higher CI reduction target, we recognize that a reduction scenario of at least 30% would help set California on a path to meet its ambitious target of at least a 40%
363.2 reduction in economy-wide GHGs by 2030 and carbon neutrality by 2045. Strong CI reduction
goals will continue to accelerate carbon reductions in the transportation sector while establishing clear market signals that will drive innovation and investments.

We Support Tightening the Automatic Acceleration Mechanism

We have consistently supported the concept of creating an automatic adjustment mechanism ("AAM") as a tool within the LCFS and appreciate the inclusion of the AAM in CARB's proposal. We urge CARB to design the details of the mechanism to ensure that the AAM is triggered when the market truly needs it.

The AAM should be amended such that it could be triggered as soon as 2026 if the applicable trigger conditions are met. Additionally, the AAM should be triggered when both the "Credit
363.3 Bank to Average Quarterly Deficit Ratio" exceeds 2.5 and the annual credit generation exceeds
the annual deficit generation for the compliance year preceding the year of the May 15 announcement.

Additional RNG-Related Comments

Anew appreciates the many occasions on which CARB staff has explicitly reiterated the Board's support for RNG throughout the informal workshop process and in the ISOR. If CARB truly wants methane abatement from sources such as agricultural wastes to continue, this rulemaking must

[1] California Air Resources Board, Initial Statement of Reasons ("ISOR"), January 5, 2024, p. 25

convince the clean fuel investment community that RNG will remain a viable and important contributor to the LCFS framework.

Despite assertions to the contrary, there is no credible evidence that decarbonization programs like the LCFS incentivize the growth or consolidation of large dairies or other concentrated animal feeding operations ("CAFOs"). Even skeptical academic experts studying this issue have found no empirical evidence to support the "perverse incentive" claims made by some opponents of avoided methane crediting.[2] Anew is partnered with swine and dairy farmers who are committed to reducing emissions from their waste products. Our direct experience aligns fully with what the data indicates: decisions around development and operations in the dairy and swine livestock sectors are firmly driven by strategic intent to maximize current and future value in the meat and milk markets, while maintaining strong environmental stewardship – not by increasing RNG value or an intent to incur additional waste production.

As Americans consume meat and dairy products, the companies developing RNG projects are investing at-risk capital to abate emissions from the waste products of an essential industry. The capture and conversion of methane creates undeniable and immediate climate benefits. The LCFS today correctly recognizes RNG from agricultural digesters as an impactful methane abatement opportunity for lowering GHG emissions of livestock operations – we urge CARB to stay the
363.4 course towards realizing the full climate benefit of the substantial investments made to date and providing investors with the clarity and confidence necessary for continued development.

Avoided Methane Crediting Phase-Out

Methane is the second-largest contributor to global warming after carbon dioxide due to its alarmingly high concentration in the atmosphere and the fact that it is a potent greenhouse gas (GHG) with impact over 80 times greater than carbon dioxide over a 20-year period. The critical need to address methane as a potent short lived climate pollutant was well stated in CARB's 2017 Short Lived Climate Pollutant (SLCP) Reduction Strategy and echoed by other leading authorities. There is no more effective or immediate step that can be taken to address climate change than aggressively and rapidly reversing emissions of fugitive methane from all sectors, including society's organic waste streams.

We therefore strongly urge CARB to refrain from imposing an arbitrary end-date for avoided
363.5 methane crediting. Any such measure would not only hinder continued investment into methane abatement at farms that LCFS has been instrumental in catalyzing, but also jeopardize existing RNG production assets, which are subject to significant operational expense.

Mandatory methane abatement from farming operations is not currently on the horizon either at the state level in California or at the federal level. If mandatory abatement is implemented, the current LCFS regulation already contemplates in Section 95488.9(f)(3)(B) the phase-out of avoided methane crediting for projects subject to mandatory abatement. Given the absence of mandatory methane abatement and the continued methane emissions from farming operations that

2 Smith, Aaron, "Are Manure Subsidies Causing Farmers to Milk More Cows?" April 8, 2023. Available at https://agdatanews.substack.com/p/are-manure-subsidies-causing-farmers?r=i2qe&utm_campaign=post&utm_medium=web

are meeting America's meat and dairy demands, imposing a specific date for phasing out avoided methane crediting does not make sense for the climate. Capturing methane from California's methane sources (e.g., landfills, dairies, and wastewater) is critical for achieving California's climate targets. As staff noted in the ISOR, "[…] capturing methane from dairies is one of the primary measures for achieving the state's 2045 greenhouse gas reduction targets and SB 1383 methane reduction target."[3] Without anaerobic digesters, California would not be able to meet its SB 1383 methane reduction goals. Eliminating biomethane pathways used to produce hydrogen may also unduly restrict the development of low-CI hydrogen supply that California needs in order to displace fossil fuels. Increasing the supply of low-CI renewable hydrogen is a key strategy identified in the 2022 Scoping Plan Update and supports MDV and HDV ZEVs."[4]

While we oppose putting any end-date on avoided methane crediting, we recognize that CARB has faced unsubstantiated criticism and repeated calls for an immediate or near-term phase-out. We commend CARB for taking a measured position in support of avoided methane crediting generally and opposing any near-term phase out. We strongly urge CARB to continue following
363.5 climate science on a technology-neutral basis and to maintain the framework that has catalyzed unparalleled investment into methane abatement at swine and dairy operations.

CARB Should Maintain Eligibility for Delivery of Biomethane from All Sources

Currently, the LCFS regulation allows for indirect accounting of biomethane when injected into the North American natural gas pipeline system. In the ISOR, staff proposed that biomethane projects that break ground after December 31, 2029 in which biomethane is injected into a common carrier pipeline or claimed indirectly under the LCFS program for use as a transportation fuel or input to hydrogen production must meet new deliverability requirements. Starting January 1, 2041 for bio-CNG, bio-LNG and bio-LCNG pathways and January 1, 2046 for biomethane used as an input to hydrogen production, the entity reporting biomethane must demonstrate that the pipeline or pipelines along the delivery path physically flow from the initial injection point toward the fuel dispensing facility at least 50 percent of the time on an annual basis. The stated reason for these new deliverability requirements is that these requirements would "help ensure that California is making progress on the state's methane reduction targets."[5]

We appreciate that CARB has resisted pressure to include immediate new directional flow requirements for biomethane pathways, and that the proposal would not impact any biomethane fuel pathways for projects that break ground before January 1, 2030. However, we do not agree with CARB's decision to impose directional flow requirements on deliveries from biomethane
363.6 projects that break ground in 2030 or later. Given the realities of the interconnected U.S. gas market, the 50% directional flow requirement is arbitrary and provides preferential treatment to fossil gas imported to California relative to imported RNG.

[3] ISOR, p. 124
[4] Id.
[5] ISOR, p. 31.

A Full Credit True Up Would Reflect the True Environmental Performance of RNG Pathways

363.7 We support the proposed inclusion of a "Credit True Up" after Annual Verification. When implemented properly, such a concept can ensure that the LCFS program correctly accounts for the full GHG benefits all fuel pathways produce. Such a true up should apply both in the case of temporary pathways, as originally proposed by CARB during previous workshops, as well as for provisional and fully certified pathways.

Biological systems such as anaerobic digesters experience substantial increases and decreases in gas production due to weather, livestock herd changes, and other factors that are not present in other fuel pathways. Because the carbon intensity of the gas from these systems is calculated against a quantity of avoided methane emissions, these variations in biogas production operating conditions result in outsized changes in the digesters' carbon intensity (CI) scores every year. Pathways should be allowed to fully "true up" LCFS credit generation to their actual CI score once that score is determinable based on actual greenhouse gas performance data.

363.8 We support the provisions in the proposed rule that provide for generation of additional credits if the verified CI is lower than the certified pathway CI based on the incrementally lower verified score using backward-looking actual performance. This true up process should be automated by CARB in the LRT-CBTS system for all fuels. 363.9 However, we do not support the Proposed Rule's approach requiring a 4x "pay back" in cases where a verified CI exceeds the certified CI. This is overly punitive and not symmetrical. Instead, we recommend that if the verified CI is higher than the certified CI, the project should simply repay CARB for any excess credits claimed, and not be subject to any further enforcement liability unless there is malfeasance or other conduct contrary to the objectives of the program.

Anew is proactively developing an updated CI management approach to ensure we continue to provide maximum value recognition potential to our partners coupled with compliance risk mitigation.

Tier 1 Calculator Improvements

363.10 Anew supports allowing fuel pathway applicants to submit site specific inputs to demonstrate fugitive emissions on the 'Biogas-to-RNG' tab as outlined in comments submitted by the Coalition for Renewable Natural Gas in response to the draft Tier 1 Calculator. In addition, Anew requests that CARB allow fuel pathway applicants to submit site specific inputs to demonstrate digester leakage emissions on the 'Avoided Emissions' tab. This would allow projects to provide actual operating values that may differ from the default values of 2% for enclosed vessels and 5% for covered lagoons.

Regarding GREET inputs for L1. (1-6).14 Retention Time and Drainage, it is Anew's understanding that in the proposed GREET calculator for each September, "System Emptied in This Month" must be selected by the fuel pathway applicant. This assumption requires that all projects model their operations to include a complete annual cleanout of volatile solids. A complete annual cleanout is currently only required as a baseline assumption for greenfield projects in Table A.10 of the Compliance Offset Protocol for Livestock Projects.

The implementation of this proposed default assumption could result in non-greenfield projects being certified with a carbon intensity that is not representative of normal operating conditions. It could also result in a project's baseline methane emission levels being set below what would have otherwise been emitted to the atmosphere. This proposed default assumption may be more applicable to the average dairy operation, but the same conclusion is not as appropriate for the average swine operation. Swine industry leaders and project operators have expressed that lagoons are cleaned out far less frequently than annually over a 10 to 15-year time frame. Therefore, on the 'Manure-to-Biogas (LOP Inputs)' tab, applicants should be able to enter the project-specific lagoon cleanout frequency for swine livestock populations in the Tier 1 Calculator. Applicants should be able to select from lagoon cleanout frequencies that are less frequent than annual and have default inputs "amortized" according to CARB's current guidance document.

363.11 As an alternative, Anew encourages CARB to consider allowing swine projects to submit their site-specific lagoon clean out frequencies as part of a Tier 2 fuel pathway registration. The annual loss in volatile solids results in a significant detrimental impact to the baseline methane emissions of swine projects and unfairly penalizes the project's CI score. Anew appreciates CARB's intention to simplify and streamline the project registration process, however, this should not be done at the expense of swine projects. To accurately reflect actual operating conditions of swine manure projects and minimize pathway registration processing time, we urge CARB to consider allowing applicants to enter actual cleanout frequencies by project in the Tier 1 Calculator.

EV Considerations

363.12 Anew is supportive of the addition of medium and heavy duty ("MHDV") Fast Charging Infrastructure ("FCI") credits. The adoption of MHDV vehicles into private fleets remains an economic challenge that LCFS crediting could help address. Given the difficulties with adoption, we believe the 50% reduction for private fleets should be eliminated. Additionally, requiring proximity to a Federal Highway Administration Alternative Fuel Corridor unnecessarily restricts private operations and should be applicable only to public infrastructure projects. The minimum power requirement of 250kW also unduly restricts private operations. Operating multiple lower power chargers overnight provides many operations with the opportunity to charge in a manner more suited to extended battery life, incur less operational costs associated with moving vehicles in and out of chargers, especially in off hours, and lower utility impact and investment requirements by spreading a lower power load over a longer period of time. CARB already envisions overnight charging based on the exception to the requirement of being within 1 mile of an AFC.

363.13 We support continuing the Light Duty Vehicle ("LDV") FCI. However, in our view, the geographic restrictions, particularly the 10-mile requirement from any fast charging station, will effectively eliminate too many of the major routes in the states and cities/towns that have a minimal amount of charging but much less than is required based on EV adoption. Geographic limitations of this nature would encourage a disproportionate amount of infrastructure in locations that have inherently low utilization and would not further the objective of increased EV adoption. As an alternative, we ask CARB to consider FCI approvals to maintain a balance between the number of publicly available fast chargers and the number of EVs registered in a given area. If CARB is looking to reduce the number of overall LCFS credits from LDVs while encouraging continued adoption, it would be more effective to remove base credits from LDVs available to the utilities and allocate them to FCI credits. This approach would directly address one of the largest barriers to continued growth of EV adoption.

We thank CARB for its important work in implementing the LCFS program. Should you have any questions about anything we have stated here or seek further clarification, please contact Randy Lack at rlack@anewclimate.com

Sincerely,

Anew Climate, LLC

Comment Log Display

Here is the comment you selected to display.

Comment 373 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Kyle
Last Name	Berquist
Email Address	kberquist@earthjustice.org
Affiliation	Earthjustice
Subject	Comments from Earthjustice supporters
Comment	I am submitting comments on behalf of 1,398 additional Earthjustic supporters that were unable to file their public comments directly Thank you for considering their opinions. Sincerely, Kyle Berquist Senior Digital Advocacy Specialist Earthjustice
Attachment	www.arb.ca.gov/lists/com-attach/7055-lcfs2024-Uz8CdlwRnWTBYM0d.pdf
Original File Name	kberquist-lcfs2024 comment.pdf
Date and Time Comment Was Submitted	2024-02-20 20:17:24

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

First Name,Last Name,Email,ZIP Code,State,Message
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William,Darnell,voman@mycci.net,95860,CA,"Your proposed amendments to California’s Low Carbon Fuel Standard are a climate policy failure that backslides on the state’s role as a climate leader. The program subsidizes combustion fuels to the tune of billions of dollars per year and has no place in our toolkit of climate policies for the 2020s. There is too much on the line for our climate to get this critical program so wrong.

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Wallace,Pearce,denropro@gmail.com,95694,CA,"Your proposed amendments to California’s Low Carbon Fuel Standard are a climate policy failure that backslides on the state’s role as a climate leader. The program subsidizes combustion fuels to the tune of billions of dollars per year and has no place in

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Maria,Martinez,ms.mari@earthlink.net,94530,CA,"Your proposed amendments to California’s Low Carbon Fuel Standard are a climate policy failure that backslides on the state’s role as a climate leader. The program subsidizes combustion fuels to the tune of billions of dollars per year and has no place

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Mary,"Dean, Esq.",marydean1@earthlink.net,94595,CA,"Your proposed amendments to California's Low Carbon Fuel Standard are a climate policy failure that backslides on the state's role as a climate leader. The program subsidizes combustion fuels to the tune of billions of dollars per year and has no place in our toolkit of climate policies for the 2020s. There is too much on the line for our climate to get this critical program so wrong.

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I urge you to correct your course and modernize the program by reflecting your consensus that the only way to meet air quality standards is through eliminating combustion altogether, not piling on billions of dollars in lavish incentives for combustion each and every year. By focusing on real air pollution solutions, you could add a clean air multiplier to the credits system, especially for public fleets that transport many people at once, would deliver major benefits for California's air quality and throw a lifeline to cash-strapped transit agencies that low-income Californians depend on for mobility.

California cannot meet our clean air and climate goals without harnessing the power of the Low Carbon Fuel Standard and overhauling this multibillion-dollar program for our zero emissions future. Please act expeditiously to reform the program to achieve our state's ambitious goals."
Laura,Elizares,laura.elizares@gmail.com,95451,CA,"Your proposed amendments to California's Low Carbon Fuel Standard are a climate policy failure that backslides on the state's role as a climate leader. The program subsidizes combustion fuels to the tune of billions of dollars per year and has no place in our toolkit of climate policies for the 2020s. There is too much on the line for our climate to get this critical program so wrong.

Your budget proposes significant delays and cuts of hundreds of millions of dollars to vital zero-emission transportation programs, which makes it all the more urgent to use the Low Carbon Fuel Standard to more fully support zero-emissions transportation. Historically, California has thrown good money after bad, and devoted 80% of the LCFS's $3 to 4 billion each and every year to combustion technology. It would be wild to allow these funds to continue to languish on the climate sidelines, instead of anchoring our transition to a zero-emissions future.

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James,Sopher,jsopher49@gmail.com,92078,CA,"Your proposed amendments to California's Low Carbon Fuel Standard are a climate policy failure that backslides on the state's role as a climate leader. The program subsidizes combustion fuels to the tune of billions of dollars per year and has no place in our toolkit of climate policies for the 2020s. There is too much on the line for our climate to get this critical program so wrong.

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Comment 374 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Chris
Last Name	Gould
Email Address	Chris.Gould@CRC.com
Affiliation	California Resources Corporation
Subject	Proposed 2024 Low Carbon Fuel Standard Amendments
Comment	Please see attached letter.
Attachment	www.arb.ca.gov/lists/com-attach/7056-lcfs2024-BmUFcQFjWVUCMFdi.pdf
Original File Name	CRC 45-day Comments on Proposed LCFS 02202024 .pdf
Date and Time Comment Was Submitted	2024-02-20 20:20:43

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

February 20, 2024

Submitted electronically via ww2.arb.ca.gov

Chair Liane M. Randolph and
Members of the Board
California Air Resources Board
1001 I Street
Sacramento, CA 95814
cotb@arb.ca.gov

RE: Proposed 2024 Low Carbon Fuel Standard Amendments

Dear Chair Randolph and Members of the Board:

California Resources Corporation ("CRC") appreciates the opportunity to comment on the California Air Resources Board's ("CARB" or "the Board") proposed 2024 amendments to the Low Carbon Fuel Standard ("LCFS") published December 19, 2023 (the "Proposed Rules").[1] As explained below, in addition to other aspects of the proposal, CRC believes that the Proposed Rules approach to LCFS credit generation for hydrogen projects is not consistent with CARB's December 2022 Scoping Plan (the "2022 Scoping Plan"), and, unless CARB takes steps to revise its proposal, California's nascent low carbon hydrogen production industry will lack vital incentives necessary for the development of California's low carbon economy.

About CRC and Carbon TerraVault Holdings, LLC

California Resources Corporation is an independent energy and carbon management company committed to the energy transition. CRC has some of the lowest carbon intensity production in the US and we are focused on maximizing the value of our land, mineral and technical resources for decarbonization by developing carbon capture and storage ("CCS") and other emissions reducing projects.

Our core activities involve exploration, production, gathering, processing, and marketing of crude oil, natural gas, and natural gas liquids. We leverage advanced technologies extensively to enhance safety and boost production efficiency across our expansive mineral acreage and diverse portfolio. These cutting-edge technologies allow us to increase production while minimizing the environmental footprint of our oil and gas development operations. For more information about CRC, please visit www.crc.com.

Carbon TerraVault Holdings, LLC ("CTV"), a subsidiary of CRC, is developing services that include the capture, transport and storage of carbon dioxide for its customers. CTV is engaged in a series of CCS projects that inject CO_2 captured from industrial sources into depleted

[1] California Air Resources Board, Proposed LCFS Amendments, https://ww2.arb.ca.gov/rulemaking/2024/lcfs2024.

underground reservoirs and permanently store CO_2 deep underground. For more information about CTV, please visit www.carbonterravault.com.

CTV is involved in several green energy initiatives. These include the Grannus Ammonia and Hydrogen Project, which will sequester 370,000 metric tons ("MT") of CO_2 annually and produce clean ammonia and hydrogen in Northern California. The project aims to be California's first clean ammonia and hydrogen facility producing 150,000 MT per annum of clean ammonia and 10,000 MT per annum of clean hydrogen. The Elk Hills Hydrogen Project, in collaboration with Lone Cypress Energy Services, will sequester 205,000 MT of CO_2 per year and produce 65 tons per day of hydrogen from a new hydrogen plant.[2,3] CTV has an agreement to sequester 150,000 MT per annum with NLC Energy, who plans to build a new facility expected to produce up to 7,000 MMBtu per day of RNG from biomass and other agricultural waste feedstock. The Verde Clean Fuels renewable gasoline production facility plans to partner with CTV to sequester 100,000 MT per annum and will utilize an innovative and proprietary liquid fuels technology to produce renewable and lower-carbon gasoline and other liquid fuels from feedstocks such as biomass and agricultural waste. Inentec plans to build a new renewable dimethyl ether (rDME) production facility, with CTV sequestering 100,000 MT per annum and Inentec producing 80-100 tons per day of rDME from biomass and other wastes materials. Lastly, the Yosemite Hydrogen Facility, in partnership with Yosemite Clean Energy, will sequester 40,000 MT of CO_2 per year from a new hydrogen plant expected to produce 24,000 kilograms per day of hydrogen with forest biomass feedstock. These projects contribute to our sustainability goals to reduce carbon emissions and promote clean energy.

About Carbon TerraVault Joint Venture

Carbon TerraVault Joint Venture ("CTV JV") is a carbon management partnership focused on carbon capture and sequestration development, and was formed between Carbon TerraVault, a subsidiary of CRC, and Brookfield Renewable. The CTV JV develops both infrastructure and storage assets required for CCS development in California. CRC owns 51% of the CTV JV with Brookfield Renewable owning the remaining 49% interest.

Proposed Recommendations

As a California-based company committed to the energy transition, CRC supports CARB's overall goal of achieving carbon neutrality by 2045 and reducing greenhouse gas emissions by 2045 to a level that is 85% below 1990 levels. In its Statement of Reasons for the Proposed Rules, CARB stated that "[m]eeting this goal will require the deployment of greenhouse gas emission reduction strategies ***at an unprecedented scale and pace***."[4] However, we are concerned that many aspects of the Proposed Rules unnecessarily restrict or prohibit established and proven strategies for reducing GHG emissions in connection with the production of low carbon intensity ("CI")

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[2] Second Quarter 2023 Update, California Resources Corporation (July. 31, 2023).

[3] CRC expects that the Lone Cypress Hydrogen Project will utilize a blended feedstock consisting of natural gas and RNG, subject to the availability of RNG.

[4] 2024 LCFS Amendments Staff Report: Initial Statement of Reasons at 4 (Dec. 2023) [hereinafter "Initial Statement of Reasons"] (emphasis added).

hydrogen from generating LCFS credits. In particular, the Proposed Rules as written would exclude low-CI hydrogen with CCS (production of hydrogen utilizing CCS to capture GHG emissions) from generating LCFS credits. The Proposed Rules seemingly only provide for LCFS credits to be generated from hydrogen produced using (1) electricity generated from renewable power sources and (2) renewable natural gas ("RNG") as a feedstock. This proposal is inconsistent with the CARB 2022 Scoping Plan and will ultimately frustrate the deployment of low carbon hydrogen projects in California.

As discussed in greater length below, we respectfully request that prior to finalization of the Proposed Rules, CARB:

365.1 — Revise the definition of the term "renewable hydrogen" in the proposed LCFS amendments to allow for the use of CCS to be consistent with the 2022 Scoping Plan;

365.2 — Expand the LCFS crediting requirements for hydrogen fueling infrastructure to explicitly acknowledge that low-CI hydrogen with CCS can be used to meet the carbon intensity targets;

365.3 — Revise and broaden the refinery crediting program to allow for the use of CCS;

365.4 — Clarify that book-and-claim accounting can be used to support LCFS credit generation when RNG is used to generate electricity utilized for hydrogen production and direct air capture projects; and

365.5 — Reverse the proposed crediting changes for solar innovative crude projects.

These four requests largely stem from regulatory inconsistencies and counterproductive consequences associated with the Proposed Rules, including 1) conflicts between the amendments and CARB's 2022 Scoping Plan, 2) negative impacts to California's climate goals, and 3) harmful financial effects, including risk of stranding assets.

California Resource Corporation's Concerns with the Proposed LCFS Amendments

1. The Proposal is Not Consistent with CARB's 2022 Scoping Plan and Will Frustrate Deployment of Low Carbon Hydrogen

Assembly Bill ("AB") 32 requires CARB to develop a Scoping Plan which lays out California's strategy for meeting the state's climate goals and update the Scoping Plan every five years.[5] The 2022 Scoping Plan provides a detailed pathway to achieve targets for carbon neutrality and reduce anthropogenic GHG emissions by 85% below 1990 levels no later than 2045.

Hydrogen production plays a critical role in meeting these goals per the 2022 Scoping Plan. In order to achieve these ambitious climate targets, the 2022 Scoping Plan recognized that ***1,700 times*** the current hydrogen supply will be required by 2045.[6] AB 32 requires that any CARB

[5] Cal. Code Regs. Title 17, § 38561.(a)-(h) (2023).

[6] California Air Resources Board, *2022 Scoping Plan for Achieving Carbon Neutrality*, at 8 (Dec. 2022) [hereinafter "CARB 2022 Scoping Plan"].

scoping plan embrace "technologically feasible and cost-effective reductions in GHG emissions."[7] The 2022 Scoping Plan follows that statutory directive, but the Proposed Rules do not.

365.6 The massive scaling of low carbon hydrogen projects necessary to meet the goals of the 2022 Scoping Plan requires an "all of the above" approach to low carbon hydrogen production and ensuring that sufficient supportive financial incentives are in place. LCFS credits represent a potentially critical financial incentive for low or zero carbon hydrogen projects. However, based on how CARB proposes to define "renewable electricity," hydrogen production would generally only be eligible to generate LCFS credits if it involves: (1) the electrolysis of water or aqueous solutions using renewable electricity; (2) catalytic cracking, oxidation or steam methane reforming of biomethane or other renewable hydrocarbons; or (3) thermochemical conversion of biomass.[8] This narrow definition ignores, and if adopted as proposed will only serve to disincentivize, the entire low-CI hydrogen industry—a nascent but proven technology being implemented at scale in California by CRC. In light of the 1,700-fold expansion in the state's hydrogen supply called for by the 2022 Scoping Plan, CRC believes that CARB should be encouraging *all forms* of low carbon hydrogen production.

As highlighted above, the 2022 Scoping Plan calls for a flexible approach to supporting the development of low carbon hydrogen.[9] Specifically, the Plan makes the following key references to hydrogen and CCS:

> "For the purposes of this Scoping Plan, 'renewable hydrogen' and 'green hydrogen' are interchangeable and are not limited to only electrolytic hydrogen produced from renewables." (page 26)
>
> "CCS can support hydrogen production until such time as there is sufficient renewable power for electrolysis and an abundant water source." (page 86)
>
> "If steam methane reformation is paired with CCS, the hydrogen produced could potentially be low carbon." (page 88)

These references were included in the final adopted version of the 2022 Scoping Plan despite multiple commenters calling on CARB to explicitly exclude CCS from its definition of hydrogen production eligible to generate LCFS credits. Adhering to the 2022 Scoping Plan requirements outlined in AB 32, CARB refused to take such a narrow approach and built flexibility into the final 2022 Scoping Plan. But merely a year later, in December 2023, CARB published the draft LCFS amendments that seem to take the opposite approach in contrast to that of the 2022 Scoping Plan. This change in the Board's direction seems arbitrary and capricious in light of the rulemaking record.

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[7] AB 32 § 38561.(a) "[CARB] shall prepare and approve a scoping plan, as that term is understood by the state board, for achieving the **maximum technologically feasible and cost-effective reductions** in greenhouse gas emissions [emphasis added]."
[8] 2024 LCFS Amendments, Proposed Regulation Order, 17 C.C.R. § 95481.(a).
[9] CARB 2022 Scoping Plan at 6.

This abrupt change in CARB's stance towards low-CI hydrogen with CCS is further evidenced in the Board's responses to public comments on the draft 2022 Scoping Plan. When a public commenter called for CARB to only support electrolytic hydrogen generation via renewable electricity, the Board responded by stating that:

> [t]he 2022 Scoping Plan does not prescribe the energy source to produce hydrogen, and therefore, steam methane reformation paired with CCS could be considered in the near term to ensure a rapid transition to hydrogen and increase hydrogen availability until such time as electrolysis with renewables and biomass-based hydrogen can meet the ongoing need.[10]

CARB further acknowledged that because "the build-out [of renewable power generation] takes time and is additive to the growth in demand growth associated with electrification across the economy, the state needs to keep options open for other methods to produce zero carbon hydrogen at the scale needed to meet the projected demand."[11] The Proposed Rules, however, do not embrace the approach called for in the 2022 Scoping Plan and seemingly only contemplate a role for CCS in hydrogen production when RNG is used as a feedstock.[12] Restricting LCFS crediting to hydrogen produced from CCS only when RNG is also used does not keep California's "options open."

The Proposed Rules ignore the technical realities associated with the time to scale the deployment of hydrogen solely produced from renewable electricity and other factors discussed below that may limit the availability of RNG as a feedstock. In this interim period, low-CI hydrogen with CCS is the only proven and scalable technology capable of meeting the demands of California's expanding low carbon economy.[13] Even CARB itself has acknowledged, in its 2022 Scoping Plan, that "[t]here is a high degree of uncertainty around the availability of solar to support both electrification of existing sectors and the production of hydrogen through electrolysis."[14] Given this uncertainty, we are concerned that CARB is playing a zero-sum game by directly linking hydrogen generation LCFS credits largely to renewable power generation. Instead of devoting renewable power supplies to meet other grid demands, these LCFS amendments would incentivize more of this zero-carbon electricity to be devoted to hydrogen generation via electrolysis. This unnecessary competition over scarce renewable energy supplies can be avoided by revising the LCFS amendments to incentivize low-CI hydrogen with CCS as an interim solution while these other hydrogen generation technologies develop.

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[10] CARB 2022 Scoping Plan Response to Comments, Appendix B at 57.
[11] *Id.*
[12] While the 2022 Scoping Plan used the example of CCS with hydrogen production using RNG as a feedstock as an example of low carbon hydrogen production, *see id.*, nothing in the 2022 Scoping Plan suggested that CARB viewed this as the only pathway for CCS to support low carbon hydrogen production and LCFS credit generation.
[13] Bracci, J., et al., *Fueling the California Mobility Market with Hydrogen from Natural Gas plus Carbon Capture and Storage, Stanford Natural Gas Initiative and Stanford Center for Carbon Storage*, May 2022, at 41 ("near-term techno-economic models still point to SMR-CCS being the cheaper hydrogen generation pathway to kickstart a clean hydrogen economy in California") [hereinafter "SCCS Study"].
[14] CARB 2022 Scoping Plan at 88.

Moreover, CARB may be overestimating the availability of RNG for use in hydrogen production within California. Separate from the provisions related to hydrogen, the Proposed Rules would also effectively end LCFS crediting for biomethane projects after 2040. Given that the biomethane crediting pathway is widely used to support the development of RNG projects, this change will remove the primary financial incentive for new RNG projects in California and for producers to send RNG to California. This is because LCFS credits are critical to making RNG projects competitive with fossil gas given the comparatively low value of environmental credits available under the federal Renewable Fuel Standard ("RFS") and other state low carbon fuel programs. The Proposed Rule's inclusion of a limited pathway for crediting projects using RNG as a feedstock to produce hydrogen until only 2045 is unlikely to be enough to support the volumes of RNG needed meet the 2022 Scoping Plan's goals for low-CI hydrogen. Removing biomethane crediting from the LCFS may result in producers sending RNG to Oregon and Washington to capture more value under those state low carbon fuel programs. In addition, demand for RNG outside of California is only expected to grow over the next several years, with New Mexico recently enacting a low carbon fuel standard and the U.S. Environmental Protection Agency's expected eventual finalization of rules allowing RNG used in electricity generation to generate credits under the RFS. This will inevitably increase demand for RNG for non-hydrogen uses outside of California and could accordingly result in RNG supply shortfalls within the state. CARB's assumption that sufficient RNG may be available as a feedstock for low carbon hydrogen production does not appear to consider this factor.

The LCFS can play a critical support role in the development of California's low carbon hydrogen economy. For example, strong market signals from the LCFS have supported increased production and use of biodiesel and other low carbon fuels.[15] Even regarding CCS, a recent May 2022 study from the Stanford Center for Carbon Storage found that "LCFS is the single largest financial incentive for eligible CCS projects in California."[16] But rather than send strong market signals or incentives in support of California's growing low carbon hydrogen industry, the Proposed Rules send the opposite signal, likely harming both the low carbon hydrogen and CCS industries. By picking winners and losers at such an early stage in the energy transition, CARB is abandoning the technology-neutral approach outlined in its own 2022 Scoping Plan where it stated that "[t]he challenge before us requires us to keep all tools on the table."[17] We believe that CARB should adopt this latter approach and reverse the restrictive course proposed in the LCFS amendments. In particular, as part of this reversal, CARB needs to revise its proposal so that blue
365.7 hydrogen projects are eligible to receive additional LCFS credit generating opportunities.

2. Impact to State Climate Goals

The California Climate Crisis Act (AB 1279) sets an ambitious goal, requiring the state to achieve net zero GHG emissions as soon as possible, but no later than 2045, and thereafter achieve and maintain net negative GHG emissions. CCS is critical to this endeavor; it is, importantly, a *viable* option to reduce emissions from sectors that are key contributors to California's total

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[15] CARB 2022 Scoping Plan at 191.
[16] SCCS Study at 32.
[17] CARB 2022 Scoping Plan at 11.

emissions.[18] It is also a "critical enabler" of various carbon dioxide removal pathways and a "strong complement" to other decarbonization strategies.[19] In California specifically, CCS has the potential to play "a key role" in the removal of unabated carbon emissions, with potential geologic sequestration capacity in the state estimated to be between 35 to 425 gigatons of CO_2e in saline aquifers and 5 gigatons of CO_2e in the largest oil and gas basins.[20] This could provide storage capacity for up to 1,000 years.[21]

CARB itself has acknowledged the essential role that CCS must play in achieving California's ambitious climate goals. In fact, CARB has stated that "there is no path to carbon neutrality without carbon removal and sequestration," as indicated not just by the 2022 Scoping Plan Update but also by the IPCC's Climate Change 2022: Mitigation of Climate Change report.[22] The 2022 Scoping Plan is the main regulatory document governing how CARB will approach progress toward, and the meeting of, the state's ambitious climate aims. Integral to such progress is the development of, and support of, CCS projects—without this tool, carbon neutrality will remain an illusory hope.
365.8 CARB's LCFS Proposed Rules, then, are entirely inconsistent with the state's 2022 Scoping Plan, completely disregarding prior acknowledgement of the absolute necessity of CCS. CARB must return to embracing CCS as an integral part of its strategy to achieve the state's targets.

CCS represents a both foundational building block for meeting California's climate goals and acting as a bridge to support low carbon hydrogen production until sufficient renewable power generation capacity exists to actually allow for large-scale hydrogen production using only renewable electricity. Even if, as CARB has recognized, the transportation sector is headed toward electrification, low carbon hydrogen and CCS will be a key component in any strategy to decarbonize hard-to-abate industries, such as heavy manufacturing (*e.g.*, steel and cement).[23] The role of low-CI hydrogen with CCS as a necessary bridge to 100% renewable-derived hydrogen will be thwarted without the right support under the LCFS.

3. Financial Impacts

Notwithstanding the critical role of low-CI hydrogen with CCS in meeting the state's ambitious climate goals, the Proposed Rules fail to account for the significant financial benefits CCS can provide. For example, it is estimated that the community benefits from direct air capture CCS projects *alone* in Kern County, California, could produce $68 million a year in county property tax revenue, $25 million to surrounding cities, and a total of 23,000 jobs.[24] And, in a study

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[18] *See* Energy Future Initiatives, Standard Precourt Institute for Energy & Stanford Earth, *An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions*, at S-1 (Oct. 2020) [hereinafter "Action Plan"].
[19] *Id.* at S-2.
[20] *See* California Air Resources Board, *Achieving Carbon Neutrality in California,* at 65 (Oct. 2020).
[21] *See* Action Plan at S-6.
[22] California Air Resources Board, *Carbon Sequestration: Carbon Capture, Removal, Utilization, and Storage - About Webpage* (last visited Feb. 12, 2024), http://tinyurl.com/r46r5ucf.
[23] *See* CARB 2022 Scoping Plan, Table 2-1, at 72-79.
[24] *See* Ferrell, Jake, *Carbon Removal in California: Striving Toward Environmental Justice in the Central Valley*, American University Research Center (Dec. 2023).

365.9 from Louisiana State University, the development of a CCS hub in the region was estimated to result in thousands of jobs and several hundred million dollars in potential earnings for workers in the Gulf Coast region over a five-year construction period.[25] However, such financial benefits for state and local governments can only be realized if the right incentives are in place. To that end, CARB should ensure that any final amendments to the LCFS properly incentivize the development of CCS.

365.10 For California to be a leader in the CCS industry, and to capitalize on the substantial financial benefits that CCS can bring, CARB should use the LCFS to incentivize additional low carbon hydrogen production. LCFS credits are critical here.[26] To mitigate against the expenses of production, low carbon hydrogen developers have come to rely on stacking multiple incentives, particularly following the passing of the Inflation Reduction Act in August 2022.[27] For CCS projects, the stacking of incentives relies not only on tax credits but also the LCFS credit.[28] However, by adopting the restrictive approach proposed in the LCFS amendments, CCS projects face undue capital and economic uncertainty, stymying development and, ultimately, the achievement of energy decarbonization goals. Moreover, this unnecessary barrier to market and develop CCS projects will likely result in stranded assets, the very idea of which CARB has strongly rejected in the 2022 Scoping Plan[29] and acknowledged it must avoid in the LCFS Proposed Rules themselves.[30] It is critical that CARB revise its approach to ensure that low carbon hydrogen production is economical and financially viable.

4. Book-and-Claim Accounting and Crediting Opportunities for Low-Carbon Electricity and Hydrogen Production and Direct Air Capture ("DAC")

365.11 CRC also requests that CARB clarify the book-and-claim accounting provisions in the Proposed Rules to allow for LCFS credit generation when low-CI electricity produced from biomethane is then used to support DAC or hydrogen production. As an operator, we would like the ability to receive credits for any quantities of low-CI electricity produced onsite using biomethane feedstocks, but we anticipate these initial projects to be small in scale. As a result, our

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[25] *See* Dismukes, David E., et al., *The Economic Implications of Carbon Capture and Sequestration for the Gulf Coast Economy,* Louisiana State University Center for Energy Studies, at 4 (Mar. 2023).

[26] *See supra* n.15 and n.16.

[27] *See* Hedreen, Siri, *Stacked Tax Credits Make Green Hydrogen Economic for First Time in US*, S&P Global Market Intelligence Webpage (last visited Feb. 12, 2024), http://tinyurl.com/ycxf5se3.

[28] *See* Littlefield, Anna, et al., *Decarbonization of Ethanol: Pathways to Monetization Series Part One: Stacking 45Q with Voluntary Carbon Markets*, Colorado School of Mines: Payne Institute for Public Policy (Dec. 2023); *see also* SCCS Study at 2 ("These [federal] tax credits, combined with Low Carbon Fuel Standard incentives, offer a strong—and urgent—business case for commercial scale blue hydrogen projects in California."); SCCS Study at 42 ("Existing federal and state policies—the 45Q and LCFS—are key in making blue hydrogen more cost-competitive[.]").

[29] *Id*. at 9 "We must avoid making choices that will lead to stranded assets and incorporate new technologies that emerge over time."

[30] With respect to biomethane, CARB acknowledges that, for the fuel to transition to more sectors in the long term, "the existing market signals will need to transition accordingly to avoid stranded assets and the closure of methane capture projects." Initial Statement of Reasons at 30. The same idea is applicable to CCS projects if projects are forced to cease mid-development due to the lack of financial incentives, support and access to capital.

low carbon operations would benefit from the ability to directly offset purchased quantities of biomethane used onsite with the corresponding electricity generation credits. If CARB believes that the Proposed Rules already allow for such a crediting scheme, we request CARB issue a statement confirming that this is a valid approach.

5. Innovative Crude LCFS Credit Proposed Changes

$$Credits_{Innov}(MT) = \cancel{511}314 \times \frac{E_{electricity} \times f_{renew}}{V_{crudeproduced}} \times V_{Innov} \times C$$

Figure 1: Proposed LCFS Credits Equation for Innovative Crude Projects.

The Proposed Rules include a substantial reduction in the credits awarded to innovative crude oil produced or transported using solar or wind-based electricity. As highlighted in **Figure 1**, this reduction stems from a change in the coefficient (*i.e.*, the displacement emission factor) in the equation listed above (replacing "511" with "314") which will reduce awarded credits by approximately 40%. CRC notes that this crediting pathway has resulted in at least seventeen innovative crude oil projects to date across the state. Furthermore, our operating experience has shown that solar electricity production provides one of the best ways as an operator to directly reduce our Scope 2 GHG emissions. Despite these successful emission reductions, CARB's proposed changes to this crediting equation will impact funding investment decisions for projects currently in development. Worse still, operating projects that were financially justified based on the previous crediting equation risk becoming stranded assets if their LCFS credits are taken away.

365.12 We request CARB reverse this proposed change and keep the current displacement emission factor of 511 gCO_2e/kWh. In the alternative, we request that the Proposed Rules be revised to more explicitly state that projects that have already been approved to generate LCFS credits in this manner be allowed to keep using the existing crediting equation with a potential grace period for projects currently under development. Absent these requested revisions, the arbitrary changes to the innovative crude pathway crediting scheme sets a precedent that LCFS credits cannot be relied upon when justifying long-term project investment decisions. In turn, this could impact other LCFS crediting programs—beyond just the innovative crude pathway—by creating hesitation among investors instead of incentivizing new projects and developments to reduce emissions.

Conclusion

As more fully explained above, CRC recommends CARB revisit various of its proposed amendments to the LCFS program with respect to low-CI hydrogen with CCS, in particular. Revisions to the Proposed Rules are necessary to ensure consistency with the 2022 Scoping Plan and, importantly, to recognize the importance of blue hydrogen in meeting the state's ambitious climate goals. To that end, revisions to the definition of the term "renewable hydrogen" are required, alongside the expansion and broadening of LCFS crediting programs and requirements, among others, as detailed above.

CRC appreciates the opportunity to comment on the proposed 2024 LCFS amendments. We thank the Chair and CARB for its consideration and look forward to continued dialogue.

Respectfully submitted,

Chris Gould

Chris Gould
Chief Sustainability Officer
California Resources Corporation

Comment Log Display

Here is the comment you selected to display.

Comment 375 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Michael
Last Name	Wara
Email Address	mwara@stanford.edu
Affiliation	Stanford University
Subject	Comment by Stanford Climate and Energy Policy Program participants
Comment	Thank you for considering this comment, prepared by members of the Climate and Energy Policy Program of the Stanford Woods Institute for the Environment.
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Board Comments Home

Comments of

Michael Wara, JD, PhD,
Michael Mastrandrea, PhD,
Mareldi Ahumada-Paras, PhD,
Anela Arifi,
Chelsea Pardini, PhD,
William Scott, PhD,
and Amanda Zerbe, JD, MS,

Regarding

Proposed Amendments to the California Low Carbon Fuel Standard Regulation

February 20, 2024

Introduction

We write to provide comments on the amendments to the California Low Carbon Fuel Standard (LCFS) regulation proposed by the California Air Resources Board (ARB) in its Initial Statement of Reasons[1] (ISOR). We are research scientists, research scholars, legal fellows, and doctoral students from Stanford University with special expertise in the development of climate and energy policy. Between us, we have more than 75 years of experience in the evaluation and development of energy and climate policy. Some of us have been active participants in ARB processes since the advent of the LCFS as an early action measure in the early days of AB32 implementation.

We write in our personal capacity. None of the views expressed below can or should be attributed in any way to the Climate and Energy Policy Program, the Woods Institute for the Environment, the Doerr School of Sustainability, or Stanford University.

While these comments provide some critiques and suggested changes to the proposed amendments to the LCFS and of the ISOR, we share what we believe to be ARB staffs' core objective of a safe, affordable, equitable, and most of all rapid transition to a zero emission California. We submit these comments as Californians who heartily endorse the ambition of that shared enterprise. We also commend and respect the tremendous time and effort, particularly with stakeholders, that ARB staff has made to generate the ISOR. We hope that our comments will be viewed as constructive and substantive, in alignment with our intent of assisting ARB in achieving that crucial mission.

[1] California Air Resources Board, Public Hearing to Consider the Proposed Amendments to the Low Carbon Fuel Standard, Staff Report: Initial Statement of Reasons, December 19, 2023. *Hereafter, "ISOR".*

Executive Summary

We actively participated in the hearing processes leading up to the release of the ISOR as well as in the Environmental Justice Advisory Committee (EJAC) discussions of the rule. Our work included conducting modeling using earlier versions of the ARB California Transportation Supply (CATS) model, used in the development of the proposed amendments evaluated in the ISOR. Our earlier comments and presentations led directly to improvements in the model to better reflect ongoing trends in the transportation sector as well as new regulations implemented by ARB since its last model update.

Our main comments are as follows, and are described in greater detail in subsequent sections:

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(1) The rulemaking to date suffers from a lack of transparency because ARB staff has declined to release the CATS model input files upon which many of its conclusions are based. While ARB did release GREET modeling, which explains its views of life cycle accounting issues related to the rule amendments, the failure to release input and output files for CATS related to all alternatives considered for the ISOR fundamentally limits stakeholder opportunity to understand, let alone comment on, the proposals under consideration. **We ask that before ARB staff brings the proposal before the Board, that staff release these files and allow an additional round of public comment.**

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(2) As recently stated by Jim Bushnell with respect to the ARB administered cap-and-trade program, the LCFS is entering its "teenage years."[2] This has several important implications – including a greater need to consider distributional impacts as the program matures, as well as the interaction between the cap-and-trade and LCFS programs and lastly, that combination's cumulative impacts. The ISOR does not evaluate this interaction, even though there is a parallel rulemaking in its early phases to significantly strengthen the cap-and-trade targets to 2030. **The impacts of these programs cannot be understood in isolation and ARB needs to evaluate them together to understand both environmental and socioeconomic impacts before the Board should consider votes on proposals to amend either program.**

(3) The transportation sector, in significant part due to ARB's own successful efforts over the past quarter century to facilitate entry of Zero Emission Vehicles (ZEVs) into the California vehicle fleet and to clean up diesel trucks, is in the middle of a rapid transformation. This rulemaking, relying on a relatively simple and deterministic model, proposes to create regulatory targets that will subsidize aspects of the transportation fuels sector, the refining sector, and the agricultural sector for the next 21 years. That process assumes greater certainty about the future than currently, exists, despite the rapidly and unpredictably evolving present context. It

[2] James Bushnell, California's Cap-and-Trade Market Enters its Teen-Age Years, Energy Institute Blog, Energy Institute at Haas, 2023, *at* https://energyathaas.wordpress.com/2023/11/27/californias-cap-and-trade-market-enters-its-teen-age-years/.

evaluates alternatives without any consideration of uncertainty even though ARB's other transportation policies are likely driving and will in the future continue to drive—along with technological innovation—transformative change. We believe that given rates of change in the sector, a more cautious and short-term policy is more
366.3 prudent. **We recommend that ARB adopt a policy that sets incentives until 2035 and then reconsider the regulation in the early 2030s or thereabouts based on the facts at that point.**

366.4 **(4)** There are real questions about the greenhouse gas emissions reductions claimed in the ISOR. Notably:

(a) The interaction with the federal Renewable Fuels Standard (RFS) is critical to understanding the actual impacts (and induced leakage) from this rule, but ARB does not articulate a clear approach for considering them or do so in a transparent manner.

366.5 (b) The failure of the ISOR to cap lipid biofuels and its reliance on outdated indirect land use (ILUC) calculations raises real questions regarding the actual reductions achievable by the ISOR given unprecedented renewable diesel supply growth.

366.6 **We recommend that ARB reevaluate GHG emission reductions and adopt a cap on lipid biofuels at a level that is consistent with the assumptions underlying its current ILUC estimate.**

(5) Criteria pollutant emission reductions associated with the proposed amendments
366.7 are likely overstated, both because (1) ARB relies on an incorrect assumption about the relationship between in-state oil production and in-state fossil diesel consumption and because (2) ARB relies on outdated assumptions about the California medium and heavy-duty fleets. Over the past fifteen years, ARB has moved aggressively to force diesel retrofits with strong emission controls as well as the advent of advanced technology diesel engines that incorporate stringent emission controls. ARB's own science shows that new and retrofit diesel engines fueled by RD and BD as opposed to fossil diesel do not have lower emissions. Yet the rule, relying on older science that focused on older un-retrofitted diesel engines, makes claims that the rule will provide significant criteria pollutant benefits. **ARB staff should correct these assumptions and then recalculate an estimate of the potential criteria pollutant benefits of the different alternatives it has considered.**

(6) Although ARB included a relatively robust distributional analysis in the SRIA, it was
366.8 largely omitted from the ISOR. We believe that, particularly for the proposed amendments to the LCFS—that will increase the degree that gasoline prices are impacted by the LCFS, —a distributional analysis is essential to fully understanding the consequences of the rule for low and moderate-income Californians. The proposed LCFS amendments, through simultaneous increases in credit prices and elevated carbon intensity reductions for fuel suppliers, necessitate a detailed examination of their combined impact. **We recommend that ARB staff revise the ISOR to incorporate a thorough and robust analysis of the effects arising from deeper CI reductions, higher credit prices and the newly proposed Automatic Acceleration Mechanism before presentation to the Board.**

We recognize and appreciate the significant outreach and staff time that has gone into the development of the ISOR. Simultaneously, we believe that the concerns we describe above regarding the current proposal are serious enough to warrant substantial reconsideration of the proposal. A right-sized LCFS amendment is called for: one that reflects the role of the LCFS as an important tool to force innovation in the liquid fuels sector, but also reflects the ability – or lack thereof – to accurately predict the transportation sector's future. We urge staff to recall that the founding idea of the LCFS, as articulated by Alex Farrell of UC Berkeley, was that the program would be an important supplement to cap-and-trade because of the unique and additional barriers to innovation in the fuels sector. We also urge staff and the Board to allocate sufficient time for the consideration of potential impacts and interactions between the LCFS and cap-and-trade programs. Additionally, we recommend conducting a comprehensive analysis of the distributional impacts of both programs as they mature, are updated for scoping plan consistency, and as their ambition deepens over the next decade.

366.1 **I. To Enable Fulsome Review of the Proposed Amendments, CARB Should Provide the Inputs to its CATS Modeling, Consider Extending the Comment Period, and Hold Additional Community Meetings.**

We appreciate CARB's early disclosure of its CATS model for public evaluation of the LCFS. To realize the full benefit of public engagement associated with a public-facing CATS model, we encourage CARB to make the input and output files it relied on in analyzing alternatives for this proposed rule (CATS model data) publicly available. To do so would be particularly useful because much of CARB's analysis of the proposal's impacts in the ISOR relies on CATS model data.[3]

Publicly available CATS model data is essential for the public and commenting experts to fully assess the potential benefits and drawbacks of the preferred alternative and other alternatives. If the input files were publicly available, commenters could also evaluate how different alternatives might shift those benefits and drawbacks and make suggestions for how to optimize the program for public benefit, consistent with ARBs assumptions regarding the baseline evolution of the liquid fuels market in California.

While we recognize that the CATS modeling results do not fully determine the ARB staff proposal as described in the ISOR, they are utilized both to justify the preferred alternative and to rule out other alternatives. These inputs are therefore key to understanding CARB's rationale for its proposal. We emphasize that our earlier analysis of ARB staff CATS modeling led to improvements in the model that contribute to the ISOR.

[3] *See, e.g.,* SRIA at B-1 (table chronicling predicted percentage of future alternative fuels production, within which 3 rows cite CATS model outputs or results under "Notes"). *See also,* discussion of the EJ alternative in the ISOR.

Written communication with ARB staff[4] has indicated that they intend to release nothing more than the V0 sample input file published as a part of the public meeting to describe ARBs improvements to the CATS model (V0.2). The publicly-available CATS input file released on August 16th, 2023, is an example baseline that requires further modifications, such as current producers, market behavior and actual feedstock trends to resolve the model accurately. Without that information, stakeholders will not have a meaningful opportunity to comment on the proposed amendments to the LCFS or the discussion of alternatives in the ISOR.

If ARB were to release these files, all parties to the rulemaking would also require additional time to evaluate and provide comment on the CATS model data – both the input assumptions and the output files for different alternatives. We therefore recommend that ARB release the CATS model data as soon as possible and then provide additional time for parties to comment prior to moving forward with the proposals contained in the ISOR.

II. The LCFS amendment in the ISOR cannot be evaluated without considering its interaction with the Cap-and-Trade Program and likely amendments.

(a) The Waterbed effect needs to be considered.

Notably absent from the list of policies accounted for in the SRIA and ISOR baseline is the California cap-and-trade program. In principle, the California cap-and-trade program acts as a limit on total GHG emissions from regulated sectors in the state, including transportation. When the stringency of the LCFS is increased, any additional emissions reductions from the
366.2 transportation create additional room under the emissions cap that may be filled by other sectors, if the emissions cap level is unchanged. In this way, increasing the stringency of the LCFS will further reduce emissions from transportation within California, but at the same time allow other sectors to emit more under the cap. The net will be unchanged emissions unless leakage occurs (see below).

Accordingly, a more stringent LCFS depresses cap-and-trade program allowance prices and allows emissions in other sectors to replace some of the reductions from the LCFS—reducing the effectiveness of the policy and altering the true emissions reductions it achieves. This has been referred to as the '*waterbed effect*'.[5] Additionally, depressing cap-and-trade program allowance prices contribute to reduced revenue from the cap-and-trade program available for funding California's climate programs through the Greenhouse Gas Reduction Fund. We recommend that ARB staff reevaluate the estimated GHG emission reductions of the proposed amendments to the LCFS, taking into account the interaction with cap-and-trade.

[4] Email communication between Michael Wara and Matt Botill.
[5] Knut Einar Rosendahl, 2019. "**EU ETS and the waterbed effect**," Nature Climate Change, Nature, vol. 9(10), pages 734-735, October.

(b) Leakage caused by the interaction of LCFS and cap-and-trade could be significant.

Further, there is another issue that may cause the increased stringency of the amended LCFS program to contribute to a *net increase in emissions*. Because the cap-and-trade program does not evaluate all upstream emissions associated with biofuel production (such as agriculture emissions from feedstock production or biorefining outside of California), to the extent that the LCFS increases production of biofuels, it will also increase emissions outside of the cap-and-trade program. At the same time, any emissions reductions from gasoline and diesel fuels in California achieved by the LCFS may be offset by increases in other sectors based
366.4 on the waterbed effect (see above).[6] We recommend that ARB staff reevaluate the estimated GHG emission reductions of the proposed amendments to the LCFS, taking into account the potential for leakage effects.

(c) Prices in both emissions programs create impacts that need to be considered jointly.

All this context becomes even more important given the stated objective in the recent scoping plan update of amending the cap-and-trade program to tighten the cap prior to 2030.[7] There have been a number of preliminary workshops in 2023 to evaluate this idea.[8] At the same time, Bushnell et al. were funded by ARB staff to conduct modeling to assess the potential emissions and allowance price impacts of alternatives.[9] Notably, all four scenarios evaluated (other than an end to the program) show that prices will be at the price ceiling of $110 per allowance by 2030. In combination with strengthened 2030 LCFS ambition and the potential for
366.2 multiple triggers of the proposed LCFS Automatic Acceleration Mechanism due to the growth of RD supply,[10] a scenario is likely in which cumulative consumer price impacts could be quite substantial by the late 2020s – amounting to significantly more than $1.50 per gallon of gasoline.

We note that despite considerable efforts by ARB and other state agencies, uptake of EVs has primarily been via high-income Californians to date. This trend is not expected to change radically over the next several years. This means that the burden from combined pass-through of both cap-and-trade allowance prices and LCFS credit prices – both of which will be required inputs to each gallon of liquid fuel – could be substantially higher for low income Californians than evaluated in either program in isolation (see below re distributional effects).

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[6] William Scott, 2024, Cost, Innovation, and Emissions Leakage from Overlapping Climate Policy, SSRN working paper, *at* https://ssrn.com/abstract=4724013.

[7] Air Resources Board, 2022 Scoping Plan for Achieving Carbon Neutrality, pg. 112, *at* https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf.

[8] *See*, https://ww2.arb.ca.gov/our-work/programs/cap-and-trade-program/cap-and-trade-meetings-workshops and staff presentations therein.

[9] *See*, Bushnell, James. "California's Cap-and-Trade Market Enters its Teen-Age Years" *Energy Institute Blog*, UC Berkeley, November 27, 2023, https://energyathaas.wordpress.com/2023/11/27/californias-cap-and-trade-market-enters-its-teen-age-years/.

[10] Colin Murphy and Jim Wook, 2024, Updated Fuel Portfolio Scenario Modeling to Inform 2024 Low Carbon Fuel Standard Rulemaking, Updated Fuel Portfolio Scenario Modeling to Inform 2024 Low Carbon Fuel Standard Rulemaking, *at* https://escholarship.org/uc/item/5wf035p8.

(d) Cap-and-trade prices will likely be high enough in the next few years to incentivize methane reductions at dairies.

One particularly controversial aspect of the proposed amendments to the LCFS presented in the ISOR is the continued reliance on book-and-claim crediting of both in-state and out-of-state dairies until as late as 2040. This has been described by staff and stakeholders as needed to ensure that statutory methane reduction objectives are achieved at a major source of California's methane emissions: large dairies (also termed Confined Animal Feeding Operations, or CAFOs). ARB staff has also stated that they are concerned that eliminating book-and-claim might "strand" investments made at dairies to capture methane from liquid manure holding tanks.

366.8 Estimates of the cost of installing and operating dairy manure methane digesters vary and range from as little as $30/ton to as high as $90/ton. Today, LCFS prices are in the middle of this range – as of this writing, $65/credit. ARB staff has stated concerns that additional digesters will not come online consistent with their goals for the sector if book-and-claim, which critics point out does not consider additionality, is eliminated.

But ARB has also created a second pathway for digesters to access revenue from carbon markets in California – via a compliance grade offset in the cap-and-trade program.[11] Uptake of this opportunity has been limited: both because until very recently, allowance prices in cap-and-trade were below $30, and also because during the same time, credit prices in the LCFS were close to $200. However, ARB's own modelling[12] indicates that by 2030, the most likely outcome for all scenarios considered in cap-and-trade, so long as the program is extended, is that allowance prices will be at the price ceiling – in 2030 equal to $110/ton. If LCFS credits have been sufficient to incentivize methane digester installation, it stands to reason that the much higher allowance and offset price would as well.

The interaction between the LCFS and the CAT is therefore critical in evaluating the emissions impact and affordability of the two programs. Because the current ISOR does not evaluate this crucial policy interaction between California's flagship climate policies, ARB cannot yet fully understand even near-term impacts from the ISOR. We recommend that ARB conduct an analysis of the joint impacts of proposed amendments to the LCFS and cap-and-trade and revise the ISOR to reflect these results.

366.3 **III. ARB should limit the duration of proposed amendments and the incentives they create to balance the need for project certainty with the deep uncertainties regarding the future of the liquid fuels sector—10 years is long enough.**

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[11] *See*, Air Resources Board, Livestock Projects, *at* https://ww2.arb.ca.gov/our-work/programs/compliance-offset-program/compliance-offset-protocols/livestock-projects

[12] *See*, Bushnell, James. "California's Cap-and-Trade Market Enters its Teen-Age Years" *Energy Institute Blog*, UC Berkeley, November 27, 2023, https://energyathaas.wordpress.com/2023/11/27/californias-cap-and-trade-market-enters-its-teen-age-years/

Amendments to the LCFS proposed in this rulemaking would set a trajectory to the year 2045 for subsidies directed towards CAFOs, refineries, and other low-carbon fuel producers. In public meetings related to the scoping plan, ARB staff have repeatedly articulated concerns about the need to create long-term certainty so that investments in lipid biofuel, hydrogen, and methane digesters can secure finance based on the LCFS. This is a valid concern.

However, that concern needs to be balanced in the present rulemaking against the real uncertainty associated with the ongoing transition in the transportation sector – in significant part due to ARBs ambitious rulemakings related to light, medium, and heavy-duty vehicles. Last year, in the light duty segment, ZEVs accounted for more than 25% of new vehicle sales, up almost 6% from 2022.[13] While there will no doubt be challenges in a full transition to ZEVs in all three weight classes, the transition is rapidly picking up steam. This is even more true in light of the fact that since the pandemic, essentially all the growth in global light duty vehicle sales has come from ZEVs. California, and in particular ARB, deserves tremendous credit for this success.

366.3 The future for medium and heavy-duty ZEV technology is much less certain, however. It may be that the challenges of electrifying these fleets are overcome through a combination of innovation and smart policy support. It may also be that some or even a large fraction of these vehicles continues to rely on either liquid (RD and BD) or gaseous fuels (for example green or blue hydrogen). Despite what ARB staff CATS modelling in the ISOR and the recent 2022 Scoping Plan Update seems to indicate, how this transition will play out is fundamentally uncertain at this point – even for the early 2030s.

The idea that we know enough now to accurately predict its trajectory all the way to 2045 is simply not credible at this time. Yet the rulemaking under consideration today would lock in a variety of large subsidies for particular technologies that, given what it knows now, ARB thinks may be important for the transition to zero emissions fleets or for its agricultural methane reduction goals. And these subsidies are being offered to extremely powerful industries in California. Once offered, they will be exceedingly difficult—both from a practical and a political perspective—to pull them back as circumstances evolve.

In the past, most recently in 2018, ARB has not tried to regulate decarbonization of the liquid fuels sector using the LCFS for much longer than a decade. We recommend that ARB stay consistent with this precedent here, and limit amendments it makes today to the next decade – through 2035. A ten-year time horizon recognizes ARB's concerns today in creating sufficient certainty to allow for project finance, but also balances that concern against the tremendous uncertainty that rapid technological innovation and adoption creates for the LCFS.

That does not mean that in a future rulemaking – conducted in the early 2030s, perhaps – ARB would not act to extend incentives that they see as essential to their policy goals at that

[13] *See,* California Energy Commission, New ZEV Sales in California, *at* https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics/new-zev-sales.

time. It means only that by acting today, the agency will preserve its freedom of movement and future responsiveness to the uncertain but rapid evolution in transportation technologies.

IV. ARB's assessment of the GHG emissions impacts of the rule are almost certainly overstated and need to be reevaluated.

We perceive several issues with ARB's calculation of GHG emission reduction benefits of the proposed LCFS amendments against which costs must be judged. Quantification of GHG emission benefits is especially important for the LCFS since that is the basic justification for the policy's existence.

Below, we discuss two issues that merit substantial reanalysis or correction in the GHG emission benefits:

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(1) Transparency regarding the interaction of the LCFS proposed amendments with the federal Renewable Fuels Standard (RFS);
(2) the implications of the massive growth in RD supply for indirect land use change (ILUC) emissions.

366.4

(a) Contrary to ARB's prior practice, the ISOR is unclear on how the RFS is accounted for and appears to claim credit for emission reductions caused by the RFS. It also does not account for resource shuffling caused by the RFS and LCFS interaction. ARB should be transparent about how it accounts for this interaction if in fact that has changed since the 2018 LCFS amendments.

In prior amendments to the LCFS (again, most recently in 2018) ARB acknowledged that the RFS had significant impacts on RD and BD consumption in California. It also assumed that the best approach for estimating the benefits of the LCFS was to develop a baseline volume and carbon intensity that the RFS would produce, and then assume that the additional stringency of the LCFS would produce GHG benefits incremental to that RFS baseline. In the present rulemaking, ARB is not transparent regarding its approach and may have abandoned this approach in favor of neglecting impacts of the RFS and claiming all GHG benefits for the LCFS.

The SRIA indicates that impacts of the amendments to the LCFS account for the role of the RFS in the baseline[14] However, no additional detail is provided to indicate how this is reflected in ARB's estimates, and how contributions from the RFS change under the proposed alterations to the LCFS. The SRIA states that GHG emissions are derived from "CATS outputs of the fuel quantities and average annual CI associated with each fuel."[15] Importantly, the impacts of the RFS are not static and change in response to alterations to California's LCFS. It is not clear if and how exactly these dynamics are accounted for in the present rulemaking.

[14] SRIA at 12.
[15] *Id.* at 25.

The federal RFS sets a nation-wide volumetric mandate for biofuels and allows flexibility for where those biofuels are produced and consumed. An additional unit of biofuel consumed in California counts equally toward compliance with the federal RFS as one consumed elsewhere in the country. Therefore, when the stringency of the LCFS is increased, greater biofuel consumption in California reduces the amount required to be consumed by other states, effectively offsetting some of the emissions benefit. This dynamic is critical to incorporate into the design and evaluation of the LCFS.

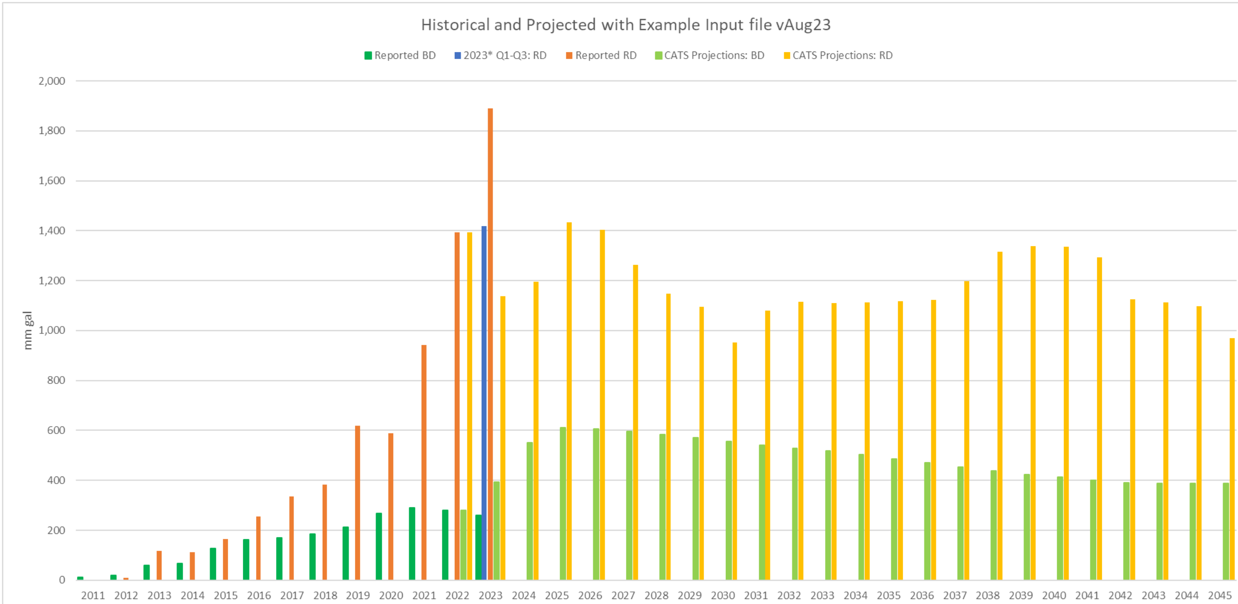
366.4 The attribution approach, from the 2018 rulemaking in Appendix F Table F-12 at page 12, suggests that only emissions reductions below the thresholds set by the federal RFS should be attributed to the LCFS. For instance, all emissions reductions from bio-based diesel fuels down to a carbon intensity of 50g/MJ are attributed to the RFS, while only emissions reductions below the 50g/MJ threshold are attributed to the LCFS. For example, an additional gallon of bio-based diesel at 40g/MJ could be said to contribute an additional 10g/MJ of emissions reduction from what would have occurred under the RFS alone.

This provides a simplistic but defensible approach that should be taken and explicitly outlined in this rulemaking. However, attributing all emissions reductions from the diesel standard to the carbon intensity of BD or RD overstates the role of the LCFS, and would contribute to misleading conclusions in evaluating the impact and cost-effectiveness of the policy.

In sum, more transparent discussion of ARBs approach to accounting for the interactions between the LCFS and RFS is required to assess how ARB accounts for emission reductions. Otherwise, the possibility cannot be ruled out that ARB has overstated the emissions contribution of the revisions to the LCFS program.

366.5 **(b) The ISOR does not consider the rapid increase in RD supply that has already occurred and which is projected to occur in the next few years. This rapid growth in supply throws into question the relatively low estimates of ILUC emissions that were developed a decade ago for the LCFS.**

In early workshops associated with the development of this amendment package, ARB staff indicated concern about the growth of crop-based biofuels in the RD supply. This growth has continued to far outstrip expectations. Shown below are comparisons of actual BD and RD supply to LCFS markets as compared to CATS estimates of their supply. Evidently, the data model fit is strong for 2022, but 2023 data significantly exceeds model projections for any time to 2045. Meanwhile, two biofuel conversions underway in Martinez, with refineries set to come online in 2024, have the potential to add 1.7 billion gallons of RD to the LCFS supply, roughly doubling supplies of liquid biofuels in the near term.



Historically, RD has been predominantly sourced from used cooking oil and other byproducts that do not impact global crop markets. Corn ethanol has long been known to interact with global commodity markets and through that, land use decisions. For that reason, in 2015, ARB incorporated Indirect Land Use Change (ILUC) emissions into its CI life cycle accounting. The ILUC estimates that were included for crop-based biofuels were based on a perturbation scaled to US biofuel consumption at that time.

Today's RD growth has far outstripped that assumption and calls into question the
validity of the ILUC calculation that relies upon it. Recently, US EPA surveyed ILUC estimates
from a variety of sources – finding a range of 11 to 260 CO2e/MJ.[16] ARB's current ILUC value, 29
CO2e/MJ, is in the very low range of these estimates. This fact, combined with the age and
366.5 outdated assumptions that underpin this value, suggests that the ILUC estimate used to
calculate CI for crop-based biofuels is too low – and perhaps significantly too low. This in turn
will lead to overestimation of emissions reductions associated with the massive growth of RD in
the fuel mix in California, by claiming benefits while causing harm elsewhere as forests are cut
and peatlands are converted to support oil seed agriculture. We recommend that either ARB
366.9 pause this rulemaking until ILUC values that reflect the possible scope and scale of RD supply
coming to market can be developed, or incorporate a lipid-based biofuels cap consistent with
its current ILUC calculation into the proposed LCFS amendments.

366.7 **V. Criteria pollutant emissions benefits of the proposed LCFS amendments are likely overestimated by the ISOR in two different ways.**

[16] US EPA, "Model Comparison Exercise Technical Document" (EPA-420-R-23-017, 2023); https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P1017P9B.pdf.

The ISOR provides a detailed assessment of the criteria pollutant benefits of the proposed LCFS amendments. We have concluded that the analysis is flawed in at least two ways. Both lead to substantial overestimation of criteria pollutant benefits.

(a) The ISOR assumes criteria pollutant benefits from older diesel trucks, but ARB's own science shows that those benefits do not exist for newer diesel trucks which now predominate in the sector.

The SRIA's analysis of particulate matter benefits includes the following explanation:

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> PM emissions changes for biodiesel relative to conventional diesel were based on testing using pre- 2007 engines without diesel filters. CARB (2015) indicates that, for 2007 and later engines equipped with PM filters, there were no meaningful differences in PM emissions between conventional diesel and biodiesel. However, Durbin et al. (2011) indicates that PM emissions for these engines were essentially at the limit of detection, and the level of efficiency of the diesel particulate factor would have masked any fuel differences. *For these reasons, staff believes that PM emissions changes for biodiesel use in pre-2007 engines without diesel particulate filters relative to conventional diesel use was also applicable to 2007 and later engines with diesel filters*.[17]

As we understand this language, ARB's analysis assumed that as post-2007 engines with diesel filters shifted to biodiesel from the reference fuel, $PM_{2.5}$ emissions would decline to a similar extent as they did when pre-2007 engines switched fuels. However, more recent work – prepared by the same author for ARB in 2021 – found no statistical difference between $PM_{2.5}$ emissions from biodiesel and ARB's reference fuel for post-2007 engines.[18]

We recommend that ARB integrate the best currently available science on the impact of newer diesel engines into its analysis of criteria pollutant benefits of the proposed LCFS amendments. In doing so, ARB should rely on its own pre-existing quantification of the fraction of the on-road diesel fleet today that lack emission controls relative to the fraction that has both selective catalytic reduction and diesel particulate filters.[19] ARB should then ascribe benefits for older diesel engines consistent with the analysis in the ISOR while ascribing a much lower or negligible criteria pollutant benefit to newer advanced diesel engines or retrofitted engines. On net, we believe that this change will significantly reduce the benefit of RD and so reduce the loss of benefits from RD associated with a cap on liquid biofuels.

[17] SRIA at B-10 n.119 (emphasis added).
[18] Thomas D. Durbin *et al.*, Final Report: Low Emission Diesel (LED) Study: Biodiesel and Renewable Diesel Emissions in Legacy and New Technology Diesel Engines, xviii-xix (Nov. 2021), https://ww2.arb.ca.gov/sites/default/files/2021-12/Low_Emission_Diesel_Study_Final_Report_12-29-21.pdf.
[19] *See*, Air Resources Board, Sunset Estimation for Biodiesel In-Use Requirements, *at* https://ww2.arb.ca.gov/resources/documents/sunset-estimation-biodiesel-in-use-requirements#footnote1_1yzdw61.

(b) The ISOR assumes that reductions in fossil fuel demand caused by the LCFS will result in equal reductions in oil production in California. This is incorrect.

366.7 In its SRIA, ARB makes an assumption that incorrectly inflates the air pollution benefits associated with the proposed rule from the upstream oil and gas sector. ARB's "Assumption 1" is that "[o]il extraction operations in California decline at the same rate that demand for petroleum products declines."[20] While such a relationship is theoretically possible, there is also substantial evidence that suggests that these dynamics may be more complex than assumed in the SRIA.

California's production of crude oil has been declining for several decades, whereas diesel demand in California has stayed relatively stable over the last 40 years.[21] And even if the two figures are related, the rate of decline may be different for crude oil production than for diesel demand, particularly in light of the many other factors that may influence both oil extraction and demand – including out of state activities and actors.[22] In particular, the most important factors influencing oil demand in California are the cost to extract California's remaining crude oil resources and the global oil price. Given favorable market conditions, there is no reason to think that crudes from California will not be exported. Given the prevailing conditions, extraction is likely to continue its seemingly inexorable decline, whatever the design of the LCFS. We recommend that ARB eliminate its reliance on this assumption in evaluating the benefits of the proposed LCFS amendments and reduce the criteria pollutant benefits accordingly.[23]

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[20] SRIA at B-1; *see also id.* ("It is reasonable to expect that the crude oil extracted in California may ramp down in tandem with declining demand for finished petroleum products.").

[21] *Contrast* Figure 1 *with* Figure 2 *infra*.

[22] *See, e.g.,* Figure 3, *infra* (portraying California imports of diesel over time, including an increasing proportion of foreign imports).

[23] Moreover, while the ISOR states that the reduction in demand associated with the COVID-19 pandemic appears to have reduced emissions associated with oil and gas extraction, there are several reasons that such a relationship may not carry over to this context. ISOR at 56. First, the pandemic constituted a comparatively limited window of time; the longer trends of state diesel consumption and California oil extraction displayed in Figures 1 and 2 below suggest the opposite (or no) relationship between those two numbers. Second, because the COVID19 pandemic was a global phenomenon, out-of-state actors may have been acting in parallel with California actors. Because the LCFS applies to diesel use in California rather than diesel use in other states, that coordination would not apply here.

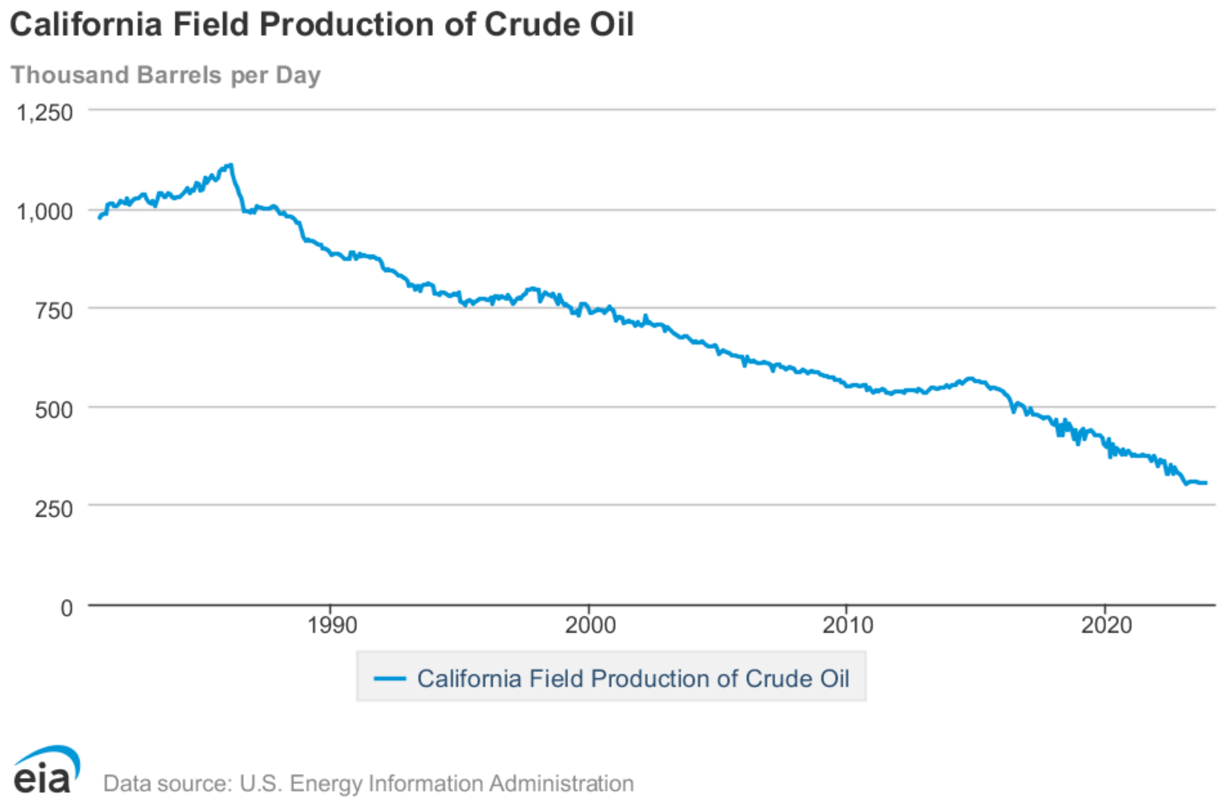

Figure 1. California's production of crude oil over time.[24]

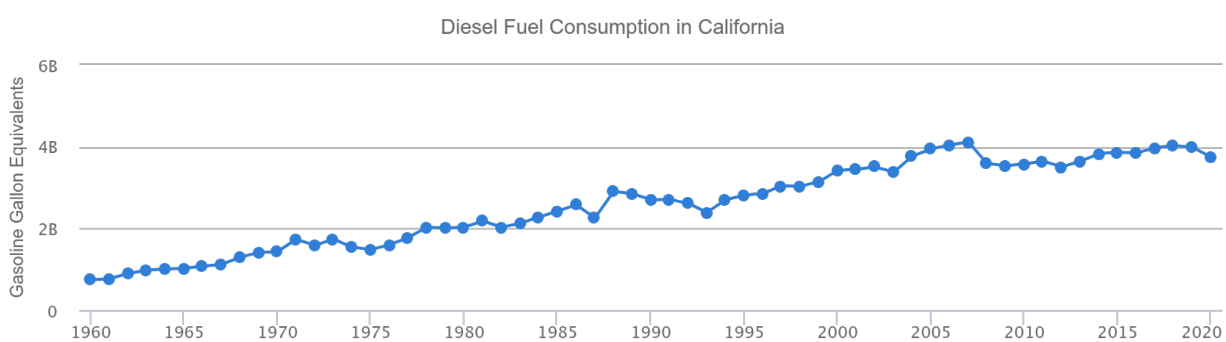

Figure 2. Diesel fuel consumption in California over time.[25]

[24] U.S. Energy Information Administration, *Petroleum and Other Liquids: California Field Production of Crude Oil* (Jan. 31, 2024), https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRFPCA2&f=M.
[25] U.S. Dep't. of Energy, *Alternative Fuels Data Center – California Transportation Data for Alternative Fuels and Vehicles* (last accessed Feb. 19, 2024), https://afdc.energy.gov/states/ca.

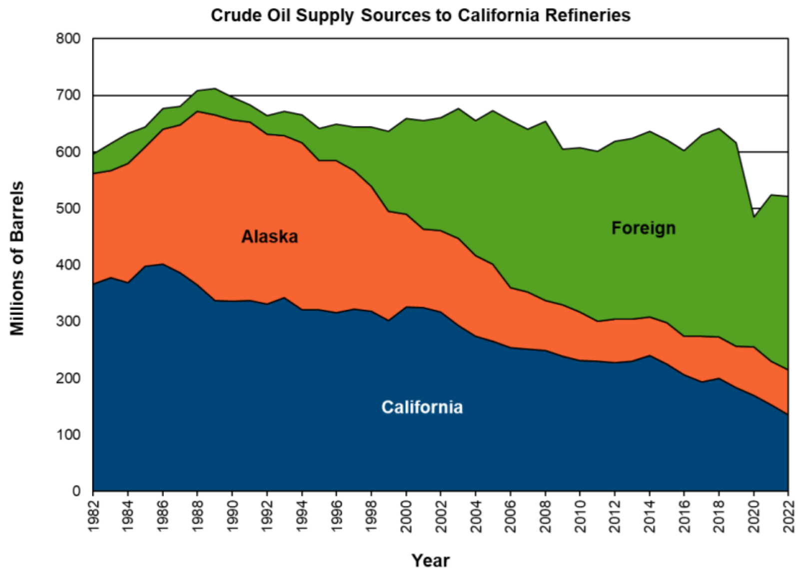

Figure 3. Crude oil supply sources to California refineries over time.[26]

VI. ARB needs to develop a thorough distributional analysis of the likely impacts of the proposed amendments because they are particularly likely to have disproportionate impacts on low-income Californians.

366.8 Though ARB staff included a discussion of expected distributional effects in the Supplementary Regulatory Impact Analysis (SRIA) for the proposed amendments to the LCFS, it omitted the qualitative distributional analysis from the ISOR – a widely-circulated and relied-upon document for decisionmakers. The ISOR should, at a minimum, contain a robust discussion of expected distributional effects. To do so is essential, and aligns with the purpose of ISOR documents—to provide comprehensive and accessible information about proposed regulations. Moreover, clarity about distributional consequences improves the regulatory process for decisionmakers and the public. An improved and transparent understanding of these consequences will support CARB in its pursuit of environmental justice.

At minimum, the ISOR should incorporate a qualitative distributional analysis because a key function of the ISOR is to provide comprehensive and accessible information about proposed regulations – including explanations and justifications – to the public and decisionmakers. For the ISOR to be accessible and comprehensive, it must transparently discuss relevant information. Information about the distribution of effects is particularly relevant for the proposed amendments to the LCFS because, as discussed in the SRIA, low-income, disadvantaged, and rural communities may bear a disproportionate share of the costs of the

[26] Cal. Energy Comm'n, *Annual Oil Supply Sources to California Refineries* (last accessed Feb. 19, 2024), https://www.energy.ca.gov/data-reports/energy-almanac/californias-petroleum-market/annual-oil-supply-sources-california.

amendments.[27]

Information about distributional effects of the proposed amendments is also relevant because any social welfare analysis – which is commonly used to justify proposed regulation – should, at a minimum, contain a discussion of likely distributional effects.[28] Social welfare analysis without distributional analysis clouds the understanding of the possible consequences of proposed and alternative regulations for the public and decisionmakers. For example, if a report only contains information about aggregate effects, it could obscure that a historically marginalized group will be uniquely burdened by the costs of a rule. A clear discussion about this in the ISOR makes essential information accessible to the public and decisionmakers.

Moreover, the ISOR should include a distributional analysis because clarity about the possible distribution of effects is beneficial to the regulatory process. To begin, clarity about the full distributional consequences of a proposal allows regulators to evaluate their normative choices. For example, a clear distributional analysis that discusses a likelihood that the proposed amendments will increase the financial burden for low-income, disadvantaged, and rural communities while alleviating their pollution exposure reveals a regulatory choice to prioritize alleviating environmental burdens. (A normative statement that aligns with this choice could be "ARB should prioritize ameliorating pollution exposure").

This transparency about expected consequences also allows regulators to more precisely identify action needed to alleviate inequitable social outcomes. For example, if the expected financial cost to low-income, disadvantaged, and rural communities is estimated to be overly burdensome, then decisionmakers can better prepare to provide material support to these communities.

Moreover, including a clear distributional analysis in the ISOR can provide an accountability mechanism for regulators with the public. For example, if ARB clearly communicates to the public that low-income, disadvantaged, and rural communities may be financially burdened, then the public can advocate for alternatives that avoid this consequence or for remedies to address it.

Finally, the clarity and additional benefits for the regulatory process associated with including a distributional analysis in the ISOR also support the pursuit of environmental justice – a core aspiration of ARB.[29] Environmental justice is defined in state law, which identifies meaningful engagement with the public as central to the pursuit of environmental justice.[30]

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[27] SRIA at 60.
[28] *See* Office of Management and Budget, 2023, Circular A-4, Part 10, *at* https://www.whitehouse.gov/wp-content/uploads/2023/11/CircularA-4.pdf
[29] ISOR at 64.
[30] *See id.* (citing Gov. Code § 65040.12, subd. (e)(1), which states that "[a]t a minimum, [environmental justice includes] the meaningful consideration of recommendations from populations and communities most impacted by pollution into land use decisions.")

Clear communication of the consequences of regulation is necessary for achieving that meaningful engagement.

This inclusive approach also ensures transparency about the full spectrum of expected consequences, facilitates informed decisionmaking and fosters meaningful public engagement. By incorporating distributional analysis into the ISOR, ARB can demonstrate its commitment to equitable regulatory practices and contribute to a more informed and participatory rulemaking process.

In summary, we recommend that ARB staff revise the ISOR to include distributional analysis because distributional analysis aligns with the goals of providing comprehensive and accessible information, improving the regulatory process for decisionmakers and the public, and pursuing environmental justice.

Comment Log Display

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Comment 376 for Proposed Low Carbon Fuel Standard Amendments (lcfs2024) - 45 Day.

First Name	Robert
Last Name	Parkhurst
Email Address	rparkhurst@sierraviewsolutions.com
Affiliation	
Subject	LCFS Coalition on Climate Smart Agriculture - UPDATED
Comment	Please see the attached comments from 19 companies on the inclusi of climate smart agriculture practices in a future LCFS rulemaking. Please replace the letter submitted earlier today.
Attachment	www.arb.ca.gov/lists/com-attach/7059-lcfs2024-BWkAZVQzUHABWARn.pdf
Original File Name	LCFS coalition on CSA FIXED.pdf
Date and Time Comment Was Submitted	2024-02-20 20:27:07

If you have any questions or comments please contact Clerk of the Board at (916) 322-5594.

Board Comments Home

February 20, 2024

The Honorable Liane M. Randolph, Chair
California Air Resources Board
1001 I Street
Sacramento, CA 95814

RE: 2024 Low Carbon Fuel Standard Amendments

Dear Chair Randolph:

The signatories of this letter appreciate the opportunity to provide comments regarding the 2024 amendments to the Low Carbon Fuel Standard (LCFS). We strongly support the increased focus by the California Air Resources Board (CARB) on ensuring that the fuels used in the LCFS program are produced in the most sustainable manner. We are strong advocates for rigorous lifecycle accounting (LCA) methods that precisely quantify the lifecycle emissions from biofuels and that recognize and incentivize lower carbon feedstocks. From a LCA perspective, "corn is not just corn." To the contrary, corn and other crops can be grown on soil using a wide variety of techniques and inputs that substantially impact real-world carbon intensity (CI). We encourage the Board to direct staff to dedicate time and resources to analyze the lifecycle issues pertaining to crop-based feedstocks and report back to the Governing Board. This focused research, analysis, and reporting by CARB staff will enable and inform potential expansions to the LCFS regulations to include field-based practices, the recognition of soil organic carbon, and the harnessing of other CI-reducing techniques and technologies with the next update to the LCFS regulations.

The supporters of this letter represent a range of fuels, feedstocks, and technologies including agriculture trade associations, crop input companies, developers of LCFS credits, and other low-carbon fuel industry participants. This diverse group is united in its interest to provide high-quality fuels to the California transportation market with the lowest environmental footprint. This includes practices that encourage producers to reduce nitrous oxide and methane emissions and increase the carbon sequestered in the soil.

In 2018, the Intergovernmental Panel on Climate Change (IPCC) published a Special Report on the impacts of a 1.5°C global warming above pre-industrial levels. This report found that achieving global carbon neutrality by mid-century is critical to avoiding the most catastrophic impacts of climate change.[1] Moreover, the IPCC Sixth Assessment identified land-based emissions mitigation as "the only [sector] in

[1] IPCC, 2018: Summary for Policymakers. In: Global Warming of 1.5°C. An IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels and related global greenhouse gas emission pathways, in the context of strengthening the global response to the threat of climate change, sustainable development, and efforts to eradicate poverty [Masson-Delmotte, V., P. Zhai, H.-O. Pörtner, D. Roberts, J. Skea, P.R. Shukla, A. Pirani, W. Moufouma-Okia, C. Péan, R. Pidcock, S. Connors, J.B.R. Matthews, Y. Chen, X. Zhou, M.I. Gomis, E. Lonnoy, T. Maycock, M. Tignor, and T. Waterfield (eds.)]. Cambridge University Press, Cambridge, UK and New York, NY, USA, pp. 3-24, doi:10.1017/9781009157940.001.

which large-scale carbon dioxide removal may currently and short term be possible" and that it is "crucial to limit climate change and its impacts."[2] The latest science finds that it is increasingly likely that the 1.5°C target will be exceeded[3] and that large-scale greenhouse gas (GHG) reductions are critical to meeting the target.[4]

Already a leader in the response to climate change, CARB's 2022 Scoping Plan Update details sector-by-sector roadmaps for California to achieve carbon neutrality by 2045 or earlier. One critical roadmap is for the aviation sector, where the scenario includes a transition of 20% of aviation fuel demand to zero-emission technologies by 2045 and sustainable aviation fuel (SAF) for the rest.[5]

The agriculture sector can play a significant role in helping California meet the goal of generating SAF. Practices including optimizing fertilizer application, reducing tillage, using enhanced-efficiency fertilizers, double-cropping and planting cover crops have the potential to reduce the CI of fuels by more than 40 g CO_2e/MJ.[6] These practices are not limited to their GHG benefits; they provide "additional ecosystem service benefits, including watershed protection, increased biodiversity, and improved soil health and fertility."[7]

There is significant opportunity to increase the adoption of these practices on U.S. farmland. A recent study found that no-till or strip-till is practiced on only 30% of cropland.[8] Furthermore, these practices are not always maintained by farmers. While no-till practices were adopted on almost 8 million acres between 2012 and 2017, farmers on more than 5 million acres discontinued no-till during the same period for a net gain of only 3 million acres.[9] Another practice that can reduce GHG emissions, the planting and cultivation of cover crops, has an even lower adoption rate than no-till. Unfortunately, only 5.1% of the approximately 300 million cropland acres planted cover crops in 2017.[10] The LCFS program has the potential to provide a strong and long-term incentive for farmers to implement no-till, cover crops, double-cropping and other similar practices.

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[2] Nabuurs, G-J., R. Mrabet, A. Abu Hatab, M. Bustamante, H. Clark, P. Havlík, J. House, C. Mbow, K.N. Ninan, A. Popp, S. Roe, B. Sohngen, S. Towprayoon, 2022: Agriculture, Forestry and Other Land Uses (AFOLU). In IPCC, 2022: Climate Change 2022: Mitigation of Climate Change. Contribution of Working Group III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change[P.R. Shukla, J. Skea, R. Slade, A. Al Khourdajie, R. van Diemen, D. McCollum, M. Pathak, S. Some, P. Vyas, R. Fradera, M. Belkacemi, A. Hasija, G. Lisboa, S. Luz, J. Malley, (eds.)]. Cambridge University Press, Cambridge, UK and New York, NY, USA. doi: 10.1017/9781009157926.009
[3] Mathews, D.H., Wynes, S. (2022) Current global efforts are insufficient to limit warming to 1.5°C. *Science* 376 (6600) 1404-1409. https://www.science.org/doi/10.1126/science.abo3378
[4] Mace, M.J., Fyson, C.L., Schaeffer, M., Hare, W.L. (2021) Large-Scale Carbon Dioxide Removal to Meet the 1.5°C Limit: Key Governance Gaps, Challenges and Priority Responses. *Global Policy* 12 (51) 67-81. https://doi.org/10.1111/1758-5899.12921
[5] CARB (2022) 2022 Scoping Plan for Achieving Carbon Neutrality. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf
[6] Liu, X. et. al. (2020) Shifting agricultural practices to produce sustainable, low carbon intensity feedstocks for biofuel production. *Environ. Res. Lett.* https://doi.org/10.1088/1748-9326/ab794e
[7] *ibid*.
[8] Pannell, D. J., & Claassen, R. (2020). The Roles of Adoption and Behavior Change. *Applied Economic Perspectives and Policy* 42 (1) 31–41.
[9] Sawadgo, W., & Plastina, A. (2022). The Invisible Elephant: Disadoption of Conservation Practices in the United States. *Choices* 37(1) 1–13.
[10] Wallender, S., Smith, D., Bowman, M., & Claassen, R. (2021). Cover Crop Trends, Programs, and Practices in the United States. https://www.ers.usda.gov/publications/pub-details/?pubid=100550

367.1 CARB is also proposing that all crop-based feedstock used for LCFS fuel pathways must obtain third-party sustainability certification by January 1, 2028, under an approved certification system. These certification systems "must consider environmental, social, and economic criteria," an expansive list that is likely to place a significant financial burden and obligations on farmers that elect to continue to supply feedstocks for biofuels production. Given the broadness of these requirements and the significant additional administrative burden this will impose on farmers and the producers who buy from them, we urge CARB staff to clarify the specific environment, social and governance ("ESG") criteria that these certifications are meant to address in the context of crop-based feedstocks and to seek further stakeholder feedback on development of these criteria after this rulemaking. This requirement is consistent with the verification of land use under the EU Renewable Energy Directive (RED). Under international polices such as RED, CORSIA, and RenovaBio, fuel producers are required to collect farm level data and are thus able to benefit from improved farming practices.

367.2 CARB should also provide a 3-year grace period for any certification system that it plans to suspend or remove, to give stakeholders sufficient time to get certified under a different certification system.

367.3 Additionally, sustainability certifications that address these ESG criteria will often also include a rigorous GHG accounting for feedstock CI calculation. For example, both the Roundtable for Sustainable Biomaterials (RSB) and the International Sustainability & Carbon Certification (ISCC) are existing sustainability certification systems that may meet the requirements outlined in Section 95488.9(g); both systems have already developed GHG methodologies for feedstock CI calculation.[11,12] If CARB requires farms to go through the rigorous process of third-party sustainability certification, then we respectfully request that CARB also consider accepting a feedstock CI score that is calculated and verified in accordance with certification system standards. This would provide a mechanism to compensate farmers adopting climate smart practices for the additional work of certification. Specifically, we ask the Board to direct staff to evaluate existing GHG calculation methodologies and develop guidance around feedstock CI calculation.

367.4 We are asking the Board to direct staff to investigate how the agriculture sector can be optimized to produce low-carbon biofuels to meet the state's SAF goal. Specifically, we are requesting the Board to prioritize policy discussions and the associated technical analysis related to low-carbon feedstocks for the production of SAF. This technical analysis should include a thorough lifecycle analysis to determine the extent to which supplies of sustainable biofuels produced from various feedstocks can be expanded while not converting additional land to agricultural uses. This technical analysis should be informed by the other primary LCA methodologies including Argonne GREET. To ensure the timely analysis of this information, we request that the Board direct staff to report back to the Board by the end of 2025 on the results of lifecycle analysis and progress toward developing policies to encourage the production of SAF.

For the foreseeable future, liquid fuels will be required to power the majority of airflight thus necessitating a rapid expansion in the supply of SAF. In order to create demand for the fuels with the lowest actual CI possible, ARB needs to account for and incentivize field-based practices. Fortunately, the

[11] RSB GHG Calculation Methodology v2.3 (2017). https://rsb.org/wp-content/uploads/2020/06/RSB-STD-01-003-01-RSB-GHG-Calculation-Methodology-v2.3.pdf
[12] ISCC EU 205 Greenhouse Gas Emissions (2021). https://www.iscc-system.org/wp-content/uploads/2022/05/ISCC_EU_205_Greenhouse-Gas-Emissions-v4.0.pdf

benefits of these sustainable agricultural practices go beyond their GHG savings, positively impacting our water, ecosystems, and soils.

CARB has been an international leader in developing and implementing programs to reduce GHG emissions across the California economy and the inclusion of climate smart agricultural practices will continue the State's leadership throughout the country. We thank CARB for this opportunity to offer these comments and look forward to continued collaboration to implement policies and strategies that further reduce emissions from the transportation sector.

Sincerely,